GAS LIFT MANUAL

Contents

Preface

The first use of air to lift water to the surface was reported in the mines of Chemnitz, Hungary around the middle of the 18th century. First in the wells of Pennsylvania, at around 1864, oil was lifted by compressed air that was later displaced by natural gas as the lifting medium. Throughout its almost 150-year long history, gas lifting proved to be one of the most popular methods of lifting liquids from wells. It can be applied in oil wells with high gas production rates where other artificial methods are plagued with frequent failures or cannot be used at all. It is especially suited to the offshore environment where extremely high liquid volumes have to be lifted.

Gas lifting can be used throughout the whole lifespan of an oil well: from the time it dies until its abandonment. At early production times, higher liquid rates are achieved by continuous flow gas lift. As the field depletes and formation pressure and liquid rates decrease, easy conversion to intermittent gas lift ensures that production goals are met. Close to well abandonment, another version of gas lifting—chamber lift—can be applied. Because of these features, gas lifting is probably the most flexible means of artificial lifting available today.

I wrote *Gas Lift Handbook* to become a handbook of up-to-date gas lift theories and practices and to cover the latest developments in this important field of artificial lifting technology. Since I present a complete review of gas lift technology and include references to all of the important literature sources, the practicing engineer can use the book as a reference on the subject. I tried to distill in this book all the experience I gathered during my 30-year teaching and consulting career in order to present a text that systematically introduces the reader to the subject matter. It would be a personal gratification if, like its predecessor *Modern Sucker-Rod Pumping* published by PennWell in 1993, this book, too, would be chosen for graduate level courses at different petroleum engineering schools.

It is fully understood by anyone in the industry that describing multiphase flow in oil wells is the basis of solving most of the problems in gas lifting. Since this is an area where almost revolutionary achievements happened in the last 20 years, I fully describe the pressure drop calculation procedures for vertical, inclined, and horizontal wells including the latest mechanistic models. The chapter on production engineering fundamentals includes, in addition to a very detailed treatment of multiphase flow, a review of fluid properties, well inflow performance, basic hydraulics, well temperature, and systems analysis.

Further chapters systematically introduce the reader to the hardware of gas lifting, reflecting the latest developments in gas lift valve and other equipment designs. The great variety of gas lift valves, their constructional and operational details are fully discussed along with the latest achievements on describing their dynamic performance. The description of gas lift installation types helps the engineer select the right combination of well equipment. The chapter on continuous flow gas lift fully describes the different ways to optimize the wells' operation, including the latest optimization theories (lift gas allocation to wells, systems analysis, etc.). Unloading and surface control of continuous flow gas lift wells round up this chapter.

The discussion of intermittent gas lift includes conventional, chamber, and plunger-assisted installations and describes the performance, design, and optimization of such wells. A detailed treatment of the surface gas lift system follows, including the operation and design of the complete system consisting of the compressor station, and the distribution and gathering facilities. The last chapter includes practical advice on the analysis and troubleshooting of gas lift installations. All necessary calculations are fully discussed, and the many charts in the appendices are intended to help field engineers.

Nowadays, personal computers belong to every petroleum engineer's desk and this book was designed with this fact in mind. Since most design and analysis problems in gas lifting are too complex to be solved by the conventional tools of the engineer, I heavily relied on computerized solutions in the text.

While writing this book I burned a lot of midnight oil and many times had regretfully neglected those I love most—my family. Their patience and understanding is appreciated.

This is already the third project I have worked on with PennWell. Ms. Marla Patterson (PennWell) and Ms. Sue Rhodes Dodd (Amethyst Enterprises) were always most helpful and forgiving. A special "thank you" to both of them.

Gábor Takács
July 2005

1 Introduction to Gas Lifting

1.1 Artificial Lifting

Most oil wells in the early stages of their lives flow naturally to the surface and are called flowing wells. Flowing production means that the pressure at the well bottom is sufficient to overcome the sum of pressure losses occurring along the flow path to the separator. When this criterion is not met, natural flow ends and the well dies.

