Analyzing Well Performance XV

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SPE Members

This paper was prepared for presentation at the 1987 Artificial Lift Workshop sponsored by Gulf Coast Section of SPE, April 22-24, 1987 in Houston, Texas.

INTRODUCTION

Analyzing well performance is an important step toward increasing profits by improving production techniques. The analysis is made by field tests and examination of well data. The acoustic liquid level instrument permits determination of the producing and static bottomhole pressures and hence the producing rate efficiency of the well. Improvements in the acoustic determination of bottomhole pressures for practical needs have occurred in recent years and are presented herein.

FLUID FLOW

Fluid flow in a reservoir is caused by movement of fluid from a high-pressure area to a low pressure area. Fluid flow into a wellbore occurs when fluids present in the wellbore are removed so that the pressure is decreased in the wellbore. Then, fluid from an area of higher pressure flows into the lower pressure wellbore (Fig. 1).

Fluid flow increases as the differential pressure increases. Vogel presents an Inflow Performance Relationship (IPR) curve for determining producing rate efficiency based upon the ratio of the wellbore pressure to the reservoir pressure. This curve is shown on the Well Analysis Sheet. Note: approximately 97% of the maximum flow rate will occur when the wellbore pressure is 10% of the reservoir pressure. Also note, 70% of the maximum flow rate will occur when the wellbore pressure is one-half of the reservoir pressure.

NECESSARY DATA FOR WELL ANALYSIS

Four factors are important in analyzing well performance:

(1) reservoir pressure, (2) producing bottomhole pressure, (3) well test and (4) pump capacity.

For maximum withdrawal, the producing bottomhole pressure (PBHP) must be low compared to the reservoir pressure or static bottomhole pressure (SBHP). A PBHP of 100 psi is low compared to a SBHP of 1800 psi and practically all of the production is being obtained. However, if the SBHP is 150 psi, approximately 50% of the maximum production rate is being obtained. The well test and pump capacity must be known. Excessive wear and a mechanical loss of efficiency occur if the pump capacity greatly exceeds the production rate. A production loss occurs if the pump capacity is less than the well’s producing capacity. See Table 1.

Determine the importance of each item by trying to determine proper action on each well in Table 1 when only one of the four items is omitted.

DETERMINING WELLBORE PRESSURE

The pressure at the wellbore can be obtained from the depth to the liquid, the casing pressure, and a knowledge of the fluids present in the casing annulus. The wellbore pressure (whether the well is at static or producing conditions) is the sum of the casing pressure, the gas column pressure, and the liquid column pressure.

The casing pressure, gas column pressure and liquid column pressure must be totaled to determine the PBHP of a well making gas, oil and water. All the liquid above the pump will be oil due to gravity separation. If the pump is above the formation, the liquid below the pump and above the formation will be oil and water in approximately the same ratio as is produced from the well.

If the SBHP is desired, additional information is necessary. If the liquid level was at the pump before being shut-in, the liquid that collects in the annulus will be approximately the same ratio of oil and water that is produced from the well (Fig. 2A). If liquid existed above the pump while the well was being produced, the height of the column must be determined. This liquid above the pump is entirely oil if sufficient time has elapsed for oil to collect and fill the annular space. The liquid level rise, after the well is shut-in, consists of the same ratio of liquids that are normally produced (Fig. 2B). If the SBHP is desired on a high WOR well with raised tubing, assume the gradient of liquids below the tubing perforations to be the produced water gradient. The fill-up will be the gradient of the produced liquids (Fig. 2C) A gaseous liquid column cannot exist in a well at static conditions.

An improved technique for obtaining the SBHP in wells which produce casing gas is to close the casing valve a sufficient time before shutting-in the well so that the casing pressure can increase. The gas will collect in the casing annulus, increase the casing pressure and cause the top of the gaseous liquid column.

References and illustrations at end of paper.
The problem of a liquid column above the pump being gaseous can occur. A gaseous liquid column exists in wells which are producing gas from the casing annulus. After stabilization, if gas is not being produced from the casing annulus, the liquid column cannot be gaseous. A gaseous liquid column is identified if the casing pressure increases when the casing valves are closed and the well is allowed to continue to pump. The casing pressure increase occurs because gas flows upward from the gaseous liquid column into the closed annular volume.

Two techniques are offered for determining the PBHP in wells which have gaseous liquid columns.

