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THE EFFECT OF PERMEABILITY DISCONTINUITIES ON PRESSURE BUILD-UP BEHAVIOR

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ABSTRACT FLUSH-LEFT CAPS, UNDLINED.

This paper presents a study of certain permeability discontinuities as observed in drill-stem test pressure build-up behavior. Pressure build-up anomalies, under unsteady-state conditions, were investigated to determine the type and relative location of discontinuities in the formation. These anomalies are identified by an interpretation of the build-up behavior and extrapolation plot and confirmed by field results.

Illustrations are submitted on permeability reduction at the wellbore resulting from formation damage, deep mud invasion, after-production, vertical permeability, permeability reduction, and linear barriers. A practical analogy of these discontinuities is made to show their immediate relation to the test and the probable ultimate reaction of the producing zone.

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INTRODUCTION FLUSH-LEFT CAPS, UNDLINED.

The pressure build-up behavior of a drill-stem test indicates all pressure transients within the radius of disturbance during the drawdown period. These pressure transients take on a definite build-up behavior for a certain combination of formation characteristics. Unfortunately, all productive zones are not homogenous and isotropic, but exhibit discontinuities of permeability. These discontinuities may be near or further removed from the wellbore and may cause an anomalous behavior of pressure.

A study of permeability discontinuities as observed on the pressure build-up of a drill-stem test was made to determine the type and relative location of such discontinuity.

PERMEABILITY DETERMINATION

The determination of the average effective permeability in an infinite reservoir by a pressure build-up analysis has been submitted[1,2] as:

[redacted]

Since this determination is made using the pressure behavior of the formation at reservoir conditions, this is the best approximation of formation permeability available. The permeability obtained by this method reflects the average permeability to the extremities of the drawdown. Formation damage, for all practical purposes, will not affect this determination because the slope of build-up is determined from that portion

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of the build-up curve reflecting the highest pressures. These pressures are a reflection of the pressure behavior further removed from the wellbore. Therefore, formation damage at the wellbore exhibited in the early portion of the curve is excluded from the slope.

An interpretation of the build-up curve will indicate the magnitude of formation permeability present. After closing-in for a build-up, a very quick inflection of pressure indicates a high permeability. As the closure of the curve approaches the final flow pressure and the inflection approaches the slope of the flow period, the permeability is decreasing as shown in Figure 1.
Fig.

WELLBORE DISCONTINUITIES

The extrapolation plot of a build-up curve will exhibit certain anomalies as the continuous nature of the formation changes. In a homogenous, isotropic formation producing one phase only, the resulting extrapolation will be a straight line in its entirety. This ideal build-up curve, shown in Figure 2, occurred in 29.5% of the tests. About 36% of the liquid and 34% of the gas wells have an ideal straight-line plot. This condition cannot be detected by an interpretation of the build-up curve.

per cent

Unfortunately, these ideal conditions are in a minority. The most common configuration of extrapolation plot, shown in the same figure, is one whose low pressure points fall below the straight-line slope of build-up. About 63.2% of the liquid wells and 32.4% of the gas wells have this characteristic plot. Since this anomalous behavior may be from any one or a combination of conditions, the plot is of little value to isolate and determine a specific reservoir condition.

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The most common cause is from after-production, which may be considered the rule rather than the exception on most tests. When the well is closed-in for a build-up of pressure, production from the formation does not cease; but it continues at a decreasing rate. This decreasing rate causes the pressure behavior to deviate from an otherwise ideal straight-line plot. A multiphase production will result in the greatest after-production.

Formation damage at the wellbore may cause the early or low pressure points of the build-up curve to plot below the ideal straight-line plot. Since wellbore damage is actually a permeability reduction, the pressure transient will reflect this permeability resulting in a steeper slope on the plot. As soon as the pressure transient has passed the damaged area, the slope will decrease to reflect a greater permeability away from the wellbore. These early low pressure points will almost always form a curved pattern because the pressure transient does not have enough time to stabilize through the normally very thin damaged section. The greater the slope, the greater the formation damage; however, this formation condition is difficult to determine due to other indeterminate formation conditions that may exist.

Partial penetration, change in formation thickness, and an asymmetrical flow pattern may cause the low pressure points to fall below the ideal straight line plot[6]. These conditions are very difficult to isolate and interpret; therefore, this plot is of little value ~~to help determine~~ in determining these conditions.

Formation damage may be easily determined from the pressure behavior of a build-up curve. Very high damage is characterized by a quick

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inflection after closing-in with a short-radius curve near reservoir pressure, illustrated in Figure 3. A noticeably low production rate will result from this condition. High permeability may result in the same characteristics; however, the production rate will be much greater. An interpretation of formation damage on high capacity gas wells is very difficult because these characteristics may be created by back pressure through a bottom-hole choke. However, damage is indicated on a gas well by the same characteristics. Formation damage is very susceptible in gas zones and occurs on approximately 83.5% of the gas wells. Liquid wells do not damage quite so easily, with only 37.5% showing formation damage. In most instances, formation damage is very stable and cannot be removed during the second flow period of the test. This is evidenced by comparing the build-up curves. However, in some cases, damage may exist during the first flow period of a drill-stem test and then clean itself up during a subsequent flow period. A damage ratio of 7.2 exists at the time of the first build-up in Figure 4, but the final build-up shows a damage of 1.2. The extrapolation plot exhibits the same variation in damage. The damage was unstable enough to be removed during the second flow period.

