PRODUCTION I (PP 414)

SUBJECT:

ANALYSIS OF MAXIMUM STABLE RATE AND CHOKES RESOLVE OF OIL WELLS

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DESIGN OF MAXIMUM STABLE RATE AND CHOKES RESOLVE

4.2. SOLUTION PROCEDURE FOR OIL WELLS

4.21 INTRODUCTION

In order to best illustrate the solution procedure, the following example was presented by Mach, Proaño, and Brown- and will be worked by taking the solution node at several different positions.

EXAMPLE PROBLEM (Oil WELL)

Given Data (flowing oil well):

separator pressure: 100 psi	γ_g = 0.65
flow line: 2·in., 3,000 ft:. long	°API = 35
WOR: 0	T = 140°F
depth: 5,000 ft mid perf	tubing size, 2 3/8 -in OD
GOR: *400/scf/bbl*	$\overline{P}_r$: 2200 psi

productivity index = 1.0

A simple system such as shown in Figure 4.4 is assumed.

For purpose of illustration only let us assume that a constant J of 1.0 exists for all flowing pressures for this well.

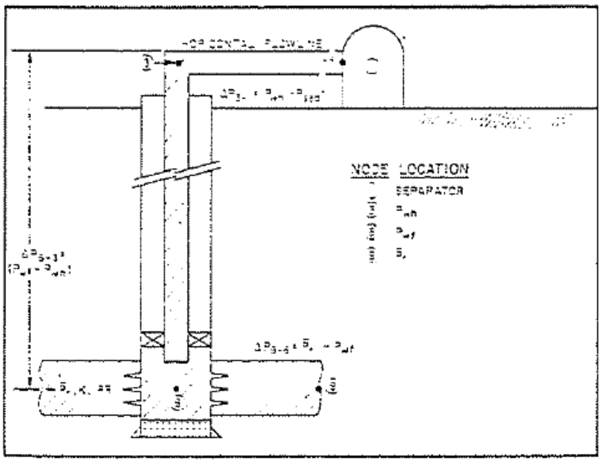


Figure 4.4 *Nodes for Simple Producing System (after Mach, Proaño, and Brown, © SPE of AIME)*

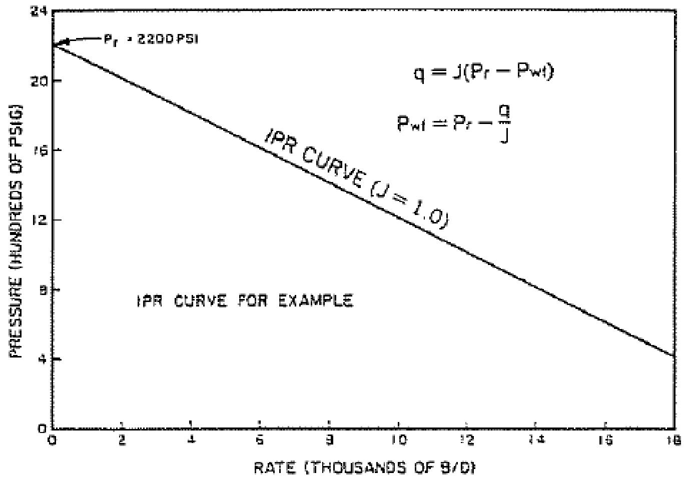


Figure 4.5 *IPR Curve for 5xample Problem (Constant J = 1.0)*

In reality, we know that two-phase flow will occur below the bubble-point pressure of 1,800 psi found from Figure 2.14. However, for the flow rates obtainable with 2o/s-in. OD tubing, the rates will differ very little from a straight-line J plot as compared to a Vogel solution (see Figure 4.5), In order to apply the constant J plus Vogel solution, we will assume a constant J of 1.0 from 2,200 psi, to 1,800 psia (bubble point) and a Vogel curve behavior from 1,800 to zero pressure.

$$q_{max} = q_b + \frac{JP_b}{1.8} = 1.0(2,200 - 1,800) + \frac{(1.0)(1,800)}{1.8}$$
$$= 400 + 1,000 = 1,400 \text{ b/d}$$

or for the constant J case, q_{max} = 1.0(2,200 - 0) = 2,200 b/d. Other pressures are assumed, and the IPR curve is constructed as noted in Figure 4.6.

For purposes of illustration, we will show the constant J solution for simplification in working the problem in most cases.

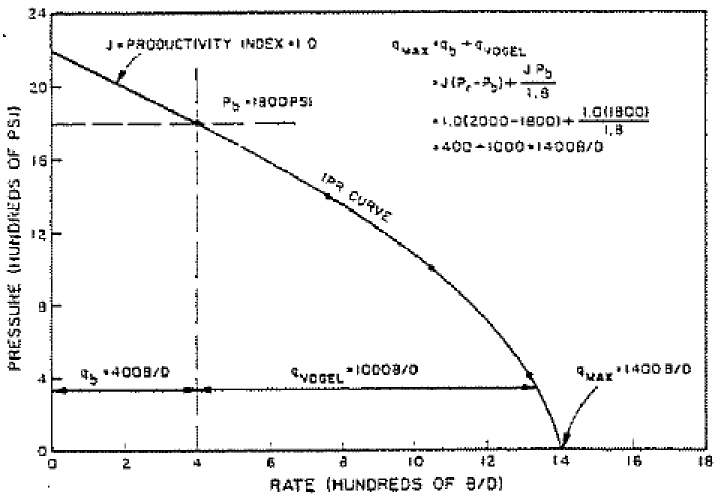


Figure 4.6 *IPR Curve for Example Problem (Vogel Solution)*

4.22 **SOLUTION AT BOTTOM OF WELL (NODE 6 FROM FIGURE** 4.4)

Probably the most common solution position is at the bottom of the well-that is, at the center of the borehole at the center of the perforated interval (node 6 from Figure 4.4).

