CONTINUOUS REMOVAL OF LIQUIDS FROM GAS WELLS BY USE OF GAS LIFT

PAT TRAMMEL
Gas Lift Sales & Service, Inc.
ADAM PRAISNAR, JR.
Ralph Viney and Associates, Inc.

ABSTRACT

Most gas wells produce liquids that are often not removed from the well because of low gas velocity. Failure to produce these liquids severely restricts gas production. This paper discusses the continuous removal of these fluids from gas wells by gas lift. It will also discuss compressor installation and operation.

INTRODUCTION

Gas wells loads up only because of insufficient velocity to carry liquids from the wellbore to the surface. The gas volume required to ensure continuous removal of liquids from gas wells is dependent on tubing size, type of fluid (water or condensate), and flowing wellhead pressures.

MINIMUM FLOW REQUIREMENTS

Many authors have suggested methods to determine if the flow rate of a well is sufficient to remove liquids from a wellbore.[1-3] The method of Turner, Hubbard, and Dukler is found to be reliable in field applications.[4] Their equations are presented in two forms: velocity and rate.

$$v_w = \frac{5.62\ (67 - 0.0031p)^{1/4}}{(0.0031p)^{1/2}} \tag{1}$$

$$v_c = \frac{4.02\ (45 - 0.0031p)^{1/4}}{(0.0031p)^{1/2}} \tag{2}$$

$$q_g = \frac{3.06\ pAVg}{Tz} \tag{3}$$

These equations reduce to the following after substituting for velocity of gas in Equation 3.

$$q_w = \frac{17.197\ pA\ (67 - 0.0031p)^{1/4}}{Tz\ (0.0031p)^{1/2}} \tag{4}$$

$$q_c = \frac{12.301\ pA\ (45 - 0.0031p)^{1/4}}{Tz\ (0.0031p)^{1/2}} \tag{5}$$

Turner, Hubbard, and Dukler presented a nomograph (Figure 1) to solve Equations 4 and 5. Their nomograph may also be used for flow in the annulus of a well. They state, "The gas/liquid ratio does not influence the minimum lift velocity in the observed ranges of liquid production up to 130 BBL/MMCF, and this liquid may be water or condensate. If both liquids are present, the properties of the denser of the two should be used in the equation."[5] Field experience has shown this to be reliable. For normal operations, their equations are presented in Figure 2; the variables are type fluid produced, tubing diameter, and wellhead pressure. The flowing wellhead temperature has been assumed at 60°F (520°R) with a gas compressibility factor of 0.9. Figure 2 can also be used, by back calculation, to determine from present well flowing and mechanical conditions when well will cease to flow.

In example shown in Figure 2 for a well equipped with 2-3/8-in. tubing and flowing pressure of 200 psia that produces water, enter the graph at the bottom at 200 psi; proceed vertically upward to intersection with 2-3/8-in. tubing; then proceed horizontally to the left and read 586 MCF/D to continuously remove water. For condensate, enter the graph at the top at 200 psia; proceed vertically downward to intersection with 2-3/8-in. tubing; then proceed horizontally to the right and read 379

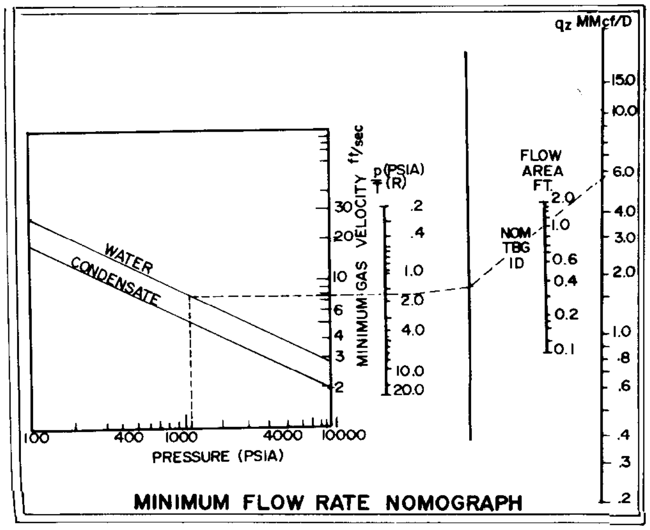

FIGURE 1

MCF/D to continuously remove condensate. If gas-entry rate is below these volumes, the well will gradually load up and die.

