Practical Use of Recent Developments in Two-Phase Horizontal and Vertical Continuous Flow

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INTRODUCTION

In a continuous two-phase flowing or gas lift well we are confronted with three stages of production as noted in Fig.1.[1] These are (1) flow in porous medium, (2) vertical flow, and (3) horizontal flow. Certainly all three of these have a decided effect on the production rate possible from a well.

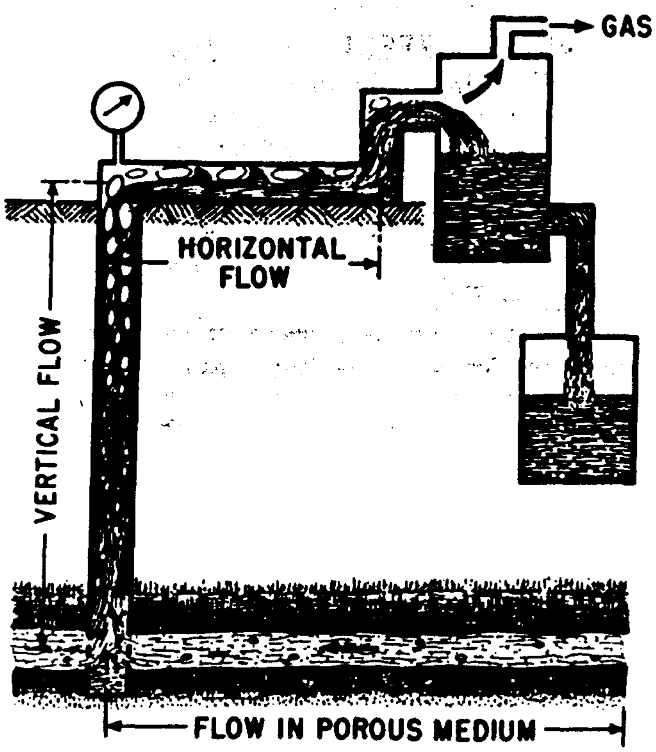

FIG. I. THREE STAGES OF PRODUCTION.
(AFTER HAGEDORN[1])

If it is assumed that we have ample reservoir and well productivity information, we can predict accurately the production rates possible from a well for varying flowing bottom-hole pressures. The reverse problem is that of being able to predict the necessary flowing bottom hole pressures in the tubing string that will allow the removal of a known fluid rate at the surface for a particular flowing tubing pressure. We must then transport these fluids from the well head to the separator through a surface flow line.

The problem is one that starts at the sand face and does not end until the surface storage facilities are reached. Therefore any alteration in the entire system will affect the drawdown at the sand face and the corresponding fluid production rate of the well.

In recent years various publications have been made available which allow the prediction and construction of vertical and horizontal pressure traverse curves. However, the full extent to which these predictions and curves can be utilized has not been exploited. The purpose of this paper is to show how these curves and predictions can be utilized to predict more closely the actual production rate possible from both a flowing well and a gas lift well.

PRESSURE TRAVERSE CURVES

Vertical Flow

Reference is made to Fig. 2 for a typical vertical pressure traverse curve which was prepared from a correlation presented by Fancher and Brown.[2] Several additional correlations have been published in past years. These correlations offer varying degrees of accuracy depending in many instances upon the particular liquid flow rate and gas liquid ratio for which the pressure traverse is calculated. For example, the Poettmann and Carpenter[3] correlation is known to be very good for 2, 2-1/2 and 3 in. tubing sizes, for flow rates in excess of 400 bbls/day, and for gas liquid ratios less than 1500 SCF/bbl. This was the first correlation from which pressure traverse curves were prepared.

