APPLICATION OF WELL TEST ANALYSIS IN DETERMINING WELLBORE FORMATION PROBLEM (SKIN FACTOR)

BY

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CERTIFICATION

This is to certify that this project work is the original work of Ogidi, Triumphant Ese of the Department of Petroleum Engineering and it has been read and approved by:

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DEDICATION

This project is dedicated to God Almighty who has been my inspiration and given me the understanding and the resources I need in accomplishing this work. Also, to my beloved parents for their love and support.

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My gratitude goes to God Almighty for being with me through the period of my studies and through the period of my project work.

I would like to show my sincere appreciation to my parents, siblings and relatives for their prayers, love, financial support and advices throughout this study.

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ABSTRACT

Well testing is a technique for estimating reservoir parameters that involves introducing disruption to oil or gas well by varying the output flow rate. Well test data contributes to reserve estimation which is used to assess whether reservoirs are economically viable. In course of drilling and completion operations, the wellbore of wells can be damaged. This damage could cause a decrease in oil or gas production. The data obtained well testing is being analyzed to identify parameters like permeability, skin, initial reservoir pressure. This is important in knowing if the well is damaged. The aim here is to identify wellbore formation problems by conducting well test analysis on buildup test data. This was achieved by carrying out a pressure transient test analysis using Saphir on two buildup test data for well A3 and well J in Gwuana and Akota field respectively. From the analysis, well A3 and J are damaged with a positive skin, 10. The initial reservoir pressure for the both wells are 3591.38psia and 5384.54psia respectively. The permeability of well A3 was calculated to be 21.3md while well J has a permeability of 107md. An IPR plot of pwf vs q was generated for well A3 to determine how well skin would affect productivity. From analysis, it shows well A3 and well J are damaged and its recommended that they are stimulated either by hydraulic fracturing or acidizing.

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LIST OF ABBREVIATIONS

BHP – Bottom Hole Pressure

DST – Drill Stem Test

PTT – Pressure Transient Testing

PTA – Pressure Transient Analysis

PI – Productivity Index

PVT – Pressure Volume Temperature

IPR – Inflow Performance Relationship

ASCII – American Standard Code for Information Interchange

STB/D – Stock Tank Barrel Per Day

CHAPTER ONE

INTRODUCTION

1.1 Background of Study

Well testing is a technique for estimating reservoir parameters that involves introducing disruption to the production of oil or gas wells by varying the output flow rate (Ghaffarian et al., 2014)**.** Well test data contributes to reserve estimation which is used to assess whether reservoirs and reservoir areas are economically viable (Slotte & Berg, 2017). Well testing is also used in reservoir monitoring, by providing average and local reservoir pressure. This pressure data is critical for production optimization, but they also contribute directly to reservoir characterization as model feedback (history matching). Well testing contributes to production by providing information on the state of the near-wellbore area volume. These findings are being used to answer questions about near-wellbore formation damage, as well as the need for and effectiveness of well stimulation treatments.

The fundamental idea behind well testing is as follows: by adjusting the well's output rate or pressure, a signal is transmitted into the reservoir, and the reaction (pressure/rate change) is determined at the well (Slotte & Berg, 2017). The response analysis is used to calculate reservoir properties. Since the response is a function of a noise that travels away from the well, the early responses are determined by the property in the immediate wellbore area, while later responses sense features further away in the reservoir. In order to analyze reservoir contact, the response must also be reported in another well. This form of test is known as an interference test. Typical information gotten from well tests include permeability, boundaries and faults distances, near wellbore damage or stimulation (skin), size and sand bodies and length of induced fractures.

The pressure and output rate (equivalently, injection rate) are the most critical calculated quantities in well testing. The pressure measured at the wellbore bottom is known as the bottom-hole pressure (BHP) (Slotte & Berg, 2017). Since it is nearest to the formation, this is the preferred pressure measurement.

Drawdown, buildup, and interference tests are the three major types of well tests. We also have injection and falloff tests, which are the injector equivalents to drawdown and buildup tests. The Drill Stem Test (DST) is a specific drawdown test used often in discovery and newly drilled wells (Slotte & Berg, 2017). A drawdown test involves allowing a static, steady, and shut-in well to flow. The flow rate should be constant for conventional analysis. A drawdown test's typical goal includes determining the drainage area average permeability (k), estimating the skin (*S*), determining the reservoir pore depth, and detecting reservoir heterogeneity. A well that is still running (ideally at a steady rate) is shut down during a buildup test, and the downhole pressure is determined as the pressure rises. As for the drawdown test, the goals require achieving average permeability k and skin *S*. In addition, the buildup test is used to determine the initial reservoir pressure (*pi*) and the average reservoir pressure over the drainage field during the pseudo-steady state. A static, secure, and shut-in well is opened to (water-)injection in an injection test. An injection test is therefore conceptually equivalent to a drawdown test, with the exception that the flow is into the well rather than out of it. The injection test's targets are usually the same as those of a production test (e.g. k, S), but it can also be used to map the injected water.

1.2 Problem Statement

During drilling and completion operation, the wellbore of most wells has been damaged. This damage is commonly referred to as skin(S) and it contributes to the reduction in well production. Well testing is a routine operation carried out to know the condition of the well. Just like humans would carry out checkups on their bodies to know their health status, so it is with wells.

The Skin can be as a result of restrictions that occur in the formation pores or within the wellbore formation area and these can cause a decrease in oil or gas production. These restrictions are as a result of changes in the formation or fluid properties around the wellbore, chemical reactions within the formation or the wellbore, mechanical problems, or inadequate completion techniques.

Data gotten from well testing is being analyzed to identify parameters like permeability, skin, initial reservoir pressure etc. These parameters will help to know if the formation has been damaged or has any impairment and if there will be a need for any form of well stimulation.

1.3 Aim and Objectives

The aim of this study is to identify wellbore problems by carrying out a well test analysis on buildup test data using the application, Saphir.

The objectives are;

1) To evaluate works related to the study.
2) To study and analyze the buildup data of well A3 and well J:
    a. To determine skin
    b. To determine the capacity of the formation
    c. To determine the initial reservoir pressures
    d. To carry out sensitivity analysis on skin.
    e. To study the effect of skin on productivity index and inflow performance relationship.

1.4 Significance of the Work

This project is intended to identify wellbore formation problems using well test analysis that is so common to many wells in the field. During the life of a well, there are bound to be formation problems that is why this study is important as it aims to carry out analysis on well test data of well A3 and well J in order to give information on well parameter. The parameters obtained is essential in making a decision if the well will need any form of stimulation or not.

1.5 Scope and Limitations

Different pressure transient tests are carried out on a well during its production life such as buildup test, interference test, drawdown test, etc. But the scope of this work focuses on buildup test data analysis to determine different reservoir parameters. The major limitation is the difficulty in accessing real life build up test data. But fortunately, sample data was obtained from the application and were helpful in achieving the aim of this work.

CHAPTER TWO

LITERATURE REVIEW

2.1 Well Test

A production well test or a transient well test is generally referred to as a "well test" (Sanni, 2018). A production well test comprises diverting a producing well to a test separator and determining the steady-state rate at the wellhead and bottom hole pressures that correspond. Changes in reservoir pressure are measured in transient well tests when well rates change (Fanchi & Christiansen, 2016). These measurements are used to monitor wells and reservoirs, as well as to determine well rates. The pressure and production rate (equivalently, injection rate) are the most important calculated quantities in well testing. The pressure measured at the well's bottom is known as the bottom-hole pressure (BHP) (Slotte & Berg, 2017). Pressure transient test is another term for well testing, which is a simpler definition of the process.

PTT (Pressure Transient Testing) is a commonly used technique for obtaining information about a reservoir that is located well far from the well (Fanchi & Christiansen, 2016). The PTT method works by measuring increases in pressure at the wellbore as a function of time that occur when the fluid flow rate in the wellbore varies. Pressure transients are changes in pressure. The pressure changes as a function of time are measured by pressure gauges.

The well test is usually used to evaluate reservoir deliverability, with the following objectives:

1. Permeability or permeability thickness
2. Initial reservoir pressure
3. Average reservoir pressure at a certain instant in the life of the well
4. Reservoir size, distance to reservoir boundaries
5. Near wellbore effects (skin)
6. Wellbore storage effects
7. Fluid properties (sampling) (Johansen, 2014).

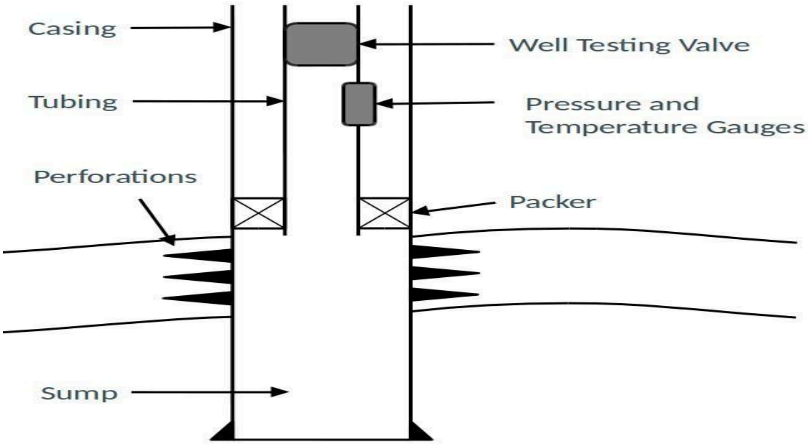

Figure 2.1: A schematic of the placement of down hole pressure gauge and flow gauge (Slotte & Berg, 2017).

2.1.1 Types of Well Test

A well test involves using a rate change to create a diffusing pressure disturbance and then measuring the pressure disturbance to define the wellbore, reservoir, and boundaries (Sanni, 2018). The method of producing a diffusing pressure disturbance by rate change can be done in a number of ways, which determines the type of well test. Slotte and Berg (2017) in their journal article titled "Lecture notes in well-testing Copyright notes" stated that the three main classes of well test are buildup, drawdown and interference tests. It was also added that there are injection tests and falloff tests, which are equivalents of drawdown and falloff tests for injectors. But according to Fanchi and Christiansen (2016), the four possible types of pressure transient tests associated with rate changes in production and injection wells are summarized in Table 2.1.

Table 2.1 Types of Pressure Transient Test (Fanchi & Christiansen, 2016)**.**

Well Type	Change in Flow Rate	Pressure Transient Test

Production well	Decrease	Pressure buildup
	Increase	Pressure drawdown
Injection well	Decrease	Pressure falloff
	Increase	Injectivity

2.1.1.1 Buildup Test

A well that is already flowing (ideally at a constant rate) is shut down during a buildup test, and the downhole pressure is measured as the pressure rises (Slotte & Berg, 2017). Pressure buildup tests are performed by producing an oil or gas well at a constant rate for a long enough period of time to establish a stable pressure distribution, stopping production by shutting in the well, and measuring the resulting pressure increase (Lyons et al., 2015). The well is usually shut in at the surface, and the pressure is measured downhole. Buildup tests in pumping wells can be performed by removing the rods and running a pressure bomb through the tubing, testing pressure in the annulus using sonic readings taken with an echo-device or using surface-indicating gauges on rare occasions. The pressure buildup curve is examined for wellbore damage or stimulation, as well as reservoir properties like formation permeability, pressure in the drainage region, reservoir limits or borders, and reservoir heterogeneities.

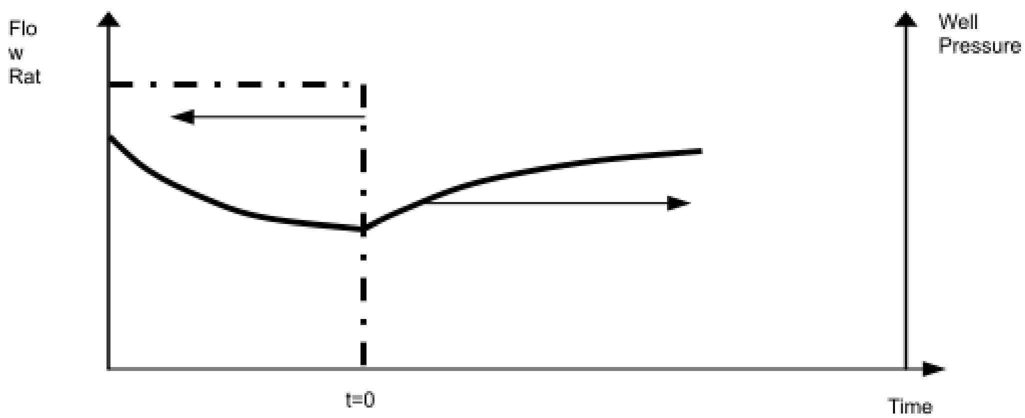

Figure 2.2: Buildup Test (Johansen, 2014).

2.1.1.2 Drawdown Test

A static, stable, and shut-in well is opened to flow in a drawdown test (Slotte & Berg, 2017). This is a term that is often used to describe pressure and rate measurements in a well that is flowing (Sanni, 2018). Pressure drawdown tests are performed by shutting down an oil or gas well for a long enough period of time to establish a stable pressure distribution, then restarting production at a constant rate and measuring the decrease in bottom hole pressure (Lyons et al., 2015). When a well is first put on production, it is ideal to do a drawdown test so calculations of reservoir volume can be made in addition to providing details on wellbore conditions and formation permeability. A drawdown test's typical goals include determining the drainage area's average permeability (k), estimating the skin (s), determining the reservoir's pore depth, and detecting reservoir heterogeneity (Slotte & Berg, 2017).

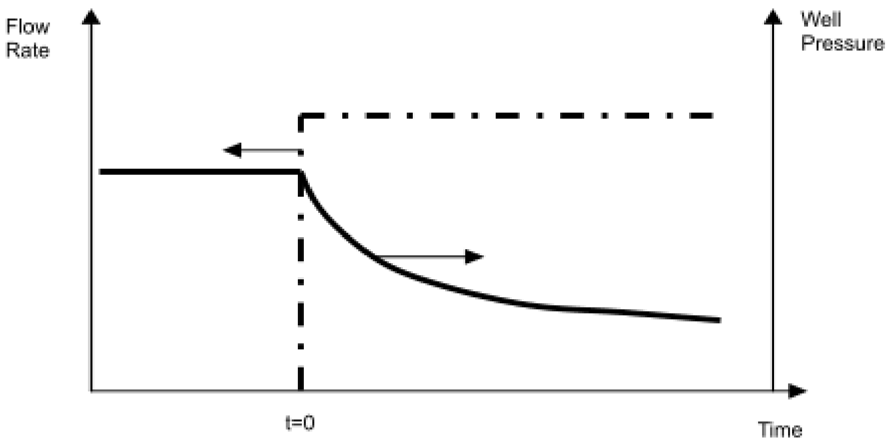

Figure 2.3: Drawdown Test (Johansen, 2014).

2.1.1.3 Injection Test

This is a measure that involves calculating the rate of fluid injection into the well through the well at a regulated rate, as well as the resulting pressure rise (Sanni, 2018). In contrast to a producer, this test has the advantage of being easier to achieve a constant rate(Johansen, 2014). A static, stable, and shut-in well is opened to (water) injection in an injection test (Slotte & Berg, 2017). An injection test is therefore conceptually equivalent to a drawdown test, with the exception that the flow is into the well rather than out of it. This type of test is critical for determining the well's and reservoir's ability to inject fluid (Sanni, 2018). The test can be evaluated using drawdown testing theory, with the exception that the flow rate is negative in this case (Johansen, 2014). To ensure that an injection well can reach the optimal injection rate, injectivity checks can be performed (Fanchi & Christiansen, 2016).

2.1.1.4 Interference Test

Multiple wells are used in this test (Johansen, 2014). This method of well test involves producing or injecting fluid from a well referred to as the active well and monitoring the pressure response from a separate well referred to as the observation well, which is at a defined distance away from the producing or injecting well (Sanni, 2018). To evaluate communication between wells and investigate compartmentalization between different reservoir sections, an interference test is performed.

2.1.1.5 Falloff Test

This explains well shut-in after fluid injection into the reservoir (Sanni, 2018). During a fall-off test, bottom hole pressure reduces. A fall-off test follows an injection test. A falloff test involves injecting fluid at a constant rate, shutting in the well, and recording the decrease in pressure (Lyons et al., 2015). The pressure falloff test is similar to the pressure buildup test (Slotte & Berg, 2017).

2.1.1.6 Drill Stem test

Drill stem testing (DST) is a method of determining the depth of a newly drilled well. The reservoir fluid runs up the drill string after a valve at the bottom of the measurement instrument opens the well to pump (Slotte & Berg, 2017). Since the flow rate varies when the fluid level increases throughout the drill string, analyzing the drill stem test requires specialized techniques.

2.1.1.7 Multi-Rate Test

In this test, the well is produced at various (usually constant) rates in a sequence of time intervals, and the flowing well pressure is measured (Johansen, 2014). Multiple-rate tests are applicable to build up or drawdown tests in producers or falloff tests in injectors, and may be performed at variable flow rates or a sequence of constant rates (Lyons et al., 2015). Data on permeability, skin, and reservoir pressure can be calculated using correct flow rate and pressure data.

2.2 Well Test Analysis

It is the process of extracting information from data collected in a producing well, such as pressure and rate.(Laura & Hofer, 2011). One of the best methods for estimating critical well and reservoir parameters is pressure transient analysis (PTA) (Cobanoglu & Shukri, 2020b). Some of those parameters include reservoir characteristics, reservoir size and shape (e.g., permeability, fracture properties, reservoir model, distance to boundary, etc.) completion reliability (e.g. skin, fracture performance...etc.) and tubing performance are only a few of them (i.e. optimum tubing design and artificial lift requirements) and well (i.e. fracture performance, skin, etc.), and reservoir characterization (i.e. dual porosity, layered reservoir, composite, etc.). As a result, understanding PTA is important for obtaining critical parameters for field development and well optimization. In production engineering well testing also contribute by providing data on the state of the near-well reservoir volume. (Slotte & Berg, 2017). The technology for pressure transient analysis has advanced over time. Real-life examples of pressure data to match a given idealized model, on the other hand, are often lacking.

There are two main types of well test analysis:

1. Pressure transient analysis
2. Decline curve analysis (Johansen, 2014).

Flow rate is known over time and the pressure is recorded in pressure transient analysis (Johansen, 2014). Flow rate is measured over a time of steady flowing well pressure in decline curve analysis. Decline curve analysis is typically used for long-term tests, while transient tests are often short-term.

2.2.1 Philosophy of Well Test Analysis

Since the well bottom hole pressure has a complex response, analysis of the dynamic pressure behavior in response to an ideally planned series of well rate changes will provide properties that characterize wells and reservoirs during monitoring, depending on the reservoir and well properties (Sanni, 2018).

2.2.2 How Well Test Analysis Is Done

1. We select a period at constant rate (usually, a buildup)
2. We plot some function of pressure vs. some function of time
3. We try to identify flow regimes (radial, linear, spherical)

4. We include these flow regimes into an interpretation model which can reproduce the pressure given the rate (or vice-versa)
5. We verify that the interpretation model is consistent with all other information (Laura & Hofer, 2011).

2.2.3 The Horner Method

The build-up test involves piloting the evolution of the pressure in the bottom hole over time The Horner approach is unique in that it examines the relationship between pressure and a variable we call Horner time" rather than the progression of the shut-in pressure over time (Clemente, 2020). This last is defined as such:

$$t_H = \frac{tp + \Delta t}{\Delta t} \quad (2.1)$$ (Clemente, 2020).

Where:

t_H= Horner time

t_p = production time, hrs.

