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EVALUATING RESERVOIR BUILD UP TEST IN SOME SELECTED XYZ WELLS IN NIGER DELTA

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Abstract

Reservoir Buildup test is the measuring the well's sand face pressure variation with time while well is shut in. The tests are economical to run and correct analysis of such tests yields information about the reservoir and well properties. This research work discusses the daily experience gained from analyzing several tests ran in the Niger Delta wells. The tests were ran with Amerada and high precision electronic gauges. Our analysis methods include the conventional method, manual type-curve method and automated type-curve analysis methods. Our results show that the available manual type-curve cannot fit data from most Niger Delta wells because of the high skin and permeability values. Also, results obtained by evaluating the test with conventional and automated type-curve method agree reasonably in situations where the well-bore storage effect dies down early and transient state flow observed. Our results show that factors that make it difficult to analyze and evaluate tests ran in Niger Delta wells include: (a) Poor precision of gauges used (b) Unusually long well-bore storage duration. (c) Interference effects. Also our results show that the ratio of pressure drop due to damage-skin to pressure drawdown is a better yardstick for ranking acid stimulation candidates.

Keywords: Pressure, Permeability, Skin factor, build up test, shut down, well bore storage, Trasient state, Interference effect and Storage duration.

INTRODUCTION

Pressure buildup test involves measuring the bottom-hole pressure while the well is shut-in. Information that can be derived from buildup tests include formation permeability, skin factor, average pressure, distance to linear no-flow boundary and wellbore storage constant. Ideally, buildup test should be performed in wells produced at constant rate before shut-in. However, the effect of varying production rate before shut-in can be correctly handled by applying superposition theory'. Many authors[4] have suggested approximate methods of handling cases with varying rate that eliminates the rigorous mathematics encountered when superposition theory is used. Buildup test can be analyzed using both conventional and type-curve methods. The conventional methods include the Miller-Dyes Hutchinson (MDH) method,[5] Homer method and Muskats method[6] The Homer method was originally developed for new wells that were produced for a short period before shut-in while MDH method was developed for old wells that were produced for long period before shut-in. Ramey and Cobb[7] reviewed the two methods and concluded that the Homer method is superior to the MDH method even when used for old wells. Detail on analysis of buildup test using conventional methods can be found in Earlougher[1]. Type-curve analysis consists of finding a type curve that matches the actual

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response of the well and reservoir during the test. From the match, reservoir and well parameters are calculated. Ramey[8] was the first to use type- curves for analyzing drawdown tests. Later, several type-curves were published and adopted for interpretation of buildup tests. In 1983, Bourdet[9] et al introduced derivative type-curve which are not only used for estimating reservoir parameters, but are used as diagonistic tools for determining the nature of the reservoir. Initially, type-curve analysis was done manually, but with the proliferation of computer, the analysis is automated. Further discussion on automated type-curve analysis is given by Homer[10]. Pressure behaviour during buildup test can be affected by wellbore storage, interference, boundaries, etc. The manner in which these factors affect buildup test is discussed by Mathews and Russel[11].

BASIS FOR ANALYSIS AND EVALUATION

Understanding the theoretical basis for well test analysis is a necessary requirement for interpreting well tests correctly. One may argue that understanding well test theory is no more necessary because there are canned computer programs that can be used by anyone to do the analysis. We do not accept such argument because well test analysis is not just running computer programme to obtain parameters. One needs to understand factors that influence pressure data. One needs to choose the correct models for analysis and also interpret obtained results realistically. Many engineers in Nigeria believe that pressure transient tests are useless in Niger Delta wells. From our experience this belief is wrong. Pressure transient tests are useful in Niger Delta wells if problems in Niger Delta wells are considered in the analysis. Some of the problems include improper design of tests and high transmissivity formation. These problems and remedies have been discussed by Onyekonwu.[12] In this section, we shall discuss the basic theory of buildup test analysis. This will be useful to reservoir engineers, production engineers and even the technicians who go to the field to run the tests.

CONVENTIONAL EVALUATION

A well goes through different flow regimes when it starts producing or shut-in. Figure 1 shows the different flow regimes for shut-in well in a closed reservoir. Figure 1 shows that a shut-in well goes through a wellbore storage dominated regime and a transient state flow regime before stabilizing at the average pressure. Note that the wellbore storage regime and transient state regime are independent. This implies that long wellbore storage duration will completely marr the transient state flow regime which is the most important flow regime. On the other hand, if the transient state duration is short, the transient state will be marred. Equations governing each flow regime are known. The conventional analysis is based on using these equations to make appropriate graphs to delineate data obtained during each flow regime. From the graphs, parameters associated with each flow regime are calculated. Note that equations governing flow during the transition flow periods are not known and pressure data obtained during this period are not useful for conventional analysis. This implies that for conventional analysis to be applied correct sections of the data must be used. Discussion on methods of identifying data obtained during each flow regime follows.