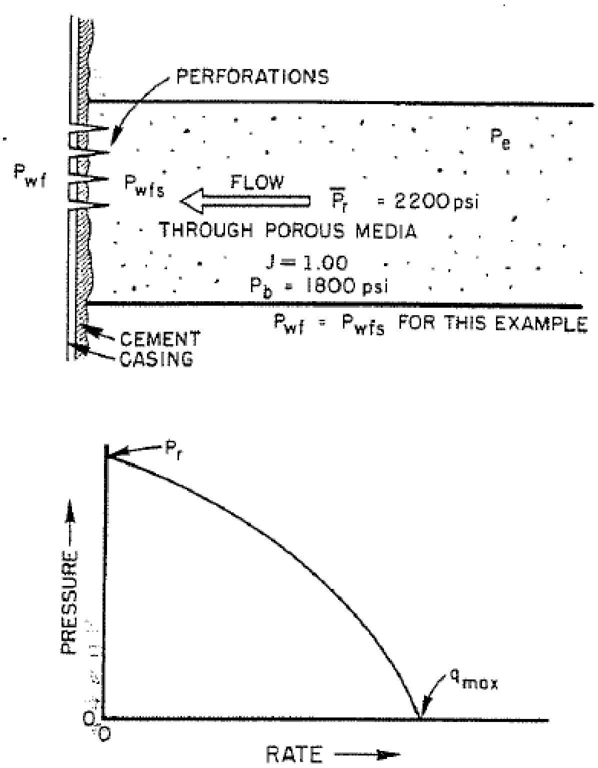


Figure 4.7 *Reservoir Component*

In order to solve for the flow rate at this solution position, the entire system is divided into two components, the reservoir or well capability component and the total piping system component. Refer to Figure 4.7, which shows the reservoir component and Figure 4.5, which shows a plot of the reservoir or IPR curve for example problem 4.1.

Figure 4.8 shows the piping system component. For our example, it is assumed that no restrictions exist, and therefore we have only the flow line and tubing pressure losses.

4.221 CONSTRUCTING THE IPR CURVE

For the constant J case, this is relatively simple.

Assume a flow rate and determine the corresponding flowing pressure. Then, extend a straight line between the static pressure of 2,200 psi at zero rate to the calculated point. For example, at a rate of 1,000 bid, the flowing pressure is

$$P_{wf} = P_r - q/J = 2{,}000 - \frac{1{,}000}{1} = $$ = 1,200 psi.

Note Figure 4.5, which shows the constant J assumption, and then Figure 4.6, which shows the more realistic Vogel solution. The same solution procedure would apply for either case-that is, constant J or Vogel.

In order to work this problem, a table should be prepared showing the various losses existing in the separate components.

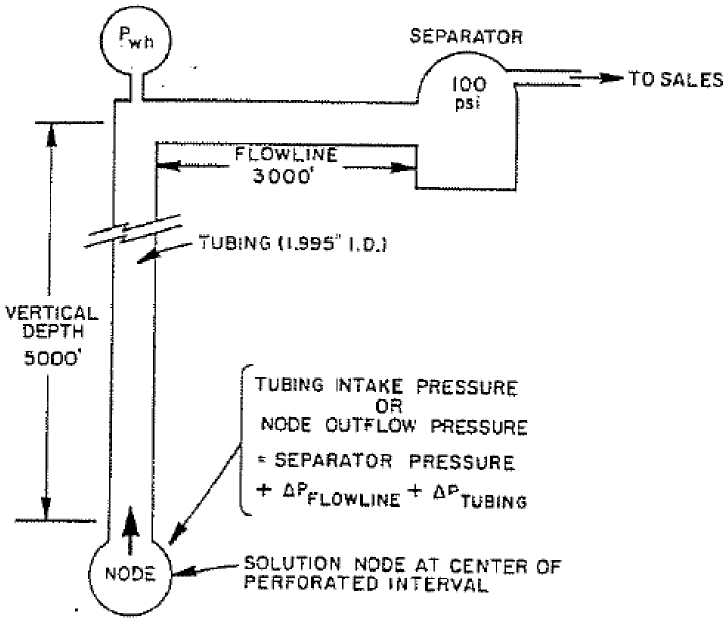


Figure 4.8 *Piping for Simple System*

Step-by-Step Solution Procedure

(1) Assume several flow rates and construct the IPP curve as noted in Figure 4.5 by solving for the corresponding pressures. The constant J equation is applicable in Figure 4.5, and Vogel's equation is applicable for pressures less than 1,800 psi for Figure 4.6.

For example, assume q = 200 *b/d.* Then, P_{wr} =

$$P_r - q/J = 2{,}200 - \frac{200}{1} = 2{,}000 \text{ psi}$$

and for 400 psi;

$$2{,}000 - \frac{400}{1} = 1{,}800 \text{ psi.}$$

For pressures less than 1,800 psi and for Figure 4.6, we will use Vogel's equation to calculate the flowing pressures. By solving Vogel's equation for P_{wr} we have:

$$P_{wf} = 0.125\overline{P}_r [-1 + \sqrt{81 - 80 (q_o/q_{o_{max}})}]$$

In our case, $\overline{P_r}$ = P_b for the Vogel section. As an example for q_o = 1,000 *b/d,* the Vogel section is q_{Vogel} = 1,000 - 400 = 600 b/d where q_b = 1.0 (2,200 - 1.800) = 400 *bid.*

$$P_{wf} = 0.125\,(1{,}800)\left[-1 + \sqrt{81 - 80\left(\frac{600}{1{,}000}\right)}\right]$$
$$= 1{,}067 \text{ psi}$$
$$q_{total} = q_b + q_{Vogel} = 400 + 600 = 1{,}000 \text{ b/d}$$

Table 4.1 shows the rates vs flowing pressures for both solutions.

