ONGC AHMEDABAD ASSET

<u>SUMMER TRAINING REPORT</u>

Under the guidance of
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Submitted by:
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ACKNOWLEDGEMENT

The summer internship opportunity I had with ONGC Ahmedabad Asset was a great chance of learning and professional development. I will strive to use the gained skills and knowledge in the best possible way, and will continue to work on their improvement, in order to attain desired career objectives.

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On behalf of my college, I express sincere gratitude towards ONGC for giving us an opportunity to pursue our summer internship in such a renowned organization.

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Sincerely,

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1. Brief about ONGC

ONGC was set up under the visionary leadership of Pandit Jawaharlal Nehru, going against the wisdom of the then multinational oil companies operating in the country, who had almost written India off as a "Hydrocarbon Barren" country. Pandit Nehru reposed faith in Shri Keshav Dev Malviya who laid the foundation of ONGC in the form of the oil and Gas division, under the Geological Survey of India, in 1955. After a few months, it was converted into an Oil and Natural Gas Directorate. The Directorate was converted into Commission and christened Oil & Natural Gas Commission on 14th August 1956. In 1994, Oil & Natural Gas Commission was converted into a corporation, and in 1997 it was recognized as one of the Navratnas by the Government of India. Subsequently, it was conferred Maharatna status in the year 2010.

Over 50 years of its existence ONGC has crossed many milestones to realize the energy dreams of India. ONGC superlative efforts have resulted in converting earlier frontier areas into new hydrocarbon provinces. From a modest beginning, ONGC has grown to be one of the largest E&P companies in the world in terms of reserves and production.

ONGC as an integrated Oil & Gas Corporate has developed in-house capability in all aspects of exploration and production business i.e. Acquisition, Processing & Interpretation (API) of Seismic data, drilling, workover and well stimulation operations, engineering & construction, production, processing, refining, transportation, marketing, applied R&D and training, etc.

Today, ONGC is the leader in Exploration & Production (E&P) activities in India having a 72% contribution to India's total production of crude oil and 48% of natural gas. ONGC has established more than 7 Billion Tonnes of in-place hydrocarbon reserves in the country. In fact, six out of seven producing basins in India have been discovered by ONGC. ONGC produces more than 1.27 Barrels of Oil Equivalent (BOE) per day. It also contributes over three million tonnes per annum of the Value-added-products including LPG, C2-C3, Naptha, MS, HSD, Aviation Fuel, SKO, etc.

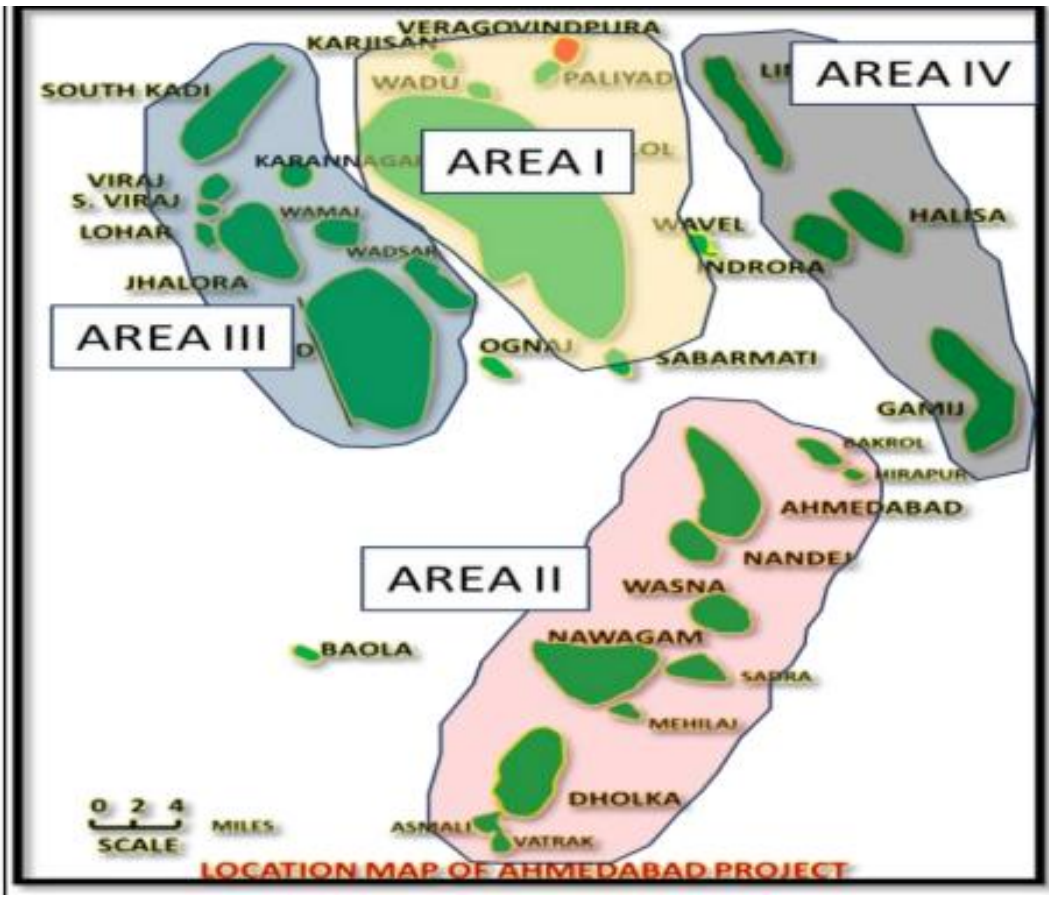
2. Ahmedabad Asset

2.1 History

Ahmedabad Asset as a virtual Corporate runs as an independent business unit headed by Executive Director reporting to Director (Onshore). Ahmedabad Asset operates over an area of over 6200 sq km in four districts of Gujarat. The Asset has a distinguished record of following eco-friendly operation and work practices. The asset has a unique distinction of having all its rigs and installations certified and accredited by international accreditation agencies. The asset has been recognized for maintaining the best safety & environmental practices being followed in Asset.

Ahmedabad oilfield started production in 1961. Since its inception, Ahmedabad Asset has produced more than 550 lakh metric tons of oil and over 158300 lakh cubic meters of gas cumulatively

❖Discovery year :1961
❖Put on production :1963



3. Introduction

During my summer internship at Oil and Natural Gas Corporation (ONGC), I had the privilege of immersing myself in the sophisticated methodologies that underpin effective reservoir management. This report aims to elucidate two critical techniques: Material Balance Equation (MBE) and Decline Curve Analysis (DCA). Both methodologies are fundamental to the field of reservoir engineering, providing essential insights into reservoir characterization, performance forecasting, and strategic decision-making.

Material Balance Equation (MBE) serves as a foundational tool in reservoir analysis, enabling the estimation of original hydrocarbons in place and the evaluation of reservoir drive mechanisms. By meticulously balancing production data against changes in reservoir pressure, MBE provides a comprehensive understanding of reservoir dynamics. This method is instrumental in predicting future production rates, designing enhanced oil recovery (EOR) strategies, and optimizing well placement and operational efficiencies. The ability to accurately model and forecast reservoir behaviour through MBE is paramount for maximizing hydrocarbon recovery and ensuring sustainable field development.

