POLITECNICO DI TORINO

Department of Environment, Land and Infrastructure Engineering

Master of Science in Petroleum Engineering

PRODUCTION DECLINE ANALYSIS IN FORECASTING PERFORMANCE OF PRODUCING WELLS

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ABSTRACT

Production Data Analysis (PDA) has become a hotspot technique in recent reservoir engineering practice used for the dynamic description of a reservoir property, predicting the long-term performance and to quantify reservoirs characteristic parameters by analyzing the daily production. It is also used to evaluate communication relation between well and infill potential of a reservoir property. Input data required for PDA are the production rates and sometimes flowing pressures if available.

The study of PDA presents a way of applying production historical data to guess the trend of production by fitting a curve through the production history and assuming this line will continue into the future and to diagnose the reservoir parameters contributing to a production decline. The parameters here in sought after includes the reservoir permeability, skin factor, drainage radius and reserves. Popular methods widely applied in PDA include the empirical methods like the Arps Decline method, type curve matching technique like classical Fetkovish and Blasingame type curves and the flowing material balance method. PDA and Pressure Transient Analysis (PTA) has some features in common but are different in terms of precision and methodology. While PDA is conducted using flow rate and pressure data which is of countless quantity during production but with low resolution, PTA uses a high-resolution pressure transient signals for analysis.

A blend of PDA and PTA enhances interpretation by reducing the uncertainties in the parameters interpretation. PDA can be used as a means of confirming reservoir characterization obtained during PTA since they complement each other but can however be used independently to achieve equivalent results as applied in this work. The strength of Production Data Analysis is seen through the resolution of the historical data and the accuracy of the predicting tool. Estimated reserves and projected performance trend enhances reservoir asset evaluation, devising developmental strategies and making overall economic and investment plans.

DEDICATION

TO THE ALMIGHTY GOD

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1 Introduction

One widespread practice by petroleum engineers is to estimate hydrocarbon reserves and to estimate or forecast the future performance of wells and also the entire reservoir. This has so been achieved by many methods (Material Balance Equation, Decline Curve and Type Curve technique), of which decline curve analysis numbers among the earliest methods and yet the conventional tool most practically applied. On a larger perspective, it aids as a means of identifying well production problems. Its output (the estimation of remaining reserves) is completely dependent and determined by certain initial conditions and the resolution of the history production data of the well or field.

The entire production lifetime of hydrocarbon reservoirs shows three main phases similar to what is described in figure 1: the ramp-up or build-up phase, corresponding to the increasing field production rate as newly drilled and completed producers are brought on stream; the plateau or peak phase, where a constant rate of production is maintained which can last after some years for an oil field but longer for a gas field; the rate decline phase, which is usually the longest period as all producers would at this phase exhibit a decline in production [1]. For depletion drive reservoirs, the peak phase is described by a decrease in bottomhole flowing pressure until the decline phase where the flowing bottomhole pressure remains fairly constant.

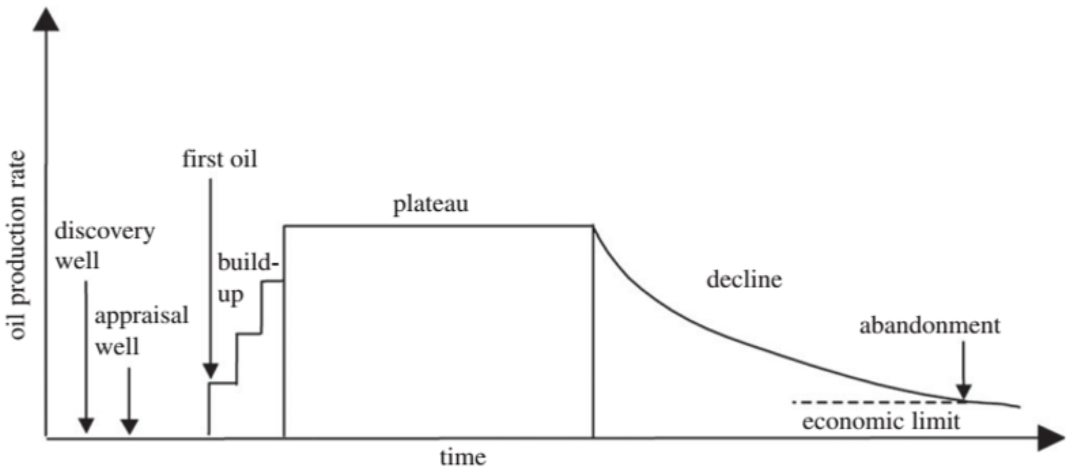

Figure 1 Idealized behavior of an oilfield production [1]

Production data analysis is the most commonly used form of data analysis employed in evaluation oil and gas production and predicting future performance. This data analysis technique is grounded on the statement that the historical production trend can be extrapolated and described by mathematical expressions. The method of extrapolating a "trend" for the purpose of estimating future performance must gratify the condition that the features which triggered changes in the past performance, i.e., decline in the flow rate, will function in the same way in the future [2]. The use of the entire rate history from production to forecast the wells future performance is achieved by the Arps empirical decline analysis. Though this method is extensively applied and yields reliable results compared to other estimation methods, its results can be compared to the others to evaluate new areas of investment. The projected performance trend of the historical production is used in implementing technical deductions, devising developmental strategies, making economic plans and as a criterion to advice management.

Arps (1945) empirical method is applicable only to a stabilized reservoir (boundary dominated flow) and assumes a constant bottomhole flowing pressure (BHFP). It estimates the expected ultimate recovery (EUR) but cannot describe the transient flow regime and determine the formation parameters unless extended by other methods. Fetkovish (1980) began this extension by introducing the transient flow equations in PTA to the Arps empirical equations making analysis possible for both transient and boundary dominated flows and since its derived from the Arps postulates, it also assumes a constant BHFP. Palacio and Blasingame (1993) removed the limitation on the Arps and Fetkovish methods when they considered the variability of the BHFP and the changes in Pressure-Volume-Temperature (PVT) characteristics with pressure by normalizing the rate with the pressure changes and introducing the concept of the material balance time (tc). They also used the flow rate integral and its derivative as supplementary curves to reduce the uncertainty of interpretation results [3].

1.1 Study Objectives

The core objective of this study is to provide an interpretation observed from a history production data through the application of conventional, classical and modern production data analysis methods. Production data generated from a synthetic reservoir model is used to envisage the future or the long-term production performance of a well and to refine our understanding by identifying key parameters that contributed to the production decline.

1.2 Scope of Work

This work involves a two-way approach; applying forward modelling by using a numerical simulator to develop a synthetic reservoir model to create the production data used in the analysis, and an inverse modelling approach by using an analytical tool on the generated production data to describe the dynamic response from the synthetic reservoir model. This analysis is based on a single producing well. Production from multi wells draining the same reservoir are mostly manifolded, hence a single well as in our case can be representative. As Decline curves still remains a useful tool in production forecast, chapter 2 of this work is focused on reviewing the various theoretical techniques applied and previous references related to decline curves. In chapter 3, we applied the various techniques, the traditional Arps method, classical Fetkovish's type curves and the modern Blasingame's type curves, to our production data obtained from numerical simulation. Chapter 4 proceeds with the interpretation of our results and discussion to ascertain the practical application of each technique with sensitivity analysis made on some notable reservoir parameters and finally, work is concluded in chapter 5.

2 Literature Review

This chapter lays a basis on which the proceeding chapters will be built on. In the first subsection, the fundamentals of oil production are described and leads to exposition of production decline in the next subsection. The techniques of decline curve analysis (DCA) are discussed as well as the methods used for multiphase flows and the impact resulting from drive mechanisms and reservoir rock and fluid properties. The chapter completes with a description of theoretical work relating to further developments to the DCA.

2.1 Basic Concept of Oil Production

The accumulation of conventional oil occurs through several geological processes of organic materials buried over an extensive range of temperatures and pressures in underground formations known as reservoirs. A typical reservoir is a rock of considerable pore space where petroleum resides in the tiny void spaces between the rock grains and is permeable as well, allowing for the rock to conduct the fluids stored up within the pores, such as sandstone or carbonates. An oilfield may comprise of one or numerous reservoirs in the subsurface accessible from the surface by drilling. Distinction is usually made between unconventional and the conventional oil resources; while the conventional resources are considered to be found in the typical rock configurations with a source rock, a reservoir rock and a trap, the unconventional resources are fossil resources where one or more of the components of the conventional resources are missing.

Conventional oilfields account for more than 90 percent of global oil production, with slight contributions coming from unconventional oil, natural gas liquids (ethane, propane, butane and pentane) and other liquids [1]. Oil production fluid volume is frequently measured in barrels (b or bbl) equivalent to a volume of 42 US gallons or approximately 159 liters. Alternatively, production flow rate, expressed in barrels per day (b/d or bbl/d) can be used. An oilfield may be described as a field containing hydrocarbon, preferably oil, from less of a million barrels (MMbbl) to several billion barrels (Bbbl). The overall number of oilfields number over 70,000 [4]. However, the contribution of individual fields to the global oil supply varies widely, few hundreds of 'giant' fields (more than 500 million barrels) accounting for nearly one-half of total oil production with about 25 fields accounting for one-fourth of it [1]. Thus, although fields share parallel overall behavior, the degree of production can differ significantly.

Höök [1] offers a typical production profile of an oilfield as seen in figure 1. His study notes that, significant deviations can be triggered by development history, alteration in production strategy or technology, oil price, political decisions, accidents, sabotage and similar factors. For some fields, the plateau periods are very short, more like a single peak, while others (especially large fields) may maintain relatively constant production for many years. But, at some point in production time, all fields will reach the inception of decline and as a result start to experience a decrease in production.

2.1.1 Oil Recovery Methods

During the production life of a reservoir, three production phases are basically observed in the extraction of the oil property, namely: primary (natural energy), secondary (pressure maintenance) and tertiary recovery (enhanced oil recovery) methods as shown in figure 2. Though three basic extraction methods are defined here, the order is not specific to all reservoir operations. Some operations may ignore one or two of the methods depending on the overall energy of the system. Fluid flow in most oilfields are controlled by numerous factors. A basic knowledge of these is necessary for better understanding of decline behaviors of oilfields.

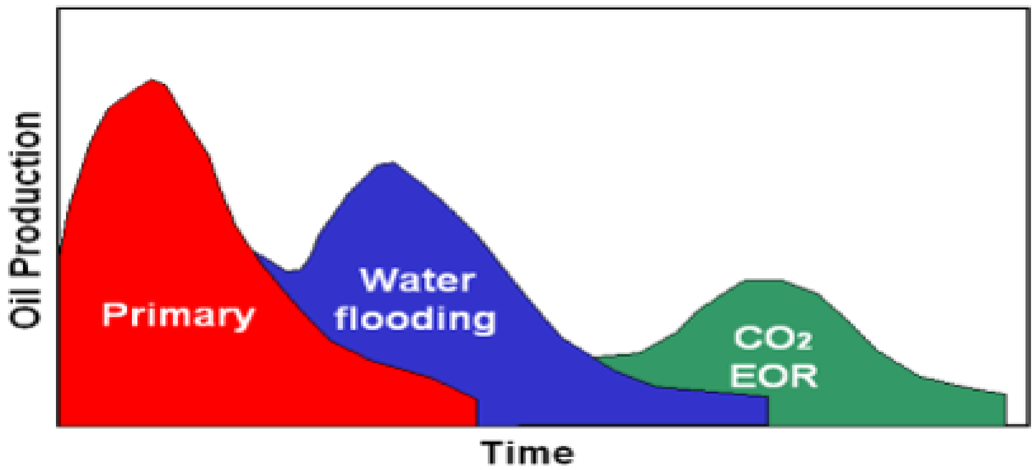

Figure 2 Expected sequences of oil recovery methods in a typical oilfield [4]

The physics of oil recovery is about flow of fluid through the porous media that makes up the oilfield. Generally, movement of downhole fluids in a reservoir depend on these outlined factors as described further expansively by Slatter et al (2008) [5]

- depletion (decline in reservoir flowing pressure),
- total compressibility of the system (rock or fluid or both),
- volume of gas phase dissolved into the liquid phase,
- angle of inclination (formation dip),
- capillary rise through minute pores,
- surrounding aquifer or overlying gas cap providing extra energy for pressure maintenance
- water or gas injection, and
- manipulation of fluid properties or by thermal means.

2.1.1.1 Primary recovery

This is the first stage of petroleum production based on buoyancy (Archimedes principle) and reservoir pressure, in which natural reservoir energy is used to push the oil to the surface. During the initial phase of production, primary recovery techniques are inherently applied by exploiting the natural energy within the reservoir and using artificial lift procedures like pumps to push the oil to the surface. In simple terms, the oil is made to flow under its own pressure, unless other fluids are injected to sustain or support the energy of the reservoir system. This primary recovery becomes limited at a point where the reservoir pressure is too low to maintain economical production rates, that consequently results in a decline in the rate of production. Typically, about 10-25% of the reservoirs oil originally in place is extracted, making the proportion of the initial oil in place produced under the primary recovery mechanism very small and therefore calls for extra methods to be applied to ensure an optimum recovery [6].

2.1.1.2 Secondary recovery

The concentration of secondary recovery is on artificial pressure maintenance (APM) strategy, where fluids are carefully injected to support the energy of the system by maintaining reservoir pressure. In significantly larger oilfields, the largest percentage of the total oil recovery is achieved by secondary recovery methods [7]. One of the mostly applied secondary recovery method for maintaining the reservoir pressure is water flooding, done by injecting water in an area just beneath the oil-water contact. When success of this method is achieved, the water forms a bank and pushes the oil towards the producing well as it moves through the pores. As illustrated in figure 3, as oil is extracted from the reservoir, the water cut is increased (volume of water in the extracted fluid) causing a decline of the oil production in spite of the high reservoir pressure.

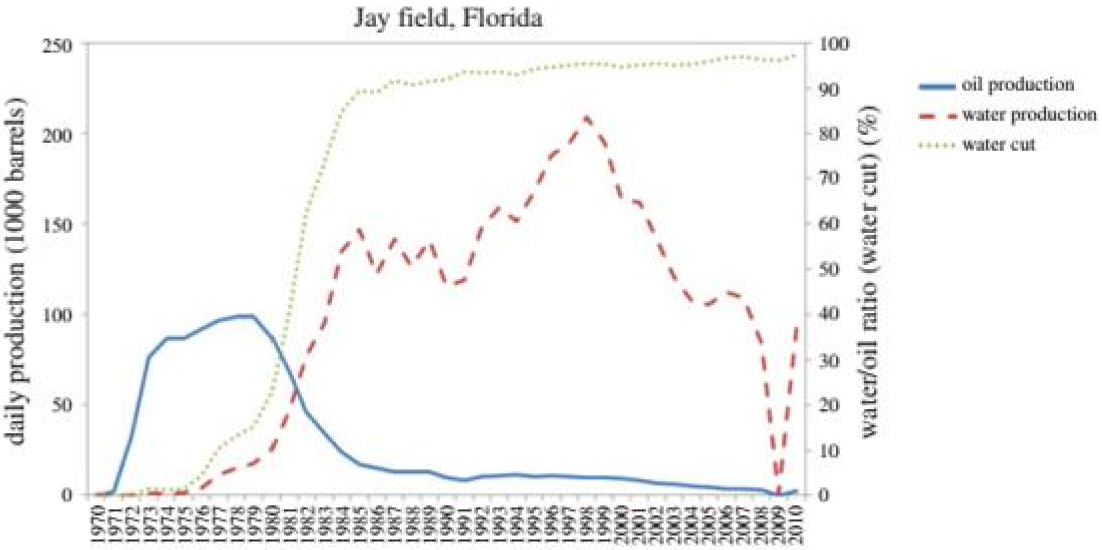

Figure 3 Oil with water production, giant Jay field in Florida, USA. In 2010, 2500 barrels of oil were produced from the field with 94 000 barrels of water per day [8]

Water flooding however brings to bear several engineering challenges that is largely dependent on the variation in reservoir heterogeneities, rock and fluid properties and the physical differences between the injected fluid (water) and the oil in place [5]. In likely situations when the viscosity of the oil is far more than the injected water, fingering effect occurs, where water moves in thin uneven fingers instead of as a unified front. The water front bypasses substantial volumes of recoverable oil and likely to cause an early water breakthrough into the production wells [1].

Oil of API gravity greater than 10° is lighter than fresh water and hence floats on fresh water, whereas API gravity less than 10° is denser and sinks. The likelihood of water flooding is when the oil API > 25° and the viscosity is relatively low (below 30 centipoise). It works best in homogeneous reservoir formations. Consequently, as the majority of the world's oil producing fields attempts the secondary recovery, it's not always effective. A combination of primary and secondary recovery methods can extract to about 30–50% of the oil in place and nearly most reservoirs that can take advantage from APM are making use of it [1, 5].

2.1.1.3 Tertiary (enhanced) oil recovery

Enhanced Oil Recovery (EOR) methods which has become a more recognized term in petroleum engineering literature instead of the usual tertiary recovery involves more compound ways of manipulating rock and fluid properties targeted at increasing the mobility of the oil to increase production [9].

According to Darcy's law, oil movement can be enhanced in a reservoir by decreasing its viscosity as long as delta pressure remains constant. For this reason, four key methods to EOR has been presented by Höök et al (2014), that is chemical, thermal, miscible and microbial methods; which are presented below.

The most commonly used approach is the thermal method which makes up to almost half of entire worldwide EOR projects. Thermal EOR method, as the name implies, comprises of altering the viscosity of oil by thermal means, such as hot-water flooding, steam flooding or in situ combustion, which produces heat that burns a portion of the oil in place by igniting the bottommost reservoir formation.

Miscible methods focus on injection of a gas or solvent miscible with the oil resulting in an improved recovery efficiency. It accounts for near 41% of worldwide EOR projects. Though the miscibility enhances the mobility of the oil, it also significantly adds up to the intricacies of the process. Carbon dioxide injection is widely applicable to many reservoirs than other methods at lower miscibility pressures [1, 5]. What actually happens is that, the net volume swells up as a portion of the CO_2 dissolves in the oil and reduces the viscosity of the oil. Due to the low interfacial tension, it makes it possible for the CO_2 and oil to flow together as the miscibility progresses. Lighter hydrocarbons (mainly natural gas) if available, can as well be injected to create miscibility which decreases the oil viscosity while increasing oil volume via same swelling process. In high-permeability reservoir formations holding light oil, nitrogen or flue gas, is sometimes a substitute. From an oil recovery standpoint, these gases are generally somewhat less expensive, but inferior to CO_2 or the lighter hydrocarbons [1, 5].

