YANGON TECHNOLOGICAL UNIVERSITY
DEPARTMENT OF PETROLEUM ENGINEERING

RESERVE ESTIMATION AND FORECASTING OF OKHMINTAUNG FORMATION, CD FAULT BLOCK

BY

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PE-10

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We certify that we have examined, and recommend to the University Steering Committee for Undergraduate Studies for acceptance of the thesis entitled **"RESERVE ESTIMATION AND FORECASTING OF OKHMINTAUNG FORMATION, CD FAULT BLOCK"** submitted by **Htoo Htoo Aung, VI PE-10 (February, 2018)** in partial fulfilment of the requirements for the degree of Bachelor of Engineering.

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ABSTRACT

Estimating hydrocarbon reserves is a complex process that involves integrating geological and engineering data. Depending on the amount and quality of data available, one or more of the following methods may be used to estimate reserves: Volumetric, Material balance, Production history, Analogy. Each method has its own rules and periods to be utilized. One of the most important points is uncertainty. Reserves estimation is heavily affected by uncertainty. For example, there is always a question in employing MBE ”how reliable the production data and PVT data are.” To collect the data precisely and regularly is essential function of reserve evaluation. There is no best method to do estimation, all the methods are applied according to its production life and stability.In this work, the very first three methods are applied. According to this work, all applied methods give reasonable results for both sands.

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CHAPTER 1
INTRODUCTION

Reserve estimation is one of the most essential tasks in the petroleum industry. It is the process by which the economically recoverable hydrocarbons in a field, area or region are evaluated quantitatively. It is the one that is not static and it tends to continue throughout the life time of a field.

1.1 Methods of Reserve Estimation

Reserve estimation methods are broadly classified as analogy, volumetric, performance types. Volumetric and performance methods are the more elaborate techniques, and the main difference between the two is the type of data used (i.e., static vs. dynamic) relating to pre and post production phases. Compared to performance methods, volumetric techniques generally involve greater errors and uncertainty and the economic effect can be greater because they generally predate development planning.

The choice of methodology depends on development and production maturity, degree of reservoir heterogeneity and the type, quality and amount of data. Different estimation methods may yield significantly different results, and reconciliation of the differences may be difficult. If there are wide differences, application of two or more methods may reveal the need for further investigation.

1.1.1 Volumetric Method

The two established volumetric approaches are deterministic and stochastic. In both approaches, mathematical formulas are used to estimate volumes.

Deterministic Approach

This approach is the traditional technique for volumetric calculations. In this approach, the input parameters are single values that are considered representative of the reservoir.

Probabilistic Approach

No industry standard exists for stochastic reserves estimation. General practice is to use continuous probability density functions (PDFs) and combine these distributions to generate a PDF for reserves. The input PDFs (e.g., triangular) are combined either analytically (Capen 1992) or by random sampling (Monte Carlo simulation). By central-limit theorem, the resultant (reserves) distribution approaches lognormal, regardless of the type of input variables. Therefore, analytical techniques assume reserves to be lognormal. Monte Carlo simulation requires a large number of iterations for stable results. Because it provides a range of reserves values with associated probabilities, the stochastic method often is the preferred procedure for volumetric calculations. It enables business decisions in the ever-present uncertainty context, providing a good understanding of risk and potential reward.

1.1.2 Performance Methods

These methods are used when there is sufficient pressure and production history to allow prediction of future performance. Although probabilistic approaches have been applied, the common practice is deterministic.

Decline Curve Analysis

The analysis refers to estimating reserves on the basis of a reasonably well-defined behavior of a performance characteristic (e.g., production rate or oil cut) as a function of time or cumulative production. The method usually is used for single-well analysis. The trend established from past behavior is extrapolated until the economic limit is reached. The basic assumption is that the trend established in the past will govern the future in a uniform manner. Strictly speaking, such estimates are P50 estimates (i.e.,proved plus probable).

Material Balance

This is a conservation-of-matter technique whereby the pressure behavior of the reservoir in response to fluid withdrawal is analyzed in several steps. The fluid properties and pressure history are averaged, treating the reservoir as a tank. For reliable estimates, there must be sufficient pressure and production data (for all fluids) and reliable pressure/volume/temperature data, and the reservoir must have reached semisteady-state conditions.

Reservoir Simulation

This procedure represents the reservoir with a grid, or a set of interconnected tanks, each containing rock and fluid properties. A computer model performs a series of material-balance calculations in different cells, and migration of fluids between adjoining cells is allowed by use of Darcy's flow equation. A development scheme and operating conditions generally are superimposed on the system. For reliable results, a good match between observed history and simulated performance is essential

1.2 Definitions of Reserve and Resources

1.2.1 Reserve

Reserves are defined by SPE/WPC as follows: Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward.

Thus, reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining. Depending on the degree of uncertainty, three main classes of reserves are recognized: proved, probable and possible.

1.2.2 Contingent Resources

Contingent Resources are those discovered and potentially recoverable quantities that are, currently, not considered to satisfy the criteria for commerciality and are defined as follows: Contingent Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.

1.2.3 Prospective Resources

Prospective Resources are those potentially recoverable quantities in accumulations yet to be discovered and are defined as follows: Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

1.2.4 Commerciality

The distinction between commercial and sub-commercial known accumulations (and hence between reserves and contingent resources) is of key importance in ensuring a reasonable level of consistency in reserves reporting. On the basis of the above classification system, it is clear that the accumulation must be assessed as commercial before any reserves should be assigned. Even though the "SPE/WPC Petroleum Reserves Definitions" do allow for some uncertainty in commercial criteria to be reflected in the reserve categories (Proved, Probable, and Possible), it is also clearly stated that reserves (of all categories) must be commercial. Thus, contingent resources may include, for example, quantities estimated to be recoverable from accumulations for which there is currently no viable market or where commercial recovery is dependent on the development of new technology. In addition, it would be appropriate to classify a new discovery as containing contingent resources rather than reserves where the evaluation is at an early stage and commerciality has yet to be confirmed. Where an accumulation has been assessed as commercial, reserves may be assigned. However, reserves still must be categorized according to the specific criteria of the SPE/WPC definitions; therefore, proved reserves will be limited to those quantities that are commercial under current economic conditions while probable and possible reserves may be based on future economic conditions.

1.3 Aim and Objectives

The main purpose of this work is to estimate reserve and forecast the future performance.
The objectives are as follows:

- To understand the reserve and resource definitions
- To analyze the PVT datas
- To apply the reserve estimation methods

CHAPTER 2
GEOLOGICAL BACKGROUND

Mann field is a mature field which is situated in the salin basin also called minbu basin. In the late 1960's, it was first mapped during gravity and seismic operations by the Burma Oil Company.

2.1 Introduction

Mann Field is a tremendously complex structural system that produces from over 20 intervals in a tectonically active area. Original oil-in-place (OOIP) has been modified several times during the field's life, and current estimates put it at 433 million stock tank barrels of oil (MMSTBO). To date, 106 million STBO have been produced, which is approximately 24.5

In 1999, Myanmar Petroleum Resources Limited (MPRL) took over operations of the field. MPRL is a unique entity in that it operates the field and oversees the technical development through a Performance Compensation Contract established with the Myanmar Ministry of Energy and the state-owned oil company, Myanma Oil and Gas Enterprise (MOGE).

2.2 Geology and Reservoir Characteristics

The Salin sub-basin, where the Mann Field is located, is part of the central basin of Myanmar. The central basin is bordered to the west by an oblique subduction zone and to the east by a right-lateral strike slip zone. These large tectonic features directly affect Mann Field, which is very complex, highly-faulted anticline structure. Numerous fault blocks divide the field into various compartments. Each individual fault block is named after the major NE-SW trending faults that cut across the field, i.e. the fault block between Faults C and D is referred to as the CD block. It is unclear at this time if these major faults are sealing or not in the various stratigraphic zones.

The producing zones in the field are the Kyaukkok, Pyawbwe, Okhmintaung, and Padaung formations. The producing layers within the four formations are commonly referred to by numbered sand units that increase in number as they get deeper, i.e. the 4500 sand is below the 4400 sand and both are part of the Padaung formation. Table 2.2 lists the four formations, the associated producing layers, and their lithologies. [Ahmed, 2006]

Table 2.1: Porosity and Permeability Value

Formation	Mean porosity(%)	St.dev porosity (mD)	Mean Perm (mD)	Min Perm (mD)	Max Perm (mD)
Kyaukkok	29.1	±5.2	261	0.001	2604
Okhmintaung	23.3	±4.5	59	0.001	1765
Pyawbwe	21.3	±5.5	4	0.001	1562

Core analysis of 477 samples from the 2200 – 3900 sands indicates a wide range of both porosity and permeabilities are present throughout the producing intervals. A maximum permeability of 2604 mD was measured in the Kyaukkok formation, and a minimum of 0.001 mD was measured in all three formations (minimum value allowed by the measuring equipment). Table 2.1 shows the wide ranges of porosity and permeabilities. No conventional core data for the Padaung formation was available. These wide ranges of reservoir parameters demonstrate how internally heterogeneous each of the producing formations is and gives evidence to the challenge of adequately maximizing the field's resources.

