MINISTRY OF EDUCATION OF REPUBLIC OF AZERBAIJAN

KHAZAR UNIVERSITY

FACULTY OF ENGINEERING AND APPLIED SCIENCES

The code of the major	60606-Oil and Gas Engineering
The name of the specialty	Petroleum Engineering

MASTERS THESIS

Title: **Well Test Analysis & Simulation of Gas Condensate Reservoir**

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BAKU – 2018

A C K N O W L E D G E M E N T

I have no words to express my deepest gratitude to Almighty, Compassionate, and Supreme **Allah (SWT)** Who enabled me to accomplish this task. I also invoke peace for **Hazrat Muhammad (PBUH)**, the last Prophet of **Allah (SWT)**; who is forever a torch of guidance for humanity as a whole.

I also pay my deepest gratitude with deepest sense of respect to my parents specially to my **Mother** for her love and affection which kept me steadfast and enabled me to attain targets and goals of academic life.

I express my gratitude to all my teachers for their teachings that brought me to this stage of academic zenith, but in particular, I wish to express immeasurable gratefulness to my good-natured project advisor **Professor Dr. Gasham Zeynalov** the Head of the department of Petroleum Engineering Khazar University for his suggestions and help during the study. I would also like to thank **Mr. Tahir Mammadov**, Manager Reservoir Engineering SOCAR for his vigilant supervision, intellectual guidance for the evaluation of data and very kind attitude.

I am extremely indebted to my loving brothers and friends for their constant encouragement which provided me the impulsion that was necessary for attaining initiatives.

Abstract

Gas condensate reservoirs are actually gas reservoirs but as pressure declines with depletion, reservoir pressure may go below dew point. Conventional analysis of transient testing which include Horner approximation, type curve analysis and Derivative type curves used for the estimation of permeability do not give accurate results for gas condensate reservoirs below dew point.

Problem in this case is that as liquid starts to build-up two phase flow of gas and condensate begins and there is no more absolute permeability. Because of change in composition of reservoir fluids at each point, it requires many pressure transient tests to find permeability or it requires relative permeability curves which need laboratory experiments on cores, making it an expensive procedure.

The solution of the problem with relatively newer techniques is presented here. Methodology is based on two techniques; one involving calculation (Fevang's) from relative permeability data acquired from core analysis conducted in laboratory.

Special emphasis have been given to second technique (Jokhio's) which includes the calculation of effective permeability as a function of pressure by using pressure transient test data only one time with the help of two phase pseudo pressure. This effective permeability of any phase can be used to predict production of second phase. Also the requirement of relative permeability as function of saturation pressure is eliminated. A field example is solved to show step by step procedure of this method.

A Well test interpretation of DST (Drill Stem Test) data using Transient testing with log-log plots, radial flow plots and type curve plots is also demonstrated using PAN SYSTEM (Software).

In last two chapters reserve estimation methods with introduction to Agarwal-Gardner Flowing Material Balance and Reservoir Simulation is done respectively.

Xülasə

Qaz kondensat rezervuarları faktiki olaraq qaz rezervuarlarıdır, lakin yatağın ehtiyatın azalması ilə təzyiqinin azalması , lay təzyiqinin pik nöqtəsindən aşağı düşməsinə səbəb ola bilər.

Kondensasisiya temperaturundan aşağıda olan qaz kondensat yataqları üçün keçiriciliyin qiymətləndirilməsi üçün Horner approksimasiyasına, əyrilik tipi analizinə , əyriliyin nisbilik tipinə daxil olan keçid sınaqlarının qəbul edilmiş təhlili dəqiq nəticələr əldə etməyə imkan vermir. Bu halda problem ondan ibarətdir ki, mayenin artmasının başlanması ilə qaz və kondensatın ikifazalı axını başlayır və burada mütləq keçiricilik iştirak etmir. Lay flüidlərinin tərkibinin dəyişməsinə görə hər nöqtədə keçiriciliyin təyin edilməsi üçün keçid dövründə çoxsaylı sınaqların aparılması tələb olunur və yaxud da bunun üçün kernalarda laborator eksperimentlərininn aparılması ilə nisbi keçiricilik əyrisinin alınması tələb olunur və bu da baha başa gələn əməliyatdır.

Bu teziş işində bu problemin həll edilməsi məsələsinə nisbətən yeni metodlarla baxılmışdır. Metodologiya əsasən iki üsula əsaslandırılmışdır: onlardan biri laboratoriyada kernalarda aparılan tədqiqatların nəticələrindən alınan nisbi keçiricilik məlumarlarının Fevangs hesablamasıdır.

İki mərhələli psevdo təzyiqinin köməyi ilə təzyiq keçici sınaq məlumatlarını yalnız bir dəfə istifadə etməklə təzyiq funksiyası kimi effektiv keçiriciliyin hesablanmasını ehtiva edən ikinci üsula da (Jokhio) xüsusi diqqət verilmişdir. Bu effektiv keçiricilik istənilən halda ikinci fazanın hasilatını proqnozlaşdırmaq üçün istifadə edilə bilər. Həmçinin, doyma təzyiq funksiyası kimi nisbi keçiriciliyin tələb olunması aradan qaldırılır. Bu metodun addım -addım prosedurunu göstərmək üçün yataq nümunəsindən istifadə edilmişdir.

Karotaj-karotaj diaqramları, radial axın diaqramları və əyrilik tipi diqaramları ilə keçici sınaqdan istifadə edərək, DST (Drill Stem Test) quyu sınananma məlumatlarının interpretasiyası PAN SYSTEM proqram təminatı ilə həyata keçirilir.

Son iki fəsildə isə ehtiyatın qiymətləndirməsı Ağarval-Gardner Flowing Material Balans və Rezervuar Simulyasiyasına giriş metodları ilə aparılmışdır.

LIST OF CONTENTS

List of Figures

List of Tables

Nomenclature

c_t	Total Compressibility
μ	Viscosity
Z	Compressibility Factor
β	Formation Volume Factor
Φ	Reservoir Porosity
ρ	Fluid Density
P*	Pressure at Outer Boundary of Region 1
P_{wf}	Wellbore Flowing Pressure
P_d	Dew Point Pressure
P_R	Reservoir Pressure
m(P)	Pseudo-Pressure
K	Permeability
K_e	Effective Permeability
K_r	Relative Permeability
R_s	Solution Gas Oil Ratio
R_p	Producing Gas Oil Ration
R_o	Solution Condensate Gas Ratio
SCF	Standard Cubic Feet

S	Composite Skin
S_m	Mechanical Skin
S_{wi}	Irreducible Water Saturation
V_{rel}	Relative Volume
V_L	Retrograde Liquid Volume
V_g	Gas Volume
A	Reservoir area, ft2
Cg	Gas compressibility at average reservoir pressure, psi-1
Co	Compressibility of oil, psi-1
D	Non-Darcy flow coefficient
G	Original gas in place, MMscf
Gp	Cumulative gas produced, MMscf
H	Pay thickness, ft
N	Original oil in place, bbl
Np	Cumulative production of oil, bbl
PV	Pore volume
PD	Dimensionless pressure, (Pi – P)kh/141.2 quB
Pi	Initial reservoir pressure, psi
Pr	Average reservoir pressure, psi
Psc	Standard pressure, 14.65 psia

Pwf	Flowing bottomhole pressure
Q	Production rate ,BPD or MMscfd
re	External reservoir radius, ft
rw	Wellbore radius, ft
t	Time, days
ta	Pseudo time, psi/cp
T	Reservoir temperature, R

INTRODUCTION

Research Background:

Gas condensate reservoirs are primarily gas reservoirs, but their behavior is slightly different from conventional gas reservoirs. Because of the composition change and phase changes, such reservoirs cannot be treated like dry gas reservoirs. Thus, production optimization and hydrocarbon recovery of gas condensate reservoirs need careful analysis, planning and management.

Upon discovery, mostly gas condensate reservoirs are found as single phase gas. As production continues, reservoir pressure eventually drops below the dew point pressure and liquid begins to condense. This isothermal condensation is known as retrograde condensation. Since the permeability to liquid at low saturation is negligible, most of the condensed liquid is unrecovered. Thus, gas condensate reservoirs are characterized in a unique sense because of rapid loss of productivity below the dew point pressure. Such reservoirs may not show any trace of condensate production at the surface. A sudden loss in well deliverability is a strong indicator of condensate build up known as condensate loss. This problem is also identifiable with the help of phase diagram.

As the pressure of the reservoir further declines due to production, the condensed liquid saturation increases. When the critical condensate saturation is reached, the liquid starts moving. Critical condensate saturation is the minimum saturation above which condensate starts moving. With multiphase flow inside the reservoir and changes in the gas composition as fluid moves towards the wellbore and encounters sharp pressure drop, characterization of gas condensate reservoirs and analysis of well test response becomes challenging.

Gas condensate well deliverability, well test interpretation and flow in reservoir in general have been the subject of interest for a long time because of many complexities and unresolved problems occurring due to multiphase flow in the reservoir and change of the

mixture composition as fluid flows towards the well (Roussennac, 2001). Literature review begins with advent of single phase pseudopressure then two phase pseudopressure leading all the way to its application in gas condensate reservoirs.

Ramey and Hussainy developed the concept of pseudopressure function in which the fluid properties such as viscosity and compressibility factor were integrated as a function of pressure.

The first gas rate equation with pseudopressure function was introduced by O'Dell and Miller (1967). It explained the effect of condensate bank.

Fussel (1973) used compositional simulations to determine that that the productivity of a gas condensate well is much higher than the one predicted by O'Dell and Miller (1967). Fussel (1973) came to conclusion that O'Dell and Miller (1967) predicted the sandface saturation by considering single-phase region where composition of gas was not changing.

Jones and Raghavan (1988) estimated the reservoir flow capacity (kh) and discussed well performance by using steady-state two-phase pseudopressure while compensating the effects of the minimum skin value (lower bound). Jones and Raghavan (1989) presented the same results for buildup tests.

Jatmiko et al. (1997) steady-state iterative technique gaves similar results as the Jones and Raghavan (1988) steady-state pseudopressure (Roussennac, 2001) .

The steady-state method gives the reservoir fluid flow in two regions without considering transition zone in the oil saturation profile. The two regions are:

1) a region near to wellbore where both oil and gas are flowing (oil saturation is above critical saturation).

2) an outer region containing gas only (oil saturation is zero).

Fevang and Whitson (1996) worked on the well deliverability of gas condensate wells. Fevang (1995) identified a third region where both oil and gas are present but only the gas is mobile. Fevang calculated two-phase pseudopressure for each of the three regions using a pressure-saturation relationship.

Penuela and Gringarten discussed the well test analysis in gas condensate reservoirs. Xu and Lee (1999b) carried out gas condensate well test analysis by applying Fevang's (1995) three-zone concept determining that the three-zone method is more accurate than the steady-state method for estimating skin and reservoir flow capacity (Roussennac, 2001). Through data interpretation, Roussennac (2001) compared the accuracy for the three-zone method and steady-state method. Steady state and Three-zone two phase psuedopressure concept required accurately defined pressure and saturation profiles obtained from relative permeability core data which is often very difficult to acquire.

Jokhio introduced a new definition of three phase pseudo-pressure which didn't require the use of relative permeability data as a function of saturation. The new technique was used to evaluate effective permeability as a function of pressure by using pressure transient data.

The second portion of this work focusses on well test interpretation in PanSystem (software) using log-log, type curve and radial flow analysis plots. The log derivative and derivative type curve have been used in combination to identify flow regimes with satisfactory accuracy for a long time. They are also generally known for their application flexibility and well test interpretation. The pressure derivative method was devised by Tiab in 1976 and improved by Dominique Bourdet in 1983. It is a very important tool for identifying flow regime, boundary response and use for diagnosing complex reservoir features till date. By using this method, the key regions of radial flow and boundary features can be adequately diagnosed.

The Third and Fourth section of this work are dedicated to a review of reserve estimation techniques with introduction & significance to Agarwal Flowing Material Balance (FMB) and Reservoir Simulation respectively.

Material-balance analysis is a fundamental technique for estimating reserves. It makes use of either static (shut-in) reservoir pressures or by use of flowing pressures and production rates. The latter approach is known as Flowing Material Balance FMB analysis and is especially appealing to gas and gas condensate reservoirs because by using flowing material-balance, average reservoir pressure can be found hence material balance calculations can be performed without shutting in the wells.

FMB was first developed by Mattar and McNeil (1998) for a dry-gas well producing at constant production rate. Those authors demonstrated that average reservoir pressure can be extracted from flowing pressures provided that the boundary-dominated-flow (BDF) regime has been reached and that both production rates and flowing pressures are measured. Following Mattar and McNeil (1998) and Agarwal et al. (1999), a number of other researchers then attempted to extend the application of the FMB to other production scenarios and / or other reservoirs with further complexities.

Problem Recognition:

Problem in condensate reservoirs is that as liquid starts to build up two phase flow of gas and condensate begins and there is no more absolute permeability. Because of change in composition of reservoir fluids at each point so its permeability changes at each pressure.

As mentioned above, not only obtaining reliable relative permeability data for gas condensate reservoirs is rare but also a very expensive procedure which requires specially preserved cores to be observed and analyzed in laboratory. Since relative permeability curves are developed on few inch long cores, their application to hundreds of acres of

drainage area is not an easy task (S.A. Jokhio, D. Tiab, 2002). Engineers involved in reservoir simulation know that how hard it is to get a good history match and how many times relative permeability curve has to be tuned to achieve it (Jokhio et al. 2002) . Thus acquiring relative permeability data doesn't guarantee the accurate forecasting. The work presented here will alleviate this problem.

In order to validate the well test analysis there is a need for some commonly used interpretation models to be compared with each other in order to confirm and justify information obtained from each model. A well test simulation software can bring the ease in accomplishing this objective.

In order to perform material balance calculation for estimating reserves wells are either shut-in for extended periods of time to attain stabilized condition for getting average reservoir pressure or achieve constant rate production for longer periods of time. Most gas wells do not have extended periods of constant rate production and wells can't be shut in for too long to attain stabilized average pressure while compromising economic value of recoverable resource. A material balance technique which makes use of flowing pressures to perform calculation without shutting in wells should eliminate this problem.

With the available data, a reservoir simulation case can be run on commercial software to obtain reservoir pressure and production forecasts.

Objectives:

The main objectives are outlined below:

- Jokhio's technique of defining two-phase pseudo pressure function without the use of relative permeability data will be employed here. Pressure transient data of an undisclosed gas condensate field will be used to test the technique yielding effective permeability values as a function of pressure.
- The second section of the work will demonstrate some well test interpretation models, the output parameters of which are compared to each other in order to validate the results. A well test simulation software such as PanSystem is chosen here as a convenient tool to carry out this procedure.
- Reserve estimation techniques of gas reservoirs are discussed in third section. The main focus will be an introduction to Agarwal Flowing Material Balance with its application to Gas Condensate field data and its significance for future prospects.
- A Reservoir Simulation case using Eclipse 100 (Black Oil Pvt model) will be run on a data availed from a producing section of the Gas condensate reservoir. Reservoir Pressure and production forecasts will be displayed in the end.

Scope of the work:

Gas condensate reservoirs are synonymous with deeper depths. As industry's focus has been recently shifted to exploitation of deeper wells, gas condensates have found their significance in reservoir engineering and planning applications. With anomalies encountered in deep wells like HP/HT during drilling and development operations, problems and complexities in production & reservoir engineering applications for gas condensate reservoirs are no exception. Therefore analyzing, interpreting and

characterizing gas condensate reservoirs have posed a major challenge for reservoir management professionals all over the world.

As Well Test analysis and interpretation of Gas-condensate reservoirs plays a pivotal role in controlling the decision factors for Well Intervention operations, Production optimization and Reservoir Management by defining parameters such as flow capacity (kh), mechanical skin and average reservoir pressure, the research is dedicated to put emphasis on implementation of a relatively newer technique other than the techniques commonly used in conventional well test analysis.

The work presented here is an analytical approach which can be applied to readily obtainable pressure transient data in order to evaluate effective permeability as a function of pressure which will lead to calculation of two phase psuedopressure function. This technique is already vastly recognized and practiced by reservoir engineering, production engineering and well testing specialists affiliated with Oil and Gas Industry all over the world. Not only does this technique eliminate the requirement of expensive and difficult to obtain relative permeability core data but also it can be extended to generate well IPRs thus giving an account of well performance characteristics for each phase.

Though FMB has just been introduced here, it's application and versatility for calculating original volumes of unconventional reservoirs has been recognized in modern times.

Getting academia to be familiarized by this technique will make it easier for students or young professionals coming from universities to transition easily into the role of either a production technologist or a reservoir engineer.

CHAPTER 1

Phase behavior of Gas Condensate Reservoirs

1.1 Classification of reservoirs

One way to classify petroleum reservoirs is based on initial condition i.e. temperature, pressure and hydrocarbon composition. On this basis, reservoirs are classified into five categories:

- Gas (Dry Gas, Wet Gas)
- Gas Condensate
- Volatile Oil
- Black Oil
- Heavy Oil (Asphalts/Bitumens)

The phase behavior depends upon hydrocarbon composition (a mixture of several components) and the pressure and temperature at which it exists. Generally, the temperature of a reservoir remains constant; however, pressure gradually declines as a result of hydrocarbon withdrawal from the reservoir. The phase distributions of hydrocarbons within a reservoir will (or will not) change due to decline in pressure, as it depends upon the phase behavior of the reservoir hydrocarbon mixture.

The pressure and temperature of gas condensate reservoirs are typically high, thus, are mostly found at higher depths of up to 10,000 ft where overburden pressure is very high. These reservoirs generally yield 30 to 300 stock tank barrels of condensate per million standard cubic feet of gas.

Gas condensate reservoirs, as will be discussed later, go through retrograde condensation as the production goes on. Because of this, the production and the management of gas

condensate reservoirs require special attention and full understanding of their phase behavior.

1.2 Phase Behavior:

Hydrocarbon mixtures exist in a volumetrically closed system as a vapor phase, a liquid phase, or a combination of both phases with varying degree of vapor-to-liquid ratios. This phase behavior is dictated by the pressure, temperature, and the mixture composition. When in equilibrium, the net balance of three forces – the internal kinetic energy due to heat, the inter-molecular adhesion, and intra-molecular cohesive forces – determine a mixture's phase behavior. Under certain conditions of pressure and temperature, this force balance allows the mixture to exist as a single phase vapor, or as a single phase liquid. At other conditions of pressure and temperature, however, the thermodynamic equilibrium may not be possible without separating out some liquid or vapor phase from the mixture. Generally, the components with most dissimilar molecular structure are the first to separate out.

Since pressure, temperature, and composition affect these forces, the phase behavior for a given mixture of hydrocarbon can be depicted graphically on a phase diagram. For a single component fluid, the phase diagram consists of a single line. As the number of components and the dissimilarity between their carbon number increases, the two-phase region becomes wider and shifts toward higher temperature and pressure.

Phase envelope for two phase fluids (Figure 1.1) consists of dew point line (below which first liquid drop condenses out of gas), and bubble point line (below which first bubble of gas comes out of oil). These two lines meet at a point called critical point. A critical point is defined as a point at which we cannot differentiate between gas and liquid properties. The maximum pressure to which the two phase envelope extends to is called cricondenbar. The maximum temperature of the two phase envelope is called

cricondentherm, which is the maximum temperature above which liquid cannot be formed regardless of pressure.

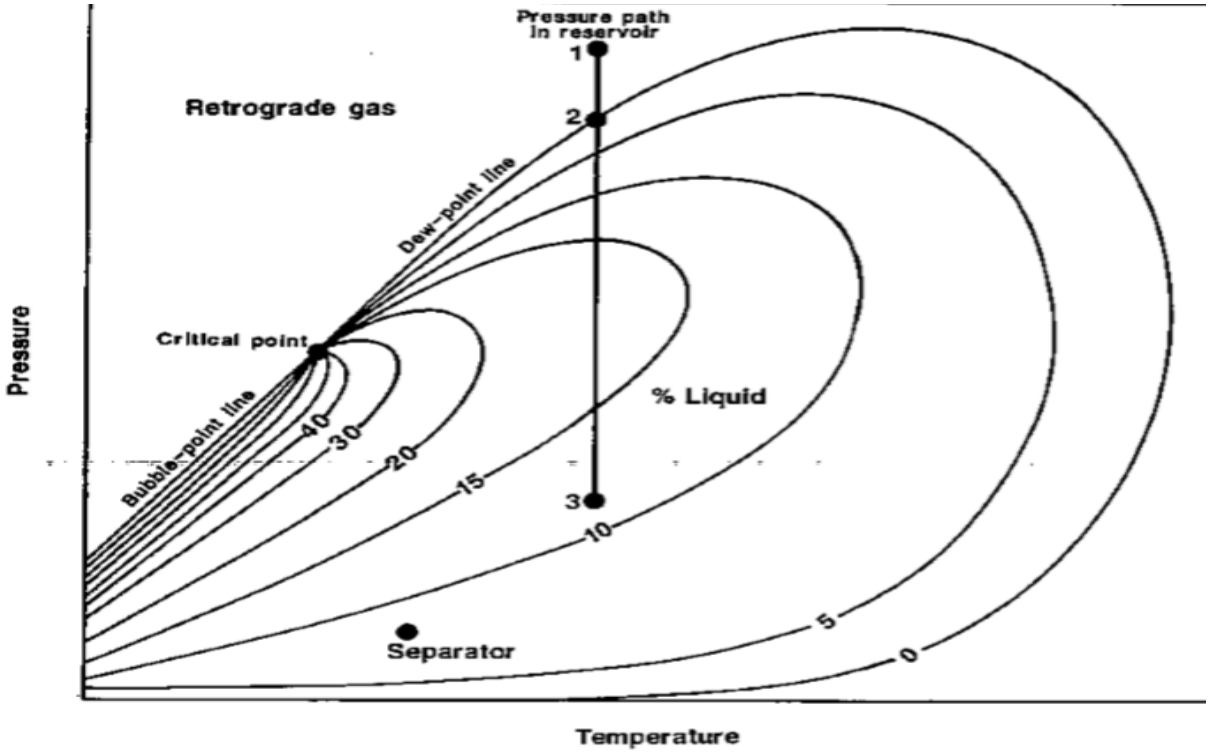


Figure 1.1: Phase Behaviour of Gas Condensate Reservoir (William D. McCain, *The properties of petroleum fluids, 1989*)

In a gas condensate system, generally, initial reservoir pressure is greater than dew point pressure, and temperature lies in between cricondentherm and critical point (Point 1). For all practical purposes, temperature of the reservoir remains constant. When the reservoir pressure reaches dew point, the first drop of liquid condenses out from gas. As pressure further declines, the condensate saturation starts increasing. The reservoir pressure path when comes out of retrograde condensation region, at Point 2, the liquid begins to decrease. This phenomenon is called re-vaporization. With the passage of time, total molecular weight of the remaining fluid increases and hence the critical point tends to move clockwise round the phase envelope.