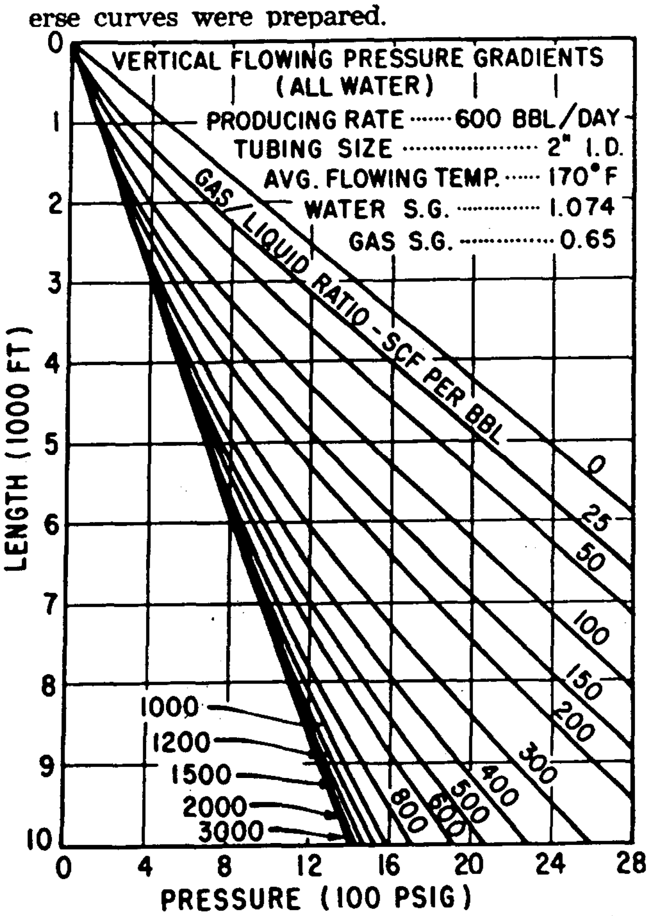

FIG. 2. TYPICAL VERTICAL PRESSURE TRAVERSE CURVES

Additional correlations have been offered by Ros,[4] Fancher and Brown,[2] and Hagedorn and Brown[5]. The authors have had occasion to check both the Fancher and Brown and Hagedorn and Brown correlations. The Fancher and Brown correlation should only be used for 2, 2-1/2 and 3 in. tubing sizes, but does offer a fair degree of accuracy in the low flow rates and high gas liquid ratios. The Hagedorn and Brown correlation seems to be completely versatile in that it is accurate for all tubing sizes, flow rates, gas liquid ratios, and in turn accounts for fluid properties such as viscosity and surface tension.

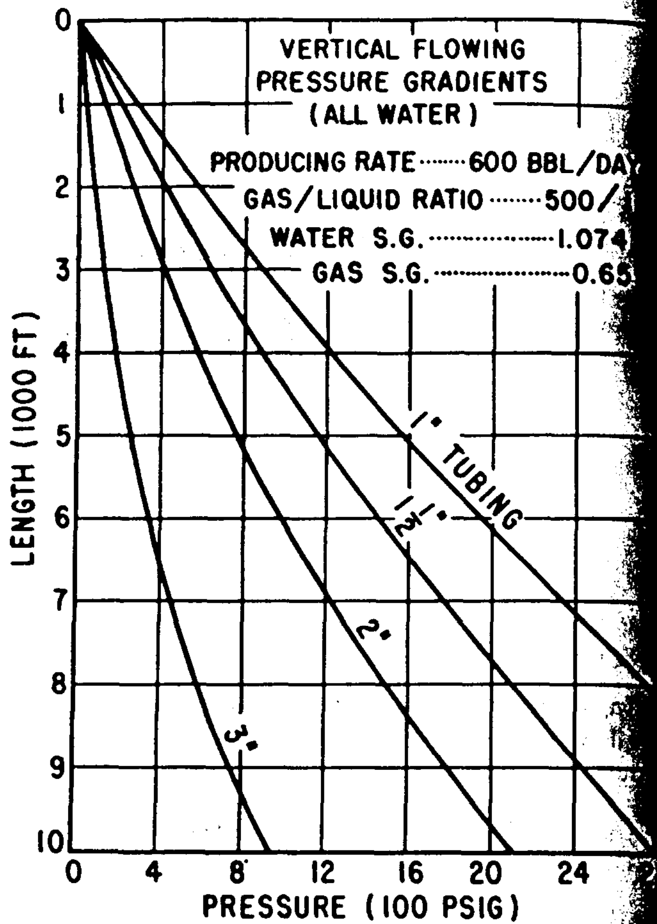

FIG. 3. EFFECT OF TUBING SIZE

This correlation accounts for variations in visco ity over the entire length of the tubing strin and appears to have solved the problem of calc lating pressure traveres for viscous crudes.