2.3 Review of OOIP

With the development of a new geologic model and the reservoir simulation model, a review of the fieldwide OOIP was conducted. As mentioned, there was some concern that the OOIP for the field was underestimated, which would have far-reaching affects on such items as the implementation of secondary and tertiary recovery and the associated economics. Underestimation of the OOIP also has implications on the long-term contractual terms of MPRL with the Myanmar government, as far as, renewal of the Performance Compensation Contract which expires in 2014.

As with the full field reservoir simulation model developed, a formal review of fieldwide OOIP is currently being conducted, but initial calculations indicate that OOIP may be underestimated by as much as 5-10%.

Table 2.2: Central Myanmar Basin Producing Formations and Associated Sand Units

Formation	Lithology	Thickness (ft)	Sand unit
Kyaukkok	Sandstone and shale	Up to 5000 ft	2200 2300 2400 2500
Pyawbwe	Shale with minor amounts of sandstone	Up to 3300 ft	2600 2700 2800 2900 3200 3300 3500 3600
Okhmintaung	Sandstone and shale	0-5000 ft	3700 3800 3900
Padaung	Shale with minor amounts of sandstone	1300-4000ft	4000 U4100 L4100 4300 4400 4500 4600 4700 4800 5100 5300 5800

CHAPTER 3
LITERATURE REVIEW

3.1 Thickness

The thickness value referred to in engineering terms as ”net pay” is the most variable component of the oil-in-place equation. The terms ”gross pay” and ”net pay” are used to describe reservoir thickness. Gross pay, referring to the total hydrocarbon-bearing zone, frequently includes intervening nonproductive intervals that may be present in the reservoir. Net pay refers to the sum of the productive sections of the reservoir and is determined by the application of cutoffs, which are the specified lower limits of core or log data (porosity, permeability, and fluid saturations) below which a formation will be unable to achieve or sustain economic production. Cutoffs are determined by using existing production information from the subject or similar formations, and by constructing correlations between production, porosity, permeability, and water saturation and the recoverable reserves requirements.

Net pay is an important factor to determine the original oil in place of a reservoir so that the total amount of energy in that reservoir could be calculated. Another major criterion in determining net pay is the potential oil available for future secondary or tertiary recovery programs.

3.2 Porosity

Porosity is the fraction of the reservoir bulk volume that is filled with fluid or non mineral matter-in other words, the ”storage capacity” of the rock. Even though porosity is independent of the size of the spheres, the porosity of a uniform sphere system can vary from over 25 percent to nearly 48 percent depending upon the packing geometry. The porosity of rocks, therefore, decreases as the variation in particle size and shape increases.

Hydrocarbons have been produced commercially from rocks with porosities as high as 50 percent. Some nonproductive rocks also have high porosities. Clays and shales and certain chalky carbonates may have fractional fluid volumes or microporosity greater than 40 percent; yet these rocks are seldom productive. Porosity, therefore, cannot be considered the sole criterion for the determination of reservoir productivity. Porosity is generally expressed as a percentage of bulk volume.

$$\phi = \frac{V_p}{V_b} \tag{3.1}$$

Where:

ϕ	=	porosity (%)
V_p	=	pore volume
V_b	=	bulk volume

Based on these three different types of pores, the total or absolute porosity of a reservoir rock comprises effective and ineffective porosities, which are defined in the following sections.

3.2.1 Total or Absolute Porosity

It is the ratio of the volume of all the pores to the bulk volume of the material, regardless of whether or not, all the pores are interconnected.

3.2.2 Effective porosity

It is the ratio of the interconnected pore volume to the bulk volume of the rock. The value of this parameter is used in all reservoir engineering calculations.

3.2.3 Determination of porosity

The porosity is determined by core analysis or by well logging.

3.3 Hydrocarbon Saturation

The saturations of hydrocarbons (both liquid and gaseous) and water in petroleum reservoirs are two of the most important properties of interest to the reservoir analyst. However, because these fluids are generally mobile, they are not always recovered during conventional coring operations. For this reason, fluid saturations measured by core analysis are generally treated as qualitative numbers rather than precise values. It should be noted that the inaccuracy of the measurements is not due to the laboratory techniques, but to the difficulty in obtaining proper samples.

For accurate estimates of saturations in a reservoir, both core and geophysical well log data must be used; furthermore, the log data must be interpreted accurately. More accurate saturation data may be obtained by using sponge core or oil-base core techniques.

$$S_o = \frac{oil\ volume}{pore\ volume} \tag{3.2}$$

$$S_w = \frac{water\ volume}{pore\ volume} \tag{3.3}$$

$$S_g = \frac{gas\ volume}{pore\ volume} \tag{3.4}$$

$$S_o + S_w + S_g = 1 \tag{3.5}$$

3.3.1 Determination of saturation

Fluid saturation in the laboratory is one of the least reliable reservoir property measurements. Factors that are likely to introduce errors into these measurements include invasion of the core by mud or mud filtrate during coring process, gas expansion during core recovery, and handling of the core during preservation and measurement.

3.4 Reservoir Temperature

Reservoir temperature is of prime importance in the determination of in-place volumes and recovery factors for gas and oil. In estimating gas reserves, a knowledge of temperature is necessary to calculate the gas compressibility factor and gas formation volume factor. To estimate oil reserves, knowledge of the temperature is critical if laboratory PVT data is to be measured under reservoir conditions. Temperature also affects other parameters such as oil viscosity and miscibility, and thereby impacts reservoir engineering estimates of Oil recovery.

Often values of reservoir temperature are estimated from data in the literature or from readings obtained during logging or testing operations. Such data may be acceptable under initial conditions, but should always be confirmed or adjusted using more reliable data as it becomes available. The most reliable source of temperature data is a bottom-hole temperature (BHT) measurement taken with a continuous recording subsurface temperature gauge under stabilized bottom-hole conditions. Other methods, such as using maximum reading thermometers during testing or logging operations, are considered less reliable.

Although temperature is usually a function of depth, a number of other factors affect temperature as well. Isotherms at depth may not always follow surface topography. This section describes various techniques used for measuring or estimating BHT and points out the shortcomings in some of the values obtained.

3.5 Reservoir Pressure

Throughout the productive life of a reservoir, a record of its pressure is necessary in order to make a number of necessary calculations. Initial pressures obtained after the discovery of a pool are needed for the calculation of volumetric reserves, particularly for gas reservoirs. Reservoir pressure is needed to determine gas compressibility and formation volume factors for oil and natural gas, and to undertake PVT analysis. Material balance calculations for both oil and gas systems require initial reservoir pressures and subsequent pressure history after production has commenced.

Fluids flow when a pressure difference is created between two points. When hydrocarbons are removed from a reservoir, a pressure drop is created in the wellbore. This causes the pressure within the formation to drop. When a flow of fluid is stopped or ”shut in,” the pressure will equilibrate until it reaches stable reservoir conditions. The time required to reach a stabilized pressure varies from reservoir to reservoir. Analysis of the pressure stabilization or ”buildup” will reveal information about the permeability of the formation, the distance to reservoir boundaries, and any damage to the formation. If stable conditions are not reached, the pressure buildup data may be extrapolated to estimate the reservoir pressure.

3.6 Formation Volume Factor

The formation volume factor could be defined as the volumes in barrels that one stock tank barrel occupies in the formation (reservoir) at reservoir temperature and with the solution gas which can be held in the oil at that pressure. Because both the temperature and the solution gas increase the volume of the stock tank oil the factor will always be greater than 1.

When the crude oil travels from the formation pressure to surface pressure the existing solution gas converts to gas, it releases causing the volume of most oil to shrink. That shrinkage is called as formation volume factor.

