Schlumberger

Gas Lift Design and Technology

Schlumberger
Well Completions and Productivity
Chevron Main Pass 313 Optimization Project
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1. Introduction & Basic Principles of Gas Lift

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CHAPTER OBJECTIVE: To give an overview of gas lift principles and their applications with illustrations of continuous and intermittent gas lift installations.

Most wells completed in oil producing sands will flow naturally for some period of time after they begin producing. Reservoir pressure and formation gas provide enough energy to bring fluid to the surface in a flowing well. As the well produces this energy is consumed, and at some point there is no longer enough energy available to bring the fluid to the surface and the well will cease to flow. When the reservoir energy is too low for the well to flow, or the production rate desired is greater than the reservoir energy can deliver, it becomes necessary to put the well on some form of artificial lift to provide the energy to bring the fluid to the surface. The types of artificial lift available are illustrated in Figure 1-1. When gas lift is used, high-pressure gas provides the energy to enable the well to produce.

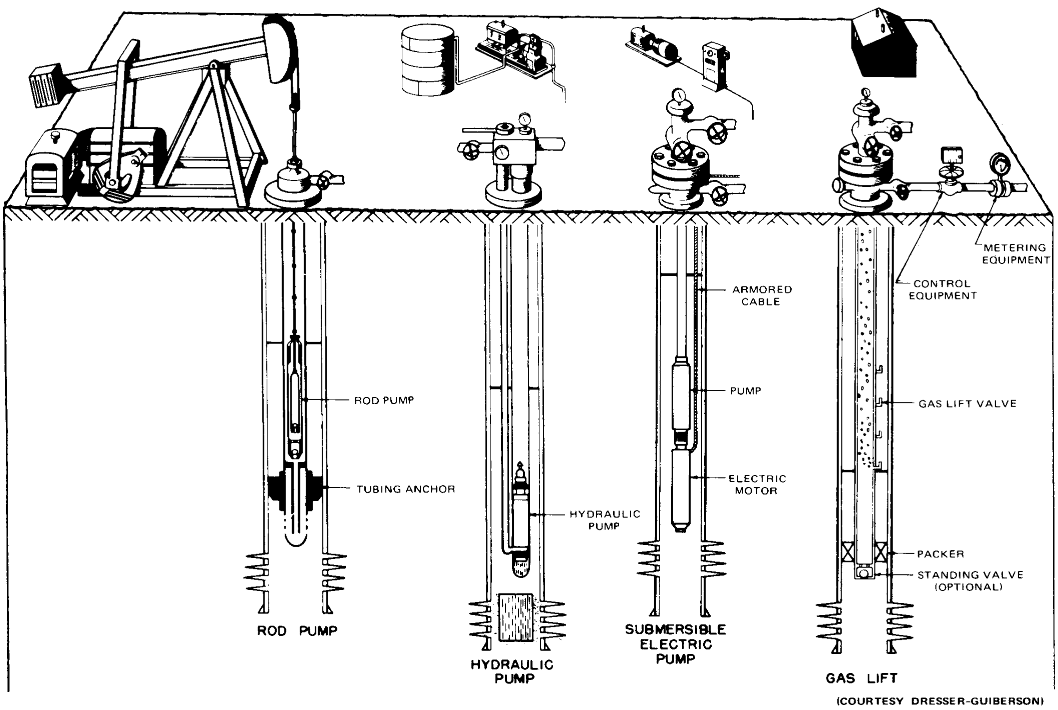


FIGURE 1-1: Artificial Lift Systems

When a well is completed, a series of conductor pipes and accessories are installed during well completion operations. The basic components of the system are labeled in Figure 1.2. This is a simplified illustration of a cased hole single zone completion. Dual and triple completions are much more complex and will not be considered here. The inner surface of the well bore is supported by the casing string. There may be up to three separate casing strings including a surface and intermediate string. The space between the tubing and casing is called the annulus. The packer seals the annulus just above the producing zone. The casing has been perforated adjacent to the producing zone to allow entrance of gas and liquid products into the wellbore or the tubing string may extend into the open hole. When reservoir drive does not provide enough pressure to lift fluids to the surface, additional equipment must be installed to help lift the fluids. There are four basic types of artificial lift: sucker rod pumping, hydraulic pumping, centrifugal pumping and gas lift.

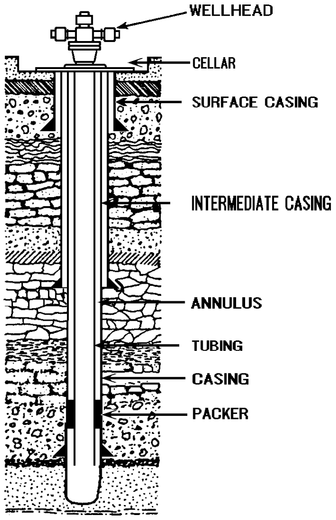


Figure 1-2 Completed Well

Table 1.1 compares these systems and lists the advantages and disadvantages of each. As you can see there are two basic types of gas lift used in the oil industry. They are called continuous flow gas lift and intermittent gas lift. The two types operate on different principles and it is always advisable to treat them as two separate subjects.

Table 1.1 Types of Artificial Lift Systems

Advantages	Disadvantages
Continuous	
GAS LIFTING	
1. Takes full advantage of the gas energy available in the reservoir. 2. Is a high volume method. 3. Equipment can be centralized. 4. Can handle sand or trash best. 5. Valves may be wireline or tubing retrieved.	1. Cannot pump off and minimum bottom hole producing pressure in creases both with depth and volume. 2. Must have a source of gas.
Intermittent	
1. Can obtain lower producing pressure than continuous gas lift obtains and at low rates. 2. Equipment can be centralized. 3. Valves may be wireline or tubing retrieved.	1. Is limited in maximum volume. 2. Cannot pump off. 3. Causes surges on surface equipment. 4. Must have a source of gas.
Rod Pumping:	
1. Is possible to pump off. 2. Is best understood by field personnel. 3. Some pumps can handle sand or trash. 4. Where suitable, it is usually the cheapest lift method.	1. Maximum volume drops off fast with depth. 2. Is very susceptible to free gas in pump. 3. Equipment gets scattered over lease. 4. Pulling rods are required to change pump.
Hydraulic Pumping:	
1. High volume can be produced from great depth. 2. It is possible to almost pump off. 3. Equipment can be centralized. 4. Pumps can be changed without pulling tubing.	1. Is very susceptible to free gas in pump causing damage. 2. Is vulnerable to solid matter in pumps. 3. Oil treating problems are greatly increased because of power oil in well stream. 4. Well testing can be difficult due to power oil including in well stream.
Centrifugal Pumping:	
1. Very high volumes at shallow depth can be produced. 2. Is possible to almost pump off.	1. Maximum volume drops off fast with depth. 2. Is very susceptible to free gas in pump causing damage. 3. Control equipment is required on each well. 4. Tubing must be pulled to change pump and cable.

Advantages and Limitations of Gas Lift

The flexibility of gas lift in terms of production rates and required depth of lift cannot be matched by other methods of artificial lift for most wells if adequate injection gas pressure and volume are available. Gas lift is considered one of the most forgiving forms of artificial lift since a poorly designed installation will normally gas lift some fluid. Many efficient gas lift installations with wireline retrievable gas lift valve mandrels are designed with minimal well information for locating the mandrel depths upon initial well completion in offshore and inaccessible onshore locations.

Highly deviated wells that produce sand and have a high formation/liquid ratio are excellent candidates for gas lift when artificial lift is needed. Many gas lift installations are designed to increase the daily production from flowing wells. No other method is as ideally suited for through-flow-line (TFL) ocean floor completions as a gas lift system. Maximum production is possible by gas lift from a well with small casing and with high deliverability and bottomhole pressure.

Wireline retrievable gas lift valves can be replaced without killing a well with a load fluid or pulling the tubing. Most gas lift valves are simple devices with few moving parts. Sand laden well production fluids do not pass through the operating gas lift valve. The subsurface gas lift equipment is relatively inexpensive. The surface injection gas control equipment is simple and light in weight. This surface equipment requires little maintenance and practically no space for installation. The reported overall reliability, replacement and operating costs for subsurface gas lift equipment are lower than for other methods of lift.

The most important limitation of gas lift operation is the lack of formation gas or the availability of an outside source of gas. Other limitations include wide well spacing and unavailable space for compressors on offshore platforms. Gas lift is seldom applicable to single well installation and to widely spaced wells that are not suited for a centrally located power system. Gas lift is not recommended for lifting viscous crude, a super-saturated brine or an emulsion. Old casing, dangerously sour gas and long small ID flowlines can eliminate gas lift operations. Wet gas without proper dehydration will reduce the reliability of gas lift operations.

Designing systems of artificial lift requires obtaining considerable information about well conditions.

Although some measurements are taken, some of the required data must be estimated by making certain inferences from available data. A system of nomenclature has been adapted by petroleum experts to designate certain well data.

It is important to know the pressure at various points in the system. Pressure is expressed in pounds per square inch (psi) or [Kilopascals (kPa)]. For gas lift calculations, pressure is understood as gauge pressure (psig).

Figure 1.3 illustrates some points in a well where pressure readings are taken. Pressure at the bottom of the hole (P_{bh}) caused by the drive mechanism within the reservoir can be expressed as a static pressure (P_{bhs}) or if the well is flowing as a flowing bottom hole pressure (P_{bhf}). If a flowing well is shut in, the bottom hole pressure is expressed as P_{ws}. It is necessary to use pressure data along the tubing string (P_t) and within the tubing casing annulus (P_c). The tubing pressure at the wellhead is referred to as P_{wh}. Temperature is measured along the tubing string from the wellhead (T_{wh}) to bottom hole (T_{bh}) as can be seen in Figure 1.4. Temperature is usually expressed in degrees Fahrenheit or degrees Celsius.

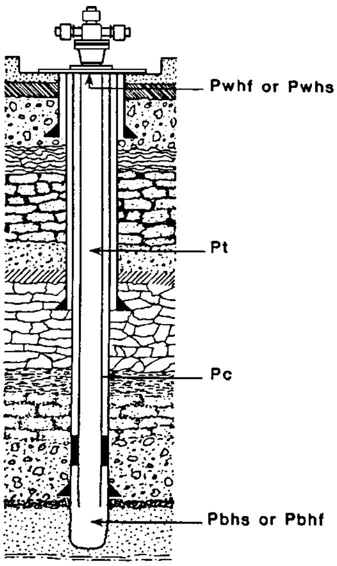


Figure 1.3

Well Measurements

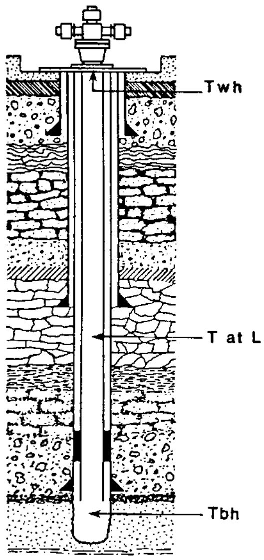


Figure 1.4

Well Temperature Measurements

For intermittent gas lift installations, the calculation of volume of the tubing and casing for a given length is required for gas lift design. When the annular volume and tubing volume are known, a ratio of these volumes can be calculated (F_{ct}). The static fluid level (SFL) refers to the level of liquid before artificial lift occurs and the working fluid level (WFL) is the level of the fluid during any given time during artificial lift (See Figure 1.5). Wells that are in production vary a great deal (See Figure 1.6). A considerable amount of information about the quality and quantity of the fluids produced is necessary for gas lift design. The specific gravity (S.G.) or relative density of the liquid can be determined. The mixture can be analyzed by comparing the amount of Gas (qg) to Liquid (ql) deriving the Gas to Liquid Ratio (GLR), the amount of Gas to Oil (GOR) and the amount of water (qw) to amount of oil to (qo) deriving WOR ratio.

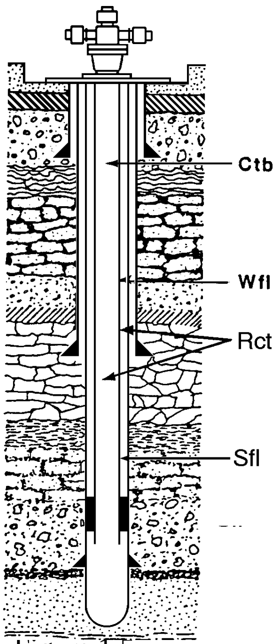


Figure 1.5

Well Fluids

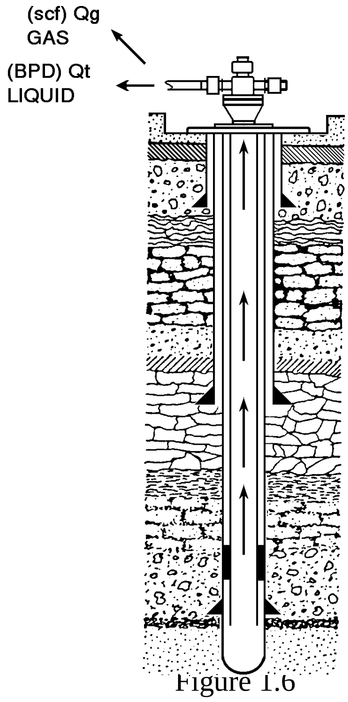


Figure 1.6

A Producing Well

Quantities of gas (Q) are expressed in scf or standard cubic feet, defined as a cubic foot of a gas under standard conditions (14.73 psia and 60°), or [M^3] [M^3 standards are 20 C and 101.32 kPa]. The change in any variable, from one point to another, is referred to as a gradient (G). A number of gradients (pressure and temperature) are observed as one travels up and down the tubing string.

For a gas lift system to work correctly, the following basic concepts and components must be understood.

1. The well is capable of production but lacks reservoir energy to raise the produced fluids to the surface. These fluids will rise to some point called the static fluid level and must be lifted from that point to the surface by artificial means.

2. The gas pressure must be adequate for injection into the well. Either it has sufficient pressure to make the gas lift system operate, or it must be compressed to raise the pressure. The volumes of gas to be used and the pressures available to the well will have been taken into account in designing the gas lift installation. The gas line bringing the input gas to the well will be of adequate size and pressure rating to handle the gas supply. Before connecting the gas line to the control equipment, it is essential that the line be flushed for a period of time to eject all foreign matter such as dirt, trash, etc. from the line. Much of the control equipment is susceptible to being plugged with such foreign matter, giving rise to operating problems in the future.

3. Gas lift valves are placed in mandrels, which are run in the tubing string and are automatic in operation, opening and closing in response to preset pressures. Conventional mandrels are run on the tubing with the valve mounted on the exterior part of the mandrel before the string is run. Figure 1.7

compares the conventional mandrel with the side pocket mandrel. The side pocket mandrel, one of Camco's major products, allows the gas lift valves to be installed and retrieved by wireline methods. The spacing of the valves in the tubing string, the selection of valve type, and the pressure setting of each valve installed in the well are very important and have to be carefully planned.

4. One or more control devices are installed on the surface to control the timing and volume of gas injected. The diagram in Figure 1.8 illustrates the surface components of a closed rotative system used with intermittent gas lift. The system may be much simpler if a natural or outside source of high-pressure gas is available and the well is on continuous flow lift. The distinction between continuous flow and intermittent flow will be discussed in the next lesson. The components may include a metering valve that will allow careful adjustment. A clock timer can be used so that gas may be injected at intervals in response to tubing or casing pressure.

5. The produced fluids are discharged into a conventional oil, water, and gas separator. Restrictions in the surface flow line should be minimized, and the backpressure on the separator should be kept as low as possible. A pressure recorder should be available to record tubing and casing pressures under operation conditions; a gas meter, either permanent or temporary, should be available to measure the volume of input gas and produced gases. Liquid meters are used for the measurement of produced oil and salt water.

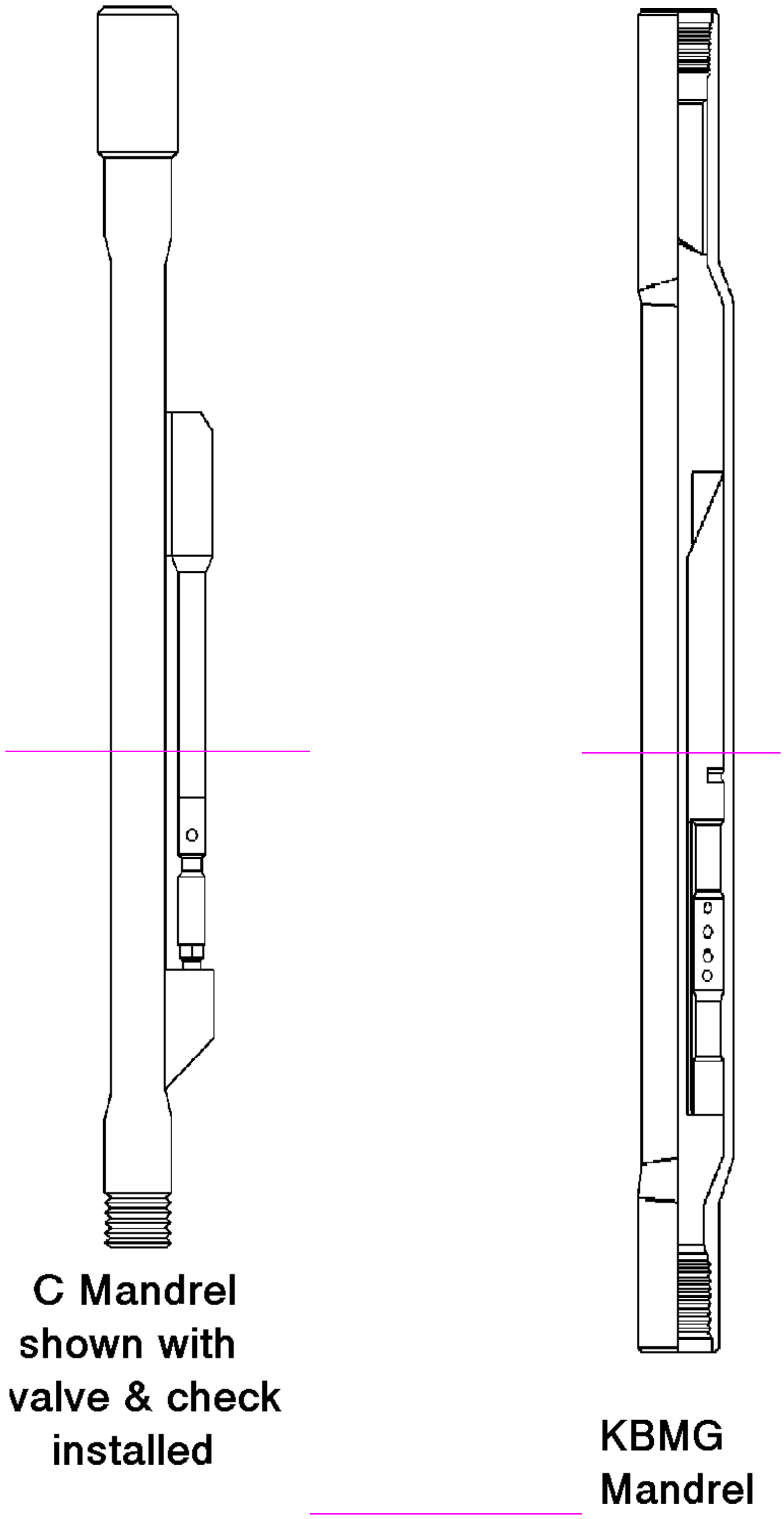


Figure 1-7 A conventional and side pocket mandrel

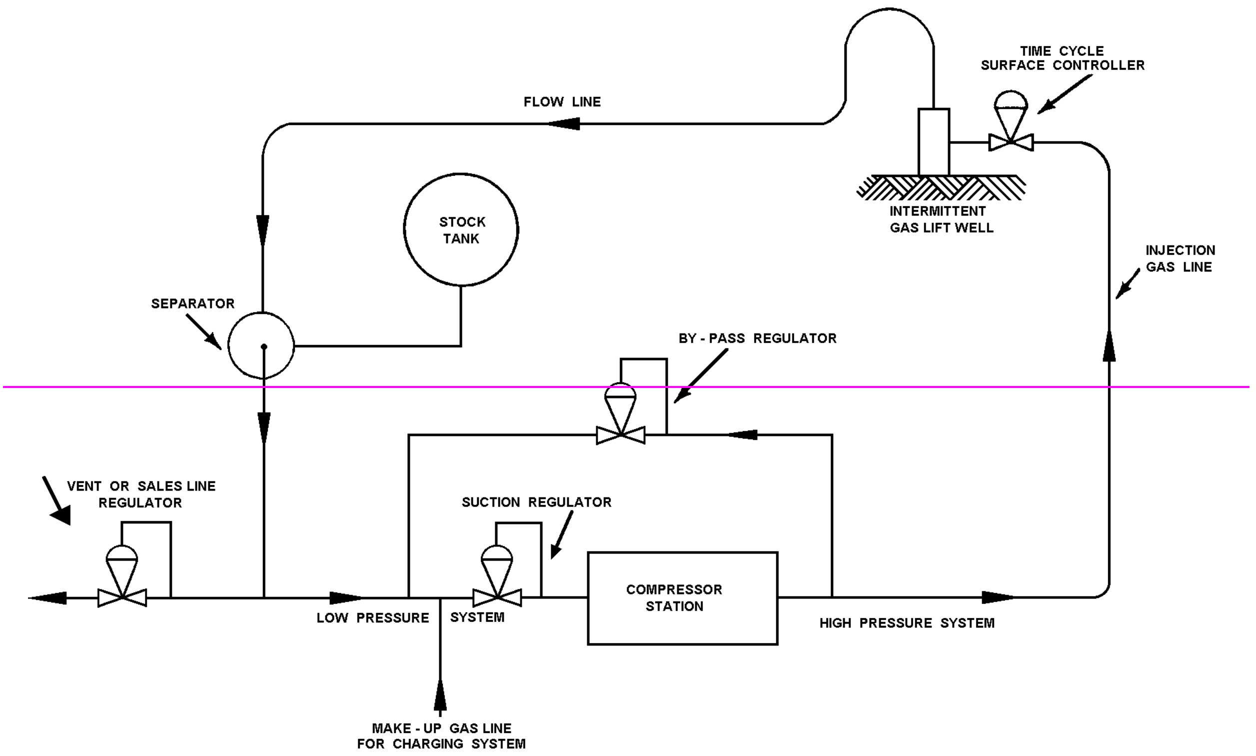


Figure 1.8 Surface Components of a Closed Rotative System with Intermittent Gas Lift

GAS LIFT VALVES:

A gas lift valve is designed to stay closed until certain conditions of pressure in the annulus and tubing are met. When the valve opens, it permits gas or fluid to pass from the casing annulus into the tubing. Gas lift valves can also be arranged to permit flow from the tubing to the annulus. Figure 1.9, shown on the following page, illustrates the basic operating principles involved. Mechanisms used to apply force to keep the valve closed are: (1) a metal bellows charged with gas under pressure, usually nitrogen; and/or (2) an evacuated metal bellows and a spring in compression. In both cases above, the operating pressure of the valve is adjusted at the surface before the valve is run into the well. The bellows dome may be charged to any desired pressure up to the pressure rating of a particular valve. The compression of the spring can be adjusted. All gas lift valves when installed are intended for one way flow, i.e. check valves should always be included in series with the valve.

The forces that cause gas lift valves to open are (1) gas pressure in the annulus and (2) pressure of the gas and fluid in the tubing. As the discharge of gas and liquid from the tubing continues and well conditions change, the valve will close and shutoff gas flow from the annulus. In the case of a continuous flow system, the one valve at the point of gas injection will remain open, thus, the injection of gas will be continuous.

In the case of intermittent flow, the injection valve opens and closes while the upper valves in the well may open to assist lifting the slug to the surface. The gas injection valve, placed at the bottom of the fluid column in the tubing, will open when pressure in the annulus reaches the required pressure and close when pressure falls below that level.

Gas lift valves using pressure operation principles date back to the King Valve patented in 1944, and

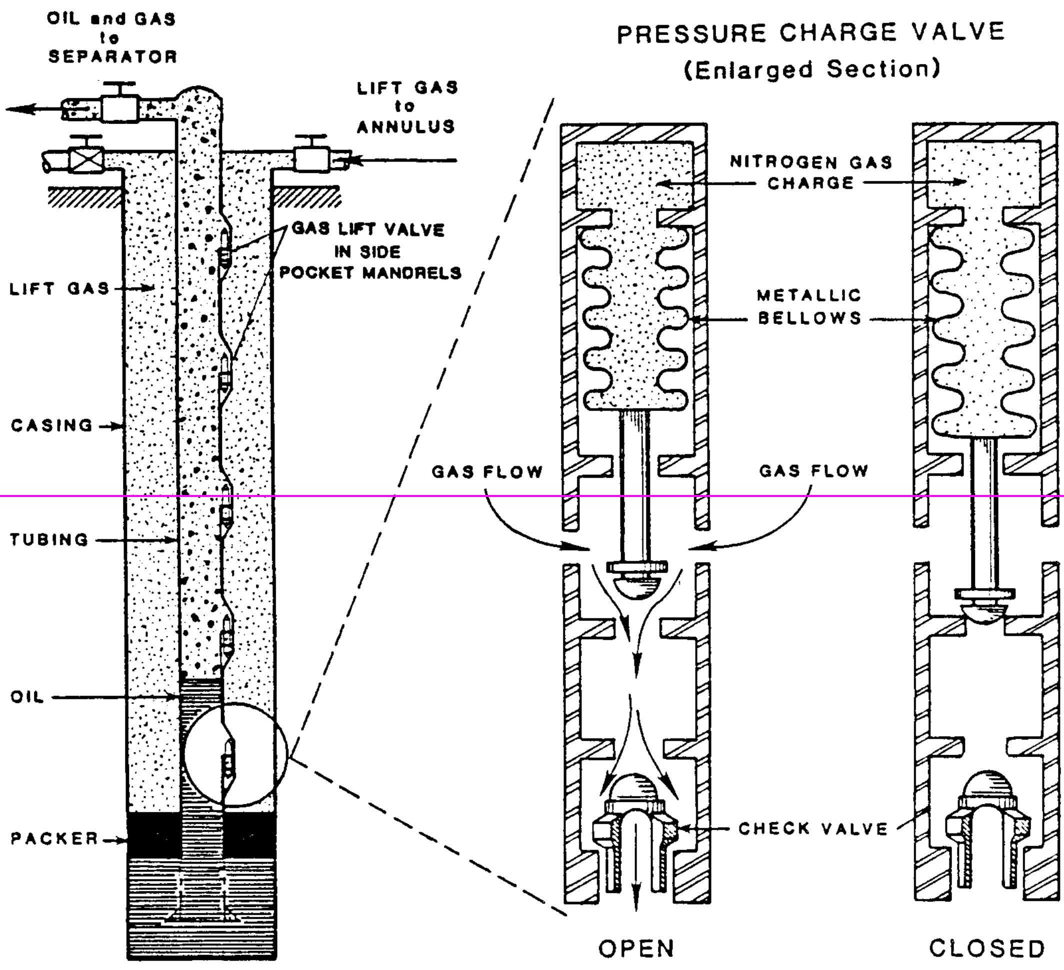


Figure 1.9 Bellows type gas lift valve

numerous bellows operated valves have been developed since that date. A most significant contribution to the industry was the invention of the Wireline Retrievable Valve in 1954.

An operating gas lift valve is installed to control the point of gas injection. Valves are installed above the desired point of injection to unload the well. After unloading, they close to eliminate gas injection above the operating valve.

For most continuous flow designs, the operating gas lift valve acts as a pressure regulator while the surface choke provides for gas flow regulation.

Applications of Gas Lift

Gas lifting of water with a small amount of oil used in the United States as early as 1846. Compressed air is known to have been used earlier to lift water. In fact, it has been reported that compressed air was used to lift water from wells in Germany as early as the eighteenth century. These early systems operated in a very simple manner by the introduction of air down the tubing and up the casing. Aeration of the fluid in the casing tubing annulus decreased the weight of the fluid column so that fluid would rise to the surface and flow out of the well. The process was sometimes reversed by injecting down the casing and producing through the tubing.

Air lift continued in use for lifting oil from wells by many operators, but it was not until the mid-1920's that gas for lifting fluid became more widely available. Gas, being lighter than air, gave better performance than air, lessened the hazards created by air when exposed to combustible materials and decreased equipment deterioration caused by oxidation. During the 1930's, several types of gas lift valves became available to the oil producing industry for gas lifting oil wells. Gas lift was soon accepted as a competitive method of production, especially when gas at adequate pressures was available for lift purposes. Two trends have developed in recent years:

1. A larger percentage of oil produced is from wells whose reservoir energy has been depleted to the point that some form of artificial lift is required.

2. The commercial value of gas in many areas has multiplied many times; with the increasing cost of gas, gas used to produce oil has achieved recognition as a hydrocarbon of specific value. It should be remembered that gas is not consumed during gas lift. The energy contained in the flowing gas is utilized but the net quantity remains the same.

Gas lift is a process of lifting fluids from a well by the continuous injection of high-pressure gas to supplement the reservoir energy (continuous flow), or by injecting gas beneath an accumulated liquid slug for a short time to move the slug to the surface (intermittent lift). The injected gas moves the fluid to the surface by one or a combination of the following: reducing the fluid load pressure on the formation because of decreased fluid density, expansion of injected gas, and displacing the fluid. In addition to serving as a primary method of artificial lift, gas lift can also be used efficiently and effectively to accomplish the following objectives:

1. To enable wells that will not flow naturally to produce.
2. To increase production rates in flowing wells.
3. To unload a well that will later flow naturally.
4. To remove or unload fluids from gas wells and to keep the gas well unloaded (usually intermittent , but can be continuous).

5. To backflow saltwater disposal wells to remove sands and other solids that can plug the perforations in the well.
6. In water source (aquifer) wells to produce the large volumes of water necessary for water flood applications.

Although other types of artificial lift may offer certain advantages, gas lift is suitable for almost every type of well to be placed on artificial lift. An added advantage to gas lift is its versatility. Once an installation is made, changes in design can be accomplished to reflect changes in well conditions. This is particularly true when wireline retrievable valves are used.

It should be remembered that "natural flow" can be a form of gas lift. The energy of compressed gas in the reservoir may be the principle force that raises the fluids to the surface. The energy of compressed gas is utilized in two ways:

1. Pressure of the gas exerted against the oil at the bottom of the tubing is frequently sufficient to lift the entire column of oil to the surface.
2. Aeration of the column of oil by gas bubbles entering it at the bottom of the tubing reduces the density of the column of oil. As the gas moves up the tubing, gas expands because of the reduction of pressure and the column of oil becomes even less dense.

With the density of the column thus reduced, less pressure is required from the reservoir to discharge the oil to the surface. Natural flow in the well continues until a change of conditions causes it to cease flowing. One change is the depletion of reservoir pressure until it no longer exerts sufficient force to move the oil up the tubing. A second change is the increase of water percentage in the flow. When a well "loads up" with water from the reservoir, more pressure is required to lift the column of fluid as water is denser than oil. Also, the water does not contain gas in solution that would reduce the density of the column.

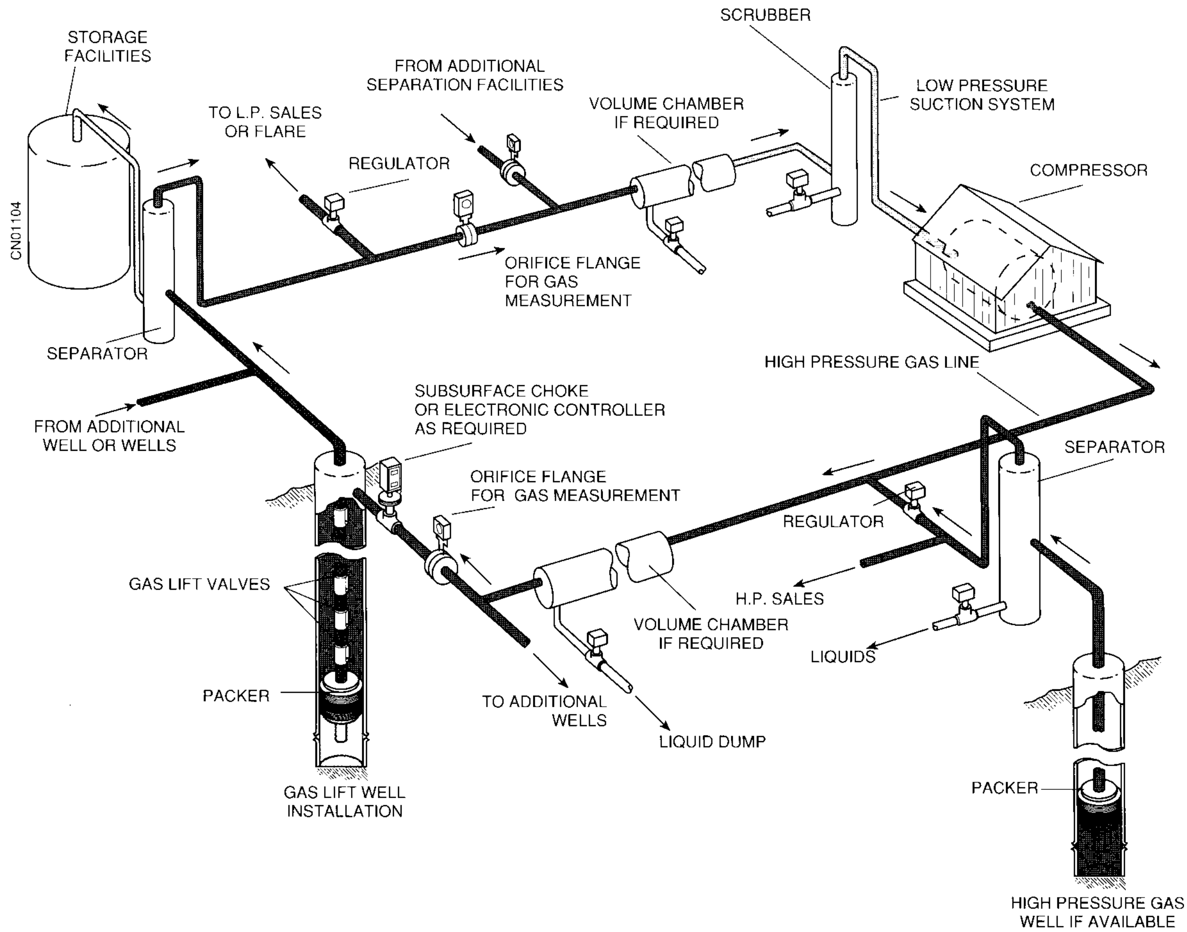
The term gas lift covers a variety of practices by which gas is used to increase the production of a well or to restore production where the well is dead. It may require a perforation or a jet collar in the tubing string, or the more complex devices, gas lift valves, which are manufactured to meet specific operating conditions and placed in the well according to carefully developed formulas. Gas lift may operate continuously or intermittently. It may be installed in a well at any depth from a few hundred feet [100 meters] to twelve thousand feet [3700 meters] or more.

The basic principles of natural flow and gas lift are essentially the same, i.e. density of the column is reduced and pressure raises the fluid to the surface. In a gas lift well, the gas is introduced from external sources under controlled conditions through gas lift valves installed for that purpose.

Gas Lift Systems

Gas Lift is the method of artificial lift which utilizes an external source of high pressure gas for supplementing formation gas to reduce the bottom hole pressure and lift the well fluids. The primary consideration in the selection of a gas lift system for lifting a well, group of wells, or an entire field, is the availability of gas and the cost of compression.

Gas lift is particularly applicable for lifting wells where high-pressure gas that is suitable for gas lift operations is available. Gas compressors may have been installed for gas injection or as booster compressors. High-pressure gas wells may be an available source of high-pressure gas. The cost of compression far exceeds the cost of subsurface gas lift equipment. Gas lift should be the first consideration when an adequate volume of high-pressure gas is available for lifting wells requiring artificial lift. Most wells can be depleted by gas lift. This is particularly true since the implementation of reservoir pressure maintenance programs in most major oil fields.



Basic Components For A Gas Lift System

Closed Rotative Gas Lift System

Most gas lift systems are designed to recirculate the lift gas. The low-pressure gas from the production separator is piped to the suction of the compressor station. The high-pressure gas from the discharge of the compressor station is injected into the well to lift the fluids from the well. Excess gas production may be sold, injected into a formation or vented to the atmosphere. This closed loop for the gas is referred to as a closed rotative system. Continuous flow gas lift operations are preferable with a closed rotative system because of the constant injection gas requirement and constant return of the gas to the low pressure facilities. Intermittent gas lift operations are particularly difficult to regulate and operate efficiently in small closed rotative systems with limited gas storage capacities in the low and high pressure gas lines and surface facilities.

CONTINUOUS FLOW GAS LIFT

The principle underlying the continuous flow gas lift method is that energy resulting from expansion of gas from a high pressure to a lower pressure is utilized in promoting the flow of well fluids in a vertical tube or annular configurations. Utilization of this gas energy is accomplished by the continuous injection of a controlled stream of gas into a rising stream of well fluids in such a manner that useful work is performed in lifting the well fluids.

A simplified analogy (Figure 1.10) illustrates this type of fluid flow system. Assume that a centrifugal pump rotating at a given speed takes liquid from an infinitely large reservoir and raises it vertically in a tube to a specified height (h_p) above the surface of the reservoir. At this point, shutoff head occurs and pump discharge pressure (K) is equivalent to h_p feet of liquid. For simplicity, pump head vs. capacity is assumed to be a straight-line relationship. Under these conditions, (Figure 1.1 2A and B), the pump shut-off head is not great enough to force liquid to the top of the tube. This situation is analogous to a well having insufficient bottom hole pressure to produce by natural flow. Well depth equals D, static pressure equals K, and the well's producing ability corresponds to the head capacity characteristics of the centrifugal pump.

If gas is injected into the tube at a point below the static liquid level, (Figure 1.1 2C and D), the gas will bubble upward through the liquid because of the difference in density of the two fluids. The column above the point of gas injection becomes a mixture of gas and liquid and when gas is injected at sufficiently high rates, liquid will be carried to the top and discharged from the tube. As a result, the pressure inside the tube at the point of injection will be lower than it was when the column was static liquid. The pressure at the pump discharge will be lowered by a proportionate amount (to K) and flow of liquid through the pump will commence. For a fixed rate of gas injection, there will be stabilized flow of liquid through the pump and out the top of the tube.

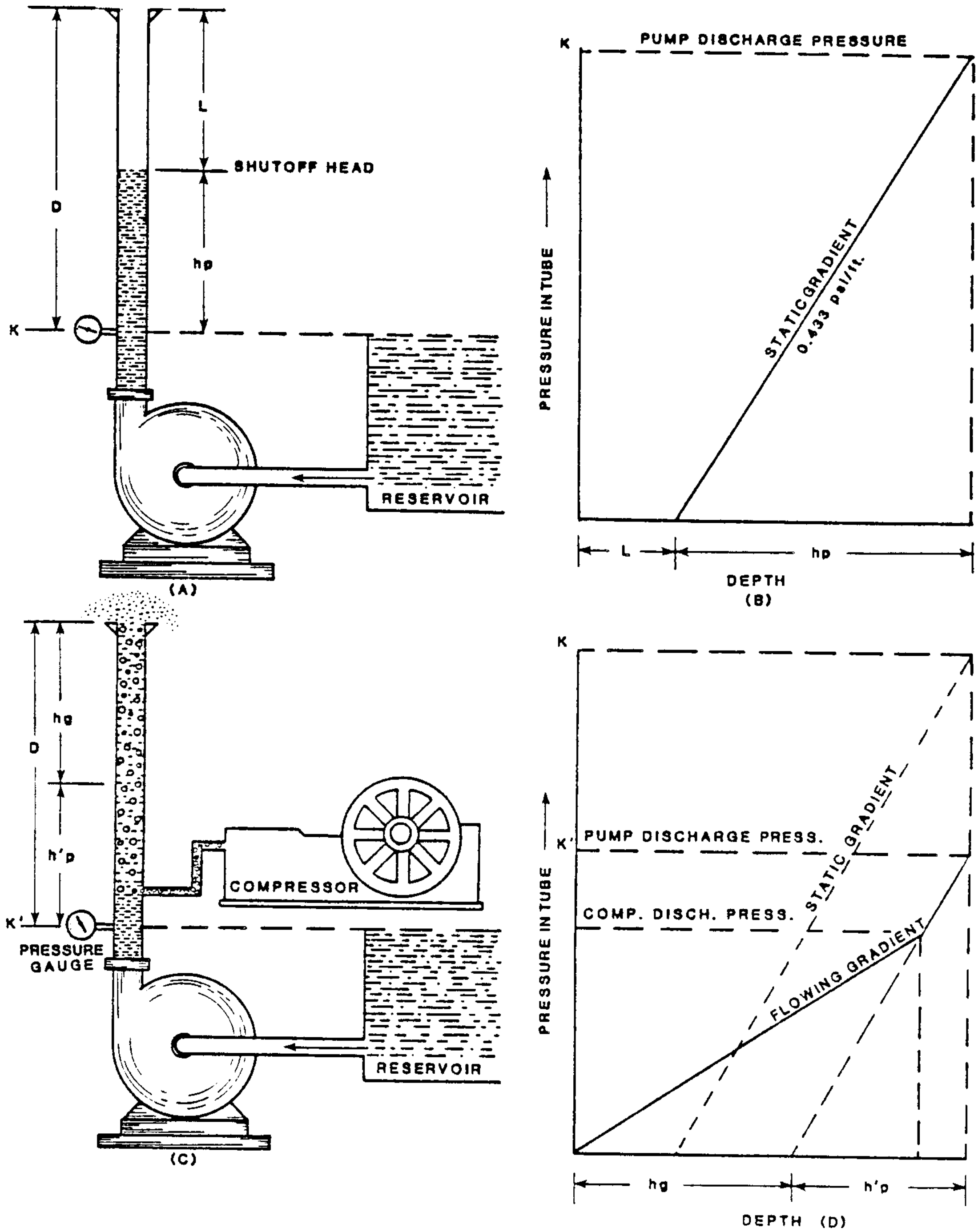


Figure 1.10 Simplified Analogy Illustrating Fluid Flow.
(from API handbook on Gas Lift)

This pattern of fluid flow describes continuous flow gas lift. When used in wells, it is common practice to utilize the annular space between the casing and tubing as a conduit to inject gas down to the injection point. Figure 1.11 shows typical installations for continuous flow gas lift. Gas lift valves are installed on the tubing string and gas from the annulus enters the well fluids that flow up the tubing.

Other arrangements of equipment can be used. About the only limitations are that there must be an adequate passageway for gas to travel downward to the point of injection and a conduit of adequate size which the gas and well fluids flow up and out of the well.

It is generally intended that, during continuous flow gas lift, only one valve will be admitting gas to the tubing and that valve will be as deep as the available gas pressure will permit. Valves above this operating valve will take part in initiating flow from the well but they are designed to close when the relation between well draw-down and available injection pressure permits sufficient gas to be injected through a lower valve. The construction and operation of gas lift valves will be covered in the Valve Mechanics Unit of this study guide.

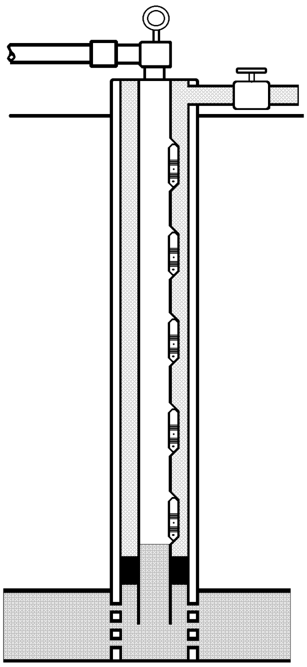


Figure 1.11
Continuous Flow Gas Lift
Installation

INTERMITTENT GAS LIFT METHOD

As the name implies, intermittent gas lift operates on the principle of intermittent gas injection. This means that gas lift injection occurs for a certain length of time and then stops. After a period a period of time has elapsed, injection again takes place and the cycle is repeated.

The principles of the intermittent gas lift cycle are illustrated in Figure 1.12. The equipment arrangement shown schematically indicates five gas lift valves. There can, of course, be more or less than this number in an actual installation. In the following description of the intermitting cycle, Valve No. 5 is the first one that opens; hence, it is the operating valve.

Figure 1.12A depicts well conditions just before gas injection takes place. The wellhead valve and flowline remain open so a minimum amount of surface backpressure is held on the well. This allows formation fluids to flow into the well bore and build up in the tubing. Figure 1.12B indicates the

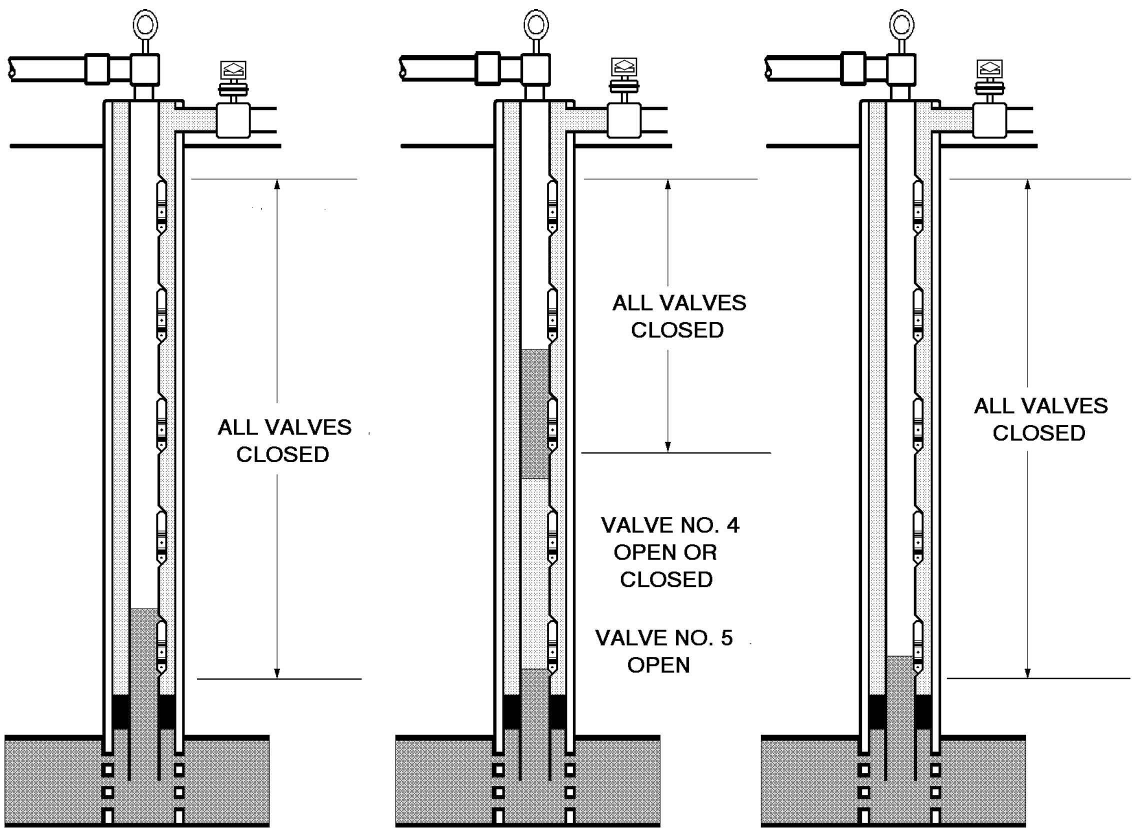


Figure 1.12 Intermittent Flow Gas Lift Installation

condition in the well just after gas injection through the valve has commenced. Injection into the annulus starts when the surface controller opens. As gas enters the annulus, the annulus pressure will increase until the opening pressure of the operating gas lift valve is reached. The opening of the gas lift valve allows gas to enter the tubing and displace the slug of well fluids to the surface. When the slug passes the next valve above the operating valve, this valve may also open to pass gas into the tubing. As soon as enough gas has been injected to remove the well fluids, the surface controller closes, injection stops and the gas lift valve closes, (See Figure 1.12C).At this point, the buildup of well fluids in the tubing has commenced. When the fluids build up to the level indicated in Figure 1.12A, the cycle is repeated. The surface controller that regulates the on and off injection gas cycle is what is generally referred to as an "intermitted". Usually there is a clock-driven mechanism in the intermitter that causes a motor valve to open at regular intervals, normally once every hour or once every two hours. The frequency of injection is adjustable and is determined mainly by the well's characteristics. The period of time the motor valve stays open during each cycle is also regulated by the intermitter. This injection period can be any set time, such as two minutes. It is also possible to regulate the injection period with a tubing or casing pressure shutoff. In this case, the intermitter shuts off injection gas whenever the tubing or casing pressure increases to some preset value. Intermittent gas lift is usually applied to wells having low productivity indexes that generally result in relatively low producing rates. A low productivity index means that the buildup of well fluids in the bottom of the well will take place over a fairly long period of time.

Open and Closed Gas Lift Installations

Most tubing flow gas lift installations will include a packer to stabilize the fluid level in the casing annulus after a well has unloaded. A packer is installed in a low flowing bottomhole pressure well to prevent injection gas from blowing around the lower end of the tubing. A closed gas lift installation implies that there is a packer and a standing valve in the well. An installation without a standing valve is referred to as semi-closed, which is widely used for continuous flow operations. An installation without a packer or standing valve is an open installation. An open installation is seldom recommended unless the well has a flowing bottomhole pressure that significantly exceeds the injection gas pressure and packer removal may be difficult or impossible because of sand, scale, etc. Casing flow gas lift requires an open installation since the production conduit is the casing annulus. A packer is required for gas lifting low bottomhole pressure wells to isolate the injection gas in the casing annulus and allow surface control of the injection gas volumetric rate to the well. Most intermittent gas lift installations will include a packer and possibly a standing valve. Although illustrations of nearly all-intermittent gas lift installations show a standing valve, many actual installations do not include this valve. If the permeability of the well is very low, a standing valve may not be needed.

The advantages of a packer are particularly important for gas lift installations where the injection gas line pressure varies or the injection gas supply is periodically interrupted. If the installation does not include a packer, most wells must be unloaded or partially unloaded after each extended shutdown. More damage to gas lift valves can occur during unloading operations than any time in the life of a gas lift installation. If the injection gas line pressure varies, the working fluid level changes in an open installation. The result is a liquid washing action through all of the valves below the working fluid level. This continuing fluid transfer can eventually fluid-cut the seat assemblies of these lower gas lift valves. A packer stabilizes the working fluid level, thus eliminating the need for unloading after a shutdown and the fluid washing action from a varying injection gas line pressure.

Considerations for Gas Lift Design and Operations

If a well can be gas lifted by continuous flow, this form of gas lift should be used to ensure a constant injection gas circulation rate within the closed loop of a rotative gas lift system. Continuous flow reduces the probability of pressure surges in the flowing bottomhole pressure, flowline and the low and high pressure surface facilities that occur with intermittent gas lift operations. Over-design rather than under-design of the gas lift valve spacing is always recommended when the well data are questionable. The subsurface gas lift equipment in the well is the least expensive portion of a closed rotative gas lift system. The larger OD gas lift valves are recommended for lifting high rate wells. The superior injection gas volumetric throughput performance of the 1-1/2 inch OD gas lift valve as compared to the 1-inch OD valve is an important consideration for gas lift installations requiring a high injection gas volumetric rate into the production conduit.

Most gas lift installation designs include several safety factors to compensate for errors in well information and to allow for an increase in the injection gas pressure to open (adequately stroke) the unloading and operating gas lift valves. It is difficult to properly design or analyze a gas lift installation without understanding the operating characteristics of the gas lift valves in a well. The operators should be familiar with the construction and operating principles of the gas lift valves in their wells. When an installation is properly designed, all gas lift valves above an operating valve will be closed and all valves below will be open in a continuous flow installation.

A large bore seating nipple which is designed to receive a lock is recommended near the lower end of the tubing for many gas lift installations. There are numerous applications for a seating nipple which include installation of a standing valve for testing the tubing and the gas lift valve checks. A standing valve may be needed in an intermittent gas lift installation. A wireline lock provides the means to secure and pack-off a bottomhole pressure gauge for conducting pressure transient tests, etc. The lock assembly should have an equalizing valve if the tubing will be blanked-off. The pressure across the lock can be equalized before the lock is disengaged from the nipple to prevent the wireline tool string from being blown up the hole.

Continuous Flow Unloading Sequence

After a well is completed or worked over, the fluid level in the casing and tubing is usually at or near the surface. The gas lift pressure available to unload the well is generally not sufficient to unload fluid to the desired depth for gas injection. This is because the pressure caused by the static column of fluid in the well at the desired depth of injection is greater than the available gas pressure at the depth of injection. In this case a series of unloading gas lift valves are installed in the well. These valves are designed to use the available gas injection pressure to unload the well until the desired depth of injection is achieved.

Figure 1-13 through 1-20 detail the unloading sequence in a continuous flow gas lift well.

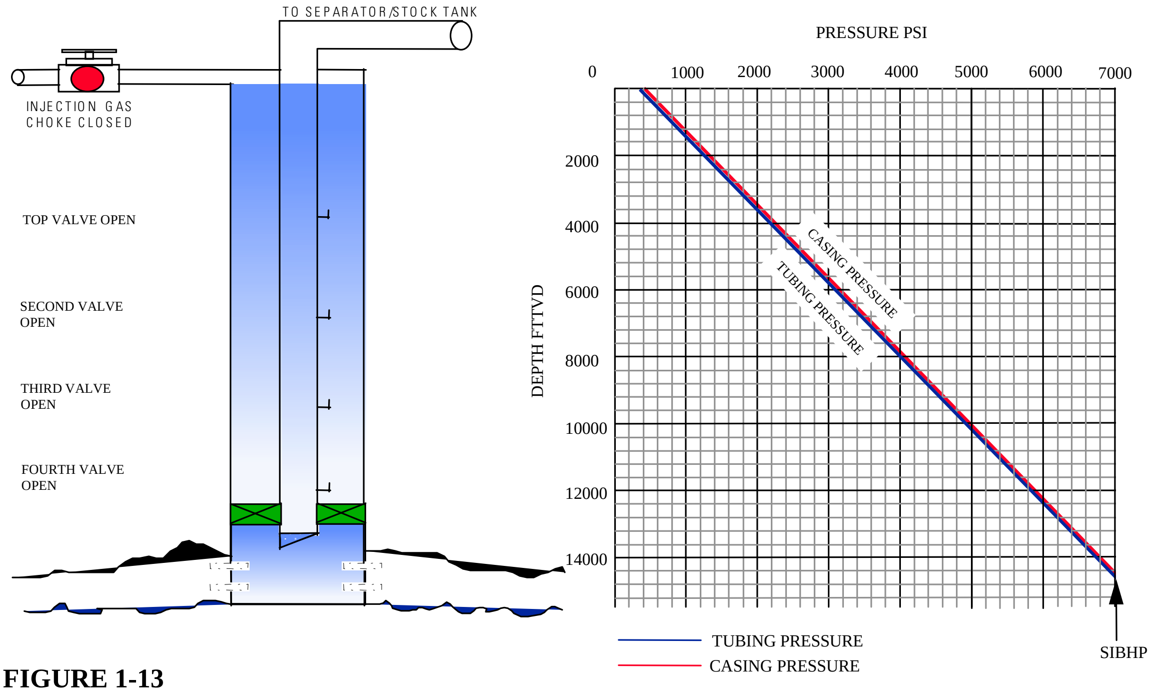


FIGURE 1-13

The fluid level in the casing and the tubing is at surface. No gas is being injected into the casing and no fluid is being produced. All the gas lift valves are open. The pressure to open the valves is provided by the weight of the fluid in the casing and tubing.

Note that the fluid level in the tubing and casing will be determined by the shut in bottom hole pressure (SIBHP) and the hydrostatic head or weight of the column of fluid which is in turn determined by the density. Water has a greater density than oil and thus the fluid level of a column of water will be lower than that of oil.