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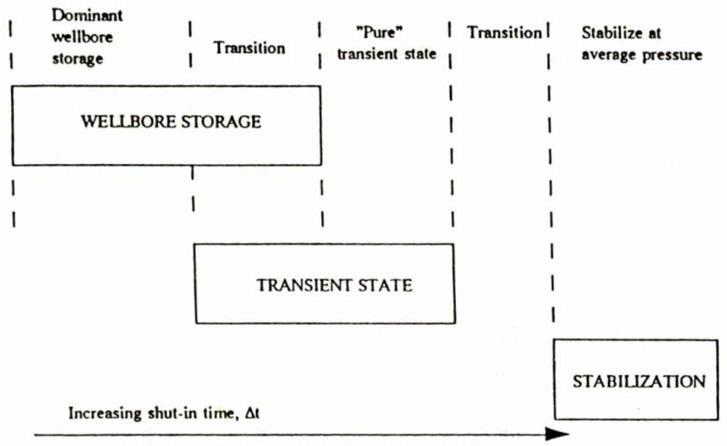

FIG. 1: FLOW REGIMES DURING BUILDUP

Wellbore Storage Effects

Flow rate measurement is usually done at the surface rather than at the sand face. Hence on opening a well at the surface, some fluid in the wellbore is produced initially. This fluid may have been stored in the annulus, tubing and surface line between the point of rate measurement and sand face. Also, on shutting- in a well at the surface, some fluid is still produced at the sand face into the wellbore at early shut-in time as fluid is compressible. The phenomenon in which some fluid is produced from or stored in the wellbore is known as wellbore storage phenomenon. It is an early time phenomenon.

Agarwal et al have shown that during drawdown, data obtained during wellbore storage dominated flow regime fail on a unit- slope straight line if a graph of log pwf versus log t is made. Data points on the unit-slope can be used to calculate wellbore storage constant. This follows from the fact that the equation governing flow during wellbore storage dominated flow regime is:

$$P_D = \frac{tp}{Cd} \qquad \text{\_\_\_\_\_\_\_\_\_\_} \qquad (1)$$

Where

P_D= dimensionless pressure

t_D= dimensionless time

C_D= dimensionless weilbore storage constant (assumed constant).

Similarly, for buildup, all data points strongly influenced by wellbore storage will fall on a unit-slope line on a graph of log ($P_{ws} - P_{wf}(t_p)$) versus log Δt. Data not influenced by wellbore storage occur at times between 10Δt* to 50Δt* where Δt* is the end of the unit-slope line. This is equivalent to the 1 to 1½ cycle rule. Figure 2 illustrates this point for a normal case.

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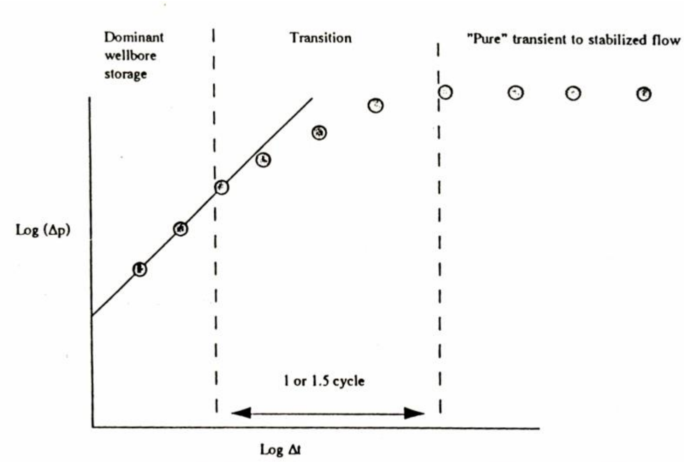

FIG. 2: DETECTION OF DATA INFLUENCED BY WELLBORE STORAGE EFFECTS

Detecting strongly influenced data points by graphing log $\left[P_{ws} - P_{wf}\left(t_p\right)\right]$ versus **Δ**t assumes that tp + **Δ**t>> **Δ**t.

Transient State

Transient state flow regime occurs when the effect of the boundary is not felt. Homer2 has shown that during the transient state period, the flow equation is

Pws=P* - 162.6$\frac{\mathbf{qB\mu}}{\mathbf{Kh}}\mathbf{log}\left\{\frac{t_p+\Delta_t}{\Delta_t}\right\}$ ______________ (2)

Where

P_{ws}	=	shut-in pressure, psi
q	=	flow rate, STB/D
B	=	formation factor, rb/STB
K	=	permeability, m4
p	=	viscosity, cp
tp	=	production time before shut-in
Δt	=	shut-in time
P*	=	false pressure, psi

Equation 2 implies that a graph of Pws versus t_y+Δt______

Log $\left\{\frac{t_p+\Delta_t}{\Delta_t}\right\}$ is a straight line and the slope Δt

m (psi/cycle) = -162.6 $\frac{\mathbf{qB\mu}}{\mathbf{Kh}}$

Similarly Miller, Dyes and Hutchinson5 have shown that for wells produced for a long time

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before shut-in, the governing equation is.

$$Pws = C + 162.6 \frac{qB\mu}{Kh} \log \Delta t \quad (3)$$

Where C is a constant.

