Recommended Practice for Design of Continuous Flow Gas Lift Installations Using Injection Pressure Operated Valves

API RECOMMENDED PRACTICE 11V6
SECOND EDITION, JULY 1999

REAFFIRMED, MARCH 2015

AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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0 Introduction

This Recommended Practice is provided to meet the needs for guidelines, procedures, and recommendations covering Continuous Flow Gas Lift Installation Designs using injection pressure operated valves. These recommended practices are those generally required for successful installation designs. Also see API Specification 11V1, Recommended Practice 11V5, and Recommended Practice 11V7.

1 Scope

This Recommended Practice is intended to set guidelines for continuous flow gas lift installation designs using injection pressure operated valves. The assumption is made that the designer is familiar with and has available data on the various factors that affect a design. The designer is referred to the API publication *Gas Lift*, (Book 6 of the Vocational Training Series, Third Edition, 1994) and to the various API 11V Recommended Practices on gas lift.

2 Intent

The only energy utilized in lifting liquids to the surface is that provided by the expansion of the compressed gas from the pressure in the production conduit at the point of injection to the pressure at the wellhead. The pressure drops taken (from the compressor to the wellhead, across the surface injection gas control device, through the injection conduit, across the gas lift valve into the production conduit, up the production conduit, and from the wellhead to the storage tank) are all energy losses. The intent of the gas lift installation design is to maximize the benefits from the lift energy used, i.e., to allow the compressed gas to be injected into the produced fluid as deep and at a pressure as close to compressor discharge pressure as possible or necessary. Such an approach normally maximizes production with a minimum of operating costs.

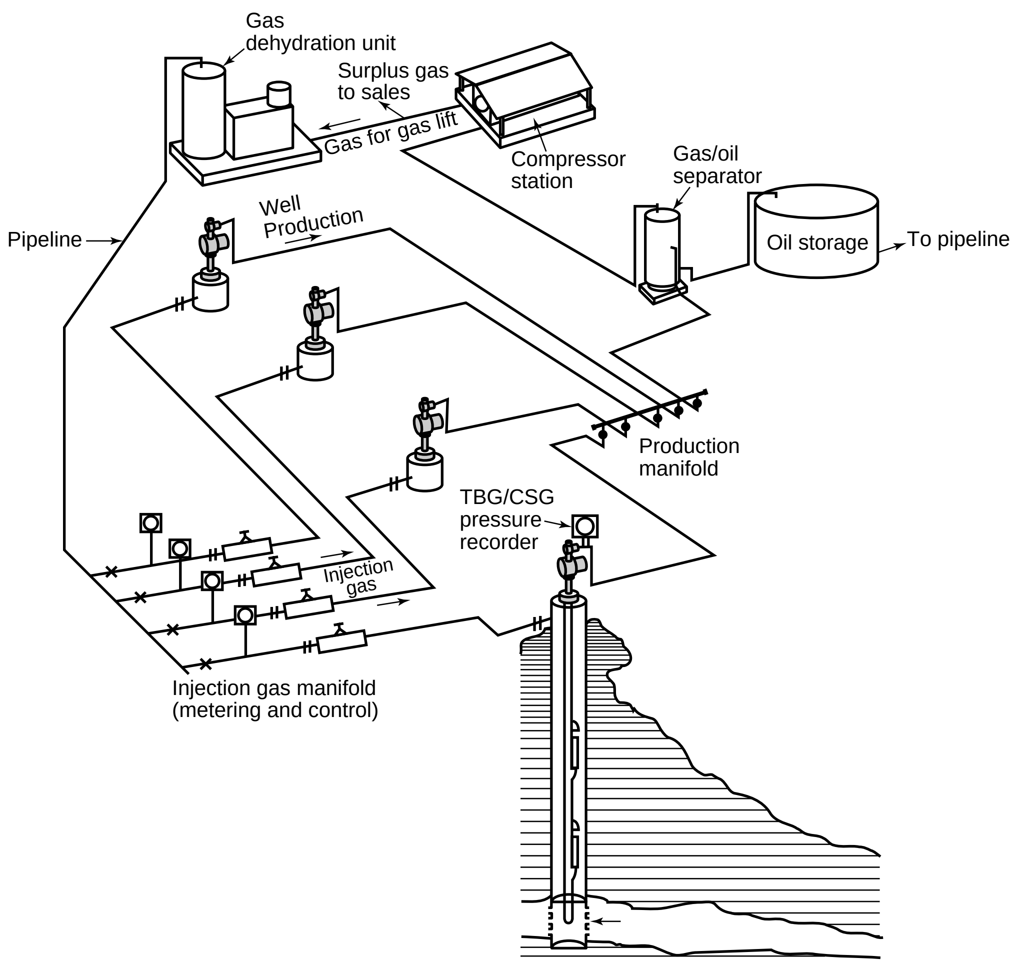


Figure 1—A Typical Gas Lift System

3 Definitions

A continuous lift gas lift installation is one where compressed high pressure gas is injected continuously at the surface into the gas injection conduit and then continuously downhole into the production fluid conduit.

4 General Design Considerations

4.1 GENERAL

4.1.1 In the design of a continuous flow gas lift installation, the complete system must be evaluated. For new installations, all the equipment should be carefully sized and selected; whereas, for existing installations, the effect of the proposed design on the system must be checked and evaluated.

4.1.2 The following design techniques are a combination of concepts by numerous people. Designing a gas lift string to operate under a range of conditions is difficult at best, and often involves many judgement calls on the part of the designer. The attached approaches attempt as much as possible to remove some of these judgement decisions; however, it is impossible to remove all of them. The graphical approach with supporting equations is recommended so that the effects of changing flow rates and the resulting effect on the valve design can be more clearly determined and analyzed.

4.1.3 Continuous flow gas lift has advantages and limitations. You are referred to API *Gas Lift*, Chapter 1. The following are brief discussions of the more important design considerations.

4.2 WELL PERFORMANCE (INFLOW AND OUTFLOW)

4.2.1 The production of an oil well can be divided into two basic categories which are called inflow and outflow performance. (See API *Gas Lift*, Chapter 2.) Inflow describes the flow of the produced fluids from the reservoir into the wellbore. Outflow describes the flow of the produced fluid from reservoir depth to the storage tanks. In order to make a good artificial lift design, good predictions of both inflow and outflow conditions are needed.

4.2.2 The well's inflow is usually expressed in terms of productivity. For single phase flow of liquids, the inflow is expressed as productivity index ($P.I. = J$) and can be written as an equation using the following engineering symbols:

$$J = q_1/(P_{ws} - P_{wf})$$

Note: See Appendix A for symbol definitions.

4.2.3 For two phase flow (liquid and free gas), the production is not linear with pressure change; thus, an inflowing performance relation curve results when plotting flowing bottom hole pressure vs. rate. A good approximation of this change (Vogel IPR) for flow at pressures less than the bubble point (with no skin) can be expressed as follows:

$$q_1/q_a = 1.0 - 0.2\,(P_{wf}/P_{ws}) - 0.8\,(P_{wf}/P_{ws})^2$$

4.2.4 A more generalized approximation for multiphase flow of oil-water-gas for all conditions is as follows:

a. For flow above the bubble point:

$$J = q_1/(P_{ws} - P_{wf})$$

$$Q_{pb} = (P_{ws} - P_B) \times J$$

$$Q_1 = (P_{ws} - P_{wf}) \times J$$

b. For flow below the bubble point:

$$Q_a = (P_b \times J)/1.8$$

$$Q_{max} = q_a + q_{pb}$$

$$Q_1 = q_a[1.0 - 0.2(P_{wf} - P_b) - 0.8(P_{wf}/P_b)^2] + q_{pb}$$

By use of the above formulae, the flowing bottom hole pressure can be calculated for any possible production rate.

4.2.5 The outflow performance of a well depends on a number of factors. These factors are often interrelated and good predictions of performance are sometimes difficult to achieve. (See API *Gas Lift*, Chapters 2 and 3.) A good vertical multiphase flow correlation for gas lift design is essential. There are a number of these correlations[1], some of which are published and others which are proprietary. Select one that gives reasonable answers for the actual well or field conditions that exist. A few good flowing bottom hole pressure surveys are recommended to confirm the correlation.

4.2.6 These vertical multiphase flow correlations can be used to develop sets of gradient curves. Before the use of computer programs became common, a set of such curves were often the basis for the gas lift design. Their use is still an acceptable (and often used) method for gas lift design. By using a suitable multiphase flow correlation, a prediction of the outflow can be calculated for specific well conditions. Thus, various rates and gas liquid ratios cases can be evaluated. Tubing performance outflow curves can be generated and plotted on the inflow performance relationship graph to find the anticipated rate when lifting from near bottom. Such plots are often very helpful in gas lift design.

[1]Commonly used correlations: Poettmann and Carpenter; Hagedorn and Brown; Orikiszewski; Duns and Ros; Ros-Gray; Moreland Mobil Shell Method; Beggs & Brill; Aziz et al.

4.3 TUBING OR ANNULUS (PRODUCTION CONDUIT) FLOW AREA/SIZE

The flow area is an important factor in gas lift design. A small conduit size increases the friction loss and may severely restrict rates. However, too large a conduit size may result in unstable flow (excessive gas slippage) and will cause the production to "head." (See API *Gas Lift*, Chapter 3.) Heading results in numerous producing problems. In a typical design for flow up the tubing, the gas lift designer should always evaluate changing to a different size tubing. Select a conduit size that permits flow rates in the stable flow region without excessive friction losses. In general, tubing size should be selected by using a total systems analysis approach.

4.4 FACILITIES

Gas handling facilities, gas compressors, meters, and pipelines are the highest equipment cost portion of the gas lift system. This equipment usually requires more operating and maintenance costs than any other part of the gas lift system. (See API *Gas Lift*, Chapter 4.) The design of such equipment is beyond the scope of this recommended practice. Hopefully, the surface facilities will provide an efficient, dependable, adequate volume and pressure supply of dry, noncorrosive, clean injection gas over the life of the project. Also, back pressure exerted on the producing wells as a result of pressure losses in the surface production facilities should be relatively low and the system provided with good control and measurement equipment.

4.5 GAS INJECTION PRESSURE

The operating injection gas pressure should be selected with care. Often the injection pressure used is based on the gas sales system discharge pressure rather than on the optimum gas lift performance. In general, gas lift systems are more efficient and cost effective if the gas injection point is near the producing formation. By deep injection, more production is normally achieved and/or less injection gas is required. Thus, when feasible, select an injection gas pressure that will permit gas injection just above the producing zone.

4.6 KICK-OFF INJECTION GAS PRESSURE

4.6.1 The injection system may permit using a higher than normal injection gas kick-off pressure for a short period of time. Some systems may have a higher pressure stage compressor or outside high pressure source that can be used for temporarily unloading or kicking off a well. Most systems have a range of normal operating pressure. Selecting a higher than normal pressure might restrict the unloading to specific time periods.

4.6.2 Use of a kick-off pressure in locating the depth of the first valve is a fairly common practice that is worthy of consideration, since it may allow deeper lift. Caution should be exercised in selecting this kick-off pressure since this elevated pressure will be required in future unloading cases.

4.7 VALVES

4.7.1 The heart of the gas lift system is the gas lift valve. (See API *Gas Lift*, Chapter 5.) In general, the designer should select a valve size, type, and design that will permit reliable, adequate single-point gas injection without frequent repairs. In most cases, simple, unbalanced, injection pressure-operated, nitrogen-charged bellows valves meet this requirement.

4.7.2 Valves can be classified as either injection pressure or production pressure (fluid) operated. Injection pressure operated valves are primarily controlled (opened) by the injection gas pressure; whereas, production pressure operated valves are primarily controlled by the flowing production pressure at valve depth.

4.7.3 Continuous flow gas lift valves normally have bellows. The most common type of valve has a nitrogen-charged bellows which makes the valve opening pressure subject to changes in temperature. Another common valve design uses a bellows that does not have a nitrogen closing force using a spring for the closing force. Temperature effects are negligible on such valves. When using this type of valve in high pressure installations, it may be necessary to supplement the spring force with a dome charge because a spring alone may not develop adequate closing force. This practice does mean, however, that temperature must be considered when calculating the valve test rack set pressure (for the portion of the opening force supplied by the dome charge).

4.7.4 Different sizes and types of valves have specific load rates, which means that the stem will move off the seat an estimated distance for a specific opening pressure condition. Such conditions should be considered in selecting the valve for a given injection rate—especially in high rate wells that require high gas injection rates. At high gas injection rates, some valves become restricted. Check with the manufacturer to see if a single valve will pass the required rate in such cases. Also as a general rule, select the smallest valve port size that will pass the required injection gas rate. The large ported valves are more likely to inadvertently reopen and cause multi-point gas lift injection than are small ported valves, due to a higher production effect factor.

4.7.5 Gas lift valves typically are available in three sizes; $^5/_8$-in., 1-in., and $1^1/_2$-in. The $^5/_8$-in. valves are recommended only where clearance makes their use mandatory. The most commonly used gas lift valve is the 1-in. These 1-in. valves are typically used in most low rate wells equipped with $2^3/_8$-in. tubing. They are used with both conventional and wireline retrievable mandrels. Some operators prefer the l-in. valve—especially for higher rate wells with larger tubing sizes. These larger valves have better flow characteristics than the smaller valves and have corresponding lower production pressure effect factors. Thus, where port sizes larger than $^1/_4$-in. are needed for gas passage, use of $1^1/_2$-in. valves are recommended.

4.8 CHARACTERISTICS OF UNBALANCED, PRESSURE CHARGED VALVES

4.8.1 For simplicity, unbalanced pressure charged valves will be referred to throughout as pressure valves. Some of the inherent characteristics of pressure valves as applicable to continuous flow gas lift design are (see Figure 2):

a. The valve utilizes a nitrogen dome charge to supply the closing force.

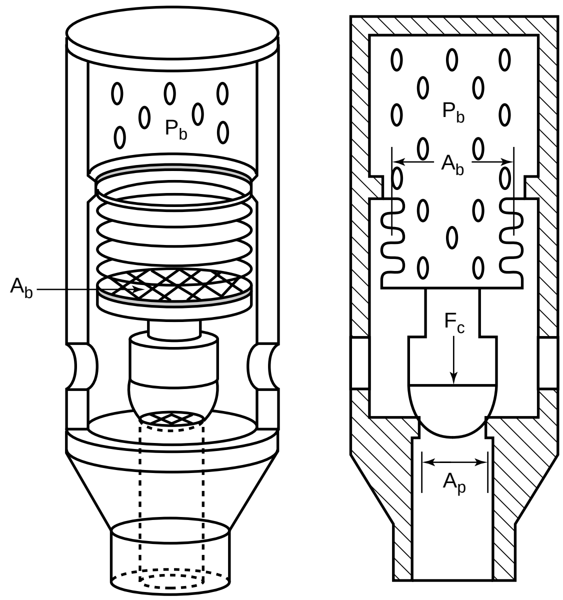
b. Valve opening and closing pressure of all pressure charged bellows valves are affected by temperature. This is an important consideration for continuous flow design since the flowing temperature within the wellbore will always be above the static temperature, at a given depth. This is of particular importance in designing for multiple flow rates since the flowing temperature gradient is a function of flow rate.

c. Relatively small ports are recommended for continuous flow gas lift valves since the objective is to reduce the gradient of the incoming fluid, not accelerate a slug of fluid by displacing it with high pressure gas as is the case with intermittent gas lift. However, the ports must be large enough to permit the needed gas injection rate.

d. Although pressure valves open primarily on injection gas pressure, a small portion of the opening force is supplied by the production pressure. The amount of the opening force supplied by the production pressure is a function of the gas lift valve port size. The larger the area of the port is in relation to the area of the bellows, the greater the opening force supplied by the production pressure. As the result of this characteristic, the injection gas pressure required to open a valve will decrease as the production pressure increases. The opposite is also true. This means that higher than anticipated production pressure may cause upper valves to reopen and interfere with the proper operation of the well.

e. Pressure valves close primarily on injection pressure decrease. In order to close a valve, the injection gas pressure must be lowered below the closing pressure of the valve. In order to prevent valve interference (the re-opening of an upper valve), the surface operating injection pressure of each successively deeper valve must be lower than the valve above it. This valve feature causes loss of operating injection pressure where pressure valves are used. A discussion of how to limit this loss of lift energy is given later in this section of the recommended practice.

4.8.2 The valves used in this Recommended Practice and the following examples will be unbalanced, pressure charged valves with ball stems and seats. All gas lift manufacturers



Pictoral
(A)

Schematic
(B)

Figure 2

offer this type of valve as it is the most commonly used type of gas lift valve in the industry today.

4.9 DESIGN METHODS

4.9.1 There are a number of design methods, all of which have certain advantages or limitations. Some are better suited for specific well conditions or for the type of valve chosen. Most designs are similar with slight modifications on how or when safety factors are applied.

4.9.2 For injection pressure operated valves, the gas lift design depends primarily on the injection gas pressure. The better the data the less the need for safety factors. If the gas injection pressure at the well under operating conditions is known (measured), then there is little need for reducing it an arbitrary amount. However, most gas lift installations have varying system pressures and there is always a measurable pressure drop (during flow) between the compressor and the well. Also, there must be a pressure drop into the well if injection gas control is needed.

4.9.3 Another important factor in valve spacing is the producing pressure at valve depth while unloading. An equilibrium curve can be used to predict the operating producing pressures for various depths. (See API *Gas Lift*, pages 72-73.) As the well is lifted deeper, the rates increase and the flowing pressures increase. If the equilibrium curve is used in spacing and no other safety factors are taken, then the well may not work down or may multi-point. This results since deeper lift increases the production rate, which in turn increases the flowing pressures causing an increased opening force on the upper valves. Multi-pointing or valve interference occurs when an upper valve inadvertently comes open when producing from the lower target operating valve. Multi-pointing normally results in poorer production performance and excess gas usage. Use an equilibrium curve to predict the production rate possible and the associated lift depth and needed injection gas pressure.

4.9.4 Another spacing approach is to use a variable gradient design. This was originally introduced under the name optiflow design. This is a common practice when using production pressure (fluid) operated valves.

A high pseudo well head flowing pressure is calculated. It is calculated by using the expected flowing pressure plus 20%–25% of the difference between the producing and injection pressure. A straight line is drawn to the expected flowing tubing pressure at the point of gas injection or to some arbitrary pressure below the gas injection pressure at depth. This line will be at a higher pressure than the operating production pressure (to the right) and is a conservative spacing method. Such a design gives closer valve spacing and normally requires more unloading valves but does not require a reduction in gas injection pressure.

4.9.5 A recommended design method for injection pressure valves is to use the maximum production rate gradient line for the producing pressure plus decreasing the gas injection pressure (taking a pressure drop) a specific amount for each successively deeper valve. The amount is based on a small nominal pressure drop plus a safety factor pressure drop. Safety factors are for errors in data and valve setting, and to account for variations of the production pressure during unloading. This pressure drop is needed to prevent the valves from multipointing. The safety factor needs to be increased for valves with high production pressure effect factors (P_{PEF}). The pressure drop can be determined as follows:

a. For the minimum case:

$$\text{Pressure Drop} = P_{PEF} \times 100 \text{ psi} + SF \text{ (optional)}$$

b. For the maximum case:

$$\text{Pressure Drop} = 20 \text{ psi} + [P_{PEF} \times 200 \text{ psi}]$$

(based on experience)

4.9.6 The pressure drop can be calculated for each valve or the same pressure drop can be used for all the same type and size valves. With good data, minimum pressure drops can be taken; however, for poor data, higher pressure drops are recommended. Also, if gas injection at the bottom can be achieved, then higher pressure drops could and probably should be taken.

Table 1—Recommended Minimum Safety Factors for Various Injection Pressure Valves

Valve OD (in.)	Port Size (in.)	Safety Factor (*SF*) (psi)
$^5/_8$	$^1/_8$	10
	$^5/_{32}$	15
	$^3/_{16}$	20
1	$^1/_8$	5
	$^3/_{16}$	10
	$^1/_4$	15
	$^5/_{16}$	20
$1^1/_2$	$^3/_{16}$	5
	$^1/_4$	10
	$^5/_{16}$	15
	$^3/_8$	20
	$^7/_{16}$	25

4.9.7 Some designers prefer to determine the pressure drop by use of a pseudo unloading pressure line. A straight line is drawn from the injection operating pressure of the valve below to the flowing surface producing pressure. This line determines the maximum producing pressure range ($P_{max} - P_{min}$) for the valve above. (See Figure 16, Example Problem No. 2.) Such an approach normally results in higher pressure drops for upper valves and results in significant pressure drops for large ported valves with high production pressure effect factors. In such cases the pressure drop is calculated as follows:

$$\text{Pressure Drop} = [P_{PEF} - (P_{max} - P_{min})] + SF \text{ (optional)}$$

4.10 TEMPERATURE

4.10.1 Gas lift valves, such as unbalanced pressure charged valves, open or close at different pressures as the temperature changes. As a result, it is necessary to establish some standard reference temperature which can be used to set the valves. Most manufacturers use 60°F as that standard temperature.[2]

4.10.2 Valve opening pressures on the design graph are calculated at downhole temperature conditions. These calculated pressures must be converted to reflect the reference temperature so that the valves can be set in the workshop under those conditions. API *Gas Lift*, Table 4.1 gives the conversion factors to account for this temperature difference. For example:

900 psi opening pressure downhole at 130°F	x	0.869 temperature factor from Table 4.1	=	782 psi opening pressure in test rack at 60°F

[2]Other manufacturers use 80°F as the reference temperature. One should check with the manufacturer to see which reference temperature is being used.

4.10.3 As flow commences in the tubing string, the heat content of the liquid mass is transferred up the hole. Since only part of this heat can be dissipated through the wellbore tubulars to the shallower formations, the flowing wellhead temperature will be elevated above the normal surface temperature.

4.10.4 The best way to determine flowing temperatures is to make actual measurements at various production rates in the field. Temperatures usually become significantly higher for increasing production rates, higher water cuts, and higher velocities (smaller ID tubing). The chart in API *Gas Lift*, Figure 6.9, is based mostly on high water cut wells using $2^1/_2$-in. nominal tubing. Use this chart with caution unless it has been verified with field data. The method of Sagar, Doty, and Schmidt in their 1989 SPE 19702 paper, "Predicting Temperature Profiles in a Flowing Well," may prove helpful.

4.10.5 As a rule-of-thumb, never base the design for a continuous gas lift design on the static geothermal (earth) temperature gradient, since the increase in temperature from flow may lock the upper valves closed before unloading to the next lower valve(s). Upper valves should theoretically be designed for actual unloading rates and temperatures. Thus, the design temperature for upper unloading valves should be greater than the static temperature, greater than the temperature at the minimum flow rate, but less than at the maximum anticipated flow rate. A common design practice is to draw a linear temperature line from the surface flowing temperature at the anticipated maximum production rate to the reservoir temperature at well depth. This will normally result in an unloading temperature line that is slightly less than the actual flowing temperatures; and this tends to lock these upper valves closed during normal producing conditions. This type of approach is recommended for most designs.

4.11 FLAG VALVE

4.11.1 In an injection pressure operated valve design, it is a common practice to set the bottom valve at a substantially lower pressure than the other valves to act as a positive indication (or flag) of operation from the bottom valve. When the surface operating injection pressure is observed to be below the operating injection pressure of the upper valves, it can be assumed that the well is operating from bottom—once the possibility of a tubing leak or other malfunction up the hole has been ruled out. This flagging is generally achieved by assuming various production pressure values (flag loads) for the bottom valve. Remember that there is nothing magic about picking the production pressure load for the flag valve. The objective is to set the flag valve at a lower surface operating pressure than the other valves in the string. Some of the ways to assign the flag load for the bottom valve include:

a. Select a minimum pressure by assuming a 0.05 psi/ft gas gradient plus the separator pressure.
b. Assume an arbitrary minimum production pressure load such as 100 psi, 200 psi, etc.
c. Assume no pressure so the flag valve will open dry without any production pressure being necessary.
d. Assume a production pressure that is based on the minimum flow rate the well is expected to produce (frequently used).

Some operators achieve the same thing by installing an orifice on bottom.

4.12 GAS PASSAGE

4.12.1 As previously discussed, using the minimum port size that will pass the desired rate of gas will minimize the injection pressure drops required between valves, and thus minimize the loss of lift energy. It has been common practice to calculate gas passage using square-edged orifice nomographs similar to the one shown in API *Gas Lift*, Figure 4.8A, and then apply temperature and gravity adjustments. The resulting gas passage from the nomograph is then adjusted by the gas lift designer in one of several different ways:

a. Assume 100% gas passage as shown by the orifice nomograph (or gas passage equations), then select the port/orifice that will pass at least this much gas. Empirical data have shown this practice to be safe for small ported valves such as $^3/_{16}$-in. or smaller ported 1-in. valves, or $^1/_4$-in. or smaller ported $1^1/_2$-in. valves.
b. Use the nomograph to calculate the required port size for the design injection gas rate (assuming 100% passage), then use one size larger port as a safety factor.
c. Size the port based on applying a 75% or 80% factor to the gas rate shown by the square-edged orifice nomographs.

4.12.2 The preceding practices have been successful for small port sizes and moderate to low gas injection rates. The advent of large diameter, high rate completions has precipitated the use of large ports and high injection gas rates, thus emphasizing the need for more accurate gas passage data related to gas lift valves. Some manufacturers have these data available for their equipment or are in the process of gathering such data. As gas passage information becomes available, it would be wise to incorporate it into the gas lift design to avoid the possibility of being unable to achieve valve transfer due to restricted gas passage.

4.13 SUMMARY

4.13.1 This recommended practice is intended to present guidelines for the design of continuous flow gas lift installations using injection pressure operated valves. The successful design of such an installation will maximize production by providing consistent single-point injection at the maximum depth allowable by the gas injection facilities. The maximum depth of injection is achieved by minimizing pressure reduction between the valves as the well unloads. Some pressure reduction is necessary as a safety factor to prevent multi-point injection.

4.13.2 Graphical techniques are commonly used to facilitate the design as they provide the designer with a feel for the various design parameters. Three examples which incorporate these graphical techniques are given in the following section.

4.13.3 Good input data are essential in making an optimized design. If adequate data are not available or if the design information is wrong, a poor design will result. Poor designs will usually result in lower rates, excessive injection gas usage, and heading. Subsequent general wireline operations risk will probably be necessary to pull and reset the valves or the tubing may have to be pulled to respace the valves and mandrels.

5 Continuous Flow Problems: Injection Pressure Operated Valves

5.1 EXAMPLE PROBLEM NO. 1—DESIGN OF TYPICAL WELL WITH GOOD PRODUCTION DATA

5.1.1 General

5.1.1.1 A gas lift design problem which commonly occurs is the case for a well that has been completed and produced but now requires a gas lift design and equipment installation. Other cases are where the existing gas lift design is not suitable, or simply when the tubing is pulled for repair and the gas lift design needs to be reviewed for modification. In all of the above cases, several good production tests were obtained. This example problem will show how to space the valves/mandrels and design for near maximum or optimum rate using a limited amount of injection gas. The design will result in gas lifting from near the producing zone or as deep as feasible. Injection pressure operated valves for unloading were selected.

5.1.2 Reservoir and Well Data

5.1.2.1 A summary of the well data are given in Figure 3, Gas Lift Well Data Sheet. The well was drilled (relatively straight hole) to 8100 ft and completed as a single producer equipped with 7-in. casing and $2^7/_8$-in. of tubing. The producing interval is from 8000 ft to 8025 ft in a sandstone. The existing equipment will be pulled, and can be replaced if necessary. The flow line is 3-in. line pipe and the central facilities are only 500 ft distant from the well. High back pressure on the well is not a problem.

5.1.2.2 The well is one of several wells completed in a limited water drive reservoir. The reservoir was originally hydropressured and had a bubble point pressure near 2445 psig. Reservoir pressure declined to about 2150 psig but has stabilized in the past two years. On a recent flowing and build-up pressure survey in the well of interest, the static pressure was measured at 2125 psig and the well had no measurable skin. On a test at the time of the pressure buildup, the well flowed 100 BOPD and 100 BWPD, with a flowing bottom hole pressure of 1941 psig—against a 100 psig flowing wellhead pressure. The oil gravity was 35° API, and the gas-oil ratio was found near its original value of 700:1 standard cubic ft (SCF) of gas per stock tank barrel of oil. The well has loaded up and died. Further data are listed on the data sheet (Figure 3). Well conditions are assumed to remain relatively stable for the next few years.

5.1.3 Gas Lift System Data

5.1.3.1 The field currently has a gas lift system installed that provides 1250 psig dehydrated sweet injection gas.

5.1.3.2 Pressure at the well was measured at 1200 psig. A maximum of 750 MCFD is available for lift of this well; however, less than 700 MCFD is desirable. The injection gas has a 0.65 specific gravity.

5.1.4 Inflow

The gas lift design will attempt to produce the well at near its maximum capability. The inflow capability of the well must be determined and then coupled with the outflow conditions. Since the well produces free gas in the reservoir below the bubble point, the Vogel correlation was used. The inflow rates and flowing pressures were calculated as follows:

Rate:	200	400	600	800	900	1000	1200	BFPD
P_{wf}:	1941	1742	1517	1260	1115	952	531	psig

5.1.5 Outflow

5.1.5.1 The Hagedorn and Brown gradient curves were selected for determining outflow performance. These curves are widely used and in many fields are adequate for gas lift design.

5.1.5.2 The well is equipped with 2.5-in. nominal tubing which is the size needed—based on the inflow of this well. Typically 2.5-in. nominal tubing is the optimum size for rates in the 500 to 1500 BPD range. Using the gradient curves in Appendix B for various rates, and assuming flowing well head pressure of 100 psig, the following rates and needed flowing bottom hole pressures were determined at various GLRs:

Rates (BPD)							For
200	400	600	800	900	1000	1200	(GLR)
P_{wf} (psig)							
980	1060	1160	1285	1350	1400	1515	(800)
900	1000	1105	1230	1290	1340	1460	(1000)
860	960	1070	1200	1250	1300	1425	(1200)
820	925	1040	1170	1220	1280	1400	(1500)

Company ______________________ Address ______________________

A. Well Completion Data
- * 1. Field name: API Example No. 1
- * 2. Lease name and well no.: Well No. 1
- 3. Producing formation: Miocene Lithology: Sandstone
- * 4. Casing: 7 in. OD; 20, 23 #/ft; J, N Grade; 8100 ft
- 5. Liner: — in. OD; — #/ft; — Grade; — ft
- 6. Open hole: (yes/no) NO Gravel pack (yes/no) ______
- * 7. Well depth (TVD/MD): 8100 ft. Plug. back TVD: 8070 ft
- * 8. Perf. Interval 8000 - 8050 ft. Reference depth: 8000 ft
- 9. Packer: Hookwall @ 7970 ft
- * 10. TBG LNG 7980 ft; OD 2 7/8 in.; WT. 6.5 lb/ft; Grade J THD EUE
- 11. SSSV: mfg & type ______ ______; Depth ______ ft; Bore ______ in.
- 12. Wellhead mfg & type ______; (Bore ID) 2 9/16; WP 3000 psi
- 13. Choke: mfg & type Removed; Size max. ID ______ / 64 in.
- 14. Flowline: size ID 3 in.; Length: 500 ft
- 15. Well profile: (TVD/MD or deg) Straight hole

B. Reservoir, Test and Production Data
- * 16. Last test: (q_o) = 100 BOPD (q_w) = 100 BWPD (q_g) = 35 MSCFD
- * 17. Water cut 50% Formation R_{go}: 700 R_{gl}: 350
- * 18. Flowing WHP (P_{wh}) 100 psig; Separator pressure (P_{sp}) 75 psig
- * 19. Static BH pressure (P_{ws}): 2125 psig @ ______ ft
- 20. Static fluid level ______ Pressure ______ psig gradient ______ psi/ft
- * 21. Flow BHP (P_{wf}): 1941 psig @ 8000 ft @ rate 200 BLPD
- * 22. Oil API gravity 35 Water specific gravity 1.07
- * 23. Formation gas SG (SG_g): .88
- * 24. BH Temp (T_f): 178 @ 8000 Surf. temp (T_s): 78 Flow temp (T_{wh}): 86
- * 25. Bubble point (PB): 2445 psig; PI (J): ______ BPD/psi; flow eff ______
- 26. Sand (yes/no) Y; Paraffin (yes/no) Y; Scale (yes/no) No
- 27. H_2S (yes/no) No; CO_2 (yes/no) NO; Emulsion(yes/no) No
- 28. Other ______

C. Design Information
- * 29. Tubing/flow ______ New installation/rerun/modification
- * 30. Production rate (q_1): min 200 max 1000 design 800
- * 31. Max water cut 50% %; Max lift depth 8000 ft; Min BHP 1200 psig
- * 32. Comp inj. gas pres (p_g): 1250 psig: Well inj. pres 1200 psig
- 33. Header/sales inj. pres 1000 psig; Max (K_o) inj. pres 1200 psig
- * 34. Inj. gas temp @ well 78 °F; Inj. gas SG (SG_i) .65
- * 35. Inj. gas volume: max/unloading/design 750/700/680 MSCFD
- * 36. Load fluid grad (g_s): .465 psi/ft lower flow grad .4 psi/ft
- * 37. Min spacing 250 ft; Min inj. decrease 25 psi; Design diff ______ psi
- * 38. Design flow press (P_{wh}) 100 psig Design flow temp (T_{wh}) 108°F
- 39. Gas lift valve: mfg & type 1"; port 3/16 in.; A_p/A_b .094
- * 40. Gas lift valve description injection pressure operated
- * 41. Other nitrogen charged bellows

Remarks: ______

By: JDC Date: Oct 91

*Indicates data that must be supplied for good design.

Figure 3—Data Sheet Example 1

5.1.5.3 A comparison of these outflow pressures with the inflow pressures of the well as shown above, indicates that rates of 900 and higher are not possible but that rates of 200 to 800 **[add definition]** BFPD are feasible. For a given stabilized production rate, the inflow performance pressure must be equal to the needed outflow performance pressure. A plot of these values is made in Figure 4.

5.1.5.4 The point of intersection of the IPR (inflow) curve with the tubing performance (outflow) curve is the predicted producing rate. For this well, a rate of 800 BFPD is near the maximum achievable rate.

5.1.6 Injection Gas

5.1.6.1 A comparison of the tubing performance curves for various gas liquid ratios (R_{gl}) is one of the methods to select the optimum injection gas. A R_{gl} of 800 will restrict production to less than 800 BFPD. Use of increasing R_{gl} will increase the production rate; but the increase in production per incremental (MCF) is steadily decreasing.

5.1.6.2 For a total R_{gl} of 1500 and a producing R_{gl}, of 350, a production rate of 800 BFPD would need:

(1500 – 350) x 800/1000 = 920 MCFD injection gas

whereas

for a 1200 R_{gl}, 680 MCFD is required,

for a 1000 R_{gl}, 520 MCFD is required,

and

for a 800 R_{gl}, 360 MCFD is required.

5.1.6.3 Since the field has a limited amount of injection gas, the design will be based on a producing R_{gl} of 1200. However, after installation, a further evaluation is recommended that is based on actual well tests. Also, in the future when water cut increases, slightly more gas may be required.

5.1.7 Temperature

5.1.7.1 The temperature of the injection gas and produced liquids have a significant effect on the gas lift

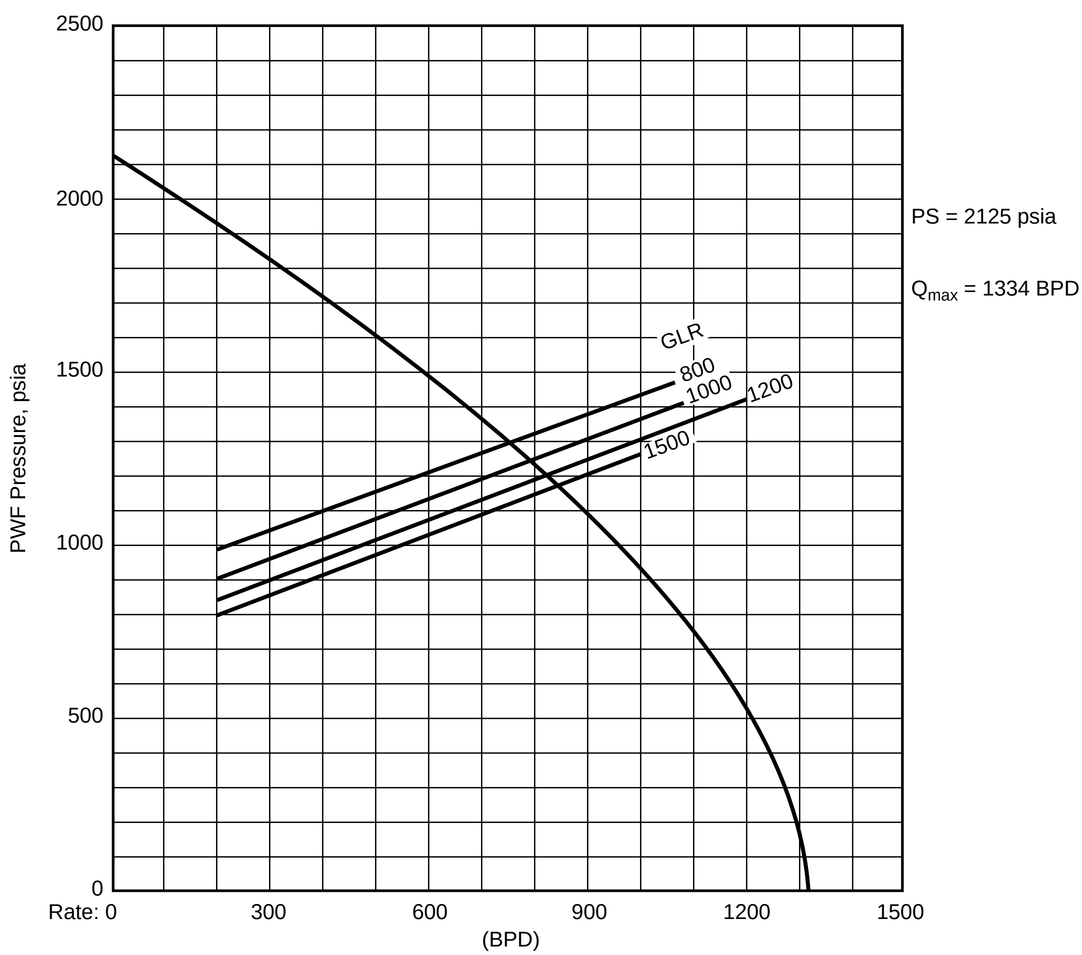


Figure 4—Oil IPR Graph

design—especially when using nitrogen charged bellows valves. Actual temperature measurements are recommended at different production rates.