Fig. 3 shows the effect of tubing size on ver cal flowing pressure gradients.

Horizontal Flow

Although numerous correlations have bee presented for two-phase horizontal flow, one th will accurately predict this pressure loss for ranges of flow has not yet been published. Som of these correlations have been presented b Lockhart and Martinelli,[6] Baker,[7,8,9] Chishol and Laird,[10] Flanigan,[11] Bertuzzi, Tek, an Poettmann,[12] White and Huntington,[13] an Beadle, Harlan and Brown[14]. Additional researc is being conducted at the present time in ord to develop new correlations that will further im prove the accuracy of calculating pressure tr verses in horizontal flow.

A typical pressure traverse for a 2 in. flowlin is shown in Fig. 4. This plot is similar to the plo for vertical curves (Fig. 2) in that the gas liqui ratio is utilized as one of the parameters. B knowing the length of flow line, separator pres sure, production rate, and gas liquid ratio, th well head pressure required to move these fluids through the flowline to the separator can be determined.

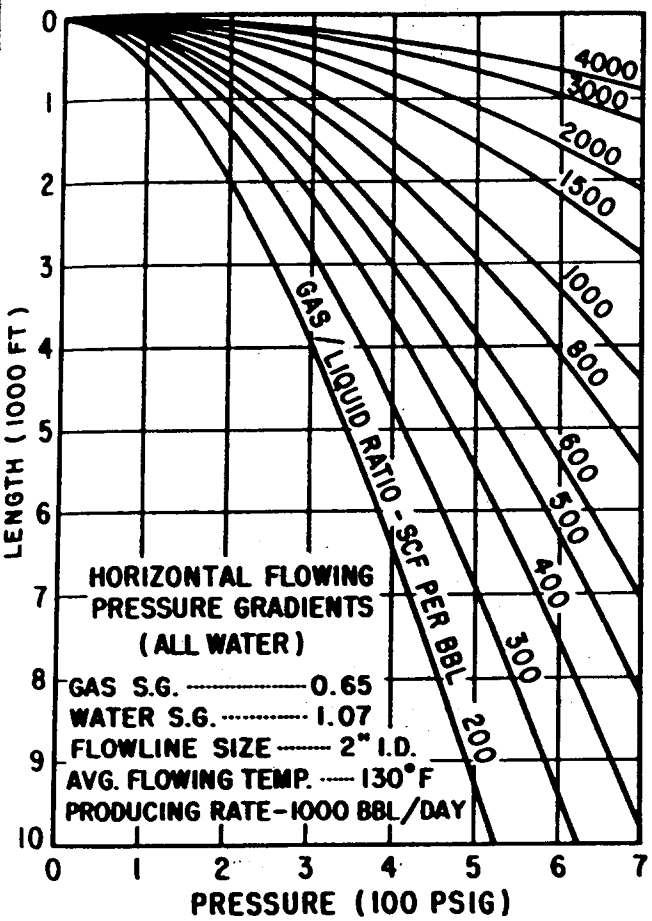

FIG. 4. EFFECT OF GAS LIQUID RATIO ON PRESSURE LOSS FOR 2" PIPE

Fig. 5 shows the effect of pipe size on horizontal flowing pressure gradients. The decreased pressure loss in the large pipe size (4 in.) is quite evident when comparing this to the 2 in. line.