3.6.1 Oil Formation Volume Factor

The oil formation volume factor, B_o, 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. B_o is always greater than or equal to unity. The oil formation volume factor can be expressed mathematically as:

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 p_b, the oil reaches its maximum expansion and consequently attains a maximum value of B_{ob} 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 ^oF , the value of B_o is equal to one. Most of the published empirical B_o correlations utilize the following generalized relationship:

Bo = f (R_s, γ_g, γ_o, T)

$$B_o = \frac{(V_o)_{P,T}}{(V_o)_{sc}} \tag{3.6}$$

Where:

B_o	=	oil formation volume factor, bbl/scf
$(V_o)_{P,T}$	=	volume of oil at reservoir pressure p and temperature, T, bbl
$(V_o)_{sc}$	=	volume of oil is measured under standard conditions, STB

A typical oil formation factor curve, as a function of pressure for an undersaturated crude oil

Six 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
- Other correlations

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

3.6.1.1 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

$$B_o = 0.9759 + 0.00012[R_s(\frac{\gamma_g}{\gamma_o})^{0.5} + 1.25(T-460)]^{1.2} \tag{3.7}$$

Where:

B_o	=	oil formation volume factor, bbl/scf
R_s	=	gas solubility, scf/STB
T	=	temperature, ^oR
γ_o	=	specific gravity of the stock-tank oil
γ_g	=	specific gravity of the solution gas

3.6.1.2 Glaso's Correlation

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

$$B_o = 1.0 + 10^A \tag{3.8}$$

Where

$$A = -6.58511 + 2.91329 \log B_{ob}^* - 0.27683(\log B_{ob}^*)^2 \tag{3.9}$$

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

$$B_{ob}^* = R_s(\frac{\gamma_g}{\gamma_o})^{0.526} + 0.968(T-460) \tag{3.10}$$

Where:

B_{ob}^*	=	correlating number
R_s	=	gas solubility, scf/STB
T	=	temperature, ^oR
γ_o	=	specific gravity of the stock-tank oil
γ_g	=	specific gravity of the solution gas

3.7 Gas formation volume factor

$$B_g = \frac{V_{p,T}}{V_{sc}} \tag{3.11}$$

Where:

B_g	=	gas formation volume factor, ft^3/scf
$V_{p,T}$	=	volume of gas at pressure p and temperature,T,ft^3
V_{sc}	=	volume of oil is measured under standard conditions, STB

In other field units, the gas formation volume factor can be expressed in bbl/scf to give:

$$B_g = 0.005035\frac{zT}{P} \tag{3.12}$$

Where:

B_g	=	gas formation volume factor, bbl/scf
z	=	gas compressibility factor
T	=	temperature, ^oR
P	=	pressure, psi

3.8 Gas Solubility

The gas solubility R_s is defined as the number of standard cubic feet of gas that 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 (bubble-point pressure) all the available gases are dissolved in the oil and the gas solubility reaches its maximum value. Rather than measuring the amount of gas that will dissolve in a given stock-tank crude oil as the pressure is increased, it is customary to determine the amount of gas that will come out of a sample of reservoir crude oil as pressure decreases.

As the pressure is reduced from the initial reservoir pressure p_i to the bubble-point pressure pb, 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 R_s 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

3.8.1 Standing's Correlation

Standing (1947) proposed a graphical correlation for determining the gas solubility as a function of pressure, gas specific gravity, API gravity, and system temperature. 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 hi proposed graphical correlation in the following more convenient mathematical form:

$$R_s = \gamma_g[(\frac{p}{18.2} + 1.4)10^x]^{1.2048} \tag{3.13}$$

with

$$x = 0.0125API - 0.00091(T - 460) \tag{3.14}$$

Where:

R_s	=	gas solubility, scf/STB
T	=	temperature, ^oR
P	=	pressure, psi
γ_g	=	specific gravity of the solution gas

It should be noted that Standing's equation is valid for applications at and below the bubble-point pressure of the crude oil.

3.9 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 pb have been proposed during the past 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 γ_g, oil gravity API, and temperature T, or:

p_b = f (R_s, γ_g, API, T)

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

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

3.10 Volumetric Method

The volumetric method entails the determining the physical size of the reservoir, the pore volume within the rock matrix and the fluid content within the void space. This provides an estimate of the hydrocarbons in place from which ultimate recovery can be estimated by using an appropriate recovery factor .Each of the factors used in the calculation have inherent uncertainties that when combined cause significant uncertainties in the reserve estimate.

$$OOIP = \frac{Ah\phi S_o 7758}{B_o} \tag{3.15}$$

Where:

$OOIP$	=	original oil in place
A	=	area
h	=	reservoir thickness
ϕ	=	porosity
S_o	=	saturation of oil
B_o	=	oil formation volume factor

$$GGIP = \frac{Ah\phi S_g 7758}{B_g} \tag{3.16}$$

Where:

$GGIP$	=	original gas in place
A	=	area
h	=	reservoir thickness
ϕ	=	porosity
S_g	=	saturation of gas
B_g	=	gas formation volume factor

3.10.1 Uncertainty

Uncertainty decreases as cumulative production increases and as more information becomes available.

Most of the parameters used to estimate reserve values are derived using the combination of subjective and objective methods. A subjective approach is essentially an opinion based on previous experience, whereas an objective approach relies on the analysis of data (eg., core data or previous well results).so the uncertainty and the level of uncertainty is affected and determined by the main following factors

- Reservoir type of oil field
- Source of reservoir energy
- Quantity and quality of the geological engineering, geophysical data and other related data
- Assumptions made as a result of estimating process
- Available technology and estimating programs
- Experience and knowledge of the reserves evaluators ,simulations and modeling

The degree of uncertainty can be of critical importance to investment and planning decisions and an inadequate appreciation of it can lead to costly failures.

3.10.2 Deterministic Method

In deterministic estimation, “best estimate” of each parameter is used in the calculation of reserves for each specific case due to the uncertainties in the fluid and rock properties. As a result, the probability distribution of the input parameters is generally not formally considered in the classification of reserves calculated using this method.

3.10.3 Probabilistic Method

Probabilistic estimation method is usually applied for circumstances where uncertainty is high, such as for reservoirs in the early stage of development or areas where new technology is being applied.

The probabilistic evaluation method is an uncertainty based approach. Probabilistic methods provide a systematical approach that represents for both the uncertainty in each of the parameters that impact reserves of individual development and production projects and the residual uncertainty in reserves in a portfolio of projects. Probabilistic methods help sure that quoted

Probabilistic methods do not launch new information nor do they initiate radical changes. They establish clarity to the statements of certainty or uncertainty

There are two types of methodology in the thesis to apply the probabilistic method.

- Plackett Burman design
- Monte Carlo simulation

3.10.3.1 Plackett Burman design

In 1964, R.L Plackett and Burman published their now famous paper “The Design of Optimal Multifuctional Experiments in Biometrika (vol.33). The paper described the construction of very economical designs with the run number a multiple of four (rather than a power of 2) . Plackett-Burman designs are very efficient screening designs when only main effects are of interest. The PB design in 12 runs for example, may be used for an experiment containing up to 11 factors. PB design exists for 20 run, 24 run, and 28 run (and higher) designs. (Source-www.itl.nist.gov) Their goal was to find experimental designs for investigating the dependence of some measured quantity on the number of independent variables (factors).

3.10.3.2 Monte Carlo simulation

Monte Carlo simulation is a process of running a model numerous times with a random selection from the input distributions for each variable. The results of these numerous scenarios can give a ”most likely” case, along with a statistical distribution to understand the risk or uncertainty involved. Computer programs make it easy to run thousands of random samplings quickly.

Generally, A, h, ϕ, Sw, and B_o are input parameters and N is the output. Once we specify values for each input, we can calculate an output value. Each parameter is viewed as a random variable; it satisfies some probability vs. cumulative–value relationship.

Parameters distributions

Log-normal distributions are often used for many of the volumetric model inputs. However, normal distributions and triangular distributions are sometimes considered for gas and other geological or engineering parameters like porosity, oil formation volume factor and gas oil saturation. Estimation the right parameters depends on the oilfield data and the reservoir engineer.

3.11 Material Balance

The concept of MBE was presented by Schilthuis in 1936 and is simply based on the principle of the volumetric balance.

The material balance equation has long been recognized as one of the basic tools of the reservoir engineers for interpreting and predicting reservoir performance when mbe is properly applied can be used to

- Estimate initial hydrocarbon volumes in place
- Predict reservoir pressure
- Calculate water influx
- Predict future reservoir performance
- Predict ultimate hydrocarbon ultimate recovery under various types of primary drive mechanisms

It states that the cumulative withdrawal of reservoir fluids is equal to the combined effect of fluid expansion pore volume compaction and water influx. In its simplest form, the equation can be written on a volumetric basis as:

Initial volume = volume remaining + volume removed

Since oil, gas, and water are present in petroleum reservoirs, the MBE can be expressed for the total fluids or for any one of the fluids present. Three different forms of the MBE are presented below in details. These are:

- Generalized MBE
- MBE as an equation of a straight line
- Tracy's form of the MBE

3.11.1 Generalized MBE

The MBE is designed to treat the reservoir as a single tank or region that is characterized by homogeneous rock properties and described by an average pressure, i.e., no pressure variation throughout the reservoir, at any particular time or stage of production. Therefore, the MBE is commonly referred to as a tank model or zero-dimensional (0-D) model. These assumptions are of course unrealistic since reservoirs are generally considered heterogeneous with considerable variation in pressures throughout the reservoir. However, it is shown that the tank-type model accurately predict the behavior of the reservoir in most cases if accurate average pressures and production data are available.