Equations 2 and 3 assume that the log approximation holds. Other assumptions made in deriving Eqs. 2 and 3 are discussed in detail by Ramey and Cobb7.

Figure 3 shows a typical Horners graph. Note that the transient state data that fall on the straight line are the ones not influenced by wellbore storage effect.

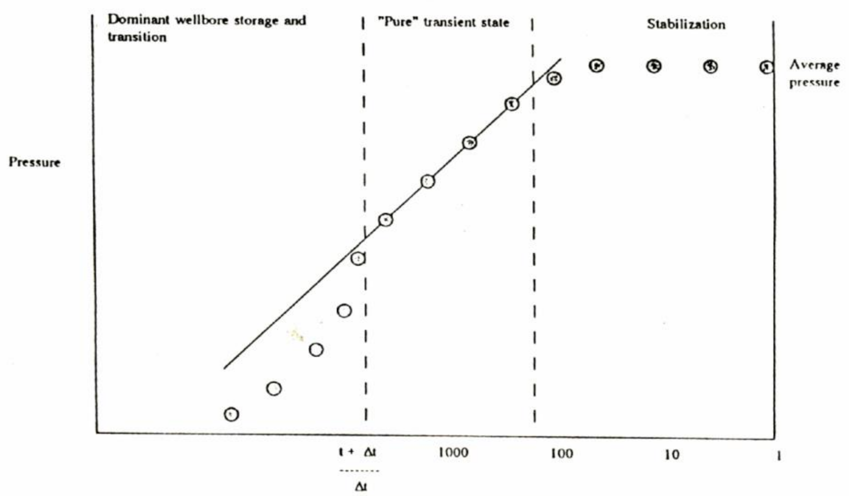

FIG. 3: TYPICAL HORNER'S PLOT

TYPE CURVE ANALYSIS

Type-curves are derived from solutions to the flow equations under specific initial and boundary conditions. Gringarten[14] defined a type-curve as a graphic representation of the theoretical response during a test of an interpretation model that represents the well and the reservoir being tested. For a constant- pressure test, the response is the change in production rate; for a constant-rate test, the response is the change in pressure at the bottom of the well. Other types of responses, such as the time derivative of the bottom whole pressure, are also used.

The first step in type-curve analysis is to select the appropriate type-curve. This is done by using a plot of the derivative of pressure with respect to the log of some function of elapsed time. This graph has some characteristics that enable one to choose the correct type-curve. Detail on the characteristics is given by Gringarten14 and Ehlig-Economides IE.

The next step is to match the data with the selected type-curve. The match can be found graphically, by physically super-imposing a graph of the actual test data with the chosen type-curves and searching for the type-curve that provides the best fit. Alternatively, an automatic

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fitting technique involving non-linear regression can be used. Once the best fit is obtained, the desired reservoir and well properties are calculated from equations defining the dimensionless parameters used in the type- curve.

TYPE CURVE ANALYSIS AND CONVENTIONAL ANALYSIS

Type curves describe the entire behaviour of the interpretation model corresponding to the well and the reservoir and include the various flow regimes that successively dominate during the test. As a result, type-curve analysis provides the entire well and reservoir parameters that can be obtained from well testing. Conventional analysis methods, on the other hand are valid only for a specific flow regime. As a result, they provide only well and reservoir parameters characteristic of that flow regime. Both type-curve analysis and conventional analysis give the same results if a given flow regime exist. Disparity in results occurs when the flow regime is incorrectly identified during the conventional analysis. Simulating the test data with calculated parameters and comparing with actual data is one way of knowing which of the analysis method is better.

NIGERIAN CASES

In this section, we shall show some cases of pressure buildup analysis for Nigerian wells. We shall discuss factors that affect these tests.

CASE i - Quality of Data

Figures 4 to 6 show graphs used in analyzing pressure buildup test ran in Well X with an electronic gauge. Figure 4 is a log-log graph and it shows that initially there was wellbore storage effect which died down completely after about 300 seconds. Figure 5 is semi log graph of pressure data with the correct straight line starting at about 300 seconds.

Figure 6 is a log-log plot showing both the pressure and pressure derivative. The pressure derivative clearly shows the wellbore storage phase and the radial flow phase. Hence, it is expected that both conventional analysis and type-curve analysis will yield similar results. Note that the noise in the pressure derivative is small because of the accuracy of data obtained with the electronic gauge.