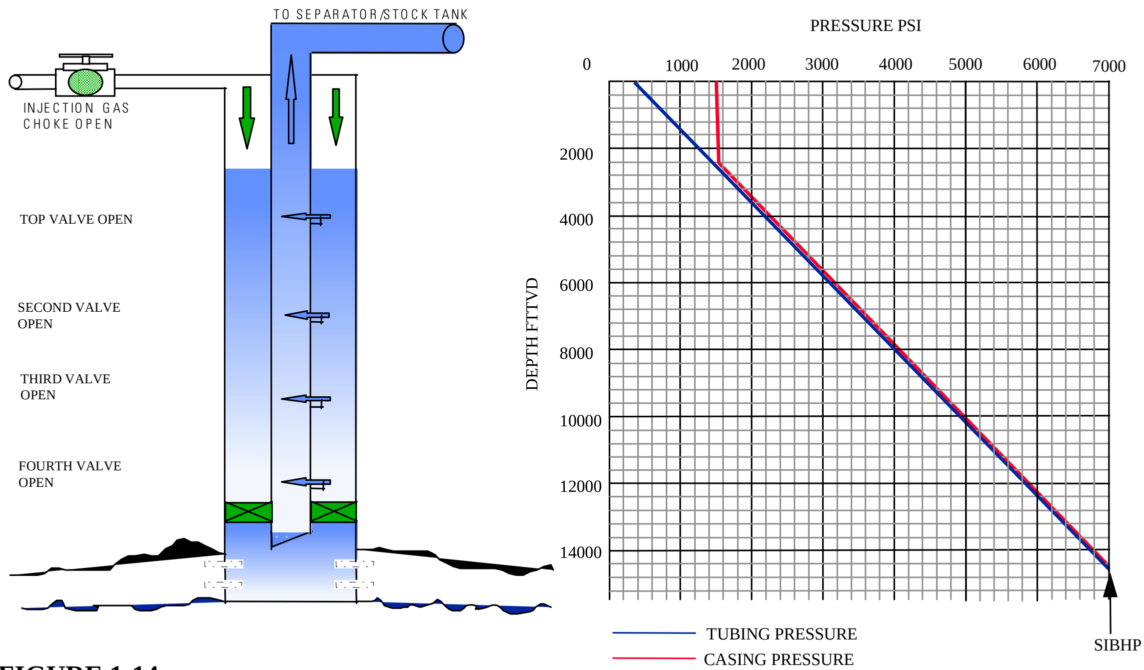


FIGURE 1-14

Gas injection into the casing has begun. Fluid is U-tubed through all the open gas lift valves. No formation fluids are being produced because the pressure in the wellbore at perforation depth is greater than the reservoir pressure i.e. no drawdown. All fluid produced is from the casing and the tubing. All fluid unloaded from the casing passes through the open gas lift valves. Because of this, it is important that the well be unloaded at a reasonable rate to prevent damage to the gas lift valves.

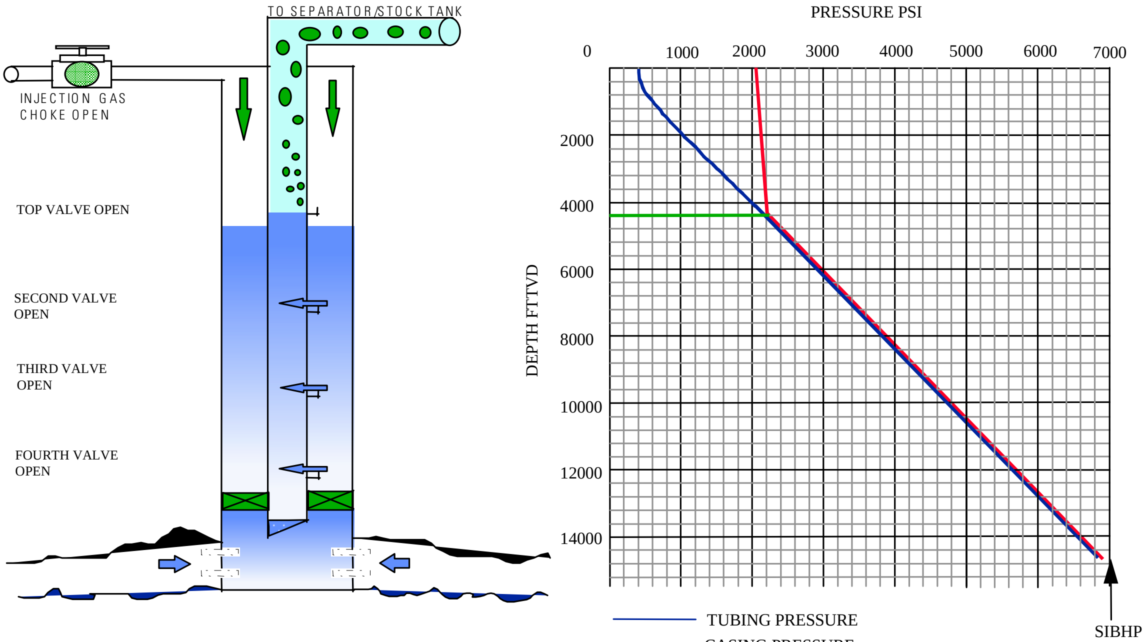


FIGURE 1-15

The fluid level has been unloaded to the top gas lift valve. This aerates the fluid above the top gas lift valve, decreasing the fluid density. This reduces the pressure in the tubing at the top gas lift valve, and also reduces pressure in the tubing at all valves below the top valve. This pressure reduction allows casing fluid below the top gas lift valve to be U-tubed further down the well and unloaded through valves 2, 3 and 4.

If this reduction in pressure is sufficient to give some drawdown at the perforations then the well will start to produce formation fluid.

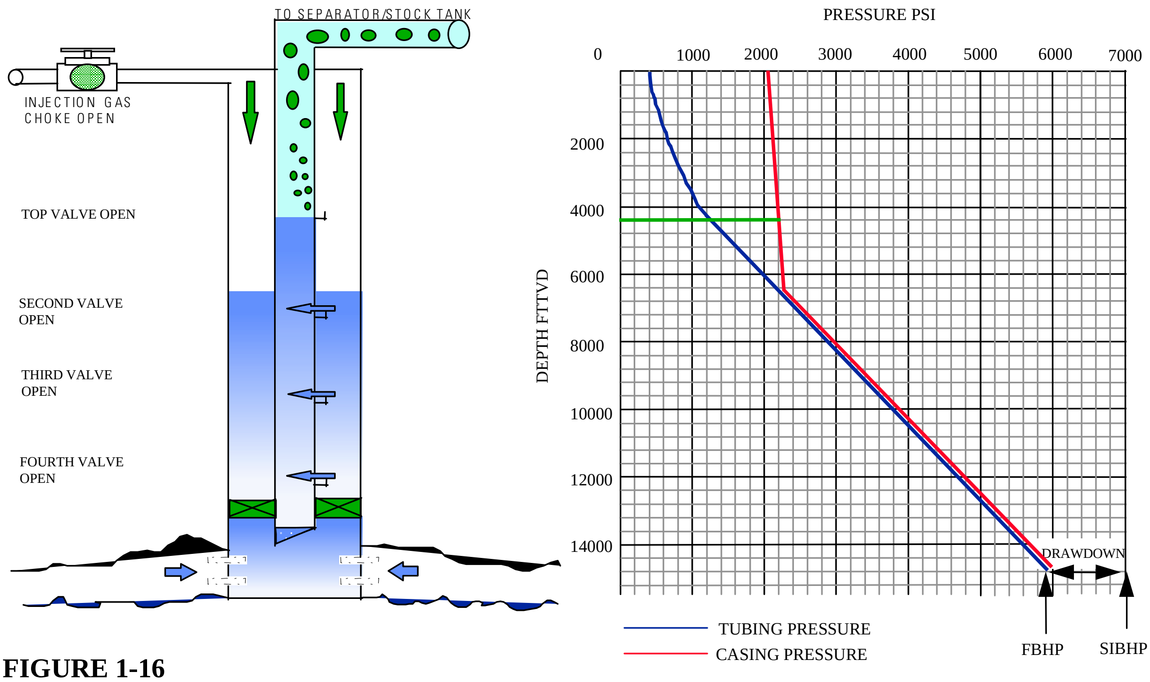


FIGURE 1-16

The fluid level in the annulus has now been unloaded to just above valve number two. This has been posssible due to the increasing volume of gas passing through number one reducing the pressure in the tubing at valve two thus enabling the U-tubing process to continue.

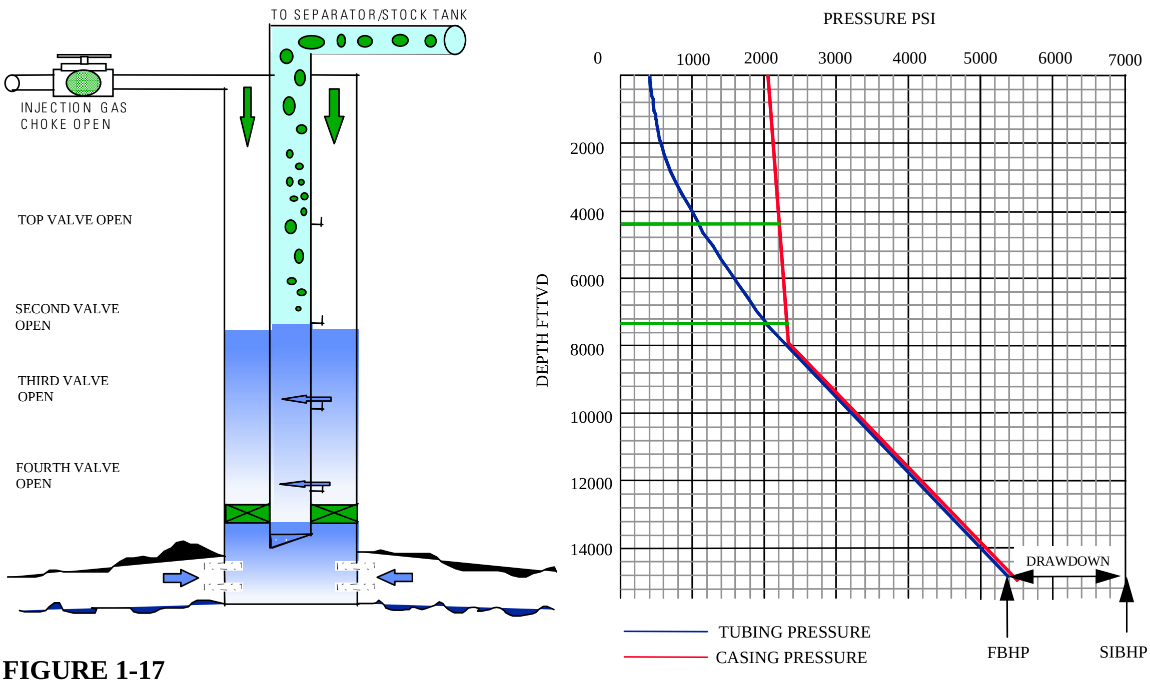


FIGURE 1-17

The fluid level in the casing has been lowered to a point below the second gas lift valve. The top two gas lift valves are open and gas being injected through both valves. All valves below also remain open and continue to pass casing fluid.

The tubing has now been unloaded sufficiently to reduce the flowing bottom hole pressure (FBHP) below that of the shut in bottom hole pressure (SIBHP). This gives a differential pressure from the reservoir to the wellbore producing a flow of formation fluid. This pressure differential is called the drawdown

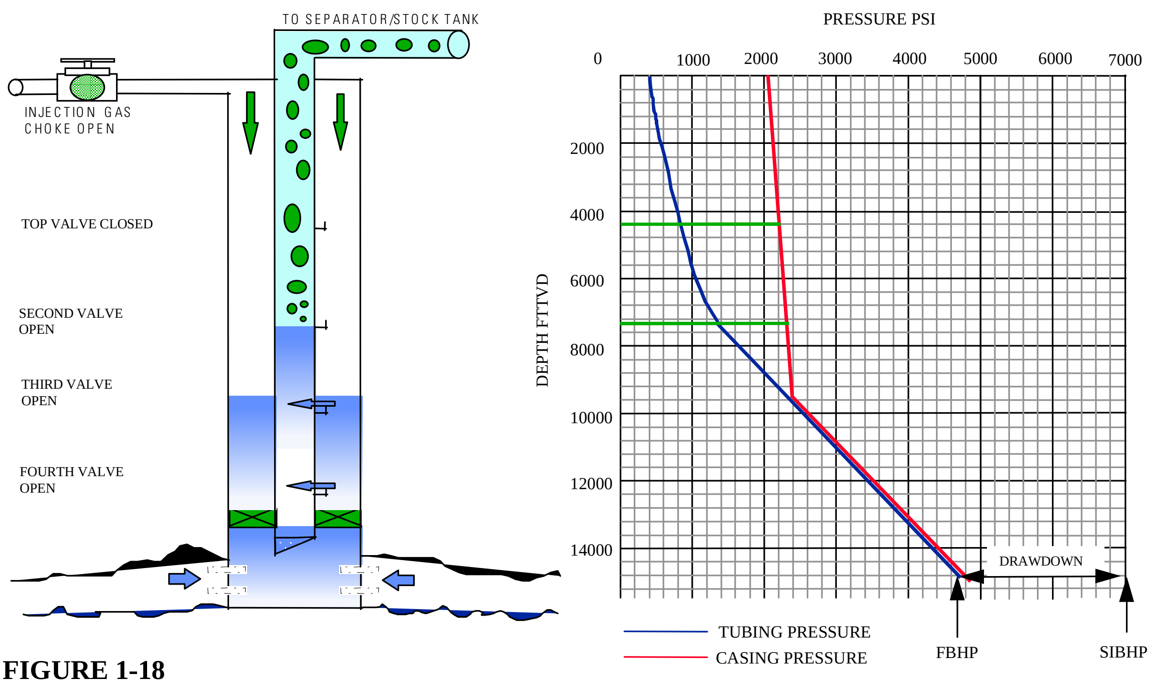


FIGURE 1-18

The top gas lift valve is now closed, and all the gas is being injected through the second valve. When casing pressure operated valves are used a slight reduction in the casing pressure causes the top valve to close. With fluid operated and proportional response valves, a reduction in the tubing pressure at valve depth causes the top valve to close. Unloading the well continues with valves 2, 3 and 4 open and casing fluid being removed through valves 3 and 4.

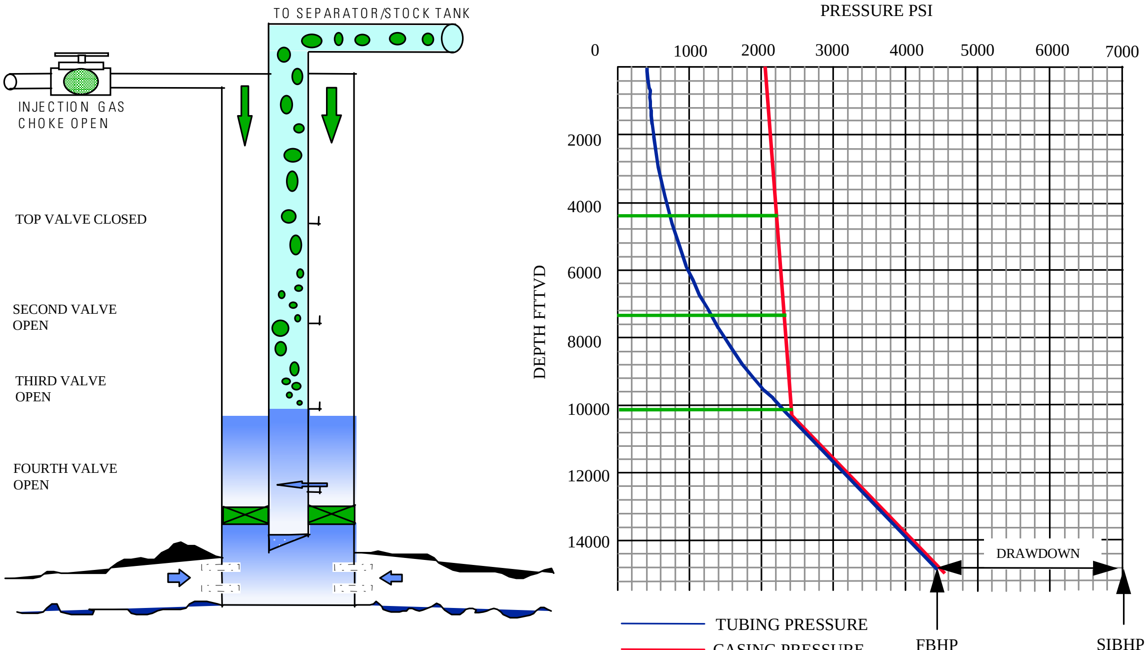


FIGURE 1-19

The No. 3 valve has now been uncovered. Valves 2 and 3 are both open and passing gas. The bottom valve below the fluid level is also open.

Note that the deeper the point of injection the lower the FBHP and thus the greater the drawdown on the well. As well productivity is directly related to the drawdown then the deeper the injection the greater the production rate.

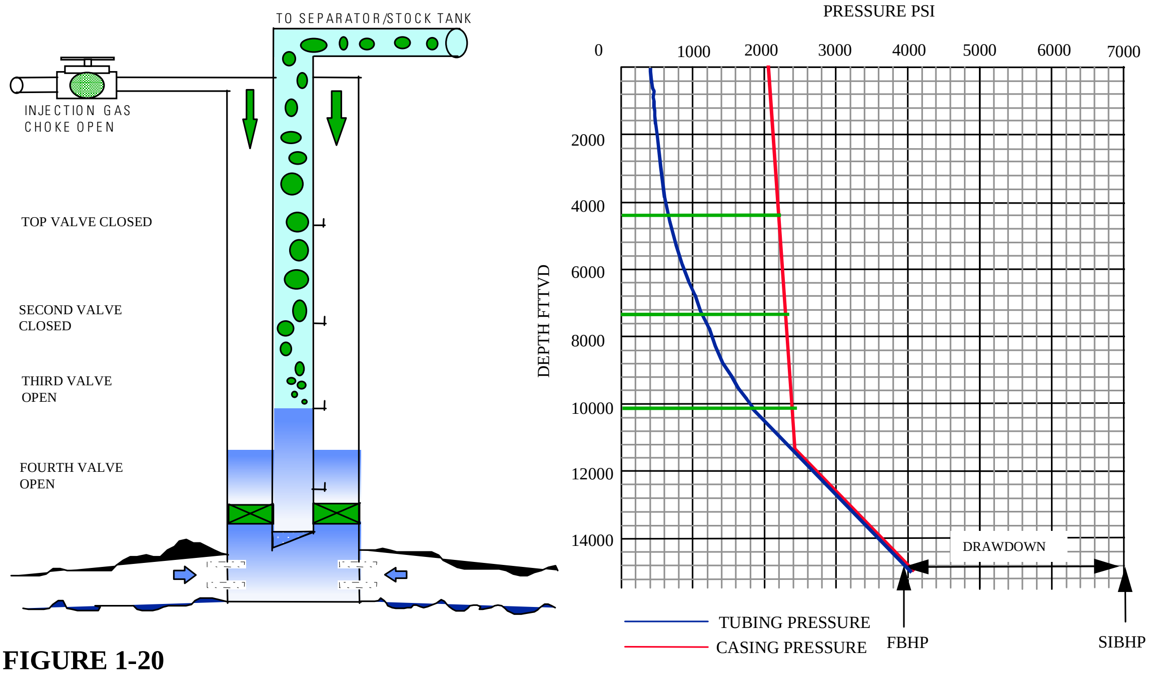


FIGURE 1-20

The No. 2 valve is now closed. All gas is being injected through valve No 3. Valve No 2 is closed by a reduction in casing pressure for casing operated valves or a reduction in tubing pressure for fluid operated and proportional response valves. Valve No 3 is the operating valve in this example. This is because the ability of the reservoir to produce fluid matches the ability of the tubing to remove fluids (Inflow/Outflow Performance). The operating valve can either be an orifice valve or can be a gas lift valve. The valve in mandrel No 4 will remain submerged unless operating conditions or reservoir conditions change.

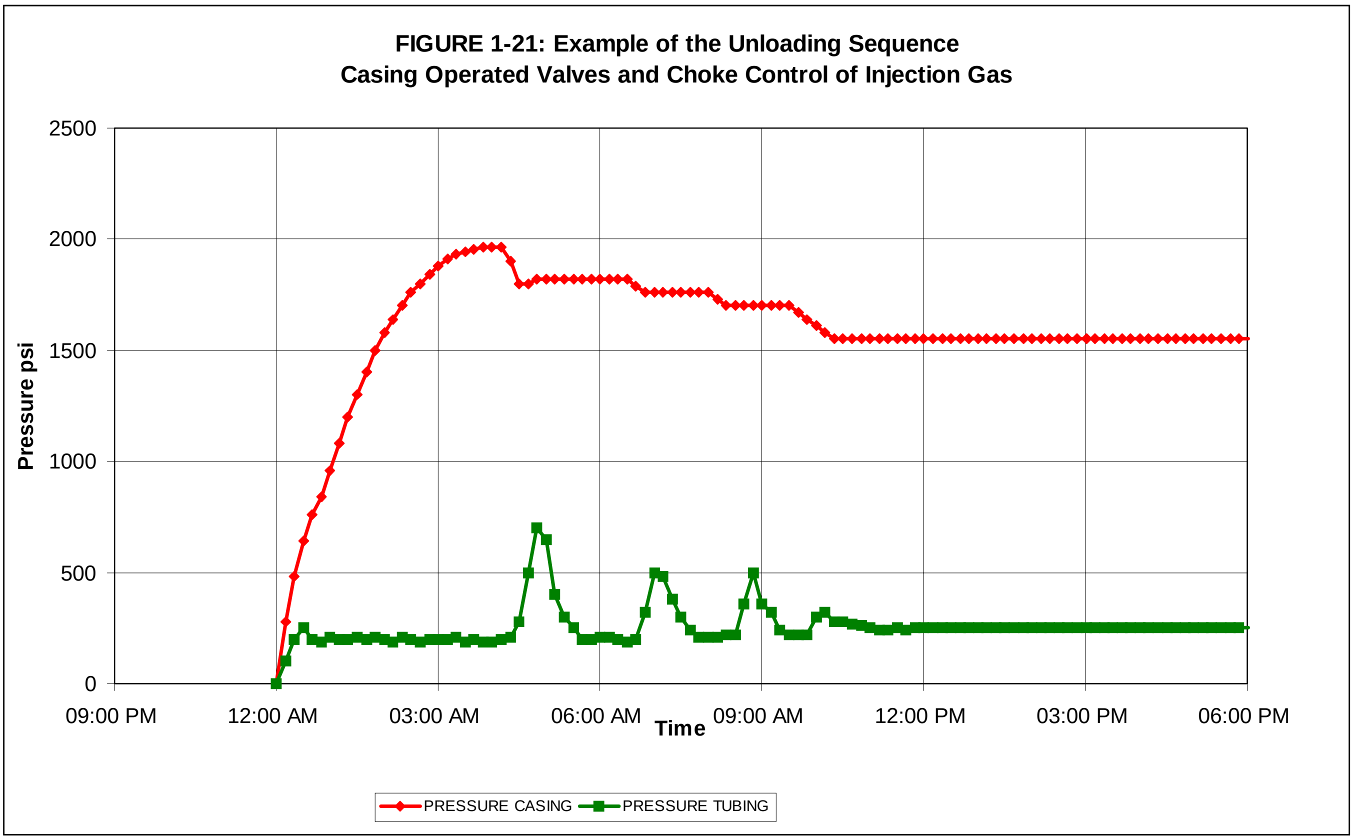


FIGURE 1-21: Example of the Unloading Sequence
Casing Operated Valves and Choke Control of Injection Gas
Pressure psi
2500
2000
1500
1000
500
0
09:00 PM
12:00 AM
03:00 AM
06:00 AM
09:00 AM
12:00 PM
03:00 PM
06:00 PM
Time
PRESSURE CASING
PRESSURE TUBING

2. Well Inflow & Outflow Performance

2. Well Inflow & Outflow Performance

UNIT OBJECTIVE: To understand inflow and outflow performance and relevance to gas lift design.

INTRODUCTION

Accurate prediction of the production rate of fluids from the reservoir into the wellbore is essential for efficient artificial lift installation design. In order to design a gas lift installation, it is often necessary to determine the well's producing rate. The accuracy of this determination can affect the efficiency of the design.

A large number of factors affect the performance of a well. An understanding of these factors allows the designer to appreciate the need to obtain all available data before his design work begins.

RESERVOIR DRIVE MECHANISMS

Introduction

Petroleum reservoirs have been classified to the type of drive mechanism which influences the flow of the trapped fluids. During the process of petroleum formation and accumulation, energy was stored which enables the flow of oil and gas from the reservoir to the wellhead. The energy is stored under high pressure that drives or displaces the oil through pores of the reservoir rock into the wellbore. There are three basic types of drive mechanisms.

Dissolved Gas Drive

FIGURE 2-1 illustrates a **dissolved gas drive**. Oil has gas dissolved in it. As the gas escapes from the oil, the bubbles expand and this explanation produces a force on the oil which drives it through the reservoir toward the well and assists in lifting it to the surface. It is generally considered the least effective type of drive yielding only 15% to 25% of the oil originally contained in the reservoir.

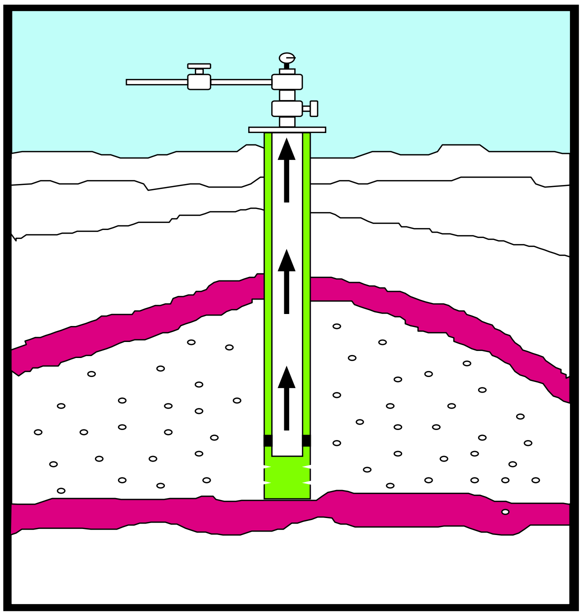


FIGURE 2-1 - Dissolved Gas Drive

Gas Cap Drive

The second type of drive also depends on energy stored in the gas of the reservoir. As can be seen in FIGURE 2-2, some reservoirs contain more gas than can be dissolved in the oil at the reservoir pressure and temperature. The surplus gas, since it is lighter than oil, rises to the top of the reservoir and forms a gas cap over the oil. The gas expands to drive the oil toward the wellbore. The Gas Cap Drive is more effective then Dissolved Gas Drive alone yielding from 25% to 50% of the oil contained in the reservoir.

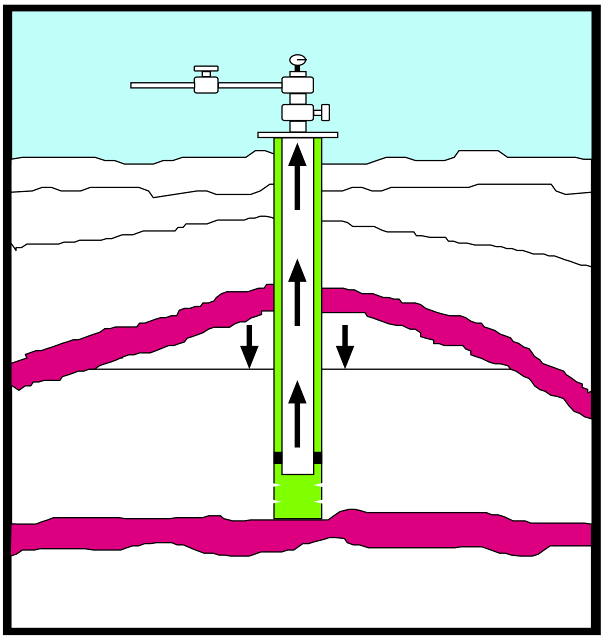


FIGURE 2-2 - Gas Cap Drive

Water Drive

When the formation containing an oil reservoir is uniformly porous and is continuous over a large area compared to the size of the oil reservoir itself, vast quantities of salt water exist in surrounding parts of the same formation.

The water often is in direct contact with the oil and gas reservoir. These vast quantities of water provide a great store of energy which can aid the production of oil and gas. FIGURE 2-3 illustrates the mechanism called "Water Drive". The energy supplied by the salt water comes from the expansion of water as pressure in the petroleum reservoir is reduced by production of oil and gas. Water is generally considered incompressible, but will actually compress and expand about one part in 2500 per 100 psi change in pressure. When the enormous quantities of water present are considered, this expansion results in a significant amount of energy which can aid the drive of petroleum to the surface. The water also moves and displaces oil and gas in an upward direction out of the lower parts of the reservoir.

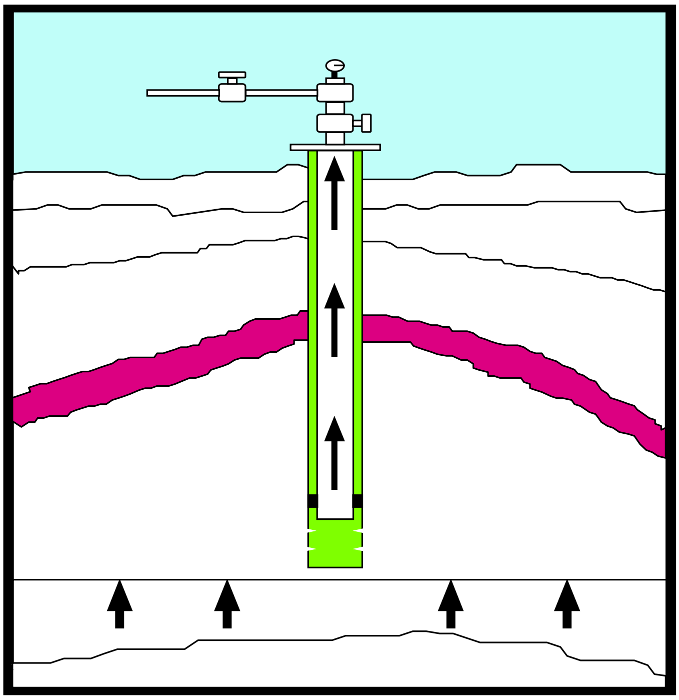


FIGURE 2-3 - Water Drive

The "Water Drive" is the most efficient of the primary drive mechanisms, capable of yielding up to 50% of the original oil in place. This process is often supplemented by the injection of high pressure treated salt water into the reservoir to maintain the pressure and 'sweep' the oil toward the well bore. In practice, most reservoirs subscribe to a combination of two or more of the above mentioned primary drive mechanisms.

When reservoir drive does not provide sufficient energy to overcome the possible pressure losses in the production system (see FIG 1-1) then steps must be taken to try to reduce these losses. The greatest pressure loss is from the hydrostatic head of the column of fluid in the wellbore and thus the installation of artificial lift equipment will overcome this pressure loss and allow the reservoir to produce.

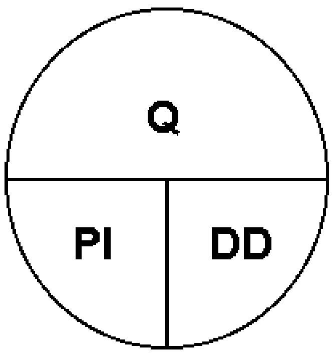
PRODUCTIVITY INDEX & INFLOW PERFORMANCE RELATIONSHIP

The success of a gas lift design depends heavily upon the accurate prediction of fluid flow into the wellbore from the formation. The ability of a well to give up fluids represents its inflow performance.

One simple method of predicting a well's inflow performance is the calculation of a productivity index (PI). The PI is a ratio of fluid production rate (Q) in barrels per day (BPD) [Meter^3] to the difference between the static bottom hole pressure (Pbhs) and the flowing bottom hole pressure (Pbhf) in pounds per square inch (psig) [Kilopascals (Kpa)]. This ratio is expressed in the following formula:

$$\mathbf{PI} = \frac{\mathbf{Q}}{\mathbf{P_{bhs} - P_{bhf}}}$$

The productivity index represents a linear relationship as can be seen in Figure 2.4. The curve is a straight line with a constant change in one variable (Q) with a corresponding change in a second variable (P). PI has been a useful method of predicting the inflow performance of a well and can be used to determine a well's rate of production at a specific flowing bottom hole pressure.



By covering the term you wish to solve, the equation is shown.

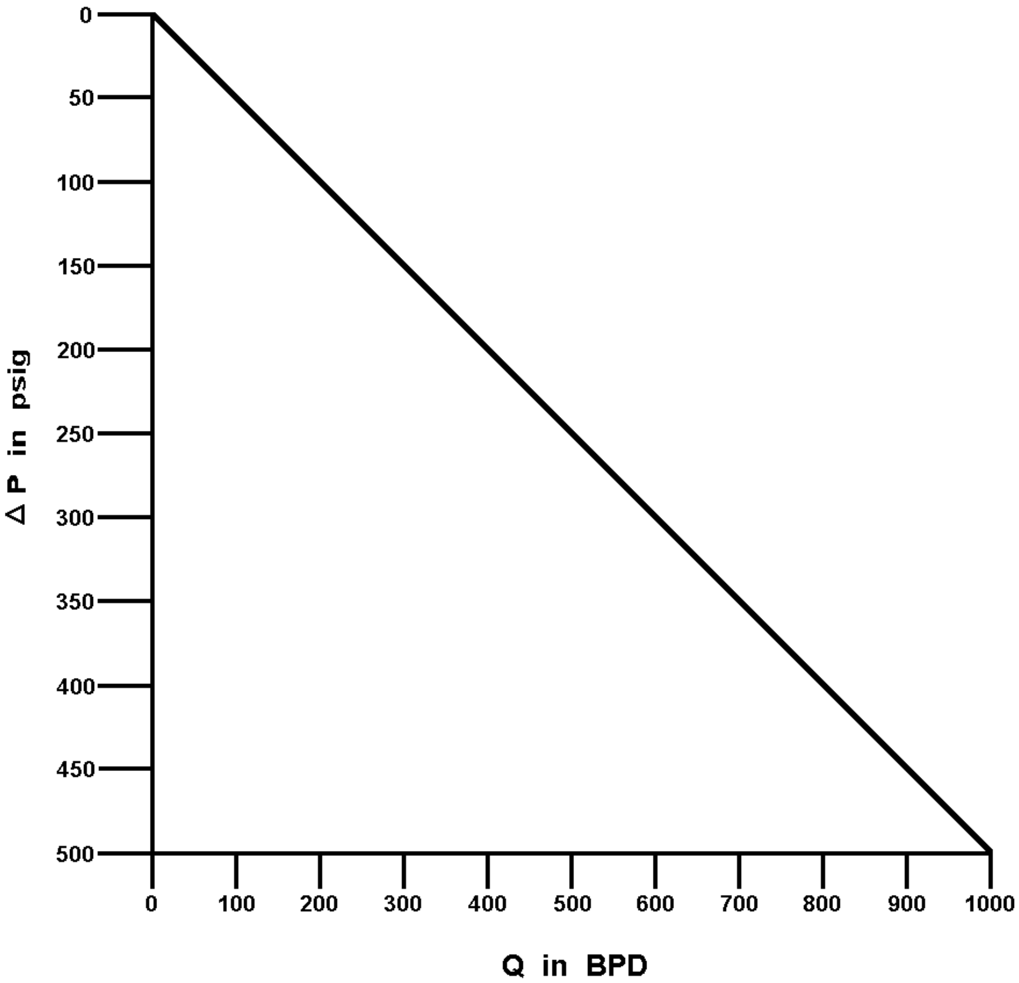


Figure 2.4 Example of a Productivity Index (PI) Curve

When given the PI of a well and the pressure draw-down (Pbhs - Pbhf), production can be determined by multiplying the PI by the pressure change. A sample problem in which potential producing rate is determined by using PI is illustrated next.

WELL DATA:

English:

Productivity Index (PI) = 1.5 BPD/psig

Static bottom hole pressure (Pbhs) = 900 psig

Flowing bottom hole pressure (Pbhf) = 600 psig

Metric:

Productivity Index (PI) = 0.0375 M3/Kpa

Static bottomhole pressure (Pbhs) = 6000 Kpa

Flowing bottomhole pressure (Pbhf) = 4000 Kpa

PROBLEM:

Find fluid production capability (Q)

SOLUTION

$$PI = \frac{Q}{(P_{bhs} - P_{bhf})} \qquad\qquad Q = PI \times (P_{bhs} - P_{bhf})$$

English:

$$Q = 1.5\frac{BPD}{psi} \times (900\,psi - 600\,psi)$$

$$Q = 1.5 \times 300$$

Metric:

$$\left[Q = 0.0375\frac{M^3}{Kpa} \times (6000Kpa - 4000Kpa)\right]$$

$$\left[Q = 0.0375 \times 2000\right]$$

$$Q = 450BPD \qquad\qquad \left[Q = 75M^3\right]$$

Studies over a given well's producing life and of different wells bring the accuracy of PI into question. PI, as we have seen, implies a linear relationship between production and bottom hole pressure draw-down. Whenever there is a two phase gas-liquid flow, the linear function does not exist and, therefore, PI is valid for only one production rate.

One of the basic assumptions of PI is the availability of a stabilized flowing bottom hole pressure. It is the word stabilized that makes the productivity index a topic of concern. If all petroleum reservoirs were composed of completely homogeneous sands and all reservoir pressures were above the bubble point pressure of the oil, (that is only one phase, liquid, existed in the reservoir), and all reservoirs had active water drives, then the productivity index, as determined from the flow characteristics of the well in the field, would not present much of a problem. But, even in the case cited the flow would not necessarily be stabilized. The PI as determined under these conditions, however, would exhibit a much more predictable behavior. The reason stabilized flow may not necessarily be attained in this nearly ideal reservoir is because the water may still be moving in under conditions of expansion. The full significance of this condition is beyond the scope of the subject matter to be presented here. The concept; however, is most important for a complete understanding of reservoir behavior, but the specific mechanics involved are not pertinent to this discussion.

A clear insight into the factors affecting PI can be understood by considering three reservoir characteristics: the physical nature of the reservoir itself, the nature of the reservoir fluids, and the nature of the reservoir drive mechanism.

Most reservoirs are composed of several beds often separated by impermeable layers of rock. These beds are usually of different thickness and permeability's. They may or may not be continuous throughout a given reservoir. It is apparent, therefore, that the productivity of a single well is a summation of the productivity or capacity of the individual beds. It is known that the capacity of a reservoir containing a series of interconnected beds under unstabilized conditions may be over four times greater than the same reservoir when pressure stabilization is reached. This is obviously significant and should be given foremost consideration when designing an installation for an extended period.

If the reservoir pressure is below the bubble point or saturation pressure, the P.I., as determined from well test, is a very unreliable yardstick for estimation of the reservoir capacity for the particular well. Since all three fluid phases exist: gas, oil, and water, the achievement of the steady state or stabilized condition is then impossible. The effect of this condition on the PI can sometimes be neglected; however, if the pressure draw-down is small compared to the absolute pressure of the reservoir. When it is realized that 50 to 90 percent of the total pressure draw-down may be in the immediate vicinity of the well bore (100 feet or so), then the heterogeneous character of the fluids flowing can be more easily visualized.

It is a commonly established principle of reservoir fluid flow that, as the saturation of a given fluid increases, it will flow more readily. Therefore, as a given unit volume of liquid phase and gas phase in the reservoir flow toward the well bore, the absolute pressure on the unit volume decreases more and more with a corresponding increase in the proportion of gas phase to the liquid phase. This, in turn, means that the reservoir begins to "deliver" the gas phase more readily than the liquid phase. The net result in terms of the PI of the well is that for a given pressure draw-down a reasonable amount of oil may be produced with a moderate GOR. However, if the pressure drop is doubled over what it was before, one cannot expect to get twice the amount of stock tank oil as before.

This is stating in effect that the PI of a well is not a straight line function and that it will often vary with producing rates. This is a very common problem in gas lift design. Many operators do not appreciate this fundamental principle of reservoir behavior.

The reservoir drive mechanism influences the PI reliability to a very great extent. As used here, the term drive mechanism is used to differentiate between reservoirs whose motive power is primarily a displacement type as opposed to depletion type.

Displacement type refers to strong active water drive or gas cap drive, and depletion type refers to a closed reservoir or one in which the motive power in the reservoir is primarily from the gas in solution in the oil. The latter is commonly termed a volumetric reservoir. It should be apparent that reservoirs with the displacement type drive will generally produce more reliable PIs from well tests than will the depletion type. In the displacement type drive, there is little or no free gas (aside from that existing in a gas cap) and; hence, the reservoir capability to deliver the single phase liquid is greater than it would be if the free gas were present. Further, the deliver-ability will be more consistently uniform over a period of time (or pressure decline). It must be pointed out, however, that under certain conditions there can be serious limitations to PI determinations from this type of reservoir drive. If an individual well is pulled too hard, then a localized depletion drive will result and obviously the PI, as determined, will not be reliable for predicting the well performance.

This depletion type reservoir mechanism will yield fairly reliable PIs only when the pressure draw-down is small compared to the shut-in reservoir pressure. This discussion of the productivity index does not include certain other mechanical factors that contribute toward its unreliability. The manner in which the well has been completed is very significant.

The PI not only changes with time or total production, but also changes with increased draw-down at any one specific time in the life of the well. If we measure several PI's in a well during a specific time interval, a relationship will be obtained between rate and flowing pressure which normally is not linear for a solution gas drive field. This may be attributed to one or more of the following factors:

1. Increased gas saturation of the oil near the well bore can occur because of the reduced reservoir pressure. This can lower the permeability of the formation to oil flow at the higher producing rates.
2. The flow may change from laminar (in thin layers) to turbulent in some of the flow capillaries near the well bore at increased producing rates.
3. The critical flow rates through pores may be exceeded at the formation face in the well bore. These pores act as orifices when the critical rate is exceeded. Increased draw-downs; therefore, have a diminished effect on increasing rates.

A second approach to the production of a well's performance is to plot production against flowing bottom hole pressure. This plot of q vs. Pbhf is called an inflow performance curve and was first used by Gilbert[1], in describing well performance. Typical curves are illustrated in Figure 2.5 and differ depending upon the type of reservoir. The curve for strong water drive is essentially a straight line as discussed above under productivity index. The determination of the non-linear relationships observed for solution gas drive wells presents a significant problem. A publication by Vogel[2] in January, 1968 offered a solution in determining an inflow performance curve for a solution gas drive for flow below the bubble point. By use of a computer, he calculated inflow performance relationship (IPR) curves for wells producing from several fictitious solution gas drive reservoirs that covered a wide range of oil and

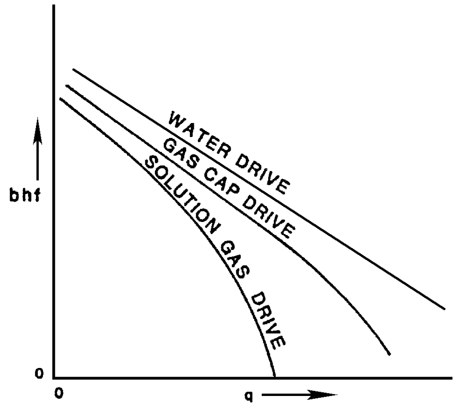


Figure 2.5 Typical Inflow Performance Curves

reservoir characteristics. He made several assumptions such as circular, radial uniform flow with a constant water saturation. He neglected gravity segregation and his solution is valid for two phase flow in the reservoir only. He showed that rate vs. flowing bottom hole pressure as a function of cumulative recovery changed. The result is a progressive deterioration of the IPRs as depletion proceeds in a solution gas drive reservoir.

He plotted all IPRs as dimensionless. This means that ratios are used so that there are no units for either variable. The pressure for each point on an IPR curve is divided by the maximum or shut-in pressure for that particular curve, and the corresponding production rate is divided by the maximum (100% draw-down) producing rate for the same curve. This produced curves that were remarkably similar throughout most of the producing life of the reservoir.

Vogel's work resulted in this construction of a reference curve (Figure 2.3) which is all that is needed from his paper to construct an IPR curve from one flowing test on a well. This curve should be regarded as a general solution of solution gas drive reservoir flow equations in which flowing pressures are below the bubble point. The constants used for particular solutions depend upon the individual reservoir conditions. It is more accurate for wells during their early stages of depletion than for later stages.

Some variation from the reference curve has been noted. For example, the more viscous crudes and reservoirs above the bubble point show significant deviation, however, curvature was still apparent.

The reference curve is very simple to use. All that is needed is one flow test of flowing bottom hole pressure (Pbhf) vs. rate (Q) and the static bottom hole pressure (Pbhs). The procedure used to determine the potential production at a given pressure is outlined below:

PART1: Determine Potential Maximum Production (Qmax) When Pbhf = 0

Step 1. Obtain the following data from a well test.

A. Flowing bottom hole pressure (Pbhf) - (psig) - (Kpa)
B. Production at that pressure (Q_l) - (BPD) - (M^3)
C. Static bottom hole pressure (Pbhs) - (psig) - (Kpa)

Step 2. Calculate the ratio of the flowing bottom hole pressure from test data to the static bottom hole pressure (Pbhf/Pbhs).

Step 3. Locate the ratio on the vertical axis of reference curve.

Step 4. Find point on the reference curve.

Step 5. Locate the ratio of production at that bottom hole pressure to the production at 0 pressure (Q_1 / Qmax).

Step 6. Solve for Qmax by dividing the value of Q1 by the ratio Q1 / Qmax.

PART 2 Determine Potential Production (Q2) At The Given Pbhf.

Step 7. Calculate the ratio of the given flowing bottom hole pressure to the static bottom hole pressure (Pbhf/Pbhs).

Step 8. Locate the ratio on the vertical axis of the reference curve.

Step 9. Find the point on the reference curve.

Step 10. Locate the ratio of production at the given bottom hole ratio (Q_2) to the production at 0 psig.

Step 11. Calculate production at the given bottom hole pressure (Q2) by multiplying the ratio times the production when Pbhf = 0 (Qmax found in Step Number 6).

A sample problem is illustrated below

WELL DATA:	**English**	**Metric**
Flowing bottom hole pressure (Pbhf)	600 psig	4135 Kpa
Production at Pbhf Q_1	400 BPD	64 M^3
Static bottom hole pressure (Pbhs)	900 psig	6205 Kpa

PROBLEM

Find potential maximum production (Qmax) when Pbhf= 500 psig / 3447 Kpa

SOLUTION:

PART 1

Determine Maximum Potential Production (Qmax) When Pbhf = 0

	English	**Metric**
Step 1. With Q1 @ Pbhf =	400 BPD	$64M^3$

Step 2. $\frac{P_{bhf}}{P_{bhs}} =$ $\frac{600}{900} = 0.67$ $\frac{4135}{6205} = 0.67$

Step 3. Using dimensionless inflow performance relationship curve for solution gas drive reservoir (after Vogel). Enter the y axis at 0.67 proceed to the right until the IPR curve is met, proceed down from the intercept of 0.67 (y - axis) and the IPR curve to the x - axis

Step 4. Using figure 2.3, read value from x - axis, 0.49.

Step 5. $Q_{\max} = \frac{Q_1}{0.49}$ $\frac{400}{0.49} = 816$ $\frac{64}{0.49} = 131$

PART 2

Determine Potential Production (Q2) At The Given Pbhf (500 psig) [3447 Kpa]

	English:	**Metric:**
Step 6. $\frac{P_{bhf}}{P_{bhs}} =$	$\frac{500}{900} = 0.56$	$\frac{3447}{6205} = 0.56$

Step 7. Using dimensionless inflow performance relationship curve for solution gas drive reservoir (after Vogel).. Enter the y axis at 0.55 proceed to the right until the IPR curve is met, proceed down from the intercept of 0.55 (y - axis) and the IPR curve to the x - axis

Step 8. Using figure 2.3, read value from x - axis, 0.65.

Step 9. $Q_2 = Q_{\max} \times .65$ $816 \times 0.65 = 530$ $131 \times 0.65 = 85$

Although the problem above was solved using the reference curve, an IPR for a specific well can be plotted when several points are known. For the purpose of this discussion, the general reference curve can be used for your calculations.

In summary, both PI and IPR can be used to determine a well's production. The producing rate will differ depending on the method used. This is particularly true as the amount of draw-down is increased as can be seen in Figure 2.6.

It is evident that IPR data more accurately reflects a well's inflow performance. The production, therefore, can be more accurately determined.

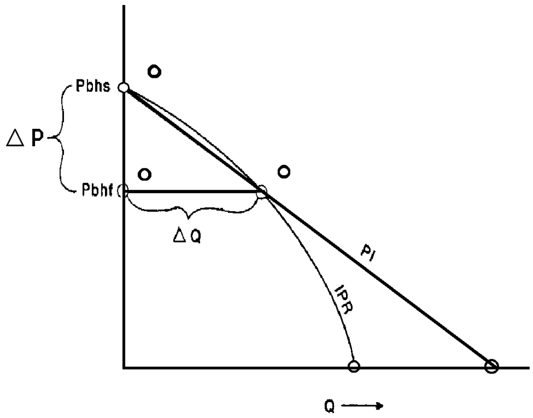


Figure 2.6 Comparison of PI with IPR

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3. Natural Gas Laws Applied to Gas Lift

3. Natural Gas Laws Applied to Gas Lift

<u>CHAPTER OBJECTIVE:</u> Given all required data and the appropriate formula, you will calculate gas pressure at depth, rate of flow through an orifice, the valve pressure set at 60°F for a given down hole temperature, and gas volumes within a closed conduit.

INTRODUCTION

The application of gas lift equipment requires the understanding of the behavior of gas. Although all gases have common behaviors known as the natural gas laws, there are some differences between the injection gas which is a mixture of several gases with different chemical properties and the nitrogen which is used to charge pressure operated gas lift valves.

Designing a gas lift installation involves the determination of gas pressure in the casing or tubing at the specific depth of a valve when the surface injection pressure is known. The designer must also be able to determine the volume of gas that can be delivered to the tubing through a particular valve in order to obtain the proper gas to liquid ratio needed to lift the fluids to the surface. Since the same pressure is set at the surface under a standard temperature, the pressure must be corrected so that proper operating pressure will exist at the down hole temperature.

PROPERTIES OF INJECTION GAS

Natural gas injected into a well, as well as the dissolved gas in the reservoir fluid, is subject to a number of gas laws. Gas, unlike liquids, is an elastic fluid. It is often defined as a homogeneous fluid which occupies all the space in a container. This is easily visualized by noting, for example, that 1 lb. of liquid placed in a closed container may fill a small portion of the total volume of that container. However, 1 lb. of gas placed in the same empty container will fill the container completely.

Gases expand with increases in temperature and contract with decreases in temperature. The volume of gases is inversely related to pressure. As the pressure increases, the gas volume decreases. Gas volume is usually measured in standard cubic feet (scf) [NM^3]. A standard cubic foot is defined as the volume contained in one cubic foot if the pressure is 14.73 psia and if the temperature is 60°F. A "normalized" cubic meter is defined as the volume contained in one cubic meter if the pressure is 101.32 KPa and if the temperature is 0º Celsius. Note that a "standard" cubic meter is defined by contractual agreement and is usually at a temperature of 20º C.

It is known that gases have weight similar to any other fluid. Air, for example, weighs 0.0764 lbs. per cubic foot [1.2238 Kg/M^3] at 14.7 psia [101.353 KPa] and 60º F [15.56º C]. On a comparative basis, gas is always compared to air as a liquid is compared to water. The ratio of the density of a gas compared to the density of air is known as the gas gravity or relative density.

One of the most important calculations required in gas lift designs is the determination of gas pressure at a given depth.

The equation for calculating pressure at depth is:

English

$$P@L = P@S \times e^{\left[\frac{S.G.\times L}{53.34\times \overline{T}\times \overline{Z}}\right]}$$

Metric

$$P@L = P@S \times e^{\left[\frac{\gamma\times L}{29.28\times \overline{T}\times \overline{Z}}\right]}$$

Where:

English		Metric	
e	= 2.71828	e	= 2.71828
$P@L$	= Pressure at depth, psia	$P@L$	= Pressure at depth, kPa
$P@S$	= Pressure at surface, psia	$P@S$	= Pressure at surface, kPa
SG	= Gas Specific gravity	γ	= Gas relative density
L	= Depth, feet	L	= Depth, meters
$\overline{T}$	= Average temperature, Degrees R	$\overline{T}$	= Average temperature, Kelvin
$\overline{Z}$	= Average Compressibility for $\overline{T}$ and average pressure	$\overline{Z}$	= Average Compressibility for $\overline{T}$ and average pressure

The average compressibility ($\overline{Z}$) is difficult to determine. Compressibility is based on the average temperature and pressure and since the average temperature and pressure are unknown, the solution becomes a repetitive trial and error procedure. A frequently used shortcut is to use a "rule of thumb" equation. The equation below is based on a gas specific gravity of 0.65, a geothermal gradient at 1.6°F/100 ft. and a surface temperature of 70°F. This equation should only be used when well conditions are close to these values.

English

$$P@L = P@S + 2.3 \times \frac{P@S}{100} \times \frac{L}{1000}$$

Metric

$$P@L = P@S + 15.65 \times \frac{P@S}{680} \times \frac{L}{305}$$

In addition to the "rule of thumb", gas lift designers frequently use charts like the one seen in Figure 3.1. To use the chart, follow the procedure outlined below:

Step 1. Obtain surface pressure P@S.

Step 2. Locate P@S on vertical axis on Figure 1.

Step 3. Locate the line on graph representing the given depth across from that point (Step 2).

Step 4. Locate P@L on Horizontal axis by dropping straight down from the line.

Injection gas pressure at depth - English

Injection gas pressure at depth - Metric

When the well conditions differ from those given above, pressure at depth is deter-mined using charts like those seen in Figures 3.2 and 3.3. The following data must be given:

1. Temperature at Surface (T@S) °F [°C]
2. Geothermal Gradient (G/T) °F/100 ft [°C/meter]
3. Specific Gravity (SG.) [Relative Density]
4. Pressure at Surface (P@S) psig [kPa]
5. Depth (L) feet [meters]

The following steps must be completed in order to determine the pressure at a given depth:

Step 1. Determine the temperature at depth by applying the following formula:

English:

$$T@L = T@S + \frac{Temp.Grad. \times L}{100}$$

Metric:

$$T@L = T@S + Temp.Grad \times L$$

Step 2. Calculate the average temperature:

$$T_{avg} = \frac{(T@L + T@S)}{2}$$

$$T_{avg} = \frac{(T@L + T@S)}{2}$$

Step 3. Estimate the P@L using the "rule of thumb" equation given above.

Step 4. Calculate the average pressure: Pavg = P@L + P@S

$$P_{avg} = \frac{(P@L + P@S)}{2}$$

$$P_{avg} = \frac{(P@L + P@S)}{2}$$

Step 5. Enter Figure 3.2 with the average temperature calculated in Step 2 on the left horizontal axis. Travel up to the given gas gravity. Travel across the graph to the right.

Step 6. Enter Figure 3.2 with the average pressure estimated in Step 4 and travel upward until the line intersects the line drawn in Step 5. Read the compressibility factor at the point of intersection.

Step 7. Enter Figure 3.3 with the given gas gravity and travel up to given depth. Travel across to the average temperature calculated in Step 2. Travel down to the compressibility factor determined in Step 6. Move across to the surface pressure line (P@S given) and down from this point to the pressure at depth line. Read the P@L on the lower horizontal axis.

Step 8. Compare P@L with your estimate. If it differs by more than 10%, repeat the entire procedure using the P@L just determined to calculate the average pressure in Step 4. Repeat the procedure until the derived P@L becomes constant (at least 2 values for P@L).

Compressibility factors for natural gas

Gas pressure at depth

VOLUME OF A GAS IN A CONDUIT

It is sometimes necessary to determine the volume of gas in a conduit under given conditions. This is particularly true when designing conventional and chamber intermitting installations. Equations have been derived to determine volume in a conduit and determine the gas required to change the pressure within the conduit.

The internal capacity of a single circular conduit such as a tubing or casing string can be calculated using the following equations:

English	Metric
Q (ft^3 / 100 ft.) = 0.5454 di^2	Q(m^3 / 100 meters) = 0.007854 di^2
Q (barrels/100 ft.) = 0.009714 di^2)	

Where:

di = the inside diameter in inches	di = the inside diameter in cm

When it is necessary to determine the annular capacity of a tubing string inside casing, the equation below can be used.