EXAMPLE PROBLEM 1:

Stated Well Conditions:	2-3/8-in. tubing 300 PSIA Sales Line Produces Water and Condensate 300 MCF/D capacity (unloaded)
Referring to Figure 2:	Needs 716 MCF/D to flow against 300 PSIA well will flow against 50 PSIA wellhead pressure
Solutions:	(1) Add 416 MCF/D gas lift gas (2) Install multistage compression (3) Install 1-1/4-in. tubing

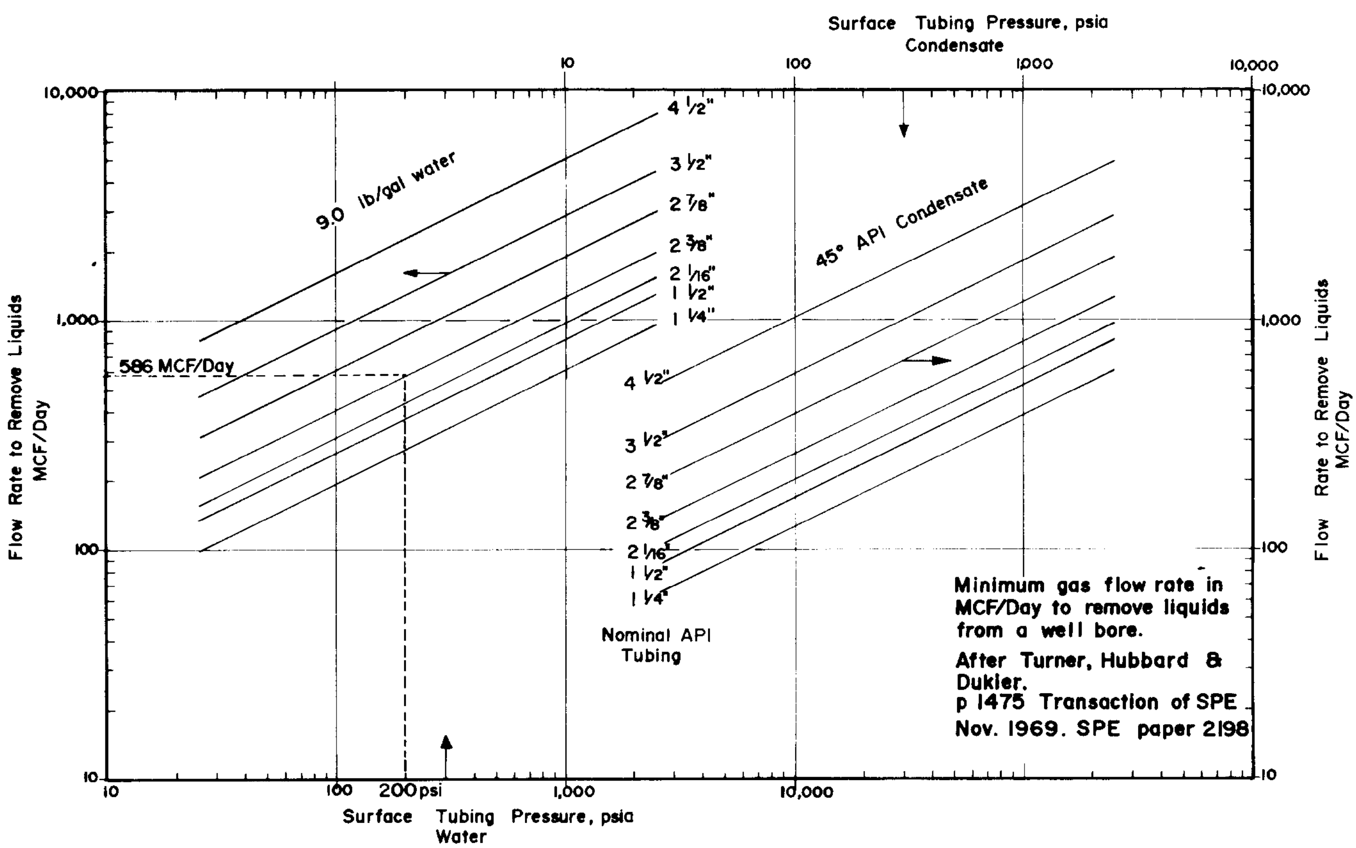

FIGURE 2

EXAMPLE PROBLEM 2:

Stated Well Conditions:	2-7/8-in. 300 PSIA Sales Line Produces Water 750 MCF/D capacity (unloaded)
Referring to Figure 2:	Well will flow against 50 PSIA wellhead pressure
Solutions:	(1) Add 292 MCF/D gas lift gas (2) Install multistage compression (3) Change tubing to 2-3/8-in. or smaller

TYPICAL GAS LIFT

Gas lift is any system in which gas at a relatively high pressure is injected into the well production conduit at a predetermined depth. Usually, the casing-tubing annulus is used for high pressure gas flow path and is transferred into the tubing through gas lift valves. In some cases, this process is reversed and is referred to as annular flow. The number of valves, type of valves, their spacing in the wellbore, and pressure settings are dictated by each individual set of well parameters and is beyond the scope of this paper. Consult a gas-lift specialist for specific well designs.

GAS LIFT FOR KICK-OFF PURPOSES

Many gas wells will produce at sufficient rates for continuous liquid removal, but load up periodically for some reason. These wells can sometimes be kicked off in different ways, such as venting to atmosphere, swabbing, nitrogen jetting, etc. Some operators have found that gas lift is more positive and economical for gas well kick-off. By running gas lift valves initially as an integral part of the production tubing string, wells can be kicked off at any time necessary by injecting high pressure gas or nitrogen into