The first technique involves measuring the increase in casing pressure over a certain period and obtaining the liquid level. With this data, a gradient correction factor can be determined which represents the effective amount of liquid present in the gaseous liquid column. Then, the gradient correction factor is multiplied by the liquid gradient in order to determine the gradient of the gaseous liquid column. This technique is less accurate when the casing annulus is almost full of the gaseous liquid column. Then, the second technique, which is more accurate but also more time consuming, is recommended.

Using the first technique to determine the pressure exerted by a gaseous liquid column, the operator should close the casing valve and continue to pump the well. Immediately, an acoustic liquid level test should be taken to determine the depth to the top of the gaseous liquid column (L). The well should be pumped with the casing valves closed until an increase in casing pressure has occurred, generally 10 to 60 minutes. The increase in casing pressure (dP) and the time period (dT) during the increase in casing pressure should be noted. Determine L x dP/dT. See Nomenclature. Enter this value in Fig. 4 and read Φ0, the approximate fraction of gas present in the liquid column. Multiply Φ0 times Hϕ (the gaseous liquid column height) to determine the equivalent amount of gas in the gaseous column. Add this equivalent height of gas in the gaseous liquid column to the gas column length (L) to obtain L’. L’ is the distance from the surface to the gas/liquid interface, if the gaseous liquid column were separated. See Nomenclature. Determine the value of L’ x dP/dT. Enter this value into Fig. 4 and proceed down to determine C which is the effective oil fraction. This effective oil fraction, or gradient correction factor, should be multiplied by the gradient of the gas-free oil to determine the gradient of the gaseous liquid column. Multiply the height of the gaseous liquid column by the gradient of the gaseous liquid column to determine the pressure exerted by the gaseous liquid column. Fig. 4 was obtained from extensive field tests and is discussed in Reference 2.

An example of determining the PBHP of the following data is given. An acoustic liquid level test indicates the liquid level at 3900 ft. The formation depth is 4900 ft. Casing pressure is 25 psi and increases 3 psi per minute when the casing valve is closed and the well continues to pump. Refer to well No. 8 on Table 2. The gas column pressure is 25 psi x 3900/30,000 or 3 psi. The value of L x dP/dT is 11,700. Enter this number into Fig. 4 and read upward to obtain Φ0. Approximately 77% of the gaseous liquid column height of 1000 ft. is gas. Add this 770 ft. to the original distance to the top of the gaseous liquid column (3900 ft.) to obtain 4,670. This is L’. Multiply L’ by dP/dT to obtain 14,010. Enter this value into Fig. 4 and read downward to obtain Φ, the effective oil fraction of the gaseous liquid column. Then, multiply the height...
of the oil column of 1000 ft. by the oil gradient of 0.333 psi/ft. by .22 (effective oil fraction) to obtain 73 psi. The PBHP is the summation of the 25 psi casing pressure plus the gas column pressure of 3 psi plus the gaseous oil column pressure of 73 psi or 103 psi.

The second technique consists of obtaining two acoustic liquid level tests at two different casing pressures. The production rate must be stabilized and equal during both tests. This may take several days. The pressures at the top of both liquid levels can be determined. Extrapolation of the liquid level depth vs the pressure at the top of the gaseous liquid column will give the pressure which exists at the wellbore. Several tests may be taken if desired. For the greatest accuracy, the highest stabilized casing pressure should depress the top of the gaseous liquid column to be slightly above but not at the pump (Fig. 5). The gradient of the gaseous liquid column is constant throughout the column. See Reference No. 2.

The downhole separation of oil and gas can be improved by placing the tubing inlet perforations below the fluid entry from the reservoir. This results in better pump efficiency and often improves acoustic liquid level data. Use a short 2-foot mud anchor if necessary to get below gas entry (Fig. 6). If the pump cannot be set below the formation due to physical reasons or the pump should be uphole for increased capacity, a Modified Poor Boy Gas Anchor should be used (Fig. 7). The gas is permitted to escape upward as the liquid flows downward toward the pump. Joe Ciegg (Reference No. 5) presents information on Gas Anchors.

INTERPRETATION OF CHARTS

Two charts on the same well should repeat. If charts do not repeat, the difficulty should be corrected before attempting to interpret the chart. When attempting to record duplicate charts, follow the manufacturer's suggestions concerning well connections, control settings, etc. When identical charts are obtained, but the liquid level is not obvious because of multiple downhole reflections, the liquid level should be moved. A movement on the chart signifies the liquid level.