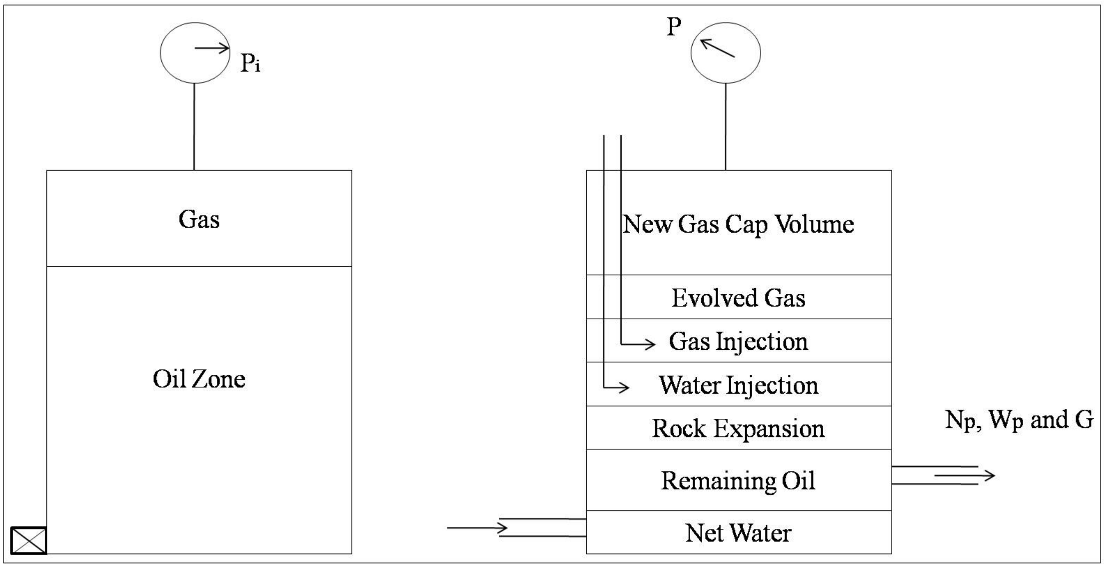

Figure 3.1: Tank-model Concept

3.11.1.1 Basic assumptions in the MBE

The MBE keeps an inventory on all material entering, leaving, or accumulating within a region over discrete periods of time during the production history. The calculation is most vulnerable to many of its underlying assumptions early in the depletion sequence when fluid movements are limited and pressure changes are small. Uneven depletion and partial reservoir development compound the accuracy problem.

The basic assumptions in the MBE are as follows:

Constant temperature

Pressure–volume changes in the reservoir are assumed to occur without any temperature changes. If any temperature changes occur, they are usually sufficiently small to be ignored without significant error.

Reservoir characteristics

The reservoir has uniform porosity, permeability, and thickness characteristics. In addition, the shifting in the gas–oil contact or oil–water contact is uniform throughout the reservoir.

Fluid recovery

The fluid recovery is considered independent of the rate, number of wells, or location of the wells. The time element is not explicitly expressed in the material balance when applied to predict future reservoir performance.

Pressure equilibrium

All parts of the reservoir have the same pressure and fluid properties are therefore constant throughout. Minor variations in the vicinity of the wellbores may usually be ignored. Substantial pressure variation across the reservoir may cause excessive calculation error.

It is assumed that the PVT samples or data sets represent the actual fluid compositions and that reliable and representative laboratory procedures have been used. Notably, the vast majority of material balances assume that differential depletion data represents reservoir flow and that separator flash data may be used to correct for the wellbore transition to surface conditions. Such “black-oil” PVT treatments relate volume changes to temperature and pressure only. They lose validity in cases of volatile oil or gas condensate reservoirs where compositions are also important. Special laboratory procedures may be used to improve PVT data for volatile fluid situations.

Constant reservoir volume

Reservoir volume is assumed to be constant except for those conditions of rock and water expansion or water influx that are specifically considered in the equation. The formation is considered to be sufficiently competent that no significant volume change will occur through movement or reworking of the formation due to overburden pressure as the internal reservoir pressure is reduced. The constant-volume assumption also relates to an area of interest to which the equation is applied.

Reliable production data

All production data should be recorded with respect to the same time period. If possible, gas cap and solution gas production records should be maintained separately. Gas and oil gravity measurements should be recorded in conjunction with the fluid volume data. Some reservoirs require a more detailed analysis and the material balance to be solved for volumetric segments. The produced fluid gravities will aid in the selection of the volumetric segments and also in the averaging of fluid properties. There are essentially three types of production data that must be recorded in order to use the MBE in performing reliable reservoir calculations.

These are:

- Oil production data, even for properties not of interest, can usually be obtained from various sources and is usually fairly reliable.
- Gas production data is becoming more available and reliable as the market value of this commodity increases; unfortunately, this data will often be more questionable where gas is flared.
- The water production term need represent only the net withdrawals of water; therefore, where subsurface disposal of produced brine is to the same source formation, most of the error due to poor data will be eliminated.

$$N = \frac{N_p[B_o + (R_p - R_s)B_g] - (W_e - W_pB_w) - G_{inj}B_{ginj} - W_{inj}B_{wi}}{(B_o - B_{oi}) + (R_{si} - R_s)B_g + mB_{oi}[(\frac{B_g}{B_{gi}}) - 1]B_{oi}(1+m)[\frac{S_{wi}c_w + c_f}{1-S_{wi}}]\Delta P} \tag{3.17}$$

3.11.2 The Material Balance as an Equation of a Straight Line

There are essentially three unknowns in Generalized MBE

- the original oil-in-place N
- the cumulative water influx We
- the original size of the gas cap as compared to the oil zone size m

In developing a methodology for determining the above three unknowns, Havlena and Odeh expressed the Generalized MBE Eq (3.17) in a more condensed form:

$$F = N[E_o + mE_g + E_{f,w}] + (W_e + W_{inj}B_w + G_{inj}B_{ginj}) \tag{3.18}$$

Assuming, for the purpose of simplicity, that no pressure maintenance by gas or water injection is being considered, the straight line relationship can be further simplified and written as:

$$F = N[E_o + mE_g + E_{f,w}] + W_e \tag{3.19}$$

in which the terms F, E_o, E_g, and $E_{f,w}$ are defined by the following relationships:
F represents the underground withdrawal and is given by:

$$F = N_p[B_t + (R_p - R_s B_g)] + W_p B_w \quad (3.20)$$

In terms of the two-phase formation volume factor B_t , the underground withdrawal “F” can be written as:

$$F = N_p[B_t + (R_p - R_{si} B_g)] + W_p B_w \quad (3.21)$$

E_o describes the expansion of oil and its originally dissolved gas and is expressed in terms of the oil formation volume factor as:

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s))B_g \quad (3.22)$$

Or, equivalently, in terms of B_t ;

$$E_o = B_t - B_{ti} \quad (3.23)$$

E_g is the term describing the expansion of the gas cap gas and is defined by the following expression:

$$E_g = B_{oi}[(\frac{B_g}{B_{gi}}) - 1] \quad (3.24)$$

In terms of the two-phase formation volume factor B_t , essentially B_{ti} = B_{oi} or:

$$E_g = B_{ti}[(\frac{B_g}{B_{gi}}) - 1] \quad (3.25)$$

$E_{f,w}$ represents the expansion of the initial water and the reduction in the PV and is given by:

$$E_{f,w} = (1+m)B_{oi}[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}]\Delta P \quad (3.26)$$

Where:

F	=	Underground withdrawal
N	=	Initial oil-in-place, STB
m	=	Ratio of gas cap gas volume to oil volume, bbl/bbl
B_{oi}	=	Initial oil formation volume factor, bbl/STB
B_o	=	Oil formation volume factor, bbl/STB
B_g	=	Gas formation volume factor, bbl/scf
B_{gi}	=	Initial gas formation volume factor, bbl/scf
R_p	=	Cumulative gas–oil ratio, scf/STB
R_s	=	Gas solubility, scf/STB
R_{si}	=	Initial gas solubility, scf/STB
W_e	=	Cumulative water influx, bbl
E_g	=	Expansion of the gas cap gas
$E_{f,w}$	=	Expansion of the initial water and the reduction in the PV
S_{wi}	=	Initial water saturation
c_w	=	Water compressibility, psi^{-1}
c_f	=	Formation (rock) compressibility, psi^{-1}

The applications of the straight-line form of the MBE in solving reservoir engineering problems are presented next to illustrate the usefulness of this particular form. Six cases of applications are presented and include:
Case 1: Determination of N in volumetric undersaturated reservoirs
Case 2: Determination of N in volumetric saturated reservoirs
Case 3: Determination of N and m in gas cap drive reservoirs
Case 4: Determination of N and W_e in water drive reservoirs
Case 5: Determination of N, m, and W_e in combination drive reservoirs
Case 6: Determination of average reservoir pressure p

Case1:Volumetric undersaturated oil reservoirs

Assuming no water or gas injection, several terms in the straight line Eq (3.17) may disappear when imposing the conditions associated with the assumed reservoir driving mechanism. For a volumetric and undersaturated reservoir, the conditions associated with driving mechanism are:

W_e	=	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

After applying the above conditions on Eq (3.17),

$$F = N(E_o + E_{f,w}) \tag{3.27}$$

or:

$$N = \frac{F}{E_o + E_{f,w}} \tag{3.28}$$

with:

$$F = N_p B_o + W_p B_w \tag{3.29}$$

$$E_o = (B_o - B_{oi}) \tag{3.30}$$

$$E_{f,w} = B_{oi}[\frac{c_w S_w + c_f}{1 - S_w}]\Delta P \tag{3.31}$$

$$\Delta p = p_i - \bar{p}_r \tag{3.32}$$

Eq (3.25) could be used to verify the characteristic of the reservoir driving mechanism and to determine the initial oil-in-place.