Δt = Change in time

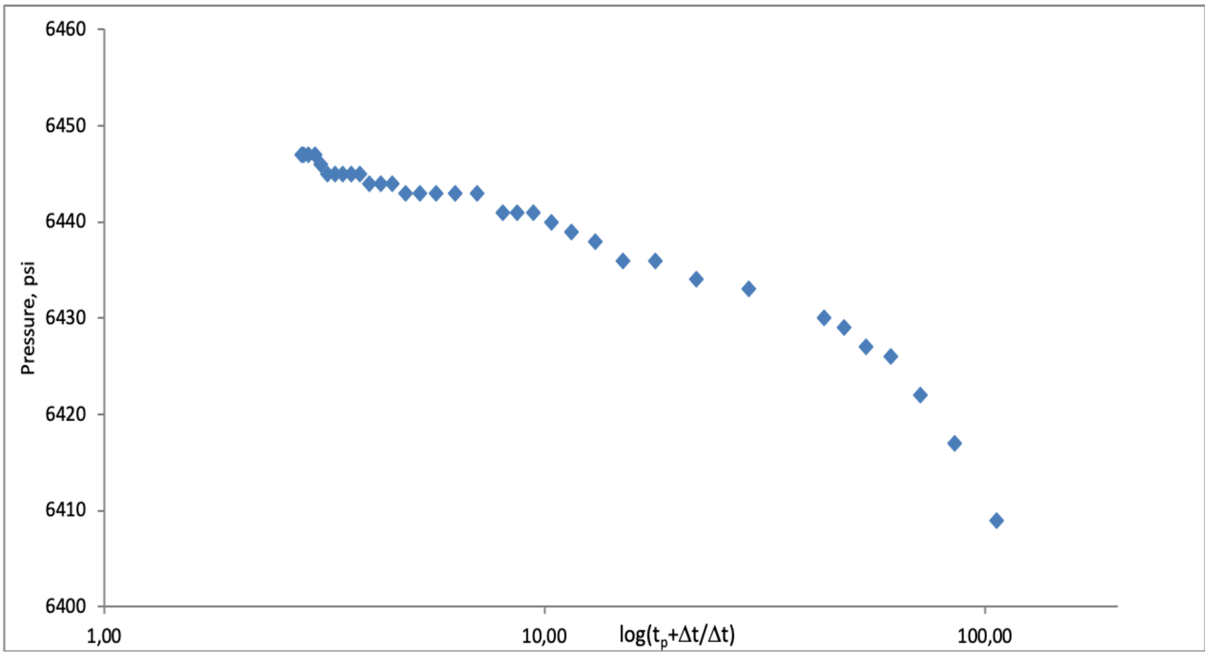

Figure 2.4: Horner Semi-Log Plot (Clemente, 2020).

As we can be seen in figure 2.4, the first step is to make a plot of the pressure in function of the Horner time.

$$pws = pi - 162.6\frac{QoBo\mu o}{koh}log\frac{tp+\Delta t}{\Delta t} \quad (2.2)$$

Where p_{ws} is the pressure of the well bottom hole shut down pressure, p_i is the initial reservoir pressure (before production), k_o is the effective permeability, Q_o is the initial oil flow rate measured at surface before shut down, μ is the oil viscosity, h is the height of the layer, and B_o is the oil formation volume factor.

From figure 2.5, k_o can be determined by means of measuring the slope as shown in figure 2.6.

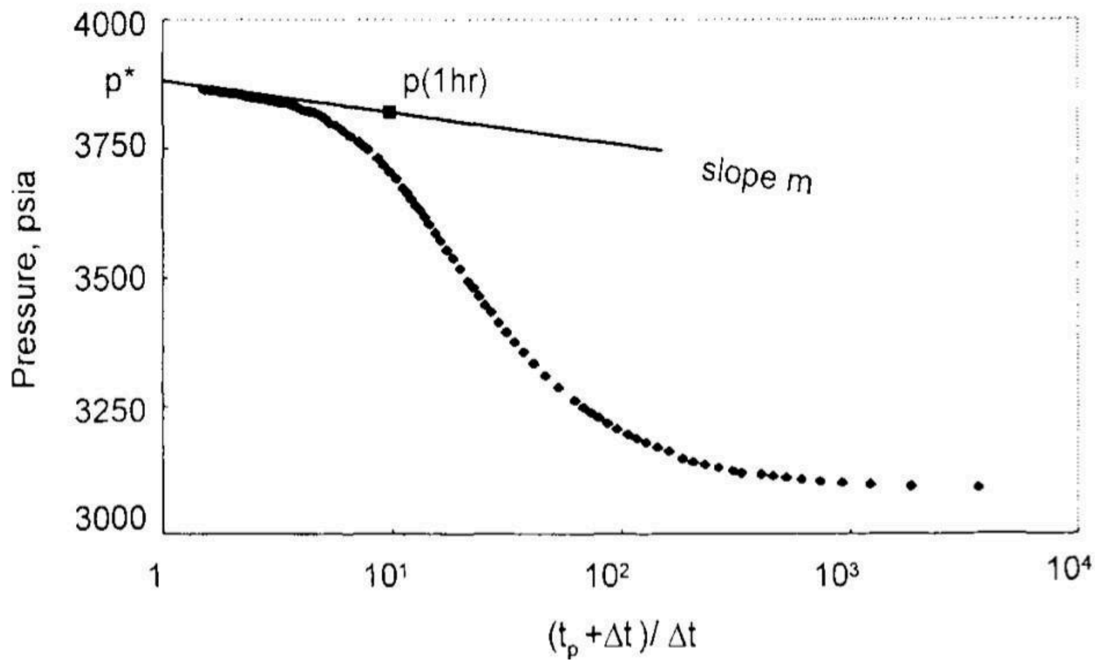

Figure 2.5: Horner Plot of Buildup (Clemente, 2020).

The slope of the straight line can be estimated in order to determine ko and the transmissibility which is a product of K_oh and is defined as such:

$$koh = 162.6\frac{QoBo\mu o}{m} \quad (2.3)$$

Also, the skin factor S can be estimated from equation 2.4

$$S = 1.151(\frac{\Delta p1hr}{m} - log\frac{ko}{\emptyset\mu octrw^2} + log\frac{tp+1}{tp} + 3.23) \quad (2.4)$$

2.3 Formation Damage

Formation damage refers to the deterioration of petroleum-bearing formations as a result of a variety of adverse processes (Alhetari, 2017). Formation damage is a broad concept that applies to a variety of processes that reduce the permeability of petroleum-bearing formations (Civan, 2015). Formation damage is one of the most serious issues in the oil industry, and it's still a very new subject of research (Alhetari, 2017). Formation damage is a costly and inconvenient issue that may arise during the different stages of oil and gas recovery from subsurface reservoirs, such as drilling, production, hydraulic fracturing, and workover. As a result of foreign-fluid invasion into the reservoir rock, it creates a region of reduced permeability near the wellbore (skin).

The four major types of formation damage mechanisms are as follows:

1. Mechanical (fines migration – external solids – phase trapping and blocking – perforation damage).

2. Chemical (clay swelling – clay deflocculating – wettability alteration).

3. Biological (plugging – corrosion – toxicity).

4. Thermal (thermal degradation – mineral transformation) (Alhetari, 2017).

2.3.1 Formation Damage Processes

According to Alhetari (2017), any type of process that reduces the flow capacity of an oil, water, or gas bearing formation is referred to as formation damage (Alhetari, 2017). He added that formation damage has long been recognized as a source of significant production losses in many oil and gas reservoirs, as well as a source of water injection issues in many operations**.** Formation damage refers to a variety of operations that result in a reduction in well efficiency or permeability. In reality, the majority of field operations can cause formation damage. This problem may arise during drilling, cementing, completion, simulation, injection, and a variety of other operations.

2.3.1.1 Formation Damage During Drilling

Formation damage is a major issue that occurs early in the well's existence. Drilling is a potential source of formation damage in and of itself. Formation damage is caused by mud solids invading reservoir rocks and drilling fluid rock interactions (Alhetari, 2017). Fines are generated as a result of bit-rock contact during drilling. The drilling fluid is expected to flush these little bits of rock out of the borehole. Fines, on the other hand, remain inside the well and get stuck at the wellbore, becoming a major cause of formation damage in overbalanced drilling operations.

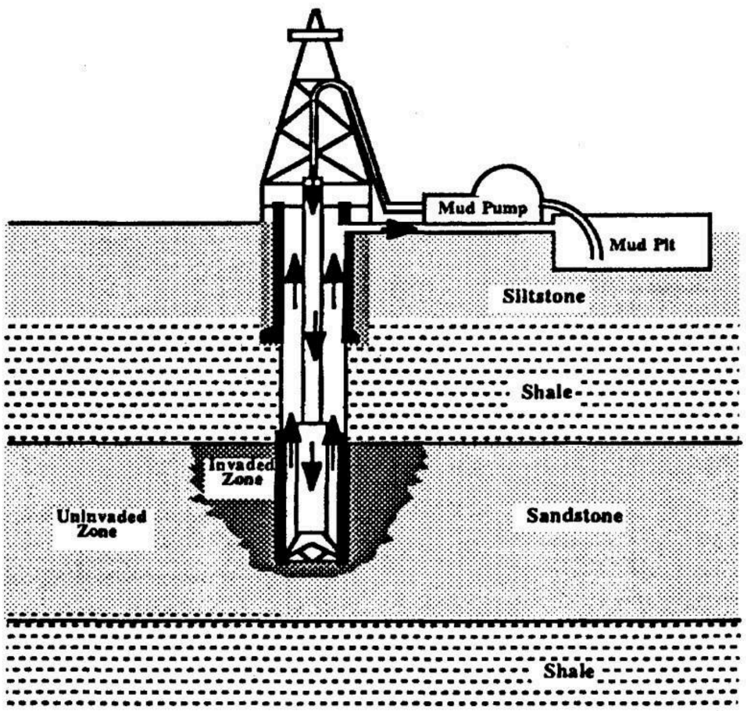

Figure 2.6: Mud filtrate invasion in the near-wellbore formation (Alhetari, 2017).

2.3.1.2 Formation Damage During Completion

Completion fluids entering the formation during well completion may cause damage to the formation (Alhetari, 2017). Although, completion fluids, like stimulation fluids, are intended to increase the efficiency and productivity of the well, they damage the formation. Completion fluids contain chemicals not compatible with the formation. These chemicals react with the rocks, causing additional damage to the formation.

2.3.1.3 Formation Damage During Production

According to Alhetari (2017), fine particles move through the pores inside the reservoir rocks during the well's production life (Alhetari, 2017). These particles are free to move, accumulate, and precipitate between the pores due to the high velocity in the porous media. He added that pathways of formation fluids are closed by thus permeability and porosity of rock matrix are reduced. Consequently, less fluids are able to reach the wellbore for production.

2.3.2 Formation Damage Indicators

Alhetari (2017) stated that the indicators of formation damage are permeability impairment, skin damage and decrease of well performance (Alhetari, 2017). He also added that when the productivity of the well starts getting lower than the expected ratio, there is a high possibility of formation damage.

2.3.2.1 Permeability Impairment

The capture and accumulation of fine particles in tortuous pathways of porous matrixes causes permeability impairment, which reduces formation permeability (Alhetari, 2017). These particles close fluid channels in a variety of ways, including bridging, plugging pore throats, and even forming cakes.

2.3.2.2 Skin Damage

Another indicator of formation damage is the skin (Alhetari, 2017). As a result of drilling, completion, or stimulation, the skin effect refers to a region of altered formation permeability near a wellbore (Lyons et al., 2015). The skin factor was applied to the petroleum industry, and researchers discovered that if the calculation of bottom hole pressure for a given flow rate is less than the theoretical value, it indicates that there is additional pressure drop that is time independent (Alhetari, 2017). This drop in skin pressure is linked to a damaged zone near the wellbore called the skin zone, as shown in Figure 2.8.

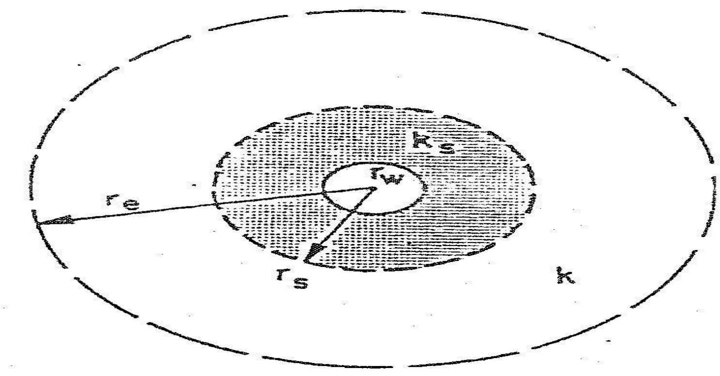

Figure 2.8: Schematic of a well with skin damage (Alhetari, 2017).

The skin factor S is a dimensionless parameter that characterizes the well condition: S > 0 for a damaged well and, by extension, S < 0 for a stimulated well (Exploration, 2002). The radius *r*d represents the damaged zone's radius. Hawkin's formula for skin is Equation 2.1. It demonstrates the skin is affected by permeability changes as well as the extent of the damaged region in relation

to the well. Analysis of well tests is usually used to determine the actual values of skin around wells (Fanchi & Christiansen, 2016).

$$s = \left(\frac{k}{kd} - 1\right) In\left(\frac{rd}{rw}\right)$$ (2.5) (Fanchi & Christiansen, 2016).

2.3.2.3 Decrease of Well Performance

Another indication of formation damage is a decrease in well performance (Alhetari, 2017). Productivity index measurements provide insight into how a well is performing. When the productivity index drops, there's a good chance that formation damage is the reason for the decrease in fluid production. The rate obtained by unit pressure drop in the reservoir is known as the productivity index.

$$PI = \frac{Qsc}{Pe - Pwf}$$ (2.6) (Alhetari, 2017).

Where:

PI = Productivity Index, STB/day/psi

Qsc = Surface flow rate at standard conditions, STB/D

Pe = External boundary radius pressure, psi

Pwf = Well sand face Pressure, psi

For steady state radial flow, productivity index for steady state radial flow is shown in equation 2.3.

$$PI = \frac{kh}{141.2B\mu\left(In\left(\frac{re}{rw}\right)+s\right)} \qquad (2.7)\ (\text{Alhetari, 2017}).$$

Where:

K = Permeability, md

h = Net thickness, ft.

B = Formation volume factor, rb/STB

μ = Fluid viscosity, cp

r_e= External boundary radius, ft.

r_w = Wellbore radius, ft.

s = Skin

2.4 Review of Existing Works

Below are few papers presented in form of review from various literatures such as journal articles, books, theses related to the project topic.

Cobanoglu and Shukri (2020) presented an article during International Petroleum Technology Conference 2020, IPTC 2020 titled "An Integrated approach to reservoir characterization of condensate banking using pressure transient analysis PTA: A Case Study Using Data from Five Gas Condensate Fields in the Sultanate of Oman" (Cobanoglu & Shukri, 2020a). In the article, they stated that condensate banking refers to the formation of condensate around the wellbore when reservoir pressure drops below dew point. They added that Condensate banking severely damages reservoir performance and results in loss of production capacity and ultimate recovery. Their study attempted to characterize the condensate banking using Pressure Transient Analysis (PTA), showing examples of pitfalls in well test analysis of rich condensate fields and provides the methods proposed to identify condensation effect in PTA analysis. A workflow was developed using PTA together with other field data (PVT/SCAL/production). After the analysis, Cobanoglu and Shukri concluded that PVT (maximum condensate drop-out), SCAL (Krg & Ng) and permeability plays a critical role for condensation effect.

Sylvester et al., (2015) published a journal article titled "Well Test and PTA for Reservoir Characterization of Key Properties" under the American Journal of Engineering and Applied Science (Sylvester et al., 2015). In this study, pressure transient analysis was adopted to determine key well and reservoir parameters for a buildup test data obtained from Agba 8 and Ukot wells in the Niger Delta region of Nigeria. The data was analyzed using well test analysis software 'Saphir' to generate the damage and flow parameters around the wellbore. The results obtained from the analysis shows that Agba well needs to be stimulated due to positive skin.

Andini et al., (2019) published a journal article titled "Reservoir Characterization Using Pressure Derivative Method in NA–20 Well Senja Field" (Andini et al., 2019). The data obtained on the NA-20 well in Senja field was analyzed using a pressure transient analysis. The results they obtained from the analysis of the data is 4.84mD permeability, skin +1.4, pressure changes due to skin ($\Delta Pskin$) 264.384 psi, and the flow efficiency 0.8442 with 851.61 ft radius of investigation. They concluded that the result from the analysis of the well shows that it has formation damage.

CHAPTER THREE

MATERIALS AND METHOD

3.1 MATERIALS

Below is a list of the data and tool (software) used in carrying out the defined objectives in achieving the desired aim of this work.

1. Well test data (Build up test data)
2. Fluid and reservoir properties
3. Kappa Ecrin Saphir
4. Excel

3.1.1 Well Test Data (Build up test data)

The data obtained is a response of pressure with time during the period of shut in resulting in pressure build up. Table 3.1 shows the varying rate in the period of shut in and flowing of the well. Table 3.2 shows buildup test data from well A3 in Gwuana field.

Table 3.1: Rate Measurements During Shut-in and Flowing Period for Well A3 in Gwuana Field

Date	ToD	FP #	Liquid Rate (STB/D)	Duration (hr)
4/12/1999	00:06:45	1	0	1.40417
4/12/1999	01:31:00	2	1600.00	0.309059
4/12/1999	01:49:33	3	1300.00	0.172651
4/12/1999	01:59:54	4	900.000	0.163797
4/12/1999	02:09:44	5	700.000	0.163797
4/12/1999	02:19:33	6	840.000	2.95353
4/12/1999	05:16:46	7	620.000	7.60050
4/12/1999	12:52:48	8	0	8.08694

Table 3.2: Buildup test data from well A3 in Gwuana Field, Well A3

Elapsed time (hr)	Pressure (psia)	Elapsed time (hr)	Pressure (psia)
0	3257.29	0.120833	3528.09

0.00416667	3351.53	0.125	3529.18
0.00833333	3390.65	0.129167	3530.22
0.0125	3414.85	0.133333	3531.21
0.0166667	3431.96	0.1375	3532.14
0.0208333	3445.00	0.141667	3533.03
0.025	3455.44	0.145833	3533.86
0.0291667	3464.12	0.15	3534.67
0.0333333	3471.44	0.154167	3535.45
0.0375	3477.71	0.158333	3536.18
0.0416667	3483.15	0.1625	3536.86
0.0458333	3487.90	0.166667	3537.53
0.05	3492.14	0.170833	3538.18
0.0541667	3495.99	0.175	3538.81
0.0708333	3508.09	0.179167	3539.40
0.075	3510.49	0.183333	3539.97
0.0791667	3512.71	0.1875	3540.52
0.0833333	3514.76	0.191667	3541.06
0.0875	3516.66	0.195833	3541.56
0.0916667	3518.42	0.2	3542.04
0.0958333	3520.09	0.204167	3542.52
0.1	3521.64	0.208333	3542.99
0.104167	3523.05	0.2125	3543.44
0.108333	3524.44	0.216667	3543.86
0.1125	3525.74	0.220833	3544.26
0.116667	3526.97	0.225	3544.66
0.120833	3528.09	0.229167	3545.05
0.125	3529.18	0.233333	3545.43
0.129167	3530.22	0.2375	3545.81
0.133333	3531.21	0.241667	3546.15
0.1375	3532.14	0.245833	3546.49

0.141667	3533.03	0.25	3546.82
0.0708333	3508.09	0.204167	3542.52

The rate and pressure data obtained from Well J in Akota field used in carrying out analysis is shown in table 3.3 and 3.4

Table 3.3: Rate Measurements During Shut-in and Flowing Period for Well J in Akota Field

Date	ToD	FP #	Gas rate Mscf/D	Duration hr
07/30/2001	00:00:00	1	4743.58	0.5209
07/30/2001	00:31:15	2	0	0.4972
07/30/2001	01:01:05	3	5878.61	0.5042
07/30/2001	01:31:20	4	0	0.4986
07/30/2001	02:01:15	5	7239.46	0.5014
07/30/2001	02:31:20	6	0	0.4972
07/30/2001	03:01:10	7	9464.78	0.497392
07/30/2001	03:31:01	8	6073.9	1.00871
07/30/2001	04:31:32	9	0	21.9999

Table 3.4: Buildup test data from well J in Akota Field

Elapsed time (hr)	Pressure (psia)	Elapsed time (hr)	Pressure (psia)
0	5384.01	0.541667	5377.99
0.00138889	5383.61	0.555556	5380.50
0.00277778	5383.04	1.14722	5340.51
0.00416667	5382.67	1.16111	5340.45
0.00555556	5382.37	1.17500	5340.41

0.00694444	5382.12	1.18889	5340.38
0.00833333	5381.94	1.20278	5340.37
0.00972222	5381.79	1.21667	5340.37
0.0111111	5381.67	1.23056	5340.35
0.0125	5374.59	0.541667	5377.99
0.0194444	5360.25	1.41111	5340.27
0.158333	5351.66	1.42500	5340.27
0.172222	5351.66	1.43889	5340.28
0.186111	5351.64	1.45278	5340.28
0.2	5351.62	1.46667	5340.27
0.213889	5351.61	1.48056	5340.28
0.227778	5351.59	1.49444	5340.27
0.241667	5351.57	1.50833	5340.27
0.255556	5351.57	1.51667	5340.26
0.477778	5351.28	1.51806	5340.27
0.491667	5351.27	1.51944	5340.26
0.505556	5351.26	1.52083	5340.26
0.516667	5351.23	1.52222	5340.34
0.518056	5351.23	1.52361	5345.74
0.519444	5351.22	1.52500	5350.70
0.520833	5351.21	1.53611	5371.15

3.1.2 Fluid and Reservoir Properties

Table 3.5: Well and Reservoir data of Well A3

TEST TYPE	Standard
Porosity, %	25
Reservoir thickness, ft.	45
Wellbore radius, rw, ft.	0.253

Oil viscosity, cp	0.31
Formation volume factor, rb/stb	1.3
Fluid type	Oil
Formation compressibility, psi-1	3E-6
Total Compressibility, Ct, psi-1	3E-6

Table 3.6: Well and Reservoir data of Well J

Porosity, %	20
Reservoir thickness, ft.	50
Wellbore radius, rw, ft.	0.291
Gas gravity	0.65
Fluid type	Gas
Total compressibility, psi-1	1.35741E-4
Bottom hole temperature ^{0}F	200
Formation compressibility, ps-1	3E-6

3.1.3 Saphir

Saphir is a pressure transient analysis software. Its simple user interface and workflow allows for fast training and self-learning for occasional users.

