DRILL STEM TEST CHART INTERPRETATION AND RESERVOIR EVALUATION

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INTRODUCTION

The Drill Stem Test (DST) is a temporary well completion, which is made in the early production life of a potential reservoir to determine both the quality and quantity of produced reservoir fluids. This can be done prior to completing the well. The drill stem is used to lower the packer(s), downhole valve assemblies and other auxiliary tools to the bottom of the hole.

The packer is a device which expands and effects a seal with the wall of the hole and isolates the zone to be tested from the drilling fluid in the annulus.

The surface-operated downhole valve assemblies are devices used to relieve the hydrostatic drilling fluid pressure from the face of the formation to be tested, allowing the produced fluids to enter the drill pipe and be trapped so that they may be recovered and measured at the surface.

An upper tool valve allows the formation to produce into the drill pipe for a specified time. The tool can then be closed and the formation buildup pressure can be recorded again for a specified time.

The opening and closing of the downhole valve can be repeated for two or more flow times and closed-in times.

Other tools and accessories are also used in modern drill stem tests.[1]

Accurate pressure data are very necessary for the interpretation of the test and analysis of the tool behavior. During DST's, two or more subsurface pressure recorders should be used. These provide the means for obtaining accurate reservoir pressure records. One recorder should be located below the packer, in a blanked-off position. Since no fluid should flow past this recorder during the test, it will record the pressures directly from the annulus. The other recorder is in the flow stream above the packer but below the tools and bottom-hole choke. This arrangement of recorders is necessary to help insure the detection of any anchor, tool and/or choke which could cause plugging, and for obtaining accurate pressure data. Most downhole pressure recordings are under dynamic rather than static conditions.

The data obtained from a DST include qualitative and quantitative description of the reservoir fluids, pressure time recording of flow and closed-in wellbore pressure measurements.

From the pressure history and fluid production during the DST, several reservoir characteristics may be estimated such as:

1. *Reservoir Pressure*: Static reservoir pressures can be determined mathematically with a good degree of accuracy. Static reservoir pressure is a very important reservoir parameter which enters into all reservoir calculations.

2. *Permeability*: The average effective permeability that is calculated from a drill stem test is the effective permeability to the fluid produced. The DST is probably the only direct means by which effective permeability can be calculated.

3. *Wellbore Damage*: The DST can, by means of empirical calculations, indicate the degree of damage. Damage restricts production but does not restrict pressure.

4. *Depletion*: The DST, when properly conducted, can indicate if any appreciable pressure loss has occurred even when a relatively small volume of fluid has been withdrawn from the reservoir. This usually indicates the existence of a small and generally noncommercial reservoir.

5. *Radius of Investigation*: Removal of formation-contained fluid can have an effect on the formation for some distance away from the wellbore.

6. *Barrier Indication*: Barrier, closing fault or other anomaly within the radius of investigation can often be detected from the DST pressure analysis.

RUNNING THE TEST

The DST must be conducted in a manner conducive to gathering of reliable and necessary data.

Hole should be in good condition, circulated clean of cuttings and other debris prior to starting the tools in the hole.

The first flow period should be of sufficient time duration to relieve the supercharge forces. Supercharge refers to a zone of abnormally high pressure in the formation surrounding the wellbore. Some of the causes of supercharge are water loss, hydrostatic pressure, pipe movement and other pressure surges. Supercharge should be removed during the first flow period, or the subsequent closed-in pressure, or initial buildup. It will have a recorded value higher than the static reservoir pressure. Generally, 30 minutes of first flow time will be sufficient to dissipate the supercharged forces, and the closed-in pressure which follows this flow period will, in effect, be truly representative of the reservoir pressure. The subsequent flow and build times should be long enough to obtain good data.

The second flow, particularly for a gas well, should be long enough so that the surface pressure will reach a maximum value and hold for 15 minutes or longer or until the flow pressure stabilizes.