1.3 Reservoir Regions based on Phase and Flow Behavior

During depletion, a gas condensate reservoir is divided into three regions:

- A near wellbore region where condensate saturation is higher than the critical condensate saturation (saturation at which condensate starts moving) and both phases are mobile
- A region in which condensate saturation is below the critical saturation, thus, only gas is mobile
- A region far away from the wellbore where the pressure is higher than dew point Pressure, therefore, only gas is present

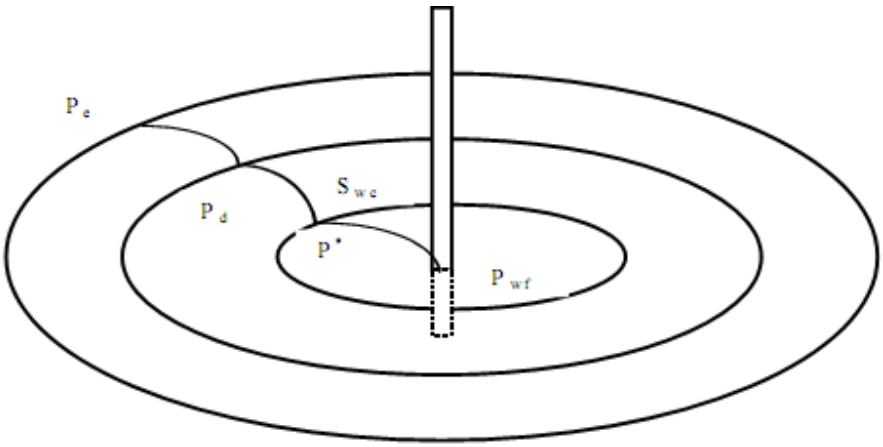


Figure1.2 : Three concentric regions around vertical wellbore

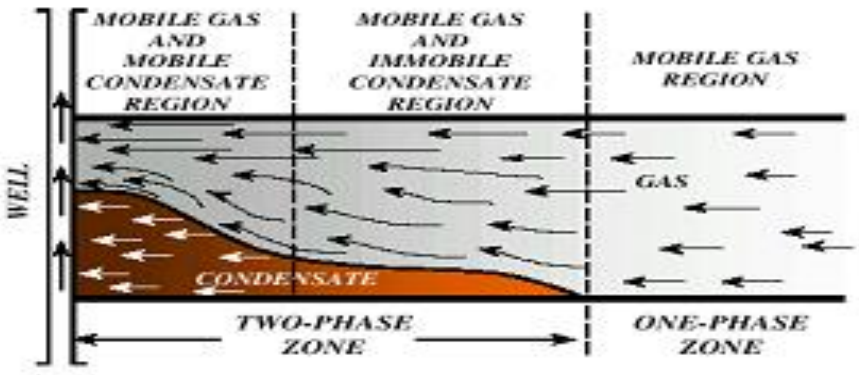


Figure 1.3: Different regions in a gas condensate reservoir (G. Penuela and F. Civan, 2000)

Region 1. The condensate saturation in this region is greater than the critical condensate saturation therefore both oil and gas phases are mobile. The flowing composition (GOR) of the mixture remains constant throughout this region. Therefore, the composition of the single phase gas entering Region 1 has the same composition as the produced wellstream mixture. As the composition of the mixture remains constant throughout this region, the liquid saturation can be found with the help of Constant Composition Expansion Test in the laboratory.

The oil dropped out in Region 1 depends upon the PVT properties of the mixture and the producing rate. Due to two phase flow in Region 1, the flow differs from single phase gas flow.

Region 2. In this region, only gas is flowing. Though condensate is present, its saturation is below critical condensate saturation thus immobile.

The pressure at the inner boundary of Region 2 is termed as P^* (a pressure at which liquid saturation becomes high enough to be mobile). At the outer boundary of Region 2, the pressure is equal to the dew point pressure of the gas mixture. The condensate drop out due to pressure decline can be computed by Constant Volume Depletion (CVD) Test in the laboratory. As the heavier components are condensing in Region 2, overall composition of the flowing gas is changing (it is becoming leaner and leaner).

In Region 2, the pressure is decreasing towards the wellbore and oil saturation is increasing until it becomes so high that oil becomes moveable. This means that Region 1 increases with the passage of time whereas Region 2 first expands from the wellbore and then moves away. Therefore, the size of Region 2 is maximum when the wellbore flowing pressure just equals the dew point pressure of the gas mixture.

As oil saturation in Region 2 is lesser than Region 1 therefore deviation from single phase flow is relatively less. However, the existence of Region 2 is very important in modeling the flow behavior.

Region 3. In this region, pressure of the reservoir is greater than the dew point pressure thus only gas is present in this zone. The pressure at the inner boundary of this region is P_d and at outer boundary is P_R.

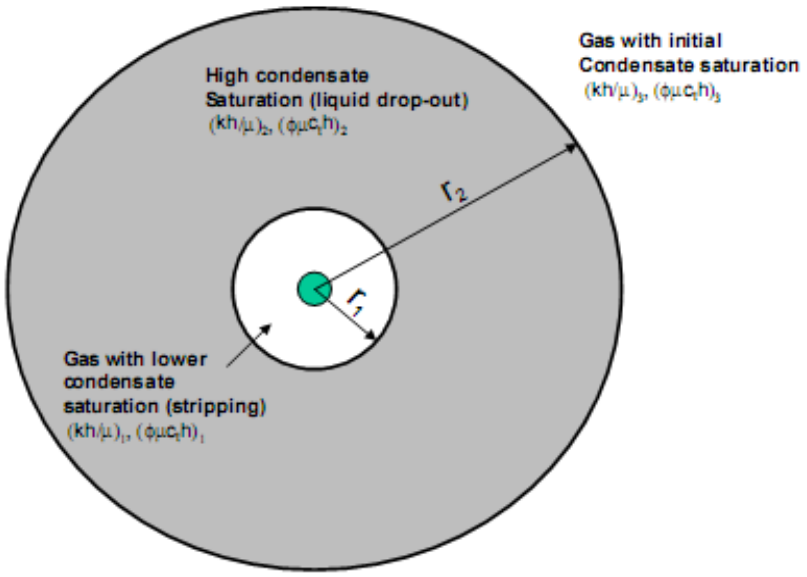


Figure 1.3: Three region composite model (A. C. Gringarten et al. 2000)

1.4 Coexistence of Flow Regions:

Region 1 exists when the wellbore flowing pressure is below the calculated P^* pressure. Region 2, on the other hand, always exists with Region 1. When reservoir pressure drops below the dew point pressure, Region 3 disappears. Region 2 also disappear if reservoir pressure falls below P^* as in our case. It also becomes negligible for very rich gas condensates (near critical gas condensate reservoirs).

Table 1.1: Coexistence of Flow Regions

	Region 1	Region 2	Region 3
$P_{wf}>P_d$	X	X	■
$P_{wf}<P_d$ & $P_R>P_d$	■	■	■
$P_R<P_d$	■	□	X

■ Exists □ May Exist **X** Does not Exist

CHAPTER 2

Transient Testing of Gas Condensate Reservoir

2.1 Concept of pseudo pressure:

The basic assumptions while deriving this equation are that the fluid is slightly compressible and the flow is single phase. These assumptions are mostly valid for oil reservoirs. For gas reservoirs where fluid properties like compressibility and viscosity are strong functions of pressure, these assumptions and therefore this equation becomes non-linear. To handle such deviation, Al Hussainy and Ramey has defined a new variable known as pseudo-pressure, m(P), given as

$$m(p) = 2\int_{p_o}^{p} \frac{p'}{uZ}\,dp'$$

(Eq. 2.3)

Therefore, diffusivity equation for linear flow of gases can be written as

$$\nabla^2 \mathrm{m(p)} - \frac{1}{\eta}\frac{\partial \mathrm{m(p)}}{\partial \mathrm{t}} = 0$$

(Eq. 2.4)

For radial flow of gases, the diffusivity equation becomes

$$\frac{\partial^2 m(p)}{\partial r^2} + \frac{1}{r}\frac{\partial m(p)}{\partial r} = \frac{1}{\eta}\frac{\partial m(p)}{\partial t}$$

(Eq. 2.5)

Where η in the above equation is called "hydraulic diffusivity", which is equal to 0.000264k/φμc.

2.1.1 Concept of two phase pseudo pressure:

Single phase pseudo pressure gives good estimation of reservoir permeability but yields an erroneous value of skin. By this method, a composite skin is obtained which accounts for both the mechanical skin as well as the skin due to condensate bank. Because of this limitation, we cannot design stimulation or any other remedial technique on the basis of this erroneous value of skin. Since one phase pseudo pressure does not consider the decrease in gas permeability due to the presence of condensate, therefore, it is not exact method to evaluate gas condensates

To overcome this difficulty, A two phase pseudo pressure has been defined as

$$m(p) = \int_{p_{ref}}^{p} \left(\frac{k_{rg}}{\beta_g \mu_g} + \frac{k_{ro}}{\beta_o \mu_o} R_s \right) dp \qquad \text{(Eq. 2.6)}$$

All the parameters in equation are pressure dependent.

2.1.2 Fevang's concept of two phase pseudo pressure:

According to Fevang gas condensate flow towards the wellbore can be divided into three regions

Region 1: Near wellbore where both gas and liquid are in mobile phase. Here condensate saturation is high. The pressure range in this region is from P_{wf} to P^*. This region develops only after the wellbore flowing pressure drops below the dew point.

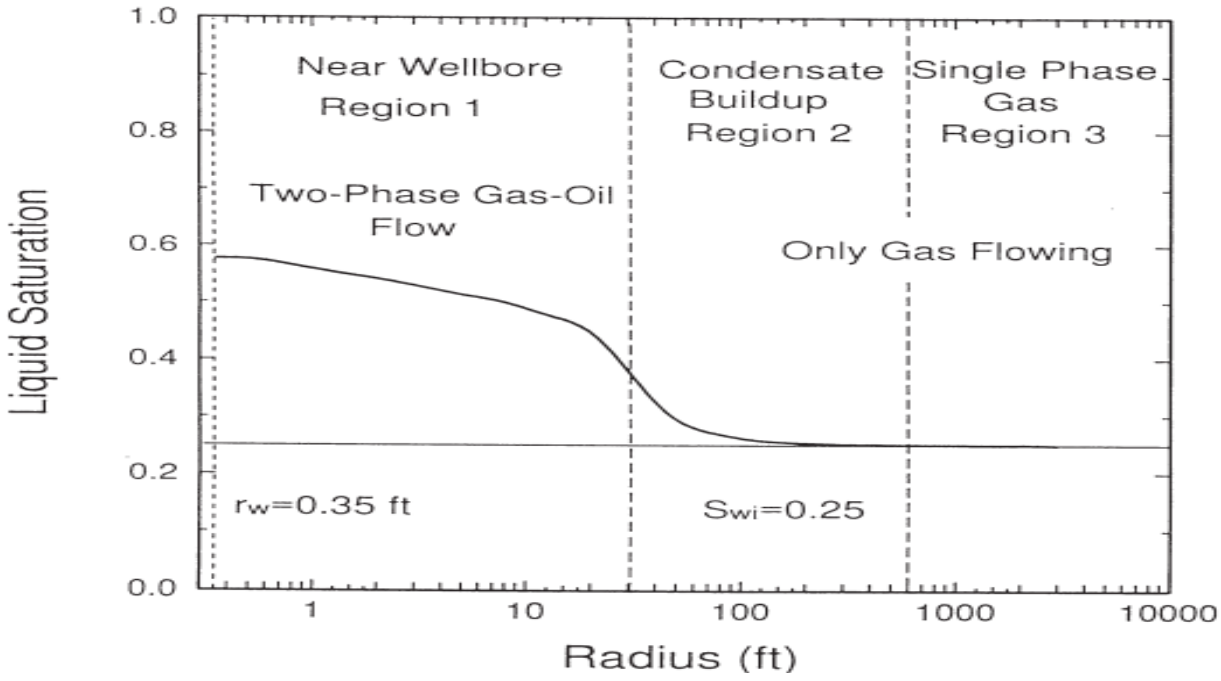


Figure 2.1: Illustration of liquid build-up for Gas Condensates. (Fevang, 2000)

Region 2: This is condensate buildup region and only gas phase is mobile. Here the pressure range is $P^*$to P_d where P^* is the lower pressure and P_d is the pressure at the outer boundary of this region.

Region 3: It contains only gas. It exists only when the reservoir pressure is greater than dew point pressure of the original gas. Here the pressure range is from P_d to P_R.

Fevang divided the pseudo-pressure integral into three parts.

Two phase pseudo pressure pseudo pressure is calculated using following equations

$$Total \qquad m(P) = \int_{P_{wf}}^{P_R} \left(\frac{K_{rg}}{\mu_g \beta_g} + \frac{K_{ro} R_s}{\mu_o \beta_o} \right) dP$$

$$Region\ 1 \qquad = \int_{p_{wf}}^{p^*} \left(\frac{k_{rg}}{\beta_g \mu_g} + \frac{k_{ro}}{\beta_o \mu_o} R_s \right) dp$$

$$Region\ 2 \qquad + \int_{p^*}^{p_d} \left(\frac{k_{rg}}{\beta_g \mu_g}\right) dp$$

$$Region\ 3 \qquad + k_{rg}(Swi) \int_{p_d}^{p_R} \left(\frac{1}{\beta_g \mu_g}\right) dp \qquad \text{(Eq. 2.7)}$$

2.1.3 Jhokio's concept of two phase pseudo pressure:

In Jhokio's method the requirement of relative permeability as function of saturation pressure is eliminated. Relative permeability curves need laboratory experiments on cores, making it an expensive procedure. So Jhokio replaced the relative permeability with effective permeability. He has given separate pseudo pressures for gas and oil phases.

Pseudo pressure for gas is

$$m(P)_g = \int_{P_{wf,s}}^{P_{ws}} \left(\frac{k.\, k_{rg}}{\mu_g \beta_g} + \frac{k.\, k_{ro} R_s}{\mu_o \beta_o}\right) dP \qquad \text{(Eq. 2.8)}$$

Similarly, pseudo pressure for oil is

$$m(P)_o = \int_{P_{wf,s}}^{P_{ws}} \left(\frac{k.\, k_{rg} R_o}{\mu_g \beta_g} + \frac{k.\, k_{ro}}{\mu_o \beta_o}\right) dP \qquad \text{(Eq. 2.9)}$$

2.2 Pseudo-Pressure derivation (Jokhio's concept):

Jokhio's concept to determine two phase pseudo pressure without considering relative permeability data is discussed in section.

Producing Gas Oil ratio

As it can be seen that below the dew point, producing gas oil ratio GOR, increases steadily. A direct relationship exists between Rp and pressure as shown in figure.

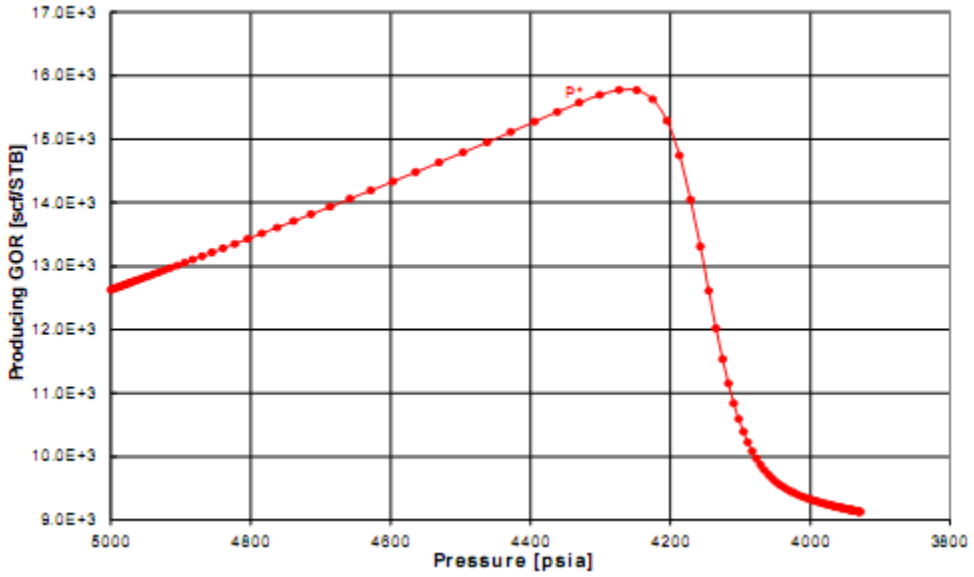


Figure 2.2: Producing GOR below dew point (Jokhio et al. 2002)

By definition we have

$$R_p = \frac{q_g}{q_o} = \frac{q_g + q_o.R_s}{q_o + q_g.R_o}$$

(Eq. 2.10)

Since R_p (Producing GOR) is constant for a given reservoir pressure, its equation can be written as follows

$$q_g = C \int_{P_{wf}}^{p^*} \left(\frac{K_{rg}}{\mu_g \beta_g} + \frac{K_{ro} R_s}{\mu_o \beta_o} \right) dP$$

(Eq.2.11)

$$q_o = C \int_{P_{wf}}^{p^*} \left(\frac{K_{rg} R_o}{\mu_g \beta_g} + \frac{K_{ro}}{\mu_o \beta_o} \right) dP$$

(Eq. 2.12)

So

$$R_p = \frac{C \left(\frac{K_{rg}}{\mu_g \beta_g} + \frac{K_{ro} R_s}{\mu_o \beta_o} \right)}{C \left(\frac{K_{rg} R_o}{\mu_g \beta_g} + \frac{K_{ro}}{\mu_o \beta_o} \right)}$$

(Eq. 2.13)

By simplifying the above equation

$$R_p = \frac{\left(\frac{K_{rg}}{\mu_g \beta_g} + \frac{K_{ro} R_s}{\mu_o \beta_o} \right)}{\left(\frac{K_{rg} R_o}{\mu_g \beta_g} + \frac{K_{ro}}{\mu_o \beta_o} \right)}$$

(Eq. 2.14)

By simplifying the above equation

$$R_p = R_s + \left(\frac{k_{rg}}{k_{ro}} \right) \left(\frac{\mu_o \beta_o}{\mu_g \beta_g} \right) (1 - R_o R_p)$$

(Eq. 2.15)

Solving above equation for K_{rg}/K_{ro}

$$\left(\frac{k_{rg}}{k_{ro}} \right) = \left(\frac{R_p - R_s}{1 - R_o R_p} \right) \left(\frac{\mu_g \beta_g}{\mu_o \beta_o} \right)$$

(Eq. 2.16)

Modeling pseudo pressure without considering relative permeability data:

Region 1

The two phase pseudo pressure for gas in Region 1 is given by

$$m(p)_g = \int_{\mathrm{P_{wf}}}^{\mathrm{p^*}} \left(\frac{\mathrm{k.\,k_{rg}}}{\mu_\mathrm{g}\beta_\mathrm{g}} + \frac{\mathrm{k.\,k_{ro}R_s}}{\mu_\mathrm{o}\beta_\mathrm{o}} \right) \mathrm{dP}$$

(Eq. 2.17)

From Equation 2.16

$$k_g = k.k_{rg} = \left(\frac{R_p - R_s}{1 - R_o R_p} \right) \left(\frac{\mu_g \beta_g \{k.k_{ro}\}}{\mu_o \beta_o} \right)$$

(Eq. 2.18)

Similarly, for oil

$$k_o = k.k_{ro} = \left(\frac{1 - R_o R_p}{R_p - R_s} \right) \left(\frac{\mu_o \beta_o \{k.k_{rg}\}}{\mu_g \beta_g} \right)$$

(Eq. 2.19)

Substituting Equation (2.19) in the two phase pseudo pressure equation (2.17), and simplifying

$$m(P)_{g,g,1} = \int_{p_{wf}}^{p^*} \left(\frac{k.k_{rg}}{\mu_g \beta_g} \right) \left(\frac{R_p(1 - R_o R_s)}{(R_p - R_s)} \right) (P)\, dP$$

(Eq. 2.20)

$m(P)_{g,g,1}$is pseudo pressure for gas in Region 1 in terms of gas relative permeability. The above equation (2.20) without relative permeability term can be written as

$$m(P)'_{g,g,1} = \int_{p_{wf}}^{p^*} \left(\frac{1}{\mu_g \beta_g} \right) \left(\frac{R_p(1 - R_o R_s)}{(R_p - R_s)} \right) (P)\, dP$$

(Eq.2.21)

Where $m(P)'_{g,g,1}$ is called pseudo pressure function for gas in Region 1.