Decline Curve Analysis (DCA) complements MBE by focusing on the extrapolation of historical production data to forecast future production trends. Through the application of decline models, DCA facilitates the estimation of remaining reserves and the economic viability of ongoing operations. This analytical technique is indispensable for long-term production planning, financial forecasting, and risk assessment. By identifying production decline patterns, DCA aids in optimizing production schedules and investment decisions, thereby enhancing the overall management of reservoir assets.

Together, MBE and DCA form a robust framework for reservoir characterization and management, driving informed decision-making and fostering the efficient exploitation of hydrocarbon resources. This report delves into the principles, applications, and advantages of these methodologies, underscoring their significance in contemporary reservoir engineering practices.

4. Oil Recovery Mechanisms

Every reservoir is made up of a different combination of fluid characteristics, geometric shape, and principal drive mechanism found in geological rocks. While no two reservoirs are exactly the same, they can be categorized based on their main method of production recovery. Every drive mechanism has been found to have a few standard performance traits in terms of:

- Ultimate recovery factor
- Pressure decline rate
- Gas-oil ratio
- Water production

Primary recovery is the process of recovering oil using any of the natural drive mechanisms. The phrase describes the extraction of hydrocarbons from a reservoir without the need for any additional processes, like fluid injection, to boost the reservoir's inherent energy.

4.1 Primary Recovery Mechanisms

Understanding reservoir behaviour and predicting future performance requires knowledge of the driving mechanisms that affect fluid behaviour. The type of energy—that is, the driving mechanism—that is available to move the oil to the wellbore determines the overall performance of oil reservoirs. In general, the following six driving mechanisms supply the natural energy required for oil recovery:

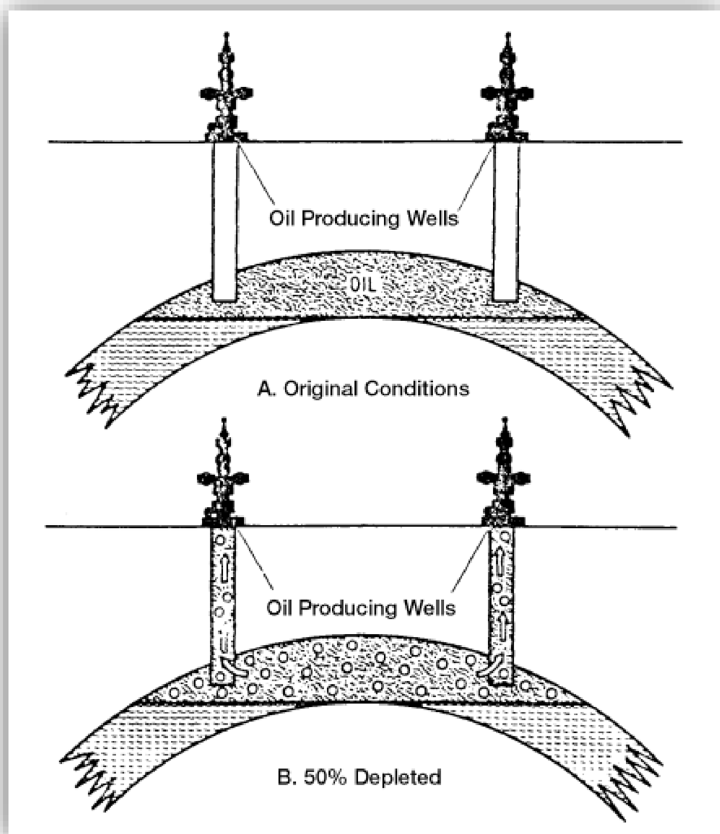
- Rock and liquid expansion drive
- Depletion drive
- Gas cap drive
- Water drive
- Gravity drainage drive
- Combination drive

4.1.1 Rock and Liquid Expansion

In an under-saturated oil reservoir (BPP < P_{res}), as the reservoir pressure declines, the rock and fluids expand due to their individual compressibilities resulting in reduction of the pore volume.
As the expansion of the fluids and reduction in the pore volume occur with decreasing reservoir pressure, the crude oil and water will be forced out of the pore space to the wellbore**.** This driving mechanism is considered the least efficient driving force and usually results in the recovery of only a small percentage of the total oil in place**.**

4.1.2 Depletion Drive Mechanism

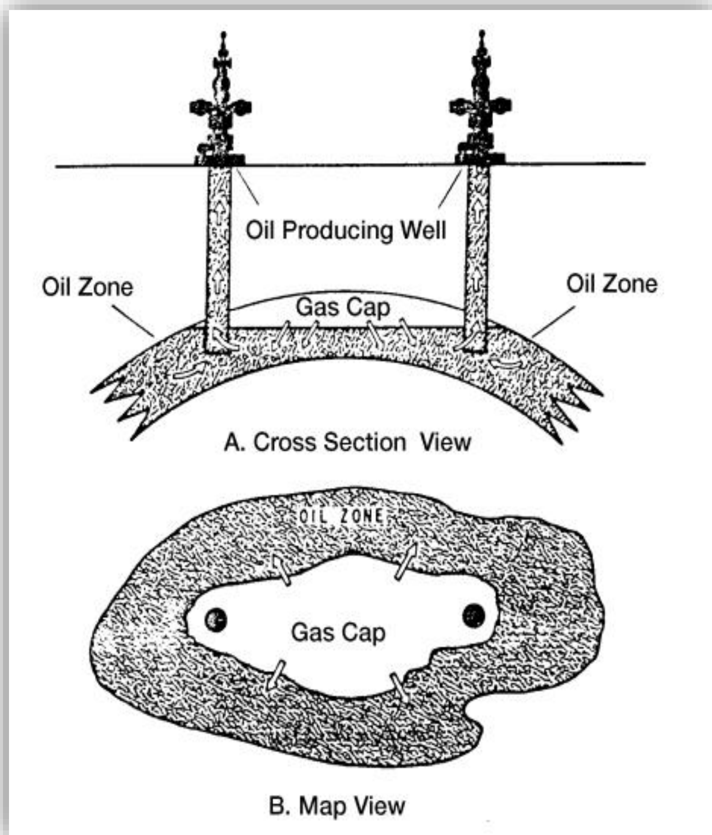
The main energy source in this kind of reservoir is the release of gas from the crude oil and the consequent expansion of the solution gas when the reservoir pressure drops. Within the microscopic pore gaps, gas bubbles are released when pressure drops below the bubble-point pressure. As schematically depicted in Figure, these bubbles expand and drive the crude oil out of the pore space.