A plot of the underground withdrawal F versus the expansion term $(E_o + E_{f,w})$ should result in a straight line going through the origin with N being the slope. It should be noted that the origin is a “must” point; thus, one has a fixed point to guide the straight-line plot.

This interpretation technique is useful in that, if the linear relationship is expected for the reservoir and yet the actual plot turns out to be non-linear, then this deviation can itself be diagnostic in determining the actual drive mechanisms in the reservoir.

A linear plot of the underground withdrawal F vs. $(E_o + E_{f,w})$ indicates that the field is producing under volumetric performance, i.e., no water influx, and strictly by pressure depletion and fluid expansion. On the other hand, a non-linear plot indicates that the reservoir should be characterized as a water drive reservoir.

Case2: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 in a volumetric saturated oil reservoir is the initial oil-in-place N. Normally, the water and rock expansion term $E_{f,w}$ is negligible in comparison to the expansion of solution gas; however, it is recommended to include the term in the calculations. that of Eq (3.25)

$$F = N(E_o + E_{f,w})$$

However, the parameters F and E_o that constitute the above expression are given in an expanded form to reflect the reservoir condition as the pressure drops below the bubble point. The underground withdrawal F and the expansion term $(E_o + E_{f,w})$ are defined by:
In terms of formation volume factor B_o ,

$$F = N_p[B_o + (R_p - R_s B_g)] + W_p B_w \tag{3.33}$$

In terms of the two-phase formation volume factor B_t ,

$$F = N_p[B_t + (R_p - R_{si} B_g)] + W_p B_w \tag{3.34}$$

E_o :In terms of th formation volume factor

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s))B_g \tag{3.35}$$

Or, equivalently, in terms of B_t ;

$$E_o = B_t - B_{ti} \tag{3.36}$$

And:

$$E_{f,w} = B_{oi}[\frac{c_w S_w + c_f}{1 - S_w}]\Delta P \tag{3.37}$$

3.12 Decline Curve Analysis

Decline curve analysis is based on the production data. The technique is based on empirical observation of oilfield production decline. Arps (1945) proposed that the "curvature" in the production rate versus time curve can be expressed mathematically by one of the hyperbolic family of equations. Arps recognized the following three types of rate decline behavior:

- Exponential
- Hyperbolic
- Harmonic

Nearly all conventional decline curve analysis is based on empirical relationships of production rate versus time given by Arps (1945) as:

$$q = \frac{q_i}{(1 + bD_i t)^{\frac{1}{b}}} \tag{3.38}$$

Where:

q	=	well's production rate at time t, (STB/day)
q_i	=	well's initial production rate, (STB/day)
D_i	=	initial nominal exponential decline rate, t=0
b	=	decline exponent
t	=	time (day)

3.12.1 Exponential Decline

The most common decline curve function is the exponential decline. In the exponential decline, the well's production data plots as a straight line on a semi log paper. The equation of the straight line on the semi log paper is given by (b=0):

$$q = q_i \exp^{-D_i t} \tag{3.39}$$

$$N_p = \frac{q_i - q_t}{D_i} \tag{3.40}$$

Where:

q	=	well's production rate at time t, (STB/day)
q_i	=	well's initial production rate, (STB/day)
D_i	=	initial nominal exponential decline rate, t=0
b	=	decline exponent
t	=	time (day)
N_p	=	cumulative oil production(STB)

3.12.2 Hyperbolic Decline

Alternatively, if the well's production data plotted on a semi-log paper concaves upward, and then it is modeled with a hyperbolic decline. The equation of the hyperbolic decline is given by (0<b<1):

$$q = q_i(1 + bD_i t)^{\frac{-1}{b}} \tag{3.41}$$

$$N_p = \frac{q_i^b(q_i^{1-b} - q_t^{1-b})}{(1-b)D_i} \tag{3.42}$$

Where:

q	=	well's production rate at time t, (STB/day)
q_i	=	well's initial production rate, (STB/day)
D_i	=	initial nominal exponential decline rate, t=0
b	=	decline exponent
t	=	time (day)
N_p	=	cumulative oil production(STB)

3.12.3 Harmonic Decline

A special case of the hyperbolic decline is known as "harmonic decline", where b is taken to be equal to 1. The following table summarizes the equations used in harmonic decline (b=1):

$$q = \frac{q_i}{1 + D_i t} \tag{3.43}$$

$$N_p = \frac{q_i}{D_i} \ln \frac{q_i}{q_t} \tag{3.44}$$

Where:

q	=	well's production rate at time t, (STB/day)
q_i	=	well's initial production rate, (STB/day)
D_i	=	initial nominal exponential decline rate, t=0
b	=	decline exponent
t	=	time (day)
N_p	=	cumulative oil production(STB)

CHAPTER 4
DESIGN PROCEDURE

In this work, the methodology approach is quite simple and usual to generate reliable and reasonable outcomes.

4.1 Volumetric Calculation

Step-1

To collect all the P10, P50, P90 values for each volumetric parameter (area, thickness,water saturation, formation volume factor, porosity)

Step-2

To build an excel work sheet and apply the simple volumetric Eq (3.15)

$$OOIP = \frac{Ah\phi S_o 7758}{B_o}$$

Step-3

To use the ”IF” function excel formula and proceed the probabilistic calculation

4.2 Material Balance Equation

Step-1

To assemble all the necessary data (production, pressure ,PVT and reservoir properties)
To assume the values of water and rock compressibility factors

Step-2

Calculate initial water and rock expansion term $E_{f,w}$ from Eq (3.31)

$$E_{f,w} = B_{oi}[\frac{c_w S_w + c_f}{1 - S_w}]\Delta P$$

Step-3

To tabulate all the values of the required data
Then, to get N value , firstly apply the the undersaturated conditions Eq (3.32, 3.29, 3.30) to compute the E_o, F, ΔP

$$\Delta p = p_i - \bar{p}_r$$

$$F = N_p B_o + W_p B_w$$

$$E_o = (B_o - B_{oi})$$

Step-4

For the undersaturated performance ,initial oil in place is described by Eq (3.28)
Calculate N using the undersaturated Reservoir data

$$N = \frac{F}{E_o + E_{f,w}}$$

Step-5

Then calculate the N using the entire reservoir dat by substitutuing in saturated conditions Eq (3.34, 3.35) to compute the E_o, F, ΔP

$$F = N_p[B_t + (R_p - R_{si}B_g)] + W_p B_w$$

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s))B_g$$

The described procedure for MBE could be applied for both 3700sand and 3800sand

4.3 Decline Curve Analysis

Step-1

Collect the production data of the 3700sand and 3800sand
Plot the production data : q_o (STB/day) vs time (years)

Choose the decline interval
Define q_i, q
Calculate the De q_i, q using the defined q_i, q

$$D_e = \frac{q_i - q}{q_i}$$

Step-2

Decide the decline type using the past production trend
There could be three types of decline according to the exponent b
Thus, check the b value for all types of decline trend
For exponential and harmonic decline, b value is 0 and 1
So, tabulate the all possible b for harmonic decline then calculate the Np Eq (3.42) using calculated De and defined q_i, q for all b values and then compare the actual Np

$$q = q_i(1 + bD_it)^{\frac{-1}{b}}$$

$$N_p = \frac{q_i^b(q_i^{1-b} - q_t^{1-b})}{(1-b)D_i}$$

We did compute the Np for exponential and harmonic to be compare with actual Np using the Eq (3.40) & (3.44)

$$q = q_i \exp^{-D_it}$$

$$N_p = \frac{q_i - q_t}{D_i}$$

$$q = \frac{q_i}{1 + D_it}$$

$$N_p = \frac{q_i}{D_i} \ln \frac{q_i}{q_t}$$

Choose the reasonable b which could give the value of calculated Np that would not be much different with the actual cumulative production Np

Step-3

After we could decide the decline type,apply the corresponding equations and estimate the future production rate and reservoir life.

CHAPTER 5

RESULTS AND DISCUSSION

3700Sand and 3800Sand of Okhmintaung Formation are selected in this work since it is the most productive formation. The objective of the work is to compute the OOIP by volumetric and to make sure it with MBE and then finally, forecast with DCA.

5.1 Volumetric Method

When the range of uncertainty is represented by a probability distribution, a low, best and high estimate shall be provided that: There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

(Table 5.1 and Table 5.2) provide the P10, P50, P90 volumetric parameters to process the deterministic and probabilistic calculations.