To calculate pseudo pressure for gas in terms of oil relative permeability, substitute

Equation (2.18) in the two phase pseudo pressure equation (2.17) and simplify

$$m(P)_{g,o,1} = \int_{P_{wf}}^{P^*} \frac{k.k_{ro}}{\mu_o \beta_o} \left[R_s + \frac{\left(R_p - R_s\right)}{\left(1 - R_s R_p\right)} \right] (P) dP$$

(Eq. 2.22)

$m(P)_{g,o,1}$ is pseudo pressure for gas in Region 1 in terms of oil relative permeability. The above equation (2.22) without relative permeability term can be written as

$$m(P)'_{g,o,1} = \int_{P_{wf}}^{P^*} \frac{1}{\mu_o \beta_o} \left[R_s + \frac{\left(R_p - R_s\right)}{\left(1 - R_s R_p\right)} \right] (P) dP$$

(Eq. 2.23)

Where $m(P)'_{g,o,1}$ is called pseudo pressure function in Region 1 without relative permeability.

Region 2

As pressure ranges in Region 2 are from p* to p_d. Pseudo pressure for Region 2 is

$$m(P)_{g,2} = \int_{P^*}^{P_d} \left(\frac{k.k_{rg}(P)}{\beta_g \mu_g} \right) dp$$

(Eq.2.24)

Where $m(P)_{g,2}$ is pseudo pressure for gas in Region 2. The above equation (2.24) without relative permeability can be written as

$$m(P)'_{g,2} = \int_{P^*}^{P_d} \left(\frac{1}{\beta_g \mu_g} \right) dp$$

(Eq.2.25)

$m(P)'_{g,2}$ is pseudo pressure function in Region 2 without relative permeability.

Region 3

Pseudo pressure for gas in Region 3 is given by

$$m(P)_{g,3} = k_{rg}(Swi)\int_{p_d}^{p_R}\left(\frac{1}{\beta_g \mu_g}\right)dp$$

(Eq.2.26)

Pseudo-pressure in Region 3 can be calculated as like single phase pseudo-pressure.

2.3 Well Test Analysis:

After the evaluation of two phase pseudo pressure, well test analysis of gas condensate reservoirs is discussed in this section.

2.3.1 Without considering Relative Permeability Data (Jokhio's concept)

In this section, well test analysis of gas condensate reservoirs has been discussed using Jokhio method and this method does not consider relative permeability data**.**

Region 1

Pressure response in Region 1 is given by

$$\int_{p_{wf}}^{p^*}\left(\frac{k.k_{rg}}{\mu_g \beta_g}\right)\left(\frac{R_p(1-R_o R_s)}{(R_p - R_s)}\right)(P)\,dP$$

$$= 162.6\left(\frac{q_g}{h}\right)\left[log(t) + log\left(\frac{k_e(P)}{\varphi \mu c_t r_w^2}\right) - 3.23 + 0.869S\right]$$

(Eq.2.27)

Simplifying the above equation

$$\int_{P_{wf}}^{P^*} \frac{1}{\beta_g \mu_g}\left(\frac{R_p(1-R_oR_s)}{(R_p-R_s)}\right)dP = \frac{162.6}{\int_{P_{wf}}^{P^*}(k.K_{rg}(P))}\left(\frac{q_g}{h}\right)\left[log(t)+log\left(\frac{k_e(P)}{\varphi\mu c_t r_w^2}\right)-3.23+0.869S\right]$$

(Eq.2.28)

If a graph between pseudo pressure function and log of time is drawn and a semi log straight line is developed.

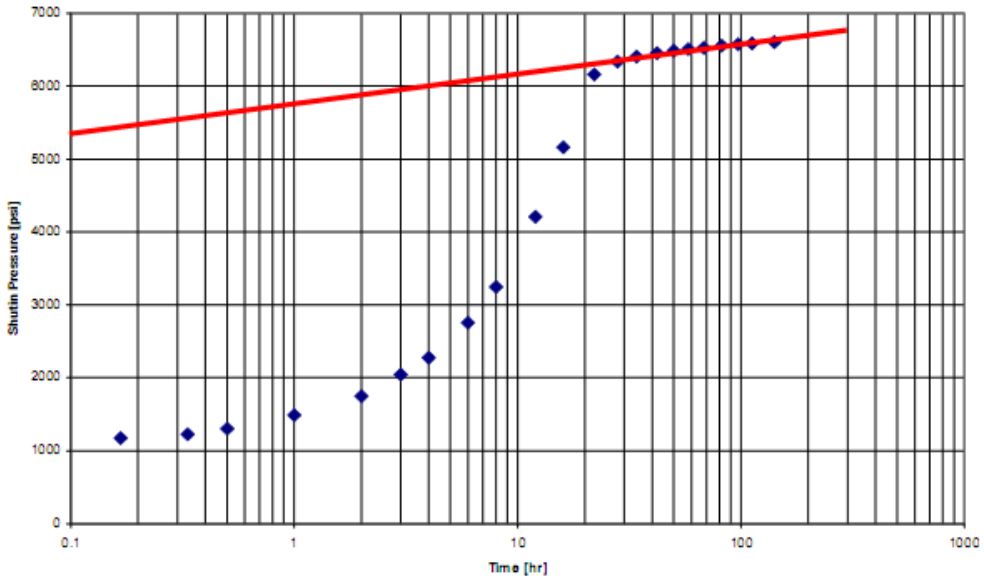


Figure 2.3: Semi-log plot between pseudo pressure function and log of time (Jokhio et al. 2002)

The effective gas permeability integral can be found as a function of pressure using equation 2.29.

$$\int_{P_{wf}}^{P^*}(k.k_{rg})dP = 162.6.\frac{q_g}{h}\left(\frac{d\Delta m(P)g,g'}{dln(t)}\right)^{-1}$$

(Eq.2.29)

The term $\left(\frac{d\Delta m(P)^{'}}{dln(t)}\right)$ can be calculated after the semi log straight line is developed by using (Eq.2.30)

$$\left(\frac{d\Delta m(P)^{'}}{dln(t)}\right)_i = \frac{\left(\left(\frac{d\Delta m(P)^{'}}{dln(t)}\right)_{i-1}(\Delta lnt)_{i+1}\right) + \left(\left(\frac{d\Delta m(P)^{'}}{dln(t)}\right)_{i+1}(\Delta lnt)_{i-1}\right)}{[\Delta lnt_{i+1} + \Delta lnt_{i-1}]}$$

(Eq.2.30)

From the K_g integral, effective permeability can be calculated as a function of pressure using equation 2.31.

$$k.k_{rg} = \frac{integral\ [kg]_2 - integral\ [kg]_1}{P_2 - P_1}$$

(Eq.2.31)

The value of skin factor can be calculated using equation 3.40.

$$S_1 = 1.151\left[\frac{h\Delta m(P)_{g,g1,1hr}}{q_{g,}} - log\left(\frac{k_g(P_{1hr})}{\varphi\mu c_t r_w^2}\right) + 3.23\right]$$

(Eq.2.32)

Similarly, for oil phase effective permeability,

$$\int_{P_{wf}}^{P^*}\frac{1}{\mu_o\beta_o}\left[R_s + \frac{(R_p - R_s)}{(1 - R_sR_p)}\right](P)dP = \frac{162.6}{\int_{P_{wf}}^{P^*}(k.K_{ro}(P))}\left(\frac{q_g}{h}\right)\left[log(t) + log\left(\frac{k_e(P)}{\varphi\mu c_t r_w^2}\right) - 3.23 + 0.869S\right]$$

(Eq.2.33)

Similarly, if a graph between pseudo pressure function in terms of oil relative permeability and log of time is plotted and a straight line is developed, effective oil permeability integral as a function of pressure can be calculated using equation 2.34.

$$\int_{P_{wf}}^{P^*} (k.k_{ro}(P)) = 162.6.\frac{q_g}{h}\left(\frac{d\Delta m(P)'g,o}{dln(t)}\right)^{-1}$$

(Eq.2.34)

The term $\left(\frac{d\Delta m(P)'g,o}{dln(t)}\right)^{-1}$ can be calculated using equation 2.30. From oil effective permeability integral, K_o with respect to pressure can be calculated using equation 2.35.

$$k.k_{ro} = \frac{integral\ [k_o]_2 - integral\ [k_o]_1}{P_2 - P_1}$$

(Eq. 2.35)

The value of skin factor can be calculated as

$$S_1 = 1.151\left[\frac{h\Delta m(P)_{g,o1,1hr}}{q_{g,}} - log\left(\frac{k_o(P_{1hr})}{\varphi\mu c_t r_w^2}\right) + 3.23\right]$$

(Eq. 2.36)

Region 2

Pressure response in Region 2 without Relative Permeability is given by

$$\int_{P^*}^{P_d}\left(\frac{1}{\mu_g\beta_g}\right)dP = \frac{162.6}{\int_{P^*}^{P_d}(k.K_{rg}(P))}\left(\frac{q_g}{h}\right)\left[log(t) + log\left(\frac{k_e(P)}{\varphi\mu c_t r_c^2}\right) - 3.23 + 0.869S\right]$$

(Eq.2.37)

Where r_c (radius at which P = P*) is calculated using equation 3.46.

$$r_c = 0.029\sqrt{\frac{Ke(P^*)t^*}{\varphi\mu^* c_t}}$$

(Eq. 2.38)

The variables with the asterisk symbol (*) are calculated at P*. The effective gas permeability integral as a function of pressure can be calculated using equation 2.38 after the semi log straight line has developed.

$$\int_{P^*}^{P_d} \left(k.k_{rg}(P)\right) = 162.6.\frac{q_g}{h}\left(\frac{dm(P)_{g,2}}{dln(t)}\right)^{-1}$$

(Eq. 2.38)

The term $\left(\frac{dm(P)_{g,2}}{dln(t)}\right)^{-1}$ can be calculated using equation 2.30. From effective permeability integral, effective gas permeability K_g as a function of pressure can be calculated using equation 2.30.

The value of skin factor can be calculated as follows

$$S_2 = 1.151\left[\frac{h\Delta m(P)_{g,2,1hr}}{q_g} - log\left(\frac{k_{g,2}(P_{1hr})}{\varphi\mu c_t r_c^2}\right) + 3.23\right]$$

(Eq. 2.39)

Region 3

In Region 3, pressure response is given (Eq. 2.40)

$$\int_{P_d}^{P_R}\left(\frac{1}{\mu_g\beta_g}\right)dP = \frac{162.6.q_g}{K.h}\left[log(t) + log\left(\frac{k}{\varphi\mu c_t r_d^2}\right) - 3.23 + 0.869S\right]$$

(Eq. 2.40)

Where r_d is the distance at which $P = P_d$. A graph between pseudo pressure for gas in Region 3 and log of time is used to find the absolute permeability of the reservoir using equation 2.41 if a straight line is developed.

$$k = 162.6.\frac{q_g}{h}\left(\frac{dm(P)_{g,3}}{dlog(t)}\right)^{-1}$$

(Eq. 2.41)

CHAPTER 3

Transient Testing Using Two Phase Pseudo Pressure

Transient testing without considering relative permeability data (Jokhio's method)

3.1 Introduction:

This chapter discusses transient testing using newer technique, two phase pseudo pressure without considering relative permeability data (jokhio's concept). In this chapter a problem is solved by calculation of effective permeability as a function of pressure by using pressure transient test data only one time with the help of two phase pseudo pressure. Also the requirement of relative permeability as function of saturation pressure is eliminated. A step wise procedure is shown also.

3.2 Given Data

Initial pressure= 6750 psia

Dew point pressure = 6750 psia

Reservoir temperature = 354^{o} F

Pay thickness = 216.5 ft

Gas S.G = 0.94

Gas flow rate = 75.4 Mscf/d

Oil flow rate = 2.58 STB/D

Molecular weight = 27.17

Wellbore radius = 0.54 ft

Average porosity = 6.2%

API = 50

GOR = 9470Scf/STB

Producing Time = 150 hrs

3.3 Related Calculations:

PVT properties are calculated with the help of following correlations and the results are given in table 2.1 below.

Solution Gas Oil Ratio (Rs) has been calculated using the following Modified Kartoatmodjo's correlation.

$$R_s = P^{1.1535}\left(\frac{SG}{37.966}\right)10^{9.441\ API/T}$$

(Eq. 3.1)

Solution Oil Gas Ratio has been calculated using:

$$R_o = -11.66 + 4.706 * 10^{-9}R_s^3 + 1.623\sqrt{R_s} - \frac{42.3815}{\sqrt{R_s}}$$

(Eq. 3.2)

Correlation deviation factor Z

$$Z = Pr\ (-.0284Tr + .0625) + .4714Tr - .0011$$

(Eq. 3.3)

And

$$Tpc = 289.6\ (S.G) + 181.89$$

(Eq. 3.4)

$$Ppc = -514.01\ (S.G)^4 + 1788.2\ (S.G)^3 - 2337.5(S.G)^2 + 1305.3\ (S.G) + 415.07$$

(Eq. 3.5)

Correlation for viscosity

$$\mu_g = 10^{-4}\ X_1 \exp(X_2\ \rho_g{}^{X3})$$

(Eq. 3.6)

Where

$$X1 = \frac{(9.4+.02M)T1.5}{209+19M+T}$$

(Eq. 3.7)

$$X2 = 3.5 + (986/T) + .01M$$

(Eq. 3.8)

$$X3 = 2.4 - .2(X2)$$

(Eq. 3.9)

3.4 Procedure for calculation of critical properties

3.4.1 Calculation of deviation factor Z:

Tpc = 289.6 (S.G) + 181.89

Tpc = 289.6(.94) +181.89 = 462.574 R

Ppc = -514.01 (S.G)^4 + 1788.2 (S.G)^3 – 2337.5(S.G)^2 + 1305.3 (S.G) + 415.07

Ppc = -514.01 (.94)^4 + 1788.2 (.94)^3 – 2337.5(.94)^2 + 1305.3 (.94) + 415.07 = 660.57 psia

At 200 psia

Tr = T/Ppc = (354+460)/462.574 = 1.759

Ppr = P/Ppc = 200/660.57 = .303

Now

Z at 200 is given by following correlation

Z = Pr (-.0284Tr + .0625) + .4714Tr - .0011

Z = .303 [-.0284(1.759) + .0625] + .4714(1.759) - .0011 = .981775b

3.4.2 Calculation of formation volume factor

We calculated formation volume factor using following formula

$$\beta g = .00504\frac{ZT}{P}$$

At p=200 psia

$$\beta g = .00504(.981775)(814)/200 = 0.020139 \text{ (bbl/scf)}$$

3.4.3 Calculation of viscosity

Formula of desity is

ρ_g = 1.601846*x*10-2 (M.W)P/RT

So density of gas at 200 as

ρg = 1.601846*x*10-2 (27.17)200/(10.73)(814) = 0.009965894 gm/cc

as

$\mu_g = 10^{-4} X_1 \exp(X_2 \rho_g^{X3})$

so

$X1 = \frac{(9.4+.02M)T1.5}{209+19M+T}$

X1 = (9.4+.02(27.17)) $354^{1.5}$/209 + 19(27.17) + 354 = 61.366

X2 = 3.5 +(986/T) + .01M

X2 = 3.5 + (986/354) .01(27.17) = 6.557

X3 = 2.4 - .2(X2)

And

X3 = 2.4 - .2(6.577) = 1.0886

Now

$\mu_g = 10^{-4} X_1 \exp(X_2 \rho_g^{X3})$

finally viscosity at 200 psia

$\mu_g = 10^{-4}(61.365) \exp(6.557 \rho_g^{1.089}) = 0.006409$

3.4.4 Calculation of solution gas oil ratio R_s

For solution gas oil ratio R_s we used equation 3.1

$$R_s = P^{1.1535}(\frac{SG}{37.966})10^{9.441\ API/_T}$$

At 200 psia

R_s = 42.45072532 Scf/STB

3.4.5 Calculation of Solution Oil Gas Ratio R_o

We calculated Solution Oil Gas Ratio using equation 3.2

$$R_o = -11.66 + 4.706 * 10^{-9} R_s^3 + 1.623\sqrt{R_s} - \frac{42.3815}{\sqrt{R_s}}$$

At 200 psia

R_o = -7.58991E-06 STB/Scf

Table (3.1): PVT Properties

P (psia)	Ppr	Z	Bg	ρg	Rso	Ro	μ_g	X
0	0	0	0	0	0	0	0	0
200	0.302766742	0.981775	0.020139	0.009965894	42.45072532	-7.58991E-06	0.006409	7785.064532
600	0.908300226	0.949063	0.006489	0.029897682	150.7455437	4.8312E-06	0.007085	22087.37924
1000	1.513833709	0.918618	0.003769	0.049829471	271.7358979	1.26176E-05	0.007883	34534.23046
1400	2.119367193	0.899154	0.002635	0.069761259	400.5951659	1.90092E-05	0.008807	44653.37554
1800	2.724900677	0.87969	0.002005	0.089693047	535.3081429	2.4781E-05	0.009868	52862.62557
2200	3.330434161	0.870142	0.001623	0.109624835	674.7324192	3.03124E-05	0.011081	58658.47061
2600	3.935967645	0.877725	0.001385	0.129556623	818.1233198	3.58577E-05	0.012467	61533.16128
3000	4.541501128	0.885309	0.001211	0.149488412	964.9534927	4.16204E-05	0.014049	62833.71072

PVT Properties (Contd…..)

3400	5.147034612	0.892893	0.001077	0.1694202	1114.8282	4.77815E-05	0.015855	62818.40254
3800	5.752568096	0.881099	0.000951	0.189351988	1267.439955	5.45117E-05	0.017915	63065.51389
4200	6.35810158	0.914905	0.000894	0.209283776	1422.541915	6.19775E-05	0.020267	59244.34634
4600	6.963635063	0.94871	0.000846	0.229215564	1579.931194	7.03448E-05	0.02295	54938.87614
5000	7.569168547	0.982516	0.000806	0.249147353	1739.437846	7.97809E-05	0.026015	50304.63873
5400	8.174702031	1.016321	0.000772	0.269079141	1900.917273	9.04552E-05	0.029515	45460.01395
5800	8.780235515	1.050127	0.000743	0.289010929	2064.244831	0.00010254	0.033514	40494.67107
6200	9.385768999	1.083932	0.000717	0.308942717	2229.311873	0.000116212	0.038084	35476.25668
6600	9.991302482	1.117738	0.000695	0.328874506	2396.022791	0.000131652	0.043309	30455.63783
6750	10.21837754	1.130415	0.000687	0.336348926	2458.945579	0.000137934	0.045457	28580.45824

3.5 Pseudo pressure calculations:

Pseudo pressure without K.Krg term is given as

$$mPg=\int_{p_{wf}}^{p}\left(\frac{1}{\mu_g\beta_g}\right)\left(\frac{R_p(1-R_oR_s)}{(R_p-R_s)}\right)(P)\,dP$$

In table 3.1 factor X is calculated as

$$X=\left(\frac{1}{\mu_g\beta_g}\right)\left(\frac{R_p(1-R_oR_s)}{(R_p-R_s)}\right)$$

Then

$$\int_{p_{wf}}^{p}\left(\frac{1}{\mu_g\beta_g}\right)\left(\frac{R_p(1-R_oR_s)}{(R_p-R_s)}\right)(P)\,dP=\int_{p_{wf}}^{p}X(P)\,dP$$

So

$$m(p)=\int_{p_{wf}}^{p^*}X(P)\,dP$$

m(p) at 200 Pisa is calculated as

$mp_{(200)} = \frac{X0+X200}{2}(200 -0)$

$mp_{(200)}$ = (0+7785)(200 -0) /2 = 778500 $Psia^2/Cp$

Now m(p) at 600 Pisa

$mp_{(600)}$ = $mp_{(200)}$ + (X_{200}+X_{600})(600-200)/2

So

$mp_{(600)}$ = 778500 +(7758+22087.379)(600-200)/2

$mp_{(600)}$ = 12716500 psia2/cp

All other calculations are given in table 3.2

Table (3.2) Calculation of Pseudo Pressure and Effective Permeability

t	(tp+Δt)/Δt	p	mP	Δmp	dΔmp	dΔln t	dΔmp/dΔln t	integral[Keg]	Keg
hrs		psia	MMpsia2/Cp	MMpsia2/Cp					(md)
0		1083.1	21.36756218	0					
0.167	899.203593	1174.5	24.98643577	3.618873594	3.618873594				
0.333	451.45045	1226.7	27.05323229	5.685670111	2.066796517	0.690148678			
0.5	301	1303.6	30.09799574	8.730433562	3.044763451	0.406465608	7.427530796		
1	151	1490.6	38.3323132	16.96475102	8.23431746	0.693147181	11.50837127		
2	76	1751.6	51.05815134	29.69058917	12.72583815	0.693147181	29.401227		
3	51	2046	67.1351334	45.76757122	16.07698206	0.405465108	38.20084654		
4	38.5	2279.4	80.49386559	59.12630341	13.35873219	0.287682072	55.80719455		
6	26	2759.4	109.6726239	88.3050617	29.17875829	0.405465108	76.13733014		
8	19.75	3246.5	140.1205815	118.7530194	30.44795766	0.287682072	109.7902478		
12	13.5	4210	199.9740527	178.6064905	59.85347113	0.405465108	141.6830135		
16	10.375	5162	251.0454209	229.6778587	51.07136823	0.287682072	139.3338359		
22	7.81818182	6161	293.345104	271.9775419	42.29968314	0.318453731	94.44725292		
28	6.35714286	6336.5	299.3263889	277.9588268	5.981284892	0.241162057	57.44056642	start of SSL	
34	5.41176471	6404.1	301.554887	280.1873248	2.228498034	0.194156014	15.60726956	0.003628332	
42	4.57142857	6452.5	303.1504388	281.7828766	1.595551847	0.211309094	8.897246017	0.006364707	5.65367E-05
50	4	6487.3	304.2976538	282.9300916	1.147214964	0.174353387	5.76394174	0.009824589	9.94219E-05
58	3.5862069	6507.6	304.9668625	283.5993003	0.669208729	0.148420005	5.187361851	0.010916601	5.37937E-05
68	3.20588235	6526.5	305.5899189	284.2223567	0.623056403	0.159064695	4.882212602	0.011598913	3.61012E-05
82	2.82926829	6556.9	306.5920837	285.2245215	1.002164797	0.187211542	3.672607052	0.015419118	0.000125665
97	2.54639175	6574.3	307.1656912	285.798129	0.573607482	0.167991731	4.011166309	0.014117679	7.47953E-05
112	2.33928571	6587.3	307.5942485	286.2266863	0.428557314	0.143787893	2.838492406	0.019950154	0.000448652
141	2.06382979	6601.8	308.0660485	286.6984863	0.471800017	0.230261019			

3.6 Effective permeability calculations:

After calculating pseudo pressure functions in terms of gas relative permeability, a graph is plotted between log of time and pseudo pressure function.