Formation damage on a liquid well may be calculated by comparing the productivity indices of the in situ formation and the actual test. The PI of the in situ formation is derived from an analysis of the build-up pressure and may be expressed as (162.6 Q/m). The PI of the actual test results may be expressed as (Q/Pe - Pf). The wellbore damage may be determined by this comparison and expressed as a ratio:

[redacted] or [redacted]

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Formation damage on a gas well may be calculated by comparing the in situ flow capacity and actual flow capacity. The in situ flow capacity is expressed as 1637 QuZT/m. The actual flow capacity is expressed as 3267 QuZT log (0.472 b/rw)/Pe^2 - Pf^2. The wellbore damage may be determined by a comparison of the flow capacities and expressed as (2):

[redacted] or [redacted].

Damage ratio is an expression of the increase in production that may be expected in the event all of the damage may be removed. Acid solutions with mud-removal qualities will normally remove formation damage. Formation damage is thought to exist as a very shallow invasion into the formation; however, a deep invasion may exist causing a very asymmetrical dual build-up test as illustrated in Figure 5. Particular attention should be paid to the great ~~almost complete~~ difference in nature ~~of~~ of build-up of the initial and final. The initial build-up reflects a low permeability and no formation damage, resulting ~~which results~~ in a lower build-up of pressure for a given time. The final reflects a comparatively greater permeability and formation damage. An extrapolation of the build-up curves shows the same reservoir pressure; therefore, it is concluded that two build-up curves are from the same source. the difference in their nature ~~Their different nature~~ is a result of the pressure transient created by a change in media.

The first flow period did not drawdown beyond the mud invasion; therefore, the initial build-up reflected the permeability of the damaged section. Since the invaded section was not crossed, it does not show a pressure transient. The second flow drewdown beyond the mud invasion, reflecting ~~which reflected~~ the true permeability of the formation. The invaded

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section was crossed; therefore, damage is indicated. This anomalous behavior usually exists in formations with small fractures that are apparently mud filled or plugged. An acid solution with mud removal qualities will increase production in a zone of this nature.

DEEP MUD INVASION OCCURRENCES

TABLE 1

Conglomerate	North Texas
Lloyd	North Texas
Morrow	S. E. New Mexico Texas Panhandle
Mississippi	South Kansas
Saratoga Chalk	North Louisiana
Hunton	Western Oklahoma
Trempealeau	Central Ohio
Stray	Michigan
Morris Sand	Central Texas

Vertical permeability or fractures may cause an "S" shaped pressure build-up behavior. In the early development of the curve, an increase in rate of build-up is noted with closed-in time as shown in Figure 6. The curve will then reverse in its direction and start decreasing in rate. This behavior is caused by the influence of hydrostatic mud in the annulus through vertical fractures. It may be compared to a well that is shut-in at the surface rather than at the sand face which results in a continued flow into the wellbore due to the compressibility of the fluids in the hole. Many of these curves will extrapolate to hydrostatic mud weight. Since

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these curves are influenced by hydrostatic mud weight, they are not representative of reservoir pressure and are not reliable. All "S" shaped curves are not caused by vertical fractures. After-production of bypassed gas either in the formation or wellbore may cause a slight compressibility curve. An "S" curve may develop when the closed-in pressure tools are set too high. This is especially true when the volume below the tool is large as compared to the flow capacity of the well.

DISCONTINUITIES FURTHER REMOVED FROM THE WELLBORE FLUSH-LEFT CAPS, UNDLNED.

Pressure build-up behavior may be used to detect formation discontinuities or permeability barriers in an otherwise infinite reservoir. These discontinuities may be a sudden change in formation characteristics such as thickness, phase change, or permeability. Thickness changes may be caused from lensing or a permeability pinchout. A change of permeability may be caused by mud invasion, shale deposits, or faulting. The reservoir is assumed to be of such extent that other discontinuities or boundaries are not reached during the test.

Horner developed a theory of barrier detection by the method of images and the superposition of the solution of the flow equations of the two wells. This theory may account for the multiple-linear behavior of the extrapolation plot of a pressure build-up curve. If the extrapolation plot has two linear slopes, one with approximately twice the slope of the other, a fault or permeability barrier is present within the radius of investigation of the test (see Figure 8). Out of 39 tests showing this behavior, the average slope ratio of the two linear portions was 2.1:1. It can be mathematically shown that more than one barrier within the radius of

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investigation may produce multiple-linear slopes with a greater slope ratio. The increase in slope ratio and number of linear portions will depend on the number of barriers and their coincidence of pressure reflections. This occurrence on a drill-stem test is very rare and difficult to ascertain, but it is occas~~s~~ionally evidenced.

