The pressure drop in tubing due to flow of homogeneous (single-phase) fluid can be calculated by conventional pipe flow equations. Gas and highly undersaturated oil wells come under this category. Just a small quantity of free gas mixed with oil and/or water creates considerably more complicated flow conditions which can be described only approximately by including empirical corrections to the conventional pipe flow equations. The tubing performance relationship of wells producing multiphase mixtures is therefore difficult to estimate with any accuracy.

For dry gas wells there are several methods for calculating pressure loss in vertical or inclined pipe. A simple and accurate equation for vertical flow of gas (Katz et al. 1959, p.306), which can be solved directly (i.e., without integration or trial and error), is

$$q_g = 200{,}000\left[\frac{sD^5(p_{in}^2 - e^s p_{wh}^2)}{\gamma_g TZHf_M(e^s - 1)}\right]^{0.5}, \tag{1.39}$$

where

q_g = gas flow rate, scf/D,
Z = average gas compressibility factor,
T = average temperature, °R,
f_M = Moody friction factor,
γ_g = gas gravity, air = 1,
D = tubing diameter, in.,
p_{in} = flowing tubing intake pressure, psia,
p_{wh} = flowing wellhead pressure, psia,
H = vertical depth, ft,
s = $0.0375\gamma_g H/TZ$.

Average temperature is simply the arithmetic average between the temperatures at the wellhead and intake to the tubing (usually reservoir temperature). The average compressibility factor is evaluated at the average temperature and the arithmetic average between the flowing wellhead and intake pressures.

A valid assumption for most gas wells is that flow is turbulent, resulting in an expression for f_M that depends only on the relative roughness of the pipe:

$$f_M = \{2\log[3.71/(\varepsilon/D)]\}^{-2}, \tag{1.40}$$

where ε is the absolute pipe roughness and $\varepsilon = 0.0006$ in. for most commercial pipe. Equation (1.40) is the best-fit equation for the fully turbulent region of the Moody diagram and is sufficiently accurate for most engineering calculations.

The simplest application of equation (1.39) is for calculating a table of rate versus flowing intake pressure, given a fixed wellhead flowing pressure and pipe size. Example 1.11 illustrates the use of equations (1.39) and (1.40), assuming a fixed wellhead pressure. Higher wellhead pressures would result in tubing performance curves that shift upward and to the left, while lower wellhead pressures would shift the TPR down and to the right.

EXAMPLE 1.11 TUBING PERFORMANCE RELATION FOR A GAS WELL

The Elk City No. 3 well is to be produced into a high-pressure, gas-gathering line requiring a minimum wellhead pressure of about 800 psia. Available tubing has a 2⅞-in. nominal diameter (about a 2.5-in. inner diameter). Other relevant data for the well include:

vertical length of tubing	7250 ft
depth to midperforations	7310 ft
gas gravity	0.75 (air = 1)
average tubing temperature	120 °F
average gas Z-factor	0.78
pipe roughness	0.0006 in.

Use equation (1.39) to calculate the tubing performance relation of this well (up to the rate of 24 MMscf/D).

SOLUTION

The first step in calculating the approximate tubing performance relation is to determine s in equation (1.39):

$$s = 0.0375(0.75)(7300)/(120 + 460)(0.78)$$

$$= 0.454.$$

The Moody friction factor is estimated from equation (1.40):

$$f_M = \{2 \log[3.71/(0.0006/2.5)]\}^{-2}$$

$$= 0.0142.$$

The approximate tubing performance relation then becomes

$$q_g = 9368(p_{in}{}^2 - 1.0 \times 10^6)^{0.5}.$$

A few values of intake flowing pressure are chosen, and table E1.11 gives the calculated flow rates corresponding to each pressure. Figure E1.11 is a plot of the rate pressure data in table E1.11.