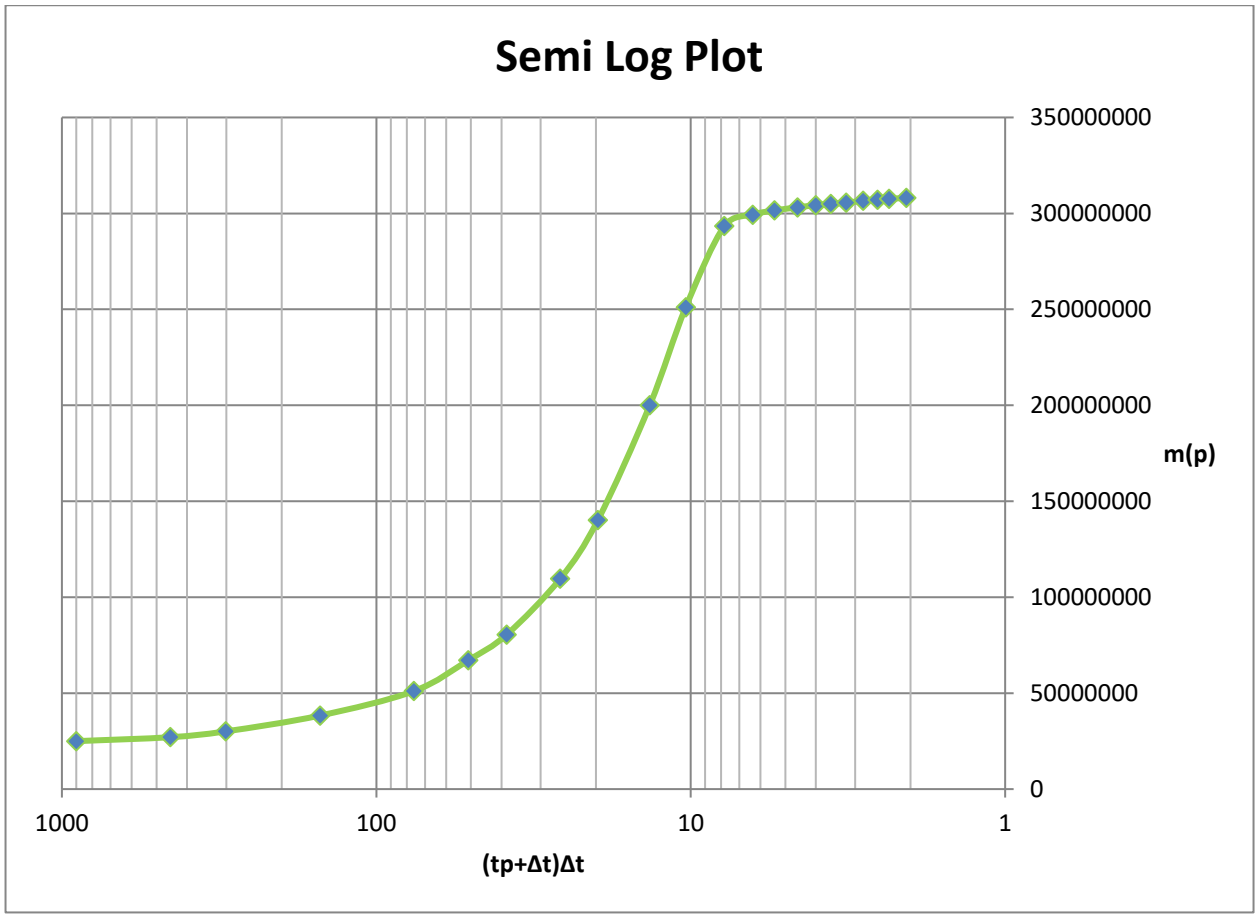


Figure 3.1: Semi-Log Plot between log of time and pseudo pressure function.

After the semi log straight line has developed, effective gas permeability integral has been calculated using equation given below.

$$\int_{P_{wf}}^{p} (K.K_{rg})dP = 162.6.\frac{q_g}{h}\left(\frac{d\Delta m(P)'}{dln(t)}\right)^{-1}$$

Where

$$\left(\frac{d\Delta m(P)'}{dln(t)}\right)_i = \frac{\left(\left(\frac{d\Delta m(P)'}{dln(t)}\right)_{i-1}(\Delta lnt)_{i+1}\right) + \left(\left(\frac{d\Delta m(P)'}{dln(t)}\right)_{i+1}(\Delta lnt)_{i-1}\right)}{[\Delta lnt_{i+1} + \Delta lnt_{i-1}]}$$

$$\Delta mp = mp - mp_{t=0}$$

From this integral effective gas permeability has been calculated using two point numerical method given below.

$$K.K_{rg} = \frac{integral\ [Kg]_2 - integral\ [Kg]_1}{P_2 - P_1}$$

At pressure 6452.5 psia effective permeability is given as

$$K.K_{rg} = \frac{0.006364707 - 0.003628332}{6452.5 - 6404.1}$$

So

$$Keg = K.K_{rg} = 5.65367E\text{-}05\ md$$

Similarly effective permeability of gas (Keg) can be calculated against each pressure after semi log straight has developed and is given in table 3.2

CHAPTER 4

Well Test Interpretation Using Pan System (Software)

4.1 Introduction:

This chapter discusses the interpretation of DST conducted on well A conducted on 2007. This interpretation is made by using "Pan System" (software). All the input data used is given. Reservoir is homogeneous, infinite acting. Parameters are calculated using three methods

- log-log plots
- radial flow plots
- type curve plots

also quick match simulation is done for, log-log plots, radial flow plots to get good estimate of reservoir parameters. Results of all these three parameters are almost same.

4.2 Data:

4.2.1 Reservoir Description

Fluid type: Gas condensate

Well orientation: Vertical

Number of wells: 1

Number of layers: 1

4.2.2 Layer Parameters

Formation thickness	50.8524 ft
Average formation porosity	0.0730
Formation compressibility	5.5407e-6 psi-1
Total system compressibility	1.0155e-4 psi-1

Layer pressure	6046.000000 psia
Temperature	285.000000 deg F

4.2.3 Well Parameters

Well radius	0.29167 ft
Wellbore storage coefficient	0.024338 bbl/psi

4.2.4 Fluid Parameters

Gas gravity	0.762800 sp grav
Check Pressure	6046.000000 Pisa
Check Temperature	285.000000 deg F
Gas density	15.3407 lb/ft3
Initial gas viscosity	0.0284129 cp
Gas formation volume factor	3.7970e-3 ft3/scf
Water density	58.3696 lb/ft3
Water viscosity	0.17297 cp
Water formation volume factor	1.06847 RB/STB
Initial Z-factor	1.08951
Initial Gas compressibility	9.6013e-5 psi-1
Water compressibility	3.6255e-6 psi-1

4.2.5 Layer Boundaries

Boundary Type	Infinite acting
Model Type	Radial homogeneous

Table 4.1: Rate Change Data

Time	Pressure	Rate
Hours	psia	MMscf/day
64.771848	5884.629000	11.607000
65.038536	5892.369000	15.800000
65.377452	5891.418000	17.214000
65.441346	5853.129000	11.484000
101.066418	6046.179000	0.000000

4.3 Analysis using pan system

4.3.1 Log-Log analysis

Log-Log Plot

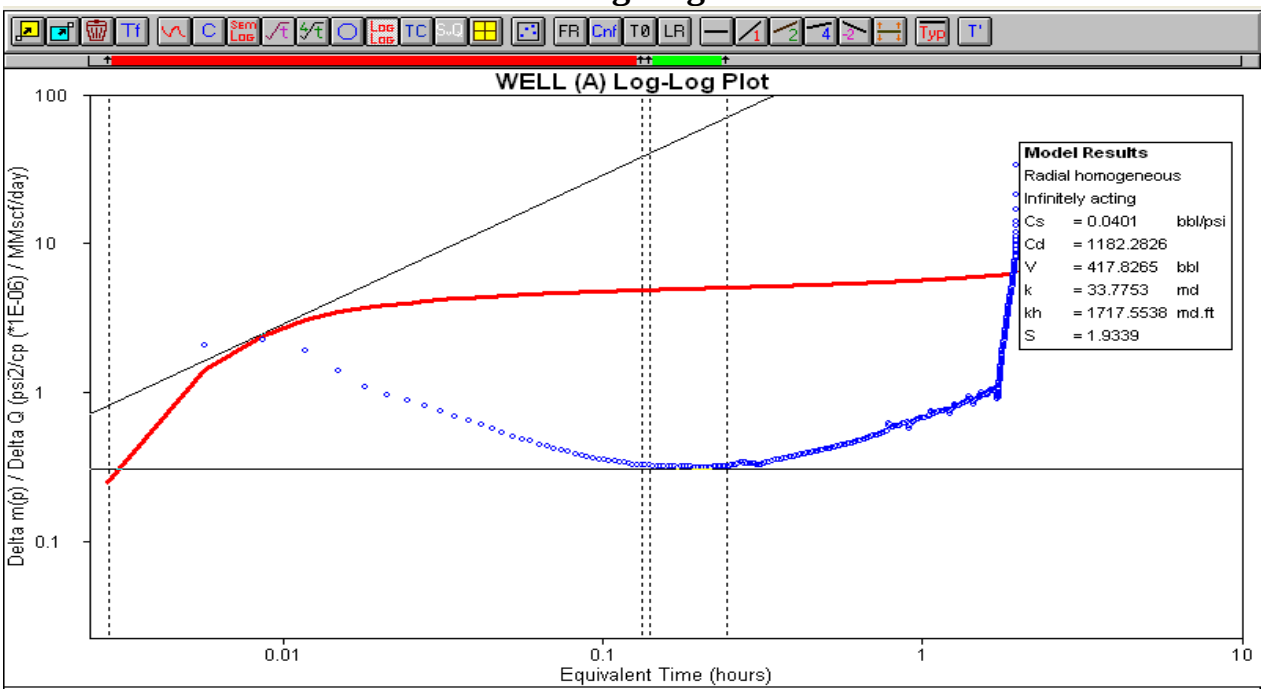


Figure 4.1 Log-Log Plot (Red line) , Derivative curve (blue line)

4.3.1(a)Log-Log Plot Line Details

Radial flow Line Slope	0
Intercept	0.308156
Wellbore storage Line Slope	1
Intercept	291.867

4.3.1(b) Quick Match Simulation of Log-Log Plot

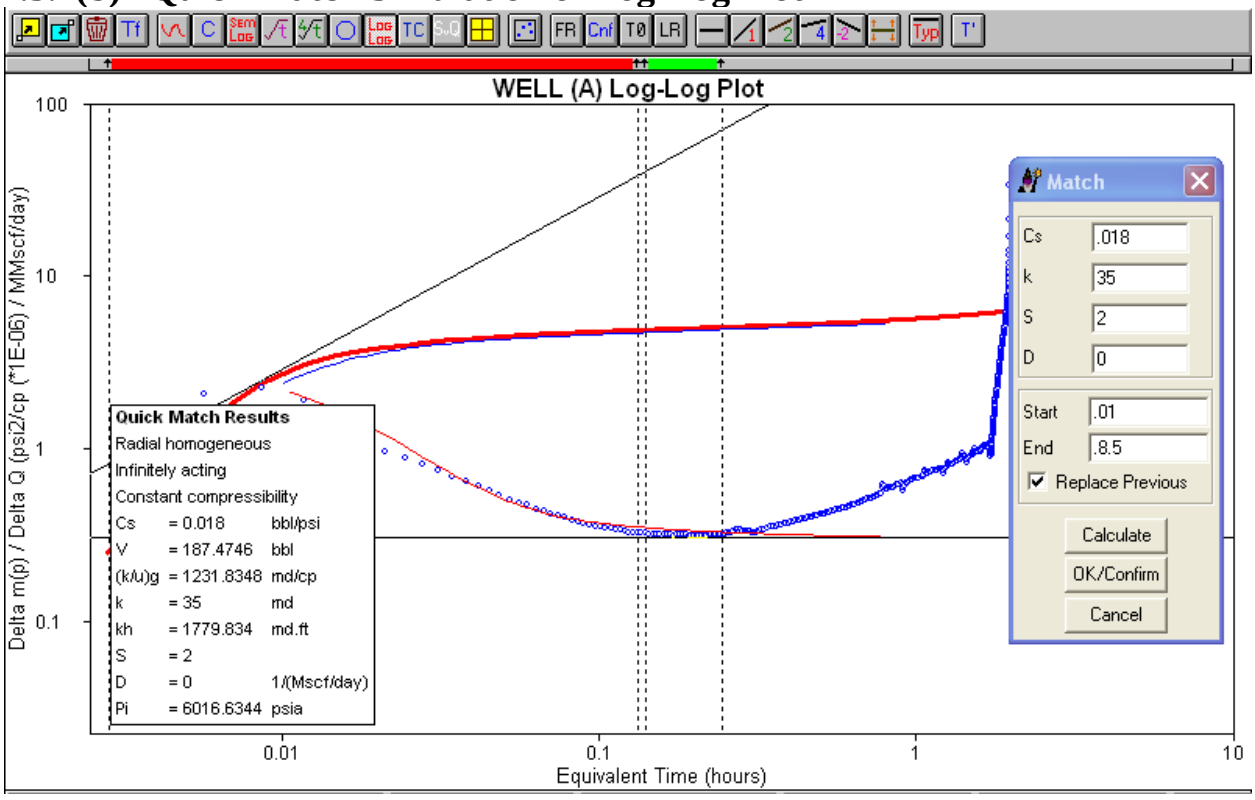


Figure 4.2: Quick Match Simulation of Log-Log Plot

4.3.1(c)Log-Log Plot Model Results

Wellbore storage coefficient	0.040117 bbl/psi
Dimensionless wellbore storage	1182.282553
Apparent wellbore volume	417.826478 bbl
Permeability	33.775274 md
Permeability-thickness	1717.553767md.ft
Skin factor	1.933906

4.3.2 Radial Flow analysis

Radial Flow Plot

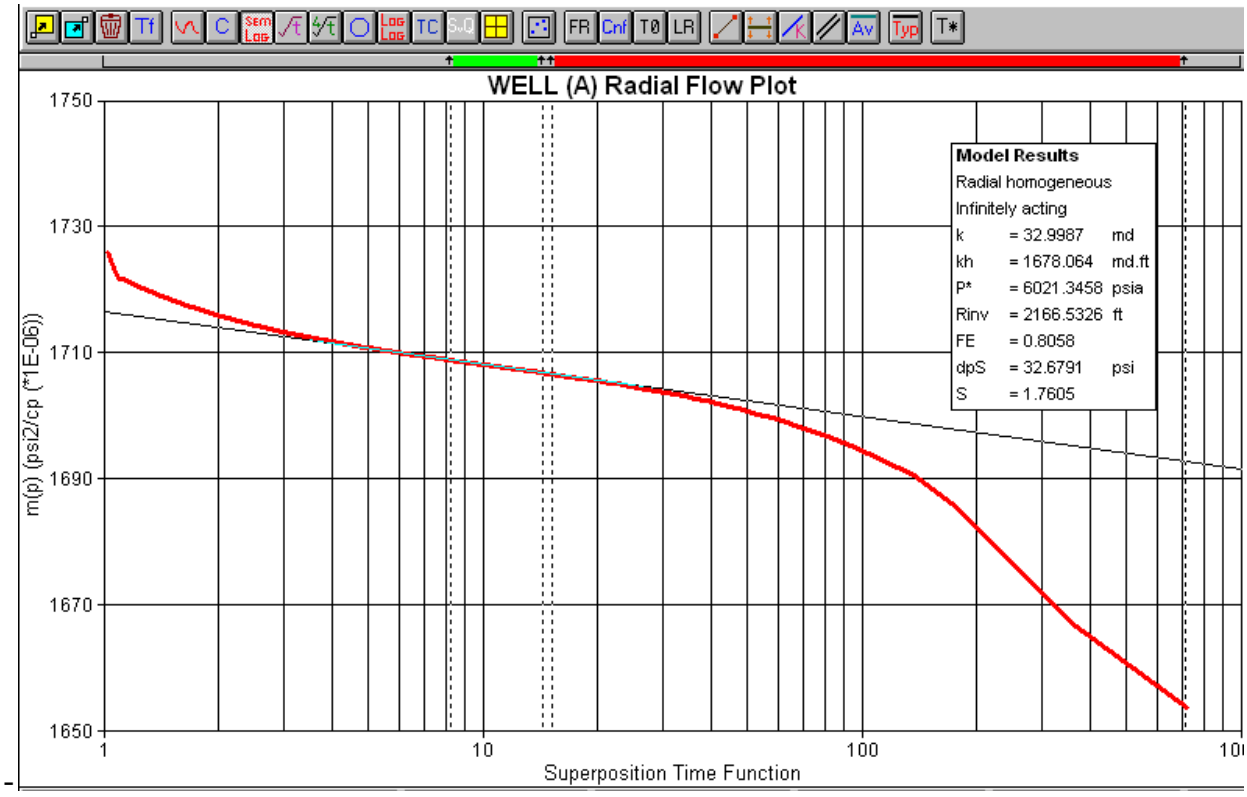


Figure 4.3: Radial Flow Plot

4.3.2(a)Radial Flow Plot Line Details

Radial flow line Slope	8.34029
Intercept	1716.41
Extrapolated m(p) psi2/cp (*1E-06)	1716.413138
m(p) at dt = 1 hr	6021.345784 psia
Extrapolated pressure psi2/cp (*1E-06)	1712.396853
Pressure at dt = 1 hour	6011.062725 psia