Table 5.1: Reservoir Parameter For 3700Sand

Area(acre)			h(ft)			ϕ			s_{wi}			B_{oi}		
P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
190	314	438	51	61	71	0.16	0.21	0.26	0.2	0.25	0.30	1.35	1.25	1.15

Table 5.2: Reservoir Parameter For 3800Sand

Area(acre)			h(ft)			ϕ			s_{wi}			B_{oi}		
P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
287	411	535	51	61	71	0.16	0.21	0.26	0.2	0.25	0.30	1.35	1.25	1.26

Volumetric equation Eq(3.15) is applied to calculate the initial oil in place. Parameters like thickness (h) and initial water saturation (S_{wi}) are huge impact on the OOIP. There is always uncertainty in such parameters. This is the reason why sometimes overestimation and underestimation occurs. To reduce the uncertainty, not only the deterministic way but also the probabilistic method is used in the work.

In the former one, for example when OOIP is calculated for P50, pick up the P50 values for each parameter and it is the same way for P10 and P90 result.

In the probabilistic approach, IF function was applied on the Microsoft Excel for three conditions low, best and high. And the design was based on the Plackmann Burmann Design Figure(5.1) .

Run time	1	2	3	4	5
1	H	L	L	H	L
2	L	H	L	L	H
3	H	L	H	L	L
4	L	H	L	H	L
5	L	L	H	L	H
6	H	H	M	H	H
7	M	M	M	M	M
8	L	L	M	L	L
9	L	H	H	L	H
10	H	L	H	H	L
11	L	H	L	H	H
12	H	L	H	L	H
13	H	H	L	H	L

Figure 5.1: Volumeric Calculation Pattern based on Plackett Burmann Design

Technically, the values of Probabilistic Approach is more precise and reliable.It can be clearly seen in (Table 5.3 and Table 5.4).

Table 5.3: OOIP Result for 3700Sand by Volumetric Method

	P90	P50	P10
OOIP by Deterministic	7.14	18.72	38.14
OOIP by Probabilistic	10.15	16.86	37.13

Table 5.4: OOIP Result for 3800Sand by Volumetric Method

	P90	P50	P10
OOIP by Deterministic	10.73	24.5	46.59
OOIP by Probabilistic	15.33	23.54	45.36

5.2 Material Balance

By applying MBE equations (described in the chapter 3), for both conditions ,saturated and undersaturated conditions were calculated.

3700Sand by MBE

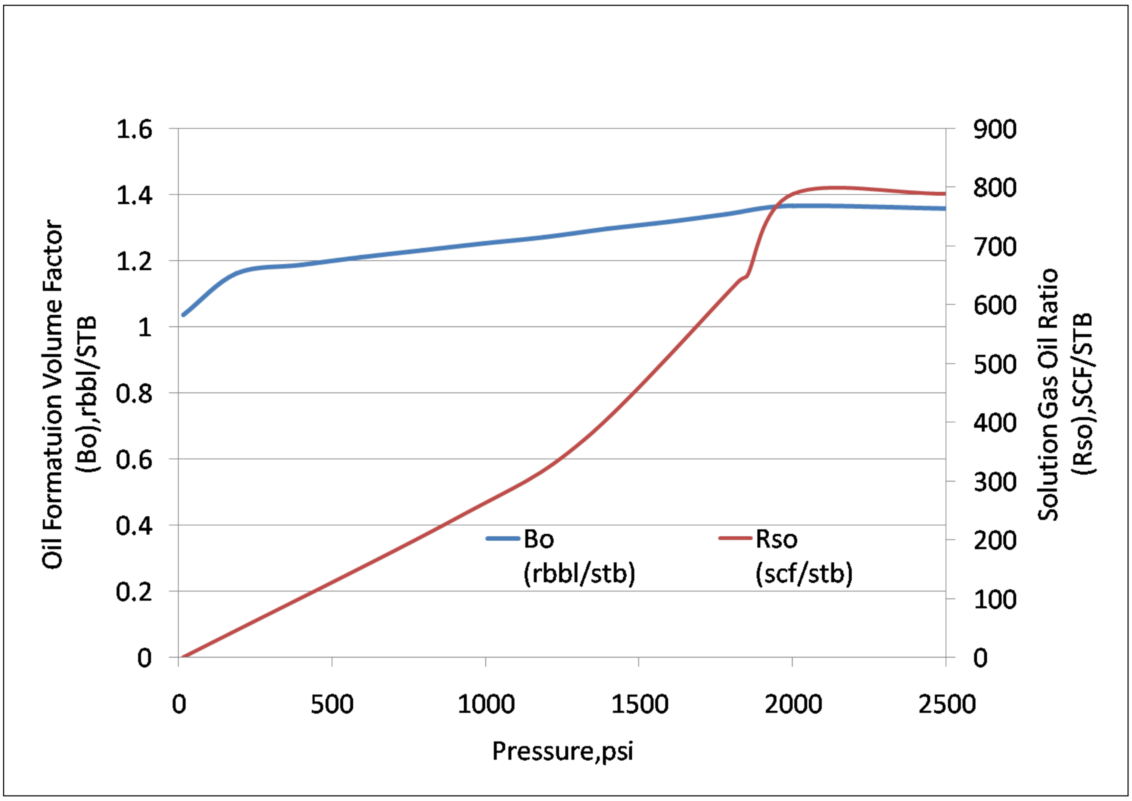

Figure 5.2: 3700Sand B_o and R_{so} chart

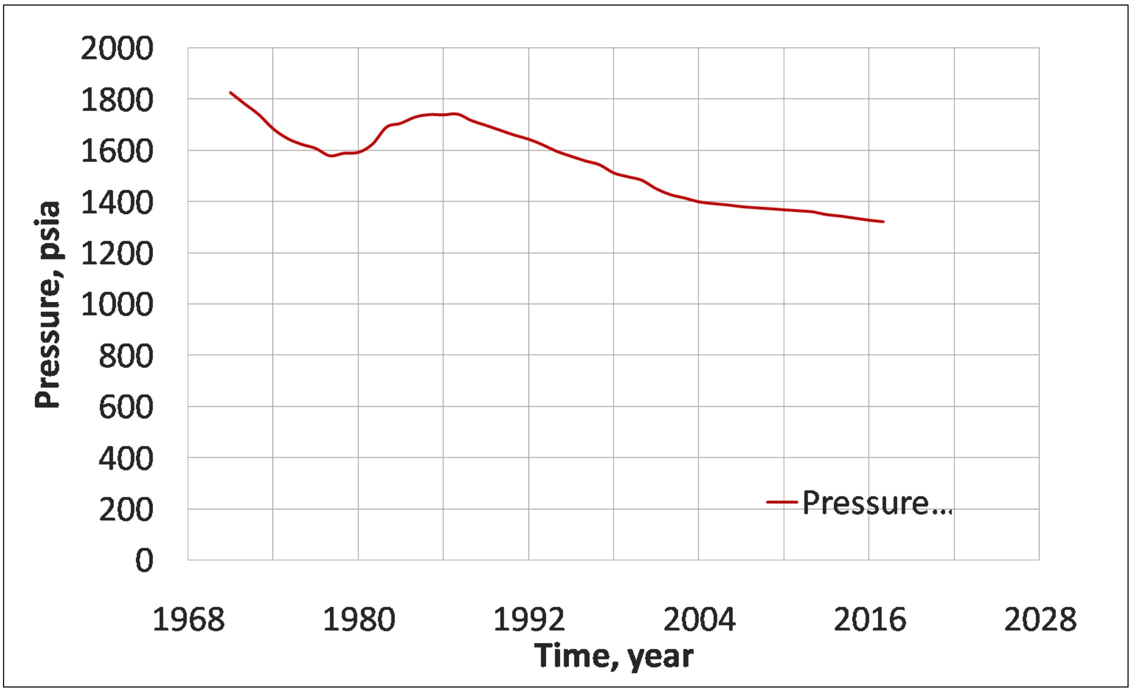

Figure 5.3: Reservoir Pressure Profile for 3700Sand

37sand is initially in saturated oil reservoir according to the pressure vs production collection. So, the following Generalized MBE was applied for this work. The required PVT datas and pressure profile is described as Figure(5.2)and Figure(5.3)

$$N = N_p(B_o + B_g(R_p - R_s))/(B_o - B_{oi}) + B_g(R_{si} - R_s) \tag{5.1}$$

The result of 37sand is presented in Table(5.5). According to the theory, OOIP by MBE is active OOIP and should be smaller than the volumetric OOIP. And in this work, theory is quite right. Cumulative production, Np is known, so recovery factor and remaining reserve were evaluated. For MBE calculation section, OOIP by MBE was applied to estimate RF and remaining oil.

