Application of Gas Lift For Small Diameter Tubing Installations

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INTRODUCTION

With the increased use of small conduits, it became necessary for oil company personnel to evaluate the different methods of artificial lift through small tubing. The Poettmann and Carpenter correlation which was published in 1952 [1] was the accepted flowing pressure gradient correlation by many in the industry at the time of initial evaluation of lifting methods through small conduits. This correlation indicated extremely high flowing pressure gradients for low producing rates through the small tubing. For this reason, gas lift was not attempted in many instances where it would have been the best method of lift. However, limited experience of flowing and gas lifting through small tubing revealed a much lower actual flowing pressure gradient than the calculated one. There was a second two-phase correlation which was developed by Ros at a later date.[2] Although this correlation is applicable for calculating two-phase flow pressure loass in small conduits, all of the necessary correlating parameters were not given in the Ros paper which prevented the calculation pressure of traverses.

EXPERIMENTAL DATA AND COMPARISON TO POETTMANN AND CARPENTER CORRELATION

Very little information had been published on two-phase flow through small conduits and the need for this data was evident. A test well at Hastings, Texas was equipped for single- and two-phase flow tests and testing began in 1960.[3] The test conduits were full-sized and approximately 1000 ft. in length. Although some end effects were anticipated, it was believed that the over-all percentage of deviation, as compared to longer tubing strings, would be of little magnitude.

The experimental results to be discussed in this paper are based on the two-phase data through 1- and 1-1/4-in. nominal tubing and gas flow through several small configurations. The fluids employed were salt water with a specific gravity of 1.056 and gas with a gravity of 0.60. Experimental data were obtained for water rates between 600 and 100 BPD. The metering facilities prevented tests at lower volumes without introducing error in measurement. However, enough rates above 100 BPD were selected to permit a reasonable extrapolation to lower rates. The pressure gradient curves in this paper for the 50 and 25 BPD rates are based on extrapolation of the test well data.

The Poettmann and Carpenter energy loss factors were calculated using the actual pressure loss data. The calculated experimental energy loss factors scattered widely when plotted in the same manner as the original Poettmann and Carpenter correlation. All calculated energy loss factors for the 1-in. nominal tubing were less than the corresponding factors for the Poettmann and Carpenter curve. The results were the same for the 1-1/4-in. nominal tubing except for the maximum water rate of 600 BPD.

Regardless of the producing rate or gas-liquid ratio (GLR), the energy loss factors were found to vary with pressure. For a given producing rate and GLR, the energy loss factors decreased with a decrease in pressure and did not remain constant as indicated by the Poettmann and Carpenter correlation. The daily mass rate is approximately the same for 100 BWPD with a GLR of 1000 cu. ft. per bbl. as for a daily water rate of 75 BPD with a GLR of 4000 cu. ft. per bbl. Therefore, the energy loss factors would, theoretically, be the same for both conditions but actually they were different. Similar observations were noted by other investigators working with a 2-in. nominal tubing.[4] In order to correlate their two-phase data, a GLR parameter was incorporated in the Poettmann and Carpenter correlation.

Two important facts were concluded from the experimental data. First, the minimum flowing pressure gradient which could exist in the system decreased as the liquid rate decreased. Secondly, the minimum GLR required to prevent heading increased with a decrease in the daily liquid producing rate. For this reason, low GLR pressure traverses are not included in the flowing pressure gradient curves in this paper. These observations were for flowing pressures based on a minimum surface pressure of 60 psig and a maximum pressure of 800 psig at 1000 ft. Intermediate pressures were obtained by increasing the wellhead pressure, which permitted stacking of the data. Most of the data were based on pressures between 70 and 600 psig. These pressures are representative of those encountered above the point of gas injection in most gas lift installations. It was apparent from this work that the original Poettmann and Carpenter correlation could not be extrapolated to small tubing.

MINIMUM FLUID GRADIENT CURVE

For this discussion, the minimum fluid gradient curve represents the lowest flowing pressure gradient and minimum flowing tubing pressure possible at any depth.[5] The minimum gradient curve is used to space gas lift valves in many continuous flow installations and is needed to estimate the minimum flowing bottom hole pressure for maximum production. A decreasing minimum fluid gradient with a decreasing liquid rate would be expected if a sufficient injection gas volume were available to attain this minimum gradient as the flow regime approached mist flow. However, pressure gradient curves based on the Poettmann and Carpenter correlation indicate a higher pressure gradient with a decrease in the daily liquid producing rate below a nominal value based on the tubing size and GLR. For 1-1/4-in. tubing, a lower minimum flowing gradient would be calculated for 200 BPD than would be calculated for 100 BPD. At a 50 BWPD rate, the calculated minimum fluid gradient is nearly 0.45 psi per ft. which is over 25% in excess of a calculated minimum gradient for 100 BWPD. Since certain previous pressure gradient curves for small tubing were based on the Poettmann and Carpenter correlation, many operators discounted the possibility of gas lift without trying this method of artificial lift due to these high calculated pressures at depth.