Wells may die for two main reasons: either their flowing bottomhole pressure drops below the total pressure losses in the well, or the opposite happens and pressure losses in the well become greater than the bottomhole pressure needed for moving the wellstream to the surface. The first case occurs when a gradual decrease in reservoir pressure takes place because of the removal of fluids from the underground reservoir. The second case involves an increasing flow resistance in the well, generally caused by (a) an increase in the density of the flowing fluid as a result of decreased gas production; or (b) various mechanical problems like a small tubing size, downhole restrictions, etc. Surface conditions, such as separator pressure or flowline size, also directly impact total pressure losses and can prevent a well from flowing.

Artificial lifting methods are used to produce fluids from wells already dead or to increase the production rate from flowing wells; and several lifting mechanisms are available to choose from. One widely used type of artificial lift method uses a pump set below the liquid level in the well to increase the pressure so as to overcome flowing pressure losses that occur along the flow path to the surface. Other lifting methods use compressed gas, injected periodically below the liquid present in the well tubing and use the expansion energy of the gas to displace a liquid slug to the surface. The third mechanism works on a completely different principle: instead of increasing the pressure in the well, flowing pressure losses are decreased by a continuous injection of high-pressure gas into the wellstream. This enables the actual bottomhole pressure to move well fluids to the surface.

Although all artificial lift methods can be distinguished based on the previous three basic mechanisms, the usual classification is somewhat different and is discussed here.

Example 2–4. Find the deviation factor for a natural gas at p = 1,200 psia (8.28 MPa) and T = 200 °F (366 K), if the pseudocritical parameters are p_{pc} = 630 psia (4.35 MPa) and T_{pc} = 420 °R (233 K).

Solution

The pseudoreduced parameters are

p_{pr} = 1,200 / 630 = 1.9

T_{pr} = (200 + 460) / 420 = 1.57

Using these values, from Figure 2–2:

Z = 0.85

Gas Volume Factor, B_g

The Engineering Equation of State enables the direct calculation of volume factors for gases. Equation 2.15 can be written for a given number of moles in the following form:

$$\frac{pV}{ZT_a} = \left(\frac{pV}{ZT_a}\right)_{sc} \qquad 2.19$$

This equation can be solved for B_g, which is the ratio of actual volume to the volume at standard conditions:

$$B_g = \frac{V}{V_{sc}} = \frac{p_{sc} Z T_a}{p Z_{sc} T_{sc}} \qquad 2.20$$

Substituting into this the values p_{sc} = 14.7 psia, T_{sc} = 520 °R, and Z_{sc} = 1, one arrives at

$$B_g = 0.0283 \frac{ZT_a}{p} \qquad 2.21$$

Example 2–5. What is the actual volume of the gas, if its volume measured at standard conditions is 1.2 Mscf (33.9 m^3)? Other data are identical to those of Example 2–4.

Solution

The volume factor of the gas, from Equation 2.21:

B_g = 0.0283 0.85 (200 + 460) / 1200 = 0.013

Actual volume is found from Equation 2.6:

$V(p,T) = B_g\, V_{sc}$ = 0.013 1200 = 15.6 cu ft (0.44 m^3).

Gas Density

The fact that gas volume factor is an explicit function of state parameters allows a direct calculation of gas density at any conditions. Based on the definition of volume factor, gas density can be expressed from Equation 2.7, and after substituting the formula for gas volume factor, we get

$$\rho(p,T) = \frac{\rho_{sc}}{B_g} = \frac{0.0764\gamma_g p}{0.0283 Z T_a} = 2.7\gamma_g \frac{p}{ZT_a} \qquad 2.22$$

The previous formula is used to find the actual density of natural gases at any pressure and temperature based on the knowledge of their specific gravities and deviation factors.

