ANALYZING THE PERFORMANCE OF GAS WELLS

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ABSTRACT

Methods for analyzing gas well performance are presented. Inflow, outflow, and tubing performance curves are defined and examples of each are given. The concept of "flowpoint" and its importance is explained. How these gas well surveillance tools can be used to evaluate compressor installations and tubing size changes are covered. The determination of an accurate reservoir abandonment pressure is also discussed.

INTRODUCTION

The surveillance of gas wells is of increasing interest to the petroleum industry as the economic importance of gas continues to grow. It is, therefore, timely to present some of the methods that have been developed to analyze and predict the performance of gas wells.

INFLOW PERFORMANCE CURVES

One of the most widely used methods for mathematically describing the downhole performance of a gas well is the empirically derived relationship.[1,2]

$$q = C_1 (\bar{P}^2 - P_{wf}^2)^n \qquad (1)$$

where:

- q = Rate of flow, MCF per day
- C_1 = A numerical coefficient, characteristic of the particular well
- $\bar{P}$ = Shut-in reservoir pressure, psia
- P_{wf} = Flowing bottom-hole pressure, psia
- n = A numerical exponent, characteristic of the particular well

This equation represents a straight line drawn through well test data points plotted on log-log graph paper as shown by Curve A in Figure No. 1.

The numerical constant "C_1" represents the horizontal displacement of the performance curve, and the exponent "n" represents the reciprocal of the curve's slope. In Figure No. 1, "n" is equal to the cotangent of the angle θ.

The procedure for collecting this well test data is commonly called a "4-point test" or a "back pressure test." The primary purpose for this type test and graphic plot is to project a well's performance to

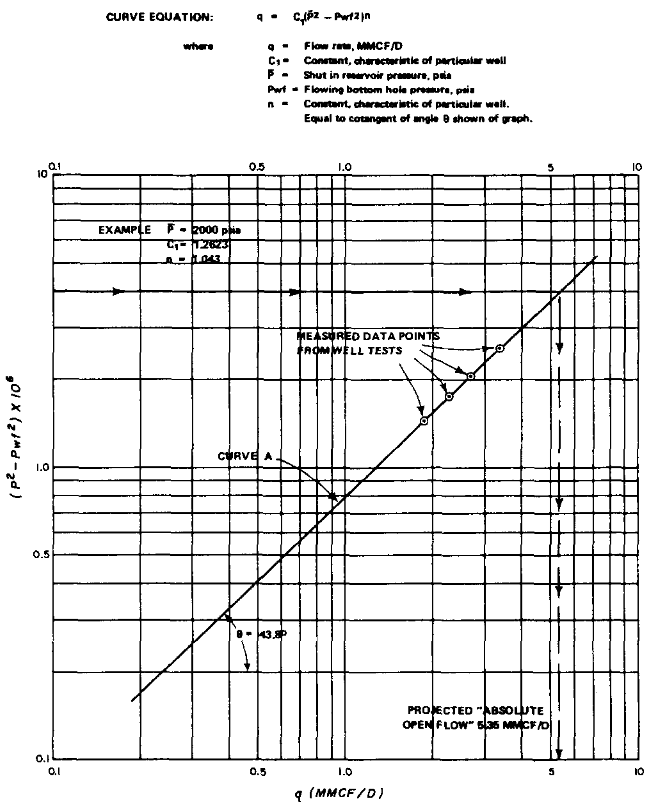

FIGURE 1—GAS WELL INFLOW PERFORMANCE CURVE "BACK PRESSURE" OR "4-POINT TEST" METHOD

what it would be with a flowing bottom-hole pressure (P_{wf}) of zero. The gas rate established by this projection is obviously the maximum possible and is appropriately called the "absolute open flow" (AOF) of the well.

The calculated AOF of a well is a fundamental measure of its ability to produce. It is a good measure to use when comparing a gas well in one area to a gas well in another area, because the many and varying effects of well depth, tubing size, wellhead back pressure, etc., are eliminated by working with downhole rather than surface measurements of rates and pressures. The AOF is used in many areas by regulatory agencies as a parameter for establishing the allowable gas production assigned to each well.