FLOWING PRESSURE GRADIENT CURVES

Flowing pressure gradient traverses for water through 1-1/4-in. nominal tubing are shown in Fig. 1. As the liquid phase decreases, the average pressure gradient decreases and the point of gas injection may be deeper for a given injection gas pressure.

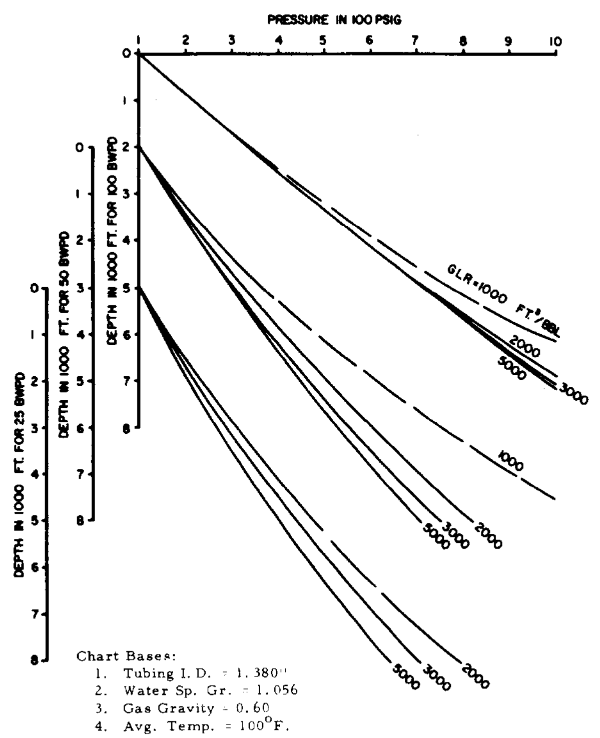

FIGURE 1
FLOWING PRESSURE GRADIENT TRAVERSES FOR TWO-PHASE FLOW (WATER-GAS) THROUGH 1-1/4-INCH NOMINAL TUBING

A set of flowing pressure gradient traverses for 1-in. nominal tubing is given in Fig. 2. There is a significant difference between the flowing pressure gradients for 100 BPD through 1-1/4-in. nominal tubing as compared to 1-in. nominal tubing. Approximately 250 BPD through 1-1/4-in. tubing will result in the same flowing pressure gradients as 100 BPD through 1-in. 1-in. tubing. Therefore, 1-in. tubing is not generally recommended for gas lift operations if a larger tubing can be used. Low cost tubing with integral joints is now available which permit the running of 1-1/4-in. nominal tubing in 2-3/8-in. OD tubing and 1-1/2-in. nominal tubing in 2-7/8-in. OD tubing.