4.3.2(b)Quick Match Simulation of Radial Flow Plot

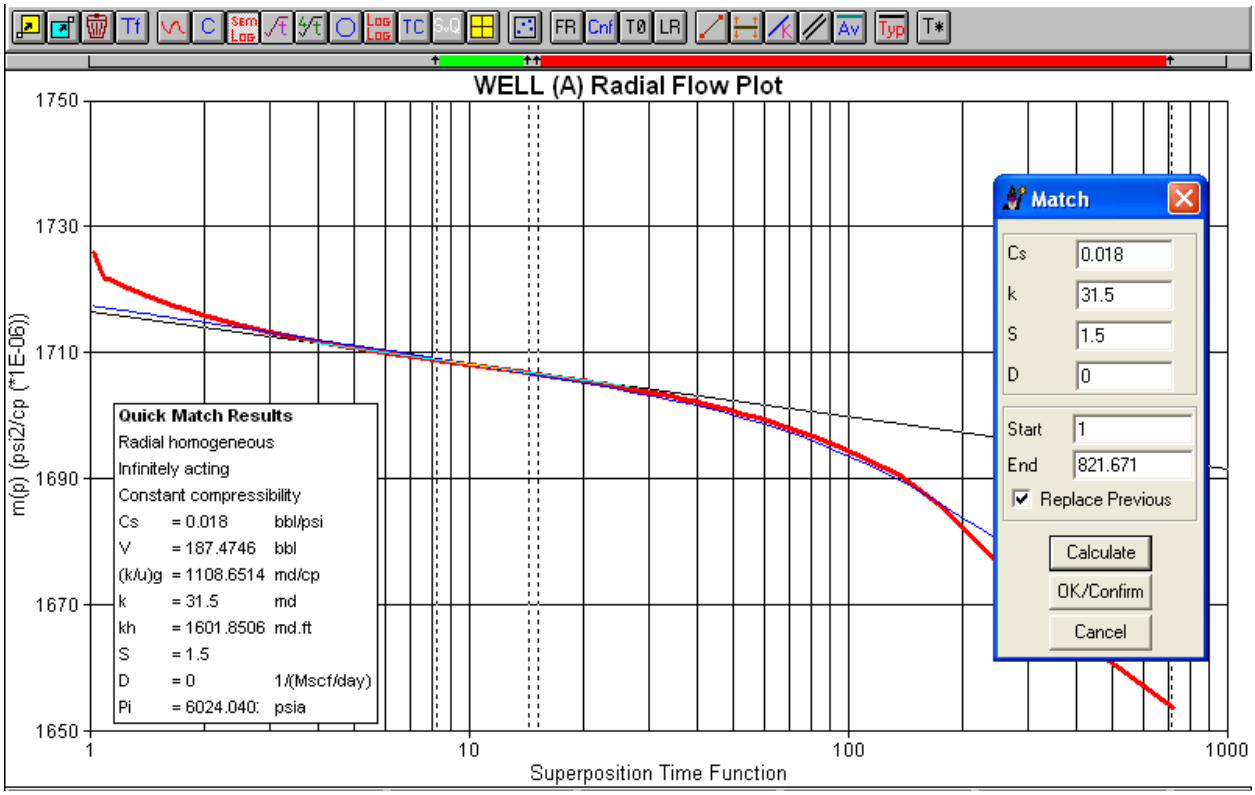


Figure 4.4: Quick Match Simulation of Radial Flow Plot

4.3.2(c)Results

Permeability	32.998717 md
Permeability-thickness	1678.063979 md.ft
Extrapolated pressure	6021.345784 psia
Radius of investigation	2166.532600 ft
Flow efficiency	0.805809
dP skin (constant rate)	32.679079 psi
Skin factor	1.760496

4.3.3 Type Curve analysis

4.3.3(a) Type Curve Plot (stage 1)

Axis Type: Td/Cd

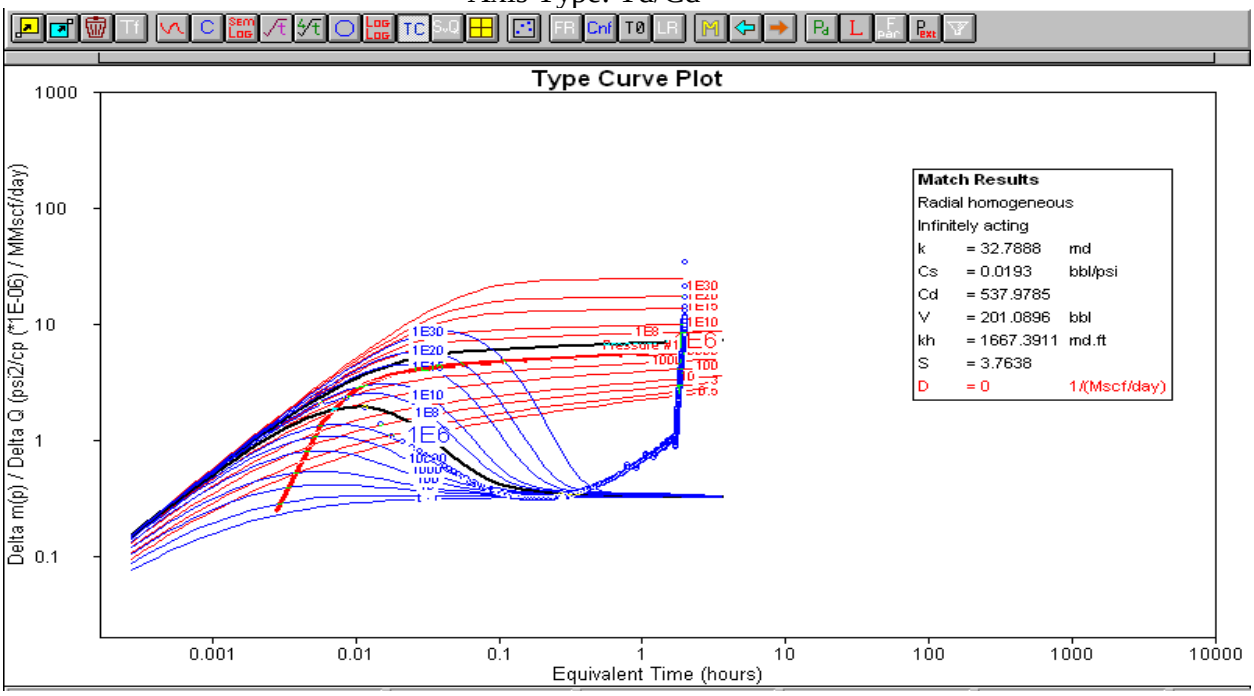


Figure 4.5: Type Curve Plot (stage 1)

4.3.3(b) Type Curve Plot (stage 2)

Axis Type: Td/Ld2

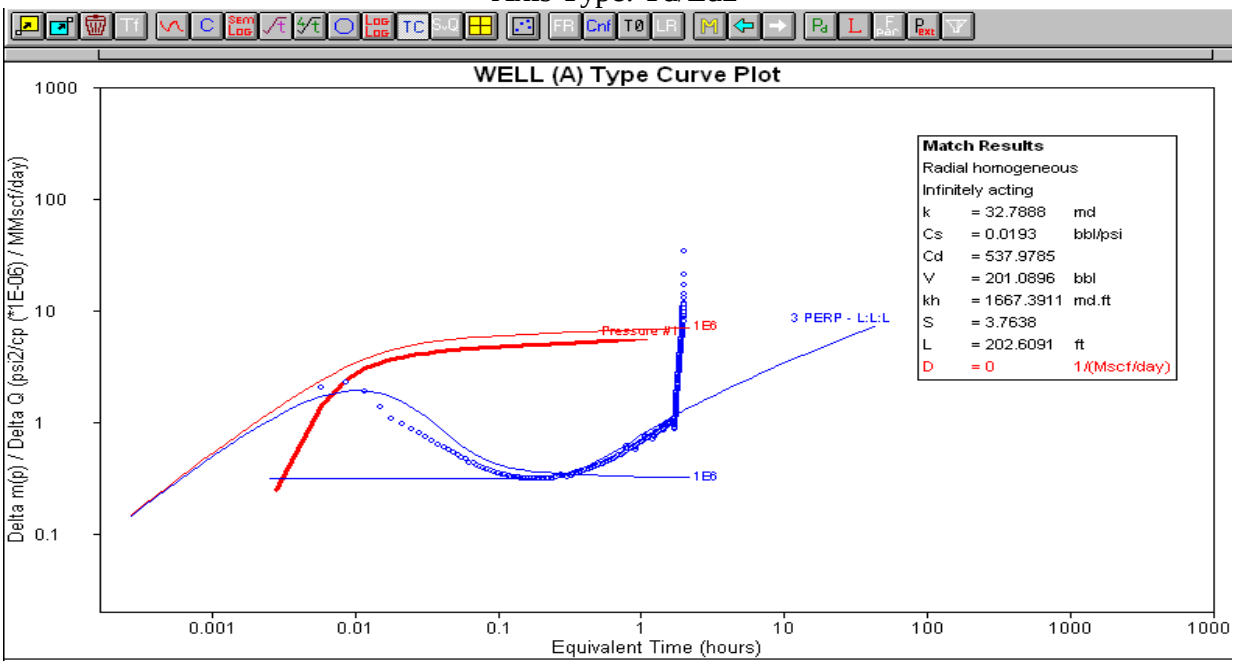


Figure 4.6: Type Curve Plot (stage 2)

	Stage 1	Stage 2
Match point - X	-2.952624	0.000000
Match point - Y	0.197327	0.197327
Curve Number	8.000000	4.000000
Curve Value	1.0000e6	3.000000

4.3.3(c) Results

Permeability	32.788838 md
Wellbore storage coefficient	0.019307 bbl/psi
Dimensionless wellbore storage	537.978525
Apparent wellbore volume	201.089551 bbl
Permeability-thickness	1667.391123 md.ft
Skin factor	3.763846

CHAPTER 5

Reserve Estimation Methods

5.1 Introduction:

There are different methods for calculating OGIP for conventional reservoirs which are named as:

- Volumetric method
- Material balance method
- P/Z method
- Decline curve analysis
- Reservoir Simulation

In this chapter three methods are discussed to give general procedure to calculate reserves. In next chapter simulation is discussed.

5.2 Volumetric method:

The volumetric method uses isopachous and subsurface contour maps based on the data from electric logs, cores, drill stem and production tests. A subsurface contour map shows lines connecting points of equal elevations thus showing geologic structure. A net isopachous map shows lines connecting points of equal net formation thickness. The individual lines connecting the points are called isopach lines. These maps determine net productive volume of the reservoir. The volume is obtained by palnimetering the areas between isopach lines of the whole reservoir or particular sections under scope. For preparing the map of this type, proper interpretations of net-sand thickness are required from well logs and proper outlining of the productive area of the field is needed as defined by fluid contacts, faults or permeability barriers on subsurface contour map. Pyramidal and trapezoidal methods are used to approximate volumes thus giving gas bearing reservoir pore volumes which ultimately helps engineers to determine original gas in place

The volumetric estimates depends on sufficiency of data if more data is available with more wells drilled in a field, the results will be accurate. However main application of volumetric method lies in the beginning of the development phase, that's why the initial estimates given by volumetric method are not reliable and they are cross checked repeatedly by material balance and other methods.

The equation for calculating original gas-in-place (OGIP) is:

$$G = \frac{43{,}560Ah\varphi(1 - S_{wi})}{B_{gi}}$$

Where:

G = Gas Initially In Place, SCF

A = Reservoir area, acres

h = Average reservoir thickness, ft

φ = Average reservoir porosity, fraction

S_g = Average gas saturation, fraction

B_g= Gas formation volume factor at reservoir pressure p, Cuft/SCF

5.2.1 Given the following data for the gas field:

Area = 90 acres

Net productive thickness = 50.8524 ft

Initial reservoir pressure = 6046 psia

Porosity = 7.3%

Connate water = 40%

Initial gas FVF = 0.00367 ft^3/SCF

Solution:

Let's start by calculating the reservoir bulk volume:

$$\mathbf{V_b = 43,560 \times A \times h}$$

$$V_b = 43{,}560 \times 90 \times 50.24 = 197 \ \text{MMft}^3$$

Initial gas in place is given by:

$$G_i = \frac{43{,}560Ah\varphi(1 - S_{wi})}{B_{gi}}$$

$$G_i = \frac{197 \times 10^6 (0.073)(1 - 0.4)}{0.00367} = 2.35 \text{ BCF}$$

5.3 P/Z Method:

Also known as pressure decline curve method is one of the conventional technique commonly used for predicting reserves of Gas Reservoirs. The technique is known for its convenience in application because it doesn't require extensive reservoir data for estimating Gas reserves originally in place. By using P/Z method, reserves at any pressure can also be found for any selected abandonment pressure. These recoverable reserves help in estimating ultimate recovery.

5.3.1 Conventional P/Z Method

$$\frac{p_{sc} G_p}{RT_{SC}} = \frac{p_i V}{ZRT} - \frac{p[V - (W_e - B_w W_P)]}{ZRT} \qquad Equation\ 3.2.2$$

Rearranging Equation 3.2.2 when there is no water influx or water produced and solving for *p*/*Z* gives:

$$\frac{p_f}{Z_f} = \frac{p_i}{Z_i} - \left(\frac{p_{sc} T}{RT_{SC}}\right) G_p \qquad Equation\ 3.3.1 \qquad OR: \qquad \frac{p_f}{Z_f} = \frac{p_i}{Z_i} - (m) G_p$$

Equation 3.3.1 is the equation of a straight line with a negative slope *m*, when *p*/*Z* is plotted versus the cumulative gas production G_p as shown in Figure 3.3.1

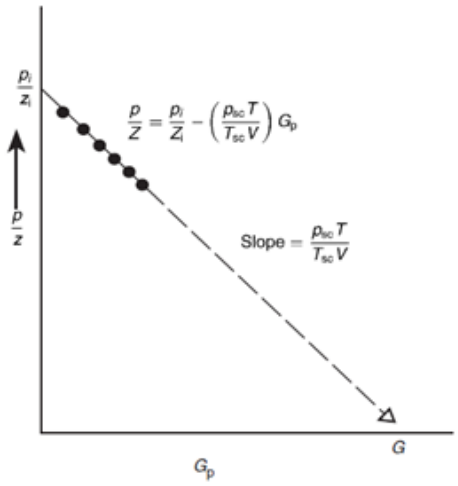


Figure 5.1: Gas Material Balance Equation

This straight-line relationship is perhaps one of the most widely used relationships in gas-reserve determination. Equation 3.3.1 reveals the straight-line relationship provides the engineer with the following four characteristics of plot:

- Slope of the straight line is equal to:

$$-m = -\left(\frac{p_{sc}T}{VT_{SC}}\right) \qquad OR: \qquad V = \left(\frac{p_{sc}T}{mT_{SC}}\right)$$

The calculated reservoir gas volume *V* can be used to determine the areal extend of the reservoir from:

$V = 43560Ah\varphi\,(1 - S_{wi})$ $A = V / [43560h\varphi\,(1 - S_{wi})]$

If reserve calculations are performed on a well-by-well basis, the drainage radius of the well can then be estimated from:

$$r_e = \sqrt{\frac{43{,}560A}{\pi}}$$

Where '*A'* is: The area of the reservoir in acres.

- Intercept at $G_p = 0$ gives P_i/Z_i .
- Intercept at $P/Z = 0$ gives the gas initially in place *G* in scf. Notice that when $P/Z = 0$, Equation 3.3.1 is

Reduced to:

$$0 = \frac{p_i}{Z_i} - \left(\frac{p_{sc}T}{RT_{SC}}\right) G_p$$

Rearranging:

$$\frac{T_{SC}}{p_{sc}} \frac{p_i}{TZ_i} V = G_p$$

5.3.2 Interpretation of field data(P/Z Method)

Table (5.1) Interpretation of field data(P/Z Method)

P (Psia)	Z	P/Z (psia)	G.E (scf)
6064	0.934403	6489.703	0
2000	0.851043	2350.056	14314365.1
2000	0.851043	2350.056	13317948.9
1980	0.850633	2327.678	14384433.6
2005	0.851146	2355.648	14448558.9
1980	0.850633	2327.678	13679156.3
2000	0.851043	2350.056	14255558.9
2005	0.851146	2355.648	13788560.7
1970	0.850428	2316.48	13934392.5
1985	0.850736	2333.274	13692059.8
1965	0.850326	2310.88	14393074.5
1960	0.850223	2305.278	14385601.3
1960	0.850223	2305.278	12620240.5
1945	0.849915	2288.463	13709555.2
1935	0.84971	2277.247	14210322.7
1925	0.849505	2266.025	13141406.8
1920	0.849403	2260.412	14094573.2
1920	0.849403	2260.412	14342614.3
1910	0.849197	2249.183	14083267.2
1910	0.849197	2249.183	14179086.6
1900	0.848992	2237.947	13824351.4
1995	0.850941	2344.464	14331448
2025	0.851556	2377.999	14156226.1
2035	0.851761	2389.167	12558768.2
2020	0.851454	2372.413	14116211.8

1890	0.848787	2226.707	14205517.8
1890	0.848787	2226.707	13907948.9
1885	0.848685	2221.084	14361558.9
1880	0.848582	2215.461	13824351.4
1870	0.848377	2204.209	13796129.6
1850	0.847967	2181.69	14271448
1870	0.848377	2204.209	13729115.2
1970	0.850428	2316.48	14326267.3
1825	0.847454	2153.51	13922059.8
1800	0.846941	2125.295	14129156.3
1795	0.846839	2119.649	13595879.1
1790	0.846736	2114	14310119.2
1780	0.846531	2102.7	13819990
1760	0.846121	2080.082	14405130
1745	0.845813	2063.104	14155991.3
1745	0.845813	2063.104	13608005.7
1740	0.84571	2057.442	13693838
1860	0.848172	2192.952	14506071
1825	0.847454	2153.51	7917451.64
1800	0.846941	2125.295	14269448
1705	0.844992	2017.77	13345046.8
1700	0.84489	2012.097	9565088.39
1690	0.844685	2000.746	14321897.4
1690	0.844685	2000.746	14300795
1840	0.847762	2170.422	11943838
1845	0.847864	2176.056	14345276.1
1685	0.844582	1995.069	14015004.3
1680	0.84448	1989.391	13950573.9
1655	0.843967	1960.978	14015004.3
1645	0.843762	1949.603	13607948.9
1635	0.843557	1938.222	14125558.9
1630	0.843454	1932.53	13937351.4
1915	0.8493	2254.798	14466274.8
1765	0.846223	2085.738	14259337
1620	0.843249	1921.141	14290322.7

1610	0.843044	1909.747	13602059.8
1605	0.842941	1904.047	13322100.9
1610	0.843044	1909.747	13115725.2
1610	0.843044	1909.747	13590281.6
1610	0.843044	1909.747	13067049
1610	0.843044	1909.747	14198503.4
1610	0.843044	1909.747	14163268.6
1585	0.842531	1881.236	13730935.8
1745	0.845813	2063.104	13638644.2
1615	0.843146	1915.444	14215108.4
1520	0.841198	1806.947	11129215
1510	0.840993	1795.497	13610240.5
1495	0.840685	1778.312	14507905.9
1495	0.840685	1778.312	13426766.3
1485	0.84048	1766.848	14242143.3
1780	0.846531	2102.7	12766170.7
1470	0.840172	1749.641	14229669.8
1465	0.84007	1743.903	14467174.7
1425	0.839249	1697.946	11272213.6
1405	0.838839	1674.934	14231448
1400	0.838736	1669.178	13190948.9
1400	0.838736	1669.178	11478893.4
1400	0.838736	1669.178	14491503.4
1455	0.839864	1732.422	13596226.1
1460	0.839967	1738.163	14125558.9
1385	0.838429	1651.9	13485558.9
1385	0.838429	1651.9	14328503.4
1380	0.838326	1646.138	13826170.7

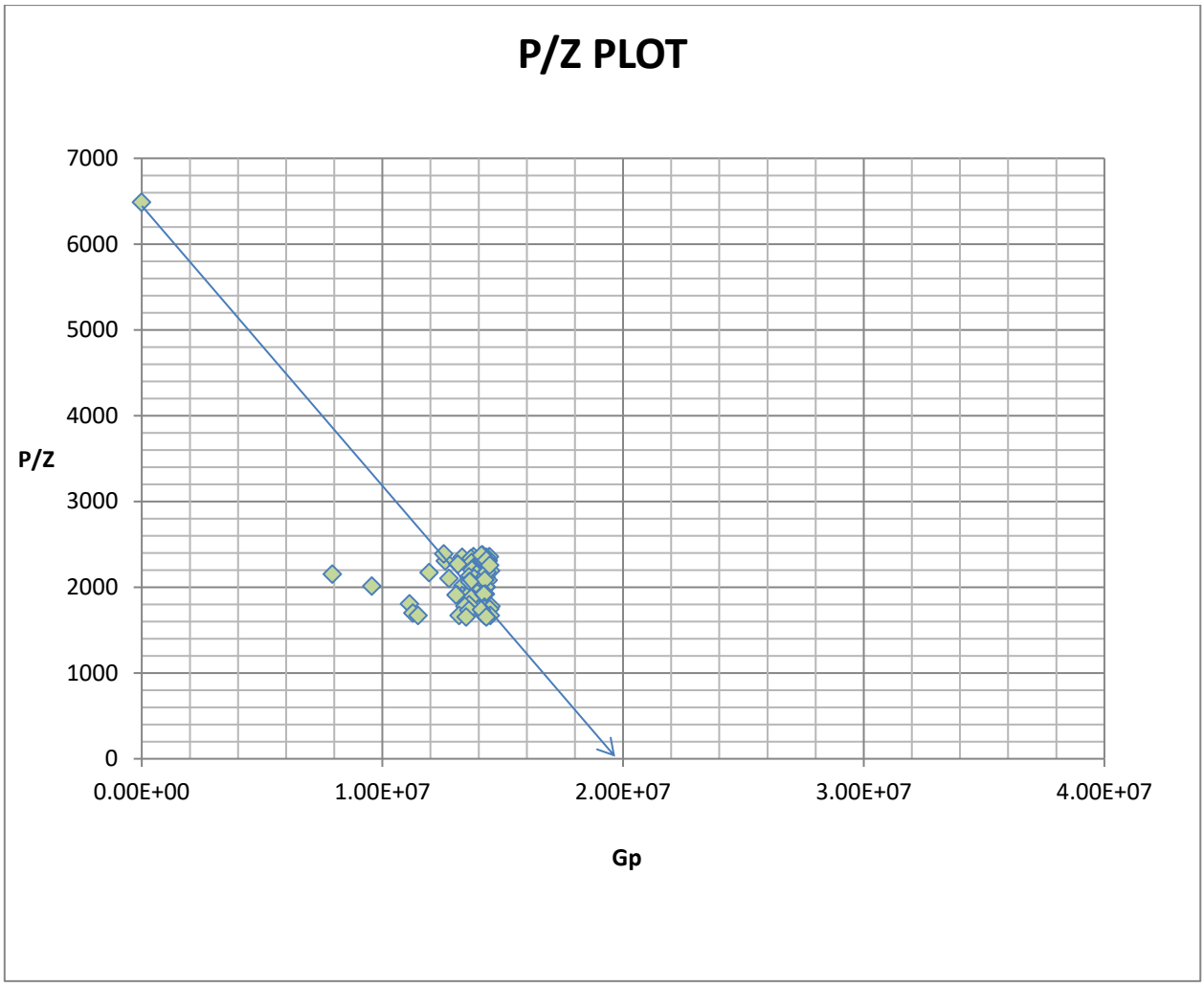


Figure 5.2: P/Z Plot

So Gi by P/Z method is = .02 Bscf

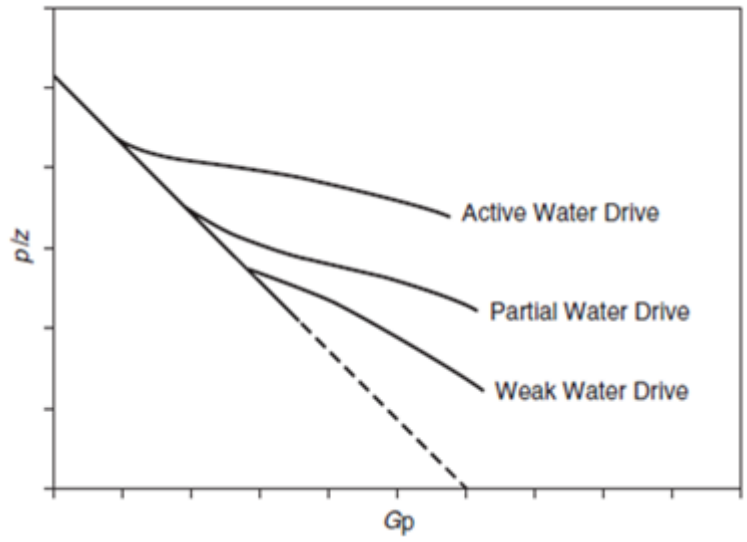


Figure 5.3: Effect of ware drive on P/Z

Where: ΔP and ΔG_p are the incremental pressure difference and cumulative production, respectively.