English	Metric
Q(ft^3 / 100 ft.) = 0.5454 (di^2 - do^2)	Q(m^3 / 100 meters = 0.007854(di^2 - do^2)
Q(barrels/100 ft.) = 0.09714 (di^2 - do^2)	

Where:

di = the inside diameter in inches	di = the inside diameter in cm
do = the outside diameter in inches	do = the outside diameter in cm

Once the volume or capacity of a conduit has been determined, it is often necessary to find the volume of gas contained in the conduit under specific well conditions. The equation below can be used for this purpose:

$$b = V \times \frac{\overline{P} \times T_b}{\overline{Z} \times P_b \times \overline{T}}$$

Where:

b = gas volume at base conditions

V = capacity of conduit in cubic ft. (see formula above)

$\overline{P}$ = average pressure within conduit (psia)

T_b = temperature base in degrees Rankin

$\overline{Z}$ = compressibility factor for average pressure and temperature in a conduit

(See Figure 3.2)

P_b = pressure base (14.73 psi)

$\overline{T}$ = average temperature in the conduit in degrees Rankin

VOLUMETRIC GAS THROUGHPUT OF A CHOKE

Another important determination is the quantity of gas that can pass through a given opening during a specific time period. In a gas lift installation, if sufficient gas will not pass through a particular port, the required GLR cannot be obtained to lift fluids from a given depth. In gas lift design work, the rate of gas flow is expressed in standard cubic feet over a unit of time.

Most gas passage calculations for valve port sizing are based on the Thornhill-Craver studies. The equation is:

$$Q=\frac{155\times C_d\times A\times P_1\sqrt{2g\times\frac{k}{k-1}\times\left[r^{2/k}-r^{(k+1)/k}\right]}}{G\times T}$$

Where :

Q = Gas flow in 1000 scfd (MCFD) at 60 Deg. F. and 14.7 psia

C_d = Discharge coefficient

A = Area of opening, square inches

P_1 = Upstream pressure, psia

P_2 = Downstream pressure, psia

g = Acceleration of gravity, = 32.2 ft./sec.2

$K = \text{Ratio } \frac{C_p}{C_v} = \frac{\text{Specific heat at constant pressure}}{\text{Specific heat at constant volume}}$

$r = \text{Ratio } \frac{P_2}{P_1} \geq r_o$

$r_o = \left[\frac{2}{k+1}\right]^{k/(k-1)}$ = Critical Flow Pressure Ratio

G = Specific gravity (Air = 1)

T = Inlet temperature, Deg. R.

Since the equation above is so complex and its calculation is very time consuming, the chart in Figure 3.4 provides a means of quickly obtaining an approximate gas passage rata for a given port size. It must be remembered, when using the chart, that a correction factor should be used. Since gas passage through a gas lift valve occurs downhole, the chart must be corrected for specific gravity and temperature at the valve depth.

To determine the gas passage rate using the chart and correction factors use the following procedure:

Step 1. Obtain port size, upstream pressure, downstream pressure, specific gravity (gas gravity), and temperature in degrees Fahrenheit.

Step 2. Calculate the ratio of downstream pressure to up stream pressure applying the following equation:

$$R = \frac{P_d}{P_{up}}$$

Step 3. Enter Figure 3.4 with the ratio on the vertical axis.

Step 4. Travel across to the curve and down to the horizontal axis.

Step 5. Read value for K.

Step 6. Read coefficient for port (C) on Figure 3.4.

Step 7. Calculate gas passage Q using the following equation:

$$Q = P_{up} \times K \times C$$

Step 8. Correct the chart value by applying the following equation:

English

$$Q_{actual} = \frac{Q_{chart}}{.0544\sqrt{SG \times (T_f + 460)}}$$

Metric

$$Q_{actual} = \frac{Q_{chart}}{0.07299\sqrt{\mathrm{Re}l.\,Dens \times (T_f + 273)}}$$

NOTE: "C" in step six is determined by the following equation:

$$C = 46.08 \times d^2$$

$$C = 0.29334 \times d^2$$

Where:

d = port diameter in inches

d = port diameter in inches

page reserved for Thornhill-Craver gas passage chart - English

This page reserved for gas passage chart - Metric

PROPERTIES OF NITROGEN

Most gas lift valves using a pressure charged bellows are filled with nitrogen. Therefore, special consideration is given to this gas. Nitrogen has advantages over other potential gases to be used in pressure charged bellows. It is readily available, non-corrosive, and non-explosive. In addition, the compressibility of nitrogen and its temperature changes are predictable.

Like all other gases, when the temperature of nitrogen is increased and the volume held constant, the pressure will increase. When the pressure of a valve is set at the test bench at 60°F [15 C , the pressure of the valve will be higher downhole where the temperature is greater. This increase in pressure due to temperature increase can be approximated by the following equation:

$$P_2 = P_1 \times T_c$$

Where:

P_1 = Pressure at initial temperature

P_2 = Pressure resulting from change of temperature

T_c = Temperature correction factor

and

English:

$$T_c = \frac{1+.00215\times(T_2-60)}{1+.00215\times(T_1-60)}$$

Metric:

$$T_c = \frac{94195+387\times T_2}{94195+387\times T_1}$$

Where:

T_1 = Initial temperature, Deg. F.	T_1 = Initial temperature, Deg. C.
T_2 = Present temperature, Deg. F.	T_2 = Present temperature, Deg. C.

When valves are set at a certain constant temperature, a table may be made for ease in applying temperature corrections. For example, if all valves are to be charged with nitrogen when they are at 60°F [15°C], a correction for temperature (at well depth) may be created using the following equation:

English:

$$C_t = \frac{1}{1+.00215\times(T@L-60)}$$

Metric:

$$C_t = \frac{100000}{94195+387\times T_1}$$

Where:

C_t = Correction for temperature

$T@L$ = Temp at valve depth, °F.

$T@L$ = Temp at valve depth, °C.

Then: $P_b = C_t \times P_{bt}$

Where:

P_b = Bellows pressure at 60°F., psig

P_{bt} = Bellows pressure at valve depth temp, psig

P_b = Bellows pressure at 15°C., kPa

P_{bt} = Bellows pressure at valve depth temp, psig

Table 3.1A contains the correction for temperature (Ct) for temperatures from 60°F to 300°F. Table 3.1B contains the correction for temperature (Ct) for temperatures from 16°C to 150°C. These tables should be readily available for problems requiring the determination of dome pressure. Since it is based on the most frequently used pressures and temperatures, it should be limited to use with moderate temperature corrections. It is not accurate at extreme pressures and temperatures.

TABLE 3.1A

Nitrogen Temperature Correction Factors for Temperature in Fahrenheit

° F	Ct	° F	Ct	° F	Ct	° F	Ct	° F	Ct	° F	°Ct
61	0.998	101	0.919	141	0.852	181	0.794	221	0.743	261	0.698
62	0.996	102	0.917	142	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

TABLE 3.1B

Nitrogen Temperature Correction Factors for Temperature in Celsius

° C	Ct	° C	Ct	° C	Ct	° C	Ct
16	0.998	51	0.879	86	0.786	121	0.710
17	0.994	52	0.876	87	0.783	122	0.708
18	0.991	53	0.873	88	0.781	123	0.706
19	0.987	54	0.870	89	0.779	124	0.704
20	0.983	55	0.868	90	0.776	125	0.702
21	0.979	56	0.865	91	0.774	126	0.701
22	0.976	57	0.862	92	0.772	127	0.699
23	0.972	58	0.859	93	0.769	128	0.697
24	0.968	59	0.856	94	0.767	129	0.695
25	0.965	60	0.853	95	0.765	130	0.693
26	0.961	61	0.850	96	0.763	131	0.691
27	0.958	62	0.848	97	0.760	132	0.689
28	0.954	63	0.845	98	0.758	133	0.688
29	0.951	64	0.842	99	0.756	134	0.686
30	0.947	65	0.839	100	0.754	135	0.684
31	0.944	66	0.837	101	0.752	136	0.682
32	0.940	67	0.834	102	0.749	137	0.680
33	0.937	68	0.831	103	0.747	138	0.678
34	0.933	69	0.829	104	0.745	139	0.677
35	0.930	70	0.826	105	0.743	140	0.675
36	0.927	71	0.823	106	0.741	141	0.673
37	0.923	72	0.821	107	0.739	142	0.671
38	0.920	73	0.818	108	0.737	143	0.670
39	0.917	74	0.816	109	0.734	144	0.668
40	0.914	75	0.813	110	0.732	145	0.666
41	0.910	76	0.810	111	0.730	146	0.665
42	0.907	77	0.808	112	0.728	147	0.663
43	0.904	78	0.805	113	0.726	148	0.661
44	0.901	79	0.803	114	0.724	149	0.659
45	0.898	80	0.800	115	0.722	150	0.658
46	0.895	81	0.798	116	0.720	151	0.656
47	0.892	82	0.795	117	0.718	152	0.654
48	0.888	83	0.793	118	0.716	153	0.653
49	0.885	84	0.791	119	0.714	154	0.651
50	0.882	85	0.788	120	0.712	155	0.649

OUTFLOW PERFORMANCE

The outflow performance describes the relationship between the surface flowrate and pressure drop in the tubing. The prediction of this relationship is complicated by the multi-phase nature of the fluids. Analysis of the outflow performance therefore requires the prediction of phase behavior, flowing temperatures, effective fluid density and frictional pressure losses. The results of the outflow performance are usually presented graphically. The most common plot depicts how the flowing bottom hole pressure (P_{bhf}), varies with flowrate for a fixed back pressure (usually the wellhead or separator pressure). The resulting curves are termed tubing performance curves (TPC) or lift curves. Any point on the curve gives the pressure required at bottom hole conditions, P_{wf}, to achieve the given surface flowrate against a specified back pressure.

VERTICAL AND HORIZONTAL MULTIPHASE FLOW

The pressure of fluids in the tubing and flow line is subject to changes in pressure. Since the fluids are a mixture and because of the large number of factors involved, calculating the fluid pressure at a given point is a very difficult task. The proper design of gas lift installation requires this information so solutions to this problem are necessary.

Mathematical solutions have been developed which allow the designer to arrive at a specific pressure gradient curve for the well. The available well data is fed into a computer which constructs the curve. Since all data is not known, the curve is approximate but can be used for most design work.

Without computer curves, existing published curves can be matched with well data. These "working" curves are applied to the solution of numerous problems. The data obtained from these curves are accurate estimates when they are read with great care.

As fluids flow from the reservoir to the wellbore and eventually to the surface through the production system, there is a continual pressure drop. This pressure drop is not constant throughout the system and is caused by many factors. The fluid moving through the system actually may consist of three different fluids (gas, water and oil) flowing at three different velocities. This movement of free gases and liquids at the same time is called multiphase flow.

Multiphase flow can be divided into four categories depending on the direction of movement. As can be seen in Figure 2.7, most production systems include: vertical multiphase flow, horizontal multiphase flow, inclined multiphase flow, and directional multiphase flow. For the purposes of our discussion, we will consider only vertical and horizontal flow.

The gases and liquids may exist as a homogeneous mixture or the liquid may be in slugs with the gas pushing behind it. The liquid and gas may also flow parallel to each other or other combinations of flow patterns may be present. Figure 2.8 illustrates some common vertical and horizontal multiphase flow patterns. Each of these flow patterns will produce a different pressure drop over a given distance. In addition to flow pattern, factors affecting the pressure loss in multiphase flow include:

1. Inside diameter of flowing conduit
2. Wall roughness
3. Inclination
4. Liquid density
5. Gas density
6. Liquid viscosity
7. Gas viscosity
8. Superficial liquid velocity
9. Superficial gas velocity
10. Liquid surface tension
11. Wall contact angle
12. Gravity acceleration
13. Pressure gradient

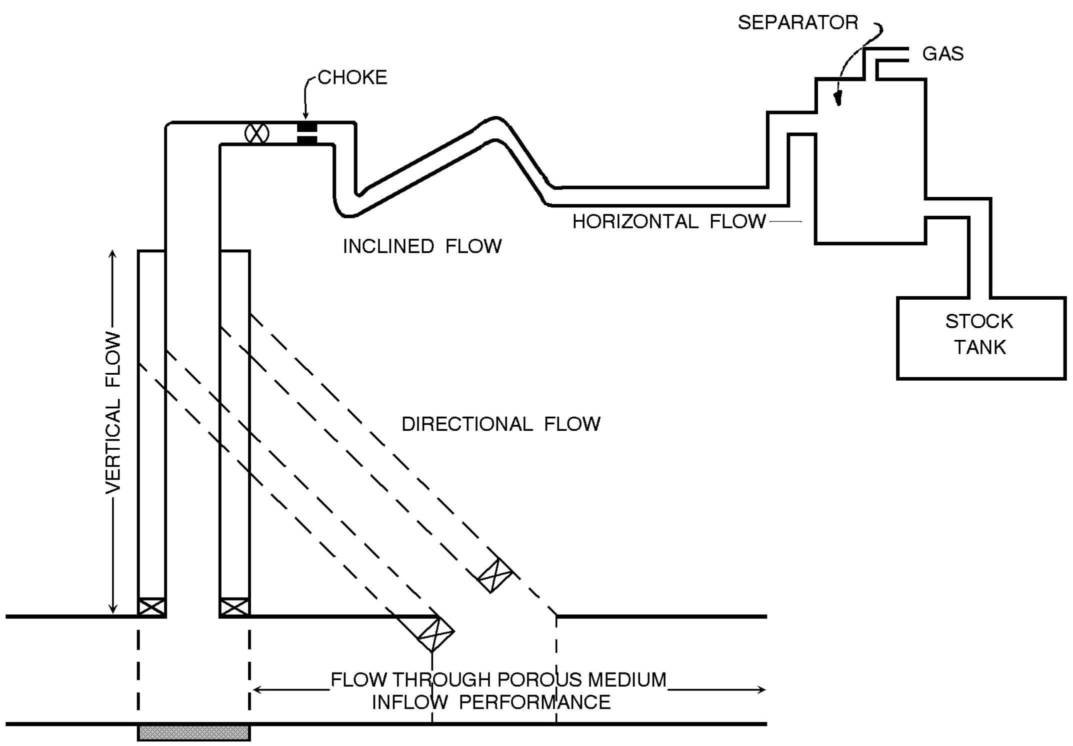


Figure 2.7 Flow through the Production System

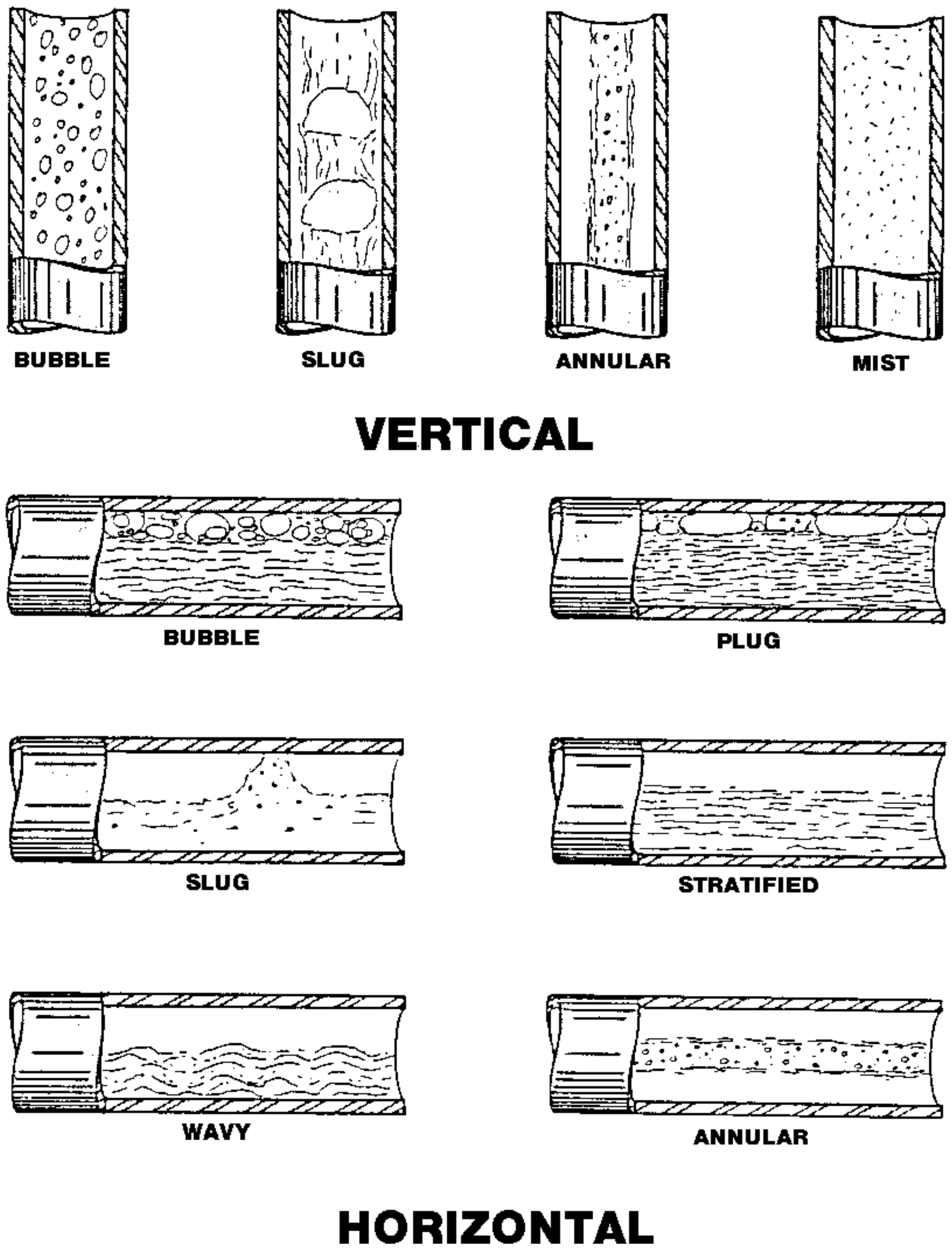


Figure 2.8 Multiphase Flow Patterns

Since the pressure drop is caused by a complex interaction of many factors, one of the major problems in analyzing flowing wells and designing gas lift installations has been the prediction of flowing pressure at depth. It is also important to understand the pressure drop in the horizontal flow line in order to determine the back pressure at the wellhead. This problem has been the subject of numerous studies.

In 1939, E.C. Babson[1] published a paper on vertical multiphase flow. W.E. Gilbert[2] did a considerable amount of work in 1939 and 1940 on vertical multiphase flow. However, he did not report his work until 1954. Gilbert's very important contribution to the state of the art is the pressure depth plot that is called the gradient curve.

Poettmann-Carpenter[3] published their paper in 1952. Their work resulted in a correlation rather than a set of gradient curves. It was the first fundamental mathematical approach which gave good results over a rather wide range of flowing conditions. Gradient curves plotted from calculations made according to the Poettmann-Carpenter correlation have been widely used in the design of gas lift installations. The correlation is good for 2- 3/8" and 2-7/8" tubing for flow rates between about 300 BPD and 2500 BPD. Figure 4.3 is an example of such a flowing pressure gradient based on this correlation. Notice that the curves are valid only under the conditions stated on the curve.

More recently there have been several other investigators publish general correlations. Of these, the better known correlations are the Hagedorn and Brown[4], Orkiszewski[5] and Ros[6] '

The vertical multiphase flow correlations are accurate enough to be very useful to production personnel. They have been used to accomplish the following functions:

1. Select correct tubing sizes (tubing or annular flow).
2. Predict when a well will quit flowing and require artificial lift.
3. Design artificial lift systems.
4. Determine flowing bottom hole pressures.
5. Determine Pl's of wells.
6. Predict maximum flow rates.

There are two methods by which vertical multiphase flow correlations can be used by production personnel. The calculation can be made by computer or "published curves" (see Figure 4.3) can be used. Most companies have at least one program available for vertical multiphase flow, and there are numerous sets of published curves available.

When possible, the computer calculations are recommended but there are numerous occasions when published curves must be used.

All vertical gradient curves have certain limitations. The fluids must be free of emulsions. At the present time there is no way to predict the pressure losses that occur with emulsions. The tubing must be unrestricted. The tubing string should be free of scale and paraffin build up. Mashed or kinked joints must not exist in order for the vertical gradient curves to be accurate. The flow pattern must be relatively stable. There should be no severe heading or slugging where there is several hundred psi between maximum and minimum tubing pressures.

The well must be essentially vertical. The correlations do not take into consideration deviated holes. The use of drilled depth results in pressures that are too great and the use of true vertical depth results in pressures that are too low.

The calculation of pressure loss in flow lines requires a horizontal multiphase flowing pressure gradient. One such gradient is based on a paper by Eaton[3] et al, in which data was obtained for horizontal flow over several conditions including different pipe diameters and lengths.

When vertical flowing pressure gradients are compared with horizontal flowing pressure gradients one obvious and important difference can be observed. As the Gas to Liquid Ratio (GLR) increases on the vertical gradient, the pressure drop decreases, but with increased GLR in the horizontal gradient the pressure drop increases. This can create problems for the gas lift designer. If the GLR produced by the injected gas necessary to lift the fluids reaches high enough values, the increased pressure drop in the flow line may actually cause loss in production. Only through a complete understanding of multiphase flow through vertical and horizontal conduits, can a gas lift system be designed to operate efficiently.

Some of the correlation's most widely accepted in the industry are:

- Duns and Ros (1963)
- Hagedorn and Brown (1967)
- Orkiszewski (1967)
- Aziz, Govier and Fogarasi (1972)
- Beggs and Brill (1973)

These correlations are available in most computer software used for predicting outflow performance. Modifications have been made to some of these correlations in an attempt to improve their predictions. These correlation's predict different pressure drops for the same application. Any one of these correlation's or modifications may be successful for a given field. Validation with actual field data in the form of flowing surveys is the only reliable method for choosing a pressure loss prediction method. In the North Sea the Hagedorn and Brown modified correlation generally gives the best fit to measured data.

Calculation Background Information (reproduced courtesy of Edinburgh Petroleum Services Ltd.)

This section serves as a brief technical reference for the engineering calculations in WellFlo™. Where modification work has been carried out in-house, it is explained briefly here.

Pressure Drop Correlation's

There are a number of pressure drop correlations in WellFlo™. Six are basically taken from standard theory, four have been modified in various ways (variants of the Duns and Ros, Beggs and Brill and Hagedorn and Brown correlation's), and two are hybrids (Dukler-Eaton-Flanigan and Barnea-Ansari-Xiao (BAX)). The *standard* forms of the correlations follow the published references as closely as possible. The BAX correlation is mechanistic.

There are three sources of pressure drop:

- **Hydrostatic Gradient** which arises from the density of the multi-phase column of fluids. It is calculated from a knowledge of the liquid hold-up (the proportion of the flowing area occupied by liquid), and the densities of the phases. It is proportional to the cosine of the deviation, being zero in a horizontal pipe. Most correlations use a flow-regime map to determine the type of flow, and then use a particular correlation for the flow regime concerned to determine hold-up.

- **Friction Gradient** arising from the drag of the fluids on the walls of the pipe. This is calculated in a specific way for each correlation, but generally uses the concept of a Friction Factor diagram (such as Moody's) to calculate the friction factor as a function of the Reynolds Number and pipe roughness. The friction factor is used to calculate the friction pressure gradient.

- **Acceleration Gradient** arising from the increasing kinetic energy of the fluids as they expand and accelerate with decreasing pressure. This term is often negligible, but is always included in these correlation's. All correlation's in WellFlo use an acceleration term proposed by Beggs and Brill based on the mean phase velocities in each computational segment.

Each correlation is described in terms of these three pressure gradient components. Note that, for the frictional gradient, the following correlation's do not use the wall roughness entered in the component dialog box, but compute their own roughness factors internally: *Beggs and Brill, Beggs and Brill (no-slip), Fancher-Brown, Dukler-Eaton-Flanigan.*

- **Duns and Ros** follows the methods described by Brown. The correlation makes use of a flow regime map covering bubble, slug and mist flow. There is a linear transition between slug and mist. Each regime has its own holdup correlation. Holdup is not changed by deviation. Friction is calculated with liquid properties for bubble and slug flow, and gas properties for mist. In mist flow, wall friction is increased due to liquid ripples on the pipe wall.

- **Duns and Ros (modified)** has a flow regime map extended by the work of Gould et al. This includes a new transition region between bubble and slug flow, and an additional froth flow region at high flow rates. The holdup is considered as no-slip for froth flow, and is interpolated over the bubble-slug transition. The other holdup relationships are as for the standard Duns and Ros. To model deviation, the calculated holdup is modified using the Beggs and Brill corrections (see below). Friction is calculated by the method proposed by Kleyweg. This uses a monophasic friction factor rather than two-phase, but involves use of an average fluid velocity. This is claimed by Kleyweg to be a better method.

- **Beggs and Brill** again follows the methodology outlined by Brown. This correlation is unique in that it is based on a flow regime map for *horizontal* flow, from which a regime is first determined as if the flow were horizontal. A horizontal holdup is then calculated by correlations. Lastly, this holdup is corrected for the actual angle of deviation. Beggs and Brill's correlation models up- and down-flow. **It is therefore recommended for all pipeline applications.** However, since it was not derived for vertical flow, it must be used with caution in vertical wells. Friction calculations in Beggs and Brill use an internally defined two-phase *smooth pipe* friction factor. This may be expected to under-estimate friction in rough pipes.

- **Beggs and Brill (no-slip)** uses the same methodology as the standard Beggs and Brill, with the exception that the holdup used is not the horizontal holdup described above, but simply the no-slip holdup, without deviation correction.

- **Beggs and Brill (modified)** also uses the same methodology as the standard Beggs and Brill, with the following changes. There is no extra flow regime of froth flow, which (as in Duns and Ros (modified)) assumes a no-slip holdup. This is triggered by highly turbulent flow. The friction factor is changed from the smooth pipe model to the method used in Duns and Ros (modified) - a single-phase friction factor using pipe roughness and average fluid velocity.

- **Hagedorn and Brown** again is as per Brown, with the modifications to Hagedorn and Brown's original work as recommended by them. These are: the use of the Griffith and Wallis correlation for bubble flow (using a simplified flow regime map to detect bubble flow); and the use of no-slip holdup if it gives greater density than Hagedorn and Brown's correlation. There is no change to holdup with deviation. A two-phase friction factor using pipe roughness is used.

- **Hagedorn and Brown (modified)** involves the adjustment of the standard Hagedorn and Brown holdup for deviation using the Beggs and Brill correction. When Griffith and Wallis' holdup correlation is invoked (in bubble flow), it is also corrected. Otherwise, this is the same as the standard Hagedorn and Brown correlation.

- **Fancher and Brown** is a no-slip correlation[1], with no flow regime map. It has its own friction factor model, which is independent of pipe roughness. This correlation cannot be recommended for general use. According to Brown, it is only suitable for 2-3/8 - 2-7/8 inch tubing. It is included for any historical comparisons which may be required. Generally, it differs widely from the results of the other seven correlations.

- **Orkizewski** is again based on the description by Brown. This is perhaps the most sophisticated correlation, as it uses the work of Duns and Ros and Griffith and Wallis, for mist and bubble flow respectively (using a flow regime map similar to Duns and Ros'). It has its own correlation in the slug flow region, which is based on the approach of Griffith and Wallis. A transition between slug and mist flow is also modeled. The holdup is adjusted for deviation using the Beggs and Brill correlation (as in the modified Duns and Ros and Hagedorn and Brown correlation's). The friction factor calculation uses wall roughness but varies with flow regime, and for mist flow retains the Duns and Ros extra friction due to ripples in the film of liquid on the wall.

- **Gray:** this is a widely recommended correlation[6] for gas and condensate systems which are predominantly gas phase (with liquid entrained as droplets). No flow regime map is used, flow being treated as pseudo-single phase. Water or liquid condensate is considered to adhere to the pipe wall, resulting in a modified roughness term.

- **Dukler-Eaton-Flanigan** is a hybrid of the Dukler friction component and Flanigan correlation for the hydrostatic component. A mixture density is calculated using Dukler's equation, but with Eaton's holdup definition, and this is used in Dukler's friction term. The liquid density is used in the Flanigan hydrostatic term. The acceleration component is modeled with the Beggs and Brill correlation. <u>This correlation is not suitable for downflow.</u>

- **BAX** (**B**arnea-**A**nsari-**X**iao) correlation is 'mechanistic' in that is has been formulated largely on physical modeling principles. It is applicable to all fluid types, in all sizes of pipe at any inclination.

- Flow regimes are predicted according to Barnea. Xiao's model is used to compute the hydrostatic and frictional pressure gradients for stratified flow, and Ansari's model for all other flow regimes. Hasan's corrections for deviation from the horizontal or vertical are applied to these model where necessary.

Combining the IPR and TPC Curves

After the IPR and TPC curves have been established for a given set of conditions, they are usually presented on the same plot.

The intersection of the IPR and TPC can be used to predict the flowrate of a well at a given set of stable flow conditions. Changing system parameters such as tubing ID, reservoir pressure, water cut, flowing well head pressure or Gas Liquid Ratio affect either or both the IPR and the TPC, and hence alters the wells production rate. Systematically varying the different system parameters allows one to compare the incremental effects on production. In Figures 2-9 a & b the gas lift injection rate has been systematically increased and the resulting effect on production can be used to produce a well performance curve for use in optimizing gas injection rates see Figure 2-10.

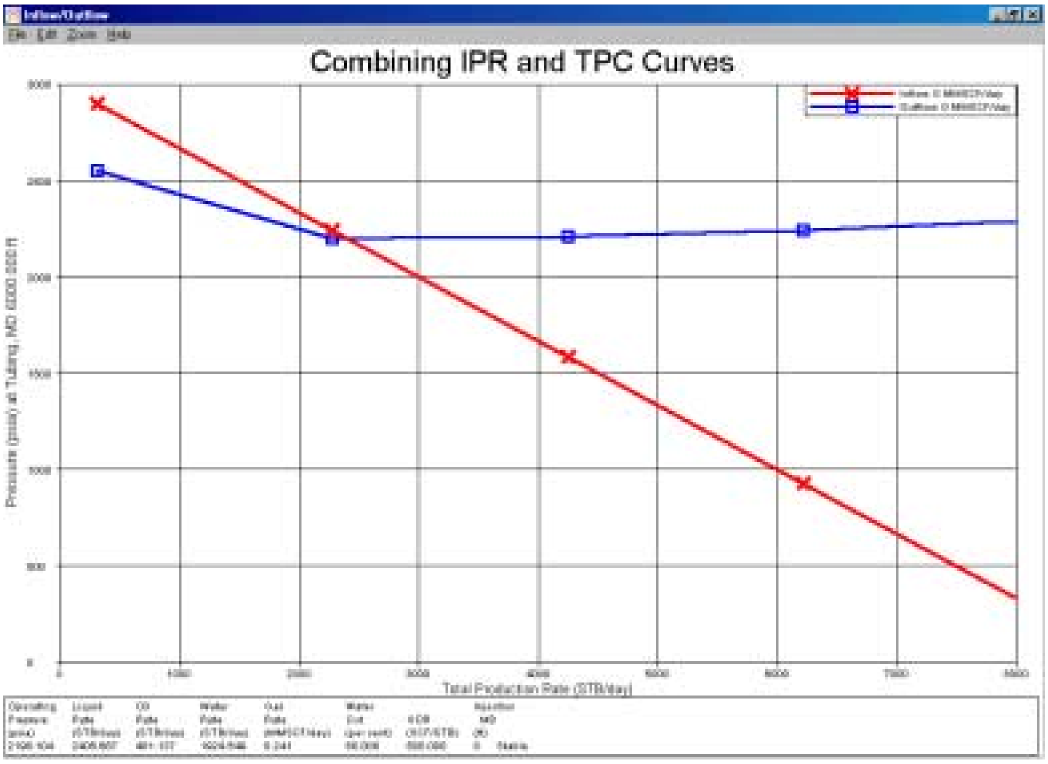


Figure 2-9a

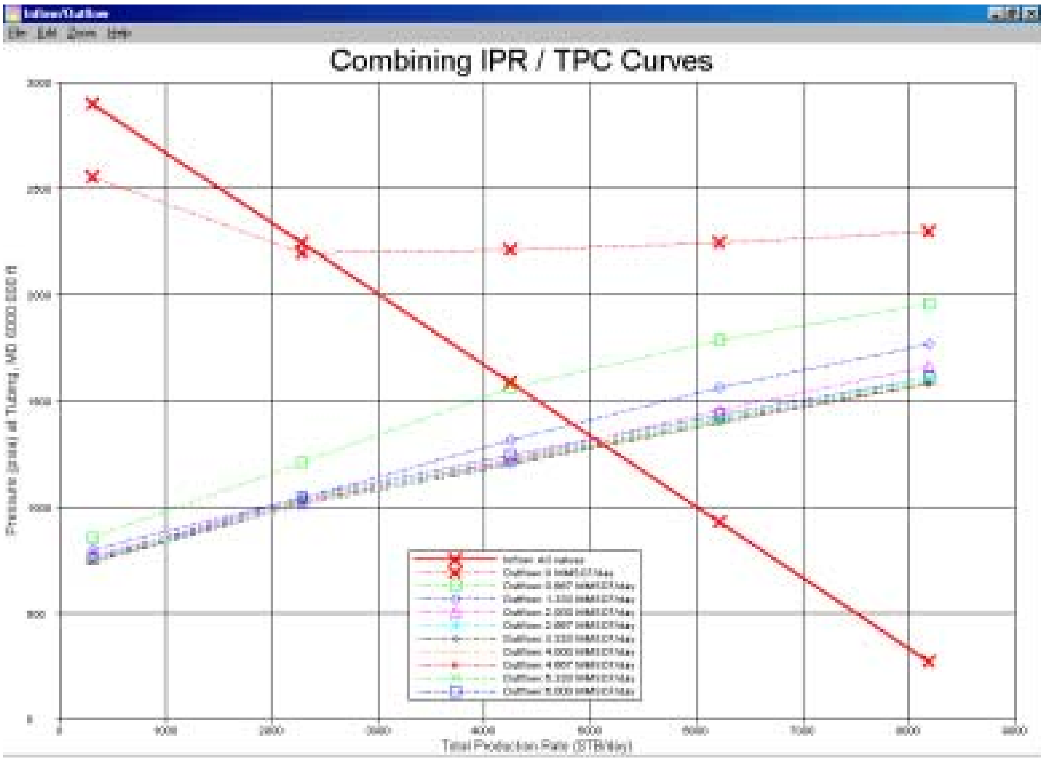


Figure 2-9b

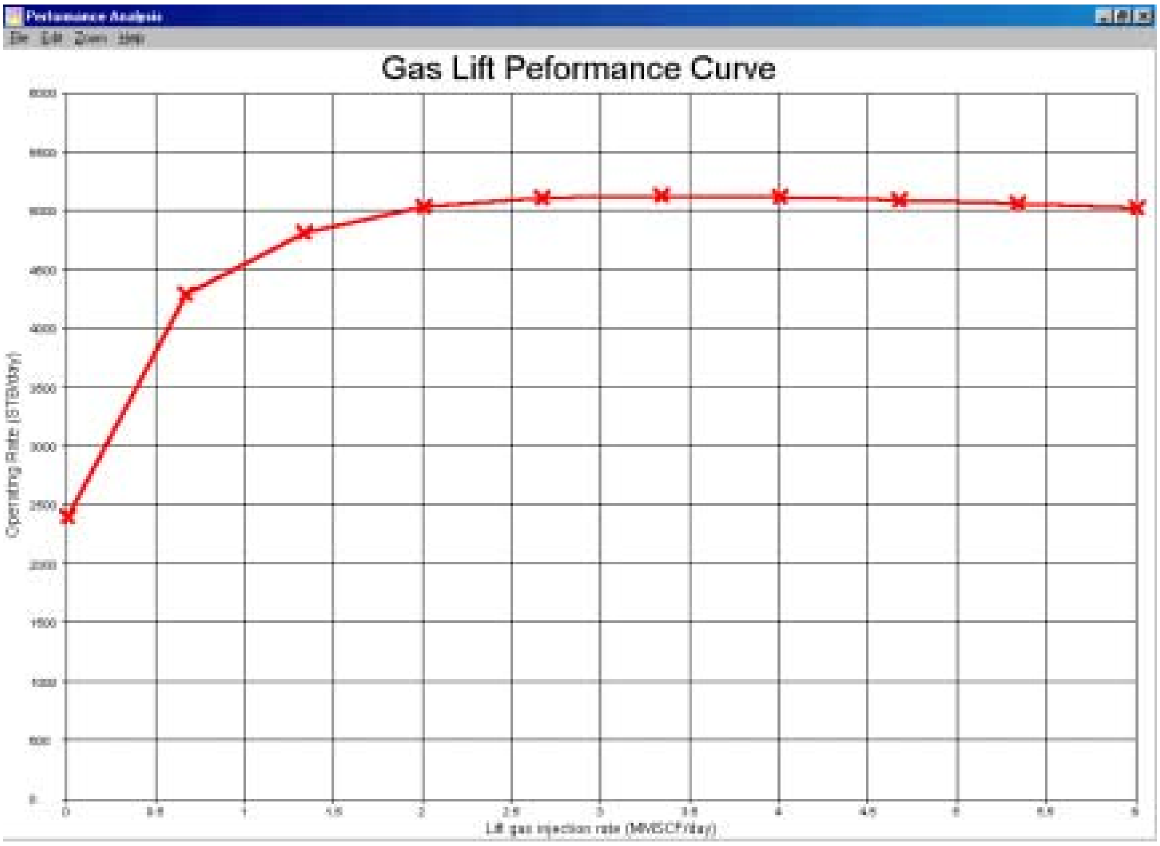

Performance Analysis
Gas Lift Peformance Curve
Operating Rate (STB/day)
Lift gas injection rate (MMSCF/day)

Figure 2-10

3. Natural Gas Laws Applied to Gas Lift

3. Natural Gas Laws Applied to Gas Lift

CHAPTER OBJECTIVE: Given all required data and the appropriate formula, you will calculate gas pressure at depth, rate of flow through an orifice, the valve pressure set at 60°F for a given down hole temperature, and gas volumes within a closed conduit.

INTRODUCTION

The application of gas lift equipment requires the understanding of the behavior of gas. Although all gases have common behaviors known as the natural gas laws, there are some differences between the injection gas which is a mixture of several gases with different chemical properties and the nitrogen which is used to charge pressure operated gas lift valves.

Designing a gas lift installation involves the determination of gas pressure in the casing or tubing at the specific depth of a valve when the surface injection pressure is known. The designer must also be able to determine the volume of gas that can be delivered to the tubing through a particular valve in order to obtain the proper gas to liquid ratio needed to lift the fluids to the surface. Since the same pressure is set at the surface under a standard temperature, the pressure must be corrected so that proper operating pressure will exist at the down hole temperature.

PROPERTIES OF INJECTION GAS

Natural gas injected into a well, as well as the dissolved gas in the reservoir fluid, is subject to a number of gas laws. Gas, unlike liquids, is an elastic fluid. It is often defined as a homogeneous fluid which occupies all the space in a container. This is easily visualized by noting, for example, that 1 lb. of liquid placed in a closed container may fill a small portion of the total volume of that container. However, 1 lb. of gas placed in the same empty container will fill the container completely.

Gases expand with increases in temperature and contract with decreases in temperature. The volume of gases is inversely related to pressure. As the pressure increases, the gas volume decreases. Gas volume is usually measured in standard cubic feet (scf) [NM^3]. A standard cubic foot is defined as the volume contained in one cubic foot if the pressure is 14.73 psia and if the temperature is 60°F. A "normalized" cubic meter is defined as the volume contained in one cubic meter if the pressure is 101.32 KPa and if the temperature is 0º Celsius. Note that a "standard" cubic meter is defined by contractual agreement and is usually at a temperature of 20º C.

It is known that gases have weight similar to any other fluid. Air, for example, weighs 0.0764 lbs. per cubic foot [1.2238 Kg/M^3] at 14.7 psia [101.353 KPa] and 60º F [15.56º C]. On a comparative basis, gas is always compared to air as a liquid is compared to water. The ratio of the density of a gas compared to the density of air is known as the gas gravity or relative density.

One of the most important calculations required in gas lift designs is the determination of gas pressure at a given depth.

The equation for calculating pressure at depth is:

English

$$P@L = P@S \times e^{\left[\frac{S.G. \times L}{53.34 \times \bar{T} \times \bar{Z}}\right]}$$

Metric

$$P@L = P@S \times e^{\left[\frac{\gamma \times L}{29.28 \times \bar{T} \times \bar{Z}}\right]}$$

Where:

English

e = 2.71828

$P@L$ = Pressure at depth, psia

$P@S$ = Pressure at surface, psia

SG = Gas Specific gravity

L = Depth, feet

$\bar{T}$ = Average temperature, Degrees R

$\bar{Z}$ = Average Compressibility for $\bar{T}$ and average pressure

Metric

e = 2.71828

$P@L$ = Pressure at depth, kPa

$P@S$ = Pressure at surface, kPa

γ = Gas relative density

L = Depth, meters

$\bar{T}$ = Average temperature, Kelvin

$\bar{Z}$ = Average Compressibility for $\bar{T}$ and average pressure

The average compressibility ($\bar{Z}$) is difficult to determine. Compressibility is based on the average temperature and pressure and since the average temperature and pressure are unknown, the solution becomes a repetitive trial and error procedure. A frequently used shortcut is to use a "rule of thumb" equation. The equation below is based on a gas specific gravity of 0.65, a geothermal gradient at 1.6°F/100 ft. and a surface temperature of 70°F. This equation should only be used when well conditions are close to these values.

English

$$P@L = P@S + 2.3 \times \frac{P@S}{100} \times \frac{L}{1000}$$

Metric

$$P@L = P@S + 15.65 \times \frac{P@S}{680} \times \frac{L}{305}$$

In addition to the "rule of thumb", gas lift designers frequently use charts like the one seen in Figure 3.1. To use the chart, follow the procedure outlined below:

Step 1. Obtain surface pressure P@S.

Step 2. Locate P@S on vertical axis on Figure 1.

Step 3. Locate the line on graph representing the given depth across from that point (Step 2).

Step 4. Locate P@L on Horizontal axis by dropping straight down from the line.

When the well conditions differ from those given above, pressure at depth is deter-mined using charts like those seen in Figures 3.2 and 3.3. The following data must be given:

1. Temperature at Surface (T@S) °F [°C]
2. Geothermal Gradient (G/T) °F/100 ft [°C/meter]
3. Specific Gravity (SG.) [Relative Density]
4. Pressure at Surface (P@S) psig [kPa]
5. Depth (L) feet [meters]

The following steps must be completed in order to determine the pressure at a given depth:

Step 1. Determine the temperature at depth by applying the following formula:

English:

$$T@L = T@S + \frac{Temp.Grad. \times L}{100}$$

Metric:

$$T@L = T@S + Temp.Grad \times L$$

Step 2. Calculate the average temperature:

$$T_{avg} = \frac{(T@L + T@S)}{2}$$

$$T_{avg} = \frac{(T@L + T@S)}{2}$$

Step 3. Estimate the P@L using the "rule of thumb" equation given above.

Step 4. Calculate the average pressure: Pavg = P@L + P@S

$$P_{avg} = \frac{(P@L + P@S)}{2}$$

$$P_{avg} = \frac{(P@L + P@S)}{2}$$

Step 5. Enter Figure 3.2 with the average temperature calculated in Step 2 on the left horizontal axis. Travel up to the given gas gravity. Travel across the graph to the right.

Step 6. Enter Figure 3.2 with the average pressure estimated in Step 4 and travel upward until the line intersects the line drawn in Step 5. Read the compressibility factor at the point of intersection.

Step 7. Enter Figure 3.3 with the given gas gravity and travel up to given depth. Travel across to the average temperature calculated in Step 2. Travel down to the compressibility factor determined in Step 6. Move across to the surface pressure line (P@S given) and down from this point to the pressure at depth line. Read the P@L on the lower horizontal axis.

Step 8. Compare P@L with your estimate. If it differs by more than 10%, repeat the entire procedure using the P@L just determined to calculate the average pressure in Step 4. Repeat the procedure until the derived P@L becomes constant (at least 2 values for P@L).

VOLUME OF A GAS IN A CONDUIT

It is sometimes necessary to determine the volume of gas in a conduit under given conditions. This is particularly true when designing conventional and chamber intermitting installations. Equations have been derived to determine volume in a conduit and determine the gas required to change the pressure within the conduit.

The internal capacity of a single circular conduit such as a tubing or casing string can be calculated using the following equations:

English	Metric
Q (ft^3 / 100 ft.) = 0.5454 di^2	Q(m^3 / 100 meters) = 0.007854 di^2
Q (barrels/100 ft.) = 0.009714 di^2)	

Where:

di = the inside diameter in inches	di = the inside diameter in cm

When it is necessary to determine the annular capacity of a tubing string inside casing, the equation below can be used.

English	Metric
Q(ft^3 / 100 ft.) = 0.5454 (di^2 - do^2)	Q(m^3 / 100 meters = 0.007854(di^2 - do^2)
Q(barrels/100 ft.) = 0.09714 (di^2 - do^2)	

Where:

di = the inside diameter in inches	di = the inside diameter in cm
do = the outside diameter in inches	do = the outside diameter in cm

Once the volume or capacity of a conduit has been determined, it is often necessary to find the volume of gas contained in the conduit under specific well conditions. The equation below can be used for this purpose:

$$b = V \times \frac{\overline{P} \times T_b}{\overline{Z} \times P_b \times \overline{T}}$$

Where:

b = gas volume at base conditions

V = capacity of conduit in cubic ft. (see formula above)

$\overline{P}$ = average pressure within conduit (psia)

T_b = temperature base in degrees Rankin

$\overline{Z}$ = compressibility factor for average pressure and temperature in a conduit (See Figure 3.2)

P_b = pressure base (14.73 psi)

$\overline{T}$ = average temperature in the conduit in degrees Rankin

VOLUMETRIC GAS THROUGHPUT OF A CHOKE

Another important determination is the quantity of gas that can pass through a given opening during a specific time period. In a gas lift installation, if sufficient gas will not pass through a particular port, the required GLR cannot be obtained to lift fluids from a given depth. In gas lift design work, the rate of gas flow is expressed in standard cubic feet over a unit of time.

Most gas passage calculations for valve port sizing are based on the Thornhill-Craver studies. The equation is:

$$Q = \frac{155 \times C_d \times A \times P_1 \sqrt{2g \times \frac{k}{k-1} \times \left[r^{2/k} - r^{(k+1)/k} \right]}}{G \times T}$$

Where :

Q = Gas flow in 1000 scfd (MCFD) at 60 Deg. F. and 14.7 psia

C_d = Discharge coefficient

A= Area of opening, square inches

P_1 = Upstream pressure, psia

P_2 = Downstream pressure, psia

g = Acceleration of gravity, = 32.2 ft./sec.2

$K = \text{Ratio } \frac{C_p}{C_v} = \frac{\text{Specific heat at constant pressure}}{\text{Specific heat at constant volume}}$

$r = \text{Ratio } \frac{P_2}{P_1} \geq r_o$

$r_o = \left[\frac{2}{k+1} \right]^{k/(k-1)}$ = Critical Flow Pressure Ratio

G = Specific gravity (Air = 1)

T = Inlet temperature, Deg. R.

Since the equation above is so complex and its calculation is very time consuming, the chart in Figure 3.4 provides a means of quickly obtaining an approximate gas passage rata for a given port size. It must be remembered, when using the chart, that a correction factor should be used. Since gas passage through a gas lift valve occurs downhole, the chart must be corrected for specific gravity and temperature at the valve depth.

To determine the gas passage rate using the chart and correction factors use the following procedure:

Step 1. Obtain port size, upstream pressure, downstream pressure, specific gravity (gas gravity), and temperature in degrees Fahrenheit.

Step 2. Calculate the ratio of downstream pressure to up stream pressure applying the following equation:

$$R = \frac{P_d}{P_{up}}$$

Step 3. Enter Figure 3.4 with the ratio on the vertical axis.

Step 4. Travel across to the curve and down to the horizontal axis.

Step 5. Read value for K.

Step 6. Read coefficient for port (C) on Figure 3.4.

Step 7. Calculate gas passage Q using the following equation:

$$Q = P_{up} \times K \times C$$

Step 8. Correct the chart value by applying the following equation:

English

$$Q_{actual} = \frac{Q_{chart}}{.0544\sqrt{SG \times (T_f + 460)}}$$

Metric

$$Q_{actual} = \frac{Q_{chart}}{0.07299\sqrt{\mathrm{Re}l.Dens \times (T_f + 273)}}$$

NOTE: "C" in step six is determined by the following equation:

$$C = 46.08 \times d^2$$

$$C = 0.29334 \times d^2$$

Where:

d = port diameter in inches

d = port diameter in inches

PROPERTIES OF NITROGEN

Most gas lift valves using a pressure charged bellows are filled with nitrogen. Therefore, special consideration is given to this gas. Nitrogen has advantages over other potential gases to be used in pressure charged bellows. It is readily available, non-corrosive, and non-explosive. In addition, the compressibility of nitrogen and its temperature changes are predictable.

Like all other gases, when the temperature of nitrogen is increased and the volume held constant, the pressure will increase. When the pressure of a valve is set at the test bench at 60°F [15 C , the pressure of the valve will be higher downhole where the temperature is greater. This increase in pressure due to temperature increase can be approximated by the following equation:

$$P_2 = P_1 \times T_c$$

Where:

P_1 = Pressure at initial temperature

P_2 = Pressure resulting from change of temperature

T_c = Temperature correction factor

and

English:

$$T_c = \frac{1+.00215\times(T_2-60)}{1+.00215\times(T_1-60)}$$

Metric:

$$T_c = \frac{94195+387\times T_2}{94195+387\times T_1}$$

Where:

T_1 = Initial temperature, Deg. F.

T_2 = Present temperature, Deg. F.

T_1 = Initial temperature, Deg. C.

T_2 = Present temperature, Deg. C.

When valves are set at a certain constant temperature, a table may be made for ease in applying temperature corrections. For example, if all valves are to be charged with nitrogen when they are at 60°F [15°C], a correction for temperature (at well depth) may be created using the following equation:

English:

$$C_t = \frac{1}{1+.00215\times(T@L-60)}$$

Metric:

$$C_t = \frac{100000}{94195+387\times T_1}$$

Where:

C_t = Correction for temperature

$T@L$ = Temp at valve depth, °F.

$T@L$ = Temp at valve depth, °C.

Then: $P_b = C_t \times (P_{bt})$

Where:

P_b = Bellows pressure at 60°F., psig

P_{bt} = Bellows pressure at valve depth temp, psig

P_b = Bellows pressure at 15°C., kPa

P_{bt} = Bellows pressure at valve depth temp, psig

Table 3.1A contains the correction for temperature (Ct) for temperatures from 60°F to 300°F. Table 3.1B contains the correction for temperature (Ct) for temperatures from 16°C to 150°C. These tables should be readily available for problems requiring the determination of dome pressure. Since it is based on the most frequently used pressures and temperatures, it should be limited to use with moderate temperature corrections. It is not accurate at extreme pressures and temperatures.

TABLE 3.1A

Nitrogen Temperature Correction Factors for Temperature in Fahrenheit

° F	Ct	° F	Ct	° F	Ct	° F	Ct	° F	Ct	° F	°Ct
61	0.998	101	0.919	141	0.852	181	0.794	221	0.743	261	0.698
62	0.996	102	0.917	142	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

TABLE 3.1B

Nitrogen Temperature Correction Factors for Temperature in Celsius

° C	Ct	° C	Ct	° C	Ct	° C	Ct
16	0.998	51	0.879	86	0.786	121	0.710
17	0.994	52	0.876	87	0.783	122	0.708
18	0.991	53	0.873	88	0.781	123	0.706
19	0.987	54	0.870	89	0.779	124	0.704
20	0.983	55	0.868	90	0.776	125	0.702
21	0.979	56	0.865	91	0.774	126	0.701
22	0.976	57	0.862	92	0.772	127	0.699
23	0.972	58	0.859	93	0.769	128	0.697
24	0.968	59	0.856	94	0.767	129	0.695
25	0.965	60	0.853	95	0.765	130	0.693
26	0.961	61	0.850	96	0.763	131	0.691
27	0.958	62	0.848	97	0.760	132	0.689
28	0.954	63	0.845	98	0.758	133	0.688
29	0.951	64	0.842	99	0.756	134	0.686
30	0.947	65	0.839	100	0.754	135	0.684
31	0.944	66	0.837	101	0.752	136	0.682
32	0.940	67	0.834	102	0.749	137	0.680
33	0.937	68	0.831	103	0.747	138	0.678
34	0.933	69	0.829	104	0.745	139	0.677
35	0.930	70	0.826	105	0.743	140	0.675
36	0.927	71	0.823	106	0.741	141	0.673
37	0.923	72	0.821	107	0.739	142	0.671
38	0.920	73	0.818	108	0.737	143	0.670
39	0.917	74	0.816	109	0.734	144	0.668
40	0.914	75	0.813	110	0.732	145	0.666
41	0.910	76	0.810	111	0.730	146	0.665
42	0.907	77	0.808	112	0.728	147	0.663
43	0.904	78	0.805	113	0.726	148	0.661
44	0.901	79	0.803	114	0.724	149	0.659
45	0.898	80	0.800	115	0.722	150	0.658
46	0.895	81	0.798	116	0.720	151	0.656
47	0.892	82	0.795	117	0.718	152	0.654
48	0.888	83	0.793	118	0.716	153	0.653
49	0.885	84	0.791	119	0.714	154	0.651
50	0.882	85	0.788	120	0.712	155	0.649

4. Gas Lift Equipment

4. Gas Lift Equipment

CHAPTER OBJECTIVE: To get an understanding of the basic gas lift equipment and accessories, with a more detailed knowledge of gas lift valve mechanics and the application in design and operations.

Introduction

Continuous Gas Lift usually consists of a number of unloading valves with an orifice valve at the operating point. In this context the role of the unloading gas lift valve should be to allow smooth, positive and reliable unloading of the well to the orifice over many years with continuously changing conditions. There are several different types of gas lift valves used in order to achieve this and each uses a particular design technique. The following is a brief summary of the common types of valve and design techniques used for continuous gas lift in the North Sea

Injection Pressure Or Casing Pressure Operated Valves

The IPO valves are designed in such a way that the casing pressure is acting on the larger area of the bellows and thus they are primarily sensitive to the casing pressure (see FIGURE 4-1). The drop in casing pressure which occurs during unloading is used to close the valves in the correct sequence. The added benefit of this type of operation is that when the desired injection point is reached then an additional casing pressure drop can be designed in ensuring the upper valves are firmly closed and that fluctuations in tubing pressure are very unlikely to result in the valve re-opening. Worldwide they are considered the primary unloading valve type when continuous gas lifting, being suitable for all conditions other than those in which the PPO valve excels.

Production Pressure or Tubing Operated Valves

In the PPO valves the flow path is reversed and thus the tubing pressure is acting on the larger area of the bellows making the valve primarily sensitive to the tubing pressure. The drop in the tubing pressure as gas is injected is used to close the valve. As this is less predictable than the injection pressure their uses are generally limited to dual wells where changes in casing pressure would cause interference between the strings with the IPO valve and also in situations where the injection pressure is prone to fluctuate and the production pressure can be considered the more predictable.

Production Pressure (Tubing) Sensitivity and Gas Passage

The degree to which either type of valve is sensitive to the tubing or casing is determined by the area of the port in relation to the bellows area i.e. in the Camco R-20 IPO valve the sensitivity to tubing pressure ranges from 3.8% for a 3/16" port to 26% for the 1/2" port whereas the Camco R-25 PPO valve ranges from 96.2% for a 3/16" port to 89.7% for the 5/16" port.

As either type of valve acts for the most part like an orifice when fully open then gas passage through the valve can be calculated accurately using Thornhill Cravers gas passage through a choke corrected for a gas lift valve using a discharge coefficient. This has been proved to be an accurate method of calculating gas passage for many years. The large range of port sizes available for these valves enables the design engineer to size the valve to pass the correct amount of gas for the conditions he would like it to operate under.

Proportional Response Valves

A third type of design has been developed called the Proportional Response Design (PR). This technique is basically a refined PPO design and utilizes some minor changes to the mechanics of the valve to increase the throttling range (see FIGURE 4-3). All Gas lift valves have some degree of throttling effect as the ball approaches the seat and gas passage is restricted i.e. the valve no longer acts as a simple orifice.

If the natural throttling effect of a spring is used (the more you try to compress a spring the greater the force required) and the seat or port of the valve is beveled or given an angle so that during stem travel (the amount to which the ball moves off seat as the opening force is increased) the ball never moves out of the flow stream and thus continues to be sensitive to the tubing pressure then the valve will respond proportionally to the tubing pressure i.e. the greater the tubing pressure the more the valve will open and thus the more gas the valve will pass until critical flow is reached.

The result of this is that the valve requires a much larger port to pass gas and this has a considerable impact on its tubing sensitivity. The LN-21R for example has a tubing sensitivity ranging from 34% for the small trim up to 60% for the large. Thus while the valve mechanics are basically the same as the IPO valve, the valve is neither a PPO nor an IPO valve.