4.1.3 Gas Cap Drive

As seen in Figure, gas caps with little to no water drive are indicative of gas-cap-drive reservoirs. These reservoirs have a gradual drop in reservoir pressure because of the gas cap's capacity to expand. The following two sources provide the natural energy needed to make the crude oil:

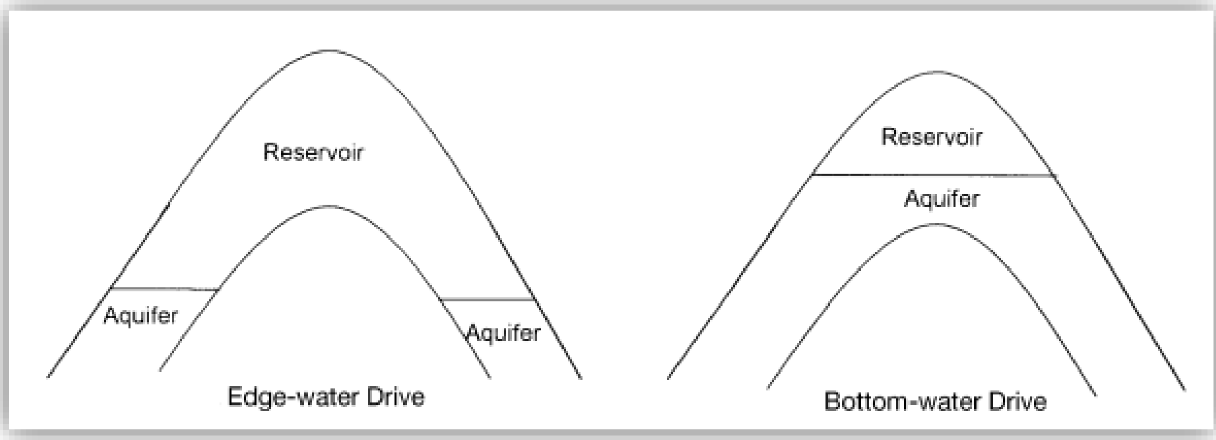
- Expansion of the gas-cap gas
- Expansion of the solution gas as it is liberated



4.1.4 Water Drive Mechanism

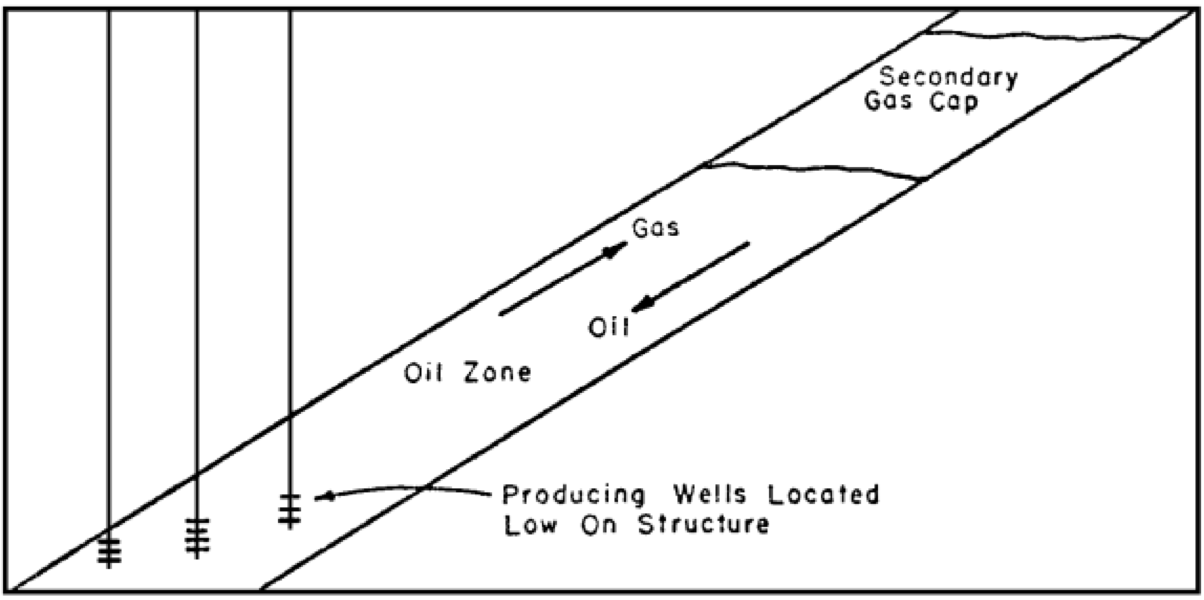
Many reservoirs are bounded on a portion or all of their peripheries by water bearing rocks called aquifers. It is common to speak of edge water or bottom water in discussing water influx into a reservoir. Bottom water occurs directly beneath the oil and edge water occurs off the flanks of the structure at the edge of the oil as illustrated in Figure.

The water drive is the result of water moving into the pore spaces originally occupied by oil, replacing the oil and displacing it to the producing wells.



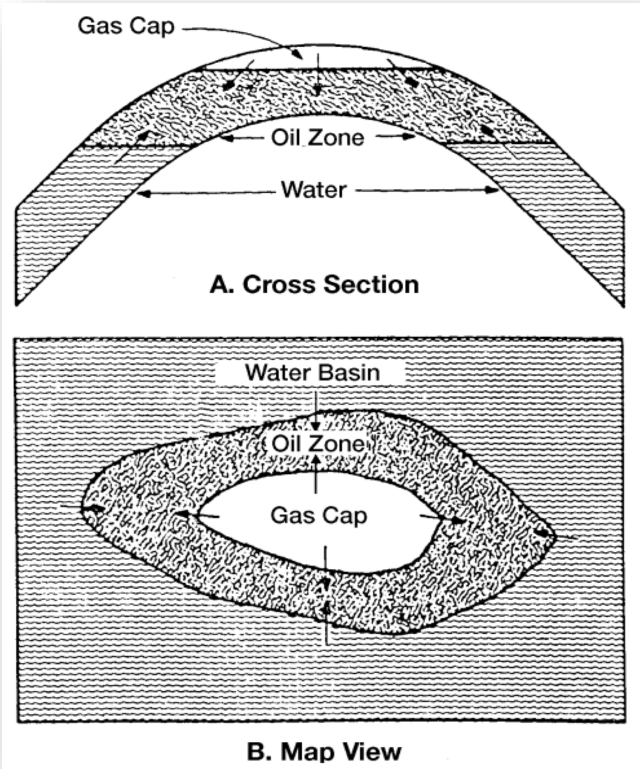
4.1.5 Gravity Drainage Drive Mechanism

The mechanism of gravity drainage occurs in petroleum reservoirs as a result of differences in densities of the reservoir fluids. The fluids in petroleum reservoirs have all been subjected to the forces of gravity, as evidenced by the relative positions of the fluids, i.e., gas on top, oil underlying the gas, and water underlying oil. Due to the long periods of time involved in the petroleum accumulation-and-migration process, it is generally assumed that the reservoir fluids are in equilibrium. Gravity segregation of fluids is probably present to some degree in all petroleum reservoirs, but it may contribute substantially to oil production in some reservoirs.
A typical gravity-drainage reservoir is shown in Figure



4.1.6 Combination Drive Mechanism

The driving mechanism most commonly encountered is one in which both water and free gas are available in some degree to displace the oil toward the producing wells. The most common type of drive encountered, therefore, is a combination-drive mechanism as illustrated in Figure



Two combinations of driving forces can be present in combination drive reservoirs. These are
(1) depletion drive and a weak water drive and
(2) depletion drive with a small gas cap and a weak water drive.