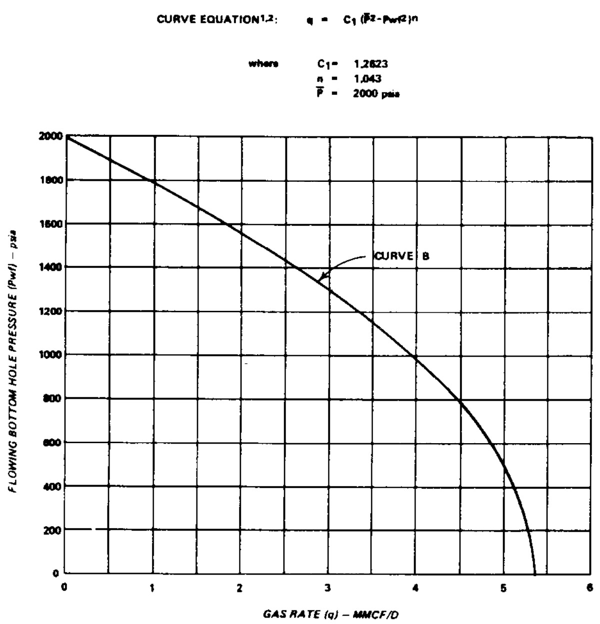

FIGURE 2—INFLOW PERFORMANCE CURVE LOG-LOG PLOT FROM FIGURE 1 REPLOTTED ON COORDINATE PAPER

A replot of Curve A in Figure No. 1 on Cartesian coordinate graph paper is shown in Figure No. 2 as Curve B. This *inflow performance curve* then appears very similar to the kind of performance curve normally seen for oil and gas wells. However, it was found by Perry and Russell[3] that the use of inflow performance Equation (1) gave producing rates too low and that a given reservoir would actually flow at higher rates than those predicted by this equation. This investigation produced an exact, but much more complex solution based upon fundamental gas flow theory. They then developed the following simplified version without a significant sacrifice of accuracy.

$$q = \frac{T_{sc}\, kh\, (\bar{P}^2 - P_{wf}^2)}{50.304\, P_{sc}\, T\, \mu(\tilde{P})\, Z(\tilde{P})\, \left(\ln \frac{r_e}{r_w} - \frac{3}{4} + S\right)} \qquad (2)$$

where:

q = Rate of flow, MCF/D
T_{sc} = Temperature at standard conditions, °R (520°R)
Kh = Permeability-thickness product, md-ft
$\bar{P}$ = Shut-in reservoir pressure, psia
P_{wf} = Flowing bottom-hole pressure, psia
P_{sc} = Base pressure (14.7 psia), psia
T = Temperature in reservoir, °R
$\mu(\tilde{P})$ = Gas viscosity at average pressure, micro Poise
$Z(\tilde{P})$ = Gas deviation factor at average pressure
$\tilde{P} = \frac{(\bar{P} + P_{wf})}{2}$ average pressure, psia
r_e = Radius of external boundary, ft
r_w = Radius of wellbore, ft
S = Saturation, fraction of pore space

Neely[4] rewrote this equation by collecting the parameters that were constant for a given well and putting them into the numerical constant "C." The result was the following very useful gas well inflow performance formula.

$$q = \frac{C\, (\bar{P}^2 - P_{wf}^2)}{\mu\, (\tilde{P})\, Z\, (\tilde{P})} \qquad (3)$$

It should be noted that the constant "C" in Equation (3) is not the same as the constant "C_l" in Equation (1) even though they may appear to be related by their similar designation and position in the two equations.

The constant "C" may be determined from a single flowing well test if the shut-in reservoir pressure $\bar{P}$ is known. The downhole flowing pressure (P_{wf}) must either be measured with a pressure bomb or calculated from a flowing surface pressure. The viscosity (μ) and deviation factor (Z) are determined at the average bottom-hole temperature and pressure ($\tilde{P}$) from the known or measured composition and specific gravity of the gas being produced.