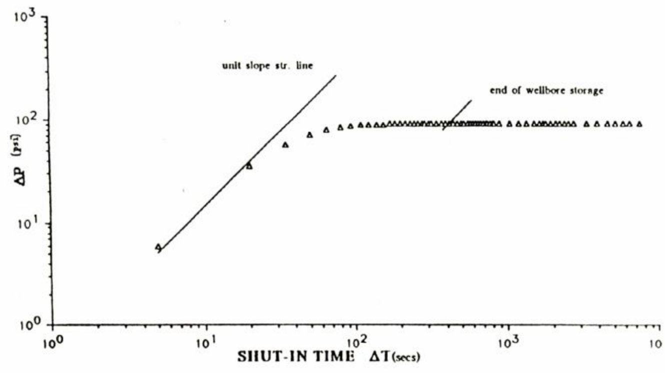

FIG. 4: LOG-LOG PLOT (WELL A)

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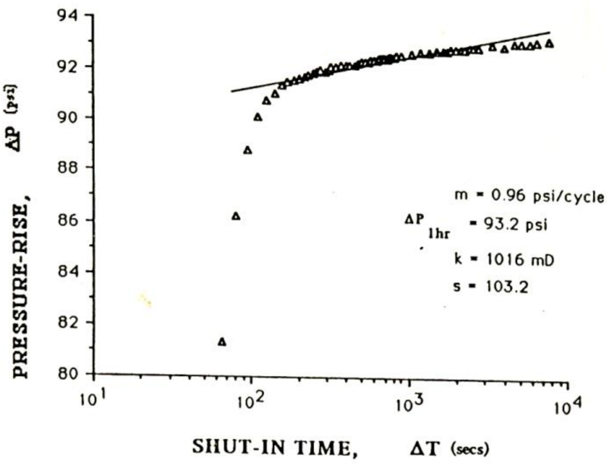

FIG. 5: ENLARGED MDH PLOT (WELL A)

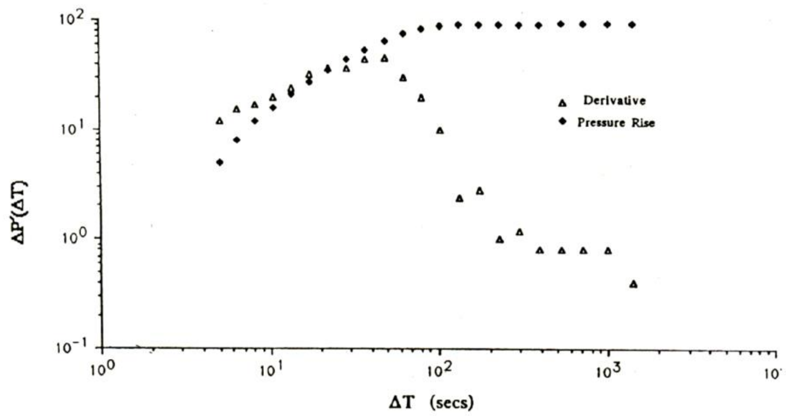

FIG. 6: TYPE CURVE ANALYSIS (WELL A)

Table 1 contains a summary of results obtained by analyzing this test.

Table 1: Results or Test Analysis (Well X)

	Values Obtained	
Parameter	**Conventional**	**Type-Curve**
Permeability, md	959.000	1015.000
Total Skin	13.730	12.520
Skin due to damage	3.200	2.500
Wellbore Storage bb/psi	0.089	0.086

From Table 1, we conclude that both conventional analysis and type-curve analysis methods yield the same results if the tests are properly run.

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CASE ii. Interference Effect

Figure 7 is a buildup graph of Well Y. On shutting the well, the pressure rises and later drops due to interference effect. Interference in this case was as result of communication between the long string and short string.

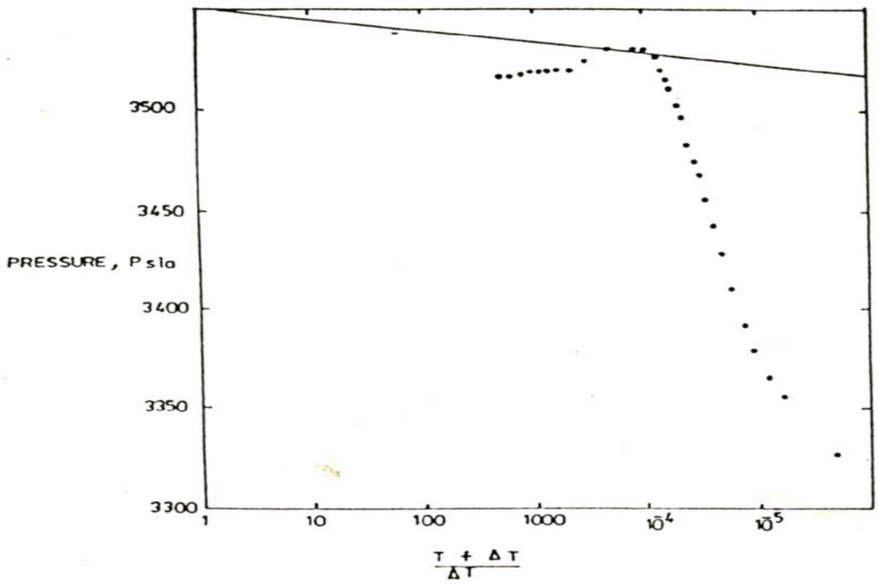

FIG. 7: HORNER PLOT (WELL B)

Table 2 shows results obtained by analyzing this test using both conventional and type-curve methods

Table 2: Results of Test Analysis (Well Y)

	Values Obtained	
Parameter	**Conventional**	**Type-Curve**
Permeability, md	673	3396
Total Skin	53	193
Skin due to damage	9	628
Wellbore Storage bb/psi	135	167

From Table 2, the values that should be accepted are not obvious. Such problems can be solved by simulating the pressure profiles with calculated values and comparing with real data.