the casing-tubing annulus at a high enough rate to create sufficient velocity for liquid removal. Once injection is terminated, the casing pressure will remain at the gas lift valve design closing pressure. Therefore, subsequent kick-off will not require as much gas or nitrogen. This method of kick-off has proven successful even in deep wells with tapered tubing strings and wells where other kick-off methods have been unsuccessful.

GAS LIFT SOURCE

Gas from any source may be used for gas lift. Historically, the sources of lift gas for gas-lift systems were provided by high pressure gas wells, large scale recycling, or gas repressuring plants. The increasing economic value of natural gas, together with more vigorous gas-conservation practices, has resulted in a widespread application of small compressor systems designed specifically for single gas lift wells. Figure 3 illustrates a typical gas lift well.

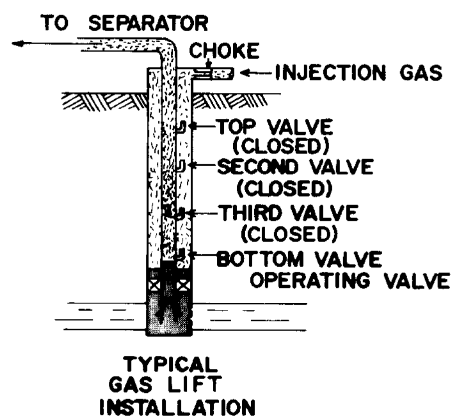

FIGURE 3

CLOSED ROTATIVE GAS LIFT

A closed rotative gas-lift system utilizes a quantity of gas circulated from a compressor discharge down the casing-tubing annulus, through gas lift valves, and up the tubing to a compressor suction. The rotative gas supplements the produced gas from the well to create sufficient velocity for continuous removal of liquids from the wellbore. With the exception of compressor fuel gas and a small amount of gas for heater, controls, etc., all produced gas is directed to sales. Once the maximum volume of lift gas requirements in the system has been fulfilled, a nominal amount of make-up gas (available from production) is all that is necessary. Field experience has shown that less than 4 percent of the discharge capacity of the compressor is adequate for these requirements. Fuel consumption for gas-driven compressors can normally be estimated at 10 cubic feet per brake horsepower hr.