TABLE 4.1

Assumed rate. *b/d*	P_{wf} for constant J, psi	P_{wf} for Vogel, psi
200	2.000	2.000
400	1,800	1,800
600	1,600	1,590
800	1,400	1,350
1,000	1.200	l,067
1,500	700	--

2) Assume several flow rates and obtain the required wellhead pressures necessary to move the fluids through the horizontal flow line to the separator using an appropriate multi-phase flow correlation (See Appendix 4.1 for gradient curves.) Table 4.2 shows these results:

TABLE 4.2

Assumed rate, *b/d*	P_{wh} (required horiz), psi
200	115
400	140
600	180
800	*230*
1,000	275
1,500	420

3) Using the same assumed flow rates as step 2 and the corresponding wellhead pressures, determine the required tubing intake (node outflow) pressures from the appropriate multiphase flow correlations. (See Appendix 4.2 for gradient curves.) Table 4.3 shows these results.

Table 4.3

Assumed rate b/d	P_{wh} horizontal, psi	Tubing intake pressure (node outflow), psi
200	115	750
400	140	880
600	*180*	1.030
800	230	1.225
1.000	275	1,370
1.500	420	1,840

(4) Plot the tubing intake (node outflow) pressures of step 3 vs the node inflow pressures of step 1. The intersection of these two curves shows the flow rate to be 900 *b/d* for the constant J case and 870 *b/d* for the Vogel IPR case. Refer to Figure 4.9a. It should be emphasized that this is "the rate" possible for this system. It is not a maximum, minimum, or optimum but is the rate at which this well will produce for the piping system installed. The rate can be changed only by changing something in the system-that is, pipe sizes, choke, separator pressure-or by shifting the IPR curve through stimulation treatment. This procedure is also given in Reference 2.

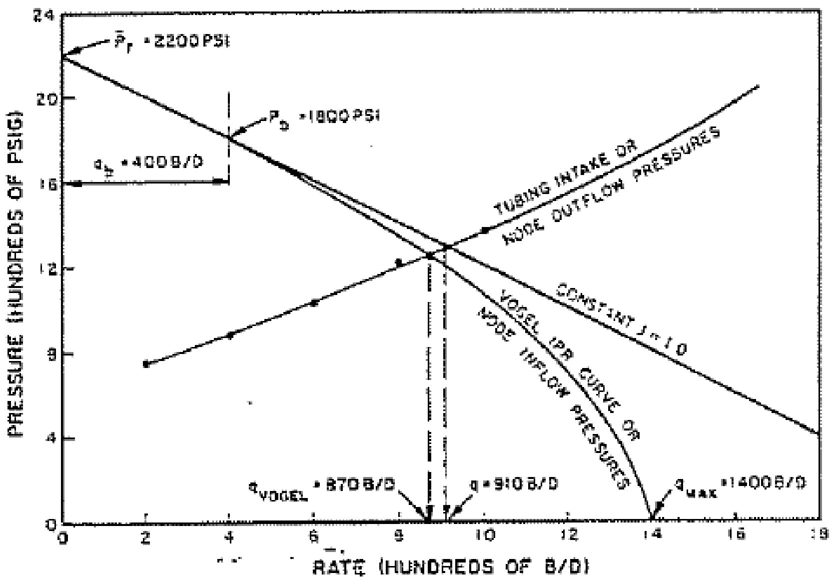


Figure 4.9a Solution at Bottom of Well (Center of Perforated Interval)

4.23 SOLUTION AT TOP OF WELL

4.231 INTRODUCTION

The next-most-common solution position is at the top of the well-that is, at the Christmas tree. The entire system is again divided into two components in order to solve for the flow rate. The separator and flow line are considered as one component (Figure 4.13)

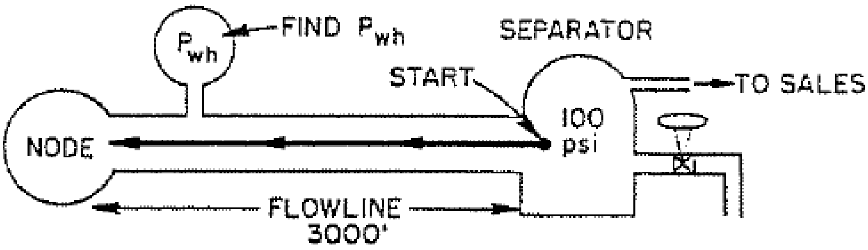


Figure 4.13 *Flow Line and Separator Component*

and the reservoir and tubing string as the other component (Figure 4.14), Start at both end positions. In Figure 4.13, start with separator pressure and find the wellhead pressures necessary to move the assumed flow rates through the flow line and to the separator. In Figure 4.14, start at $\overline{P}_r$ assume a flow rate, proceed to the center of the wellbore to obtain P_{wf} using the appropriate IPR plot or equation, and using that pressure, proceed to the top of the tubing string to find the wellhead pressure necessary tor a set flow rate.

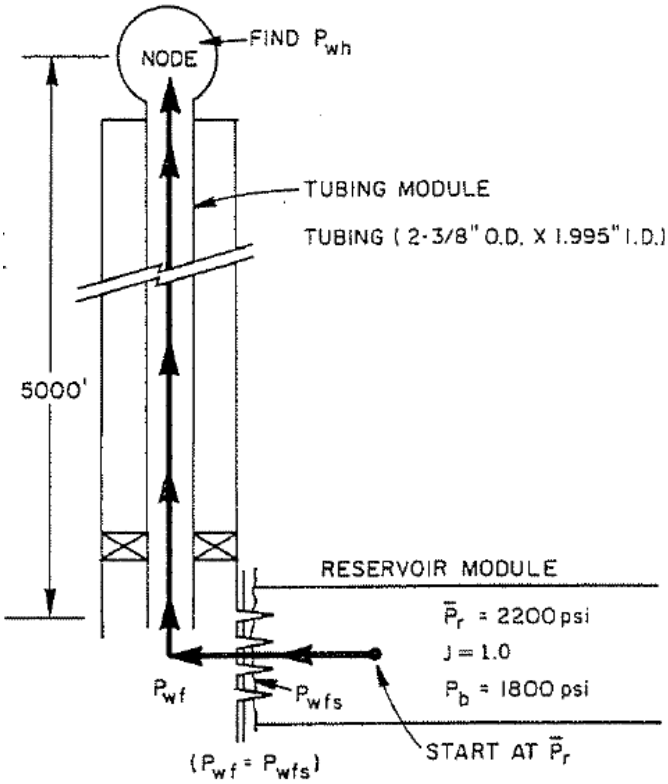


Figure 4.14 *Tubing and Reservoir Component*

4.232 STEP·BY-STEP SOLUTION PROCEDURE

(1) Assume several flow rates as before: 200, 400, 600, 800, 1,000, and 1,500 b/d.