Once the constant "C" is determined for a given well, it will not change as flow rates from that well are varied. A valid *inflow performance curve* for the well can be constructed from this single "C" factor and the known reservoir pressure. The solid line, Curve C, shown in Figure No. 3 is an example plot of Equation (3). The well data used in plotting Curve C is the same as that used in plotting Curves A and B in Figure Nos. 1 and 2. It is, therefore, not surprising that the curves are similar. For comparison, Curve B from Figure No. 2 is also shown on Figure No. 3 as a dashed line.

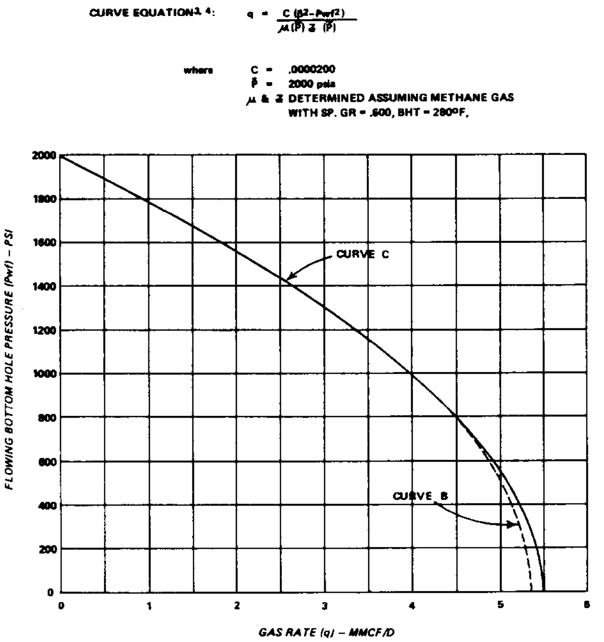

FIGURE 3—INFLOW PERFORMANCE CURVE PERRY-RUSSELL-NEELY METHOD

Figure No. 3 illustrates the lower flowing rates in the higher pressure drawdown range which result from using the old empirical log-log method instead of the more accurate Perry-Russell-Neely method when calculating gas inflow performance. The Perry-Russell-Neely *inflow performance curve* gives a calculated AOF of 5.5 MMCF/D. Using the same well data, the log-log method gives a calculated AOF of about 5.3 MMCF/D.

The more accurate method should be used when possible. All further reference to inflow performance herein will mean only inflow performance calculated by the Perry-Russell-Neely method.

OUTFLOW PERFORMANCE CURVES

Every gas well has a unique *outflow performance curve* just as it has a unique *inflow performance curve*. A well's outflow performance curve is a pressure vs. rate representation of its behavior at the surface just as its inflow performance curve represents its downhole behavior. Example inflow and outflow performance curves are shown in Figure No. 4. Curve C on this graph is the inflow performance curve and is the same as Curve C in Figure No. 3. Curve D on this graph is the outflow performance curve which was calculated from the inflow curve and from a mathematical model of the gas flow up the well's tubing. The pertinent well data parameters used in this calculation are listed on Figure No. 4.

The calculation of pressure gradients in vertical flowing gas/liquid columns has been the subject of