5.3.3 Assumptions for P/Z method:

The technique gives accurate result and is easier to be exercised on high permeability reservoirs where pressure stabilization occurs earlier for build-up tests. The reservoirs must have less heterogeneities with less pressure disturbances as well in order to obtain average reservoir pressures readily which are representative of the whole reservoir.

The material balance equation ordinarily used assumes

- ✓ An unchanging drainage volume (no fluid entering or leaving the volume except through the wellbores and no change in pore volume).
- ✓ Tank like manner is assumed, which means there are no substantial pressure drops.
- ✓ Stabilized (boundary-dominated) flow. (Modifications can be made for pore volume changes due to formation and water expansion as pressure drops, and can be important for high pressure reservoirs.)

These material balance methods are less applicable to individual wells because the drainage volumes of individual wells tend to change with time as the relative fraction of

total production from individual wells in the reservoir changes, increasing some wells' drainage volume and decreasing others. If these conventional gas reservoirs have high permeability, they can be modeled adequately as tanks characterized by a single pressure (the average reservoir pressure) at a given time and, importantly, it will be possible to determine average drainage area pressure in individual wells with relatively short shut-in periods.

5.4 Procedure for Plotting Agarwal-Gardner FMB to determine OGIP:

- Convert Flowing Pressure to Pseudo-Flowing Pressure by using the following formula

$$P = 2\int \frac{P}{\mu Z}\, dP$$

The final formula as derived above is:

$$P_{pwf2} = P_{pwf1} + \frac{2\left[\left(\frac{P_{wf}}{\mu Z}\right)_1 + \left(\frac{P_{wf}}{\mu Z}\right)_2\right]}{2}(P_{wf2} - P_{wf1})$$

- Convert Flowing Pressure to Average Reservoir Pressure.

The P/Z Material Balance Equation is used for this step, which is:

$$\frac{\overline{P}}{\overline{Z}} = \frac{P_i}{Z_i}\left(1 - \frac{G_P}{G_i}\right)$$

However; there is a bit of a problem with it, before calculating Viscosities and Compressibility factors at each reservoir pressure, we need to know how large the

tank is to start with, and for that we assume Initial Gas in Place as what the reservoir has accumulated so far.

$$G_i = \Sigma G_P$$

This is an iterative procedure in which the exact Reservoir Pressure is determined when the correct OGIP is used in the above formula. When the above formula is applied again we need to iterate the compressibility factor at reservoir pressure in order to find the average reservoir- pressure. The following table is a step by step procedure for iterating average reservoir pressure.

a. Assume OGIP as the Cumulative gas produced so far, the above formula yields a $\bar{P}/\bar{Z}$ value.
b. Now assume the compressibility factor as that previously calculated by flowing pressure and determine $\bar{P}$.
c. By following the same procedure explained in STEP 3**,** calculate compressibility factor using the recently determined average reservoir pressure.
d. Use the Z factor calculated in ***step c*** for the next assumption in ***step b***, and keep iterating in that manner until the difference of $\boldsymbol{Z_{itetrated} - Z_{assumed}}$ is zero.
e. Now, the calculated average reservoir pressure in the above steps is only for the assumed OGIP, and thus whenever a new OGIP is assumed the reservoir pressure must be iterated for that particular OGIP.

The above procedure is time consuming as it requires subsequent iterations and is best determined by using Microsoft Excel 2016 iterative calculations enabled, whenever the OGIP is changed all the iterations are done at the same time, and the average reservoir pressure is always calculated for the assumed OGIP at that time. To enable Microsoft Excel 2016 iterative calculations:

1. Select File -> Excel Options -> Formulas.

2. Click Enable Iterative calculation checkbox and set the Maximum Iterations.
3. After the first assumption of Z factor, equate $\mathbf{Z}_{assumed} = \mathbf{Z}_{itetrated}$, and choose a number of iteration limit large enough to iterate for the accurate values.

- Convert Reservoir Pressure to Reservoir Pseudo-Pressure.

  By following the same procedure explained in ***STEP 1*** we can convert Reservoir pressure into Reservoir pseudo-Pressure, where the only difference is that the parameters are calculated at Reservoir pressure.

$$P_{p2} = P_{p1} + \frac{2\left[\left(\frac{P}{\mu Z}\right)_1 + \left(\frac{P}{\mu Z}\right)_2\right]}{2}(P_2 - P_1)$$

- Calculate Normalized Rate and Normalized Cumulative Production**.**

  By using the following two formulas Normalized Rate & Normalized cumulative production will be calculated.

  Normalized Rate $= \frac{q_g}{P_{pi} - P_{pwf}}$

  Normalized Cum $= \left(\frac{P_{pi} - P_p}{P_{pi} - P_{pwf}}\right) G_i$

  The normalized rate is plotted against the normalized cumulative. A line is then drawn through the best fit of the points, and the x-intercept is the original gas in place.

5.4.1 Interpretation of field data for FMB:

Data is interpreted in below table and graph is shown

Table 5.2: Interpretation of field data for FMB

Gas rate	Oil Rate	G.E	Tubing Pressure	Flowing Pressure	PR	Reservoir Pseudo-P	Normalized Rate	Normalized cum.
scfd	bbl/d	BSCF	psi(a)	Psi	Psi	(Psi2/Cp)	(Scf/d)/(Psi2/Cp)	Bscf
					8100.0	1.459E+09	1.218E-11	0.030216
13,704,000	865.097	0.01431	1890.00	2102.49	8016.3	1.429E+09	1.097E-11	0.023948
12,810,000	719.938	0.01332	1610.00	1940.00	8031.5	1.435E+09	1.310E-11	0.032765
13,780,000	856.69	0.01438	2000.00	2409.45	8015.2	1.429E+09	1.243E-11	0.031300
13,863,000	829.938	0.01445	1920.00	2156.73	8014.3	1.429E+09	1.125E-11	0.025826
13,110,000	806.69	0.01368	1605.00	1930.00	8026.0	1.433E+09	1.145E-11	0.028236
13,670,000	829.938	0.01426	1690.00	1800.78	8017.2	1.430E+09	1.192E-11	0.027759
13,330,000	649.938	0.01379	1385.00	2180.00	8024.3	1.432E+09	1.148E-11	0.027233
13,370,000	799.938	0.01393	1985.00	1939.64	8022.1	1.431E+09	1.100E-11	0.025301
13,170,000	739.938	0.01369	1860.00	1800.78	8025.8	1.433E+09	1.310E-11	0.032798
13,795,000	847.677	0.01439	1920.00	2409.45	8015.1	1.429E+09	1.298E-11	0.032473
13,780,000	858.345	0.01439	1980.00	2373.39	8015.2	1.429E+09	1.034E-11	0.020094
12,110,000	723.186	0.01262	1765.00	1910.00	8042.2	1.439E+09	1.190E-11	0.027426
13,202,000	719.38	0.01371	1380.00	2200.00	8025.5	1.433E+09	1.145E-11	0.028082
13,620,000	836.69	0.01421	1850.00	1818.90	8017.9	1.430E+09	1.186E-11	0.025193

12,610,000	753.186	0.01314	2025.00	2373.39	8034.2	1.436e+09	1.150e-11	0.027824
13,542,000	783.186	0.01409	1655.00	1890.00	8019.6	1.431E+09	1.152E-11	0.028678
13,750,000	839.938	0.01434	1790.00	1800.78	8015.9	1.429E+09	1.267E-11	0.030612
13,500,000	826.69	0.01408	1800.00	2361.36	8019.8	1.431E+09	1.278E-11	0.031215
13,590,000	834.938	0.01418	1880.00	2367.37	8018.4	1.430E+09	1.158E-11	0.027096
13,300,000	743.186	0.01382	1425.00	2030.00	8023.8	1.432E+09	1.151E-11	0.028613
13,760,000	809.938	0.01433	1745.00	1800.78	8016.0	1.429E+09	1.157E-11	0.028194
13,613,000	769.938	0.01416	1645.00	1900.00	8018.7	1.430E+09	1.067E-11	0.020513
12,039,000	736.69	0.01256	1995.00	2102.49	8043.1	1.439E+09	1.152E-11	0.027931
13,540,000	816.69	0.01412	1680.00	1890.00	8019.3	1.431E+09	1.170E-11	0.028664
13,660,000	773.186	0.01421	2000.00	1939.64	8018.0	1.430E+09	1.182E-11	0.027940
13,400,000	719.938	0.01391	1400.00	2100.00	8022.5	1.432E+09	1.159E-11	0.028922
13,776,000	829.938	0.01436	1885.00	1830.98	8015.6	1.429E+09	1.134E-11	0.026535
13,300,000	743.186	0.01382	1610.00	1920.00	8023.8	1.432E+09	1.184E-11	0.027609
13,300,000	703.186	0.01380	1455.00	2150.00	8024.2	1.432E+09	1.146E-11	0.028304
13,700,000	809.938	0.01427	1780.00	1800.78	8017.0	1.430E+09	1.143E-11	0.026426
13,200,000	749.938	0.01373	1485.00	2000.00	8025.2	1.433E+09	1.218E-11	0.030259

13,749,000	818.186	0.01433	1870.00	2102.49	8016.1	1.429E+09	1.169E-11	0.027683
13,400,000	739.938	0.01392	1405.00	2040.00	8022.3	1.432E+09	1.135E-11	0.027564
13,560,000	806.69	0.01413	1690.00	1800.78	8019.1	1.430E+09	1.124E-11	0.025511
13,062,000	756.69	0.01360	1585.00	1960.00	8027.3	1.433E+09	1.233E-11	0.030591
13,710,000	850.575	0.01431	1960.00	2168.78	8016.4	1.429E+09	1.134E-11	0.026514
13,272,000	776.69	0.01382	1620.00	1920.00	8023.8	1.432E+09	1.264E-11	0.031695
13,800,000	857.677	0.01441	2000.00	2253.08	8014.9	1.429E+09	1.157E-11	0.028196
13,628,000	748.345	0.01416	1635.00	1900.00	8018.7	1.430E+09	1.129E-11	0.025675
13,093,000	729.94	0.01361	1520.00	1980.00	8027.1	1.433E+09	1.178E-11	0.027100
13,200,000	699.938	0.01369	1460.00	2160.00	8025.8	1.433E+09	1.194E-11	0.030269
13,870,000	901.531	0.01451	1980.00	1939.64	8013.4	1.428E+09	6.594E-12	0.005156
7,600,000	449.938	0.00792	1780.00	2000.00	8114.6	1.464E+09	1.293E-11	0.031928
13,698,000	809.938	0.01427	1890.00	2391.42	8017.0	1.430E+09	1.099E-11	0.024079
12,810,000	758.345	0.01335	1610.00	1940.00	8031.1	1.435E+09	8.162E-12	0.003935
9,097,000	663.442	0.00957	2035.00	2120.58	8089.1	1.455E+09	1.179E-11	0.029289
13,750,000	810.575	0.01432	1925.00	1939.64	8016.2	1.429E+09	1.149E-11	0.028459
13,720,000	823.186	0.01430	1825.00	1800.78	8016.5	1.429E+09	9.593E-12	0.016172

11,450,000	699.938	0.01194	1840.00	1800.78	8052.5	1.442E+09	1.307E-11	0.032551
13,746,000	849.38	0.01435	1910.00	2415.45	8015.8	1.429E+09	1.186E-11	0.028407
13,500,000	729.938	0.01402	1400.00	2080.00	8020.9	1.431E+09	1.255E-11	0.029834
13,398,000	783.187	0.01395	1870.00	2361.36	8021.8	1.431E+09	1.190E-11	0.028523
13,500,000	729.938	0.01402	1400.00	2100.00	8020.9	1.431E+09	1.140E-11	0.025916
13,100,000	719.938	0.01361	1465.00	2030.00	8027.1	1.433E+09	1.134E-11	0.027538
13,540,000	829.938	0.01413	1800.00	1800.78	8019.2	1.430E+09	1.141E-11	0.027080
13,413,000	743.186	0.01394	1630.00	1910.00	8022.0	1.431E+09	1.318E-11	0.033258
13,850,000	873.473	0.01447	1965.00	2415.45	8014.0	1.429E+09	1.227E-11	0.030253
13,702,000	789.938	0.01426	1935.00	2162.75	8017.1	1.430E+09	1.147E-11	0.028391
13,700,000	836.69	0.01429	1760.00	1800.78	8016.7	1.430E+09	1.126E-11	0.025582
13,080,000	739.938	0.01360	1745.00	1970.00	8027.2	1.433E+09	1.131E-11	0.024687
12,760,000	796.69	0.01332	1970.00	2096.47	8031.4	1.435E+09	1.084E-11	0.022927
12,509,000	859.938	0.01312	1610.00	1960.00	8034.6	1.436E+09	1.116E-11	0.025328
13,040,000	779.938	0.01359	1610.00	1930.00	8027.3	1.433E+09	1.182E-11	0.024814
12,550,000	732.836	0.01307	2005.00	2385.41	8035.3	1.436E+09	1.140E-11	0.027919
13,620,000	819.938	0.01420	1740.00	1800.78	8018.1	1.430E+09	1.155E-11	0.028176

13,600,000	798.345	0.01416	1685.00	1890.00	8018.6	1.430E+09	1.143E-11	0.026431
13,210,000	738.345	0.01373	1495.00	2000.00	8025.2	1.433E+09	1.133E-11	0.025883
13,120,000	735.097	0.01364	1495.00	1990.00	8026.6	1.433E+09	1.286E-11	0.031555
13,620,000	843.473	0.01422	1945.00	2385.41	8017.8	1.430E+09	8.939E-12	0.011910
10,700,000	608.345	0.01113	1845.00	1800.78	8065.0	1.447E+09	1.134E-11	0.025786
13,100,000	723.186	0.01361	1470.00	2000.00	8027.0	1.433E+09	1.244E-11	0.031535
13,913,000	843.186	0.01451	1900.00	2144.68	8013.4	1.428E+09	1.108E-11	0.024560
12,780,000	916.69	0.01343	1610.00	1950.00	8029.8	1.434E+09	1.144E-11	0.028153
13,660,000	825.097	0.01424	1705.00	1800.78	8017.4	1.430E+09	1.025E-11	0.020466
12,230,000	759.938	0.01277	1825.00	1800.78	8039.9	1.438E+09	1.172E-11	0.028797
13,630,000	849.938	0.01423	1960.00	1939.64	8017.6	1.430E+09	1.255E-11	0.031672
13,860,000	860.575	0.01447	1970.00	2198.89	8014.0	1.429E+09	9.231E-12	0.012907
10,823,000	636.69	0.01127	1915.00	1910.00	8062.8	1.446E+09	1.143E-11	0.028098
13,660,000	809.938	0.01423	1700.00	1800.78	8017.6	1.430E+09	1.092E-11	0.023387
12,683,000	719.938	0.01319	1615.00	1970.00	8033.4	1.436E+09	9.463E-12	0.014103
10,978,000	709.938	0.01148	2020.00	1945.68	8059.7	1.445E+09	1.187E-11	0.030024
13,913,000	819.938	0.01449	1910.00	1909.47	8013.6	1.428E+09	1.128E-11	0.025612

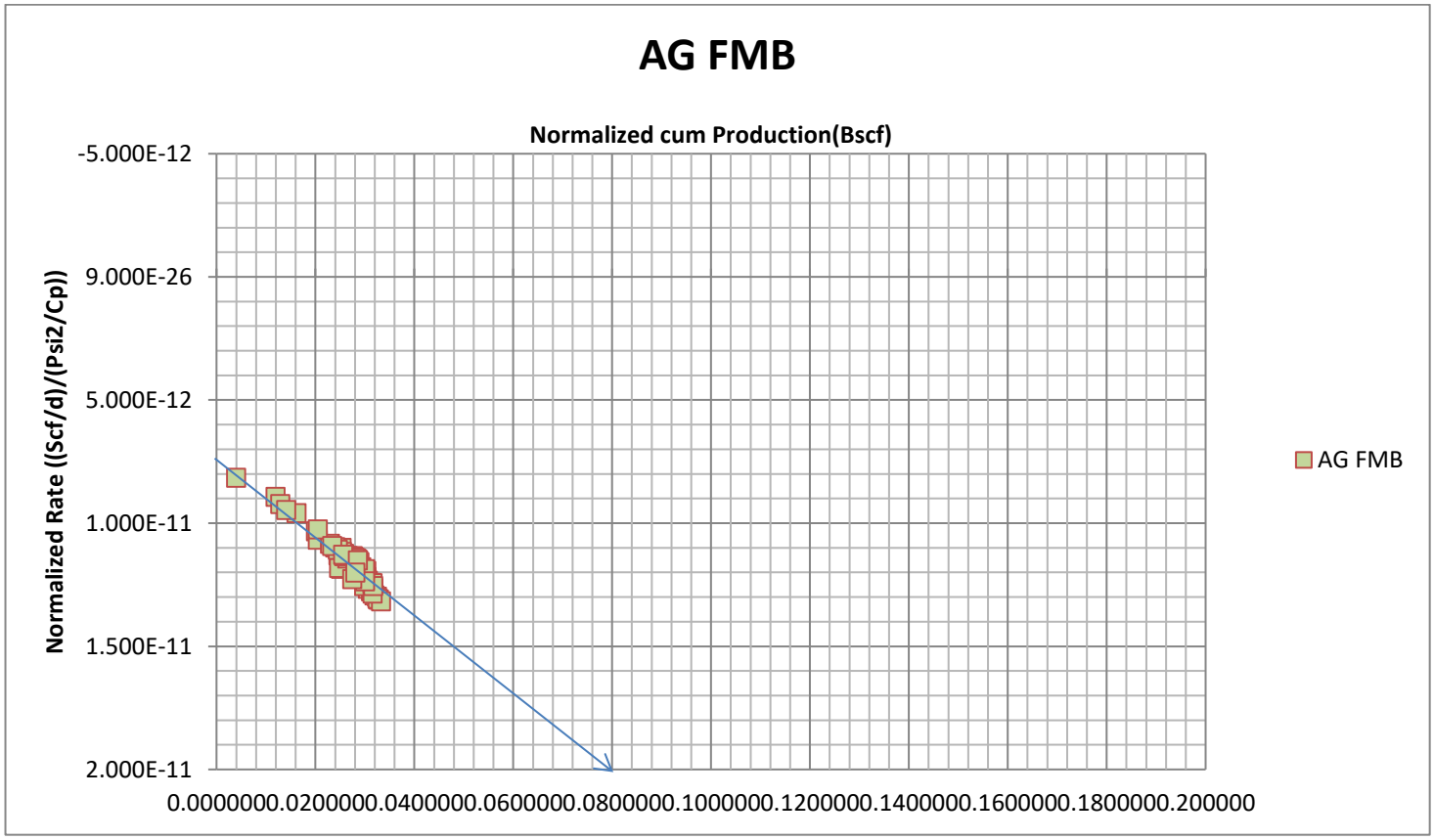


Figure: 5.4: Agarwal Flowing Material Balance Plot

So Gi by FMB Evaluation = .08 Bscf

CHAPTER 6

Reservoir Simulation

6.1 Introduction:

Reservoir Simulation is the study of numerical models discretizing and linearizing complex non-linear system of equation for fluid flow in porous media (diffusivity equation) and then uses linear solvers to generate direct or approximate solutions.