The liquid level can be raised by shutting-down a producing well. When shutting-down a well, the fill-up rate will depend upon the production rate of the well and the annular area of the casing. A fill-up chart is shown in Fig. 8. The initial fill-up rate will be as shown on the chart. A decrease in fill-up rate will occur as the liquid exerts back-pressure on the formation. A high liquid level on an acoustic test can be depressed by increasing the casing pressure, if casing gas is produced.

PRINCIPLES OF WELL PRODUCTION

Numerous opinions exist about the proper method to produce wells. Some operators prefer to hold some casing pressure; other operators open the casing to atmospheric pressure. In order to study the factors involved, the following discussion presents some equivalent methods of producing a well so that the effect of varying casing pressure, pump setting depth, and length of oil over the pump can be predicted. The PBHP is the total of casing pressure, gas column pressure and liquid column pressure. The same PBHP can result from a high casing pressure with little liquid above the pump or from a low casing pressure with a high liquid column over the pump. If the totals of the casing pressure plus the gas column pressure plus the liquid column pressure are equal in two different ways of producing a well, then the production rate will be the same in both cases.

Fig. 9 shows a well being produced at three different values of casing pressure. In all three cases, the PBHP is the same so the inflow rate is equal. Note that the fluid being produced from the formation and the fluid entering the pump cannot sense whether the surrounding pressure is the result of casing pressure or a gaseous liquid column so the inflow rate from the formation and the pump capacity remain constant. The production from the well is constant in all three cases, both up the tubing and from the casing annulus.

Pressure build-up data accuracy, can be improved on a well with a high gaseous liquid column. A casing gas backpressure valve should be used to cause an increase in casing pressure which will result in the top of the gaseous liquid column being depressed. The casing gas backpressure valve should be adjusted until the top of the gaseous liquid column is located immediately above the tubing perforations. The oil and gas production rates, casing pressure and liquid levels must be allowed to stabilize, which may require several days. The PBHP will be the same as originally because the pump capacity and the formation characteristics have not changed. The high casing pressure can be measured with more accuracy than the gradient of the gaseous liquid column can be determined. This technique will improve the accuracy of pressure build-up data on wells having gaseous liquid columns.

After stabilization, the gas production from a well will not be increased or decreased by varying the casing pressure for a constant oil producing rate. After a period which could be up to several weeks during which the fluid in the casing annulus stabilizes, the operator will produce from the wellbore the oil and gas that is migrating into the wellbore. The migration rates of oil and gas are dependent upon the difference in pressure between the wellbore and the reservoir, and not upon what fluid was removed to cause the drop in pressure. Thus, the GOR is the same for any certain PBHP regardless of whether the gas is freely produced from the casing, or an attempt is made to restrict gas production by increasing the casing pressure. The casing annulus gas flow rate is the same in both cases and will remain the same unless the top of the gaseous liquid column is depressed to the pump and additional gas is forced into the pump which restricts flow and increases the PBHP.

Figure 10A shows three different methods of producing an oil well (no water) at partial capacity. In all three cases, the PBHP is 500 psi. In Case C, the 500 psi PBHP is the result of a casing pressure of 455 psi plus the gas column pressure of 45 psi. Gas is vented from the casing annulus. In Case D, the PBHP is 500 psi as the result of approximately 1500 ft. of oil above the formation. In case E, the pump is set up-hole which will also result in the 500 psi PBHP when the casing pressure is near 0 psi. The oil gradients and the heights of the gaseous liquid columns are approximately the same. The important factor is the PBHP and these cases are shown for illustrative purposes rather than exact conditions. The resulting PBHP is the controlling factor rather than the amount of casing pressure or liquid column pressure that caused the PBHP. In all three cases, the oil and gas production rates in the formation and from the well are the same after stabilization.

"Skimming" does not occur; the water/oil ratio is not changed by raising the pump if the oil production rate remains constant. Refer to Fig. 10B, cases G and H. These could be an example of a high
volume, high WOR well with the pump set at the formation and then with a raised pump. Oil has a gradient approximately two-thirds of water. If a pump in a high water/oil ratio well is raised approximately two-thirds of the oil column height, the same PBHP will exist. This assumes that the well does not produce gas or that the gas lightening effect in the oil column in case G is the same as in the water column in case H. In all cases shown in Fig. 10B, the same PBHP exists so the production of oil, water and gas will be the same as soon as stabilization occurs.