APPLICATION OF BOTH HORIZONTAL AND VERTICAL CURVES

Flowing Well

A typical well would be one in which the tubing size and length, flow line size and length, separator pressure, static bottom hole pressure, productivity index, and fluid properties were known. The problem may then be one of determining the maximum production rate possible from this well. Fig. 6 shows a typical plot of how this problem would be solved. We must utilize both vertical and horizontal pressure traverse curves in arriving at a solution. As noted in Fig. 6 we have plotted production rate vs pressure. This pressure represents the surface wellhead flowing pressure. In addition an intersection of two curves is shown. One of these curves has been plotted from the vertical pressure traverses and the other from the horizontal pressure traverses.

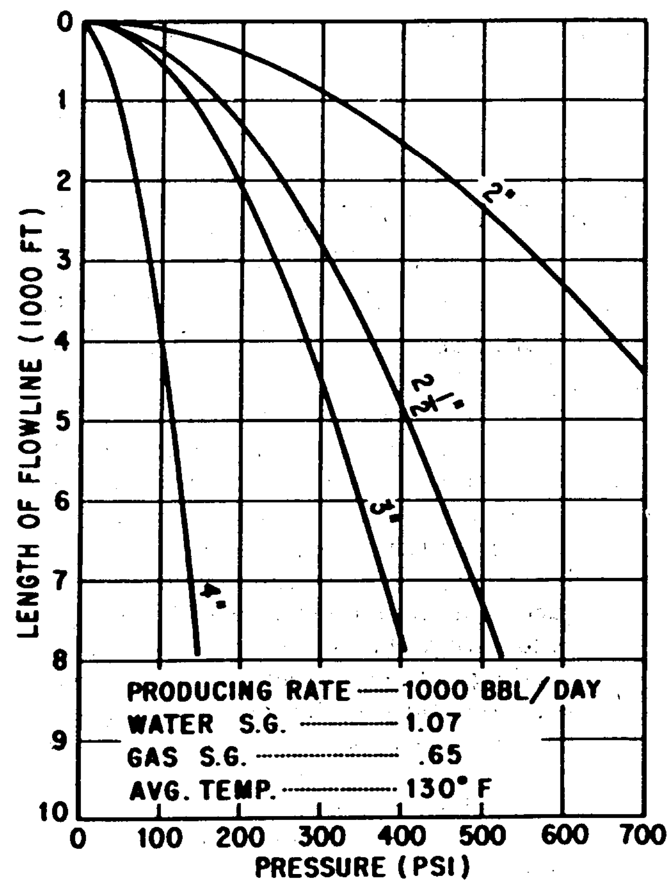

FIG. 5. EFFECT OF PIPE SIZE ON HORIZONTAL FLOWING PRESSURE GRADIENTS

In order to establish the curves arrived at from the vertical and horizontal pressure traverses, the following procedures were followed.