COMPRESSORS

There are a number of high quality packaged compressor units in the low-to-medium horsepower range available on a purchase, lease-purchase, or rental basis. A packaged compressor unit simply means that all components necessary to make a complete plant are installed on a single skid mounting. This includes compressor, prime mover, gas and water piping manifolds, radiator, gas cooling section, and scrubbers.

INSTALLATION OF COMPRESSORS

Compressors in closed rotative gas lift systems are connected to sales in two manners. We will refer to gas sales before compressor suction as "Low Pressure Sales" system and after discharge as "High Pressure Sales" system. In a "Low Pressure Sales" system, the produced gas is directed to sales when it exceeds compressor suction requirements (Figure 4).

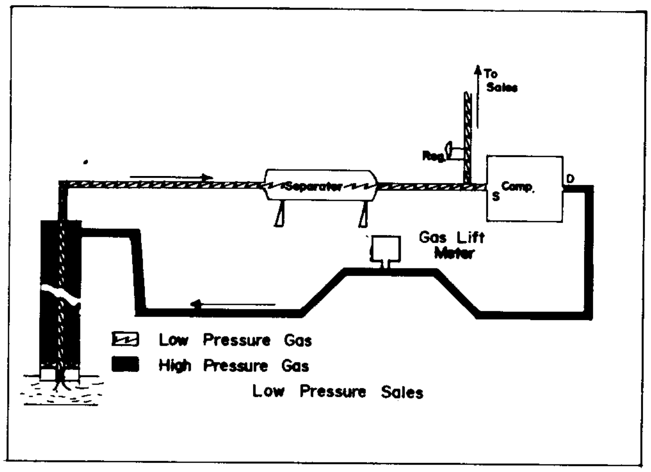

FIGURE 4

EXAMPLE PROBLEM 3

Well Product:	175 MCF/D 100 PSIA Wellhead Pressure and Loads Up
Gas Sales Pressure:	100 PSIA
Gas Lift Design Pressure:	500 PSIA
Tubing:	2-3/8 nominal

Solution

Total Gas Required (Figure 2) water 100 PSIA Wellhead Pressure	414 MCF/D
Gas Production	175 MCF/D
Gas Lift Gas Required	239 MCF/D

Initially the compressor will have to compress 239 MCF/D from 100 PSIA to 500 PSIA. Consideration should be given to sizing the compressor to compress more gas as well deliverability declines.

In a "High Pressure Sales" system, the produced gas is directed to sales when it exceeds gas lift gas requirements (Figure 5).

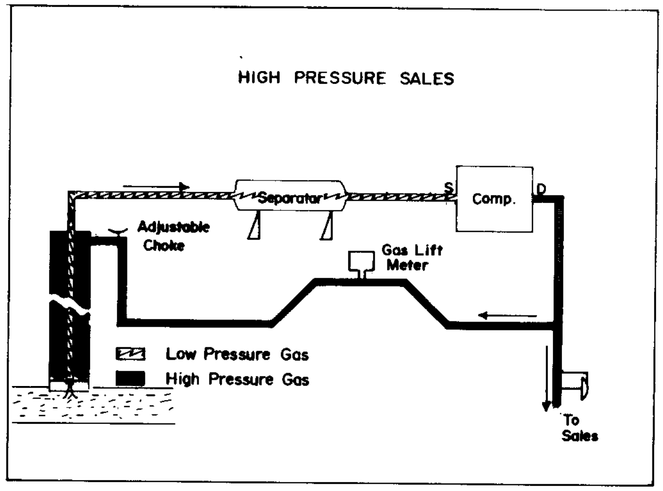

FIGURE 5

EXAMPLE PROBLEM 4

Well Production:	175 MCF/D and Loads up
Gas Sales Pressure:	500 PSIA
Gas Lift Design Pressure:	500 PSIA