Such level of computing can only be done by high speed computers. Thus integration of numerical reservoir simulation and computer programming yields an efficient system to portray fluid flow in reservoir and predict reservoir performance in future.

6.2 Need of reservoir simulation:

Reservoir Simulation is required by petroleum engineers to determine

- performance predictions
- Reservoir Management
- Optimizing Development Plan
- Water / Gas injection, pressure Maintenance and infill wells
- Workover and intervention
- Enhanced Oil Recovery

6.3 Phases of Simulation studies:

- Define objectives
- Data collection
- Data review and analysis
- Pre-simulation analysis
- Select type of simulator
- Model construction

- History match
- Predictions
- Reporting

6.3.1 Study Objectives

The most important step in the application of reservoir simulation to a successful reservoir study is the design of the study objectives. It includes structural information, rock properties, fluid properties, well data, historical production and operating constraints

6.3.2 Data Analysis

After study objectives have been defined, reservoir and production data are gathered. Only the data required to meet the objectives of the study should be incorporated into the simulation model. We should not include abstract information because incorporating additional detail that does not add to understanding the objectives leads to overkill. The raw data available before the simulation contains:

a) Geophysical and Geological data

b) Engineering data.

6.3.3 Model Construction

Once the data has been gathered and validated, the simulation model is built. The reservoir is divided into grid blocks. Formation properties such as porosity, permeability and net to pay thickness are assigned to theses grid cells. The properties within a grid cell are homogeneous but it varies from one grid cell to another. This is the third and the most important step in reservoir simulation is the model construction. There are three steps involved in model construction that are following:

a) Model Selection.

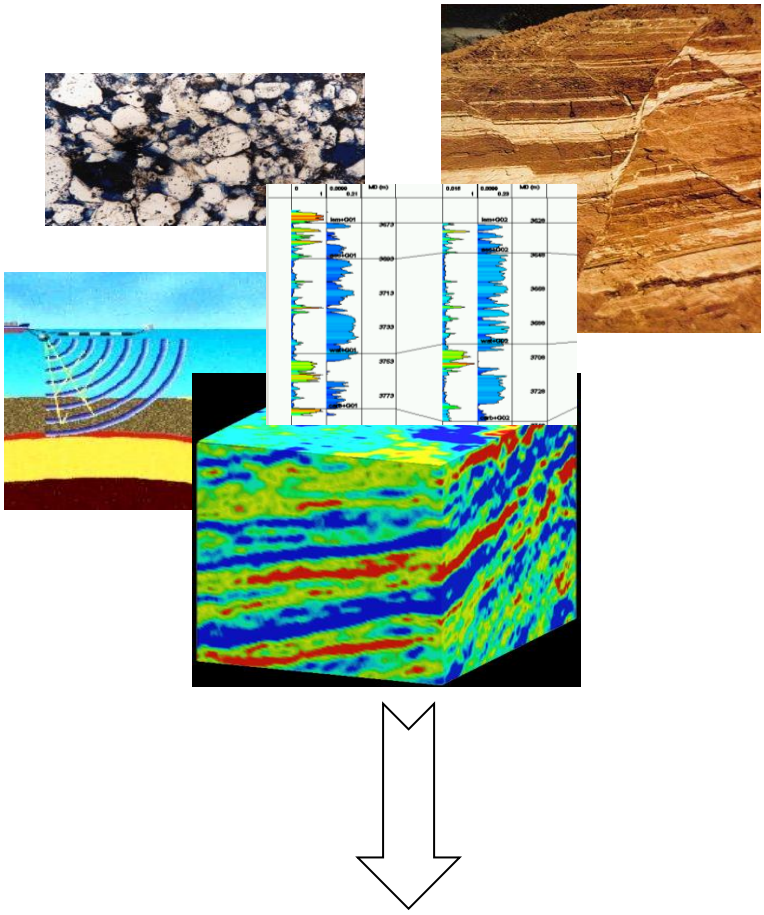
b) Model Discretization.

c) Assignment of Grid-Cell Properties.

d) Equilibration.

6.3.4 History matching

After constructing the model it must be history matched with the available production data that either it is conforms to the present production data or not. The reservoir engineer tunes the input parameters to match past production performance.



Data interpretation & collection

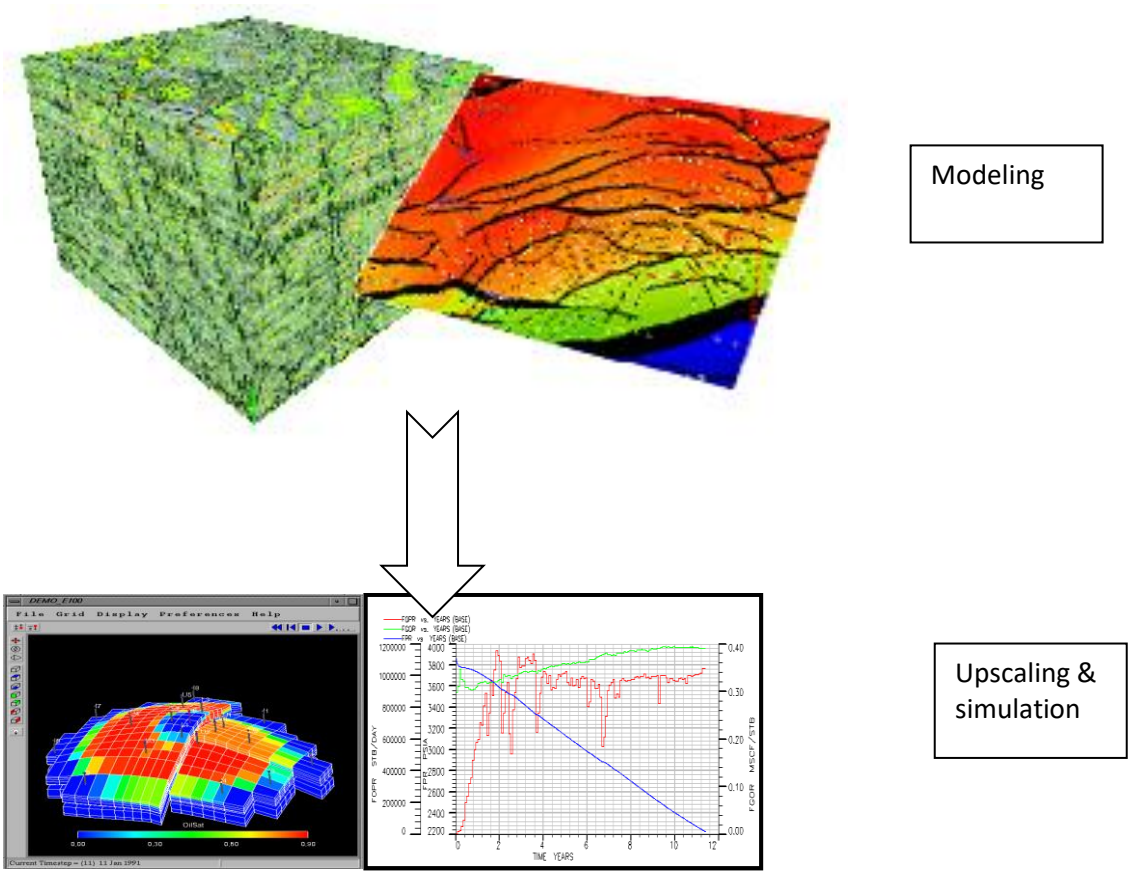


Figure 6.1: Workflow of Reservoir Simulation

6.3.5 Run prediction cases

The final step of a reservoir simulation study is the phase in which most of the study objectives are achieved. In this phase Evaluate future performance for different operating strategies find and recover hydrocarbons left over from primary depletion and use for reservoir management, economic decisions.

6.4 Grids

The fluid flow in a reservoir is described by partial differential equations, which cannot be solved analytically. These equations can be solved numerically, by replacing the differential equations with difference equations. Implicit in a difference equation is Discretization the subdivision of distance into definite, specified increments. This means,

to use finite difference equations it is necessary to treat the reservoir as it is composed of distinct small volume elements called *grid-blocks.*

A real reservoir is never completely horizontal, and also has a complex internal structure defined by the different geologic units that build the reservoir. These units are also commonly natural flow units, and hence when building grids, we generally keep in mind the depth variation of the units in the grid.

6.4.1 Grid-blocks

The subdivision of the reservoir into finite volume elements or cells is termed as discretization of the reservoir. Collectively the set of all the volume elements is called the reservoir grid and individually each element is called as Grid-block.

The rock properties of Grid remain uniform for most part negating geomechanical effects As production proceeds some properties such as relative permeability may change with time if there are two phases flowing in the block

The connection between blocks conveys fluid from one block to another. The simplest grids are those which are comprised of a number of equal cube-shaped cells. The grid is the uniquely defined by the size of each cube, and the number of cubes in each of the major directions, *X, Y, and Z.*

6.4.2 Grid-block size selection

Grid block selection is a very crucial step. So, grid blocks should be selected keeping in mind the following important points which are:

1. To identify saturations and pressures at the specific locations and times required by the study;
2. To describe the geometry, geology, and initial physical properties of the reservoir adequately;

3. To describe dynamic saturations and pressures profiles in sufficient detail that meet the objectives of the reservoir study;
4. To model reservoir fluid mechanics properly; and
5. To be in commitment with the mathematics in the solution segments of the simulator so that the solutions to the fluid-flow equations are accurate and stable.

The requirements 1 through 4 should be necessarily met, so that a successful simulation is possible.

6.5 Eclipse software

Eclipse is a black oil simulator which uses backward difference implicit technique in time to predict pressures in future (new time level pressures). It is applicable for multiphase three dimensional, radial and cartesian block center geometrical configurations. It can model for both gas dissolving in oil (Gas/oil ratio) with varying bubble pints and oil vaporizing in gas (oil / gas ratio) systems with varying dew points.

6.5.1 Starting Eclipse?

Eclipse can be started by preparing input data file either

- in text format using eclipse syntax or
- use the interactive eclipse office module to create a custom data files

In both cases sufficient reservoir rock and fluid properties together with production format should be defined in an input data file.

Note that the text format file should have an extension “name.DATA”. For manual creation in text format other than eclipse office file, after typing all Inputs in “.txt”, Save the text file as “.DATA”

6.5.2 Input data file

There are Eight basic Components of Eclipse Data Input file. These are called Section Headers. Some things to keep in note before writing in Eclipse Syntax are as follows:

- The start of each section is represented by keyword also known as Section header.
- There must be no other characters (or spaces) on the same line as a keyword.
- All data associated with a keyword must appear on the subsequent lines
- Data entry is terminated by a forward slash symbol (/)
- Lines beginning with two dashes (--) are ignored, and treated as comment lines
- Blank lines are ignored

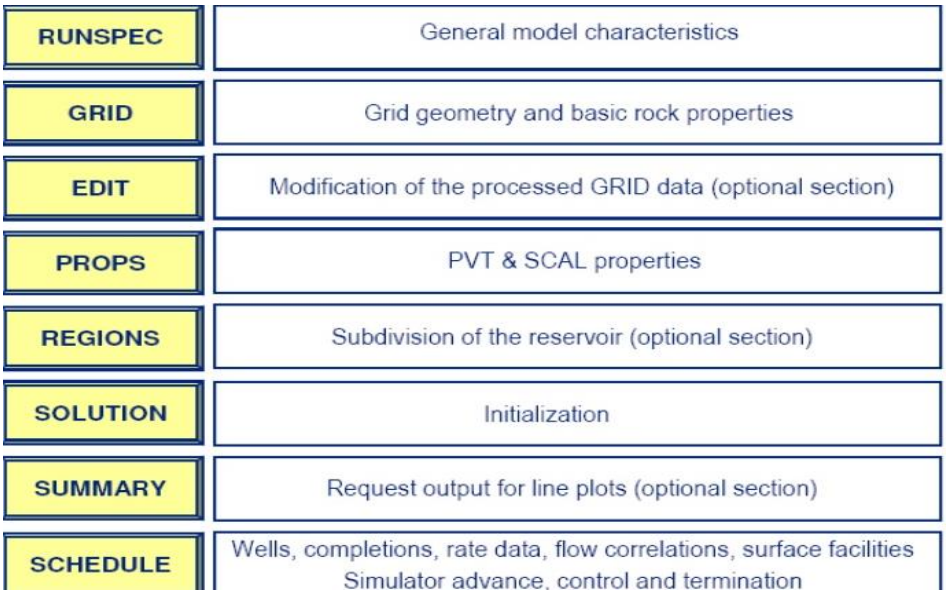


Figure 6.2:Interface of an Input data file

6.5.3 Section- header Key words:

6.5.3(a) RUNSPEC

Describes general properties of reservoir

```
RUNSPEC

TITLE
   ODEH PROBLEM - IMPLICIT OPTION - 1200 DAYS

DIMENS
   10   10    3  /

OIL

WATER

GAS

DISGAS

FIELD

WELLDIMS
    2    1    1    2 /

START
  19 'OCT' 1982  /

UNIFOUT

UNIFIN

NOSIM

...
```

DIMENS: Number of cells in X, Y and Z directions

OIL: Calculate oil flows

WATER: Calculate water flows

VAPOIL / DISGAS: calculate other phase flows

FIELD: Use field units throughout (i.e. feet, psi, lb, bbl, etc.)

WELLDIMS: Number of wells, connections per well, groups, wells per group

UNIFIN: unified input files

UNIFOUT: Unified output file

START: Start date of simulation (1st day of production)

NOSIM: no simulation data check

6.5.3(b) GRID

The GRID in Eclipse is mainly used to describe rock properties and dimensions of a reservoir section in question. Sizes of grid block in three dimensions, depths, porosity and permeability in three dimensions is defined here.

```
...

GRID

--     ARRAY  VALUE     ------- BOX ------
EQUALS
      'DX'    1000      /
      'DY'    1000      /
      'PORO'  0.3       /

      'DZ'    20        1  10  1  10  1  1  /
      'PERMX' 500       /
      'MULTZ' 0.64      /
      'TOPS'  8325      /

      'DZ'    30        1  10  1  10  2  2  /
      'PERMX' 50        /
      'MULTZ' 0.265625  /

      'DZ'    50        1  10  1  10  3  3  /
      'PERMX' 200       /

/       EQUALS IS TERMINATED BY A NULL RECORD

-- THE Y AND Z DIRECTION PERMEABILITIES ARE COPIED FROM PERMX
--    SOURCE  DESTINATION  ------- BOX ------
COPY
      'PERMX'    'PERMY'   1  10  1  10  1  3  /
      'PERMX'    'PERMZ'   /
/

...
```

TOPS: Depth of cells from top layer

DX, DY, DZ: Size of cells in X,Y,Z direction

PERMX, PERMY, PERMZ: cell permeabilities X,Y,Z direction

PORO: cell porosities

INIT: Output Grid Values to .INIT file

6.5.3(c) PROPS

The fluid properties are defined in this section. The data from PVT reports is inserted here along with viscosities and core analysis data (SCAL / RCAL) consisting of capillary pressures, saturation and relative permeability.

```
-- ROCK COMPRESSIBILITY
--
--    REF. PRES   COMPRESSIBILITY
ROCK
        14.7          3.0D-6          /

-- SURFACE DENSITIES OF RESERVOIR FLUIDS
--
--         OIL    WATER    GAS
DENSITY
         49.1    64.79  0.06054  /

-- PVT PROPERTIES OF DRY GAS (NO VAPOURISED OIL)
-- WE WOULD USE PVTG TO SPECIFY THE PROPERTIES OF WET GAS
--
--   PGAS    BGAS    VISGAS
PVDG
     14.7 166.666    0.008
    264.7  12.093    0.0096
    514.7   6.274    0.0112
   1014.7   3.197    0.014
   2014.7   1.614    0.0189
   2514.7   1.294    0.0208
   3014.7   1.080    0.0228
   4014.7   0.811    0.0268
   5014.7   0.649    0.0309
   9014.7   0.386    0.047   /

-- PVT PROPERTIES OF LIVE OIL (WITH DISSOLVED GAS)
-- WE WOULD USE PVDO TO SPECIFY THE PROPERTIES OF DEAD OIL
--
-- FOR EACH VALUE OF RS THE SATURATION PRESSURE, FVF AND VISCOSITY
-- ARE SPECIFIED. FOR RS=1.27 AND 1.618, THE FVF AND VISCOSITY OF
-- UNDERSATURATED OIL ARE DEFINED AS A FUNCTION OF PRESSURE. DATA
-- FOR UNDERSATURATED OIL MAY BE SUPPLIED FOR ANY RS, BUT MUST BE
-- SUPPLIED FOR THE HIGHEST RS (1.618).
--
--   RS      POIL  FVFO  VISO
PVTO
    0.001    14.7 1.062  1.04    /
    0.0905  264.7 1.15   0.975   /
    0.18    514.7 1.207  0.91    /
    0.371  1014.7 1.295  0.83    /
    0.636  2014.7 1.435  0.695   /
    0.775  2514.7 1.5    0.641   /
    0.93   3014.7 1.565  0.594   /
    1.270  4014.7 1.695  0.51
           5014.7 1.671  0.549
           9014.7 1.579  0.74    /
    1.618  5014.7 1.827  0.449
           9014.7 1.726  0.605   /
/

...
```

PVTO: Formation volume factor and viscosity of live oil as functions of pressure and Solution Gas Oil ratio

PVTG: Formation Volume Factor and viscosity of Wet gas as functions of pressure and Relative volume

DENSITY: densities of fluids at standard conditions

ROCK: rock compressibility

6.5.3(d) SOLUTION

Once the rock and fluid properties have all been defined, the initial pressure and saturation conditions in the reservoir must be specified. This may be done in one of three ways:

1) Enumeration

2) Equilibration

3) Restart from a previous run

```
...

SOLUTION

-- DATA FOR INITIALISING FLUIDS TO POTENTIAL EQUILIBRIUM
--
--    DATUM  DATUM   OWC    OWC    GOC    GOC    RSVD   RVVD   SOLN
--    DEPTH  PRESS  DEPTH   PCOW  DEPTH   PCOG  TABLE  TABLE   METH
EQUIL
       8400   4800   8500    0     8200    0      1      0       0  /

-- VARIATION OF INITIAL RS WITH DEPTH
--
--    DEPTH    RS
RSVD
       8200  1.270
       8500  1.270  /

-- OUTPUT CONTROLS (SWITCH ON OUTPUT OF INITIAL GRID BLOCK PRESSURES)
RPTSOL
   1  11*0  /

...
```

EQUIL Equilibration data (pressure at datum depth and contact depths)

RPTSOL: report switches for SOLUTION data

RPTRST Request output of cell pressures and saturations at t = 0

RESTART: restarts file

6.5.3(e) SUMMARY

Mentions the output summary files to be needed for interpretation.

FPR Field average pressure

WBHP Well Bottomhole pressure

FOPR Field Oil Production Rate

WOPR: Well Oil Production Rate

FWPR Field Water Production Rate

FOPT Field Oil Production Total

FGOR: Field Gas-Oil Ratio

FOE: Field Oil Efficiency

FWPT Field Water Production Total

WWCT Well Water Cut

FWIR: Field Water Injection Rate

FWCT: Field Water Cut

CPU CPU usage

Newton: Number of Newton Raphson iterations

EXCEL Create summary output as Excel readable Run Summary file

```
...

SUMMARY

--REQUEST PRINTED OUTPUT OF SUMMARY FILE DATA

RUNSUM

-- FIELD OIL PRODUCTION
FOPR

-- WELL GAS-OIL RATIO FOR PRODUCER
WGOR
'PRODUCER'
/
-- WELL BOTTOM-HOLE PRESSURE
WBHP
'PRODUCER'
'INJECTOR'
/

-- GAS AND OIL SATURATIONS IN INJECTION AND PRODUCTION CELL
BGSAT
10 10 3
1  1  1
/
BOSAT
10 10 3
1  1  1
/

-- PRESSURE IN INJECTION AND PRODUCTION CELL
BPR
10 10 3
1  1  1
/

...
```

6.5.3(f) SCHEDULE

RPTRST: Request output of cell pressures and saturations at all time steps (t > 0)

WELSPECS: Well specifications define location of wellhead and pressure gauge

COMPDAT: Completions data defines completion intervals and wellbore diameter

TUNING: controls time steps and convergence for non-linear solver

WCONPROD: Production control

WCONINJ: Injection control

TSTEP: Time step sizes (for output of calculated data)

END: End of input data file

```
-- PRODUCTION WELL CONTROLS
--
--      WELL      OPEN/  CNTL   OIL  WATER   GAS  LIQU   RES   BHP
--      NAME      SHUT   MODE  RATE   RATE  RATE  RATE  RATE
WCONPROD
     'PRODUCER' 'OPEN' 'ORAT' 20000  4*                     1000 /
  /

-- INJECTION WELL CONTROLS
--
--      WELL      INJ   OPEN/  CNTL    FLOW
--      NAME     TYPE   SHUT   MODE    RATE
WCONINJ
     'INJECTOR' 'GAS' 'OPEN' 'RATE'  100000  /
  /

--  YEAR 1

TSTEP
 1.0 14.0 13*25.0
  /

RPTSCHED
 1 1 1 1 1 0 2 1 2 0
 2 2 0 0 2 /

TSTEP
   25.0
  /

TSTEP
...
  /

END
```

6.5.4 Running simulation and obtaining results:

Input file is run by Eclipse Launcher where the path to the location of saved input data file is defined. The «Run» button will start simulation. The command prompt will open up and start showing the status of simulation run. First it reads the data, if there is an error in the beginning of data reading then there is a problem either with syntax or there is insufficient memory of your system to run the program in case data is huge. For a successful run without any inerruption the problems should not exceed beyond the permitted limit otherwise it will generate an error.