3.1.4 Excel

Excel is being utilized in this work to determine the productivity index of well A3 by varying the skin. It was also used in making a plot of bottom hole flowing pressure, pwf vs flowrate, q. The result should produce a straight line IPR (Inflow Performance Relationship).

3.2 DESCRIPTION OF SEQUENTIAL ORDER OF THE METHOD

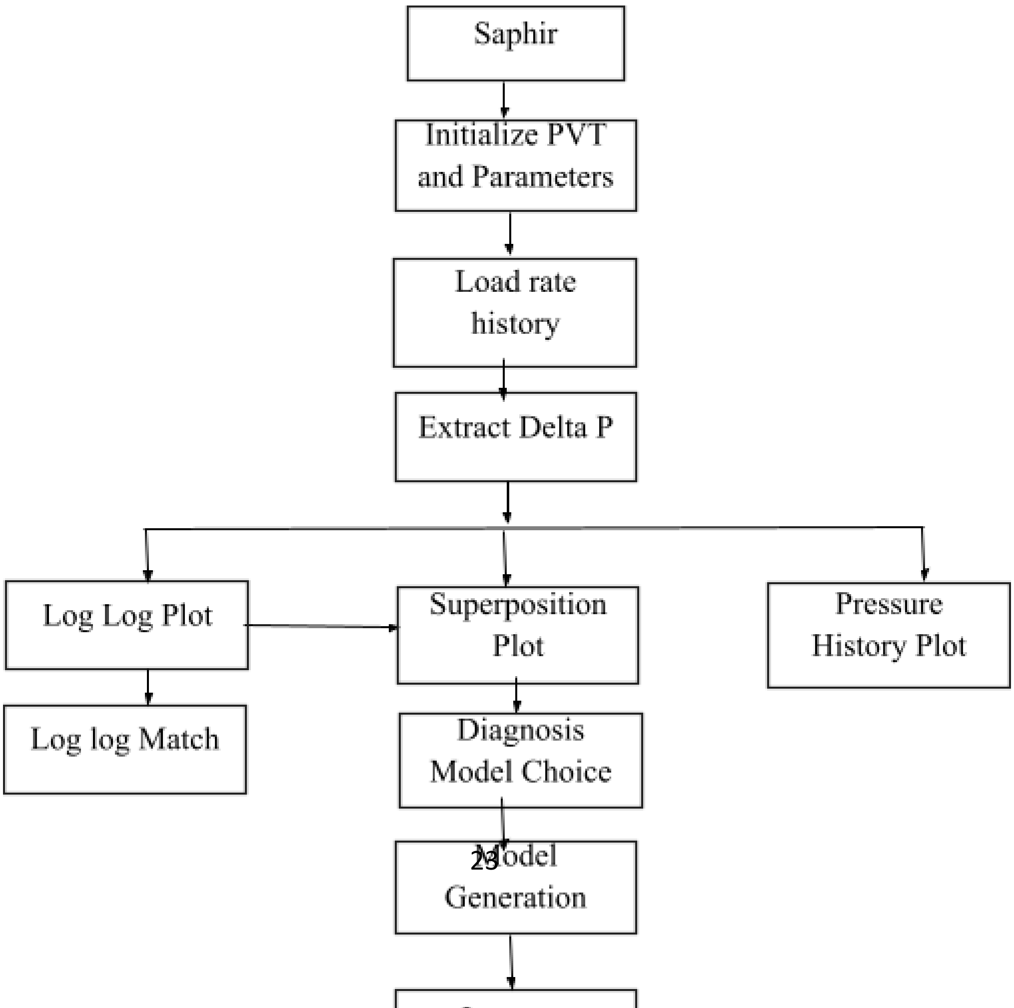

Figure 3.1: Pressure Transient Analysis Workflow (Kappa Ecrin)

3.2.1 Steps in Performing Pressure Transient Analysis with Kappa Ecrin Saphir

Below are the step by step procedures using in carrying the proposed topic in achieving the aim of the work.

Step 1: The software was launched and a new project was created. A dialog box displayed as shown in figure 3.2, in which the information about the field was entered. There was a section for comments in cases where the user wants to say something about the project. These comments are recorded for future purposes where operator wants to know something about the test being conducted. The test type, reference fluid type, the available fluid rates, net drained thickness, well radius and average porosity were also entered. A reference time of the date was set which is the same as the date when the gauge start reading from the reservoir. Every other parameter was kept in default. Then next.

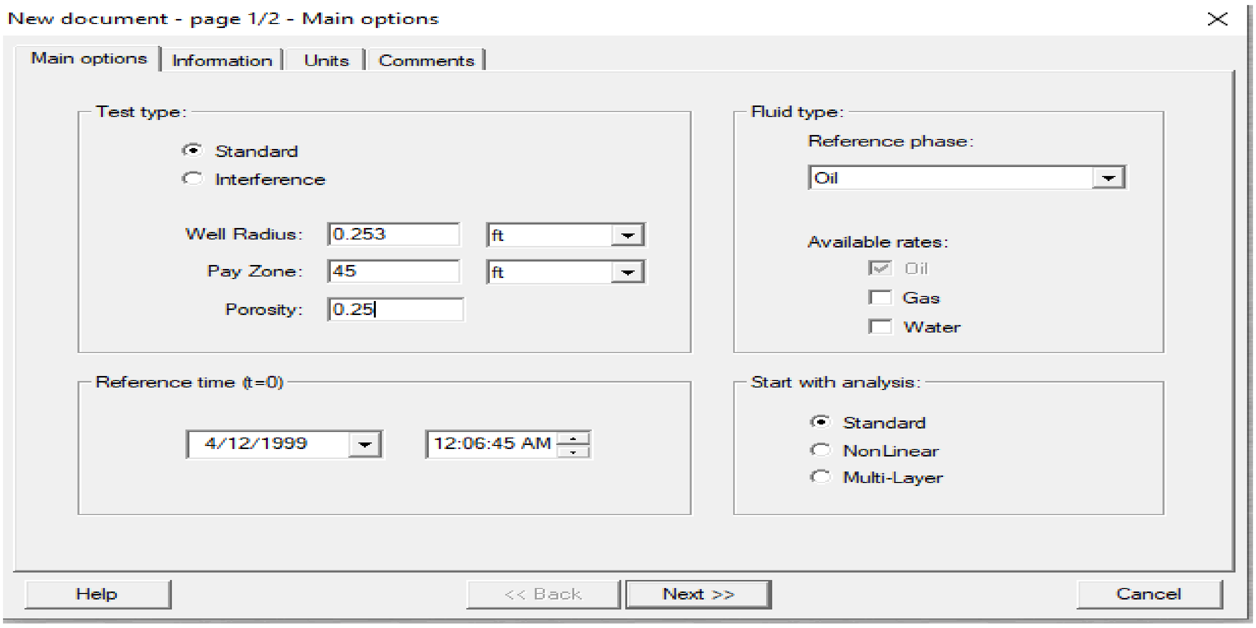

Figure 3.2: System Option Setup

After clicking the Next button, a PVT property input box popped up in which the formation volume factor, viscosity, total compressibility was inputted as shown in figure 3.3.

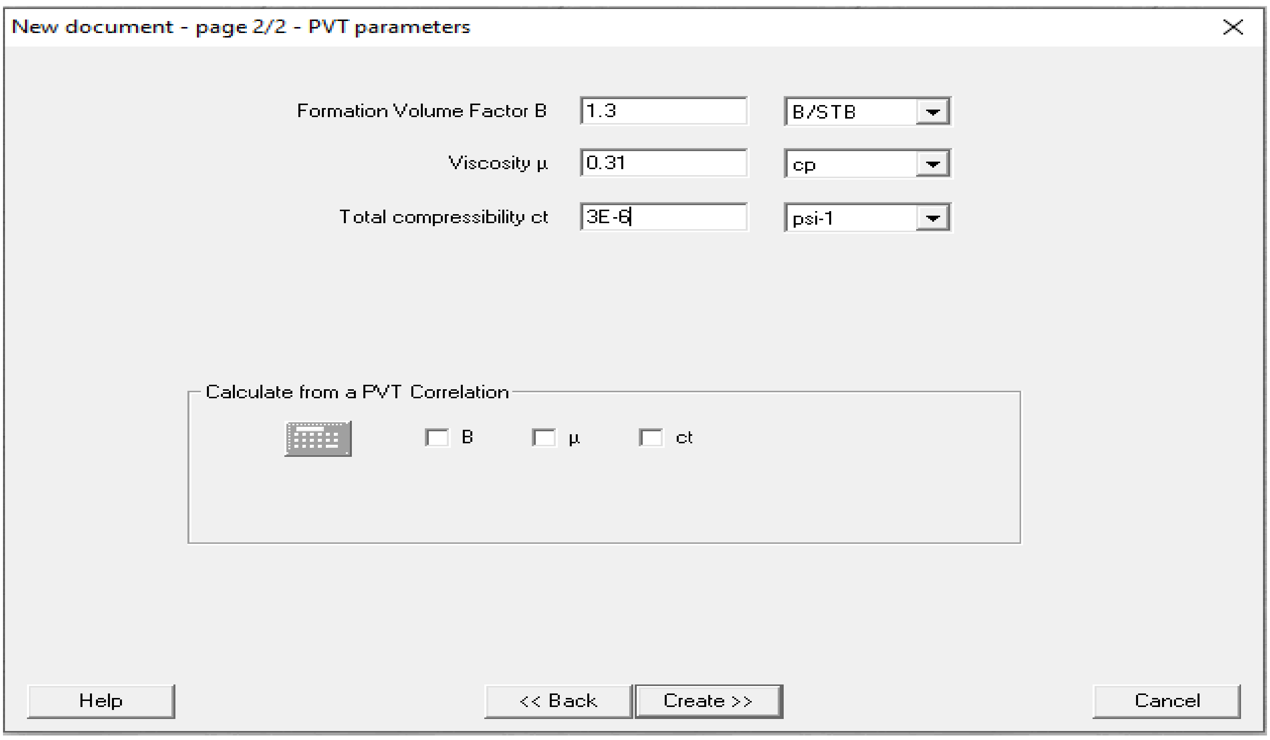

Figure 3.3: PVT input dialog box

After entering the PVT properties, the create button was clicked which shows the Saphir main screen as shown in figure 3.4.

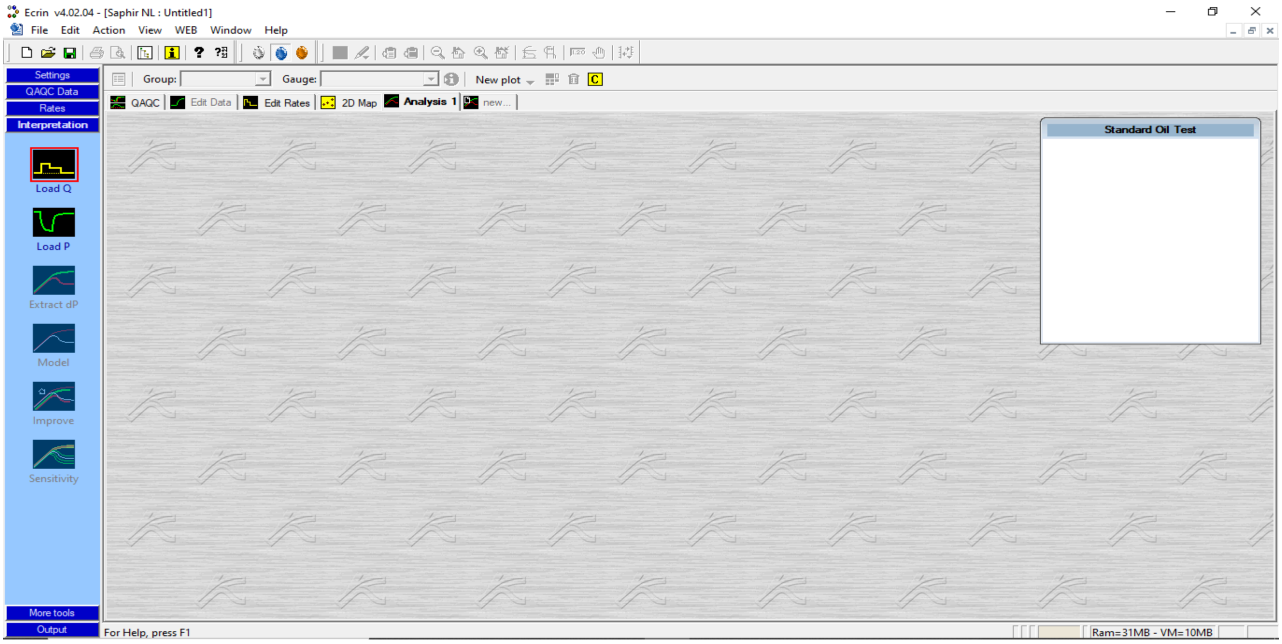

Figure 3.4: Saphir main screen display

Step 2: Loading Data

Rate data was loaded into the software by clicking on the Load Q section of the Saphir main screen display. A dialog box popped up to select the file format for example, ASCII or excel as shown in figure 3.5. After the data source was defined, the file containing the rate data was browsed for and selected. Data could be added manually by clicking on the keyboard – spreadsheet checkbox.

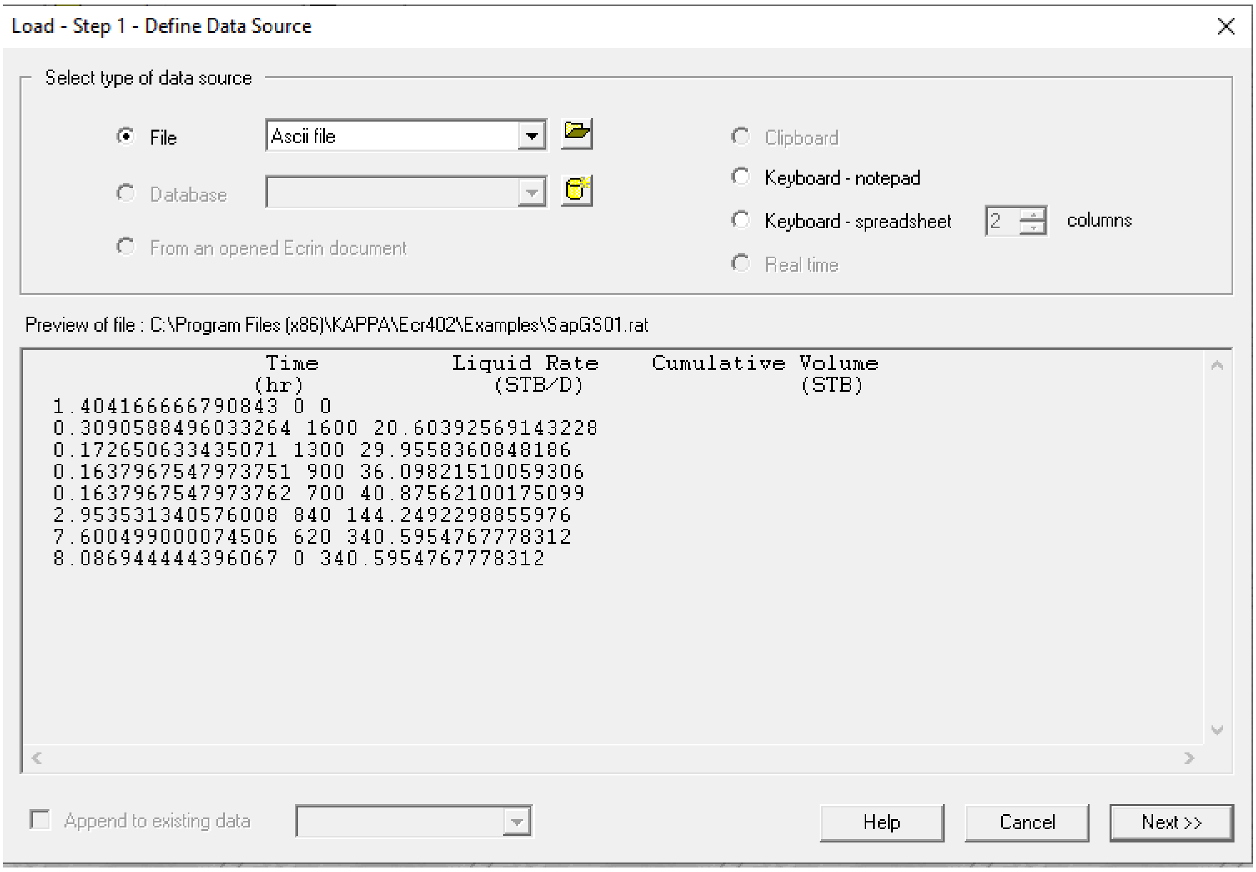

Figure 3.5: Load – Step 1 – Define Data Source

The Next button was clicked which displayed another dialog box as shown in figure 3.6. The load button was clicked resulting in the generation of a history plot.

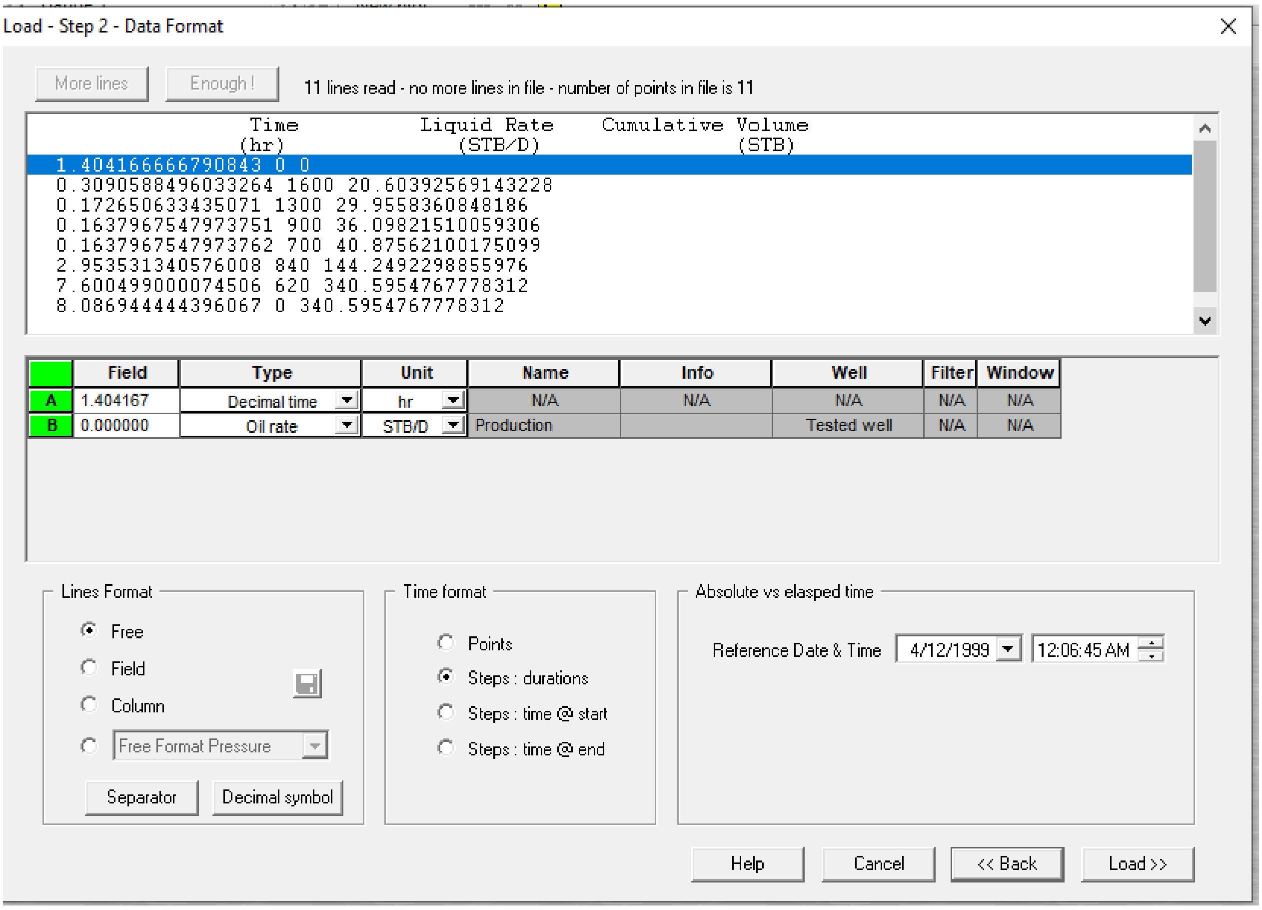

Figure 3.6: Load – Step 2 – Data Format

After generating the history plot for the rate data, the pressure data of the well was entered by clicking the Load P section on the left side of the Saphir software. A dialog box similar to the previous one that popped up when loading the rate appears in which the type of data source was selected, the pressure data loaded and then the Next button was clicked as shown in figure 3.7.