Characteristics of different Driving Mechanisms

Characteristics	Rock and Liquid expansion	Depletion drive	Gas-cap drive	Water drive	Gravity drainage	Combination drive
Reservoir pressure	rapid decline	rapid decline	declines slowly	gradual decline	rapid decline	rapid decline
GOR	constant	rapidly increasing	rise continuously	slight change	low	increases
Water production	-	no	negligible	increases appreciably	little or no	slowly increasing
Ultimate oil recovery	small %	(5-30)%	(20-40)%	(35-75)%	>80%	(30-70)%

5. Material Balance Equation

The material balance equation (MBE) has long been recognized as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance. The MBE, when properly applied, can be used to:

- Estimate initial hydrocarbon volumes in place
- Predict future reservoir performance
- Predict ultimate hydrocarbon recovery under various types of primary driving mechanisms

The formula is set up to simply maintain track of all the items that come into, go out of, and accumulate within the reservoir. Schilthuis introduced the idea of the material balance equation in 1941. The equation's most basic form, expressed in volumetric terms, is as follows:

Volume at start = volume left over + volume eliminated

5.1 Assumptions and Applications

5.1.1 Basics Assumptions in MBE

1. Constant Temperature: It is expected that there will be no temperature changes in the reservoir during pressure-volume variations. If there are temperature variations, they are typically so slight as to be disregarded without major error.
2. Pressure Equilibrium: Since there is consistent pressure throughout the reservoir, the fluid's characteristics are constant. Usually, little changes around the well bores can be disregarded. Significant pressure variation throughout the reservoir could lead to a high computation error.
3. Constant Reservoir volume: With the exception of the circumstances of rock and water expansion or water influx that are expressly taken into account in the calculation, the reservoir volume is assumed to be constant. The arrangement is thought to be sufficiently capable that, when the internal reservoir pressure is lowered, there won't be any appreciable volume change as a result of formation movement or reworking brought on by overburden pressure.
4. PVT data set are reliable and representative laboratory procedure has been used.
5. Reliable production data: Three production data are required – oil, gas and water.

5.1.2 Applications of MBE

- Estimation of contributing hydrocarbon volume in place
- Estimation Gas Cap or aquifer size
- Determine pressure, type and size of an aquifer
- Future reservoir performance prediction
- Predict ultimate hydrocarbon recovery under various type of drive mechanism
- We can see how pressure is declining and additional support is required or not

Standard nomenclature adopted by the SPE –

p_i	Initial reservoir pressure, psi
p	Volumetric average reservoir pressure
Δp	Change in reservoir pressure = $p_i - p$, psi
p_b	Bubble point pressure, psi
N	Initial (original) oil in place, STB
N_p	Cumulative oil produced, STB
G_p	Cumulative gas produced, scf
W_p	Cumulative water produced, bbl
R_p	Cumulative gas-oil ratio, scf/STB
GOR	Instantaneous gas-oil ratio, scf/STB
R_{si}	Initial gas solubility, scf/STB
R_s	Gas solubility, scf/STB
B_{oi}	Initial oil formation volume factor, bbl/STB
B_o	Oil formation volume factor, bbl/STB
B_{gi}	Initial gas formation volume factor, bbl/scf
B_g	Gas formation volume factor, bbl/scf
W_{inj}	Cumulative water injected, STB
G_{inj}	Cumulative gas injected, scf
W_e	Cumulative water influx, bbl
m	Ratio of initial gas-cap-gas reservoir volume to initial reservoir oil volume, bbl/bbl
G	Initial gas-cap gas, scf
P.V	Pore volume, bbl
c_w	Water compressibility, psi^{-1}
c_f	Formation (rock) compressibility, psi^{-1}

The MBE can be written I generalized form as follows–

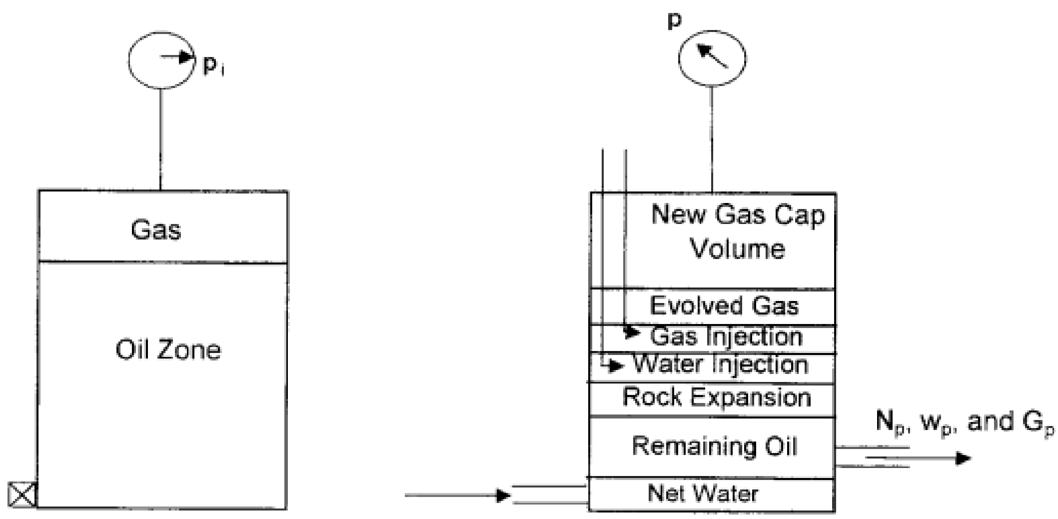


Figure 11-14. Tank-model concept.

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

The Below relationship is referred to as the material balance equation.

$$N = \frac{N_p B_o + (G_p - N_p R_s) B_g - (W_e - W_p B_w) - G_{inj} B_{ginj} - W_{inj} B_w}{(B_o - B_{oi}) + (R_{si} - R_s) B_g + mB_{oi}\left[\frac{B_g}{B_{gi}} - 1\right] + B_{oi}(1+m)\left[\frac{S_{wi} c_w + c_f}{1 - S_{wi}}\right]\Delta p} \quad (11\text{-}13)$$

where N = initial oil in place, STB

G_p = cumulative gas produced, scf

N_p = cumulative oil produced, STB

R_{si} = gas solubility at initial pressure, scf/STB

m = ratio of gas-cap gas volume to oil volume, bbl/bbl

B_{gi} = gas formation volume factor at p_i, bbl/scf

B_{ginj} = gas formation volume factor of the injected gas, bbl/scf

The cumulative gas produced G_p can be expressed in terms of the cumulative gas-oil ratio R_p and cumulative oil produced N_p by:

$$G_p = R_p N_p \tag{11-14}$$

Combining Equation 11-14 with Equation 11-13 gives:

$$N = \frac{N_p [B_o + (R_p - R_s) B_g] - (W_e - W_p B_w) - G_{inj} B_{ginj} - W_{inj} B_{wi}}{(B_o - B_{oi}) + (R_{si} - R_s) B_g + m B_{oi} \left[\frac{B_g}{B_{gi}} - 1\right] + B_{oi} (1+m) \left[\frac{S_{wi} c_w + c_f}{1 - S_{wi}}\right] \Delta p} \tag{11-15}$$

A more convenient form of the MBE can be created by using the concept of the total (two-phase) formation volume factor, B_t -

$$B_t = B_o + (R_{si} - R_s) B_g$$

$$N = \frac{N_p \left[B_t + (R_p - R_{si}) B_g\right] - (W_e - W_p B_w)}{(B_t - B_{ti}) + m B_{ti} \left[\frac{B_g}{B_{gi}} - 1\right] + B_{ti} (1+m) \left[\frac{S_{wi} c_w + c_f}{1 - S_{wi}}\right] \Delta p} \tag{11-17}$$

where S_{wi} = initial water saturation
R_p = cumulative produced gas-oil ratio, scf/STB
Δp = change in the volumetric average reservoir pressure, psi

Taking $A = N_p [B_t + (R_p - R_{si}) B_g]$
MBE can be written as -

$$\frac{N(B_t - B_{ti})}{A} + \frac{N m B_{ti} (B_g - B_{gi}) / B_{gi}}{A} + \frac{W_e - W_p B_w}{A} + \frac{N B_{oi} (1+m) \left[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\right] (p_i - p)}{A} = 1$$

In a combination drive reservoir, it is important to determine the relative contribution of each driving mechanism to production.

$$DDI + SDI + WDI + EDI = 1.0$$

where DDI = depletion-drive index
SDI = segregation (gas-cap)-drive index
WDI = water-drive index
EDI = expansion (rock and liquid)-depletion index

The four terms of the left-hand side of above equation represent the major primary driving mechanisms by which oil may be recovered from oil reservoirs –

1. The Depletion Drive: The oil recovery mechanism known as the depletion drive works by expanding the initial oil volume with all of its original dissolved gas content in order to produce oil from its reservoir rock.