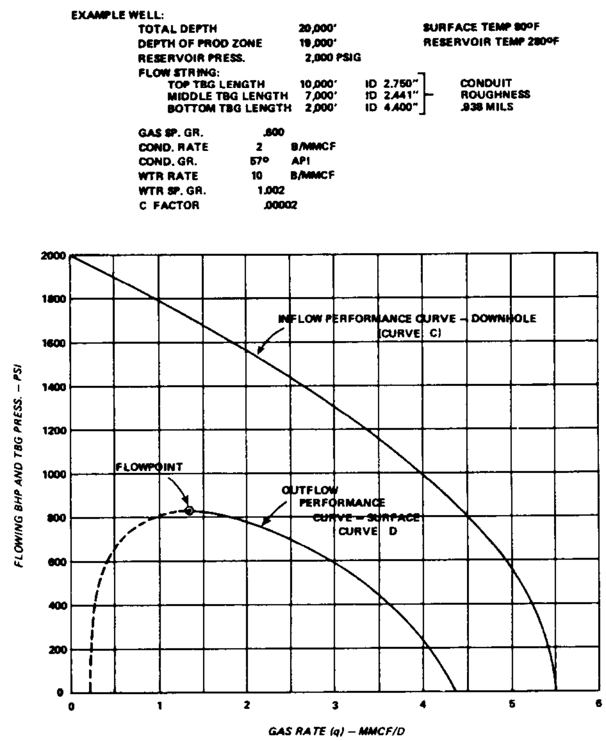

FIGURE 4—OUTFLOW PERFORMANCE CURVES

many studies and reports over the past 25 years.[5,6,7,8,9] The desirability of one of these methods over the others is beyond the scope of this paper. The method used herein is a computerized method originally developed by H. E. Gray in 1965 for Shell. It is now available through the API, Reference 9.

It can be seen that the vertical distance between the two curves in Figure No. 4 represents the difference in the flowing bottom-hole pressure and the flowing tubing pressure at various gas flow rates. Naturally, this pressure difference will vary with any change that affects the vertical flowing column weight. Some parameters which obviously affect this weight are well depth, gas gravity, and rate of liquid (condensate and water) production. The tubing size also affects the vertical pressure loss because of the different liquid removal efficiencies and because of different frictional losses.

The shape of the outflow performance curve in Figure No. 4 is very significant. The apex of this typical curve is designated the *flowpoint*. This critical point marks the *minimum sustainable flow rate* possible from this well. It also marks the *maximum flowing tubing pressure* possible. The solid portion of the outflow performance curve to the right of the *flowpoint* represents the operating range of the well which in the example is from 1.3 MMCF/D to 4.3 MMCF/D. The dashed portion of the curve to the left of the *flowpoint* represents an unstable transition area of flow through which the well must pass as it is being opened up or as it is ceasing to flow.

The reason that stabilized flow can be maintained above the *flowpoint* rate and not below it is directly related to the slopes of the inflow and outflow performance curves. Above the flowpoint rate, the slopes of these curves are in the same direction and, therefore, "self adjusting." Any change in surface pressure is transmitted through the gas column to affect a similar change downhole. The inflow rate simply adjusts to a compatible position on the inflow performance curve and stabilized flow is resumed.

Below the *flowpoint* rate the interaction is quite different. A change in surface pressure is transmitted downhole as a similar pressure change, but a compatible inflow rate in the same direction as the pressure change does not exist. The result is an unstable flow condition that will either kill the well or, under certain conditions, move the flow rate to a compatible position above the *flowpoint* rate. Changes initiated in a well's bottom-hole pressure will be similarly reflected to the surface and will result in this same interaction.

The following example will illustrate how these two performance curves may be used. Assume that the well in Figure No. 4 is shut-in with a tubing pressure of 800 psi and that the gas purchaser's line pressure is 600 psi. It can be seen that the well's *flowpoint* rate is 1.3 MMCF/D and that this is its minimum sustainable flow rate. From the well's inflow performance curve it can also be seen that the bottom-hole pressure required to produce an inflow rate of this amount is about 1,700 psi. Since the reservoir pressure is 2,000 psi, a 300 psi bottom-hole pressure *drawdown* is necessary to obtain the desired inflow rate. However, the drawdown available at the surface is only 200 psi, the difference between the 600 psi sales line pressure and the 800 psi shut-in wellhead pressure. Chances are that stabilized flow could never be achieved by simply opening the well into the purchaser's line.

A possible solution would be to produce the well to the atmosphere until a stabilized flow rate exceeding the 1.3 MMCF/D minimum were established. Then the flow could be turned to the 600 psi sales line and produce at any rate desired between 1.3 and 2.9 MMCF/D. This procedure has nothing to do with unloading water per se, but is simply a method for establishing a flow rate above the minimum possible from the well.

A predicted abandonment pressure is often needed by the reservoir engineers in order to calculate ultimate recovery from a gas well. This pressure can be determined with a good degree of accuracy by utilizing the performance curves described herein if the behavior of the water and condensate production from the well is known with some degree of certainty. Various reservoir pressures are assumed, and performance curves are calculated for each assuming a constant "C" factor (see Equation (3)). The calculated *flowpoint* pressure from the outflow performance curve is compared to the sales line pressure and recalculated by trial-and-error until they are equal. At this point the well will no longer sustain flow and the corresponding reservoir pressure on the inflow performance curve is the abandonment pressure. In practice, some pressure about 100 psi above the calculated abandonment pressure should be used, because it is difficult to flow a well and maintain control of it without some positive pressure differential between the wellhead and sales line.