The continuous lines in Figure 8 show the simulated profiles obtained with results obtained from conventional analysis. The discrete points are the actual pressures and derivatives. Figure 9 is similar to Fig. 8, but in this case the simulated profiles were obtained with values obtained from type-curve analysis from the derivative plot, it is obvious that the conventional analysis results are more reliable because the simulated derivatives match the actual derivative reasonably well.

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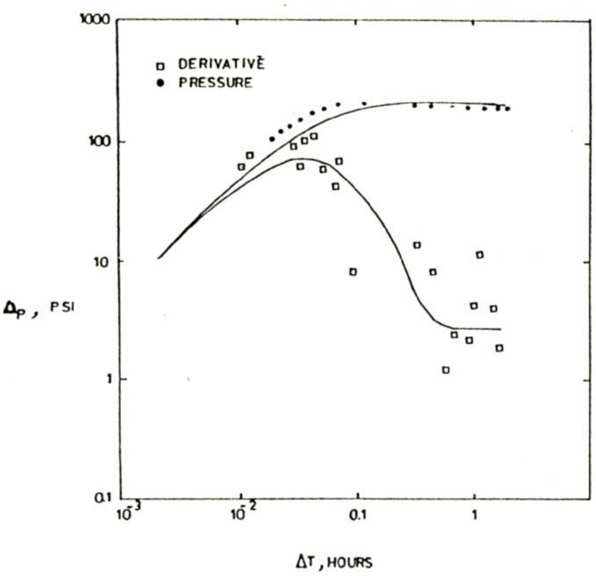

FIG. 8: SIMULATED PROFILES-CONVENTIONAL ANALYSIS (WELL B)

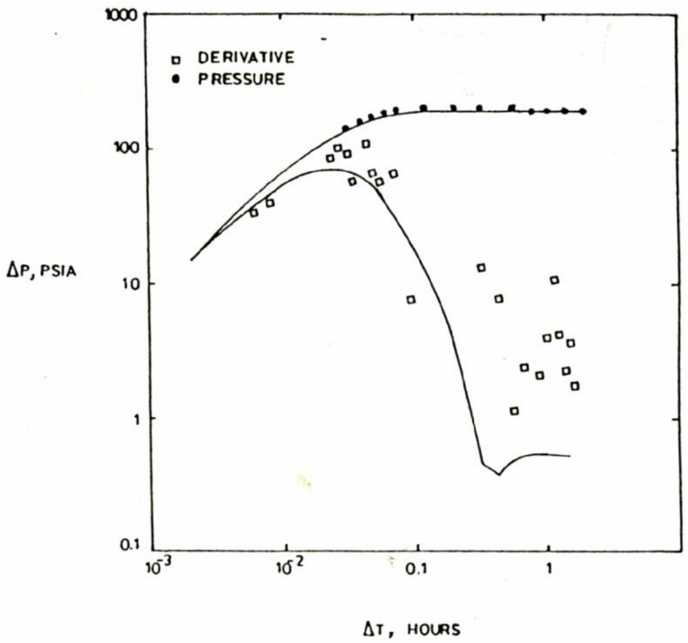

FIG. 9: SIMULATED PROFILES - TYPE CURVE ANALYSIS (WELL B)

Generally, the type-curve analysis is superior to the conventional analysis, but when the data contain errors, results from type-curve analysis are poor. This is because every data point in automated type-curve analysis is weighted equally.

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Such problems in automated type-curve analysis can be solved by correcting for interference, if possible, or filtering the data. Alternatively the manual type-curves may be used with the bad data points disregarded. Note that even though results obtained with conventional and type-curve analysis methods do not agree, but the pressure drop across the skin calculated with both methods are fairly close. We found this to be true in most cases. Hence, conclusions reached on the state of damage may not be erroneous.

CASE iii - Effect of Low Permeability

Generally, the duration of wellbore storage effect is long in reservoir with low permeability. Figure 10 shows such case in Well Z in Niger Delta. The wellbore storage effect lasted for more than 3 hours. Well C produces with a GOR of 5545 SCF/STB. This is substantial and hence contributed to the long duration of the wellbore storage. Also, the calculated low permeability is the effective permeability to the oil phase.

The well was shut-in for six hours, but the derivative plot in Fig. 10 shows that the well was not shut-in long enough to reach a clearly defined transient state regime. This suggest that there is need to use a down whole shut-in tool while testing such high GOR wells. This is to reduce the wellbore storage duration and enhance reaching a transient state regime early.