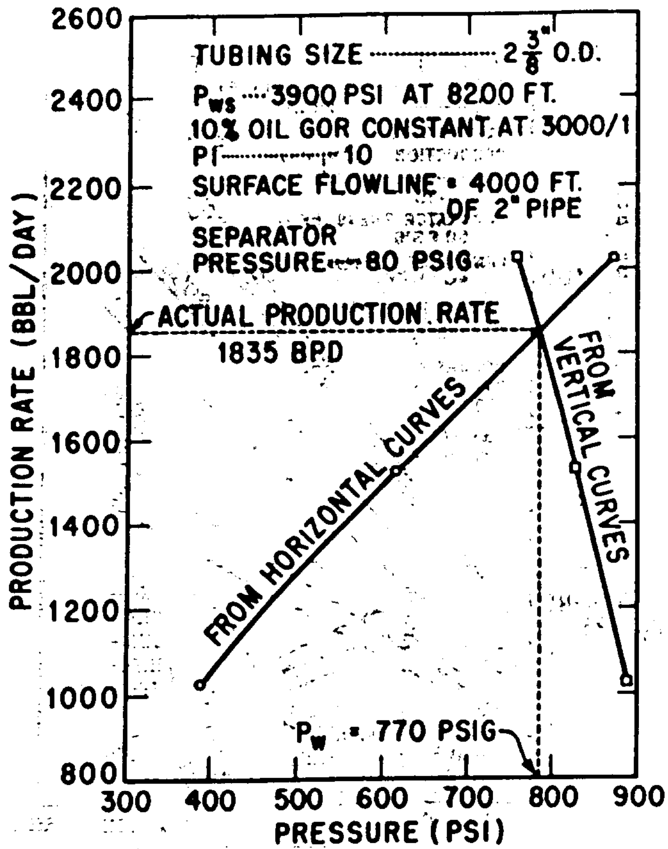

FIG. 6. MAXIMUM PRODUCTION RATE POSSIBLE FROM A FLOWING WELL

Vertical Curve Procedure

(1) Select a flow rate somewhere in the neighborhood of the expected production rate.

(2) From the static bottom hole pressure, assumed flow rate, and PI, determine the flowing bottom hole pressure

(3) Select the vertical pressure traverse for the particular production rate and gas liquid ratio. From the equivalent depth corresponding to the intersection of the traverse with the flowing bottom hole pressure, subtract the depth of the well. Find the pressure corresponding to this depth. This will be the flowing well head pressure, and is to be plotted as one point of pressure vs rate on the vertical curve.

(4) Repeat this procedure for both lower and higher flow rates.

(5) Construct a line through these points.

Horizontal Curve Procedure

(1) Use the horizontal pressure traverses which correspond to the same flow rates and gas liquid ratio as used in establishing the line from the vertical pressure traverses.

(2) For a particular flow rate, find the len[gth] corresponding to the intersection of [the] horizontal pressure traverse with the se[pa]rator pressure. To this length, add [the] length of the surface flow line. Find [the] pressure corresponding to this new len[gth]. This pressure represents the surface [well] head pressure necessary to move the fl[uid] to the separator, and is to be plotted as [a] point of pressure vs rate on the horizo[ntal] curve.

(3) Repeat this procedure for each rate.

(4) Construct a line through these points.

The intersection of this line with the line [es]tablished from the vertical curves represents [the] maximum production rate possible from this w[ell] and the well head pressure at which it will fl[ow]. This solution assumes that there are no well h[ead] restrictions such as a choke or excess bends, etc. Fig. 6 shows the production rate to be 1[835] bbl/day at a well head pressure of 770 psig.

The effect of changing the surface flow [line] size can be seen in Fig. 7. It is quite evident [that] an immediate increase in production rate can [be] obtained by increasing the flow line size. For [ex]ample, we note a production rate of 1450 bbl/[day] in the 4 in. surface pipe as compared to 970 b[bl/]day in the 2 in. surface flow line. Note that [Fig.] 7 utilized the same data as in Fig. 6 except [the] PI is 1 instead of 10.

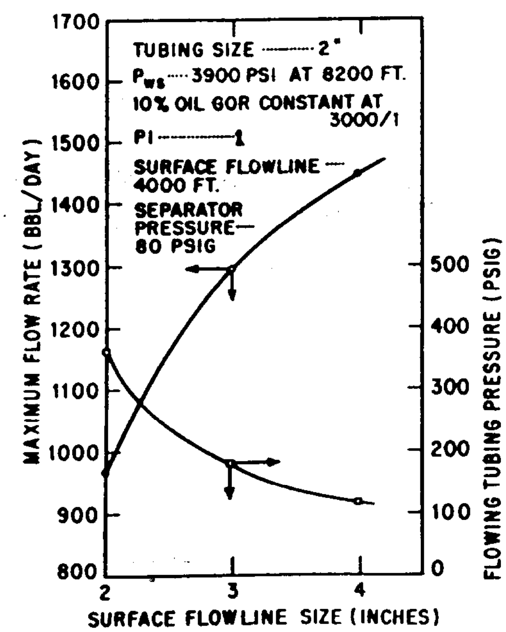

FIG. 7. MAXIMUM PRODUCTION RATE VS. FLOWLINE SIZE

Gas Lift Well

The gas lift problem requires a longer and more tedious solution, but only slightly more complicated. Fig. 8 shows one of a series of plots that must be made for each liquid rate, utilizing vertical pressure traverses only. A series of liquid rates are assumed possible and a plot similar to Fig. 8 is made for each one. The corresponding tubing pressures and gas liquid ratios to produce this rate are varied. The reason for this is that we do not know the required tubing pressure to move these fluids through the surface flow line to the separator.