Conclusions

The type of gas lift valve and design technique selected for a continuous gas lift installation is in many cases down to personal preference of the operator. All three of the above techniques work and will achieve the desired objective of unloading the well. Each technique has its own advantages and disadvantages but generally speaking the casing operated or IPO valve has been the accepted standard technique worldwide for many years. Currently in the North Sea over 90% of new gas lift installations use the casing operated valve. Both the fluid operated or PPO valve and the proportional response valve are generally accepted as specialist valves for particular applications.

Orifice Valves

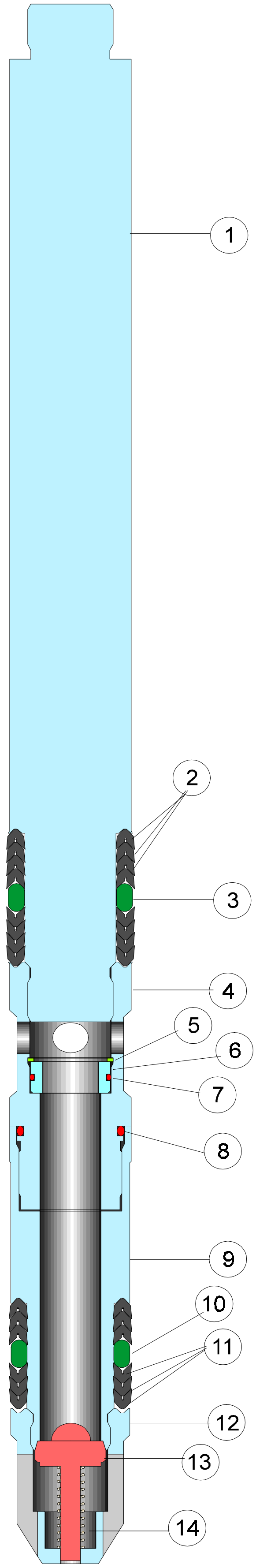
Gas passage through an orifice valve is determined by the following:

1. The downstream pressure (or tubing pressure)
2. The upstream pressure (or casing pressure)
3. The port size in the valve

The other factors that will affect gas passage are the gas S.G., the temperature at the valve and the valve discharge coefficient (ranges from 0.54 to 0.86 for orifice valves depending on port size and number of back checks). For a particular well and valve these can be considered to be constant so their effect can be ignored.

There are distinct advantages to operating at critical flow as this ensures the gas passage through the valve remains constant even if the tubing pressure is unstable. The attached graph (page 4-7) shows four different flow rates. What is plotted is both the measured gas passage from a series of flow tests and also the equivalent calculated gas passage using Thornhill Cravers equation with a discharge coefficient of 0.77. As the upstream pressure is held constant and the downstream pressure is decreased so the volume of gas through the valve increases until critical flow is achieved. Thus for an RDO-5 Orifice Valve with a 1/2” port with an upstream pressure of 1900 psi the gas passage increases rapidly through the valve so that at a downstream pressure of 1800 psi the flow through the valve is over 3 MMscf/D. Because this part of the curve is so steep any small fluctuations in the tubing pressure will have a big effect on the gas passage through the valve. As the tubing pressure is dependent on the gas injection rate, any fluctuation in the gas passage will make the tubing pressure more unstable and thus a slugging cycle will start. When the tubing pressure is decreased to 1045 psi (55% of upstream pressure) the valve goes into critical flow at a rate of 7.7 MMscf/D.

In most gas lift applications there is insufficient differential across the valve to operate at critical flow and hence the benefit of using the NOVA valve. This achieves critical flow at about 90% downstream as opposed to a square edged orifice which is about 55% downstream pressure. When at critical flow the gas passage through the valve will be dictated by the upstream pressure only. Thus on the attached graph for the 1/2” port, the maximum gas passage increases from 4.9 MMscf/D to 7.7 MMscf/D by increasing the casing pressure from 1200 psi to 1900 psi.



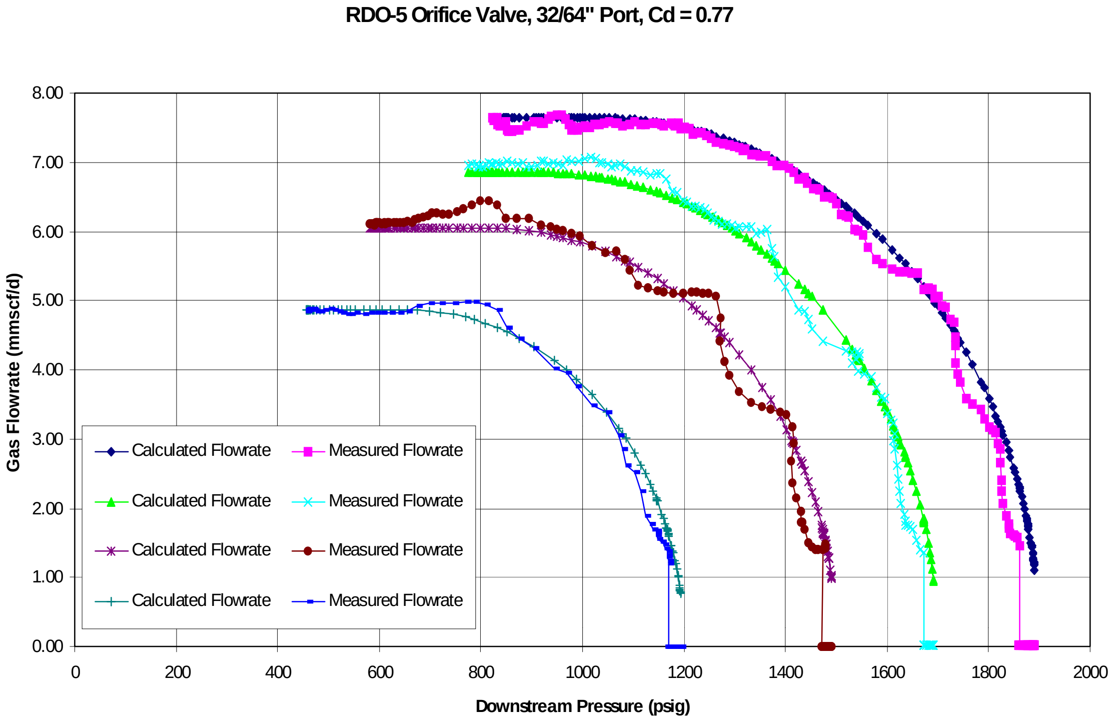
PARTS LIST - RDO-5 ORIFICE VALVE

Item	Description	Part Number	Quantity
1	Body	01413-001-00000	1
2	Packing	01302-014-00000	8
3	Adapter Ring	01302-015-00000	1
4	Seat Housing	01423-001-00000	1
5	Tru-Arc Ring	01347-014-00000	1
6	Floating Seat	* See Chart	1
7	O-Ring	* See Chart	1
8	O-Ring	16846-122-00000	1
9	Lower Packing Body	01423-002-00000	1
10	Adapter Ring	01304-023-00000	1
11	Packing	01302-022-00000	6
12	Nose	01423-004-00000	1
13	Check Element	01423-008-00000	1
14	Spring	01423-006-00000	1

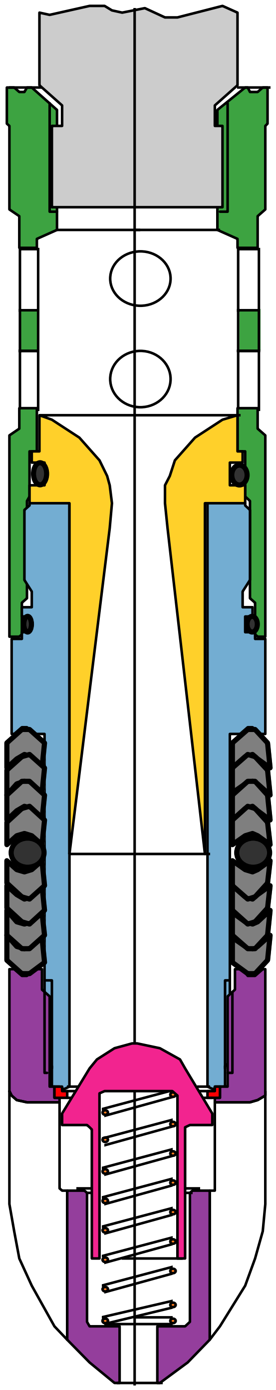
* Optional Floating Seats and O-Rings are available.

Floating Seats and Seals

Port Size (inches)	Seat (Item #6) Part Number	O-Ring (Item #7) Part Number
1/8	01400-015-00200	16846-210-00000
3/16	01400-015-00300	16846-210-00000
1/4	01400-015-00400	16846-210-00000
5/16	01400-015-00500	16846-210-00000
3/8	01400-015-00600	16846-210-00000
7/16	01400-015-00700	16846-210-00000
1/2	01423-005-00800	16846-020-00000
9/16	01423-005-00036	16846-020-00000
5/8	01423-005-00040	16846-020-00000
11/16	01423-005-00044	16846-020-00000
3/4	01423-005-00048	16846-020-00000


RDO-5 Orifice Valve, 32/64" Port, Cd = 0.77
Gas Flowrate (mmscf/d)
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0
200
400
600
800
1000
1200
1400
1600
1800
2000
Downstream Pressure (psig)
Calculated Flowrate
Measured Flowrate
Calculated Flowrate
Measured Flowrate
Calculated Flowrate
Measured Flowrate
Calculated Flowrate
Measured Flowrate

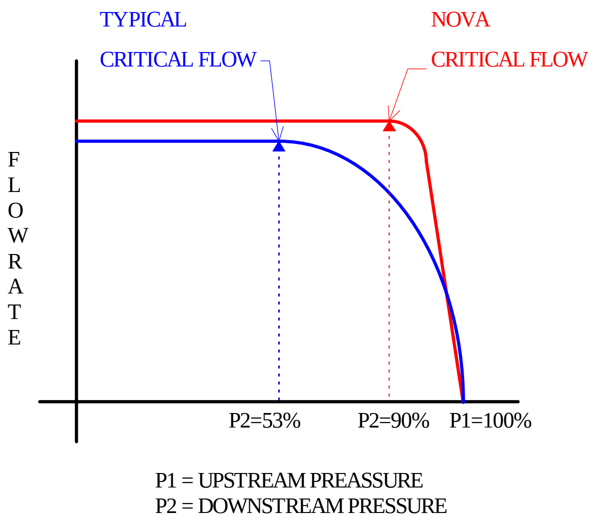
The Nova™ Gas Lift valve



NOVA™ Technical Specifications

- NACE approved Stainless Steel material construction.
- Industry Standard 1" and 1-1/2" valve formats.
- Compatible with existing side-pocket mandrels, latches and slickline tools.
- Compatible with existing unloading valves.
- Erosion resistant material options.

The flow regime present in the NOVA™ valve virtually eliminates any effect of tubing pressure on the gas injection rate. Changes in tubing pressure are not allowed to affect the casing pressure. The gas flow rate remains constant and this has a negative feedback effect on any tubing instability. The result is generally a completely stable casing pressure and a production tubing where pressure fluctuations are completely eliminated or reduced to a minimum.



The NOVA™ Gas Lift Valve works to stabilize the dynamic situation. Critical flow is achieved through the valve with as little as 10% pressure drop or less. Conventional valves require between 40 to 60% pressure drop to achieve critical flow and in most cases it is not practical to operate with this much loss.

The NOVA™ Gas Lift Valve is unique in that it allows the prevention of instability to be achieved without the losses in production or increases in operating expense associated with previously used methods. In fact the stabilization of the flowing bottomhole pressure in a well will generally increase the overall production from that well. Stabilizing the injection pressure can lead to reduced maintenance costs too.

A spin-off benefit from the use of the NOVA™ Gas Lift Valve will be the improved controllability of gas lift fields where computer controlled optimization schemes are implemented. Until now unstable wells have largely had to be left out of any optimizing algorithms due to the destabilizing effect these wells have on the measuring and feedback controls in such a system. With the NOVA™ Gas Lift Valve even if a well is slightly tubing unstable the gas rate will remain constant and hence the gas measurement which is the control parameter for these systems will remain stable. This should make it possible to include more wells than ever in optimization schemes.

The Nova™ Gas Lift Valves and Dual Wells

For many oilfield operators the use of common annulus dual completions (Duals) has been an attractive way of maximizing the return from a single well drilled into a multi-zone area. The major drawback with this type of completion has in the past been when attempts have been made to gas lift these wells. The production tubing in duals have been fed by separate formations which may have similar or widely different pressure and productivity parameters. However, when gas lifting these duals, only one injection pressure and surface gas rate is possible which means that both strings must be controlled from the same gas supply. This has led to sometimes extreme difficulty in maintaining both strings on production, and often stable production has been impossible. These stability problems have resulted mainly from the fact that in most cases the flow performance of the downhole gas injection valves has been dependent on the tubing pressures in the strings as well as the casing pressure common to both strings. This control problem has usually resulted in one string taking most of the gas injected at surface while the other string has simply died. One partial solution has been to try to substantially increase the gas flow rate to the casing in the hope that sufficient pressure would be maintained in the casing to allow gas passage to both wells. In some cases this would result in the second string functioning again but at the cost of destabilizing the first string due to excessive gas injection. A technique is required where the comparative rate of injection of gas to each string is largely independent of the production pressure in the strings, whether stable or not.

- Analysis of individual strings to optimize gas lift parameters.
- The NOVA™ Gas Lift Valves for both strings can be set up to pass gas at the appropriate rates based on a common casing pressure.
- The tubing pressure whether stable or not will no longer affect the gas rate to the strings.
- The casing pressure will stabilize.
- Both strings will act independently of each other and both will be on production simultaneously.
- Over all production rate will increase.

There is more information on the application of the NOVA™ valve in the instability section, chapter 7.

GAS LIFT VALVE CONSTRUCTION AND OPERATION

The advent of the unbalanced single-element bellows-charged gas lift valve revolutionized gas lift application and design method for lifting oil wells. Prior to the bellows-charged gas lift valve, there were pressure differential valves and other types of unique devices for gas lifting oil wells. Certain devices, or valves, were operated by rotating or vertically moving the tubing and by means of a sinker bar on a slickline.

The original patent for an unbalanced single-element bellows-charged gas lift valve was filed in 1940 by W.R. King. Today this unbalanced single-element bellows valve remains the most widely used type of gas lift valve for gas lifting wells. The original King valve had most of the protective design features of the present gas lift valves. The bellows was protected from high hydrostatic fluid pressure by a gasket that sealed the bellows chamber from well fluids after full stem travel. A small orifice was drilled in a bellows guide tube. The orifice was designed to be an anti-chatter mechanism and the bellows guide provided bellows support.

Unbalanced Single-Element Gas Lift Valves

Single-element implies that the gas lift valve consists of a bellows and dome assembly, stem with a tip which is usually a carbide ball, and a metal seat housed in a valve body. The unbalanced single-element gas lift valve is an unbalanced pressure regulator. Unbalanced implies that the pressure applied over the port area (stem-seat contact area) exerts an opening force; whereas, this same pressure has no effect on the opening pressure of a balanced backpressure or pressure reducing regulator. The closing force for a gas lift valve can be a gas pressure charge in the dome and bellow exerted over the effective bellows area or a spring force or a combination of both a charge pressure and a spring. The closing force for the regulator or gas lift valve can be adjusted to maintain a desired backpressure for injection pressure operation or a design downstream pressure for production pressure operation. The regulator or valve will remain closed until the set closing force is exceeded.

The major initial opening force for most gas lift valves is the pressure exerted over the effective bellows area less the stem-seat contact area, and the lesser opening force is the pressure acting over the stem-seat contact area. In like manner for an unbalanced pressure regulator, the major opening pressure is applied over an area equal to the diaphragm area less the port area. The effect of the unbalanced opening force is far less for most unbalanced backpressure and pressure reducing regulators than for gas lift valves because the ratio of the stem-seat contact are to the total effective bellows are of a gas lift valve is much greater than the ratio of the port area to the total diaphragm area for most regulators. The operating principle is the same for the gas lift valve and regulator, but the pressure applied over the stem-seat contact area has greater effect on the initial opening pressure of most gas lift valves.

Purposes of Gas Lift and Check Valves

The gas lift valve is considered the heart of most gas lift installations. The predictable performance of this valve is essential for successful gas lift design and operations. The gas lift valve performs one or more functions in a typical gas lift installation.

The primary function of the gas lift valves is to unload a well with the available injection gas pressure to a maximum depth of lift that fully utilizes the energy of expansion of the injection gas pressure from the depth of gas injection to the surface. Gas lift valves provide the flexibility to permit a changing depth in the point of gas injection to compensate for a varying flowing bottomhole pressure, water cut, daily production rate and well deliverability. The operating gas lift valve in an intermittent gas lift installation prevents an excessive injection gas pressure decrease in the casing annulus following an injection gas cycle. The operating valve provides the means to control the injection gas volume entering the tubing per cycle.

Another important function of gas lift valves is the ability to create an excessive flowing bottomhole pressure drawdown in a temporarily damaged well until the well cleans up. This operation is accomplished by lifting from near total depth until reservoir deliverability returns to normal. The final operating depth of gas injection for the stabilized production rate in certain deep wells with a high reservoir pressure can be nearer the surface than the depth of gas injection to establish initial bottomhole pressure drawdown during unloading if the load is heavy salt water. Gas lift valves must be installed below the depth of the operating gas lift valve to create initial bottomhole pressure drawdown and clean up the well.

When the injection gas line pressure significantly exceeds the flowing bottomhole pressure at the maximum valve depth, freezing can occur across the surface controls for the injection gas if the operating valve is a large orifice check valve. The orifice check valve can be replaced by an injection pressure operated gas lift valve to transfer the pressure drop from the surface to the gas lift valve at well temperature where hydrates will not form.

The reverse check in a gas lift valve is important for valves below the working fluid level and for testing the tubing. The check prevents backflow from the tubing to the casing in tubing flow installations. A reliable check assembly is important if the well produces sand and has a packer to prevent sand from accumulating in the annulus above the packer.

Valve Specifications and Full-Open Stem Travel

Gas lift valve specifications are published by the manufacturers for their valves. Some manufacturers assume a sharp edged seat for the ball-seat contact area and others arbitrarily add a small incremental increase to the port ID for a sharp-edged seat to account for a slight bevel at the ball-seat contact. Some gas lift valve seats have a chamber and the ball or tip on the valve stem contacts the seat on the taper or at the bottom of the chamber. There is no standard angle of taper or ball-seat size ratio relationship. For this reason, only sharp-edged seat geometry is used in the installation design calculations in this text.

Since most manufacturers use the same source for their supply of bellows, the effective bellows area for most 1 and 1-1/2 inch OD valves are relatively standard. The theoretical full-open stem travel is not included in the typical valve specifications published by most manufacturers. These published gas lift valve specifications are used primarily in static force balance type equations.

The stem travel required to fully open an unbalanced single-element gas lift valve increases with increased port size. These curves were calculated for gas lift valves with a sharp-edged ball-seat contact and a ball on the stem which is 1/16 inch larger in diameter than the bore diameter (ID) of the port. The equivalent port area before a valve is fully open is based on the lateral area of the frustum of a right circular cone. The major area of the frustum is the port area which remains constant, and the minor area decreases with an increase in stem travel as the ball moves away from its ball-seat contact.

There is an important gas lift valve injection gas throughput rate performance consideration that is not noted in the published literature for most valves. The problem needs to be understood by operators with high production rate wells being gas lifted through tubing or the casing annulus. An injection gas throughput rate based on a full-open port size should not be assumed for single-element unbalanced gas lift valves with large port sizes. For nearly all of these gas lift valves with a large port area relative to the bellows area, the maximum equivalent port area open to flow of the injection gas will be less than an area based on the reported port size for an actual range of the surface injection gas pressure during typical unloading and stabilized gas lift operations. The necessary increase in the injection gas pressure to fully open a 1 inch OD gas lift valve with a large port can approach or exceed 200 psi. This required stem travel is not possible for many valves. Maximum stem travel may be limited by a mechanical stop or bellows stacking before an equivalent full-open port area could be achieved.

Bellows Protection

The bellows functions like a piston. A small high pressure diaphragm would not work because of its limited movement. With a bellows, the travel is distributed uniformly along all the active convolutions thereby allowing adequate stem travel to obtain the required port opening.

Reputable manufacturers of gas lift valves provide bellows protection in the design of their valves. A bellows should be protected from a high pressure differential between the bellows-charge and the well pressures and an unpredictable resonance condition that can result in a high frequency valve stem chatter and ultimate bellows failure. Gas lift bellows are protected from high hydrostatic well pressures by the following four methods:-

1) hydraulically performed by a high pressure differential
2) support rings within the convolutions of the bellows
3) confined liquid seal inside or out of a bellows after full steam travel and
4) isolation by a physical seal of the bellows from outside well pressure after full steam travel

The primary purpose of these methods for protecting the bellows is to prevent a permanent change in the radii of the convolutions which in turn can effect the operating pressure of a gas lift valve. The highest pressure differential across a bellows will occur in most installations during initial unloading operations when the lower gas lift valves are subjected to exceedingly high hydrostatic load fluid pressures in deep wells. The pressure differential across the bellows of a spring loaded valve will be greater than for a bellows-charged valve because the dome pressure is atmospheric in spring-loaded valves. The possibility of a chatter condition is not predictable nor fully understood. The evidence of valve stem chatter will be a bellows failure and a dished-out seat if the valve seat is not manufactured from an extremely hard material. Most gas lift valves will have some form of dampening mechanism and the majority of these devices will operate hydraulically. The bellows will be partially or completely filled with a viscous liquid to restrict instantaneous undampened stem movement.

Static Force Balance Equations for Unbalanced Single-Element Bellows-Charged Gas Lift Valves

Most gas lift equipment manufacturers use a valve setting temperature base of 60^o for nitrogen charged gas lift valves. The valve is submerged in a 60^{o}F water bath to ensure a constant nitrogen temperature in the dome of each valve during the test rack setting procedure. The test rack set initial opening pressure is measured with the tester pressure applied over the bellows area less the stem-seat contact area with atmospheric pressure (0 psig) exerted over the stem-seat contact area. For the test rack initial opening pressure, a valve is actually closed and beginning to open from an opening force that is slightly greater than the closing force. The tester gas rate through the valve seat is very low. Although most gas lift valves are set on the basis of an initial opening pressure, test rack closing pressures are used for certain types of valves with very high production pressure factors and other valves with unique construction.

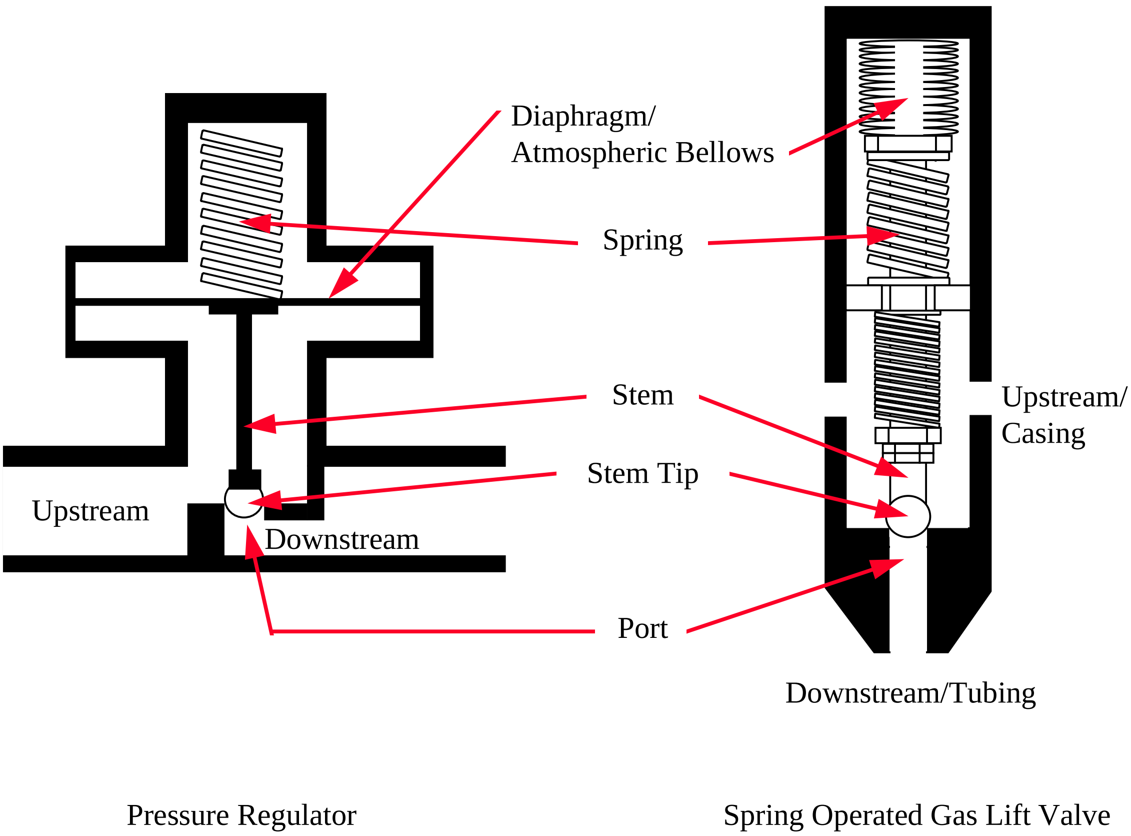
The test rack closing pressure is determined by slowly bleeding the tester gas from the downstream (port) side of the gas lift valve after the lift valve has been opened. This theoretical closing pressure occurs when the downstream and upstream tester pressures are equal at the instant a gas lift valve closes. An accurate test rack closing pressure is more difficult to observe than a test rack initial opening pressure and can be affected by the rate of decrease in the tester pressure during bleed-off of the tester gas. An encapsulating tester with physical capacity for gas in the tester rather than a ring type tester is recommended for determining accurate test rack closing pressures in order that small leaks in the tester piping will not prevent observation of the true closing pressure. The tester pressure can be bled-off of the downstream side of the valve through a small orifice to ensure a more accurate closing pressure determination.

The equations for initial opening pressure in a tester and well and closing test rack pressure are based on static force balance equations and apply to unbalanced spring-loaded gas lift valves. The spring pressure effect replaces the bellows-charge pressure of the valve as the closing force. Several manufacturers of spring-loaded gas lift valves report a test rack closing pressure for their installation designs. The spring is adjusted until the force exerted by the spring is equal to the desired test rack closing pressure. Since there is no nitrogen gas charge pressure in the dome, spring-loaded gas lift valves are not set at a base tester temperature. Spring-loaded valves are considered temperature insensitive.

CASING OPERATED VALVE OPENING AND CLOSING FORCES

Before the operation of a gas lift valve can be explained, the relationship between pressure and force must be clearly understood. Force is push or pull usually measured in units of weight such as ounces, pounds, tons or Newtons. Pressure is the force exerted over a unit area of surface and is generally expressed in pounds per square foot or pounds per square inch. For our purposes, force will be expressed in pounds (lbs. or Newtons) and pressure in pounds per square inch (psi or kPa).

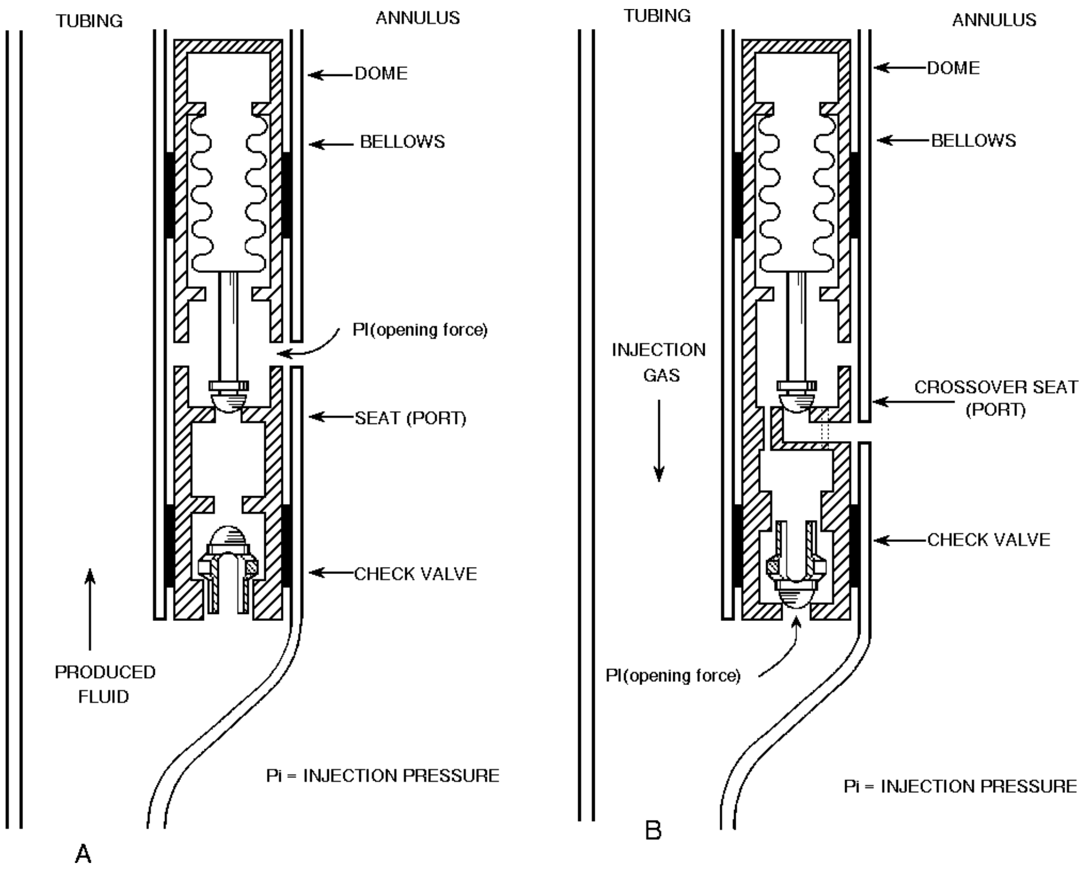
A gas lift valve is a pressure regulator (see diagram below). In response to either injection gas or production fluid pressure, it opens to allow injection gas to enter the production fluids. One common design is the nitrogen charged bellows type injection pressure operated valve shown in Figure 4-1. The valve opens in response to injection pressure in the annulus and gas enters the fluid column in the tubing through which the fluids are produced.



Elements of a Pressure Regulator and a Gas Lift Valve

Injection pressure operated valves have one or more entrance ports through which injection gas can enter the valve chamber from the casing or tubing. The chamber contains the bellows. The dome above the bellows contains nitrogen gas under pressure when the bellows is charged. The valve stem extends to the ball which seals on a seat (port). In Figure 4-1, fluid pressure (Pt) is exerted against the ball on the seat from below. Injection gas pressure (Pc), exerted on the outside of the bellows, causes the valve to open by lifting the ball off of the seat allowing injection gas to enter the production fluids through the port. The bellows and attached stem lowers onto the seat to close the port.

Some gas lift valves are operated by production fluid pressure. the primary opening force is provided by the produced fluids. Although injection pressure operated valves are more common, fluid operated valves have certain applications. Fluid operated valves have advantages for dual completions. They are also less sensitive to injection pressure fluctuations.



The two principal areas of importance for an unbalanced pressure operated valve are the effective area of the bellows (Ab) and the area of the valve port (Ap). The effective area of the bellows (Ab) is the cross-sectional area over which a pressure acts. The same force would result if this pressure were exerted on a piston with a cross-sectional area equal to the effective bellows area. The valve port area (Ap) is equal to the cross-sectional area of the valve seat.

Closing Force

The closing force for most injection pressure operated gas lift valves is obtained from a pressure charged bellows (Pb). The bellows functions like a piston. A small high pressure diaphragm would not work because of its limited movement. With a bellows, the travel is disturbed uniformly along all the active convolutions thereby allowing adequate stem travel to obtain the required port opening. The closing force in a nitrogen charged bellows consists of the charge pressure (Pb) exerted over the total effective bellows area (Ab) and creates a force (Fc) that is applied to the stem. This can be expressed mathematically as:

$$Fc = Pb\ Ab.$$

Opening Forces

There are two pressures which cause a valve to open, injection or casing pressure (Pc) and production or tubing pressure (Pt). One opening force (Fo1) is produced by the pressure of the injection gas (Pc) operating on the effective bellows area (Ab) minus the effective port area (Ap). This first opening force then, can be expressed mathematically as:

$$Fo1 = Pc\ (Ab - Ap)$$

A second opening force (Fo2) is created by the production pressure (Pt) exerted over the area of the valve port (Ap) or mathematically as:

$$Fo2 = Pt\ Ap$$

The total opening force (Fo) is the sum of these two forces:

$$Fo = Fo1 + Fo2$$
$$Fo = Pc\ (Ab - Ap) + Pt\ Ap$$

Just before the valve opens, the opening force and closing force are equal:

$$Fo = Fc$$

$$Pc\ (Ab - Ap) + Pt\ Ap = Pb\ Ab$$

Solving for Pc (injection pressure required to balance the opening and closing forces prior to opening an casing operated valve under operating conditions):

$$Pc = \frac{Pb - Pt\ (Ap / Ab)}{1 - (Ap / Ab)}$$

Pc	Casing pressure.
Pt	Tubing pressure.
Ap	Area of the portion of the stem tip sealed by the seat (port).
Ab	Area of the bellows
Ap/Ab	Ratio of port area to bellows area (obtained from valve specifications)

Production Pressure Effect Factor

As discussed earlier, the valve is opened by the forces of Pc acting on the bellows less the area of the port (Ab-Ap), and Pt acting on the stem tip area that is sealed by the seat. Without Pt to assist opening, Pc would have to be somewhat greater. The Production Pressure Effect (PPEF) represents the amount that the opening pressure Pc is reduced as a result of the assistance of Pt.

PPE (sometimes referred to as the tubing effect) is obtained by multiplying production or tubing pressure (Pt) by the area over which it is applied (Ap) and dividing by the force obtained by the area (Ab - Ap) over which the valve opening pressure (Pc) acts. The result obtained is the amount the valve opening pressure (Pc) is reduced in psi:

$$PPEF = \frac{(Ap / Ab)}{(1 - Ap / Ab)}$$

and is one of the values supplied by valve manufacturers and is found in Table 4.1.

The above equation can, therefore, be expressed as: $Pc = Pbt/(1 - Ap/Ab) - Pp \times (P.P.E.F.)$

Closing Pressure

The closing pressure of the valve will be equal to the injection gas opening pressure (Pc) if the production pressure remains constant. The minimum closing pressure is equal to the dome pressure (Pb) only at the time when the production, injection and dome pressure are equal.

To solve for production pressure when casing pressure and bellows charge pressure are known, the following operations must be performed. First, solve for Pt x (Ap/Ab) by transposing this value with Pbt and making all appropriate sign changes to yield:

Pp x (Ap/Ab) = Pbt - Pc x (1 - Ap/Ab)

Then the equation above is divided by (Ap/Ab) to yield:

Pp = Pb / (Ap/Ab) - [Pc x (1 - Ap/Ab) / (Ap/Ab)]

Table 4.1 Camco Valve Specifications

Type	A_b - Effective Bellows Area (sq in.)	Port Size (in.)	A_p - Area of Port With Bevel (sq in.)	A_p / A_b	$1-(A_p / A_b)$	$PPEF = \frac{A_p / A_b}{1-(A_p / A_b)}$
R-20	0.77	3/16	0.029	0.038	0.962	0.040
		1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
		3/8	0.113	0.147	0.853	0.172
		7/16	0.154	0.200	0.800	0.250
		1/2	0.200	0.260	0.740	0.351
R-28	0.77	1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
R-25	0.77	3/16	0.029	0.038	0.962	0.040
		1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
Rp-6 **	0.77	1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
		3/8	0.113	0.147	0.853	0.172
		7/16	0.154	0.200	0.800	0.250
		1/2	0.200	0.260	0.740	0.351
RPB-5 **	0.77	1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
		3/8	0.113	0.147	0.853	0.172
		7/16	0.154	0.200	0.800	0.250
RMI	0.65	1/4	0.051	0.078	0.922	0.085
		5/16	0.079	0.122	0.878	0.139
		3/8	0.113	0.174	0.826	0.211
		7/16	0.154	0.237	0.763	0.311
		1/2	0.200	0.308	0.692	0.445
BK	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104
		1/4	0.051	0.165	0.835	0.198
		5/16	0.079	0.255	0.745	0.342
BK-1	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104
		1/4	0.051	0.165	0.835	0.198
		5/16	0.079	0.255	0.745	0.342
		3/8	0.113	0.365	0.635	0.575
BKR-5	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104
		1/4	0.051	0.165	0.835	0.198
BKF-6	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104
		1/4	0.051	0.165	0.835	0.198
J-20	0.77	3/16	0.029	0.038	0.962	0.040
		1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
		3/8	0.113	0.147	0.853	0.172
		7/16	0.154	0.200	0.800	0.250
		1/2	0.200	0.260	0.740	0.351
JR-20	0.77	1/8	0.013	0.017	0.983	0.017
		3/16	0.029	0.038	0.962	0.040
		1/4	0.051	0.066	0.934	0.071
J-40	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104
		1/4	0.051	0.165	0.835	0.198
		5/16	0.079	0.255	0.745	0.342
		3/8	0.113	0.365	0.635	0.575
JR-40	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104

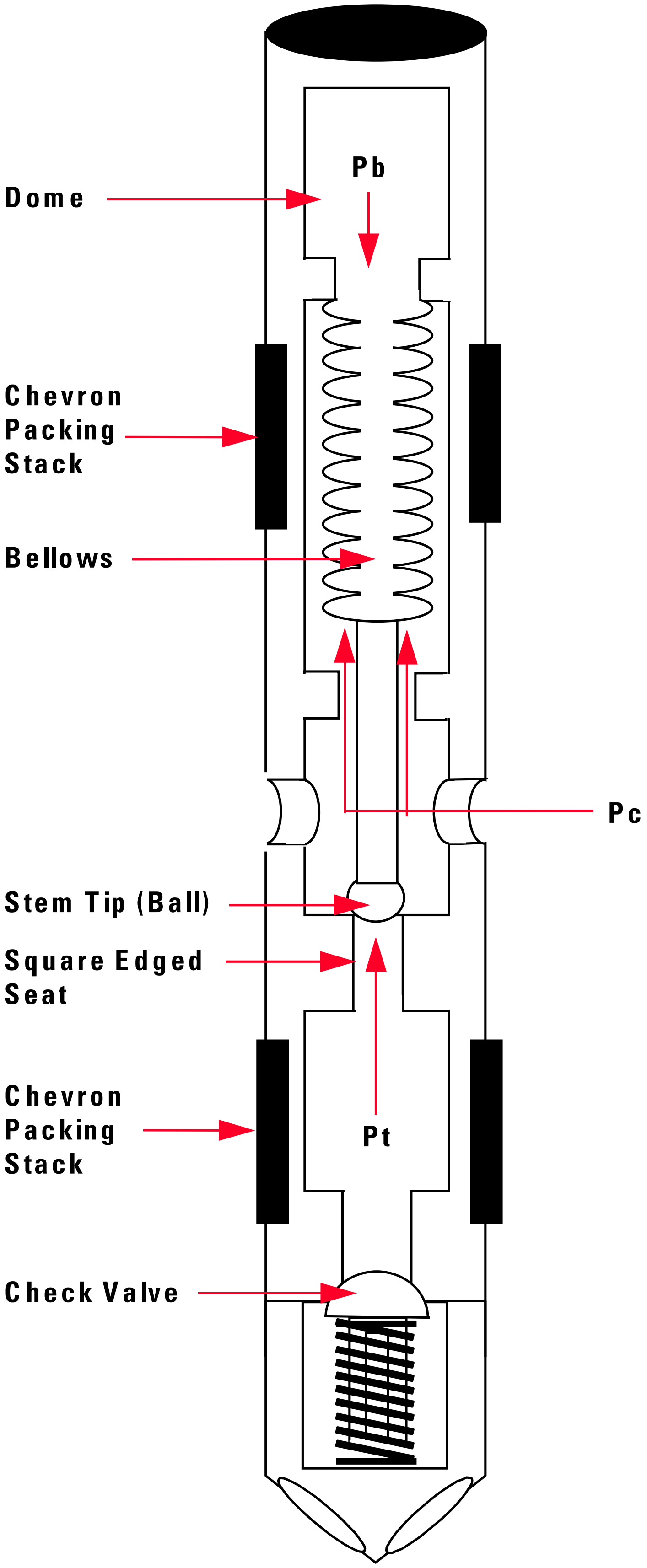


FIGURE 4-1: Nitrogen Charged Bellows Type Injection Pressure (Casing) Operated Gas Lift Valve

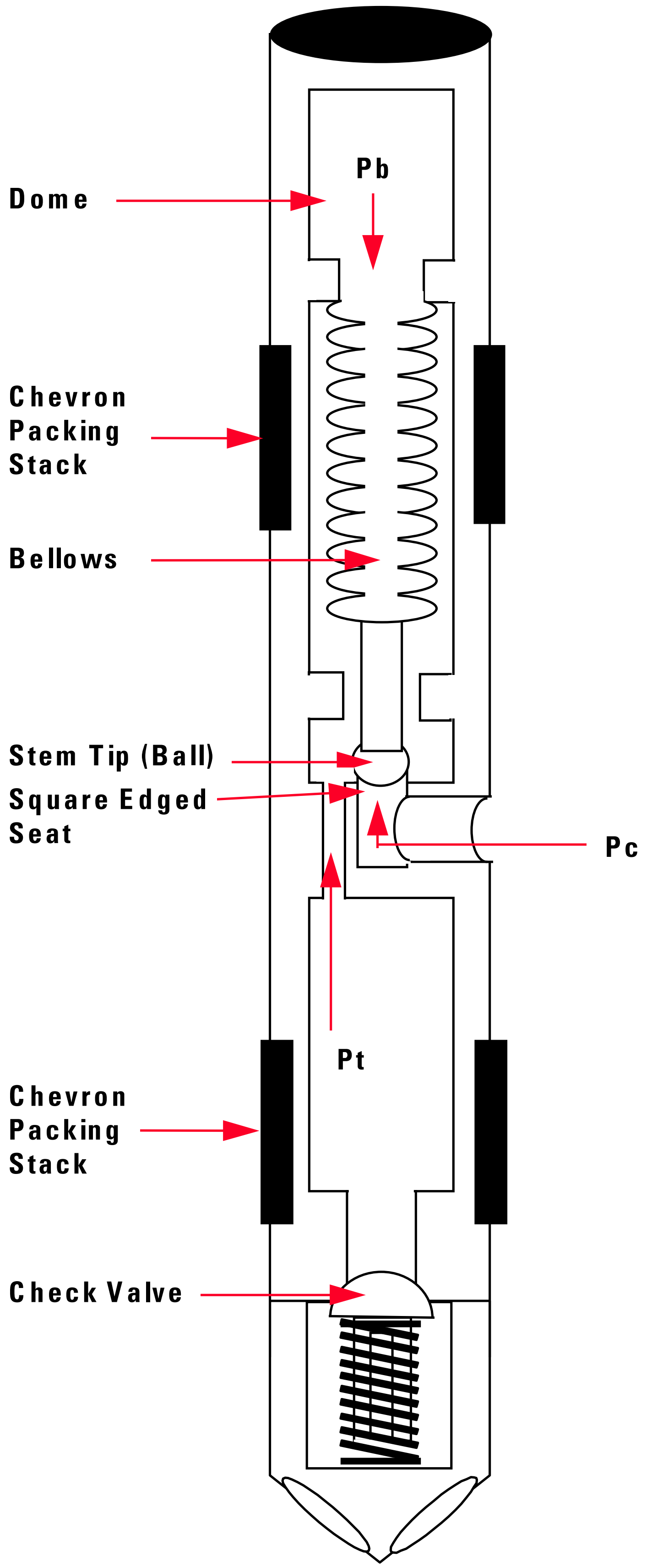
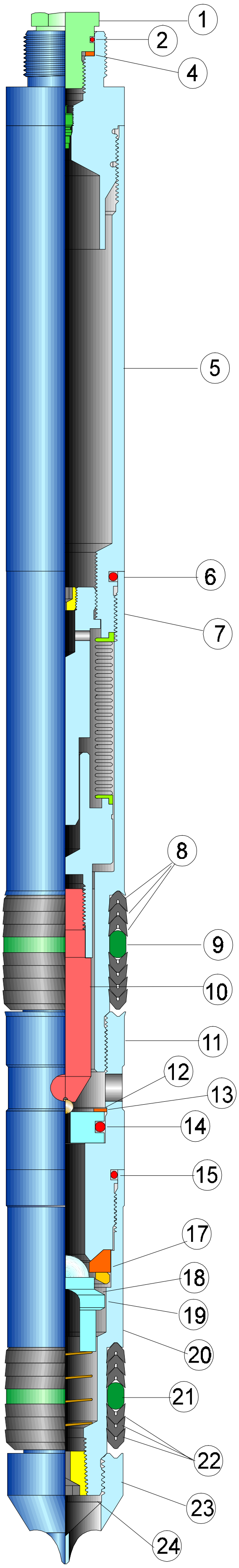


FIGURE 4-2: Nitrogen Charged Bellows Type Production Pressure (Fluid) Operated Gas Lift Valve



PARTS LIST - R-20 GAS LIFT VALVE

Item	Description	Part Number	Quantity
1	Tail Plug	01400-001-00000	1
2	O-Ring #016	16846-016-00000	1
4	Copper Gasket	01400-003-00000	1
5	Bellows Assembly	01400-C00-00000	1
6	O-Ring #215	16846-215-00000	1
7	Bellows Housing	01401-009-00000	1
**8	Packing	01302-014-00000	7
9	Adapter Ring	01302-015-00000	1
10	Stem Tip Assembly	See Chart	1
11	Seat Housing	01400-030-00000	1
12	Tru-Arc Ring #5000-100-C	01347-014-00000	1
13	Floating Seat	See Chart	1
14	O-Ring #210	16846-210-00000	1
15	O-Ring #122	16846-122-00000	1
17	Seat Gasket	01304-018-00000	1
18	Retainer Ring	01304-019-00000	1
19	Check Disc	01304-020-00000	1
20	Body	01400-021-00000	1
21	Adapter Ring	01304-023-00000	1
22	Packing	01302-022-00000	6
23	Nose	01302-024-00000	1

Optional Components

24	Choke (Optional)	40001-005-00000	1
*25	Stem Tip / Floating Seat Assembly (Carbide)	See Chart	1
26	Check Spring	01400-005-00000	1

* Optional Carbide Seat and Stem Tip Assembly (Item #25) are available in matched lapped sets under Part No. 01400-F00-00000.

** Optional high-temperature packing sets are available on request.

The bellows charge pressure Pbt would exist in a valve operating downhole. Since the valves are set at the surface at a different temperature (60° F) [15° C] all bellows charge pressures must be converted to pressure at standard condition (Pb).

The first step is to convert the pressure using the temperature correction factor (Ct) found in Table 4.2. The following operation corrects the pressure to test bench conditions.

Pb = Ct x (Pbt)

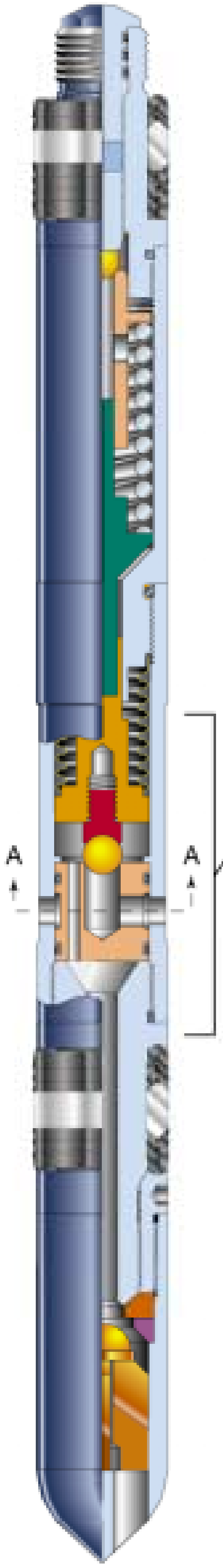
The pressure setting on the test bench at 60° F [15° C] or Test Rack Opening pressure (TRO) can be determined by dividing the corrected pressure by (1 - Ap/Ab) to produce:

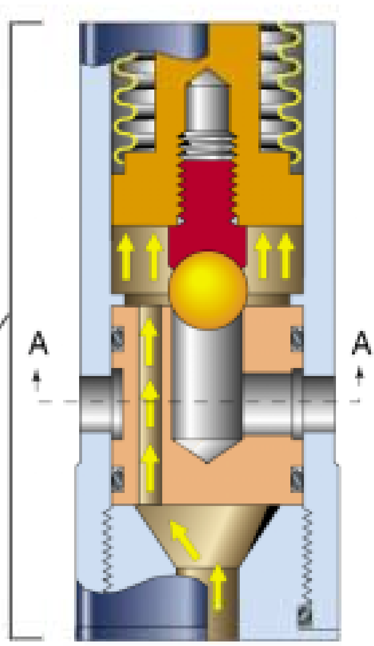
TRO = Pb / (1 - Ap/Ab)

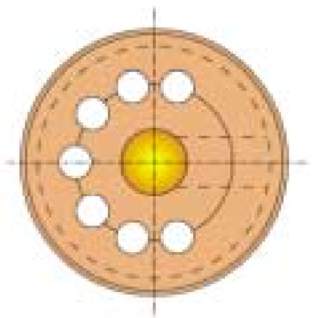
For those valves whose primary opening pressure comes from the production fluids, a special crossover seat allows production fluid to enter the valve chamber and act upon the effective area of the bellows. As we saw in the injection pressure operated valves, there is only one closing force and that is the bellows charge pressure times the effective area of the bellows (Pbt x Ab). The two opening forces have been reversed since the production fluid replaces the injection gas as the principle opening force Pp x (Ab - Ap). The injection gas pressure acts to create the second opening force by acting upon the area of the valve port Pi x (Av). The resulting force balance equation is:

Pbt x (Ab) = Pp x (Ab - Ap) + Pc x (Ap)

BKF-12 Series Gas Lift Valves







SECTION A–A

Camco
A Schlumberger Reservoir Development Company

TABLE 4.2A

Nitrogen Temperature Correction Factors for Temperature in Fahrenheit

° F	Ct	° F	Ct	° F	Ct	° F	Ct	° F	Ct	° F	°Ct
61	0.998	101	0.919	141	0.852	181	0.794	221	0.743	261	0.698
62	0.996	102	0.917	142	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

TABLE 4.2B

Nitrogen Temperature Correction Factors for Temperature in Celsius

° C	Ct	° C	Ct	° C	Ct	° C	Ct
16	0.998	51	0.879	86	0.786	121	0.710
17	0.994	52	0.876	87	0.783	122	0.708
18	0.991	53	0.873	88	0.781	123	0.706
19	0.987	54	0.870	89	0.779	124	0.704
20	0.983	55	0.868	90	0.776	125	0.702
21	0.979	56	0.865	91	0.774	126	0.701
22	0.976	57	0.862	92	0.772	127	0.699
23	0.972	58	0.859	93	0.769	128	0.697
24	0.968	59	0.856	94	0.767	129	0.695
25	0.965	60	0.853	95	0.765	130	0.693
26	0.961	61	0.850	96	0.763	131	0.691
27	0.958	62	0.848	97	0.760	132	0.689
28	0.954	63	0.845	98	0.758	133	0.688
29	0.951	64	0.842	99	0.756	134	0.686
30	0.947	65	0.839	100	0.754	135	0.684
31	0.944	66	0.837	101	0.752	136	0.682
32	0.940	67	0.834	102	0.749	137	0.680
33	0.937	68	0.831	103	0.747	138	0.678
34	0.933	69	0.829	104	0.745	139	0.677
35	0.930	70	0.826	105	0.743	140	0.675
36	0.927	71	0.823	106	0.741	141	0.673
37	0.923	72	0.821	107	0.739	142	0.671
38	0.920	73	0.818	108	0.737	143	0.670
39	0.917	74	0.816	109	0.734	144	0.668
40	0.914	75	0.813	110	0.732	145	0.666
41	0.910	76	0.810	111	0.730	146	0.665
42	0.907	77	0.808	112	0.728	147	0.663
43	0.904	78	0.805	113	0.726	148	0.661
44	0.901	79	0.803	114	0.724	149	0.659
45	0.898	80	0.800	115	0.722	150	0.658
46	0.895	81	0.798	116	0.720	151	0.656
47	0.892	82	0.795	117	0.718	152	0.654
48	0.888	83	0.793	118	0.716	153	0.653
49	0.885	84	0.791	119	0.714	154	0.651
50	0.882	85	0.788	120	0.712	155	0.649

Frequently, production pressure operated valves use a spring to supply the closing forces as illustrated in Figure below. This valves have an uncharged (14.7 psig) [101.32 kPa] bellows. In the force balance equation, the spring pressure effect (Pst) is used in stead of the bellows charge pressure at well temperature (Pbt). The force balance equation for these valves must include one additional value. Unlike pressure charged valves, the load rate of the valve bellows should be included in the calculation of the valve's opening pressure in a well. Load rate is a measure of the force required to compress or stretch the bellows in a gas lift valve at its opening pressure. The measure of bellows load rate used for a gas lift valve is the increase in pressure required to obtain a given stem travel (psi/in.) [kPa/mm] rather than the units of force (lbs.)

To account for a valve's bellows load rate and insure adequate gas through-put, the valve's opening pressure should be set lower than calculated with the above force balance equations. One design technique used is to ignore the forces exerted by the injection pressure applied over the port area so that the force balance equation is:

$$Pst = Pp \times (1 - Ap/Ab)$$

Another "rule of thumb", which is particularly applicable to the higher load rate of the spring loaded valve, is to subtract an arbitrary pressure difference (Pk) from the production pressure to yield the following force balance equation:

$$Pst = (Pp - Pk) \times (1 - Ap/Ab) + Pc \times (Ap/Ab)$$

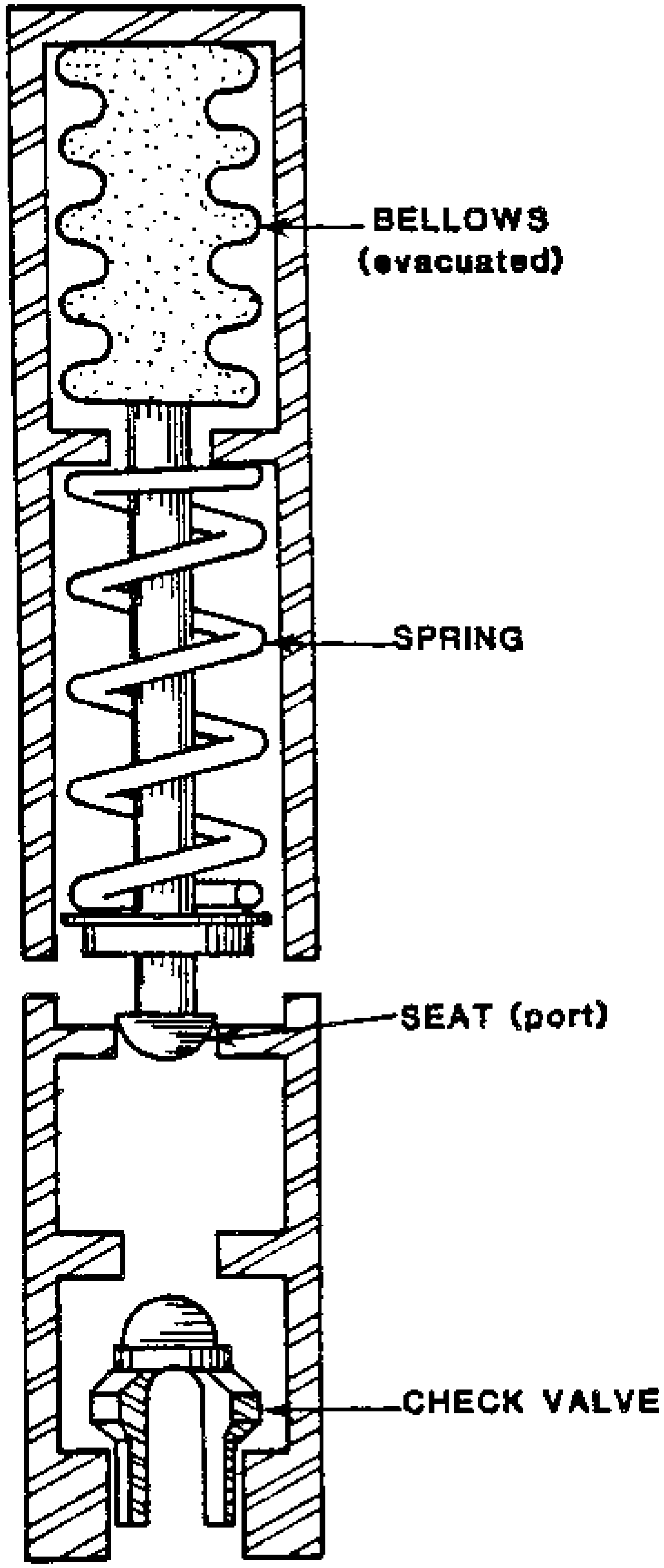
The value of Pk is a least 60 psi. [400 kPa] As a "rule of thumb", 60 psi [400 kPa] is used for 1-1/2" valves and 75 psi [500 kPa] is used for 1" valves.