5.1.7.2 In this well the formation temperature of the reservoir (bottom hole temperature) is 178°F, the surface static temperature is 78°F, and the flowing wellhead temperature at 200 BFPD was measured to be 86°F. The well flows up 2.5-in. nominal tubing. The geothermal gradient is found to be 1.25°F per 100 ft.

5.1.7.3 The flowing temperature at 800 BFPD is determined as follows:

$$T_{wh}(800\text{ BFPD}) = 178 - 0.87 \times 8000/100 = 108°\text{F}$$

5.1.7.4 Since the well will not produce at the maximum rate until injection begins at the maximum depth, the upper valves will be required to close at lower rates, therefore at lower temperatures.

5.1.7.5 As the well lifts deeper, the higher flowing temperatures will help keep the upper valves closed.

5.1.7.6 Average injection gas temperature = (78 + 178)/2 = 128°F. (The flowing fluids have only a small effect on the injection gas temperature.)

5.1.8 Gas Gradient

The available injection gas pressure will increase with depth due to the weight of the gas where relatively large injection tubulars are used. For this well, the surface gas injection will be a maximum of 1200 psig and operating pressures are anticipated to be about 1100 psig. The approximate increase in pressure per 1000 ft can be found by use of Figure 5. Thus, for a gas specific gravity of 0.65, the pressure will increase about 30 psi per thousand ft with a surface pressure of 1100 psig and about 32.5 psi per thousand ft with a surface pressure of 1200 psig. A conservative estimate of 30 psi per thousand ft will be assumed in this case.

5.1.9 Valve Spacing

5.1.9.1 There are many methods for spacing valves. This design will use a graphical (pressure-depth) approach but will also provide supporting calculations. Ample safety factors

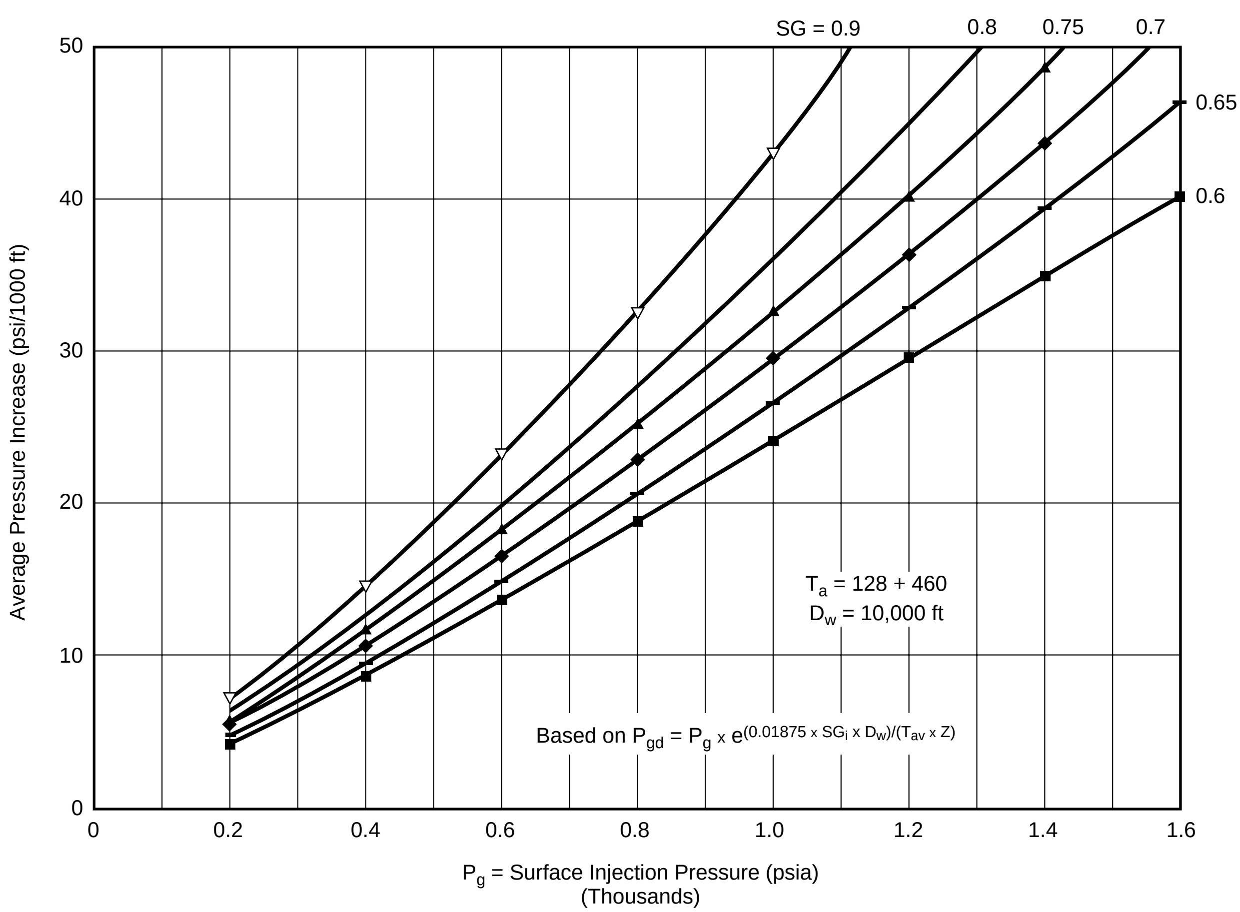


Figure 5—Weight of Injection Gas Column

will be used to ensure unloading. The following are the given pressure and depth data that need to be initially plotted:

P_{wh} = Pressure at the wellhead = 100 psig.

P_g = Pressure of injection gas at well = 1200 psig.

T_s = Static temperature at surface = 78°F.

T_{wh} = Flowing temperature at wellhead = 108°F.

g_s = Static gradient of load fluid in annulus = 0.465 psi/ft.

g_g = Gas gradient = 30 psi/1000 ft or 0.03 psi/ft.

D_w = Depth of well = 8000 ft.

P_{gd} = Pressure of injection gas at well depth 1440 psig.

T_f = Formation temperature = 178°F.

f_w = Water cut fraction = 0.50.

5.1.9.2 A prediction of the tubing flowing pressure is required in order to space the valves. Various methods have been used successfully; however, one of the best approaches is to use the gradient curve for the anticipated maximum production rate. In this case the rate is 800 BFPD with a GLR of 1200/1 through 2.5-in. nominal tubing. The following depth and pressure values were read off the appropriate graph in Appendix B.

Depth:	0	2500	4000	5000	6000	7000	8000	ft
Pressure:	100	400	600	740	880	1030	1200	psig

These values are then plotted on the design graph (see Figure 6).

Note: If the design graph has the same scale as the flowing gradient curves in Appendix B, the curve may be traced.

5.1.10 Valve Setting Depths

Basically the gas injection pressure must be slightly higher than the tubing pressure when the valve is uncovered during unloading operations—otherwise no gas injection will occur and unloading operation deeper will cease. Also, when using injection pressure operated valves, the casing pressure must be dropped to insure the upper valve(s) close—otherwise deeper lift is uncertain and excessive gas will be required. A pressure drop (*PD*) of 25 psi in the gas injection pressure was selected as a reasonable amount to ensure proper valve action. Example: For a valve with a P_{PEF} = 0.1, and using a typical but conservative 15 psi safety factor, then: $PD = 0.1 \times 100 + 15 = 25$ psi. This 25 psi drop is slightly higher than the 10 psi minimum, and is less than the 40 psi maximum recommended as discussed in 4.9.

5.1.11 First Valve Setting Depth

5.1.11.1 The depth of the first valve can be found graphically by starting at P_{wh} and paralleling the 0.465 psi/ft load fluid gradient line to the intersection with the gas injection pressure line. To provide a small pressure differential, move back up the hole to a depth where there is a 20 psi pressure differential (see Figure 7). A depth of about 2475 ft results. For a more precise depth, calculate the actual depth.

These values are then plotted on the design graph.

See Figure 7.

Note: If the design graph has the scale as the flowing gradient curves in Appendix B, the curve may be traced.

5.1.11.2 Calculate the setting depth as follows:

Tubing pressure = casing pressure – Nominal Pressure Differential

(or)

Maximum unloading flowing pressure = gas injection pressure – P_{sf}

$$P_{wh} + g_s \times D_{(1)} = P_g + g_g \times D_{(1)} - P_{sf}$$

$$100 + 0.465 \times D_{(1)} = 1200 +.03 + D_{(1)} - 20$$

$$(0.465 - 0.030) \times D_{(1)} = 1200 - 100 - 20 = 1080$$

$$D_{(1)} = 2483 \text{ ft}$$

(Graphically: 2475 ft)

See Appendix A for symbol definitions.

5.1.12 Subsequent Valve Setting Depths

5.1.12.1 The second valve depth can be found graphically by starting at the flowing tubing pressure at the depth of the first valve. A straight line is drawn parallel to the 0.465 gradient line to the intersection of the gas injection pressure minus the selected pressure drop, *PD*—which is 25 psi. A surface pressure of 1175 psig will be used for the second valve. In locating the depth of valve 2, move back up the hole to a depth where the gas injection pressure exceeds the unloading line by 20 psi. Find on the design graph (Figure 8) the depth of second valve at about 4375 ft.

5.1.12.2 To calculate the depth use the following formula:

$$P_{pd(n)} + g_s \times D_{bv} = (P_g - n \times PD) + g_g \times (D_{(n)} + D_{bv}) - P_{sf}$$

$$P_{pd(2)} + g_s \times D_{bv} = (P_g - 25) + g_g \times (D_{(1)} + D_{bv}) - P_{sf}$$

$$400 + 0.465 \times D_{bv} = (1200 - 1 \times 25) + 0.03 \times (2483 + D_{bv}) - 20$$

$$D_{bv} = [(1200 - 25) + 74.5 - 20 - 400]/(0.465 - 0.030)$$

$$D_{bv(2)} = 1907$$

$$D_{(2)} = D_{(1)} + D_{bv(2)} = 2483 + 1907 = 4390 \text{ ft}$$

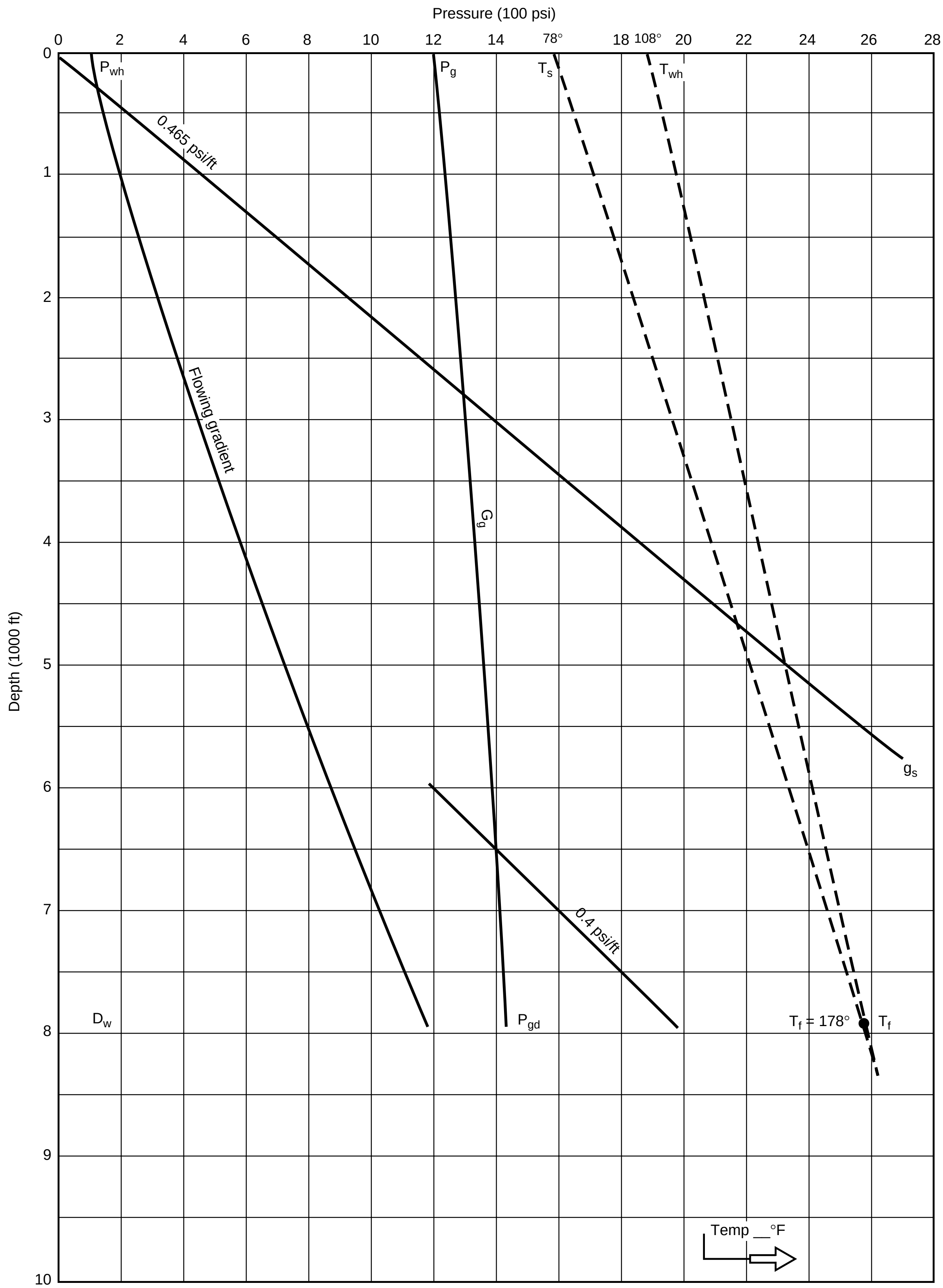


Figure 6—Gas Lift Design

5.1.12.3 Using the same approach, find depth of third valve graphically at a depth of about 5800 ft or calculate.

$$(0.435) \times D_{bv(3)} = (1200 - 50) + (0.03 \times 4390) - 20 - 650$$

$$D_{bv(3)} = 612/0.435 = 1407$$

$$D_{(3)} = D_{(2)} + D_{bv(3)} = 4390 + 1407 = 5797 \text{ ft}$$

5.1.12.4 Continue using the same graphical technique or calculation methods find subsequent valves depths as follows:

		Graph	Calculated	
$D_{(4)}$	=	6775	6783	
$D_{(5)}$	=	7425	7434	
$D_{(6)}$	=	7825	7820	*See Adjustment to 7690 ft
$D_{(7)}$	=	8000		*See Adjustment to 7940 ft

Note 1: There will be minor differences between the graph and calculated values due to the difficulty of reading the graph to values closer than 10 psi or 25 ft.

Note 2: Closer valve spacing occurs with increasing depths. Typically the designer will reach total depth or will find spacing closer than a practical limit. The recommended minimum limit on spacing ranges from 90 ft for a high production index well with accurate lift depth data to 500 ft for a low productivity index well with poor design data. A practical limit of 250 ft was selected for this well based on economics.

5.1.13 Valve Spacing Adjustment

5.1.13.1 Most wells will not have the valve spacing come out exactly correct and adjustments in the setting depths are recommended. In general, try to valve as deep as practical and do not increase the spacing between valves significantly. Closer spacings are best near the anticipated operating injection point. Also avoid excessive use of valves and mandrels. Consideration should be given to possible future changes in operating conditions. It is good design practice to add one or more valves/mandrels for future use if total depth is not reached.

5.1.13.2 Adjustment of the last few valve setting depths is needed for this well. Start with the bottom valve and work back up the hole. The perforations are from 8000 ft to 8025 ft, which requires that the packer be set no deeper than 7970 ft. Any mandrel should be placed about one joint above the packer to permit tubing cutting and jarring without undue workover difficulties. Thus the bottom valve will be set at 7940 ft.

5.1.13.3 The next to the bottom valve is affected by the minimum spacing limit of 250 ft. Place this valve up the hole 250 ft at a depth of 7690 ft. No other adjustments are needed for this well. The adjusted setting/spacing design is shown in Figure 8.

Note: The actual setting depths of the valves can easily vary by 25 ft; and the designer needs to compensate for such alterations. In this example the 20 psi safety factors allows for a (20/0.465) = 43-ft deviation.

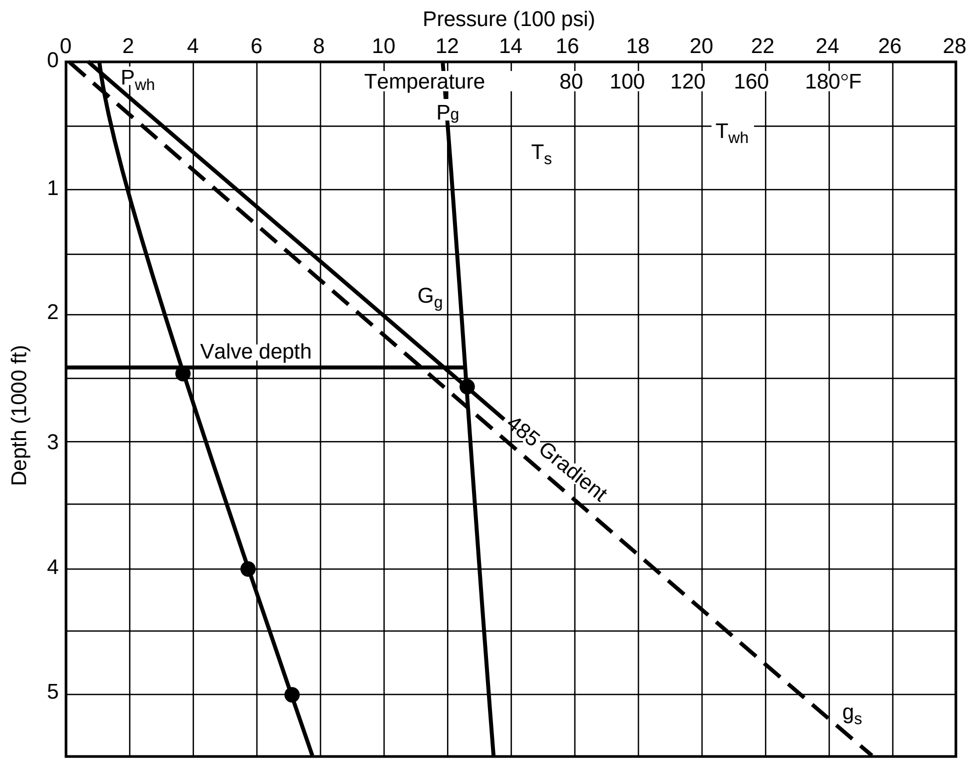


Figure 7

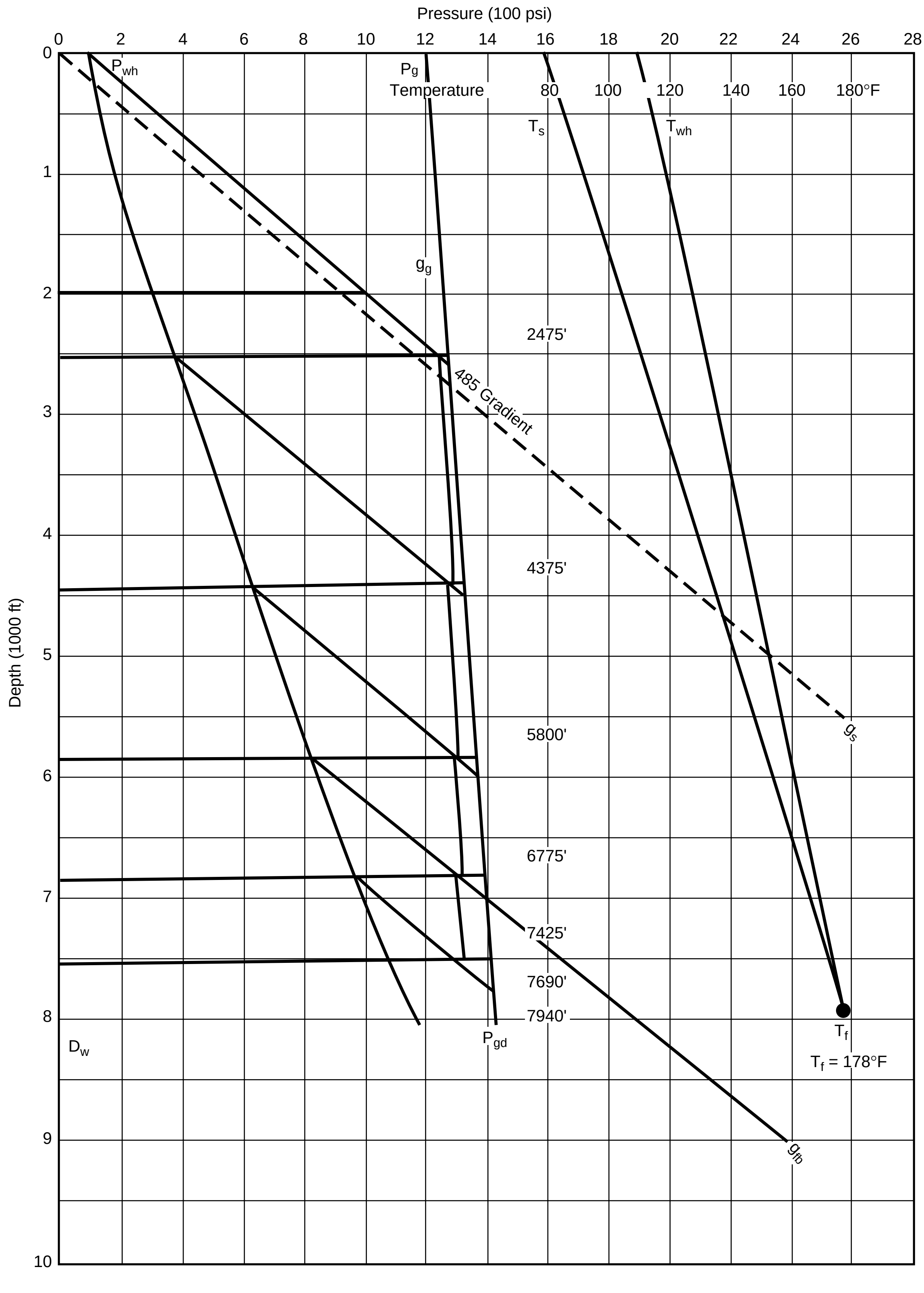

Pressure (100 psi)
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28
Depth (1000 ft)
0 1 2 3 4 5 6 7 8 9 10
P_{wh}
P_g
Temperature
80 100 120 140 160 180°F
T_s
T_{wh}
g_g
2475'
485 Gradient
4375'
5800'
6775'
7425'
7690'
7940'
g_s
P_{gd}
D_w
T_f
T_f = 178°F
g_{fb}

Figure 8

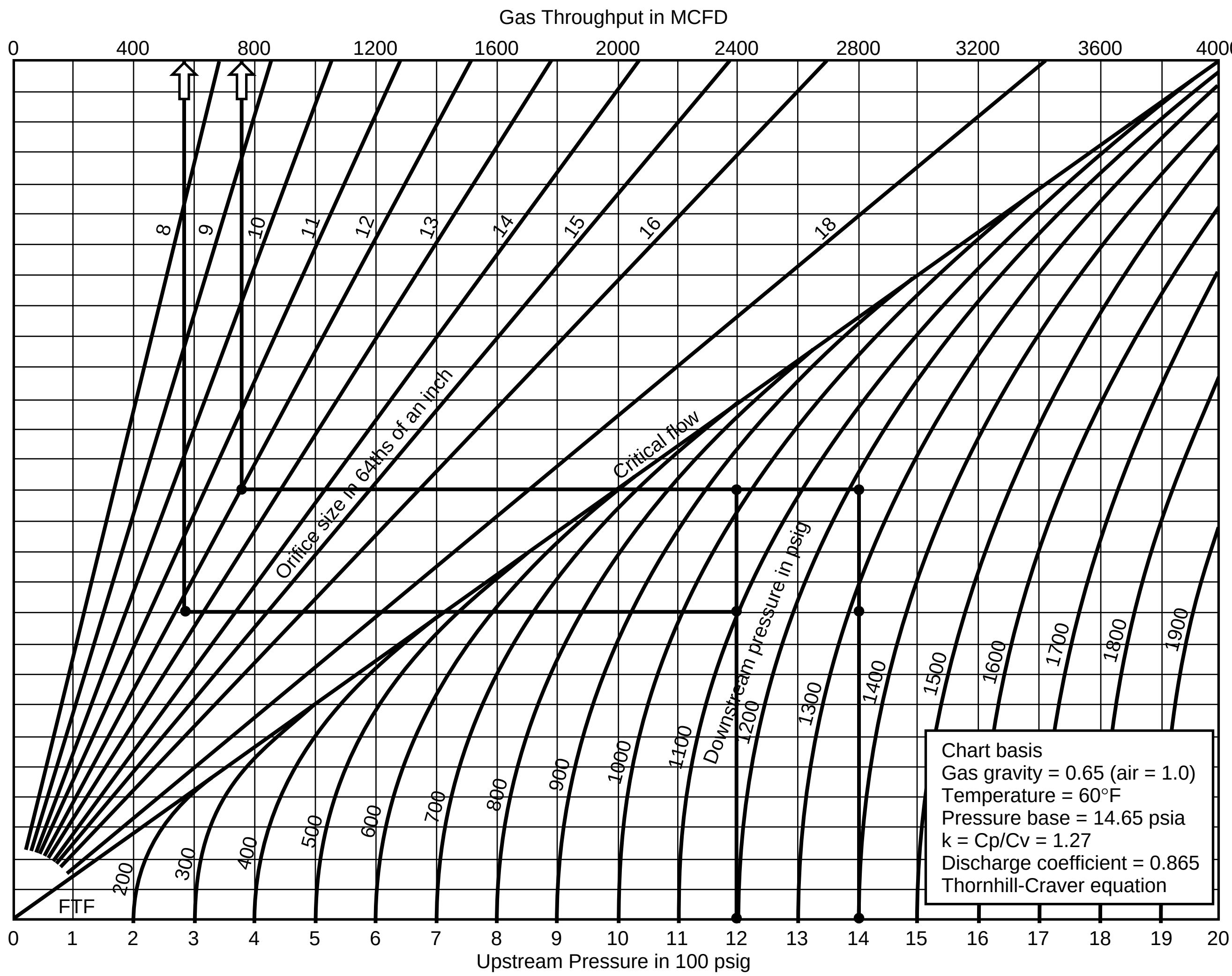
5.1.14 Valve Selection

5.1.14.1 This design is for injection pressure valves. The commonly used 1-in., unbalanced, nitrogen-charged bellows valve was selected. This selection was based on good experience with using 1-in. valves where gas injection rates are relatively low (less than 750 MCFD), and since the cost of 1-in. valves and mandrels are less than the larger $1^1/_2$-in. valves and mandrels. High rate wells (> 2000 BPD) may produce better with $1^1/_2$-in. OD valves.

5.1.14.2 Since the injection gas rate will be less than 750 MCFD (the maximum available from the system), the use of 1-in. valve with a $^3/_{16}$-in. ported valve will be evaluated. See Figure 9 for gas passage for various orifice sizes. It shows that to inject 750 MCFD through a $^3/_{16}$-in. port (approximately equal to a $^{12}/_{64}$-in. orifice), a pressure differential of about 225 psi must exist between the downstream with an upstream pressure of 1200 psig and slightly less for an upstream pressure of 1400 psig. With only a 100 psi differential for an upstream pressure of 1200 psig, only 560 MCFD can theoretically be injected (uncorrected) through a $^3/_{16}$-in. ported valve.

Note: For more accurate answers, a temperature and gravity correction must be applied since the gas passage chart is based on a temperature of 60°F and a gas gravity of 0.65.

5.1.14.3 These charts assume that the valve opens fully and that there are no other restrictions. A $^3/_{16}$-in. port should be adequate for unloading, since pressure differentials are normally high at that time. However, for the operating point, a larger port/orifice may be needed to allow for adequate gas passage.



Note: Gas flow capacities (0–4000 MCF/D) for known upstream pressure, downstream pressure, and orifice size. Courtesy F.T. Focht.

Figure 9—Gas Passage Chart for Various Orifice Sizes

5.1.14.4 A check of the manufacturer's catalog, for this commonly used 1-in. valve with a $^3/_{16}$-in. port, shows that an A_p/A_b ratio of about 0.094 is typical which results in a production pressure effect factor (P_{PEF}) = 0.104. Such data are required in order to set the valves in the shop so that they will operate in the well properly.

5.1.15 Valve Pressure Setting

5.1.15.1 Calculation of the valve test rack opening set pressure, P_{vo}, is critical for proper gas lift design.

This is the injection pressure (P_1) to open the valve in a tester with a back (P_2) equal to zero pressure and at a base temperature of normally 60°F. The valve, in turn, should open in the well under the desired operating pressure and temperature conditions. See API *Gas Lift*, page 61.

5.1.15.2 For a typical bellows valve, the balance of forces when the valves is just ready to open is:

$$P_{bv} \times A_b = P_1 (A_b - A_p) + P_2 \times A_p$$

5.1.15.3 When: $P_2 = 0$ and $P_1 = P_{vo}$ (in the valve tester) then:

$$P_{bv} \times A_b = P_{vo}(A_b - A_p)$$

and, in general,

$$P_{vo} \times (A_b - A_p) = P_1(A_b - A_p) + P_2 \times A_p$$

or at well conditions

$$P_{vo} = P_{iod} + \frac{P_{pd}(A_p)}{(A_b - A_p)}$$

and since

$$P_{PEF} = \frac{A_p}{(A_b - A_p)}$$

$$P_{vo} = P_{PEF} \times P_{pd} + P_{iod}$$

5.1.15.4 This formula must be corrected for temperature and becomes:

$$P_{vo} = (P_{PEF} \times P_{pd} + P_{iod}) \times C_T$$

5.1.15.5 C_T may be looked up in tables (see Table A-1 in Appendix A) or calculated at 60°F as follows:

$$C_T = \frac{1}{1.0 + 0.00215 \times (T_v - 60)}$$

5.1.15.6 Thus, for valve no. 1 (find C_T values from Table A-1) $C_T = 0.869$ for 130°F.

$$P_{vo(1)} = (0.104 \times 400 + 1275) \times 0.869 = 1144 \text{ psig}$$

5.1.15.7 The temperature at each valve can be calculated as follows assuming a linear increase:

$$T_{v(n)} = T_{wh} + D_{(n)} \times \frac{g_{Tpf}}{100}$$

$$T_{v(1)} = 108 + 2475 \times \frac{0.87}{100} = 130°\text{F}$$

5.1.15.8 The injection pressure can be calculated as follows:

$$P_{iod(n)} = P_{iod(n)} + g_g \times D_{(n)}$$

$$P_{iod(1)} = 1200 + 0.030 \times 2475 = 1275 \text{ psig}$$

5.1.15.9 The flowing production pressure must be determined from a gradient chart. See Appendix A.

5.1.15.10 Table 2 is a summary of the valve test rack pressures.

Table 2—Test Rack Pressure Calculation Sheet

Well: API Example 1 Goodwell Data Valve: Pressure Injection 1 in.

Valve No.	Depth ft.	T_v D.	P_{PEF}		P_{pd} psig		P_{iod} psig	psig		C_T	P_{vo} psig[a]
1	2475	130	0.104	x	400	= 42	+ 1275	= 1317	x	0.869	= 1144
2	4375	146	0.104	x	650	= 68	+ 1305	= 1373	x	0.844	= 1158
3	5800	159	0.104	x	850	= 88	+ 1325	= 1413	x	0.825	= 1166
4	6775	167	0.104	x	1000	= 104	+ 1330	= 1434	x	0.813	= 1166
5	7425	173	0.104	x	1100	= 114	+ 1325	= 1439	x	0.805	= 1158
6	7690	175	0.104	x	1150	= 120	+ 1305	= 1425	x	0.802	= 1143
7	7940	177	_______		1200		+ 1300				= $^{14}/_{64}$ in. Orifice

[a]Some operators round the values off to the nearest 5 psig.

5.1.15.11 It should be noted that the test rack pressures for this case actually increase for the first few valves. In lower pressure injection systems, such settings seldom occur. Arbitrarily dropping the test rack pressures some 10 to 20 psi for injection pressure systems over 800 psig is not a recommended design practice since it reduces injection pressure too radically.

5.1.15.12 Before concluding the design, a check should be made to determine if ample gas can be injected for each valve—especially those near the injection point.

5.1.15.13 Some operators have had good success by using an orifice in lieu of the bottom operating valve. The orifice size should be selected with care. In this case, the surface injection pressure must be less than 1075 psig to ensure the upper valves do not open; thus, the pressure at 7940 ft must be less than 1315 psig. Assuming an upstream injection pressure of 1300, and a flowing pressure of 1200 psig when producing about 800 BFPD, an orifice of $^{14}/_{64}$-in. size was selected to pass about 750 MCFD (uncorrected). Applying a 1.12 temperature correction (see Correction Factor Chart), this orifice would pass about 670 MCFD—very close to the amount required. To vary the injection gas volume, simply adjust the surface gas injection pressure slightly. This approach requires close control of the surface gas injection pressure.

5.1.15.14 The valve at 7690 ft with a $^{3}/_{16}$-in. port should permit the passage of about 680 MCFD. Thus operating from 7690 ft is feasible.

5.1.16 Summary

A gas lift design has been made using injection pressure operated valves. Well data were collected and a gas lift rate of about 800 BFPD was predicted. A gas injection rate of about 680 MCFD will be required and the producing GLR will be about 1200:1 SCF/BBL. A flowing surface temperature of 108°F was predicted and an injection gas gradient of near 30 psi per thousand ft was used. A graphical design was made supported by calculations. The spacing of the valves indicated that six unloading valves were required to reach the screened orifice at 7940 was predicted and an injection gas gradient of near 30 psi per thousand ft was used. A graphical design was made supported by calculations. The spacing of the valves indicated that six unloading valves were required to reach the screened orifice at 7940 ft. The test rack pressures of the valves were calculated and a check was made to ensure that the port size used would pass the needed injection gas rate. An anticipated operating surface gas injection pressure slightly less than 1075 psig will be needed to produce 800 BFPD on continuous gas lift. After installation, production tests should be run to optimize production and injection gas rates.

5.2 EXAMPLE PROBLEM NO. 2—DESIGN OF A WELL WITH LITTLE OR NO PRODUCTION DATA

5.2.1 General Discussion

5.2.1.1 In many instances, a gas lift design is required where there is little or no detailed production information. Examples may include (a) a newly drilled well, (b) a well worked-over to a previously unproduced sand, or (c) simply a lack of information on currently producing wells. Regardless of the reason for the lack of information, it becomes necessary to generate a gas lift design that will work over a wide range of producing conditions. Although an adequate design can be formulated, the penalty cost of such a design is usually that more equipment will have to be purchased than would be required if better well data were available. The same design techniques can be used in cases where well data may be available; but a wide range of flow rates must be accommodated by a single design due to multiple through-tubing recompletions to zones with different producing characteristics.

5.2.1.2 All the discussions and examples in this section will assume tubing flow. This means that the term *production pressure* will refer to the production pressure in the tubing; and the term *injection gas pressure*, or injection pressure, will refer to the injection gas pressure in the tubing-casing annulus.

5.2.2 Selecting the Design Flow Rate(s)

When little or no production information exists for the well being designed, it is possible to get an idea of the flow rate by analyzing data from other wells producing in the same reservoir, or by using analog well or field data. In other cases, the design must accommodate a known range of flow rates due to multiple through tubing recompletions within the same wellbore. In some cases, such as a wildcat well, or a workover to a previously unproduced zone, absolutely no information on anticipated flow rate may be available. In cases such as these, the designer must establish a minimum and maximum rate, based on available data, between which he feels the proposed well should produce. The spacing and valve settings must then be designed to accommodate any flow rate within the assumed range of rates. Remember that a greater range in flow rates will require more valves.

5.2.3 Gas-Liquid Ratio

The target gas-liquid ratio (R_{gl}) curve for the design flow rate(s) is selected on the basis of the total gas rate available to lift the well, up to, but not exceeding minimum gradient. (Minimum gradient is the R_{gl} beyond which additional gas injection will not further lighten the fluid being lifted.) For example: if the anticipated liquid flow rate is 400 BFPD, and the maximum available rate of lift gas is 400 MSCF/D, then the gas-liquid ratio curve for design purposes would be

1000/1, provided this ratio is less than the minimum gradient R_{gl}. However, other R_{gl} curves for the design flow rate may be used as a reference to determine the rate of gas necessary for valve transfer and sizing the ports. Remember that minimum gradient is related to depth. The example shown in Figure 10 illustrates that minimum gradient for depth 1 is 800/1, while minimum gradient for depth 4 is 1500/1. In this example, the absolute minimum gradient for maximum depth would be 1500/1; whereas the practical minimum gradient for depths shallower than depth 4 will be less than the absolute value of 1500/1. Using gas-liquid ratios higher than the practical minimum gradient for your design lift depth is inefficient, and would prove counterproductive.