The pressure chart is the graphic story of the pressure recorded during the DST and is the basis for most all interpretations. Consequently, the recorder charts should be compared to ascertain that mechanically the test was successful. In addition, the recorded pressures should be verified as to their accuracy. The recorder should indicate zero pressure before starting the tools in the hole and after the tools have been pulled out of the hole. The recorder should start and end on the zero pressure or base line. Hydrostatic pressure should be calculated and compared with recorded hydrostatic pressure and comparison of hydrostatic difference of the two recorders should be made.

The flowing pressure curve is a prime source of interpretative data. When the tool valve opens, the initial flow pressure should approach the zero or base line. If appreciable pressure is noted in the absence of a water cushion, then a drill pipe leak should be suspected. If water cushion is in the pipe, the initial flow pressure should not be less than the hydrostatic pressure of the water cushion head.

INTERPRETATION

The slope of the flowing pressure curve is an indication of the rate of fluid entry, since the recorders will reflect the hydrostatic head of any fluid which enters the drill pipe. A steep flow curve slope usually indicates high productivity or high volume of fluid entry into the drill pipe. Low slope or near parallel slope relative to the pressure base line usually indicates low productivity. The pressure which occurs during the flow period can normally be used to calculate the production rate of a liquid well. The closed-in pressure curve can indicate whether low productivity is an inherent property of the formation, or due to low permeability, or a result of wellbore damage which restricts the flow from the formation to the wellbore.

At least two flow periods, each followed by a closed-in pressure period should be obtained on each DST in order to reliably evaluate the reservoir.

Two or more closed-in pressures can usually be extrapolated mathematically to obtain the static reservoir pressure, indicate the degree of formation damage, estimate the effective permeability value, and determine depletion (if occurring) and presence of a permeability barrier if present within the radius of investigation. Comparison of the two extrapolated pressure values will indicate if depletion is occurring.

In order to obtain reliable evaluation of the reservoir, both the flow pressure and the closed-in pressure should be considered jointly in the mathematical analysis along with reliable reported and gathered data.

A properly conducted and interpreted DST will generally yield more valuable reservoir information at a lower cost than any other interpretative tool.

EXAMPLES

Figures 1A and 1B indicate a good liquid test. The charts indicate fairly good hole conditions as tools and pipe are lowered in the hole, points A to B. After reaching bottom and the tool opens, B to C, the initial flow curve, C to D, has a rather high slope relative to the base line, points A to L.

The initial closed-in pressure curve, D to E, indicates good closure and the closed-in pressure curve can be extrapolated to obtain the static reservoir pressure.

The second flow pressure curve, points F-G-H, initially is at approximately the same pressure value as was indicated at the end of the first flow period, point D. These two pressures, being approximately equal, indicate that no fluid entered the drill pipe during the first closed-in pressure period.

At point G, the flow pressure slope changes, and the slope from G to H indicates a slope that is less steep. At point G, the fluid has reached the top of the drill collars and the remaining fluid entry is being produced into the drill pipe. A direct angular change, when noted on a liquid well flow curve, indicates tubular goods of two differing capacities in the pipe string above the tools.

At point H, the tool is closed for the recording of the final closed-in pressure; and at point I the test is concluded, the packer is unseated, and the hydrostatic pressure is now back on the face of the formation.

The second closed-in pressure can be extrapolated to static reservoir pressure, and compared with the first closed-in extrapolated pressure value. These two values should be equal for a nondepleting reservoir.

Point J indicates final hydrostatic pressure as the tools are started out of the hole. The test was not reversed. At point K, pipe and tool withdrawal is stopped, the mud pumps are started, and the hole is filled. Pipe pulling is continued until all pipe and tools have been retrieved at the surface and the recorder indicates zero pressure, at point L.

