Well Test Analysis in The Determination of Wellbore Formation Problems (Skin Factor)

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***Abstract*: Well-testing is a method of determining reservoir parameters that involve altering the output flow rate of an oil or gas well. Data from well-tests are used to estimate reserves, which is utilized to determine whether reservoirs are economically viable. The wellbore of a well can be damaged during well-drilling and completion procedures.**

Oil or gas output may suffer as a result of this damage. The data collected after well testing is examined to determine factors such as permeability, skin, and starting reservoir pressure. This is critical information for determining whether or not the well has been harmed. The goal is to conduct a well-test analysis on buildup test data to identify wellbore formation issues. This was accomplished by analyzing two buildup test data sets for well A3 and well J in the Gwuana and Akota fields, respectively, using Saphir. According to the results, wells A3 and J are damaged, with a positive skin score of 10. Both wells have initial reservoir pressures of 3591.38psia and 5384.54psia, respectively. Well A3 has a permeability of 21.3 md, but well J has a permeability of 107 md. To see how well skin affected productivity, an IPR plot of pwf vs q was created for well A3. According to the analysis, wells A3 and J are damaged, and they should be stimulated either by hydraulic fracturing or acidizing.

***Keywords*: Well, reservoir, test, pressure, skin**

I. INTRODUCTION

Well, testing is a method for evaluating reservoir parameters that involve disrupting oil or gas well production by changing the output flow rate Furui, et al., [1]. Data from well-tests is used to estimate reserves, which is utilized to determine whether reservoirs and reservoir locations are economically viable Ouyang, [2].

By providing average and local reservoir pressures, well testing is also employed in reservoir monitoring. This pressure data is important for optimizing production, but it also helps to characterize reservoirs as model feedback (history matching). A rate change is utilized to generate a diffuse pressure disturbance during a well-test, which is then measured to characterize the wellbore, reservoir, and boundaries [3]. Well-testing assists production by providing information on the condition of the volume surrounding the wellbore. These findings are being used to address issues such as formation damage near wellbores, as well as the need for and effectiveness of well-stimulation treatments. Well-testing works on the following principle: when the well's output rate or pressure is modified, a signal is delivered into the reservoir, and the reaction (pressure/rate change) is detected at the well [4]. A response analysis is used to calculate reservoir parameters. Early reactions are influenced by qualities in the close wellbore area, whereas later responses are influenced by features in the reservoir that are further away because the reaction is a function of a noise that moves away from the well. To investigate reservoir contact, another well's response must also be provided. An interference test is a name for this type of exam. Permeability, boundaries and fault distances, near wellbore damage or stimulation (skin), size and sand bodies, and duration of induced fractures are all examples of information obtained from good tests. The most critical computed quantities in well testing are pressure and output rate (equivalently, injection rate). The bottom-hole pressure (BHP) refers to the pressure measured at the wellbore's bottom [4]. Because it's closest to the formation, this is the optimal pressure measurement. Drawdown, buildup, and interference testing are the three types of well testing available. The injection and falloff tests are the injector counterparts of drawdown and buildup tests. The Drill Stem Test (DST) is a drawdown test used in newly drilled wells and discovery wells [4]. The purpose of a drawdown test is to allow a static, stable, and closed-in well to flow. The flow rate must be constant for classical analysis. A drawdown test is used to calculate the drainage area average permeability (k), estimate the skin (S), determine the reservoir pore depth, and find reservoir heterogeneity. A well that is still running (ideally at a steady speed) is shut down during a buildup test, and the downhole pressure is measured as the pressure rises. The drawdown test's goals are to obtain average permeability k and skin S. The buildup test is used to calculate 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. As a result, an injection test is similar to a drawdown test in theory, except that the flow is into the well instead of out of it. Injection tests usually have the same aims as production tests (e.g. k, S), but they can also be used to map the injected water. Most wells' wellbore was damaged during drilling and completion operations, according to reports. This sort of damage is known as skin(S) damage, and it results in a decrease in well-productivity. Well-testing is a common process for determining the condition of a well.

Wells, like humans, are subjected to routine physical tests to establish their overall health. Constraints in the formation pores or within the wellbore formation area might produce the Skin, which can lead to a decrease in oil or gas flow. Changes in formation or fluid properties around the wellbore, chemical reactions inside the formation or wellbore, mechanical difficulties, or inadequate completion techniques are all factors that contribute to these restrictions. Data from wells is analyzed to estimate permeability, skin, and beginning reservoir pressure, among other things. These measurements will aid in determining whether the formation has been damaged or destroyed, as well as whether well-stimulation is required. As a result, using the Saphir tool to do a well-test analysis on buildup test data, a thorough study is required to locate wellbore concerns. The following objectives were employed to achieve this goal: to assess the study's contributions, to examine and analyze the well A3 and well J buildup data, to determine skin b, formation's capability, to figure out what the initial reservoir pressures are, to carry out a skin sensitivity test, and to investigate the impact of skin on the productivity index and the relationship between inflow and performance.

II. RELATED TERMS/WORKS

Well test

A "well test" [4,5] is a word used to define a production or temporary well-test. Diverting a producing well to a test separator and estimating the steady-state rate at the relevant wellhead and bottom hole pressures is what a production well test includes. Transient well-tests are used to measure changes in reservoir pressure when well rates fluctuate (Fanchi & Christiansen, 2016). These metrics are used to monitor wells and reservoirs, as well as to calculate well rates. In well testing, the most important computed quantities are pressure and output rate (equivalently, injection rate). The pressure measured at the bottom of the well is known as bottom-hole pressure (BHP). Pressure transient test is another term for well testing, which is a simplified explanation of the procedure. PTT (Pressure Transient Testing) is a frequently used technique for learning about a reservoir that is far away from the well [7]. The PTT method measures an increase in pressure at the wellbore as a function of the time when the fluid flow rate changes in the wellbore. Pressure transients are a type of change in pressure. Pressure gauges track variations in pressure over time. The well-test is a typical method for determining reservoir deliverability. Its objectives are as follows:

Permeability thickness also referred to as permeability, is a measurement of how permeable something is 1. The reservoir's initial pressure. 2. Average reservoir pressure at a specific point in the well's life 3. Reservoir size and distance from reservoir limits. 4. The implications of being close to a wellbore (skin). 5. Effects of wellbore storage. 6. Fluid characteristics (sampling) [7]

Production and injection wells are the two types of well-tests.

Well test analysis

It is the process of obtaining information from a producing well's data, such as pressure and rate of production [8]. One of the most efficient methods for estimating important well and reservoir characteristics is to use pressure transient analysis (PTA) [9]. Reservoir size and shape (e.g., permeability, fracture properties, reservoir model, distance to boundary, etc.), completion reliability (e.g., skin, fracture performance...etc.), tubing performance (e.g., optimum tubing design and artificial lift requirements), and reservoir characterization are just a few (i.e. dual porosity, layered reservoir, composite, etc.). As a result, understanding PTA is critical for gathering critical information for field development and well optimization. Well, testing helps with production engineering by revealing the state of the reservoir volume near the well Agarwal, [10]. With time, pressure transient analysis technology has advanced. Real-world samples of pressure data that correlate to a given idealized model, on the other hand, are usually unavailable.