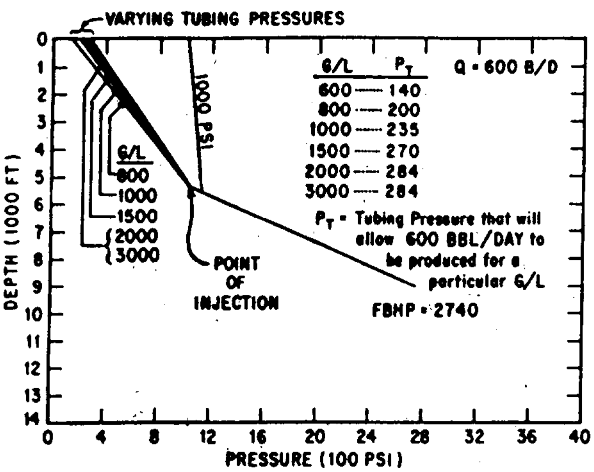

FIG. 8. TYPICAL PLOT THAT MUST BE MADE FOR EACH LIQUID RATE (GAS LIFT WELL)

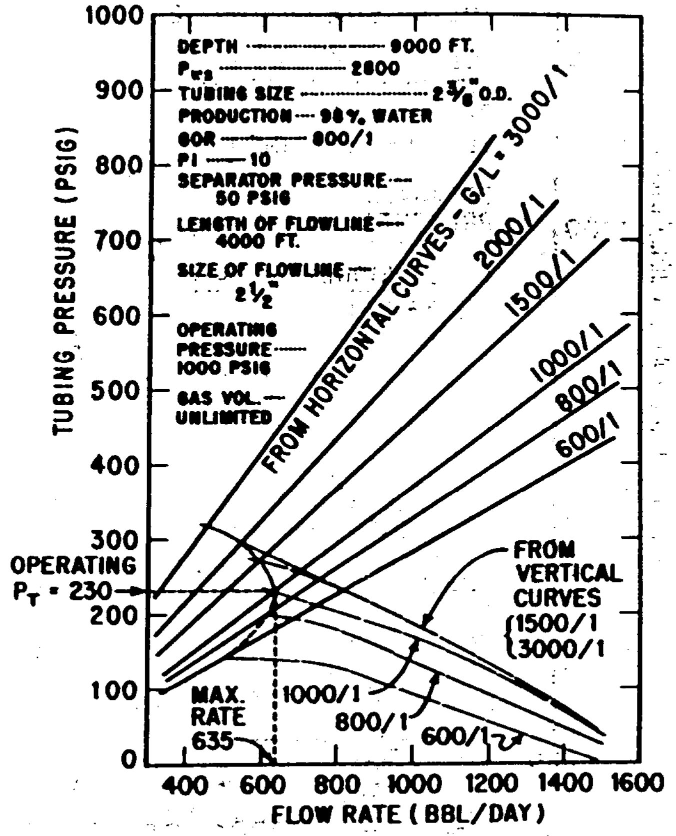

FIG. 9. ACTUAL PRODUCTION RATE POSSIBLE FROM A GAS LIFT WELL

A plot similar to Fig. 9 is then prepared from which we can arrive at the actual production rate and the corresponding actual surface tubing pressure. We also arrive at the gas liquid ratio at which these conditions will occur. In this problem we can produce 635 bbl/day at a tubing pressure of 230 psig and at a gas liquid ratio of approximately 1000 SCF/bbl. This represents the optimum conditions for this well and a decrease or increase in injection gas will cause a decrease in production. This solution can be utilized to show many instances where the production rate from a gas lift well under a particular set of conditions cannot be further increased.