This well test indicated possible depletion. The first flow indicated 150 BOPD, and the second flow indicated 119 BOPD. The extrapolated pressures indicated 28-psi loss for the total flow time of 90 minutes. The test did not indicate any wellbore damage. The 28-psi loss indicates possible depletion,

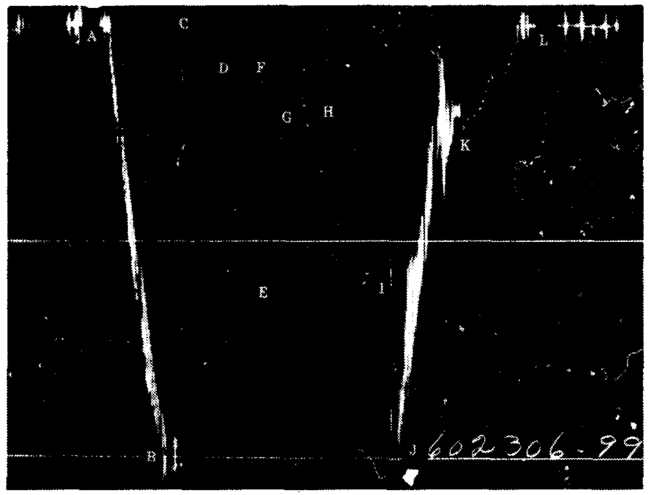

FIGURE 1A

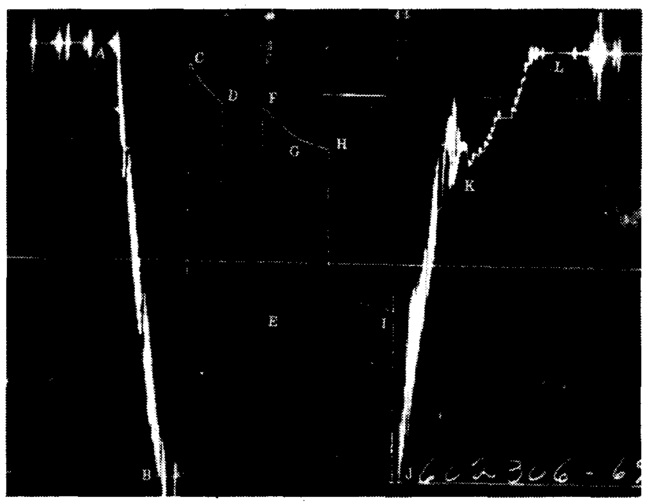

FIGURE 1B

and was determined from extrapolation and not visual or recorded pressures.

In Figs. 2A and 2B, the well test indicates a production rate of 30 BWPD and a damage ratio of 2.0. With damage removed, the well would produce at the rate of 60 BPD. The final flow pressure curve has a rather low slope and a low final flow pressure relative to the closed-in pressure value. Also, the final buildup curve has a rather short radius curve, which is a visual indication of wellbore damage.

A comparison of Figs. 3A and 3B does not indicate the same pressure surges during either or both of the flow periods. The anchor perforations are probably plugging, restricting the flow or fluid entry to the upper gauge. The pressure recordings of Fig. 3B (blanked-off gauge) indicate increasing and decreasing pressure surges during the flow periods.