Table 5.5: Result for 3700Sand by Material Balance Equation

OOIP	24.22MMSTB
RF	37%
Remaining Reserve	15.32 MMSTB

3800Sand by MBE

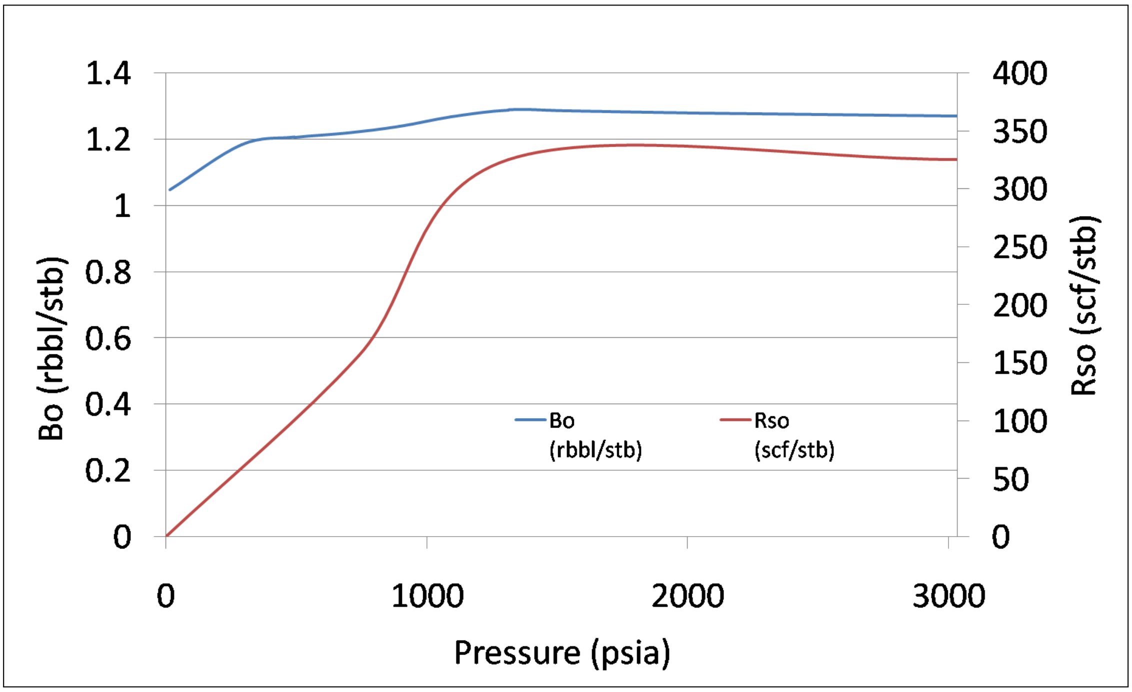

Figure 5.4: 3800Sand B_o and R_{so} chart

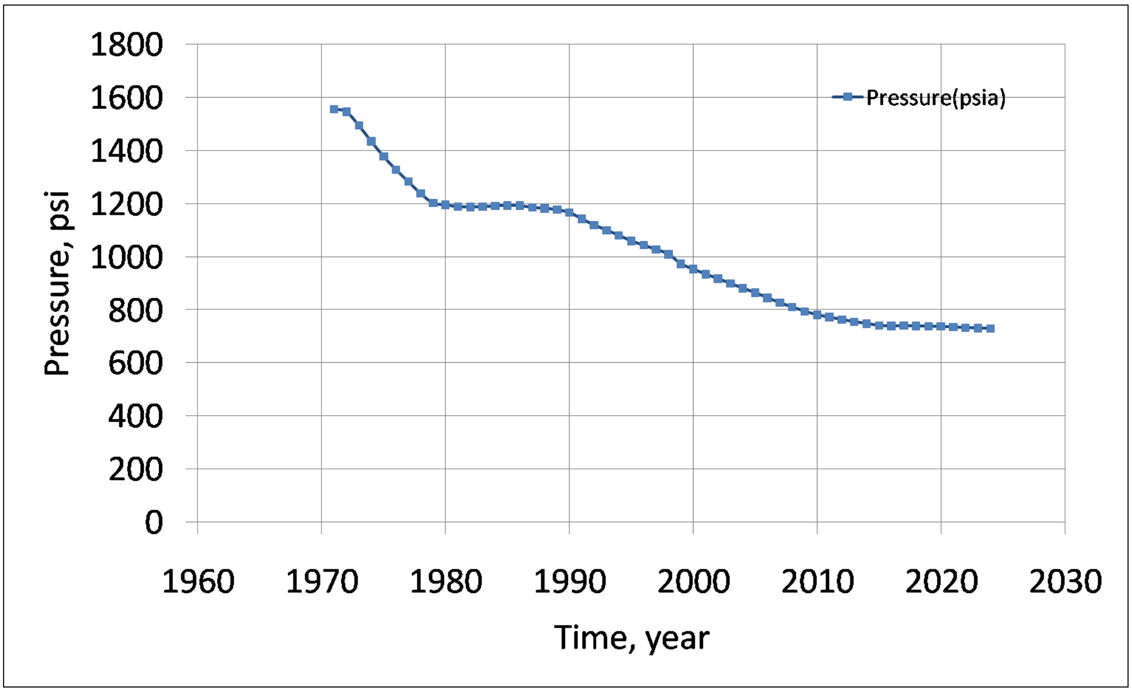

Figure 5.5: Reservoir Pressure Profile for 3800Sand

According to the pressure vs production collection, 38sand is considered to be undersaturated condition at the initial reservoir pressure. So,both of the undersaturated and saturated reservoir conditions were applied in this work.

The result of 38sand is presented in Table(5.6). OOIP value of 38sand is almost equal with the P10 result by volumetric calculation. Consequently, MBE result for 38sand is approved as a reasonable one. Therefore, 38Sand can be confirmed as a productive one and it still has a pretty great amount of remaining reserve.

Table 5.6: Result for 3800Sand by Material Balance Equation

OOIP	45.409MMSTB
RF	20%
Remaining Reserve	36.65 MMSTB

5.3 Decline Curve Analysis

Since 3700sand and 3800sand are productive ones, efficient production data are available and so, decline curve analysis was applied to both sands. Methodology approach is the same for two of them.

3800sand by DCA

In this work, for 3800sand,the production was intended to start at time zero. As a very first step , production history of 3800sand Figure(5.6) was employed to define the decline period.

Theoretically, the most reasonable period was selected to be employed in DCA. After that , the past production decline rate trend and exponent were decided. Finally, as the main purpose of DCA, forecasting the future was performed and could be seen in Figure(5.7). The economic consideration is not included in this work.