Chemical flooding applies the injection of polymers, surfactants, and caustic alkaline or other chemicals. Presently, on the global perspective, chemical flooding makes up to about 11% of EOR projects. The conditions favorable for the water flooding technique is also applied here since they are grounded on similar principle save the polymer used instead of water. Polymers can be used to enhance water flooding process by changing water viscosity and mobility. After the water floods, more oil will be produced in the initial stage, and this is the key economic benefit, as ultimate recovery is mostly the same as for conventional water flooding [1, 5]. Surfactants are also used to recover extra oil by enhancing mobility and solubility of oil and emulsifying oil and water.

2.2 Fundamentals of fluid flow

The transport of petroleum fluid through the reservoir formation is to a significant extent dictated by physical properties related to the geological formation of the reservoir under discussion and the characteristics of the petroleum it contains. Disparities in these characteristics cause production rates to vary from field to field. A reservoir houses its fluid in tiny microscopic pores inside the rock formation, and the term porosity of a rock is defined as the ratio of the pore spaces to the rocks bulk volume. The larger the porosity, the better the rock is at storing fluids.

In 1856 a French physicist, Henry Darcy, investigated the flow of fluid through a layered bed of packed sand and came up with an expression to describe the fluids' behavior, which is now known to be Darcy's law (equation 2.1). The equation postulated by Darcy considers important physical properties such as its permeability which is the capacity of the porous media to conduct the fluid and its viscosity which describes the degree of internal resistance to fluid flow. Comparing viscous forces to gravity and capillary forces, the influence of the viscosity to fluid flow both produced and injected fluids under normal conditions are superior than the later forces. This suggests that fluids flowing through parallel layered porous media encounters few disruptions (i.e. laminar flow conditions) and the rate of fluid flow is directly relational to the pressure gradient in the reservoir [5].

$$q = -\frac{kA}{\mu}\frac{\partial P}{\partial L} \qquad (2.1)$$

where q is the volumetric flow rate (cm^3/s), k is the permeability (darcy), A is the cross-sectional area to the flow (cm^2), μ is the viscosity (centipoise), and $\partial P/\partial L$ is the pressure gradient over the length of the fluid flow path (atm/cm)[2]

Equation 2.1 describes a unidirectional flow, where the fluid is transmitted straight in one single direction. However, the flow inside the rock formation is far more complicated. Despite this, Darcy's law is important when studying fluid flow in oil reservoirs since it gives the physical boundaries to the possible production rate and indicates in what manner the flow rate is affected by the different parameters [10]. The negative sign shows that the fluid flows from high pressure to low pressure. The key constraint for the fluid to flow is the pressure gradient hence the greater the pressure gradient, the greater the flow rate. When recovering oil or gas from a reservoir, the pressure gradient decreases along with the extraction. When the pressure in the reservoir has decreased to a level too low to drive the flow any longer the pressure can be maintained by feeding additional energy into the reservoir by a secondary recovery method, injecting water and/or gas [11].

Basically, Darcy's law states that a fluid which has a high viscosity will have a low flow rate at constant delta pressure; and that if the rock permeability is high, a high flow rate is anticipated; and that pressure gradient is necessary for fluid to flow. The negative sign in the Darcy's equation also indicates that the fluid flows oppositely (from higher to lower potential) of the pressure gradient [1].

2.3 Production Decline and Decline Rate

Oil and gas wells usually reach their peak output shortly after completion shown in figure 1, and from that time begins to decline. Wells completed in water-drive reservoirs may not suffer an early decline due to the support from the aquifer. The speed of decline depends on the output of the wells and on other factors as earlier described.

When estimating future production in an oil field or an oil well, the idea of decline rate is fundamental. The decline rate, λ, is the reduction in the production rate from an individual well, or a group of wells, after the production has peaked and is regularly stated on an annual or monthly or sometimes daily basis. Changes can either be positive or negative but are usually negative so long as a field has passed its peak of production [1]. It is expressed below;

$$\text{Decline rate}_n = \frac{\text{Production}_n - \text{Production}_{n-1}}{\text{Production}_{n-1}} \tag{2.2}$$

Physical and intrinsic factors driving the oil depletion like falling reservoir pressure, increasing water cut etc., does not certainly relate to the decline rate studies. Non-physical factors such as underinvestment, government policies, production shares, damage or interruption has been observed to affect decline. In essence, decline rates simply provide uncertain indications for unguarded analysts. Compound connections between reservoir physics, economics, technology and decision-making has been found to frequently influence decline in production. Production rates are influenced by many factors and much care must be taken in extrapolating decline trend into the future [1]. Decline rates seen in actual oilfields can vary significantly and research has shown that those of small fields may vary from those of giant fields [11].

Since the early years of the petroleum industry, increasing exploitation and depleting reserves have been related to declining production. The analysis of decline curves has since then been a practical tool for predicting field behavior and forecasting well life.

2.4 Comparing Predictive Models

Several models have so far been developed to estimate the original hydrocarbon in place with the knowledge of some existing data acquired either through well log interpretation, experimental analysis or pressure transient tests. These models use numerical computations to arrive at their results.

The results of these computations can be presented as 1-, 2-, or 3-dimensional spatial analysis of the reservoir operating under diverse well-configuration and different conditions of depletion. These studies take a lot of time and is costly as well and therefore calls for more information than required for a study of the decline curve characteristics [12].

Reservoir evaluation and the science of projecting future production can be sectioned into four areas that roughly correspond to the allotted time and effort to be consumed as well as the quantity and quality of information [12]. The advantages and flaws of each method is herein discussed as described by Poston (2007);

2.4.1 Volumetric Method

The volume of hydrocarbon (N or G for oil and gas respectively) in the subsurface reservoir formation depends on the reservoir bulk volume (Vb), fraction of the bulk volume which is porous (Ø), and the connate water saturation (Swc). The equations below apply to oil and gas respectively;

$$N = \frac{Vb\emptyset(1-Swc)}{Boi} \qquad (2.3)$$

$$G = \frac{Vb\emptyset(1-Swc)}{Bgi} \qquad (2.4)$$

The volumetric method is an easy to understand evaluation technique for defining hydrocarbon in-place. It's a low-cost method such that isopach maps can be combined with structural maps to provide a comprehensive picture for making reservoir and field extent estimations. This method however has several limitations; the results are dependent on the well spacing and the quality of porosity and saturation values which are mostly not achieved due to the degree of reservoir heterogeneities, especially using a single porosity as a representative for the entire reservoir formation; the maps are also unable to generate future forecast and difficulty in predicting recovery from layered or naturally fractured formation or in reservoirs with commingled production [12].

2.4.2 Decline Curves Method

Many years ago, discovery has shown that plotting rate of production against time for a single or several wells can be inferred into the future to provide an approximation of the future rates of production of a well. With the future rates known, it is of course possible to determine the future total production or reserves of the well [13].

It's of a great advantage to apply production decline curves due to the readily availability of production data. It's a low-cost method and time efficient as well as being easy to be programmed for operation on personal computers [12].

The analysis of production decline curves comes with its own limitations some of which include; the alteration of the profile of the decline curve when operating conditions are changed, inability to quantitatively infer the reservoir characteristics from the shape of the curve, and the struggle in interpretation of the future performance in low-permeability, multilayered or fractured reservoirs due to the high variability and uncertain effects of crossflow. Changes in operating conditions or any probable changes must be carefully considered when developing the equation representing a production decline curve and, more particularly, when predicting performance. [12].

2.4.3 Material Balance Method

Reserve estimation with material balance (Shilthuis Equation) is based on production history data. Pressure-dependent rock and fluid properties are built into a reservoir material-balance-type equation. The material-balance analysis is a tank-type model based on the conservation of mass, which does not take into consideration variable flow conditions.

For a saturated oil reservoir with constant porous volume, its material balance on a cartesian plot produces a straight line with a slope of slope N (Oil Originally in Place) as shown in the equation below;

$$N_p\left[B_o + B_g(R_p - R_s)\right] = N[B_o - B_{oi} + B_g(R_{si} - R_s)] \qquad (2.5)$$

The strong point of material-balance-type calculations include; Pressure-dependent reservoir rock and fluid properties, as well as the production history are included in a reservoir model; it is also a low-cost and time efficient analysis method that can be easily computed with a computer program. This method can also be easily applied to determine the depletion efficiency in a moderate-to-high permeability field.

Recovery factor is needed to calculate reserves which makes the material balance method a weak asset in such estimation. Moreover, vertical and areal variations in the reservoir character must be included as part of the reserves calculations.

Recovery factors should be applied only to fairly homogeneous, modest-sized reservoirs in which the producing zone exhibits permeability greater than 100 md for oil reservoirs and 1 md or less for gas reservoirs [12].

2.4.4 Reservoir Simulation Method

The reservoir is upscaled and divided into a grid system. It applies a combination of several equations; material balance equation, diffusivity flow equation, and equation of state into an iterative process to calculate the effect of the depletion history for each cell in the system.

They can be applied to a 2D or 3D system and also to systems with widely changing fluid composition; it allows all probable variables to be involved in the model making it easy to study the effects of reservoir heterogeneity and variation on future performance.

The reservoir simulation method generally requires a person skilled in the technique of running the model to be involved in the study; the models comes with its complications and requires a considerable amount of time, effort and expense to run and a huge volume of field data. The field model is often simplified by forcing reservoir heterogeneities and geology to fit the computer model, therefore, the results obtain are dependent on the quality of the input data [12].

2.5 The Decline Curve Analysis

Firstly, presented by Arps [14], decline curve analysis' is a tool used extensively to model and forecast production under the basic assumption that the driving mechanism controlling the decline is depletion drive thus water drive is not in existence. The used analysis techniques assume that the historical production trend will stay same in the future, and hence could be expressed mathematically and the productive indexes of the producing wells remains constant such that the reservoir production rate is proportional to the change in reservoir pressure. The methodology comprises analyzing production history and fitting certain type curves to the flowing production data. The future production behavior can be predicted by extrapolating the type curves. The great advantage of the methodology is that little data is required. Only production data of sufficient length to cover the behavior is needed. A weak side is that non-physical factors such as government policies and production shares may also be reflected by the production data hence care needs to be taken when extrapolating production trends into the future.

Three factors characterize decline curves; initial rate of production (production at a certain time), shape of the decline trend and rate at which the production declines. The decline rate (see equation 2.2), λ, can also be expressed by means of derivatives where q is production rate and t is time in arbitrary units. The solution in the differential equation form allows for the expression of decline characteristics using the decline rate (λ_t), its exponent (b) and a constant denoted C [1]

$$\lambda_t = -\frac{\dot{q}}{q} = -\frac{{dq}/{dt}}{q} = Cq^b \qquad (2.6)$$

The expression in equation 2.6 implies that the decline can be constant (b = 0), directly proportional to production rate (b = 1) or proportionate to the fractional power of the production rate (0 < b < 1). The presence of the negative sign in the expression is a way of converting the negative decline rate to a positive one [12]. This simple expression explains why no detailed reservoir data like permeability and saturations are required for the decline curve extrapolations, but van be simply done with the available production data which is somewhat acquired easily. The curve-fitting method can also be used to evaluate ultimate recovery of the field. Several reservoir studies of oil depletion have shown that, cases that involves the sum of production from individual fields are mostly achieved with decline curve forecasts and also for analyzing a single field or well [1]. Since its introduction by Arps, several different decline curve models have been developed, all of which are hinged to the work developed by Arps [14].

2.5.1 Arps Decline Curve Analysis

Arps (1945) proposed that the curve of the production rate against time can be expressed by one of the hyperbolic family equations; Exponential (constant percentage) decline, Harmonic decline and Hyperbolic decline. Mathematically, his proposal was based on the theoretical concept of loss-ratio (1/D) and the derivative of the loss-ratio (b), where D and b are the decline curve parameter and decline curve exponent, respectively, expressed as follows [14]

$$\frac{1}{D} = -\frac{q}{dq/_{dt}} = \frac{1}{\lambda_t} \qquad (2.7)$$

$$D = -\frac{1}{q}\frac{dq}{dt} \qquad (2.8)$$

$$b = \frac{d}{dt}\left(\frac{1}{D}\right) = -\frac{d}{dt}\left(\frac{q}{dq/_{dt}}\right) \qquad (2.9)$$

where $0 \leq b \leq 1$

$$q_t = \frac{q_i}{(1+bD_it)^{\frac{1}{b}}} \qquad (3.0)$$

$$N_p = \frac{q_i - q}{D} \qquad (3.1)$$

where

q_t = production flow rate at time t, stb/day or stb/time

q_i = initial flow rate, stb/day or stb/time

D_i = initial decline rate constant, 1/day or 1/time

N_p = Cumulative production at time t, STB

b = Arp's decline curve exponent.

t = time

The above equations are strictly applicable for pseudo-steady state flow conditions (the existence of a boundary-dominated flow regime) which is observed for most conventional reservoirs. The assumption governing Arp's analysis rate-time decline curves are constant drainage areas, wells are producing at or near capacity and operation is under constant bottom-hole pressure. The idealistic shape of each of the hyperbolic family equations from Arps's deduction is shown in figure 4.

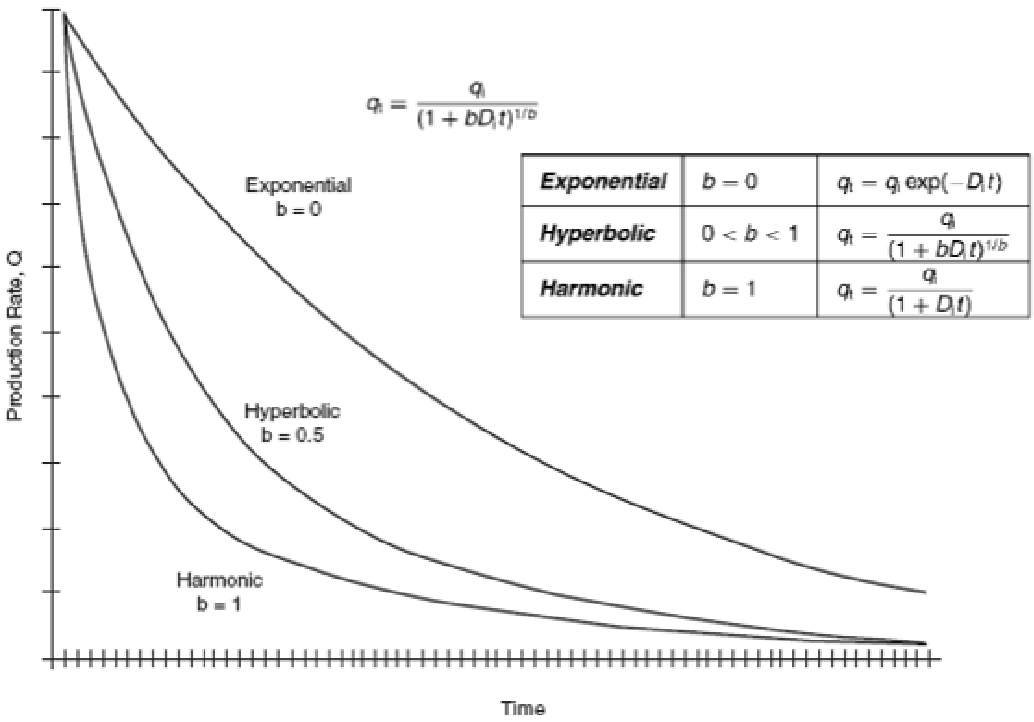

Figure 4 Decline curve-rate/time for exponential, hyperbolic and harmonic curves [15]

In reference to equation 3.0, three diagnostic equations can be attained conforming to the three decline types (exponential, harmonic and hyperbolic) depending on the numerical value of b.

2.5.1.1 Exponential Decline Curve

When b=0, the decline type is exponential or constant percentage which, graphically, is a straight-line fitting historical performance plot of production rate versus time on a semi-log or versus cumulative production. The exponential decline defines how the production rate drops per unit time is relational to the rate [14]. The empirical equations for exponential decline are:

$$q(t) = q_i * e^{-D_i t} \qquad (3.2)$$

$$N_{p(t)} = \frac{q_i - q_t}{D_i} \qquad (3.3)$$

where

q_t = production flow rate at time t, stb/day or stb/time

q_i = initial flow rate, stb/day or stb/time

D_i = initial decline constant

N_p = Cumulative production at time t, STB

2.5.1.2 Hyperbolic Decline Curve

Hyperbolic decline is for the limit 0 < b < 1. The hyperbolic decline plot is a curve (concave upwards) on the semi-log rate-time, since decline exponents change with time, in contrast to the constant percentage decline [16]. Typical low productivity wells exhibit hyperbolic-harmonic decline behavior [16]. Arps' hyperbolic modeling equations are as follows:

$$q_t = \frac{q_i}{(1+bD_i t)^{\frac{1}{b}}} \tag{3.4}$$

$$N_{p(t)} = \frac{q_i}{D_i(1-b)}\left[1-\left(\frac{q_t}{q_i}\right)^{(1-b)}\right] \tag{3.5}$$

where

q_t = production flow rate at time t, stb/day or stb/time

q_i = initial flow rate, stb/day or stb/time

D_i = initial decline rate constant, 1/day or 1/time

$N_{p(t)}$ = Cumulative production at time t, STB

b = Arp's decline curve exponent.

t = time

The influence of the b value on the hyperbolic curve ranging 0.01 to 0.99 was investigated by Hooke et al (2014) and illustrated in figure 5. In reservoir studies, the Ultimate Recoverable Reserves (URR) is considered to be the integral of the curve. Hence, only slight changes in the b-parameter have large impacts on the URR [1]. The higher the b-parameter, the greater the URR estimate. The hyperbolic decline curve suffers the danger of overestimating the URR and subsequently the economic yield of a project, creating an argument to abandon the hyperbolic curve for a less optimistic project concerning the late production ("tail production") [1]

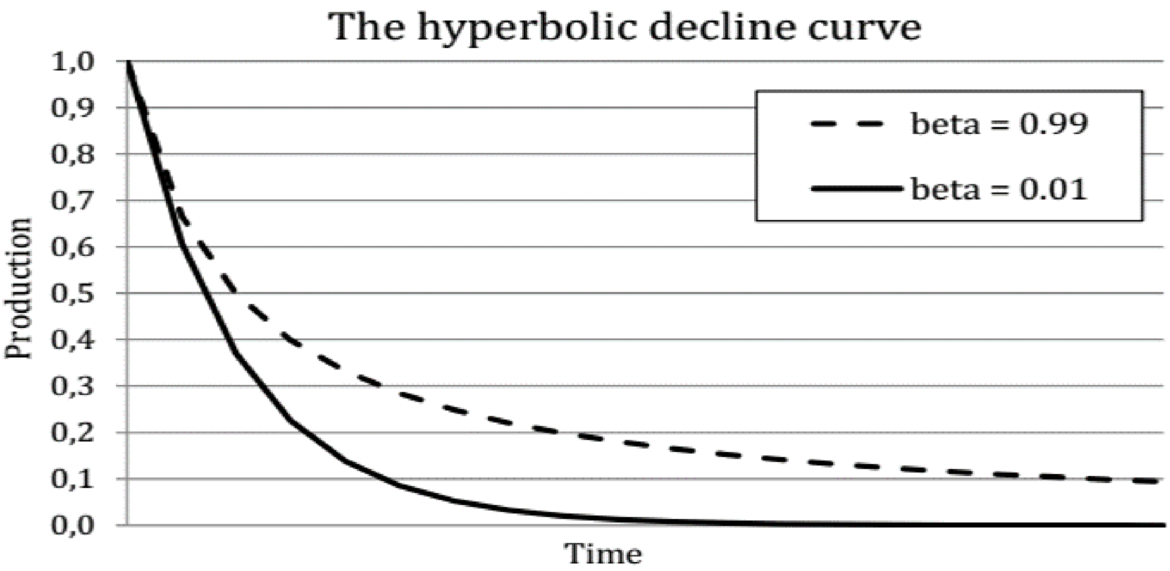

Figure 5 Illustration of how different b-parameters affect the hyperbolic curve. A b closer to zero gives a curve closer to the exponential curve, the special case of b=0. A b closer to one gives a curve closer to the other special case, the harmonic curve with b=1. [17]

In addition to the URR which is an integral of the curve and affected by slight changes in the b value, its numerical value after Arps and Fetkovish is used to determine the sort of decline properties one could expect for the diverse kinds of fluid production and their drive mechanisms as shown in table 2. Fetkovish stated that Arps model shouldn't be used at all for transient system since their b values according to his study is greater than one. Challenges occurring in the industry recently involves production from formations with very low permeabilities like tight and unconventional gas reservoirs [18].