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

2. Drive of Segregation: The mechanism by which the initial free gas cap expands to facilitate the extraction of oil from the formation is known as the segregation drive, or gas-cap drive.

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

3. Drive of Segregation: The mechanism by which the initial free gas cap expands to facilitate the extraction of oil from the formation is known as the segregation drive, or gas-cap drive.

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

4. Drive with Water. The process known as "water drive" involves the net encroachment of water into the oil zone in order to move the oil.

$$\mathbf{WDI = (W_e - W_p\ B_w)\ /A}$$

5.2 MBE as an Equation of a Straight Line

In developing a methodology for determining the above three unknowns, Havlena and Odeh (1963) expressed in the following form:

$$N_p[B_o + (R_p - R_s)B_g] + W_p\ B_w = N[(B_o - B_{oi}) + (R_{si} - R_s)B_g]$$
$$+ m N B_{oi}\left(\frac{B_g}{B_{gi}} - 1\right) + N\,(1 + m)B_{oi}\left[\frac{c_w S_{wi} + c_f}{1 + S_{wi}}\right]\Delta p$$
$$+ W_e + W_{inj}\,B_w + G_{inj}\,B_{ginj} \qquad (11\text{-}24)$$

Havlena and Odeh further expressed Equation 11-24 in a more condensed form as:

$$\mathbf{F = N\,[E_o + mE_g + E_{f,w}] + (W_e + W_{inj}\,B_w + G_{inj}\,B_{ginj})}$$

where,

F represents the underground withdrawal given by:

$$F = Np\ [Bo + (Rp - Rs)\ Bg] + Wp\ Bw$$

Eo describes the expansion of oil and its originally dissolved gas given by:

$$Eo = (Bo - Boi) + (Rsi - Rs)\ Bg$$

Eg is the term describing the expansion of the gas-cap gas given by:

$$Eg = Boi\ [(Bg/Bgi) - 1]$$

Ef,w represents the expansion of the initial water and the reduction in the pore volume given by:

$$E_{f,w} = (1+m)B_{oi}\,[(c_w\,S_{wi} + c_f)/(1-S_{wi})]\ \Delta p$$

Assuming no water or gas injection is done for pressure maintenance, W_{inj} and $G_{inj} = 0$

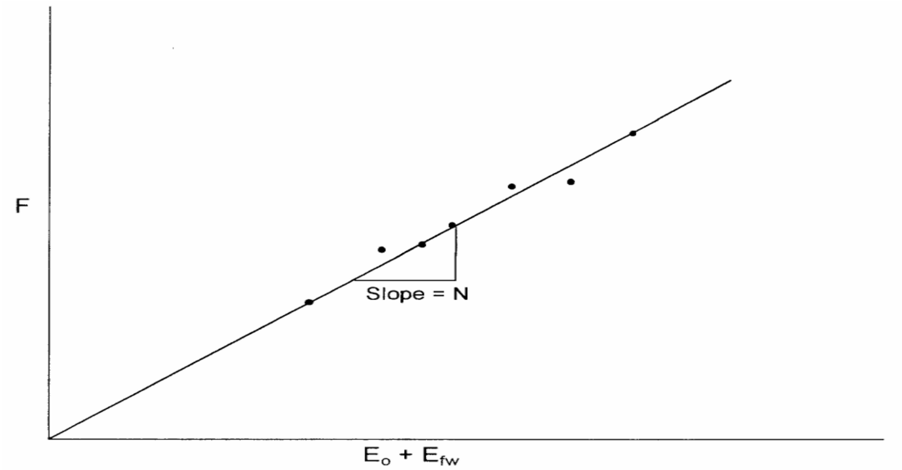
$$\mathbf{F = N\,[E_o + mE_g + E_{f,w}] + W_e}$$

Taking different assumption for different cases, MBE can be represented as a straight line. If the plot deviates from straight line, then the assumptions are incorrect.

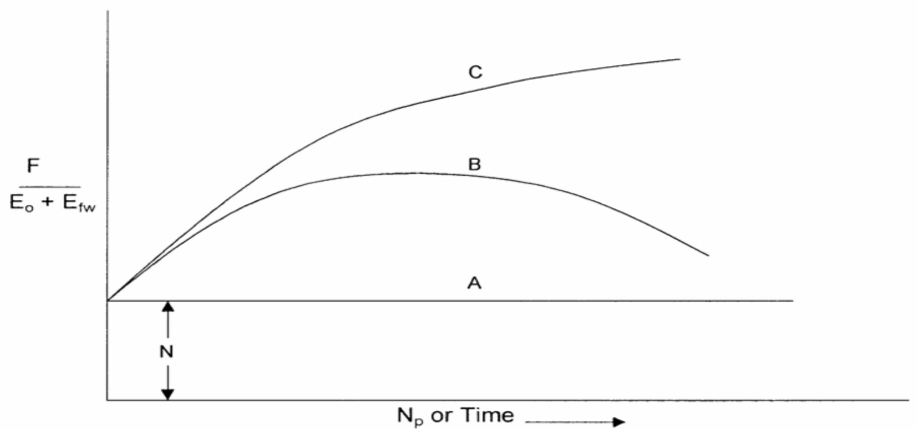
Case I - Volumetric Undersaturated Oil Reservoir

- We = 0, since the reservoir is volumetric
- m = 0, since the reservoir is undersaturated
- $R_s = R_{si} = R_p$, since all produced gas is dissolved in the oil

F = N (Eo + Ef,w)



- Line A in the plot implies that the reservoir can be classified as a volumetric reservoir.
- Curve C is strong water drive
- Curve B is weak water drive



Case II - Volumetric Saturated Oil Reservoir

- An oil reservoir that originally exists at bubble-point pressure is referred to as a saturated oil reservoir.
- Assuming that water and rock expansion term $E_{f,w}$ is negligible in comparison with the expansion of solution gas
- No initial gas cap, so m = 0

$$\mathbf{F = NE_o}$$

Case III - Gas Cap Drive Reservoirs

- Assumig that the natural water influx is negligible (W_e=0)
- The effect of water and pore compressibilities can be considered negligible.