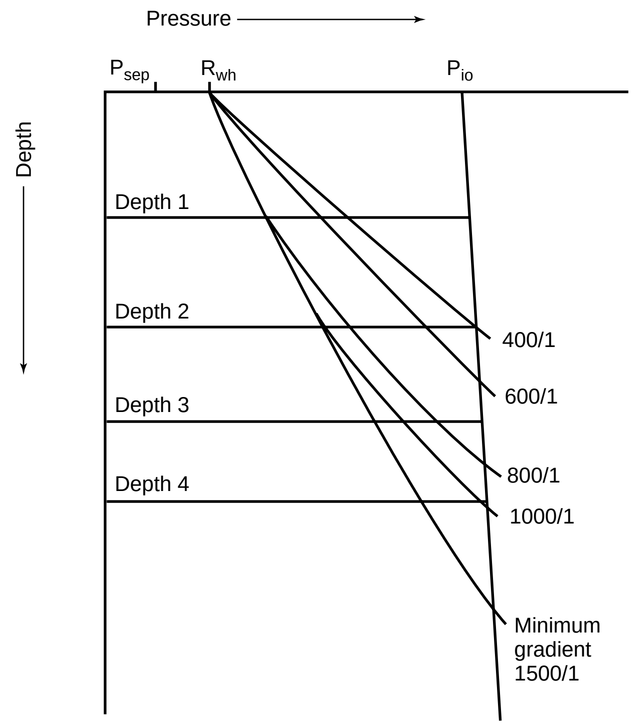


Figure 10

5.2.4 Temperature Considerations

5.2.4.1 A major problem associated with designing injection pressure operated valves for multiple flow rates is temperature, since the flowing temperature in the wellbore is a function of the flow rate—which, in this case, is the unknown parameter. It is possible to have the valves lock-out (not be able to open) due to higher-than-design temperature if the flowing temperature is based on a flow rate that is too low. Higher-than-design temperature increases the dome pressure in nitrogen charged pressure valves. If a well should produce at a lower-than-design flow rate, the flowing temperature gradient will be reduced and the valve opening pressures will be lowered, making valve interference possible.

5.2.4.2 Several options exist for selecting the flowing surface temperature for multiple flowrate designs. They include:

a. Assume a flowing surface temperature based on your best guess of the initial flow rate, and be prepared to pull and reset the valves when production data is obtained (if necessary).

b. Assume an average flowing surface temperature where the range between the anticipated high and low producing rates is not too great (i.e., low = 400 BFPD, and high = 800 BFPD, etc.—use 600 BFPD for flowing temperature estimate).

c. Where the difference between the range of possible flow rates is large, it may be necessary to use a flowing surface temperature above the average to prevent valve lock-out (i.e., low = 200 BFPD, and high = 1000 BFPD—use 700 or 800 BFPD for flowing temperature estimate).

5.2.4.3 In reality, there is the risk of having to pull the valves and reset them based on actual data when the well is placed on production. This risk increases as the validity of the design information decreases.

5.2.5 Use of Retrievable Equipment

While it is a good practice to use retrievable equipment in areas where workover costs are high, it is especially important to use retrievable valves when designing wells for a wide range of flow rates. This will allow the flexibility of being able to pull and reset the valves for optimum performance once production data is available. Major problems may thereby be avoided as long as the spacing between the valves was designed to accommodate the target flow rates.

5.2.6 Port Size

The gas lift valve ports should be sized to pass the objective rate of gas as dictated by the Gas-Liquid Ratio (R_{gl}) curve being used. The total required injection gas rate is defined by multiplying the total fluid rate in BFPD times the R_{gl}. In the design method discussed in the following pages, it is important to remember that the calculated pressure drops between valves are significantly affected by the port size selected. So where operating injection pressure is limited and the pressure drops must be minimized to save lift energy, use the smallest port that will pass the required rate of gas. This will also minimize the possibility of inadvertently overinjecting gas.

5.2.7 Injection Pressure Drops

As discussed previously, the injection pressure drops between successively deeper valves is the mechanism whereby valve interference is deterred. One approach to accomplish this is to set each successively deeper valve to open at the closing pressure of the valve above it. This unfortunately results in massive loss of operating injection pressure. Selecting arbitrarily low injection pressure drops of 5 psi, 10 psi, etc., is likely to result in a higher incidence of valve interference depending on the port size being used, whereas selecting arbitrarily large injection pressure drops of 50 psi, or higher, will result in loss of lift energy and may cause operation much higher up the hole than would otherwise be necessary.

The following method offers a rational way of selecting injection pressure drops which falls in between these two extremes. It also takes port size into consideration, which is important because larger ported valves with high production pressure effect factors are more likely to cause valve interference and therefore require larger injection pressure drops than smaller ported valves. The rationale behind this method of calculating the required pressure drop is discussed in the next few paragraphs.

5.2.7.1 Calculating Injection Pressure Drop—Minimum Injection Pressure Drop

5.2.7.1.1 This method is applicable where low operating injection pressure or widely spaced mandrels require the maximum use of available injection pressure. An alternate method which utilizes more safety factors is also discussed following the first method. The alternate procedure is applicable where there is adequate injection pressure and/or properly spaced mandrels for the well being designed.

5.2.7.1.2 Although injection pressure operated valves open primarily on injection pressure, a percentage of the opening force comes from the production pressure. The amount of opening force supplied by the production pressure is a function of the port size. The effective amount of opening pressure (P_{eo}) supplied by the production pressure is defined by the equation:

$$P_{eo} = \begin{array}{c}\text{Effective}\\\text{Opening}\\\text{Pressure}\end{array} = \begin{array}{c}\text{Prod. Pressure}\\\text{Effect Factor}\end{array} \times \begin{array}{c}\text{Production}\\\text{Pressure Acting}\\\text{on Valve}\end{array}$$

$$P_{eo} = P_{PEF} \times P_{pd}$$

5.2.7.1.3 For a gas lift valve of a given outside diameter, *d*, the production pressure effect factor (P_{PEF}) increases with increasing port size. In other words—as the port size increases, a greater percentage of the production pressure is effectively acting to open the valve. The importance of the above is shown in Figure 11A. Notice that the injection pressure is a controllable variable, and P_{wh} is also controllable to a degree, as long as a sufficiently high, or safe, value of P_{wh} is assumed. The uncontrollable variable is the production pressure downhole since it increases with rate, and the rate is the unknown factor in this example. Also notice that as the flow rate increases, the effective production pressure trying to open the gas lift valve increases as well. Larger ports will contribute a higher percentage of this increase in production pressure to the opening of the valve. With a fixed injection gas pressure, unexpected increases in production pressure can cause upper unloading valves to reopen and interfere with the proper operation of the well. Injection gas pressure drops are taken to prevent this from happening.

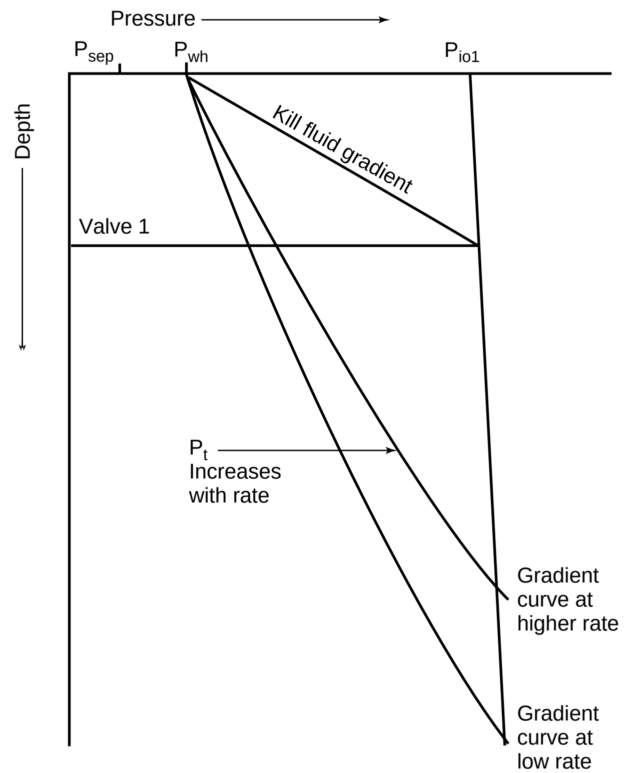


Figure 11A

5.2.7.1.4 Since the uncontrollable variable is the production pressure, it is important to approximate the maximum amount it could increase. Also, since the flowing gradient curve for any rate is a curved line, it could never be greater than a straight line between the flowing wellhead pressure (A) and the injection pressure at which gas will be introduced into the tubing (tubing flow) at the second valve (see Figure 11B). As a result, the maximum possible flowing production pressure at valve 1, regardless of the flow rate, is defined by the point shown in Figure 11B as P_{max1}, If we know the maximum production pressure increase possible at valve 1, and we know the production pressure effect factor of the valve; the amount of effective reopening pressure caused by this potential increase in production pressure can be calculated by the equation:

$$PD = (P_{max} - P_{min}) \times P_{PEF}$$

5.2.7.1.5 Set valve 2 to operate at a casing pressure lowered by the amount calculated: $P_{io2} = P_{io1} - PD$. We can ensure that valve 1 will not reopen and interfere, regardless of fluctuations in the flow rate (assuming that a safe value of P_{wh}

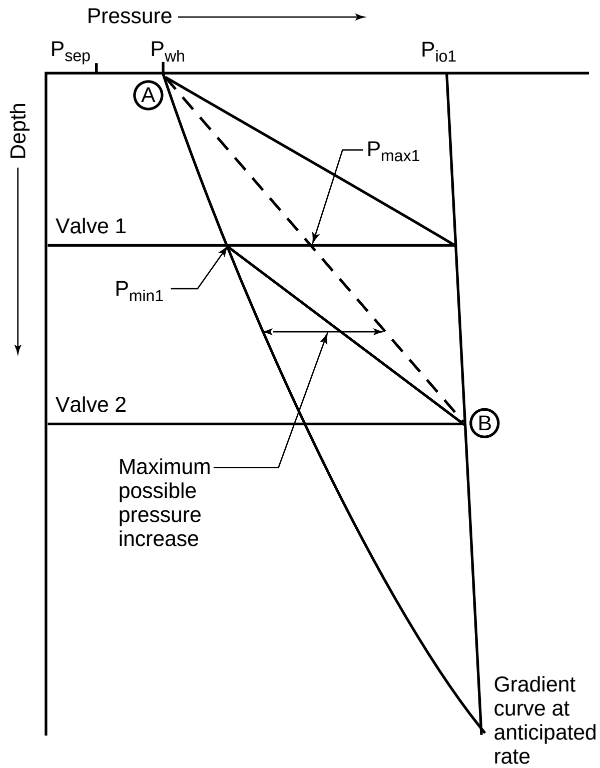


Figure 11B

was selected). Since the difference in P_{min} and P_{max} is multiplied by the production pressure effect factor, it can easily be seen that larger ports with high production pressure effect factors will require much higher injection pressure drops than smaller ported valves. Using the smallest port that will provide the required gas passage will minimize the loss of lift energy by minimizing the injection pressure drop required. Pressure drops for subsequent valves are calculated in the same manner (Figures 11C and 11D). See the design examples for specific details.

5.2.7.2 Calculating Injection Pressure Drop with Safety Factor

5.2.7.2.1 In cases where the gas lift system injection pressure is significantly above the minimum injection pressure required for the well being designed, a greater safety factor can be allowed in the injection pressure drops taken between valves. Larger injection pressure drops taken between valves minimize the chance of valve interference. The preceding section dealt with the minimum injection pressure drop required between valves. Where the available injection pressure allows more safety factor, add additional amounts of pressure drop to those calculated by the previously discussed procedure as shown below:

$$PD = (P_{max} - P_{min}) \times P_{PEF} + \text{Safety Factor}$$

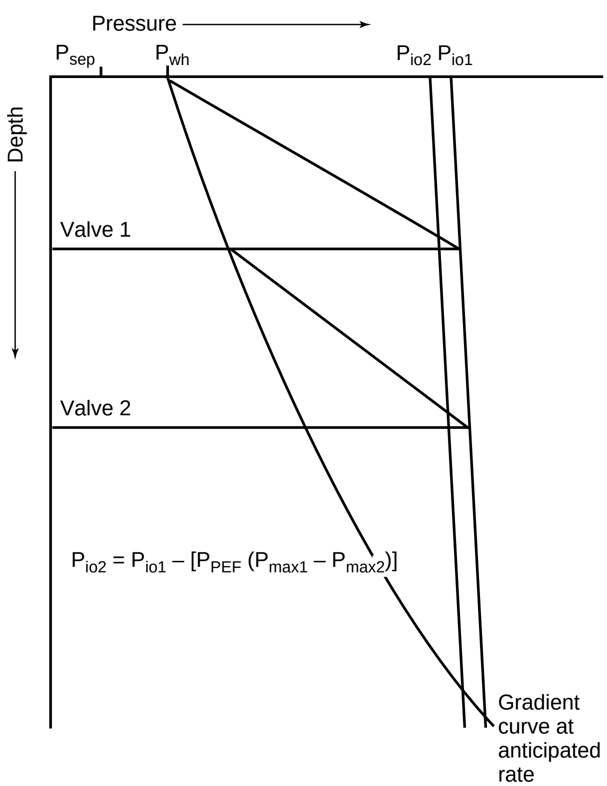


Figure 11C

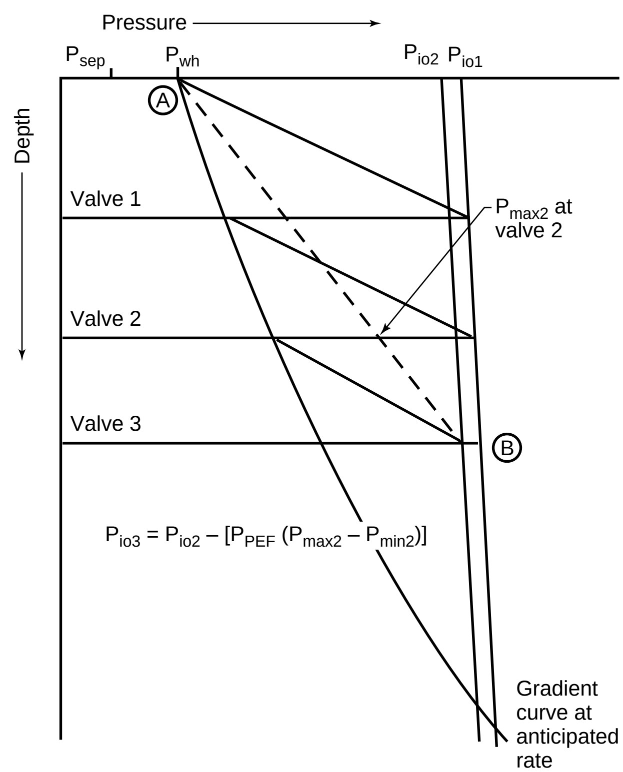


Figure 11D

5.2.7.3 Notes on Using P_{max} in Designing a Well for Multiple Flow Rates

5.2.7.3.1 At a given injection pressure, wellhead pressure, and flow rate (single flow rate), there is an assumed value of P_{max} for each valve: P_{max} is the production pressure at which that particular valve may reopen with existing injection pressure. In Figure 11E it can be seen that the reopening production pressure (P_{max}) for valves 1 through 4 is above the actual production pressure represented by the objective gradient curve. As a result, valves 1 through 4 are closed. Valve 5 is open because the production pressure defined by the objective gradient curve at valve 5 is greater than the production pressure required to open the valve (P_{max}) with the existing injection pressure (P_{io5}). In this case, valve 6 is open; however, insufficient differential pressure exists between the tubing and the casing to inject the required gas through the valve.

5.2.7.3.2 Figure 11F shows how the use of P_{max} can be helpful in designing for multiple flow rates. Note the locations of P_{max} for each valve in relation to the three flowing gradient curves shown, remembering that P_{max} at a given valve is the production pressure at which that valve will open (with a given injection pressure and an operating temperature.) If the well should flow at the high rate, operation would be from valve 2 since the production pressure at the high rate exceeds P_{max} at valve 2. The flowing production pressure at valve 1 at the high rate does not exceed the P_{max} at valve 1; so valve l is closed. Valve 3 will be open but no gas can be injected at valve 3 (at the high rate) since the production pressure exceeds the injection gas pressure. If the well should produce at the intermediate rate, operation would be from valve 4 for the same reasons as above. At the low rate, operation would be from valve 6. In the multiple flow rate design it may be necessary to move the design line by shifting point A to the right or left to achieve the desired location of P_{max} various gradient curves. Equations for the selection of points A and B are discussed in detail in 5.2.9.4.

5.2.8 Unloading Differential Safety Factors

It is considered good practice to space each gas lift valve on slightly less than the design injection gas pressure at valve depth (P_{iod}) as a safety factor to insure unloading. A pressure value of 20 psi to 50 psi is normally used (see Figure 12). The higher the value, the more safety factor is introduced into the design. This 20 psi to 50 psi differential at a given valve can be taken from the section pressure being maintained by the valve above it (in this case P_{io1}), since the upper valve will maintain this pressure until valve transfer is achieved. (Another similar approach is to take a 50 ft to 100 ft decrease in spacing.)

5.2.8.1 Unloading Gradient

5.2.8.1.1 Valves are commonly spaced based on the gradient of the kill fluid used when the equipment was installed, or the gradient of the produced water—whichever is heavier.

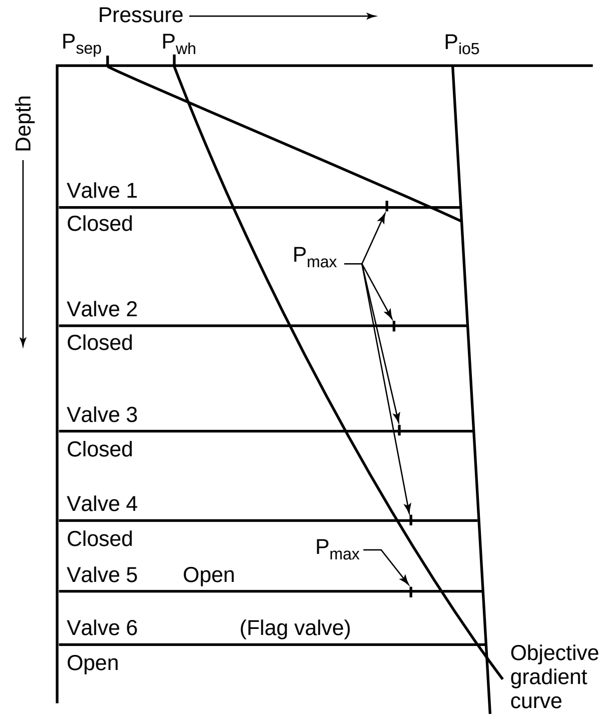


Figure 11E

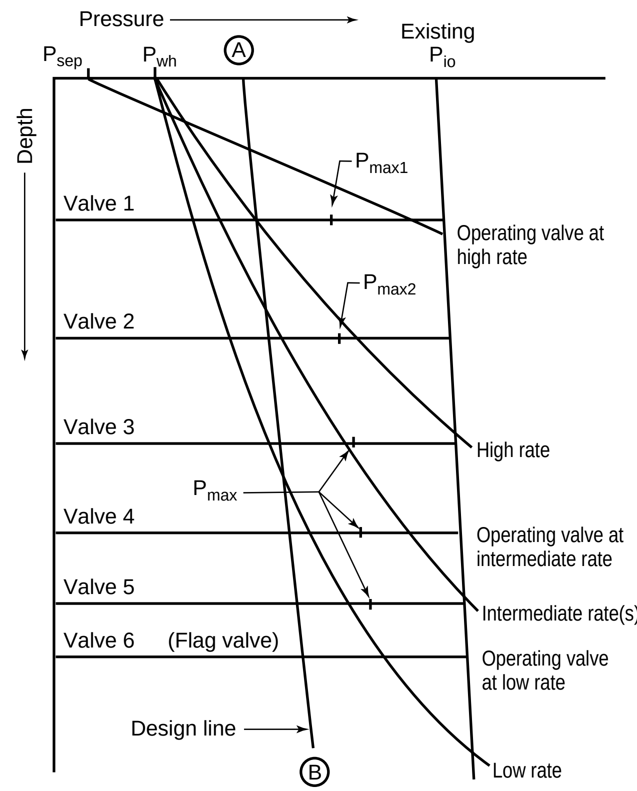


Figure 11F

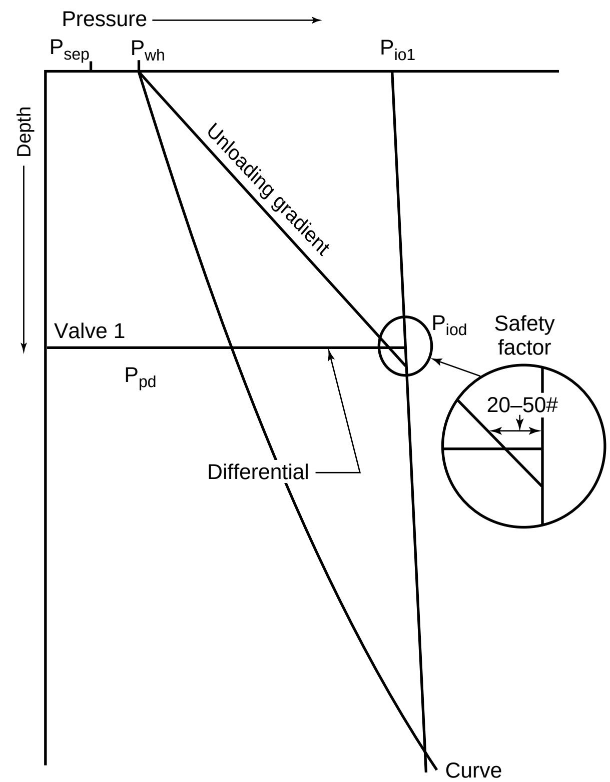


Figure 12

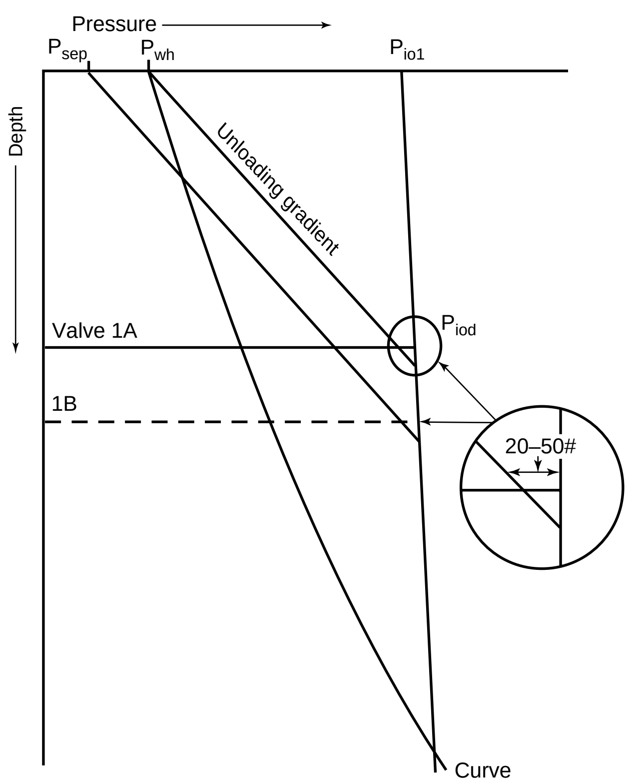


Figure 13

The purpose of this practice is to allow the well to unload with available gas lift pressure, without having to swab it in. It is not a good practice to space a design on an oil gradient even if the well is expected to produce 100% oil initially because:

a. The kill fluid used when the valves are installed is heavier than oil and must be unloaded.
b. The valves will be too widely spaced when the well begins to produce water and the fluid gradient becomes heavier than an oil gradient.

5.2.8.1.2 A gradient of 0.465 psi/ft is most commonly used on the Gulf of Mexico coast (since this is the gradient of most produced saltwater in this area). However, the gradient is higher for heavier than normal kill fluids or produced fluids. If the fluid gradient is unknown, it can be calculated as follows:

Static gradient = Weight of kill fluid in lb/gal x 0.052

5.2.8.1.3 Following workover operations, some operators circulate out the heavy kill fluid with a lighter fluid so that a wider spacing (and fewer valves) can be achieved. This practice involves some risk where conventional (tubing retrievable) valves are run, since the circulating process involves the possibility of cutting out the valve seats.

5.2.8.1.4 Regardless of the unloading fluid gradient selected, a well can be designed to unload against either the separator pressure or the anticipated flowing wellhead pressure that will be present when the well is producing (P_{wh}). Unloading against separator pressure is permitted for the first valve because the wellhead pressure will not increase significantly until gas is injected through the first valve. Some designers prefer to space against the P_{wh} as a safety factor. Figure 13 illustrates how valve 1 can be run at a greater depth when spacing against separator pressure (1B) as compared with spacing against P_{wh} (lA).

5.2.9 Multiple Flow Rate Design Procedure

5.2.9.1 Plot the separator pressure (P_{sep}), flowing wellhead pressure (P_{wh}), and operating injection gas pressure (P_{io1}), as illustrated in Figure 14A, on graph paper.

5.2.9.2 Establish the minimum and maximum flow rates between which the well is likely to produce.

5.2.9.3 Plot the flowing gradient curves for the rates within the range of rates determined above. Use the R_{g1} curve for each rate which describes the available gas volume or practical minimum gradient, whichever is less.

5.2.9.4 Construct a design line between points A and B as shown in Figure 14B. Points A and B are defined as follows:

$$\text{Point A} = (P_{io1} - P_{wh})\,(0.2) + P_{wh}$$

$$\text{Point B} = P_{iod} - 150$$

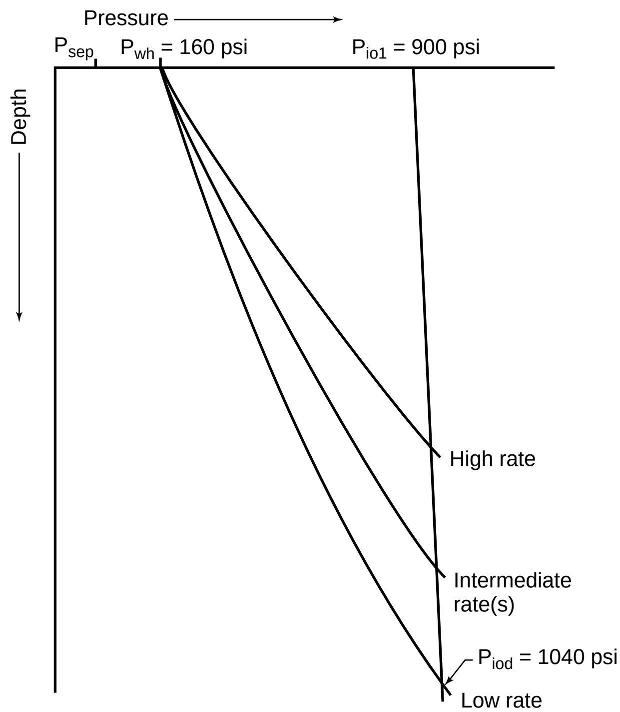


Figure 14A

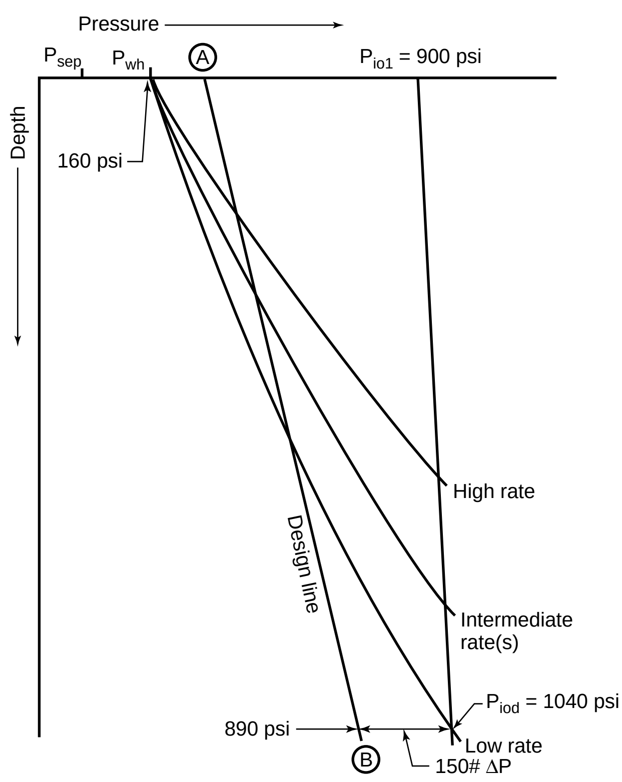


Figure 14B

Example:

$$\text{Point A} = (900 - 160)(0.2) + 160 = 308 \text{ psi (Surface)}$$

Example:

$$\text{Point B} = 1040 - 150 = 890 \text{ psi } (TD)$$

Note: If the low flow rate curve does not intersect P_{io1} at maximum valve depth (falls to the left of the P_{io1}), point B can be the value of P_{pd} defined by the low rate gradient curve provided that this value is at least 150 psi less than P_{iod1}. The design line is to be used as a general guide only. It may be necessary to shift points A and B to the right or left depending on the specific case.

5.2.9.5 Construct an unloading gradient line from the separator pressure or P_{wh} to valve 1 as shown in Figure 14C. Remember to allow for the 20 psi to 50 psi unloading differential safety factor, as discussed in 5.2.8.1. Use the gradient of the kill fluid or produced saltwater, whichever is heavier.

The gradient can be determined as follows:

$$\text{Unloading gradient} = \text{Kill fluid weight in lb/gal} \times 0.052$$

Example:

$$\text{Unloading gradient} = 8.94 \text{ ppg} \times 0.052 \text{ psi/ft/ppg} = 0.465 \text{ psi/ft}$$

5.2.9.6 In order to size the port for valve 1, the required gas passage must be calculated. The gradient curve that intersects P_{min} (design line at valve 1) will indicate the volume of gas necessary for transfer. As shown in Figure 14C, the high rate curve intersects this point. The gas passage required would be:

$$\text{Gas volume required} = R_{gl} \text{ Required} \times \text{Flow Rate}$$

Example:

$$\begin{matrix}\text{Gas}\\ \text{volume}\\ \text{required}\end{matrix} = 400\ s_{cf}/\text{bbl} \times \frac{800 \text{ BPD}}{1000} = 320 \text{ MSCF/D}$$

Generally, larger ports will be required for valves when using a multi-rate design as compared to single flow rate designs. Every valve might be a possible operating valve and must therefore be able to pass the total required gas rate. The production pressure effect factor (P_{PEF}) for the calculated port size will be used to determine the required injection pressure drop. The port sizes for subsequent valves are determined by the same procedure.

5.2.9.7 Space to valve 2, starting from the intersection of the design line and the valve 1 line (P_{min}). Allow for the 20 to 50 psi unloading differential safety factor as before. It is acceptable to space to valve 2 using the P_{io1} injection pressure line because valve 1 will maintain this injection pressure (P_{io1}) until valve 2 is uncovered in the loading sequence.

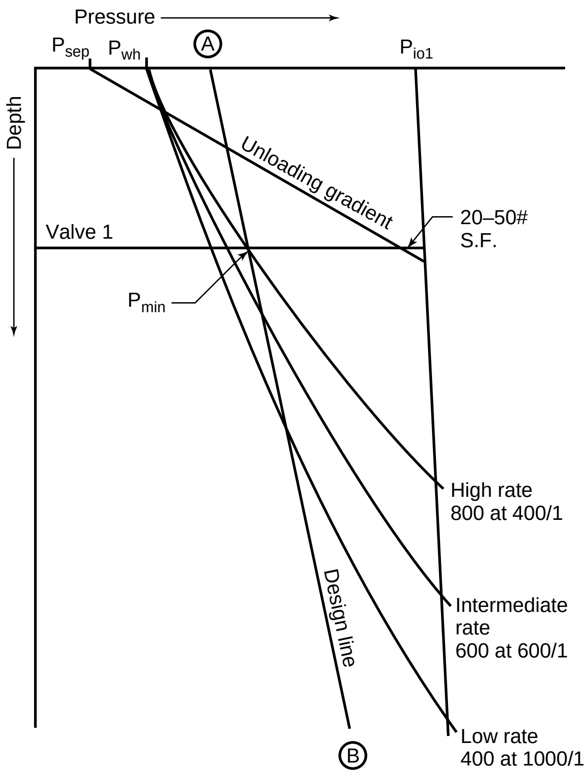


Figure 14C

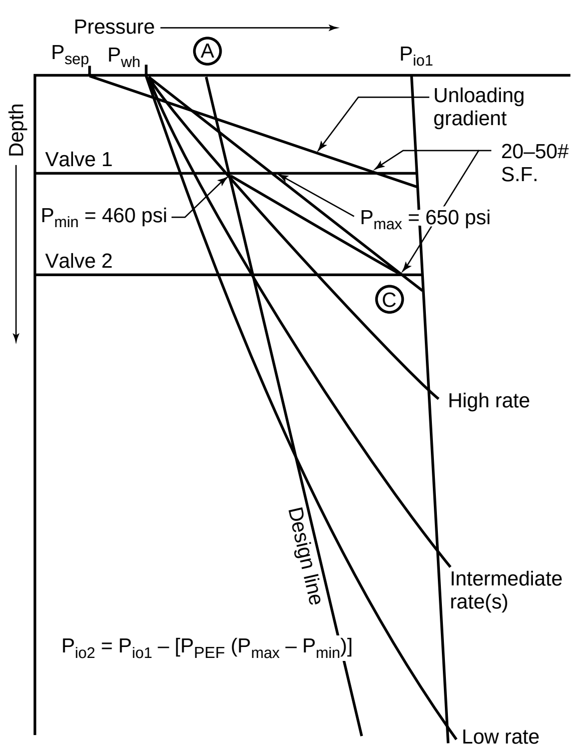


Figure 14D

5.2.9.8 Next, determine the injection pressure drop required to prevent valve 1 from reopening. To do this P_{max} at valve 1 is determined. P_{max} is the intersection of the valve 1 line and a straight line extended between point C and the P_{wh} as shown in Figure 14D. Note that P_{max} is greater than the flowing production pressure at the high rate, indicating that valve 1 will remain closed after the initial unloading, and at any production rate less than the anticipated high rate.

5.2.9.9 The required injection pressure drop is calculated by the equation: (assume a 1-in. valve with a $^3/_{16}$-in. port) P_{PEF} = 0.101.

$$PD = (P_{max} - P_{min}) \times P_{PEF} + \text{Safety Factor}$$

Example:

$$PD_1 = (650 - 460)\ (0.101) + 10 = 29 \text{ psi}$$

Note: Where low injection pressure or wide mandrel spacings are encountered it may be necessary to reduce or eliminate the safety factor as discussed in previous sections.

5.2.9.10 Plot the new injection pressure at which valve 2 will operate (P_{io2}):

$$P_{io2} = P_{io1} - PD_1$$

Example:

$$P_{io2} = 900 - 29 = 871 \text{ psi}$$

5.2.9.11 Space to valve 3, starting from P_{min} at valve 2 (intersection of valve 2 and design line), allowing an unloading differential safety factor as before. Spacing to valve 3 using P_{io2} is valid since valve 2 will maintain P_{io2} until valve 3 is uncovered (see Figure 14E).

5.2.9.12 Next, determine the injection pressure drop required to prevent valve 2 from reopening. To locate P_{max} at valve 2 extend a line between point D and the P_{wh} as before. P_{max} for valve 2 will be at the intersection of this line and the valve 2 line. Note that P_{max} is still greater than the flowing pressure at the high rate. As a result, valve 2 will also remain closed at any rate less than the high rate, after the initial unloading has occurred.

5.2.9.13 The required injection pressure drop is calculated using the same equation used in step 9.9.

$$PD_2 = (P_{max} - P_{min})\ (P_{PEF}) + \text{Safety Factor}$$

Using the data from Example 2A:

$$PD_2 = (740 - 545) \times (0.101) + 10 = 30 \text{ psi}$$

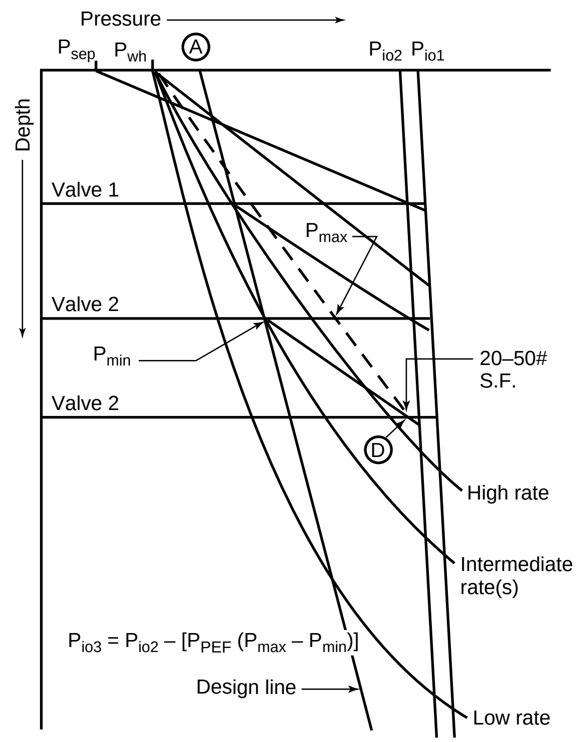


Figure 14E

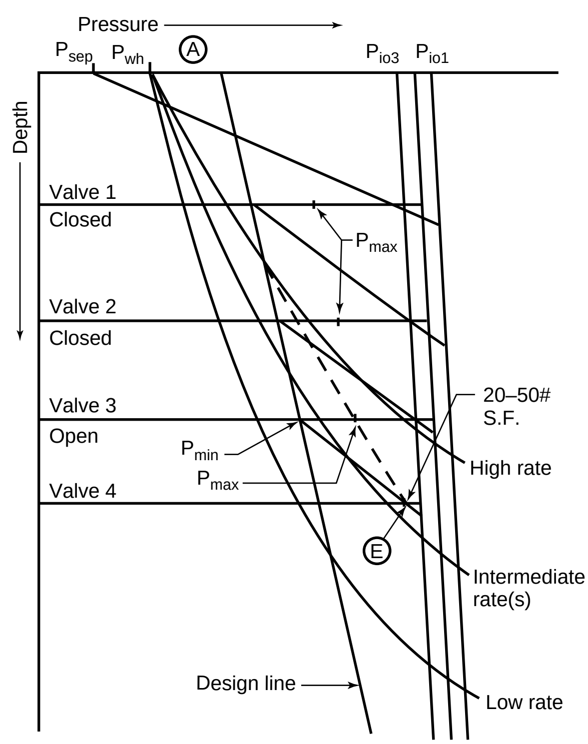


Figure 14F

5.2.9.14 Plot the new injection pressure at which valve 3 will operate (P_{io3}) as shown in Figure 14F.

$$P_{io3} = P_{io2} – PD_2$$

$$P_{io3} = 871 – 30 = 841 \text{ psi}$$

5.2.9.15 Space to valve 4 starting from P_{min} at valve 3 as before. Allow for the 20–50 psi unloading differential safety factor.