(2) Start with the separator pressure and find the required wellhead pressures to move the fluids through 3,000 It of 2-in. flow line. This will be the node outflow pressure at the solution position. These values, which can be found in Table 4.2, represent the solution to the flow-line component of the problem.

(3) Using the same assumed flow rates and starting from $\overline{P}_r$ find the corresponding flowing pressures for the reservoir to produce these rates. These values have also been previously determined and shown in Table 4.1.

(4) Using the flowing pressures obtained from step 3, determine the permissible (allowable) wellhead pressure for these flow rates-node inflow pressures. Note that these wellhead pressures control the flow rate of the well. An appropriate vertical multiphase flow correlation should be used. Gradient curves from Appendix 4.2 were used in this case. Refer to Table 4.5 for these results.

(5) Plot wellhead pressures of step 2 vs wellhead pressures of step 4 to obtain the flow rate. Refer to Figure 4.15a and b. The intersection of these two wellhead pressure curves gives the flow rate of 900 *b/d* and 870 *b/d* for the constant J and Vogel solutions.

TABLE 4.5
PERMISSIBLE WELLHEAD PRESSURES VS RATES

Assumed rate, bid	P_{wf} Vogel	P_{wh} Vogel	P_{wf} constant J	P_{wh} constant J
200	2,000	610	2,000	610
400	1,800	540	1,800	540
600	1,590	440	1,600	450
800	1.350	300	1,400	330
1,000	1,067	100	1,200	180
1.400	a	–	800	–
1,500	0	–	700	–

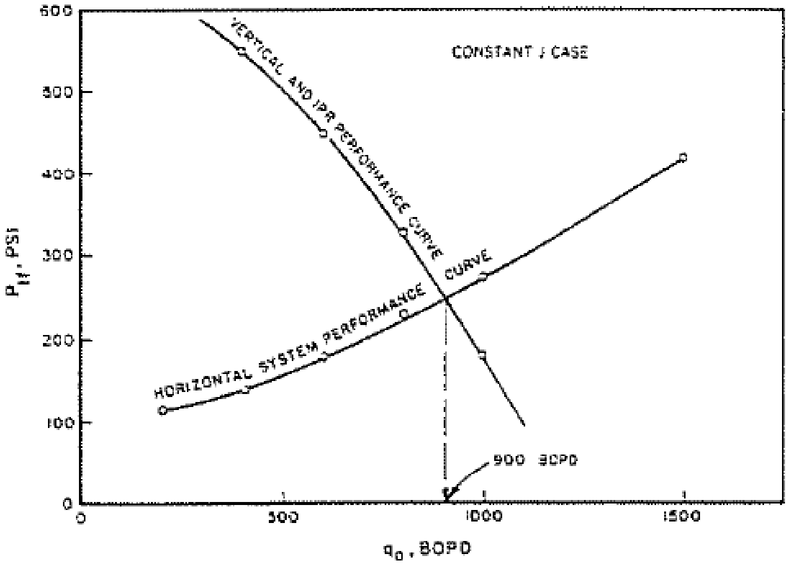


Figure 4. *15a Wellhead Pressure Solution*

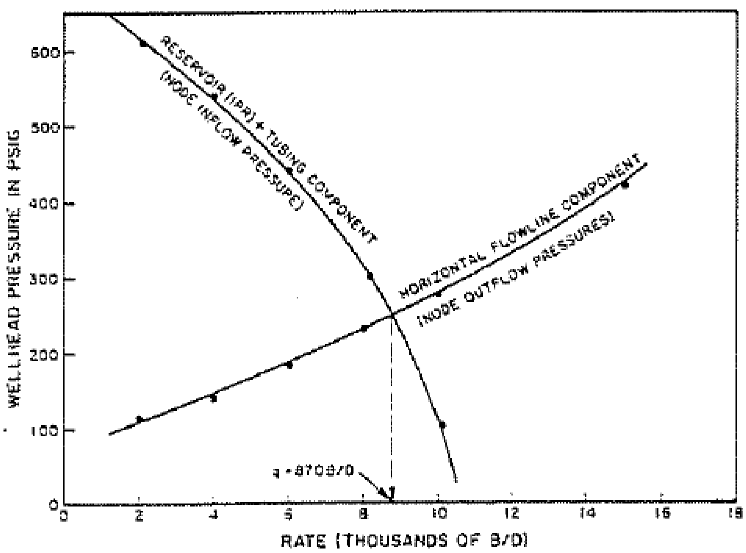


Figure 4.15b Wellhead Pressure Solution (Vogel/IPR)

4.233 WHY USE THE WELLHEAD AS SOLUTION POSITION

By taking the solution at the wellhead, the flow line is isolated, and therefore it is easy to show the effect of changing the flow line size. Reference to Figure 4.16 shows the flow rate possible from this well by utilizing a 3-in. flow line. See Appendix 4.1. This rate is found to be 1,020 *b/d* as compared to 900 *b/d* for the 2-in. flow line. Notice also that the 3·in. flow line is relatively flat for all rates, indicating that friction is not excessive in this line, even at the higher rates. There is no need to evaluate a larger line size such as 4 in. since the 3·in. line is sufficiently large to maximize the rate.