The tester for tubing pressure operated valve is designed to apply the opening pressure over the effective bellows less the port in the same manner employed for a casing pressure operated valve

The equation below is for Test Rack Opening pressure for spring loaded valves:

$$TRO = Pst / (1 - Ap /.Ab)$$

No temperature correction is required for the spring loaded valve.

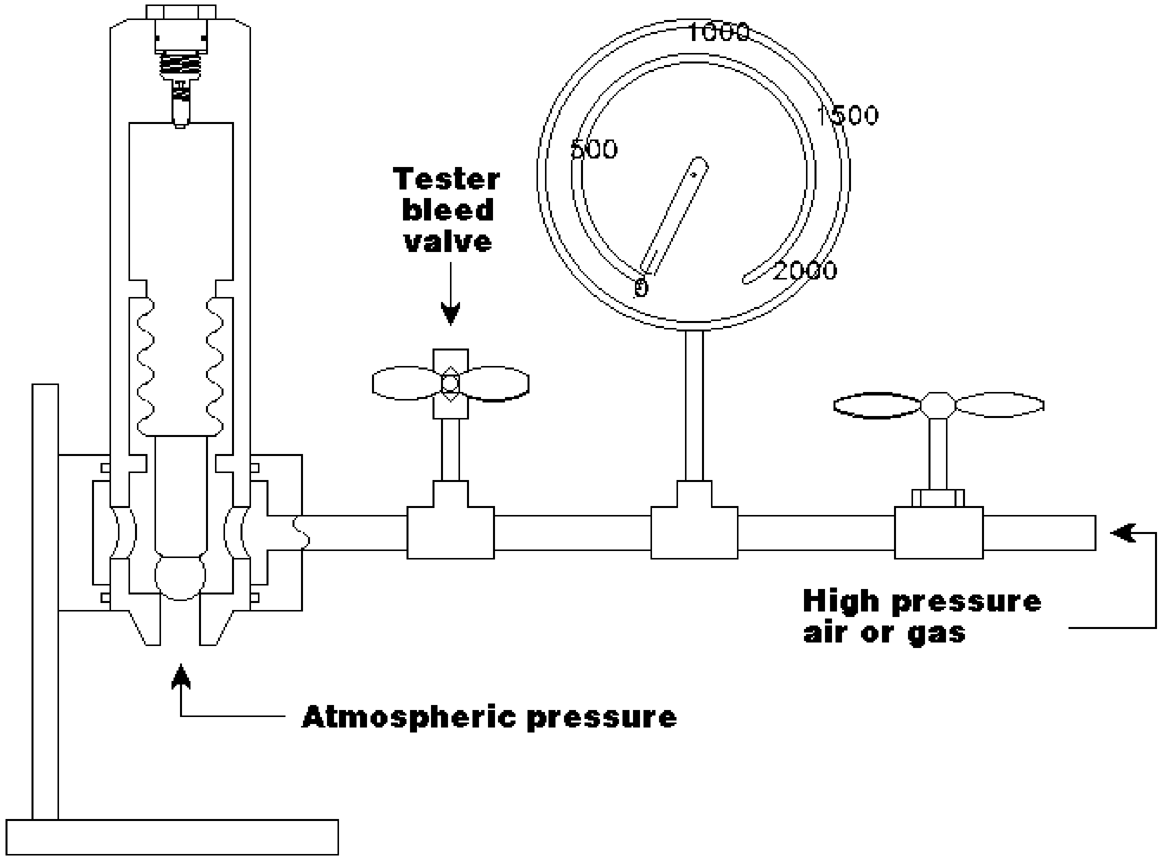

BELLOWS
(evacuated)
SPRING
SEAT (port)
CHECK VALVE

When a valve is placed in a bench tester only atmospheric pressure is applied over the small port area as production pressure below the seat. The nitrogen pressure applied externally to the area of bellows less seat area is used to cause the valve to open in order to set it. When the nitrogen pressure is shut off using the needle valve on the test rack, the set pressure is "locked" in the bellows chamber (not the bellows) because the ball is on the seat. In reality, a small amount of leakage from the valve is typical.

In order to determine why a small leak is expected, we can calculate the forces trying to open and close the valve to find out what the force of the ball against the seat is at the time the valve closes in the tester.

First, let's assume the valve is set to 800 psi [5515 kPa]. This means that when we apply that pressure from our supply on the test bench, the valve will begin to open and we can hear nitrogen escaping through the nose of the valve. This means that we must have a lower pressure in the dome of the valve in order to offset the effect of the seat area. If the bellows is a 0.31 sq. in. [1.99 sq. cm.] and the port is 0.25 inch [0.635 cm.] diameter, the area that the pressure is acting upon is 0.2609 sq. in. [0.6627 sq. cm.] and the pressure in the bellows is acting over the full 0.31 sq. in. [0.7874 sq. cm.]. The ratio of these two areas is approximately 0.8416, so the pressure in the bellows must be only 84.16% of the applied pressure. This calculates to 674 psi [4649 kPa]. Under these conditions, the force of the ball against the seat is 0 pounds [0 kg].

When we close the needle valve on the tester, the pressure is <u>supposed</u> to be trapped in the valve because the ball is on the seat. It is true that the ball is on the seat, but at this moment the closing forces (pressure in the bellows times the bellows area) are equal to the opening forces (the pressure trapped in the valve outside of the bellows times the bellows area minus the area of the port). The net force (closing force minus opening force) holding the ball against the seat is virtually nil. As a result of this fact, it is not unusual to experience some leakage from the valve until the trapped pressure in the valve has dropped sufficiently to create enough net closing force to effect a seal. Usually a drop of 50 psi [345 kPa] is sufficient to accomplish this.



Typical test rack configuration

PROPORTIONAL RESPONSE GAS LIFT VALVES

FIGURE 4-4-1 - Curve A illustrates a typical gas flow rate curve from an orifice with a constant upstream (casing) pressure of 800 psi with a variable downstream (tubing) pressure. When the tubing pressure is less than one half the casing pressure, the flow is a constant at critical flow.

Curve B illustrates the curve which is generated during the flow tests of an Camco L Series valve. In the example, the valve is adjusted to open at an operating casing pressure of 800 psi and to close when the tubing pressure reduces to 300 psi. During the test, the casing pressure is held constant and the tubing pressure is varied. When the tubing pressure is 800 psi, the valve is open but no flow exists since there is no differential across the valve. As the tubing pressure decreases, the flow increases to a peak since the valve is fully open and a differential exists. Further reduction in tubing pressure results in a reduced upward force on the ball and the spring moves the ball proportionally closer to the seat until the valve closes at 300 psi.

Two basic factors control the proportional response of these valves: (1) The force causing the ball to move toward the seat is a spring which is proportional to its compressed length. For example, when the ball is 1/8 inch off seat, this force is 275 lbs.; then when it is 1/16 inch off seat, the closing force would be only 250 lbs. (2) The forces holding the ball off seat are those created by tubing pressure and casing pressure. Since the casing pressure is held constant, the tubing pressure controls the ball movement. As the tubing pressure decreases, the upward force is reduced and the force exerted by the spring begins to move the ball downward, creating the throttling effect. When the liquid gradient in the tubing increases, the valve passes more gas to maintain the desired gradient. It will pass less gas as the fluid gradient decreases.

FIGURE 4-4-2 - Illustrates the flow rate characteristics of the Camco LN-21R valve with different trim sizes as determined by flow tests. The valve in this example is adjusted for an operating casing pressure of 1400 psi, and is set to close when the tubing pressure reaches 400 psi. As shown, the valve with medium trim will pass 3.8 MMcf/D when tubing pressure equals 800 psi.

LN Series Valves are slickline-retrievable throttling type valves (see FIGURE 4-3). The dome nitrogen charge applied to the external area of the bellows provides the downward force, holding the valve on its seat. This dome pressure is preset at the reference temperature and corrected to operating temperature. The opening forces on the valve are the casing pressure acting on the internal area of the bellows (less the area of the seat) and the tubing pressure acting on the seat area. When the combined casing and tubing pressures are sufficient, the valve opens. Once the valve is open, it remains open until the tubing pressure is reduced to the predetermined closing pressure.

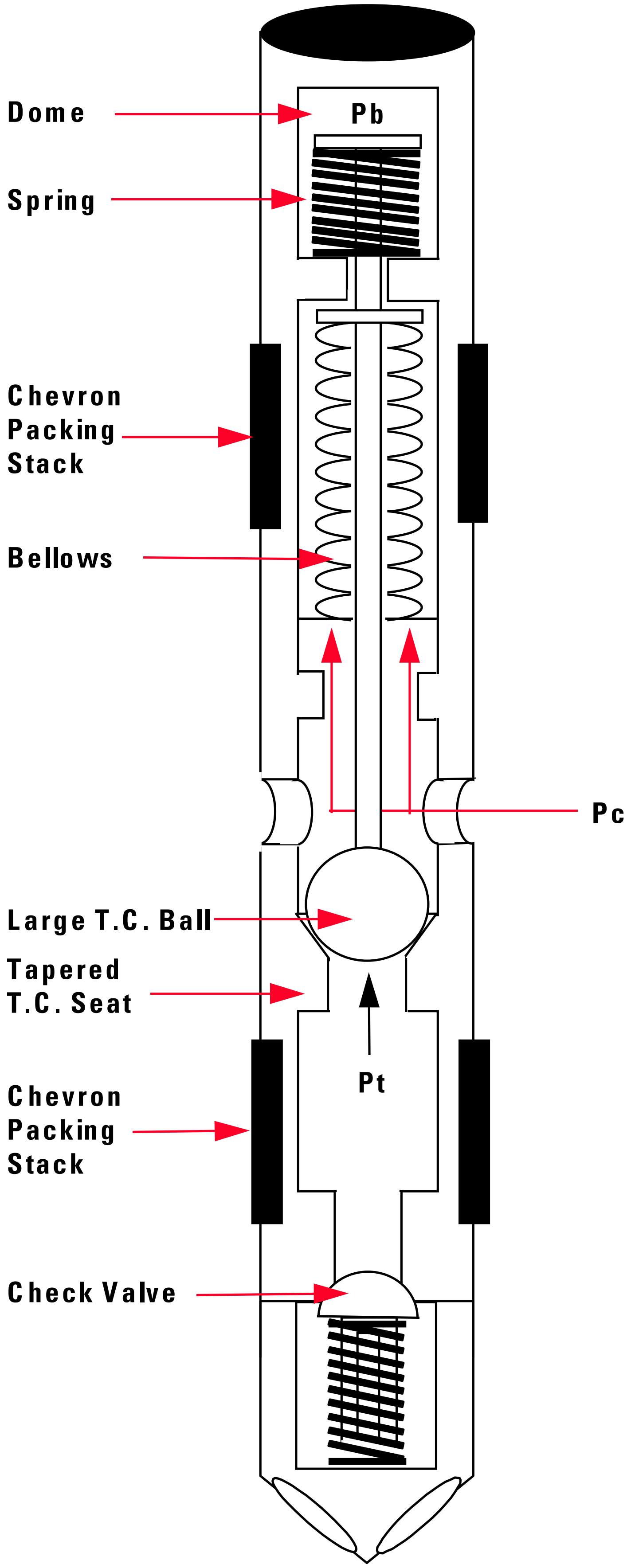


FIGURE 4-3: Nitrogen Charged Bellows Type Proportional Response Gas Lift Valve

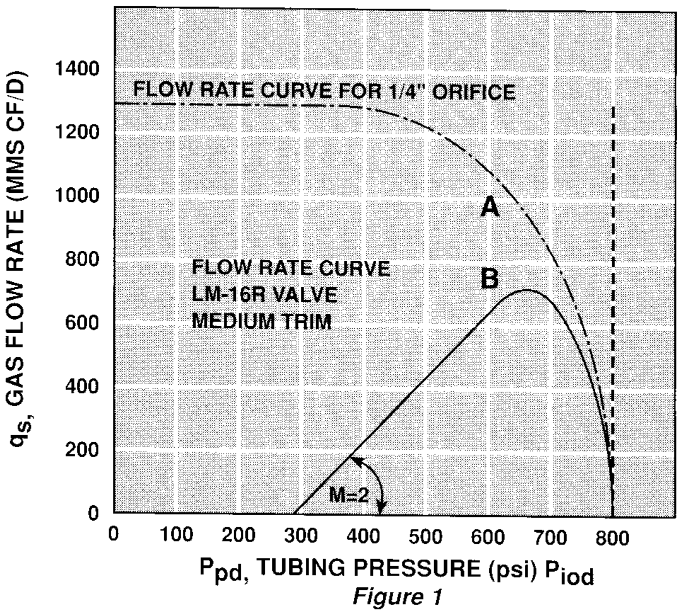


Figure 1

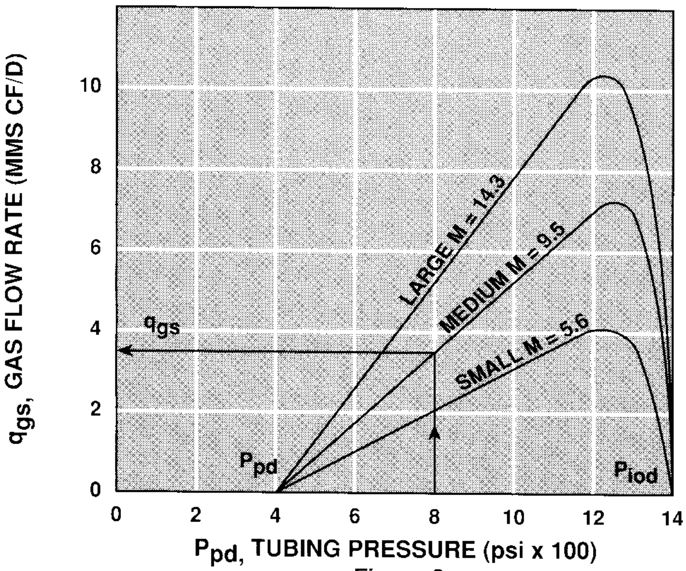


Figure 2

M	=	$\frac{MSCF/D}{psi}$
q_{gs}	=	GAS SUPPLIED THROUGH VALVE, MSCF/D
P_{iod}	=	CASING PRESSURE AT WHICH VALVE OPENS/CLOSES WHEN TUBING PRESSURE EQUALS P_{pd}
P_{pd}	=	TUBING PRESSURE AT WHICH VALVE OPENS/CLOSES WHEN CASING PRESSURE EQUALS P_{iod}, P_{sig}
P_{max}	=	TUBING PRESSURE AT WHICH GAS INJECTION BEGINS AT NEXT LOWER VALVE STATION

EXAMPLE FOR TYPE LN-21R VALVE:

$$q_s = M (P_{max} - P_{pd})$$
$$= 9.5 (800 - 400)$$
$$= 3.8 \text{ mmscf/d}$$

FIGURE 4-4

CAMCO SIDEPOCKET MANDRELS

Introduction

Camco's introduction of the sidepocket mandrel in 1954 revolutionized the world of gas lift and completion technology by providing a more flexible, efficient alternative to conventional mandrels. Since 1954, Camco has continually improved and refined the sidepocket mandrel design to provide customers with the most technologically advanced mandrels for a variety of applications.

Camco's KBG and MMRG round series sidepocket mandrels are made up as part of the tubing string when preparing a well for gas lift production, chemical injection, or other special applications. The mandrel can be located anywhere in the tubing string between the annular safety valve and the packer. The KBG and MMRG sidepocket mandrel is available in various tubing sizes and reduced O.D. sizes. Each KBG and MMRG series mandrel has eccentric swages on both ends and a "machined" type solid sidepocket. This sidepocket serves as a receiver for 1” or 1-1/2" dummy and gas lift valves.

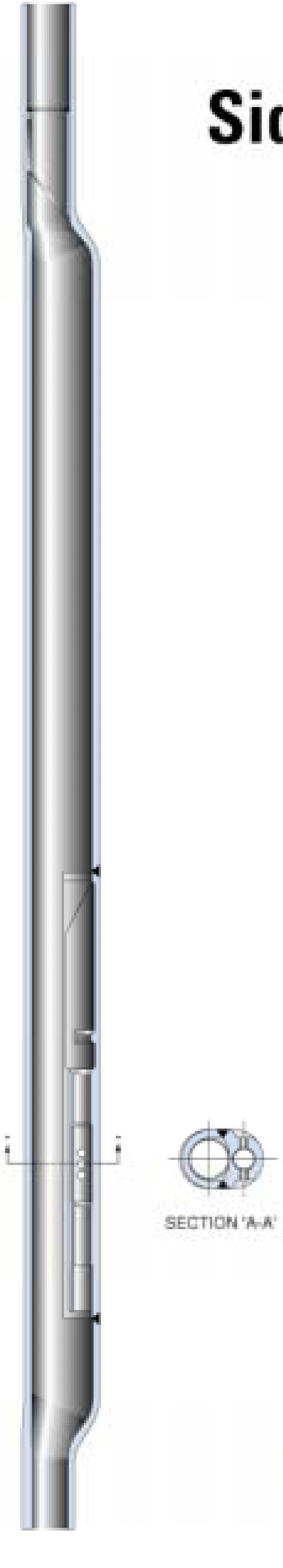
Description

The mandrel pocket consists of a latch lug and two polished bore packing sections straddling holes which provide communication between the casing annulus and the tubing. Each slickline retrievable gas lift valve has packing which seals in the polished bore sections, above and below the casing ports in the mandrel pocket. The packing prevents leakage and ensures direct communication between the annulus and the valve once the valve is secured in the mandrel pocket.

The KBG and MMRG series sidepocket mandrel incorporates additional design features which are designated by the letter "G". These features include a guide or "orienting sleeve" for aligning sidepocket accessories by receiving the "finger" on the OK or OM kickover tool and positively orienting the tool with the pocket. This feature allows ease of installation and retrieval of gas lift valves even in high deviations of up to 70^0.

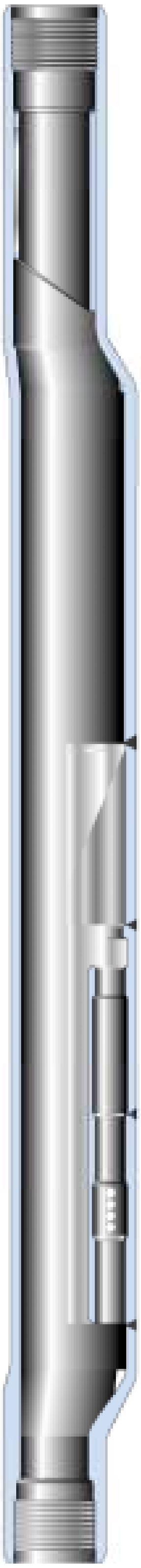
A machined tool discriminator above the mandrel pocket guides the smaller sidepocket equipment into the pocket, and automatically deflects larger diameter tools into the tubing bore. The latch recess in this series of mandrel is the 'G' style profile. This takes a BK-2 style latch in the KBG series or an RK Latch in the MMRG series.

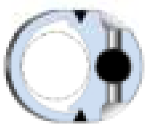
KBMG Series
Side Pocket Mandrels



Camco
A Schlumberger
Reservoir Development Company

MMG Series
Side Pocket Mandrels





SECTION "A-A"

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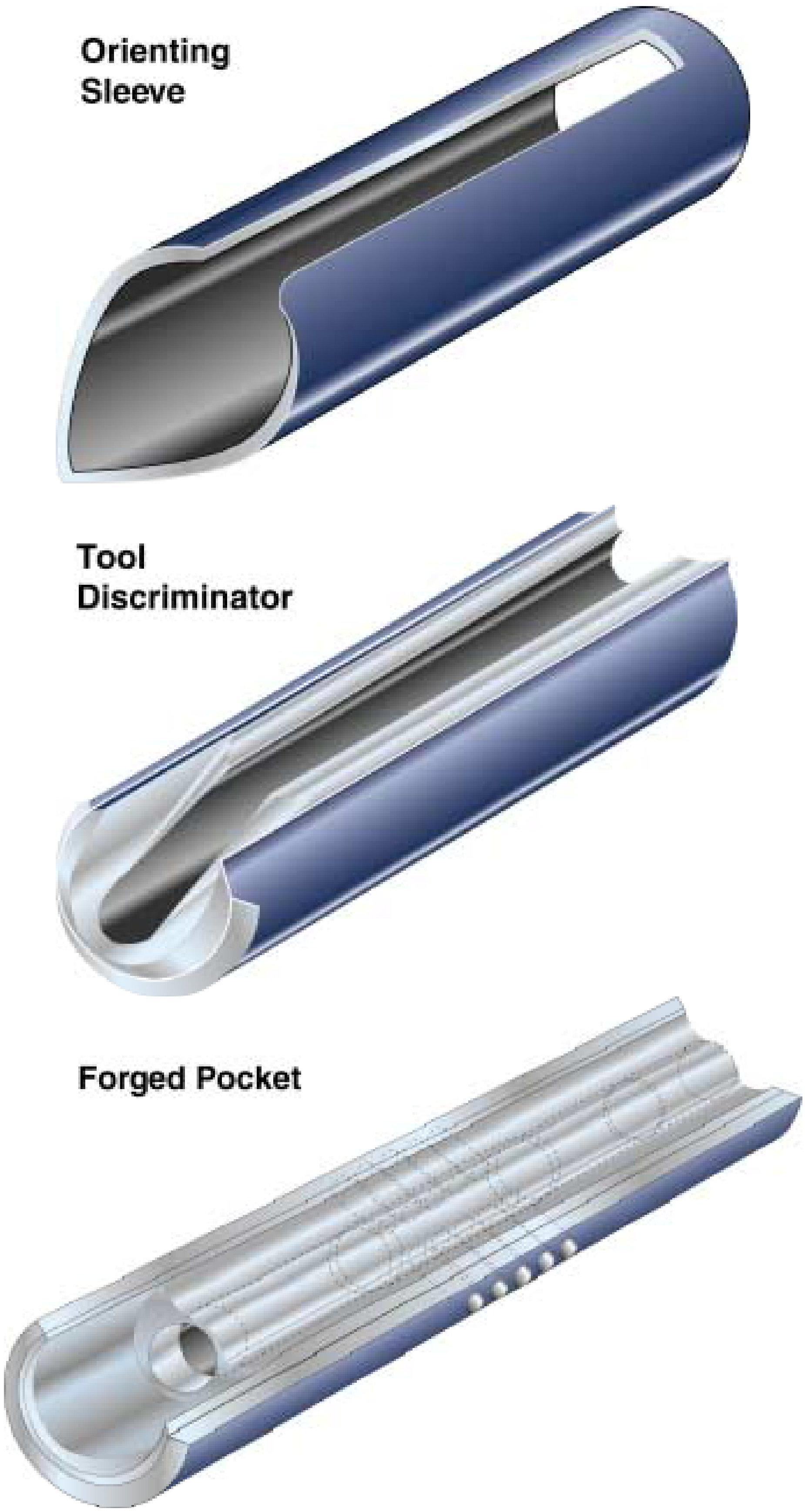

Orienting Sleeve
Tool Discriminator
Forged Pocket

Latch Profiles

There is one G latch profile available for the 1” pocket and all 1” equipment is compatible regardless of the manufacturer. The latch for this size is either the BK-2 ring style latch or the M collet style latch. However there are two latch profiles available to go in the 1 1/2” sidepocket mandrels. These are the 'G' type and the 'A' type profiles. As a general rule the old Halliburton (Otis and Merla) mandrels were built with the ‘A’ profile and all other manufacturers use the ‘G’ profile. The two are **not** interchangeable and use different running and pulling tools.

'G' Type Profile

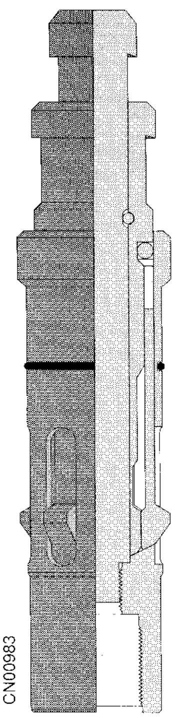
The 'G' type profile has a 180^{o} latch ring recess. The appropriate Camco 'RK' latch is a spring loaded, ring style latch with the no-go surface located near the lower end. This latch is installed and removed from the sidepocket mandrel using standard slickline methods. A minimum amount of force is required to install the latch. This is particularly important in deviated wells where forceful downward jarring is difficult.

'A' Type Profile

The 'A' type profile has a 360^{o} latch profile. The appropriate Camco 'RM' style latch utilizes a set of locking dogs configured inside a slotted sleeve. The no-go surface in this case being above the locking mechanism. As with the 'RK' latch, the RM is installed and removed from the sidepocket mandrel using standard slickline methods, with a minimum amount of force is required to install the latch.

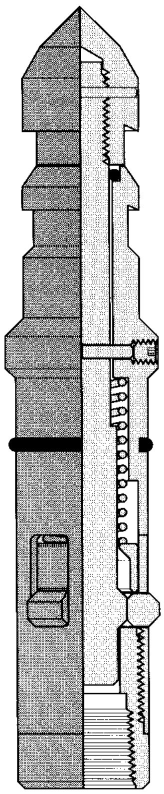
Running and pulling of both the 'G' and 'A' type latch is similar. As the 'G' style latch is jarred into position onto the no-go, the locking ring moves upward and out locking itself and the latch into the recessed area of the profile. When the 'A' style latch has been jarred into position onto the no-go, an upward pull forces the locking dogs to move over an inner mandrel and locks the latch into place. Upward pull on both style latches shears a pin, causing inner locking mandrels to move up and allow the either the latch ring or locking dogs to collapse, thus allowing retrieval of the latch and gas lift device.

The latches used in a sidepocket mandrel manufactured with a 'G' style pocket are not interchangeable with the latches used in an 'A' style pocket. i.e. You cannot use a 'G' style latch in an 'A' style profile and vice versa. However, either latch can used with any type of gas lift or flow control device.



CN00983

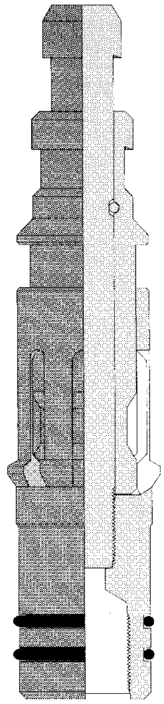
Otis 1 ½-Inch T2 Latch



CN00654

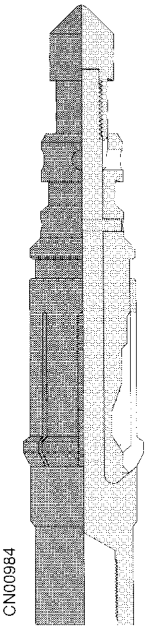
Otis 1 ½-Inch RM Latch

A PROFILE



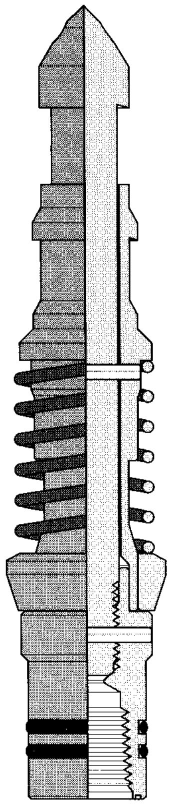
CN00982

Otis 1 ½-Inch TG Latch



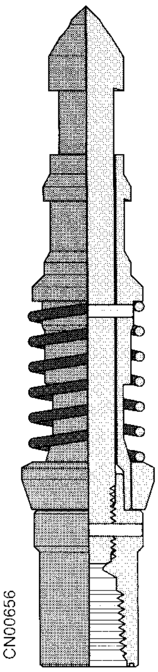
CN00984

Otis 1-Inch M Latch



CN00942

Otis 1 ½-Inch RK Latch



CN00656

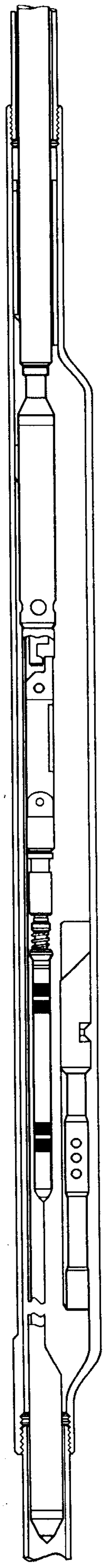
Otis 1-Inch BK-2 Latch

G PROFILE

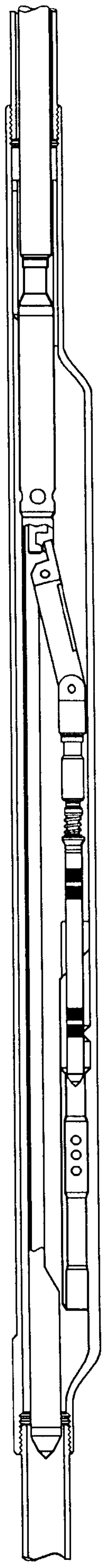
Discussion on Latch Profiles

Camco manufactures sidepocket mandrels with both the 'G' and 'A' style profiles as well as the appropriate latches. Often the question of preference and reliability is raised of one style verses another. The simple answer to this is there does not appear to be any. Both style of latches are widely used throughout the world. Aside from specific operational or downhole condition problems both have proved reliable. Moreover, Camco has discussed this question with the engineers, slickline supervisors and crews working for numerous North Sea operators. None have highlighted any specific problems with either type of latch profile.

In recent years the 'G' style latch has progressively become the industry standard, this being especially true in the North sea. Unless otherwise specified Camco will supply sidepocket mandrels with 'G' style latch profiles and the appropriate latches.



1A



1B

OK SERIES KICKOVER TOOL WIRELINE RUNNING PROCEDURE

1. Make up the JK or GA-2 running tool and valve onto the OK series kickover tool. Make up the kickover tool onto the bottom of the wireline tool string installed in the lubricator.

2. Lower the tool string into the tubing until the kickover tool is below the selected mandrel, the depth of which is known from well records. See Fig. 1-A.

3. Raise the tools slowly until they stop, This indicates that the locating finger in the kickover tool has contacted the top of the slot in the orienting sleeve of the mandrel.

4. Pull tension on the wireline until the weight indicator on the wireline unit indicates a weight approximately 150 pounds greater than the tool string weight. The kickover tool will release and kick the valve into position above the side pocket.

5. Slowly lower the tools until a weight loss registers on the weight indicator. This indicates that the kickover tool has kicked over and located the pocket of the mandrel. See Fig. 1-B. No weight loss means that the kickover tool did not release to the kicked over position and Steps 3, 4 and 5 must be repeated.

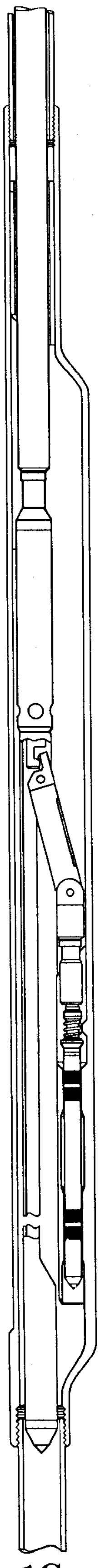
6. Jar downward to drive the valve into the pocket of the mandrel. See Fig. 1-C.

7a. Jar upward. This separates the JK running tool from the BK type latch and gives a positive indication that the latch and valve are firmly locked in the pocket.

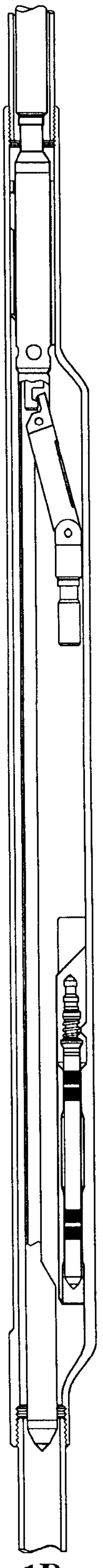
CAUTION: The GA-2 running tool, unlike the JK running tool, is released by downward jarring only. Upward jarring will remove the valve from the mandrel pocket.

7b. To release the GA-2 running tool, jar downward. Downward jarring shears the two brass pins that attach the running neck of the valve to the running tool.

8. The tool string can now be withdrawn from the well. See Fig. 1-D. As the kickover tool is pulled upward through the mandrel, the locating finger in the kickover tool will stop in the slot in the orienting sleeve of the mandrel. Sharp upward jarring will release the finger housing which will permit the kickover tool to pass through the mandrel.

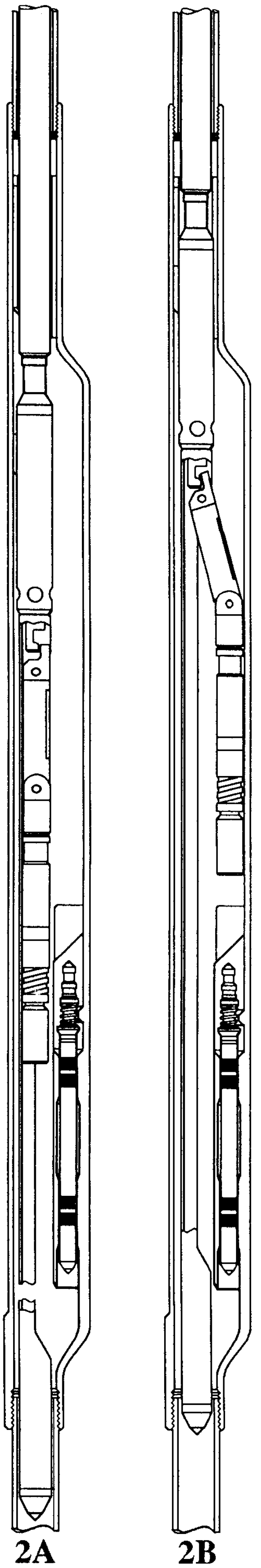


1C



1D

4



2A **2B**

OK SERIES KICKOVER TOOL WIRELINE PULLING PROCEDURE

1. Make up the JDC pulling tool to the OK series kickover tool. Make up the kickover tool to the bottom of the wireline tool string installed in the lubricator.

2. Lower the tool string into the tubing until the kickover tool is below the selected mandrel, the depth which is known from well records. See Fig. 2-A.

3. Raise the tools slowly through the tubing until they stop, which indicates that the locating finger in the kickover tool has contacted the top of the slot in the orienting sleeve of the mandrel.

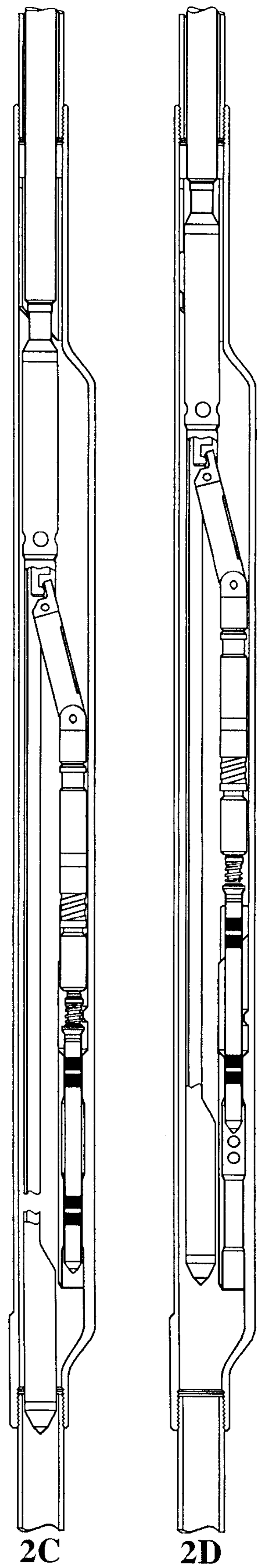
4. Pull tension on the wireline until the weight indicator on the wireline unit indicates a weight approximately 150 pounds greater than the tool string weight. The kickover tool will release and kick the pulling tool over into position above the mandrel pocket.

5. Slowly lower the tools until a weight loss registers on the weight indicator. This means that the kickover tool has kicked over and located the side pocket of the mandrel. See Fig. 2-B. No weight loss indicates that the kickover tool did not release to the kicked over position and Steps 3, 4 and 5 must be repeated.

6. Jar downward lightly to secure the dogs of the pulling tool to the fishing neck of the valve or latch. See Fig. 2-C.

7. Jar upward. This pulls the valve from the pocket. If it is not possible to pull the valve, heavy downward jarring will shear a pin in the pulling tool, releasing it from the valve. The tool string can now be withdrawn from the well. See Fig. 2-D.

8. As the kickover tool is pulled upward through the mandrel, the locating finger in the kickover tool will stop in the slot in the orienting sleeve of the mandrel. Sharp upward jarring will release the finger housing which will permit the kickover tool to pass through the mandrel.



2C **2D**

Control Line Protection

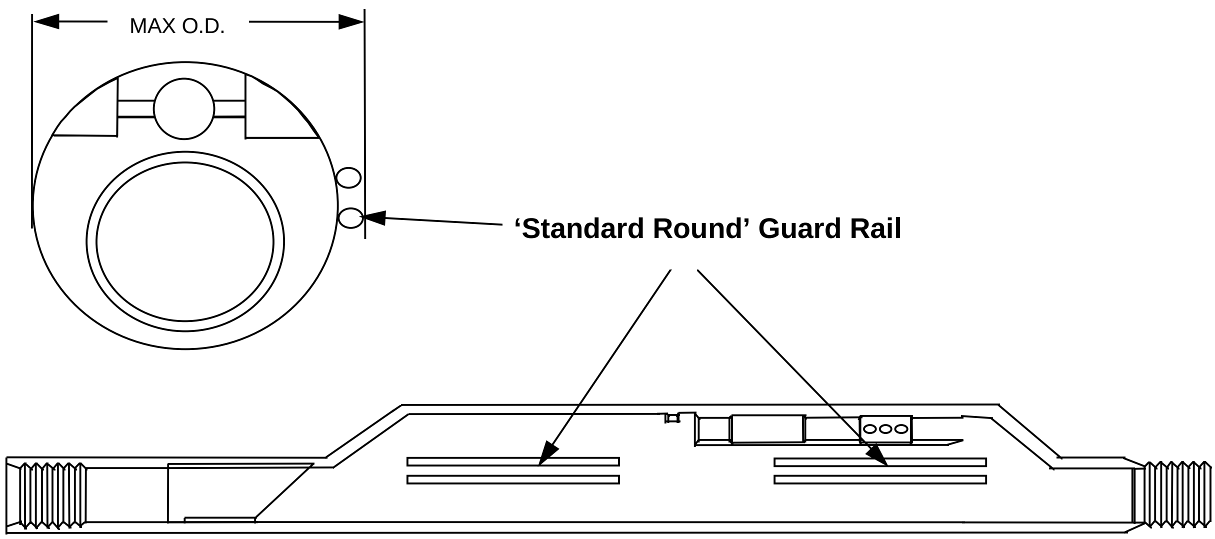
With the growing popularity of downhole gauges in recent years, there has been an increasing demand for good control line protection past sidepocket mandrels. In order to meet this demand, Camco in association with Lasalle and Schlumberger Slickline & Testing has designed a range of devices for protecting both single and double encapsulated 11mm square control lines. This range of devices can be broadly divided into three levels:

Lasalle Coupling Clamp Protector

This 'retrofit' option is considered to be the least effective as it only protects the cables at the nearest coupling either side of the mandrel, which in effect leaves the cable exposed at the high point of the mandrel body. By careful design it is possible to make the protectors provide a stand off that in theory will prevent the cables being damaged.

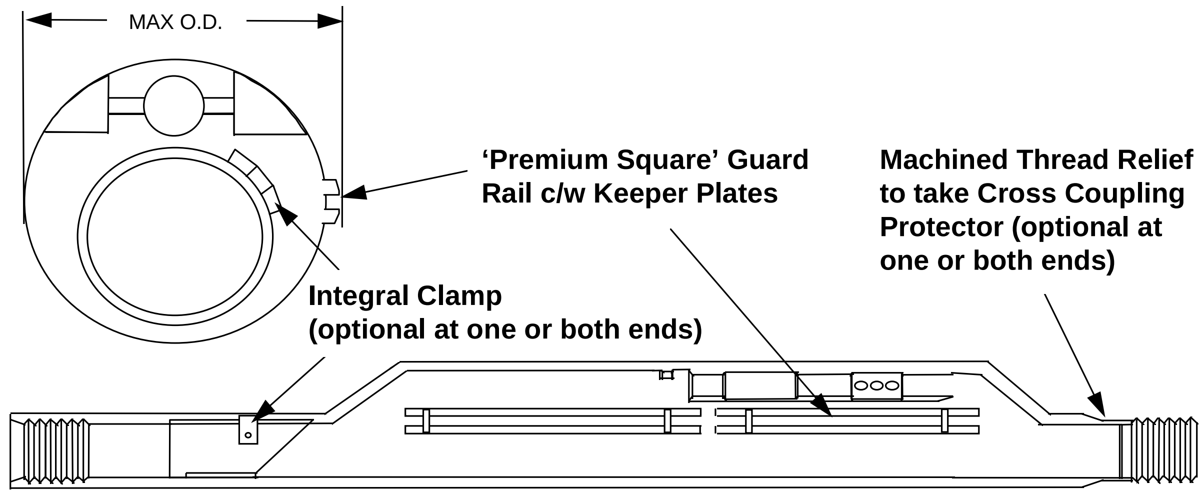
'Standard Round' Guard Rails

As the name suggests these guard rails are basic in design and thus have a relatively small impact on the mandrel cost. They generally consist of two or three short lengths of round bar welded at the either end of the mandrel body into which the control line fits. They should be run in conjunction with the Lasalle cross coupling clamp protector as covered above.



‘Premium Square’ Guard Rails

The Premium guard rail design features square rails with between three and six keeper plates along its length. The keeper plates are set slightly below the rail top and are held in place with countersunk allan type screws. In addition an integral clamp is welded onto the top swaged end and the pin thread at the bottom end of the mandrel has a 100 mm machined back profile to allow a Lasalle cross coupling protector to be fitted. This rail design has been used extensively with several North Sea operators and offers a high level of cable protection.



5. Gas Lift Design

5A. Manual Design of Continuous Flow Gas Lift Installations

CHAPTER OBJECTIVE: - Given all necessary well data, equations and charts, gas lift design paper, and necessary equipment, you will design one gas lift installation using injection pressure operated valves or one utilizing production fluid operated valves. The design must include:

1. Correct calculation of injection pressure at total depth.
2. The selection of proper flowing gradient curves.
3. The selection of the correct unloading GLR for design.
4. The location of the first valve depth within 25 feet.
5. The use of the proper pressure drop from the injection pressure line.
6. The use of the correct static gradient to space valves to packer or until valve spacing is less than 300 feet.
7. The use of the correct procedure to select the proper port size.
8. The use of the correct procedure to calculate valve set pressure.

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INTRODUCTION

The most efficient operation of a gas lift installation depends on proper design. Although the selection of the valves for the well has been discussed in a previous unit, the spacing of the valves and the determination of proper pressure setting depends upon accurate design techniques.

Modern design procedures can be accomplished by computer, but gas lift personnel must understand design fundamentals in order to use these tools effectively. The best method of achieving this understanding is to personally design a system without computer assistance.

The procedures outlined in this unit are graphical and contain a margin of error. Extreme care must be taken when reading the design paper and working with gradient curves.

A thorough understanding of design procedures is essential to the gas lift specialist and very helpful to all others who work with gas lift equipment.

DESIGN BIAS

The gas lift design process is composed of two stages. They include:

1) The spacing of mandrels and/or gas lift valves, and
2) The calculation of setting pressures for unloading valves.

The objective of the design process is to ensure that the unloading valves are closed when the well is lifting from the designed operating point. Each of the design techniques presented in this manual has been developed for the stated objective of achieving single-point injection.

With this in mind, it is often desirable to incorporate various forms of “design bias” into gas lift designs. This bias is used to ensure that the design is successful in accomplishing the above stated objective. That is, to ensure that the unloading valves are closed when the well is lifting from the designed operating point. There are numerous forms of design bias. They include: design bias at the transfer point, casing pressure bias, temperature bias, FWHP bias, available injection pressure bias and even selection of the flowing gradient curves.

Transfer Point Bias

One of the most common forms of design bias involves the location of the transfer point (and, accordingly, the spacing of the mandrels.) This bias is intended to account for uncertainty in the flowing gradient as it pertains to the unloading process. The transfer point is located using the design bias added to the tubing pressure at valve depth. There are several different approaches in taking this design bias, based on different assumptions, as follow:

- A fixed percentage of the differential between the tubing and casing pressure
  The rationalle for this approach is that it will bias the transfer point more at the top of the well than at the bottom of the well. During unloading at the top of the well, we basically u-tube fluid around from the casing at the top of the well. However, as we work down the well, we begin to get drawdown on the formation, producing well fluids and formation gas, which aids in the unloading process. For this reason, biasing the upper mandrels is believed by many to have a greater effect on the unloading process than biasing the lower mandrels.

- A fixed percentage of the tubing pressure
  For the upper unloading valves, there is a certain amount of design bias built-in when the objective tubing gradient is chosen as the location for the transfer pressures. This is easily illustrated by generating an equilibrium curve for the well. If we develop an equilibrium curve for the objective production rate, we will find that the resulting pressures will be considerably less than those found using the objective tubing gradient. Hense, we have built-in design bias when we use an objective tubing gradient to design the system. As we move down the hole, the equilibrium curve and

objective tubing gradient start to converge. Therefore, the greatest uncertainty is not at the upper unloading valves; but, rather, is at the lower unloading valves. The ultimate result of this method is that the spacing at the top of the well is relatively unaffected, while the mandrels at the bottom of the well are forced closer together. A comparison of the various methodologies should also reveal that this method would actually result in fewer mandrels being placed in the well. This is because the differential pressure (and spacing) is widest at the top of the well.

- Constant value (50 psi)
  This method is a simple and rough approach. It simply involves adding a fixed value to the tubing pressure at depth to determine the transfer point of each valve.

Other forms of design bias

- FWHP – Engineers often choose to select a flowing wellhead pressure which is higher than what will be seen in reality. This has the effect of moving the entire objective tubing gradient to the right, and indirectly does the same thing as the transfer pressure bias discussed above. It may be desirable to choose a slightly higher wellhead pressure than what is anticipated, so that the well can operate effectively at higher than normal system pressures.
- Available injection pressure – It is often prudent to design a gas lift installation to operate at a kickoff pressure which is less than the actual injection pressure available. This will allow the well to unload even during situations such as compressor shut-downs, low gas sales line pressure, etc.
- Selection of flowing gradient – The selection of the flowing gradient curve can serve as yet another form of bias. Often, engineers will select a flowing gradient that is "heavier" (or further to the right) than what is anticipated. In most cases, this requires increasing either the water cut or rate associated with the curve. However, in applications with complex PVT properties, a more rigorous analysis is needed to know which gradient to select.
- Temperature bias – Another form of bias involves the selection of design temperatures for the unloading valves. Since the objective of the gas lift design is to ensure that the upper unloading valves are closed when the operating point is reached, it is often desirable to take additional precautions to ensure that this happens. One way to ensure that the this objective is achieved, is to "temperature lock" the upper unloading valves. This is accomplished by selecting temperatures for the upper valves that are greater than the static temperature gradient, but less than the flowing temperature gradient. Since these temperatures are greater than the static temperature gradient, the valves will open while fluids are being u-tubed from the casing to the tubing. However, once draw-down is achieved and the well starts to flow, the temperature at depth will be greater than what the valves were calibrated for, forcing the valves to "lock" closed. When temperature locking valves, it is important to select temperatures in such a way that the valves are not closed prematurely. Otherwise, the unloading process will become stymied. For this reason, this is considered an

advanced design technique and should not be attempted without a thorough understanding of the processes involved.

Casing pressure (or operating pressure) bias

This is probably the most common form of bias used in a gas lift design and serves as the basis of most design techniques. We know that in order to ensure that each unloading valve closes when the successive valve opens, we must take a drop in casing pressure. However, the amount of pressure drop to take is often in dispute. There are two basic design techniques (and numerous variations) which have been developed to address this issue. They include the "fixed pressure drop" and "Ppmax – Ppmin" methods. A summary of these methods and the rationalle behind them follows:

- **Constant pressure drop method** – This is a very simple method for choosing pressure drops, that is based in large part on field experience. This method entails taking equal casing pressure drops for all valves in the design. This pressure drop is generally 10 – 30 psi and is based in large part upon field experience. An advantage of this method is that it allows the engineer to perform a less conservative design. This means that an experienced engineer will be able to inject deeper with the same amount of available injection pressure than they would be able to with the "Ppmax – Ppmin" method. A draw-back of this method is that it is less technically rigorous than other methods and does not necessarily incorporate valve mechanics into the design process. For this reason, it is strongly recommended that individuals using this method double-check their work by back-calculating the opening and closing pressures under design conditions. The proper application of this technique is an iterative process involving both valve spacing and calculation of opening and closing pressures.

- "**Ppmax-Ppmin" method** – This technique incorporates the relationship between valve mechanics and spacing in a design. The rationalle and theory behind this design technique follows:

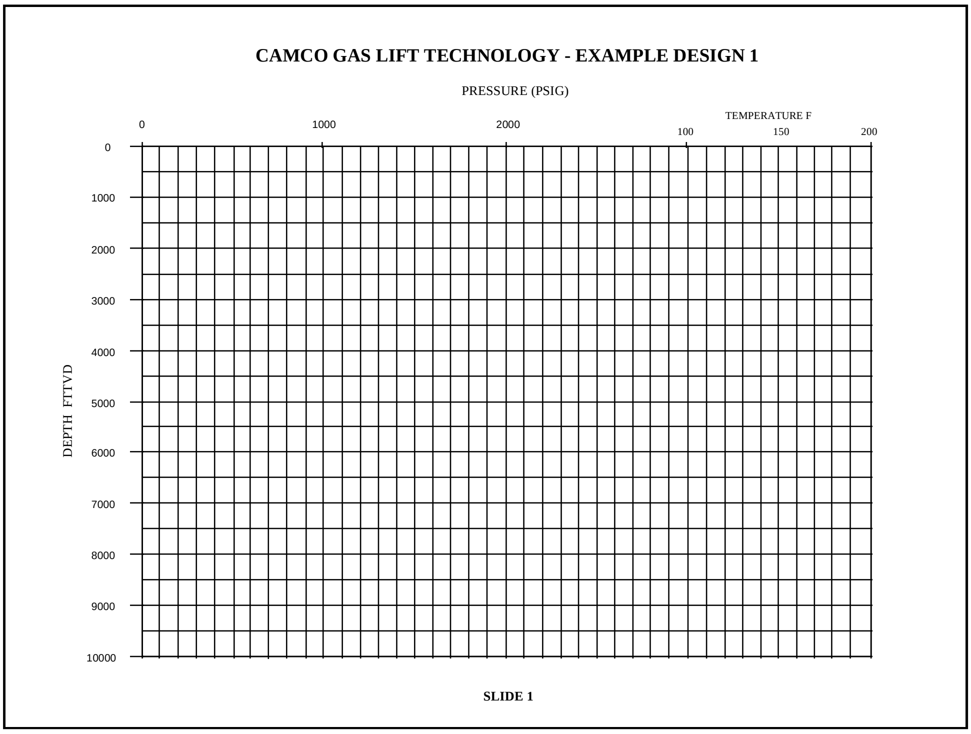
The amount of opening force supplied by production pressure to open the valve is a function of the port size (PPEF). The effective amount of opening pressure (Peo) supplied by the production pressure is:

Peo = PPEF x Ppd

where Ppd is production pressure acting in valve. This means that pressure acting on the downstream (or tubing) side of the valve is equivalent to or gives the same effect on the opening the valve as some fraction of the pressure acting on upstream (or casing) side of the valve. Since the uncontrollable variable is the production pressure, it is important to approximate the amount it could increase. The maximum possible flowing production pressure (Ppmax), regardless of flow rate, occurs if the gradient curve between the flowing wellhead pressure and the injection pressure on the next valve form a straight line. In reality, this gradient would be curved, making "Ppmax " greater than what would be seen in reality. Therefore this is a certain amount of design bias built into this method. The minimum possible flowing production pressure (Ppmin) occurs when the well is lifted at the target point of injection. This is also a conservative approach, because the gradient curve during unloading will never be the same as the gradient curve during production. During the unloading process, the flowing production pressure will be between Ppmin and Ppmax, regardless of fluctuations in the flow rate. Therefore any increase in production pressure will not exceed the value of (Ppmax-Ppmin) and (Ppmax-Ppmin) can represent the maximum possible increase in production pressure.

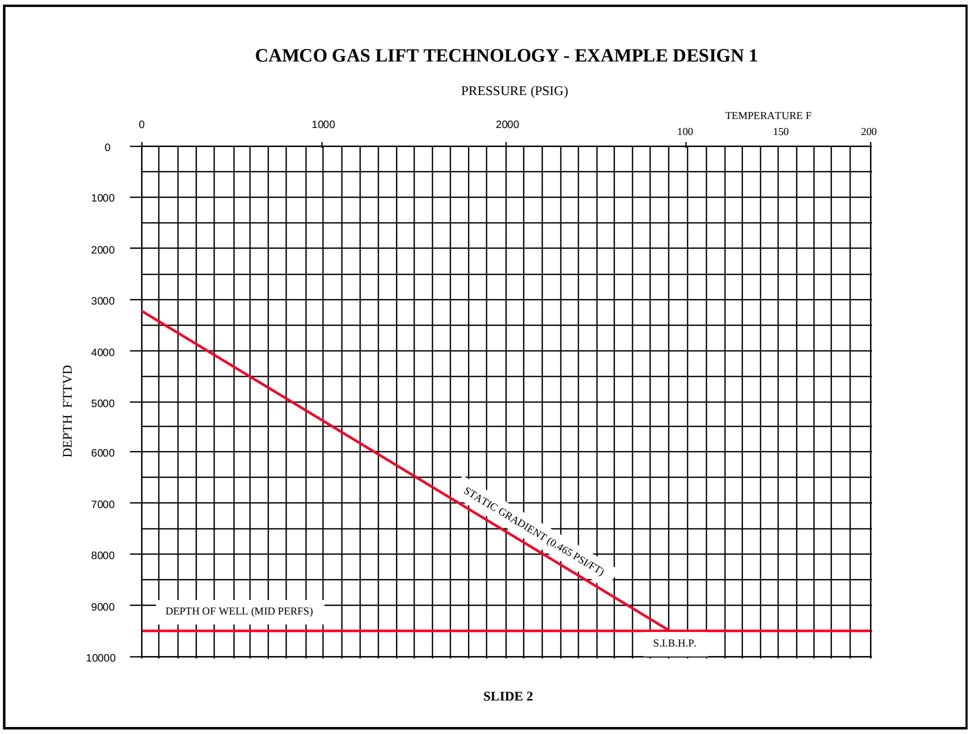
To prevent the opening of the valve, the possible increase in production pressure (Ppmax-Ppmin) must be anticipated by reducing the injection pressure an equivalent value. With this in mind, the casing pressure for each valve needs to be lowered by the amount of:

$$PD = PPEF \times (Ppmax - Ppmin)$$



EXAMPLE 1 WELL INFORMATION

Tubing Size	3 1/2” 9.2 lb/ft (2.992 “ I.D.)
Deviation	Vertical Well
Target Design Rate	2000 blpd
Water Cut	99%
Oil Specific Gravity	0.85 (API 34.971)
Water Specific Gravity	1.08
Gas Specific Gravity	0.65
Packer Depth	9000 ft TVD
Mid Perf Depth	9500 ft TVD
Flowing Tubing Head Pressure	200 psig
Shut-in Bottom Hole Pressure	2900 psig
Productivity Index	2 stb/d/psi
FGOR	1000:1
FGLR	10:1
Surface Gas Injection Pressure	1200 psig
Available Gas	2 mmscf/d
Bottom Hole Temperature	200 degrees F
Static Surface Temperature	80 degrees F
Flowing Surface Temperature	120 degrees F
Kill Fluid Gradient	0.465 psi/ft



1. Draw a line at the depth of the mid perforations i.e. 9500 ft TVD.

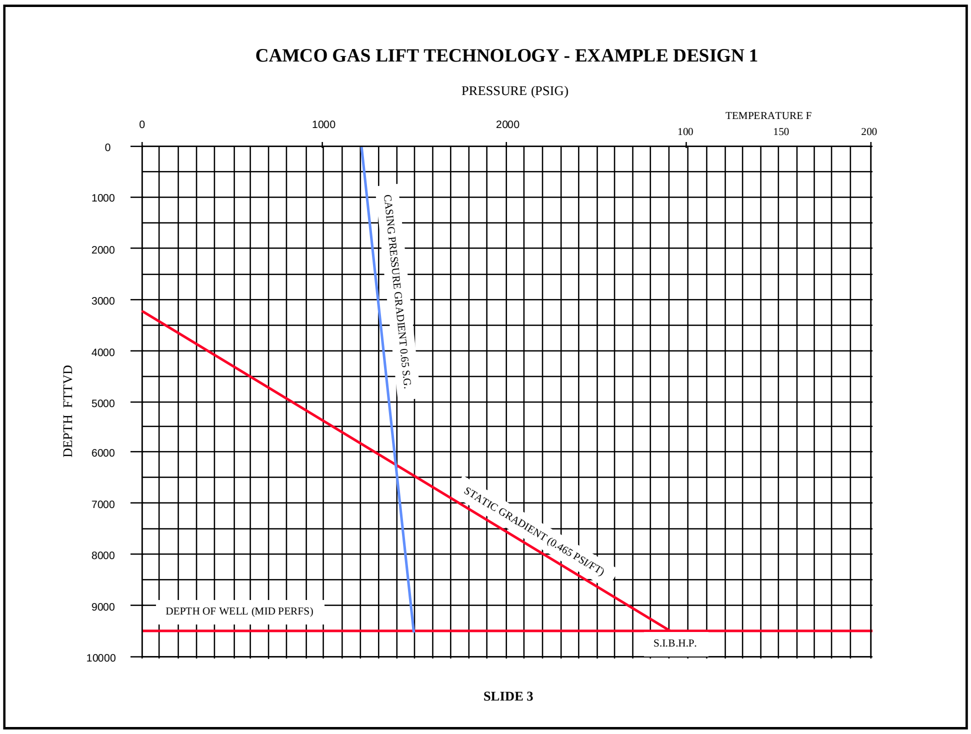
2. Draw the static gradient line starting from the shut in bottom hole pressure (SIBHP) of 2900 psig using a kill fluid gradient of 0.465 psi/ft. If the tubing pressure at surface was 0 psig then the fluid level would be at 3263 ft TVD.