If the same PBHP exists using any one of numerous methods of producing a well, the oil, water and gas production will be the same. This applies whether the well is produced by beam pumping, hydraulic pumping, gas lift, turbine or any other method. Erroneous conclusions about the proper method to produce a well are sometimes reached on the basis of a brief production test immediately following a change in the manner in which the well is being produced. This test may not be representative of fluid flow from the formation due to changes of fluid content in the casing annulus. For example, if the casing pressure is increased on a well which is being produced with a high gaseous liquid column, the oil production will increase as the gaseous oil column is depressed. A well test during this time will indicate a greater oil production rate than will be obtained after stabilization.

PRACTICAL PRODUCTION CONSIDERATIONS

From the foregoing discussion, the present production, cumulative production and reservoir performance resulting from the manner in which an oil well (no water) is being produced will be the same if (1) the pump is set at the formation with a casing pressure of 100 psi, or (2) the pump is set approximately 300 ft. above the formation and the casing pressure is zero. In either case, the PBHP is approximately 100 psi. Whether the backpressure is the result of an oil column or gas pressure, the actual production from the well will be the same.

In a pumping well, the fact that a well is "pounding" does not necessarily indicate that the maximum production is being obtained. To have a minimum PBHP, the casing pressure must be low and the pump near or below the formation.

When a well is pumped with the casing valves closed, gas collects in the casing annulus and always depresses the liquid level to the tubing perforations unless the liquid pressures at the casing and tubing perforations exceed the bubble-point pressure (no free gas). When high casing pressure depresses the liquid to the tubing perforations, the well will be "pounding". But, the well is not being produced efficiently unless the PBHP is low compared to the reservoir pressure. Do not pump a well with the casing valves closed if a high casing pressure results and the liquid is depressed to the tubing perforations (if maximum production is desired). The liquid capacity of the pump is greatly reduced when the pump is required to handle free gas. The casing valve should be open to the flow line or a gathering system to prevent an excessive casing pressure and PBHP if the well produces free gas at the formation.

For maximum production, a low reservoir pressure well must be produced with low PBHP. For a high SBHP well, a higher PBHP can be tolerated. A PBHP of 100 psi (resulting from 60 psi casing pressure and a 100 ft. oil column due to setting the pump 100 feet above the formation) would not materially restrict the production from an oil well with a SBHP of 1800 psi. But, it would reduce the production rate from an oil well completed in a reservoir with a SBHP of 150 psi to approximately one-half the maximum rate. Refer to Table 1.

For the maximum production, a minimum producing bottomhole pressure is necessary. If mechanically possible, pipe should be set through the formation, the pump set below the formation, and a minimum casing pressure maintained. The casing pressure should be less than 5% of the SBHP if possible. Setting the pump below the formation will permit liquid to enter the wellbore during a short down-time without restricting production from the well since the liquid would not exert a back-pressure on the formation. Naturally, if some unfavorable condition develops through use of this practice, additional consideration, should be given to the method. This type of completion is also useful when gas production from a well has a tendency to gas-lock the pump. The interval of casing between the formation and the pump acts as a separator, with the liquid pumped out of the bottom and the gas bled off the top. This is considerably different from setting the pump above the formation where both the gas and liquid must pass by or through the pump.

ADDITIONAL PRACTICAL FIELD USES

A popular use of the liquid level instrument is to determine whether an oil well, which is responding to a waterflood, is being produced at its capacity. A loss of oil occurs when oil bypasses a producing well because the well has excessive back-pressure. The amount of this oil loss is dependent upon the location of the producing well with respect to other producing and water injection wells, the amount of back-pressure in the well, and numerous other conditions. A substantial loss of oil occurs if oil bypasses a producing well located on the edge of a field and injected water continues to drive the oil into an undeveloped portion of the reservoir.

Liquid level tests will often indicate a particular condition which cannot be found by any other means. For example, if a well producing from a high pressure reservoir had low casing pressure and 100 ft. of liquid above the pump, the pump would not "pound" and the operator would believe that additional fluid could be produced by installing larger equipment. The backpressure exerted by 100 ft. of oil is less than 35 psi. Installing larger equipment to "pump-down" the well would not be justified since only a very small increase in production would be obtained under these conditions.