There are two types of well-test analysis: qualitative and quantitative.

Pressure transients are investigated.

The decrease curve was examined [11]. Pressure transient analysis tracks both the flow rate and the pressure over time [11]. The flow rate is computed throughout constant well pressure in decline curve analysis. Transient testing is used for short-term research, whereas decline curve analysis is used for long-term investigations.

Philosophy of Well Test Analysis

Examination of the dynamic pressure behavior in response to an adequately designed sequence of well rate changes will disclose properties that characterize wells and reservoirs during monitoring, depending on reservoir and well parameters [3].

What Is the Quality of Test Analyses?

i. We choose a constant rate period (typically a buildup). ii. We plot a function of pressure vs. time iii. We try to identify flow regimes (radial, linear, spherical). iv. We incorporate these flow regimes into an interpretation model capable of reproducing the pressure given the rate (or vice versa) [8]

Skin Damage

Another indicator of formation damage is the skin [12]. A zone of altered formation permeability near a wellbore that occurs as a result of drilling, completion, or stimulation is known as the skin effect [13]. When the skin factor was applied to the petroleum industry, researchers discovered that if the calculated bottom hole pressure for a given flow rate is less than the theoretical value, additional time-independent pressure loss is present [12]. This decrease in skin pressure is linked to a damaged zone around the wellbore known as the skin zone, as shown in Fig. 1.

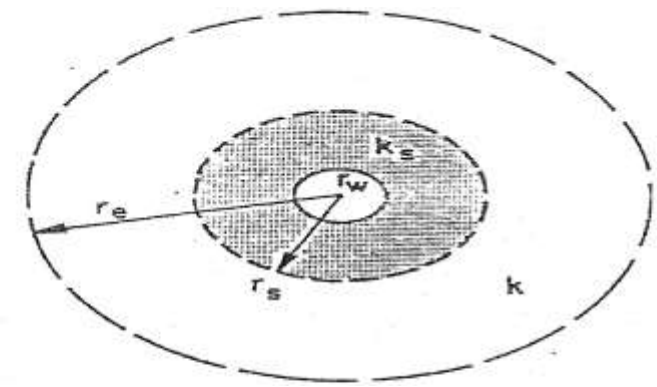

Fig. 1: A well with skin damage is illustrated in a diagram [12].

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 [14]. 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 [6].

$$s = \left(\frac{k}{kd} - 1\right) In\left(\frac{rd}{rw}\right) \quad (1) \quad [6].$$

Decrease of Well Performance

A decline in well performance is another indication of formation deterioration [12]. Measurements of the productivity index reveal how well a well is doing. When the productivity index falls, there's a significant possibility that the decline in fluid production is due to formation damage. The productivity index is the rate calculated by measuring unit pressure decrease in the reservoir.

$$\text{PI} = \frac{Qsc}{Pe - Pwf} \quad (2) \quad [12].$$

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.

$$PI = \frac{kh}{141.2B\mu\left(In\left(\frac{re}{rw}\right) + s\right)} \quad (2.7) \ [12].$$

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.

III. MATERIALS AND METHOD

The data and tool (software) utilized to carry out the set objectives in order to achieve the desired goal of this work are Well test data (Build up test data), Fluid and reservoir properties, Kappa Ecrin Saphir and Microsoft Excel.

3.1.1 Well Test Data (Build up test data)

During the period of shut-in, the data acquired is a response of pressure with time, resulting in a pressure build-up.

The fluctuating rate during the well's shut-in and flowing periods is shown in Table 3.1. Data from well A3 in the Gwuana field is shown in Table 3.2.

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

1Date	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

Tables 3.3 and 3.4 show the rate and pressure data obtained from Well J in the Akota field, which was employed in the analysis.

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

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 ºF	200
Formation compressibility, ps-1	3E-6

3.1.3 Saphir

Saphir is a program for analyzing pressure transients.

Its straightforward user interface and workflow enable quick training and self-learning for casual users.

3.1.4 Excel

In this project, Excel is being used to determine the productivity index of well A3 by changing the skin. It was also used to plot bottom hole flowing pressure (pwf) against flowrate (q). The end result should be an IPR with a straight line (Inflow Performance Relationship).

3.2 Description of Sequential Order of The Method

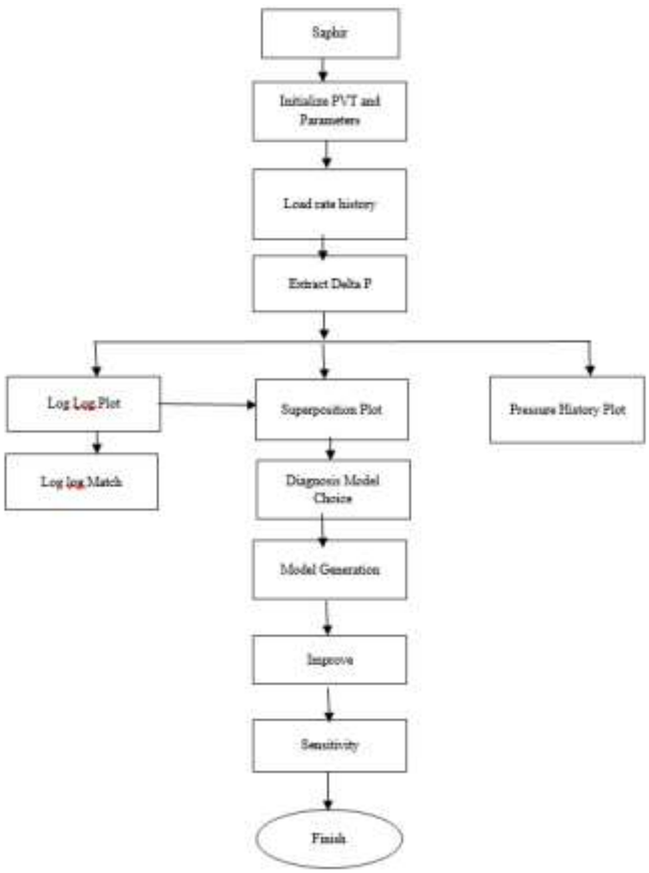

Fig. 2: Pressure Transient Analysis Workflow (Kappa Ecrin)

3.2.1 Steps in Performing Pressure Transient Analysis with Kappa Ecrin Saphir

The following are the step-by-step techniques for carrying out the proposed topic and attaining the work's goal.

Step 1: A new project was formed once the software was introduced. The information for the field was entered into a dialog box, as illustrated in Fig.3. If a user want to comment on the project, there existed a space for it. These remarks are saved in case the operator needs to know more about the test being performed in the future. There were extra fields for the test type, reference fluid type, available fluid rates, net drained thickness, well radius, and average porosity. The date was set to a reference time that coincided with the date the gauge began reading from the reservoir. The default values for all other parameters were used. After that, I'll proceed.