5.2.9.16 Determine the location of P_{max} at valve 3 by extending a line from point E to the P_{wh}. As seen in Figure 14F, P_{max} at valve 3 will be the intersection of this line and the valve 3 line. Note that P_{max} at valve 3 is less than the production pressure described by the high rate curve at valve 3. This means that valve 3 will be open at the high rate. Valves 1 and 2 will be closed since the previously assigned values of P_{max} at these valve depths are greater than the production pressure that will exist at the respective depths when the well is producing at the high rate. Gas cannot be injected at valve 4 at the high rate since the production pressure existing at this depth is greater than the injection pressure (at the high flow rate). Calculate the new injection pressure at which valve 4 will operate. The surface operating injection pressure for valve 4 is calculated by:

$$P_{io4} = P_{io3} – (P_{max} – P_{min}) (P_{PEF}) + SF$$

or

$$P_{io4} = P_{io3} – PD_3$$

Note: Remember that it may be necessary to shift point A to the right or left on a trial and error basis to achieve the desired values of P_{max} that will insure single point injection at the target flow rates.

5.2.9.17 Plot the new injection pressure at which valve 4 will operate as shown in Figure 14G.

5.2.9.18 Space to valve 5 starting from P_{min} at valve 4. Allow for the 20–50 psi unloading differential safety factor. Use the same technique to determine P_{max} at valve 4 (a line between point F and P_{wh}. See Figure 14G). Determine the required injection pressure drop using P_{max} and P_{min} as previously discussed.

Plot the new injection pressure line for valve 5, and continue spacing additional valves, using the same techniques, until a differential of 100 psi exists between the low rate gradient curve and the injection pressure line of the last valve (see Figure 14H). There is no need to valve deeper than this since insufficient pressure differential will exist between the tubing and casing to inject gas. Valving deeper may be required if loss of static reservoir pressure or decrease in P_I are anticipated over the life of the well. It is a good design practice to add one or two valves/mandrels for future use. Note how the locations of P_{max} allow for single point injection at each of the three target rates.

5.2.9.19 Plot the depth of the perforations on the design graph.

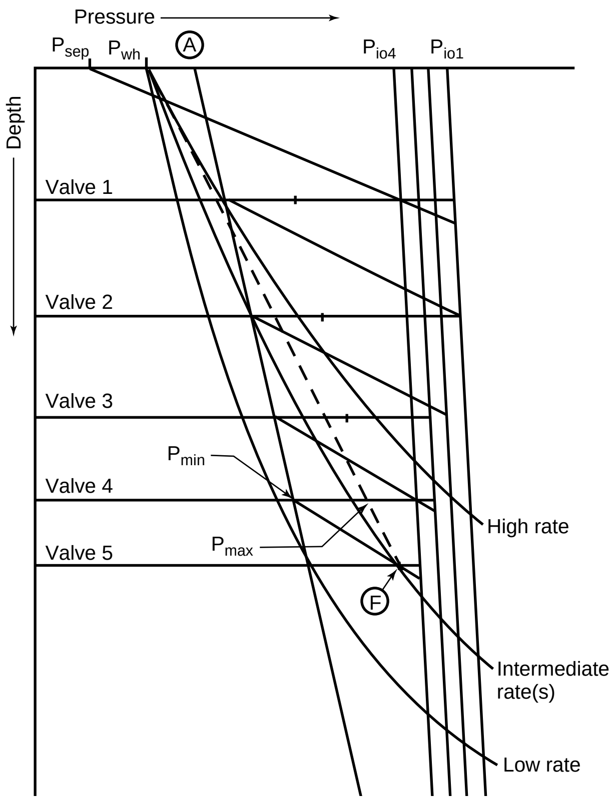


Figure 14G

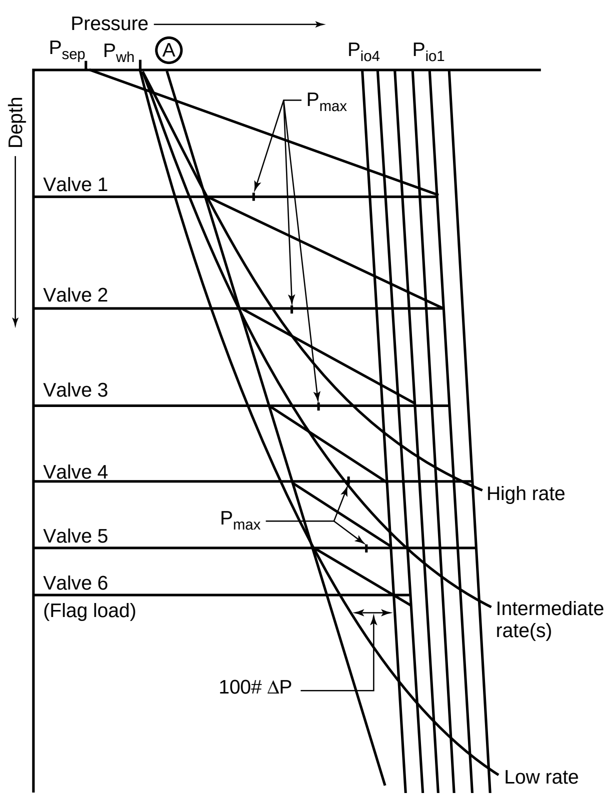


Figure 14H

5.2.9.20 Plot the surface flowing temperature (T_{wh}) and the static bottom hole temperature (T_f). Connect these two points to derive a flowing temperature at each valve depth $T_{v(1)}$ to $T_{v(6)}$ (see Figure 14I).

5.2.9.21 In order to determine the valve test rack opening pressures at a reference temperature of 60°F, it will be necessary to use the temperature conversion factors for nitrogen charged domes (C_T).

Valve set pressures will be based on production pressure loads from the design line (P_{min1} to P_{min6}), and injection pressures from each valve depth (P_{iod1} to P_{iod6}) as follows:

$$P_{vo} = TRO \text{ at } 60°\text{F} = [(P_{min}) \times (P_{PEF}) + P_{iod}]\, C_T$$

5.2.9.22 The bottom valve may be flagged by assigning a low value for the production pressure load rather than using P_{min} from the design line. This assigned production load should be lower than the anticipated production pressure as defined by the vertical flowing gradient curve of the lowest rate at which the well is likely to produce. For a detailed discussion of selecting the flag load, see 4.11. The important thing is that the bottom valve open at a significantly lower pressure than the other valves to give a positive surface indication of operating from the bottom valve. An orifice can be used on bottom to serve the same purpose.

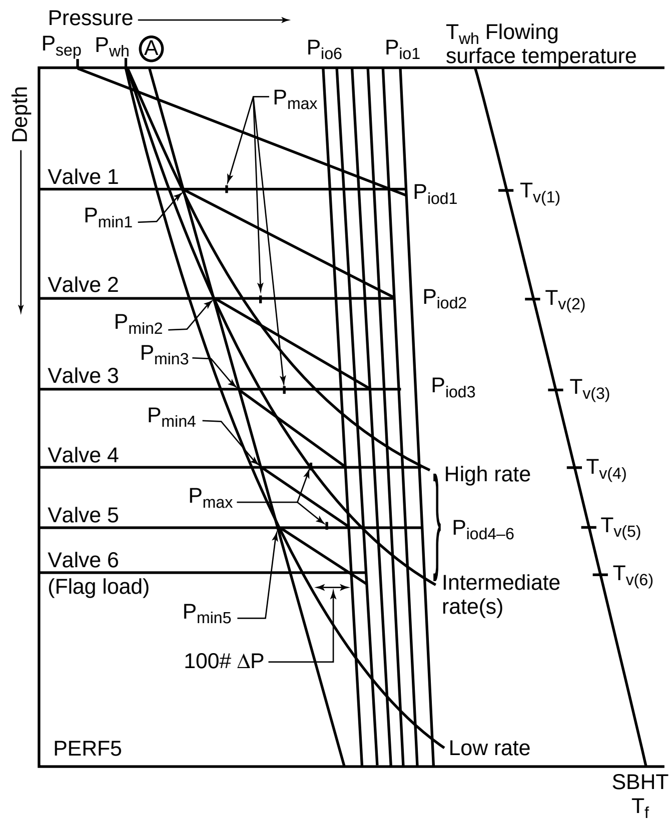


Figure 14I

5.2.10 Details for Example Problem 2—Minimum Injection Pressure Drops

5.2.10.1 The given data for this design is listed on the Gas Lift Well Data Sheet (Figure 15). No production data were available for this well, so the design must accommodate a range of flow rates. For this example, the range of rates is from 400 bbl/day to 800 bbl/day.

5.2.10.2 Things to remember prior to designing include the following:

a. There is a limit of 400 MSCF/D injection gas, so don't use more than this amount. Less injection gas can be used when near-minimum gradient conditions are met.
b. The maximum design valve depth will be based on having a 100 psi differential between the tubing and casing (at the low flow rate) so that gas can be injected.
c. Injection pressure operated valves are used. The P_{PEF} values for the valves used are given on the well data sheet.

5.2.10.3 Significant points concerning the design include the following:

a. The flowing surface temperature was based on the average flow rate (600 bbl/d) since the range between the anticipated high and low rate is small. See 4.1 for a detailed discussion of temperature considerations.
b. Using the minimum required injection drop, the well was valved to 5425 ft, resulting in a loss of 103 psi operating pressure, and requiring 7 valves.

5.2.11 Details in Example Problem 2A—Additional Safety Factor in Calculating Injection Pressure Drops

5.2.11.1 The given data is identical to the previously worked Example 2. The only difference is that additional safety factor will be taken as discussed below.

5.2.11.2 Things to remember prior to designing are the following:

a. The design line is the same as Example 2.
b. An additional safety factor will be used to calculate the required injection pressure drops.
c. The initial spacing of valves 1 and 2 will be the same as the previous example since the same P_{io1}, is used and the fact that valve 1 will maintain P_{io1} until valve 2 is uncovered. Subsequent valve spacings will change since the injection pressure drops taken between valves is greater.

5.2.11.3 Significant points concerning the design are as follows:

a. While additional insurance against valve interference is gained by allowing greater injection pressure drops, there is also a greater loss of operating injection pressure. In this example, 131 psi of operating pressure was lost compared to 103 psi in the previous example.
b. Example 2 resulted in one less gas lift valve since the 100 psi minimum required differential for gas injection (at the low rate) was reached much sooner due to the additional loss of operating pressure. The additional safety factor also resulted in not being able to lift as deep as in design Example 2. Example 2A, using the greater safety factors, valved the well to only 4850 ft, compared to 5425 ft in Example 2.

5.3 EXAMPLE PROBLEM NO. 3—DESIGN OF A TYPICAL OFFSHORE WELL WITH GOOD PRODUCTION DATA AND THE MANDRELS ALREADY SPACED

5.3.1 General

A typical gas lift problem is one when an adequate design must be made where the mandrels have previously been spaced and installed. This problem often occurs for completed flowing wells that will no longer flow at sufficient rates or not at all and for existing gas lift wells that are not producing at near maximum rates. The following is a case for a directional well where the mandrels have been run but are not ideally spaced.

5.3.2 Well Data

5.3.2.1 The well was completed using 2-in. nominal side pocket mandrels with dummies installed in the receiving pockets. A schematic plot of the well as shown in Figure 19 should be made.

Note: The well is directional; being straight to 1,500 ft and then having a 41° angle from 2450 ft (D_m) to total depth. All measurements were corrected from measured depths (D_m) to true vertical depths (D_{tv}), with both mandrel depths being noted on the schematic. In most cases, the gas lift design should be based on true vertical depths rather than measured depth in determining flowing pressures since the head components are usually much greater than the friction components.

5.3.2.2 The well flowed for some period, but the water increased from 0% to about 50%; and the well now tends to load up and die. The water cut is expected to continue to increase over time to cuts in excess of 90%. The productivity index (PI = J) is expected to change only slightly with increasing water cuts. (There may be some relative permeability and viscosity changes.) In the near future, the well's current producing conditions are not expected to change significantly. The Gas Lift Well Data Sheet with the well information, shown in Figure 20, was filled out.

5.3.3 Bubble Point

In this small field, no produced oil PVT samples were taken. To determine rates in typical wells, the bubble point (P_b) is often needed in order to predict production rates

Company Example 2 - Multi Rate Limited Information Address Minimum Pressure Drop maximize use of available injection gas pressure

A. Well Completion Data

* 1. Field name: Anyfield

* 2. Lease name and well no.: #1

3. Producing formation: — Lithology: —

* 4. Casing: 7" in. OD; 26# #/ft; — Grade; — ft

5. Liner: — in. OD; — #/ft; — Grade; — ft

6. Open hole: (yes/no) NO Gravel pack (yes/no) NO

* 7. Well reference depth (D_{tv}/D_m): Straight hole / ft

* 8. Perf. Interval (D_{tv}/D_m) 7100 - 15 (Straight hole) ft

9. Packer: Model D (D_{tv}/D_m) 7050 / 7050 ft

* 10. TBG LGT 7050 ft; OD 2 3/8 in.; WT. 4.7 lb/ft; Grade N-80 THD 8R

11. SSSV: (type) None; Depth — ft; Bore — in.

12. Wellhead bore (ID): 2" in.; WP — psi

13. Choke: (type) none; Size max. ID — / 64 in.

14. Flowline: size ID 2.441 in. Length: 1500 ft

15. Well profile: (D_{tv}/D_m or deg) Straight hole

B. Reservoir, Test and Production Data

* 16. Test date: None; (q_o) — BOPD: (q_w) — BWPD (q_g) = — MCFD

* 17. Water cut (f_w): —; Formation GOR (R): — (R_{gl}): —

* 18. Flowing WHP (P_{wh}) — psig; Separator pressure (P_{sep}) 80 psig

* 19. Static BHP (P_{ws}): unknown psig @ — ft

20. Static fluid level none ft & P_{wh} — psig & g_w — psi/ft

* 21. Flow BHP (P_{wf}): none psig @ ft @ q_l — BLPD

* 22. Oil gravity — deg API; Water SG (SG_w) —

* 23. Formation gas SG (SG_g): .65; BH temp (T_f) 173 °F @ 7100 ft

* 24. Static surf. temp (T_s): 74 °F; Flow surf. temp (T_{wh}): — °F

* 25. Bubble point (P_b): — psig; P_I (J): Unknown BPD/psi; Flow eff —

26. Sand (yes/no) no; Paraffin (yes/no) no; Scale (yes/no) no

27. H_2S (yes/no) no; CO_2 (yes/no) unknown; Emulsion (yes/no) no

28. Other unusual lift problems

C. Design Information

* 29. Tubing/Annulus flow Tubing Space/set/run WL valves Space + set

* 30. Production rate (q_1): min 400 max 800 design multi rate BPD

* 31. Max water cut 100%; Max lift depth 7050 ft; Min BHP unknown psig

* 32. Well inj. pres (P_g): 900 psig: Operating pressure (P_{io}) 900 psig

33. Compressor discharge pressure 960 psig; P_{ko} 900 psig

* 34. Inj. gas temp (T_{gs}) 74°F °F Inj gas SG (SG_i) .65

* 35. Inj. gas volume: max/unloading/design 400 MCF R_{gli}/MCFD

* 36. Load fluid grad (g_s): .465 psi/ft; Lower grad (g_{fb}) — psi/ft

* 37. Min spacing of valves none ft; Min pressure drop (PD) none psi

* 38. Design flow press (P_{wh}) 160 psig; Design flow temp (T_{wh}) °F

39. Gas lift mandrel: Retrievable, nonorienting, 1-inch valve

* 40. Gas lift valve (mfg & type): 1-inch Retrievable (generic for design example

41. Gas lift valve description injection pressure operated

42. Other Valve type Port PPEF A_p/A_b Bellows Area

Remarks: injection pres. valve } 3/16 .101 .9080 .30

1/4 .196 .8364 .30

By: Date:

*Indicates data that must be supplied for good design.

Figure 15—Data Sheet Example 2

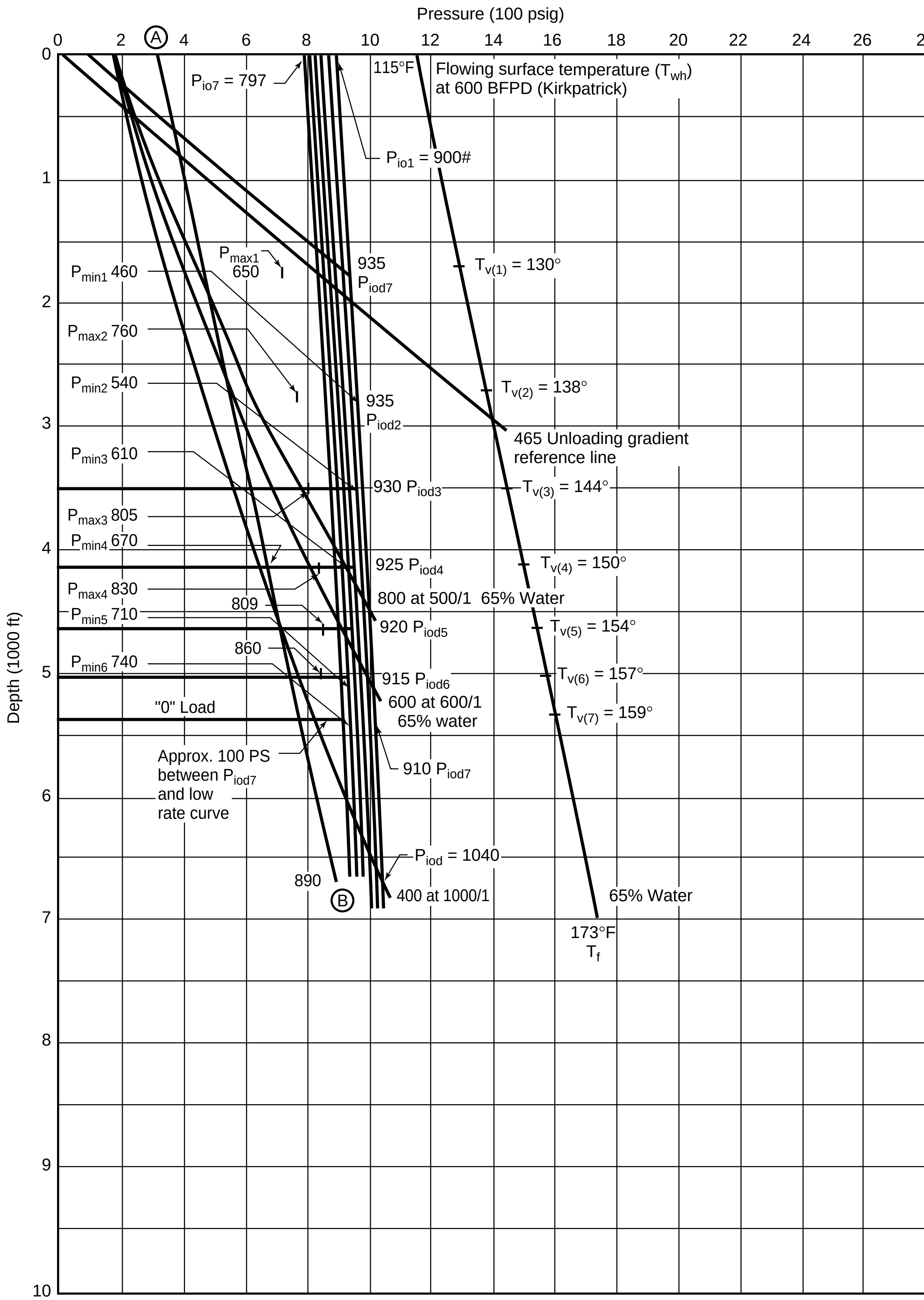


Figure 16—Example Problem 2

Company Example 2A - Multi Rate Limited Information Address Additional Safety Factor In Calculating Injection Pressure Drops

A. Well Completion Data

* 1. Field name: Anyfield

* 2. Lease name and well no.: Smith #1

3. Producing formation: ______ Lithology: ______

* 4. Casing: 7 in. OD; 26 #/ft; — Grade; — ft

5. Liner: — in. OD; — #/ft; — Grade; — ft

6. Open hole: (yes/no) No Gravel pack (yes/no) No

* 7. Well reference depth (D_{tv}/D_m): Straight Hole / ______ ft

* 8. Perf. Interval (D_{tv}/D_m) 7100 - 15 ft

9. Packer: Baker D (D_{tv}/D_m) 7050 / 7050 ft

* 10. TBG LGT 7050 ft; OD 2 3/8 in.; WT. 4.7 lb/ft; Grade N-80 THD 8R

11. SSSV: (type) none; Depth — ft; Bore — in.

12. Wellhead bore (ID): 2" in.; WP ______ psi

13. Choke: (type) none; Size max. ID — / 64 in.

14. Flowline: size ID 2.441 in. Length: 1500 ft

15. Well profile: (D_{tv}/D_m or deg) Straight Hole

B. Reservoir, Test and Production Data

* 16. Test date: None; (q_o) — BOPD: (q_w) — BWPD (q_g) = — MCFD

* 17. Water cut (f_w): —; Formation GOR (R): —; (R_{gl}): —

* 18. Flowing WHP (P_{wh}) — psig; Separator pressure (P_{sep}) 80 psig

* 19. Static BHP (P_{ws}): Unknown psig @ — ft

20. Static fluid level None ft & P_{wh} — psig & g_w — psi/ft

* 21. Flow BHP (P_{wf}): none psig @ — ft @ q_l — BLPD

* 22. Oil gravity — deg API; Water SG (SG_w) —

* 23. Formation gas SG (SG_g): .65; BH temp (T_f) 173 °F @ 7100 ft

* 24. Static surf. temp (T_s): 74 Flow surf. temp (T_{wh}): — °F

* 25. Bubble point (P_b): — psig; P_I (J): unknown BPD/psi; Flow eff —

26. Sand (yes/no) no; Paraffin (yes/no) no; Scale (yes/no) no

27. H_2S (yes/no) no; CO_2 (yes/no) unknown; Emulsion (yes/no) no

28. Other unusual lift problems ______

C. Design Information

* 29. Tubing/Annulus flow Tubing Space/set/run WL valves Space + set

* 30. Production rate (q_1): min 400 max 800 design Multi Rate BPD

* 31. Max water cut 100%; Max lift depth 7050 ft; Min BHP Unknown psig

* 32. Well inj. pres (P_g): 900 psig: Operating pressure (P_{io}) 900 psig

33. Compressor discharge pressure 960 psig; P_{ko} 900 psig

* 34. Inj. gas temp (T_{gs}) 74 °F Inj gas SG (SG_i) .65

* 35. Inj. gas volume: max/unloading/design 400 MCF R_{gli}/MCFD

* 36. Load fluid grad (g_s): .465 psi/ft; Lower grad (g_{fb}) — psi/ft

* 37. Min spacing of valves none ft; Min pressure drop (PD) none psi

* 38. Design flow press (P_{wh}) 160 psig; Design flow temp (T_{wh}) 115 °F

39. Gas lift mandrel: Retrievable, non-orienting, 1-inch valves

* 40. Gas lift valve (mfg & type): 1-inch Retrievable (generic for design example)

41. Gas lift valve description Injection pressure operated

42. Other Valve Type Port PPEF 1-Ap/Ab Bellows Area

Remarks: Generic Inj. 3/16 .101 .9080 .30
pres. valve 1/4 .196 .8364 .30

By: Mike Schrantz Date: 3-1-98

*Indicates data that must be supplied for good design.

Figure 17—Data Sheet Example 2A

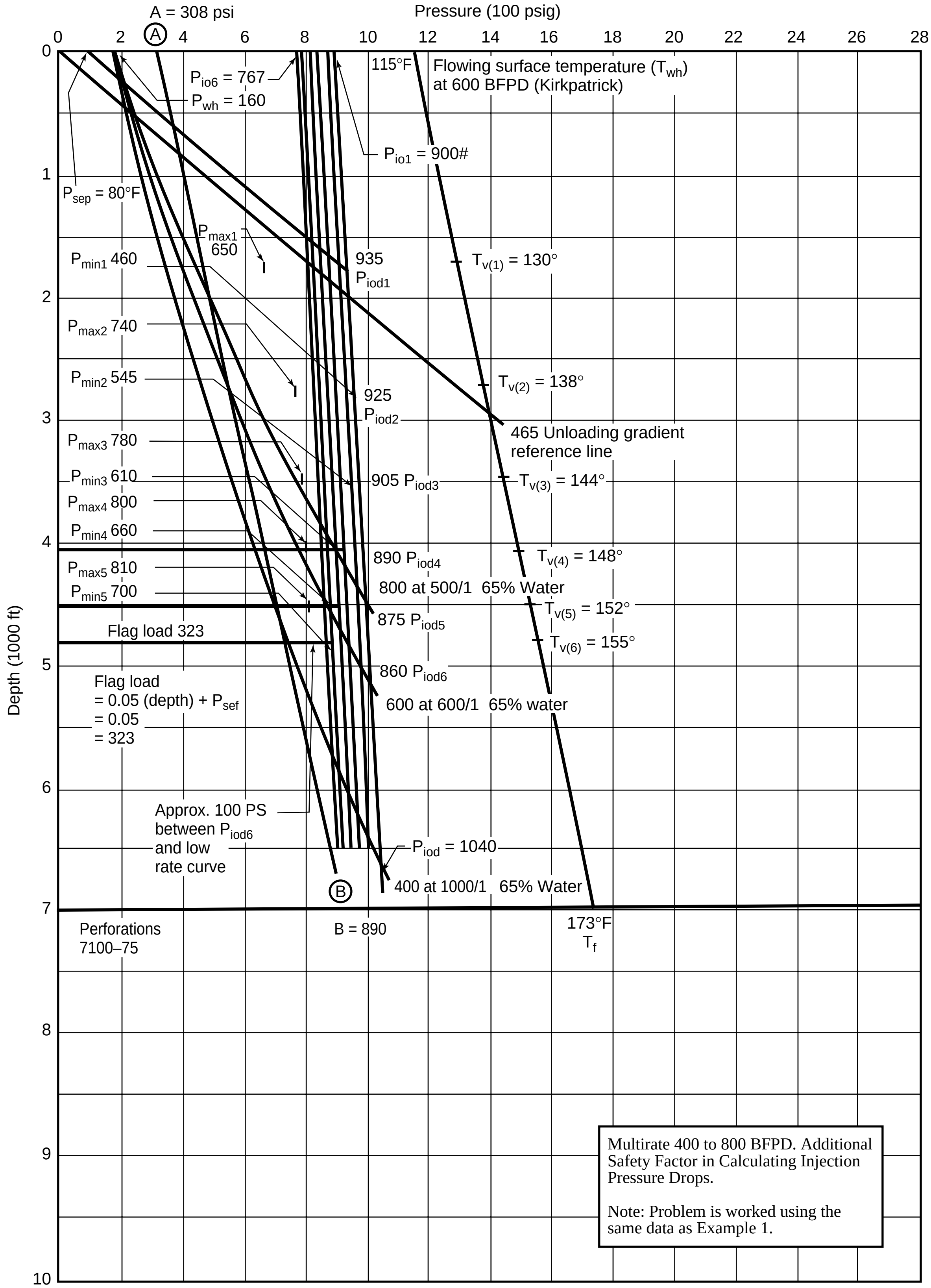


Figure 18—Example Problem 2A

(below the bubble point) more accurately. The bubble point can be easily found using Standing's nomograph.

Find: P = 1515 psia or 1500 psig.

5.3.4 Well Inflow

5.3.4.1 An Inflow Performance Graph (IPR) needs to be developed for the well. A straight line productivity index (J) was assumed above the bubble point. For flow below the bubble point, a Vogel IPR approach will be used; however, other approaches such as Fetkovitch, can be used. To use the Vogel IPR equation, a good well production test and a flowing bottom hole pressure are needed. No flowing surveys were available. A good stable test was made and available gradient curves[3] were used to predict the flowing bottom hole pressure.

[3]Use available gradient curves that give reasonable answers for the actual field of interest. In this example, the Hagedorn and Brown correlation was used.

5.3.4.2 Calculate flowing bottom hole pressure:

Well Test: Oil Rate: 99 BOPD
Water Rate: 101 BWPD
Gas Rate: 40 MCFD
Flowing Wellhead Pressure: 120 psig
Oil API Gravity: 35
Water Specific Gravity: 1.07
Flowing Surface Temperature: 100°F

Find: R_{gl} =

$$\frac{\text{Gas rate}}{\text{Total fluid rate}} = \frac{40\text{ MCFD} \times 1000}{99 + 101} = 200\frac{\text{ft}^3}{\text{Bbl}}$$

5.3.4.3 Select the Vertical Flowing Pressure Gradient Curve that most closely matches well flowing conditions.[3] Of primary importance is the selection of the correct tubing size and the nearest oil to water ratio. Next, select a close match of

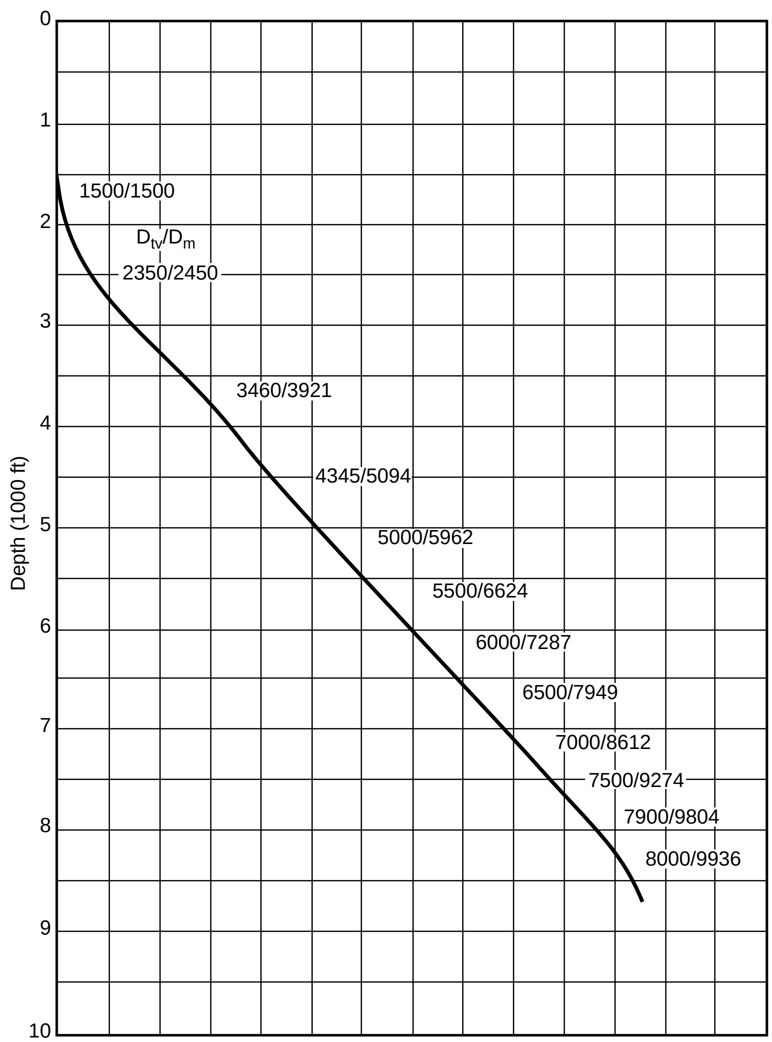


Figure 19—Example Problem 3

Company API Address

A. Well Completion Data
- * 1. Field name: Example - Fixed Mandrel
- * 2 Lease name and well no.: 3
- 3. Producing formation: a a Lithology: Sandstone
- * 4. Casing: 7 in. OD; 23 + 26 #/ft; K + N Grade; 10,200 ft
- 5. Liner: — in. OD; #/ft; Grade; ft
- 6. Open hole: (yes/no) Gravel pack (yes/no)
- * 7. Well reference depth (D_{tv}/D_m): 8000 / 9936 ft
- * 8. Perf. Interval (D_{tv}/D_m) 8000 to 8050 ft
- 9. Packer: Permanent (D_{tv}/D_m) 7975 / ft
- * 10. TBG LGT 9900 ft: OD 2 3/8 in: WT. 4.7 lb/ft: Grade J + N THD EUE
- 11. SSSV: (type) Surface Controlled; Depth 2000 ft; Bore 1.875 in.
- 12. Wellhead misc: —; (Bore ID) 2 1/16 in.; WP 3000 psi
- 13. Choke: (type) Adjustable; Size max. ID 32 / 64 in.
- 14. Flowline: size ID 3 in. Length: 100 ft
- 15. Well profile: (D_{tv}/D_m or deg) 0/0; 2350/2450; 5000/5962; 8000/9936

B. Reservoir, Test and Production Data
- * 16. Test date: 2-4-98; (q_o) 99 BOPD: (q_w) 101 BWPD (q_g) = 40 MCFD
- * 17. Water cut (f_w): 50%; Formation GOR (R): 400 (R_{gl}): 200
- * 18. Flowing WHP (P_{wh}) 120 psig; Separator pressure (P_{sep}) 50 psig
- * 19. Static BHP (P_{ws}): 3350 psig @ 8000 DTU ft
- 20. Static fluid level 745 ft & P_{wh} 0 psig & g_w .465 psi/ft
- * 21. Flow BHP (P_{wf}): 2550 psig @ 8000 ft @ q_l 200 BLPD
- * 22. Oil gravity 35 deg API; Water SG (SG_w) 1.074
- * 23. Formation gas SG (SG_g): .85; BH temp (T_f) 180 °F @ 8000 ft
- * 24. Static surf. temp (T_s): 74° Flow surf. temp (T_{wh}): 100 °F *
- * 25. Bubble point (P_b): 1500 psig P_I (J): .25 BPD/psi Flow eff
- 26. Sand (yes/no) .01%; Paraffin (yes/no) Minor; Scale (yes/no)
- 27. H_2S (yes/no); CO_2 (yes/no); Emulsion (yes/no)
- 28. Other unusual lift problems Directional Well

*@ 500 BPD

C. Design Information
- * 29. Tubing/Annulus flow Space/set/run WL valves
- * 30. Production rate (q_1): min 200 max 500 design 500 BPD
- * 31. Max water cut 50-90%; Max lift depth 8000 ft; Min BHP 3300 psig
- * 32. Well inj. pres (P_g): 1200 psig; Operating pressure (P_{io}) 1100 psig
- 33. Compressor discharge pressure 1250 psig; P_{ko} 1200 + psig
- * 34. Inj. gas temp (T_{gs}) 74 °F Inj gas SG (SG_i)
- * 35. Inj. gas volume: max/unloading/design 600 / 500 R_{gli}/MCFD
- * 36. Load fluid grad (g_s): .465 psi/ft; Lower grad (g_{fb}) .42 psi/ft
- * 37. Min spacing of valves 500 ft; Min pressure drop (PD) 20 psi
- * 38. Design flow press (P_{wh}) 120 psig; Design flow temp (T_{wh}) 100 °F
- 39. Gas lift mandrel: 20" Wireline Side Pocket
- * 40. Gas lift valve (mfg & type): Injection Pressure - Bellows
- 41. Gas lift valve description One inch w/ 3/16" port
- 42. Other

Remarks:

By: Joe Shell Date: Feb. 98

*Indicates data that must be supplied for good design.

Figure 20—Data Sheet Example 3

the producing rate. In some cases it may be necessary to interpolate between two graphs. A close match of the oil API gravity and water specific gravity are not critical; however, a small correction factor may be needed for large discrepancies, i.e., a 10° API gravity change. The Vertical Flowing Pressure Gradients are not very sensitive to gas specific gravity or to the average flowing temperature; thus, a close match is not essential.

5.3.4.4 The Vertical Flowing Pressure Gradient Curve selected is shown in Figure 21. Enter the graph at the flowing wellhead pressure of 120 psig and proceed to the intersection of the appropriate GLR of 200. Find the depth correction of about 1400 ft. This point matches the surface flowing pressure of the production test. Since the well is 8000 ft true vertical depth, find the corrected total depth to be (8000 + 1400) 9400 ft.

5.3.4.5 Proceed to the point of 9400 ft and the 200 GLR line. Read the flowing pressure to be about 2550 psig.

5.3.4.6 The stabilized static fluid level (*SFL*) when the well was filled with 0.465 psi/ft salt water was found to be at about 795 ft from the surface when the wellhead pressure (P_{wh}) was zero. Thus, the static bottom hole pressure (P_{ws}) was calculated to be 3350 psig.

$$P_{ws} = 0.465\ (\text{Depth} - SFL) + P_{wh}$$

$$P_{ws} = [0.465\ (8000 - 795)] + 0 = 3350 \text{ psig}$$

The IPR graph was constructed. The following data were used:

P_{ws}:	Static Reservoir Pressure	= 3350 psig
P_b:	Bubble Point	= 1500 psig
P_{wf}:	Flowing Bottom Hole Pressure	= 2550 psig
q_1:	Production (Liquid) Rate	= 200 BPD

5.3.4.7 For above the Bubble Point (≥ 1500 psig):

$$J = \text{Change in Rate/Change in Pressure} = q_1/(P_{ws} - P_{wf})$$

$$J = 200/(3350 - 2550) = 0.25 \text{ BPD/psi}$$

Note:

J = Productivity Index, commonly referred to as "*PI*"

and:

$$q_1 = J \times (P_{ws} - P_{wf}) = 0.25 \times \Delta P$$

$$q_{pb} = J\ (P_{ws} - P_b) = 0.25 \times (3350 - 1500) = 462.5 \text{ BPD}$$

5.3.4.8 For below the Bubble Point: (P_{wf} < 1500 psig):

$$q_a = P_b \times JI/1.8 = 208 \text{ BPD}$$

$$q_{max} = 208 + 462.5 = 670.5 \text{ BPD}$$

$$q_1 = \text{Production below } P_b + \text{Production above}$$

$$q_1 = Q_a\ [1.0 - 0.2\ (P_{wf}/P_b) - 0.8\ (P_{wf}/P_b)^2] + q_{pb}$$

5.3.4.9 Example: For P_{wf} = 1200

$$q_l = 208 \times [1 - 0.2(1200/1500) - 0.8(1200/1500)^2] + 462.5$$

$$q_l = 530 \text{ BPD}$$

the following table was calculated:

Rate (q_1) (BPD)	Pressure (P_{wf}) (BPD)
0.0	3350
200.0	2550
300.0	2150
400.0	1750
462.5	1500
500.0	1340
530.0	1200
585.0	900
600.0	803
627.0	600
642.0	450
655.0	300
664.0	150
670.5	0

A graph of the results is shown in Figure 22.