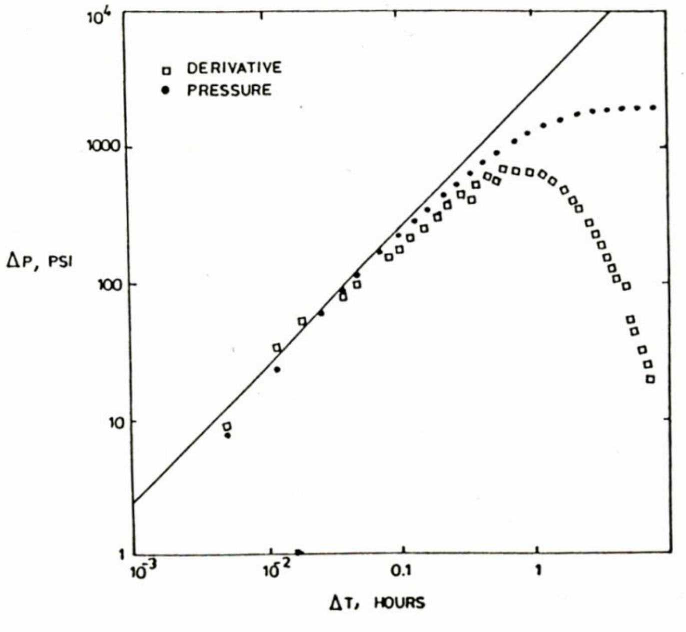

FIG. 10: LOG-LOG PLOT (WELL C)

Table 3 shows results obtained by analyzing tests run in Well Z.

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Table 3: Results of Test Analysis (Well Z)

	Values Obtained	
Parameter	**Conventional**	**Type-Curve**
Permeability, md	4.13	4.89
Total Skin	41.79	50.45
Δpskin, psi	1604.00	1639.00
Skin due to damage	2.81	3.91
Wellbore Storage bb/psi	864.00	

Initially, we doubted the low permeability value obtained in this test. However, the simulated profiles shown in Fig. 11 convinced us. The match between simulated profiles and actual data in Fig. 11 is good. Actually this is the best we have got with an Amerada chart data. From Table 3, the pressure drop due to damage- skin is large although the skin due to damage is small. We discuss this further. But well C is actually damaged.

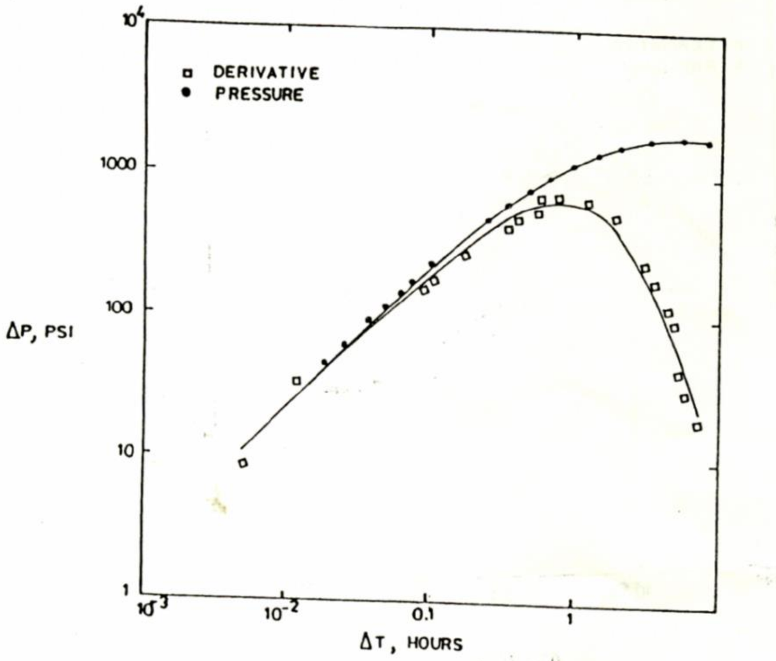

FIG. 11: SIMULATED PROFILE - TYPE CURVE ANALYSIS (WELL C)

CASE iv - Well With Vertical Plane Fracture

So far, we have seen one case of a well whose pressure buildup data fits the vertical plane fracture model. Figure 12 is a schematic of such model. Physically, this may represent a well on a linear fault. Figure 13 shows the actual data obtained from Well Z1 and the simulated profiles generated with results obtained from type-curve analysis.