Fig. 3: System Option Setup

After pressing the Next button, a PVT property input box appeared, allowing you to enter the formation volume factor, viscosity, and total compressibility, as illustrated in Fig.4.

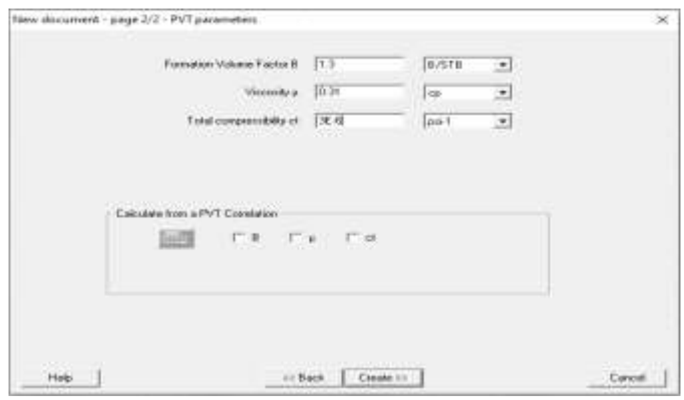

Fig. 4: PVT input dialog box

The create button was hit after entering the PVT properties, which brought up the Saphir main screen, as illustrated in Fig.5.

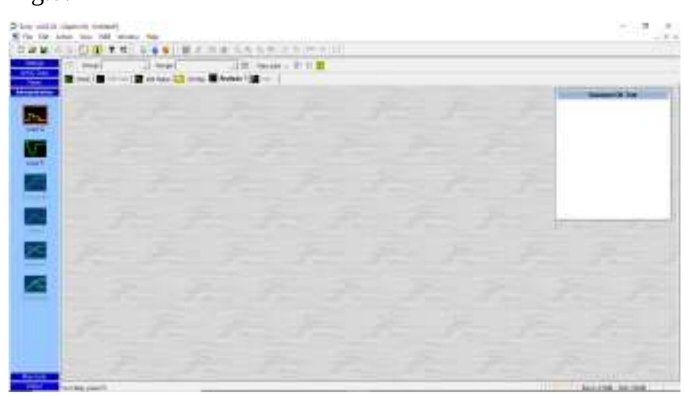

Fig. 5: Saphir main screen display

Step 2: Loading Data

By selecting the Load Q section of the Saphir main screen display, rate data was loaded into the software. As shown in Fig.6, a dialog box appeared, allowing you to choose the file format, such as ASCII or Excel.The file containing the rate data was looked for and selected after the data source was defined. Data could be manually entered by selecting the spreadsheet checkbox on the keyboard.

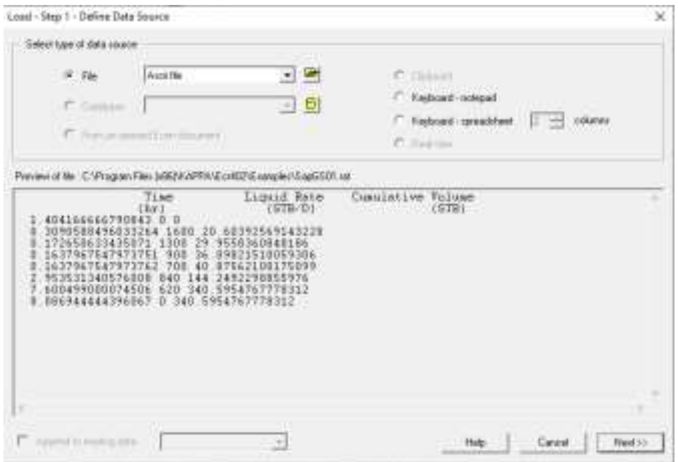

Fig. 6: Load – Step 1 – Define Data Source

The Next button was clicked which displayed another dialog box as shown in Fig. 7. The load button was clicked resulting in the generation of a history plot.

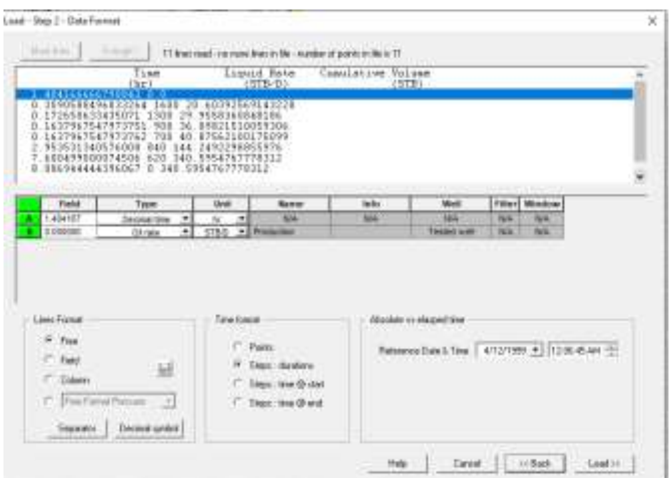

Fig. 7: Load – Step 2 – Data Format

The well pressure data was input after the history plot for the rate data was generated by clicking the Load P section on the left side of the Saphir software. As illustrated in Fig.8, a dialog box similar to the one that appeared when loading the rate appears, in which the type of data source is selected, the pressure data is loaded, and the Next button is clicked.

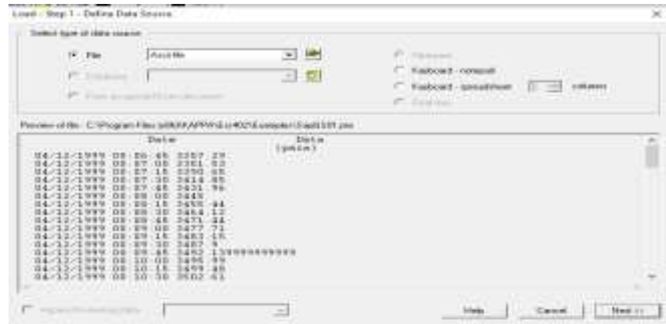

Fig. 8: Pressure Loading Step 1 – Define Data Source

The lines format was changed to field, and the date, time, and pressure formats were changed to the appropriate columns, as shown in Fig. 9. Then it was time to press the load button. Pressure (Psia) and Liquid Rate (STB/D) were plotted against Time (hr) in a history plot.

Fig. 9: Pressure Loading Step 2 – Data Format

Step 3: Extracting Delta P

The next phase in the Saphir software's pressure transient analysis is to extract delta P. A dialog box appeared when the extract delta P button on the left side of the screen was clicked, as illustrated in Fig.10. This dialog box is used to select the extraction timeframe. It's the 'build – up #1' in this situation. Following the selection of the extraction time, the OK button was pressed, and a new dialog box appeared, as seen in Fig.11. The software's default parameters were left alone, and the OK button was pressed.