The liquid level instrument is very beneficial in efficiently producing a high volume well when the well cannot be "pumped down" due to the limited size of the mechanical equipment (and economics do not justify the installation of larger equipment). If the high volume producer has a relatively high PBHP, the pump should be raised off bottom to obtain more production from the well. The proper depth to set the pump for maximum production can be determined in the following manner. See Figure 11. A SBHP and a PBHP with a well test can be used to determine available producing rates at various pump depths. The capacity of the pumping unit at various depths can be calculated from the API 11L bulletin. The equipment can then be sized to a particular well by raising the pump up the hole and enlarging the size of the pump to handle the liquid at that depth. The maximum efficiency from the producing equipment will then be utilized, since the equipment's maximum producing rate for a particular depth will be matched with the well's producing capacity at that depth. The producing rate of the well as the pump setting depth is lowered is plotted on the same graph as the lifting capacity of the equipment with the pump at various depths. The liquid gradient below the pump will be the liquid produced by the well. Normally, this high pump condition exists in high water-oil ratio wells and the liquid gradient below the pump is approximately 0.5 psi/ft. The static liquid level at zero producing rate would be the top of the liquid normally produced by the well supported by the SBHP. Divide the
reservoir pressure by the liquid gradient (approximately 0.5 psi/ft.) to
obtain the height of the liquid column at zero production rate.
The maximum producing rate is determined on the Well Analysis
Sheet. The Vogel curve is adapted to these two points by deter-
mining a third point on the chart which is one-half of the height
of the column and 70% of maximum production rate. Connect these
three points by a smooth curve which resembles the Vogel curve.
Plot the pumping unit capacity (obtained by using the API 11L
procedure) vs. depth on the same chart. The intersection of these
two curves gives the maximum producing rate which can be ob-
tained from the well with existing surface equipment. In this par-
cular example, the producing rate would be increased from 200
BPD (30 BOPD and 170 BWPD) to approximately 365 BPD (55
BOPD and 310 BWPD) with the pump at 4200 ft. Approximately 25
BPD additional oil would be obtained by raising the pump to the
proper depth - an increase of 82%.

Raising a pump from the formation to the top of the oil liquid level
in a high volume, high WOR well will decrease production since a
heavy, predominantly water column will exist below the high pump.
In contrast to a light oil column existing above the pump. Do not raise
a pump over two-thirds of the distance to a high liquid level. The pump
should normally be raised to a depth about midway between the liquid
level and the pump depth and generally, increased in size.

WELL ANALYSIS SHEET

An analysis of a producing well requires knowledge of the PBHP,
the SBHP, a well test, and the pump capacity. A convenient form
for presenting this data is shown on the WELL ANALYSIS SHEET.
In addition to the above data, the producing rate efficiency and
the maximum production rates can be determined. The PBHP and
SBHP should be expressed as absolute pressures. However,
negligible differences will result with use of gauge pressure unless
the reservoir pressure is low.

DISCUSSION OF LIQUID LEVEL TEST DATA

Table 2 is a summary of well analysis data. The SBHP, PBHP,
producing rate efficiency, well test, maximum producing rate,
pump data and remarks are on each well.
Well 1 is being produced efficiently. Well 2 has a high producing
rate efficiency. However, the pump capacity excessively exceeds
the production, and undue "pounding" in the pump will occur
which is damaging to equipment. The pump capacity should be
reduced to approximately 25% in excess of the maximum produc-
tion rate of the well. Wells 3 and 4 have considerable wellbore
pressure which restricts the entry of fluid into the wellbore. The
pump capacity is in excess of the well's maximum producing
capacity, and the excessive PBHP is indicative of a failure in the
downhole pump equipment. Smaller pumps which have a capac-
ity of 25% more than the maximum producing rates of the well
should be run in these wells.
Wells 5 and 6 have maximum producing capacities exceeding the
pump capacity. This often occurs in the later stages of a water-
flow and in waterdrive reservoirs. Considerable amounts of fluid
are prevented from entering the wellbore due to the high back-
pressure in the wellbore. Additional fluid production is possible,
and the economic feasibility of increasing the pump capacities
should be considered. The pump should be raised and increased
in size if economics do not justify larger equipment at the forma-
tion which can produce all of the available fluids.
Well 7 has a PBHP of 547 psi and a SBHP of 1465 psi. It is being
produced at 80 percent of maximum rate. The pump is operating
at capacity. For maximum production, a pump with a capacity
approximately 25% in excess of the maximum producing rate of
138 BPD should be used.
Well 8 has a PBHP of 103 psi, a SBHP of 1163 psi, and is being
produced at 98 percent of its maximum production rate. The 1000
feet of gaseous liquid column above the pump restrict the oil
production less than 1 BPD and installing larger equipment would
not be justified.