5.3.5 Injection Pressure

5.3.5.1 Gas lift injection pressure at the well varies from 1250 psig to 1150 psig, but typically averages about 1200 psig over 90% of the time. Since injection pressure operated valves are planned, actual operating pressure at the surface will be on the order of 1100 psig. The 1200 psig will be needed only during the unloading operation—which will be infrequent. It is assumed that 1200 psig will normally be available for kick off; and the practice of taking a 50 psi pressure drop safety factor in injection gas pressure at the well is not warranted in this case. Some designers prefer to be more conservative and use the minimum injection pressure for design purposes since time periods exist where the available 1200 psi kickoff pressure may not be available. The injection gas gravity was measured and found to be about 0.7.

5.3.5.2 The injection gas pressure at depth and the injection gas gradient need to be determined. Use can be made of charts for different gas gravities at assumed average temperature conditions or calculated for various injection pressures.

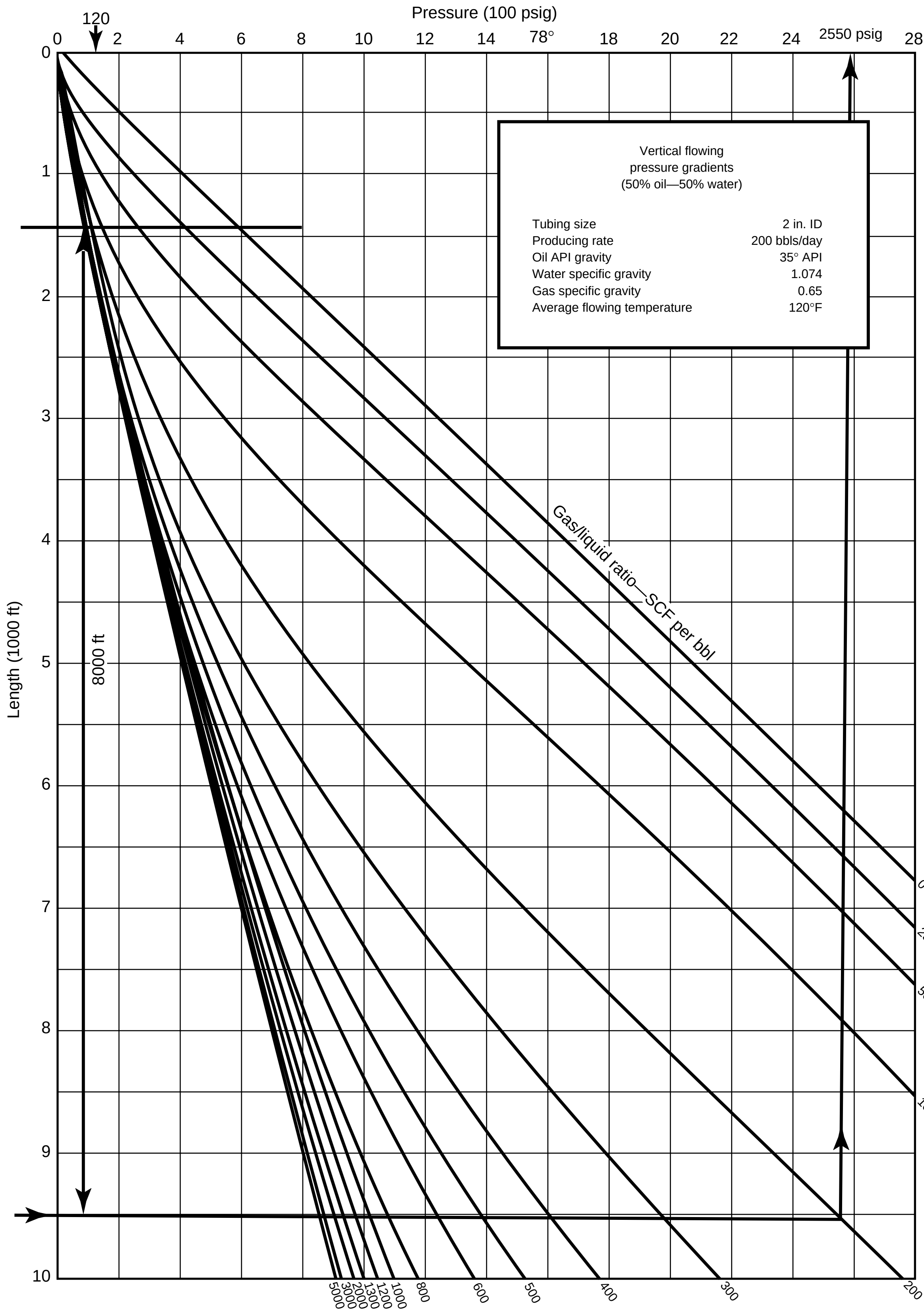


Figure 21—Vertical Flowing Pressure Gradient Curve

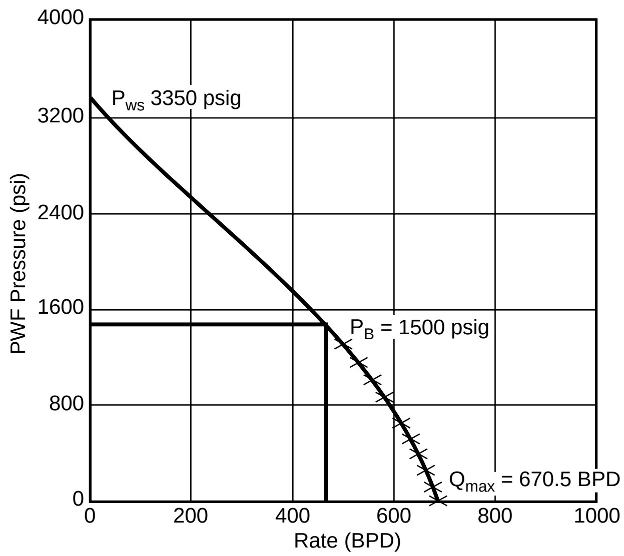


Figure 22—IPR Graph

The following is one method for predicting the static bottom hole injection gas pressures:

Surface Gas Injection Pressure = P_g

Max Pressure of Injection Gas at depth = P_{gd}

$$P_{gd} = P_g \text{ x } e^{(0.01875 \times SG_i \times D_w)/[(460 + T_a) \times Z]}$$

For P_g = 1100 psig (assumed average surface operating pressure.)

and

Z = 0.86 (at average temperature and pressure.) See Appendix A.

T_a = (74 + 180)/2 = 127

$$P_{gd} = 1100 \text{ x } e^{(0.01875 \times 0.7 \times 8000)/[(460 + 127) \times 0.86]}$$

P_{gd} = 1350 psig

Gas Gradient = $g_g = (P_{gd} - P_d)/D_w$

g_g @ 1100 psig = (1350 – 1100)/8000 = 0.032 psi/ft

5.3.5.3 For this problem, an average approximate injection gas gradient of 0.032 psi/ft will be used.

5.3.6 Equilibrium Curve

5.3.6.1 To make a good gas lift design, an estimate of the maximum possible production rate for the given conditions must be made. One technique recommended for determining this rate is use of an equilibrium curve. The equilibrium curve defines the maximum rate possible for any given depth with a specific well P.I. and a given injection pressure. See API *Gas Lift*, pages 72 and 73 for further detail.

5.3.6.2 Various points on the equilibrium curve can be calculated but most gas lift designs construct the equilibrium curve using a graphical approach. The equilibrium curve for this example is constructed in Figure 23. Several suitable production rates are picked that cover the range of interest. For this case, rates of 300, 400, and 500 BPD were selected. Gas lift gradient curves for R_{gl} s of 1000 were assumed since this amount of gas was known to be available and experience indicates that this GLR is often an adequate amount for gas lifting inside 2-in. nominal tubing. Other R_{gl} s can be selected if the available injection rates are defined for the local conditions. See Section 7 for more details on selecting the R_{gl}.

5.3.6.3 The lower flowing gradient curves below the point of gas injection are for the produced R_{gl} of the well. In this case, the flowing gas oil ratio (R_{glf}) is 400 ft^3/bbl and the gas liquid ratio (R_{gl}) is 200 ft^3/bbl. These curves can be traced from gradient curves or estimated closely by straight lines for pressures greater than 500 psi. For this case, gradients at pressures near the bubble points are almost linear and in the 0.42 psi/ft range.

Note: A weighted average of the oil and water gives gradient values on the high side since this method does not account for free gas or the decrease in oil gradient due to gas in solution. Some designers prefer to use a lower flowing gradient based on zero R_{gl}. Another approach is to use the average slope ($\Delta P/\Delta D$) of the gradient curves in the range from the lift depth to the production interval depth. A lower flowing gradient value (g_{fb}) of 0.42 psi/ft was selected for this case.

5.3.6.4 To graphically construct an equilibrium curve is relatively easy. We know the well will flow 200 BPD with a R_{gl} of 200. A higher flow rate will require gas injection at a deeper depth.

5.3.6.5 The first rate considered was the case when producing 300 BPD. Find on the IPR graph, or calculate:

$$P_{wf} = 3350 - 300/0.25 = 2150 \text{ psig}$$

Plot this point at 8000 ft.

Note: In deviated wells all depth should be corrected to true vertical depths (D_{tv}). Draw a line with a 0.42 psi/ft slope starting at 2150 psig and 8000 ft. The ending depth at zero pressure is found as follows:

$$\text{Depth} = D_w - P_{wf}/\text{Gradient}$$

$$\text{Depth} = 8000 - 2150/0.42 = 2880 \text{ ft}$$

5.3.6.6 Plot the point at 0 psig and 2880 ft and connect with the first point. This is a 0.42 gradient line for a well flowing 300 BPD below the point of gas injection. Plot or trace the flowing gradient curve for 300 BPD with a GLR of about 1000. This is the upper flowing gradient line above the point

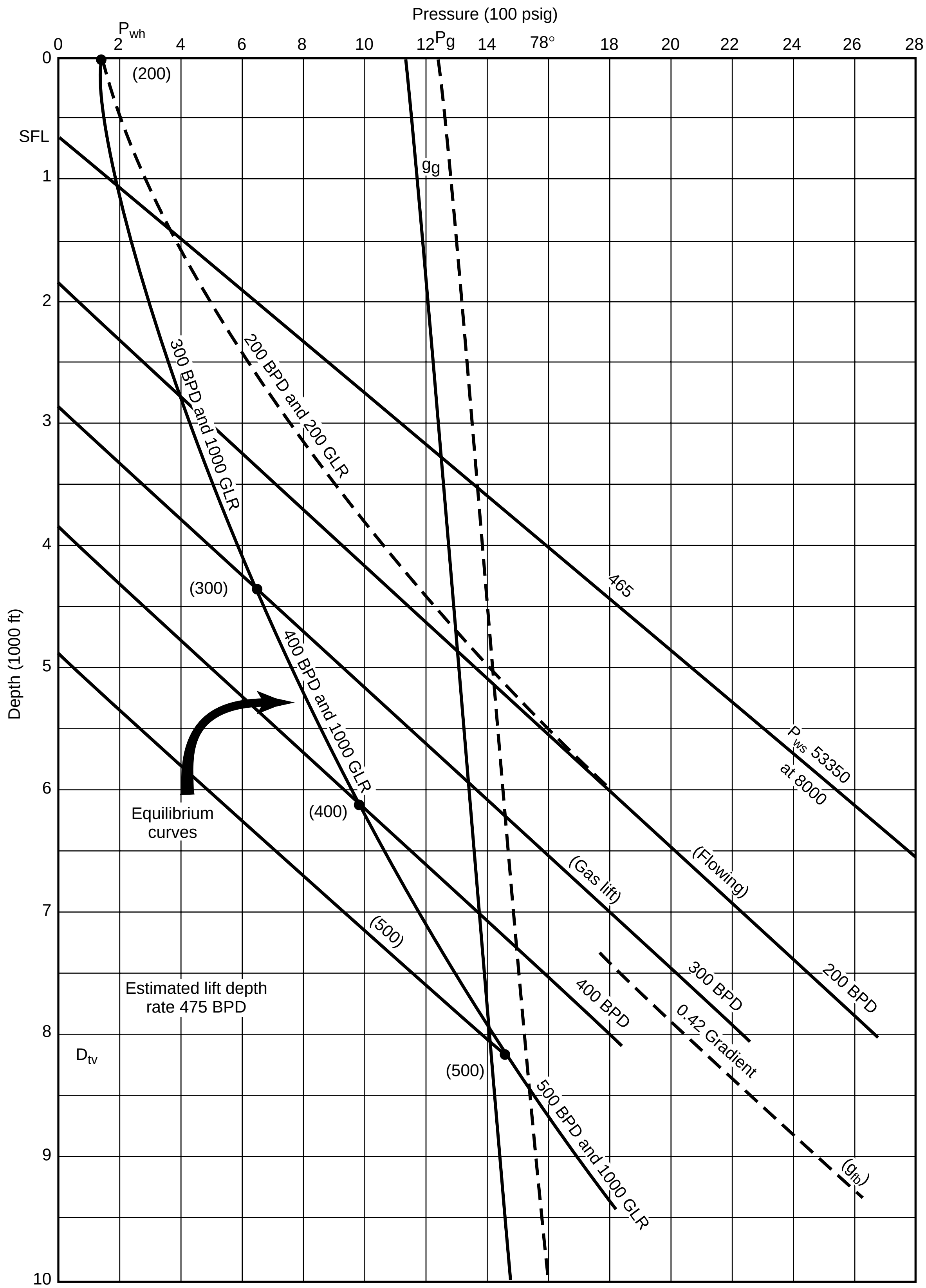


Figure 23—Gas Lift Design

of gas injection. Note the intersection of the upper and lower flowing gradient lines. This point is the depth (4400 ft) and pressure (650 psig) that is required for gas injection to make about 300 BPD.

5.3.6.7 Repeat the above procedure for a rate of 400 BPD. Find from the IPR graph that the flowing bottom hole pressure (P_{wf}) to make 400 BPD is 1750 psig. Plot this point at 8000 ft. Find the depth for zero pressure:

$$\text{Depth} = 8000 - 1750/0.42 = 3833 \text{ ft}$$

5.3.6.8 Connect these two points. Trace the flowing gradient line for 400 BPD for a R_{gl} of 1000. Note the intersection at about 6200 ft and 1000 psig. This represents the gas lift injection point to produce 400 BPD (See Figure 23).

5.3.6.9 Again repeat the above procedure for a rate of 500 BPD. Find from IPR graph a flowing bottom hole pressure of 1340 psig to make 500 BPD. Plot this point at 8000 ft. Find the depth for zero pressure:

$$\text{Depth} = 8000 - 1340/0.42 = 4810 \text{ ft}$$

5.3.6.10 Trace the flowing gradient line for 500 BPD and a R_{gl} of 1000. Find the intersection of the upper and lower gradient lines at slightly below 8000 ft with a pressure of 1420 psig. This is the calculated point of gas injection to produce 500 BPD (see Figure 24).

5.3.6.11 It is obvious that the maximum production rate on gas lift is slightly less than 500 BFD unless the gas injection is increased.

5.3.6.12 Now plot the above three points on a graph. This is the equilibrium curve for this well, assuming a R_{gl} of 1000 while gas lifting, and a P.I. of 0.25 (see Figure 23).

5.3.6.13 The maximum rate would theoretically occur at the intersection of the equilibrium curve and the gas injection pressure line, a rate slightly less than 500 BPD. This rate cannot be achieved in practice since the injection gas pressure must be decreased when injection pressure valves are used and the injection gas pressure must be about 100 psi higher than the flowing production pressure to obtain ample gas injection. Also, the produced rate will be limited due to mandrel location.

Table 3—Vertical Flowing Pressure at Depth[a]
500 BFPD

Mandrel	D_{tv} (ft)	D_m (ft)	R_{gl} 600 (Scf/bbl)	R_{gl} 800	R_{gl} 1000	R_{gl} 1200	
0	0	0	120	120	120	120	
1	2350	2450	430	430	430	430	
2	3460	3921	600	580	570	570	
3	4345	5094	760	730	710	700	
4	5000	5962	890	840	810	800	
5	5500	6624	990	930	900	880	
6	6000	7287	1090	1020	980	940	= psig
7	6500	7949	1190	1120	1080	1050	
8	7000	8612	1310	1220	1180	1140	
9	7500	9244	1430	1330	1270	1240	
10	7900	9804	1530	1420	1350	1310	
D_{tv}	8000	9936	1560	1440	1370	1330	

[a]Based on Hagedorn and Brown "Vertical Flowing Pressure Gradients:" (50% oil–50% water) (Tubing Size: 2 in. nominal).

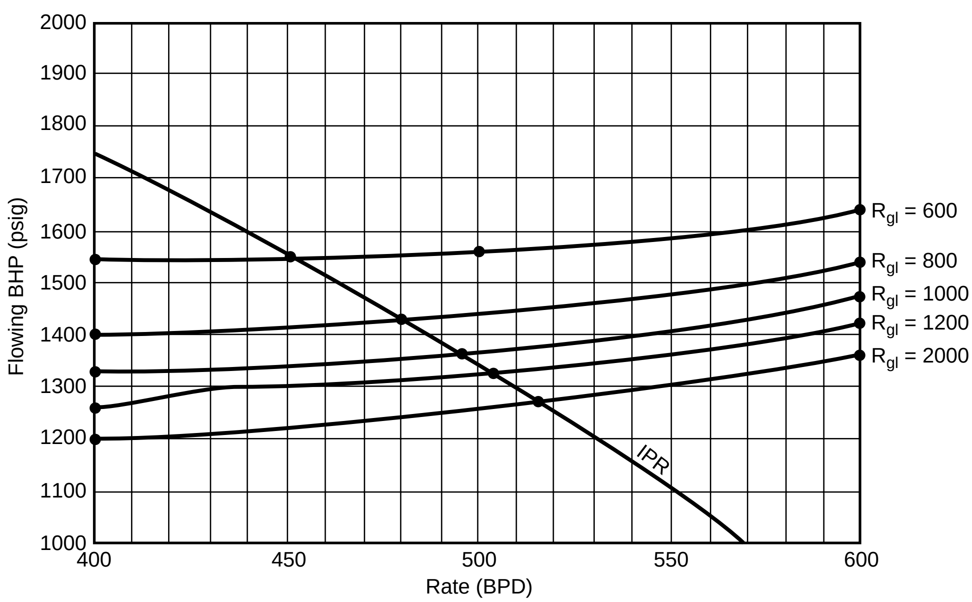


Figure 24—Tubing Performance Curve

5.3.6.14 An examination of Figure 23 indicates that for the available gas injection pressure that the maximum possible production rate would be about 450 BPD to 475 BPD. This will require injection at about 7500 ft. Deeper injection is desirable—but is not feasible, in this case, unless the tubing is pulled and the mandrels re-spaced.

5.3.7 Producing Gas Liquid Ratios

5.3.7.1 For the conditions outlined for this problem, the following depth-pressure flowing gradient traverses were determined for 500 BPD flow condition up 1.995-in. ID tubing, 50% cut. Use of a slightly higher gradient curve rate than actual is a conservative/safe design approach.

5.3.7.2 Gas Liquid Ratio of 600, 800, 1000, and 1200 were investigated.

5.3.8 Outflow Injection Gas Volume

5.3.8.1 The selection of the volume of injection gas to use is important since it has a direct effect on production volumes and operating costs. A tentative injection GLR of 1000 was selected; however, this GLR needs to be confirmed.

5.3.8.2 One recommended method to determine the GLR and the needed injection volumes is to draw the tubing performance curve on the IPR graph. The flowing bottom hole pressures for various production rates and gas liquid ratios (R_{gl}) are plotted (see Figure 24). For this problem, R_{gl} s of 600, 800, 1000, 1200 and 2000 were selected for production rates near 500 BPD. This analysis assumes that gas injection near total depth is feasible.

5.3.8.3 It is apparent that a R_{gl} of 600 is a reasonable base case. R_{gl} s of 800, 1000, 1200, and 2000 each increase production but with decreasing rate gains per MCF of injection gas. A summary of these results are shown in Table 5.

5.3.8.4 The minimum gradient for this well using the Hagedorn-Brown curves for 500 BPD is a R_{gl} of about 2000. Any increase in gas injection rate over a 2000 GLR will result in a decrease in production rate since the resulting friction loss will be greater than any reduction in head.

5.3.8.5 For this case produced gas liquid ratios of about 1200 appears reasonable. Approximately 3.7 BOPD will be obtained for the last 100 MCFD of injection gas. An increase of 6 BOPD is obtained by injecting an additional 424 MCFD. In this field this injection volume could be used more profitably in other gas lift wells. Further checks on optimum R_{gl} should be made after gas lift production has been established. Each installation has different operating costs and incomes; thus, the decision on the amount of gas to use is an economic one.

Table 4—Tubing Performance Curve[a]

Pressure at Depth for Various Rates and Gas Liquid Ratios (R_{gl})						
Rate	R_{gl} 600	R_{gl} 800	R_{gl} 1000	R_{gl} 1200	R_{gl} 2000	
(BPD)	(ft^3/bbl)					
400	1545	1400	1320	1280	1200	
500	1560	1440	1370	1330	1260	= Psig
600	11640	1540	1470	1420	1360	

[a]Based on an 8000 ft lift depth.

5.3.9 Temperature

5.3.9.1 A good prediction of the flowing temperature is required to determine the valve set pressures under test rack conditions.

5.3.9.2 Field measurement in a nearby well with the same tubing size and making 500 BPD with a 50% water cost were 120°F at 2000 ft. A linear flowing temperature of 100°F at the surface and 180°F at 8000 ft D_{tv} was assumed as a good approximation of the producing temperatures.

5.3.10 Gas Lift Valve Selection

5.3.10.1 Care should be taken in the selection of the valve type, size OD, and port size. Simple nitrogen charged, injection pressure operated valves were chosen due to their good reliability and performance.

5.3.10.2 A number of port sizes are available in this type 1-in. OD valve from a number of manufacturers. The port size normally range from $^1/_8$ in. to $^5/_{16}$ in. The port sizes should allow passage of the needed injection gas at the predicted pressure differentials; however, the port should be sized small enough to prevent excess use of gas. A smaller port will be less likely to "head" and cause systems upsets.

5.3.10.3 A $^3/_{16}$-in. port with a 0.104 production pressure effect factor (P_{PEF}) appears a good choice. Using the Gas Flow Capacity charts in API *Gas Lift* (Figure 4-8B and Figure 4-9), the following approximate gas flow rates were found for the $^3/_{16}$-in. port (choke). See Figure 25.

5.3.11 Mandrel Depth

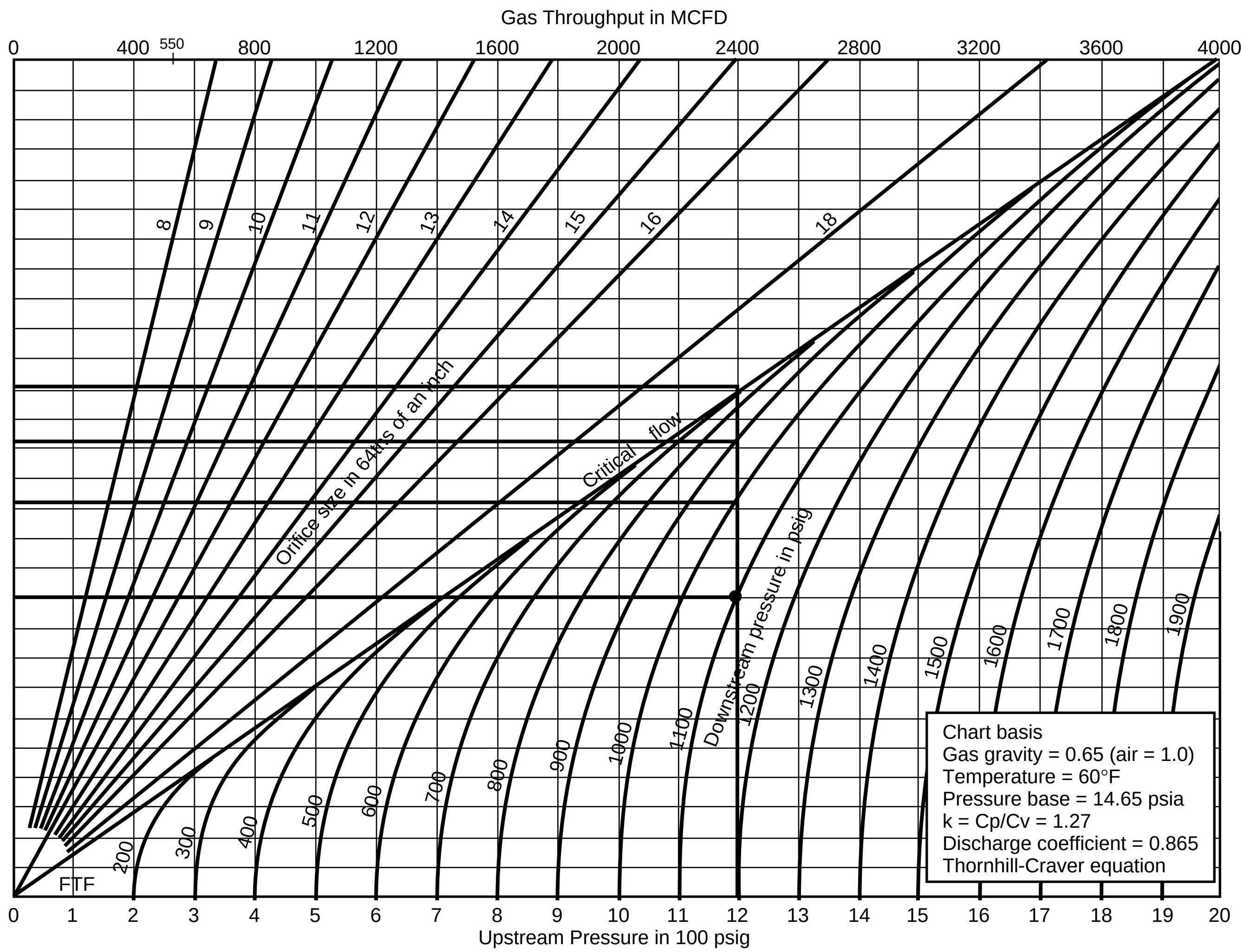
5.3.11.1 Mandrels were installed on completion using a conservative pseudo linear gradient design to 5000 ft and then spaced every 500 ft (D_{tv}) to total depth. See Figure 26. The mandrels are at the following depths:

No.	=	1	2	3	4	5	6	7	8	9	10
D_{tv}	=	2350	3460	4345	5000	5500	6000	6500	7000	7500	7900
D_m	=	2450	3921	5094	5962	6624	7287	7949	8612	9274	9804

Table 5—Summary of Rate vs. Gas Injection

RG (SCF/bbl)	P_{wf} (psig)	Rate (BPD)	Injection Gas[a] (MCFD)	Change in Oil Rate Δ(BPD)	Change in Injection Gas Δ(MCFD)	Change in Oil Rate (BOPD)/(MCFD)
600	1550	449	179.6	(Base Case)	—	—
800	1430	478	286.8	14.5	107.2	0.135
1000	1370	494	395.2	8.0	108.4	0.074
1200	1335	502	502.0	4.0	106.8	0.037
2000	1275	514	926.2	6.0	424.2	0.014

[a]Injection gas required = Rate x (R_{gl} – 200).



Note: Gas flow capacities (0 – 4000 MCF/D) for known upstream pressure, downstream pressure, and orifice size. Courtesy F.T. Focht.

Figure 25—Gas Passage Chart for Various Orifice Sizes

Table 6—Summary of Gas Flow Using $^3/_{16}$-in. Port/Orifice

Upstream Pressure (psig)	Downstream Pressure (psig)	Uncorrected Gas Rate (MCFD)	Correction Factor[a]	Corrected Gas Rate (MCFD)
1200	1100	550	1/1.15	478
1200	1000	720	1/1.15	626
1200	900	830	1/1.15	722
1200	800	880	1/1.15	765
1200	700 (critical)	920	1/1.15	800

[a]Gas Gravity = 0.70 and Temperature = 180°F (see API *Gas Lift*, Figure 4.9).
These results indicate that a $^3/_{16}$-in. ported valve when fully open should allow sufficient gas injection during unloading.

Note: Some designers recommend using smaller ported valves or installing $^{10}/_{64}$-in. chokes in the upper unloading valves. This practice will normally aid in unloading, but may cause multi-pointing.

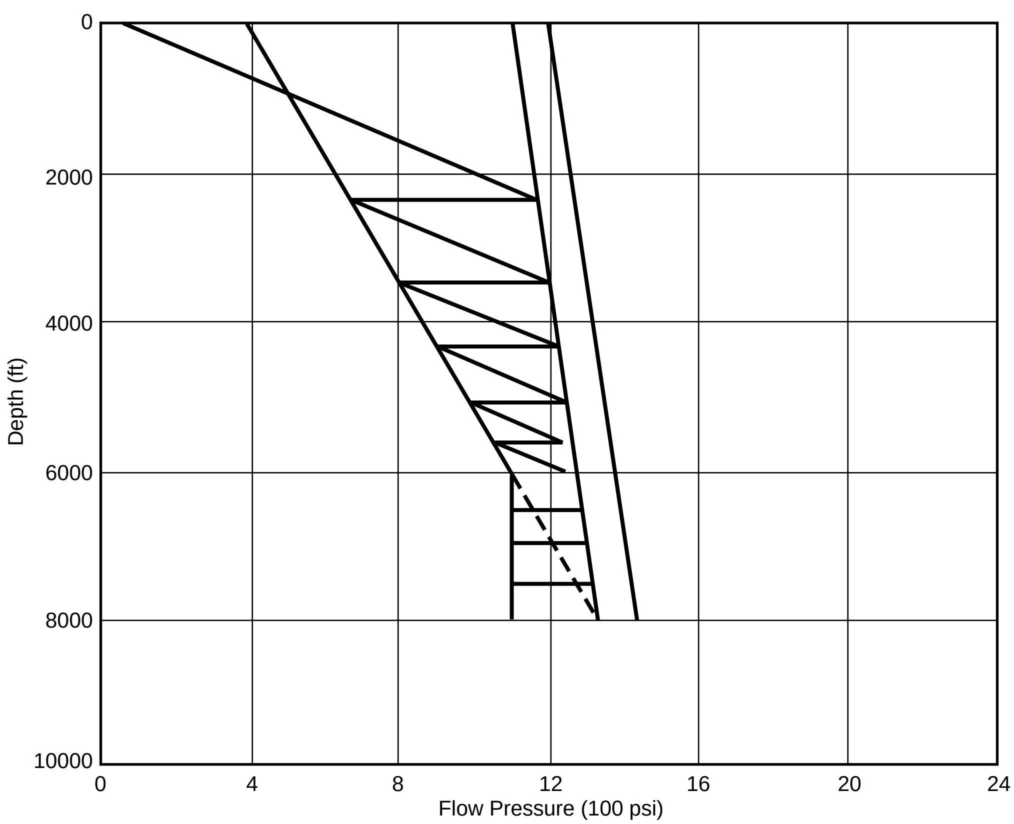


Figure 26—Pressure-Depth Gas Lift Space Graph for: API

5.3.11.2 Although the well is equipped with an adequate number of mandrels, their spacing is not ideal for the actual producing condition. Pulling the well to respace valves and mandrels would be expensive and should be avoided if an adequate design can be obtained with the existing spacing.

5.3.12 Spacing and Valve Setting

5.3.12.1 The objective is to work to the deepest mandrel feasible. Spacing will be based on producing about 500 BPD, the anticipated rate of the well by using the equilibrium curve. A R_{gl} of 1200 was assumed based on the tubing performance outflow curves. Injection gas pressure will be dropped 20 psi to allow the upper valves to close and thus prevent valve interference. This 20 psi drop is based on allowing a 10 psi valve safety factor and 100 psi increase in flowing production pressure during unloading or producing. (With a production pressure effect factor of 0.104, a 100 psi pressure change is equivalent to about 10 psi injection gas pressure change). Thus a minimum drop of 20 psi was taken. An unloading gradient of 0.465 psi/ft will be used; however, once well production has been established, the gradient in the tubing will decrease to about 0.42 psi/ft. A gas gradient of 0.032 psi/ft was used. The valve setting will be worked out analytically and graphically. Individual mandrels should be evaluated to determine if they must be used or if adequate pressure exists to allow jumping or skipping it. Mandrels not required for the valve design will be equipped with dummy valves if they are not already equipped with dummies as given in this example.

5.3.12.2 For each valve, there must be a pressure differential from the casing to the tubing during transfer to the next valve. Also, the tubing pressure must be reduced sufficiently at each valve so that the transfer to the next valve is possible. This design is based on attempting to lift as deep as possible with a wide mandrel spacing; therefore, all safety factors are kept to a minimum. Eliminating safety factors always involves some risk that the valves may have to be pulled and redesigned. (In this case, the valves are wireline retrievable.)

Valve #1

Since the well will flow and has a static bottom hole pressure that will support a 0.465 psi/ft water column to near the surface, the first mandrel must be used. (It is sometimes possible in low pressure wells with low fluid levels to skip the upper mandrels, i.e., put the first valve in the first mandrel above the static fluid level.)

Unloading Tubing Pressure < Gas Injection Pressure @ Depth

$P_{ul(1)}$ = Unloading tubing pressure @ 2350 ft

$P_{ul(1)} = P_{wh} + g_s \times D_{(1)}$

$P_{ul(1)} = 120 + 0.465 \times 2350 = 1213$ psig

Inj. Pressure @ depth = Inj. @ Surface + Gas Gradient x Depth

$P_{iod(1)} = P_{iod(1)} + g_g \times D_{(1)}$

$P_{iod(1)} = 1200 + 0.032 \times 2350 = 1275$ psig

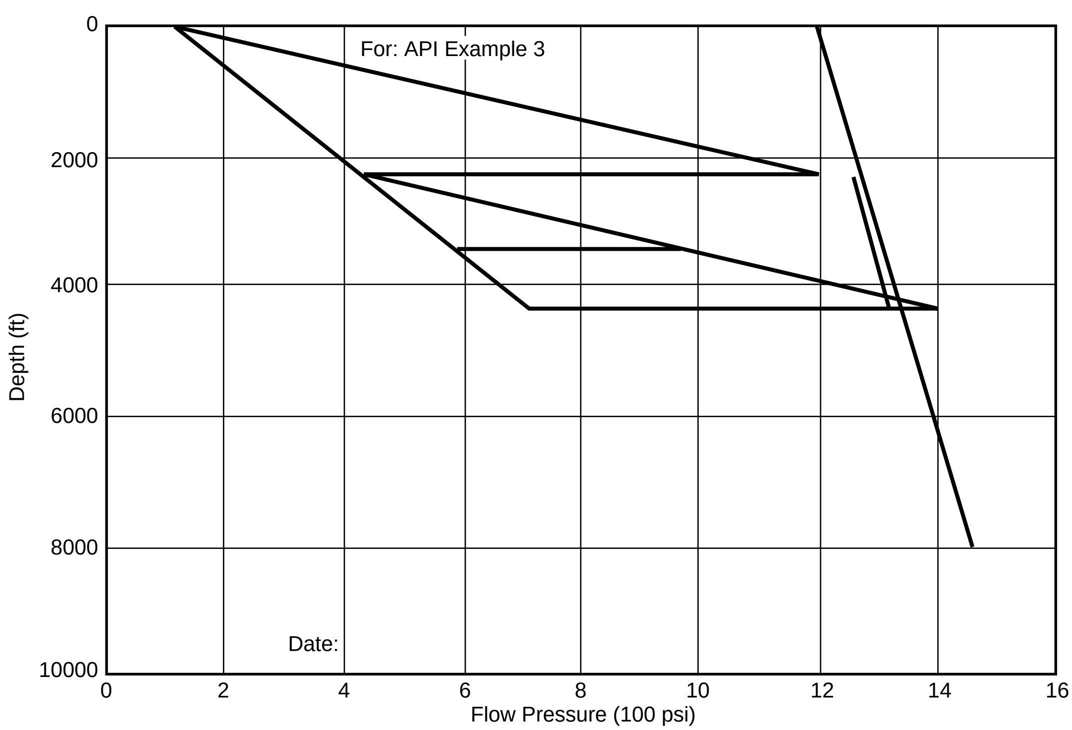


Figure 27—Pressure-Depth Gas Lift Set

Since the Injection Pressure (P_{iod}) is 62 psi greater than the unloading fluid pressure (P_{ul}), valve #1 can be uncovered. (If P_{ul} is greater than P_{iod}, then it may be necessary to rock the well, circulate with lighter kill fluid, or use a nitrogen unit to initiate flow.)

