

Section 2

Multiphase Flow, Flowing Well Performance

Multiphase Vertical Flow

When producing an oil or gas well the flow of the fluids up the tubing while in most cases be 2 phase, liquid and gas. The pressure at any point in the tubing string is influenced by many factors. Such as type of flow at that point, the viscosity's of the oil and gas, the PVT characteristics of the fluid which are pressure and temperature dependent, the bottom hole and tubing pressures. In the tubing there is a pressure drop and a temperature variation which causes several of the fluid properties to vary along with the pressure drop that allows the solution gas to come out of the oil at different rates in various parts of the tubing, causing holdup behavior. The drag of the flowing fluids (friction) also plays a part along with gravity in resisting the flow.

Flow Regimes

As the oil travels up the tubing different types of flow can occur as the gas is liberated from the liquid phase.

If the well is producing above the bubble point pressure the flow is single phase but as it rises up the tubing the pressure will drop below this pressure and the multiphase regimes will start to form.

Bubble Flow

The gas starts to come out of solution and form in the liquid medium in an even dispersion.



Slug or Plug Flow

As the fluid moves upward the gas bubbles move faster than the liquid, because of the buoyancy effect, and collect in large bubbles. These bubbles grow to a size where extend across the diameter of the tubing separating slugs of liquid containing the smaller bubbles



Churn Flow

With increasing gas velocity, the larger bubbles become unstable and collapse, resulting in a highly turbulent flow pattern. Churn flow is characterized by oscillatory, up and down motions of the liquid.

Annular Flow

As the pressure is lowered these large pockets of case break through the slugs and form a continuous phase in the center of the tubing carrying droplets of the liquid with a film of oil flowing along the walls of the tubing.



Mist Flow

Eventually the gas volume is so large that the film of liquid on the wall of the tubing disappears and the only liquid moving is the droplets or mist in the gas phase.



Not all of these regimes are necessarily present in a well but usually more than one is present.

As can be seen the flow of oil and gas up a string of tubing has many complex components that must be considered in designing a flowing well. For a given bottom hole pressure there is a certain amount of reservoir fluids that will enter the well bore, what is needed to be known is whether the pressure drop in the tubing will allow flow to the surface. Several methods have been developed to describe this flow so pressure curves of the tubing can be drawn to use in the planning of the well and its equipment.

Poettmann & Carpenter Method

Based on the energy equation with the assumptions that the difference in the kinetic energy at the top and bottom is negligible and that external work done by the flowing fluid is also negligible. The energy loss W_f is caused by the slippage and frictional effects.

$$W_f = 4fu^2 \frac{\Delta h}{2gD} \quad (2-1)$$

where u is the average mixture velocity over Δh and D is the inside diameter of the tubing, g is gravity constant and f is found empirically.

With the given assumptions and field units equation 2-1 can be reduced to

$$144 \frac{\Delta p}{\Delta h} = \bar{\rho} + \frac{\bar{K}}{\bar{\rho}} \quad (2-2)$$

where Δp = pressure drop over Δh , psi
 $\bar{\rho}$ = average density of the fluid, lb/cu ft

$$\bar{K} = \frac{fq^2 M^2}{(7.413 \times 10^{10} D^5)} \quad (2-3)$$

q = liquid production rate, STB/day
 M = Total mass of gas and liquid associated with 1 STB, lb
 D = ID of tubing, ft
 f = energy loss factor defined by equation 2-1

The way that this is used is to start at the bottom of the tubing with the known p_{wf} which can produce a certain production of reservoir fluids that is known from the productivity index of the well. All the PVT and reservoir parameters such as FVF, water-cut, gas solubility are known or can be estimated. Divide the tubing into equal parts, H_1, H_2, H_3, H_4 , each a length of Δh and let the pressures, p_1, p_2, p_3, p_4 , at the H_n points. At H_1 the pressure is p_{wf} , so this pressure can be used for H_1H_2 for the first approximation for the factors needed for equation 2-2, such as the density and Mass. If a better approximation is needed use the average between of p_{wf} and

the first approximation for the next calculations. This process is repeated for all the intervals in the tubing, to the surface or till a negative pressure is calculated. Doing this for several starting p_{wf} a plot can be generated for any size tubing.