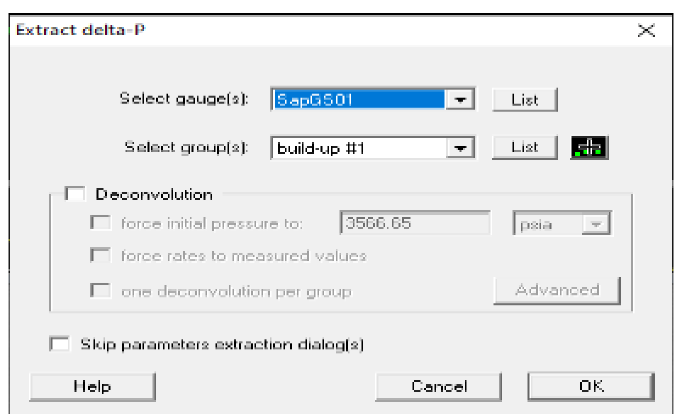

Fig. 10: Extract dialog 1

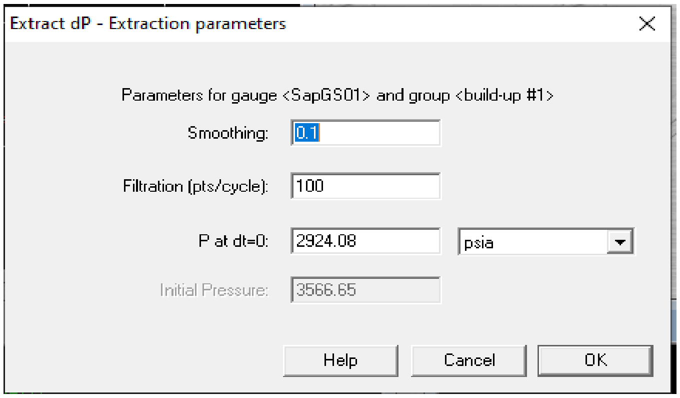

Fig. 11: Extract dialog 2

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

Step 4: Modelling

The model was adjusted in this section in order to mimic the reservoir's trend. This is the diagnostic phase, and it entails looking for all possible flow regimes in the extracted period's response. This enables the interpreter to select the model that best fits all of the identified flow regimes. The next step was to run the model and get the match, which produced the same results as before. When the model icon on the Saphir software's left side was clicked, a dialog box appeared with wellbore, well, boundary, and reservoir models, as illustrated in Fig.12. When OK was selected, a model was created that did not match the original. After that, the model must be improved to match.

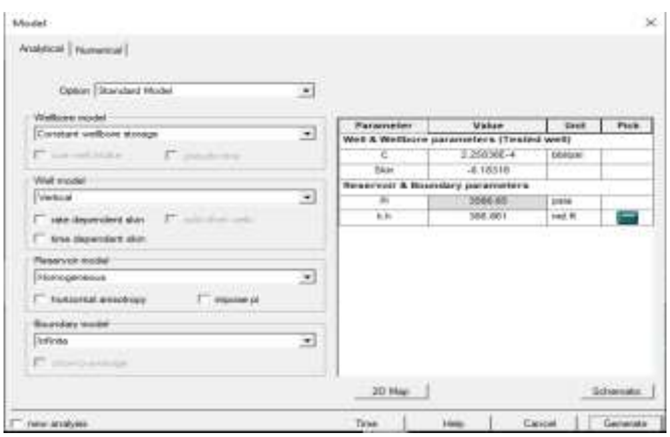

Fig.12: Model dialog

Step 5: Improving

When the enhance icon was clicked, a dialog box appeared, as seen in Fig. 13. The Wide search checkbox was chosen, and then the Run button was pressed, resulting in a model that matched the data on each of the Saphir screen's four plots.

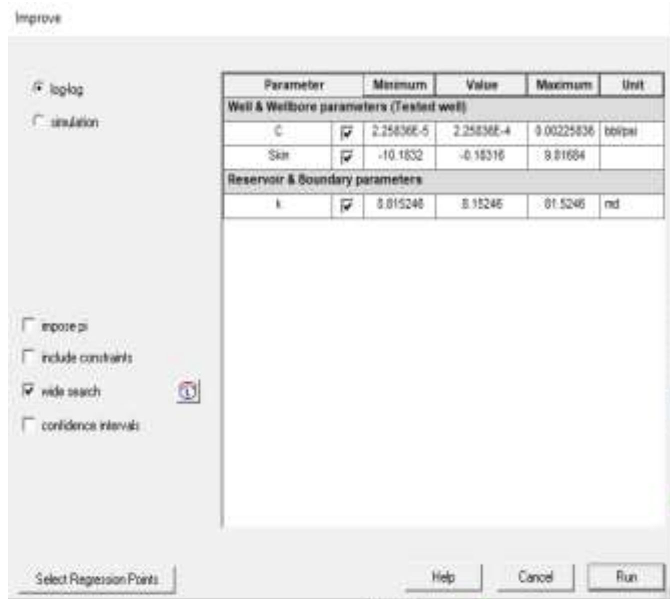

Fig.13: Improve Dialog

Step 6: Sensitivity

The workflow's final phase is sensitivity. When the sensitivity icon was clicked, a dialog appeared, as shown in Fig. 14, with the skin as the parameter to perform sensitivity on. The numbers 2, 4, 6, 8, 12, 14, 18, 20 were entered, and then Generate was clicked.