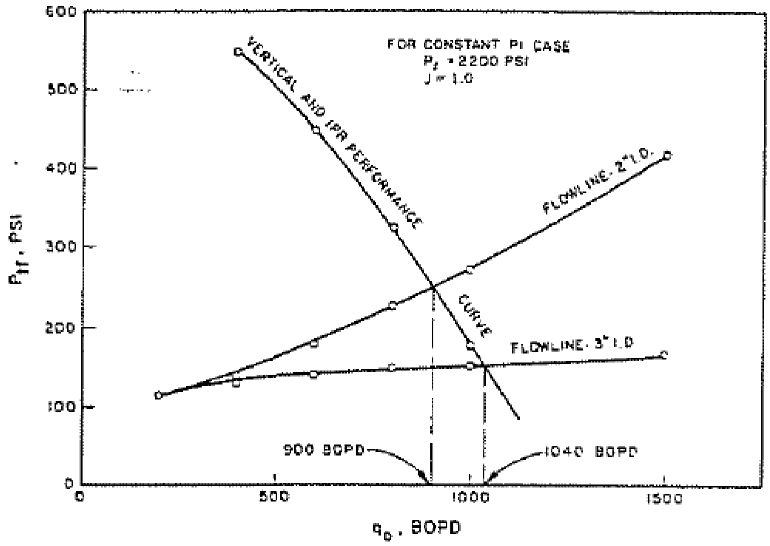


Figure 4. 16 *Effect of Change in Flow Line Size*

Figure 4.17a shows a plot whereby several flow-line sizes and several tubing sizes can be evaluated on one plot. The intersections show rates possible for various combinations of flow-line and tubing sizes.

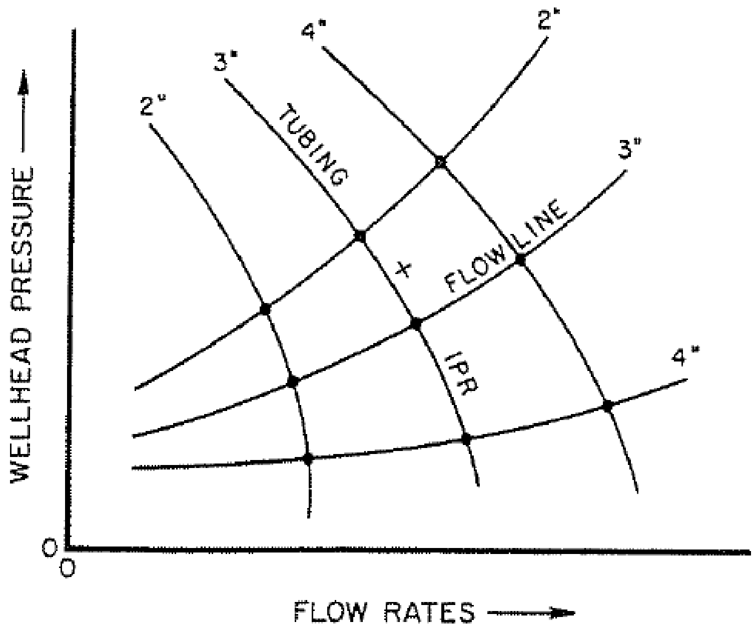


Figure 4.17a Wellhead Solution for Several Combinations of Flowline and Tubing Sizes

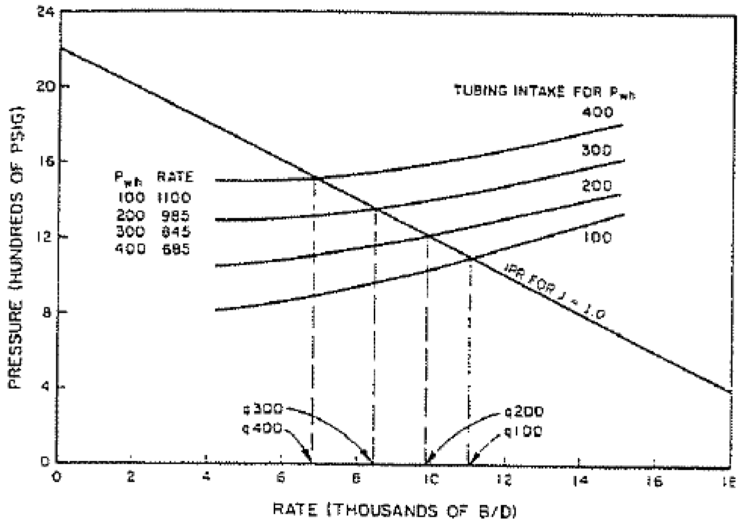


Figure 4,18 *Solution Node at Bottom of Well for Varying Wellhead Pressures*

The flow rates for each line size are totaled for various wellhead pressures and then plotted as the total rate from both lines vs wellhead pressure.

A rate can be determined for a particular well by plotting the combination of IPR plus tubing curve on the same plot as described in Section 4.23.

4.24 COMBINATION SOLUTION AT BOTTOM AND TOP OF WELL

4.241 INTRODUCTION

Another solution procedure that is used quite often is shown in Figures 4.18 and 4.19. The final result appears the same as in Figure 4.15a for the solution at the wellhead. The difference is that the wellhead pressure vs flow rate was determined in a different manner.

4.242 SOLUTION PROCEDURE

The manner of solution is as follows for the constant J case:

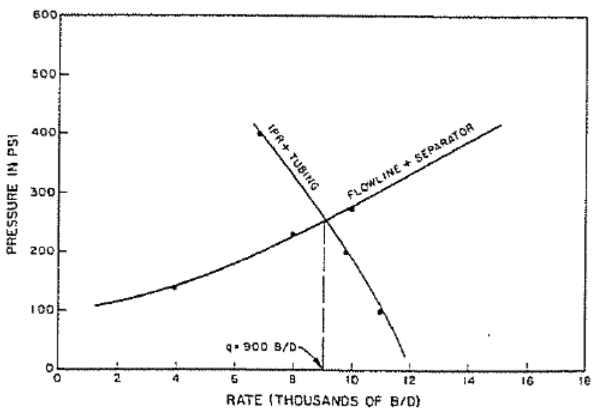


Figure 4.19 *Solution Node at Wellhead with Data Taken from Figure* 4.18.