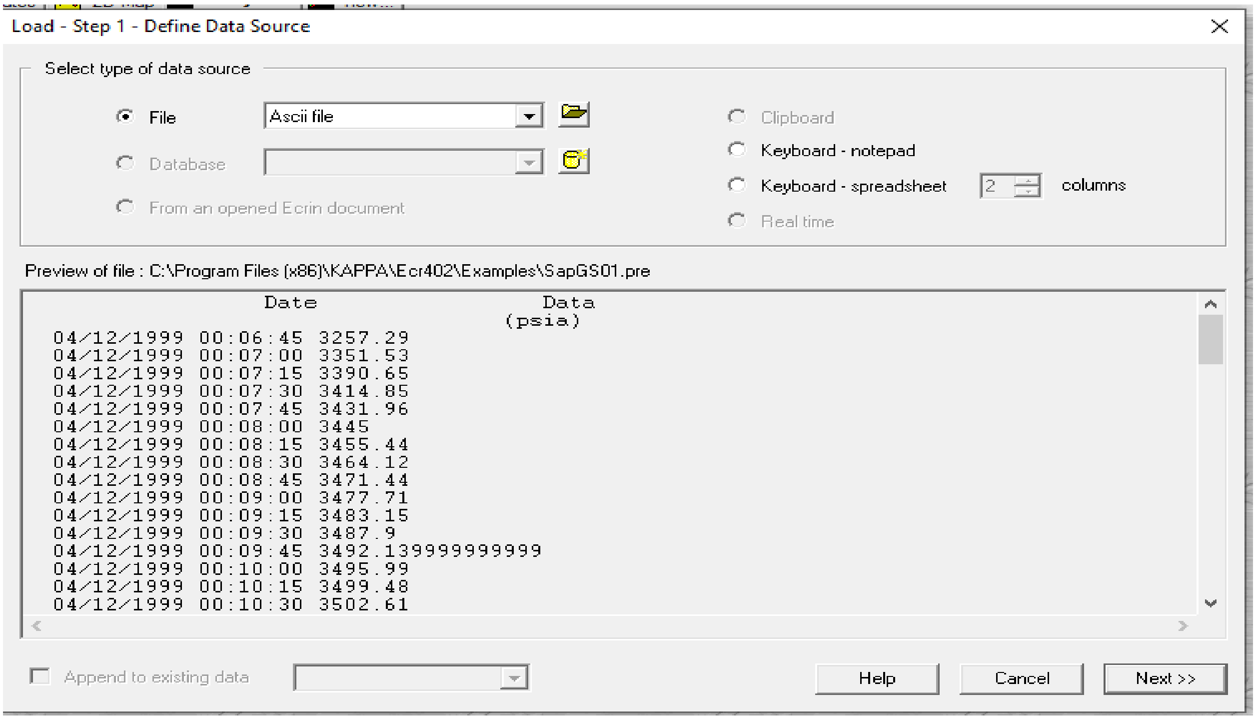

Figure 3.7: Pressure Loading Step 1 – Define Data Source

As shown in figure 3.8, the lines format was set to field and the format for date, time and pressure was set to the corresponding columns. After that, the load button was clicked. A history plot displaying Pressure (Psia), Liquid Rate (STB/D) vs Time (hr) was generated.

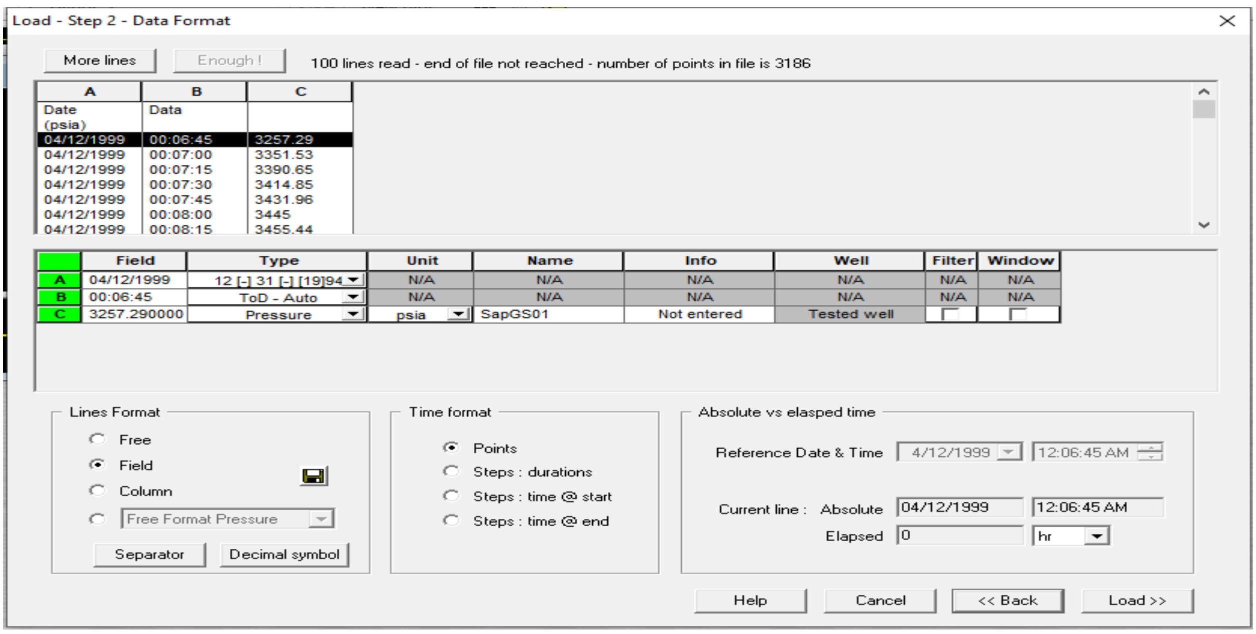

Figure 3.8: Pressure Loading Step 2 – Data Format

Step 3: Extracting Delta P

Extracting delta P is the next step in achieving the pressure transient analysis on the Saphir software. The extract delta P icon on the left side of the screen was clicked and a dialog box popped up as shown in figure 3.9. This dialog box is to choose the period to be extracted. In this case it's the 'build – up #1'. After selecting the period to be extracted, the OK button was clicked and another dialog box popped up as shown in figure 3.10. Leaving the parameters set to default by the software, OK button was clicked.

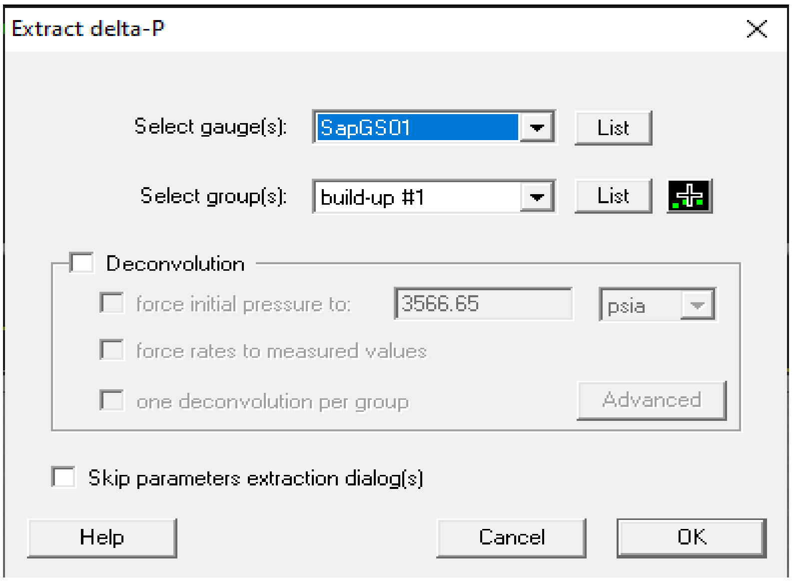

Figure 3.9: Extract dialog 1

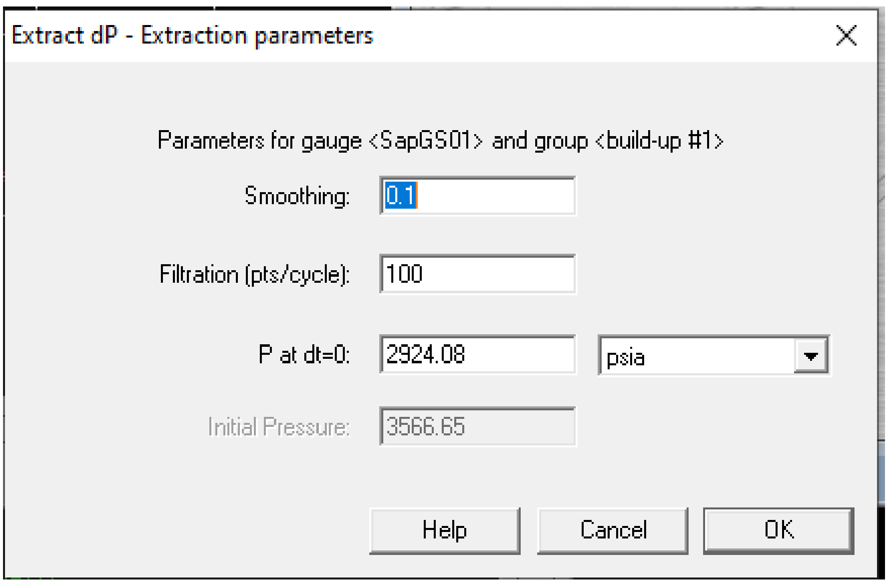

Figure 3.10: Extract dialog 2

After OK was clicked, the software generated the log-log plot and semi-log plot.

Step 4: Modelling

In this section, the model was manipulated to obtain a trend that matches that of the reservoir. This is the diagnostic phase which involves the search for all flow regimes that may be present in the response of the extracted period. This allows the interpreter to choose the most appropriate model that includes all the flow regimes identified. Then the next step was to run the model and obtain the match which again will yield the results.

The model icon on the left side of the Saphir software was clicked and a dialog box popped up displaying wellbore model, well model, boundary model, reservoir model as shown in figure 3.11. OK was clicked which generated a model which did not match. Then next step is to improve on the model to match.

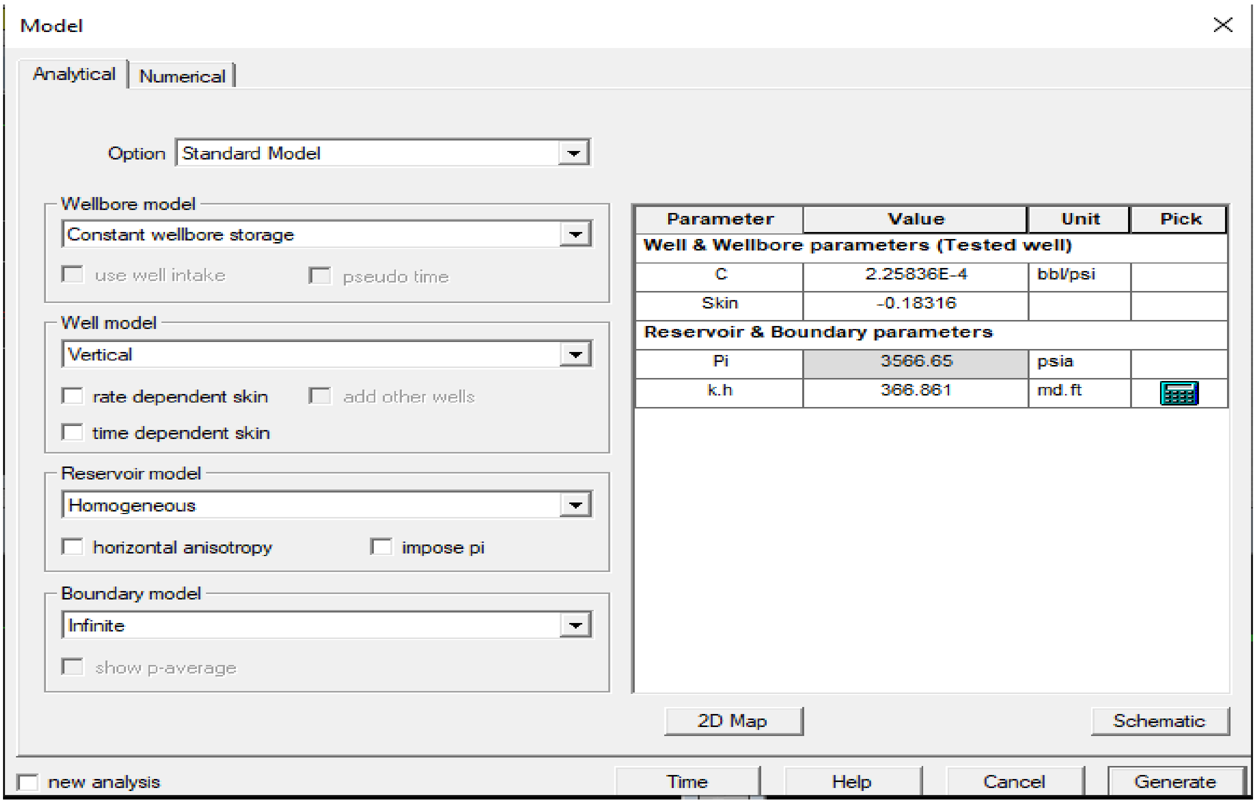

Figure 3.11: Model dialog

Step 5: Improving

The improve icon was selected and dialog box as showed in figure 3.12 popped up. Wide search checkbox was selected and then the Run button was clicked resulting in a model that matched with the data on all the four different plots on the Saphir screen.

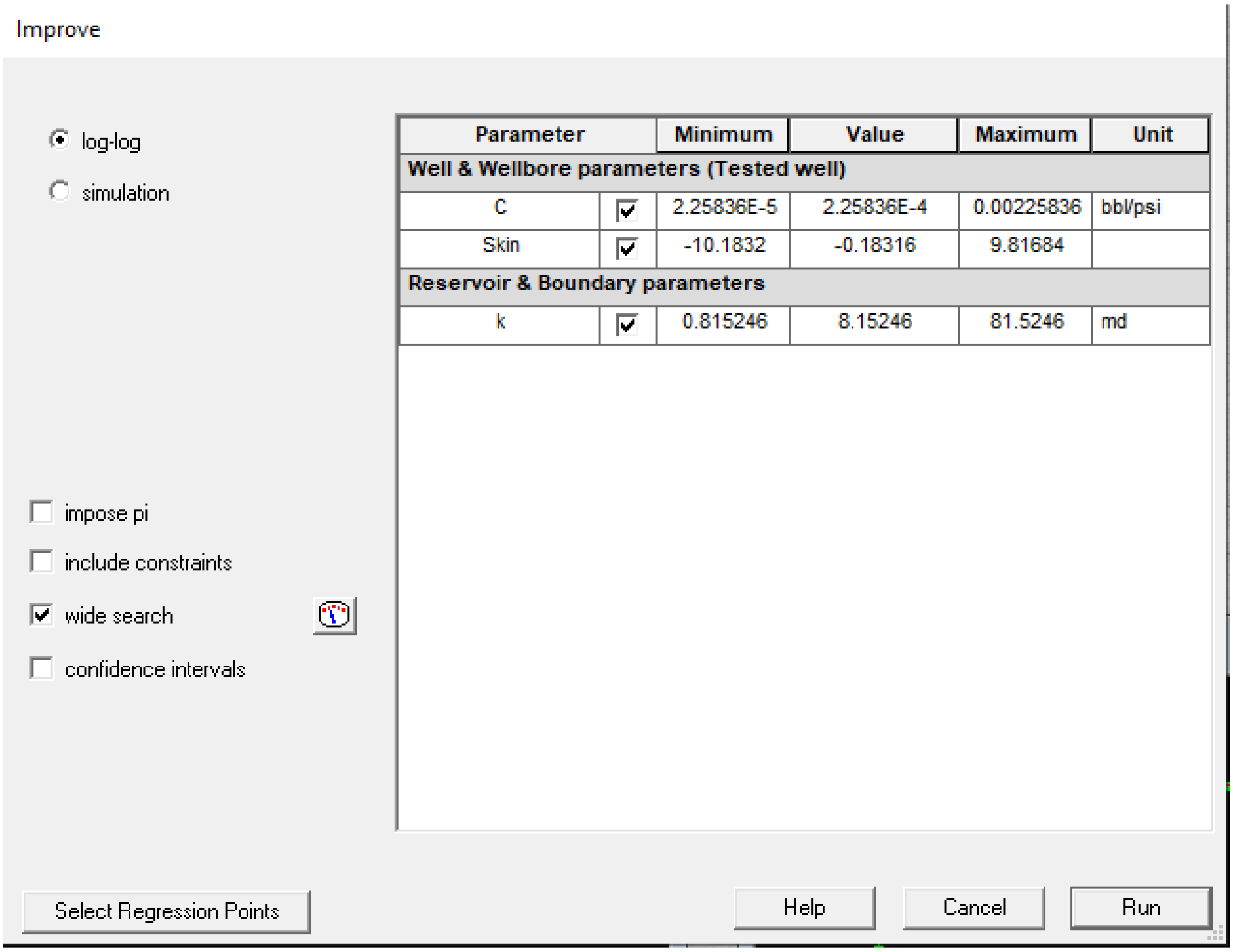

Figure 3.12: Improve Dialog

Step 6: Sensitivity

Sensitivity is the final step in the workflow. The sensitivity icon was clicked and a dialog displayed presented in figure 3.13 where the skin was the parameter specified to carry out sensitivity on. The values entered were 2, 4, 6, 8, 12, 14, 18, 20 and then clicked Generate.