The temperature at valve #1 is calculated as follows:

$$\text{Temp @ depth} = \text{Surface flowing temp} + g_{Tpf} \times \text{valve depth}/100$$

$$g_{Tpf} = \frac{T_f - T_{wh}}{\text{Depth}} \times 100 = \frac{180 - 100}{8000} \times 100 = 1.0°\text{F}/100 \text{ ft}$$

$$T_{v(1)} = 100 + 1.0 \times 2350/100 = 123.5°\text{F}$$

$$C_{T(1)} = 0.880 \text{ (See Appendix A, Table A-1)}$$

Based on the 500 BPD gradient curve, the flowing producing pressure $P_{min(1)}$ at 2350 ft is about 430 psig.

P_{vo} = Valve (Test Rack) Set Pressure @ 60°F = (Production Pressure Effect Factor x Flowing Pressure + Inj. Gas Pressure @ Depth) x Temp Correction.

$$P_{vo} = (P_{PEF} \times P_{min} + P_{iod}) \times CT$$

$$P_{min} = 430 \text{ psig (See Table 5)}$$

$$P_{vo(1)} = (0.104 \times 430 + 1275) \times 0.880 = 1161 \text{ psig}$$

Valve #2

Check conditions at 3460 ft.

$$P_{ul(2)} = P_{min(1)} + g_s \times D_{bv}$$

$$= 430 + 0.465\,(3460 - 2350) = 946 \text{ psig}$$

$$P_{iod(2)} = P_{io(2)} + g_g \times D_{(2)}$$

$$= 1180 + 0.0320 \times 3460 = 1290 \text{ psig}$$

The injection pressure is much higher than the tubing unloading pressure. Check to determine if mandrel/valve at 3460 ft can be skipped and the one at 4345 ft used (see Figure 27).

$$P_{ul(2)'} = P_{min(1)} + g_s \times D_{bv}$$

$$P_{ul(2)'} = 430 + 0.465\,(4345 - 2350) = 1358 \text{ psig}$$

$$P_{iod(2)'} = P_{io(2)} + g_g \times D_{(2)}$$

$$P_{iod(2)'} = 1180 + 0.0320 \times 4345 = 1319 \text{ psig}$$

Since $P_{iod(2)'}$ is less than $P_{ul(2)'}$, the mandrel at 3460 ft can not be skipped.

$$T_{v(2)} = T_{wh} = g_{Tpf} \times D_{(2)}/100$$

$$T_{v(2)} = 100 + 1.0 \times 3460/100 = 134.6°\text{F}$$

$$C_{T(2)} = 0.862 \text{ (See Table A-1)}$$

From gradient curve for 500 BPD find $P_{min(2)}$ @ 3460 ft = 570 psig.

$$P_{VO(2)} = [P_{PEF} \times P_{min(2)} + P_{iod(2)}]\ CT$$

$$P_{VO(2)} = (0.104 \times 570 + 1290) \times 0.862 = \text{psig}$$

Valve #3

Check condition for mandrel at 4345 ft.

$$P_{ul(3)} = P_{min(2)} + g_g \times D_{bv}$$

$$P_{ul(3)} = 570 + 0.465 \times (4345 - 3460)' = 982 \text{ psig}$$

$$P_{iod(3)} = P_{io(3)} + g_g \times D_{(3)}$$

$$P_{iod(3)} = 1160 + 0.0320 \times 4345 = 1299 \text{ psig}$$

Again, since the injection pressure is much higher than the unloading pressure requirement, check to see if this mandrel can be skipped; go to next mandrel at 5000 ft.

$$P_{ul(3)'} = 570 + 0.465\,(5000 - 3460) = 1286 \text{ psig}$$

$$P_{iod(3)'} = 1160 + 0.0320\,(5000) = 1320 \text{ psig}$$

The injection pressure, $P_{iod(3)}$, is higher than the unloading pressure $P_{ul(3)}$, thus, the mandrel at 4345 ft will be skipped and the one at 5000 ft used.

$$T_{v(3)} = 100 + 1.0 \times 5000/100 = 150°\text{F}$$

$$C_{T(3)} = 0.838 \text{ (See Appendix A, Table A-1)}$$

Find that $P_{min(3)}$ = 800 psig (see Table 3)

$$P_{vo(3)} = 104 \times 800 + 1320) \times 0.838 = \text{psig}$$

Valve #4

Check conditions at 5500 ft.

$$P_{ul(4)} = 800 + 0.465 \times (5500 - 5000) = 1033 \text{ psig}$$

$$P_{iod(4)} = 1140 + 0.0320 \times 5500 = 1316 \text{ psig}$$

Possibly can skip this mandrel. Check conditions at 6000 ft.

$$P_{ul(4)} = 800 + 0.465 \times (6000 - 5000) = 1265 \text{ psig}$$

$$P_{iod(4)} = 1140 + 0.032 \times 6000 = 1332 \text{ psig}$$

The required unloading pressure is less than the available gas injection pressure; thus the mandrel at 5500 ft can be skipped, and the mandrel at 6000 ft used.

$$T_{v(4)} = 100 + 1.00 \times 6000/100 = 160°F$$

$$C_{T(4)} = 0.823 \text{ (See Appendix A, Table A-1)}$$

Find $P_{min(4)}$ = 940 psig (See Table 1)

$$P_{vo(4)} = (0.104 \times 940 + 1332) \times 0.823 = 1177 \text{ psig}$$

Valve #5

Check conditions @ 6500 ft.

$$P_{ul(5)} = 940 + 0.465 \times (6500 - 6000) = 1173 \text{ psig}$$

$$P_{iod(5)} = 1120 + 0.0320 \times 6500 = 1328 \text{ psig}$$

$$P_{iod(5)} > P_{ul(5)}$$

A check to skip this mandrel showed that it was not possible.

$$T_{v(5)} = 100 + 1.00 \times 6500/100 = 165°F$$

$$C_T = 0.816 \text{ (See Table A-1)}$$

Find $P_{min(5)}$ = 1050 psig (See Table 3)

$$P_{vo(5)} = (0.104 \times 1050 + 1328) \times 0.816 = 1173 \text{ psig}$$

Valve #6

Check conditions at 7000 ft.

$$P_{ul(6)} = 1050 + 0.465 (7000 - 6500) = 1283 \text{ psig}$$

$$P_{iod(6)} = 1100 + 0.0320 (7000) 1324 \text{ psig}$$

$$P_{iod(6)} > P_{ul(6)}$$

$$T_{v(6)} = 100 + 1.00 \times 7000/100 = 170°F$$

$$C_T = 0.809$$

Find $P_{min(6)}$ = 1140 psig

$$P_{vo(6)} = (0.104 \times 1140 + 1324) \times 0.809 = 1167 \text{ psig}$$

Valve #7

Check conditions at 7500 ft.

$$P_{ul(7)} = 1140 + 0.465 (7500 - 7000) = 1373 \text{ psig}$$

$$P_{iod(7)} = 1080 + 0.032 \times 7500 = 1320 \text{ psig}$$

Cannot reach (transfer to) next valve since $P_{ul(7)} > P_{iod(7)}$; however, only a small change in operating conditions might permit injecting gas at 7500 ft.

5.3.12.3 Since lift from 7500 ft is just out of reach, install an orifice at this depth. Possibly, use of slightly more injection gas during unloading or a drop in the unloading gradient will permit injection at 7500 ft.

5.3.12.4 Carefully select the orifice size needed. By use of the Gas Passage Chart (see Figure A-4), an orifice size of $^{14}/_{64}$-in. should be adequate to pass 500 MCF at the operating pressures.

A summary of the above results are given in Table 7.

5.3.12.5 With this design, there is a good chance of lifting from 7500 ft through the orifice (see Figure 28). A production rate slightly less than 500 BPD should result with injection gas of 500 MCFC. If the orifice cannot be reached, then injection will be through the valve at 7000 ft and a production rate of about 450 BPD should result. If trouble is encountered which prohibits lift from 7000 ft or deeper run a flowing pressure survey and redesign. Since the mandrel at 7900 ft cannot be reached based on the above design analysis, a dummy will be installed.

Table 7—Mandrel/Valve Summary

Mandrel	Valve No.	Depth (ft)	Valve/ Dummy	P_{io}	P_{iod} (psig)	P_{min} (psig)	T_v (°F)	P_{vo}
1	1	2350	V	1200	1275	430	123.5	1161
2	2	3460	V	1180	1290	570	134.6	1162
3	—	4345	D	—	—	—	—	—
4	3	5000	V	1160	1320	800	150	1176
5	—	5500	D	—	—	—	—	—
6	4	6000	V	1140	1332	940	160	1177
7	5	6500	V	1120	1328	1050	165	1173
8	6	7000	V	1100	1324	1140	170	1167
9	7	7500	O	1080	1320	1240	175	—
10	—	7900	D	—	—	—	—	—

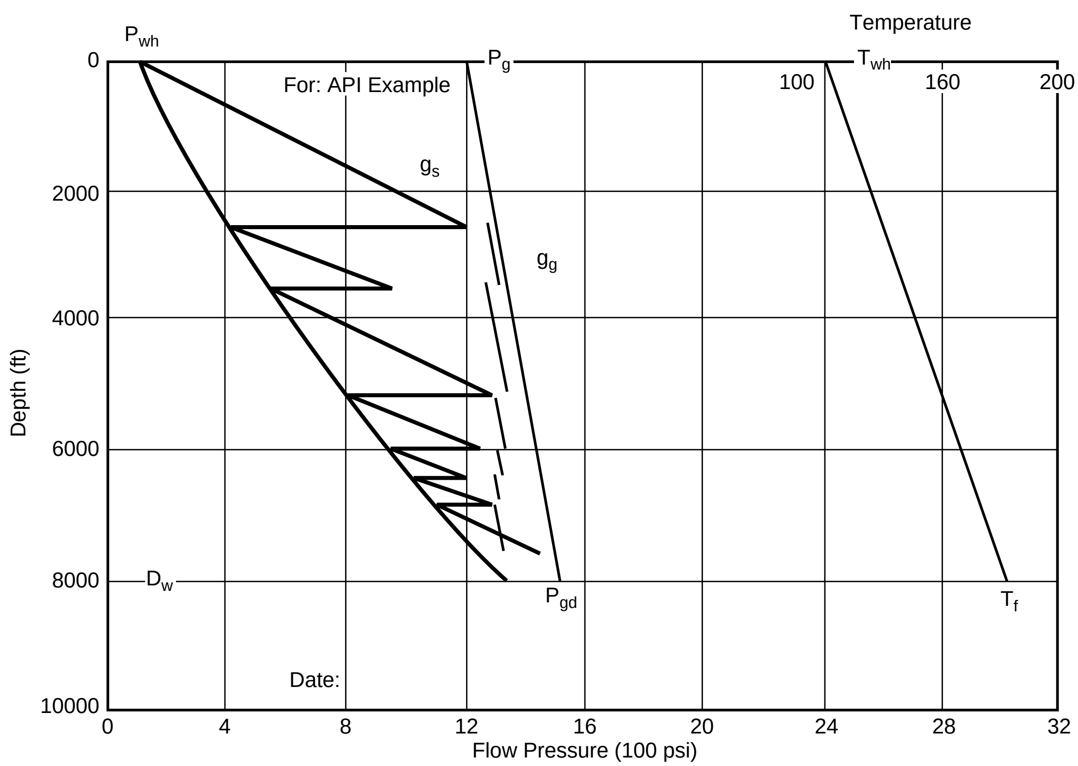


Figure 28—Pressure-Depth Gas Lift Program

APPENDIX A—API SYMBOLS FOR GAS LIFT DESIGN

Symbol	Definition
A_b	= Total effective area of Bellows, in.^{2}
A_p	= Area of Valve Seat or Port-Ball seat contact area, in.^{2}
A_p/A_b	= Ratio of Gas Lift Valve Port to Bellows area: From mfg. data.
ck	= Choke or Port diameter of the Gas Lift Valve, $^1/_{64}$-in.
C_d	= Discharge coefficient for gas flow through an orifice.
C_g	= Correction factor for gas passage through a choke.
C_T	= Temperature correction factor for nitrogen gas.
$D_{(1)}$	= Depth of top valve, ft.
$D_{(n)}$	= Depth on nth valve, ft.
D_{bv}	= Distance between valves, ft.
D_i	= Depth of gas injection, ft.
D_m	= Measured depth of deviated wells, ft.
D_{min}	= Minimum spacing of gas lift valves or mandrels, ft.
D_{ov}	= Depth of operating valve or gas injection, ft.
D_{sfl}	= Depth of static fluid level, ft.
D_{tv}	= True vertical depth of well, ft.
D_w	= Reference depth of well: Normally measured mid-point of perfs., on top of perfs., ft.
F_c	= Closing force on gas lift valve, pounds force.
F_o	= Total opening force on valve, pounds force.
F_{o1}	= Opening force due to pressure on the bellows, pounds force.
F_{o2}	= Opening force due to pressure on valve stem, pounds force.
f_o	= Oil cut fraction of total produced liquid.
f_w	= Water cut fraction of total produced liquid.
g	= Gradient, psi/ft.
g_{fa}	= Flowing gradient above point of gas injection, psi/ft.
g_{fb}	= Flowing gradient below point of gas injection, psi/ft.
g_g	= Gas gradient of injection gas, psi/ft.
g_o	= Gradient of oil, psi/ft.
g_s	= Static gradient of load fluid, psi/ft.
g_w	= Gradient of produced water, psi/ft.
G_{Tpf}	= Flowing production temperature gradient, °F/100 ft.
G_{Ts}	= Static temperature gradient, °F/100 ft.
J	= Productivity Index ($J = PI$), BLPD/psi.
n_v	= Total number of gas lift valves.
PD	= Pressure Drop in inj. gas pressure to deter interference, psi.
P_1	= Pressure applied under the bellows of a gas lift valve, psig.
P_2	= Pressure applied under the stem of a gas lift valve, psig.
P_B	= Bubble point pressure of the produced oil, psig.
$P_{bt(n)}$	= Pressure of bellows at temperature of nth valve, psig.
P_{bv}	= Bellows pressure at 60°F, psig.
P_{eo}	= Effective opening pressure due to production pressure, psig.
P_g	= Max available pressure of injection gas at surface, psig.
P_{gd}	= Max pressure of injection gas at D_w, psig.
$P_{iod(1)}$	= Operating gas injection pressure at valve number 1, psig.
$P_{iod(n)}$	= Operating gas injection pressure at nth valve, psig.
$P_{io(1)}$	= Operating gas injection pressure to open valve 1, psig
$P_{io(n)}$	= Surface operating gas injection pressure to open nth valve, psi.
P_{ko}	= Max kickoff gas injection pressure at surface, psig.

$P_{max(1)}$ = Max flowing pressure at valve 1 while lifting deeper, psig.

$P_{max(n)}$ = Max flowing pressure at nth valve while lifting deeper, psig.

$P_{min(1)}$ = Min flowing pressure at valve 1 while unloading, psig.

$P_{min(n)}$ = Min flowing pressure at nth valve while unloading, psig.

$P_{pd(1)}$ = Flowing production pressure at valve 1, psig.

$P_{pd(n)}$ = Flowing production pressure at nth valve, psig.

P_{pe} = Production pressure effect, psig.

P_{PEF} = Production pressure effect factor—mfg. data—(Previously *TEF*)

P_{sc} = Pressure at standard conditions, psig.

P_{sep} = Pressure of oil and gas separator, psig.

P_{SF} = Pressure safety factor to ensure valve is uncovered, psig.

P_{sp} = Spring pressure effect on valve, psig.

$P_{ul(1)}$ = Max unloading pressure at valve 1 when uncovered, psig.

$P_{ul(n)}$ = Max unloading pressure at nth valve when uncovered, psig.

$P_{vcd(1)}$ = Valve closing pressure of valve 1 at depth, psig.

$P_{vcd(n)}$ = Valve closing pressure of nth valve at depth, psig.

$P_{vc(1)}$ = Surface closing pressure of valve 1, psig.

$P_{vc(n)}$ = Surface closing pressure of nth valve, psig.

$P_{vo(1)}$ = Test rack set opening pressure for valve 1, psig.

$P_{vo(n)}$ = Test rack set opening pressure for nth valve, psig.

P_{wf} = Flowing bottom hole pressure at D_w, psig.

P_{wh} = Flowing pressure at the wellhead, psig.

P_{ws} = Static bottom hole formation or reservoir pressure, psig.

q_a = Max production rate below the bubble point, BLPD.

q_g = Gas production rate—from formation, MSCF/D.

q_{gi} = Injection gas rate, MSCF/D.

q_{gt} = Total gas rate measured (formation + injection), MSCF/D.

q_1 = Total liquid rate, BLPD.

q_{max} = Maximum liquid rate of well, BLPD.

q_o = Total oil production rate, BOPD.

q_{pb} = Production rate at the bubble point, BLPD.

q_w = Total water production rate, BWPD.

R_{gl} = Ratio of gas to liquid, scf/bbl.

R_{glf} = Ratio of formation gas to liquid, scf/bbl.

R_{gli} = Ratio of injected gas to liquid, scf/bbl.

R_{go} = Ratio of gas to oil, scf/bbl.

SG_g = Specific gravity of produced gas.

SG_i = Specific gravity of injected gas.

SG_O = Specific gravity of oil.

SG_w = Specific gravity of produced water.

T_a = Average gas injection temperature, °F.

T_f = Formation temperature, °F.

T_{gs} = Surface temperature of injection gas, °F.

T_s = Static earth surface temperature, °F.

T_{sc} = Temperature at standard conditions, °F.

$T_{v(1)}$ = Temperature at valve 1 depth, °F.

$T_{v(n)}$ = Temperature at nth valve, °F.

T_{wh} = Flowing temperature at wellhead, °F.

Z = Gas compression factor at average pressure and temperature.

Company ____________________ Address ____________________
____
____

A. Well Completion Data
- * 1. Field name:____________________
- * 2. Lease name and well no.: ____________________
- 3. Producing formation: ____________________ Lithology: __________
- * 4. Casing: ________ in. OD; ________ #/ft; ________ Grade; ________ ft
- 5. Liner: ________ in. OD; ________ #/ft; ________ Grade; ________ ft
- 6. Open hole: (yes/no) ____________ Gravel pack (yes/no) ____________
- * 7. Well reference depth (D_{tv}/D_m): ____________ / ____________ ft
- * 8. Perf. Interval (D_{tv}/D_m) ____________________ ft
- 9. Packer: ____________________ (D_{tv}/D_m) ________ / ________ ft
- * 10. TBG LGT ______ft; OD ______ in.; WT. ______ lb/ft; Grade ______ THD ______
- 11. SSSV: (type) ____________; Depth ________ ft; Bore ________in.
- 12. Wellhead misc: ________; (Bore ID) ________ in.; WP ________ psi
- 13. Choke: (type) ____________; Size max. ID ____________ / 64 in.
- 14. Flowline: size ID ____________ in. Length: ____________ft
- 15. Well profile: (D_{tv}/D_m or deg) ____________________
____

B. Reservoir, Test and Production Data
- * 16. Test date: ______; (q_o) ______ BOPD (q_w) = ______ BWPD (q_g) = ______ MCFD
- * 17. Water cut (f_w): ________; Formation GOR (R):________ (R_{gl}):________
- * 18. Flowing WHP (P_{wh}) ________ psig; Separator pressure (P_{sep}) ________ psig
- * 19. Static BHP (P_{ws}): ____________ psig @ ____________ft
- 20. Static fluid level ________ ft & P_{wh} ________ psig & g_w ________ psi/ft
- * 21. Flow BHP (P_{wf}): ________ psig @ ________ ft @ q_l ________ BLPD
- * 22. Oil gravity ____________ deg API; Water SG (SG_w) ____________
- * 23. Formation gas SG (SG_g): ________; BH temp (T_f) ________ °F @ ________ft
- * 24. Static surf. temp (T_s): ____________ Flow surf. temp (T_{wh}): ____________ °F
- * 25. Bubble point (P_b): ________ psig P_I (J): ________ BPD/psi Flow eff ________
- 26. Sand (yes/no) ________; Paraffin (yes/no) ________; Scale (yes/no)________
- 27. H_2S (yes/no) ________; CO_2 (yes/no) ________; Emulsion (yes/no) ________
- 28. Other unusual lift problems ____________________

C. Design Information
- * 29. Tubing/Annulus flow ____________ Space/set/run WL valves ____________
- * 30. Production rate (q_1): min________ max ________ design ________ BPD
- * 31. Max water cut ________; Max lift depth ________ ft; Min BHP ________ psig
- * 32. Well inj. pres (P_g): ____________ psig: Operating pressure (P_{io})________ psig
- 33. Compressor discharge pressure ____________ psig; P_{ko} ____________ psig
- * 34. Inj. gas temp (T_{gs}) ____________ °F Inj gas SG (SG_i) ____________
- * 35. Inj. gas volume: max/unloading/design ____________________R_{gli}/MCFD
- * 36. Load fluid grad (g_s): ____________ psi/ft; Lower grad (g_{fb})____________ psi/ft
- * 37. Min spacing of valves ____________ ft; Min pressure drop (PD) ____________ psi
- * 38. Design flow press (P_{wh}) ____________ psig; Design flow temp (T_{wh}) ____________ °F
- 39. Gas lift mandrel: ____________________
- * 40. Gas lift valve (mfg & type): ____________________
- 41. Gas lift valve description ____________________
- 42. Other ____________________

Remarks: ____________________
____

By: ____________________ Date: ____________

*Indicates data that must be supplied for good design.

Figure A-1—Gas Lift Well Data Sheet

Test Rack Pressure Calculation Sheet

Well ______________________________ Valve ______________________________

Valve No.	Depth ft	T_v °F	P_{PEF}		P_{pd} psig		psig		P_{iod} psig		psig		C_T		P_{vo} psig	
1				x		=		+		=		x		=		
2				x		=		+		=		x		=		
3				x		=		+		=		x		=		
4				x		=		+		=		x		=		
5				x		=		+		=		x		=		
6				x		=		+		=		x		=		
7				x		=		+		=		x		=		
8				x		=		+		=		x		=		
9				x		=		+		=		x		=		
10				x		=		+		=		x		=		
11				x		=		+		=		x		=		
12				x		=		+		=		x		=		
13				x		=		+		=		x		=		
14				x		=		+		=		x		=		
15				x		=		+		=		x		=		

Remarks: ____

____

____

$P_{vo} = (P_{PEF} \times P_{pd} + P_{iod}) \times C_T$

$C_T = 1/(T_v - 60) \times 0.00215 + 1.0)$ or look up in Table A.1

Designer: ______________________________ Date: ____________________

Figure A-2—Test Rack Pressure Calculation Sheet

Table A-1—Temperature Correction Factors for Nitrogen Based on 60°F

°F	C_t	°F	C_t	°F	C_t	°F	C_t	°F	C_t	°F	C_t
61	0.998	101	0.919	141	0.852	181	0.794	221	0.743	261	0.698
62	0.996	102	0.917	141	0.850	182	0.792	222	0.742	262	0.697
63	0.994	103	0.915	143	0.849	183	0.791	223	0.740	263	0.696
64	0.991	104	0.914	144	0.847	184	0.790	224	0.739	264	0.695
65	0.989	105	0.912	145	0.845	185	0.788	225	0.738	265	0.694
66	0.987	106	0.910	146	0.844	186	0.787	226	0.737	266	0.693
67	0.985	107	0.908	147	0.842	187	0.786	227	0.736	267	0.692
68	0.983	108	0.906	148	0.841	188	0.784	228	0.735	268	0.691
69	0.981	109	0.905	149	0.839	189	0.783	229	0.733	269	0.690
70	0.979	110	0.903	150	0.838	190	0.782	230	0.732	270	0.689
71	0.977	111	0.901	151	0.836	191	0.780	231	0.731	271	0.688
72	0.975	112	0.899	152	0.835	192	0.779	232	0.730	272	0.687
73	0.973	113	0.898	153	0.833	193	0.778	233	0.729	273	0.686
74	0.971	114	0.896	154	0.832	194	0.776	234	0.728	274	0.685
75	0.969	115	0.894	155	0.830	195	0.775	235	0.727	275	0.684
76	0.967	116	0.893	156	0.829	196	0.774	236	0.725	276	0.683
77	0.965	117	0.891	157	0.827	197	0.772	237	0.724	277	0.682
78	0.963	118	0.889	158	0.826	198	0.771	238	0.723	278	0.681
79	0.961	119	0.887	159	0.825	199	0.770	239	0.722	279	0.680
80	0.959	120	0.886	160	0.823	200	0.769	240	0.721	280	0.679
81	0.957	121	0.884	161	0.822	201	0.767	241	0.720	281	0.678
82	0.955	122	0.882	162	0.820	202	0.766	242	0.719	282	0.677
83	0.953	123	0.881	163	0.819	203	0.765	243	0.718	283	0.676
84	0.951	124	0.879	164	0.817	204	0.764	244	0.717	284	0.675
85	0.949	125	0.877	165	0.816	205	0.762	245	0.715	285	0.674
86	0.947	126	0.876	166	0.814	206	0.761	246	0.714	286	0.673
87	0.945	127	0.874	167	0.813	207	0.760	247	0.713	287	0.672
88	0.943	128	0.872	168	0.812	208	0.759	248	0.712	288	0.671
89	0.941	129	0.871	169	0.810	209	0.757	249	0.711	289	0.670
90	0.939	130	0.869	170	0.809	210	0.756	250	0.710	290	0.669
91	0.938	131	0.868	171	0.807	211	0.755	251	0.709	291	0.668
92	0.936	132	0.866	172	0.806	212	0.754	252	0.708	292	0.667
93	0.934	133	0.864	173	0.805	213	0.752	253	0.707	293	0.666
94	0.932	134	0.863	174	0.803	214	0.751	254	0.706	294	0.665
95	0.930	135	0.861	175	0.802	215	0.750	255	0.705	295	0.664
96	0.928	136	0.860	176	0.800	216	0.749	256	0.704	296	0.663
97	0.926	137	0.858	177	0.799	217	0.748	257	0.702	297	0.662
98	0.924	138	0.856	178	0.798	218	0.746	258	0.701	298	0.662
99	0.923	139	0.855	179	0.796	219	0.745	259	0.700	299	0.661
100	0.921	140	0.853	180	0.795	220	0.744	260	0.699	300	0.660

$$C_t = \frac{\text{Gas Lift Valve Dome Pressure at 60°F}}{\text{Gas Lift Valve Dome Pressure at Well Temperature}}$$

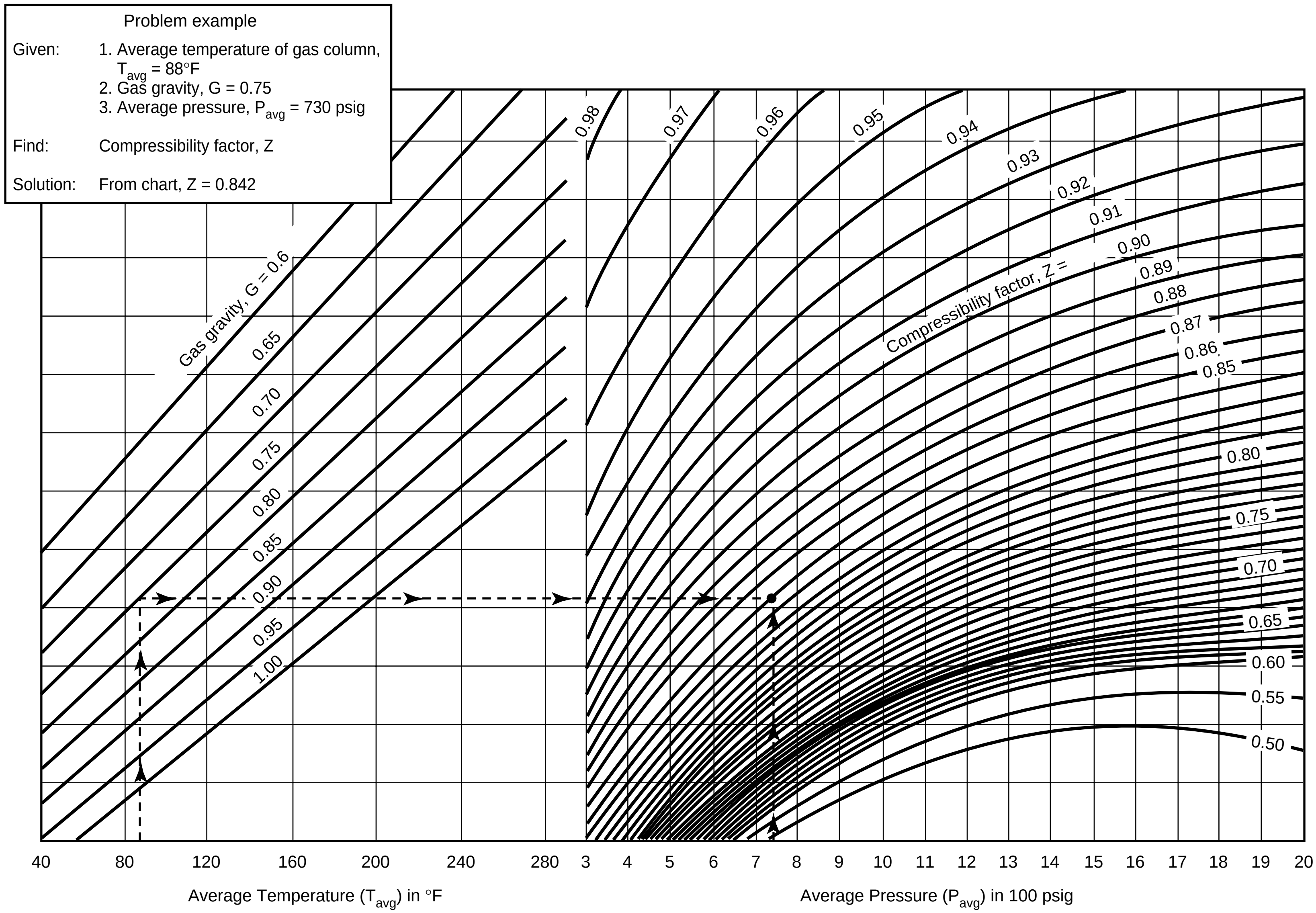


Figure A-3—Compressibility Factors for Natural Gas

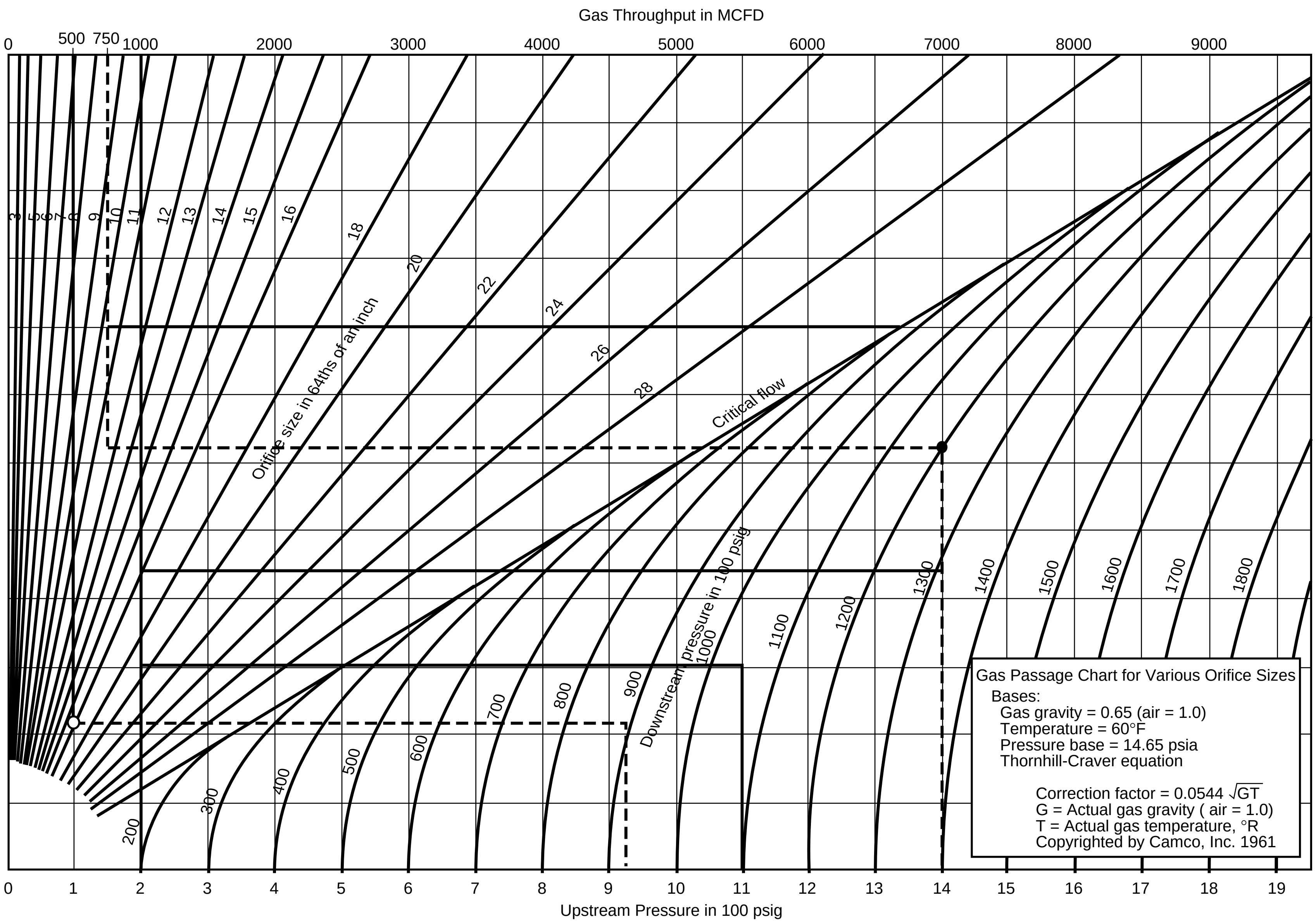


Figure A-4—Upstream Pressure in 100 psig

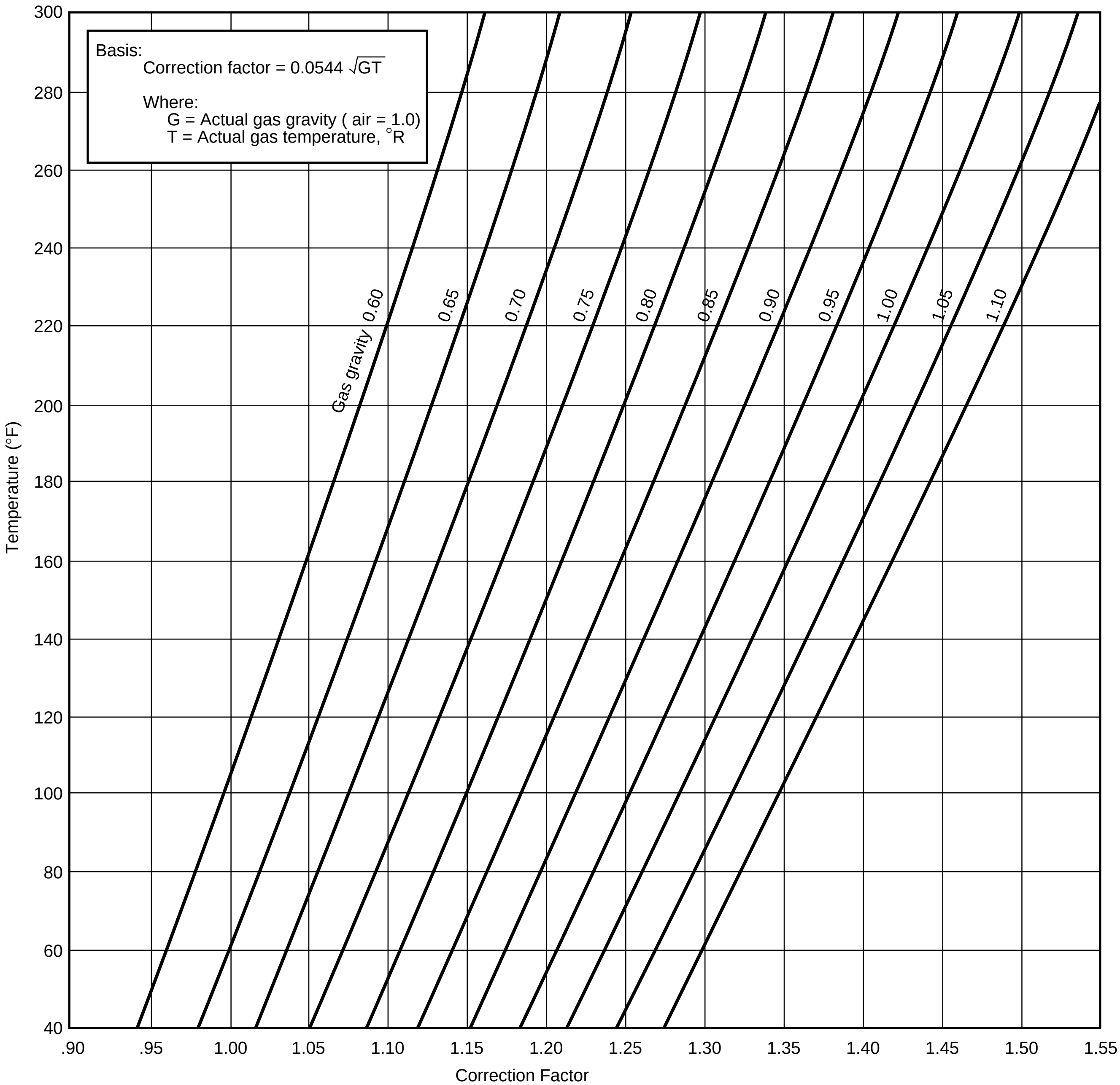


Figure A-5—Correction Factor

APPENDIX B—VERTICAL FLOWING PRESSURE GRADIENTS CHARTS

Vertical flowing Pressure Gradients for:

35°API, 1.074 Water Specific Gravity, and 0.65 Gas Specific Gravity.

Tubing nominal size—2 in. for 50/50 oil-water mix.