(1) Assume various wellhead pressures such as 100, 200, 300, and 400 psi.

(2) For each wellhead pressure, assume various flow rates such as 400, 600, 800, 1,000, 1,200, and 1,500 *b/d.*

(3) Determine the tubing intake pressure for each wellhead pressure for the various assumed flow rates.

(4) Prepare a pressure-flow-rate diagram as noted in Figure 4.18 for the various wellhead pressures.

(5) Note the flow rates at the intersection of the tubing intake curves for each wellhead pressure with the IPR curve.

(6) Replot wellhead pressure vs rate as noted in Figure 4.19.

(7) Complete the solution by plotting the wellhead pressures required for the horizontal flow line as noted in Figure 4.19.

The advantage to this solution is that we obtain both a bottom-hole and wellhead solution with a minimum amount of effort. If we have a changing reservoir condition such as a drop in static pressure to 1,800 psi and a J change to 0.75 as noted in Figure 4.20, this IPR curve can be placed on the same plot with no changes for the tubing intake curves unless a change in the gas-oil ratio occurs and/ or the well begins to produce some water.

Flow rates vs wellhead pressures can be obtained from Figure 4.20 and placed on Figure 4.21 to obtain a wellhead pressure solution for changing IPR curves. The wellhead pressure solution easily permits the opportunity to observe the effect of changing flow-line sizes.

4.28 FUNCTIONAL NODES

4.281 INTRODUCTION

In the previous discussions, it has been assumed that no pressure discontinuity exists across the solution node. However, in a total producing system, there is usually at least one point or node where this assumption is not true. When a pressure differential exists across a node, that node is termed a "functional node" since the pressure flow rate response can be represented by some physical or mathematical function. A functional node is one where an immediate pressure loss Occurs in a short distance. Figure 4.2 shows examples of some common system parameters that are functional nodes.

There are many surface or downhole tools or completion methods that could create pressure drops with flow rates as those shown in Figure 4.2. Some of these are surface chokes, safety valves, downhole chokes, regulators, gravel-packed completions, and normal perforated completions.

It is important to notice that, for each restriction placed in the system shown in Figure 4.2, the calculation of pressure loss across that node as a function of flow rate is represented by the same general form; that is, ΔP is some function of rate.

4.282 SURFACE WELLHEAD CHOKES

4.2821 INTRODUCTION

Refer to Figure 4.32, which physically describes a well with a surface choke installed. The most common formula used for calculations concerning multiphase flow through surface chokes is the one offered by Gilbert.> Numerous other correlations are available, and these are discussed by Brown and Beggs.

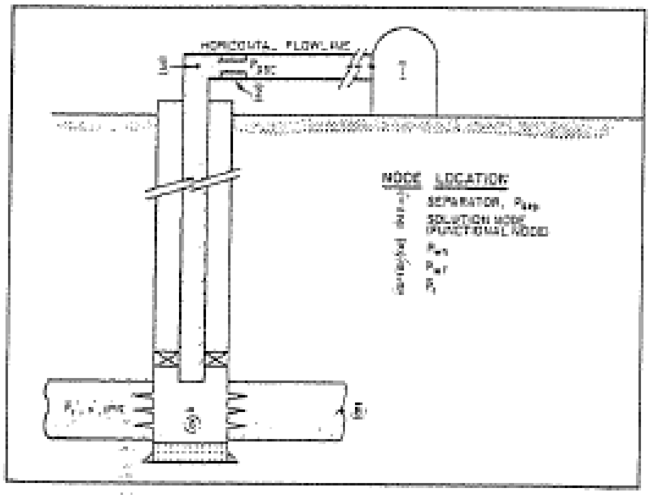


Figure 4.32 Surface Choke Problem

Gilbert's equation is as follows:

$$P_{wh} = \frac{435\, R^{0.546}(q)}{S^{1.89}}$$

where:

P_{wh} = wellhead pressure, psig
R = gas-liquid ratio, Mcf/bbl
q = flow rate, *b/d*
S = choke beam diameter, *64ths* of an inch
Notice that the downstream pressure is not included in this equation; that is, the equation is independent of the downstream pressure. Gilbert developed his equation from field data in California, and he found his equation to be valid as long as the downstream pressure was less than 70% of the upstream pressure--that is, $P_D/P_{wn} \le 0.7$. His equation has been found to give reasonable results and certainly is accurate enough for a first sizing of choke-beam requirements.

Therefore, in order to correctly size a choke beam. all that is needed is the necessary wellhead pressure for a set flow rate. Assume that, for the previous example problem, an objective flow rate of 600 b/d is desired. It is necessary to refer to Figure 4.15a, which shows the solution position at the top of the well. In Figure 4.15a, permissible wellhead pressures for certain flow rates have been plotted. The wellhead pressures required for the horizontal line do not enter into the calculations except to check the validity of the equation-that is, $P_D/P_{wh} \leq 0.7$. Therefore, the objective flow rate is 600 *b/d.* The P_{Wh} value necessary to allow this rate is 450 psig.

Solving the equation for S:

$$S^{1.89} = \frac{435\ R^{0.546}(q)}{P_{wh}}$$

$$S = \left[\frac{435\ R^{0.546}(q)}{P_{wh}}\right]^{1/1.89}$$

$$S = \left[\frac{(435)(0.4)^{0.546}(600)}{450}\right]^{1/1.89}$$

$$= 22.2/64ths \text{ of an in.}$$

The nearest standard bean size would be used, or the exact size could be set with an adjustable choke.

Recall that the unrestricted rate for this well is 900 b/d. Table 4.16 shows the various choke sizes needed for the assumed flow rates.