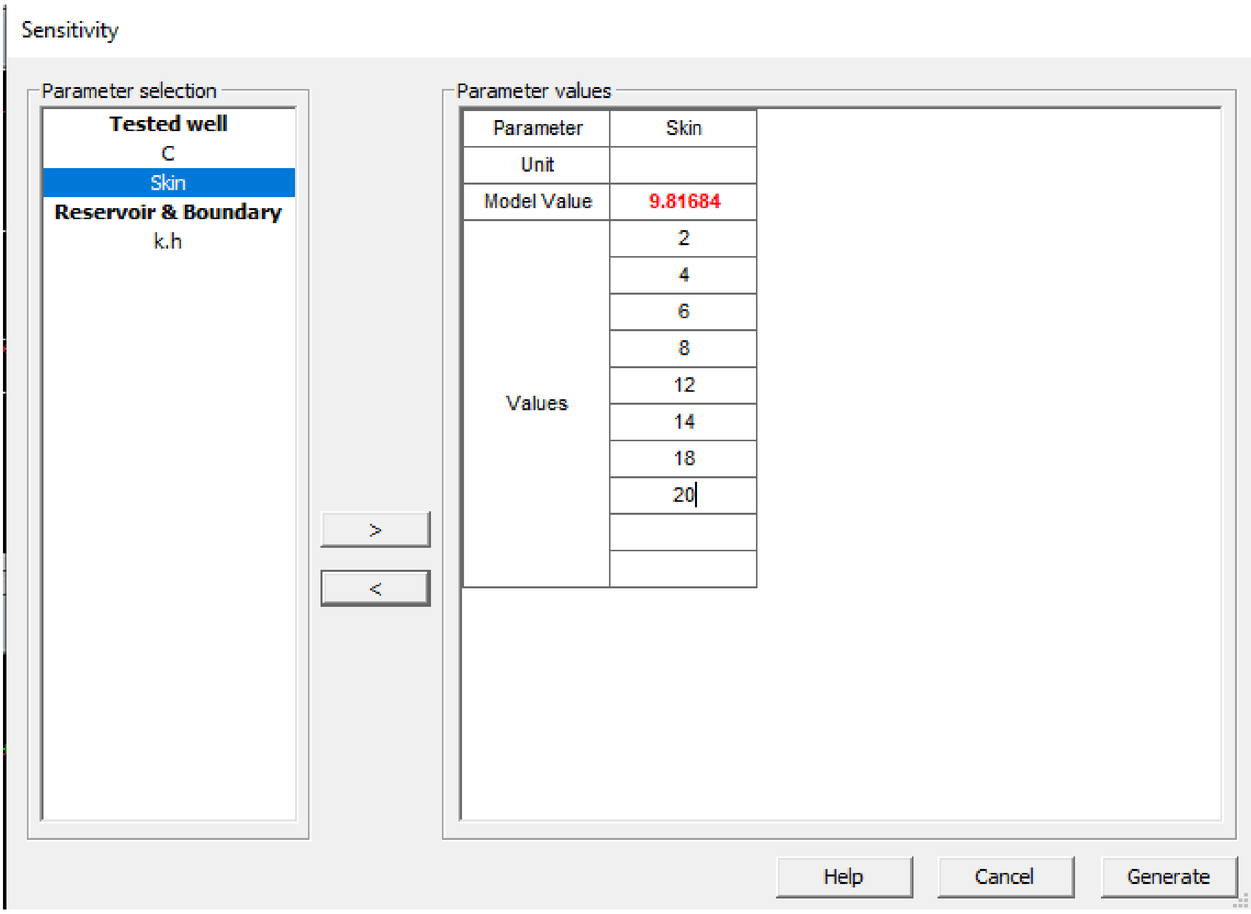

Figure 3.13: Sensitivity Dialog

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 Results

Below are the results obtained from the pressure transient analysis using Saphir on well A3 and well J.