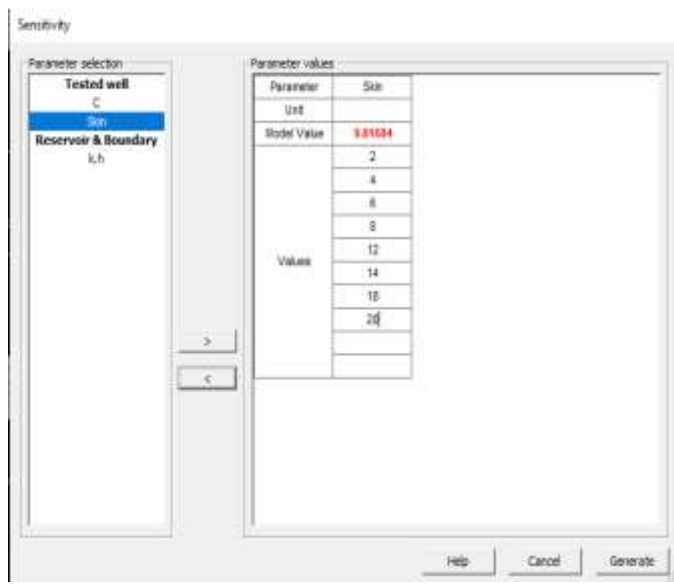

Fig. 14: Sensitivity Dialog

IV. RESULTS AND DISCUSSION

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

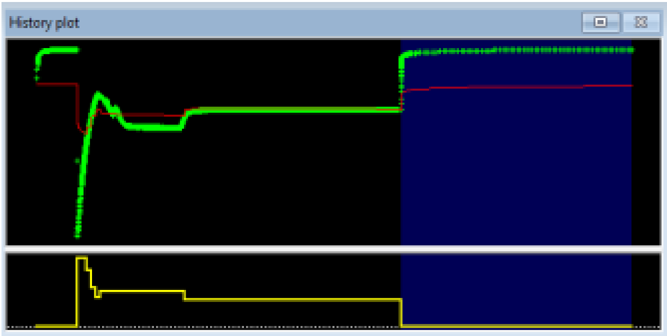

Fig. 15: History Plot Model Mismatch

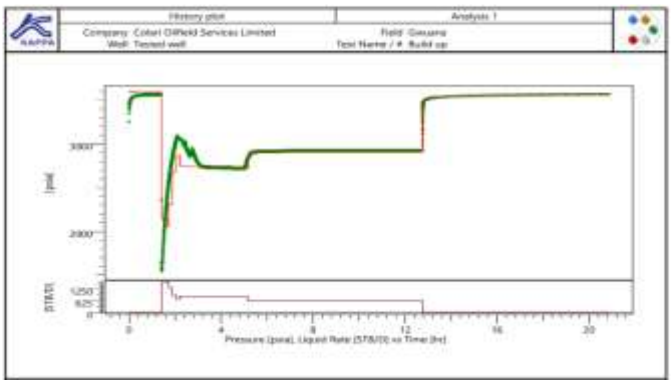

Fig. 16: History Plot Model Match

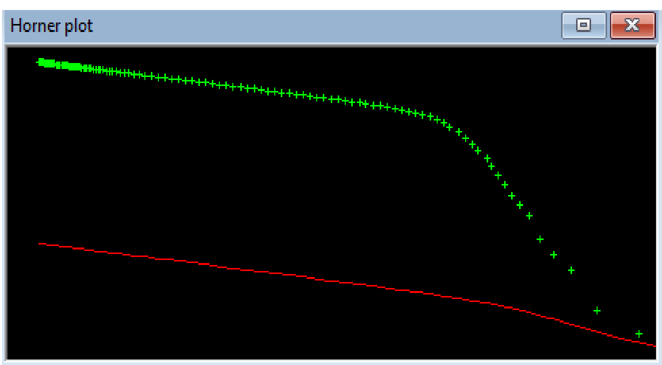

Fig. 17: Horner Plot Model Mismatch

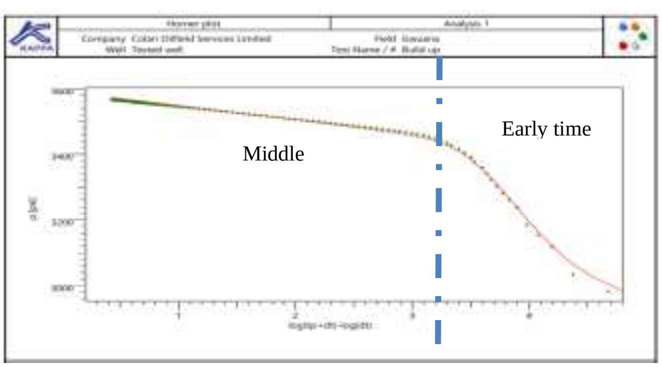

Fig. 18: Horner Plot Model Match

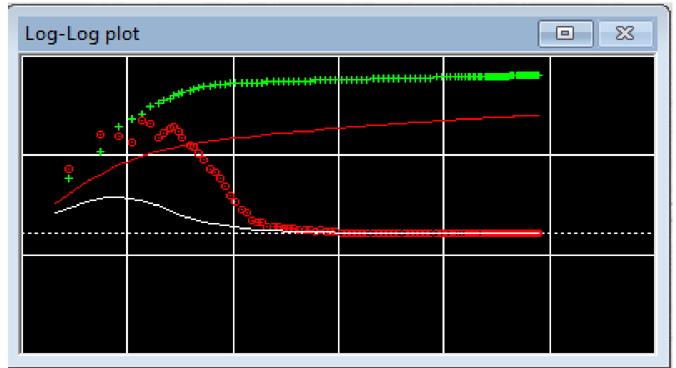

Fig. 19: Log-Log Plot Model Mismatch

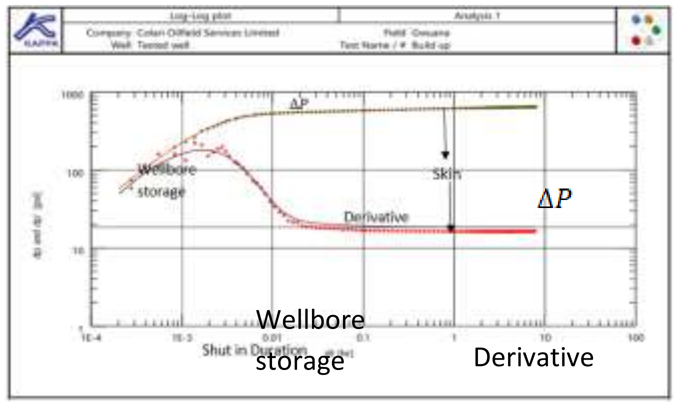

Fig. 20: Log-Log Plot Model Match

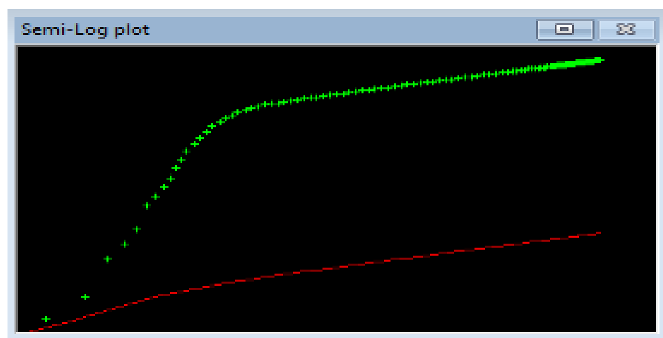

Fig. 21: Semi Log Plot Model Mismatch

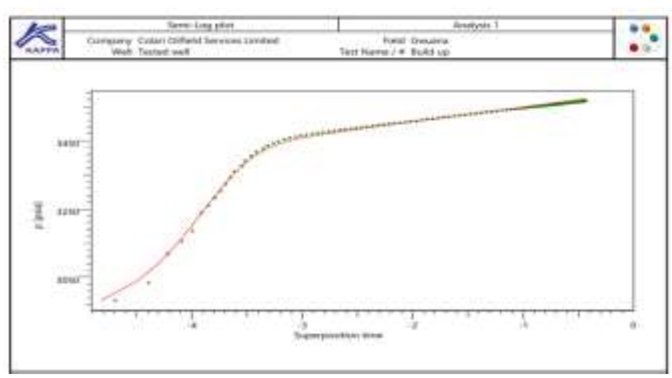

Fig. 22: Semi-Log Plot Model Match

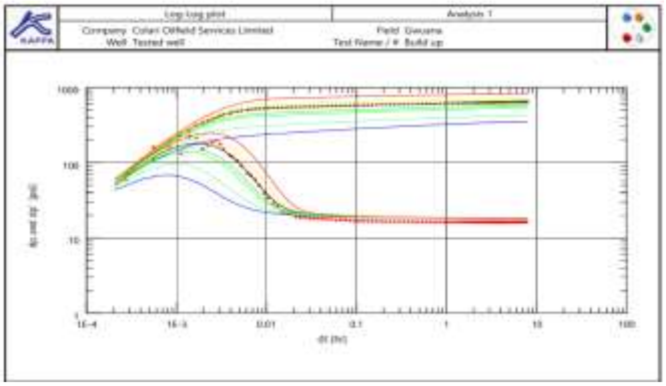

Fig. 23: Log-Log Plot - Skin Sensitivity Analysis

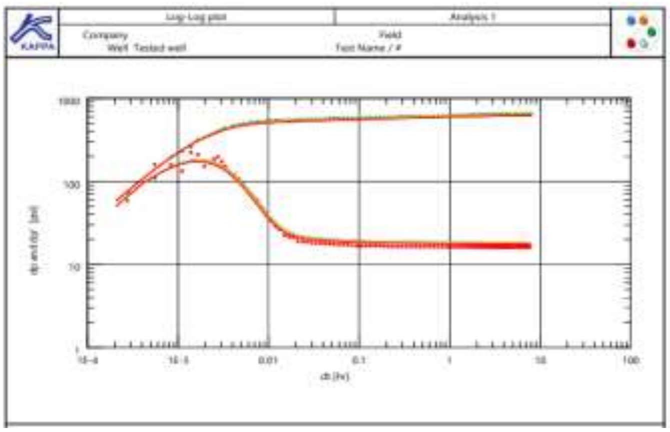

Fig. 24: Log-Log Plot – Permeability-Thickness Sensitivity Analysis

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

Fig.25: 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

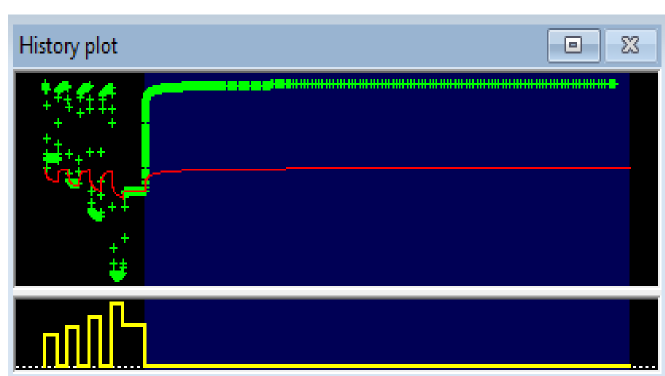

Fig. 26: History Plot Model Mismatch

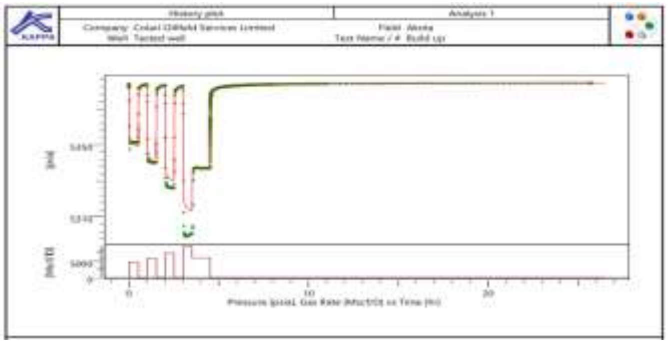

Fig. 27: History Plot Model Match

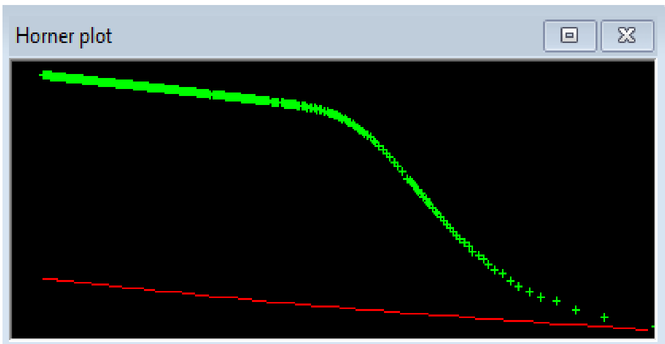

Fig. 28: Horner Plot Model Mismatch

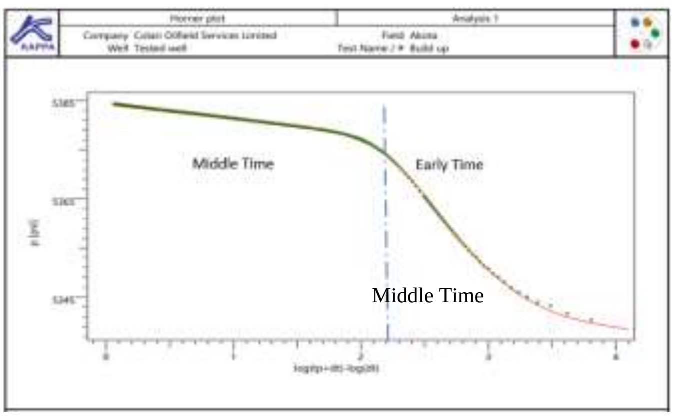

Fig. 29: Horner Plot Model Match

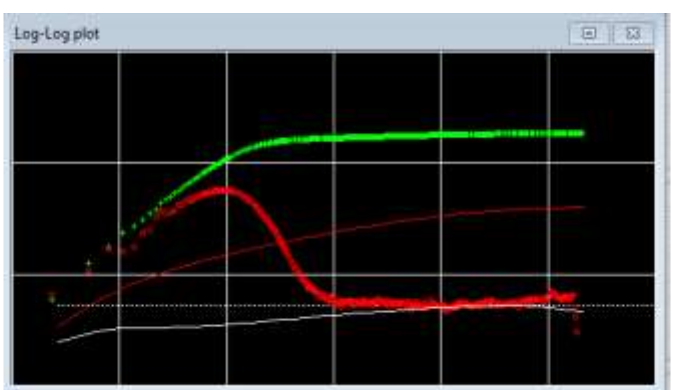

Fig. 30: Log-Log Plot Model Mismatch

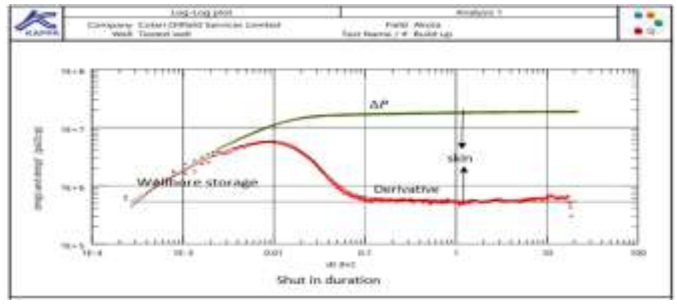

Fig. 31: Log-Log Plot Model Match

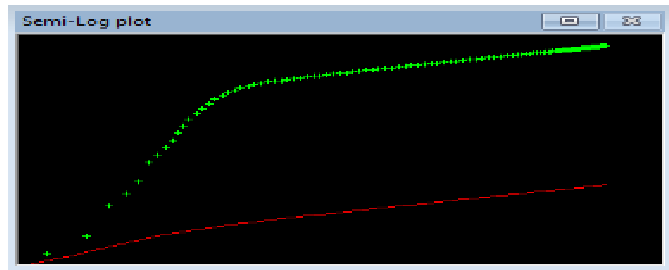

Fig. 32: Semi-Log Plot Model Mismatch

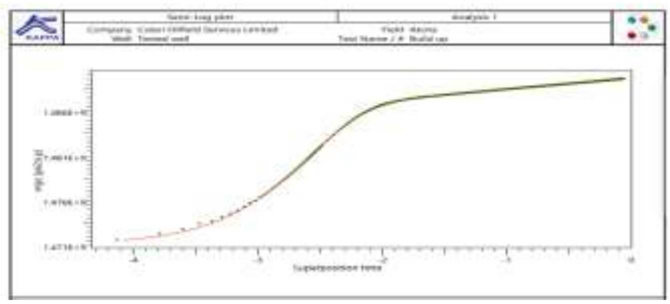

Fig.33: Semi-Log Plot Model Match

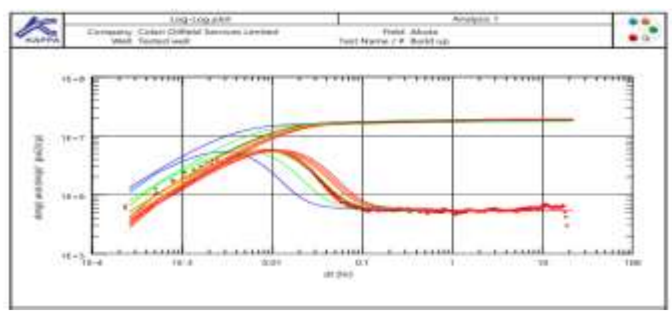