TABLE 4.16

Assumed q, b/d	P_{wh} for assumed rate, psi	Choke size, 64ths of in.	P_{wh} horiz., psi	$\frac{P_D}{P_{wh}}$
200	610	12.4	115	0.188—(O.K.)
400	540	17.9	140	0.259—(O.K.)
600	450	22.2	180	0.4—(O.K.)
800	330	25.9	230	0.697—(O.K.)

Note that the choke sizes calculated for 200, 400, 600, and 800 b/d are all valid by using Gilbert's equation; that is, $P_D/P_w \leq 0.7$ in all cases, with 800 *b/d* being very close with a P_D/P_{wn} value of 0.697.

4.2822 ΔP SOLUTION FOR WELLHEAD SURFACE CHOKES

4.28221 INTRODUCTION

Referring to Figure 4.33 shows the solution paths.

In this solution, the differential available at the wellhead is utilized in order to solve the choke problem and determine flow rates possible for different choke sizes.

The differentials created at the wellhead can be obtained from the wellhead solution as previously described in section 4.23 (refer to Figure 4.15a).

Solution procedure:

(1) Assume various flow rates: determine the wellhead pressures necessary to move the fluids to the separator; then determine the allowable wellhead pressures for the assumed flow rates as set out in Section 4.23.

(2) Plot wellhead pressures vs rates and note ΔP's at different flow rates (see Figure 4.34).

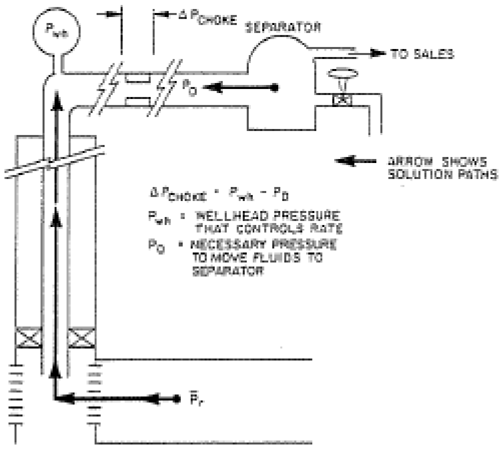


Figure 4.33 Solution Paths for Surface Choke

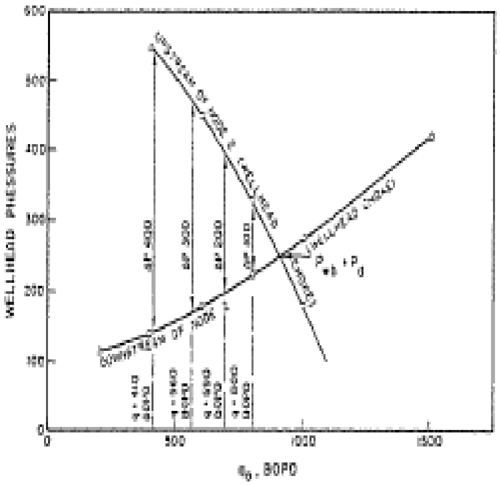


Figure 4.34 *Surface Choke evaluation*

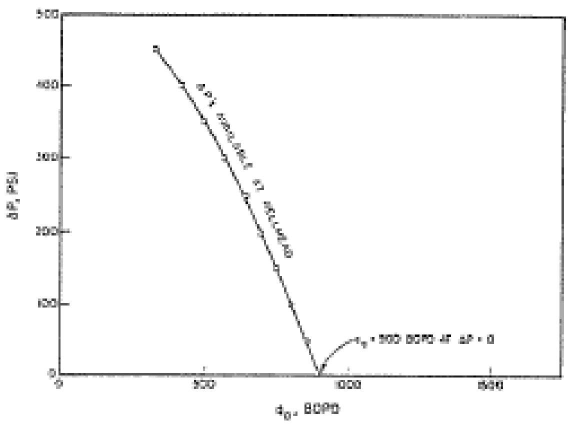


Figure 4.35 Total Systems Performance Curve for Surface Choke Problem

(3) Re-plot the ΔP values from Figure 4.34 in the form shown in Figure 4.35.

(4) From an appropriate choke formula, assume various flow rates and determine the corresponding wellhead pressures.

For this example, use the same equation as in the paper by Mach. Proaño, and Brown;'

$$P_{wh} = \frac{500\ R^{0.5}(q)}{S^2}$$

This is a modification of Gilbert's equation and uses the same units. The following choke sizes are checked for flow rates possible: 16/64, 20/64. 24/64, and 28/64. Table 4.17 shows the resulting calculations, including the ΔP values between the wellhead pressure required to move the assumed rates through the choke and the necessary downstream pressure to move the fluids to the separator. The downstream pressures are taken from Figure 4.15a.

Gilbert's equation can be adjusted quite easily to more closely reproduce data from a particular well or field.

TABLE 4.17
ΔP vs RATE FOR DIFFERENT CHOKE SIZES

Choke size	Assumed rate, b/d	P_D from horiz. correl., psi	P_{wh} from choke eq., psi	P_D/P_{wh}	ΔP across choke, psi
16/64	300	128	370	0.35	242
	400	140	494	0.28	354
	500	160	617	0.26	457
	600	180	741	0.24	561
20/64	300	128	237	0.54	109
	500	160	395	0.41	235
	700	200	553	0.36	353
	900	250	711	0.35	461
24/64	500	160	274	0.58	114
	700	200	384	0.52	184
	900	250	494	0.51	244
	1,100	300	603	0.50	303
28/64	800	227	322	0.70	95
	1,000	275	403	0.68	128
	1,200	330	484	0.68	154

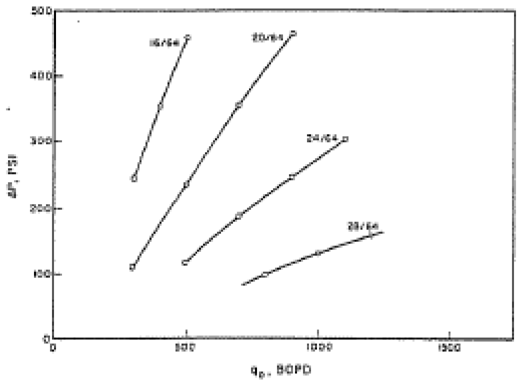


Figure 4.36 Choke Bean Performance

The ΔP's calculated are unique to the example system since the downstream pressures were calculated for the example system. Notice that in each case a check was made to ensure $P_D/P_{wh} \leq 0.7$ so that Gilbert's equation would apply. If this is not the case, a subcritical flow equation must be used to calculate ΔP across the choke.