Solution

Total Gas Required (Figure 2) water 100 PSIA Wellhead Pressure	414 MCF/D
Gas Produced	175 MCF/D
Gas Lift Gas Required	239 MCF/D

The compressor will have to be sized to compress 414 MCF/D from 100 PSIA to 500 PSIA and should be adequate throughout life of the well unless lower wellhead pressure is desired.

SELECTION OF COMPRESSOR

Selection of a compressor depends upon the following factors: gas lift valve design pressure, gas volume needed (current and ultimate), pressure needed at wellhead, gas sales-outlet pressure, separator pressure, availability of make up gas, and most important, well inflow performance and gas sales contract. Keep in mind that a well can always be depleted to a lower pressure with multiple-stage compression. On the other hand, multiple-stage compressors cost more initially and are more costly to operate. There are many fleets of packaged rental compressors available to meet any requirement today and compressor change out is usually quite simple. Therefore, it is conceivable that economics and would justify compressor change out at different stages of the productive life of a well.

COMPRESSOR SIZING

The following is a very basic procedure for estimating compression horsepower sizing requirements and related performance. It is reasonably safe to say that compression ratios for high-speed separable units should not exceed 5. The slow-speed integral units can probably go to a compression ratio of 6.

GUIDELINES FOR ESTIMATING COMPRESSOR REQUIREMENTS

Determine the overall pressure ratio of the compressor.

$$R = \frac{P_D}{P_S}$$

R = overall pressure ratio
P_s = suction pressure, psia
P_d = discharge pressure, psia

In general: when $R \leqslant 5$, a single stage compressor is required.
when $R = 5\text{-}25$, a two stage compressor is required.
when $R = 25\text{-}125$, a three stage compressor is required.

Determine the horsepower required for compression.

For single stage, $HP = R \times 22 \times Q$
For two stage, $HP = R \times 44 \times Q$
For three stage, $HP = R \times 66 \times Q$
Q = volume of gas to be compressed, MMSCFD

Determine the required piston displacement of the cylinder(s).

$$PD = \frac{10{,}000 \times Q}{P_s \times VE}$$

PD = piston displacement, cubic feet per minute
VE = volumetric efficiency of the cylinder (use 0.75)

From this calculated piston displacement an approximate cylinder size(s) can be chosen from available published date.

If no data is available, the cylinder diameter(s) can be solved for with the following.

$$D = \frac{1100 \times PD}{S \times RPM} \quad \text{For a double acting cylinder}$$

D = cylinder diameter, inches
RPM = compressor operating speed
S = compressor piston stroke, inches

With a value for "D" calculated, use the next largest standard-size cylinder diameter(s).

The same cylinder sizing procedure is used for a multi-stage unit, with the interstage pressure (the intermediate pressure between stages) being used as the suction pressure to the next higher stage cylinder.

The interstage pressure is determined by the product of the low-stage suction pressure and the square root of the overall pressure ratio (for two stage). A three stage unit would use the cube root of R, etc.

Example:

Assume, PS = 50 PSIG = 64.7 PSIA
PD = 800 PSIG = 814.7 PSIA

$$R = \frac{814.7}{64.7} = 12.59 \qquad (\sqrt{R} = 3.55)$$

This is a two stage application. The interstage pressure would be 230 PSIA (64.7 x 3.55). The final discharge pressure is 814.7 PSIA (230 x 3.55). Therefore, the first stage cylinder is compressing from 64.7 PSIA up to 230 PSIA and the second stage cylinder is compressing from 230 PSIA to 814.7 PSIA. With these pressures the piston displacement for each stage can be determined.