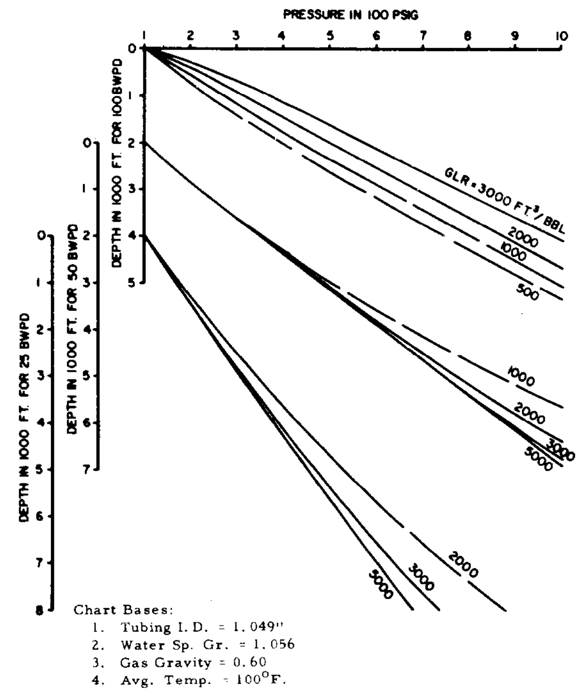

FIGURE 2
FLOWING PRESSURE GRADIENT TRAVERSES FOR TWO-PHASE FLOW (WATER-GAS) THROUGH ONE INCH NOMINAL TUBING

Excessive GLR's result in increasing pressure gradients at low flowing pressures and high liquid rates relative to the tubing size. This phenomenon is apparent for 100 BWPD through 1-in. nominal tubing. Increasing the injection gas volume would increase the flowing tubing pressure at the point of gas injection and decrease the daily producing rate. The reversal in the flowing pressure traverse (increase rather than a decrease in pressure gradient with a decrease in pressure) is also apparent for this rate. For this reason, decreasing the surface wellhead back pressure from 100 psig to near atmospheric pressure will have little effect on the drawdown when the GLR is high. A substantial increase in the GLR has little effect on the flowing pressure gradient for certain rates of liquid production. This is apparent for 100 BWPD through 1-1/4-in. tubing and 50 BWPD through 1-in. tubing. A significant difference in flowing BHP will not occur by greatly increasing the injection gas volume.

GAS FLOW PRESSURE LOSS

The maximum injection gas rate through the small tubing or small annular area is limited. The pressure loss due to friction per 1000 ft. of conduit can be calculated for 5 different configurations using the appropriate "R^2" value from Fig. 3. The pressure loss due to friction curves for the 1- and 1-1/4-in. nominal tubing and the 1- x 2-in. and 1-1/4- x 2-1/2-in. annulii are based on actual measured data. The curve for 3/4-in. tubing was calculated using the method

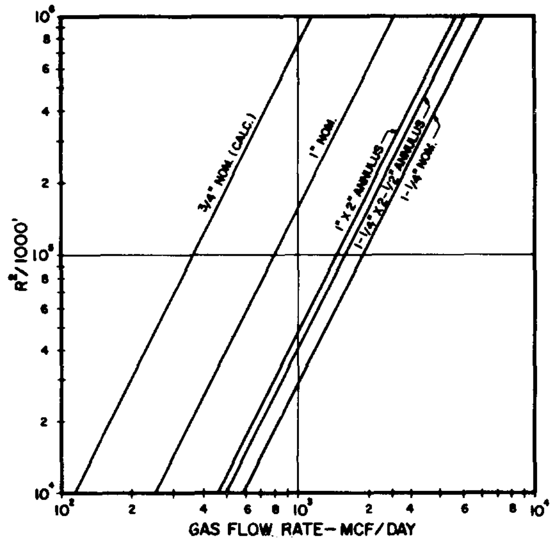

FIGURE 3

PRESSURE LOSS DUE TO FRICTION PER 1000 FEET OF CONDUIT FOR DRY GAS FLOW (GAS GRAVITY = 0.60)

outlined by the Texas Railroad Commission.[6] The two curves for the small annulii indicate approximately the same pressure loss because the 1-in. tubing was non-upset (1.660-in. OD coupling) and the 1-1/4-in. tubing was upset (2.200-in. OD coupling). The term "R^2" is a function of the pressure loss due to friction only and is used to calculate the downstream pressure (P_{dn}) with the following equation:

$$P_{dn} = \sqrt{P_{up}^2 - R^2}$$

The actual discharge pressure at the lower end of a vertical conduit is equal to the downstream pressure plus the increase in pressure due to the gas column weight (gas density). The following calculations are offered to illustrate the use of an "R^2" value from Fig. 3:

Given:

Tubing size = 1-in. nominal (in 2-7/8-in. OD tubing)
Injection gas volume for gas lifting through annulus = 800 MCF/day
Length of 1-in. tubing = 5000 ft
Upstream pressure = 1200 psia

Solution:

Step 1: Determine the pressure loss term due to friction from Fig. 3:

$$R^2/1000 \text{ ft} = 100{,}000$$
$$R^2/5000 \text{ ft} = 500{,}000$$

Step 2: Calculate the pressure loss due to friction:

$$P_{dn} = \sqrt{1{,}440{,}000 - 500{,}000} = 970 \text{ psia}$$

Step 3: Determine the approximate discharge pressure at 5000 ft:

$$\text{Dischg. Press.} = P_{dn} + \Delta P_{wt} = 970 + 140$$
$$= 1110 \text{ psia} = 1095 \text{ psig at 5000 ft}$$

Where: ΔP_{wt} is based on $\frac{P_{up} + P_{dn}}{2}$ and the actual gas gravity and average temperature of the gas column.

GAS LIFT INSTALLATION DESIGN

The expected maximum production for the same operating conditions may be less for small tubing than for larger tubing. Generally, the gas lift valves which are run in conjunction with small tubing are miniaturized versions of identical construction to the larger sized valves. The specifications for the smaller valves are used in the equations for valve opening pressure calculations in exactly the same manner as those used for the larger valves.