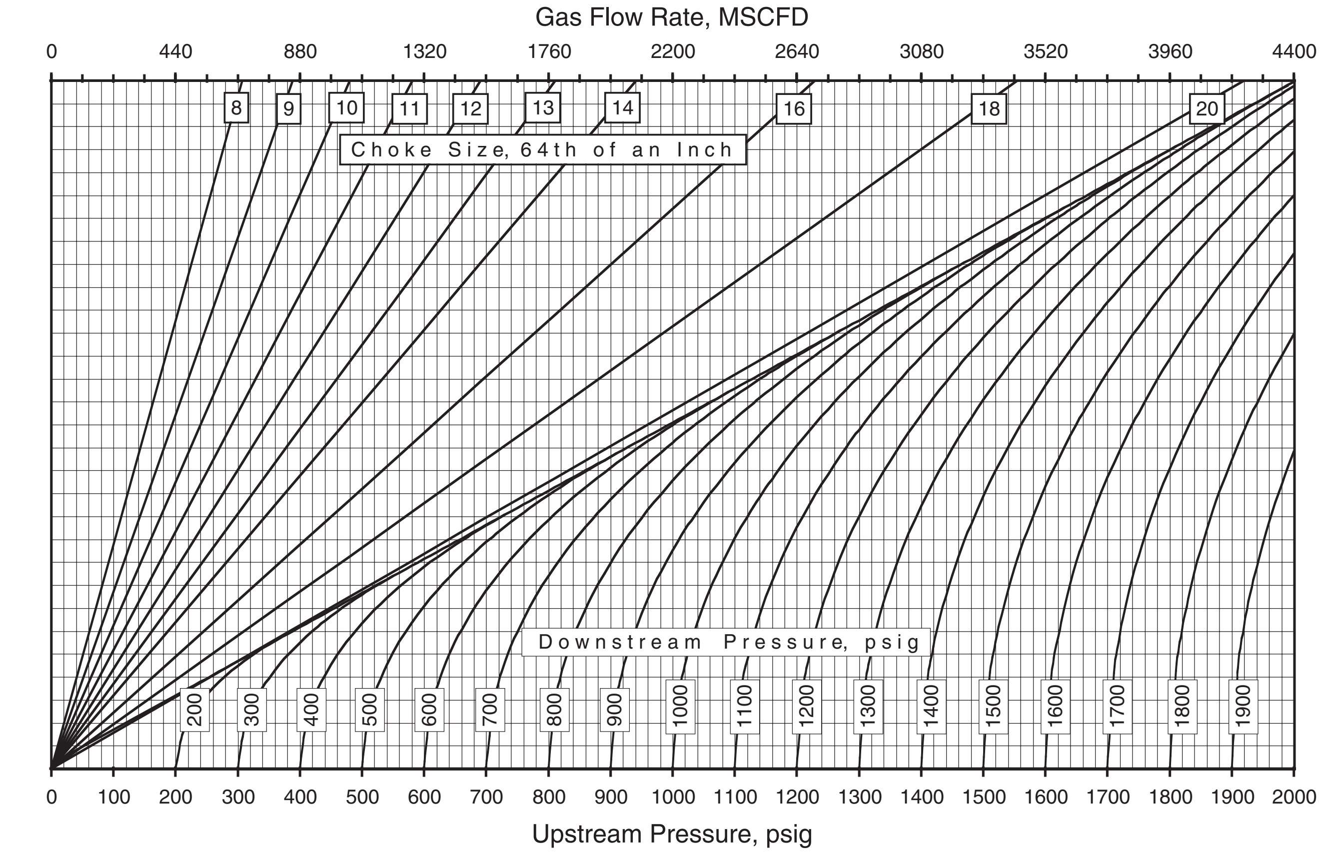

Fig. 2–12 Gas throughput capacity chart for different choke sizes.

Appendix C contains two gas capacity charts for different ranges of choke sizes, as well as a correction chart that can be used to correct gas volumes at temperatures different from chart base.

Example 2–18. Find the gas volumes for the cases given in the previous example with the use of the gas capacity chart in Figure 2–12.

Solution

For case one, start at an upstream pressure of 1,014 psia (7 MPa) and go vertically until crossing the curve valid for a downstream pressure of 814 psia (5.6 MPa). From the intersection, draw a horizontal to the left to the proper choke size (16/64 in.). Drop a vertical from here to the upper scale to find the gas flow rate of 1,140 Mscf/d (32,281 m^3/d).