Rate	T_a
100 BPD	100 °F
200 BPD	120
300 BPD	120
400 BPD	120
500 BPD	140
600 BPD	140
700 BPD	140
800 BPD	140
900 BPD	140
1000 BPD	140

Tubing nominal size 2.5-in. for 50/50 oil-water mix

Rate	T_a
100 BPD	100 °F
200 BPD	120
300 BPD	120
400 BPD	120
500 BPD	140
600 BPD	140
700 BPD	140
800 BPD	140
900 BPD	140
1000 BPD	140

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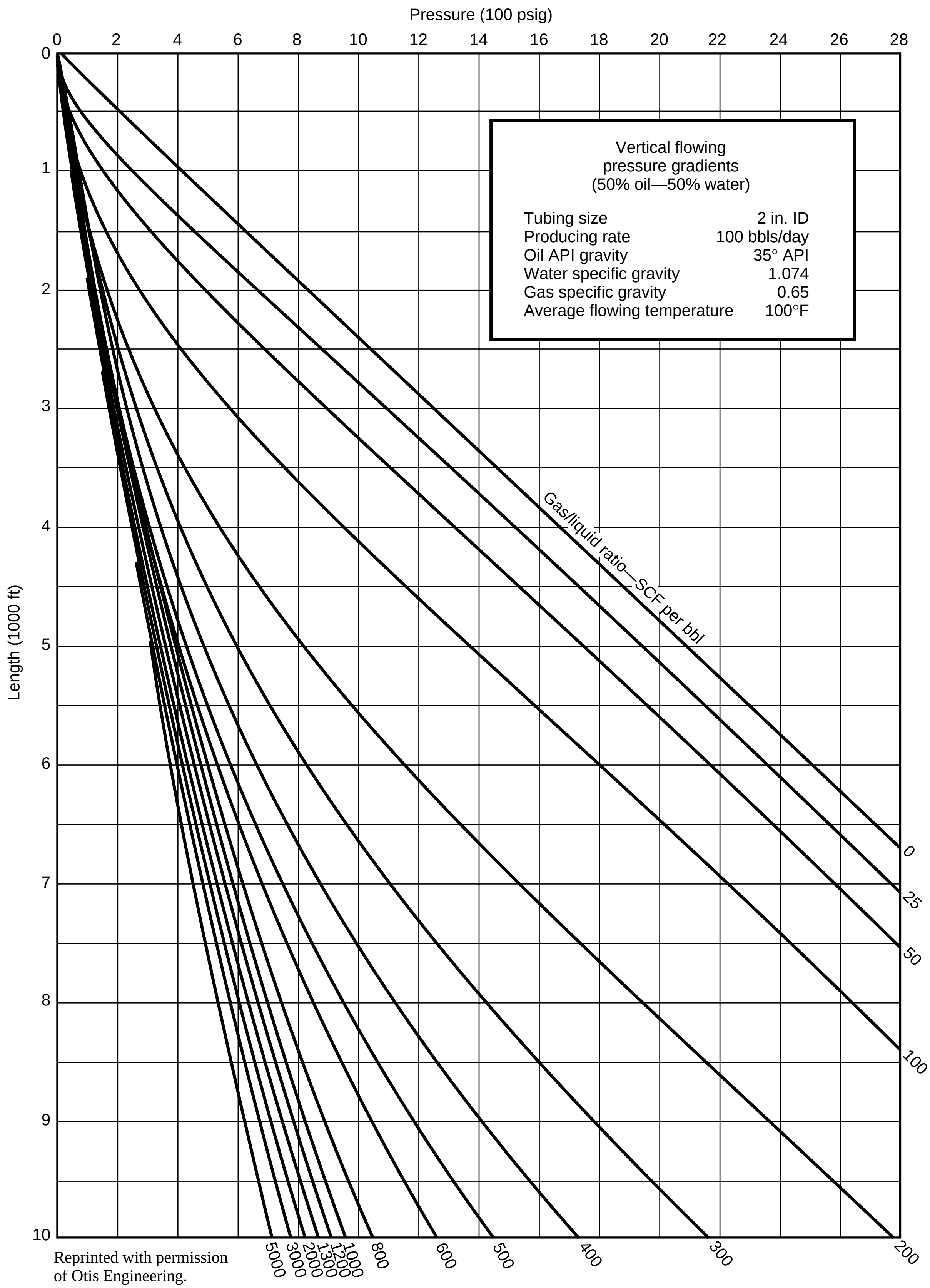

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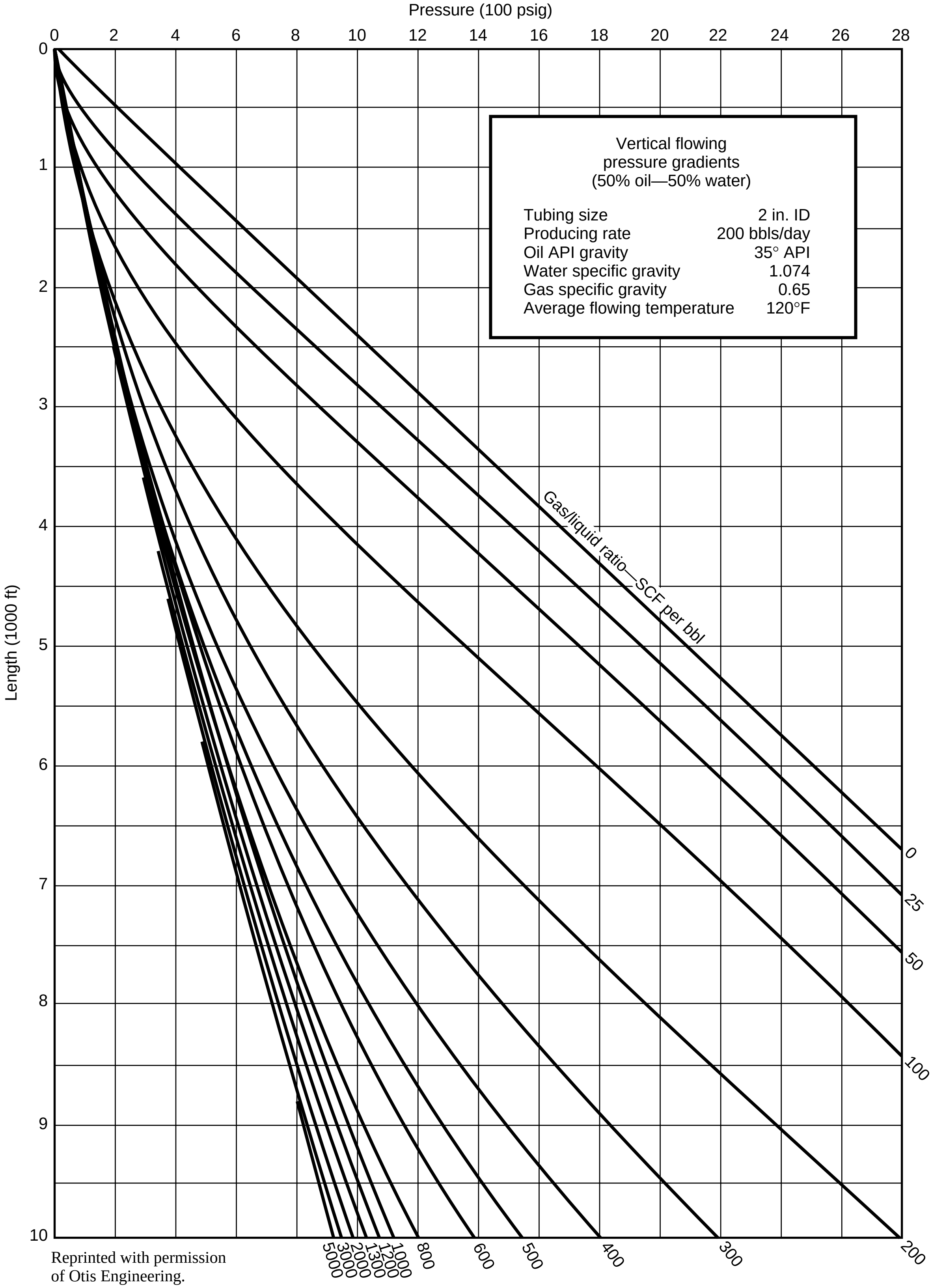

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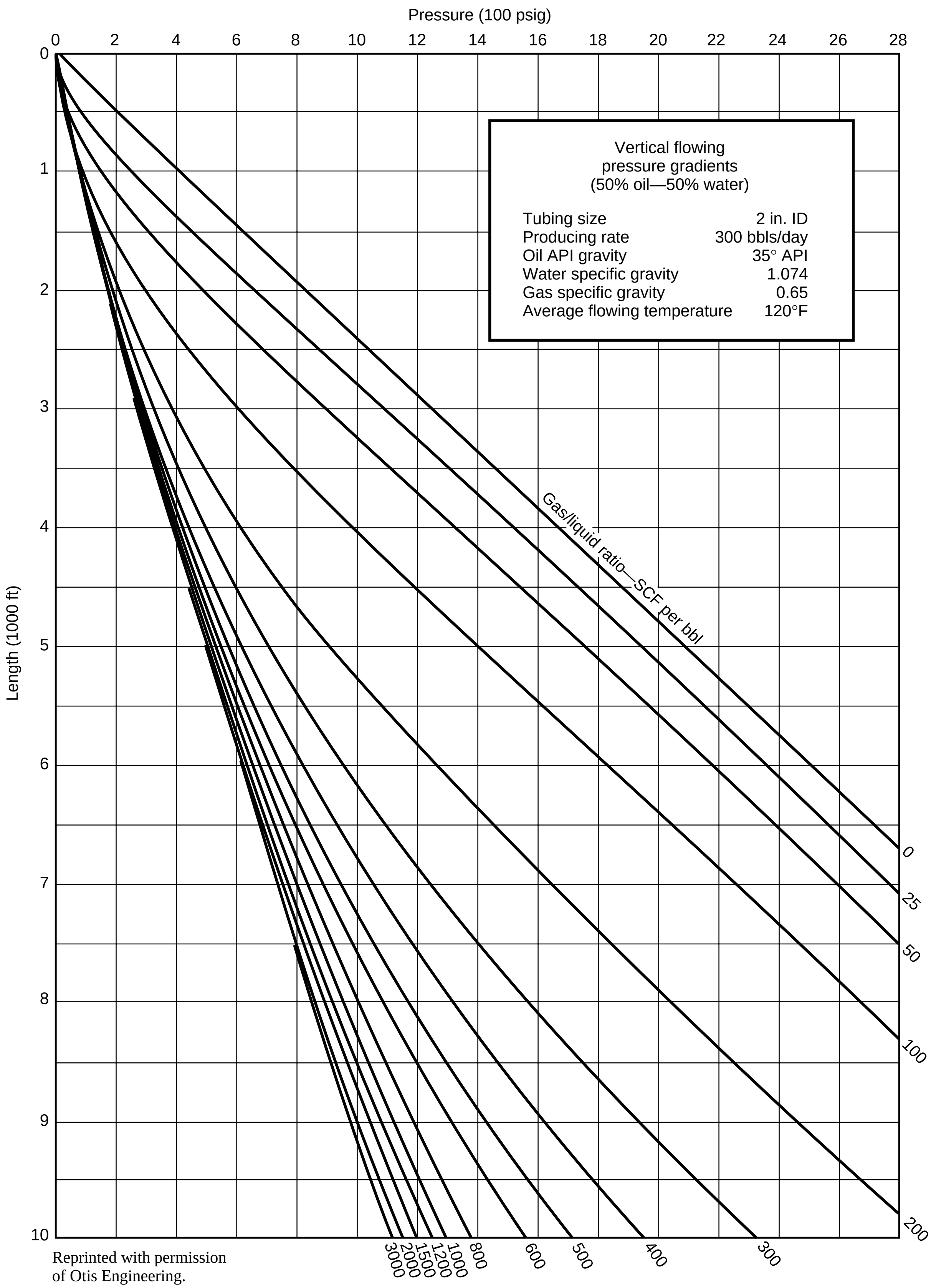

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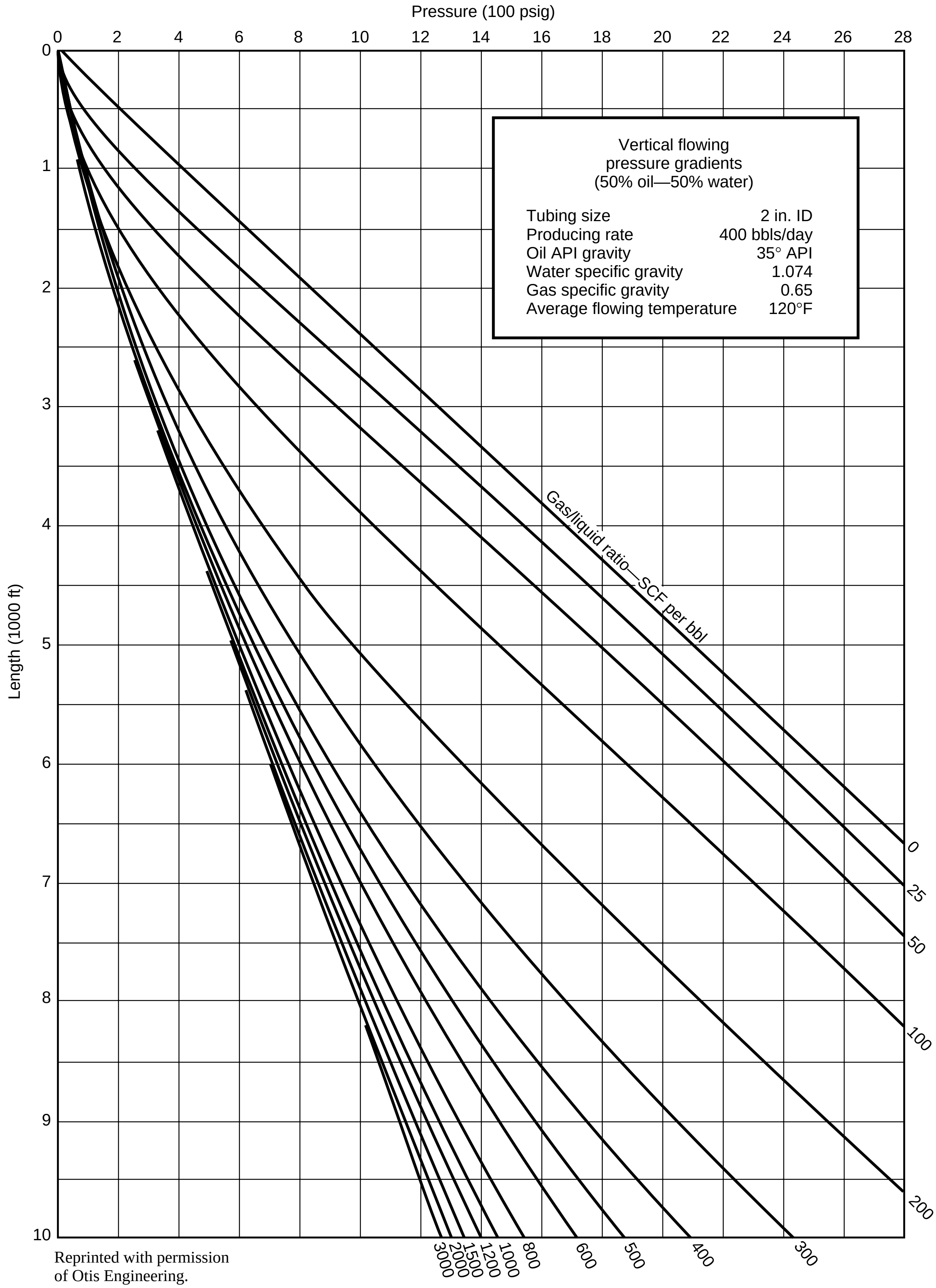

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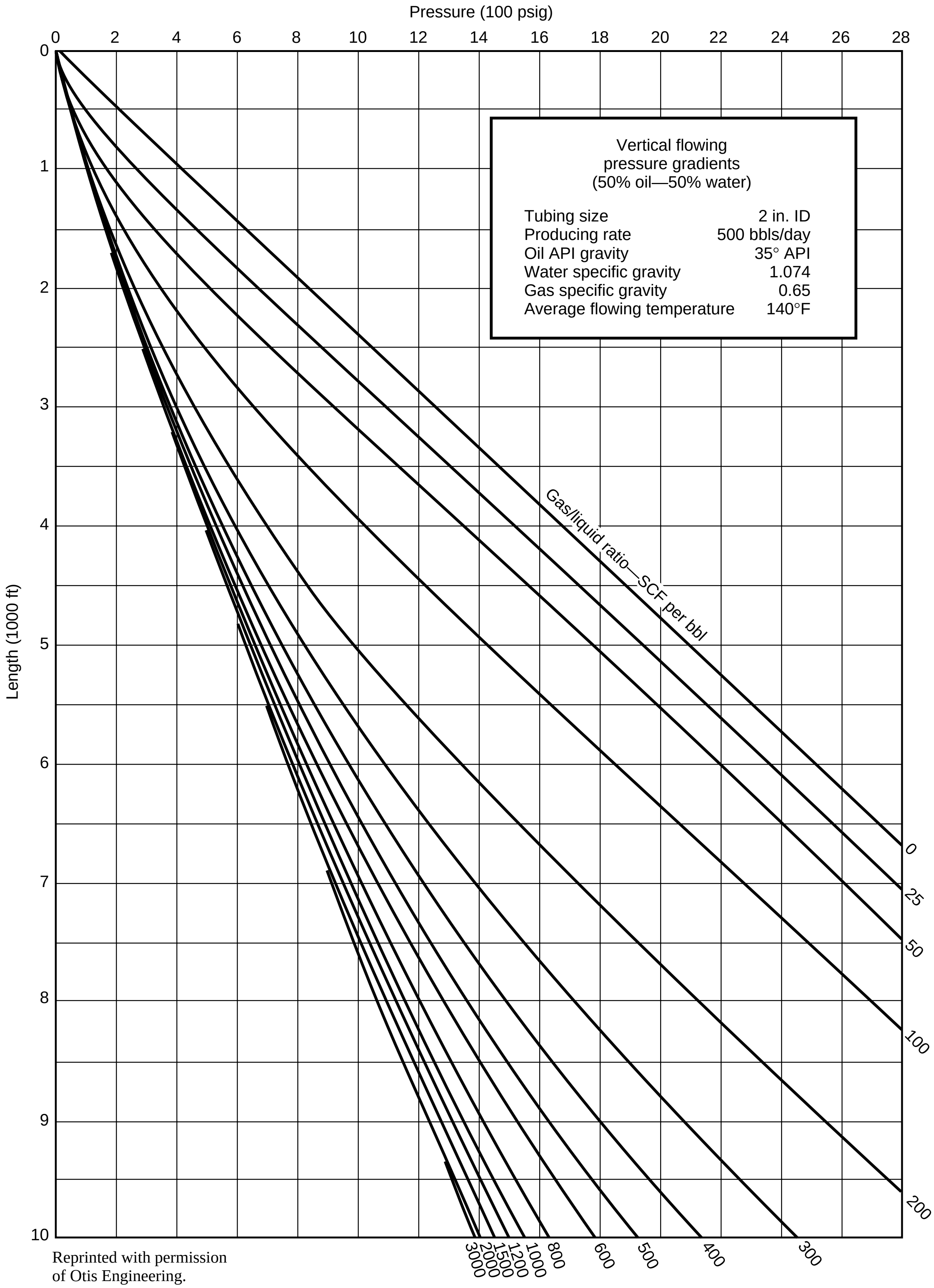

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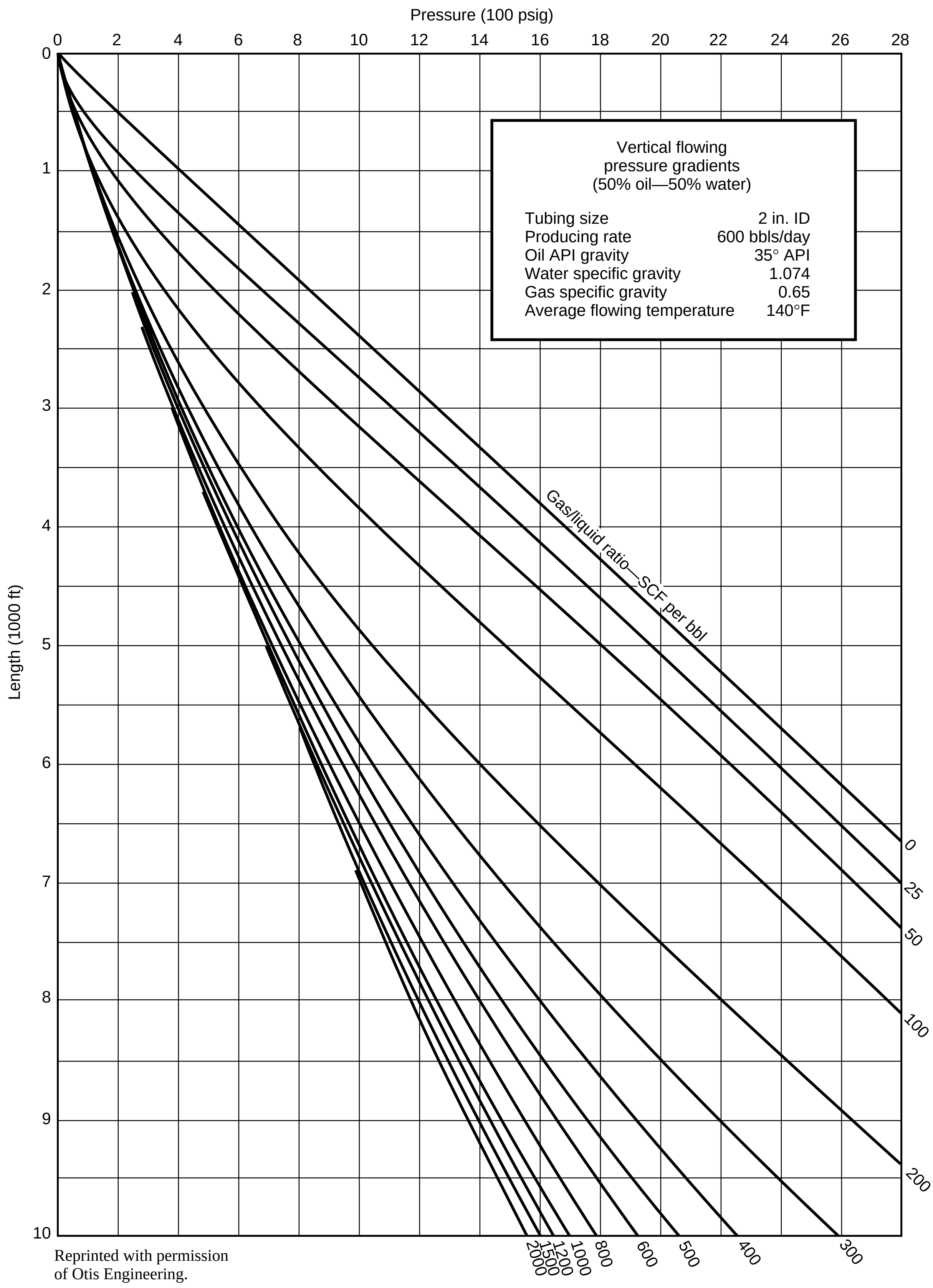

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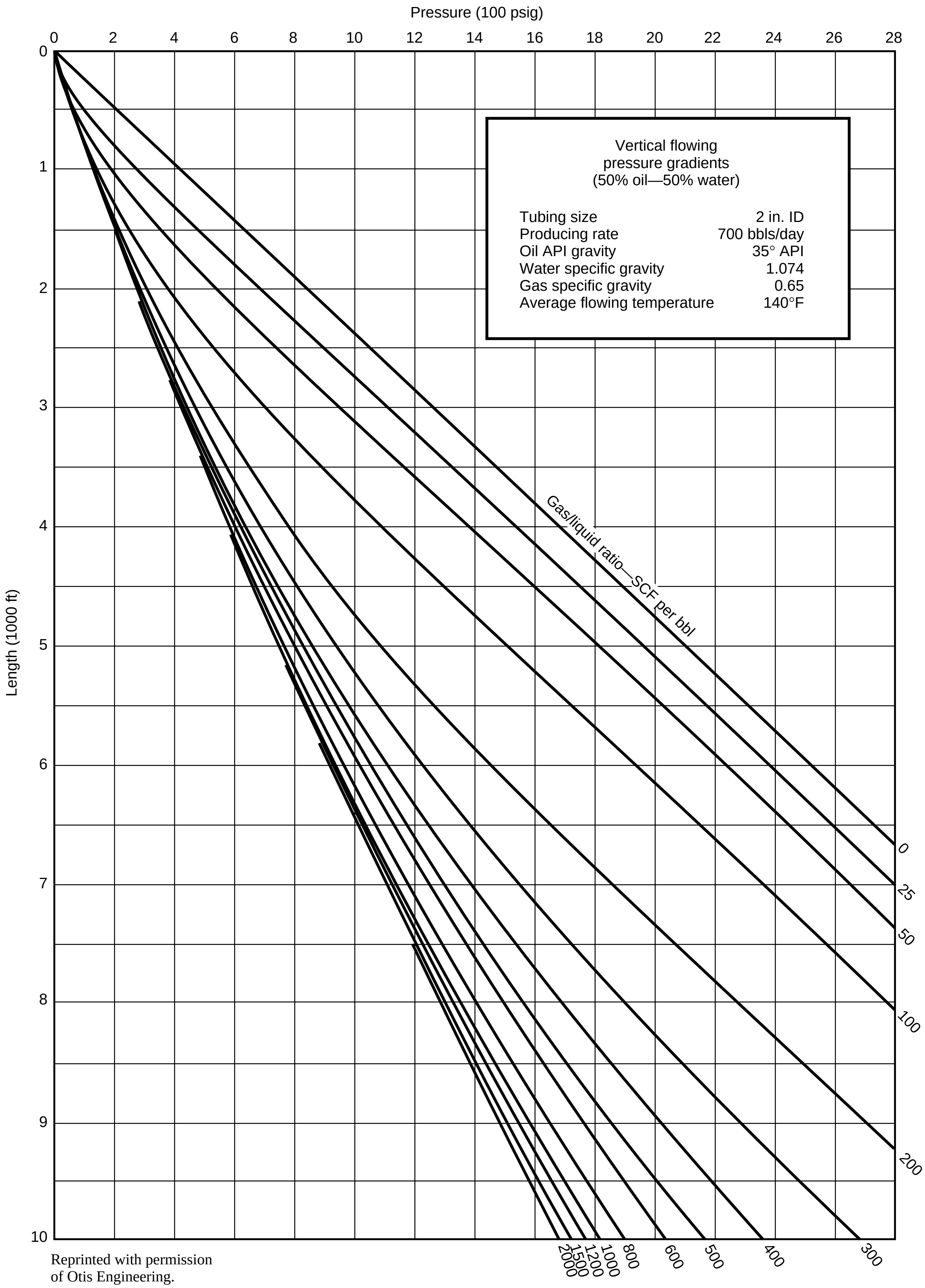

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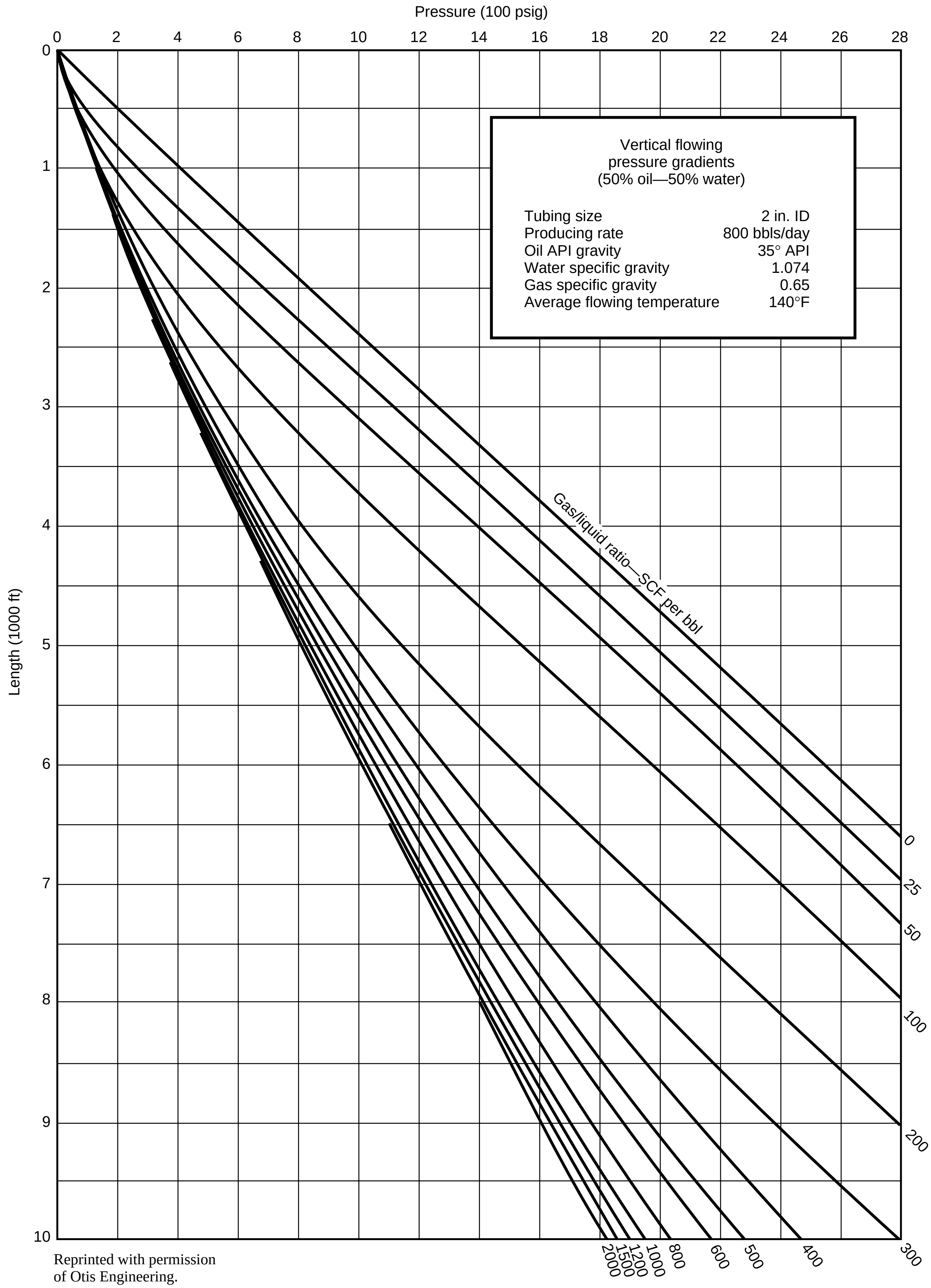

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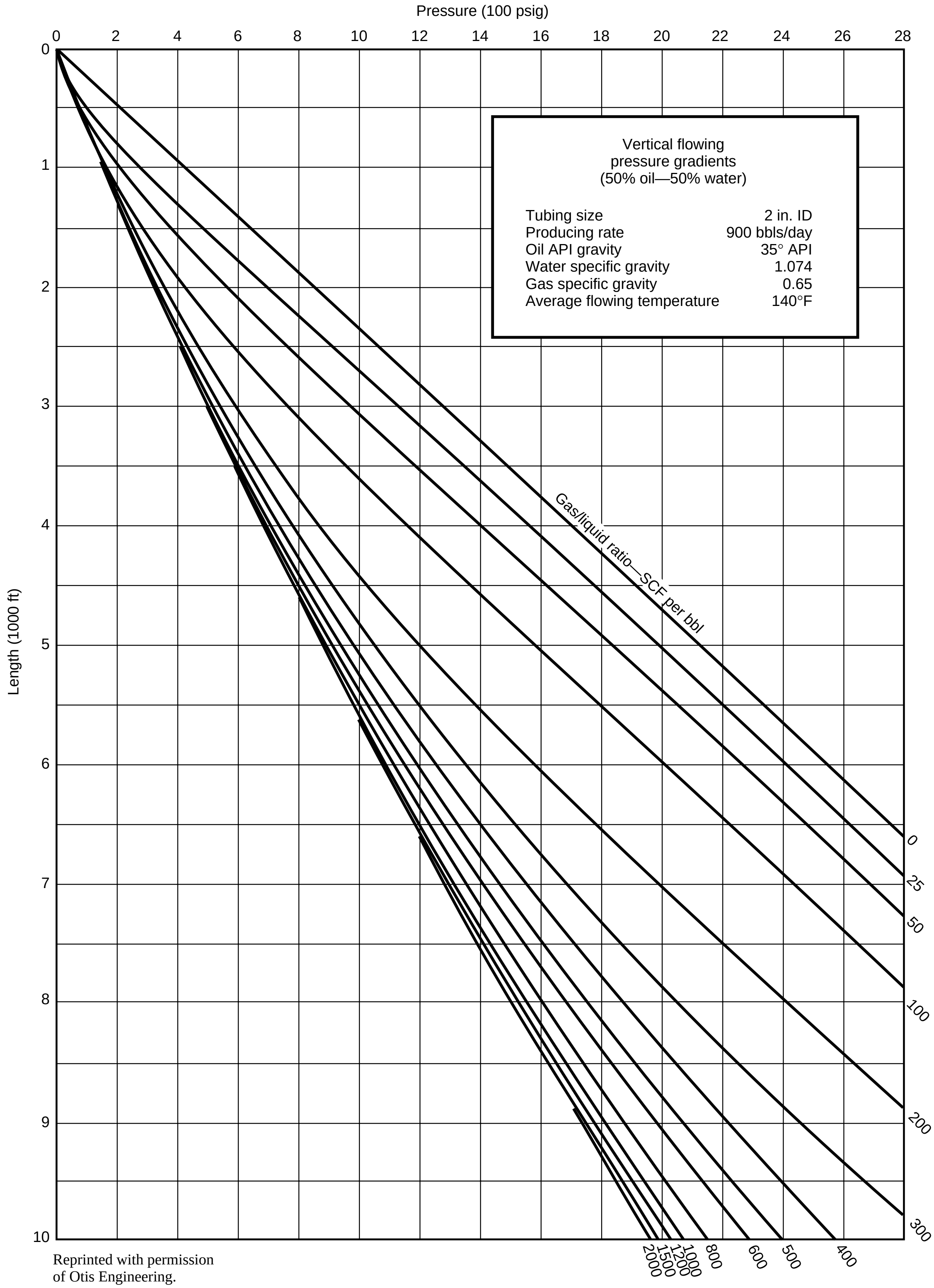

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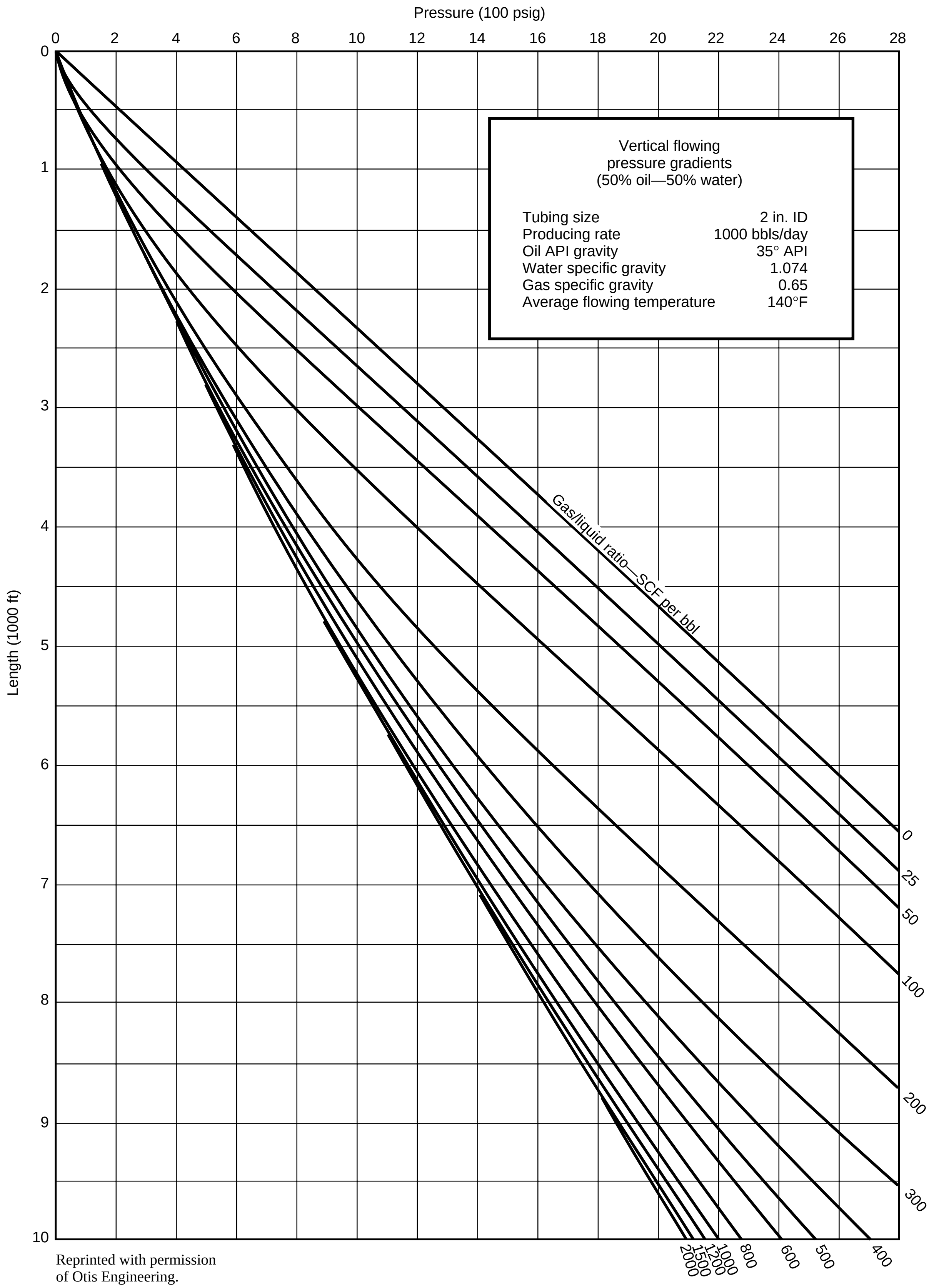