Value of b	Drive Mechanism
0	Liquid expansion (Single phase oil above bubble point) Gas expansion (Single phase gas at high pressures) Water breakthrough or gas coning in an oil well
0.1-0.4	Dissolved gas drive
0.4-0.5	Single phase gas expansion at low pressures
0.5	Edge water drive
0.5-1.0	Layered reservoirs
>1.0	Transient (Tight gas and unconventional reservoirs)

Table 1 Identification of Drive Mechanism from b value (FEKETE)

2.5.1.3 Harmonic Decline Curve

When b=1, decline is harmonic and forms a straight line on the semi-log plot of production rate versus cumulative production. The empirical equations for harmonic decline are:

$$q_t = \frac{q_i}{(1+D_i t)} \qquad (3.6)$$

$$N_{p(t)} = \frac{q_i}{D_i} \ln\left[\left(\frac{q_i}{q_t}\right)\right] \qquad (3.7)$$

where

q_t = production flow rate at time t, stb/day or stb/time

q_i = initial flow rate, stb/day or stb/time

D_i = initial decline rate constant, 1/day or 1/time

$N_{p(t)}$ = Cumulative production at time t, STB

b = Arp's decline curve exponent.

t = time

On a linear plot of production vs time (see figure 5), the harmonic model gives a decline curve that approaches an asymptote of a constant rate of production greater than zero in the long run. In other words, the harmonic curve ends up in an infinite URR, which cannot be probable in reality.

Table 1 is a summary of the variants of Arp's production decline curve equations

Table 2 ARPS' EQUATIONS

	EXPONENTIAL	HYPERBOLIC	HARMONIC
DECLINE RATE	$\frac{q_i - q_t}{(N_p)}$	$\frac{\left(\frac{q_i}{q_t}\right)^b - 1}{b_t} = \left\{\frac{q_i}{N_p(1-b)}\right\}\left\{1 - \left[\left(\frac{q_i}{q_t}\right)^{1-b}\right]\right\}$	$\frac{\frac{q_i}{q_t} - 1}{(t)} = \frac{q_i}{N_p} \ln\frac{q_i}{q_t}$

PROD. RATE, q	$q_t = q_i * e^{-D_i t}$	$q_t = \frac{q_i}{(1 + bD_i t)^{\frac{1}{b}}}$	$q_t = \frac{q_i}{(1 + D_i t)}$
CUM.PROD., $N_{p(t)}$	$N_{p(t)} = \frac{q_i - q_t}{D_i}$	$N_{p(t)} = \frac{q_i}{D_i(1-b)}\left[1 - \left(\frac{q_t}{q_i}\right)^{(1-b)}\right]$	$N_{p(t)} = \frac{q_i}{D_i} \ln\left[\left(\frac{q_i}{q_t}\right)\right]$

2.5.1.4 Approach to the Traditional Arps Method

The Arps method is applied by plotting graphs of rate against time and sometimes against cumulative production by targeting straight lines which is easy for decline analysis. Figure 6 shows target plots on normal cartesian, semi-log and log-log plots.

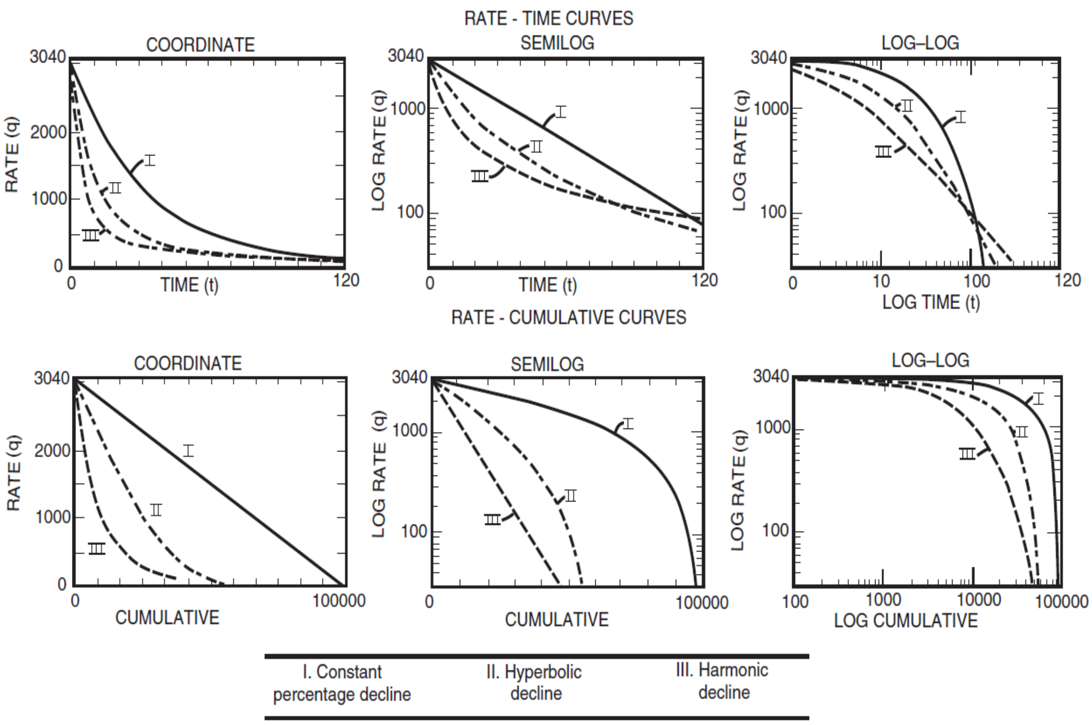

Figure 6 Production decline curve classifications [2]

Assuming the historical production from a single well or field is predictable by an exponential production decline behavior, the subsequent steps summarizes the technique to forecast the performance of the well or the field as a function of time.

Step 1. Plot qt vs. Np on a Cartesian scale and qt vs. t on semilog paper.

Step 2. For both plots, draw the line of best fit through the points.

Step 3. Extrapolate the straight line on qt vs. Np to Np = 0 which intercepts the qt axis at a flow rate value identified as the initial flow rate, qi.

Step 4. The initial decline rate, Di, is calculated by picking a point on the straight line with coordinates of (qt, Np) or on a semilog line with coordinates of (qt, t) and applying the exponential equations.

Step 5. Estimate the time to reach the economic flow rate limit qa (or any rate) and the equivalent cumulative production from the exponential Equations in table 1. [2]

2.6 Further Developments to the Decline Curve Analysis (DCA)

Otherwise known as production analysis or rate transient analysis, various decline curve analysis techniques for production forecasting have been established by several authors for dealing with specific reservoir problems. Most of these methods and techniques were improvements on the Arps traditional equations.

Pressure Transient Analysis is achieved with the availability of pressure and rate data but has recently been complimented with the development of Production Analysis (PA). Both analysis is achieved with the spread of Permanent Downhole Gauge (PDG), which extract data applicable for both analysis techniques [19] .

The Arps decline curves are not applicable to all reservoirs due to its empirical nature but applied as deemed fitting for any specific scenario. Some advanced models of the decline curves for specific reservoir conditions are outlined below;

2.6.1 Fetkovish DCA

Fetkovich came up with his findings after identifying that the conventional Arps decline method was applicable only during the depletion period (boundary dominated flow condition) and for that matter, did not account for the early production life (transient flow period) of the well. Fetkovich used analytical flow equations in dimensionless terms to develop type curves which incorporated the empirical decline curve equations initially documented by J.J. Arps resulting in its use to analyze both transient and boundary-dominated flows [20].

As shown in figure 7 below, the Fetkovich type-curve combined two families of curves: one for the transient flowing period and one for the late time boundary dominated response. The left region of the curves (green to blue) links to the transient part of the response and on the right-hand side, are the Arps decline stems (red to yellow). On the figure 7 below, exponential decline stem of the Arps curve is red colored and that of harmonic decline is yellow colored [19].

An advantage that makes this method outstanding over other modern methods is that in order not to bias the interpretation it does not use superposition time functions to plot data and also remaining a widespread practice for the analysis of conventional vertical wells. It is also used to describe the performance of unconventional well production data but has its shortcomings in that, the transient type curves are limited to radial flow systems [21].

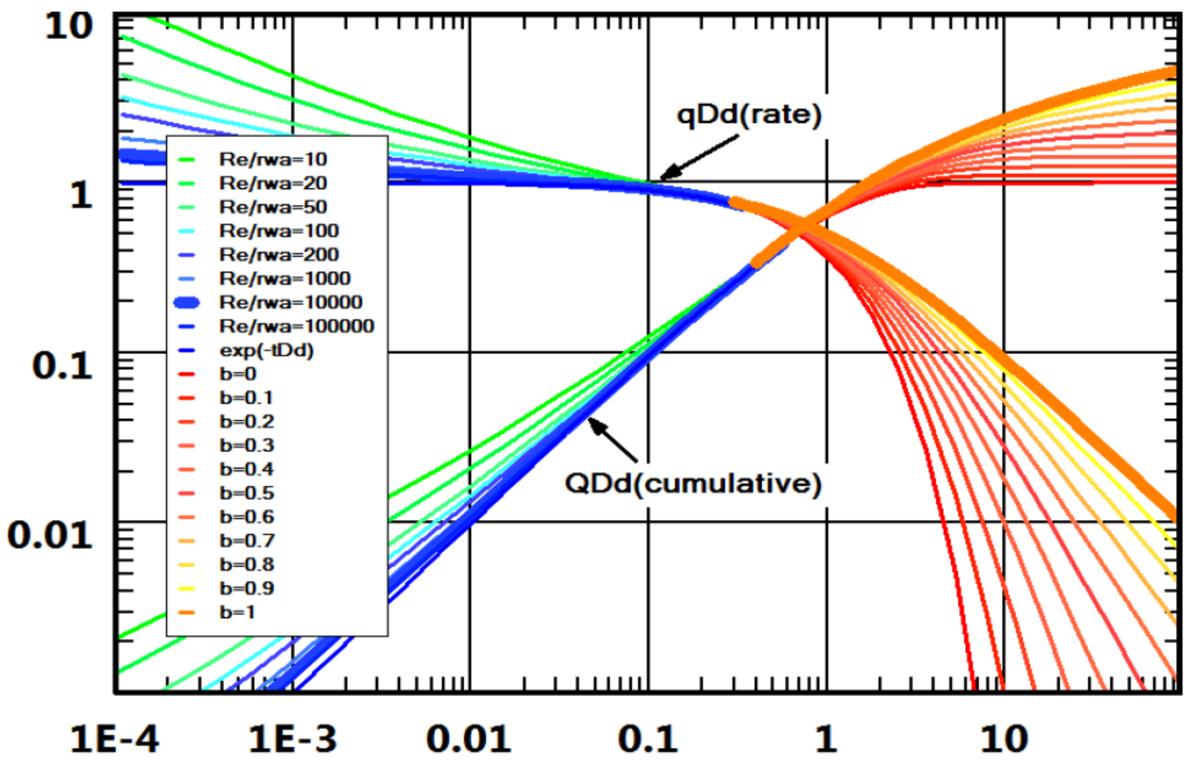

Figure 7 A typical Fetkovich type curve [19]

An assumption for deriving the Fetkovich type analysis is the existence of a slightly compressible fluid and constant flowing pressure. Due to the constant flowing pressure condition, breaks in the production data due to shut-in or well under compression, may not be affected since a segmented approach can be taken.

However, Fetkovish analysis will not work for a rate restricted production [18]. The original type-curve presented by Fetkovich displayed rate only but to reduce the effect of the noise and bring more confidence in the matching process a merged presentation including the cumulative was later introduced similar to figure 7 [19].

Fetkovich's decline curve dimensionless variables are defined in oilfield units below [20];

Decline Curve dimensionless time: $t_{Dd} = D_i t$ (3.8)

Dimensionless time: $t_D = \frac{0.00634kt}{\emptyset\mu C_t r_w^2}$ (3.9)

t_{Dd} and t_D are related by: $t_{Dd} = \frac{t_D}{\frac{1}{2}\left[\left(\frac{r_e}{r_{wa}}\right)^2 - 1\right]\left[\ln\left(\frac{r_e}{r_{wa}}\right) - \frac{1}{2}\right]}$ (4.0)

r_{wa} and r_w are related by: $r_{wa} = r_w e^{-s}$ (4.1)

Decline Curve dimensionless rate: $q_{Dd} = \frac{q(t)}{q_i}$ (4.2)

Dimensionless flow rate for oil: $q_d = \frac{141.2q(t)\mu B}{kh(P_i - P_w)}$ (4.3)

Dimensionless flow rate for gas: $q_{Dd} = \frac{50300Tq(t)P_{sc}}{T_{sc}kh[m(P_i) - m(P_w)]}$; (4.4)

Where $m(p) = \int_0^P \frac{2pdp}{\mu Z}$ (4.5)

q_{Dd} and q_d are related by: $q_{Dd} = q_d\left[\ln\left(\frac{r_e}{r_w}\right) - \frac{1}{2}\right]$ (4.6)

Decline Curve dimensionless cumulative: $Q_{Dd} = \frac{Q(t)}{N_{pi}}$; (4.7)

where Npi is the Ultimate Recovery.

A good match will bring values of re and kh, Di and qi. The decline exponent, b, is not connected to any of the match ratios but obtained by choosing the correct type-curve. Knowing the external boundary distance, the reservoir pore volume can be estimated. From the Arps parameters known, the future performance can be forecasted; Npi can be calculated as well as N_p for any specified abandonment rate [19]. In relation to equation 5.0, the numerical value of the skin is estimated from the link between the well radius and the apparent wellbore radius. From the analytical point of view, the parameters can be estimated from the curve match as show below;

$$k = \frac{141.2\mu B}{h(pi-pwf)}\left[\ln\left(\frac{re}{r_{wa}}\right)-\frac{1}{2}\right]\frac{q}{qDd_{match}} \tag{4.8}$$

$$r_{wa} = \sqrt{\frac{0.00634k}{\mu \emptyset c_t}\frac{1}{\frac{1}{2}\left[\ln\left(\frac{re}{r_{wa}}\right)-\frac{1}{2}\right]\left[\left(\frac{re}{r_{wa}}\right)^2-1\right]}\frac{t}{tDd_{match}}} \tag{4.9}$$

$$s = \ln\left(\frac{r_w}{r_{wa}}\right) \tag{5.0}$$

$$r_e = \sqrt{2\frac{141.2B}{h(pi-pwf)}\frac{0.00634}{\emptyset c_t}\frac{q}{qDd_{match}}\frac{t}{tDd_{match}}} \tag{5.1}$$

2.6.2 Blasingame DCA

The main limitation in the Arps and Fetkovich type-curve is the assumption of constant flowing pressure. Arps [14] made it clear in his work that in an ideal situation, pressures are not constant and for that matter productivity index is also not constant but declines gradually as reservoir depletes. Blasingame and McCray [22] made it clear that using a pressure normalized flow rate did not solve the problem even with varying bottom-hole pressure.

This method presents the material balance time and pressure normalized rates to develop analytical constant rate type curves that features a single depletion stem that is independent of the reservoirs driving mechanism or its shape and size. The material balance time is a time concept that takes variable rate history and converts it to an equivalent constant rate history. This time corrects the constant pressure solution curve to the constant rate (Harmonic) curve such that in every flowing condition whether constant rate or constant pressure, the harmonic stem of the Fetkovish model can be sufficient in analyzing all sort of production data and with consistency [18]. The outcomes of Blasingame analysis include volume of hydrocarbons in place, formation permeability, skin factor, and drainage area of the reservoir. To ensure a more accurate type curve match, flow rate integral and flow rate integral derivative functions was used instead of using the flow rate data alone.

These integral functions are also capable of removing problems associated with production data with inconsistent rate and bottom-hole pressure behavior. Different reservoir types make a practical use of the Blasingame type curve method and include:

- Radial and Elliptical flow wells
- Wells produced under water drive mechanism
- Fractured wells (cylindrical)
- Horizontal well

With this method, given a type curve match, formation permeability, skin, fracture half length, dimensionless fracture conductivity, drainage area, original oil- or gas-in-place can be found if reservoir thickness, total compressibility, and wellbore radius are known [20].