ANALYSIS OF DOWNHOLE EQUIPMENT

A pump needs service if the liquid level instrument indicates ex-
cessive liquid above the pump and the maximum producing rate
(shown on the Well Analysis Sheet) is less than pump capacity.
Determination of a maximum producing rate exceeding pump
capacity indicates the need for larger pump capacity. However,
if a liquid level test and casing pressure information indicate that the
wellbore pressure is already at a relatively low value compared to
the SBHP, then pulling and servicing the pump will not increase
the production rate.

Liquid level tests are often used to determine the pumping condi-
tions of a new well when the maximum production rate is not
known. Trouble with pumping equipment is often encountered in
a newly completed well and the acoustic test will indicate if the
fluid is being removed from the wellbore.

The dynamometer is a valuable tool to pinpoint a failure in the
downhole equipment. The condition of the traveling valve, stand-
ing valve, tubing perforations and other possible trouble sources
can be readily checked. This will permit the operator to select the
proper procedure to correct the equipment failure. A pump
"pounding" liquid does not indicate that maximum production is
being obtained from the well unless the casing pressure is low
compared to reservoir pressure and the pump is set at or below
the formation.

SPECIAL RESERVOIR ANALYSIS

Several important reservoir characteristics can be determined by
the rate at which the fluid enters the wellbore when a producing
well is shut-in or when a shut-in well is put on production. Probably
the one most important characteristic that can be measured is the
amount of formation damage immediately surrounding the well-
bore. Homer, Lee, Earlieghi, Miller, et al., and numerous other
authors offer techniques for obtaining wellbore and reservoir
characteristics from BHIP build-up and drawdown data. This infor-
mation is useful in selecting wells for treatment and special con-
sideration.

SPECIAL USES OF THE INSTRUMENT

The instrument records pressure wave reflections from the annu-
lar space of any conduit. Any enlargement or obstruction in the
annular space is shown on the chart. For example; perforations,
liners, parted tubing, shot holes, collapsed casing, tubing an-
chors, paraffin deposits, salt rings and gas lift valves are
recorded. Generally, these conditions produce particular chart
characteristics which permit the operator to distinguish which
condition is present.
Distance to obstructions or liquid in gas lines or untubed casing
filled with gas) is possible by acoustic travel time and acoustic
velocity developed by Podio, Thomas or McCoy.

The location of the mud level in a drilling well is very useful for
safety considerations.
CASING ANNULUS GAS FLOW RATE

The casing annulus gas flow rate can be calculated using the following equation (See Fig. 8 for annular area) (See Reference 2 for details)

\[ Q_g = 0.68 \times A \times L \times \frac{dP}{dT} \]

CONCLUSIONS

Analyzing well performance is a daily job. Careful attention, planning and testing are necessary to determine and maintain favorable downhole conditions. An increase in oil production, more efficient producing methods, better well treatments and lower operating costs are possible with a good well analysis program. 

A new computerized Well Analyzer is available to perform the analysis described herein. The Well Analyzer consists of a laptop computer and an analog to digital converter.

The Well Analyzer is used in conjunction with acoustic sensors to obtain acoustic downhole data from which the depth to the liquid level is calculated automatically. The depth to the liquid level is used in conjunction with casing pressure data obtained with a pressure transducer to permit the calculation of a bottomhole pressure even in wells having gaseous liquid columns. This data is used in conjunction with well data contained in a well file data base to present the operator with the well analysis described in this paper. Software performs this analysis automatically for visual display or printout. Request reference #15 for details of system.

The Well Analyzer can be used with dynamometer sensors to acquire and analyze dynamometer data. The compact system permits load, position, and motor current acquisition and analysis. A downhole card is presented for ease of pump performance analysis. Refer to reference #14.

The Well Analyzer permits further in-depth well and reservoir analysis by acquisition and analysis of acoustic data while unattended, thus permitting pressure transient data acquisition and analysis.