Fig.34: Log-Log Plot - Wellbore Storage Sensitivity Analysis

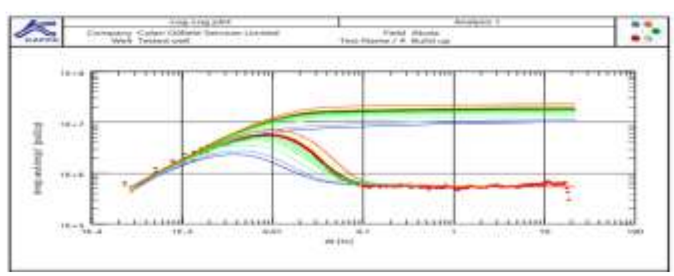

Fig. 35: Log-Log Plot - Skin Sensitivity Analysis

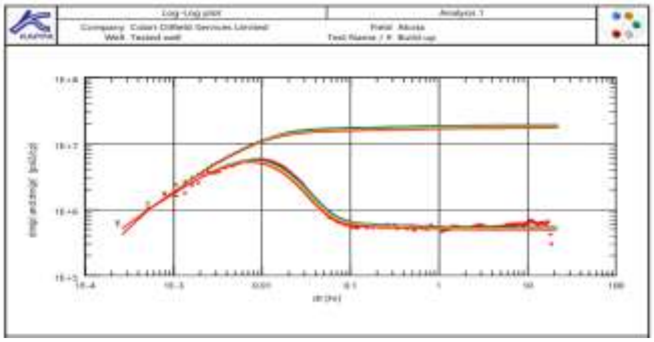

Fig. 36: Log-Log Plot - Permeability-Thickness Sensitivity Analysis

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 results of the pressure transient study of Well J and Well A3 utilizing Ecrin Saphir are discussed below. The explanation would include a detailed interpretation of the plots generated by the analysis, including semi-log, log-log, history, and Horner plots.

4.2.1 Discussion of Results from Well A3

The history plot of well A3 when the model did not match is shown in Fig. 15. The rate and pressure data were loaded into the software to create the history plot displayed in Fig. 16. A plot of liquid flow rate q (STB/D) vs. time (hr) is shown below, whereas a plot of well bottom hole flowing pressure (psia) vs. time is shown above (hr). The well was shut in for 1.40417 hours on 04/12/1999 at 00:06:45 a.m. This is a test survey of the pressure response during the shut-in time. The well was opened at 01:31:00am to produce at a rate of 1600STB/D for 0.309059 hours, then reduced to 1300STB/D at 01:49:33am for 0.172651 hours.

The rate was then decreased to 900STB/D for 0.163797hr at 01:59:54am. The rate was dropped to 700STB/D for another 0.163797hr at 02:09:44am, then the producing well's rate was boosted to 840STB/D at 02:19:33am. The rate was reduced to 620STB/D at 05:16:46am for 7.6005 hours after producing the well for 2.95353 hours. The well was sealed in (q = 0) for 8.08694 hours at 12:52:48pm. The production phase of the historical plot runs from 01:31:00am to 05:16:46am, whereas the buildup section runs from 12:52:48pm. Fig. 15 model is misaligned, however Fig. 16 model