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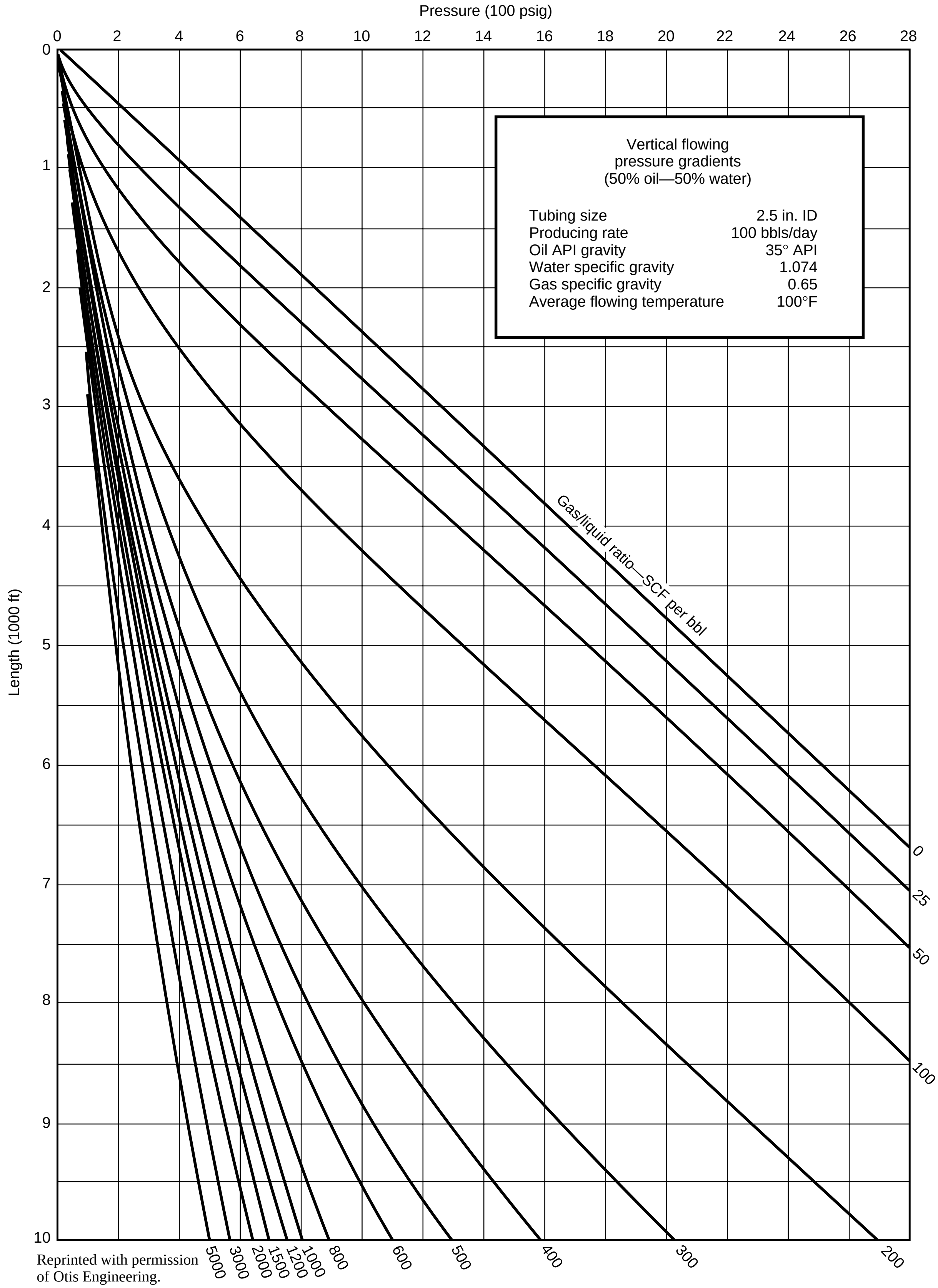

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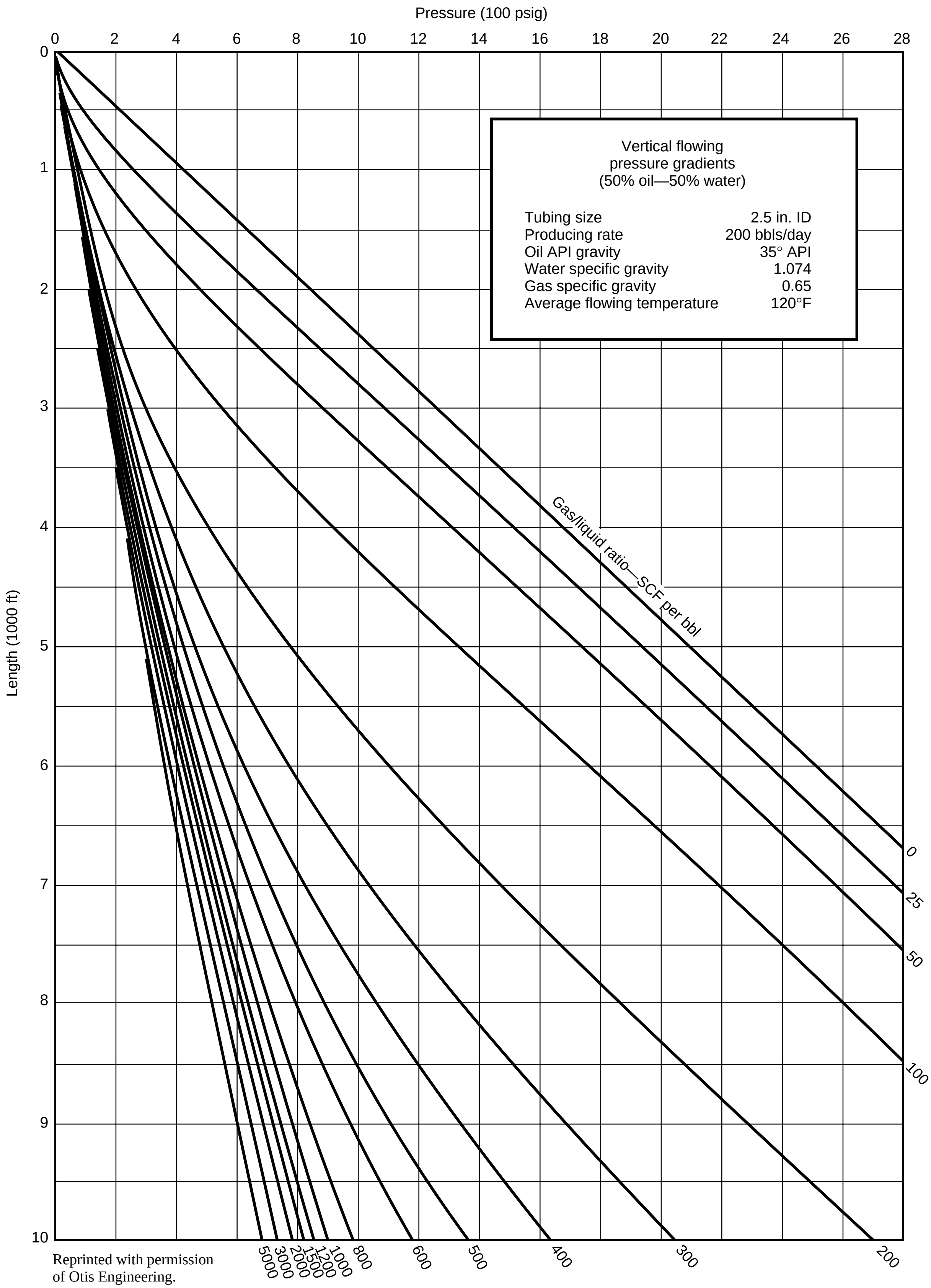

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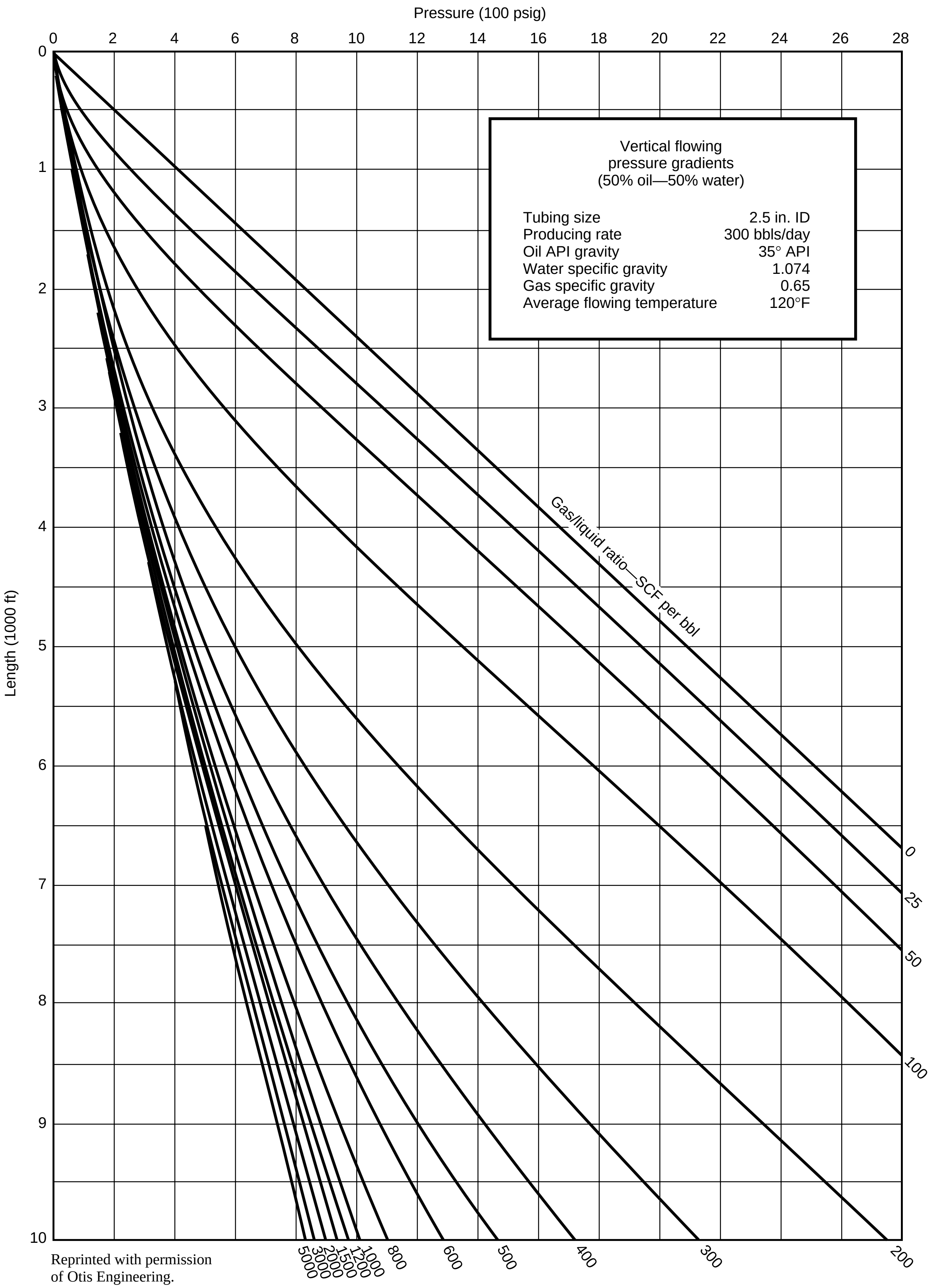

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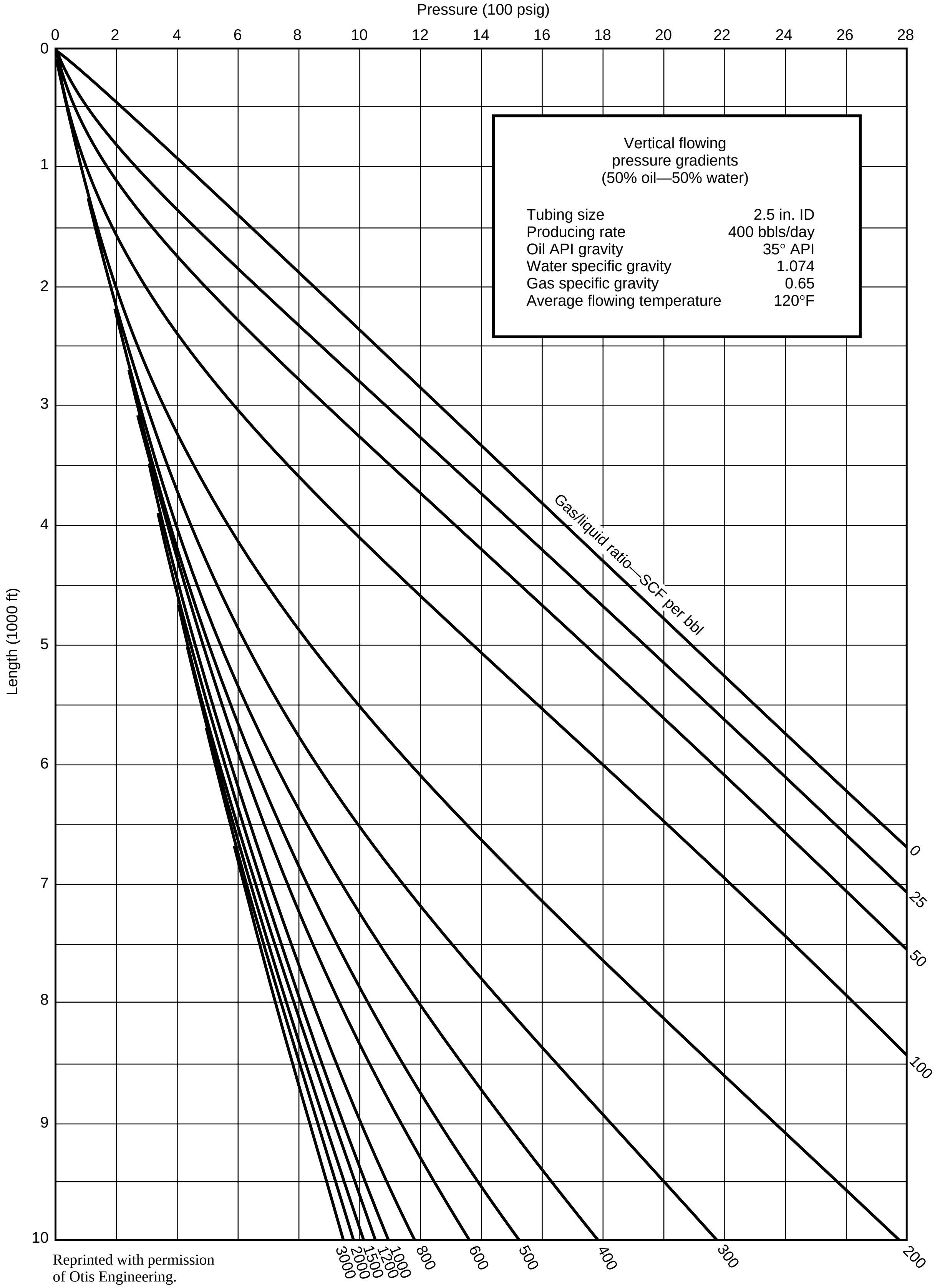

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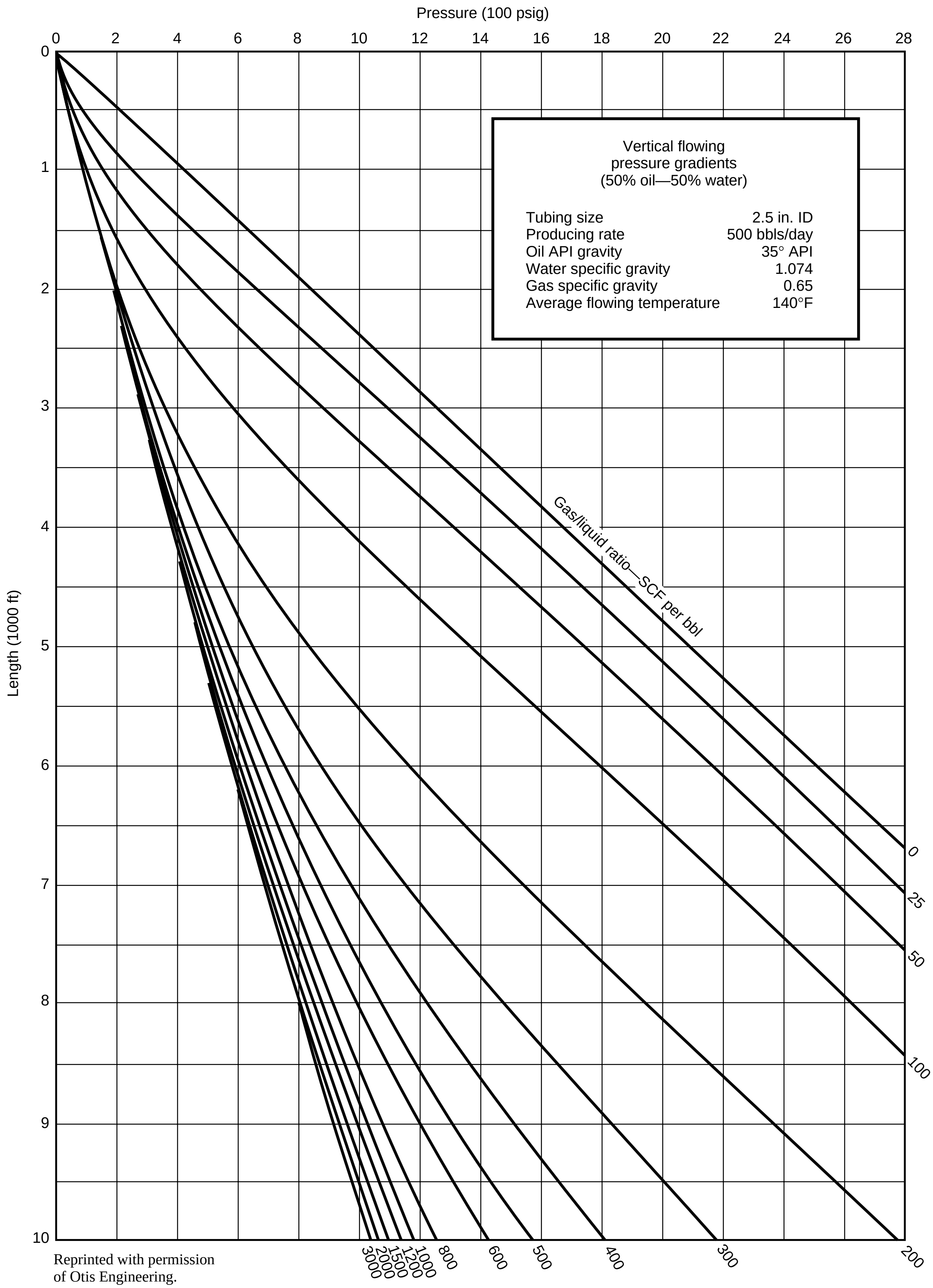

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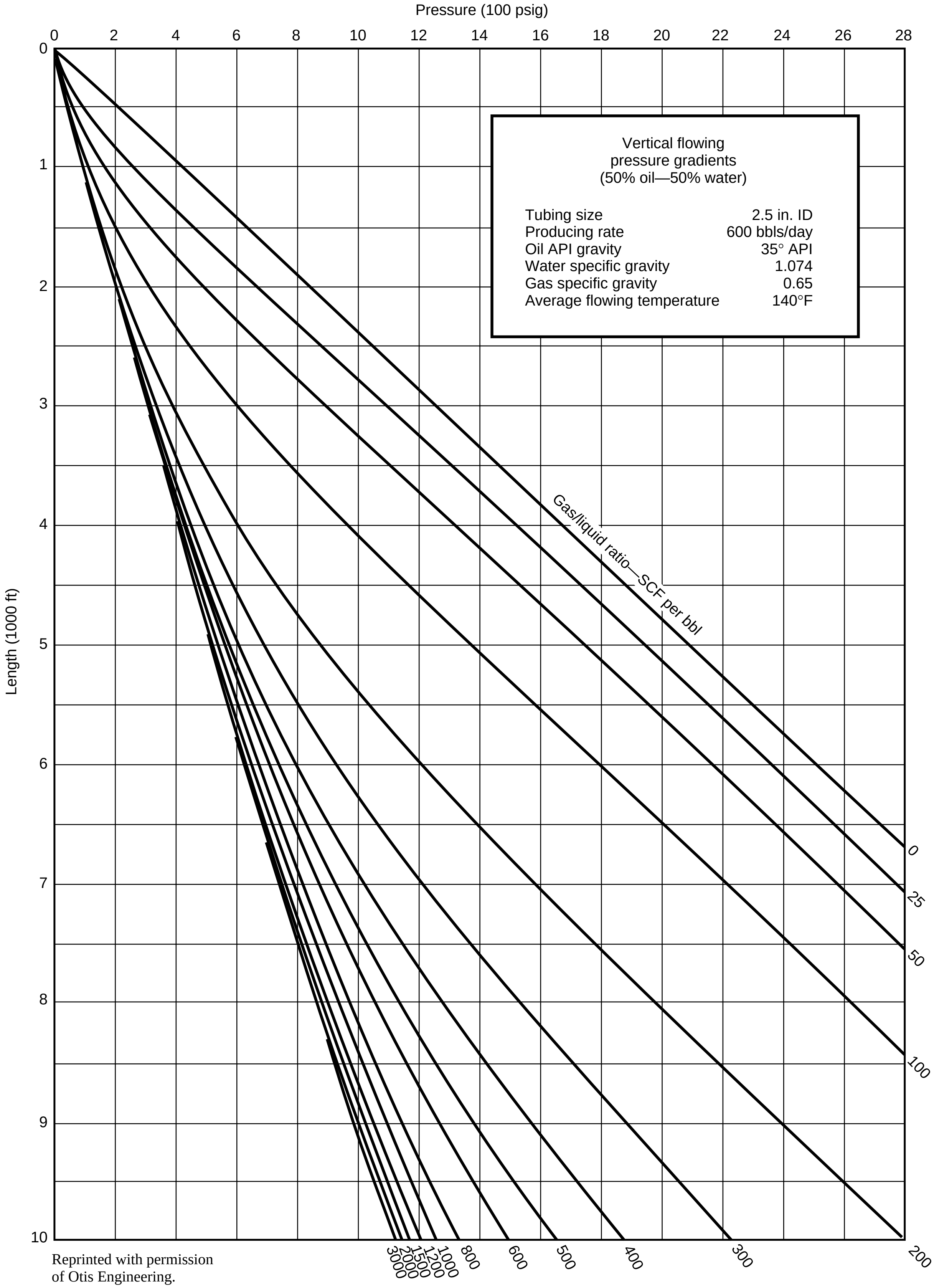

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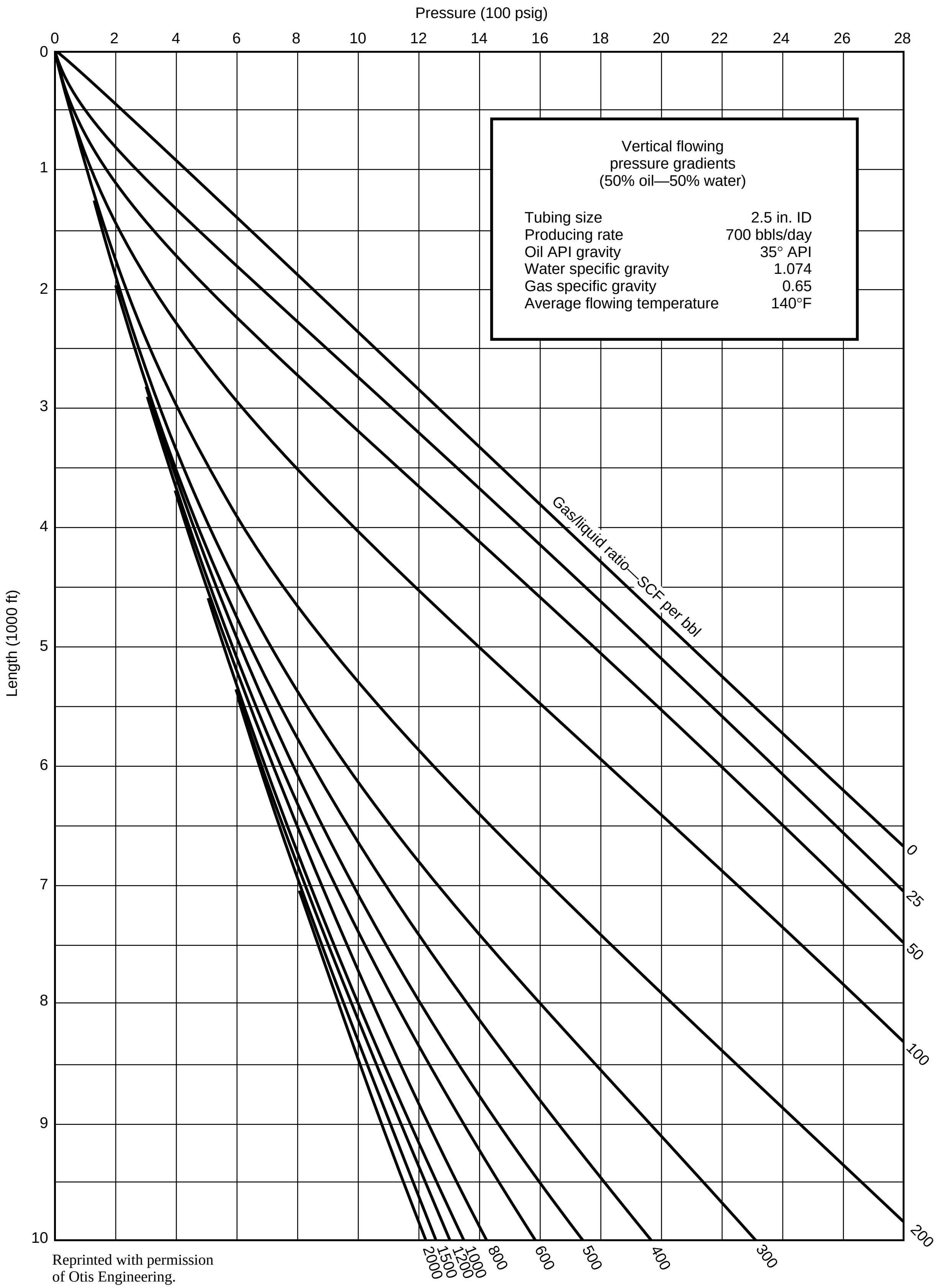

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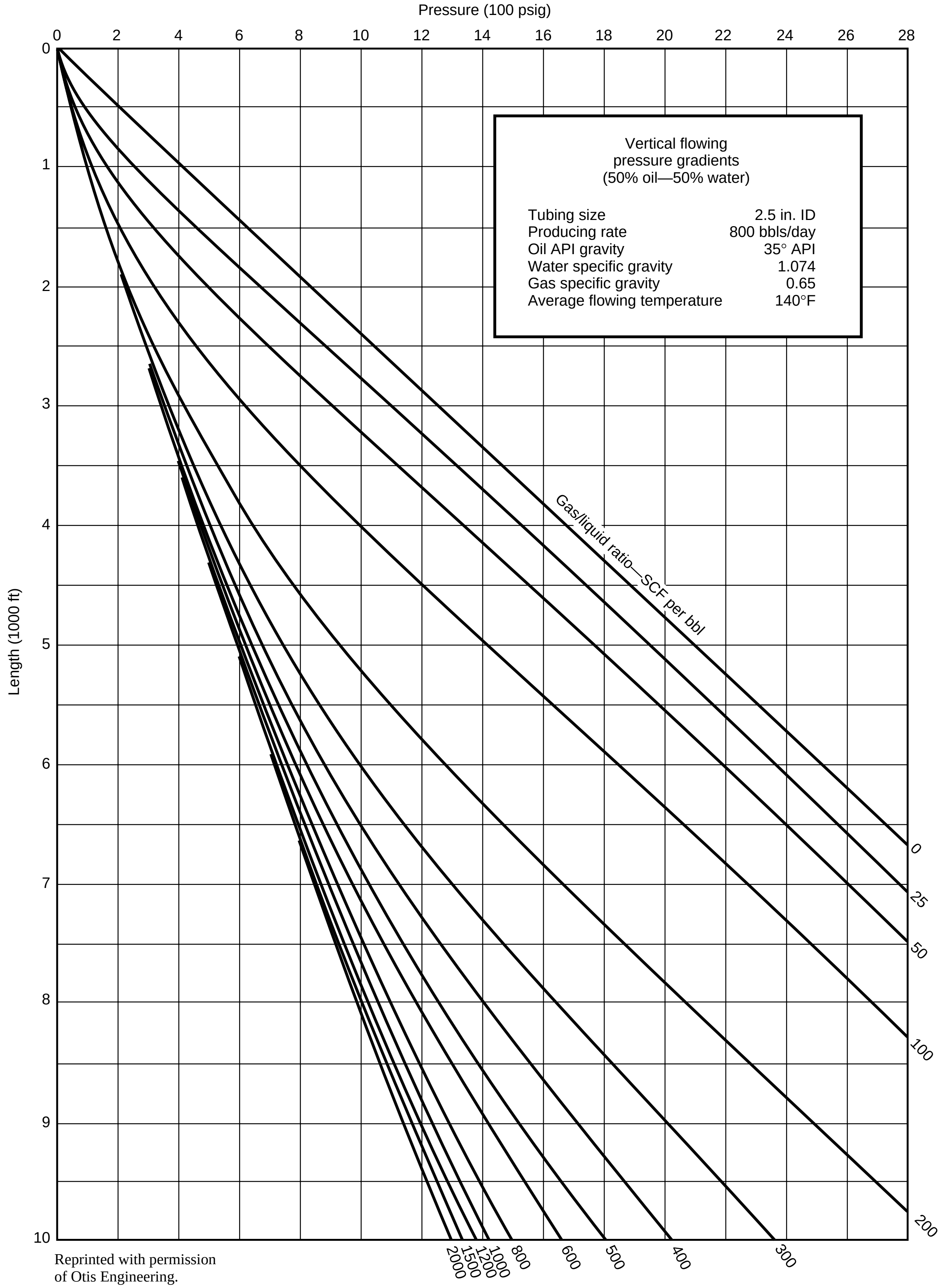

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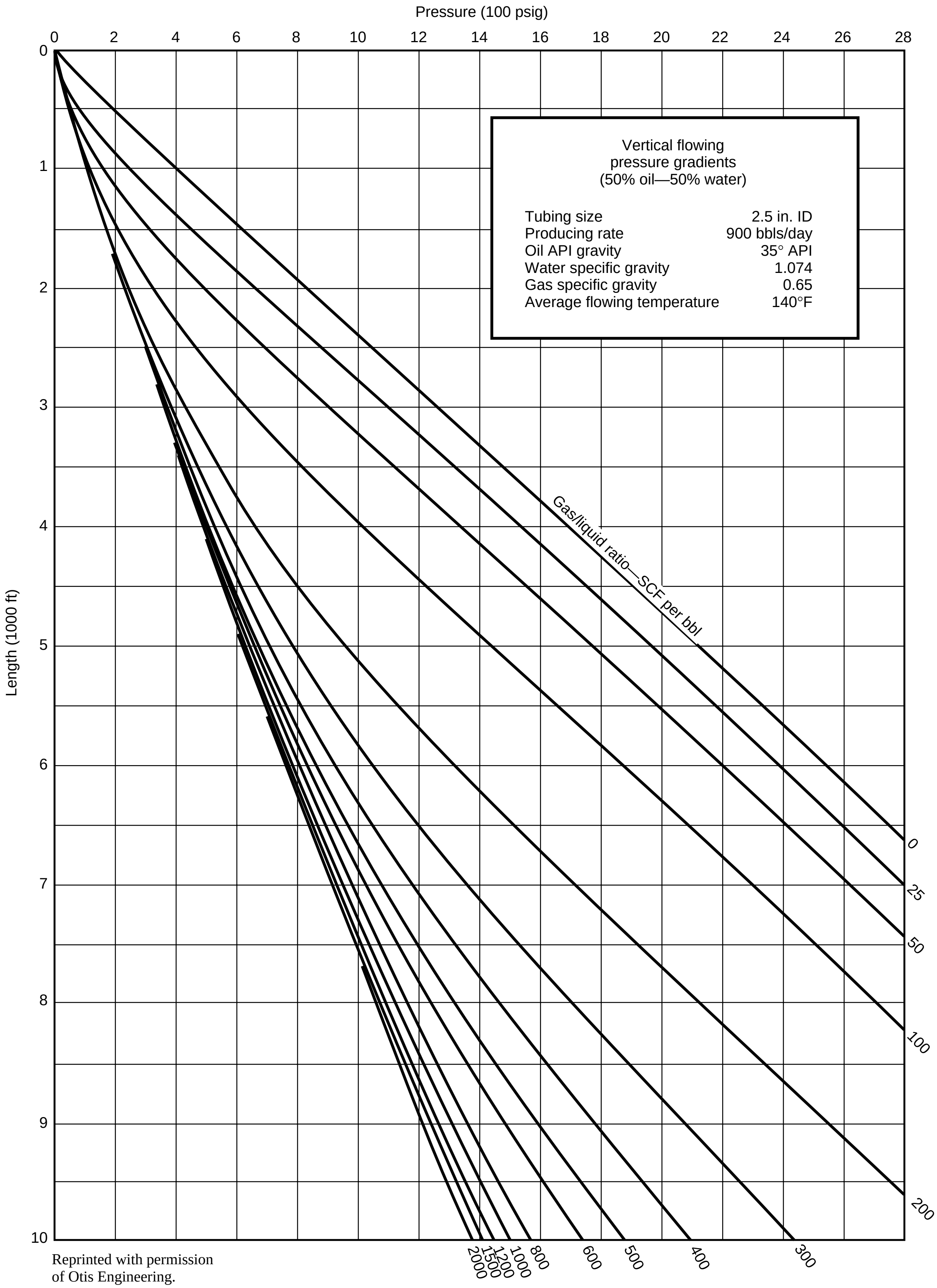

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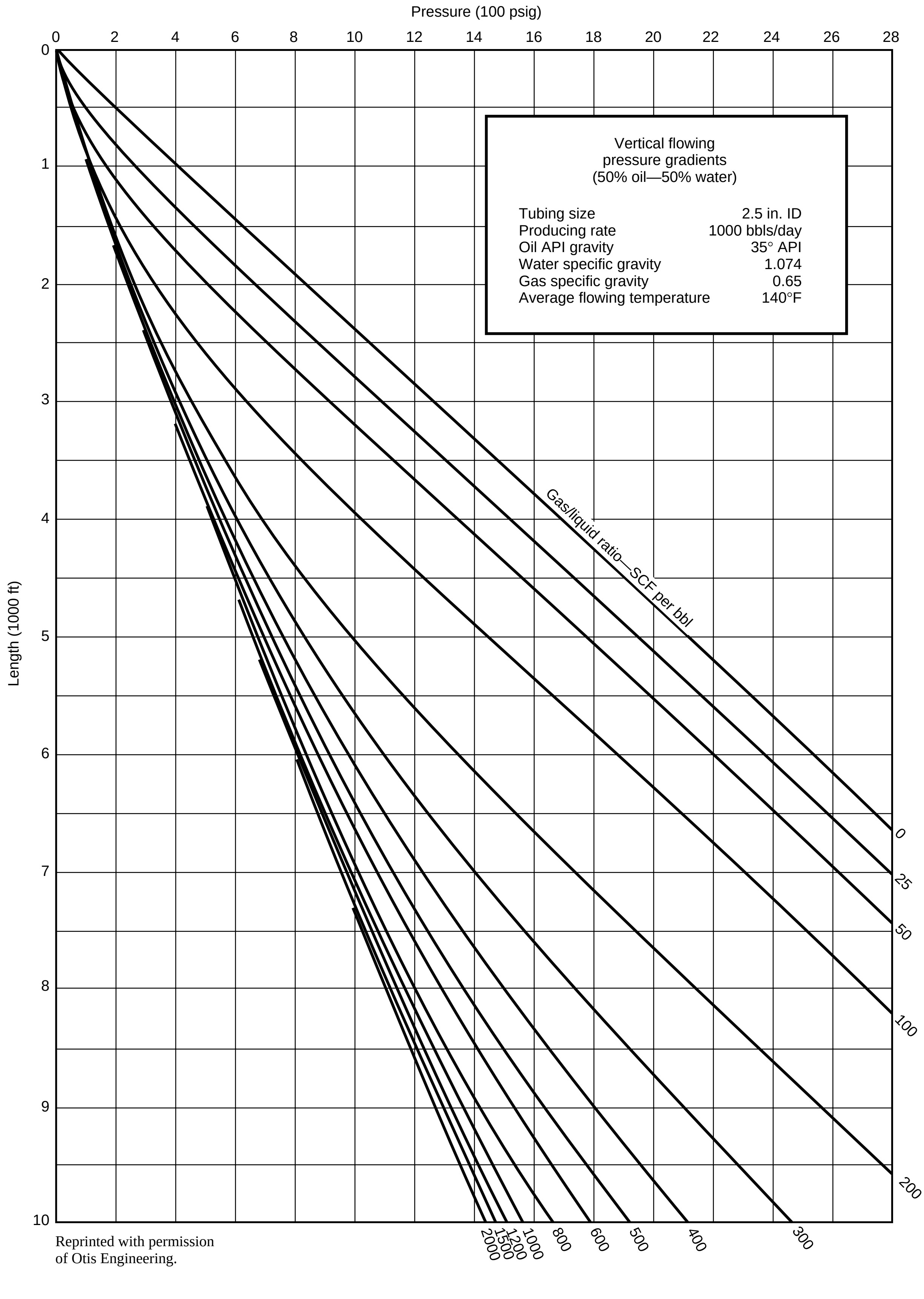

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