Hydrostatic head = 2900 / 0.465

= 6237 ft

Fluid level depth = 9500 - 6237

= 3263 ft TVD



Draw in the gas injection (casing) pressure line.

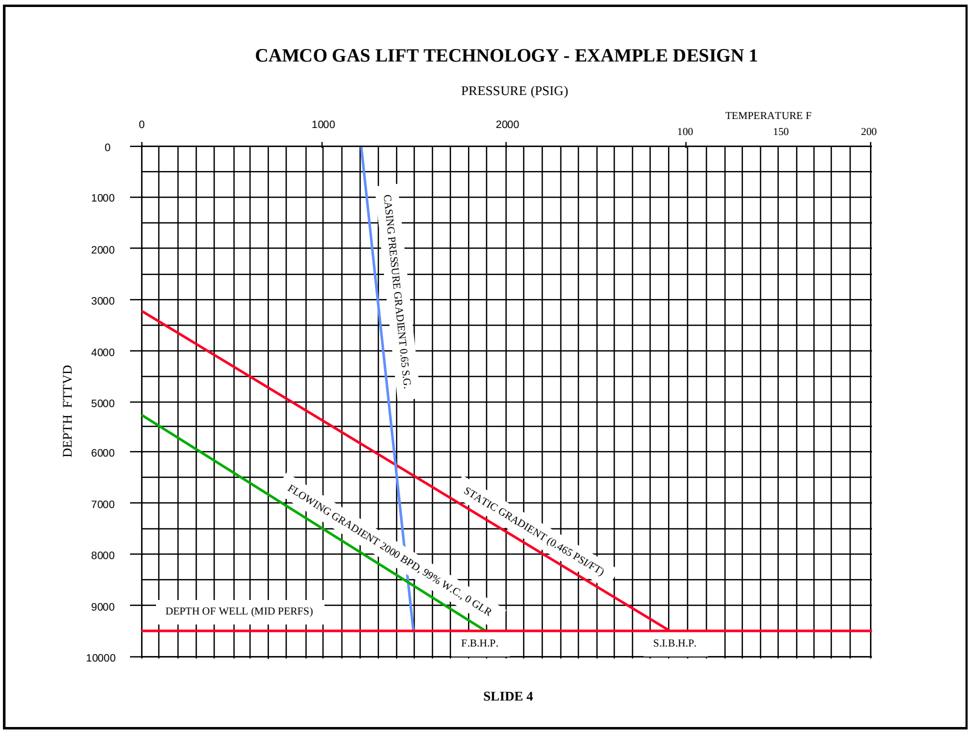
Starting at 1200 psig and using the Factor Table - Gas Column Pressures for a S.G of 0.65 calculate the casing pressure at 10000 ft of 1504 psig.

Select factor (F) from the table for 10000 ft and S.G. of 0.65 (0.253)

Pcf (at depth) = Pcf (at surface) (1 + F)

= 1200 x (1+ 0.253)

= 1503.6 psig



1. Calculate target flowing bottom hole pressure (FBHP).

Q liquid = (SIBHP- FBHP) x PI

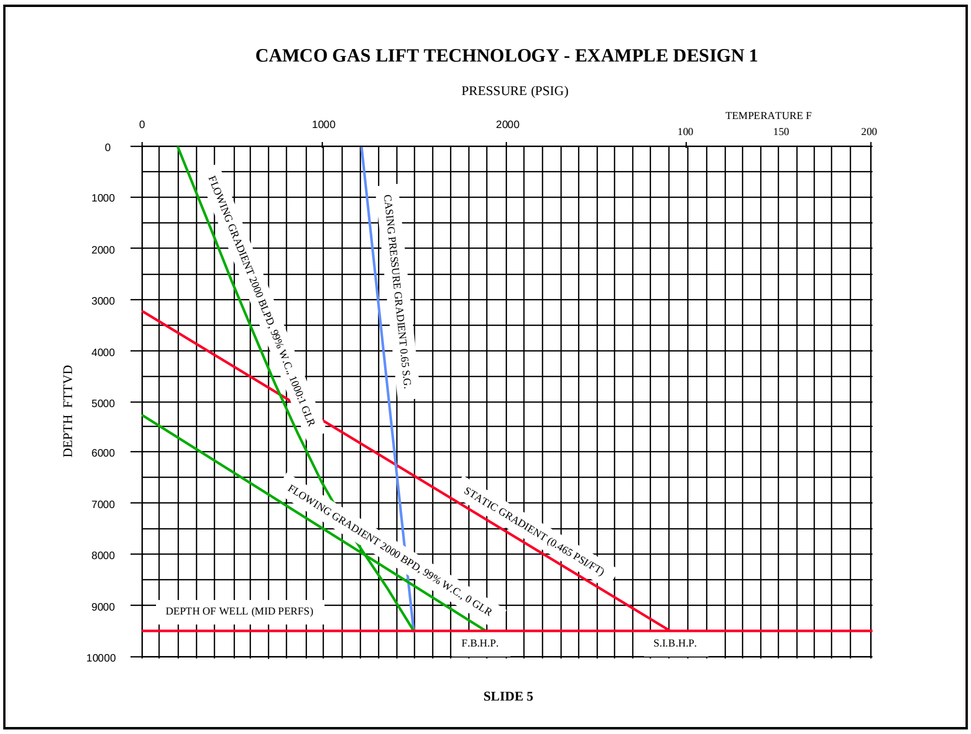
FBHP = SIBHP - (Q / PI)

= 2900 - (2000 / 2)

= 1900 psig

2. Select appropriate flowing gradient curve for 3 1/2" tubing, 2000 BPD, 99% water cut, 10:1 GLR (use closest line of 0 GLR) and plot on graph starting at 1900 psig at mid perf and intersecting y-axis at approximately 5300 ft TVD.

Where this flowing gradient line intersects the casing pressure line is the deepest point that gas could be injected. However because we require a differential across the valve of a minimum of 150 psi for stable gas injection (the smaller the differential across the orifice valve the more the gas passage will be effected by fluctuations in the tubing pressure) we must move up the well to a point with at least 150 psi differential between tubing and casing pressures.



1. Select appropriate flowing gradient curve for 3 1/2” tubing, 2000 BPD, 99% water cut, 1000:1 GLR

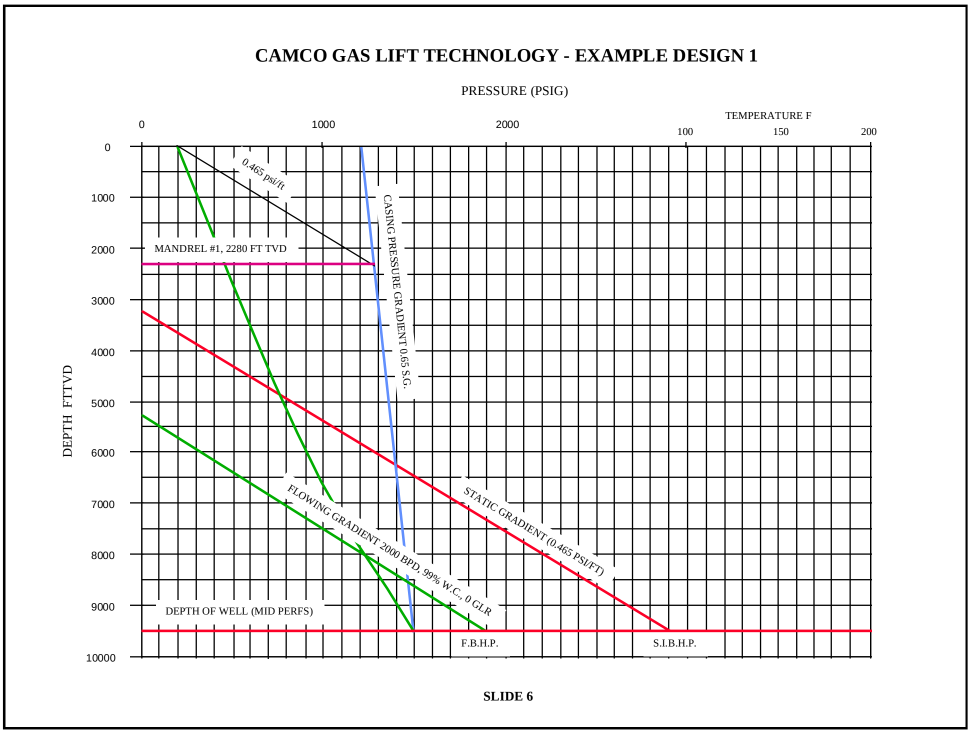
GLR = Available gas in scf/d / Production Rate in bpd

= 2 000 000 / 2000

= 1000:1

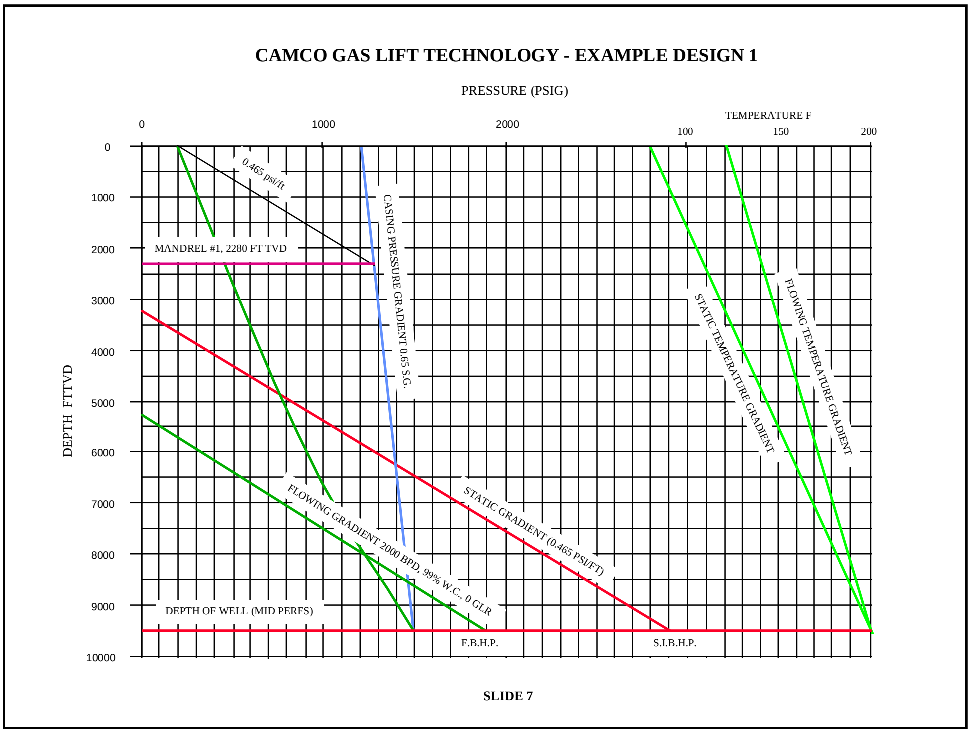
2. Plot gradient on the graph starting at the flowing tubing head pressure of 200 psig down to mid perfs. The line should cross the mid perfs at approximately 1500 psig.

We are trying to achieve the deepest point of injection as determined in the previous slide so whilst our available gas is predetermined we may find that the selected GLR is inappropriate to achieve this point. It should be remembered that gas lift designing is to some extent an iterative process as the depth of injection and GLR will influence the FBHP and thus the production rate which will in turn influence the depth of injection.



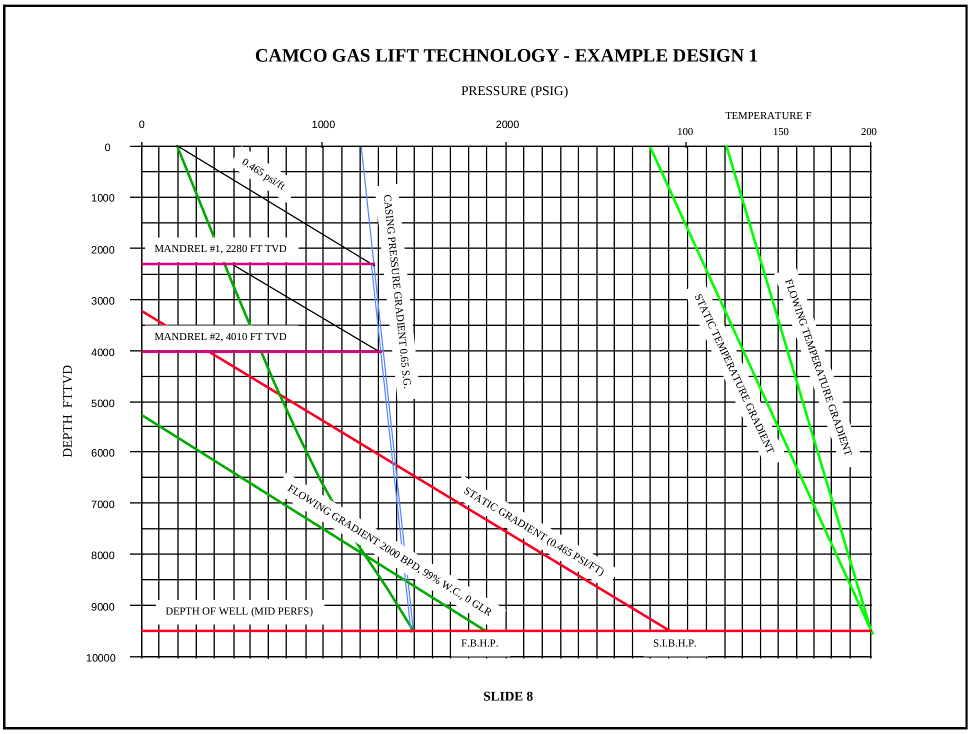
Space the top mandrel using the static gradient of 0.465 psi/ft. Draw a line with this gradient starting at 200 psig until it intersects the casing pressure at a depth of 2280 ft TVD.

This is the deepest point at which gas could be U-tubed around and is therefore where the top mandrel must be located. As the well will not be flowing at the time of kick off the tubing head pressure will be lower than the 200 psig expected when flowing and thus there will be sufficient differential in order to pass gas. If we expected no change in the wellhead pressure then we would have to move the depth of this first mandrel up in order to have a minimum of 50 psi differential across the valve.



Plot temperature gradients (assume straight line)

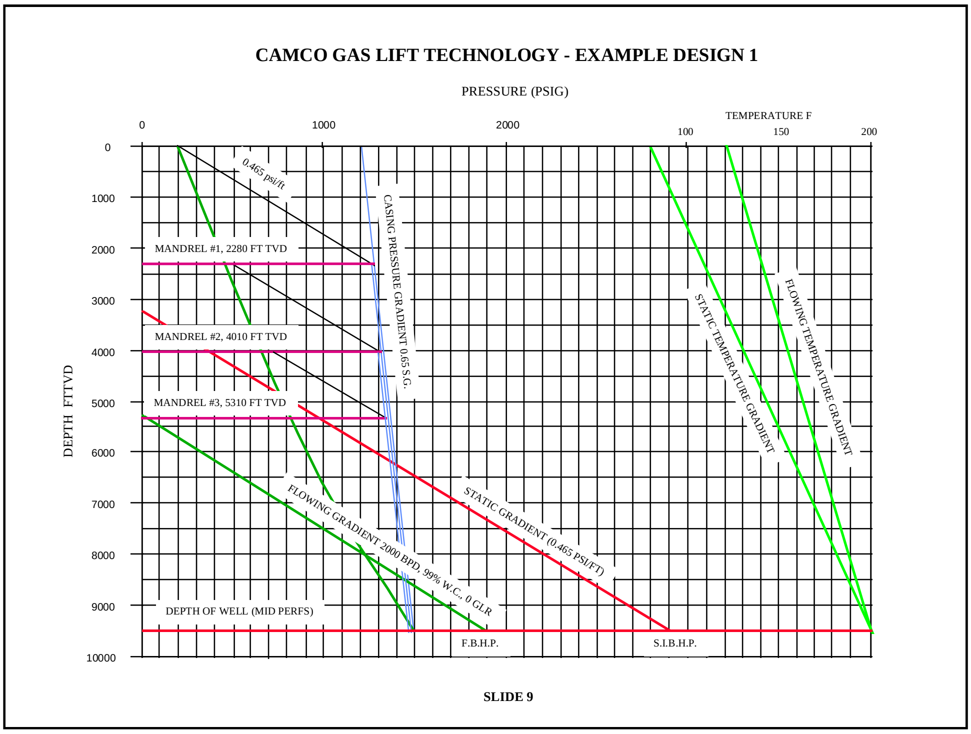
Static 80 degrees at surface to 200 degrees at mid perf
Flowing 120 degrees at surface to 200 degrees at mid perf



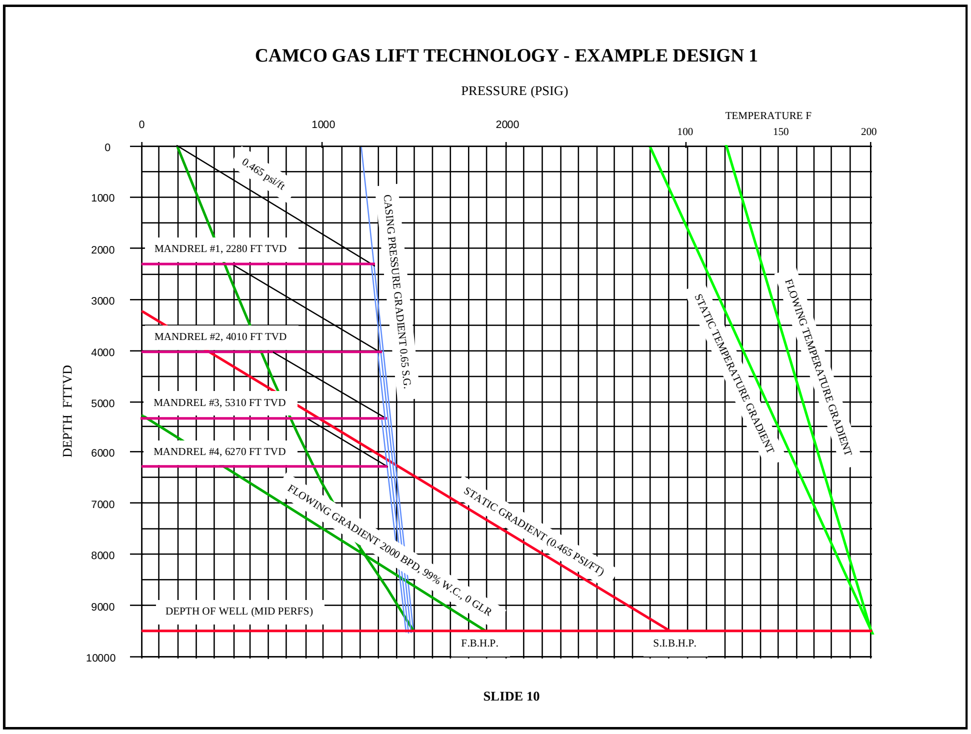
1. Draw in the casing pressure drop of 10 psig required to close valve number one starting at mandrel #1 using a parallel line to original casing gradient. This 10 psi drop is arbitrary and is the minimum recommended. If the design was such that we could afford to take a larger pressure drop then this figure could be increased building in a greater safety factor to ensure the upper valves close.

2. Space mandrel #2 using the static gradient of 0.465 psi/ft starting at the transfer point of 495 psig until the line intersects the new casing gradient line at a depth of 4010 ft TVD.

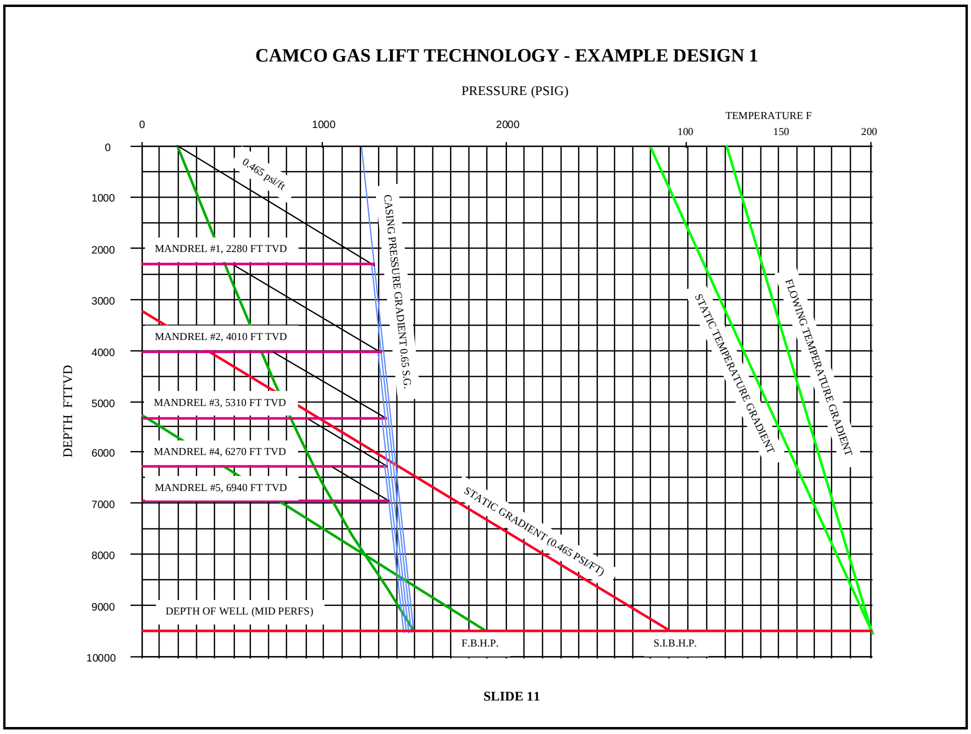
The transfer point is the tubing pressure at mandrel 1 which we expect to achieve through gas injection. Thus in theory we could start on our flowing gradient curve at a pressure of 450 psig. However as the gradient curve is theoretical and may not exactly match actual flowing conditions it is prudent to incorporate some safety factor here. The amount of safety incorporated will depend on the designers personal preference and his knowledge and experience of the well or field to be designed. In this example we will use a safety factor of 10% of the predicted tubing pressure. Thus our transfer point will be 495 psig.



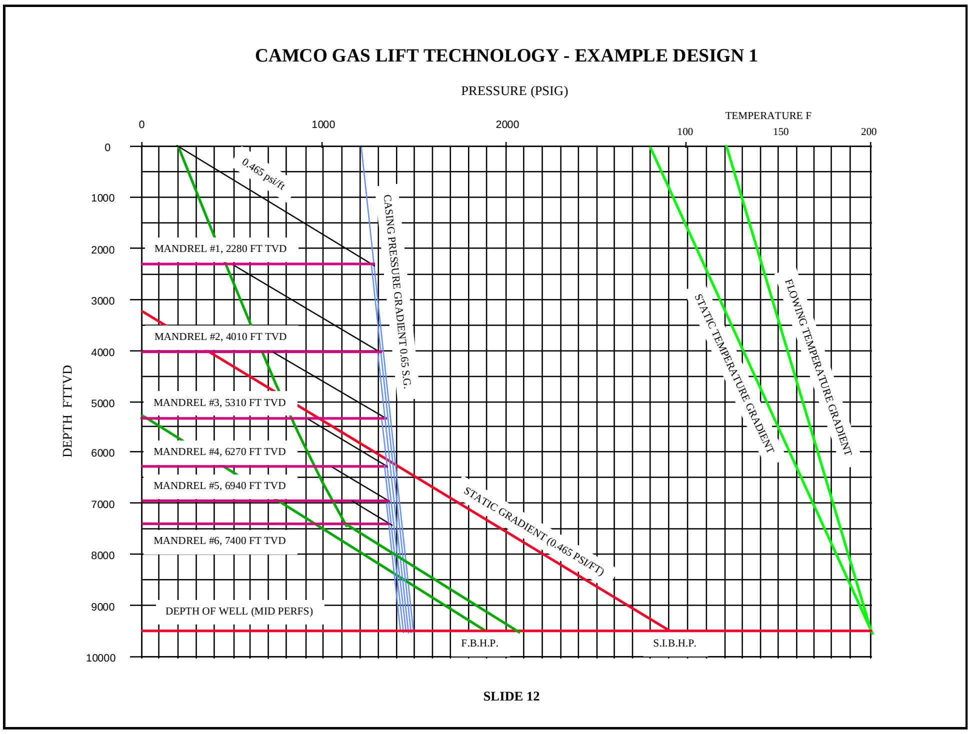
The process followed with the previous slide is repeated here. Thus we draw in a new casing gradient with a 10 psi pressure drop. We then draw our unloading gradient of 0.465 psi/ft starting at the transfer point of 726 psig and intersecting the new casing gradient line at 5310 ft TVD.



The process followed with the previous two slides is again repeated. Thus we draw in a new casing gradient with a 10 psi pressure drop. We then draw our unloading gradient of 0.465 psi/ft starting at the transfer point of 902 psig and intersecting the new casing gradient line at 6270 ft TVD.



The process followed with the previous three slides is again repeated. Thus we draw in a new casing gradient with a 10 psi pressure drop. We then draw our unloading gradient of 0.465 psi/ft starting at the transfer point of 1050 psig and intersecting the new casing gradient line at 6940 ft TVD.

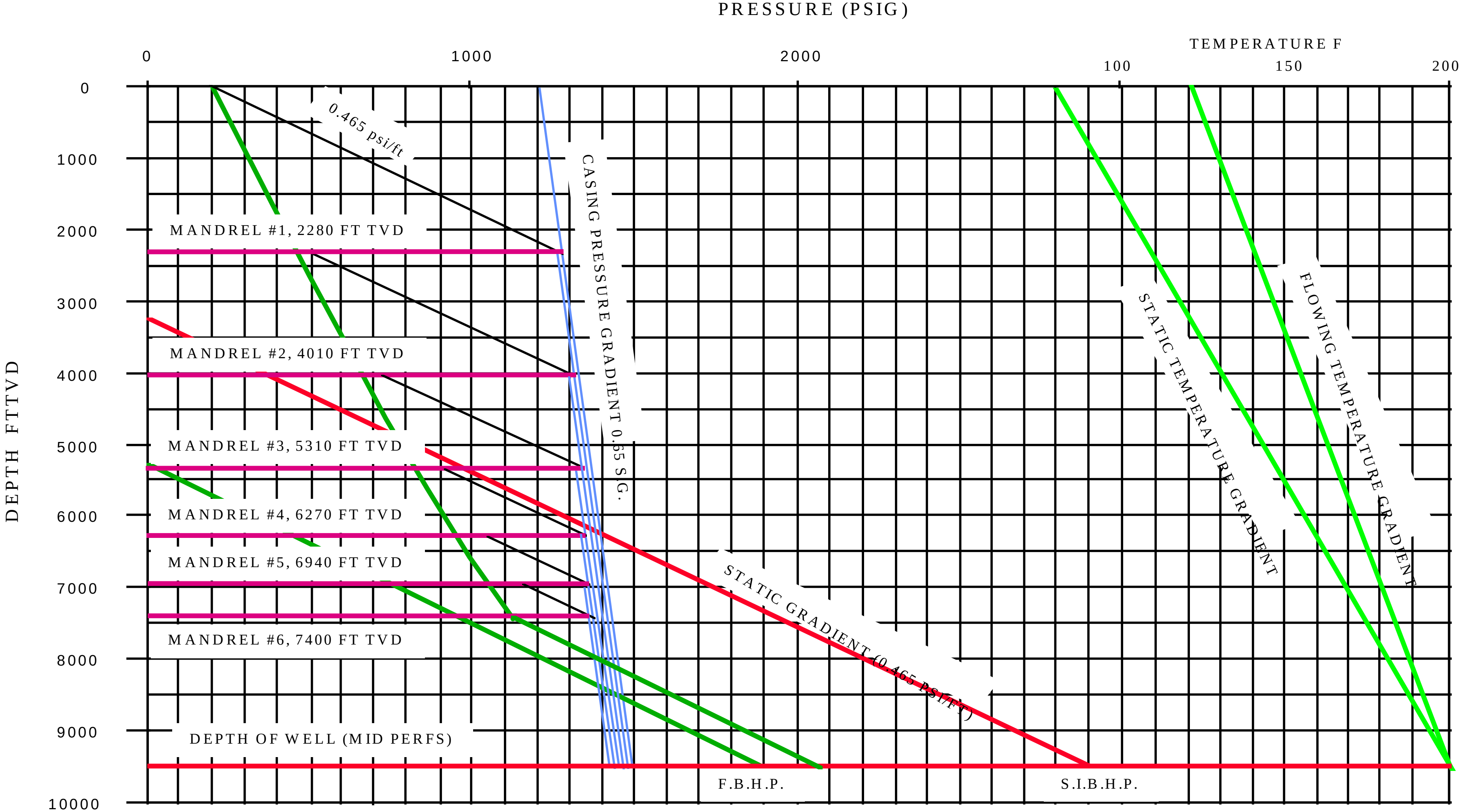


The process followed with the previous four slides is again repeated. Thus we draw in a new casing gradient with a 10 psi pressure drop. We then draw our unloading gradient of 0.465 psi/ft starting at the transfer point of 1155 psig and intersecting the new casing gradient line at 7400 ft TVD.

It can be seen from the graph that we have not achieved the deepest point of injection possible and thus if we redraw the flowng gradient below mandrel 6 our FBHP will be higher than originally anticipated. This will in turn reduce the flowrate from the well. We could have designed in further mandrels but the spacing between them would have become too close to be practical (generally a minimum spacing of about 450 ft is considered practical but in high productivity wells it maybe economic to space the mandrels closer).

Alternatively we could reduce the safety factor used for the transfer point and thus be able to space each mandrel deeper achieving the desired point of injection with the same number of mandrels. If we are confident that our information and predictions are accurate then this could be done.

CAMCO GAS LIFT TECHNOLOGY - EXAMPLE DESIGN 1



SLIDE 12

CAMCO GAS LIFT TECHNOLOGY

CASING OPERATED VALVE CALCULATION WORKSHEET

COMPANY: ANOILCO
FIELD: EXAMPLE
VELL NO: EX-1

UNLOADING VALVE TYPE: R-20 MONEL PORT
OPERATING VALVE TYPE: RDO-5
DESIGN PRODUCTION RATE: 2000 BLPD
DESIGN GAS INJECTION RATE: 2 MMSCF/D

VALVE NO	DEPTH TVD	Tv	TCF	PORT SIZE	R	1-R	Pc	D Pc	Pt	PtR	Pvc	Pd&Pvc	OP	Pvo	Pd@60F	TRO	SET TO
1	2280	108	0.9020	0.1875	0.038	0.962	1260	60	495	19	1171	1231	1260	1200	1110	1140	**1140**
2	4010	130	0.8640	0.1875	0.038	0.962	1310	110	726	28	1161	1271	1292	1182	1098	1127	**1125**
3	5310	166	0.8070	0.2500	0.066	0.934	1350	150	902	60	1151	1301	1329	1179	1050	1110	**1110**
4	6270	175	0.7950	0.3125	0.103	0.897	1380	180	1050	108	1141	1321	1352	1172	1050	1156	**1155**
5	6940	180	0.7880	0.3125	0.103	0.897	1400	200	1155	119	1131	1331	1351	1151	1049	1155	**1155**
6	7400	184		0.3750					1110				1260				
7																	
8																	
9																	
10																	

VARIABLES DESCRIPTION:

Depth TVD - True Vertical Depth ft RKB
Pt - Tubing pressure; psia @ Valve depth @ Transfer
R - Ap/Ab
Pso - Surface Operating pressure; psia
Psc - Surface Closing pressure; psia
Pc - Full Casing Pressure @ Depth; psia
D Pc - Casing Pressure @ Depth - Casing Pressure @ Surface; psia
OP - Operating Pressure @ Depth of Valve; psia
Pvc - Closing Pressure @ Depth of Valve; psia
Pd - Dome Pressure @ Depth of Valve; psia
Ptro - Test Rack Opening; psig
TCF - Temperature Correction Factor
Tv - Temperature in Degrees F @ Depth of Valve

Equations

1) $OP @ Depth = \dfrac{Pvc @ Depth - (Pt\,R)}{1 - R}$

2) $OP @ Depth = Pso + D\,Pc$

3) $Pvc @ Depth = Pd @ Depth$

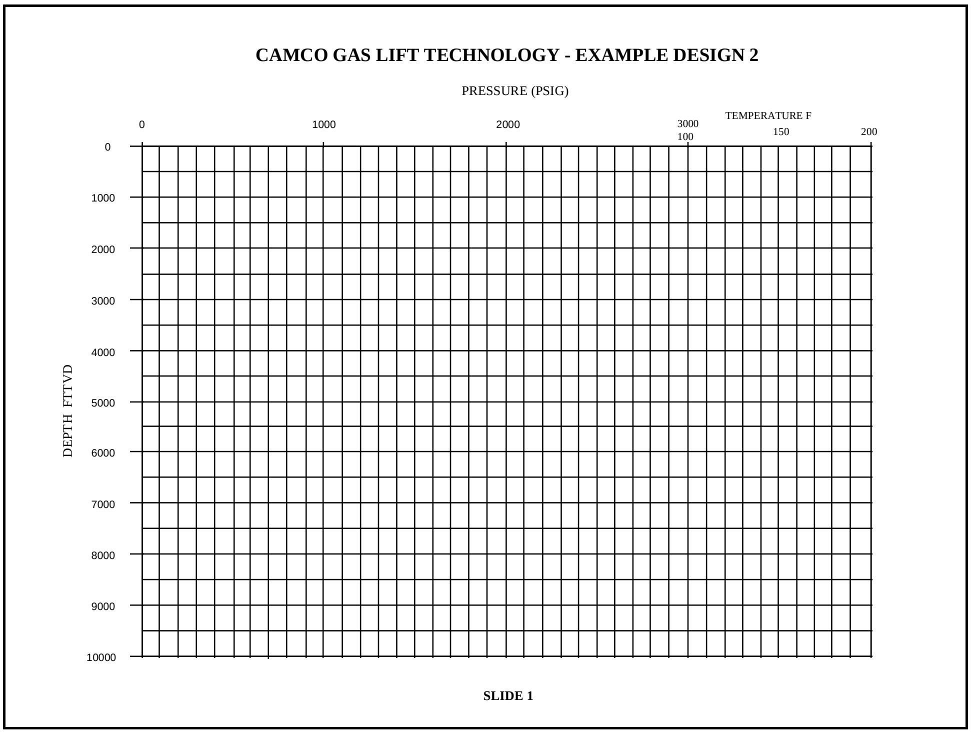
4) $Pvc @ Depth = Psc + D\,Pc$

5) $Pvc @ Depth = (OP @ Depth)(1 - R) + (Pt\,R)$

6) $Pd @ 60F = (TCF)(Pd @ Depth)$

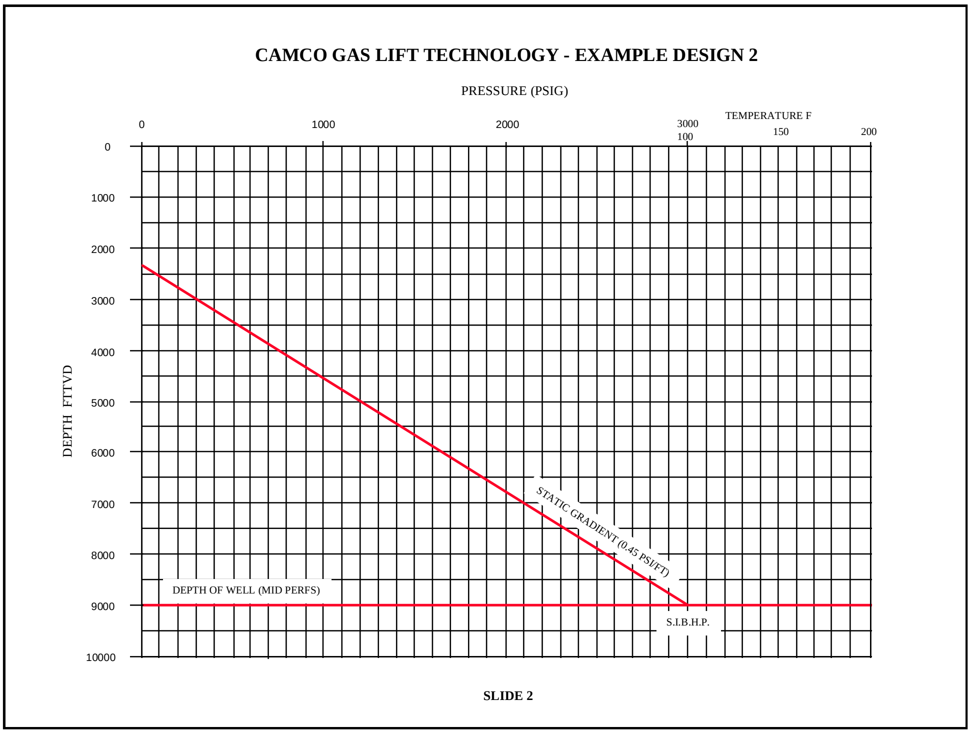
7) $TRO = \dfrac{Pd @ 60F}{1 - R}$

Calculated by : Mike Buchanan　　For : A.N. Other　　Checked :　　Date : 25/3/97



EXAMPLE 2 WELL INFORMATION

Tubing Size	4 1/2” Tubing 12.6 lb/ft
Deviation	Vertical Well
Target Design Rate	6000 blpd
Water Cut	50%
Oil Specific Gravity	0.85 (API 34.971)
Water Specific Gravity	1.06
Gas Specific Gravity	0.65
Packer Depth	8500 ft TVD
Mid Perf Depth	9000 ft TVD
Flowing Tubing Head Pressure	150 psig
Shut-in Bottom Hole Pressure	3000 psig
Productivity Index	4.5 stb/d/psi
FGOR	300:1
FGLR	150:1
Surface Gas Injection Pressure	1600 psig
Available Gas	4 mmscf/d
Bottom Hole Temperature	200 degrees F
Static Surface Temperature	60 degrees F
Flowing Surface Temperature	120 degrees F
Kill Fluid Gradient	0.45 psi/ft



1. Draw a line at the depth of the mid perforations i.e. 9000 ft TVD.

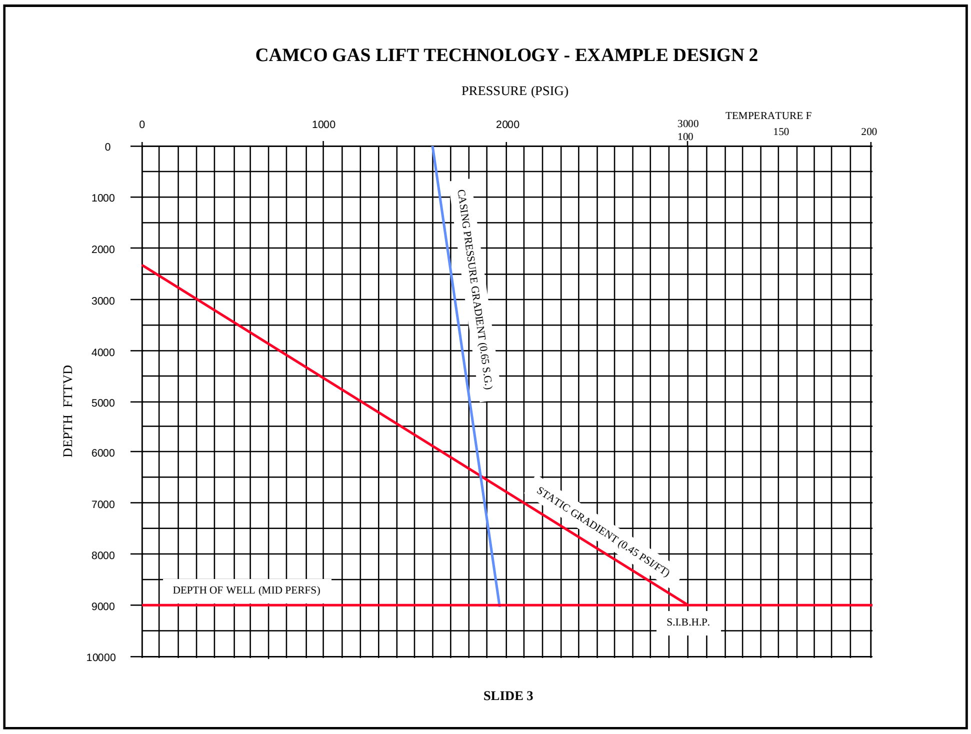
2. Draw the static gradient line starting from the shut in bottom hole pressure (SIBHP) of 3000 psig using a kill fluid gradient of 0.45 psi/ft. If the tubing pressure at surface was 0 psig then the fluid level would be at 2333 ft TVD.

Hydrostatic head = 3000 / 0.45

= 6667 ft

Fluid level depth = 9000 - 6667

= 2333 ft TVD



Draw in the gas injection (casing) pressure line.

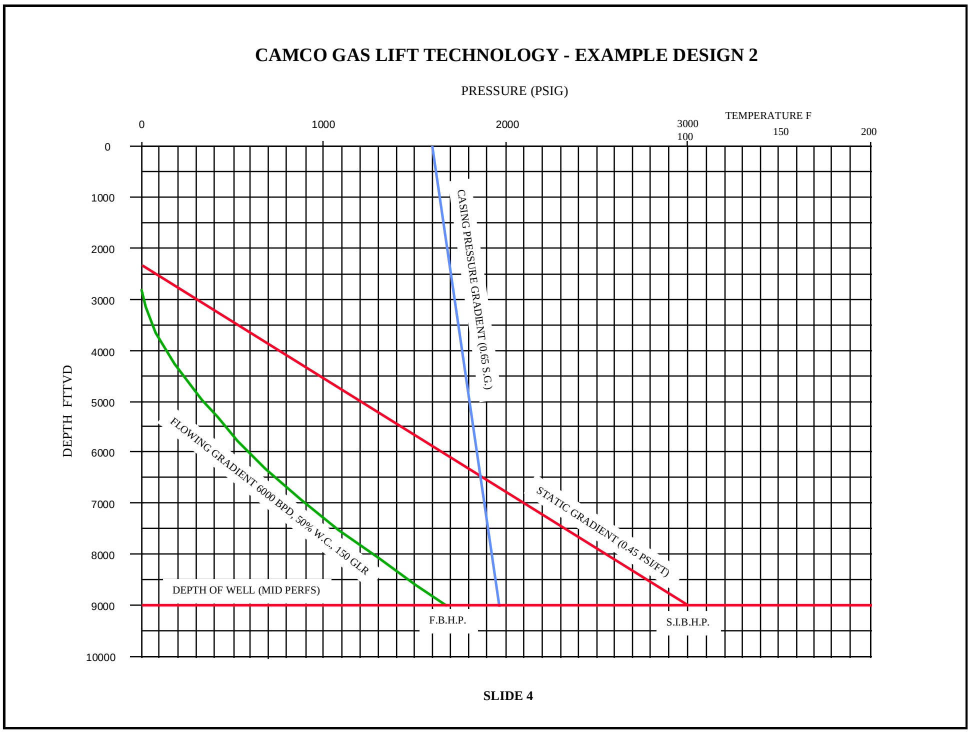
Starting at 1600 psig and using the Factor Table - Gas Column Pressures for a S.G of 0.65 calculate the casing pressure at 9000 ft of 1960 psig.

Select factor (F) from the table for 9000 ft and S.G. of 0.65 (0.225)

Pcf (at depth) = Pcf (at surface) (1 + F)

= 1600 x (1+ 0.225)

= 1960 psig



1. Calculate target flowing bottom hole pressure (FBHP).

Q liquid = (SIBHP- FBHP) x PI

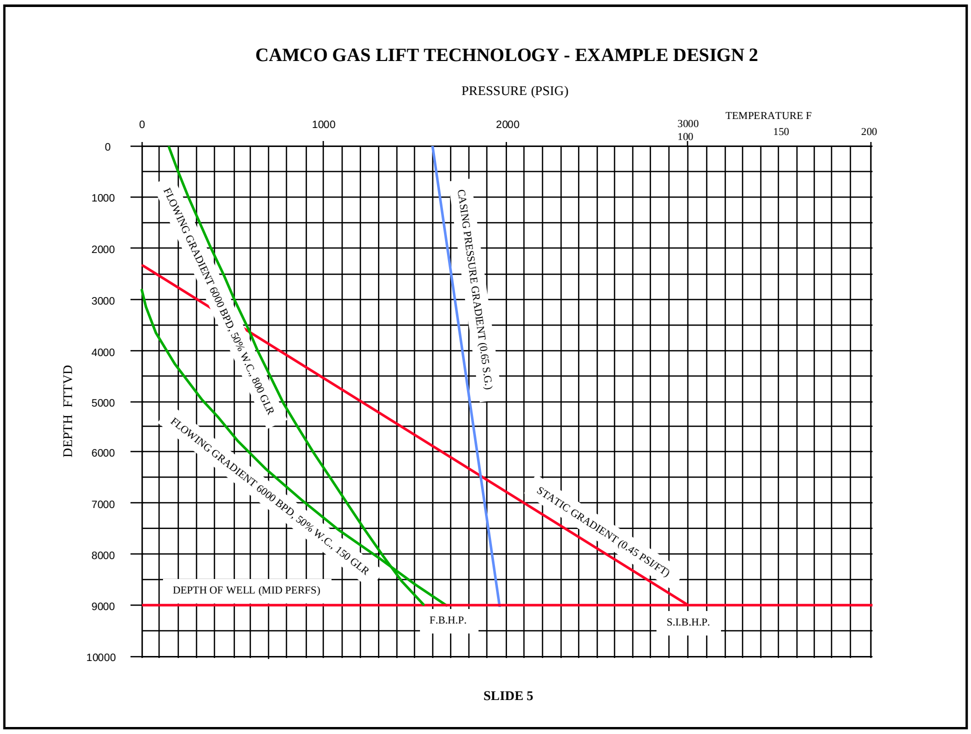
FBHP = SIBHP - (Q / PI)

= 3000 - (6000 / 4.5)

= 1667 psig

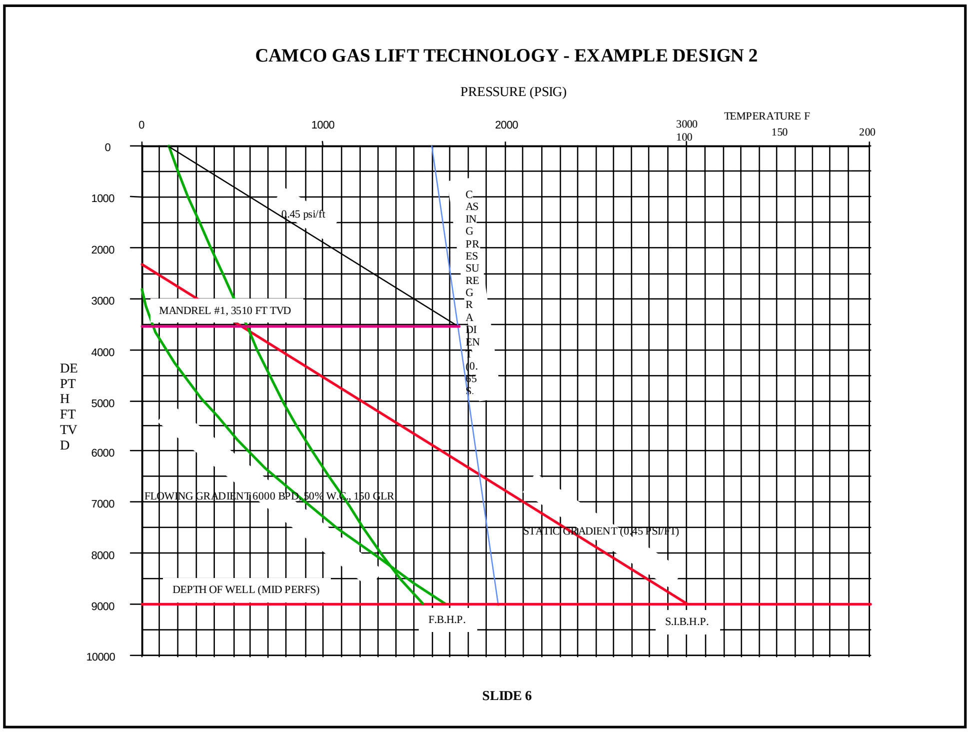
2. Select appropriate flowing gradient curve for 4 1/2" tubing, 6000 BPD, 50% water cut, 150:1 GLR and plot on graph starting at 1667 psig at mid perf and intersecting y-axis at approximately 2800 ft TVD.

In this example the flowing gradient does not intersect the casing line and thus we can inject at the bottom of the well i.e. just above the packer.



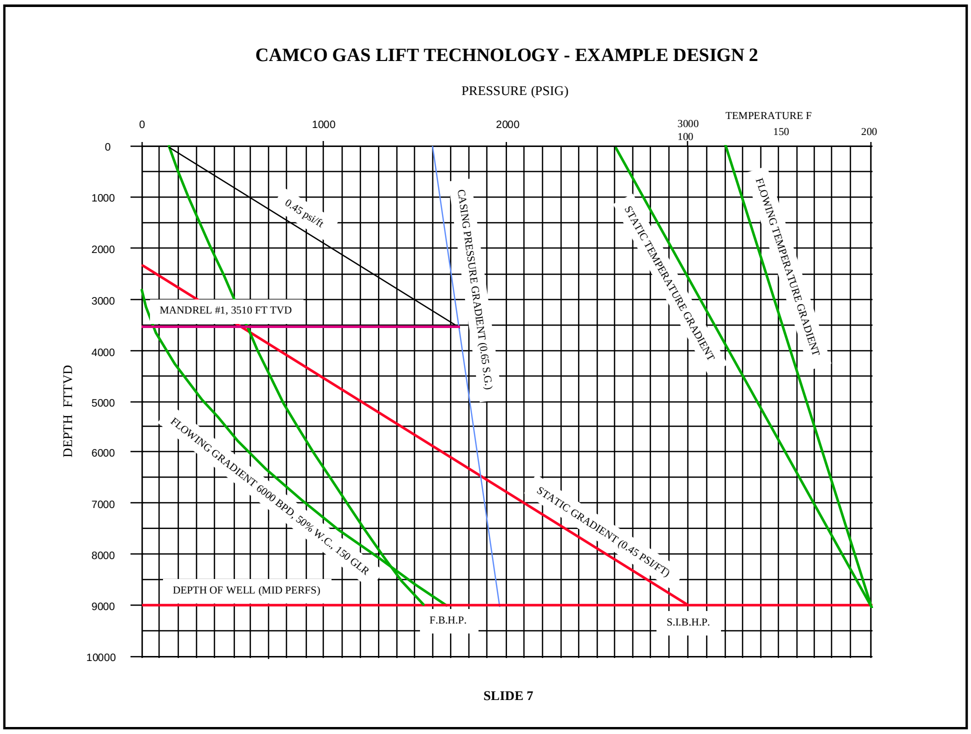
1. Select appropriate flowing gradient curve for 4 1/2” tubing, 6000 BPD, 50% water cut and a GLR that intersects the previously plotted flowing gradient at 8500 ft TVD (packer depth). This should be an 800:1 GLR

2. Plot gradient on the graph starting at the flowing tubing head pressure of 150 psig down to mid perfs. The line should cross the mid perfs at approximately 1540 psig.



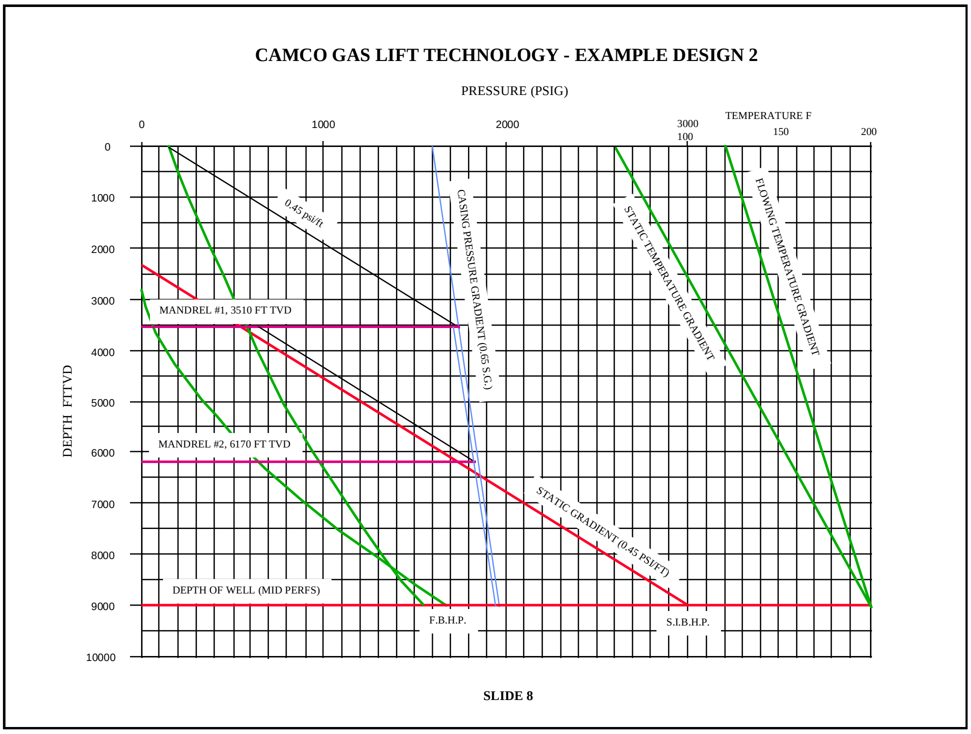
Space the top mandrel using the static gradient of 0.45 psi/ft. Draw a line with this gradient starting at 150 psig until it intersects the casing pressure at a depth of 3510 ft TVD.