Since actual flow conditions differ from chart base values, a correction must be applied. According to Equation 2.65, the actual gas flow rate is

$$q_{act} = 1{,}140\ 0.9\ \frac{21.25}{\sqrt{0.65610}} = 1{,}140\ 0.96 = 1{,}094 \text{ Mscf/d } (30{,}978 \text{ m3/d}).$$

The second case involves critical flow and the vertical line from the upstream pressure should be drawn to the upper boundary line of the downstream pressures constituting critical flow. Using the same procedure as in the first case, a gas flow rate of 1,360 Mscf/d (38,511 m^3/d) is read from the chart. Since flow conditions are similar to case one, again a correction factor of 0.96 is used to find the actual flow rate:

$$q_{act} = 1{,}360\ 0.96 = 1{,}305 \text{ Mscf/d } (36{,}953 \text{ m}^3\text{/d}).$$

Flow Pattern Map

The flow pattern map used by the authors is given in Figure 2–19. The coordinate axes are the gas and liquid velocity numbers defined before. As seen, four flow patterns are distinguished: bubble, slug, transition, and mist. The boundaries of the flow patterns (shown in the figure for air-oil flow in an 8-cm pipe) are found from the following equations:

$$N_{gv} = L_1 + L_2 N_{lv} \quad \textit{bubble-slug boundary} \tag{2.102}$$

$$N_{gv} = 50 + 36 N_{lv} \quad \textit{slug-transition boundary} \tag{2.103}$$

$$N_{gv} = 75 + 84 N_{lv}^{0.75} \quad \textit{transition-mist boundary} \tag{2.104}$$

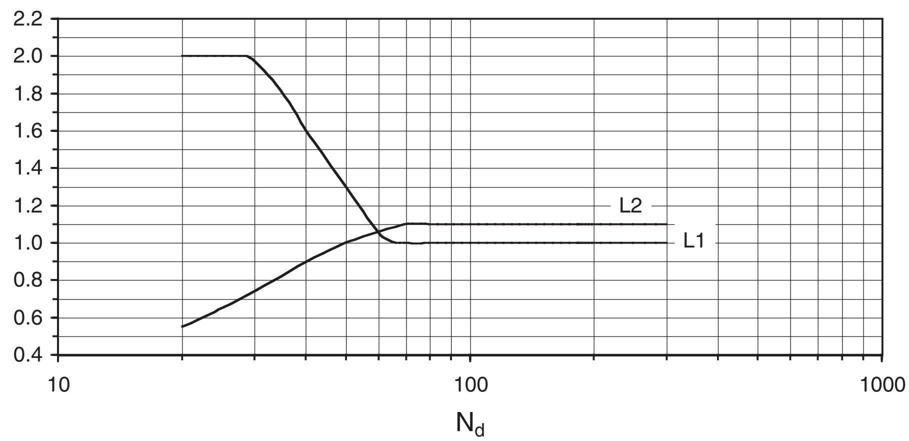

Fig. 2–24 Bubble-slug flow pattern transition parameters.

Functions L_1 and L_2 previously are evaluated from Figure 2–24 in the function of the pipe diameter number N_d.

Liquid Holdup Calculation Basics

According to Duns-Ros' general approach, measured liquid holdup data were correlated by using the dimensionless groups defined previously as independent, and the dimensionless slip velocity number as the dependent parameter. The latter is defined as follows:

$$S = v_s \sqrt[4]{\frac{\rho_l}{g\sigma_l}} = 1.938 v_s \sqrt[4]{\frac{\rho_l}{\sigma_l}} \tag{2.105}$$

After calculating the dimensionless slip velocity number, the real slip velocity v_s can be expressed from the previous equation:

$$v_s = 0.52 S \sqrt[4]{\frac{\rho_l}{\sigma_l}} \tag{2.106}$$

As derived in Two-Phase Flow Concepts (Section 2.5.2.1), knowledge of the slip velocity enables one to find liquid holdup (see Equation 2.78) from the formula reproduced here:

$$\varepsilon_l = \frac{v_s - v_m + \sqrt{(v_m - v_s)^2 + 4 v_s v_{sl}}}{2 v_s} \tag{2.107}$$

2.5.3.3.6 *Chierici et al. correlation.*

Summary

Practically identical to the Orkiszewski model. The only difference is in slug flow, where the authors eliminated the discontinuities in liquid holdup occurring when the original model is applied.