is correct. Fig. 15 was the result of the first stage of constructing a random model for the plot. The new result, as shown in Fig. 16, is a representation of what is happening in the reservoir after optimization. This model is critical for determining vital reservoir and wellbore parameters. The horner plot is a type of graphic used to analyze data from well tests, specifically buildup tests. The horner time is based on the notion of super positioning the shut-in and production times. The Horner plot is an extraction of delta P from the history plot's pressure buildup portion. Fig. 17 and 18 depict this plot. The graph shows the building pressure vs. Horner time, tH. The horizontal axis of the Horner plot is set to a log scale, while the vertical axis is set to an arithmetic scale. The vertical axis represents the pressure, while the horizontal axis represents the Horner time. The Horner plot is identical to the semi log plot, with the exception that the time (Horner time) advances from right to left in the Horner plot. The horner time is derived from the radial flow equation and should only be applied to radial flow analysis. It's valid if the reservoir is infinitely acting and the rate was constant previous to the shutoff. Fig. 17 depicts the horner plot model mismatch for well A3, whereas figure 4.4 depicts the horner plot model match for well A3. The mismatch is caused by the fact that the chosen model does not accurately represent the reservoir. The model match is shown in Fig. 18, which will aid in estimating important reservoir and wellbore parameters. After production shut in, there is a wellbore storage effect, as illustrated in Fig. 18, as a result of the early pressure behavior being dominated by the compressibility and volume of the wellbore fluid.