In the Figure No. 4 example, if the sales line pressure were 800 psi, the well would be on the verge of dying, and the reservoir abandonment pressure would be 2,000 psi, the current pressure.

Deliverability is often referred to in gas sales contracts. The deliverability of a well usually means the rate at which it will flow into some designated sales line or against some specific wellhead back pressure. It can be seen in Figure No. 4 that the example well has an absolute open flow (AOF) potential of 5.5 MMCF/D, but will actually flow only 4.3 MMCF/D against zero back pressure. With a sales line pressure of 400 psi, the well's deliverability will be 3.6 MMCF/D, as shown from the outflow performance curve. Deliverabilities at any flowing wellhead pressure can be determined from this curve.

The effects of installing a compressor on the example well can also be predicted with this type of graph. Assuming an existing sales line pressure of 800 psi, this well would be flowing 1.8 MMCF/D. By installing a single-stage compressor with a compression ratio of four, the compressor suction and, therefore, the flowing wellhead pressure would be reduced to about 200 psi. The well would then produce about 4.1 MMCF/D at the current well conditions. Additional sets of curves would be required to predict future compressor performance with declining reservoir pressure.

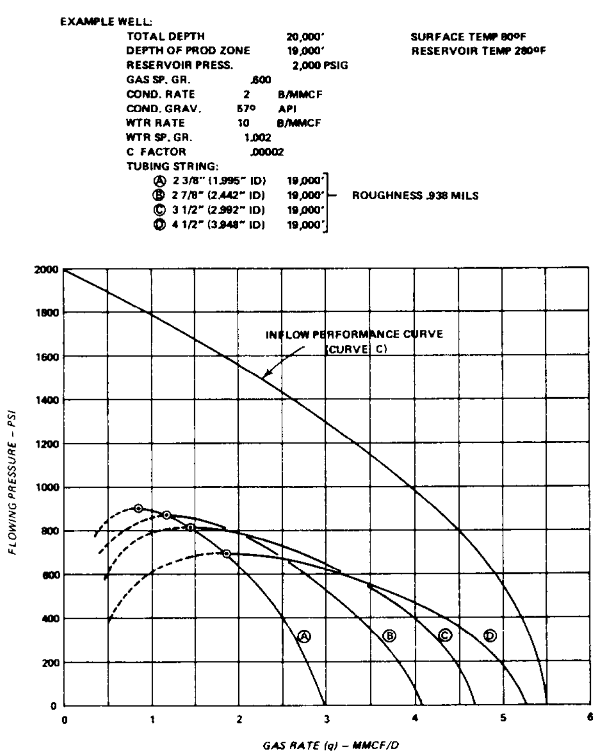

FIGURE 5 OUTFLOW PERFORMANCE CURVES FOR VARIOUS TUBING SIZES

It is common practice in areas where formation compaction does not occur to assume that a well's "C" factor does not change with time. It is then a simple matter to calculate future inflow and outflow performance curves with only a prediction of reservoir pressure decline with time.

The effects of changing tubing sizes can also be predicted by plotting an outflow performance curve for each tubing size. Figure No. 5 shows outflow performance curves for four common tubing sizes. It can be seen from these curves that at low gas rates the smaller strings have better flow efficiencies and at high rates the larger strings have better efficiencies. Although this may seem obvious, the advantage of having such curves is to quantify the relative advantage of each size tubing string. For example, in Figure No. 5 the flowing information is available for each size tubing string:

FLOW-POINT			DELIVERABILITY AT WELLHEAD PRESSURES				
TBG. SIZE (IN.)	MAX. PRESS (PSI)	MIN. RATE (MMCF/D)	0 PSI (MMCF/D)	200 PSI (MMCF/D)	400 PSI (MMCF/D)	600 PSI (MMCF/D)	800 PSI (MMCF/D)
2-3/8	898	0.84	3.0	2.8	2.5	2.1	1.5
2-7/8	870	1.16	4.1	3.8	3.4	2.8	1.9
3-1/2	815	1.48	4.8	4.5	4.0	3.0	1.7
4-1/2	698	1.91	5.3	5.0	4.3	3.2	

If the example well were equipped with 2-3/8 in. tubing and flowing into a 400 psi sales line, the flowing rate would be 2.5 MMCF/D. By the installation of a 4-1/2 in. tubing string, the flowing rate could be increased up to 4.3 MMCF/D. A rough payout calculation could be made from only this data. To make an accurate economic evaluation, a gas production rate prediction for each tubing string would have to be made over the remaining life of the well and the calculated present value profit of each string compared. The smaller string would have the advantage of producing the well to a lower reservoir abandonment pressure and, therefore, would probably recover slightly more ultimate reserve. The larger string would have the advantage of accelerating the gas recovery which, in a well-connected, competitive reservoir, could also result in an increased ultimate recovery. Obviously, the ideal manner in which to deplete a gas well would be through a large tubing string during its early life and through a small string in its later life. This is usually not practical because of the cost of tubing and the expense of changing it out. However, where an adequate price is being received for the gas and where a well's reservoir pressure decline with production is moderate, it has been profitable to install both smaller tubing and gas compression.

It has been stated that any gas well that produces liquid will have a *flowpoint* and will not sustain flow below that *flowpoint* rate. However, a dry gas well that does not produce liquid does not have a *flowpoint* and will sustain flow at any rate no matter how small. The outflow performance curve of a dry gas well does not have an apex. Its slope parallels the inflow performance curve from maximum to zero flow rate. At a zero flow rate, the vertical difference between the two performance curves represents the static weight of the gas column in the well.

TUBING PERFORMANCE CURVES

Another type of curve sometimes used in analyzing gas well performance is the *tubing performance curve* or constant tubing pressure curve. Figure No. 6 shows an example tubing performance curve, Curve E, plotted with the inflow performance curve. The tubing performance curve is a plot of the flowing bottom-hole pressure required to produce various gas rates through a given size tubing string at some constant flowing wellhead pressure, in this case 400 psi. This curve will not change as the well depletes. It is not at all dependent upon well performance, only upon the pertinent gas, condensate and water properties, the well depth, and the temperature gradient. Of course, each assumed constant flowing wellhead pressure will yield a different tubing performance curve.

If it is assumed that the 400 psi flowing wellhead pressure used in Figure No. 6 will remain constant throughout the life of this example well, the tubing performance curve provides a means of predicting the reservoir abandonment pressure. By declining the inflow performance curve parallel to its present

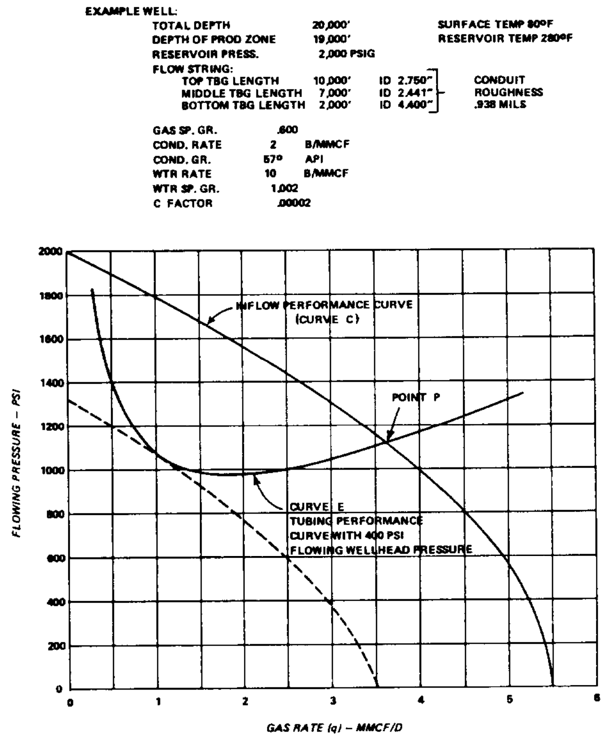

FIGURE 6—TUBING PERFORMANCE CURVES

line until it becomes tangent to the tubing performance curve (see dashed line on graph), it can be seen that the well will not flow when the reservoir pressure reaches 1,300 psi. This then will be the reservoir abandonment pressure unless the wellhead pressure is lowered or a different tubing string is installed.