4.1.1 Results from Gwuana Field, Well A3

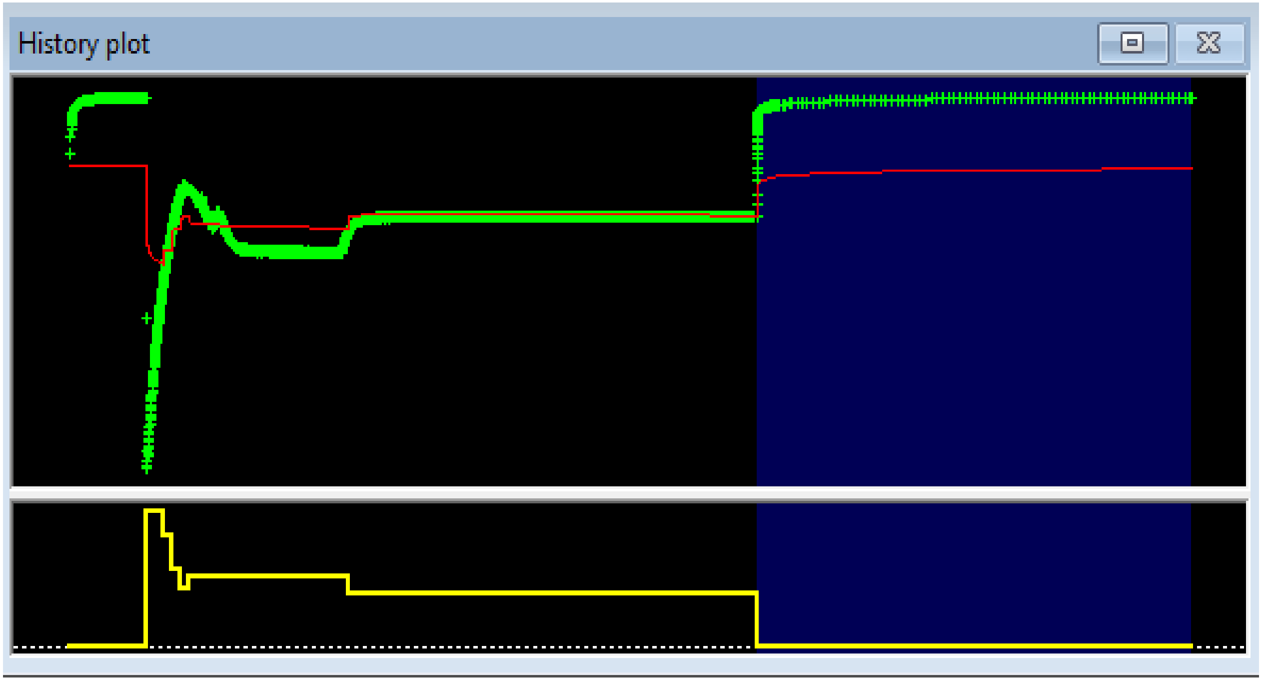

Figure 4.1: History Plot Model Mismatch

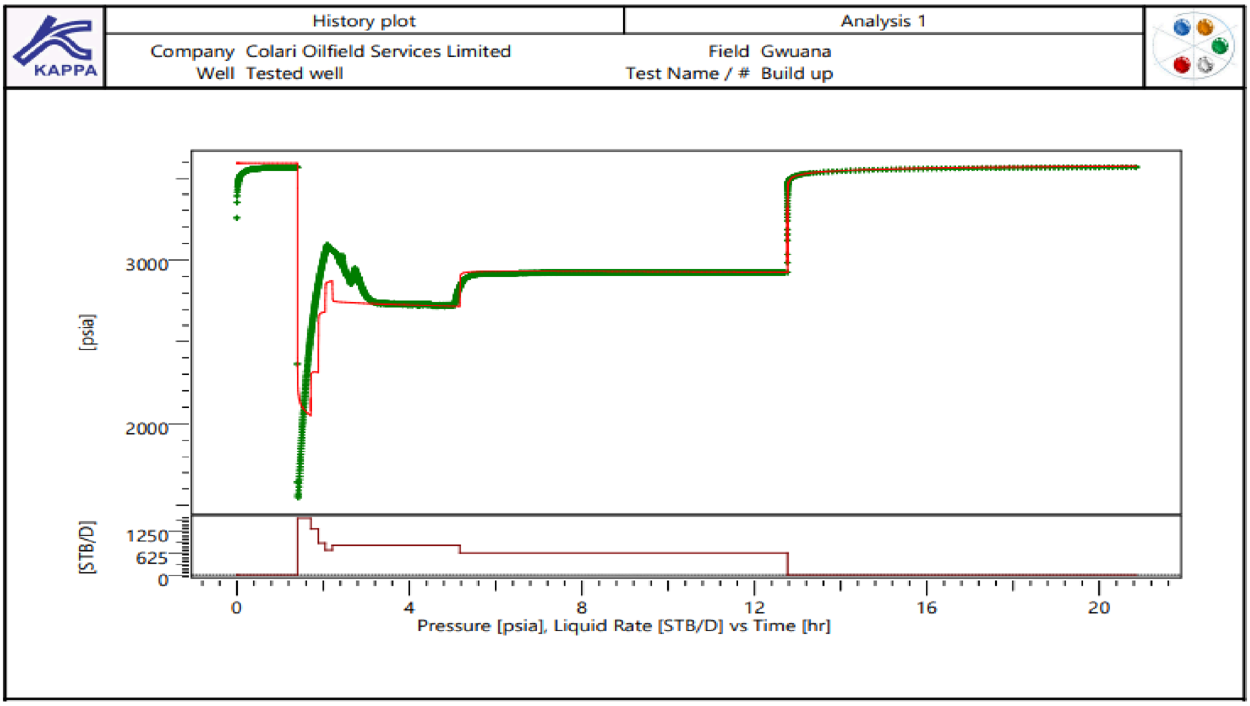

Figure 4.2: History Plot Model Match

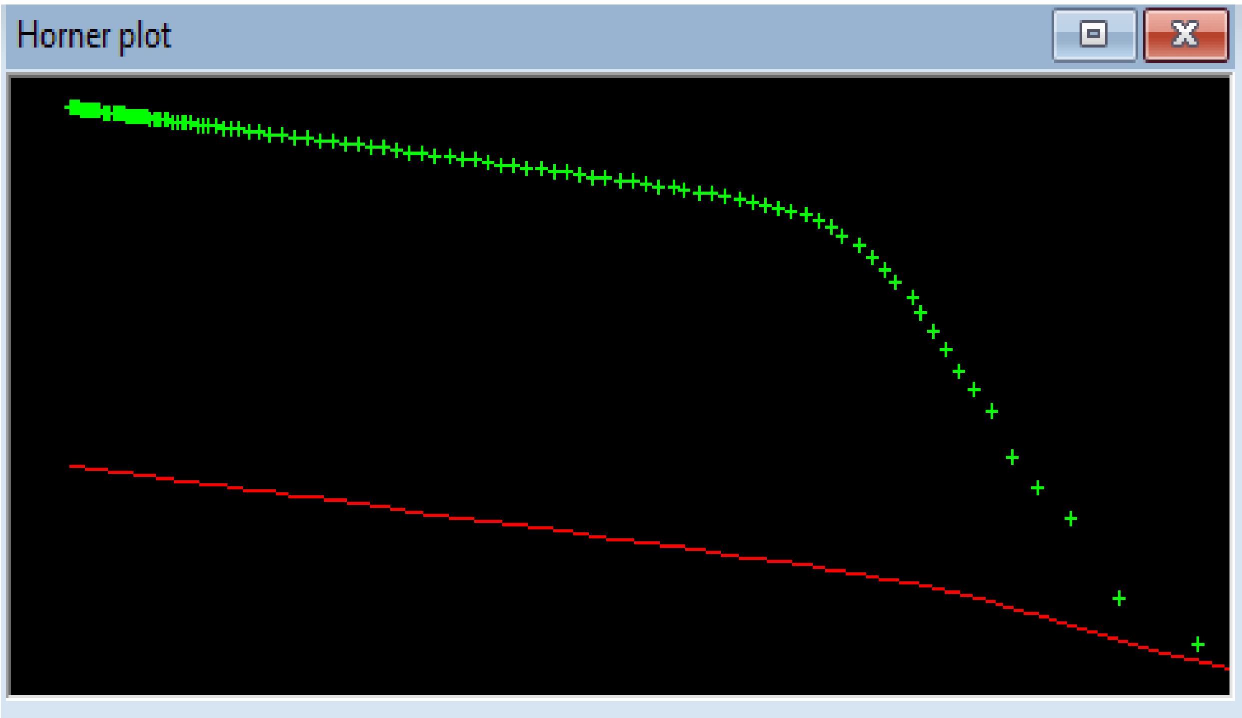

Figure 4.3: Horner Plot Model Mismatch

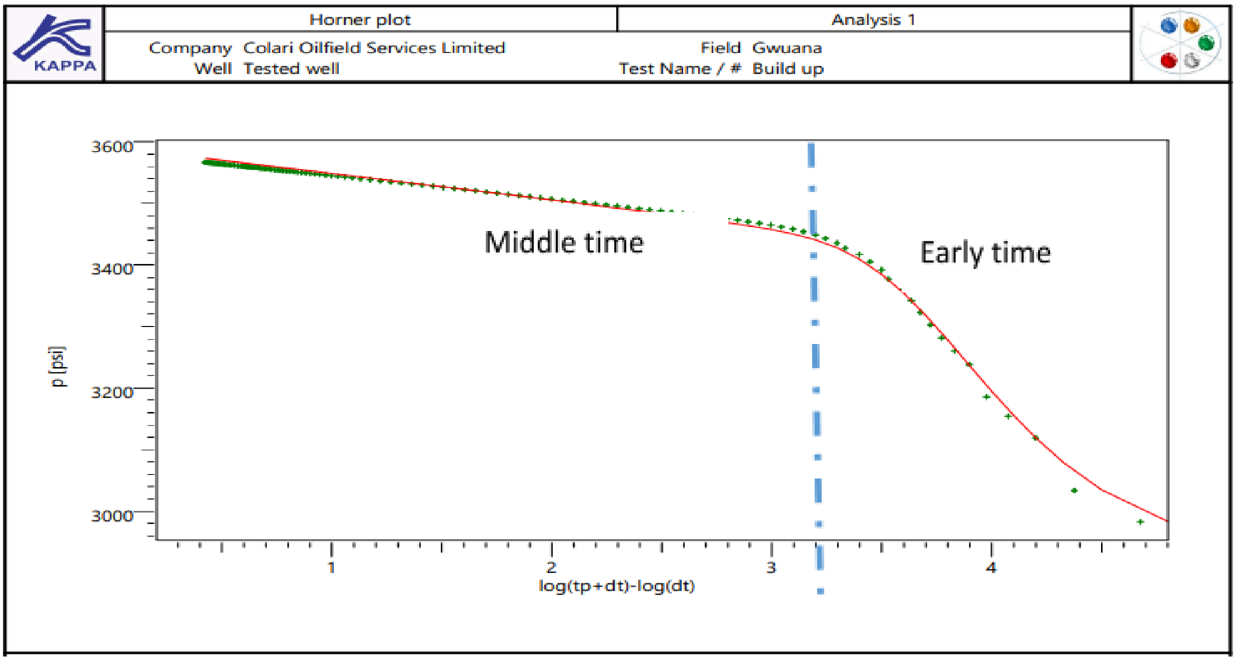

Figure 4.4: Horner Plot Model Match

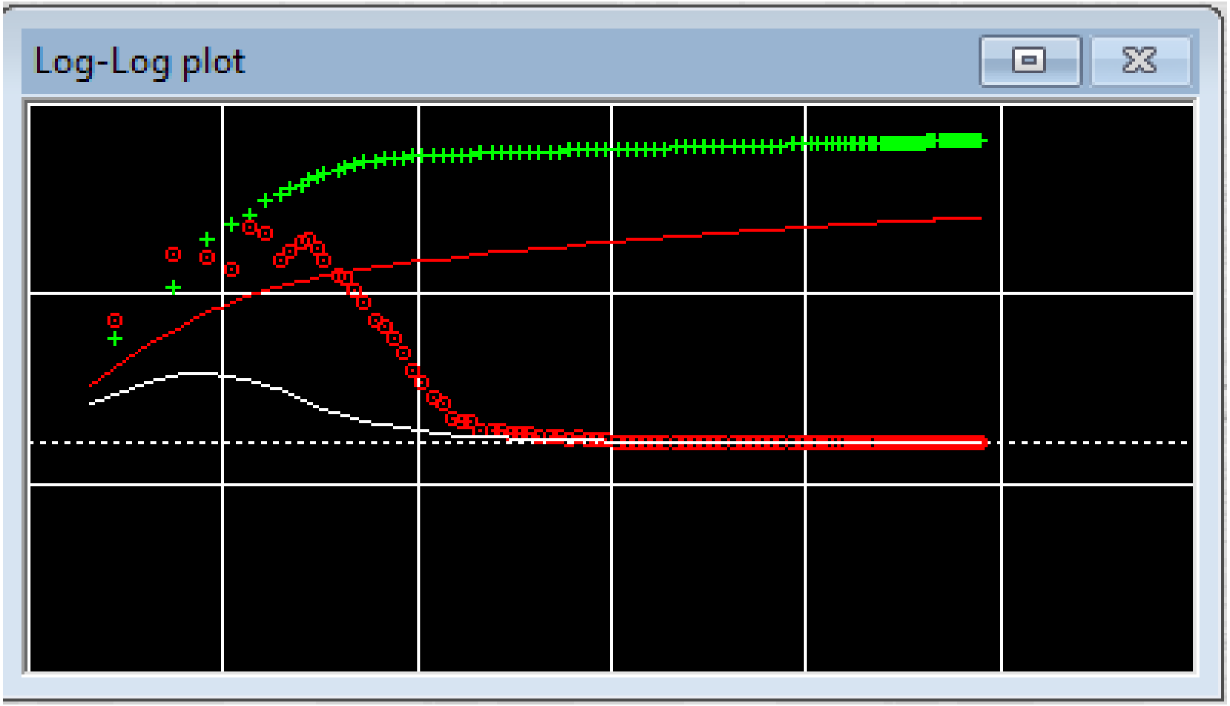

Figure 4.5: Log-Log Plot Model Mismatch

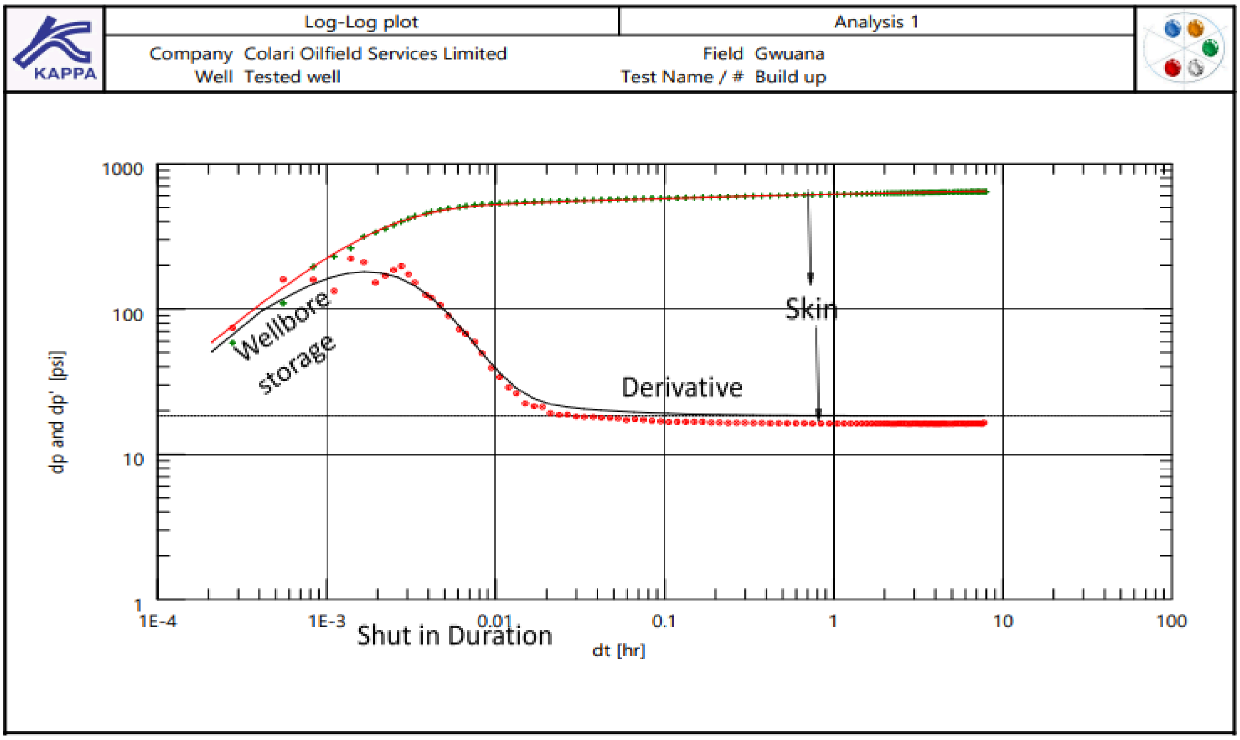

Figure 4.6: Log-Log Plot Model Match

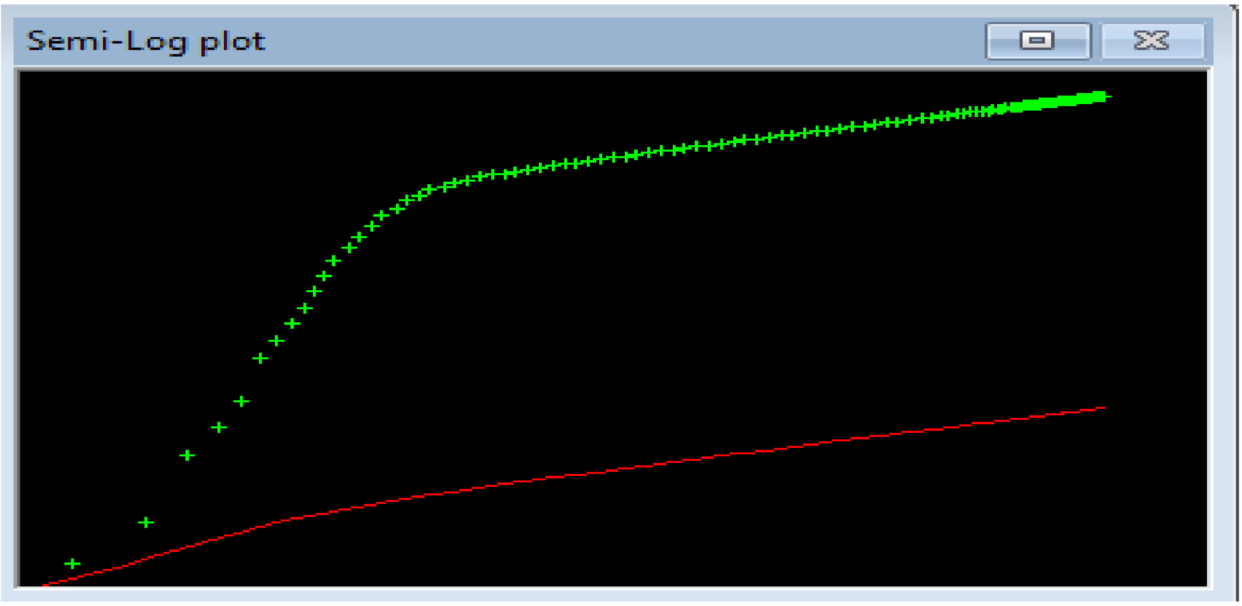

Figure 4.7: Semi Log Plot Model Mismatch

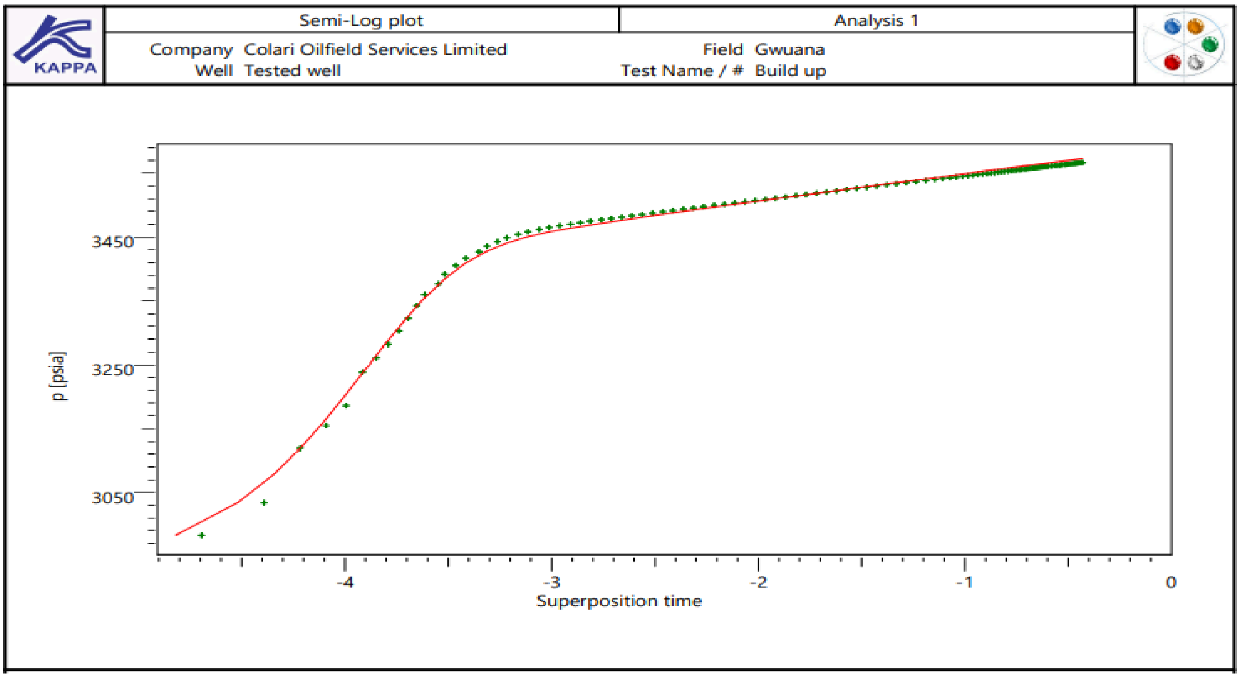

Figure 4.8: Semi-Log Plot Model Match

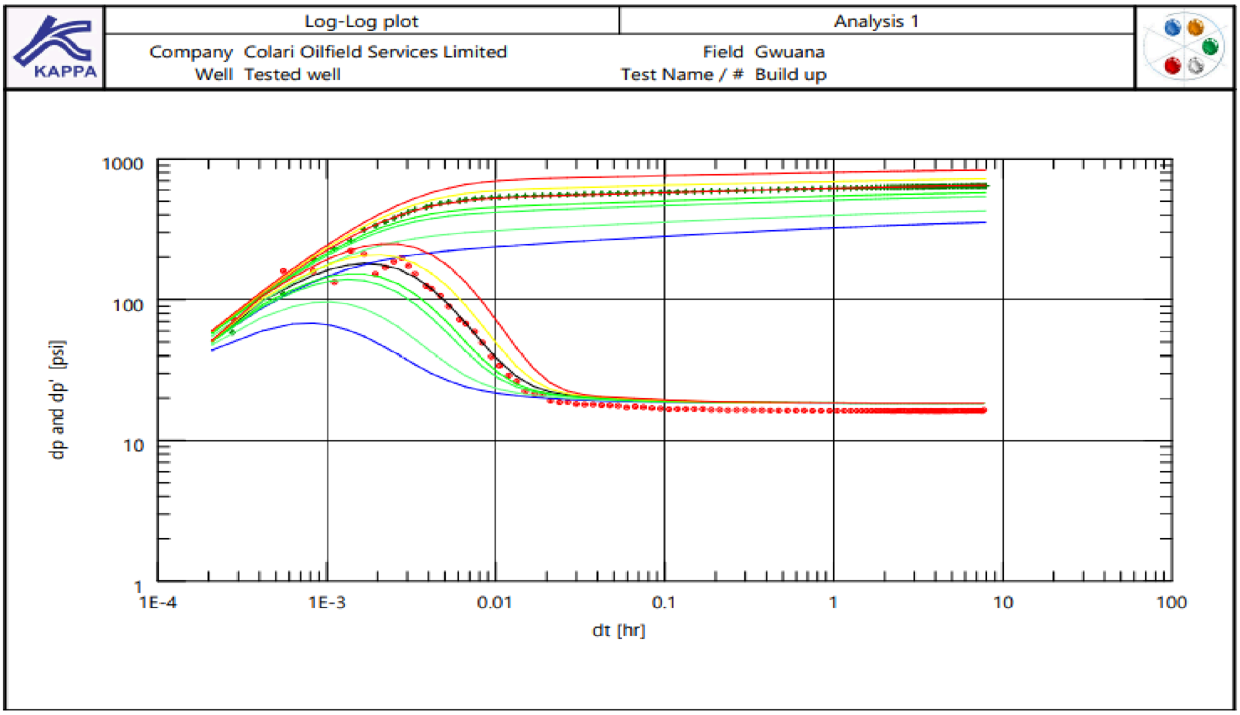

Figure 4.9: Log-Log Plot - Skin Sensitivity Analysis

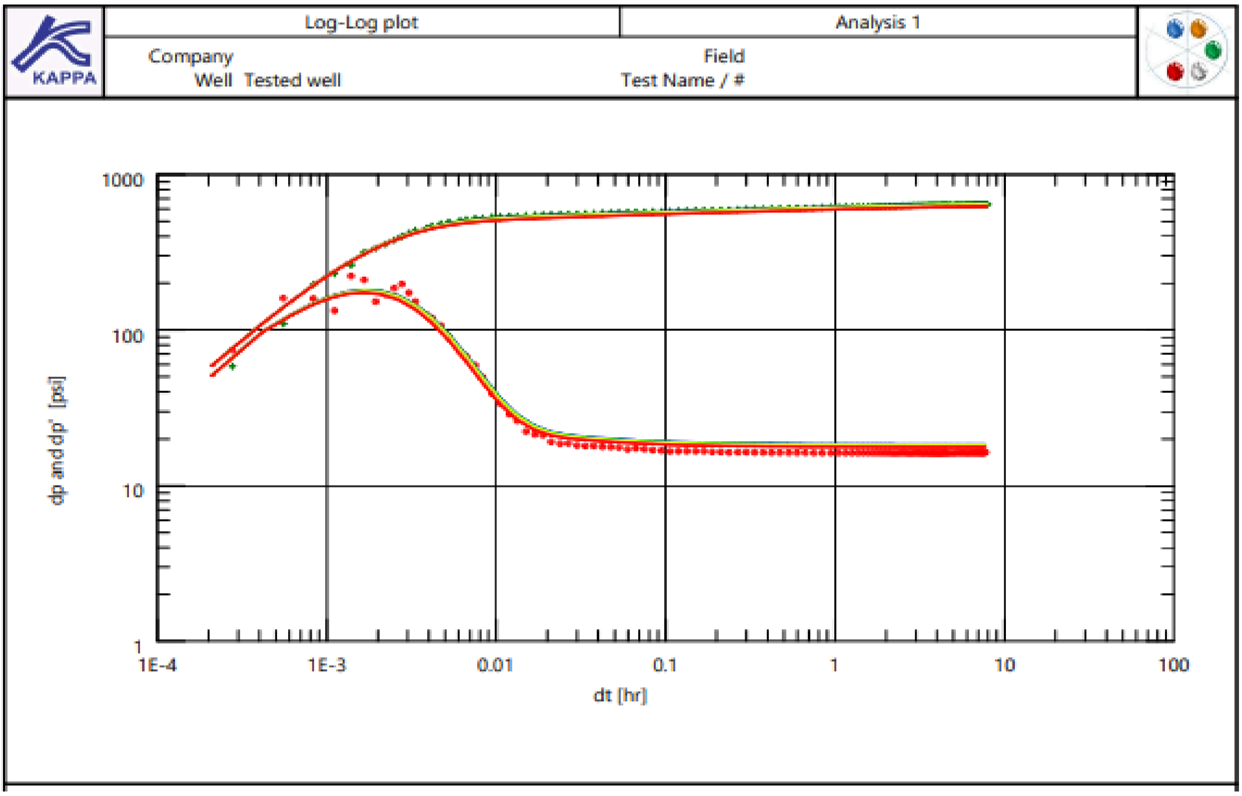

Figure 4.10: Log-Log Plot – Permeability-Thickness Sensitivity Analysis

Table 4.1: Skin and Permeability-Thickness Selections for Sensitivity Analysis

Skin Selections	Permeability-thickness selections (md.ft)
2	950
4	955
7	959 (current)
8	962
10 (current)	978
12	983
15	988

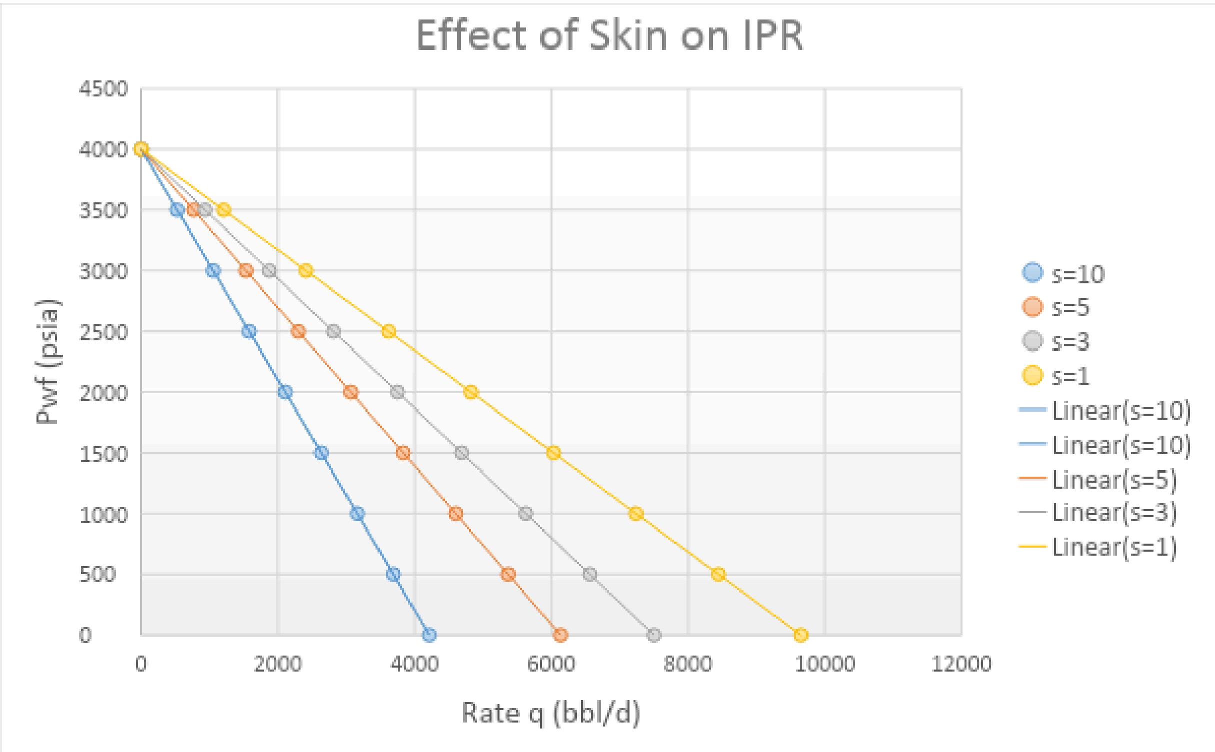

Figure 4.11: Effect of Skin on IPR

Table 4.2: Effect of Skin on Productivity Index (PI)

Skin, S	PI (bbls/d/psi)
10	1.053795076
7	1.297361967

4	1.687368668
3	1.875281348
2	2.110292676
1	2.41264697
0.5	2.598821334
0	2.81613095

Table 4.3: Model Parameter for well A3

Well and Wellbore Parameters (Tested Wells)	
C	1.1E-4bbl/psi
Total Skin	10
K, h, total	959md.ft
K, average	21.3md
Pi	3591.38psia
Selected Model	
Model option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Infinite
SapGS01 build up #1	
Rate	0STB/D
Rate Change	620STB/D
P @ dt=0	2924.08psia
Pi	3591.38psia
Derived and Secondary Parameter	
Rinv	784ft