Palacio and Blasingame [23] further came up with type-curves that could be used extensively for variable flowing pressure conditions. The Bourdet [24] derivative was also considered to offer improvement to the type-curve analysis, but due to the noise characteristic of the production data, the derivative was applied to the normalized flow rate integral but not to the normalized flow rate. More precisely, the Palacio-Blasingame type-curve plot presents the following [19]:

Material Balance time: $$t_e = \frac{Q(t)}{q(t)} \tag{5.2}$$

Normalized Rate: $$PI(t) = \frac{q(t)}{P_i - P_w(t)} \tag{5.3}$$

Normalized Rate integral: $$PI\ Int. = \frac{1}{t_e}\int_0^{t_e} PI(\tau)d\tau = \frac{1}{t_e}\int_0^{t_e} \frac{q(\tau)}{P_i - P_w(\tau)} d\tau \tag{5.4}$$

Normalized Rate integral derivative: $$PI\ Int.\ Derivative = \frac{\partial(PI_{int})}{\partial \ln(t_e)} \tag{5.5}$$

Figure 8 shows a typical Blasingame type-curve, a loglog plot of pressure normalized rate, its integral and derivative of the integral against material balance time. The normalized rate versus material balance time follows a negative unit slope line on the log-log scale indicating the boundary dominated flow period [19].

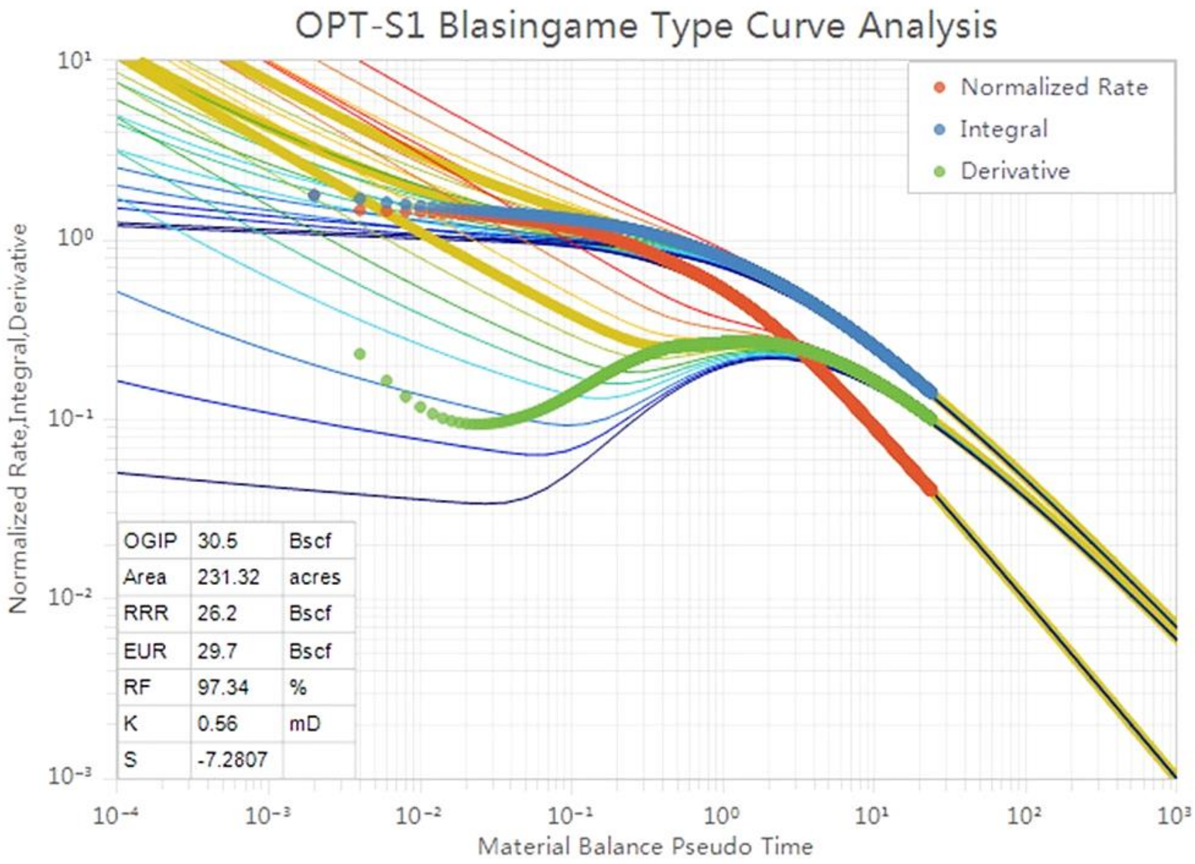

Figure 8 A typical Blasingame type curve [25]

2.6.3 Material Balance Plot (Pressure Normalized Rate – Cumulative)

Agarwal and Gardner [26] decline type curves for analyzing production data built upon the work of Fetkovish, Palacio, and Blasingame, makes use of the theories of the similarity between constant pressure and constant rate analytical solutions. Agarwal and Gardner also present dimensionless variables different from that used by Fetkovish and Blasingame. It applies dimensionless variables used in conventional well testing. They also present their decline curves in an extra format to the typical normalized rate versus material balance time plot, which consist of the rate vs. cumulative, and cumulative vs. time analysis plots [27]. The dimensionless rate and dimensionless cumulative plot follows a straight line with negative slope during boundary dominated flow and are related as [19];

$$q_D = \frac{1}{2\pi} - Q_{DA} \qquad (5.6)$$

The expression of the dimensionless parameters, considering an oil case is defined below:

$$q_d = \frac{141.2q\mu B}{kh(P_i - P_w)} \tag{5.7}$$

$$Q_{DA} = \frac{0.8936QB}{\emptyset hAC_t(P_i - P_w)} \tag{5.8}$$

The dimensionless cumulative production can as well be stated in terms of the fluid in place, in STB/D:

$$N = \frac{\emptyset hA}{5.615B} \tag{5.9}$$

$$Q_{DA} = \frac{0.8936QB}{\emptyset hAC_t(P_i - P_w)} = \frac{Q}{2\pi NC_t(P_i - P_w)} \tag{6.0}$$

So, the linear relationship between dimensionless rate and cumulative becomes:

$$\frac{141.2q\mu B}{kh(P_i - P_w)} = \frac{1}{2\pi} - \frac{0.8936QB}{5.615NC_t(P_i - P_w)} \tag{6.1}$$

From the above equations, a plot of $\frac{q}{P_i - P_w}$ against $\frac{Q}{C_t(P_i - P_w)}$ exhibits a straight line which intercept the x-axis directly at N for boundary dominated flow as shown in figure 9.

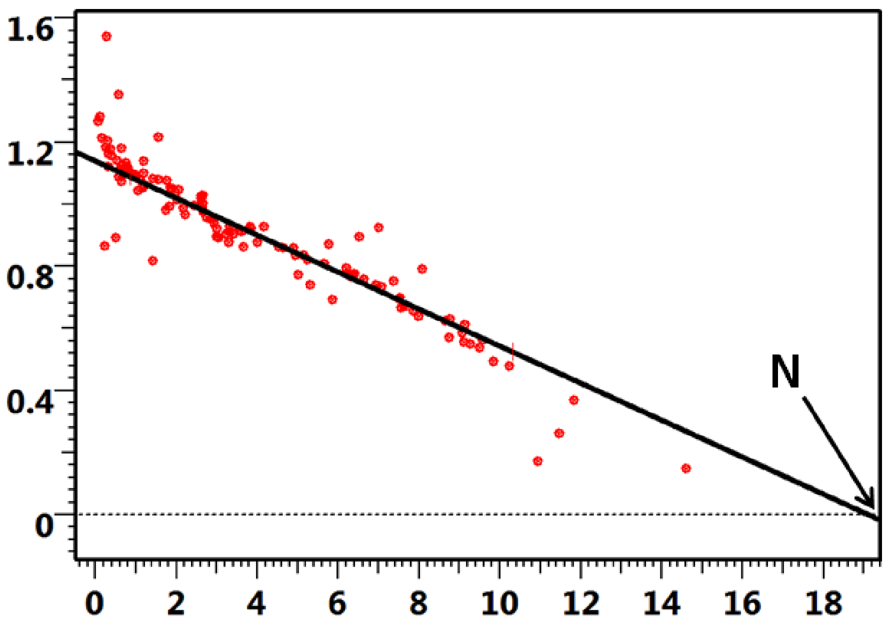

Figure 9 Material Balance Plot [19]

3 Methodology

3.1 Introduction

As discussed earlier, the petroleum industry is masked by huge financial commitments. This makes it necessary for production performance forecast of the reservoir property towards making good and quality decisions. In a field, after some years of production, information about the depletion and historical performance can be used as a benchmark to gain understanding into the future production performance if well's production strategy remains unaltered.

In this work, numerical reservoir simulations were applied to build a synthetic reservoir model that represents the static and dynamic performance of the reservoir. This numerical model is built on series of mathematical equations, sets of assumptions, initial and boundary conditions and the purpose to which it was employed in terms of operating conditions. Schlumberger's commercialized software, ECLIPSE was the numerical simulator used in this research work. Ecrin's TOPAZE software (commercialized by KAPPA Engineering) was used to provide analytical interpretation of the numerically simulated production data obtained from ECLIPSE.

The reason for assuming a numerical simulator and an analytical software is for the fact that it acts as a dependable and flexible tool to identify optimum production and management approaches by developing several operating scenarios. Due to lack of real life data, a complete set of synthetic data with reservoir, fluid and production properties was employed. Again, the synthetic data provides the opportunity to make sensitivity analysis on significant parameters.

The production data (time function of rate and pressures) used for the rate transient analysis is generated by the numerical simulator. The decline curve analysis was then performed analytically to make a production forecast and obtain the reservoir parameters that contributed to the rate decline. For the purpose of our study, a base case scenario was considered which is described here in this chapter. This work seeks out to investigate the integrity of the various developments in forecasting production performance, their strengths and weaknesses, when to and when not to apply a method. In this case, the traditional Arps methods as well as several modern methods were investigated to identify coherence and limitations. Details of the simulation workflow and computations are described in this chapter.

3.2 Synthetic Reservoir Model

To obtain production data used for our analysis, Schlumberger's Eclipse 100 (Black Oil) Simulator was used to model a synthetic rectangular reservoir. An undersaturated oil reservoir with initial pressure (Pi) of about 5000 psi at a datum depth, 8000 ft ss and a reservoir temperature of 212^{o}F. The reservoir is made up of 1200 active grid cells, 20 each in the x and y direction, and 3 in the z direction as shown in figure 10. Each cell has dimension 300ft by 300ft by 50ft in the x, y and z direction respectively. The reservoir top is at a depth of 8000 ft ss. The reservoir is 100% saturated with oil, such that, there is no irreducible water saturation. The Oil-Water contact (OWC) is positioned at a depth of 9000ft ss, far below the bottommost depth and that stands to mean that the reservoir is producing under depletion drive mechanism.

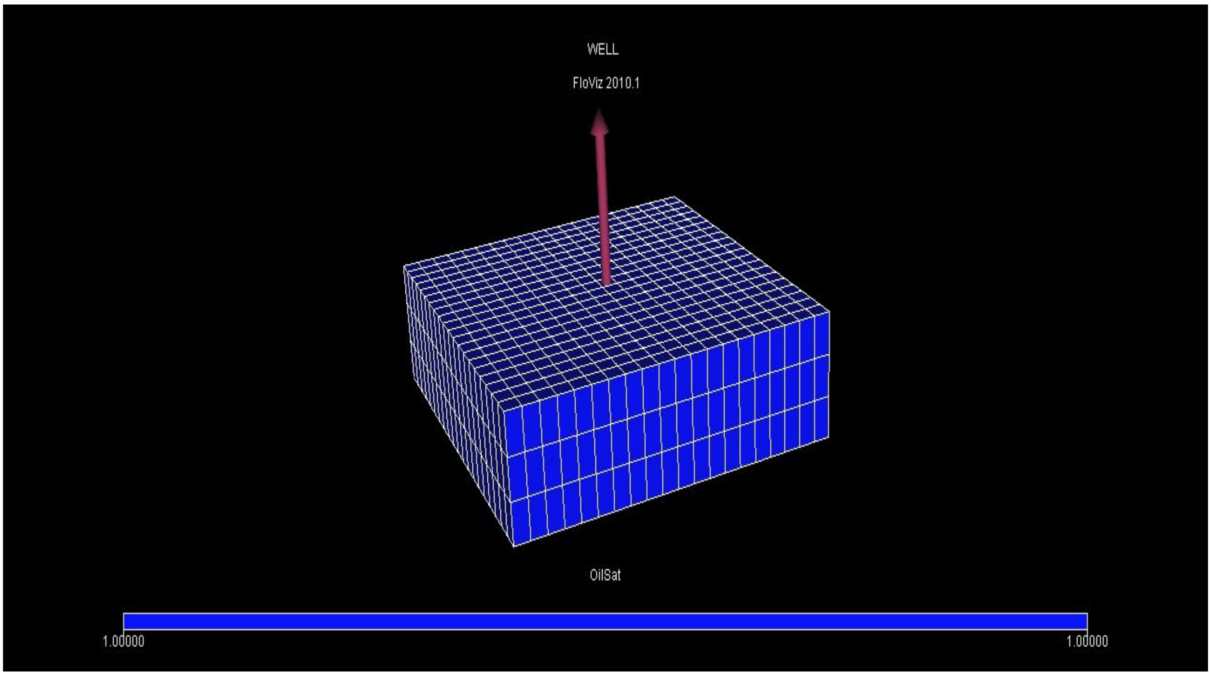

Figure 10 3D Reservoir Geometry

The reservoir is homogeneous and isotropic with a single vertical production well of radius, 0.328 ft placed at the center of the square-shaped bounded geometry (10,10) shown in figure 10. The well is completed in all three layers where the well traverse, from top to bottom cells, thus at cells (10,10,1), (10,10,2), and (10,10,3) and all completed cells are open to production as shown in figure 11. The well is producing at a constant bottomhole flowing pressure of 3200 psia, which is sometimes known as the critical bottomhole pressure (P_{wfc}).

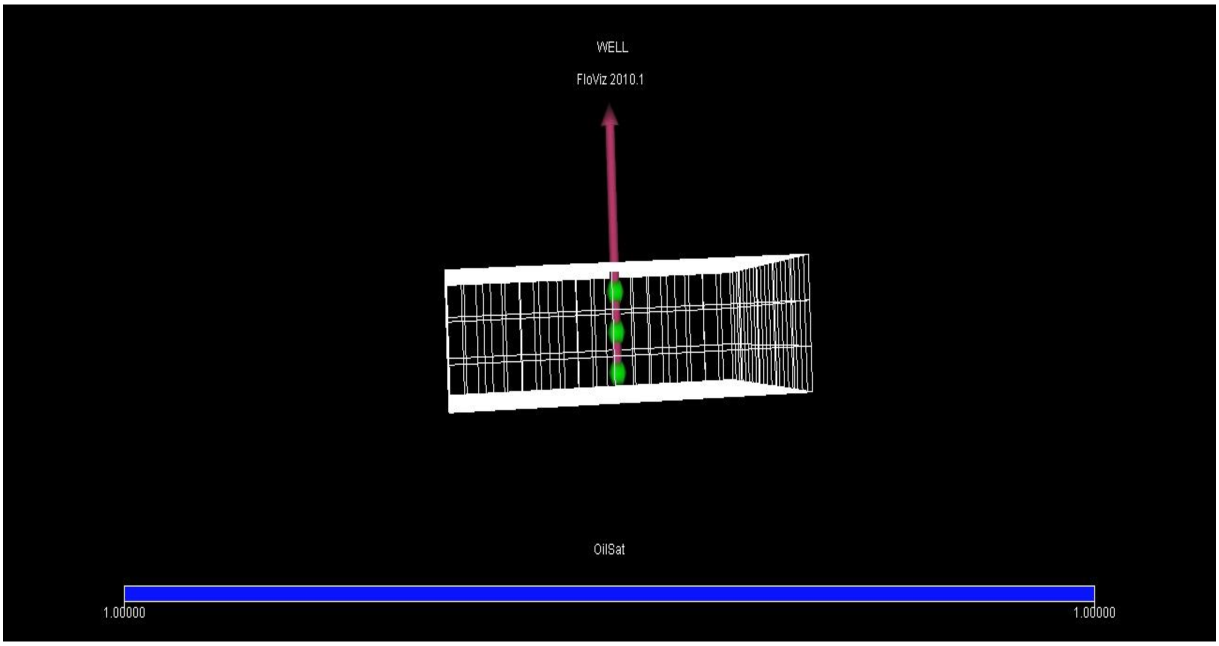

Figure 11 Reservoir Completion

3.3 PVT and Petrophysical Properties

The reservoir, fluid and rock properties defined at a reference pressure of 5000 psia are summarized in the table below;

Table 3 Rock and Fluid Properties

Reservoir Fluid Properties	**Values**
Oil Gravity	30 ^{o}API
Oil Viscosity (μ_o)	1.0842 cp
Oil Formation Volume Factor (Boi)	1.2487 rb/stb
Oil Saturation (So)	1.0000
Water Saturation (Sw)	0.0000
Water Formation Volume Factor (Bw)	1.0050 rb/stb
Water Compressibility	2.5E-06 psi^{-1}
Constant Flowing Bottomhole Pressure (Pwfc)	3200 psia
Reservoir Rock Properties	

Formation compressibility (Cf)	3.8E-06 psi^{-1}
Porosity (ø)	0.2300
Total Compressibility (Ct)	1.1809E-05 psi^{-1}
Net to Gross Ratio (NTG)	1.0000
Permeability (K)	100 mD
Pay Zone Thickness (h)	150 ft
Transmissibility (Kh)	15000 mD.ft
No Flow Boundaries (North, South, East, West)	3000 ft

Compressibility of Oil at any pressure is estimated from PVT plot as shown in plot by applying its relationship with Bo and pressure; $C_o = -\frac{(Boi-Bo)}{Boi(Pi-P)}$ (6.2).