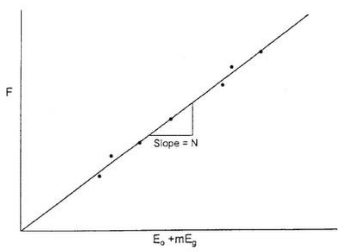
$$\mathbf{F = N\,[E_o + m\,E_g]}$$

There are three possible unknowns in above equation:

- N is unknown, m is known
- m is unknown, N is known
- N and m are unknown

a. Unknown N, known m:

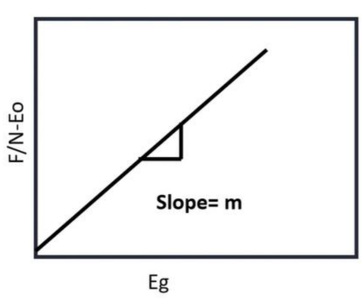
A plot of F versus (E_o + m E_g) on a cartesian scale would produce a straight line through the origin with a slope of N



b. Unknown m, known N:

F= N(Eo+ mEg)
Re arranging above equation to :

$$\left(\frac{F}{N} - E_o\right) = m\,E_g$$

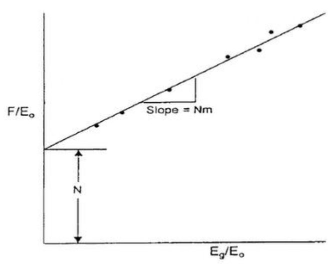


c. N and m are Unknown

F= N(Eo+ mEg)

Re arranging above equation to :

F/Eo = N+ mN (Eg/Eo)

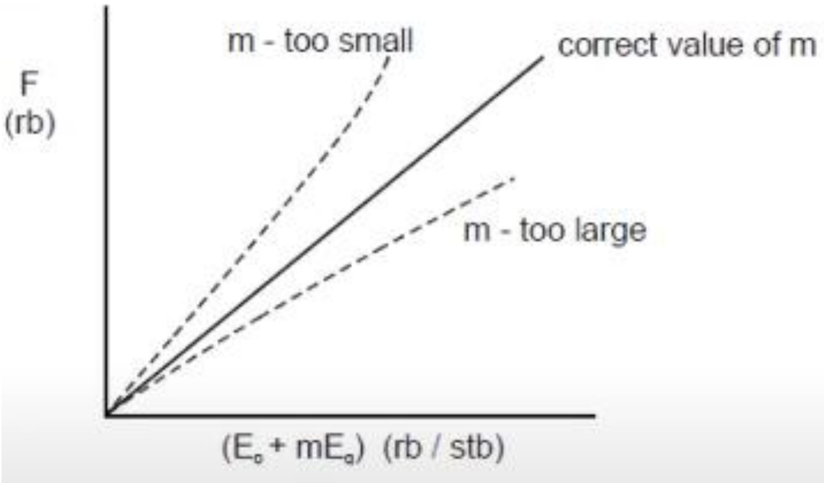


A plot of F/E_o versus E_g/E_o should then be linear with intercept N and slope mN.

Case IV – Water Drive Reservoirs

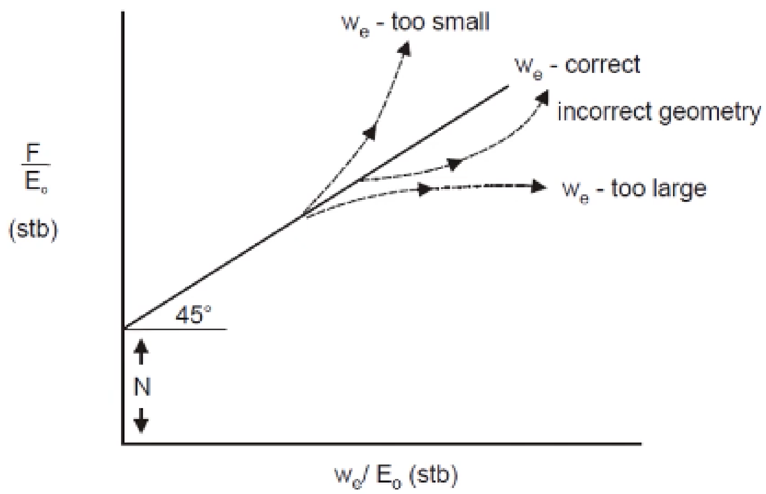
- $E_{f.w}$ can frequently be neglected in water-drive reservoirs
- the reservoir has initial gas cap

F = N Eo + We



Several water influx models can be used:

- Pot-aquifer model
- Schilthuis steady-state method
- Van Everdingen-Hurst model
-



Trial and error method of determining the correct aquifer model (Havlena and Odeh)

6. Decline Curve Analysis

Decline curve analysis, introduced in the 1940s, is one of the most popular methods to date for evaluating the future production potential of oil and gas wells. Oil and gas reserves can be estimated by identifying and extrapolating the decline characteristics of wells in a field. The methodology is intuitive, and currently used to evaluate the future production potential of wells in both conventional and unconventional reservoirs based on current trends. As a reservoir is depleted during production, oil and gas wells exhibit an identifiable declining trend in rates that can be extrapolated for the future and analyzed to obtain valuable information.

6.1 Assumptions and Limitations

Traditional decline curve analysis, as applied to conventional reservoirs, is based upon a number of assumptions as follows:

- The well is produced by depletion drive alone. Water or gas injection, influx of water from an adjacent aquifer, or the presence of a gas cap usually influences production rate in a manner that a decline may not be identifiable.
- The well produces from its own drainage area without any interference from nearby wells. The flow regime is referred to as boundary dominated flow.
- The well produces at a constant bottom-hole pressure. In reality, such a condition may not be observed.

Limitations -
Traditional decline curve analysis is useful for predicting future performance of oil reservoirs, but it is only applicable when the well production rate is declining with an identifiable trend. Factors such as fluid injection, stimulation, hydraulic fracturing, operational issues, well recompletion, perforation, and water breakthrough can affect the decline trend. Reservoir simulation is also needed for long-term production constraints. Traditional decline curve analysis is inadequate for estimating ultimate recovery or reserves in unconventional resources like shale gas reservoirs due to their unique fluid flow characteristics and complex network of induced and natural fractures. Recognizing various flow regimes during the well's productive life is crucial. Extrapolating initial decline characteristics to the economic limit may result in overestimation or underestimation in ultimate recovery.

6.2 Decline curve models

Decline curve models are empirical, and predict the future well rates based upon past performance. In order to do so, the model equation requires a best fit to the existing production data by determining one or more unknown coefficients in the equation by graphical or mathematical techniques. The types of well rate decline models widely known in the petroleum industry are as follows:

- Exponential
- Hyperbolic
- Harmonic

The above are collectively referred to as the Arps model. In recent times, other models have been proposed as the traditional models have been found to be inadequate in the analysis of unconventional reservoirs.

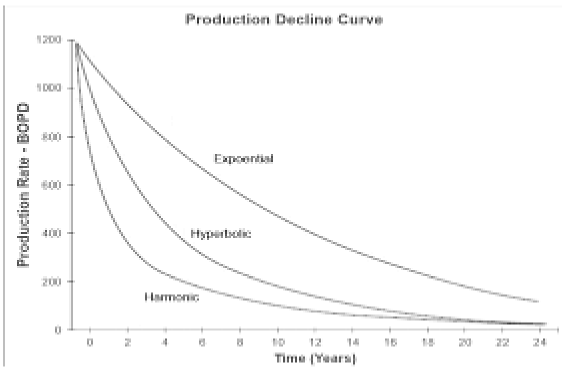
A generalized equation correlating the decline rate with production rate and time can be expressed as follows:

$$D = dq^b = -\frac{1}{q}\frac{dq}{dt}$$

Where,

D = instantaneous decline rate, 1/day
q = well production rate, MCF/day or bbl/day
t = time period of production, days
d, *b* = empirical constants depending on well decline characteristic.
(Note that the consistent units of time are used in the above equation; for example, if *t* is in days then *q* is in MCF/day and *D* is in 1/day.)