Delta P (Total skin)	368psi

4.1.2 Results from Akota Field, Well J

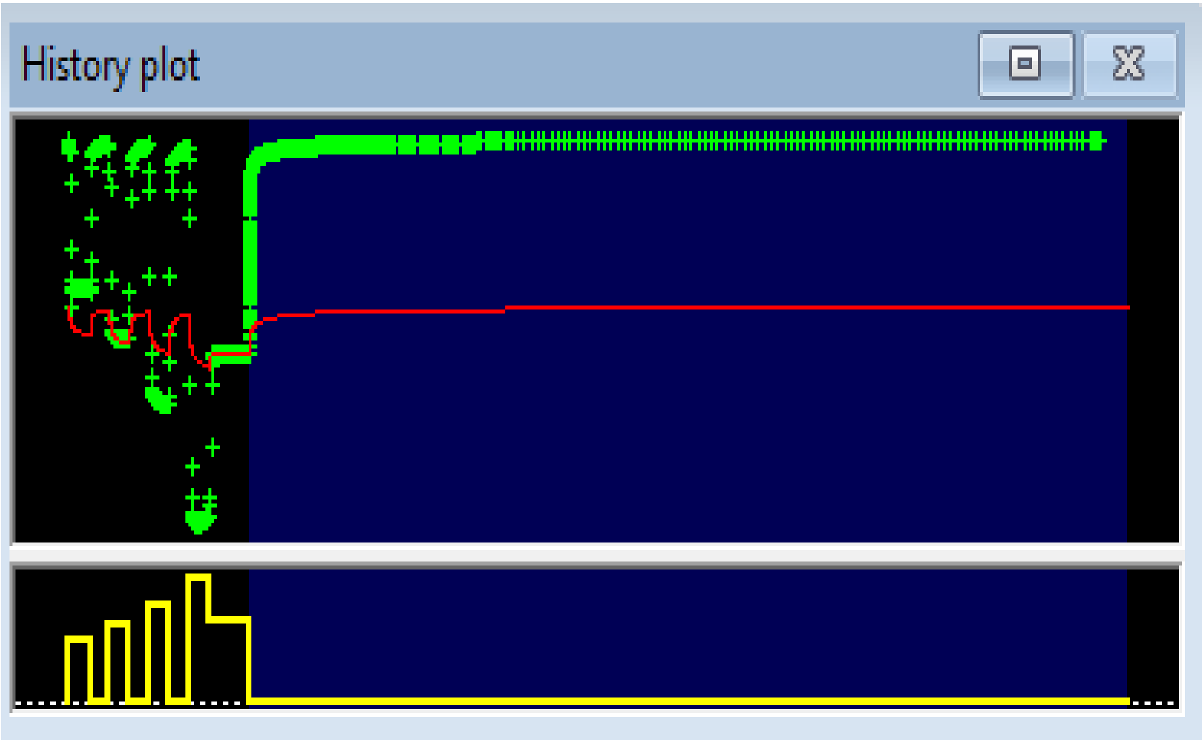

Figure 4.12: History Plot Model Mismatch

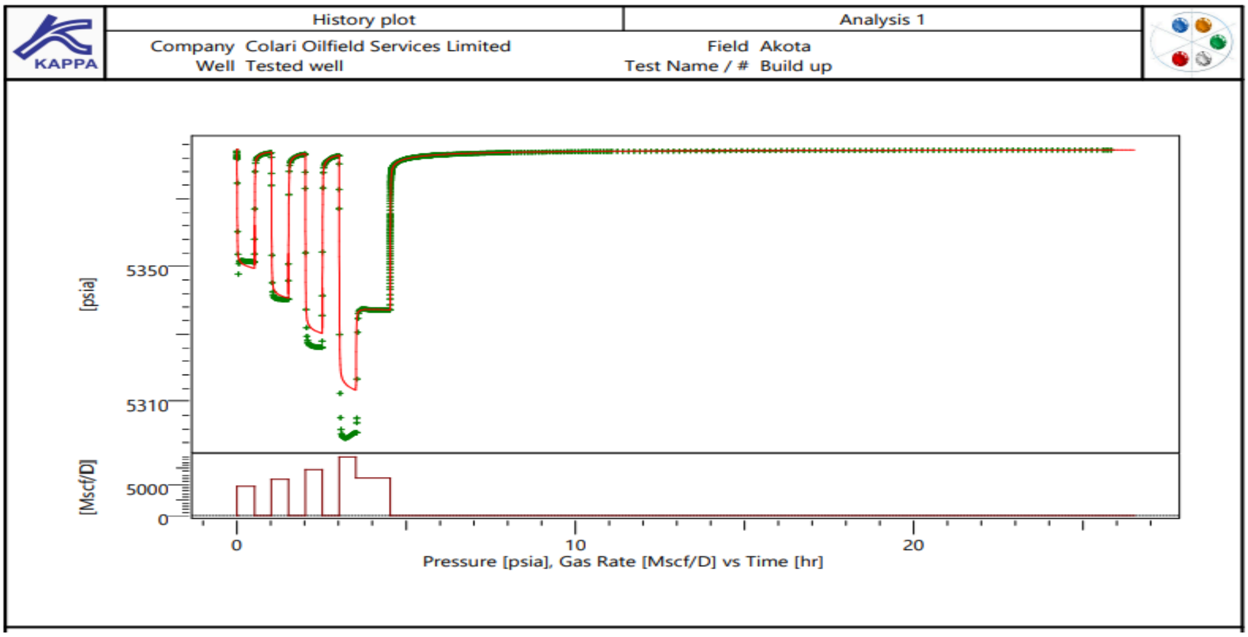

Figure 4.13: History Plot Model Match

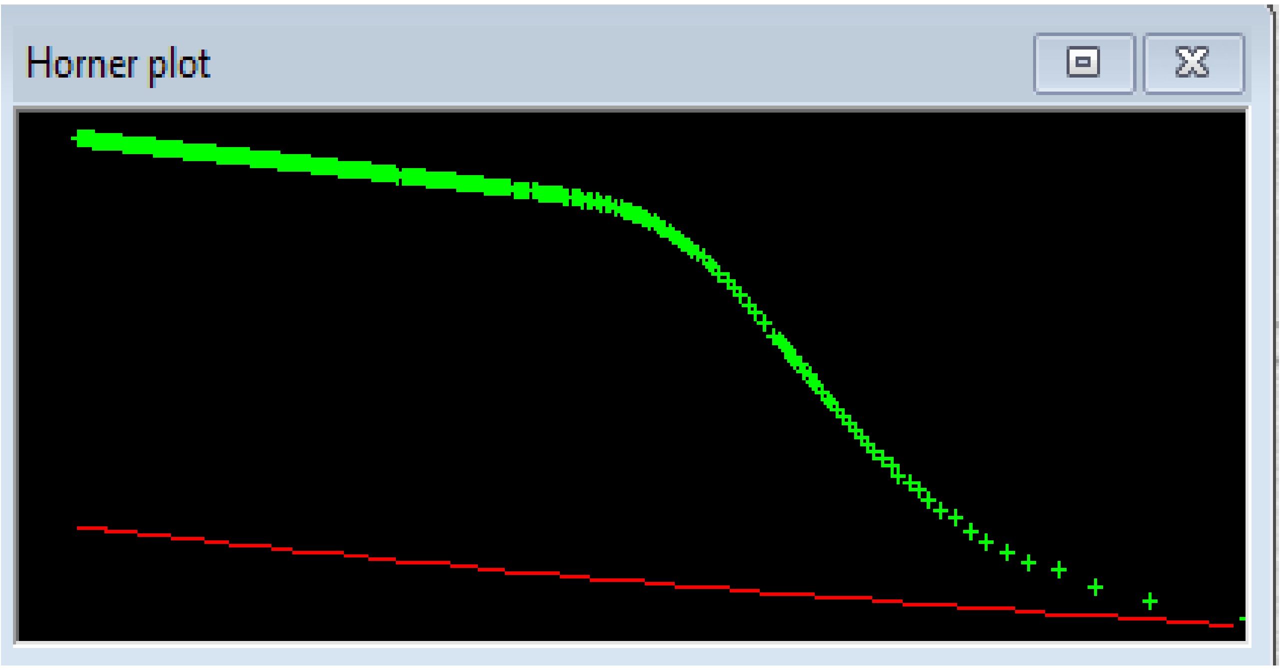

Figure 4.14: Horner Plot Model Mismatch

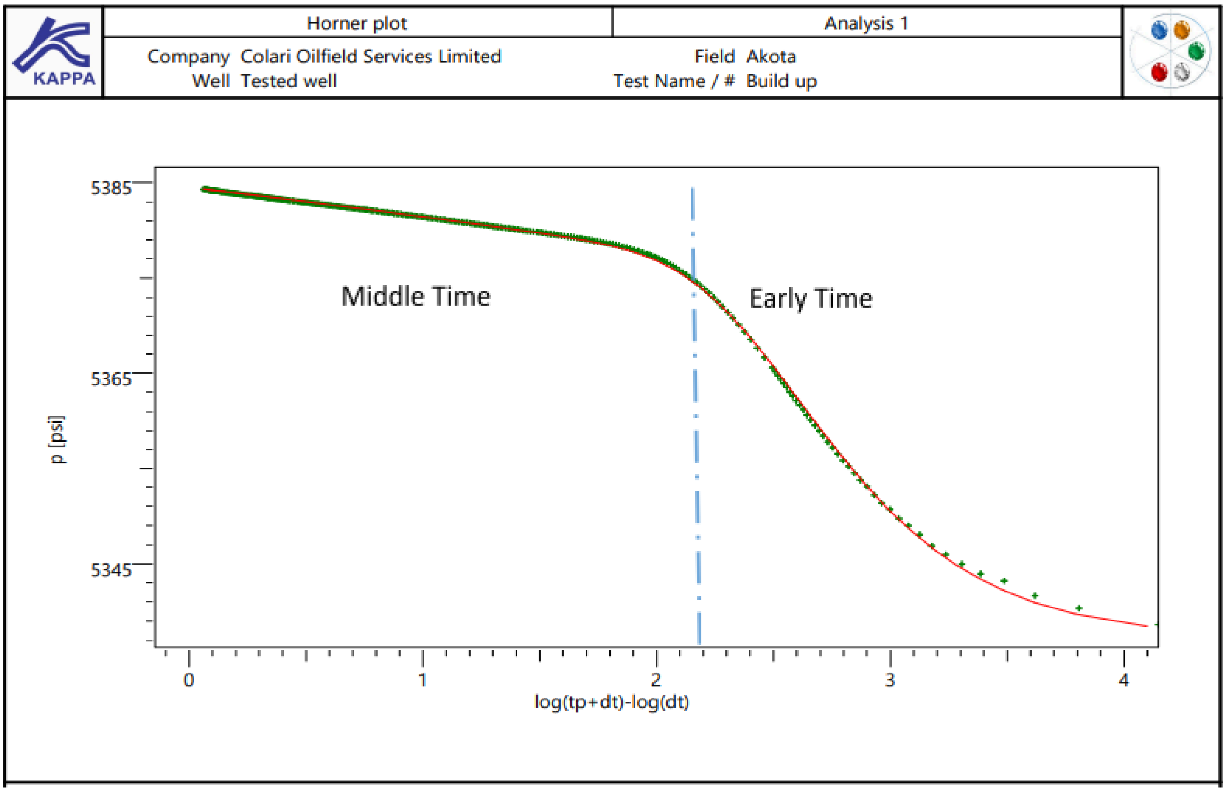

Figure 4.15: Horner Plot Model Match

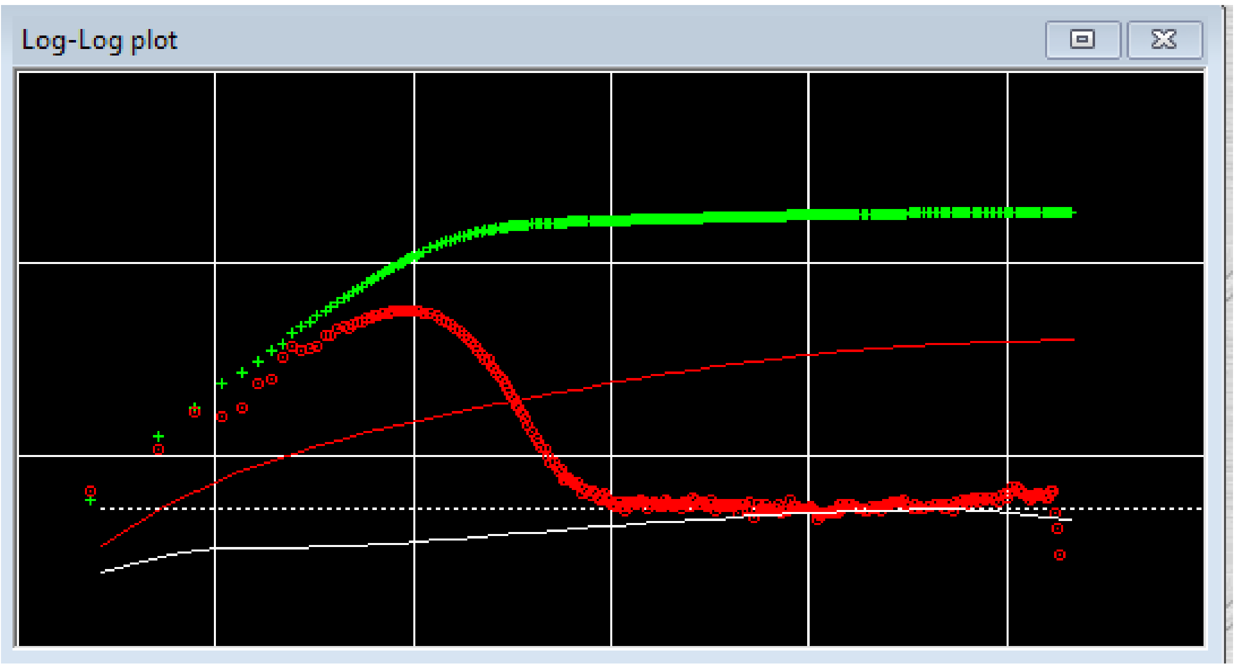

Figure 4.16: Log-Log Plot Model Mismatch

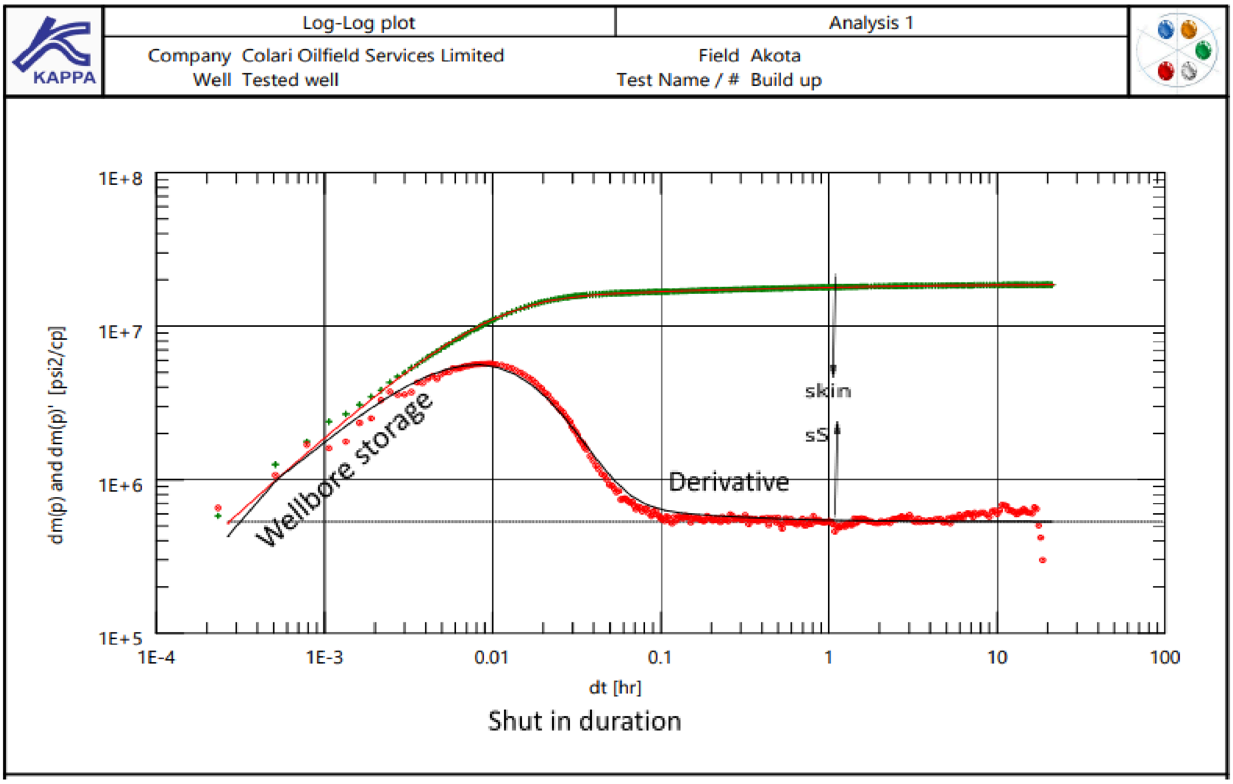

Figure 4.17: Log-Log Plot Model Match

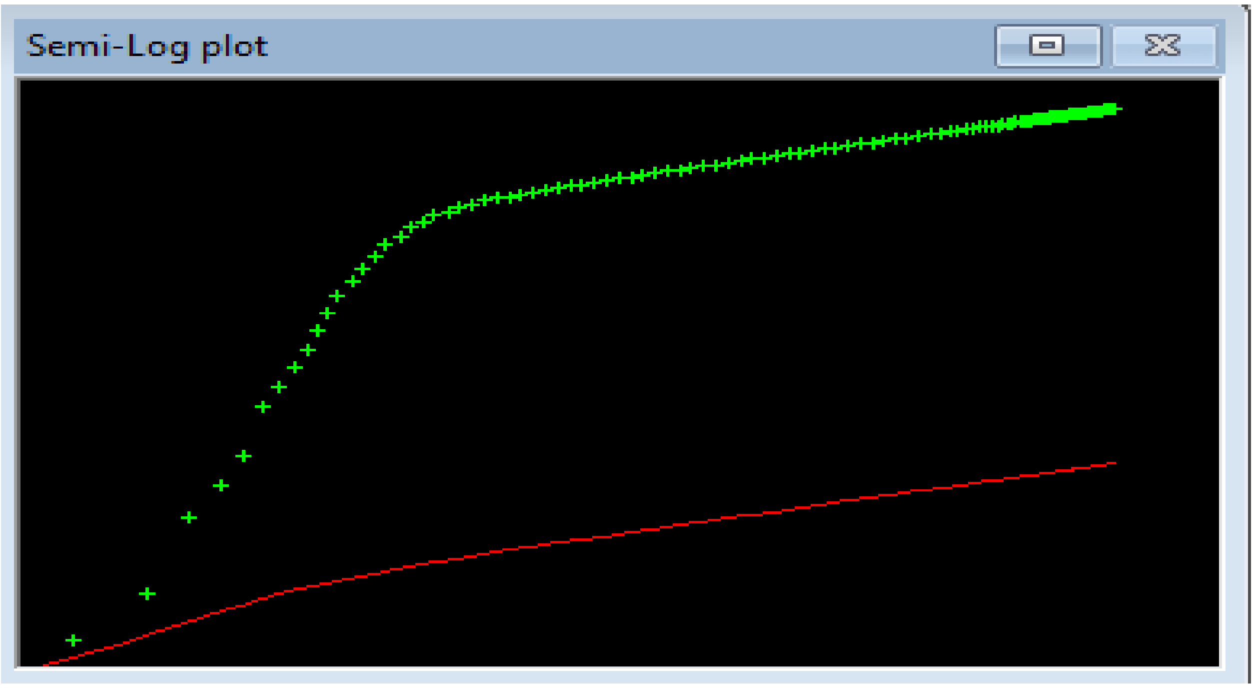

Figure 4.18: Semi-Log Plot Model Mismatch

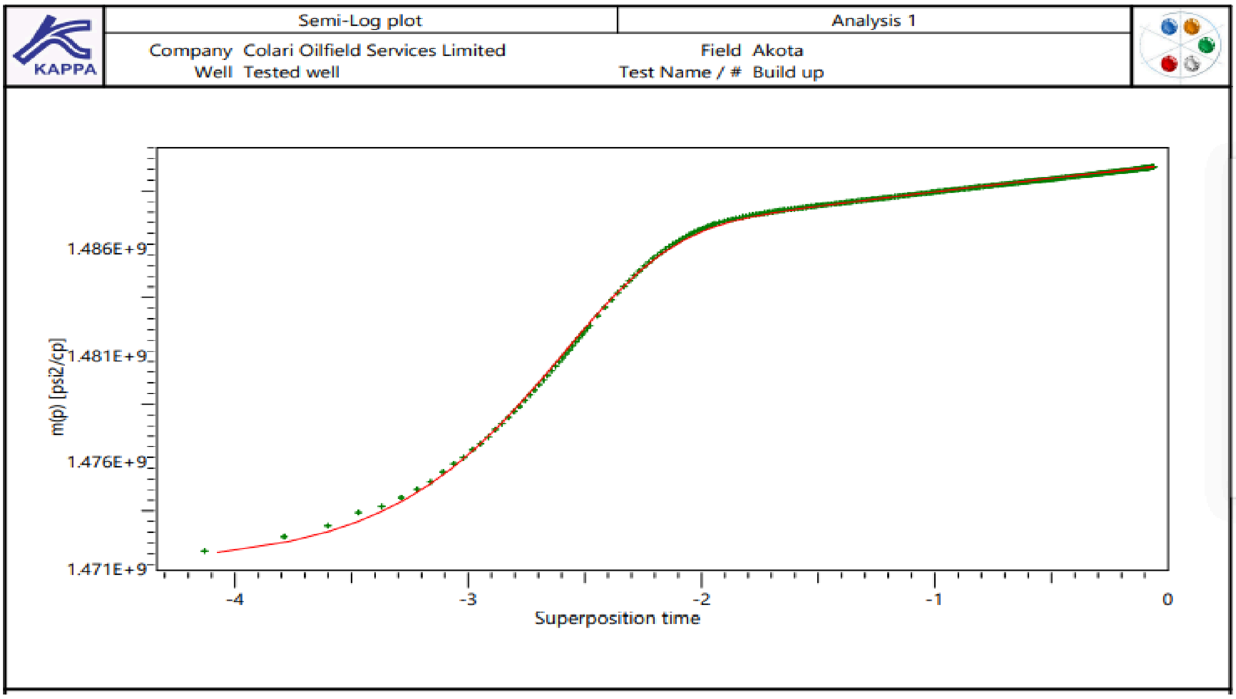

Figure 4.19: Semi-Log Plot Model Match

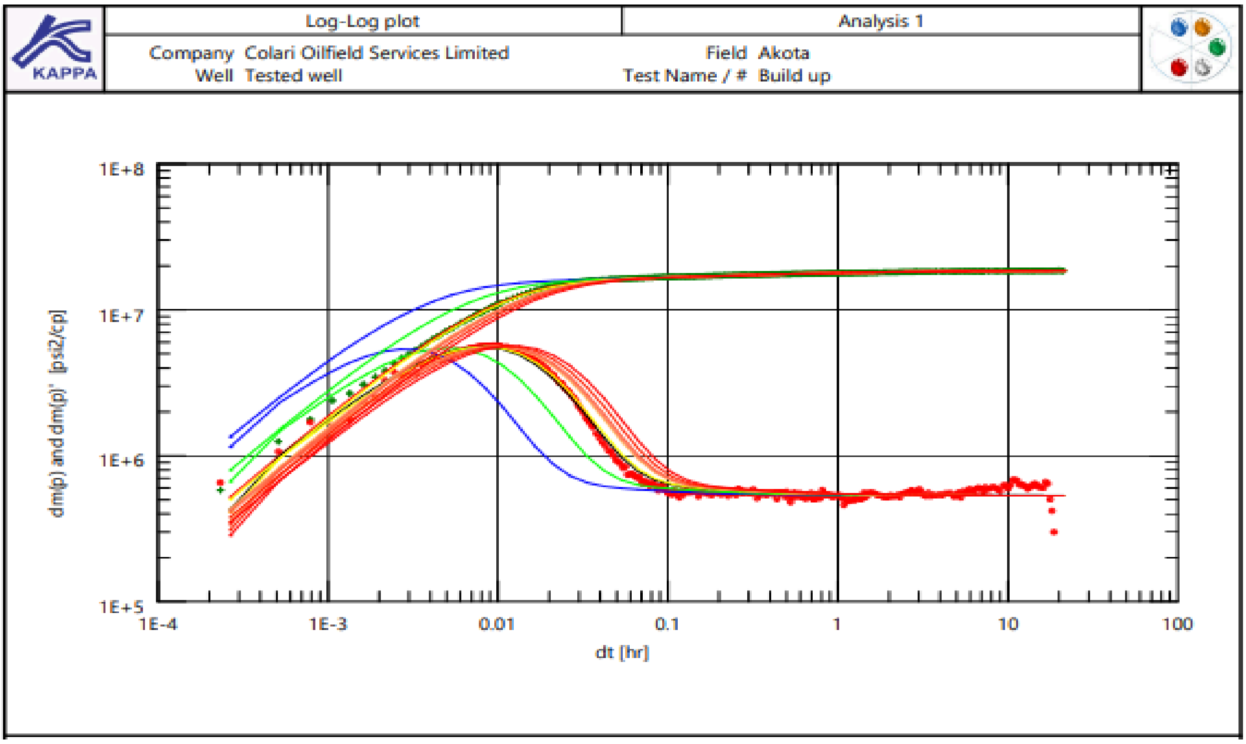

Figure 4.20: Log-Log Plot - Wellbore Storage Sensitivity Analysis

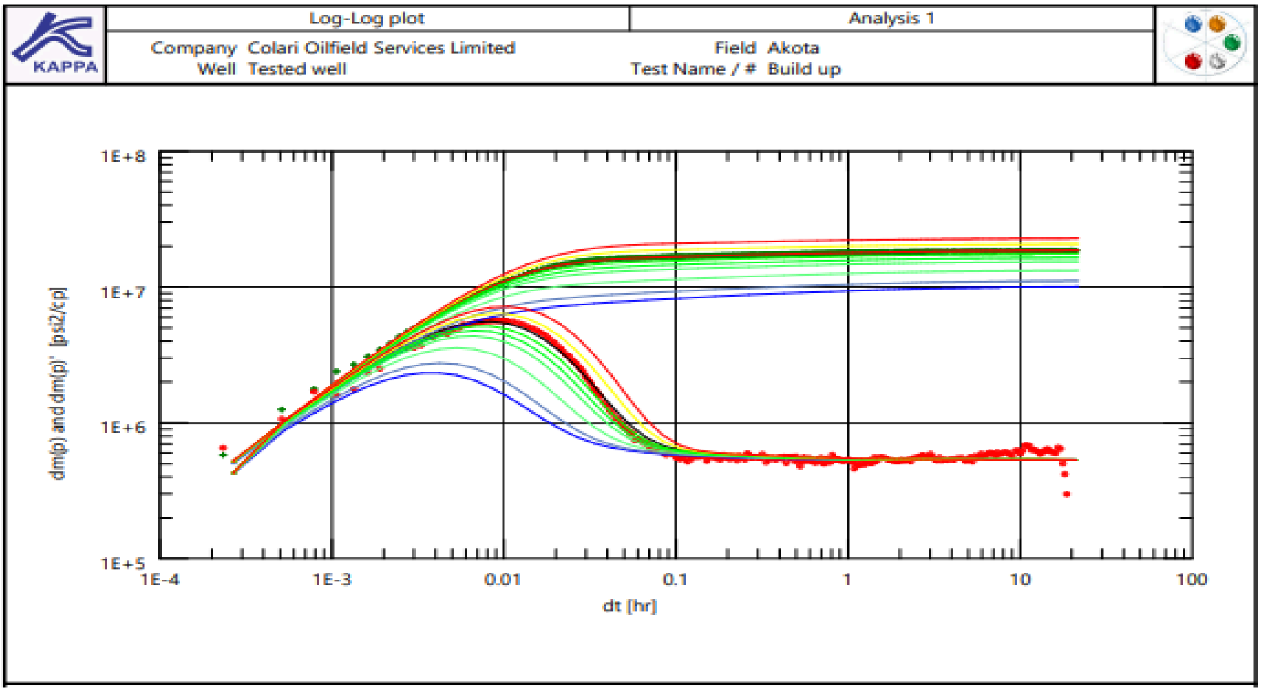

Figure 4.21: Log-Log Plot - Skin Sensitivity Analysis

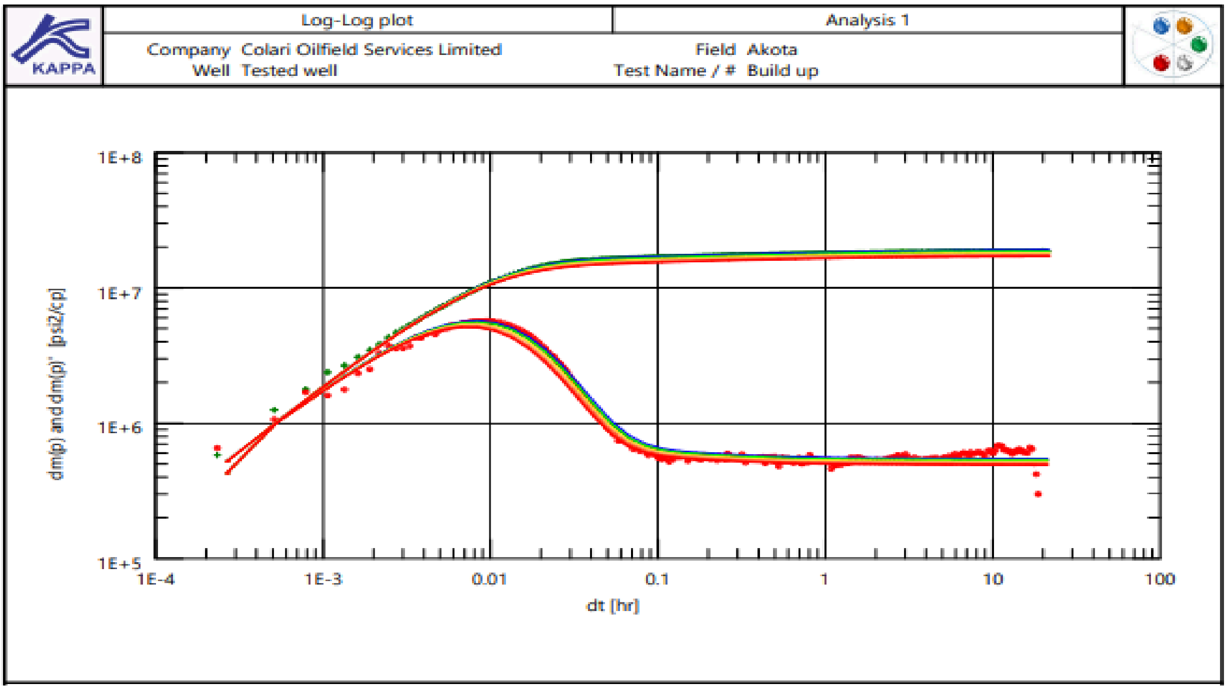

Figure 4.22: Log-Log Plot - Permeability-Thickness Sensitivity Analysis

Table 4.4: Skin, permeability-thickness and wellbore storage coefficient selections

Skin Selections	Permeability-thickness selections (md.ft)	Wellbore Storage Coefficient Selections (bbl/psi)

2	5223	0.0123654
3	5337	0.0214567
5	5350 (current)	0.0331457 (current)
7	5490	0.0345565
8	5557	0.0399978
9	5680	0.0408987
10 (current)	5721	0.0421654
12	5773	0.0456789

Table 4.5: Model Parameter for well J

Well and Wellbore Parameters (tested wells)	
C	0.0331bbl/psi
Total Skin	10
K, h, total	5350md.ft
K, average	107md
Pi	5384.54psia
Selected Model	
Model option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Infinite
SapGS01 build up #1	
Rate	0Mscf/D
Rate Change	6073.9Mscf/D
P @ dt=0	5337.14psia

Pi	5384.54psia
Derived and Secondary Parameter for well J	
Rinv	1670ft
Delta P (Total skin)	27.0538psi

4.2 Discussion

The discussion of the results gotten from the pressure transient analysis of Well J and Well A3 using Ecrin Saphir, is presented below. The discussion would involve detailed interpretation of the plots gotten from the analysis which would include, semi log, log-log, history and Horner plots.

4.2.1 Discussion of Results from Well A3

Figure 4.1 is a display of the history plot of well A3 when the model did not match. The history plot as shown in figure 4.2 was generated by loading the rate data and the pressure data into the software. The plot below is a plot of liquid flow rate q (STB/D) vs time (hr) and the plot above is plot of well bottom hole flowing pressure (psia) vs time (hr). The well was shut in on 04/12/1999 at 00:06:45am for 1.40417 hr. The pressure response during this shut in period is a test survey. At 01:31:00am, the well was opened to produce at a rate of 1600STB/D for 0.309059hr and then the rate was reduced to 1300STB/D at 01:49:33am for 0.172651hr. The rate was then reduced again to 900STB/D at 01:59:54am for 0.163797hr. At 02:09:44am, the rate was reduced to 700STB/D for another 0.163797hr and at 02:19:33am, the rate of the producing well was increased to 840STB/D. After producing the well for 2.95353hrs, the rate was reducing to 620STB/D at 05:16:46am for 7.6005hrs. At 12:52:48pm, the well was shut in (q = 0) for 8.08694hrs. The section from 01:31:00am to 05:16:46am on the history plot is referred to as the production section while the section from 12:52:48pm is referred to as the buildup section.

It can be noticed that figure 4.1 model mismatched while figure 4.2 matched. At initial stage of generating a random model for the plot, figure 4.1 was the result. After optimization, the new result is what is shown in figure 4.2 which is a representation of what is happening in the reservoir. This model generated is important in determining key reservoir and wellbore parameters.

The horner plot is a plot used for well test data analysis specifically for buildup test. The horner time is on the principle of superposition of the time of shut in and the time of production. The Horner plot is an extraction of delta P from the pressure buildup section of the history plot. This plot is shown in figure 4.3 and 4.4. The plot is simply a plot of the buildup pressure vs the Horner time, t_H. The Horner plot has a log scale on the horizontal axis and an arithmetic scale on the vertical axis. The pressure is on the vertical and the Horner time is on the horizontal axis. The Horner plot is similar to the semi log plot but one difference is that the time (Horner time) increases from the right to left. The horner time is based on the radial flow equation and should only be used for analyzing radial flow. Its valid if the reservoir is infinite acting and the rate prior to shut was constant.

Figure 4.3 is a display of horner plot model mismatch for well A3 while figure 4.4 is a display of horner plot model match for well A3. The reason for the mismatch is due to the fact that the selected model is not a representation of the reservoir. Figure 4.4 shows the model match as this would help in determining key reservoir and wellbore parameters.

During the early time of the pressure buildup as shown in the figure 4.4, there is occurrence of wellbore storage effect after production shut in, which as a result of the early pressure behaviour being dominated by the compressibility and volume of the wellbore fluid. At the end of the wellbore storage effect, there was an occurrence of transient pressure response representing the middle time. From the plot, the reservoir pressure did not get to the boundary.

The log – log plot also called a derivative plot comprises of the delta P plot and the derivative plot. The delta P (ΔP) plot is a plot of Δp vs shut in duration, delta T (hr) as shown in figure 4.6. While the derivative plot is the plot of the pressure derivate to the shut-in duration, delta T (hrs). In figure 4.6, the vertical separation between the derivative and the delta P plot is an indication of skin or damage in the well. Higher separation means higher skin, while lower separation means lower skin. Delta t increase to the right which means increase away from the wellbore. From the plot, wellbore storage at the early time of the shut-in period which is due to the expansion of the fluid in the wellbore. When the well is shut in, the rate at the surface is zero but, in the reservoir, it is not zero. A delay occurs as the rate in the reservoir gradually reduces to zero. From the plot, the stabilization of the derivative plot could be indicative of a radial flow or circular flow towards the well in the horizontal plane. Large delta t tells approach towards the boundaries but from the result, the boundary is infinite because the pressure response did not approach the boundaries.

Figure 4.5 is a display of model mismatch. This is because the model parameters do not correspond with the reservoir and well parameters. Figure 4.6 is a display of model match after optimization. In this optimization process, the tool generates the best model for the plot.

The semi log plot follows symmetrical with the horner plot but the two have different time exit direction. In semi log plot, the time increases from left to right as shown in figure 4.8. At the early start of shut in, wellbore storage occurs and at the end of the wellbore storage period, the pressure response is transient. Figure 4.7 is a display of model mismatch which would not give the correct well and reservoir parameters. Figure 4.8 is a display of model match.

In order to validate the skin, sensitivity analysis was carried out by choosing different values of skin above and below the calculated skin gotten from the software. After choosing random values for the skin, the sensitivity to skin of wellA3 was generated on the log-log plot. There was no change in the initial skin calculated by the software. This is to show the calculated skin from the model is indeed the skin of the reservoir. This plot can be seen in figure 4.9.

The permeability-thickness, kh gotten from the analysis needs to be validated. A sensitivity analysis was conducted by choosing values above and below the result obtained. The resulting plot is shown in figure 4.10. There was no change in the permeability-thickness initially obtained.

Table 4.1 is simply a list of the assumed skin and permeability-thickness in trying to carry out sensitivity analysis on the results from the tool.

The graph as shown in figure 4.11 is a straight line IPR. It tells the well is producing under saturated oil (no gas at the wellbore). AOF is the Absolute Open Hole Factor or qmax. It is the flowrate at zero bottom hole flowing pressure. AOF is idealistic but a useful parameter in comparing wells in the same field. The straight line IPR plotted is important to monitor the well performance. It is a plot of well flowing bottom hole pressure, pwf vs Oil flowrate, q.

From the graph, there is an increase in the straight line IPR with decreasing skin. This shows if the well can be stimulated such that the skin is reduced, there will be better production from the well.

Table 4.2 is a tabular display of the skin effect on productivity index. The productivity index of well A3 was generated using excel by applying the formula for productivity index with changing skin factor. It is observed that the productivity index of the well increased with decreasing skin.

Table 4.3 is the model parameter results for well A3. It contains the well and wellbore parameters for the well. The total skin gotten is 10. This indicates the well is damaged, that is, there is reduced permeability around the wellbore and needs stimulation. K, average which is 21.3md is the average permeability of the oil reservoir. Pi is the initial pressure of the well. Its value is 3591.38psia. C which is equal to 1.1E-4bbl/psi refers to the wellbore storage.

The table also shows the model option chosen, an indication that the well is vertical, the reservoir homogeneous and the boundaries infinite.