Chierici et al. [55] adopted the Orkiszewski model for the prediction of flow patterns and the calculation of pressure gradients in all but the slug flow pattern. Therefore, this correlation can be regarded as a slightly modified version of the original. For this reason, only the modifications are detailed as follows.

In slug flow, Chierici et al. used the drift-flux approach for the determination of the liquid holdup. According to this theory, liquid holdup is found from the following basic equation (see Equation 2.76):

$$\varepsilon_l = 1 \frac{v_{sg}}{C_0 v_m + v_b} \qquad 2.152$$

where: C_0 = distribution factor, -

v_m = mixture superficial velocity, ft/s

v_{sg} = gas superficial velocity, ft/s

v_b = bubble rise velocity, ft/s

The authors assumed the distribution factor to be $C_0 = 1$, and calculated the bubble rise velocity v_b as suggested by Griffith and Wallis [52]:

$$v_b = C_1 C_2 \sqrt{gd} \qquad 2.153$$

where: d = pipe diameter, ft

As with the Orkiszewski model, C_1 is found from Figure 2–34. When finding the other parameter C_2, the authors showed that the method proposed by Orkiszewski is defective. There are no problems in the $N_{Rel} \leq 6{,}000$ range, but at higher Reynolds numbers the extrapolation functions given by Orkiszewski (see Equations 2.140 –2.143) result in discontinuities.

To prevent the discontinuities caused by the Orkiszewski extrapolations of Figure 2–35, Chierici et al. proposed the use of the following formula:

$$C_2 = \frac{1}{1 - 0.2 \dfrac{v_m}{v_b}} \qquad 2.154$$

The authors proved that the use of the previous equation eliminates the discontinuities of the calculated C_2 values and ensures the convergence of pressure gradient calculations in slug flow.

2.5.3.3.7 *Beggs-Brill correlation.*

Summary

The first correlation developed for all pipe inclination angles was based on a great number of data gathered from a large-scale flow loop. Flow patterns are determined for a horizontal direction only and are solely used as correlating parameters. Its main strength is that it enables a simple treatment of inclined wells and the description of the well-flowline system.

Gas core liquid entrainment is limited to values E ≤ 1.0 since part of the total liquid content is situated in the liquid film covering the pipe wall. The definition of the critical vapor velocity v_{crit} figuring in the previous formulas is

$$v_{crit} = 10^4 \times \frac{v_{sg}\mu_g}{\sigma_l}\sqrt{\frac{\rho_g}{\rho_l}} \qquad 2.240$$

where: ρ_l = liquid density, lb/cu ft

ρ_g = gas density, lb/cu ft

σ_l = interfacial tension, dyne/cm

v_{sg} = gas superficial velocity, ft/s

μ_g = gas viscosity, cP

The elevation term can now be calculated from Equation 2.222, by substituting into the mixture density the gas core density defined as follows:

$$\rho_m = \rho_c = \rho_l\lambda_{lc} + \rho_g(1 - \lambda_{lc}) \qquad 2.241$$

The frictional pressure drop occurs due to the high-velocity flow of the gas core on the wavy liquid film covering the pipe inside wall. Since the thickness of this film is not very significant (typically less than 5% of the pipe diameter), the basic formula to be used in this special case neglects the changes in diameter:

$$\left(\frac{dp}{dl}\right)_f = 1.294 \times 10^{-3} f_c \frac{\rho_c}{d}\left(\frac{v_{sg}}{1 - \lambda_{lc}}\right)^2 \qquad 2.242$$

where: ρ_c = gas core no-slip density, lb/cu ft

v_{sg} = gas superficial velocity, ft/s

λ_{lc} = liquid holdup in gas core, -

f_c = liquid film friction factor, -

d = pipe diameter, in.

In the previous formula, friction factor in the liquid film is found, according to Hasan and Kabir from the formula:

$$f_c = 0.024\ (1 + 75\lambda_{lc})\sqrt[4]{\frac{\mu_g}{\rho_g v_{sg} d}} \qquad 2.243$$

where: ρ_g = gas density, lb/cu ft

μ_g = gas viscosity, cP

Gas core density being defined by Equation 2.240, frictional pressure gradient is easily found from Equation 2.241.