This is the deepest point at which gas could be U-tubed around and is therefore where the top mandrel must be located. As the well will not be flowing at the time of kick off the tubing head pressure will be lower than the 150 psig expected when flowing and thus there will be sufficient differential in order to pass gas. If we expected no change in the wellhead pressure then we would have to move the depth of this first mandrel up in order to have a minimum of 50 psi differential across the valve.



Plot temperature gradients (assume straight line)

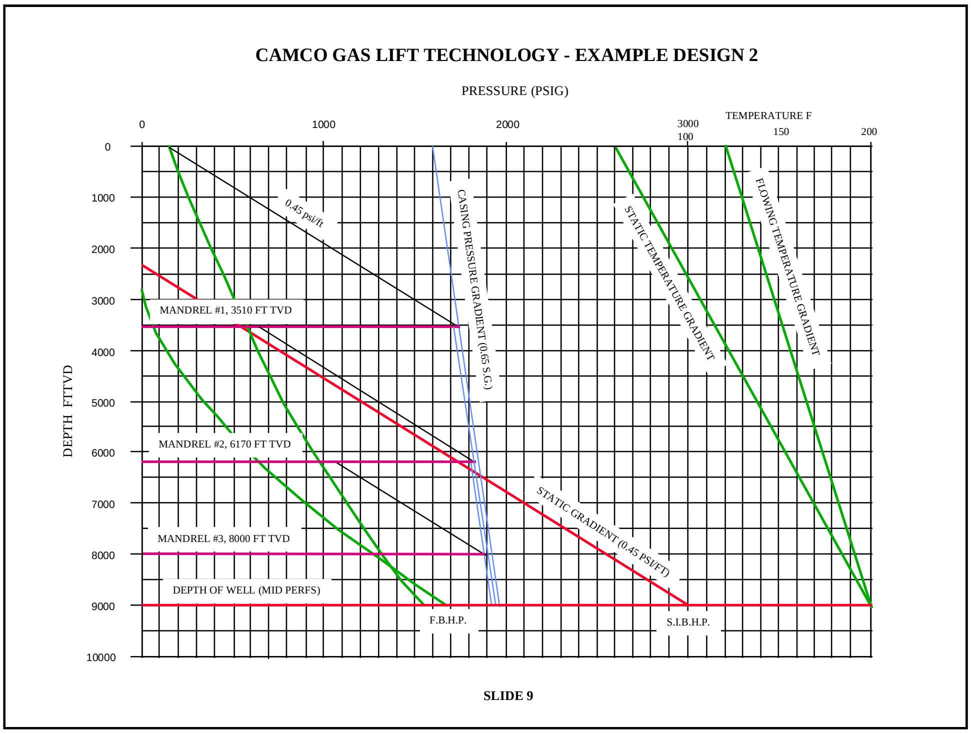
Static 60 degrees at surface to 200 degrees at mid perf
Flowing 120 degrees at surface to 200 degrees at mid perf



1. Draw in the casing pressure drop of 10 psig required to close valve number one starting at mandrel #1 using a parallel line to original casing gradient. As a rule we tend to use a minimum of 10 psig when using 1 1/2” gas lift valves but as with the previous example this could be increased further if the design allows.

2. Space mandrel #2 using the static gradient of 0.45 psi/ft starting at the transfer point of 638 psig until the line intersects the new casing gradient line at a depth of 6170 ft TVD.

The transfer point is the tubing pressure at mandrel 1 which we expect to achieve through gas injection. Thus in theory we could start on our flowing gradient curve at a pressure of 580 psig. However as the gradient curve is theoretical and may not exactly match actual flowing conditions it is prudent to incorporate some safety factor here. The amount of safety incorporated will depend on the designers personal preference and his knowledge and experience of the well or field to be designed. In this example we will use a safety factor of 10% of the predicted tubing pressure. Thus our transfer point will be 638 psig.



The process followed with the previous slide is repeated. Thus we draw in a new casing gradient with a 15 psi pressure drop. We then draw our unloading gradient of 0.45 psi/ft starting at the transfer point of 1067 psig and intersecting the new casing gradient line at 8000 ft TVD.

It can be seen from the graph that we have not achieved the deepest point of injection possible and thus if we redraw the flowing gradient below mandrel 3 our FBHP will be higher than originally anticipated. This will in turn reduce the flowrate from the well. We could have designed in a further mandrel but the spacing between 3 and 4 would be much closer than required.

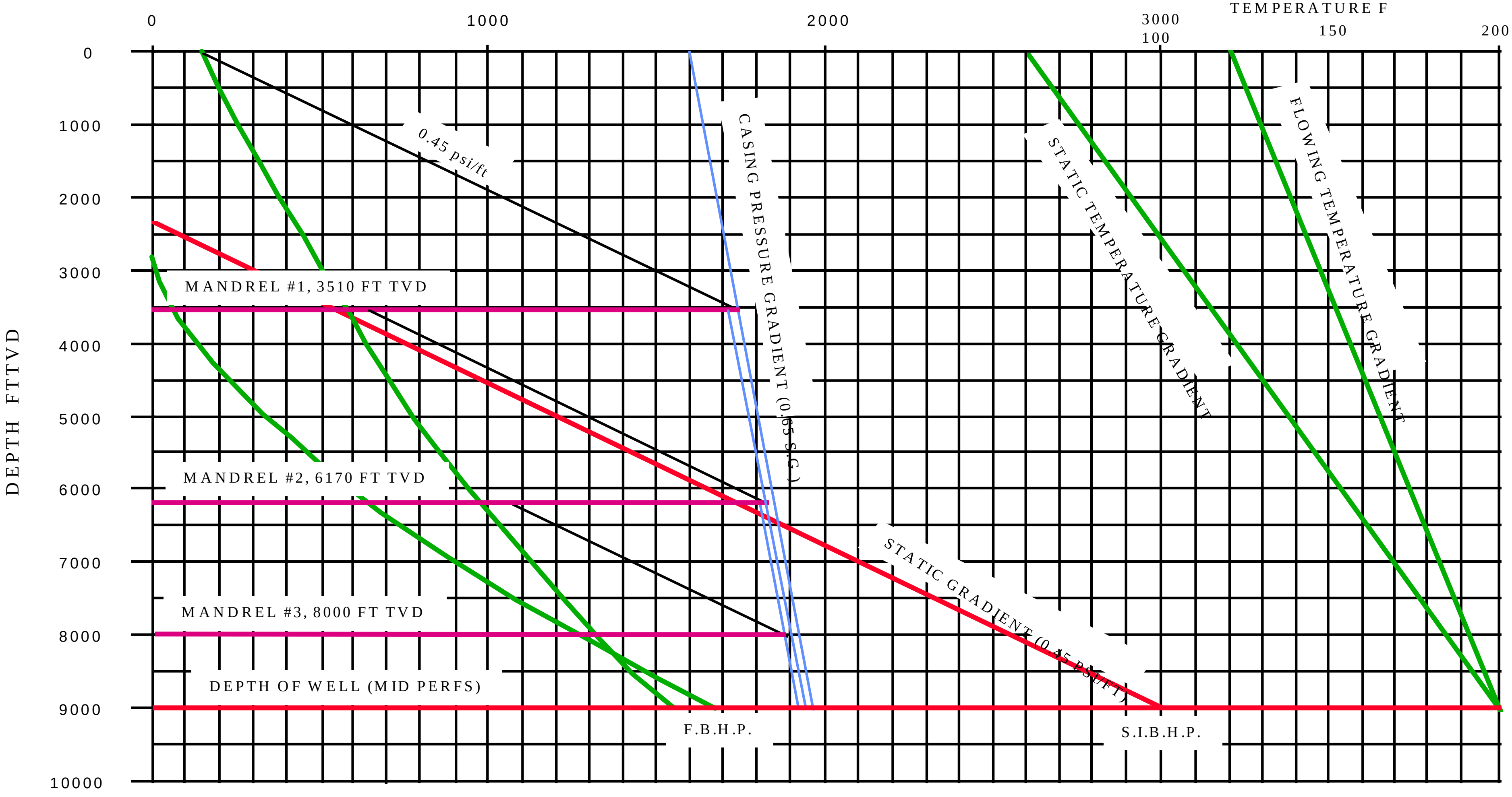
The options at this point would be to:

a) stick with the design as shown using three mandrels down to 8000 ft TVD. This will result in a loss in rate amounting to about 110 bopd.

b) reduce the safety factor used for the transfer point and thus be able to space each mandrel deeper achieving the desired point of injection with the same number of mandrels. If we are confident that our information and predictions are accurate then this could be done.

c) design with four mandrels. If this option was to be followed then it would make sense to respace the upper mandrels to give a more even distribution. This will in turn lead to amuch safer design allowing us to handle rates higher than 6000 bpd and also take a larger pressure drop at each mandrel.

CAMCO GAS LIFT TECHNOLOGY - EXAMPLE DESIGN 2



SLIDE 9

CAMCO GAS LIFT TECHNOLOGY

CASING OPERATED VALVE CALCULATION WORKSHEET

COMPANY: ANOILCO
FIELD: EXAMPLE
WELL NO: EX-2

UNLOADING VALVE TYPE: R-20
OPERATING VALVE TYPE: RDO-5
DESIGN PRODUCTION RATE: 6000 BLPD
DESIGN GAS INJECTION RATE: 3.9 MMSCF/D

VALVE NO	DEPTH TVD	Tv	TCF	PORT SIZE	R	1-R	Pc	D Pc	Pt	PtR	Psc	Pd&Pvc	OP	Pso	Pd@60F	TRO	SET TO
1	3510	114	0.886	0.1875	0.038	0.962	1730	130	638	24	1559	1689	1730	1600	1496	1541	**1540**
2	6170	165	0.800	0.2500	0.066	0.934	1850	250	1067	70	1549	1799	1850	1600	1439	1526	**1525**
3	8000	192		0.3750					1310				1700				**3/8"**
4																	
5																	
6																	
7																	
8																	
9																	
10																	

VARIABLES DESCRIPTION:

Depth TVD = True Vertical Depth ft RKB
Pt = Tubing pressure; psia @Valve depth @Transfer
R = Ap/Ab
Pso = Surface Operating pressure; psia
Psc = Surface Closing pressure; psia
Pc = Full Casing Pressure @ Depth; psia
D Pc = Casing Pressure @ Depth - Casing Pressure @ Surface; psia
OP = Operating Pressure @ Depth of Valve; psia
Pvc = Closing Pressure @ Depth of Valve; psia
Pd = Dome Pressure @ Depth of Valve: psia
Ptro = Test Rack Opening; psig
TCF = Temperature Correction Factor
Tv = Temperature in Degrees F @ Depth of Valve

Equations

1) $OP\ @\ Depth = \dfrac{Pvc\ @\ Depth - (PtR)}{1-R}$

2) OP @ Depth = Pso + D Pc

3) Pvc @ Depth = Pd @ Depth
4) Pvc @ Depth = Psc + D Pc
5) Pvc @ Depth = (OP @ Depth) (1 -R) + (Pt R)
6) Pd @ 60 F = (TCF) (Pd @ Depth)

7) $TRO = \dfrac{Pd\ @\ 60\ F}{1 - R}$

Calculated by : Mike Buchanan   For : A.N. Other   Checked :   Date : 31/3/97

PRESSURE VALVE CALCULATIONS (TRO)

Step 1 Record the depth of the valve in TVD's Column B. Record (P_{so}) Pressure Surface Operating and / or Kickoff Pressure for Top Valve in Column O.

Step 2 Record the Operating (casing) pressure at valve depth (Op) in Column N. This can either be calculated or taken from the graph. Record the Full Casing Pressure (Pc) at each valve, at its mandrel depth TVD in Column H. This can either be calculated or taken from the graph.

Step 3 Now record the Tubing Pressures required for transfer (P_t) for each valve, at its mandrel depth TVD in Column J. This is taken from the graph.

Step 4 Calculate the volume of gas required through this valve in order to reduce the tubing pressure to the transfer pressure (Pt) to complete unloading to next mandrel depth. This can either be done using the appropriate set of curves or using appropriate software. Using the Thornhill Craver square edged orifice calculation corrected for gas gravity, temperature and discharge through a gas lift valve to calculate the orifice size needed. Use (O_P @ D) operating pressure at depth for the upstream pressure and the transfer pressure in the tubing at the valve location (P_t) for the downstream pressure.

Step 5 Once the port size for Top Valve has been selected, record the size in Column E, its (R), (A_p / A_b) factor in Column F and the (1-R), (1- (A_p / A_b) factor in Column G.

Step 6 Record temperature at depth of each valve in Column C. Note that care must be taken when selecting the temperature as to whether the well will be in a static or flowing condition.

Step 7 Multiply Tubing Pressure at transfer (P_t), Column J by (R) Column F, and record as PtR in column K. Now multiply operating pressure at depth (O_P), Column N by (1-R) Column G then add PtR Column K. This answer is recorded in Column M as (P_{vc}) Pressure Valve Close, at depth, which is the same as (P_d) Pressure needed in dome to close valve at depth.

Step 8 We have now determined the pressure required at the depth and temperature of the valve, to close it after transfer has been made. In order to set that pressure at the surface in a shop environment, we must now convert that pressure to 60^{o}F from downhole flowing temperature. In order to do this we must first determine the temperature correction factor from the Correction Factor Chart and record in Column D. We then multiply the appropriate temperature correction factor, Column D, by the (P_{vc} or P_d) Column M and record the answer in P_d at 60^0F Column P.

Step 9 The pressure in Column P, P_d at 60^0 , only needs to be divided by the (1-R) Column G to achieve final Test Rack Opening Pressure in psia. As the valve will be set up to psig subtract 14.5 from this answer. This step converts the P_d at 60^0F in psia to the pressure directed on the effective area that P_d at 60^0F is acting on.

Step 10 Subtract operating casing pressure at surface (P_{so}) Column O from full casing pressure at depth (Pc) Column H to obtain the (Dpc) Column I.

Step 11 Subtract (Dpc) Column I from pressure valve closing or dome pressure (Pd & Pvc) Column M to obtain surface closing pressure Column L.

Step 12 NOTE: PROCEED TO STEP 13 IF NO KICKOFF PRESSURE USED

If a kickoff pressure was used for valve #1 then valve #2 follows exactly the same steps 1 through 11, the only difference being the lower casing pressure.

Step 13 For the next valve we can now choose our surface closing pressure instead of it being determined by the surface conditions as in valves #1 (and #2 if kick-off pressure used). In order to ensure the valve above closes after this valve is uncovered, we must make sure there is a 10-50 psi drop in surface closing pressure (P_{sc}) Column L. Use 10 psi as a minimum but remember the larger the pressure drop the safer the design. However this pressure drop should be such that injection depth is not seriously compromised. So now in order to calculate the rest of the valves, we will simply drop each surface closing pressure 10 psi per valve station. Record this pressure in Column L.

Step 14 Subtract Surface Operating Pressure, Pso, Column O, from the Full Casing Pressure at this valve Pc, Column H, and record as Dpc in Column I. Add this weight of gas to the surface closing pressure (Psc) in Column L to give Pd&Pvc, Column M.

Step 15 Calculate the volume of gas required as per step 4 and size port accordingly. Record R, Column F, and (1-R), Column G.

Step 16 Multiply the appropriate temperature correction factor Column D by the P_{vc} Column M. Record answer in Column P, P_d at 60^{o}F.

Step 17 Divide P_d at 60^{o}F, Column P by the (1-R) Column G, subtract 14.5 and record your answer in TRO, Column Q.

Step 18 Now multiply P_t Column J by R Column F and record in Column K. Subtract this number from P_d Column M, then divide that answer by (1-R) Column G. This answer is the operating pressure at depth of this valve (Op). Record this number in Column N.

Step 19 To arrive at a surface operating pressure, simply back out gas weight Dpc Column I. Record this answer in Column O, P_sO.

Step 20 Continue this procedure until all valves' TRO are calculated.

CAMCO GAS LIFT TECHNOLOGY

CASING OPERATED VALVE CALCULATION WORKSHEET

UNLOADING VALVE TYPE:
OPERATING VALVE TYPE:
DESIGN PRODUCTION RATE:
DESIGN GAS INJECTION RATE:

COMPANY:
FIELD:
WELL NO:

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
VALVE	DEPTH TVD	Tv	TCF	PORT SIZE	R	1-R	Pc	D Pc	Pt	PtR	Psc	Pd&Pvc	OP	Pso	Pd@60F	TRO	SET TO
1	GRAPH	GRAPH	CHART	SELECT	VENDOR	VENDOR	GRAPH	H-O1	GRAPH	J*F	M-I	(N*G)+K	GRAPH	GRAPH	M*D	P/G-14.5	ROUND
2	GRAPH	GRAPH	CHART	SELECT	VENDOR	VENDOR	GRAPH	H-O1	GRAPH	J*F	L1-10	L+H	(M-K)/G	N-I	M*D	P/G-14.5	TO 5 PSI
3	REPEAT AS FOR VALVE NO.2																
4																	
5	TVD RKB	Temp	Temp	INCHES	Ap/Ab	1-Ap/Ab	Full	Change	Tubing	Force	Valve	Dome	Valve	Valve	Dome	Test	Test
6		at	Corr'n				Casing	in	Pressure	Exerted	Closing	Pressure	Opening	Opening	Pressure	Rack	Rack
7		Valve	Factor				Pressure	Casing	at	by	Pressure	or	Pressure	Pressure	@ 60F	Opening	Opening
8		DEG F					PSIA	Pressure	Transfer	Tubing	at	Valve	at	at	PSIA	Pressure	Pressure
9								from	Point	Pressure	Surface	Closing	Depth	Surface		PSIG	PSIG
10								Surface	PSIA		PSIA	Pressure	PSIA	PSIA			
11								to				PSIA					
12								Valve									
13								Depth									
14								PSI									

VARIABLES DESCRIPTION:

Depth TVD = True Vertical Depth ft RKB
Pt = Tubing pressure; psia @Valve depth @Transfer
R = Ap/Ab
Pso = Surface Operating pressure; psia
Psc = Surface Closing pressure; psia
Pc = Full Casing Pressure @ Depth; psia
D Pc = Casing Pressure @ Depth - Casing Pressure @ Surface; psia
OP = Operating Pressure @ Depth of Valve; psia
Pvc = Closing Pressure @ Depth of Valve; psia
Pd = Dome Pressure @ Depth of Valve: psia
Ptro = Test Rack Opening; psig
TCF = Temperature Correction Factor
Tv = Temperature in Degrees F @ Depth of Valve

Equations

1) $\text{OP @ Depth} = \dfrac{\text{Pvc @ Depth} - (\text{PtR})}{1-R}$

2) OP @ Depth = Pso + D Pc

3) Pvc @ Depth = Pd @ Depth
4) Pvc @ Depth = Psc + D Pc
5) Pvc @ Depth = (OP @ Depth) (1 -R) + (Pt R)
6) Pd @ 60 F = (TCF) (Pd @ Depth)

7) $\text{TRO} = \dfrac{\text{Pd @ 60 F}}{1 - R}$

Calculated by : For : Checked : Date :

6. Optimization

6. Optimization

<u>CHAPTER OBJECTIVE</u>: To understand how to optimize single gas lift wells and multi well gas lift systems.

VALUE OF OPTIMIZATION

Maximizing field value is an important, but difficult and often neglected task. Optimizing production well by well is one way to improve field output, but this approach is limited by constraints from other wells and facilities. Another approach is to look at entire production systems—wells, reservoirs over time and surface networks. In this way, constraints can be identified and eliminated.

The value of production optimization may be difficult to quantify and varies from case to case. Incremental production above baseline decline curves through focused production management and continuous optimization Figure 6-1 is the objective. The area under this production curve between optimized and a baseline rate represents cumulative incremental production and ultimately additional reserve recovery, particularly when the ultimate abandonment pressure can be reduced.

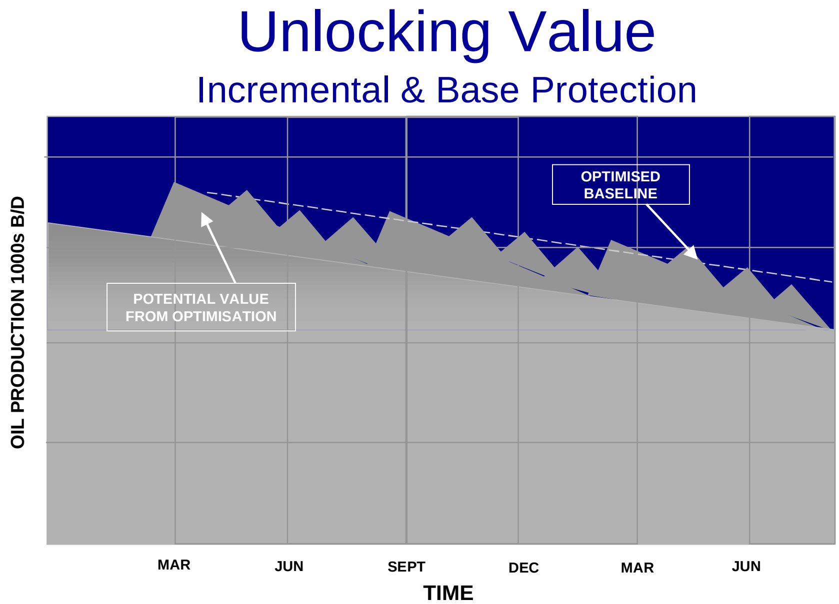


Figure 6-1

It is our experience that 3 to 25% incremental production can be achieved with production optimization. This percentage varies, depending on the degree of optimization that has already been done and quality or age of the original production system, the added value can be significant, especially in large fields. Generally, the majority of gains (up to 80%) come from the simple well-by-well efforts, and that these gains are the most economical to achieve (generally < $ 1.00 per bore). The remaining of the gains are achievable through full-field optimization and automation. However, these gains are generally more costly to achieve (generally > $ 1.00 per bore).

A modest 1% improvement in production rates can deliver millions of dollars in added revenue. Three to 25% increases equate to order of magnitude revenue increases in tens of millions of dollars per year. Moreover, value is delivered not just from increased production, but also by better gas or power utilization, reduced operating costs and lower capital expenditure. After optimizing existing wells for example, the number of required new or infill development wells can often be reduced.

PRELIMINARY PROCESS

Understanding the System

When considering optimization, often the first thought is in relation to gas lift oil fields. Today, however, the approach and tools to achieve optimization allows all forms of producing systems—natural flow, gas lift, electrical submersible pump and gas wells—to be considered. Moreover, this process lends itself to performing short studies that access commercial and technical impacts of alternative development scenarios and provides important data in field management decision-making processes.

Maximizing gas lift performance one well at time was standard in the past. But instead of a focused finite approach, ongoing production optimization and management on a system-wide basis, which includes compressors, is increasing revenues, enhancing profitability and providing long-term value more effectively. This systems approach is made possible by computing advances, and further improved by data collection, information and permanent well monitoring technologies. Whatever the level of optimization, from basic processes of data acquisition, system control, communication to actual optimization, more is achieved and can be accomplished with a systemized plan implemented and followed in a disciplined, structured approach.

Before optimization begins or strategic, economic or design choices are made, it is necessary to understand production systems as a whole. Reservoir parameters are productivity, changes in performance with time and specific problems like sand or water influx. The wellbore includes tubing and casing size as well as depth, completion configuration—packers, perforations and sand control screens—type of gas lift valve, wellbore hydraulics and fluid flow regimes. Surface facilities involve compressors, separators, manifolds, and field flow lines Figure 6-2. Another important consideration is operating environment, from geographic location to type of installation and export method.

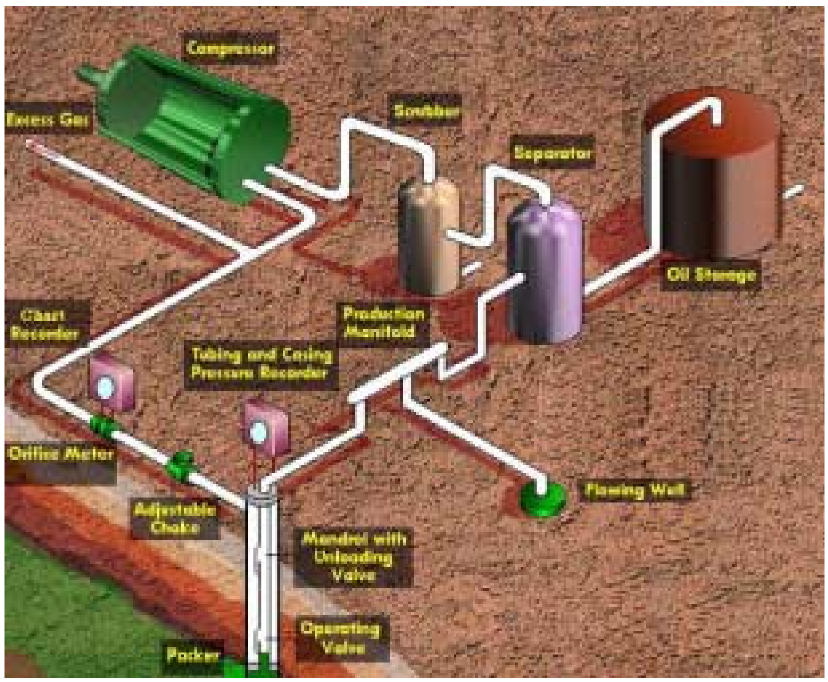


Figure 6-2

Identifying Candidates and System Inefficiencies

The next step is to identify under-performing wells. Data management tools are used to identify and target wells with steep declines. Using gas utilization factor (GUF = (GL Inj. Rate) / (Oil Rate) [MMcf/D / BOPD]) inefficient gas lift well can be identified. Some wells might be flowing unstably and stability criteria can be use to identify those wells. Some wells might be under performing due to downhole problems.

Poor production performance can also be contributed by system inefficiencies. Evaluating gathering system and facilities is necessary to identify inefficiencies. Pressure restrictions in flowlines are to be identified and eliminated. Thorough understanding about limitations of the facilities – water handling capacity, oil handling capacity, gas compression capacity, gas sales and/or dehydration capacity, lowest possible LP (low pressure) system pressure, gas sales pressure and gaslift gas pressure & volumes available— aids in determining the maximum production rate of the field at acceptable cost.

WELL-BY-WELL OPTIMIZATION

Data

Well-by-well optimization is prioritized to under-performing wells. It's important to understanding the well's flowing condition by obtaining accurate single-rate or multi-rate well tests using 2-pen recorders Figure 6-3 to measure tubing and casing pressures throughout test. Where SCADA (System Control and Data Acquisition) is available, the need to collect 2-pen charts is eliminated, as both this information and additional real-time information (manifold pressures, etc.) is available at remote locations. These tools aid in understanding well performance characteristics, as well as identifying, analyzing, and troubleshooting problems.

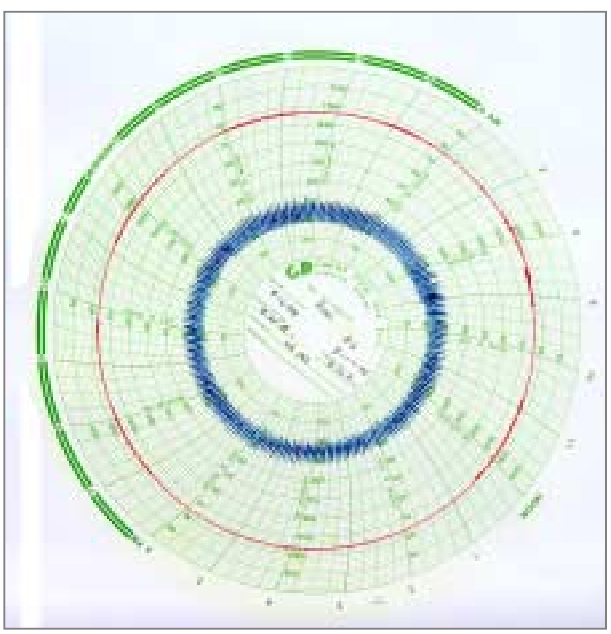


Figure 6-3

Active interaction with field personnel is essential. Other tools such as static and flowing bottom hole pressure and temperature surveys also need to be obtained. Fluid level in tubing / casing annulus can be determined using acoustic liquid level recorder (Echometer or Sonolog). Production logs are very beneficial as troubleshooting tool.

Multi-rate Testing

Multi-rate testing (see attached procedure) is probably the most accurate method as this represents actual measured data. This type of testing is invaluable in optimization of gas lifted wells. However testing such as this is time consuming and often causes operational problems. It can also be misleading as the tests may be carried out over a relatively short period which does not allow the well to stabilize at the new rate and the information gained may quickly date where well conditions such as water cuts are changing rapidly. It is essential that these tests are carried out on a regular basis and also that the normal well tests are compared with the performance curve from the model. Modeling allows the engineer to carry out this function at his desk but it should be remembered that modeling of the well can be inaccurate and will reflect the quality of the input data.

Building Computer Model

In gas lift systems, downhole equipment and surface facilities are closely related. Because well parameters and conditions like reservoir pressure are dynamic, producing operations change over time. By using sophisticated software to link wellbore, surface facilities and predicted reservoir response in a single model, integrated engineering teams can balance surface and downhole considerations.

The model is built for each well based on the well information using NODAL analysis techniques. The saying “garbage in garbage out” applies here; an accurate model is the result of accurate input data. Inflow and outflow performance curves are generated and the intersection of them represents the calculated flowing bottom hole pressure (FBHP) and the associated production rate.

Matching

It is essential to have simulation that matches reality by adjusting proper well and surface parameters in the model. Flowing gradient well surveys are often were used to select the best vertical flow correlation. The field flowline network and export pipeline pressures and rates were recorded to match and select a horizontal flow correlation. PVT data is important to allow PVT matching as the basis for multiphase modeling of the production system. After model is built, multi-rate gas injection tests need to be performed to validate the model.

Evaluating

The matched model shows the well performance in the present time Figure 6-4 and then can be used to predict the changes over time and the effect of uncertainties. Another way to evaluate the present condition of the well is by plotting the vertical lift performance curve Figure 6-5. In a gas lift well, this curve will intersect the casing pressure curve at the current point of injection. An analysis of these curves may indicate system inefficiencies or may help identify instability problems.

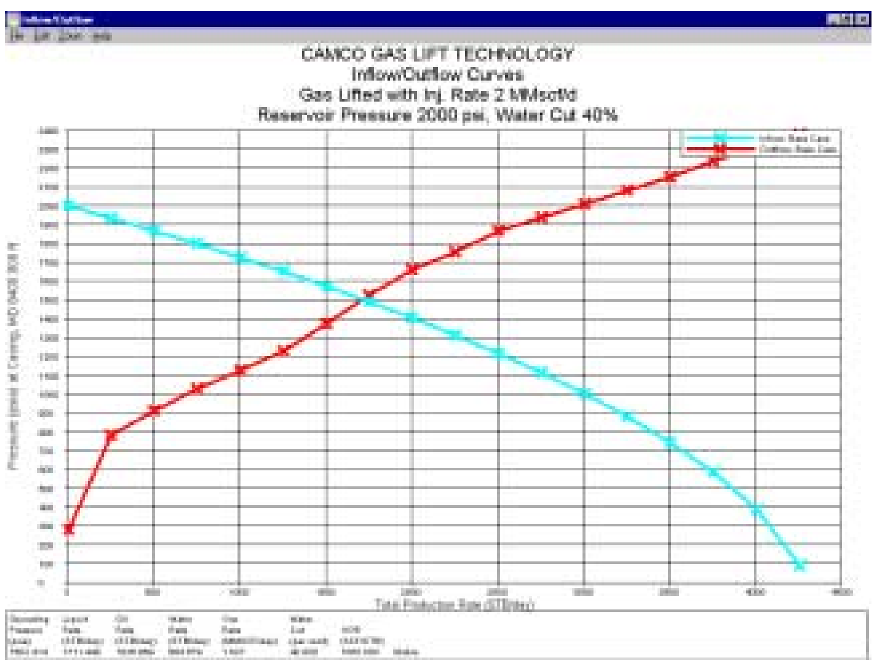


Figure 6-4

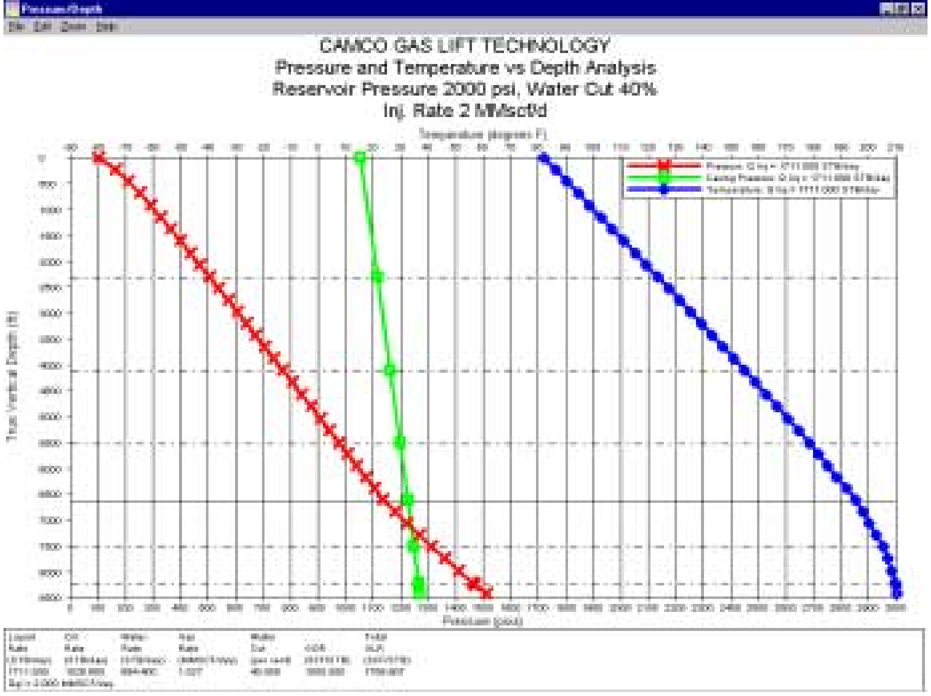


Figure 6-5

Foreseeing and Optimizing

Foreseeing the well performances in the future when the reservoir pressure decreases, the water cut increases, or GOR changes, is done by doing sensitivity analyses on those parameters Figure 6-5. Once the piping system is fixed and the flowing well head pressure (FWHP) is assumed constant, the extent of reduction in the BHFP (and therefore increase in production rate) depends mainly on two parameters: the amount of gas injected and the depth of injection.

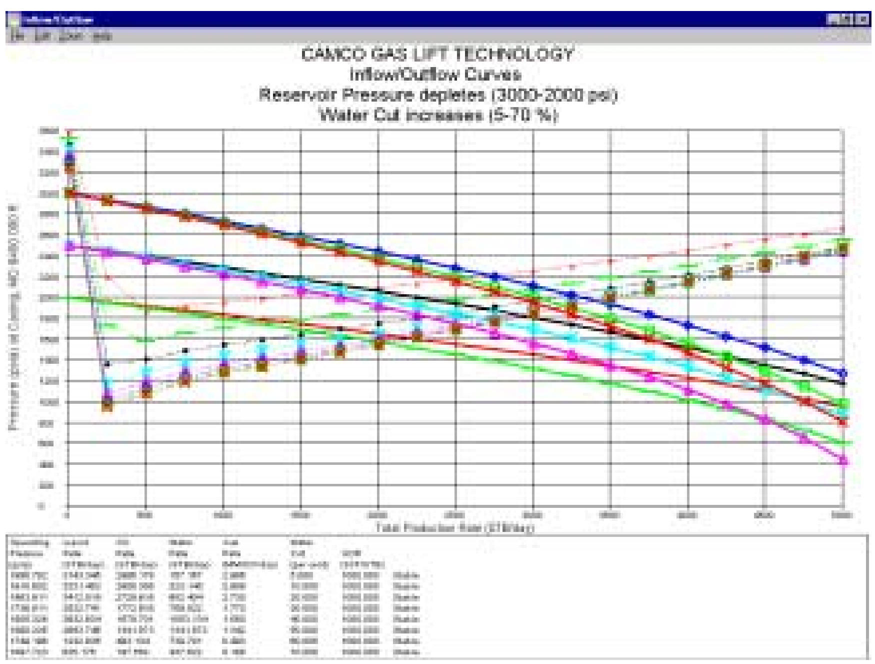


Figure 6-6

If the mandrels are already in place, sensitivity analysis to the injection rate can be done to select the most optimum gas injection rate according to the existing condition Figure 6-7. The degree to which production can be increased through increased gas injection depends on many variables but generally the higher the water cut of the well and the lower the associated gas in the fluid the more gas lift will benefit production. Thus for any gas lift optimization program the well need to be multi-rate tested.

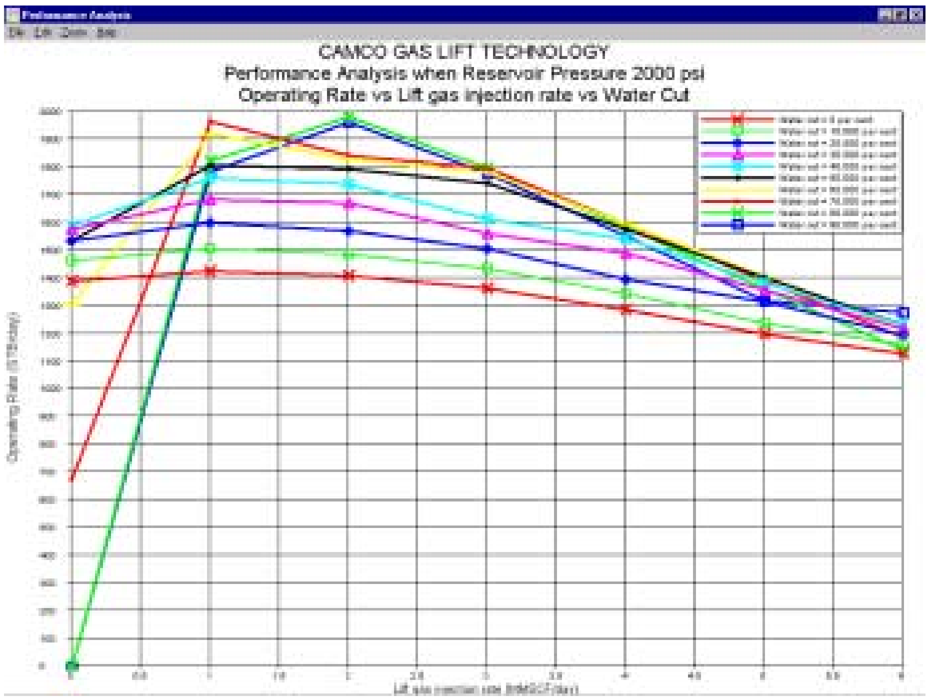


Figure 6-7

The engineer can either optimize for the maximum production rate if there are no constraints or select a gas injection rate that gives the maximum economic return. If all the associated costs are known such as gas compression then it is possible to produce the same performance curve but for gas injected against profit.

The model can also be used to foresee the effect of changing the depth of injection, whether going up (moving the point of injection up-hole) to reduce drawdown pressure for reservoir management purposes. This may also be necessary for stability purposes, i.e. achieving a stable point of injection and obtaining enough differential pressure at depth to be in critical flow (refer to discussion on stability in section 7). Or going down to increase production rate. Usually, in the later life of the well the point of injection is located deeper than in the early life of the well to maintain the drawdown pressure and the production rate. Therefore, in gas lift design it's common to put bracket of mandrels below the designed point of injection down to the deepest point of injection anticipated over the life of the well (generally just above the packer).

Foreseeing how the selected injection rate affects the well performance in the future, sensitivity analyses are performed, such as against the reservoir pressure depletion Figure 6-8. Sometimes it's necessary to design a new gas lift system for wells to be put on gas lift, or redesign the existing gas lift system in some wells. Changes in well parameters need to be accommodated in this process to ensure the possibility to unload the well and inject deeper when needed in the future. Correct sizing of the port in square edge orifice or Nova ™ valve (refer to discussion on NOVA™ gas lift valve in section 7) will ensure stable gas passage through the valve.

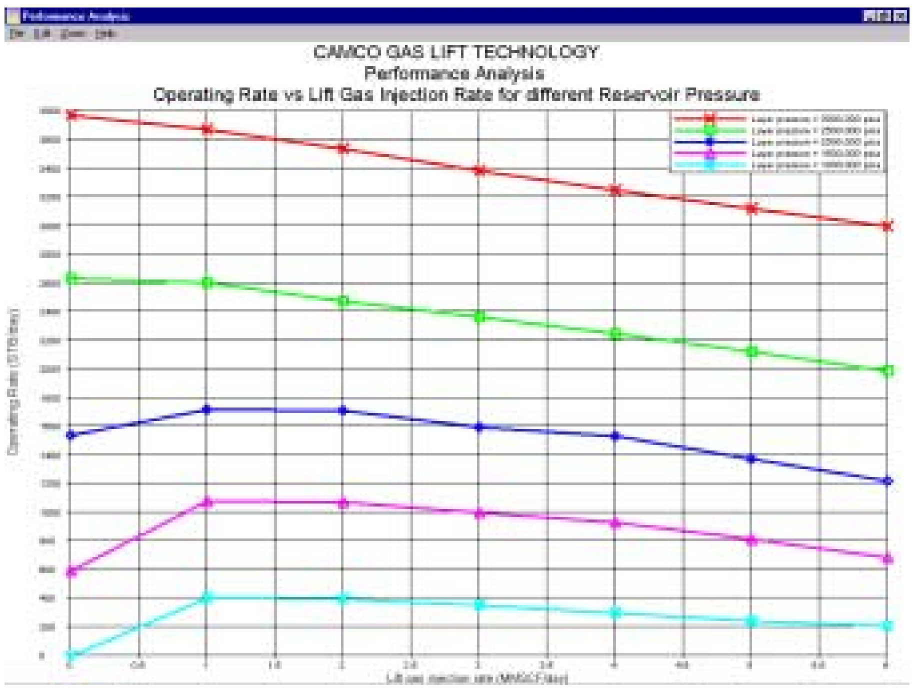


Figure 6-8

Reducing Back Pressure

If the FWHP can be lowered by reducing back pressure of the system, additional gains may be achieved. These are generally the least expensive optimization gains to achieve, because no well intervention is needed. Understanding the surface gathering system is therefore very important to determine the changes needed (such as removing restrictions, lining up to lower pressure separator, etc.) and the impact to the overall system.

Executing

The analysis process comes out with a list of works to execute, such as adjusting gas injection rate, wireline intervention to change valves, etc. Interaction with field personnel is needed to ensure all the works are done correctly.

FIELD-WIDE OPTIMIZATION

Field optimization would be fairly simple if there were no constraints in the system as the aim would be to produce at the top of the curve. But it must be remembered that it is possible to over-inject or restrict fluid production through injecting too much gas. However most fields are either constrained by the available quantity of gas for injection or by the amount of fluid and gas that can be processed through surface facilities. When this situation is encountered, optimization becomes a much more complicated procedure as the return from each well will differ for the same quantity of gas injected. The problem of field optimization has now been simplified with the availability of allocation software.

Building the Model

For field-wide optimization it is necessary to have a field-wide model. Individual well models generated before, together with data of compressors, separators, manifold, flowline network, and export pipelines are used to build networked full-system model Figure 6-9. Once the basic full-field model is built, all of the chokes, flowline dimensions, roughness and horizontal flow correlations are then modified to ensure that the pressure drops that are estimated by the simulation match those seen in reality.

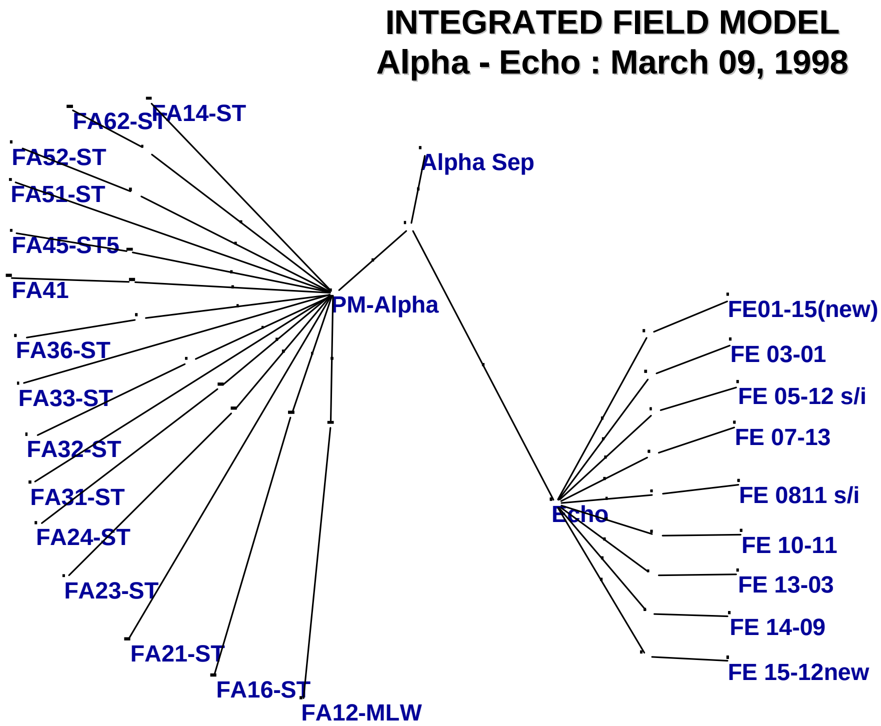


Figure 6-9

Evaluating Scenarios and Allocating Gas

Once a reliable match is found between the full-field model and measured data, the model is then used to perform a series of "what-if" scenarios by doing sensitivity analyses on different parameters to evaluate options. For example, sensitivities to compressor suction pressure can be performed to determine the benefit of reducing the back pressure in the system. Simulation can also be done to see the effect of managing choke / drawdown on flowing wells.

Scenarios must be generated with understanding of the limitations of the facilities. The gas injection rates from single well model and optimization process might not be able to be allocated to all the wells because of facilities limitations, such as water handling capacity, gas lift volume availability, etc. The full-field model can be used to find the best gas allocation to maximize oil production.

This is done by evaluating the performance curve for each well in the system. By selecting the same slope on each curve i.e. the same incremental oil gain for each additional unit of injected gas, the optimum field production can be achieved., Here, it is important to operate all of the wells at the same injection pressure. This is necessary to prevent multi-point injection / instability problems in adjacent wells.

Whilst this can be done by hand it is an extremely time consuming procedure and where gas availability, process constraints and well performance curves may be constantly changing it is almost impossible to maintain. With full-field model changes can be quickly evaluated and new gas rates set. This operation can be taken a step further and fully automated.

Sometimes it's necessary to do well stimulation or water shut-offs / conformance control to enhance well performance. Well and full-field models can be used to screen and prioritize candidates by predicting the benefit of those works to enhance production performance.

In some cases, several wells are fed with gas from compressor through a single gas line. In such instance, it is difficult to provide the right volume of lift gas to each well. Even though the well is equipped with choke, finding the right choke size is not an easy task. This problem is simplified by having the full-field model, which helps in calculating the right choke size for each of the well.

Maintaining the Model

The most important item to remember about optimization is that it is a continual process requiring maintenance of models by doing regular scrutiny of surface data and well test information. Thus the operator can be pro-active in maintaining his optimum production at all times both through gas allocation and also through the early identification of problem and under-performing wells.

The result of optimization work is evaluated by comparing the predicted results to the actual results. Performance is measured based on pre-determined criteria. Often the actual results are still far from the prediction. Appropriate adjustments are made and the process is repeated. This is a closed loop optimization process.

SUMMARY

In general, over the productive life of a field, optimization includes:

- well & field modeling and monitoring,
- data acquisition and management,

- continuous liaison contact with the onshore and offshore personnel to monitor the well performance
- reconciling model predictions with measured data
- updating recommendations regularly for gas injection rates to ensure full field optimization
- training for both onshore and offshore staff to ensure a high level of gas lift awareness amongst operations staff
- regular reporting of actual performance against targets
- equipment tracking **(**for reliable database**)**
- and equipment or system redesign if necessary

GENERAL PROCEDURES
FOR SINGLE OR MULTIRATE TESTING OF GAS LIFT WELLS

1. Before Test

- Check all surface gas injection facilities function and are calibrated correctly.
- Check there is full gas pressure from compressor.
- Ensure choke of well to be tested is fully open.

  Note: Choke must be fully open at all times and never altered during testing.
- Connect chart recorders to the tubing and gas injection string at the wellhead. Tubing and annulus pressure to be recorded for duration of test.

  The following information is required:

- Test Separator Pressure & Temperature
- Oil and Gas Flow Rates from Test Separator
- WHFP / gage on tree
- WHFT
- Gas Injection Rate
- Gas Injection Pressure to Injection Header
- Gas Injection Pressure to Well at Wellhead
- Discharge Pressure and Temperature at Gas Compressor
- Water-cuts
- Choke Setting

2. Flow Well to (Test) Separator

- Set the desired gas injection rate.
- Flow well in test separator until it is stable.
- Ideally the well should be given at least a 6-12 hours stabilizing period, depending on the mechanical configuration of the well i.e. highly deviated, horizontal well, long flowline, etc. This should be extended if there is any sign of instability.
- Record stabilizing period start and end time.

- During stabilizing period monitor flow rate and record every hour. Every half an hour if well shows signs of instability.
- Monitor and record wellhead flowing pressure (WHFP).
- Record wellhead flowing temperature (WHFT).
- Record test separator pressure and temperature.
- In later part of stabilizing period take water-cut sample and record result.

3. Commence Test

Once well is considered to be stable commence test. Test period at each gas injection rate should be at least 6 hours, preferably 12 -18 hours.

- Record test start and end time.
- Monitor gas injection rate. Record **any** change that occurs during stabilizing period.
- Do not adjust choke or gas injection rate.
- If a chart can be connected to continuously record gas injection rate then do so.
- Record liquid flow rate from test separator every hour.
- Record gas flow rate from test separator every hour.
- Record totaliser readings at the start and at each hour of test
- Throughout test monitor separator pressure and temperature and note any changes.
- During test monitor separator pressure and temperature and note any changes.
- During test take water-cut sample and confirm this is consistent with earlier value.
- End test.

Note:

- ❑ Maximum injection rate is the maximum sustained gas rate which can be injected into the well. This rate should be recorded.
- ❑ It is important that each well is tested and as good a spread of injection rates as possible achieved.

7. Troubleshooting

7. Troubleshooting

<u>CHAPTER OBJECTIVE</u>: To understand the methodologies to troubleshoot problematic gas lift wells.

INTRODUCTION

Gas lift problems are usually associated with three areas: *inlet*, *outlet*, and *downhole*. Examples of inlet problems may be the input choke sized too large or small, fluctuating line pressure, plugged choke, etc. Outlet problems could be high backpressure due to a flowline choke, a closed or partially closed wing or mater valve, or plugged flowline. Downhole problems, of course, could include a cut-out valve, restrictions in the tubing string, or sand covered perforations. Further examples of each are included in this booklet. Oftentimes, the problem can be found on the surface. If nothing is found on the surface, a check can *then* be made to determine whether the downhole problems are wellbore problems or equipment problems. *Troubleshoot your well before you call a rig!*

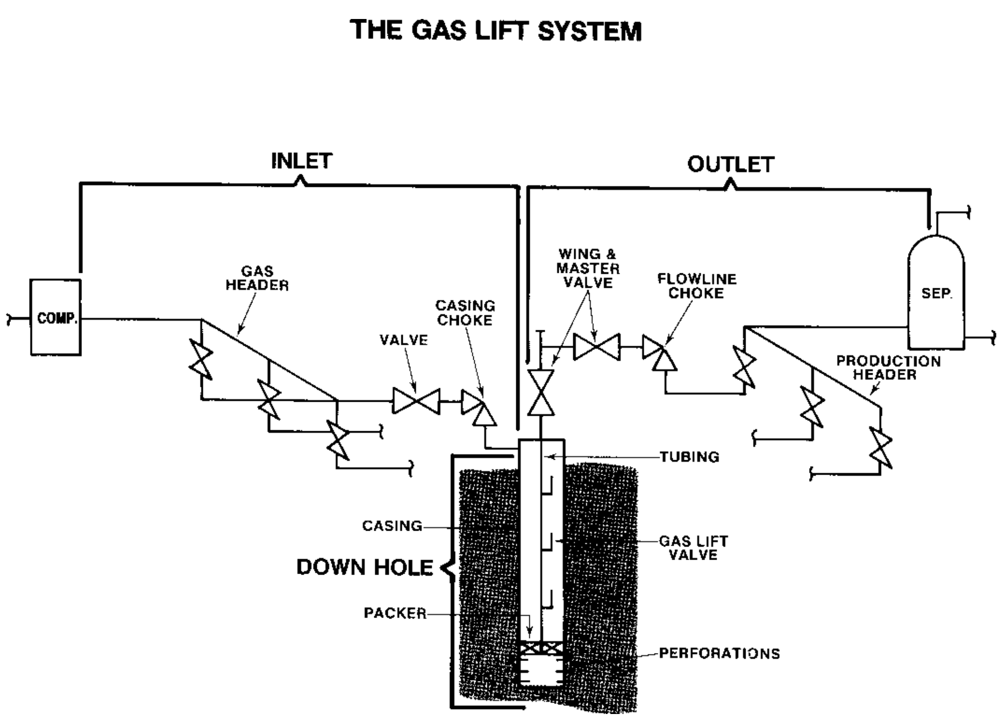


FIGURE 7-1

INLET PROBLEMS

Choke sized too large

Check for casing pressure at or above design operating pressure. This can cause reopening upper pressure valves and/or excessive gas usage. Approximate gas usages for various flow rates are included in the section on “tuning in” the well.

Choke sized too small

Check for reduced fluid production as a result of insufficient gas injection. This condition can sometimes prevent the well from fully unloading. The design gas liquid ratio can often give an indication of the choke size to use as a starting point.

Low casing pressure

This condition can occur due to the choke being sized too small or the choke being plugged or frozen up. Choke freezing can often be eliminated by continuous injection of methanol in the gas lift gas. A check of gas volume being injected will separate this case from low casing pressure due to a hole in the tubing or cutout valve. Verify the gauge readings to be sure the problem is real.

High casing pressure

This condition can occur due to the choke being sized too large. Check for excessive gas usage due to reopening upper pressure valves. If high-casing pressure is accompanied by low injection gas volumes, it is possible that the operating valve may be partially plugged or high tubing pressure may be reducing the differential between the tubing and casing. (Remove flowline choke and restriction). High casing pressure accompanying low injection gas volumes may also be caused by higher than anticipated temperatures raising the set pressures of pressure operated valves.

Verify gauges

Inaccurate gauges can cause false indications of high or low casing pressures. Always check the wellhead casing and tubing pressures with a calibrated gauge.

Low gas volume

Check to insure that the gas lift line valve is fully open and that the casing choke is not too small, frozen or plugged. Check to see if the available operating pressure is in the range required to open the valves. Be sure that the gas volume is being delivered to the well, as nearby wells may be robbing the system - especially intermittent wells. Sometimes a higher than anticipated producing rate and the resulting higher temperature will cause the valve set pressure to increase and thereby restrict the gas input.

Excessive gas volume

This condition can be caused by the casing choke sized too large or excessive casing pressure. Check to see if the casing pressure is above the design pressure causing upper pressure valves to be open. A tubing leak or cut-out valve can also cause this symptom but they will generally also cause a low casing pressure.

OUTLET PROBLEMS

Valve restrictions

Check to insure that all valves at the tree and header are fully open or that an undersized valve is not in the line (i.e. 1-inch valve in 2-inch flowline). Other restrictions may result from a smashed or crimped flowline. For example, check places where the line crosses a road.

High back pressure

Wellhead pressure is transmitted to the bottom of the hole, reducing the differential into the wellbore and thereby reducing production. Check to insure that no choke is in the flowline. Even with no choke bean in a choke body, it is usually restricted to less than full I.D. Remove the choke body if possible. Excessive 90^o turns can cause high back pressure and should be removed where feasible. High backpressure can also result from paraffin or scale buildup in the flowline. Hot oiling the line will generally remove paraffin. However, scale may or may not be able to be removed depending on the type. Where high backpressure is due to long flowlines, it may be possible to reduce the pressure by "looping" the flowline with an inactive line. The same would apply to cases where the flowline I.D. is smaller than the tubing I.D. Sometimes a partially open check valve in the flowline can cause excessive backpressure. Common flowlines can cause excessive backpressure and should be avoided if possible. Check all possibilities and remove as many restrictions from the system as possible.