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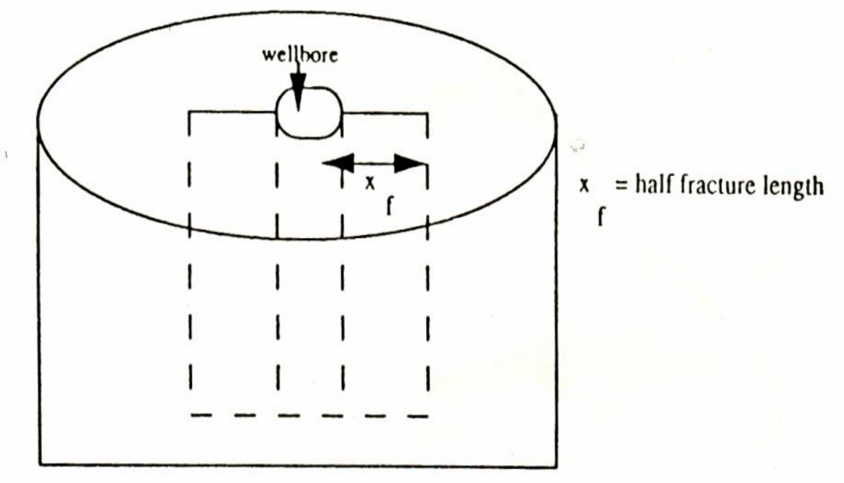

FIG 12: VERTICAL PLANE FRACTURE MODEL

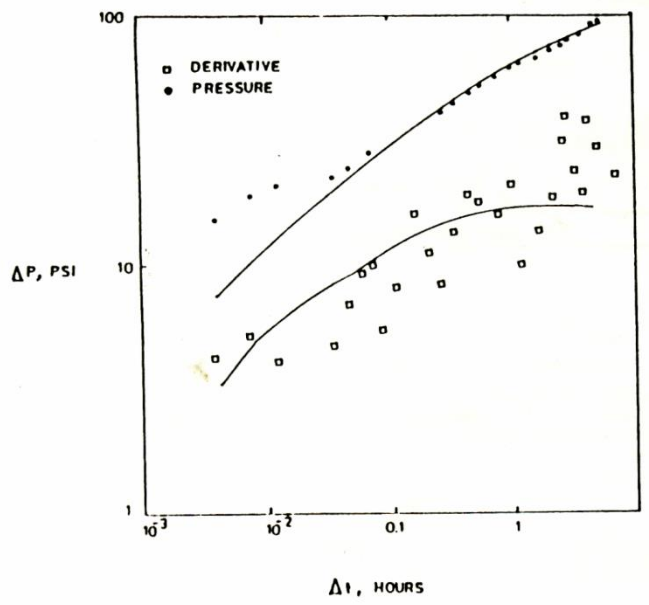

FIG. 13: SIMULATED PROFILE - TYPE CURVE ANALYSIS (WELL D)

Table 4 shows a summary of the results obtained from the analysis.

Table 4: Results of Test Analysis (Well Z1)

	Values Obtained	
Parameter	**Conventional**	**Type-Curve**
Permeability, md	23.3	34.1
Fracture length, ft	29.6	46.2
Total Skin	-4.6	-4.1

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CASE v - Skin Effect

In course of our interaction with clients, we observed that the skin effect obtained from well test is interpreted as the skin due to damage. Hence the decision on whether to stimulate a well was based on this skin. This is not the correct interpretation of the skin factor calculated from well tests. The skin factor calculated from well test is correctly called the total skin factor. It is not just skin due to alteration of permeability around wellbore, but includes other skins due to partial completion (mechanical skin), slanted well, perforation, and factors that create additional pressure drop around the wellbore. The skin due to alteration of permeability around the wellbore can be calculated from the total skin by deducting other skin factors. The procedure for the deduction is described by Onyekonwu and Okpobin[16].

The decision on whether to acidize should be based on the skin due to alteration of permeability around wellbore. This is also called the damage skin. However, in making the decision, the magnitude of the skin should not be the most important fx4or rather the determining factor should be the pressure drop due to the damage skin.

The pressure drop due to damage skin is given in Oilfield units as:

$$\mathbf{Dp_{damage\ sk\ in}} = \mathbf{141.2\frac{qB\mu}{Kh_c}S_d} \qquad \text{---------} \qquad \textbf{(4)}$$

where

Δp damage = pressure drop due to damage skin, psi

q = flow rate, STB/D

μ = viscosity, cp

k = permeability, md

hc = perforated thickness, ft

Sd = damage skin factor

The magnitude of $\Delta p_{\text{damage skin}}$, give the amount of pressure loss due to damage.

In addition to $\Delta p_{\text{damage skin}}$ the ratio of $\Delta p_{\text{damage skin}}$ to total drawdown may be used as yardstick for selecting stimulation candidates. Mathematically, the ratio is defined as follows:

$$R = \frac{\Delta p_{\text{damage skin}}}{P - Pwf\,(\Delta t = 0)} \qquad \text{- - - - - -} \qquad (5)$$

Where

P = average pressure, psi (could be replaced by false pressure p*)

$p_{wf}(\Delta t=O)$ = flowing pressure just before shut-in, psi

Wells with higher R need immediate attention.

Selecting a well for acid stimulation assumes that whatever caused the damage can be dissolved by the acid. In cases where there is high gas saturation around the wellbore due to gas

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production, the problem of excessive gas production should be addressed before an acid stimulation job is done.

