

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

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.

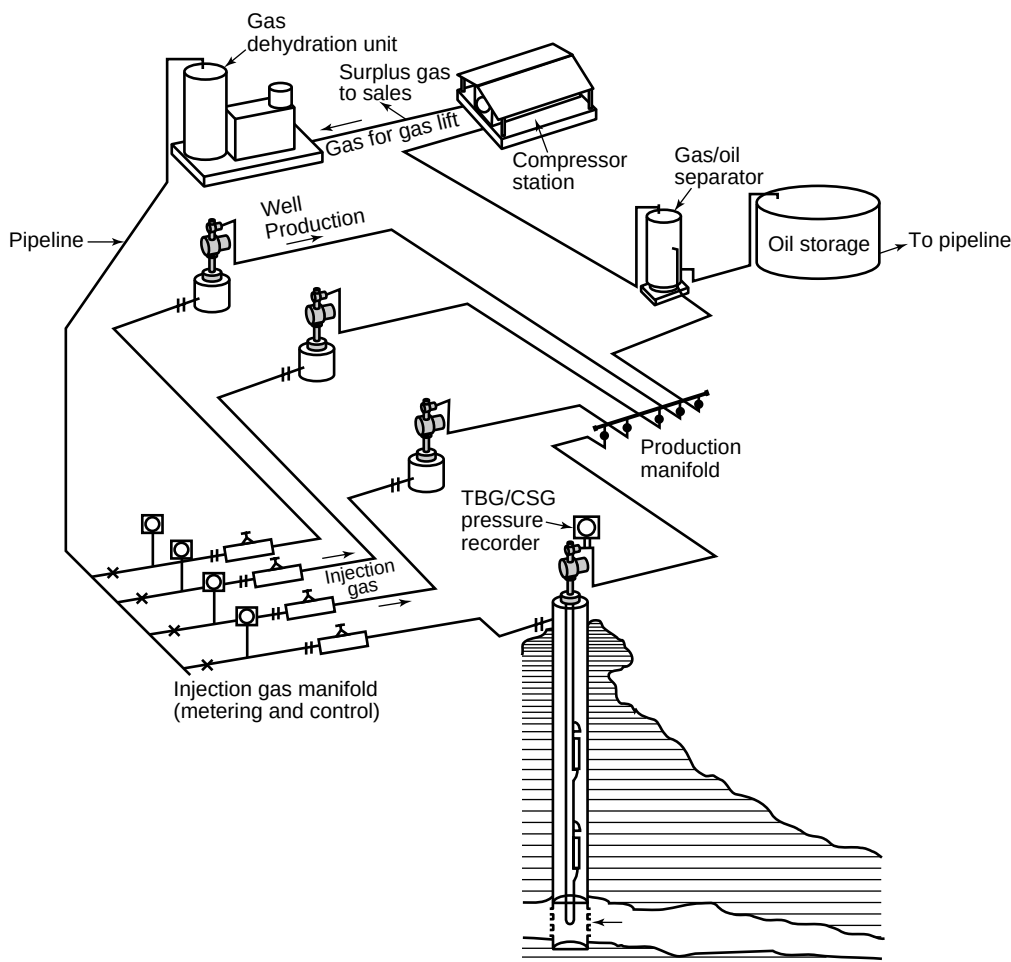


Figure 1—A Typical Gas Lift System

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 correlations¹, 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.

¹Commonly used correlations: Poettmann and Carpenter; Hagedorn and Brown; Orliszewski; 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; $\frac{5}{8}$ -in., 1-in., and $1\frac{1}{2}$ -in. The $\frac{5}{8}$ -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 $2\frac{3}{8}$ -in. tubing. They are used with both conventional and wireline retrievable mandrels. Some operators prefer the 1-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 $1\frac{1}{2}$ -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