Table 4.3 also displays the shut-in rate for the buildup section which is at 0STB/D, the rate change of 620STB/D, and the initial pressure of the reservoir, Pi

It also contains the derived and secondary parameter for well A3. The radius of investigation Rinv was calculated to be 784ft which is the distance the pressure transient has moved into the formation following the change of rate in the well. Delta P (total skin) is another parameter derived from the analysis. Its value is 368psi.

4.2.2 Discussion of Results from Well J

A pressure buildup test conducted on 07/30/2001 at 00:00:00am on a gas well J began with flowing the well at a rate of 4743.58Mscf/D for 0.5209hr. From the plot in figure 4.13, it can be read that the well was then shut in at 00:31:15am to allow for pressure buildup for a duration of 0.4972hr and then open to flow at a rate of 5878.61MScf/D for 0.5014hr at 01:01:05am. At 01:31:20am, the well was shut in for 0.4986hr to allow for pressure buildup. At 02:01:15am, the well was set in production for 0.5014hr at a flow rate of 7239.46MScf/D. The well was then shut in at 02:31:20am for 0.4972hr. At 03:01:10am, the well is open to flow at a rate of 9464.78Msct/D for 0.497392hr and then the flow rate was reduced to 6073.9Mscf/D for 1.00871hr. At 04:31:32am, the well was shut in for 21.99999hrs and the pressure transient response was measured.

It can be noticed that figure 4.12 model mismatched while figure 4.13 matched. At initial stage of generating a random model for the plot, figure 4.12 was the result. After optimization, the new result is what is shown in figure 4.13 which is a representation of what is happening in the reservoir. This model generated is important in determining key reservoir and wellbore parameters.

The Horner plot is an extraction of delta P from the pressure buildup section of the history plot. This plot is shown in figure 4.14 and figure 4.15. The plot is simply a plot of the buildup pressure vs the Horner time, t_H. The horner time is on the principle of superposition of the time of shut in and the time of production. The Horner plot has a log scale on the horizontal axis and an arithmetic scale on the vertical axis. The pressure is on the vertical and the Horner time is on the horizontal axis. The Horner plot is similar to the semi log plot but one difference is that the time (Horner time) increases from the right to left. The horner time is based on the radial flow equation and should only be used for analyzing radial flow. Its valid if the reservoir is infinite acting and the rate prior to shut was constant.

During the early time of the pressure buildup as shown in the figure 4.15, there is occurrence of wellbore storage effect after production shut in, which as a result of the early pressure behaviour being dominated by the compressibility and volume of the wellbore fluid. At the end of the wellbore storage effect, there was an occurrence of transient pressure response representing the middle time. From the plot, the reservoir pressure did not get to the boundary and so considered infinite acting.

Figure 4.14 is a display of model mismatch. This is because the model parameters do not correspond with the reservoir and well parameters. Figure 4.15 is a display of model match after optimization. In this optimization process, the tool generates the best model for the plot.

The log – log plot also called a derivative plot. It comprises of the delta P plot and the derivative plot. The delta P (ΔP) plot is a plot of Δp vs shut in duration, delta T (hr). While the derivative plot is the plot of the pressure derivate to the shut-in duration, delta T (hrs). The vertical separation between the derivative and the delta P plot is an indication of skin or damage in the well as shown in figure 4.17. Higher separation means higher skin, while lower separation means lower skin. Delta t increase to the right which means increase away from the wellbore. From the plot, wellbore storage at the early time of the shut-in period which is due to the expansion of the fluid in the wellbore. When the well is shut in, the rate at the surface is zero but, in the reservoir, it is not zero. A delay occurs as the rate in the reservoir gradually reduces to zero. From the plot, the stabilization of the derivative plot could be indicative of a radial flow or circular flow towards the well in the horizontal plane. Large delta t tells approach towards the boundaries but from the result, it is infinite because the pressure response did not approach the boundaries.

Figure 4.16 is a display of model mismatch. This is because the model parameters do not correspond with the reservoir and well parameters. Figure 4.17 is a display of model match after optimization. In this optimization process, the tool generates the best model for the plot.

It follows symmetrical with the horner plot but the two have different time exit direction. In semi log plot, the time increases from left to right as shown in figure 4.18 and 4.19. At the early start of shut in, wellbore storage occurs and at the end of the wellbore storage period, the pressure response is transient. Figure 4.18 is a display of model mismatch which would not give the correct well and reservoir parameters. Figure 4.19 is a display of model match.

The wellbore storage coefficient, C gotten from the analysis needs to be validated. A sensitivity analysis was conducted by choosing values above and below the result obtained. The resulting plot is shown in figure 4.20. There was no change in the wellbore storage coefficient initially obtained.

In order to validate the skin, sensitivity to skin was carried out by choosing different values of skin above and below the calculated skin gotten from the software. After choosing random values for the skin, the sensitivity to skin of well J was generated on the log-log plot. There was no change in the initial skin calculated by the software. This is to show the calculated skin from the model is indeed the skin of the reservoir. This plot can be seen in figure 4.21.

A sensitivity analysis was conducted by choosing values above and below the permeability-thickness, kh. The resulting plot is shown in figure 4.22. There was no change in the permeability-thickness initially obtained.

Table 4.4 is simply a list of the assumed permeability-thickness in trying to validate the calculated result from the tool. It also contains a list of the assumed wellbore storage coefficient in trying to validate the calculated result from the tool. It contains a list of the assumed skin in trying to carry out a sensitivity analysis on the calculated skin from the Saphir software.

Table 4.5 contains information about the well and wellbore parameters which include the wellbore storage, C obtained to be 0.0331bbl/psi, total skin 10, average permeability 107md and the initial pressure 5384.54psia. The table also shows the model used is a standard model, the well is vertical, the reservoir is homogeneous, and the boundary condition, infinite. This model matched with the pressure transient plot indicating the reservoir parameters. It shows the rate at 0Mscf/D, indicating the shut in, the rate change of 6073.9Mscf/D, and the initial pressure of 5384.54psia. The radius of investigation Rinv is 1670ft and delta P (total skin) is 27.0538psi.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

5.1 Conclusion

From the pressure transient analysis of well A3, it shows the well is vertical, the reservoir is homogeneous, and the boundary condition infinite. This is the same result for well J. At the early time, the both wells experienced wellbore storage effect. The fluid in well A3 is oil while well J is gas. At initial running of the model, there was a mismatch which led to the reason for optimization. The model generated after the optimization process matched the pressure transient behaviour of the reservoir. The model match is essential in generating the reservoir capacity, average permeability, skin and the initial pressure. The average permeability of well A3 is 21.3md while the average permeability of well J is 107md. It can be seen from the analysis of the pressure build up data obtained from well A3 and well J that the wellbore is damaged with a skin factor of 10. This would necessitate the need for the permeability around the wellbore to be improved for better productivity. The pressure transient analysis done on well A3 and well J, the productivity index, PI of well A3 was generated using excel by applying its formula with changing skin factor. It is observed that the productivity index of the well increased with decreasing skin. Also, a straight line IPR was also plotted as this is helpful in determining the production from the well. In addition, it can be seen clearly that well A3 and J are badly damaged and would require stimulation to enhance productivity.

5.2 Recommendations

1. Since the results of the analysis show that well A3 and well J are damaged, it would be recommended that management stimulate the well either by hydraulic fracturing or acidizing. This would increase the permeability around the wellbore.
2. After carrying out the stimulation job, it is recommended that management carryout another test on the wells to validate if indeed the skin have been removed.
3. From the graph in figure 4.11, management can make a decision on the extent they desire the wellbore to be stimulated. From the graph, management can choose the skin that gives the maximum production rate for the well.
4. Productivity index is a measure which provides insight into how a well is performing. When the productivity index drops, there's a good chance that formation damage is the reason for the decrease in fluid production. It is recommended that management monitors the productivity index of the producing well in order to know when there is a drop.

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