Based on the value of *b*, traditional decline curve analysis is classified into three types of rate decline as follows:



- Exponential decline: $b = 0$
- Hyperbolic decline: $0 < b < 1$
- Harmonic decline: $b = 1$

Derivation of rate-time and rate cumulative equation for exponential decline (b = 0)

$$\frac{1}{q}\frac{dq}{dt} = -dq^0$$

$$\frac{1}{q}\frac{dq}{dt} = -d$$

$$\int_{qi}^{q}\frac{dq}{q} = -\int_{0}^{t}(d)dt$$

$$\ln\left(\frac{q}{qi}\right) = -dt$$

$$q = qi\ e^{-dt}$$

The cumulative production of a well over time *t* under exponential decline is obtained by integrating

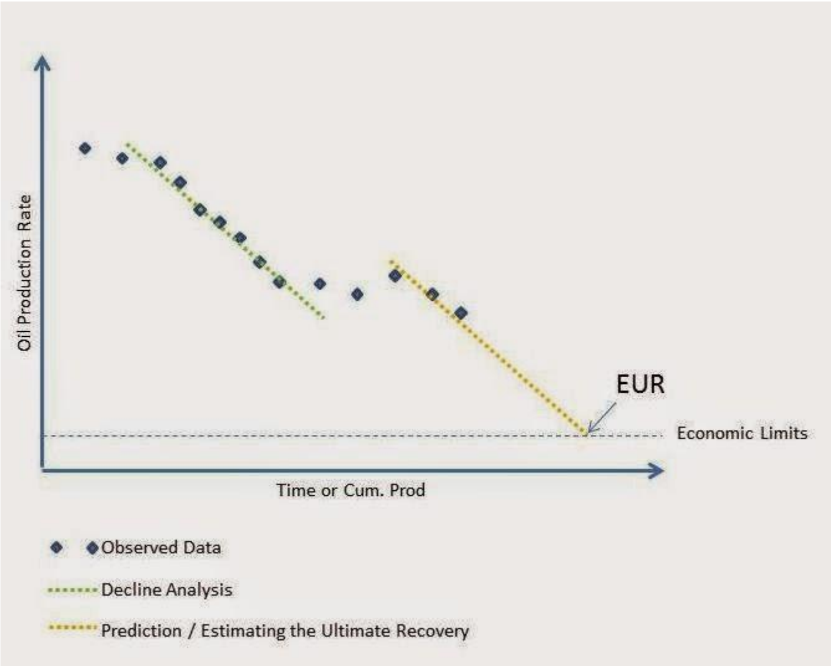
$$Q = \int_0^t q.dt$$

$$= \int_0^t qi\ e^{-dt}.dt$$

$$= \frac{(qi\ - q)}{d}$$

Similar equations can be derived for hyperbolic and harmonic decline.

6.3 Estimation of EUR



EUR = Q + Remaining reserve as per the trend obtained

Recovery Factor (RF) = EUR/OOIP

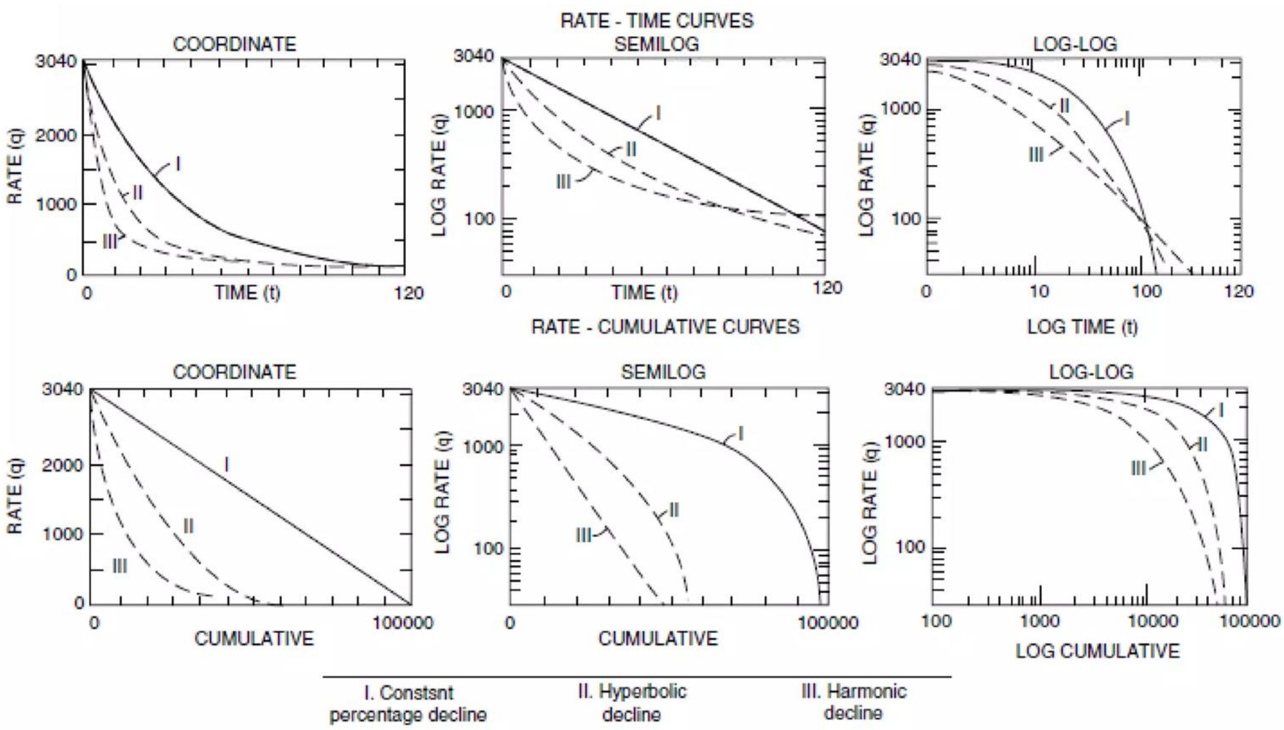
Type	Exponential	Hyperbolic	Harmonic
b	b = 0	0 < b < 1	b = 1
Rate time	$q = q_i\, e^{(-d\, \Delta t)}$	$q = \dfrac{q_i}{(1 + b\, d\, \Delta t)^{(\frac{1}{b})}}$	$q = \dfrac{q_i}{(1 + d\, \Delta t)}$
Rate cumulative	$Q = \dfrac{q_i - q}{d}$	$Q = \dfrac{q_i^{\,b}}{d\,(1-b)}\left(q_i^{(1-b)} - q^{(1-b)}\right)$	$Q = \dfrac{q_i}{d}\ln\left(\dfrac{q_i}{q}\right)$
EUR	$Q_f = Q_i + \left[\dfrac{q_i - q_f}{d}\right]$	$Q_f = Q_i + \left[\dfrac{q_i^{\,b}}{d\,(1-b)}\left(q_i^{(1-b)} - q_f^{(1-b)}\right)\right]$	$Q_f = Q_{i+}\left[\dfrac{q_i}{d}\ln\left(\dfrac{q_i}{q_f}\right)\right]$

6.4 Identification of Decline Curve

Exponential decline -
Straight line will be observed for flow rate vs time in semi-log scale and on rate vs cumulative production on Cartesian scale.