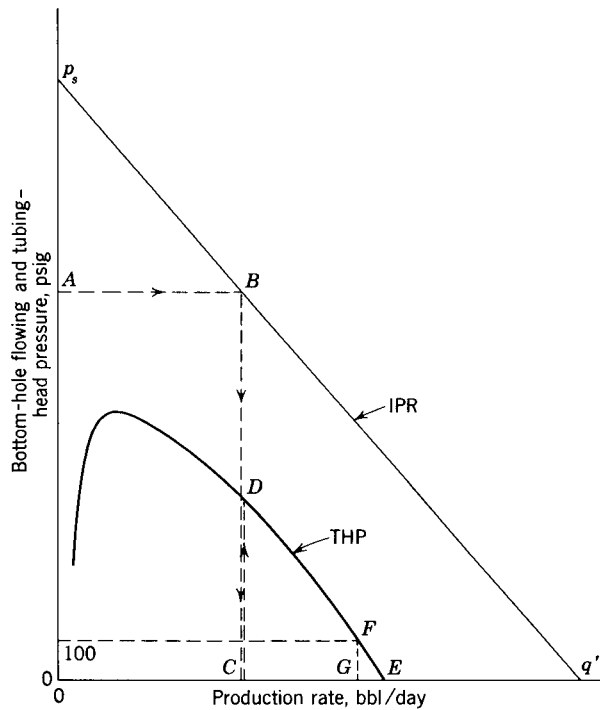


Figure 2-1

This graph can be used to find the bottom hole pressure and production rates for any producing tubing head pressure. The maximum rate that the well can flow is indicated by point E on the graph, this point must always be lower than q' since there is a positive pressure loss in the tubing.

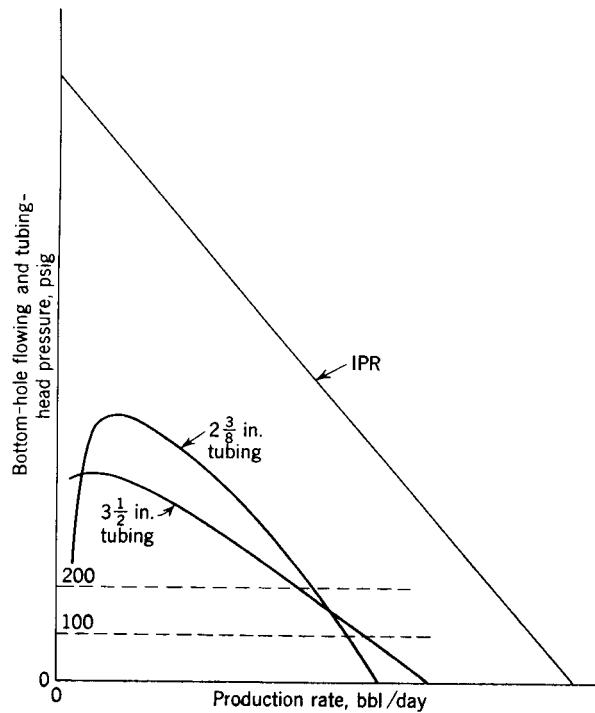


Figure 2-2

Plotting the tubing head pressures for several sizes of tubing is used to find the optimal tubing size for different flow rates. In this case at 200 psi THP the 2" tubing is better but at 100 psi the 3 1/2" tubing produces at a higher rate.

The only factor in equation 2-3 that is not easily found is the energy loss factor f . In an effort to establish values for f as a function of the variables involved in the flow of oil wells a reverse calculation was made. This involved taking field data in the form of production, PVT data, and pressure and temperature transverses. It was found that f correlated best as a function of tubing ID and mass velocity of the fluid in the tubing. In terms of field units

$$D_{vp} = (1.4737 \times 10^{-5}) \frac{Mq}{D} \quad (2-4)$$

From this the following plot is used to find f for different flow rates and tubing sizes.

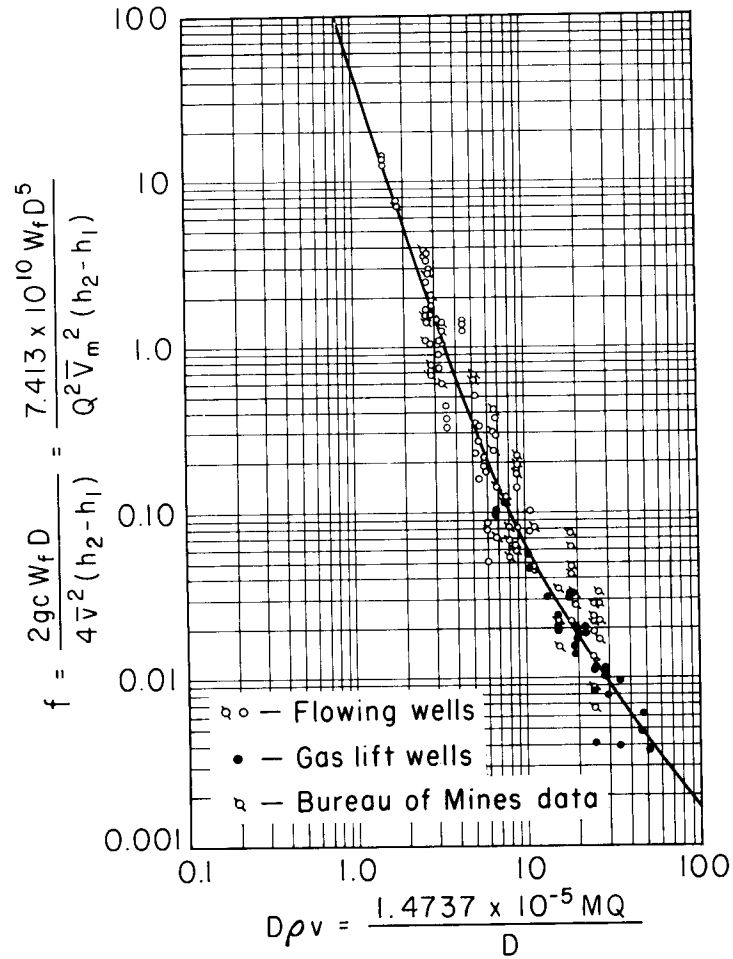


Figure 2-3

It is noted here that this plotted on log-log paper and that the scatter of the points is greater than it appears on this graph. Also Baxendell extended this work to include flow in an annulus, and with Thomas plotted f over higher flow rates.