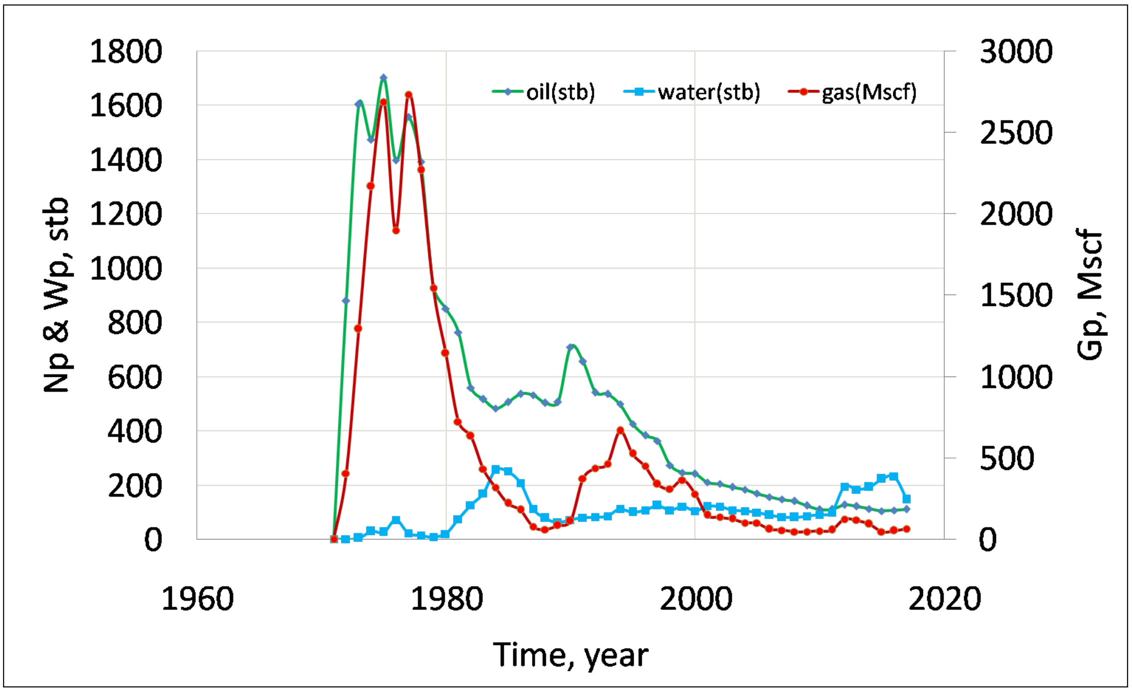

Figure 5.6: 3800Sand Production Performance Chart

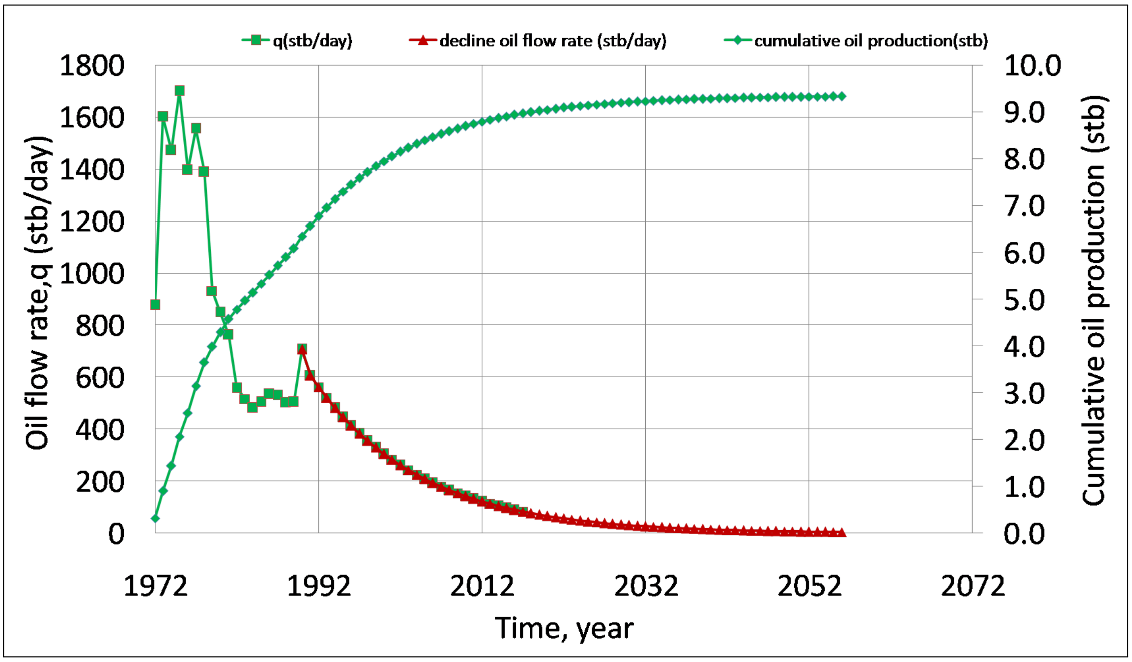

Figure 5.7: 3800Sand Future Forecasting Decline Curve

3700Sand by DCA

The same procedure as described in 3800Sand

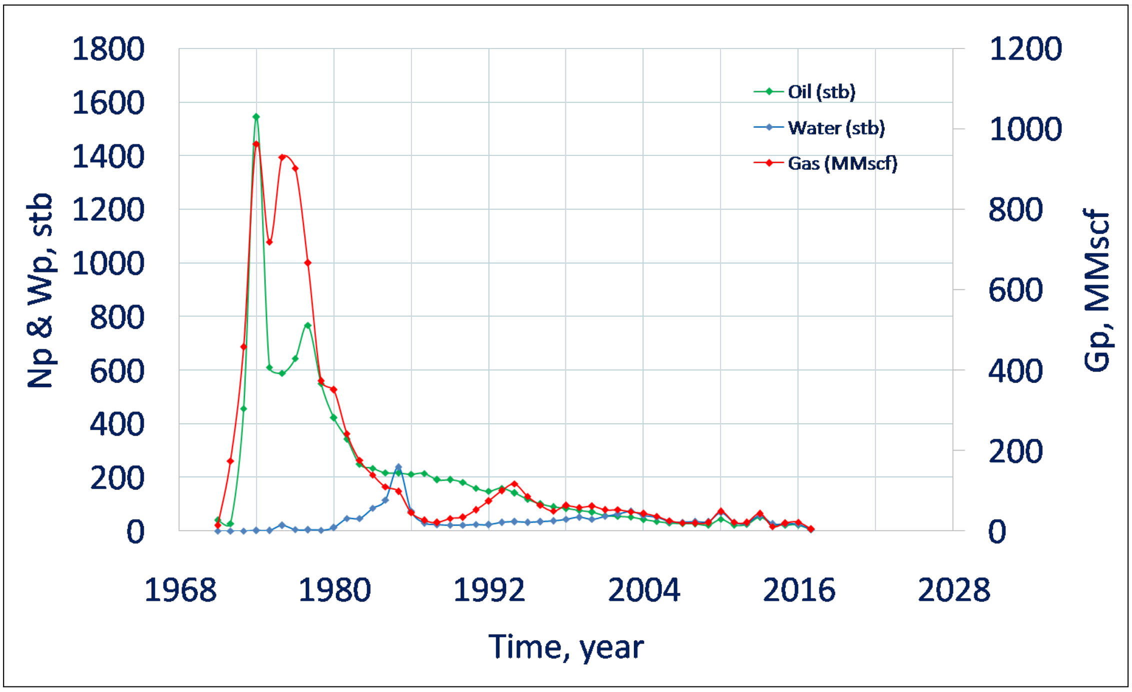

Figure 5.8: 3700Sand Production Performance Chart

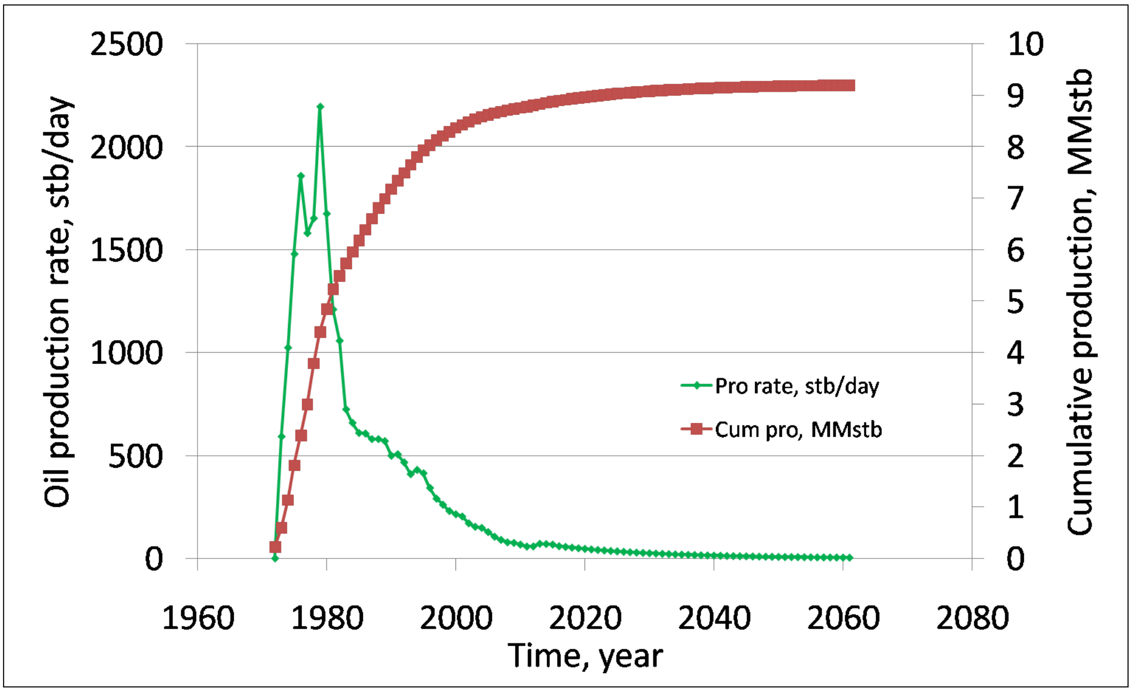

Figure 5.9: 3700Sand Future Forecasting Decline Curve

CHAPTER 6
CONCLUSION AND RECOMMENDATION

CONCLUSION

Reserve estimation is a complex process affected by many factors, not all of them are transparent. Uncertainty and subjectivity are inherent in the process. Improving reliability is a challenge in this work. However, it is obvious that probabilistic approach should be preferred over the deterministic approach in the volumetric method. In the MBE calculations, a source of error is introduced while determining the initial oil in place. So for reliable estimate, there must be sufficient pressure and production data. Another methodology, DCA analysis is intended to forecast future performance. The trend established form the past behavior is extrapolated until the defined flow rate limit is reached.

RECOMMENDATION

According to this work, there should be adequate and reliable data collection in terms of pressure, production , PVT and reservoir fluid and rock properties in both frequency and quality for proper use of the reserve estimation.
Moreover, it is known that reserves are intrinsically dynamic , being subject to revisions over time with more developed and updated technology as more data become available so that It could be a good impact on reservoir management palan and economic decisions especially for mature field such like Mann Field

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