If high producing rates are required from an installation, annular flow should be considered for 2-7/8-in. OD and larger casing provided no scale or deposition problem exists. If the gas is injected through a 3/4- or 1-in. nominal tubing string inside of 2-7/8-in. OD tubing, the resulting flowing pressure gradients will be near those for 2-in. nominal tubing. A concentric 3/4- or 1-in. tubing string in 3-1/2-in. OD tubing provides an annular configuration with an area in excess of that for 2-7/8-in. OD tubing. Therefore, high producing rates are possible for small diameter

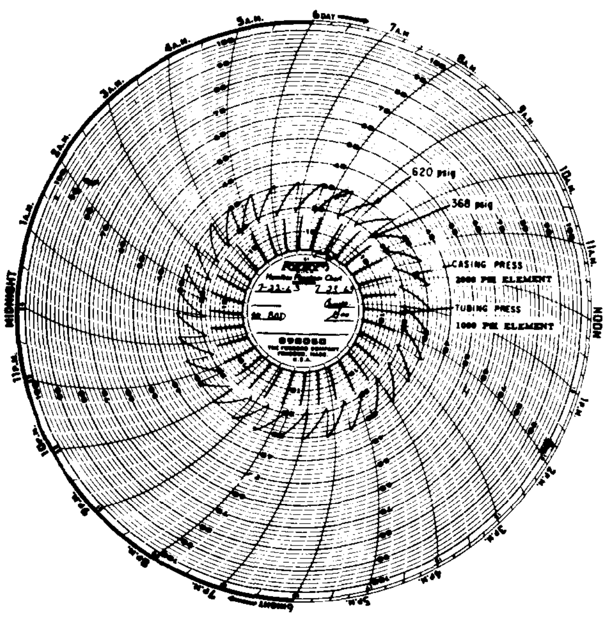

FIGURE 4

TWO-PEN PRESSURE RECORDER CHART FROM INTERMITTENT INSTALLATION WITH 1-1/2-INCH MACARONI STRING IN 2-7/8-INCH O. D. CASING

casing wells by gas lift if the flowing bottom hole pressure is high relative to total depth and annular flow is permissible.

The valve depths are calculated in exactly the same manner for continuous flow through a small conduit as for gas lifting through a large one, except that the flowing pressure gradient curves for the small tubing are used to determine the flowing pressures at depth. Several sets of these gradient curves are illustrated in Figs. 1 and 2. When lifting through macaroni tubing, pressure loss in the small annulus from the surface to the point of gas injection will not affect a continuous flow installation design in most instances because the daily injection gas demand is low and continuous. This per-minute gas rate is much lower than the per-minute rate required to lift a liquid slug by intermittent lift when the operating gas lift valve is open in an intermittent installation. The gas through-put of a small conduit may be of importance for continuous flow operation if the installation is designed for high fluid volumes through the annulus.

For an intermittent installation, fluid-operated valves are generally recommended for the unloading valves with annular pressure-operated valves as the operating valve. The fluid-operated valves are particularly applicable for unloading in a small annulus installation. A high per-minute injection gas volume can be introduced into the casing and the pressure transmitted from the surface to the bottom annular pressure-operated valve without opening the upper fluid-operated valves during the period of gas injection.

Fluid-operated valves can be employed to provide a significant difference between the maximum and minimum annulus pressure necessary to supply the injection gas volume required to displace a solid liquid slug when the injection gas must be stored in the small annulus. A two-pen pressure recorder chart from this type of installation with 1-1/2-in. nominal tubing in 2-7/8-in. OD casing is shown in Fig. 4.[7] This installation had 6 fluid-operated valves to a depth of 5254 ft. Two pilot type gas lift valves were located at 5885 ft. and 6320 ft. The pressure in the annulus increased slowly to approximately 620 psig, at which time the lower pilot valve opened. As the solid liquid slug passed the upper fluid-operated valves, the injection gas pressure under the slug would open these valves. Although the annulus pressure decreased below the pressure required to hold the pilot valves open, the fluid-operated valves remained opened until the slug entered the flow-line and the tubing pressure decreased. During the interval illustrated in Fig. 4, the well produced over 40 bbl. of liquid per day (24 bbl. of oil) with an injection GLR of approximately 250 cu. ft. per bbl. per 1000 ft. of lift and the average slug velocity was nearly 2000 ft. per minute.

CONCLUSIONS

Additional experimentation and experience with small tubing have greatly extended its application for gas lift in small diameter casing installations. In the past, gas lift has not been employed in many wells where this type of artificial lift would have proven to be the one most suited to do the job. Since flowing pressures at depth in small tubing can be predicted now with reasonable accuracy and the minimum flowing pressures at depth are much lower than initially believed possible for the lower daily liquid rates, the use of gas lift as a major method of artificial lift in small diameter casing installations should increase in the future.

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