EXAMPLE 1.11 continued

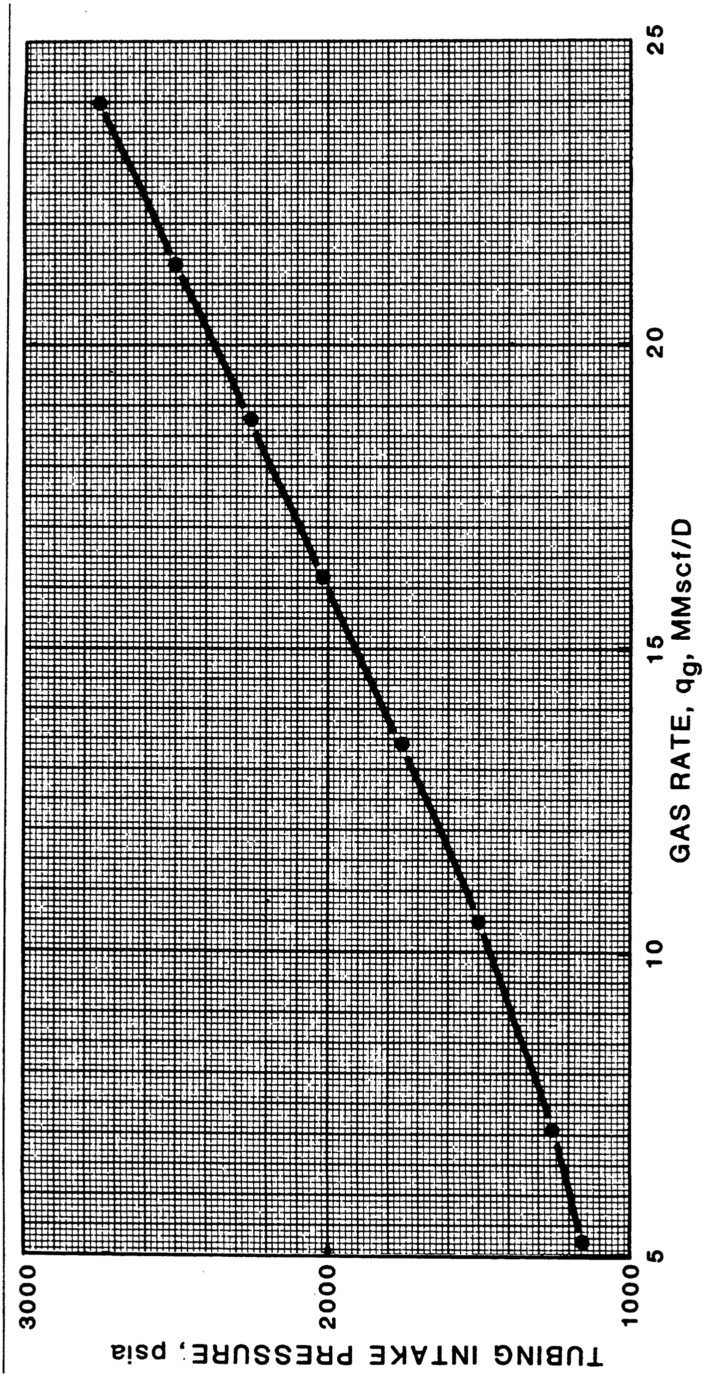

Figure E1.11 The tubing performance of the Elk City No. 3 gas well.

EXAMPLE 1.11 continued

Table E1.11 Calculated Tubing Performance Relation for the Elk City No. 3 Well

p_{in} (psia)	$p_R^2 - p_{in}^2$ (psi^2)	q_g (MMscf/D)	p_{in} (psia)	$p_R^2 - p_{in}^2$ (psi^2)	q_g (MMscf/D)
1150	9.9×10^6	5.32	2000	7.3×10^6	16.23
1250	9.7×10^6	7.03	2250	6.2×10^6	18.88
1500	9.0×10^6	10.47	2500	5.0×10^6	21.46
1750	8.2×10^6	13.45	2750	3.7×10^6	24.00

The approximate TPR equation (1.39) can be used only for dry gas. If water or condensate is produced as an entrained liquid phase (GOR greater than about 7000 scf/STB), then gas velocity must generally exceed 18 to 20 ft/s if equation (1.39) is to be used. At lower velocities it has been observed that liquid accumulates, thereby increasing pressure loss considerably above that calculated from equation (1.39). If velocity decreases to 10 to 12 ft/s, then the well will probably die. The reason for this is that equation (1.39) cannot be applied to gas condensate wells or water-producing gas wells with a gas/liquid ratio less than about 7000 scf/STB; gradient curves or multiphase correlations must be used instead.

Let us examine the pressure elements constituting the total pressure at the bottom of the tubing:

1. backpressure exerted at the surface from the choke and wellhead assembly (wellhead pressure)
2. hydrostatic pressure due to gravity and the elevation change between the wellhead and the intake to the tubing
3. friction losses, which include irreversible pressure losses due to viscous drag and slippage