Table 5 shows the total skin, damage skin, pressure drop across the skin and R for different wells.

Table 5: Total Skin, Damage Skin, Pressure Drop, and R

	WELL TEST NO						
	1	2	3	4	5	6	7
Total Skin	18.40	35.0	26.40	192.00	6.1	196.00	63.60
Dpskin,psi	57.86	174.2	216.60	723.00	9.9	119.00	367.00
Damage Skin	3.34	9.1	16.60	45.00	-17.6	66.00	3.15
DPthmage Skin Psi	30.72	135.2	204.00	677.00	-17.5	115.00	190.00
R	0.34	0.71	0.75	0.91	-	0.95	.47

From Table 5, we inferences can make the following

1) A positive total skin does not necessarily imply that a well is damaged. See Well 5 results in Table 5.
2) Wells 4 and 6 have a substantial amount of their drawdown lost due to damage around the wellbore.
3) Using the damage skin factor instead of the R factor for determining the priority for acid stimulation may not be proper always.

For example, Well 6 has a damage skin of 66 and damage pressure drop of 115 psi while Well 4 has a damage skin of 45 and damage pressure drop of 677 psi. From the damage skin alone, it seems as if Well 6 should be given immediate attention. However, the R factors of Wells 4 and 6 are close. This implies that both wells need immediate attention.

Other Cases

In course of our analysis, we made other observations. The first concerns the use of Amerada gauges and electronic gauges. The electronic gauges give more accurate data than the Amerada gauges because of their better precision. However, the Amerada gauges are not useless. With good scanners, Amerada gauge data can be read correctly. With the exception of Case A, all other test data discussed in this paper were read from Amerada charts.

Secondly, we noticed that the polished pressure and derivative type-curves could not be used to match some of our data because of the high skin and transmissivity in some of our systems. New type-curves have to be produced for such formations. An example where a match was obtained is shown in Fig 14. The problem of finding type-curves that can be used was solved by using automated type-curve matching packages.

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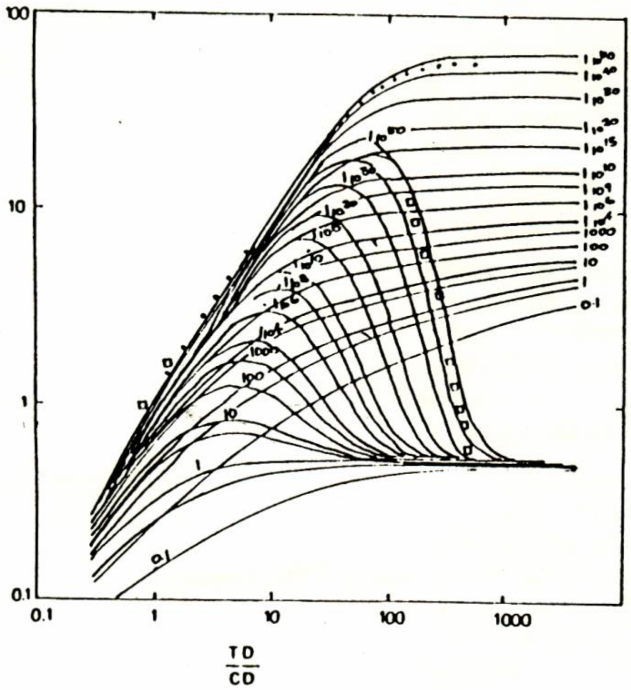

FIG 14: MANUAL TYPE-CURVE MATCHING

Finally, we noticed that the wellbore storage factor may not be constant. A constant wellbore storage factor is used in all well test packages.

CONCLUSIONS

From our experience in analyzing well tests, we make the following conclusions:

1. The quality of data affects the results obtained from well test analysis. It also influences results obtained using different analysis methods
2. Differences in results obtained using different analysis methods may also be due to long duration of wellbore storage effects and tests not run long enough to exhibit the transient state flow regime.
3. Interference effects affect the results obtained from well tests analysis if such interference effects are not corrected. The interference may be as a result of communication between long and short strings or interference from adjacent wells.
4. The total skin should not be used for determining stimulation candidates. The skin due to damage should be used. We recommend that the ratio of pressure drop due to damage skin to drawdown should be used for ranking stimulation candidates.

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NOMENCLATURE

P	= average pressure, psi [could be replaced by false pressure p*)
Pwf(Δt=O)	= flowing pressure just before shut-in, psi
ΔP damage skin	= pressure drop due to damage skin, psi
q	= flow rate, STB\D
p	= viscosity, cp
k	= permeability, md
h_c	= perforated thickness, ft
S_d	= damage skin factor
P_{ws}	= shut-in pressure, psi
B	= formation factor, rb/STB
tp	= production time before shut-in
Δt	= shut-in time
P*	= false pressure, psi
P_D	= dimensionless pressure
t_D	= dimensionless tune
C_D	= dimensionless wellbore storage constant (assumed constant)
R	= ratio of pressure drop due to damage skin to draw down

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