(5) From Table 4.17, plot the ΔP's for each choke as shown in Figure 4.36.

Rates	THP	0.7THP	Pd	ΔP
200	610	427	115	312
400	540	378	140	238
600	440	308	180	128
800	300	210	230	-20
1000	100	70	275	-205

(6) Overlay the results of Figures 4.35 and 4.36 as shown in Figure 4.37.

Figure 4.37 displays the total system performance for different wellhead choke sizes. The system performance curves show the "required" ΔP for various flow rates considering the entire system from reservoir to separator. The choke performance curves show the "created" ΔP for various flow rates considering choke performance for different choke sizes. The intersection points of the created and required P's represent the flow rates possible. For example, the rate will drop from 900 b_o/d to 715 b_o/d with the installation of a *24/64* wellhead choke.

Figure 4.38 shows another presentation that is often used to evaluate wellhead chokes.

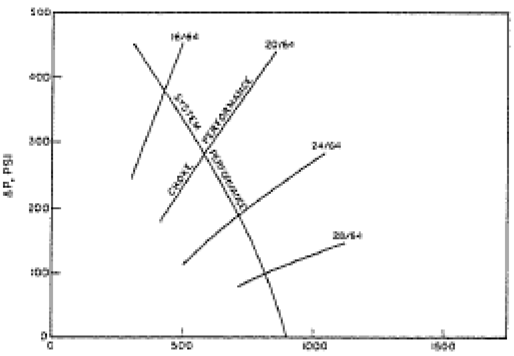


Figure 4.37 Systems Performance for Various Wellhead Chokes

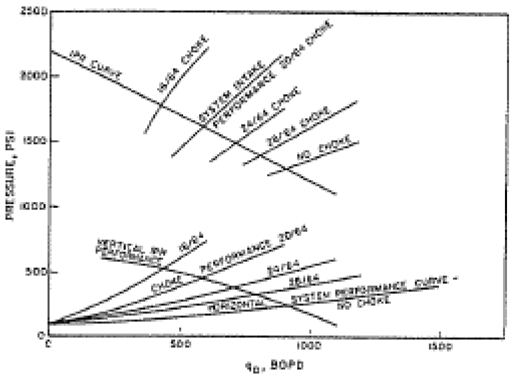
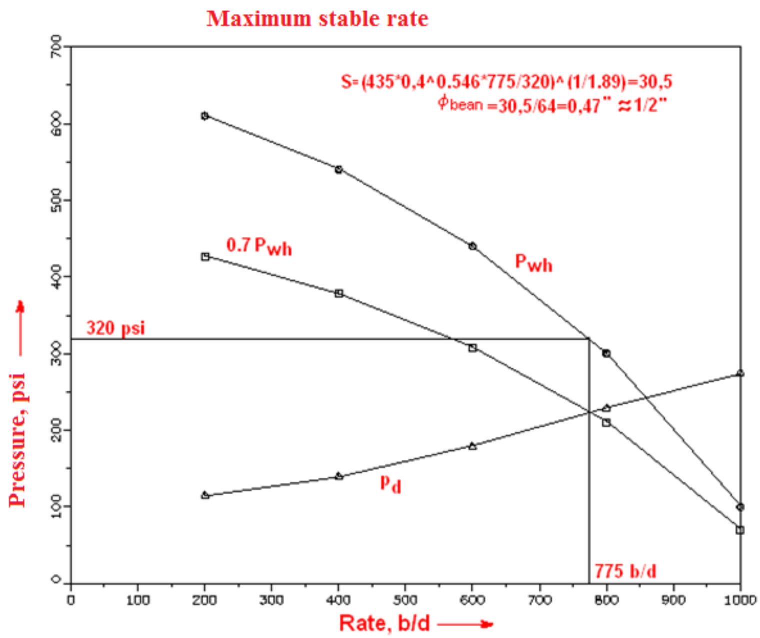


Figure 4.38 Surface Choke Evaluation

Other presentation is the following:



The solution is shown at the bottom of the well at the top of Figure 4.38. In this case, the solution is obtained by starting at the separator and proceeding all the way to the bottom of the tubing and on to the center of the perforated interval to find the tubing intake pressure.

The solution at the bottom of Figure 4.38 shows allowable wellhead pressures (P_{wh} values necessary for certain rates) plotted against the horizontal performance curves, which include the choke.

All three solution positions will give the same answer.

The secret to sizing chokes is to remember that the wellhead pressure controls the flow rate. The choke is merely a means of setting and controlling the wellhead pressure.

The various reports that are seen in the morning *paper* and numerous company reports always bother us a little when they say "well # A-22 came in producing 600 *b/d* on a *14/64* choke." From that bit of information, it is difficult to know whether the well is any good. Now, if the report says "well # A-22 came in producing 600 *b/d* with a wellhead pressure of *2,500* psi," it is obviously an excellent well. However, if it says "well #A-22 came in at 600 *b/d* with 100 psi wellhead pressure," it may be a much weaker well. The wellhead pressure has much more significance than the choke size, and it controls the flow rate.

References

1. Kermit E. Brown et al.: “The Technology of Artificial Lift Methods”, Volume 4, Production Optimization of Oil and Gas Wells by Nodal Systems Analysis, PennWell Books, Tulsa, Oklahoma, 89-91, 92-94, 103-109.