REFERENCES


8. Earlougher, R.C., Jr., Advances in Well Test Analysis, Monograph Series, SPE, Dallas, Texas (1977) 5.


14. SWPSC Dynamometer.

15. SWPSC Acoustic.

NOMENCLATURE

A  Annular Area, square inches
BPD  Flow rate, barrels per day
C  Effective oil fraction, approximates the fraction of oil in a gaseous liquid column
D  Depth from surface to formation, feet
dPr/dT  Pressure build-up rate, psi/min.
F_g  Gas fraction in a gaseous liquid column. (The portion of a gaseous liquid column which would be gas if the gas and liquid were allowed to separate.)
H  Height of a liquid or gaseous liquid column above the formation, feet
Hos  Height of oil column in a static well, feet
H_l  Height of a liquid or gaseous liquid column above the formation in a producing well, feet
H_s  Height of the liquid column above the formation in a static well, feet
Hws  Height of a water column above the formation in a static well, feet
Lp  Distance from the surface to the top of the liquid or gaseous liquid column in a producing well, feet
L  Distance from the surface to the imaginary oil/gas interface in a gaseous liquid column if the gaseous liquid column were instantly separated, feet
Ls  Distance from the surface to the liquid level in a static well, feet
Pc  Casing pressure, psi
Pcp  Casing pressure in a producing well, psi
Pcs  Casing pressure in a static well, psi
Pgp  Gas column pressure in a producing well, psi
Pgs  Gas column pressure in a static well, psi
Q_g  Gas flow rate, CF/D
Q_o  Oil Production rate, BPD
Q_w  Water production rate, BPD
Q_t  Total production rate, BPD
FIGURE NO. 1 FLUID FLOW INTO A WELL
FIG. 2A - DETERMINING SBHP, LIQUID LEVEL AT FORMATION WHILE PRODUCING

FIG. 2B - DETERMINING SBHP, LIQUID LEVEL ABOVE FORMATION WHILE PRODUCING

FIG. 2C - DETERMINING SBHP, LIQUID LEVEL ABOVE FORMATION WHILE PRODUCING

FIG. 2D - DETERMINING SBHP, IMPROVED TECHNIQUE FOR GASEOUS LIQUID COLUMN
FIG. 3 ECHOMETER SYSTEM
TABLE 1

<table>
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<tr>
<th>WELL</th>
<th>RESERVOIR PRESSURE (PSIA)</th>
<th>PRODUCING BOTTOM HOLE PRESSURE (PSIA)</th>
<th>WELL TEST BOPD</th>
<th>BWPD</th>
<th>TOTAL BPD</th>
<th>PUMP CAPACITY BPD</th>
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TABLE 2 - WELL ANALYSIS DATA

<table>
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<tr>
<th>Well</th>
<th>SBHP (psi)</th>
<th>Depth to Liq (ft.)</th>
<th>Casing Pressure (Pc)</th>
<th>Pc Buildup Rate, dP/dt (psi/min)</th>
<th>PBHP @ Formation</th>
<th>Producing Rate Eff. (percent)</th>
<th>Well Test BPD</th>
<th>Max. Producing Rate (BPD) Oil</th>
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The PBHP and SBHP were determined in gauge pressure because of negligible error and ease of data presentation.

Assumed Oil Gradient = 0.333 psi/ft
Assumed Water Gradient = 0.50 psi/ft
Assumed Pgc = Pc*L/30,000

DEF: Downhole Equipment Failure
PPC: Producing Pump Capacity, consider larger pump and/or raising pump.
SI: Shut-in for SBHP: Pump set at formation on all wells.

Pump Data

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<th>Number of Strokes and Length, (In.)</th>
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Fluid Removal
Casinghead Gas
Formation
Perforations
Pump Intake
Set Below Casing Perforations

Slow downward flow of liquid permits gas bubbles to escape up the annulus, rather than enter the pump.

Fig 6 - Natural Gas Anchor

Tubing
Casing
Gas Anchor

Downward flow of liquid should be less than 1/2 ft/sec.