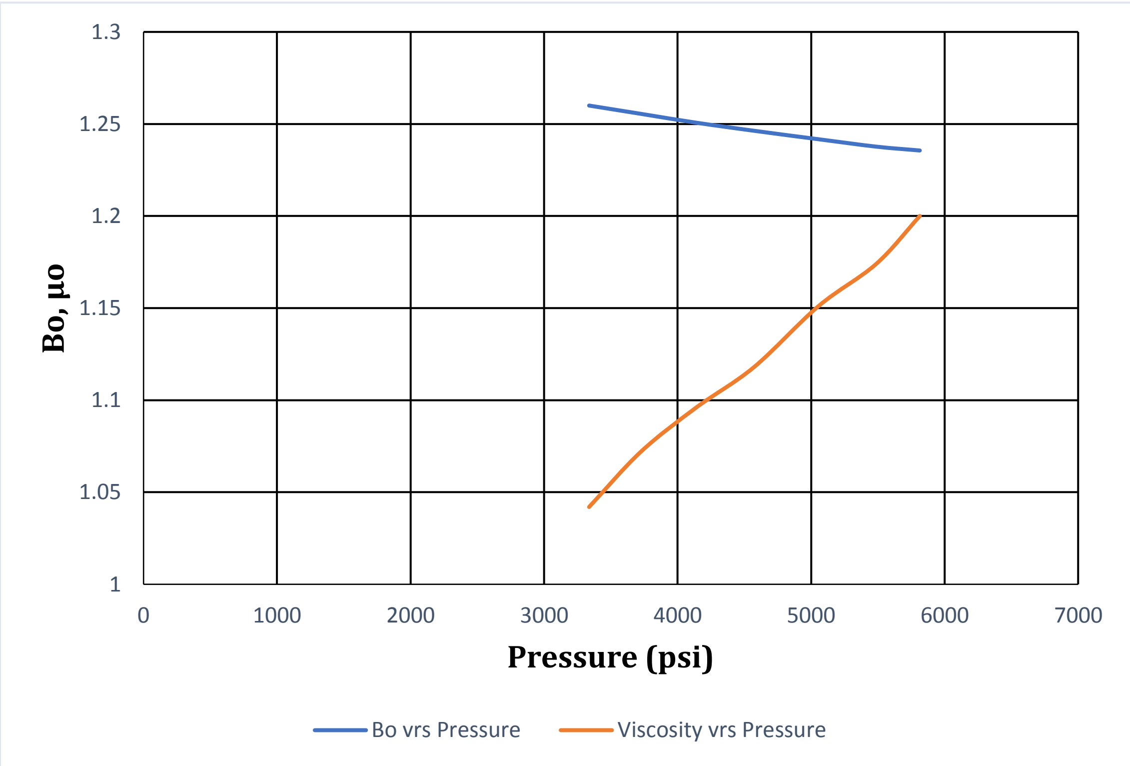

Figure 12 Oil PVT Data Plot

3.4 Simulation Controls

Considering this simple model developed with Eclipse 100, vertical well in a homogeneous and isotropic reservoir, appropriate ECLIPSE keywords were used in .DATA file to specify inputs along with our required output. Content of the output data is presented in Appendix I of this report.

SCHEDULE section of the eclipse dataset defines the well data and production schedule. The WELSPECS keyword defines the specifications of the well by describing its name and the position of the wellhead, its bottomhole reference depth and other specification data. COMPDAT keyword was used to specify where the well was placed, and the connections opened to flow from the reservoir. This keyword was also used to specify the wellbore diameter. In order to generate the outcome of a declining oil well, the well control used was BHP instead of ORAT such that the well produces at the constant bottomhole pressure (Pwf). The simulator was set to give an output report every 10 days interval, continuously for 1850 days of production and thus our decline was monitored for about 5 years. Several output parameters were requested to be reported after each time step but the most relevant of it were;

1. Well Oil Production Rate, WOPR (STB/D)
2. Well Oil Production Total, WOPT (STB)
3. Well Bottomhole Pressure, WBHP (psia)
4. Field Oil in Place, FOIP (STB)

The Field Oil in Place requested from the simulation run was used as a means of verifying the correctness of the analytical model built from Ecrin's Topaze.

3.5 Application of Arps Empirical Model

The parameters required for the Arps model were the time interval in years, Well Oil Production Rate and the Well Oil Production Total. The conventional Arps model uses the rate history data alone without the pressure history. After the simulation run was completed, the 5 years production data were reported on the .RSM file and exported to EXCEL.

Data from the first year of production was extracted and was used to identify the model that best suites the decline and was consequently used to determine the decline parameters. In this case, we chose the first year of production as the historical data and was then used to forecast the production for the following two years.

Data quality and resolution has been found to be one of the set-backs of the Arps Empirical Model application, such that, a short-term data cannot be evidently ascribed to a specific model. To clear our doubts in relation to the model selected, two years production was also selected as history and was used to forecast the production for the following year and fortunately, the same result was achieved.

Our data showed a complete drawdown period with no build up or intervention to satisfy the assumption that fluid flow follows an uninterrupted condition and that, causes that controlled the trend of the curve previously will remain same into the future.

As summarized in figure 6, cartesian plot, semi-log and log-log plots were applied to the production data with the aim of obtaining a straight line for an easier description of the model unless the decline follows the hyperbolic model which will inevitably produce a curve from all the plots. After a suitable model was identified, its corresponding empirical equation from the hyperbolic family as listed in table 1 is used to evaluate the initial flow rate, decline rate constant and Arps decline exponent.

3.6 Analytical Simulation in TOPAZE

3.6.1 Initialization

The analytical simulation in Ecrin's Topaze begins with the initialization procedure which required the input of PVT data, geometric well and the reservoir information. Data required for our analysis include;

1. Production history
2. Pressure history
3. PVT, Correlations, tables or constraints
4. Wellbore radius
5. Porosity
6. Net vertical drained thickness

A new document is created in TOPAZE for Single Well Production Analysis and the reservoir information is keyed in. In the PVT parameter dialog opened, the formation volume factor and viscosities are computed from PVT table used in the numerical simulation. Compressibility is selected to be correlated from the formation volume factor table. Setting this up makes the document ready for analysis.

TOPAZE makes use of the available data thus both rate and pressure histories. For our analysis, two years production history is imported from the EXCEL spreadsheet obtained from the numerical simulation and loaded into the new document created in TOPAZE. After the data upload, the software uses the production history to generate the cumulative production automatically. Pressure data is also loaded and displayed in the history plot. The analysis page now displays production data on top the pressure data in a single window.

3.6.2 Data Extraction and Diagnostics

After data has been synchronized, analysis begin by using the extraction button to select the step amount of rate and pressure gauge for interpretation within a defined range of time. The selected time range will be same for both pressure and rate histories. In addition to the history data, other plots generated by the software include;

1. Fetkovish plot and its type curves
2. Blasingame plot and its type curves
3. The log-log plot
4. Normalized Rate-Cumulative plot

3.6.3 Model Generation

After the diagnostics, analytical models are selected as we try to simultaneously obtain a match between the models and the real data in all applicable plots including the history plot. Knowledge of the well configuration and the reservoir was used as a contrast between the real and the model. The model parameters were finally varied until a realistic match was obtained.

3.6.4 Production Forecast and Sensitivity Analysis

A production forecast was later performed after obtaining a reasonable and realistic match by defining a bottomhole flowing pressure. This was done to extend the model, in terms of pressure and rate by adding to the present history for the following year. At this point, we concluded the interpretation of the model by making sensitivity analysis, achieved by running different values of a given parameter and display of model generations that corresponds to it to compare with the history.

4 Results and Sensitivity Analysis

4.1 Results and Discussion

In our quest to forecast the production trend, first two years of production was extracted from the results obtained from the numerical simulation output, shown in Appendix I of this research work. Various plots were investigated (figure 6) until a straight line was obtained from a semi-log plot of Rate against time as shown in figure 13. The rate of the production decline followed a constant percentage decline (Exponential Model) and thus decline exponent b=0. Hence, transforming Equation 3.2 into a linear form, $\ln q(t) = \ln qi - Di * t$ was used to find the decline parameters such that the slope of the line yields Di (Decline Rate) and the intercept on the y-axis yielded Ln qi of which the initial flow rate (qi) was estimated.

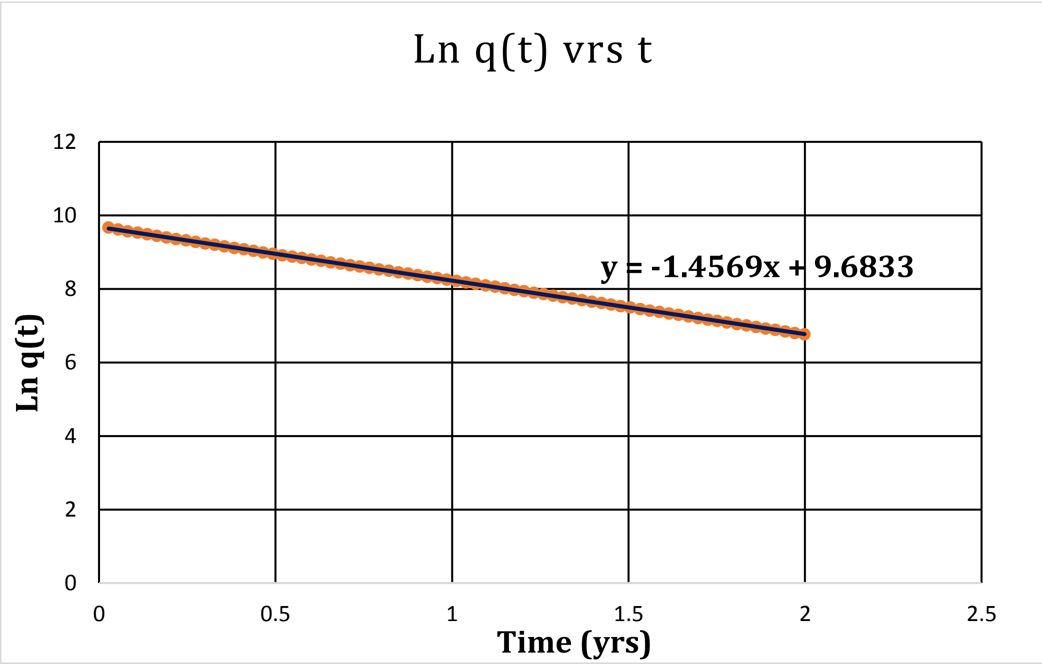

Figure 13 Plot of Ln q(t) against t

Having found the model and its corresponding parameters, equations 3.2 and 3.3 were used to forecast the first year of production up until the third year shown in figure 14. Setting an economic flow rate (qa) of 50 STB/D, equation 3.2 was used to evaluate the time (ta) to reach the economic limit. The corresponding reserves (Npa) at the economic limit is estimated from equation 3.3.

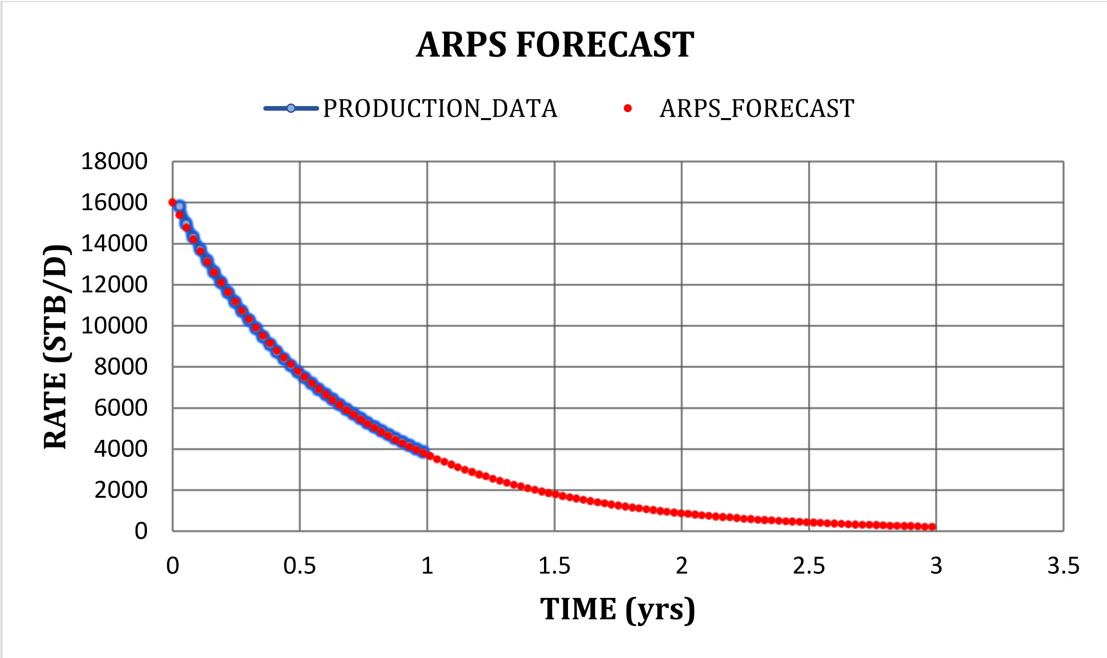

Figure 14 Arps Model Forecast

TOPAZE was later used to analyze the production data analytically with type curves to identify the reservoir parameters or properties that contributed to the production decline. Detailed result of the analytical simulation is reported in Appendix II. The type curve analysis is intended at finding a theoretical type curve plot that matches the actual response from the reservoir due to variations in production rates or pressures. Input of two years production data yielded the plot in figure 15 from the software. The model parameters were tweaked until a reasonable match was obtained after the various plots and type curves were extracted from the software.

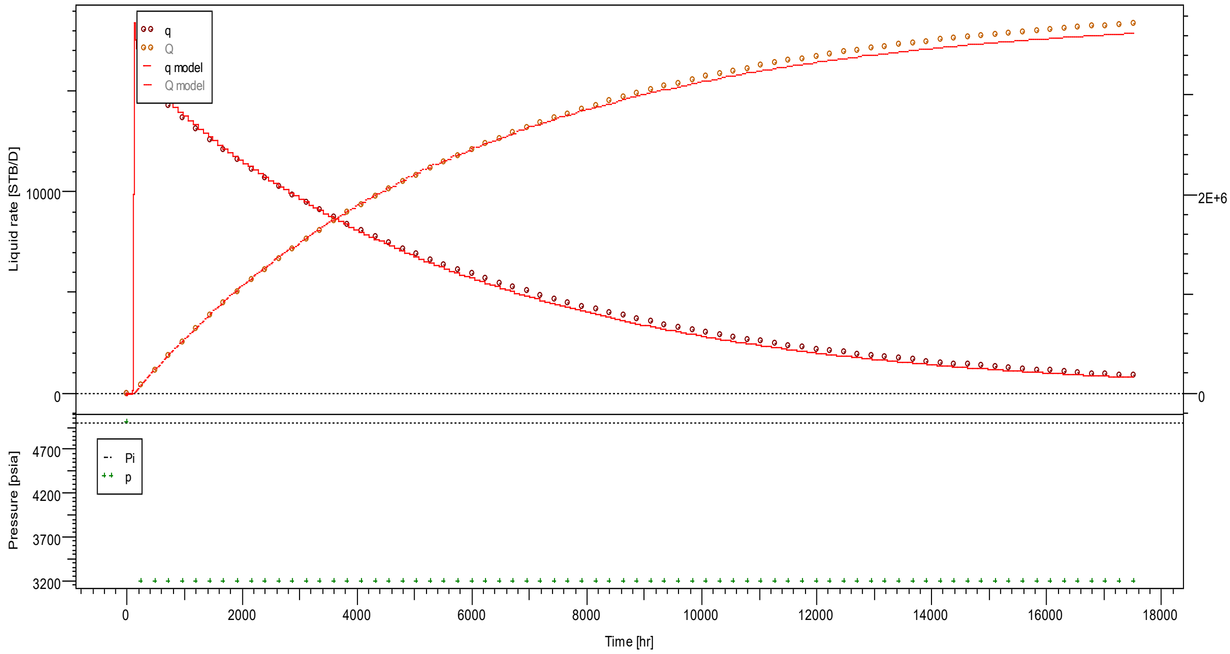

Figure 15 Production History Plot

Using the historical production decline trend as a useful reference tool to characterize well and reservoir, requires that the transient flow regime (early time) and boundary-dominated flow regime (late time) responses be combined into a single set of decline curve, providing a reliable advantage to determine the transient flow and boundary-dominated flow period of the production. Beginning with the Fetkovish type curve (figure 16), it combines the Arps decline curves on the right which is only useful for boundary dominated flow analysis and the left part for transient analysis. The transmissibility (Kh) and external radius of the reservoir (Re) was estimated, knowing Pi and flowing pressures. Fetkovish type curve assumed a circular bounded reservoir when estimating the external radius, Re, of the reservoir. The closest fit is highlighted with thick line. The pore volume (PV) was estimated from the product of the Re-squared, porosity and the reservoir thickness which consequently estimates the Stock Tank Oil Initially in Place (STOIIP) by introducing the formation volume factor. Our result showed that Fetkovish type curve overestimated the STOIIP but however, gave a good estimate of the formation permeability and skin.

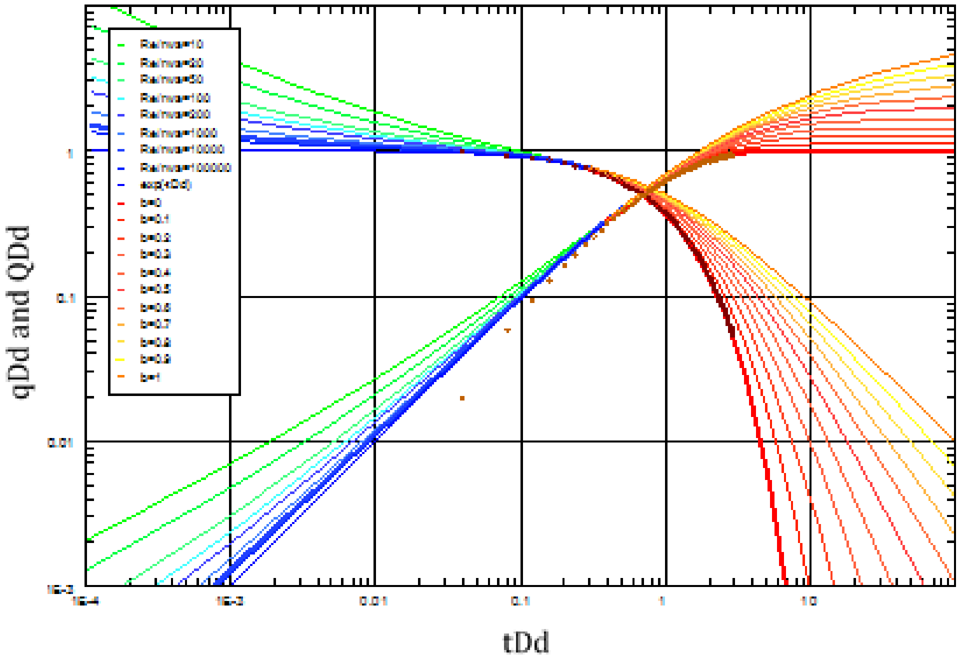

Figure 16 Fetkovish Type Curve Plot

Based on the application of equations 5.3, 5.4 and 5.5, which presents the graphical presentation of the dimensionless variables of the pressure drawdown normalized flow rate, its integral and its integral derivative functions, the software extracted the Blasingame type curve plot. Analysis of the production history data is achieved using dimensionless production decline rate transient solution that are expressed in terms of dimensionless decline variables of flow rate, flow rate integral, and the integral-derivative of the flow rate as shown in figure 17 as a function of dimensionless decline time. Blasingame type curve was used as a diagnostic tool to relate the historical production data to the model response. The analysis with Blasingame plots and type curves was seen to provide a good estimate of the reservoir parameters obtained from the numerical simulation. From the figure 17, the functions of dimensionless decline flow rate integral and the integral-derivative shows a negative slope of one during the boundary-dominated flow regime as the dimensionless decline flow rate shows a harmonic decline stem. From a fundamental basis that adheres rigorously to rate-transient fluid flow theory, a mathematical justification for a harmonic production decline during the boundary-dominated flow, without first assuming a steady-state relationship exists between the pressure transient and rate transient solutions at late time is unjustified from theoretical point of view. If the late-time production decline trend had deviated from the theoretical exponential decline behavior to a harmonic decline behavior, certain factors which include the effect of non-linear fluid and reservoir properties, reservoir layering or pressure support at the boundaries which will render the system to be in steady-state condition will be required to be investigated as well. All the three type curves on the Blasingame plot were used simultaneously to give a better characteristic and enhances visual pattern recognition. The derivative and the normalized rate curve converging and crossing each other indicates that the well is in the boundary dominated flow regime. The Blasingame type curve was very conservative in obtaining the fluids in place when it has a downward concavity at the boundary dominated flow. It gave a sound estimate of the fluid in place and the skin though the permeability was not so perfect, it wasn't far from that of the model.