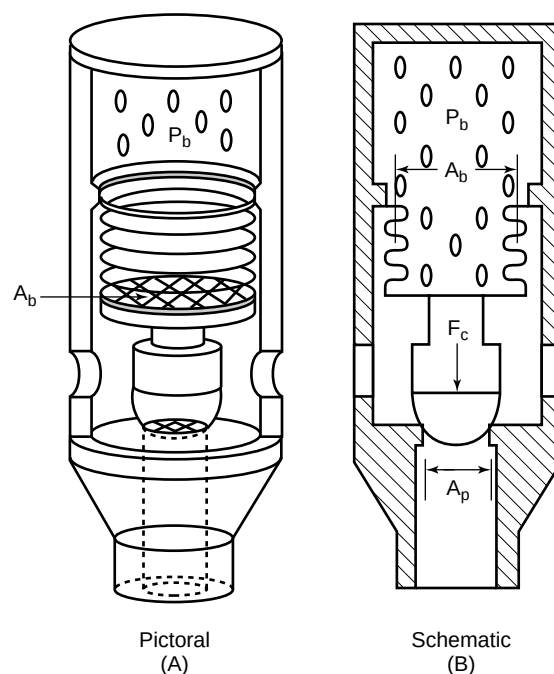


Figure 2

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)
$\frac{5}{8}$	$\frac{1}{8}$	10
	$\frac{5}{32}$	15
	$\frac{3}{16}$	20
1	$\frac{1}{8}$	5
	$\frac{3}{16}$	10
	$\frac{1}{4}$	15
	$\frac{5}{16}$	20
$1\frac{1}{2}$	$\frac{3}{16}$	5
	$\frac{1}{4}$	10
	$\frac{5}{16}$	15
	$\frac{3}{8}$	20
	$\frac{7}{16}$	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:

$$\begin{array}{rcl} 900 \text{ psi opening} & & 0.869 \text{ temperature} \\ \text{pressure downhole} & \times & \text{factor from} \\ \text{at } 130^\circ\text{F} & & \text{Table 4.1} \end{array} = \begin{array}{l} 782 \text{ psi opening} \\ \text{pressure in test} \\ \text{rack at } 60^\circ\text{F} \end{array}$$

²Other 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 $\frac{1}{2}$ -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:

- Select a minimum pressure by assuming a 0.05 psi/ft gas gradient plus the separator pressure.
- Assume an arbitrary minimum production pressure load such as 100 psi, 200 psi, etc.

- Assume no pressure so the flag valve will open dry without any production pressure being necessary.
- 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:

- 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 $\frac{3}{16}$ -in. or smaller ported 1-in. valves, or $\frac{1}{4}$ -in. or smaller ported 1 $\frac{1}{2}$ -in. valves.
- 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.
- 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 2⁷/₈-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 hydro pressured 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 E4E
- * 11. SSSV: mfg & type _____; Depth _____ ft; Bore _____ in.
- * 12. Wellhead mfg & type _____; (Bore ID) 2 9/16 in.; 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. H₂S (yes/no) No; CO₂ (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 9/

*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:

$$(1500 - 350) \times 800/1000 = 920 \text{ MCFD injection gas}$$

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

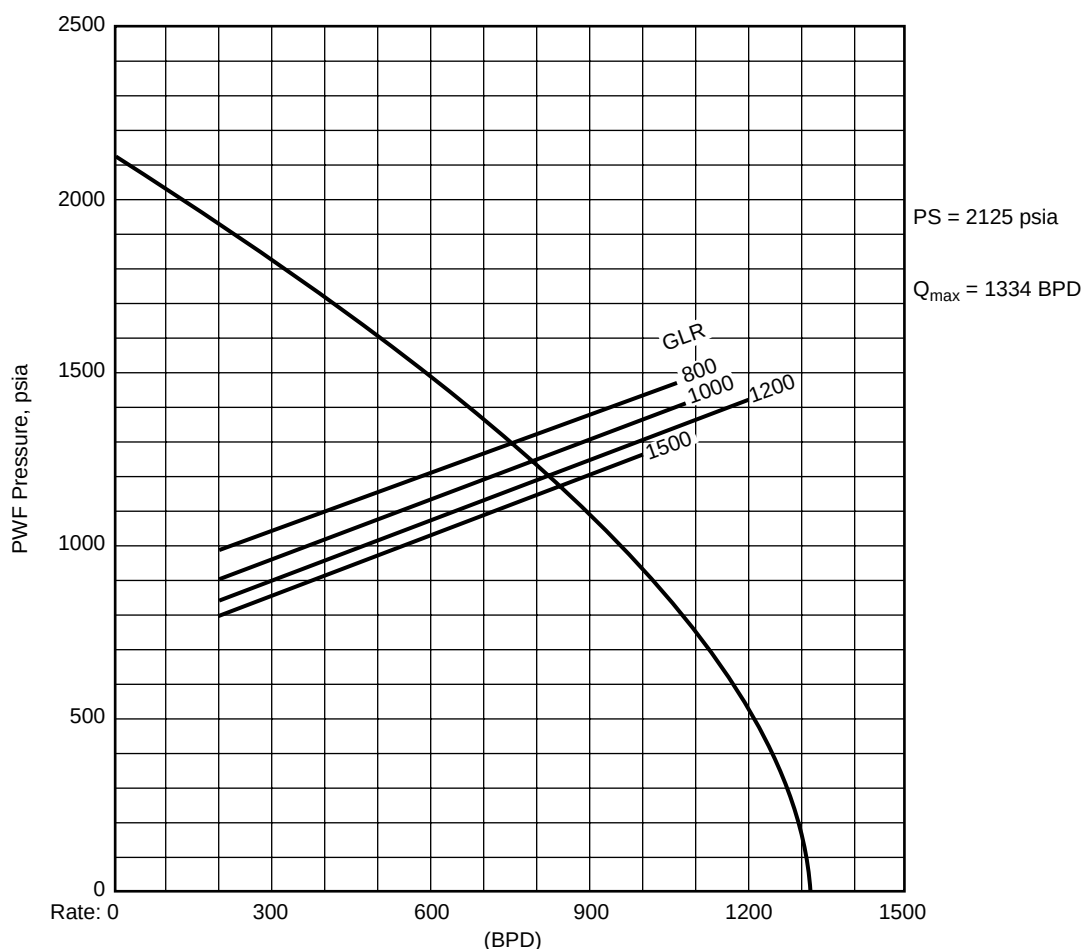


Figure 4—Oil IPR Graph

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:

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

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 = $(78 + 178)/2 = 128^\circ\text{F}$. (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