There was a transitory pressure response representing the intermediate period at the conclusion of the wellbore storage effect. The reservoir pressure did not reach the boundary, according to the plot. The delta P plot and the derivative plot make up the log – log plot, often known as a derivative plot. The delta P (P) plot, as shown in Fig. 20, is a plot of p vs. shut in duration, delta T (hr). Delta T is the plot of the pressure derivate to the shut-in duration, whereas the derivative plot is the plot of the pressure derivate to the shut-in duration (hrs). The vertical difference between the derivative and the delta P plot in Fig. 20 indicates the presence of skin or damage in the well. A higher separation indicates a thicker skin, whereas a smaller separation indicates a thinner skin. Delta t rises to the right, indicating that it rises away from the wellbore. According to the plot, wellbore storage occurs early in the shut-in phase due to fluid expansion in the wellbore. The rate at the surface is zero when the well is shut in, but it is not zero in the reservoir. As the rate in the reservoir steadily decreases to zero, a delay arises. The stability of the derivative plot could indicate a radial or circular flow towards the well in the horizontal plane, based on the plot. Large delta t indicates that the pressure response is approaching the boundaries, but the outcome indicates that the boundary is infinite because the pressure response did not approach the boundaries. The semi log plot is symmetrical to the horner plot, but the time exit direction is different. As shown in Fig. 22, the time increases from left to right in a semi log plot. Wellbore storage occurs early in shut in, and the pressure response is transient at the end of the wellbore storage phase. Fig. 21 depicts a model mismatch that results in incorrect well and reservoir parameters. Model match is shown in Fig. 22. Sensitivity analysis was used to validate the skin by selecting different skin values above and below the computed skin obtained from the software. The sensitivity to skin of wellA3 was generated on the log-log plot after random values for the skin were chosen. The software's original skin calculation remained unchanged. This is to demonstrate that the reservoir's computed skin is, in fact, the reservoir's skin. Fig. 23 illustrates this plot. Validation of the permeability-thickness, kh, obtained from the analysis is required. A sensitivity analysis was carried out by selecting values above and below the final result. Fig. 24 depicts the resulting plot. The permeability-thickness that was first obtained did not change.

Table 4.1 is merely a list of the assumed skin and permeability-thickness in an attempt to perform sensitivity analysis on the tool's results.

Fig. 25 depicts an IPR graph with a straight line. It indicates that the well is producing under saturated oil conditions (no gas at the wellbore). The Absolute Open Hole Factor, often known as qmax, is a measurement of how open a hole is. It's the flow rate when the bottom hole's flowing pressure is zero. The AOF is an idealized parameter that can be used to compare wells in the same field. The IPR depicted in a straight line is crucial for monitoring the well's performance. It's a graph of pwf (well flowing bottom hole pressure) vs. q (oil flowrate). The straight line IPR increases with decreasing skin, as shown in the graph. This demonstrates that if the well can be stimulated so that the skin is reduced, the well will produce more.

The skin effect on productivity index is tabulated in Table 4.2. Using Excel, the productivity index of well A3 was calculated using the formula for productivity index with changing skin factor. It was discovered that when the skin thickness decreased, the well's production index climbed. The model parameter results for well A3 are shown in Table 4.3. It contains the well's well and wellbore parameters. The total number of skins obtained is ten. This implies that the well is damaged, with reduced permeability around the wellbore, and that stimulation is required. The average permeability of the oil reservoir is K, which is 21.3md. The well's initial pressure is Pi. C, which is equal to 1.1E-4bbl/psi, relates to the wellbore storage and has a value of 3591.38psia. The model choice selected is also shown in the table, indicating that the well is vertical, the reservoir is homogeneous, and the boundaries are infinite. Table 4.3 also shows the buildup section's shut-in rate of 0STB/D, the rate change of 620STB/D, and the reservoir's beginning pressure. Pi It also includes the well A3 derived and secondary parameters. The scope of the investigation Rinv was determined to be 784 feet, which is the distance the pressure transient has traveled into the formation as a result of the well's rate shift. Another parameter produced from the analysis is Delta P (total skin). Its pressure value is 368 psi.

4.2.2 Discussion of Results from Well J

On July 30, 2001, at 00:00:00am, a pressure buildup test on a gas well J started with the well flowing at a rate of 4743.58Mscf/D for 0.5209 hours.The well was then shut in at 00:31:15am for 0.4972 hours to allow for pressure buildup, and then opened to flow at a rate of 5878.61MScf/D for 0.5014 hours at 01:01:05am, according to the plot in Fig. 27.The well was shut down for 0.4986 hours at 01:31:20 a.m. to allow pressure to build up. The well was started up for 0.5014 hours at a flow rate of 7239.46 MScf/D at 02:01:15 a.m. At 04:31:32am, the well was shut in for 21.99999hrs and the pressure transient response was measured.

It can be noticed that Fig. 26 model mismatched while Fig.27 matched. At initial stage of generating a random model for the plot, Fig. 26 was the result. After optimization, the new result is what is shown in Fig. 27 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 Fig. 28, and Fig. 29. 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 Fig. 29, 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.

Fig. 28 is a display of model mismatch. This is because the model parameters do not correspond with the reservoir and well parameters. Fig. 29 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 Fig. 30. 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.

Fig. 30 is a display of model mismatch. This is because the model parameters do not correspond with the reservoir and well parameters. Fig. 31 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 Fig. 32 and 4.33. At the early start of shut in, wellbore storage occurs and at the end of the wellbore storage period, the pressure response is transient. Fig. 32 is a display of model mismatch which would not give the correct well and reservoir parameters. Fig. 33, 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 Fig. 34. 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 Fig. 35.

A sensitivity analysis was conducted by choosing values above and below the permeability-thickness, kh. The resulting plot is shown in Fig. 36. 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 alsocontains 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.

V. CONCLUSION

The well is vertical, the reservoir is homogeneous, and the boundary condition is infinite, according to the pressure transient analysis of well A3. This is also the case with well J. Both wells exhibited wellbore storage effect from the start. Oil is present in well A3, whereas gas is present in well J. There was a mismatch when the model was first run, which led to the need for optimization. The model created following the optimization process matched the reservoir's pressure transient behavior. The reservoir volume, average permeability, skin, and beginning pressure are all determined by the model match. Well A3 has an average permeability of 21.3md, while well J has an average permeability of 107md. The wellbore is damaged with a skin factor of ten, as evidenced by the examination of pressure build-up data from wells A3 and J. For better productivity, the permeability around the wellbore would have to be increased. The productivity index, PI, of well A3 was developed using excel by applying its formula with varying skin factor, as part of the pressure transient analysis performed on well A3 and well J. The well's productivity index grew as the skin thickness decreased, according to the findings. Also plotted was a straight line IPR, which is useful in calculating the well's production. Furthermore, wells A3 and J are clearly damaged and would benefit from stimulation to increase productivity.

VI. RECOMMENDATIONS

i. Because the findings of the analysis suggest that wells A3 and J are damaged, management should stimulate the wells using either hydraulic fracturing or acidizing. The permeability around the wellbore would be increased as a result of this.

ii. After the stimulation job is completed, management should conduct another test on the wells to confirm that the skin has been removed.

iii. Using the graph in Fig. 25, management can decide to what extent the wellbore should be stimulated. Management can choose the skin that gives the well the highest production rate based on the graph.

iv. iv. The productivity index is a metric that indicates how well a well is working. When the productivity index lowers, there's a good possibility that the fall in fluid production is due to formation damage.

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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