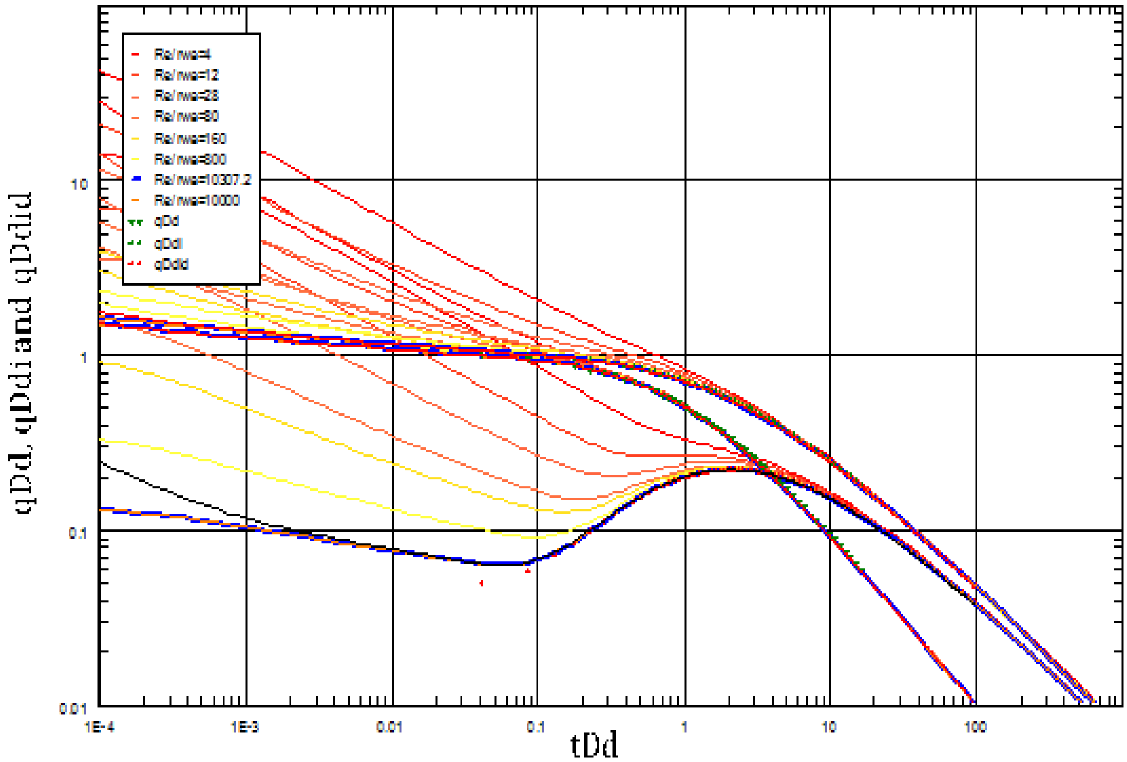

Figure 17 Blasingame Type Curve Plot

The flowing material balance plot (figure 18) was used to directly estimate the Stock Tank Oil Initially in Place from the linear plot of the normalized rate against Cumulative produced as described by equation 6.1, which was the intercept on the x-axis. The STOIIP attained from the flowing material balance plot was overestimated but not as much as the Fetkovish type curve did. Comparatively, the intercept on the x-axis of the rate against cumulative traditional plot, yielded the Ultimate Recovery. The intercepts on both plots were used to estimate the Recovery Factor at abandonment.

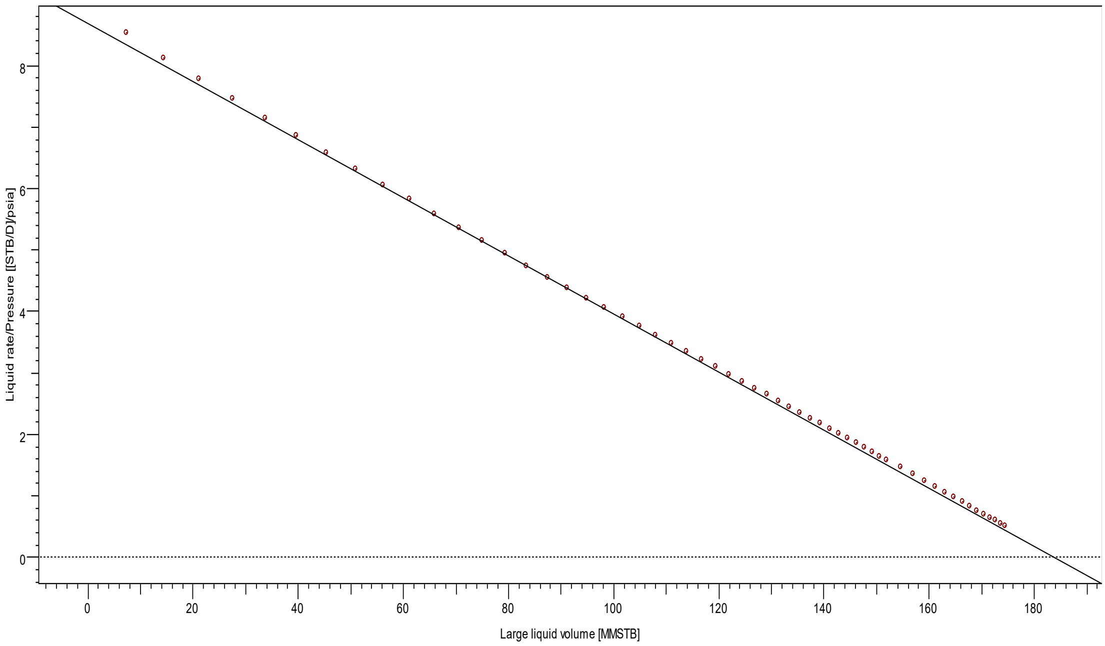

Figure 18 Normalized Rate-Cumulative Plot

4.2 Sensitivity on Skin and Permeability

Sensitivity analysis was performed to identify how skin and permeability would affect the output. Different values of skin and permeability were assumed for a pessimistic case (Case 1) and optimistic case (Case 2), and their result and effect were compared to the base case scenario.

	CASE 1	**BASE CASE**	**CASE 2**
PERMEABILITY (mD)	50	98	140
SKIN (-)	5	0	-5

Table 4 Parameters for Sensitivity

The most desired observation was the decline trend while varying the formation permeability and skin effects. These parameters are likely to change during the reservoirs producing life. From figure 19, higher permeability of the reservoir rock causes a faster travel of the pressure transient from the wellbore to the boundaries of the porous rock and so boundary-dominated flow is likely to be felt earlier than expected. Setting the permeability to 140 mD as against the 98 mD in the base case, the initial flow rate at decline also increased to approximately 2500 STB/D and caused a faster rate of decline. The reverse was encountered when permeability was reduced from 98 mD to 50 mD as indicated by the blue curve. The initial flow rate decreased to approximately 900 STB/D with a steady rate of decline.

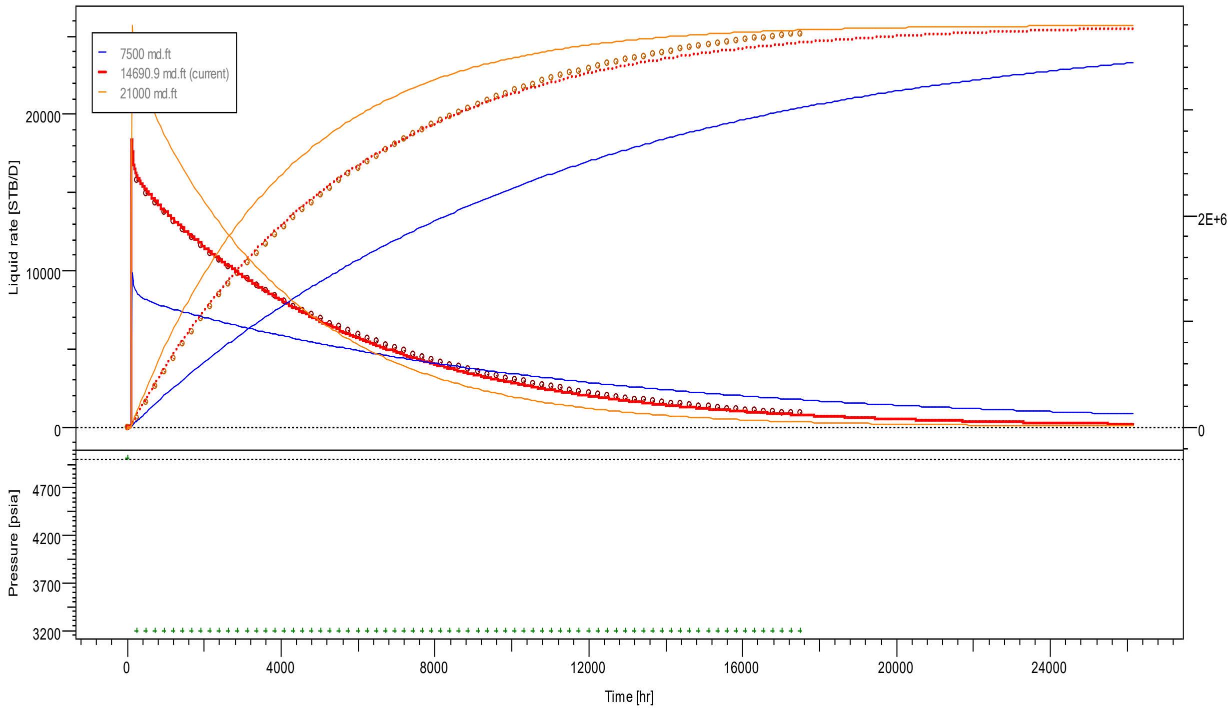

Figure 19 Sensitivity to Kh

Permeability reduction at the vicinity of the wellbore is likely to be caused by drilling fluids, migration of fines etc. and this results in a positive skin. The permeability can be enhanced by matrix acidizing or hydraulic fracturing which results in a negative skin. In figure 20, setting the skin factor to -5 as against the 0 in the base case will enhance the effective permeability and so will follow a curve similar to that of the high permeability in figure 19, a higher initial flow rate at decline and a fast decline rate. On the other hand, setting the skin factor to 5, for a damaged well reduces the effective permeability and thus decreasing the initial flow rate at decline.

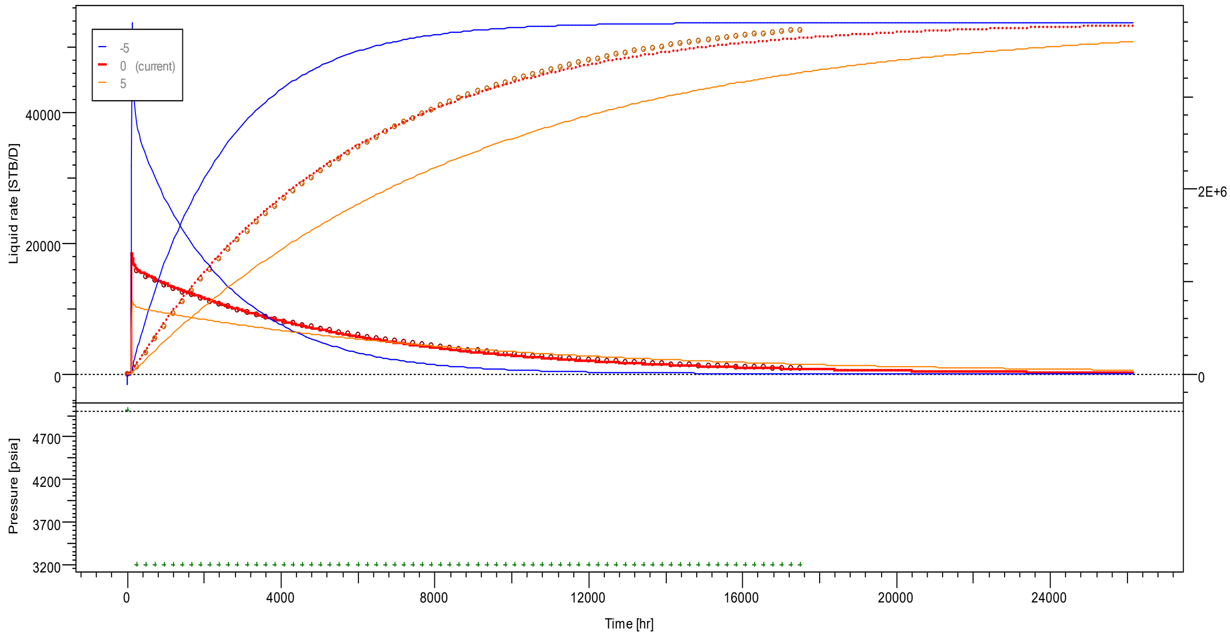

Figure 20 Sensitivity to Skin

5 Conclusion

Throughout this work, a comprehensive approach for the interpretation of production data for predicting the long-term production of a producing well while using same data as a means of diagnosing the reservoir characteristics. Various methods have been discussed with their diagnostic plots and characteristic signatures on each plot.

The Arps traditional method was successfully applied to forecast the historical production data and to estimate the reserves. However, the method should not be absolutely relied on since it may overestimate or underestimate the reserves due to the fact that it ignores the pressure data, though it gives a reasonable approximation of the reserves. Seen from our results, as shown in Table 5 the Arps Exponential method overestimated the cumulative produced. Moreover, for transient production data, this method cannot be applied since it only works for boundary-dominated flows. The b value was expected to be zero (b=0) since it had already been stated categorically that, the reservoir was producing by depletion drive and nothing more could have been expected other than an exponential decline and more so producing at constant operating conditions of pressure and variable rate.

On the basis of comparison (Table 5), the Blasingame type curve plot was seen to provide a good estimate of the fluid in place as well as the parameters contributing to the reservoir response. However, the Fetkovish type curve gave a close estimate of the permeability than that of the Blasingame type curve, though not by any wide margin.

In this study, application of both numerical simulation and rate transient analytical methods using commercialized software, Schlumberger's Eclipse and Ecrin TOPAZE from KAPPA helped to comprehend the effect of reservoir parameters on the inconsistencies in our imposed values.

	Arps Plot	N. Rate-Cumulative	Blasingame	Fetkovish	Model
STOIIP (MMSTB)		184	178	187	178
STOIP (MMSTB)		180	175	184	175
Re (ft)			3380	3470	3385
kh (md.ft)			14400	14800	14700
k (md)			95.7	98.9	97.9
Skin			0	0	0
rwa (ft)			0.328	0.328	
b	0				
Di [Day]-1	0.004				
qi (STB/D)	16000				
UR (MMSTB)	3.78				3.73

Table 5 Comparison of results from different methods

In addition, the diagnostic plots extracted from the analytical software were able to characterize early time transient flow and boundary-dominated flow regimes. That notwithstanding, quality control may occasionally be required to enhance resolution of the production data to remove the generation of noise.

The technique used in this work saves money that is likely to be lost during shut-in periods in pressure transient analysis and can be used as a reliable tool to diagnose reservoir problems to make decisions for workover. As a matter of convenience, various methods should be applied to reduce the uncertainties that is possible to arise from a single method.