If the low pressure points of the build-up curve fall above the ideal straight-line plot, a permeability reduction away from the wellbore is indicated. For a small reduction in permeability or zone thickness, the curved portion will be very slight as shown in Figure 7. This permeability barrier will probably not make a noticeable reduction in the production rate of the well.

A barrier may be indicated on a drill-stem test build-up curve that exhibits a double radi~~l~~us pressure transient as shown in Figure 8. The first radius is usually short and occurs immediately after the initial inflection or early pressures. The second radius follows the first and is usually much longer. In the most obvious cases, the build-up curve has the appearance of having the top sliced off. However, many times this behavior cannot be detected by interpretation. Because of the difficulty of interpreting a barrier from build-up curves, it quite often becomes necessary to do an extrapolation plot to identify this characteristic. The extrapolation plot may be used to help determine the nature of the barrier and the approximate distance to such anomaly.

The early linear portion represents the slope of build-up of the in situ permeability. This slope must be well defined in order to insure that after-production or formation damage are not influencing it. The

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later linear portion is the image slope which will result in an indicated initial reservoir pressure.

If the first flow period is of such duration to reach the barrier, it may be detected in both build-up curves. It was noted that the break in the extrapolation plot occurs at the same relative time of the build-up. That is, the break occurs at approximately the mid-point of the extrapolation plot regardless of the previous flow time or other build-up curves. Only time and pressure displacements may be noted.

The initial build-up curve will frequently have an early linear slope that is greater than the early linear slope of the final build-up curve. This is a result of insufficient flow time prior to the initial build-up. It is noted that first flow periods of 30 ~~minutes~~ min. or longer will usually result in parallel slopes as illustrated in Figure 9. Obviously, if the slopes are not parallel, a different permeability will be indicated. It is concluded that, unless the slopes are parallel, the initial flow and build-up are not usable to calculate formation characteristics or barrier distance.

The distance to a permeability barrier may be approximated by the following 1/:

[redacted]

Oil

Gas

The above formulas are based on the assumption that there is no fluid across the permeability barrier. This would imply that only a sealing

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fault would be applicable; however, it appears that thickness changes and permeability barriers result in approximately the same extrapolation plot pattern with the characteristics of an ideal case. The ideal case would require a complete reflection of pressure transients from the image well. It appears that many of the permeability barriers have so little fluid movement across them that theoretical development would apply. Approximately 6% of all tests show a pressure disturbance that results from thickness changes, permeability barriers, or faulting. When there is a long transition to a second linear portion, the calculated distance may be very erroneous. In any event the relative distance to a barrier seems to be nominal compared to the most important fact that a barrier exists within the radius of investigation of the test. Even though the presence and approximate distance may be determined, the direction may not be determined without studying adjacent wells. This characteristic may be helpful in further development of a field, especially if it is suspected that this is an edge well or on the flank of a reef or fault. It was noted that 51% of tests showing a barrier indicated a depletion of reservoir pressure. Nearly all of these wells decreased rapidly in reservoir pressure. A typical example of a barrier and depletion is shown in Figure 10. This illustration shows a typical ideal plot on the initial while the final indicates a barrier and a decrease in reservoir pressure.

Figure 11 shows two typical barrier cases. Well No. #1 in Plot 1 had two zones. The top zone was present in Well No. #2 only, and the bottom zone was absent in all other wells. The zone of interest in Well No. #1, Plot 2 did not show in wells to the north. Table II shows a typical section of barrier conditions studied.

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CONCLUSIONS

The following conclusions are made from this study and from field tests:

1. Wellbore conditions such as formation damage, after-production, and vertical permeability may be detected by the pressure build-up behavior of a drill-stem test.

2. Deep mud invasion may be detected on a build-up curve in the event the second flow period has drawndown beyond the invaded area.

3. Permeability barriers and faults may be detected on a build-up curve. The distance to such discontinuities may be approximated using either of the build-up curves of a dual drill-stem test, provided the previous flow period is sufficient to stabilize flow at the barrier.

4. Longer flow and build-up times will result in greater accuracy in detecting barriers and calculating their distances.

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NOMENCLATURE

B	=	Formation volume factor
b	=	Radius of investigation - ft.
c	=	Compressibility - vol/vol/psi - gas $(\frac{1}{Pe})$
d	=	Distance to barrier - ft.
h	=	Permeability height - ft.
K	=	Permeability - md.
Kh_a	=	Actual flow capacity on test - md. ft.
Kh_i	=	In situ flow capacity - md. ft.
$\log \frac{t+o}{o}$	=	Slope intercept
m	=	Slope of build-up - psi/cycle gas - psi^2/cycle
Pe	=	Extrapolated static reservoir pressure - psi
Pf	=	Final flow pressure - psi
Q	=	Production rate - oil BPD - gas MCFD Mcf/day bbl/day
rw	=	Radius of wellbore - ft.
T	=	Temperature Rankin - °F.
t	=	Total flow time - ~~minutes~~ min
u	=	Viscosity - cp.
Z	=	Gas deviation factor
ø	=	Porosity - fraction

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