The lines on the graph for the horizontal curves are prepared as mentioned for Fig. 6 except that several lines are prepared for varying gas liquid ratios. The vertical curve plots are taken off a series of plots similar to Fig. 8.

Although this solution looks somewhat tedious and complicated, it lends itself quite easily to machine computation. By utilizing a good vertical two-phase flow correlation and striving for an improved horizontal two-phase flow correlation, the problem of optimizing flow rates from flowing and gas lift wells can be solved more accurately.

The example problem of Fig. 9 was worked for an unlimited gas supply. Fig. 10 shows another problem worked in which the available gas was limited to 1,500,000 SCF day. This problem was worked with vertical curves only, assuming a short surface flowline of negligible effect. As noted, a plot of flow rate vs gas liquid ratio shows an intersection of two curves which are: (1) a curve for gas liquid ratio available, and (2) a curve for gas liquid ratio required. The point of intersection of these two curves predicts the exact flow rate and gas liquid ratio at which this well will produce.

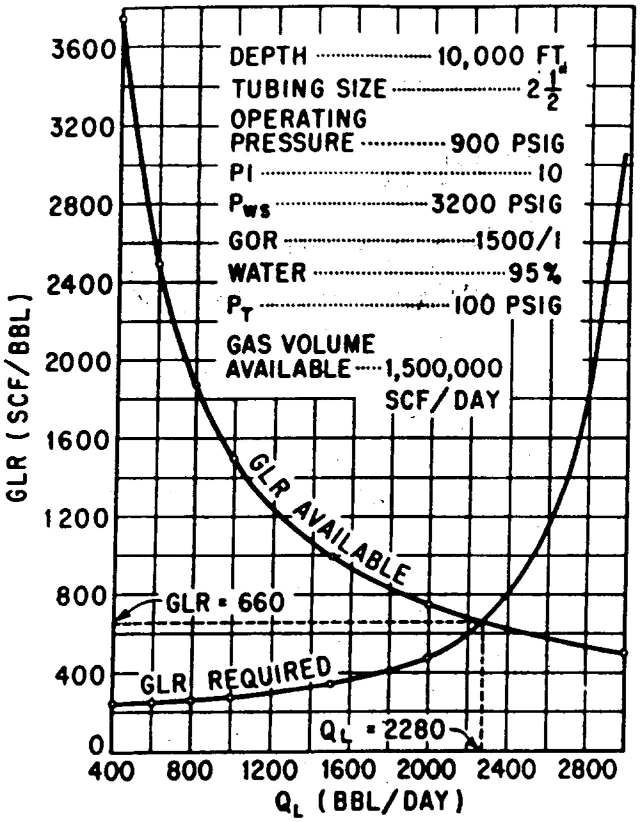

FIG. 10. MAXIMUM PRODUCTION RATE FOR A LIMITED GAS VOLUME AVAILABLE (GAS LIFT WELL)

Numerous problems may be worked using both vertical and horizontal curves. It may be desirable to determine such factors as: (1) the water-cut at which a well will quit flowing, (2) the gas liquid ratio required to gas lift a well, (3) the effect of fluid properties such as viscosity, and others.

CONCLUSIONS

1. The utilization of accurate vertical and horizontal two-phase flow correlations will allow the accurate prediction of flow rates possible from both flowing and gas lift wells.
2. There is no reason why these correlations cannot be beneficial in predicting vertical and horizontal pressure losses for all types of artificial lift.
3. The flowing life of a well can be determined accurately.
4. The effect of fluid properties such as viscosity can be determined.

RECOMMENDATIONS

1. It is recommended that production engin make use of available correlations to pr well behavior more accurately.
2. It is recommended that research be con ued to improve and check all correlation all ranges of flow.

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