The warnings given are mostly about linear convergence failures. The problems include critical threats to hault simulation and include non-linear (Newton Raphson) convergence failures. The output files should come as:

- .PRT – If the run was successful, this file will contain summary data such as field average pressure and water cut for each time step. Otherwise, it is the platform where you can look for errors in KEYWORDS, etc.
- .GRID – binary file that contains the geometry of the model, and is used by post processors for displaying the grid outline.
- .INIT – initial grid property data such as permeabilities and porosities.
- .UNRST – contains pressure and saturation data for each time step.
- .RSM – file that can be read into MS Excel to display summary data in line chart format.
- Graf and FloViz. Are used for visualization and interpretation of the results

6.6 Simulation Results

Simulation results are compiled in appendix

Conclusions and Recommendations

Conclusions:

Some conclusions drawn from this work are as follows:

- A relatively new analytical approach for evaluating two phase psuedopressure without using relative permeability data is presented here. The effect of reduced gas permeability due to condensate blockage is incorporated in psuedopressure function.
- Well Test / pressure transient data was then used to estimate effective permeability of gas phase as a function of pressure using two-phase pseudo pressure thereby eliminating the use of relative permeability as a function of saturation.
- Thus, it is possible to determine formation flow capacity, kh, average reservoir pressure, p, the mechanical skin factor (s), the skin factor associated with two-phase flow and associated well performance when the producing pressure is below the dewpoint pressure.

- Interpretation of a DST test conducted on a well was conducted by Pan System using log-log plots, radial flow and type curve analysis. The quick match simulation in case of log-log plots and radial flow plots gave a good estimation of reservoir parameters like Permeability-thickness (kh) and Skin factor. The results from three models were compared and checked for agreement.

- Reserve estimates were calculated by using Volumetric and P/Z methods for given data. An alternative to the flowing p/z plot for calculating Original Gas In Place (OGIP) known as the Agarwal flowing material balance (FMB) analysis was applied on field data and results were interpreted. The Normalized Rate / Normalized Cumulative analysis can work for both oil and gas reservoirs and applicable for constant or variable rate systems. The main advantage of this technique is that

flowing pressures are used for material balance calculations without shutting in the wells for extended periods of time as is required for conventional Material balance using static pressures. It can also be used to estimate reservoir pressures.

- A simulation case was run on Eclipse 100 (black oil PVT) for a producing section of gas condensate reservoir. The file composed for simulation run shows that ECLIPSE may also be used to model oil vaporizing in gas (variable dew point pressure or oil/gas ratio).Results such as Total gas in place, Field gas and oil (condensate) production rates and field gas/oil ratio were presented at the end.

Recommendations and Limitations:

- With the help of reliable relative permeability core data, fevang's approach of three region two phase psuedopressure for gas condensate reservoirs can be implemented and the results can be compared with those obtained from Jokhio's approach applied here on the same reservoir.
- The work can be extended to generate inflow performance relationships and describe well performance for each phase provided the production (rate) data is available. The psuedopressure function is calculated without considering Krg values and modified to give mP. A log-log plot between mP and Flow rate will produce a straight line, the slope and intercept of which will give values of n (turbulence coefficient) and C (performance coefficient). These parameters will then create an IPR equation for reservoir inflow.
- Recent studies have shown the presence of fourth region near immediate vicinity of wellbore where turbulence effects due to high velocity Gas flow (non-darcy / inertial flow or positive coupling) creates an additional skin known as rate dependent skin. There are two competing phenomena which may cause the effective gas permeability to be rate dependent.

- The gas relative permeability increase with velocity. This effect is termed as velocity stripping or positive coupling. This region is characterized by high capillary number, low interfacial tension and high flow rates.
- Inertial (non-Darcy) flow effects, which at high velocity reduce the gas permeability.

Since simultaneous flow of gas and condensate is usually affected by the combined effect of these phenomena (coupling and inertia), both of them should be included in reservoir modeling. The complications of transient test analysis in this type of reservoir are caused by multiphase flow and change in the composition of the flowing mixture. The total skin can be accurately determined by incorporating both inertial and positive coupling effects near wellbore in compositional simulation of Gas condensates. For that purpose a capillary number model is selected in compositional simulators.

- The quality, reliability and validity of well test interpretation can be improved by integrating it with geophysical (seismic), geomechanical and petrophysical (logging) interpretations simultaneously. With sufficient data available like the one obtained from LWD/MWD, PLT (production logs) and reservoir surveillance, an integrated well test interpretation model can be built which will give a complete account of gas condensate reservoir characterization.

  So far there is no accurate pressure transient data analysis method which can incorporate all kind of reservoir data and give comprehensive results with clarity.

  For instance, Derivative curve usually fails to identify fluid patterns from rock heterogeneities in complex heterogenous reservoirs. These heterogeneities may include faults, natural fractures and highly laminated formations. It is also due to

noisy derivative data near wellbore which occurs due to multiphase flow. Some smoothing techniques such as deconvolution alters the characteristics of data.

Current literature on analytical multiphase pressure transient techniques also doesn't address and distinguish between the rock heterogeneities and multiphase fluid effects. A new technique of well testing using density derivatives coupled with statistical method, has efficiently predicted flow regimes & reservoir properties and identified such problems in multiphase system. A comparison between analytical multiphase (PTA) and numerical density derivative method can bring significant improvements in the interpretation and theory of analytical techniques.

- Latest trends in research have recognized a new improved version of Flowing Material Balance which can be applied to multiphase fluid flow by utilizing the concept of two-phase pseudopressure (as mentioned in this paper) to assimilate two-phase oil/gas flow in estimating total hydrocarbon in place. It can also take into account the changes in the reservoir due to depletion, injection/production of water, varying GORs due to production and multiwell production effects. The multiphase FMB can be extended to estimate reserves in Gas Condensate fields producing below dew point pressure without shutting in the wells.

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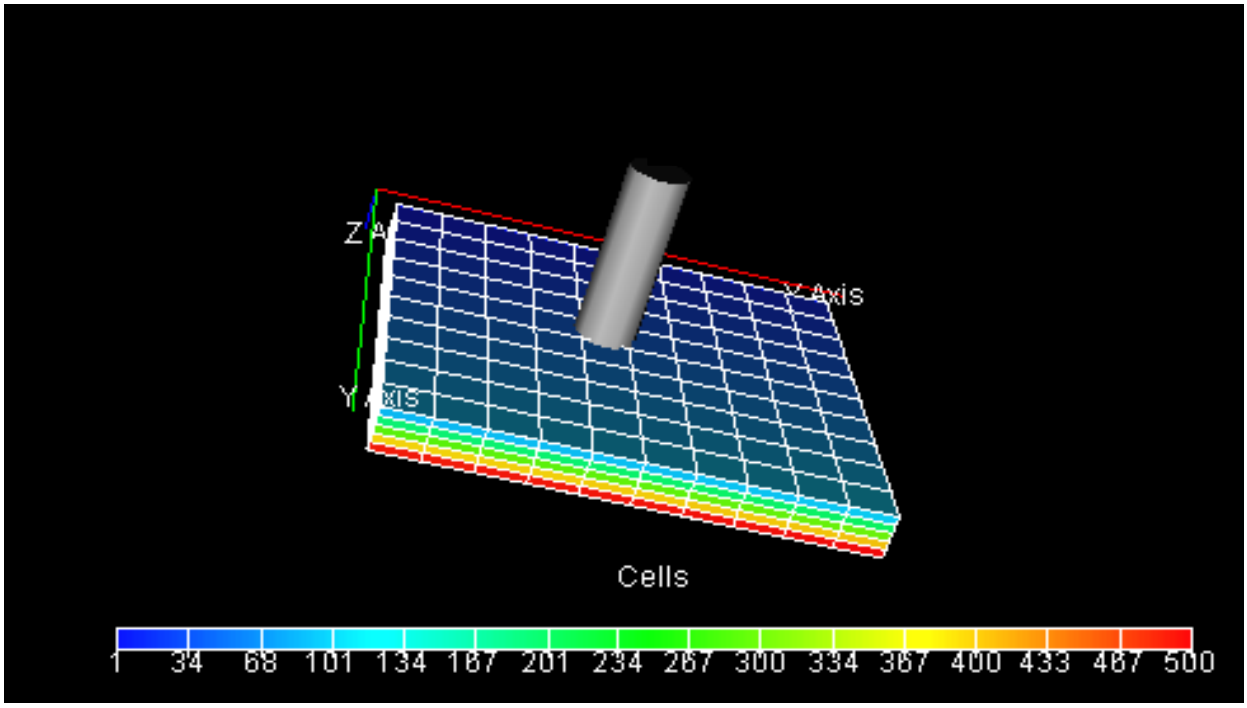
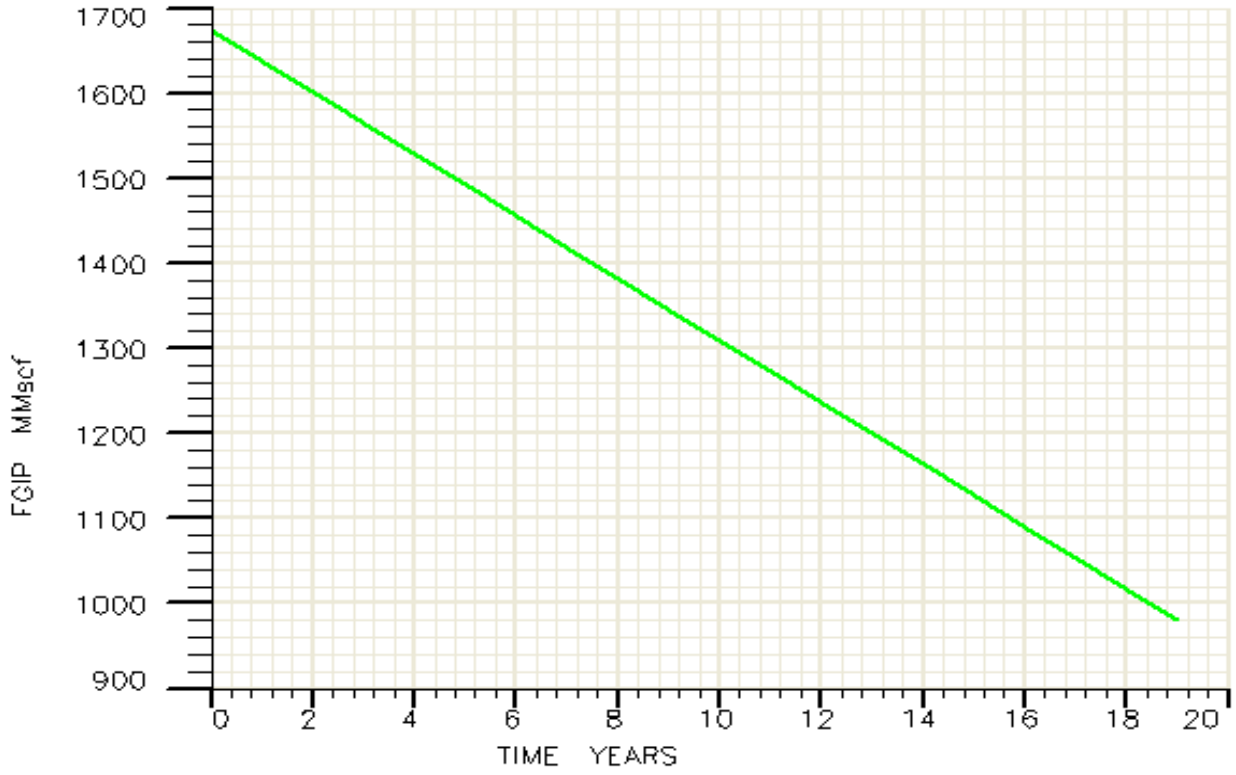
APPENDIX

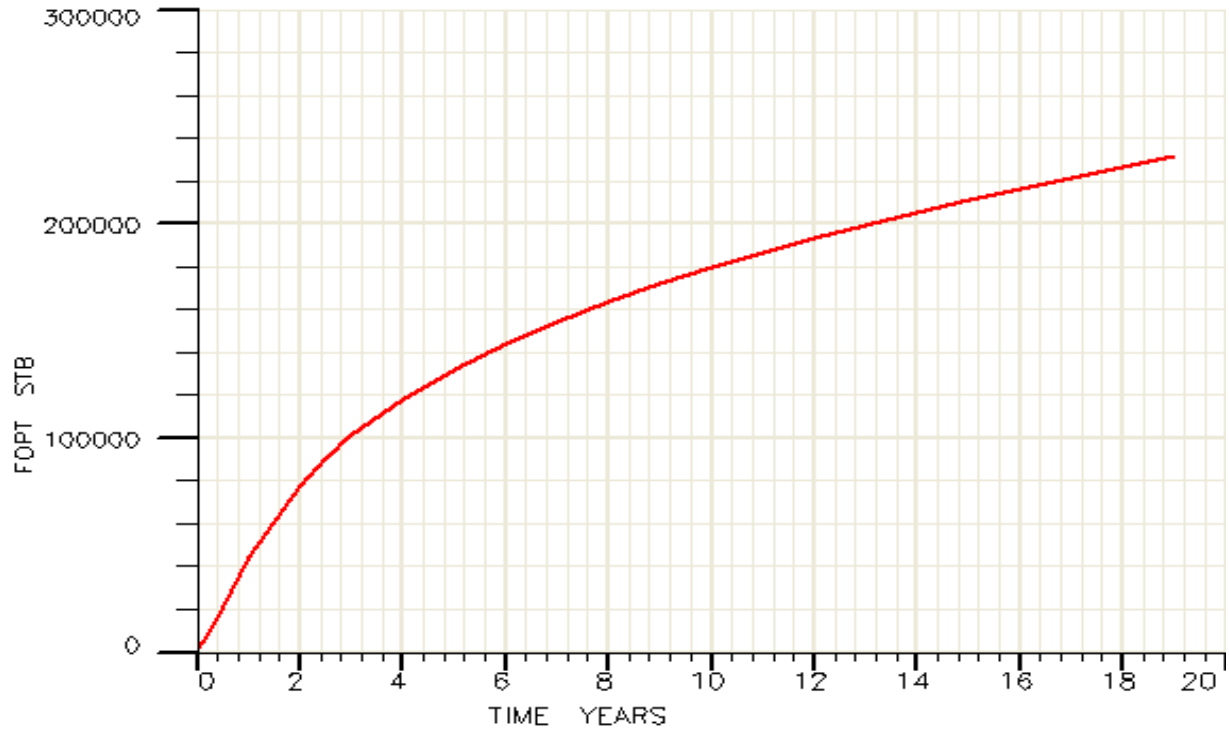


FIELD GAS IN PLACE



FIELD GAS PRODUCTION TOTAL

FIELD OIL PRODUCTION TOTAL



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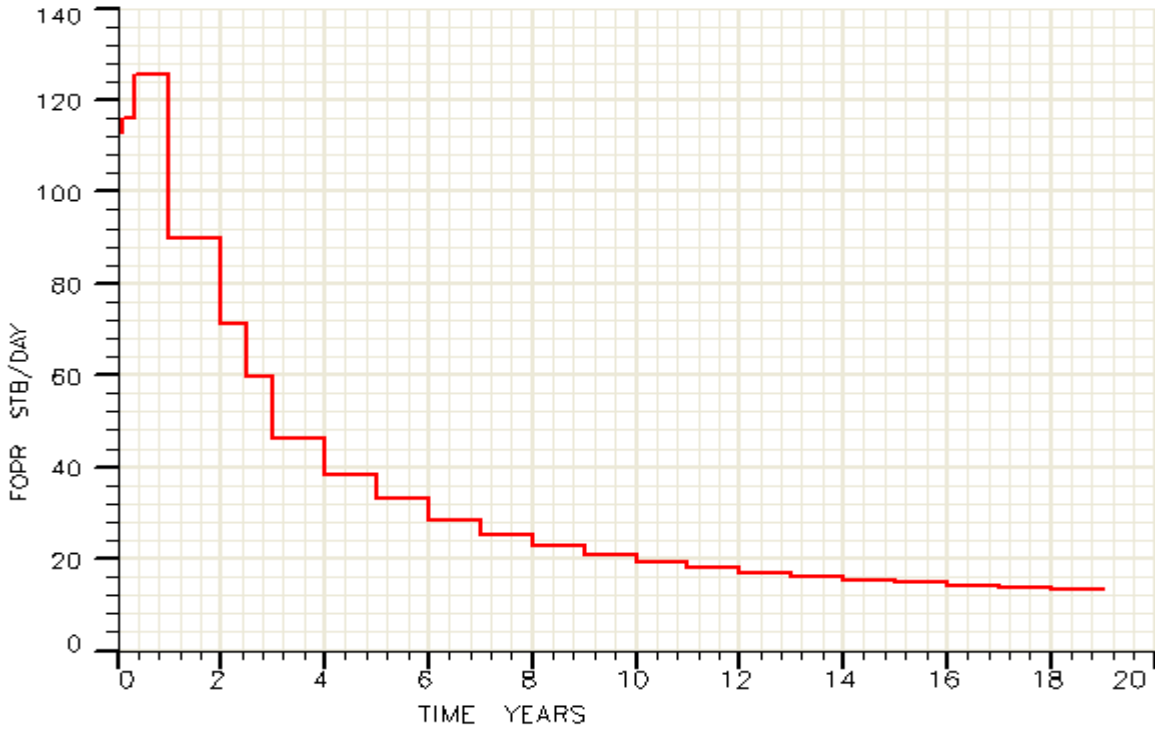

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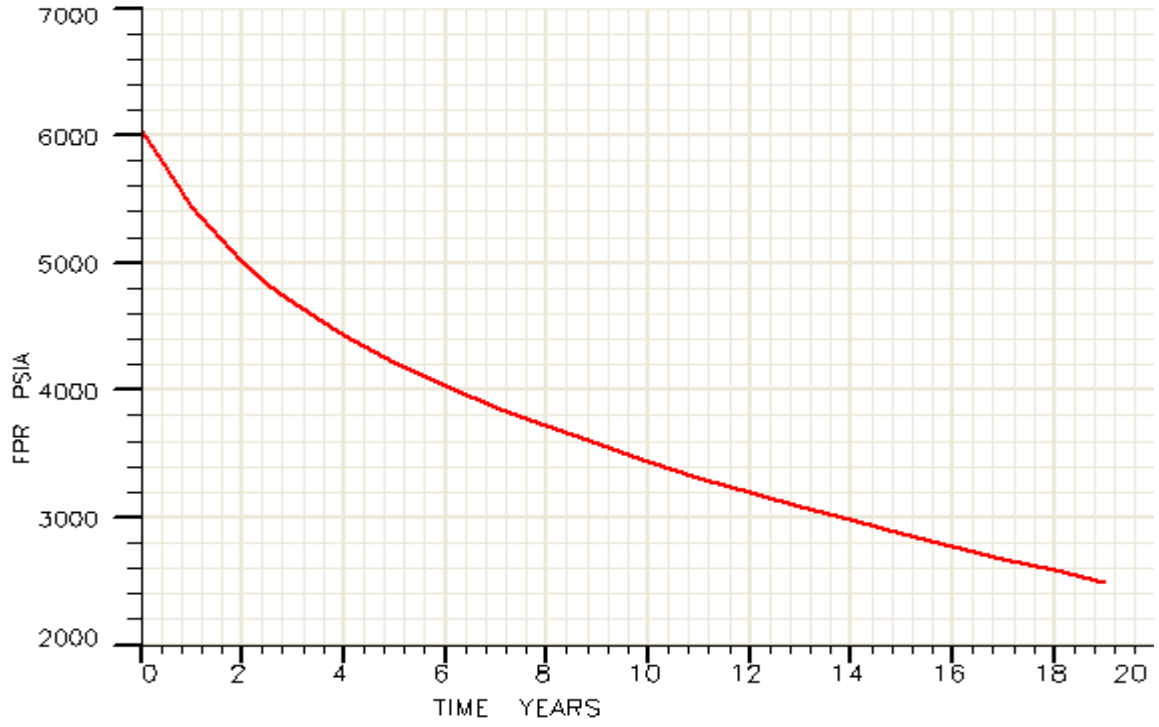

FIELD GAS OIL RATIO