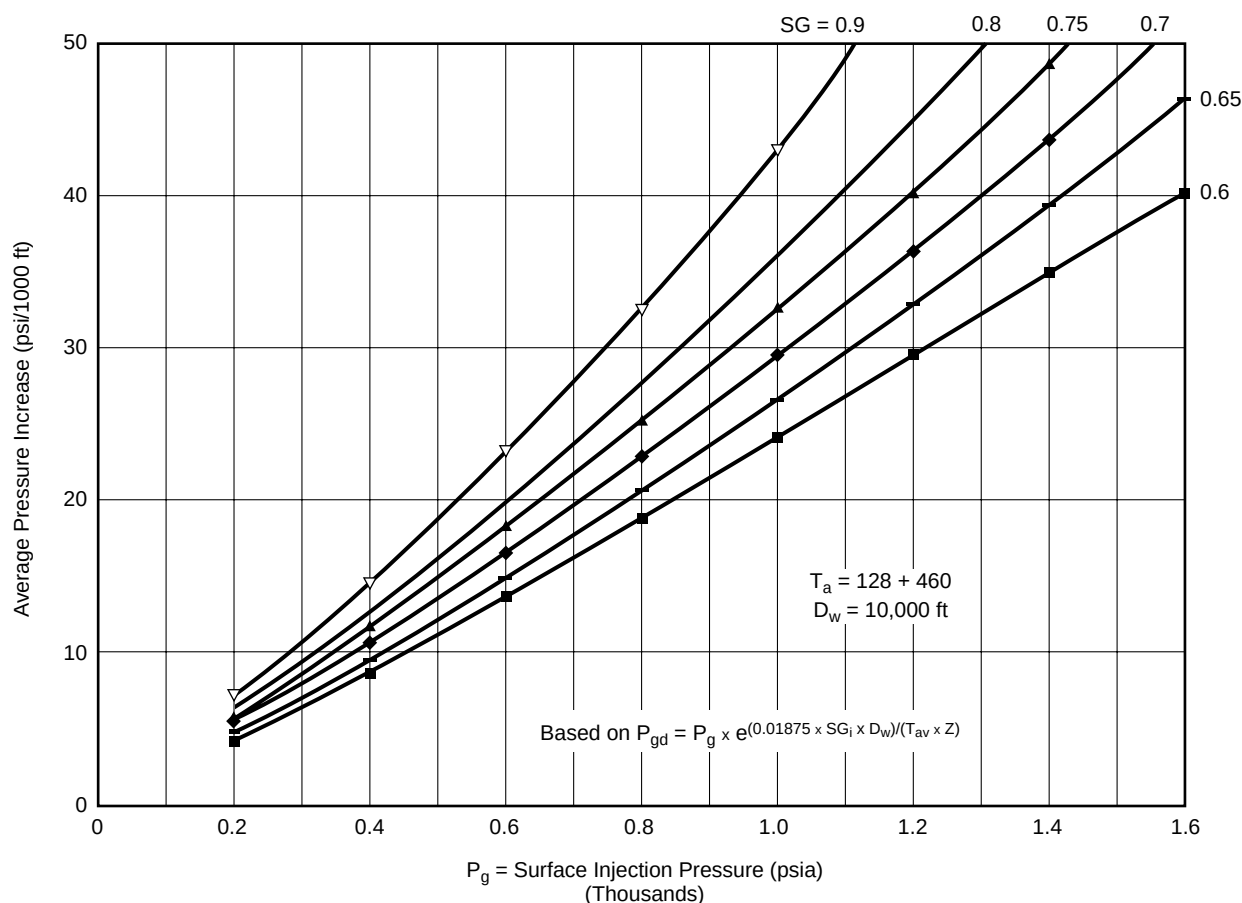


Figure 5—Weight of Injection Gas Column

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:

$$\text{Tubing pressure} = \text{casing pressure} - \text{Nominal Pressure Differential}$$

(or)

$$\text{Maximum unloading flowing pressure} = \text{gas injection pressure} - P_{sf}$$

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

$$100 + 0.465 \times D_{(1)} = 1200 + 0.03 \times D_{(1)} - 20$$

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

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

(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:

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

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

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

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

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

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

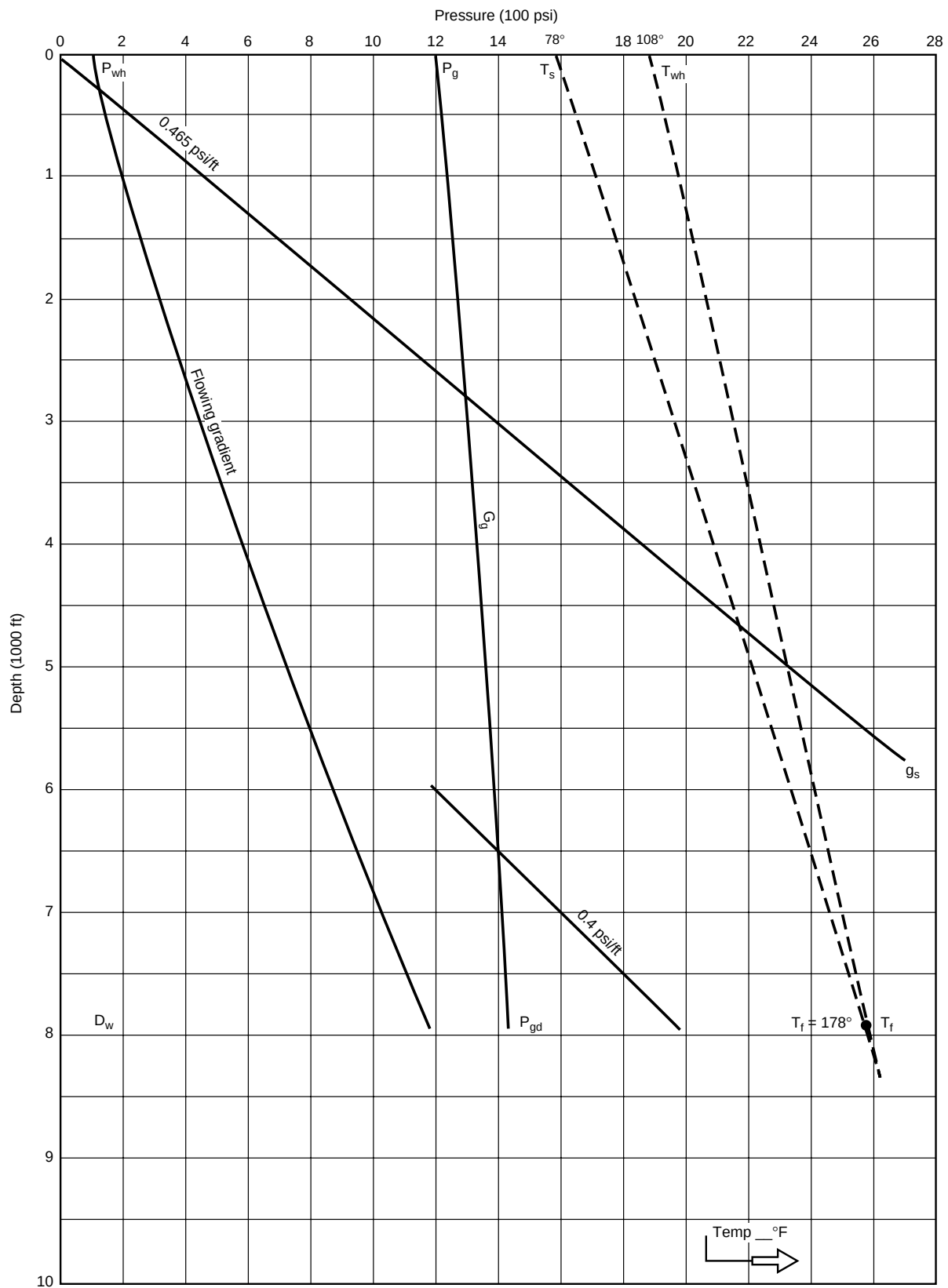


Figure 6—Gas Lift Design

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.