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APPENDIX I

Simulation Data Output & Arps Exponential Model

	NUMERICAL SIMULATED MODEL				ARPS EXPONENTIAL MODEL		
FOIP	YEARS	WOPR	WOPT	WBHP	Di = D	$q_o(t)$	Np
STB (10^3)	YEARS	STB/DAY	STB	PSIA	1.46	16000	
178119.7	0	0	0	5007.64		16000	0
177955.6	0.02738	15800	164108.5	3200		15373.04	156739.78
177806	0.05476	14962.32	313731.8	3200		14770.67	307332.34
177662.9	0.08214	14302.56	456757.4	3200		14191.88	452029.32
177525.8	0.10951	13706.99	593827.2	3200		13635.79	591051.38
177394.4	0.13689	13145.81	725285.4	3200		13101.48	724630.85
177268.3	0.16427	12609.58	851381.2	3200		12588.11	852971.42
177147.3	0.19165	12097.05	972351.7	3200		12094.85	976287.56
177031.2	0.21903	11609.53	1088447	3200		11620.93	1094767.3
176919.8	0.24641	11144.41	1199891	3200		11165.57	1208608.7
176812.8	0.27379	10697.29	1306864	3200		10728.06	1317985.3
176710.1	0.30116	10267.81	1409542	3200		10307.68	1423079.9
176611.5	0.32854	9855.528	1508097	3200		9903.789	1524052.8
176516.9	0.35592	9459.987	1602697	3200		9515.709	1621072.6
176426.1	0.3833	9080.507	1693502	3200		9142.85	1714287.4
176338.9	0.41068	8717.759	1780680	3200		8784.588	1803853
176255.2	0.43806	8373.378	1864414	3200		8440.377	1889905.8
176174.7	0.46544	8049.821	1944912	3200		8109.641	1972589.7
176097.2	0.49281	7745.012	2022362	3200		7791.877	2052030.8
176022.7	0.52019	7454.042	2096902	3200		7486.552	2128361.9
175951	0.54757	7173.359	2168636	3200		7193.203	2201699.3
175882	0.57495	6903.112	2237667	3200		6911.338	2272165.6
175815.5	0.60233	6642.482	2304092	3200		6640.527	2339868.3
175751.6	0.62971	6391.128	2368003	3200		6380.318	2404920.5
175690.1	0.65708	6148.75	2429491	3200		6130.315	2467421.3
175631	0.68446	5915.139	2488642	3200		5890.099	2527475.3
175574.1	0.71184	5690.241	2545544	3200		5659.304	2585174.1
175519.4	0.73922	5473.541	2600280	3200		5437.544	2640614
175466.7	0.7666	5264.65	2652926	3200		5224.482	2693879.5
175416.1	0.79398	5063.401	2703560	3200		5019.761	2745059.8
175367.4	0.82136	4869.485	2752255	3200		4823.069	2794232.8
175320.6	0.84873	4683.304	2799088	3200		4634.077	2841480.7
175275.5	0.87611	4503.209	2844120	3200		4452.498	2886875.6
175232.3	0.90349	4328.29	2887403	3200		4278.027	2930493.3
175190.7	0.93087	4160.826	2929012	3200		4110.398	2972400.4
175150.7	0.95825	3999.358	2969005	3200		3949.333	3012666.8
175112.2	0.98563	3844.235	3007448	3200		3794.584	3051354
175075.3	1.01301	3694.855	3044396	3200		3645.893	3088526.7
175039.8	1.04038	3551.017	3079906	3200		3503.034	3124241.4
175005.6	1.06776	3412.559	3114032	3200		3365.768	3158558
174972.9	1.09514	3279.311	3146825	3200		3233.885	3191528.7

174941.3	1.12252	3151.094	3178336	3200		3107.166	3223208.6
174911.1	1.1499	3027.732	3208613	3200		2985.416	3253646
174882	1.17728	2909.054	3237704	3200		2868.433	3282891.8
174854	1.20465	2794.894	3265653	3200		2756.037	3310990.7
174827.2	1.23203	2685.09	3292504	3200		2648.042	3337989.5
174801.4	1.25941	2579.485	3318298	3200		2544.282	3363929.4
174776.6	1.28679	2477.928	3343078	3200		2444.585	3388853.8
174752.8	1.31417	2380.272	3366880	3200		2348.797	3412800.7
174730	1.34155	2286.375	3389744	3200		2256.76	3435810
174708	1.36893	2196.098	3411705	3200		2168.332	3457917
174686.9	1.3963	2109.31	3432798	3200		2083.366	3479158.5
174666.6	1.42368	2025.881	3453057	3200		2001.732	3499566.9
174647.2	1.45106	1945.686	3472514	3200		1923.295	3519176.3
174628.5	1.47844	1868.606	3491200	3200		1847.933	3538016.7
174610.5	1.50582	1794.524	3509145	3200		1775.522	3556119.5
174593.3	1.5332	1723.328	3526378	3200		1705.951	3573512.3
174576.8	1.56058	1654.909	3542928	3200		1639.103	3590224.2
174560.9	1.58795	1589.163	3558819	3200		1574.877	3606280.7
174545.6	1.61533	1525.989	3574079	3200		1513.166	3621708.6
174531	1.64271	1465.289	3588732	3200		1453.875	3636531.4
174516.9	1.67009	1406.969	3602802	3200		1396.905	3650773.9
174503.4	1.69747	1350.94	3616311	3200		1342.169	3664457.8
174490.4	1.72485	1297.112	3629282	3200		1289.576	3677606
174478	1.75222	1245.403	3641736	3200		1239.046	3690238.5
174466	1.7796	1195.73	3653694	3200		1190.494	3702376.5
174454.5	1.80698	1148.015	3665174	3200		1143.845	3714038.9
174443.5	1.83436	1102.184	3676196	3200		1099.025	3725243.8
174432.9	1.86174	1058.163	3686777	3200		1055.959	3736010.1
174422.8	1.88912	1015.882	3696936	3200		1014.583	3746354.2
174413	1.9165	975.2745	3706689	3200		974.8268	3756293.3
174403.6	1.94387	936.2749	3716052	3200		936.6297	3765842.6
174394.7	1.97125	898.8209	3725040	3200		899.9279	3775018
174386	1.99863	862.8522	3733668	3200		864.6655	3783833.6
174377.7	2.02601	828.3112	3741951	3200		830.7836	3792304.1
174369.8	2.05339	795.1418	3749903	3200		798.2306	3800442.4
174362.2	2.08077	763.2907	3757536	3200		766.952	3808262
174354.8	2.10815	735.5416	3764891	3200		736.9001	3815775
174347.7	2.13552	705.3469	3771944	3200		708.0247	3822993.8
174341	2.1629	677.1795	3778716	3200		680.2818	3829929.6
174334.5	2.19028	649.8374	3785215	3200		653.625	3836593.8
174328.2	2.21766	623.7424	3791452	3200		628.0136	3842996.6
174322.3	2.24504	598.6023	3797438	3200		603.4049	3849148.8
174316.5	2.27242	574.5234	3803184	3200		579.7614	3855059.6
174311	2.2998	551.3734	3808697	3200		557.0435	3860739.1
174305.7	2.32717	529.1736	3813989	3200		535.2165	3866195.9

174300.6	2.35455	507.8485	3819067	3200		514.2441	3871439
174295.8	2.38193	487.3882	3823941	3200		494.0942	3876476.4
174291.1	2.40931	467.742	3828619	3200		474.7332	3881316.7
174286.6	2.43669	448.8885	3833108	3200		456.1314	3885967.1
174282.3	2.46407	430.7888	3837416	3200		438.2579	3890435.5
174278.1	2.49144	413.4178	3841550	3200		421.0854	3894728.6
174274.2	2.51882	396.7433	3845517	3200		404.5852	3898853.7
174270.4	2.5462	380.7396	3849324	3200		388.7321	3902817
174266.7	2.57358	365.3785	3852978	3200		373.4997	3906625.1
174263.2	2.60096	350.6355	3856484	3200		358.8647	3910283.8
174259.8	2.62834	336.485	3859850	3200		344.8026	3913799.4
174256.6	2.65572	322.904	3863078	3200		331.292	3917177
174253.5	2.68309	309.8694	3866177	3200		318.3103	3920422.4
174250.5	2.71047	297.3594	3869151	3200		305.8378	3923540.6
174247.7	2.73785	285.353	3872004	3200		293.8536	3926536.6
174244.9	2.76523	273.8301	3874742	3200		282.3393	3929415.2
174242.3	2.79261	262.7713	3877370	3200		271.2759	3932181
174239.8	2.81999	252.158	3879892	3200		260.6463	3934838.4
174237.4	2.84737	241.9723	3882312	3200		250.4329	3937391.8
174235.1	2.87474	232.1972	3884634	3200		240.6201	3939845
174232.8	2.90212	222.816	3886862	3200		231.1914	3942202.2
174230.7	2.9295	213.8131	3889000	3200		222.1325	3944466.9
174228.6	2.95688	205.1732	3891052	3200		213.4282	3946642.9
174226.7	2.98426	196.8817	3893020	3200		205.0654	3948733.7
174224.8	3.01164	188.9247	3894910	3200		197.0299	3950742.5
174223	3.03901	181.2887	3896722	3200		189.3096	3952672.6
174221.2	3.06639	173.9608	3898462	3200		181.8915	3954527.1
174219.6	3.09377	166.9287	3900132	3200		174.7643	3956308.9
174218	3.12115	160.1803	3901733	3200		167.9162	3958021
174216.4	3.14853	153.7043	3903270	3200		161.3366	3959665.8
174214.9	3.17591	147.4898	3904745	3200		155.0147	3961246.3
174213.5	3.20329	141.5262	3906160	3200		148.9406	3962764.8
174212.2	3.23066	135.8034	3907518	3200		143.1044	3964223.9
174210.9	3.25804	130.3117	3908822	3200		137.4971	3965625.7
174209.6	3.28542	125.0418	3910072	3200		132.1093	3966972.7
174208.4	3.3128	119.9848	3911272	3200		126.9328	3968266.8
174207.3	3.34018	115.1321	3912423	3200		121.9589	3969510.3
174206.2	3.36756	110.4754	3913528	3200		117.1799	3970705
174205.1	3.39494	106.0068	3914588	3200		112.5884	3971852.9
174204.1	3.42231	101.7189	3915605	3200		108.1768	3972955.8
174203.1	3.44969	97.60419	3916581	3200		103.9379	3974015.5
174202.2	3.47707	93.65578	3917518	3200		99.86511	3975033.7
174201.3	3.50445	89.86697	3918416	3200		95.95204	3976012
174200.4	3.53183	86.2313	3919279	3200		92.1923	3976951.9
174199.6	3.55921	82.7426	3920106	3200		88.57975	3977855.1

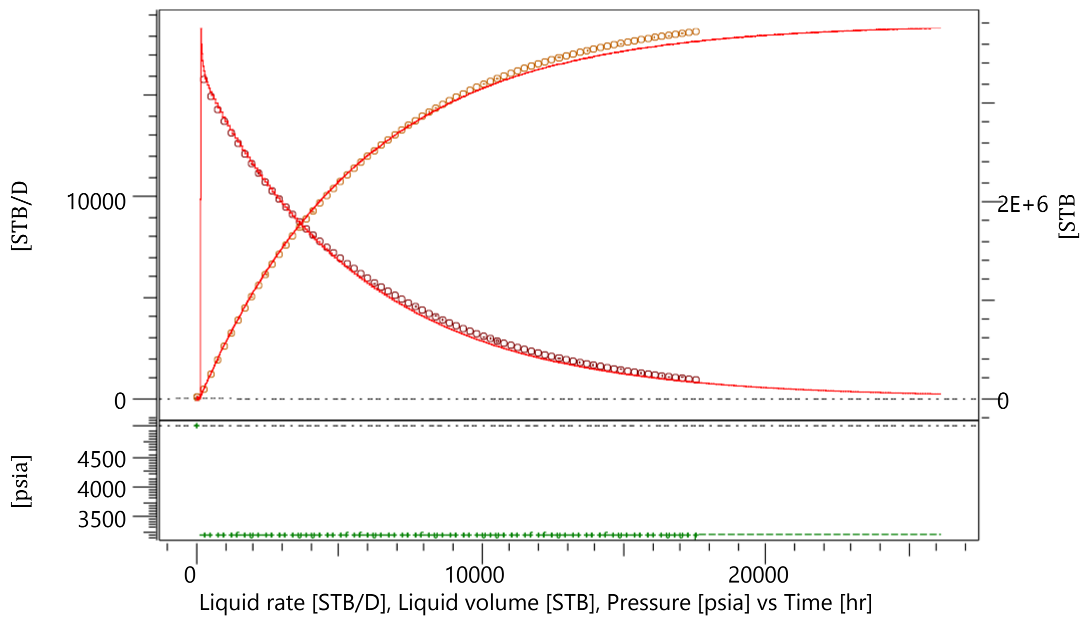
174198.8	3.58659	79.39493	3920900	3200		85.10875	3978722.8
174198	3.61396	76.1826	3921662	3200		81.77389	3979556.5
174197.3	3.64134	73.10015	3922393	3200		78.5697	3980357.6
174196.6	3.66872	70.14233	3923094	3200		75.49095	3981127.3
174195.9	3.6961	67.30412	3923768	3200		72.53284	3981866.8
174195.3	3.72348	64.58067	3924413	3200		69.69075	3982577.3
174194.7	3.75086	61.96736	3925033	3200		66.95992	3983260
174194.1	3.77823	59.45974	3925628	3200		64.33619	3983916
174193.5	3.80561	57.05354	3926198	3200		61.81518	3984546.2
174192.9	3.83299	54.74466	3926746	3200		59.39305	3985151.7
174192.4	3.86037	52.52917	3927271	3200		57.06573	3985733.6
174191.9	3.88775	50.40329	3927775	3200		54.82969	3986292.6
174191.4	3.91513	48.36341	3928258	3200		52.6812	3986829.7
174191	3.94251	46.40604	3928722	3200		50.61696	3987345.8
174190.5	3.96988	44.52786	3929168	3200		48.63354	3987841.6
174190.1	3.99726	42.72567	3929595	3200		46.7279	3988318
174189.7	4.02464	40.99638	3930005	3200		44.89687	3988775.8
174189.3	4.05202	39.33706	3930398	3200		43.13765	3989215.6
174188.9	4.0794	37.74487	3930776	3200		41.44731	3989638.2
174188.6	4.10678	36.21711	3931138	3200		39.82326	3990044.2
174188.2	4.13416	34.75116	3931486	3200		38.26278	3990434.3
174187.9	4.16153	33.34453	3931819	3200		36.76351	3990809.1
174187.6	4.18891	31.99482	3932139	3200		35.32294	3991169.3
174187.2	4.21629	30.69973	3932446	3200		33.93886	3991515.3
174187	4.24367	29.45704	3932740	3200		32.60897	3991847.8
174186.7	4.27105	28.26464	3933023	3200		31.33123	3992167.2
174186.4	4.29843	27.1205	3933294	3200		30.10352	3992474.1
174186.1	4.3258	26.02266	3933554	3200		28.92396	3992769
174185.9	4.35318	24.96924	3933804	3200		27.79057	3993052.4
174185.6	4.38056	23.95847	3934044	3200		26.70164	3993324.6
174185.4	4.40794	22.9886	3934274	3200		25.65534	3993586.2
174185.2	4.43532	22.05798	3934494	3200		24.65007	3993837.5
174185	4.4627	21.16503	3934706	3200		23.68416	3994079
174184.8	4.49008	20.30821	3934909	3200		22.75613	3994311
174184.6	4.51745	19.48608	3935104	3200		21.86443	3994533.9
174184.4	4.54483	18.69723	3935291	3200		21.00771	3994748.1
174184.2	4.57221	17.9403	3935470	3200		20.18452	3994953.9
174184	4.59959	17.21401	3935642	3200		19.39362	3995151.6
174183.9	4.62697	16.51712	3935808	3200		18.63368	3995341.6
174183.7	4.65435	15.84844	3935966	3200		17.90355	3995524.1
174183.6	4.68173	15.20682	3936118	3200		17.202	3995699.5
174183.4	4.7091	14.59118	3936264	3200		16.52794	3995868
174183.3	4.73648	14.00046	3936404	3200		15.88031	3996029.9
174183.2	4.76386	13.43365	3936538	3200		15.25807	3996185.5
174183	4.79124	12.88978	3936667	3200		14.66018	3996335

174182.9	4.81862	12.36793	3936791	3200		14.08574	3996478.6
174182.8	4.846	11.86721	3936910	3200		13.53379	3996616.6
174182.7	4.87337	11.38675	3937024	3200		13.00349	3996749.1
174182.6	4.90075	10.92574	3937133	3200		12.49395	3996876.5
174182.5	4.92813	10.4834	3937238	3200		12.00438	3996998.9
174182.4	4.95551	10.05896	3937338	3200		11.534	3997116.5
174182.3	4.98289	9.651711	3937435	3200		11.08206	3997229.5
174182.2	5.01027	9.260944	3937527	3200		10.64781	3997338
174182.1	5.03765	8.885997	3937616	3200		10.23059	3997442.4
174182	5.06502	8.526228	3937702	3200		9.829705	3997542.6

APPENDIX II

Ecrins TOPAZE Report

Production history plot	Analysis 1
Company	Field
Well Reference well	Test Name / #



Rate
- q
- Q
- q model
- Q model

Pressure
- Pi
- P
- Forecast

Main Model Parameters

Tmin	0 hr
Tmax	17508 hr
Total Skin	0
k.h, total	14700 md.ft
k, average	97.9 md
Pi	5000 psia
STOIIP	178 MMSTB
STOIP	175 MMSTB
Qo(tmax)	3.72 MMSTB

Pressure - Production

Tmin	0 hr
Tmax	17508 hr
Pi	5000 psia

Model Parameters

Well & Wellbore parameters (Reference well)

Skin	0

Reservoir & Boundary parameters

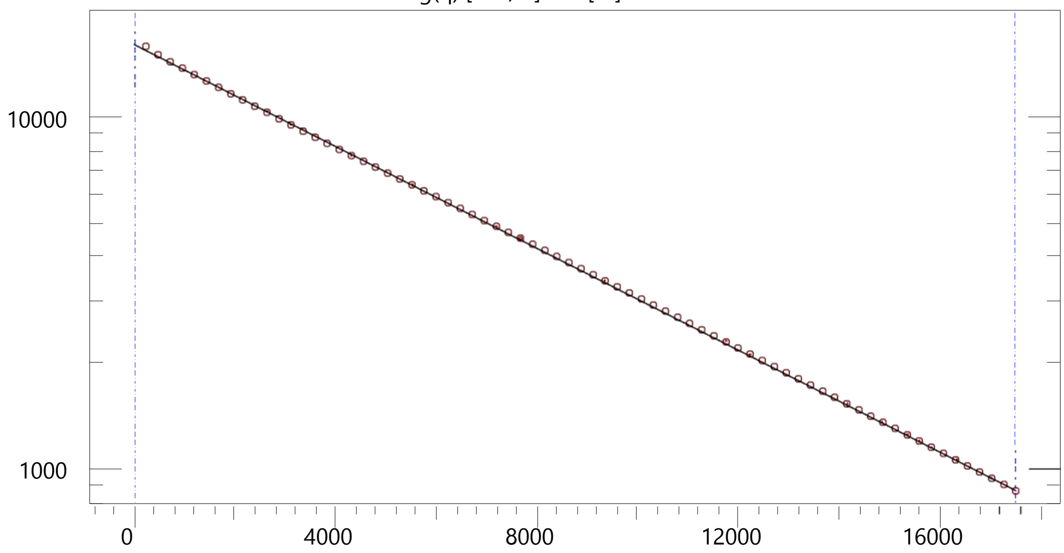
Pi	5000 psia
k.h	14700 md.ft
k	97.9 md
S - No flow	3000 ft
E - No flow	3000 ft
N - No flow	3000 ft
W - No flow	3000 ft