Harmonic decline -
Straight line will be observed for flow rate vs cumulative production in semi-log scale.

Hyperbolic decline -
Straight line is not obtained for any type of curve.



7. Application of MBE and DCA

The Material Balance Equation (MBE) and Decline Curve Analysis (DCA) are integral to various aspects of petroleum engineering, ranging from reservoir characterization to production forecasting. Here are some key applications of these techniques:

1. Reservoir Characterization:

In reservoir characterisation, the Material Balance Equation (MBE) and Decline Curve Analysis (DCA) are essential tools. By adjusting reservoir production to pressure variations, MBE calculates the initial hydrocarbons present in the reservoir, assisting in the identification of reservoir driving mechanisms and the forecasting of future performance. It is essential for maximizing recovery tactics and controlling reservoir life. Conversely, DCA evaluates reservoir performance and projects future output by examining trends in production rates over time. DCA offers information about reservoir behaviour and residual reserves by fitting historical production data to models. When combined, MBE and DCA provide a full suite of tools for assessing reservoir potential, directing planning for development, and guaranteeing effective resource management.

2. Reservoir Management:

In reservoir management, Material Balance Equation (MBE) and Decline Curve Analysis (DCA) are essential tools for optimizing hydrocarbon recovery. MBE is utilized to estimate the original hydrocarbons in place and assess the reservoir's drive mechanisms by balancing the cumulative production with pressure changes. This aids in predicting future reservoir performance and planning appropriate recovery strategies, ensuring the maximization of resource extraction.

DCA, on the other hand, involves analyzing historical production data to project future production rates. By fitting decline models to production data, it helps forecast the remaining productive life of the reservoir and estimate reserves. This is crucial for making informed decisions regarding well interventions, development planning, and economic evaluation. Combined, MBE and DCA enable a comprehensive understanding of reservoir dynamics, guiding effective reservoir management practices and enhancing production efficiency.

3. Field Development Planning:

Decline Curve Analysis (DCA) and the Material Balance Equation (MBE) are essential for maximizing resource extraction and financial returns in field development planning. By balancing output and pressure variations, MBE aids in understanding reservoir driving processes and provides an estimate of the original hydrocarbons present. This knowledge is essential for developing development strategies, which include planning enhanced oil recovery (EOR) procedures, choosing the right recovery technologies, and figuring out how many and where to put wells.

In addition, DCA forecasts future production rates and estimates the remaining reserves by evaluating existing production data. This data is essential for budgeting, planning drilling and production schedules, and assessing the field's economic feasibility. Together, MBE and DCA provide a comprehensive framework for making informed decisions, ensuring efficient field development, and maximizing hydrocarbon recovery while minimizing costs and risks.

4. Production Forecasting:

In production forecasting, Material Balance Equation (MBE) and Decline Curve Analysis (DCA) are essential tools for predicting future reservoir performance. MBE is used to estimate the original hydrocarbons in place and analyze reservoir drive mechanisms by relating production data to changes in reservoir pressure. This enables accurate predictions of future production rates and cumulative production, which are crucial for planning and optimizing production strategies.

DCA, on the other hand, involves fitting historical production data to mathematical models to forecast future production trends. By extrapolating these trends, DCA provides estimates of remaining reserves and the productive life of the reservoir. This is particularly useful for short- to medium-term forecasting. Together, MBE and DCA offer a robust methodology for generating reliable production forecasts, aiding in decision-making, financial planning, and resource management to ensure optimal reservoir performance and economic returns.

5. Economic Analysis:

The Material Balance Equation (MBE) and Decline Curve Analysis (DCA) are essential tools in economic analysis for assessing an oil and gas project's financial sustainability. By balancing cumulative output with variations in reservoir pressure, MBE aids in estimating the initial hydrocarbons present and forecasts future production rates. Planning development methods, estimating the potential revenue from a reservoir, and figuring out the economic boundaries of production all depend on this data.This is enhanced by DCA, which offers output projections based on previous data, enabling the calculation of future cash flows and residual reserves. Precise production estimates are essential for financial modeling, investment choices, and determining how profitable development plans will be. Businesses may optimize investment plans, make educated economic judgments, and more by merging MBE and DCA and ensure efficient allocation of resources to maximize returns and minimize risks

6. Risk Assessment:

Material Balance Equation (MBE) and Decline Curve Analysis (DCA) play vital roles in risk assessment for oil and gas projects. MBE provides estimates of original hydrocarbons in place and predicts future production by analyzing pressure and production data. This enables identification of uncertainties related to reservoir size, drive mechanisms, and recovery efficiency, helping to assess the technical risks associated with reservoir performance.

DCA complements this by forecasting future production trends based on historical data. It helps in identifying decline patterns and projecting future output, highlighting potential risks in achieving production targets and economic returns. By integrating MBE and DCA, companies can quantify uncertainties, evaluate the probability of different scenarios, and develop risk mitigation strategies. This comprehensive approach enhances decision-making, ensuring more reliable project planning and investment by identifying and addressing potential risks early in the development process.

In summary, the application of Material Balance Equation and Decline Curve Analysis spans various stages of reservoir development and production operations, playing a crucial role in optimizing hydrocarbon recovery, maximizing asset value, and ensuring the economic success of petroleum projects.

8. Reservoir Field Services

Reservoir Field Services evaluates the well potential during initial testing of the wells. During the production life of the reservoir, it monitors the behavior of the well / reservoir, regularly, to augment / maintain the productivity and maximize the recovery. For this, time-to-time, reservoir pressure and temperature data, spot as well as transient, has to be acquired. This data is the basic platform for deciding the well performance and life of the reservoirs.

The group looks after the field reservoir operations as per the requirement put forward by the reservoir management working groups of different area. The various types of reservoir operations carried out are as under:

- SBHP/SBHP Gradient survey
- FBHP/FBHP Gradient survey
- Temperature survey (Flowing and Static condition)
- Pressure transient Tests (Pressure Build up, Pressure Draw down Test)
- Influx study
- Gas lift survey (Continuous as well as Cyclic Gas Lift)
- Bottom Hole Sampling
- Echo meter study (Static cond., Dynamic cond., Multi shot)

8.1 Instruments Used in Data Acquisition

Several instruments are used in RFS for acquiring the data from the wells. Some of them are-

- Mechanical Pressure Gauges
- Electronic Memory Gauges
- Sub-Surface Samplers
- Echometer

8.2 Pressure Transient study

The information obtained from pressure transient tests includes estimates of

(1) Unaltered formation permeability to the fluid(s) produced in the well;

(2) Skin

- Altered (usually reduced) permeability near the well caused by drilling and completion practices;
- Altered (increased) permeability near the well created by well stimulation activities;

(3) Better understanding of Geological formations around the well;

(4) Distances to flow barriers located in the area drained by the well;

(5) Average pressure in the area drained by the well.

9. Conclusion

In conclusion, the Material Balance Equation and Decline Curve Analysis are indispensable tools for reservoir evaluation and production forecasting in the oil and gas industry. Through their systematic application and integration, practitioners can gain valuable insights into reservoir dynamics, optimize production strategies, and maximize hydrocarbon recovery. As reservoir engineering continues to evolve, the continued refinement and integration of MBE and DCA techniques will play a vital role in meeting the challenges of sustainable hydrocarbon production in the 21st century.

10. References

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[3] Arps JJ. Estimation of decline curves. Trans. AIME 1945;160:228–47.