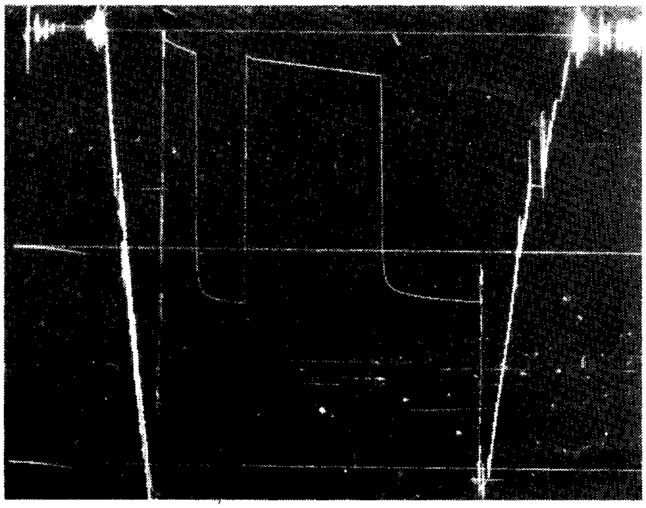

FIGURE 2A

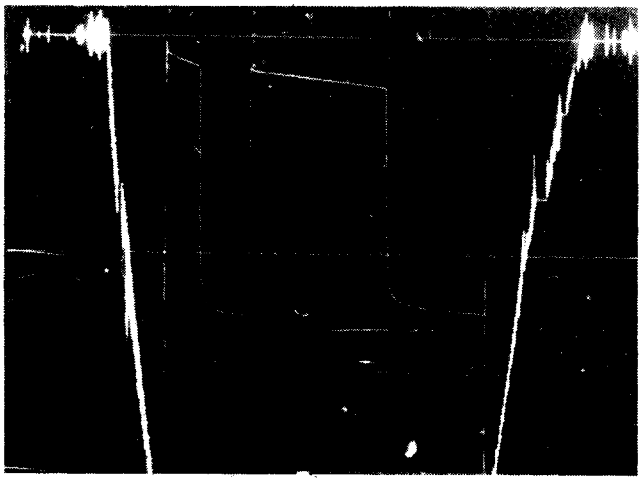

FIGURE 2B

Figure 3A (nonblanked-off gauge) indicates pressure fluctuation caused by some gauge vibration due to the sudden release of pressure through a perforated hole or holes in the anchor pipe. Generally, the closed-in pressures are not affected by the partial plugging of the anchor perforations. Visual observation of the recorded closed-in pressures indicates no wellbore damage. Cuttings and cavings will slough off since there is no fluid in motion. These charts indicate that this is not a representative test of this formation since the formation production is being restricted due to the plugging perforations.

Figures 4A and 4B illustrate a gas well test whereby the surface pressure and the downhole flowing pressure indicate that the well did not stabilize either in rate or surface pressure during

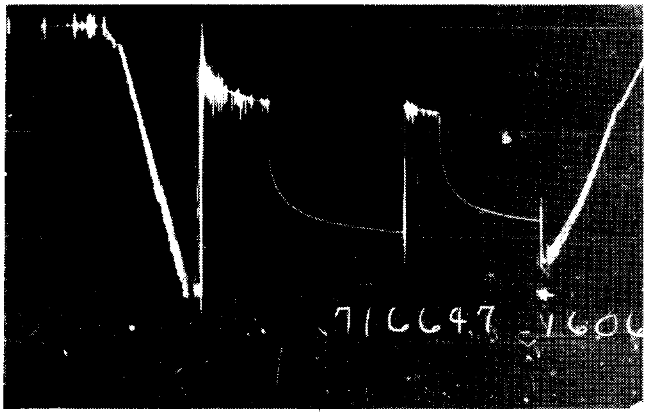

FIGURE 3A

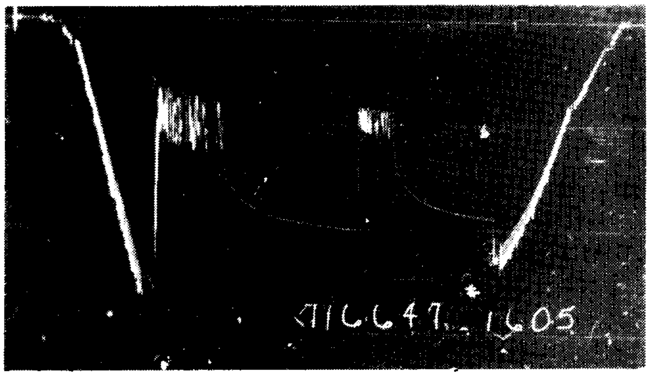

FIGURE 3B

either flow period. On a gas well, the rate is established by surface pressure and choke size or other gas-measuring device.