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Rectangle, No flow

Arps plot	Analysis 1
Company	Field
Well Reference well	Test Name / #

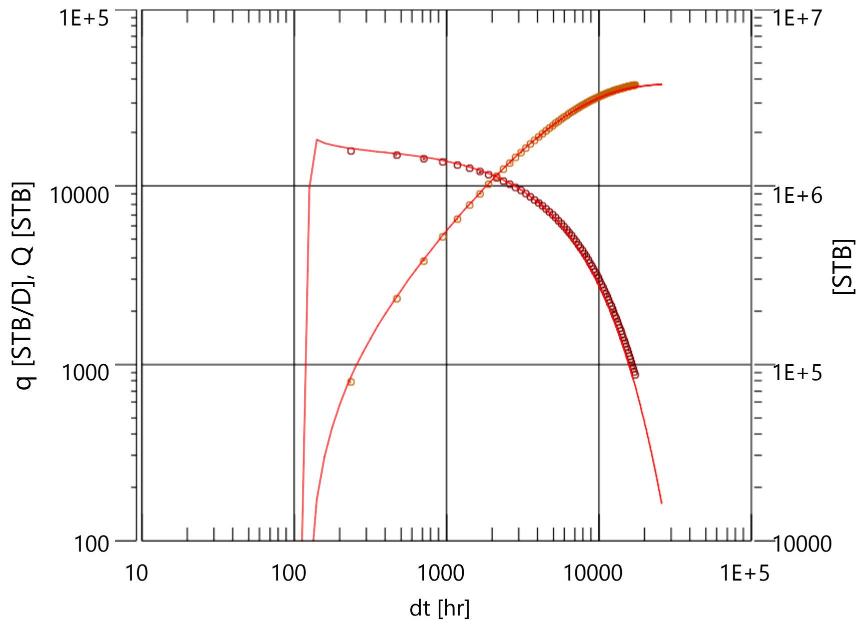
log(q) [STB/D] vs t [hr]



Ab. rate (qa)
Ab. time (ta)

Tmin	0 Day
Tmax	729.5 Day
Arps model	
b	0
Di	0.004 [Day]-1
qi	16000 STB/D
UR	4 MMSTB
Abandonment	
Ab. ratio (qa/qi)	1E-3 Fraction
Ab. time (ta)	1726.94 Day
Q(ta)	4 MMSTB
Reserve(Tmax)	0.212 MMSTB

Fetkovich plot	Analysis 1
Company	Field
Well Reference well	Test Name / #



Pressure - Production

Tmin 0 hr

Tmax 17508 hr

Pi 5000 psia

Selected Model

Model Option Standard Model

Well Vertical

Reservoir Homogeneous

Boundary Rectangle, No flow

Main Model Parameters

Tmin 0 hr

Tmax 17508 hr

Total Skin 0

k.h, total 14700 md.ft

k, average 97.9 md

Pi 5000 psia

STOIIP 178 MMSTB

STOIP 175 MMSTB

Qo(tmax) 3.72 MMSTB

Model Parameters

Well & Wellbore parameters (Reference well)

Skin 0

Reservoir & Boundary parameters

Pi 5000 psia

k.h 14700 md.ft

k 97.9 md

S - No flow 3000 ft

E - No flow 3000 ft

N - No flow 3000 ft

W - No flow 3000 ft

Derived & Secondary Parameters

TMatch 400 [hr]-1

PMatch 0.141 [psia]-1

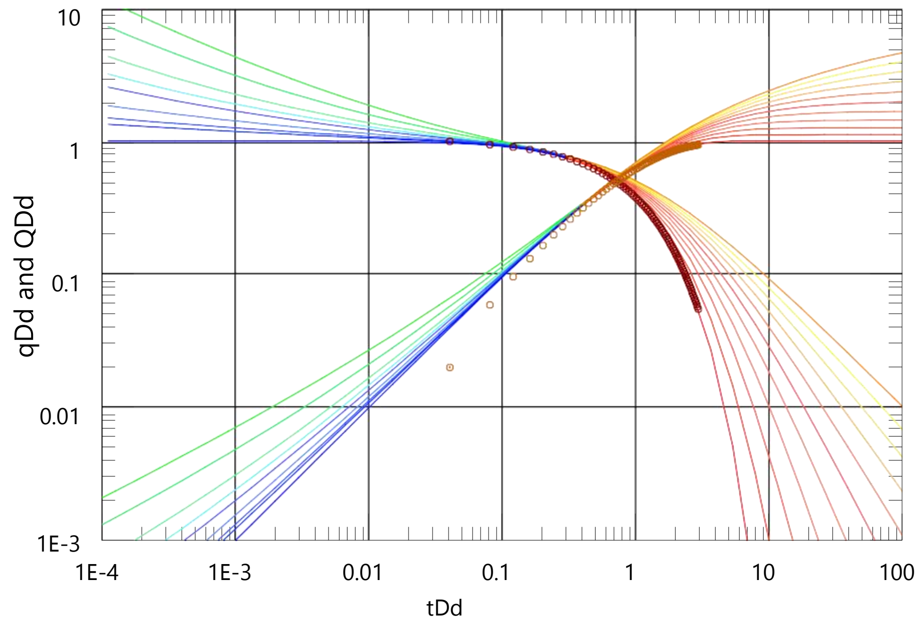
Abandonment

Ab. rate (qa) 50 STB/D

Ab. time (ta) 110.668 hr

Q(ta) N/A STB

	Fetkovich type curve pl...	Analysis 1
	Company Well Reference well	Field Test Name / #

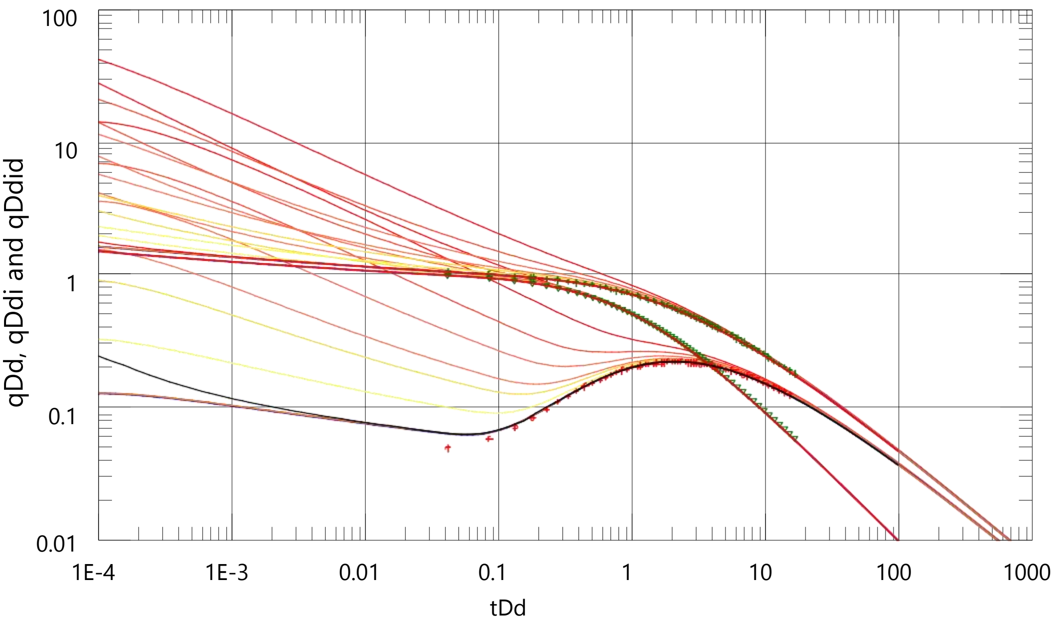


Re/rwa=10
Re/rwa=20
Re/rwa=50
Re/rwa=100
Re/rwa=200
Re/rwa=1000
Re/rwa=10000
Re/rwa=100000
exp(-tDd)
b=0
b=0.1
b=0.2
b=0.3
b=0.4
b=0.5
b=0.6
b=0.7
b=0.8
b=0.9
b=1

Pressure - Production

Tmin	0 hr
Tmax	17508 hr
Pi	5000 psia
b	0
Di	0.004 [Day]-1
qi	16000 STB/D
UR	4 MMSTB
pwf	3200 psia
k.h	14800 md.ft
k	98.9 md
Re	3470 ft
rwa	0.328 ft

Blasingame type curve...	Analysis 1
Company	Field
Well Reference well	Test Name / #



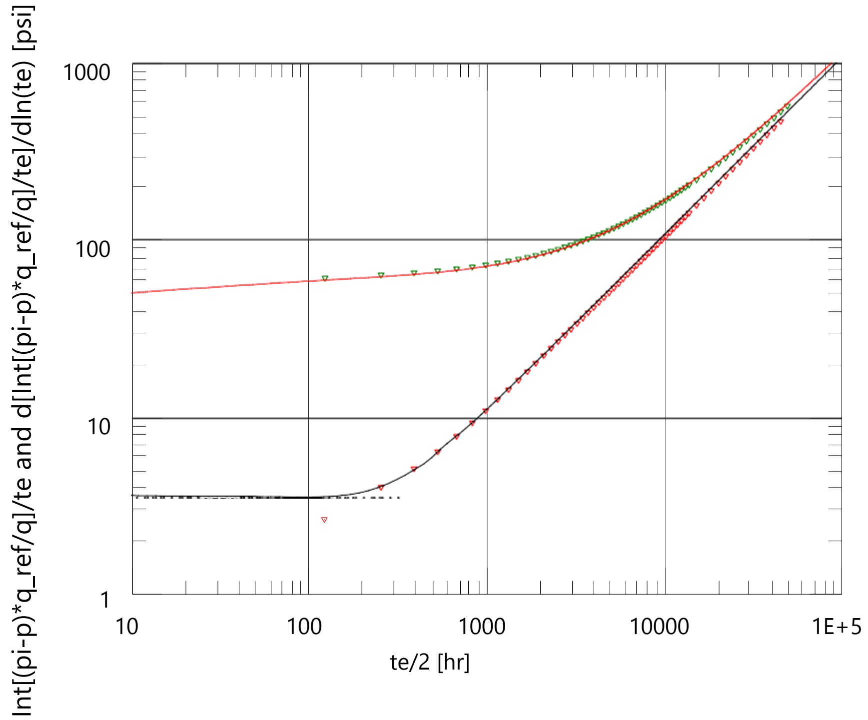
- Re/rwa=4
- Re/rwa=12
- Re/rwa=28
- Re/rwa=80
- Re/rwa=160
- Re/rwa=800
- Re/rwa=10307.2
- Re/rwa=10000
- qDd
- qDdi
- qDdid

STOIIP	178 MMSTB
STOIP	175 MMSTB
Re	3380 ft
rwa	0.328 ft
k.h	14400 md.ft
k	95.7 md
Skin	0

Pressure - Production

Tmin	0 hr
Tmax	17508 hr
Pi	5000 psia

Loglog plot	Analysis 1
Company	Field
Well Reference well	Test Name / #



Integral of normalized pressure
Integral of normalized pressure Derivative

Pressure - Production

Tmin	0 hr
Tmax	17508 hr
Pi	5000 psia

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Rectangle, No flow

Main Model Parameters

Tmin	0 hr
Tmax	17508 hr
Total Skin	0
k.h, total	14700 md.ft
k, average	97.9 md
Pi	5000 psia
STOIIP	178 MMSTB
STOIP	175 MMSTB
Qo(tmax)	3.72 MMSTB

Model Parameters

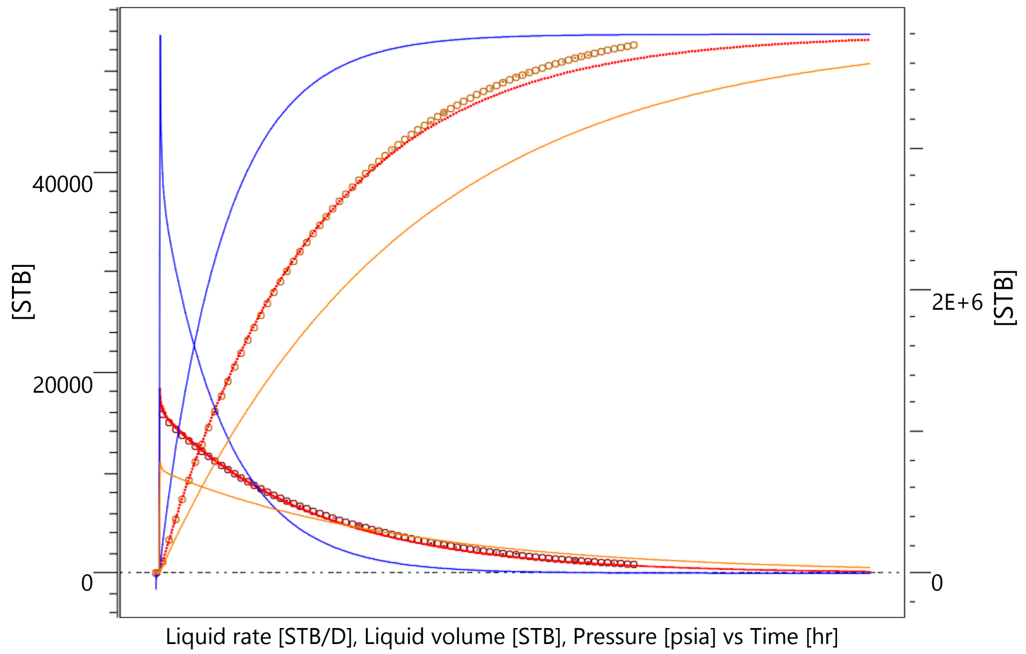
Well & Wellbore parameters (Reference well)

Skin	0

Reservoir & Boundary parameters

Pi	5000 psia
k.h	14700 md.ft
k	97.9 md
S - No flow	3000 ft
E - No flow	3000 ft
N - No flow	3000 ft
W - No flow	3000 ft

Production history plot	Analysis 1
Company	Field
Well Reference well	Test Name / #



-5
0 (current)
5

Pressure - Production

Tmin	0 hr
Tmax	17508 hr
Pi	5000 psia

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Rectangle, No flow

Main Model Parameters

Tmin	0 hr
Tmax	17508 hr
Total Skin	0
k.h, total	14700 md.ft
k, average	97.9 md
Pi	5000 psia
STOIIP	178 MMSTB
STOIP	175 MMSTB
Qo(tmax)	3.72 MMSTB

Model Parameters

Well & Wellbore parameters (Reference well)

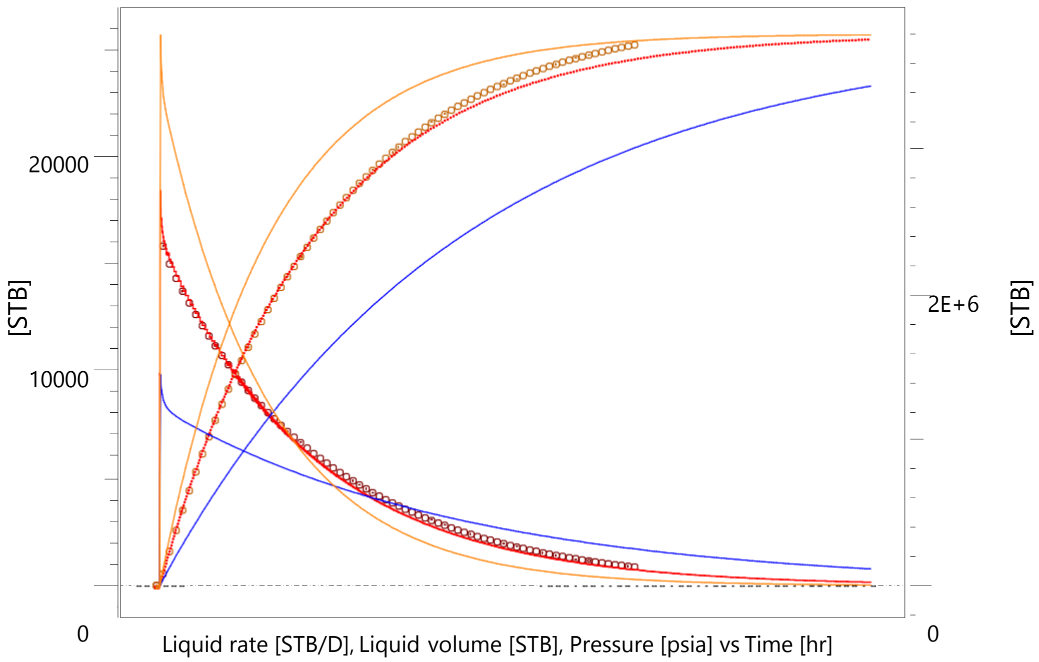
Skin 0

Reservoir & Boundary parameters

Pi	5000 psia
k.h	14700 md.ft
k	97.9 md

S - No flow 3000 ft
E - No flow 3000 ft
N - No flow 3000 ft
W - No flow 3000 ft

Production history plot	Analysis 1
Company	Field
Well Reference well	Test Name / #



— 7500 md.ft
— 14690.9 md.ft (current)
— 21000 md.ft

Pressure - Production

Tmin	0 hr
Tmax	17508 hr
Pi	5000 psia

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Rectangle, No flow

Main Model Parameters

Tmin	0 hr
Tmax	17508 hr
Total Skin	0
k.h, total	14700 md.ft
k, average	97.9 md
Pi	5000 psia
STOIIP	178 MMSTB
STOIP	175 MMSTB
Qo(tmax)	3.72 MMSTB

Model Parameters

Well & Wellbore parameters (Reference well)

Skin	0

Reservoir & Boundary parameters

Pi	5000 psia
k.h	14700 md.ft
k	97.9 md
S - No flow	3000 ft
E - No flow	3000 ft
N - No flow	3000 ft
W - No flow	3000 ft

Main results	Analysis 1
Company	Field
Well Reference well	Test Name / #

Test date / time
Formation interval
Perforated interval
Gauge type / #
Gauge depth
Analyzed by
Analysis date / time

Porosity Phi (%) 23.2
Well Radius rw 0.328 ft
Pay Zone h 150 ft

Fluid type Oil

Volume Factor B 1.24868 B/STB
Viscosity 1.08424 cp
Total Compr. ct 1.18085E-5 psi-1

Selected Model
Model Option Standard Model
Well Vertical
Reservoir Homogeneous
Boundary Rectangle, No flow

Main Model Parameters
Tmin 0 hr
Tmax 17508 hr
Total Skin 0
k.h, total 14700 md.ft
k, average 97.9 md
Pi 5000 psia
STOIIP 178 MMSTB
STOIP 175 MMSTB
Qo(tmax) 3.72 MMSTB

Model Parameters
Well & Wellbore parameters (Reference well)
Skin 0
Reservoir & Boundary parameters
Pi 5000 psia
k.h 14700 md.ft
k 97.9 md
S - No flow 3000 ft
E - No flow 3000 ft
N - No flow 3000 ft
W - No flow 3000 ft

Derived & Secondary Parameters
TMatch 400 [hr]-1
PMatch 0.141 [psia]-1
Abandonment
Ab. rate (qa) 50 STB/D
Ab. time (ta) 110.668 hr
Q(ta) N/A STB