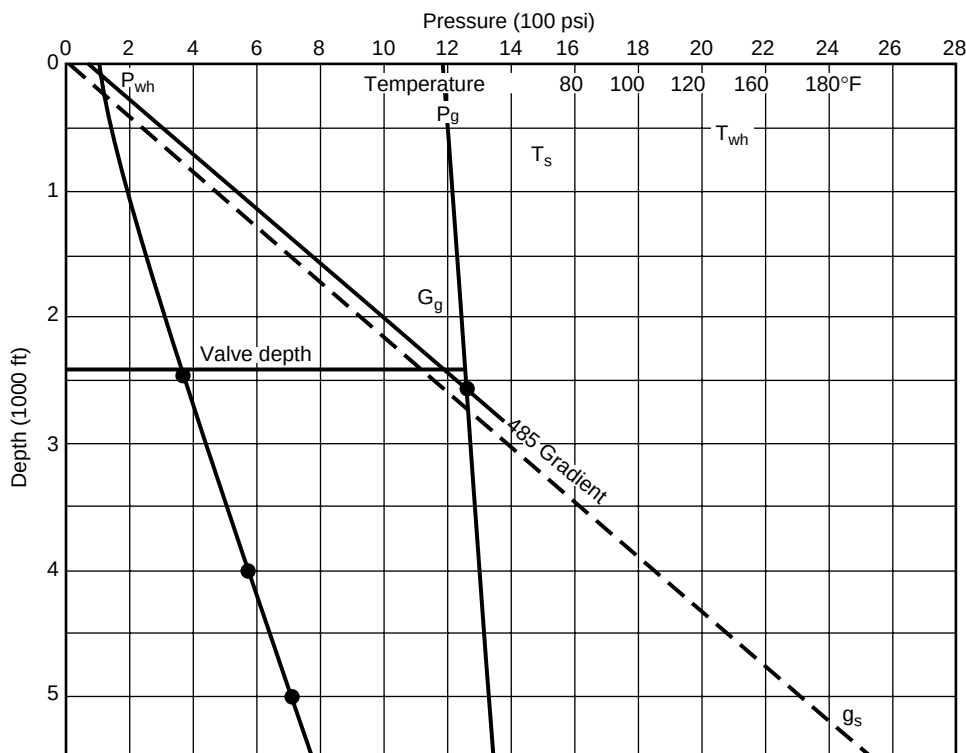


Figure 7

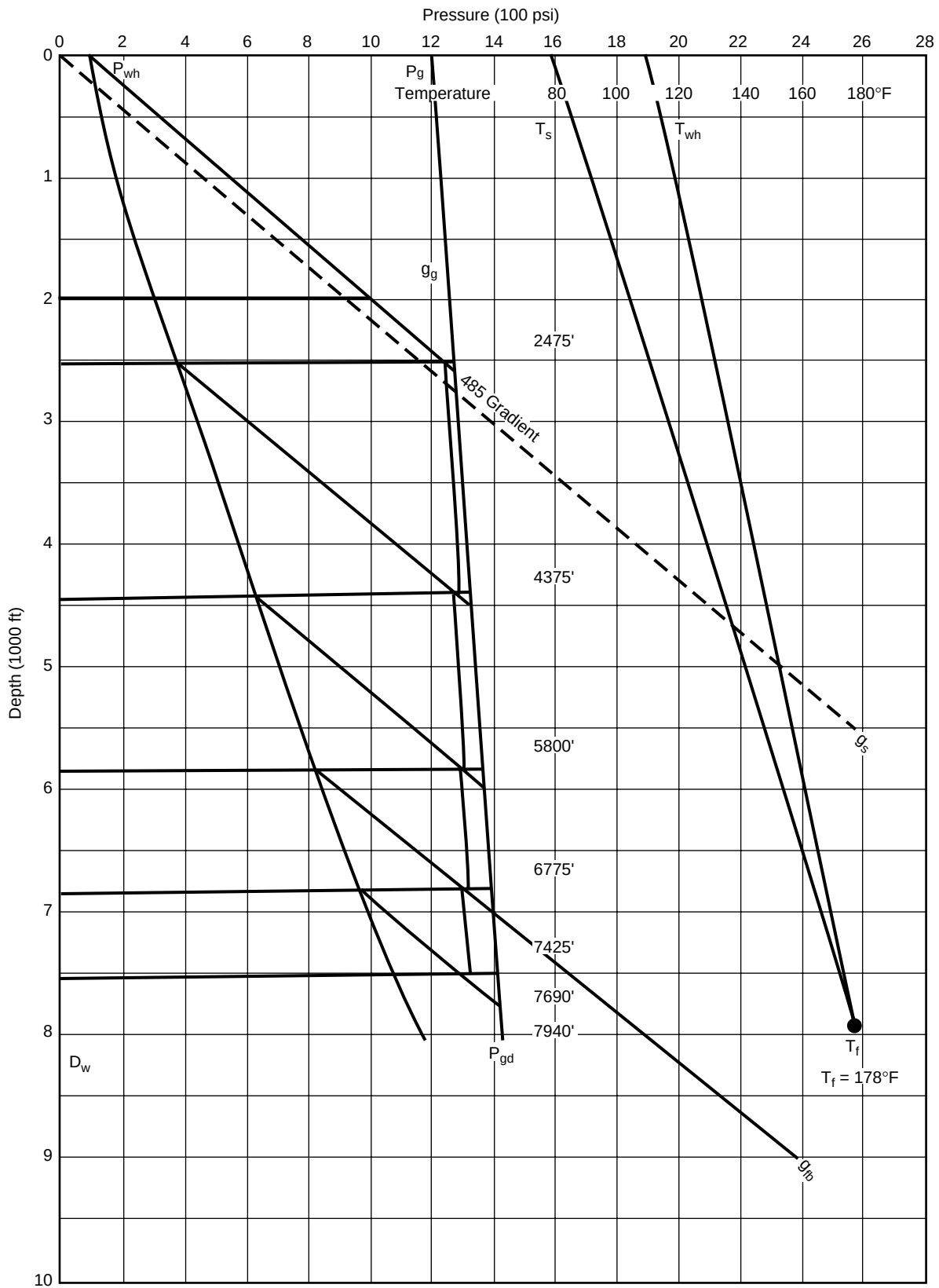


Figure 8

5.1.14 Valve Selection

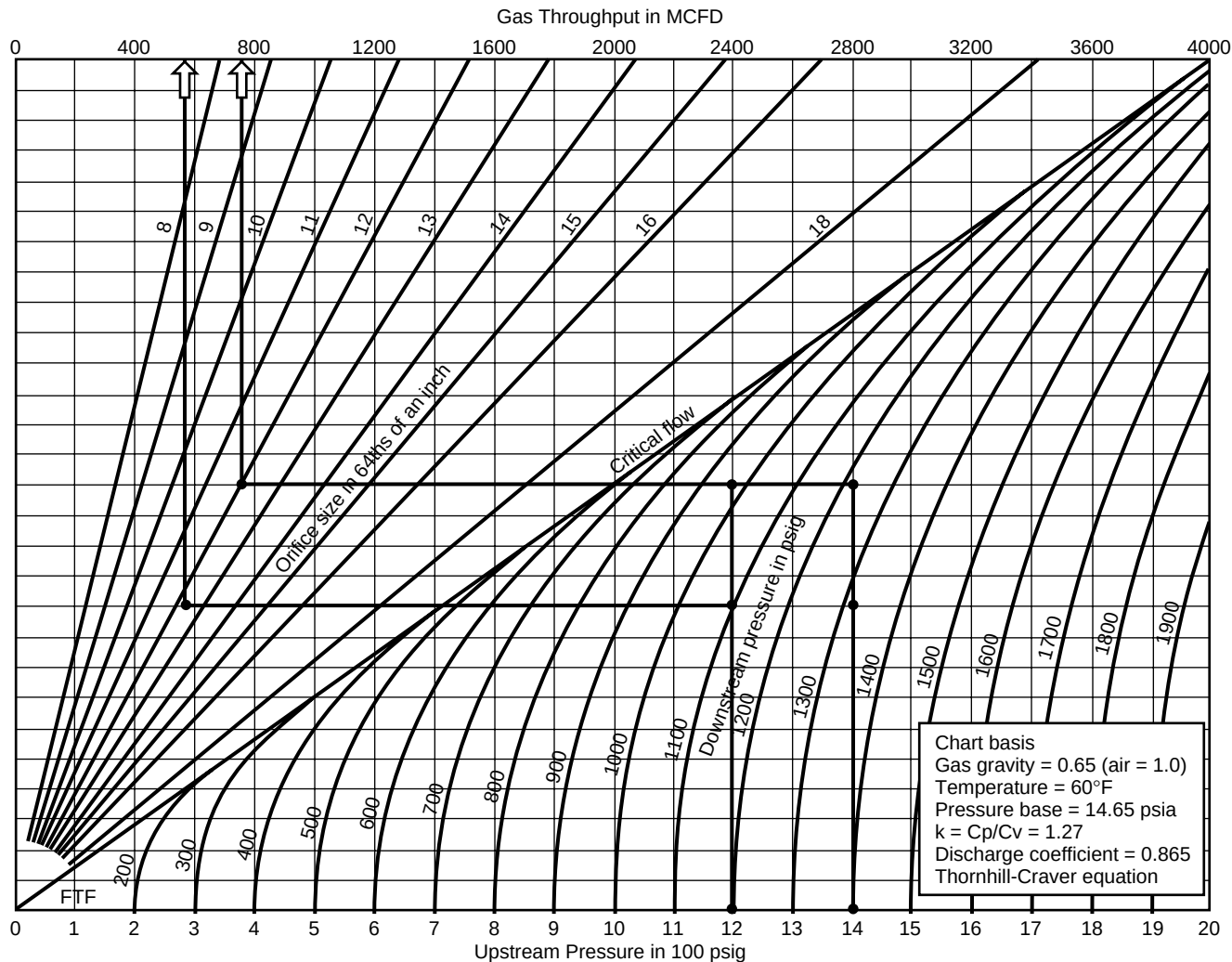
5.1.14.1 This design is for injection pressure valves. The commonly used 1-in., unbalanced, nitrogen-charged bellows valve was selected. This selection was based on good experience with using 1-in. valves where gas injection rates are relatively low (less than 750 MCFD), and since the cost of 1-in. valves and mandrels are less than the larger 1½-in. valves and mandrels. High rate wells (> 2000 BPD) may produce better with 1½-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:

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

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

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			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				= $1^{14}/_{64}$ in. Orifice

^aSome 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 $1\frac{1}{4}$ -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 $\frac{3}{16}$ -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 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.

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:

- 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).
- 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).
- 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

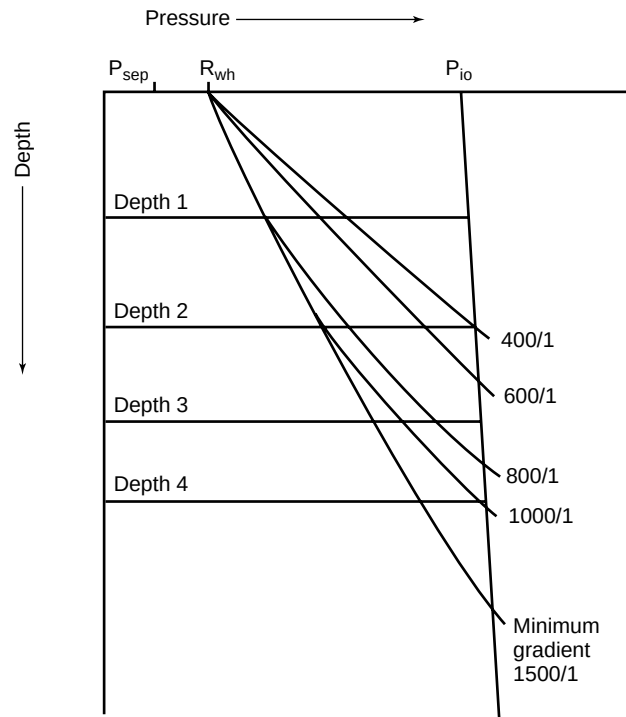


Figure 10

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:

$$P_{eo} = \frac{\text{Effective Opening Pressure}}{P_{PEF}} = \frac{\text{Prod. Pressure}}{\text{Effect Factor}} \times \frac{\text{Production Pressure Acting on Valve}}{P_{pd}}$$

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

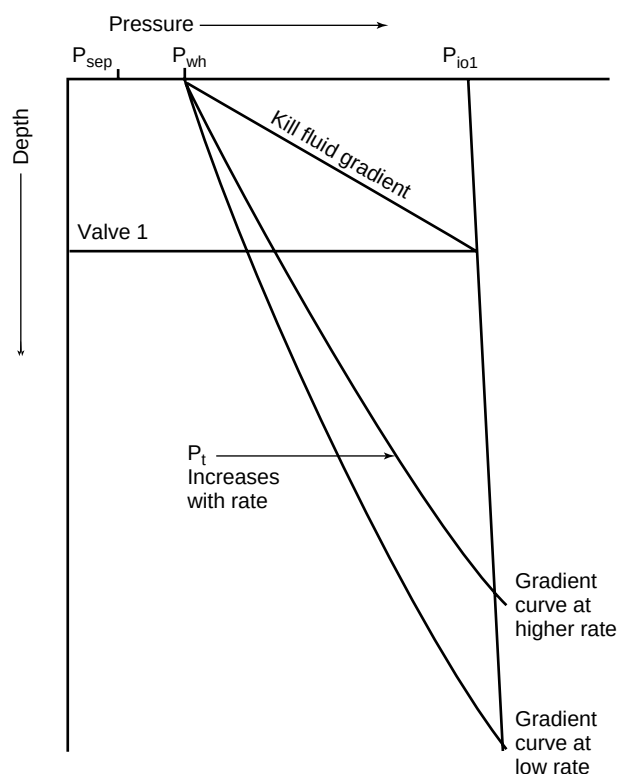


Figure 11A

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.

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}