The first closed-in pressure does not have enough closure (should have been left closed-in for a longer period of time) for a reliable extrapolation to static conditions.

The second closed-in pressure does have sufficient closure or curve development that it can be extrapolated. The well does not appear to have any wellbore damage.

The flow rate during 90 minutes of the second flow period decreased from 529 MCFD to 400 MCFD, indicating the nonstabilized flow during the testing period. Calculation of well parameters using these flow rates would not be representative of this reservoir.

Figures 5A and 5B illustrate a gas well test indicating some plugging during the first flow period and nonstabilized flow pressure. The first closed-in pressure has insufficient closure for extrapolation.

The second flow indicates that the downhole flowing pressure is continually increasing. Likewise,

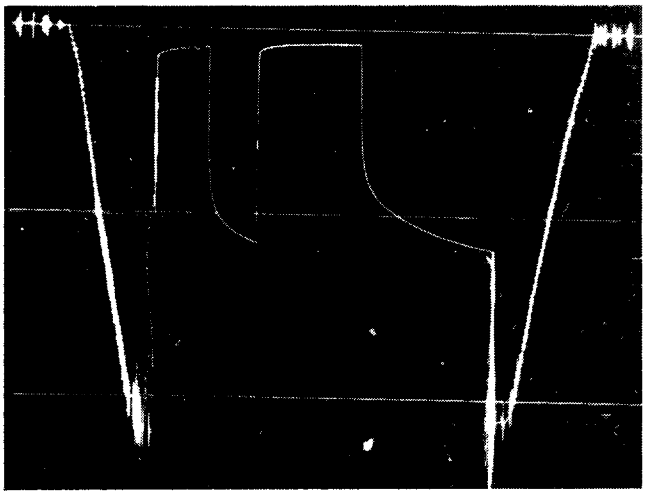

FIGURE 4A

FIGURE 4B

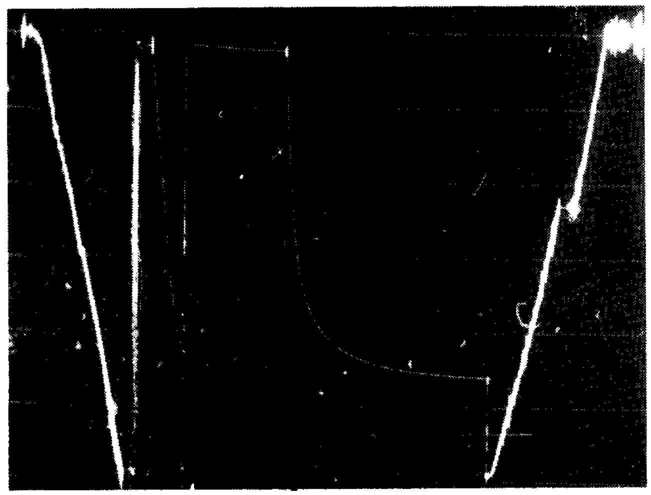

FIGURE 5A

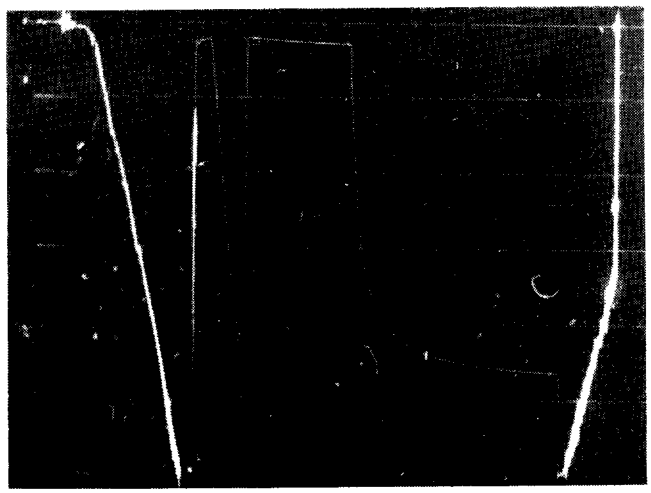

FIGURE 5B

the surface pressure continually increased during the flow period, and the reported rates were from 218 MCF to 269 MCF when the tool was closed for final CIP. Calculated parameters for this test would be representative of this reservoir capability.