The weakness of this approach is the inaccuracy of finding f . Work by others have been to overcome this problem.

Using the Poettman & Carpenter Method

Calculating M, mass of the fluid in STB

$$M = \text{wt of Oil} + \text{wt of Water} + \text{wt of Gas} \quad \text{in lb}_m/\text{STB}$$

$$\text{wt of Oil} = \text{Oil cut} \times \gamma_o \times 350 \text{ lb/bbl}$$

$$\text{wt of Water} = \text{Water cut} \times \gamma_w \times 350 \text{ lb/bbl}$$

$$\text{wt of gas} = \text{GLR cf/bbl} \times \gamma_g \times .0764 \text{ lb/cf}$$

$$w = \text{Mass flow rate,} = Mq, \text{ lb}_m / \text{day}$$

Note: $\gamma_o = \frac{141.5}{131.5 + API^o}$ γ_w and γ_g and GOR should be given & the oil and water cut calculated from the WOR.

Calculating ave. Density, ρ , lb_m/cf

$$\rho = M/\text{volume}$$

$$\text{Volume} = \text{vol of oil} + \text{vol of water} + \text{vol of free gas} \quad \text{in cf}$$

Using the pressure of interval being calculated, lab or correlations of PVT data needed. β_o , β_g , R_s

$$\text{Volume bbls} = \text{Oil cut} \times \beta_o + \text{Water cut} + \beta_g \{ \text{GLR} - \text{Oil cut} \times R_s \}$$

$$\text{Volume cf} = \text{Volume bbls} \times 5.614 \text{ cf/bbl}$$

$$\rho = M/5.614[\text{oil cut} \times \beta_o + \text{water cut} + \beta_g\{\text{GLR} - \text{Oil cut} \times R_s\}]$$

With values of M and ρ the $\Delta p/\Delta h$ can be calculated using equations 2-2 and 2-3 by finding f from figure 2-3. By dividing the pressure increment by this pressure gradient gives the length of tubing over which the increment occurs. This way a plot of the pressure can be obtained.

Example:

Given

Tubing 2"

22° API oil

$\gamma_w = 1.07$

$\gamma_g = .65$

$q_o = 400$ bpd

$q_w = 600$ bpd

GLR = 500 cf/bbl

$$\gamma_o = 141.5/131.5 + 22 = .922$$

$$M = .4 \cdot .922 \cdot 350 + .6 \cdot 1.07 \cdot 350 + 500 \cdot .65 \cdot .0764 = 378.6 \text{ lb/bbl}$$

$$w = M \cdot q = 378.6 \cdot 1000 = 378610 \text{ lb/day}$$

$$D_{pv} = 1.4737E-5 \times w/D = 1.4737E-5 \cdot 378610/1.995/12 = 33.56$$

Form fig. 2-3 $f = .008$

$$K = f w^2 / (7.413E 10 D^5) = .008 \cdot 378610^2 / (7.413E+10 \cdot .166^5) = 122.7$$

For pressure point 1, 500 psi

$$\beta_o = 1.043 \quad R_s = 59 \text{ scf/bbl} \quad z = .93$$

$$\rho = M/5.614[\text{oil cut} \times \beta_o + \text{water cut} + \beta_g\{\text{GLR} - \text{Oil cut} \times R_s\}]$$

$$378/5.614[.4 \cdot 1.043 + .6 + .0298\{500 - .4 \cdot 59\}] = 4.4 \text{ lb/cf}$$

For pressure point 2, 1000 psi

$$\beta_o = 1.083 \quad R_s = 120 \text{ scf/bbl} \quad z = .9$$

$$\rho = 378.6/5.614[.4 \cdot 1.083 + .6 + .0153\{500 - .4 \cdot 120\}] = 8.4 \text{ lb/cf}$$

$$\text{ave } \rho = \rho_1 + \rho_2 / 2 = 6.4 \text{ lb/cf}$$

Use this average density to find $\Delta p/\Delta h$ in equation 2-2

$$\Delta p / \Delta h = [\rho + K/\rho] / 144 = [6.4 + 122.7/6.4] / 144 = .178$$

Now solve for Δh for the Δp

$$\Delta h = 1000 - 500 / .178 = 2816 \text{ ft.}$$

Plot this point, say THP is 500 psi then it 1000 psi at a depth of 2816.
Then repeat the process for the next interval.

A large interval was used here in the example, the interval used when doing a pressure profile of a well the pressure intervals will be much smaller, like about 25 psi.