Determine the gas discharge temperature.

$$TD = T_s \times R^{\,n-1/n}$$

Td = gas discharge temperature, °R
T_s = gas suction temperature, °R
R = Rankine temperature = °F + 460
n = gas specific heat ratio (use 1.26)

A gas discharge temperature of 300°F is acceptable depending on the compressor model.

NOTE: All compressor calculations use absolute pressures (PSIA) and temperatures (°R).

These calculations are very approximate and should be used accordingly. They do not take into account many variables that could substantially alter compressor performance. Consult your compressor specialist before making final selection.

CLOSED ROTATIVE SYSTEM KICK-OFF

Figure 6 is a layout of a "High Pressure Sales" System. To get a rotative system kicked off, it is necessary to first charge the system — that is, to fill the casing-tubing annulus and piping from the compressor to the well to operating pressure. It is sometimes possible to make arrangements with the gas purchaser to get gas back from sales, or if some

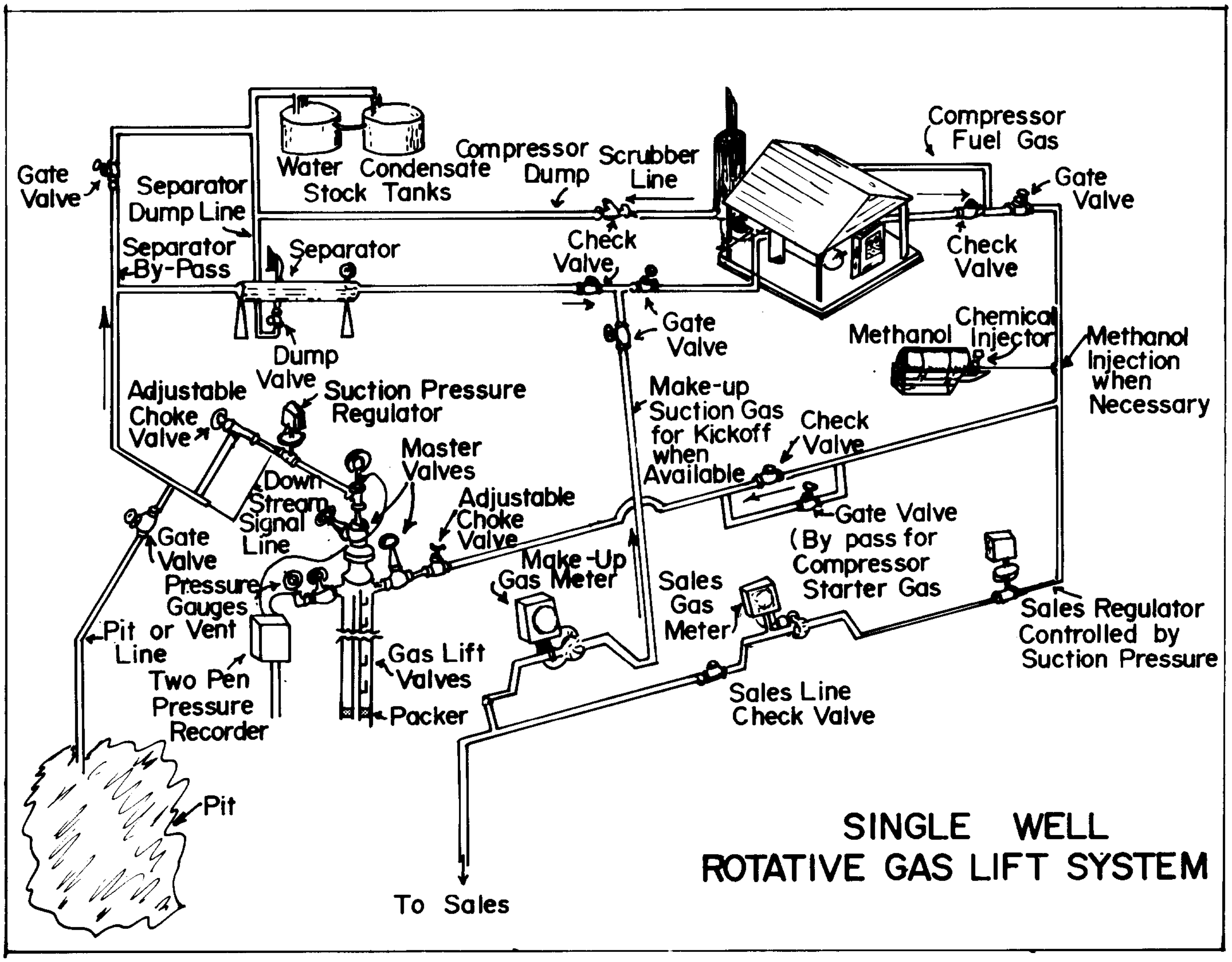

FIGURE 6

other source of gas is available, start up is no problem. If gas is not available, and the well is dead, it is necessary to swab the well and put all of the gas into the system until it is charged. As soon as gas can be rotated, no further swabbing is needed. As the well is unloaded, all gas being produced (except for fuel gas, losses from separator, heater, etc.) will go to sales.

CONTROL VALVES

A throttling control valve is recommended at the wellhead to close on pressure rise from downstream signal. The purpose of this valve is to keep compressor suction from becoming too high. Also, if the compressor is not running for any reason, the valve will close and trap all gas in the well bore, which eliminates the necessity of make up gas from outside sources for start up.

An adjustable input valve is needed to regulate the volume of gas injected into the casing. This valve will control suction pressure of the compressor. If suction pressure is low, opening the valve slightly will allow more gas into the well and consequently increase suction pressure. Closing it slightly will result in a suction pressure decrease. This valve eliminates the need of a discharge to suction bypass loop at the compressor. If the sales-line pressure fluctuates or is lower than casing operating pressure, a pressure regulator should be installed on the sales line. This regulator will stabilize compressor-discharge pressure and keep a constant differential across the casing input valve.