Dip Tube
Casing Perforations
Casing Perforations

Fig 7 - Modified Poor Boy Gas Anchor
FIGURE 8 - FILL-UP RATE FOR VARIOUS PRODUCTION RATES IN DIFFERENT SIZES OF PIPES
Figure 9 - Equivalent Production Techniques (see Figure 5)

Fig 10 A - Methods of Producing an Oil Well at Partial Capacity

Fig 10 B - Methods of Producing an Oil and Water Well at Partial Capacity
Data:
Static Bottomhole Pressure = 2000 psi
PBHP = 1500 psi
Producing Rate = 200 BPD (30 BOPD and 170 BWPD)
Formation and Pump Depth = 6000 ft.
Pumping Unit: 228,000" # Gear Box

See Well Analysis Sheet:
PBHP/SBHP = 1500/2000 = 0.75
Producing Rate Efficiency (PR%) = 40%
Maximum Production Capability of Well:
Qt*100/PR% = 200*100/40 = 500 BPD

Fig. 11 - Well Producing Capacity and Equipment Capacity Vs. Depth
Well Analysis Worksheet

Well _______ Date _______ Time _______

\[ \frac{dP}{dT} = \] _______

To determine the SBHP in a pumping well that produces casing gas, close the casing valve and continue to pump the well until the gaseous liquid column is depressed to the pump and the casing pressure becomes a maximum. Then, shut-in the tubing.

WELL DATA

Formation Depth, Ft. _______ D
Oil Gravity, API _______
Oil Gradient, Psi/FT. = 61.3/(API+131.5) = _______
Water Specific Gravity = _______ SG
Water Gradient, Psi/FT. = .433*SG = .433* _______ = _______
Oil Production, Bpd = _______ Qo
Water Production, Bpd = _______ Qw
Total Production, Bpd = _______ Qt

PRODUCING BOTTOMHOLE PRESSURE

Depth to Liquid, Ft. = _______ Lp
Casing Pressure, Psi = _______ Pcp
Gas Column Pressure, Psi = Pcp*Lp/30,000 = _______*_______/30,000= _______ Pgp
Oil Column Length, Ft. = D-Lp = _______ = _______ Hp
Casing Pressure Buildup Rate, Psi/Min. = _______ dP/dT
Lp*dp/dT = _______*_______ = _______ Fg = _______ (from graph)
L' = Fg*Hp+Lp = (_______*_______)+_______ = _______ L'
L'*dp/dT = _______*_______ = _______ C = _______
Oil Column Pressure, Psi = Hp*C*Oil Grad. = _______*_______*_______ = _______ Po
PBHP, Psi = Pcp+Pgp+Po = _______+_______+_______ = _______
Casing Pressure, Psi. = ___________ Pcs
Gas Column Pressure, Psi. = Pcs * Ls / 30,000 = __________ * ______ / 30,000 = __________ Pgs
Water Column Height, ft. = [Hs - (Hp * C)] * Qw / Qt = [____ - (____ * ___)] * ______ / ______ = _____ Hws
Note: Hp = 0 if liquid level was at the pump when the well was shut down.
C = 1 if gas is not produced up the annulus while the well is being produced.

Oil Column Height, Ft. = Hs - Hws = __________ - __________ = __________ Hos
Oil Column Pressure, Psi = Hos * Oil Gradient = __________ * ______ = ______ Pos
Water Column Pressure, Psi = Hws * Water Gradient = ______ * ______ = ______ Pws
SBPH, Psi. = Pcs + Pgs + Pos + Pws = ______ + ______ + ______ + ______ = __________

Producing Rate Efficiency

PBHP/ SBHP = ______ / ______ = ______
Producing rate as a percentage of maximum (from IPR graph) ______ PR%

Maximum Production Capability of Well

Maximum Oil Rate, BOPD = Qo * 100 / PR% = ______ * 100 / ______ = ______
Maximum Total Rate, BPD = Qt * 100 / PR% = ______ * 100 / ______ = ______

Pump Data

Pump Size, in. __________ PS
Strokes per minute __________ SPM
Length of stroke, in. __________
Rod size, in. __________
Tubing size, in. __________
Rod Stretch, in. (-) __________
Tubing Stretch, in. (-) __________
Impulse Factor __________
Overtravel, in. (+) __________
Net Stroke, in. __________ NS
Pump Capacity, BPD = 0.1166 * NS * SPM * PS²
= 0.1166 * ______ * ______ * (______)² = ______

Remarks: ____________________________

Vogel's IPR Curve

Producing Rate as a percentage of the maximum, (PR%)