The final closed-in pressure has sufficient closure for reliable extrapolation, and visual observation of the charts would indicate wellbore damage. The wellbore damage would not exceed a damage ratio of four; and with damage removal, the well would produce in the range of one MMCF.

Figures 6A and 6B contain an oil well test indicating steep flow pressure curves. From the test a production rate of 245 BOPD and a damage ratio of 5.2 were calculated. With damage removed, the well would have a production rate of approximately 1275 BPD. The above figures are based on the last and longer flow period and the last closed-in pressure. The first flow period calculated approximately at the same rate, but the calculated damage ratio was 4.5 for an approximate daily rate of 1100 BPD with damage removed.

SUMMARY

Analysis of the DST charts is essential as are the accurate measurement and reporting of the fluids produced. Also, oil gravity, GOR, surface pressures, gas gravity, surface choke sizes, bottomhole temperature, and net pay should be accurately reported. The exact time duration that each flow period and each closed-in period were in progress should be reported. Time is a very important factor and enters many equations in the calculation of well parameters.

The accuracy and reliability of the calculated

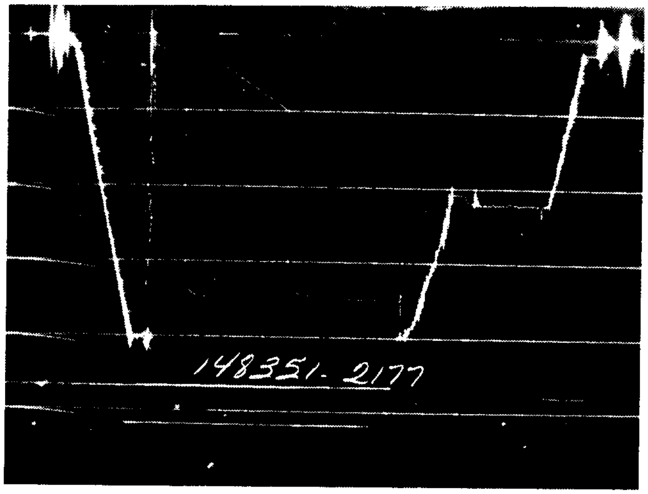

FIGURE 6A

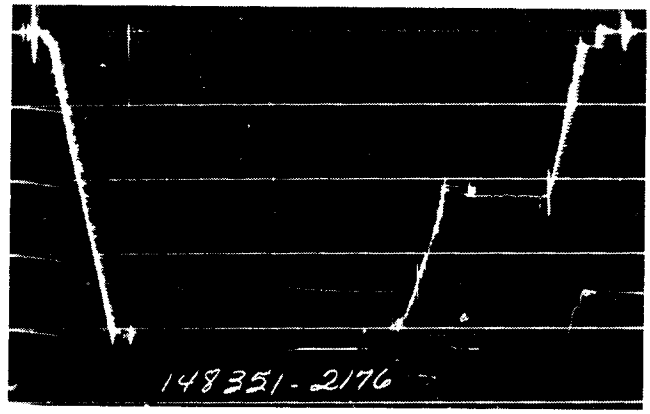

FIGURE 6B

reservoir characteristics will largely depend on the quality of data used to arrive at these calculated parameter values.

The DST can be of great value to the geologist and petroleum engineer, provided the test is properly conducted, interpreted, and evaluated. Thus, the DST can be of great aid when deciding whether to complete or abandon a well, as these decisions can then be made with greater assurance and with greater savings.

REFERENCES

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3. Murphy, W.C.: "The Interpretation and Calculation of Formation Characteristics From Formation Test Data". Halliburton Technical Publication, Apr. 1964.