A dehydrator is not normally incorporated in a single well system. A methonal injection tap should be installed in discharge piping upstream of all points of pressure drops where hydrates form or freezing is expected (that is, at the sales regulator, casing injection choke, and meter runs).

It is advisable to install a two-pen pressure recorder to continuously record casing and tubing pressures. A gas-lift measurement system is an important diagnostic tool for location of problems that may occur in the gas lift system.

CONCLUSIONS

Gas wells load up due to low inflow rates, high wellhead pressure, and unnecessarily large tubing diameter. Gas lift is an effective method of assuring continuous removal of liquids from gas wells, is flexible, and can be applied to any gas well. Gas lift can be used economically to periodically kick-off gas wells with nitrogen. Closed rotative gas lift systems can be applied to any gas well application.

NOMENCLATURE

- A = Flow area of conduit, square feet
- p = pressure, lb. force/square inch absolute
- q_g = Gas flow rates, MMCF/Day
- q_w = Gas flow rate to remove water, in MMCF/Day
- q_c = Gas flow rate to remove condensate in MMCF/Day
- T = Temperature, °R
- v_g = Velocity, ft/sec.
- v_w = Velocity required to lift water in ft/sec.
- v_c = Velocity required to lift condensate in ft/sec.
- z = Gas deviation factor

REFERENCES

1. Dugan, I. O.: "Estimating Flow Rate Required to Keep Gas Wells Unloaded," *J. Pet. Tech.* (Dec., 1961) 1173-1176.
2. Hinze, J. O.: "Critical Speeds and Sizes of Liquid Globules," *Applied Scientific Research* (1949) A-1, No. 4, 273.
3. Turner, R. G.: "An Analysis of the Continuous Removal of Liquids from Gas Wells," MS thesis, U. of Huston, (1967).
4. Turner, R. G., Hubbard, M. G., and Dukler, A. E.: "Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells," *J. Pet. Tech.* (Nov., 1969) 1475-1482.
5. Same as reference 4, p. 1480.