At point "P" in Figure No. 6, where the tubing performance curve intersects the inflow performance curve, it can be seen that a common rate and pressure exist. At this point the example well will flow 3.6 MMCF/D with a flowing tubing pressure of 400 psi. It can be seen that Figure No. 4 provides this same information plus the well's producing rate at any other flowing wellhead pressure. Except for special problems, the outflow performance curves described in the foregoing section will provide more information that is directly applicable to analyzing a gas well's performance than will these tubing performance curves.

The shape of various tubing performance curves developed for this example well are illustrated in Figure No. 7. It can be seen that each size tubing has an optimum operating range where the flowing gas/

liquid column exerts a minimum back pressure downhole. In the 2-3/8-in. size, it is at about 0.9 MMCF/D and covers a narrow range. In the 4-1/2-in. size, it is at about 4.6 MMCF/D and covers a much wider range.

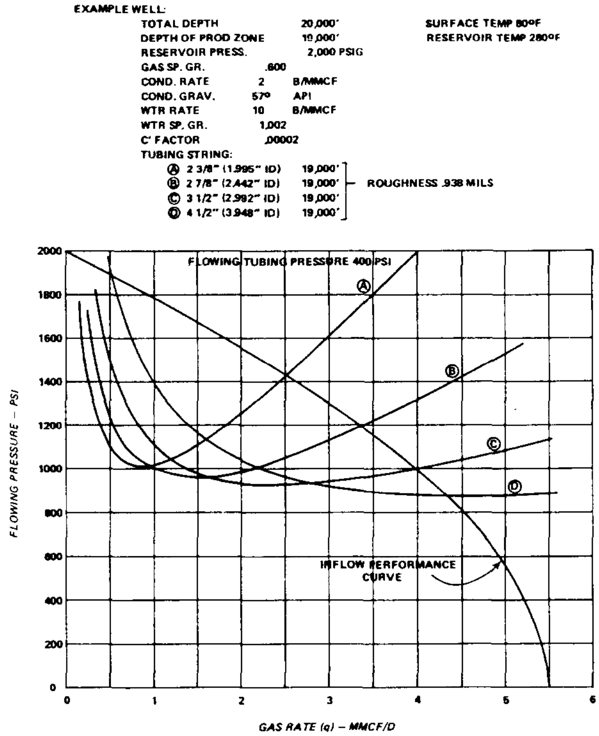

FIGURE 7—TUBING PERFORMANCE CURVES FOR VARIOUS TUBING SIZES

These ranges of better efficiency are in a flow area of good liquid lift efficiency where friction is not excessive. To the left of these optimum flow areas where the flow rate decreases, the liquid "fall back" increases and as a result the downhole pressure required increases. To the right of these optimum flow areas the friction increases as the velocity increases. As a result, the downhole pressure required is greater.

COMPUTER APPLICATION

In the foregoing sections, gas well performance has been analyzed by the use of inflow, outflow, and tubing performance curves. Obviously, the preparation of curves such as these requires many more computations than does a single-point value of pressure or rate. In fact, without computer assistance, their preparation would be completely impractical.

It is recommended that a computer be utilized at least to calculate the two-phase flowing pressure gradients between surface and downhole points. This should eliminate about 90% of the hand computation required.

More sophisticated computer programs can also be developed to calculate and plot cumulative vs. time decline curves based upon predicted reservoir pressure decline and liquid (condensate/water) production behavior with cumulative gas production. The effects of installing compressors or changing tubing sizes at selected future times can be included. Gas value and operating costs can be added to make a present-value profit calculation possible for each set of selected well conditions. The well operator can then develop a firm plan to maximize his profit over the remaining life of the well.

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