Separator operating pressure

The separator pressure should be maintained as low as possible for gas lift wells. Often a well may be flowing to a high or intermediate pressure system when it dies and is placed on gas lift. Insure that the well is switched to the lowest pressure system available. Sometimes an undersized orifice plate in the meter at the separator will cause high backpressure.

DOWNHOLE PROBLEMS

Hole in tubing

Indicators of a hole in the tubing include abnormally low casing pressure and excess gas usage. A hole in the tubing can be confirmed by the following procedure: Equalize the tubing pressure and casing pressure by closing the wing valve with the gas lift gas on. After the pressures are equalized, shut off the gas input valve and rapidly bleed-off the casing pressure. If the tubing pressure bleeds as the casing pressure drops, then a hole is indicated. The tubing pressure will hold if no hole is present since both the check valves and gas lift valves will be in the closed position as the casing pressure bleeds to zero. A packer leak may also cause symptoms similar to a hole in the tubing.

Operating pressure valve by surface closing pressure method

A pressure-operated valve will pass gas until the casing pressure drops to the closing pressure of the valve. As a result, the operating valve can often be estimated by shutting off the input gas and observing the pressure at which the casing holds. This pressure is the surface closing pressure of the operating valve. Closing pressure analysis assumes the tubing pressure to be zero, and single point injection. These assumptions *limit* the accuracy of this method since the tubing pressure at each valve is never zero, and multipoint injection may be occurring. This method can be useful when used *in combination* with other data to bracket the operating valve.

Well blowing dry gas

For pressure valves, check to insure that the casing pressure is not in excess of the design operating pressure, thereby causing operating from the upper valves. Insure that no hole exists in the tubing by the previously mentioned method. If the upper valves are not being held open by excess casing pressure and no hole exists, then operation is probably from the bottom valve. Additional verification can be obtained by checking the surface closing pressure as indicated above. In the case where the well is equipped with fluid valves and a pressure valve on the bottom, blowing dry gas is a positive indication of operation from the bottom valve *after* the possibility of a hole in the tubing has been eliminated. Operation from the bottom valve generally indicates a lack of feed-in. Often it is advisable to tag bottom with wireline tools to see if the perforations have been covered by sand. When the well is equipped with a standing valve, check to insure the standing valve is not stuck in the closed position.

Well will not take any input gas

Eliminate the possibility of a frozen input choke or a closed input gas valve by measuring the pressures upstream and downstream of the choke. Also check for closed valves on the outlet side. If fluid valves were run without a pressure valve on bottom, this condition is probably an indication that all the fluid has been lifted from the tubing and not enough remains to open the valves. Check for feed-in problems. If pressure valves were run, check to see if the well started producing above the design fluid rate as the higher rate may have caused the temperature to increase sufficiently to lockout the valves. If temperature is the problem, the well will probably produce periodically then stop. If this is not the problem, check to make sure that the valve set pressures are not too high for the available casing pressure.

Well flowing in heads

This condition can occur due to several causes. With pressure valves, one cause is port sizes too large as would be the case if a well initially designed for intermittent lift were placed on constant flow due to higher than anticipated fluid volumes. In this case large tubing effects are involved and the well will lift until the fluid gradient is reduced below a value that will keep the valve open. This case can also occur due to temperature interference. For example, if the well started producing at a higher than anticipated fluid rate, the temperature could increase causing the valve set pressures to increase and thereby lock them out. When the temperature cools sufficiently the valves will open again, thus creating a condition where the well would flow by heads. With pressure valves having a high tubing effect on fluid operated valves, heading can occur as a result of limited feed-in. The valves will not open until the proper fluid load has been obtained, thus creating a condition where the well will intermit itself whenever adequate feed-in is achieved. Since over or under injection can often cause a well to head, try “tuning” the well in.

Installation stymied and will not unload

This condition generally occurs when the fluid column is heavier than the available lift pressure. Applying injection gas pressure to the top of the fluid column (usually with a jumper line) will often drive some of the fluid column back into the formation thereby reducing the height of the fluid column being lifted and allowing unloading with the available lift pressure. The check valves prevent this fluid from being displaced back into the casing. For fluid operated valves, “rocking” the well in this fashion will often open an upper valve and permit the unloading operation to continue. Sometimes a well can be “swabbed” to allow unloading to a deeper valve. Insure that the wellhead backpressure is not excessive, or that the fluid used to kill the well for workover was not excessively heavy for the design.

Valve hung open

This case can be identified when the casing pressure will bleed below the surface closing pressure of any valve in the hole but tests to determine if a hole exists show that no hole is present. Try shutting the wing valve and allowing the casing pressure to build up as high as possible, then open the wing valve rapidly. This action will create high differential pressures across the valve seat, removing any trash that may be holding it open. Repeat the process several times if required. In some cases valves can be held open by salt deposition, and pumping several barrels of fresh water into the casing will solve the problem. If the above actions do not help, a cut out or flat valve may be the cause.

Valve spacing too wide

Try "rocking" the well as indicated when the well will not unload; this will sometimes allow working down to lower valves. If a high-pressure gas well is nearby, using the pressure from this well may allow unloading. If the problem is severe, respacing, installing a packoff gas lift valve, or shooting an orifice into the tubing to achieve a new point of operation may be the only solution.

<u>Note:</u>

*** Operating pressure valve by surface closing pressure method**

A pressure-operated valve will pass gas until the casing pressure drops to the closing pressure of the valve. As a result, the operating valve pressure can often be estimated by shutting off the input gas and observing the pressure at which the casing holds. This pressure is the surface closing pressure of the operating valve. Closing pressure analysis assumes the tubing pressure to be zero, and single point injection. These assumptions *limit* the accuracy of this method since the tubing pressure at each valve is never zero, and multipoint injection may be occurring. This method can be useful when used *in combination* with other data to bracket the operating valve.

**** "Rocking"** a well is done in the following manner:

With the wing valve closed, inject lift gas into tubing (on casing side) until the casing and tubing pressures indicate that the gas lift valve has opened. When a valve opens, the casing pressure will begin to decrease and to equalize with the tubing pressure. The tubing pressure also should begin to increase at a faster rate with injection gas entering the tubing through the valve and surface connection.

Stop the gas injection into the tubing and open the wing valve to lift the liquid slug above the valve into the flowline as rapidly as possible. A flowline choke may be required to prevent venting injection gas through the separator relief valve. Some surface facilities are overloaded easily and bleeding the tubing pressure must be controlled carefully. The rocking process may be required several times until a lower gas lift valve has been uncovered.

GAS LIFT TROUBLESHOOTING TECHNIQUES

A. Flowing Pressure and Temperature Surveys

B. Casing Pressure Analysis, Calculations and Computer Modeling

C. Historical Production and Multi-rate Test Interpretation

D. Acoustic (Echometer) Surveys

E. Tagging Fluid Level

F. Two Pen Recorder Charts

A. Flowing Pressure and Temperature Surveys

A flowing pressure survey provides the most complete and accurate representation of downhole conditions of any methods used for gas lift analysis. A flowing survey describes what is occurring in a system so that predictions can be made as to well performance when the conditions are altered.

From a graphical plot of a flowing pressure survey the following determinations can usually be made:

1. The point of operation.
2. The flowing bottomhole pressure.
3. The P.I. of the well when test data and static bottomhole pressure data is made available along with the following pressure data.
4. The confirmation and location of tubing leaks.
5. The most suitable multiphase flow correlation for the well surveyed and also other wells in the same field.
6. The character of the flow regime.
7. Multi-point injection.

Flowing Survey Guidelines:

1. Do not shut the well in during and at least 24 hours prior to running the survey. It is important that the flowing conditions be as normal as possible.

2.Test the well during the survey. To calculate the P.I. or I.P.R., the production rate is required for the drawdown measured during the survey.

3.If a tubing leak is suspected, at least one stop should be made between each gas lift valve and additional stops made in the area of the suspected leak.

4.The use of small diameter pressure instruments will minimize the restriction to flow and reduce the forces acting to “blow the tools up the hole”.

5. If the well is being entered under flowing conditions, it is important to keep the tools from being “blown up the hole”. In addition to using small diameter bombs, weighted stem and “no-flow latches” should be used. Upward movement of the tool string activates a set of slips in the no-flow latch to prevent being “blown up the hole”.

6. Running tandem pressure instruments can save valuable time, effort and money by providing a backup for the event of a miss-run with the No. 1 instrument.

7. Running a flowing temperature survey in conjunction with flowing pressure surveys can often provide very useful information. Temperature surveys can identify problems caused by miscalculations of test rack opening pressure due to erroneous temperature data and leaking gas lift valves or tubing can sometimes be located or confirmed with temperature surveys. When running a temperature survey, it is a good practice to make a stop below the mud line in addition to the stop in the lubricator for offshore wells and several hundred feed below the surface for wells in arctic or near arctic areas so that a more accurate flowing geothermal gradient can be determined.

If it is not possible to run a temperature instrument, at the very least, a temperature measurement with a maximum recording thermometer should be obtained.

8.For mechanical pressure instruments it is recommended that the maximum anticipated pressure in the well not exceed 75 percent of the maximum pressure of the instrument.

9.In general, it is better to use the fastest clock possible to drive the chart and still provide the time required to run the survey.

Plotting Survey Results:

The results of flowing pressure surveys are plotted on graph paper, along with other wellhead pressure data, to produce gradient curves. The plotted gradients allow visual interpretation of all the data.

Procedures for Running Flowing Pressure Surveys:

Continuous flow gas lift wells:

1. Flow the well to a test separator for 24 hours to obtain a stabilized producing rate. (Test facilities should duplicate as nearly as possible normal production facilities).

2. Place well on test before running the bottomhole pressure. The test should be long enough to provide a representative daily rate. The duration of the test depends largely on the stability of the flow rate.

3. Record the pressure in the lubricator for ten minutes. Obtain a pressure reading of the lubricator pressure with a dead weight tester for comparison. Run the pressure bomb down the tubing, making stops approximately 50 feet below each gas lift valve. (Do not shut the well in while rigging up or running the survey).

4. The pressure instrument should remain at bottom stop for an interval double that of the other stops.

5. The casing pressure should be recorded with a dead weight tester or a calibrated two-pen recorder.

6.If a static BHP is to be recorded, shut off lift gas and close the flow line wing valve. Leave the pressure instrument on bottom for time interval necessary for build-up. This could necessitate running two bombs in tandem with clocks having different speeds.

B. Casing Pressure Analysis, Calculations and Computer Modeling

One method of checking gas lift performance is by calculating the operating valve. This can be accomplished by calculating surface closing pressures or by comparing the valve opening pressures with the opening forces that exist at each valve downhole due to the operating tubing and casing pressures, temperatures, etc. Although this method may not be as accurate as a flowing pressure survey due to inaccuracies in the data used, it can still be a valuable tool in high grading the well selection for more expensive types of diagnostic methods.

C. Historical Well Production and Multi-rate Test Interpretation

A well test report for troubleshooting as referred to in this text will provide the following data:

1. Gross fluid production.
2. Water cut.
3. Oil production.
4. Tubing head pressure.
5. Casing head pressure.
6. Produced gas. (total)
7. Lift gas.
8. Gas liquid ratio.
9. Lift gas choke bean size.
10. Flowline choke bean size. (if applicable)

The well test should be of sufficient duration to provide a representative average daily producing rate. If a well is very unstable, it may require a test period of more than 24 hours to obtain a representative average 24-hour rate. Flowing pressure/temperature surveys or casing/tubing pressure recordings should be made during the well test period.

The well test conditions should duplicate as nearly as possible the normal producing conditions.

D. Acoustic (Echometer) Well Sounding Devices

The fluid level in the annulus of a gas lift well will sometimes give an indication of the depth of lift. This method involves firing a cartridge at the surface and utilizes the principle of sound waves to determine the depth of the fluid level in the annulus. Acoustic devices are fairly inexpensive when compared to flowing pressure surveys. It should be noted that for wells with packers, it is possible for the well to have lifted down to a deeper valve while unloading, then returned to operation at a valve up the hole. The resulting fluid level in the annulus will be below the actual point of operation.

E. Tagging Fluid Level

Tagging the fluid level in a well with wireline tools can sometimes give an *estimation* of the operating valve *subject to several limitations*. Fluid feed-in will often raise the fluid level before the wireline tools can get down the hole. In addition, fluid fallback will always occur after the gas lift gas has been shut off. Both of these factors will cause the observed fluid level to be above the operating valve. Care should be taken to insure that the input gas valve was closed prior to closing the wing valve or the gas pressure will drive the fluid back down the hole and below the point of operation. This is certainly a questionable method.

F. Two Pen Recorder Charts

In order to calculate the operating valve, it is necessary to have accurate tubing and casing pressure data. Two pen recorder charts give a continuous recording of these pressures, and can be quite useful if accompanied by an accurate well test. The two pen recorder charts can be used to optimize surface controls, locate surface problems, as well as identify downhole problems.

WHERE TO INSTALL A 2-PEN RECORDER

Connect casing pen line

1. At well; not at compressor or gas distribution header.

2. Down stream of input choke so that the true surface casing pressure is recorded.

Connect tubing pen line

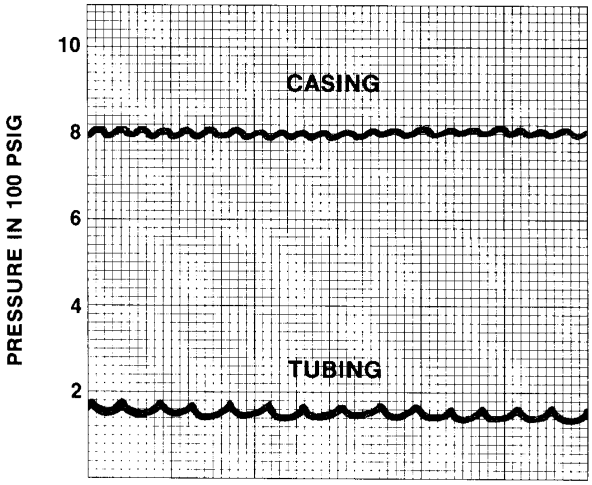
1. At the well; not at the battery, separator, or production header.

2. Upstream of choke body or other restrictions. (Even with no choke bean, less than full opening is found in most chokes).

INTERPRETATION OF 2-PEN RECORDER CHARTS ON GAS LIFT WELLS

The two most significant forces acting on any gas lift valve are the tubing pressure and the casing pressure. The downhole values can be calculated and compared to the operating characteristics of the type gas lift valves in service. From this information it is possible to estimate the point of operation. Observing the surface pressures can also give valuable information on the efficiency of the system. Charts illustrating the type of information to be gained by the use of 2-pen recorders are included.

CONTINUOUS FLOW

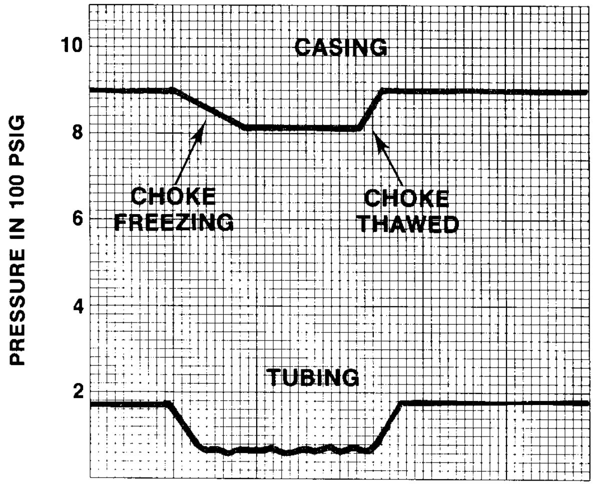


Trouble:

Fluctuating gas lift line pressure. This can be caused by intermittent wells in the same system as the continuous flow wells.

Cure:

This problem can be resolved by putting the continuous flow wells in a separate gas supply system apart from the intermittent wells, increasing the system gas pressure, or lowering the set pressures of the gas lift valves in the continuous flow well, or increasing the storage capacity of the supply system to "dampen" out pressure fluctuations.

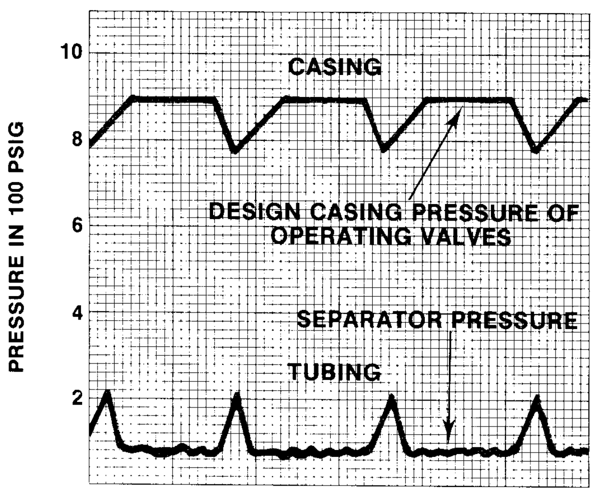


Trouble:

Injection gas choke freezing.

Cure:

Sometimes installing a slightly larger input choke will reduce freezing. Dehydrating the lift gas, injecting methanol upstream of the choke, or the use of heat exchangers may prove necessary in severe cases.

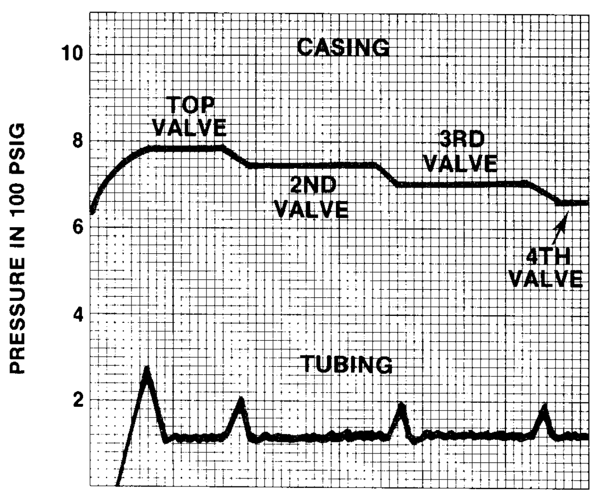


Trouble:

Valve opening periodically on tubing pressure effect.

Cure:

Correct wellbore problems which are restricting feed in, or redesign gas lift string for lower producing rate.



Trouble:

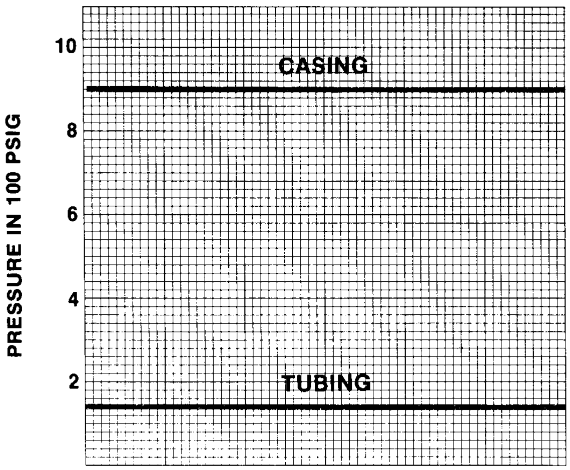
None — Well unloading.

Cure:

Allow well to unload and get stabilized well test. Make adjustments based on test.

FIGURE 7-2

CONTINUOUS FLOW

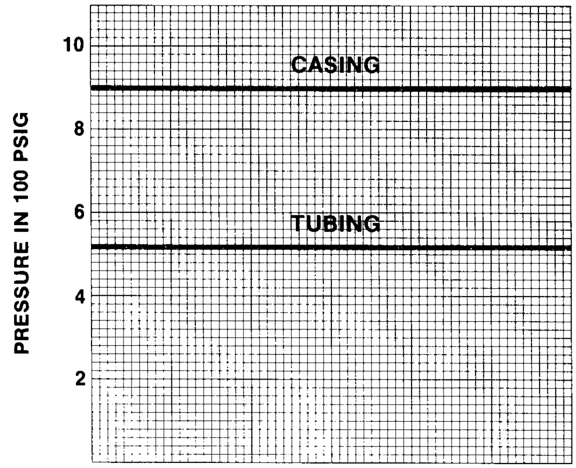


Trouble:

None. Note the uniform tubing and casing pressures, and the relatively low back pressure. Horizontal flow curves are available which will indicate if back pressure is above normal.

Cure:

Leave well alone as long as production and gas liquid ratios are optimum.

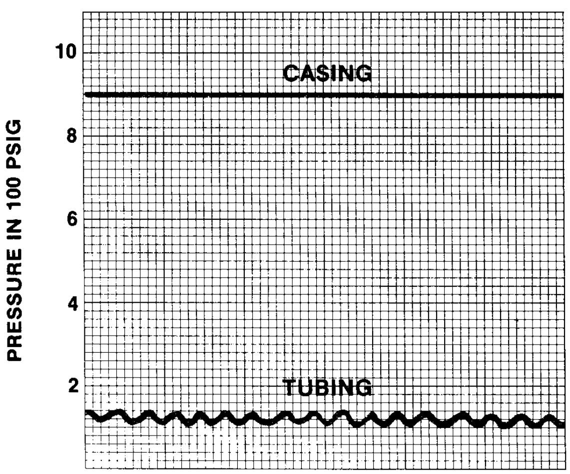


Trouble:

Excessive back pressure.

Cure:

Remove choke from flowline, excessive 90° turns, paraffin, scale or other restrictions to flow. "Looping" or replacing existing line with a larger line may be indicated in severe cases.

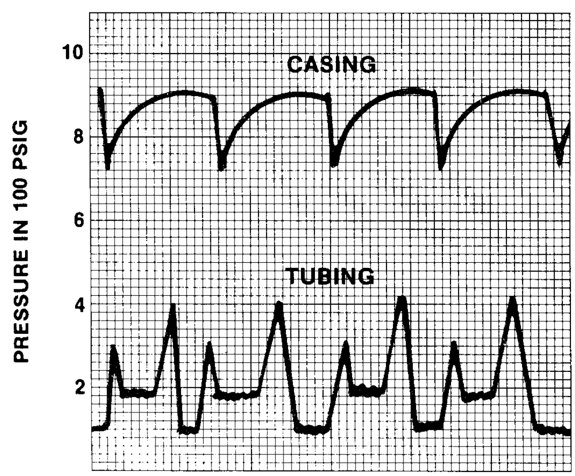


Trouble:

Valve throttling.

Cure:

The wavy tubing pressure line indicates valve throttling. This condition is caused by the casing pressure being too near the valve closing pressure. A slightly larger gas input choke would eliminate the problem. If a larger input choke causes excessive gas usage, it is probably an indication of over sized ports in the gas lift valve.



Trouble:

Holes and/or parted tubing. Well produces continuously until hole or parted tubing is uncovered, causing the casing pressure to be dropped rapidly. Production is stopped until the casing pressure builds up.

Cure:

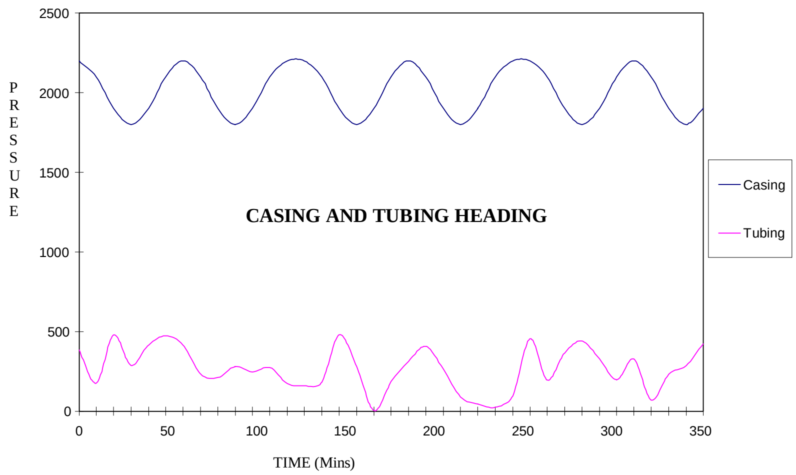
Pull well and replace faulty tubing. It may be possible to locate the hole and isolate it by installing a pack off.

2

FIGURE 7-3

WELL INSTABILITY

There are several different conditions that might lead to well instability. They could be related to reservoir/inflow, wellbore/outflow, or surface facility & compression conditions. Therefore, having instability problem in the field, the operator must evaluate carefully before coming to conclusion that gas lift instability is the cause.



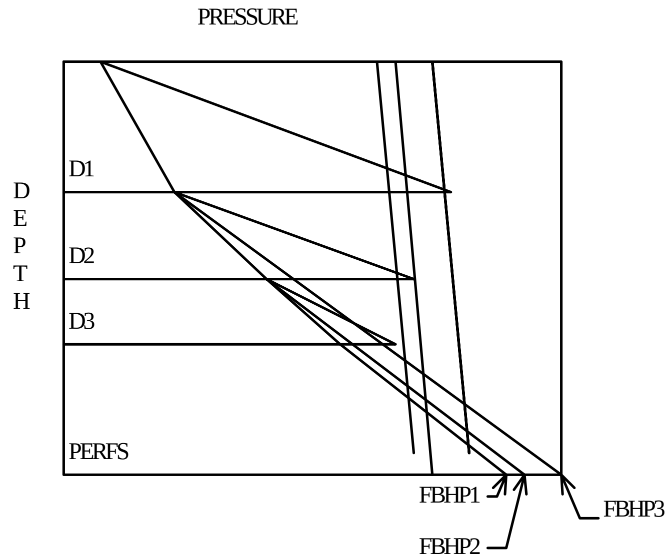
Here the discussion will be focused on the gas lift instability. Several papers have been published on the causes, effects and prediction of gas lift instability, both in the injection gas stream (usually the casing) and the production conduit (usually the tubing). A common theme in these is the relationship between casing and tubing pressures and the size and properties of the downhole orifice used to regulate the gas passage into the well.

Due to the nature of multiphase flow in inclined pipes the actual pressure in the pipe will vary either slightly or significantly over time. In gas lifted wells these changes have a direct effect on both the rate of inflow of the reservoir and the rate of gas passage through the operating orifice in the well. Given conditions where the pressure differential across the operating orifice is in the region described as sub-critical flow (refer to discussion on sub-critical flow) then the changes in tubing pressure can be reinforced by the changes in gas flow rate across the orifice. This in turn can lead to significant changes in the casing pressure in the well. When the changes in rates and pressures cannot be accommodated by the system, the changes reverse and cyclic instability occurs, often called "heading". This can be noticed either in the tubing, casing or both.

The cyclic changes to flowing bottom hole pressure reduce the overall productivity of the well reducing production and hence revenue. These cyclic changes in the casing reduce the efficiency of the gas lift supply system and lead to a higher overall gas pressure requirement and hence increased costs.

Until now the remedies available to operators all involved reductions in production, increases in operating costs or both. Typical examples are:-

- Move the operating depth higher in the well. D1 or D2 instead of D3 (Increases FBHP and reduces production)
- Increase the surface tubing pressure, by reducing production choke (Reduce production and perhaps open upper valves).
- Increase the gas pressure in the casing if possible, often leading to over injection of gas. (Increases operating expense. Can reduce well production. Can lead to multipoint injection. In optimized fields will reduce production in other wells).



All of the above lead to some reduction in profit margin for the well.

Some remedies involve reductions in production, increases in operating costs or both. Typical examples are:

- Move the operating depth higher in the well (Increase FBHP and reduce production).
- Increase the surface tubing pressure, by reducing production choke (Reduce production and perhaps re-open upper valves).
- Increase the gas pressure in the casing if possible, often leading to over injection of gas (Increase operating expense. Can reduce well production. Can lead to multi-point injection. In optimized fields will reduce production in other wells).

The Objectives of Stable Gas Lift Injection

- Maximize production
- Maintain deepest point of injection
- Minimize flowing production pressures
- Optimize use of limited gas supplies
- Minimize total operating costs
- Minimize plant downtime
- Minimize gas injection rates
- Minimize gas injection pressures

Critical and sub critical flow

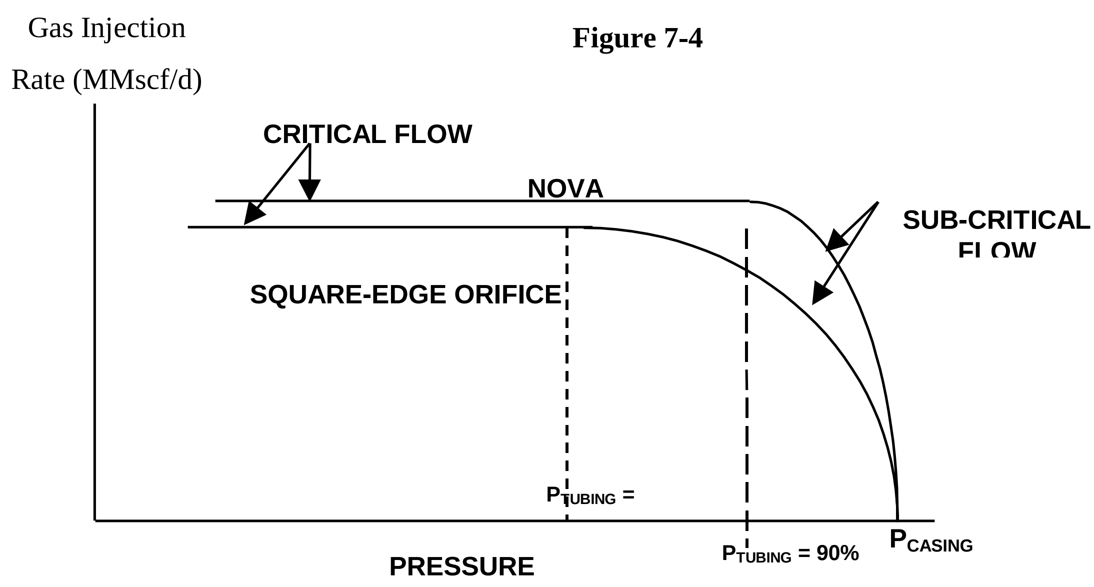
Critical flow is the flow of gas at critical velocity, which is equal to the sonic velocity at that particular condition. The sub-critical flow is the flow below the critical velocity. The maximum gas passage rate is achieved when the flow reaches the critical velocity. At the critical velocity regime, any changes in upstream or downstream pressure will not effect the amount of gas throughput. The critical velocity regime of a particular orifice depends on the type and size of the orifice and the ratio between the downstream (tubing) and the upstream (casing) pressure Figure 7-4).

Take a certain orifice valve and port size. The more the differential pressure across the valve, the less the ratio between them. Hence, following the graph, the operating point move to the left, from sub-critical to critical flow regime. As the differential pressure increases, more gas can be injected until it reaches the maximum at critical flow regime.

As mention above, at critical flow regime, the changes in tubing pressure would not lead to the changes in gas flow rate across the orifice. This in turn will not affect the casing pressure and prevent cyclic instability to occur.

Therefore the attempt is to operate at critical flow regime. For the conventional square-edge orifice, the critical flow regime falls below P_{tbg}/P_{csg} of about 55% (or more than 40-60% pressure drop). It means that high differential pressure is needed. The more differential pressure required, the less the depth of injection can be achieved the injection point, causing less lifting to the well and less production rate. In most cases it is not practical to operate with this much loss.

Figure 7-4



NOVA™ VALVE

The NOVA™ gas lift valve has been described in section 4, gas lift equipment.

The NOVA™ Gas Lift Valve works to stabilize the dynamic situation. Critical flow is achieved through the valve with as little as 10% pressure drop or less or ratio between downstream and upstream pressure as high as 90%. Figure 7-5 shows result of the test on 0.332 NOVA orifice at 3 different pressures.

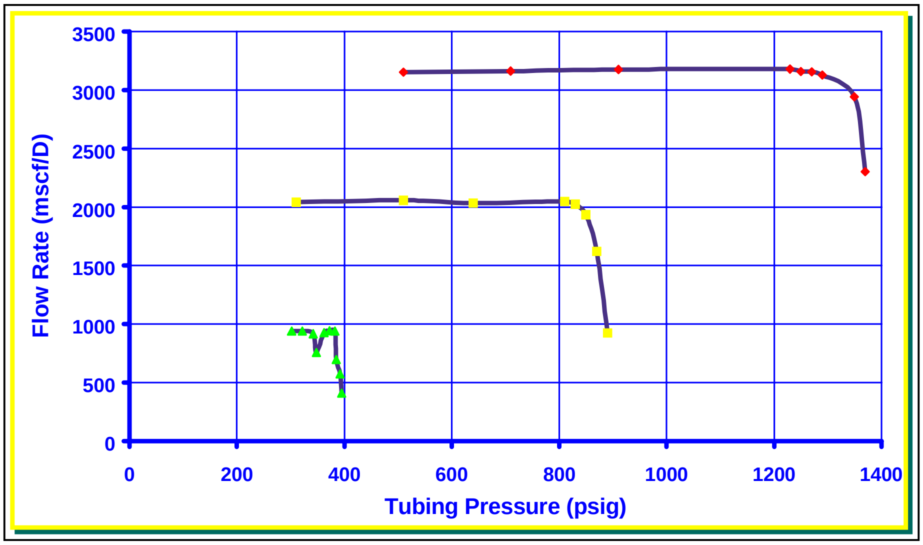


Figure 7-5

The critical flow regime present in the NOVA™ valve virtually eliminates any effect of tubing pressure on the gas injection rate. Changes in tubing pressure are not allowed to affect the casing pressure. The gas flow rate remains constant and this has a negative feedback effect on any tubing instability. The result is generally a completely stable casing pressure and a production pressure which fluctuations are completely eliminated or reduced to a minimum.

The NOVA™ Gas Lift Valve is unique in that it allows the prevention of instability to be achieved without the losses in production or increases in operating expense associated with previously used methods. In fact the stabilization of the flowing bottomhole pressure in a well will generally increase the overall production from that well. Stabilizing the injection pressure can lead to reduce maintenance costs too.

A spin-off benefit from the use of the NOVA™ gas lift valve will be the improved controllability of gas lift fields where computer controlled optimization schemes are implemented. Until now unstable wells have largely had to be left out of any optimizing algorithms due to the destabilizing effect these wells have on the measuring and feedback controls in such a system. With the NOVA™gas lift valve even if a well is slightly tubing unstable the gas rate will remain constant. Hence the gas measurement which is the control parameter for these systems will remain stable. This should make it possible to include more wells than ever in optimization schemes.

NOVA™ Gas Lift Valves and Dual Wells

Dual gas lift wells are discussed in Chapter 4, Gas Lift Equipment.

TROUBLESHOOTING EXAMPLES

Example 1 - H-54

Flowing Gradient Survey

This well would not take gas and was not flowing. A ‘flowing’ gradient survey was run with the results as plotted in FIGURE 7-6. As the well was not flowing at the time of the survey this was in effect a static survey of the well.

Mandrels one and two contained dummy valves. As can be seen on the plot the full casing pressure of 1460 psi is insufficient to U-Tube to the top unloading valve in mandrel three and thus the well will not take gas. This condition has arisen due to an increase in the reservoir pressure through water injection. The higher reservoir pressure is able to support a greater hydrostatic head of fluid in the tubing. The solution to restore production from the well would be to either reduce the reservoir pressure (impractical), increase the surface gas injection pressure (impractical) or to install two unloading valves in mandrels one and two.

It should be remembered that although installing more unloading valves will enable the well to take gas, the change in the reservoir pressure will have an effect on the well performance resulting in increased production rates which may compromise the existing valve design in the well. This may be short lived as once the well is in production the reservoir pressure may decline again to nearer the original figure.

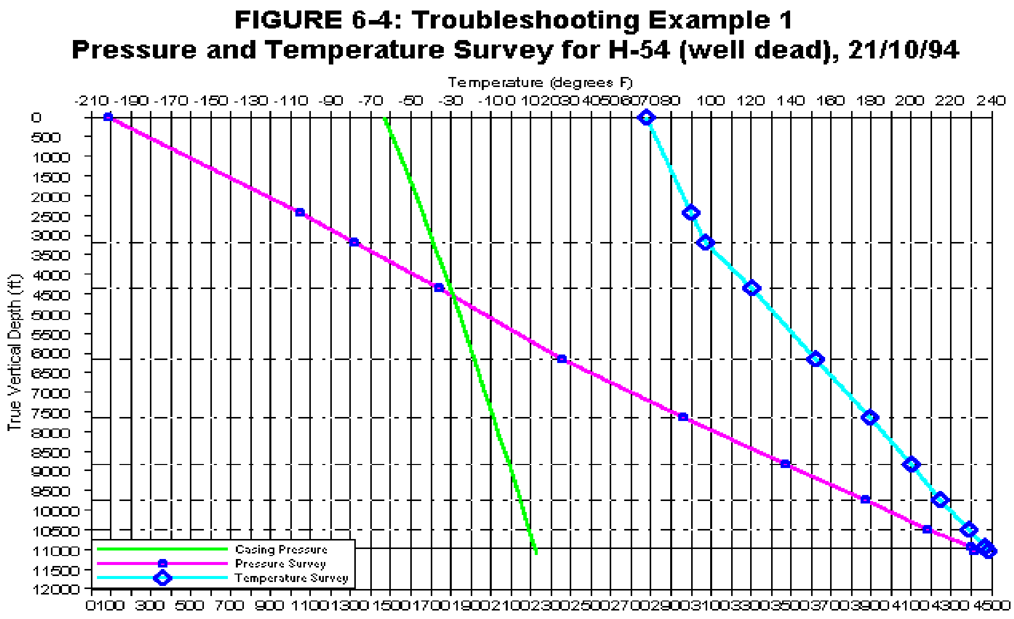


Figure 7-6

Example 2 - H-43

Following a coiled tubing water shut off this well has failed to lift as expected with both a low production rate (c. 1128 BLPD, 57% WC) and low gas injection rates (0.8 MMscf/D). A flowing survey run on the 29/30th September was analyzed and from the results of this survey (see FIGURE 6-5) recommendations for actions to improve well production were made.

Flowing Gradient Survey

The attached graph (FIGURE 7-7) shows the flowing pressure and temperature survey plotted. The large temperature drop and the significant pressure gradient change all indicate the main point of injection was at valve number one. There would appear to be a small pressure change at valves two and three which would suggest these are passing a small quantity of gas.

Performance Analysis and Gas Lift Design

Using the shut in bottom hole pressure (SIBHP) and the flowing bottom hole pressure (FBHP) measured during the survey along with the well test, a performance analysis of the well was carried out assuming gas injection at mandrel number six. The technical optimum was with about 1.5 mmscf/d and gave an expected production rate of 1840 BLPD. Using the predicted production rate from the performance analysis, a new gas lift design was carried out. Due to the age of the existing valves it was recommended that all top five valves be changed out. However it was felt that this would involve excessive wireline work and thus the valves were changed out from mandrel one working down until the fault was rectified.

After several valve change-outs stable production was achieved with the orifice valve set in mandrel four. The well production was increased from about 1100 BLPD to 2400 BLPD and it was this higher than predicted rate which prevented transfer down to mandrel six and forced the orifice valve to be set in mandrel four.

FIGURE 6-5: Troubleshooting Example 2
Pressure and Temperature Survey for H-43, 30/9/94

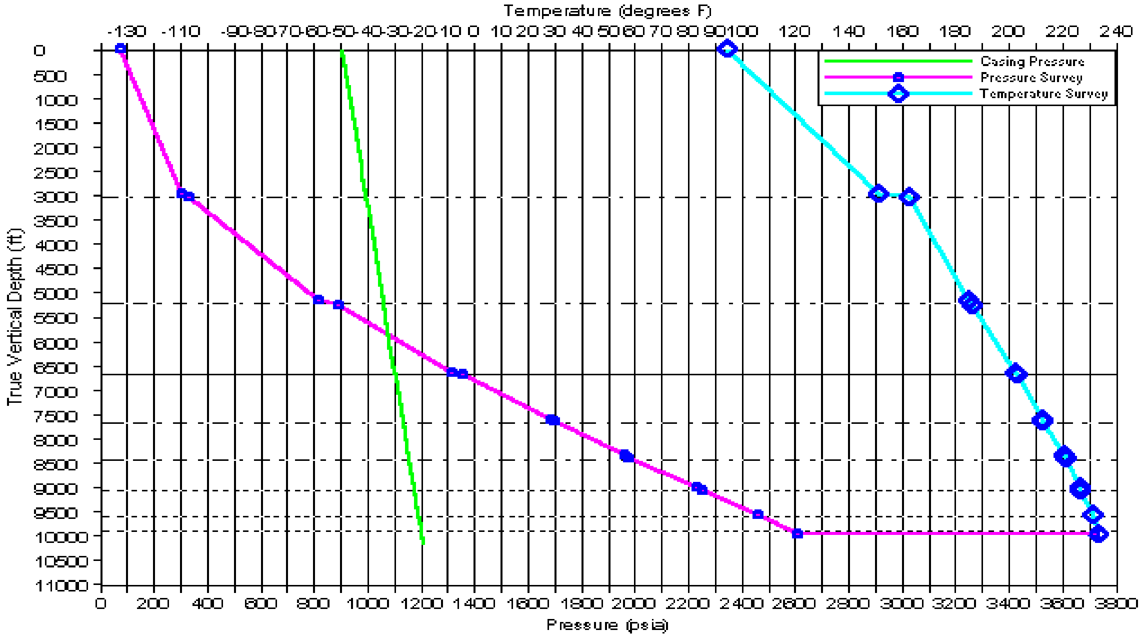


Figure 7-7

Example 3

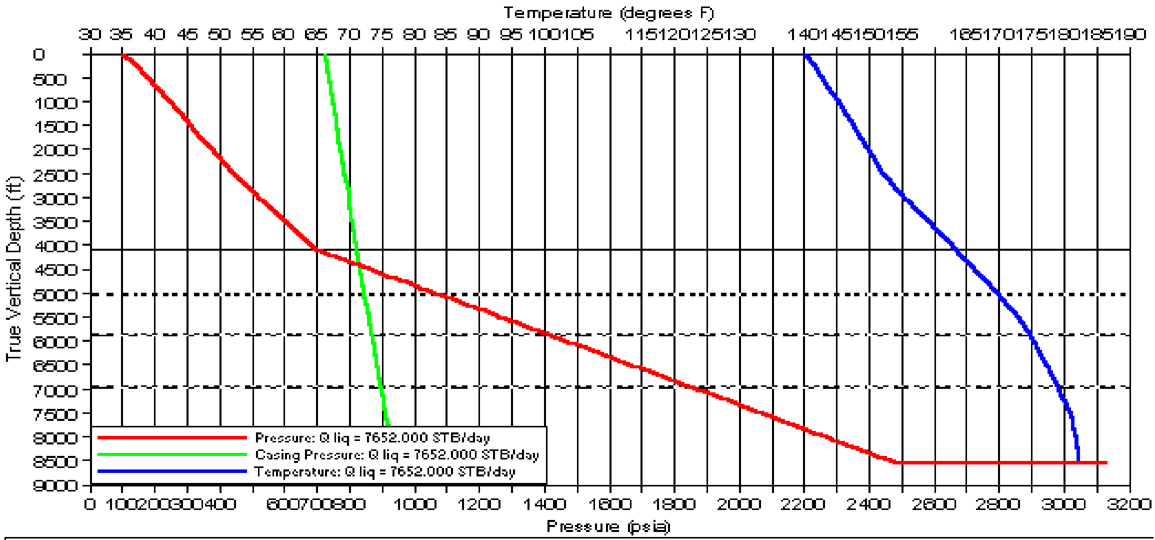
Well Test, Casing Pressure Analysis and Inflow Performance (Computer Modeling)

In this particular example (see FIGURE 7-8) the identification of the injection point in the well has been achieved through the use of well tests and computer modeling. This shows the advantage of having good reservoir information i.e. shut in bottom hole pressure (SIBHP) and P.I..

This well was producing 7652 BLPD with a reservoir pressure of c.3200 psia and a PI of 12. The required drawdown to make this rate is 7652/12 = 638 psi. Using the computer to predict a flowing gradient for this rate shows that only when the gas injection is at mandrel one do we get a flowing bottom hole pressure of about 2562. This result is also backed up by the casing injection pressure of 720 psi which as can be seen on the plot is sufficient to only U-Tube around the top mandrel station.

The solution here is to check the validity of the original design and if the well performance is still within the design capabilities then replace valve number one. Where an installation has been in the ground for a long time it maybe prudent whilst rigged up on the well to change out all the gas lift valves.

FIGURE 6-6: Troubleshooting Example 3
Pressure and Temperature vs Depth Analysis for Example 3
Well Test 28/8/94 with Gas Injection at Valve Number 1



Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	Total GLR (SCF/STB)
7652.000	3887.216	3764.784	0.599	49.200	154.000	691.144

Qgi = 4.690 MMSCF/day

Figure 7-8

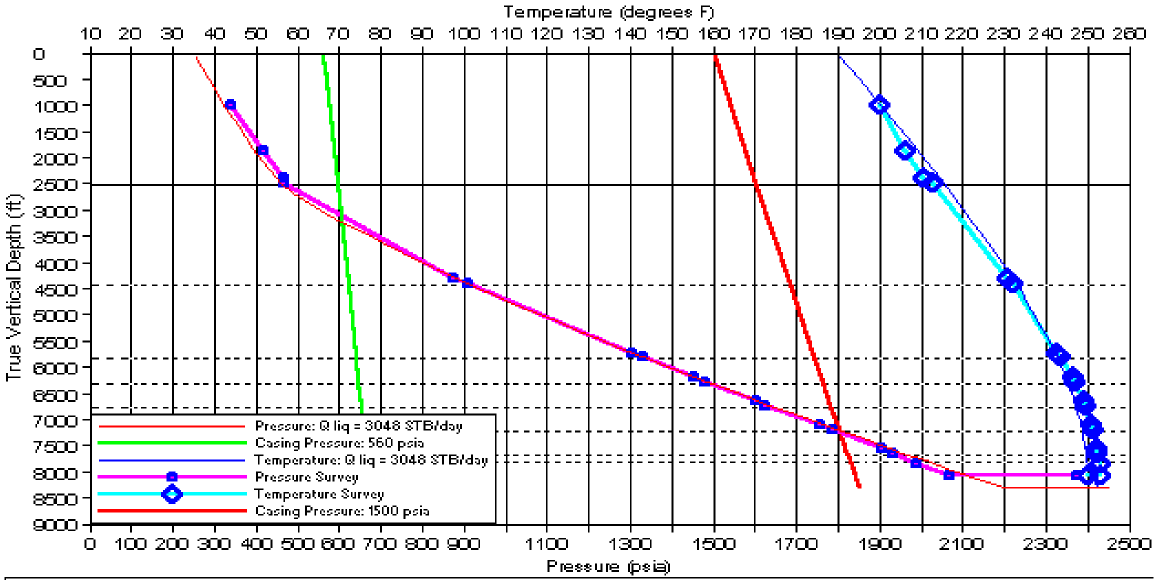
Example 4

Flowing Survey

The flowing Survey in FIGURE 7-9 shows the injection point at mandrel 1. This is also confirmed by the low gas injection pressure. The reason why the injection point is at mandrel 1 is not clear. This could be due to a failure of the valve to close, the valve being out of the pocket, the orifice valve set in the wrong place or a hole in the tubing.

In this particular example the valve was pulled and was found to be in perfect working condition with the exception of damage to the upper packing. The valve was replaced and a new survey run. The new survey showed exactly the same result. A PLT survey (electronic pressure log using a tubing collar locator (CCL) to accurately pin point pressure, temperature and flow changes in the tubing) was run and this showed several holes above and below the sidepocket mandrel. The solution in this case was to patch the tubing with a 3 1/2" coil tubing straddle set with packers at either end. If a rig had been available this well would have been worked over.

FIGURE 6-7: Troubleshooting Example 4
Pressure and Temperature Survey for Example 4, 21/5/94



Liquid Rate (STB/day)	Oil Rate (STB/day)	Water Rate (STB/day)	Gas Rate (MMSCF/day)	Water Cut (per cent)	GOR (SCF/STB)	Total GLR (SCF/STB)
3048.000	1697.736	1350.264	1.017	44.300	599.000	688.958
Qgi = 1.083 MMSCF/day						

Figure 7-9

Example 5

Flowing Survey

The flowing survey in FIGURE 7-10 shows a well with correct gas lift. The injection point is at the orifice in mandrel 7. Whilst nothing need be done to improve on the gas lift valves, the survey does give valuable information on the well performance and the accuracy of the computer model. From this information we could determine if production could be improved through changes to the gas injection rate.

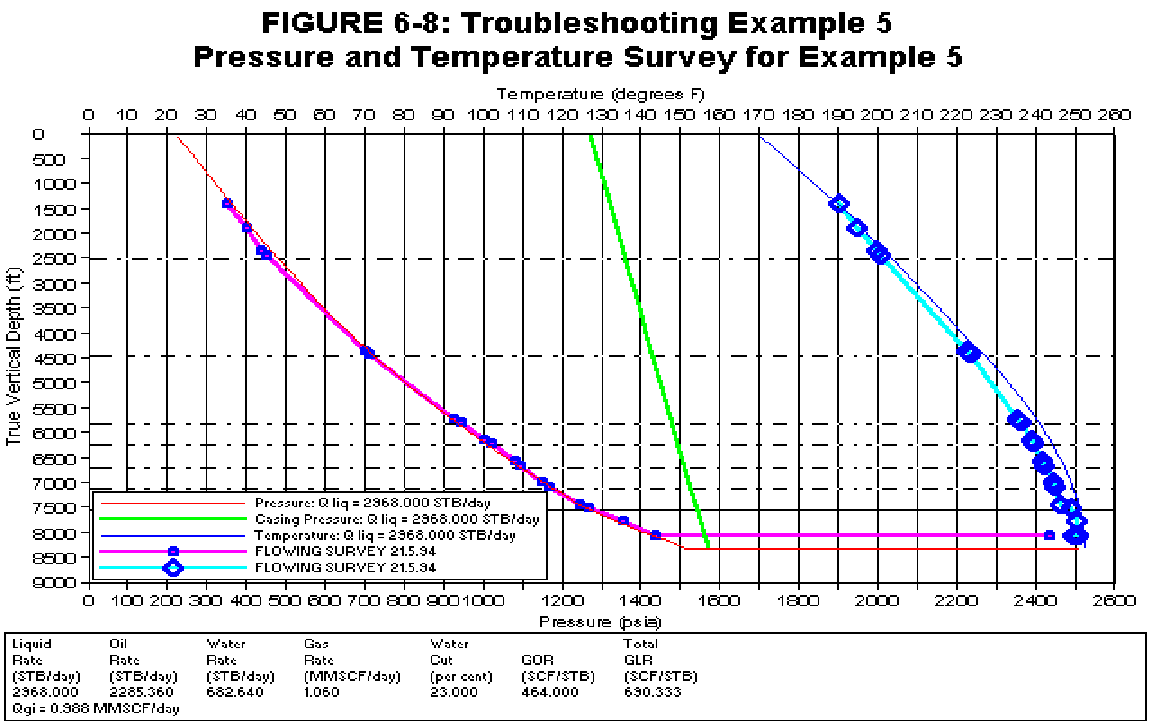


Figure 7-10

Example 6

Flowing Pressure and Temperature Survey

The flowing survey in FIGURE 7-11 was run on a well blowing dry gas. This condition can be caused by anyone of a number of reasons. The most common causes are either a hole in the tubing above the well fluid level, a gas lift valve hung open above the fluid level or damaged inflow to the well resulting in gas injection at the orifice valve but no liquid being lifted out.

In this case the gas injection point was at the top valve which was above the fluid level. However on investigation of the opening and closing pressures of the valve it was clear that the valve was working but was operating at a temperature well below the design temperature. The valve was originally designed to operate in a well that would flow naturally with a temperature at the valve of 216^0F. After a scale squeeze the well would not flow and it is clear from the attached survey that the fluid level is now below the top valve and the temperature at the valve is at best only 147^0F when static and with the additional chilling effect of gas injection the temperature actually drops down to 37^0F. At this temperature the valve closing pressure matches the observed injection pressure. However this injection pressure is not sufficient to open the second valve and thus the top valve remains open.

The only way to permanently fix this situation is to redesign the top valve to close on a much lower temperature i.e. 147^0F.

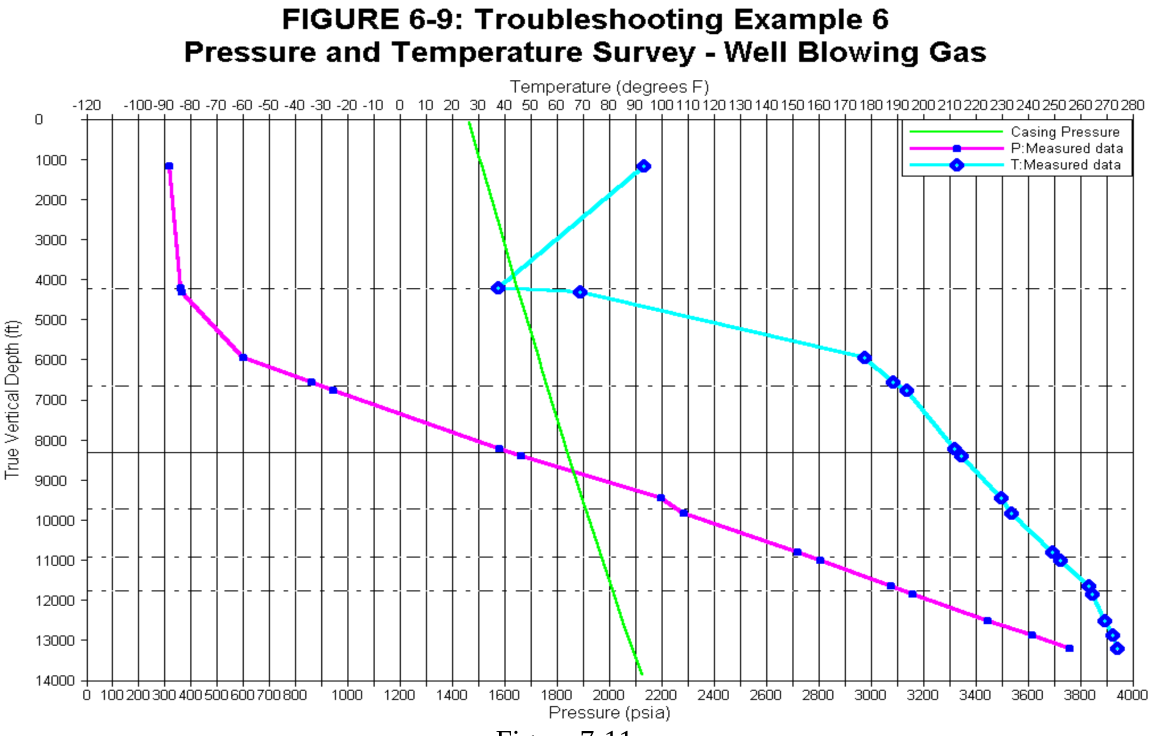


Figure 7-11

Example 7

Trouble-Shooting Gas Lift Wells

2 Case Studies using Echometer, Two-
Pen Recorder and Nodal Analysis

Case #1

- New gas lift string
  - Expected production: 1350 bbls/d @ 580 MCF/D gas injection.
  - Actual Production: 1050 bbls/d @ 520 MCF/D gas injection.
- Corrective Action Taken
  - Well modeled to aid in diagnosis.
  - Acquired fluid level in casing.
  - Wireline ran in well with impression block to confirm valve was out of pocket. Attempted to re-set valve.
  - Flowing gradient survey ordered.

Case #1
Gas Lift Design

VLV #	MD	TVD	Temp.	TCF	Port	R	TRO
1	1850	1837	144	0.847	3/16"	.094	**945**
2	2820	2698	150	0.838	3/16"	.094	**940**
3	3640	3305	156	0.829	3/16"	.094	**935**
4	4500	3902	161	0.822	3/16"	.094	**930**
5	5370	4502	1/4" Orifice Valve				**N/A**
6	6260	5106	GLV in place				

Figure 1

Case #1
Fluid Level Shot

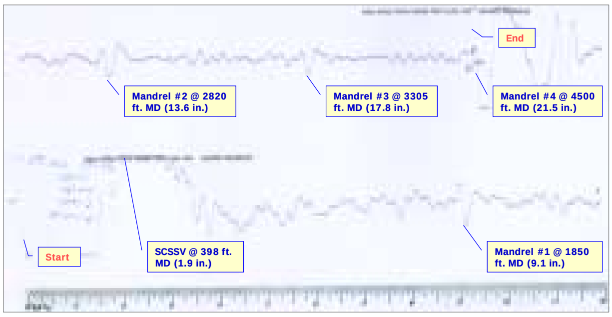


Figure 2

Case #1
Pressure vs. Depth Plot

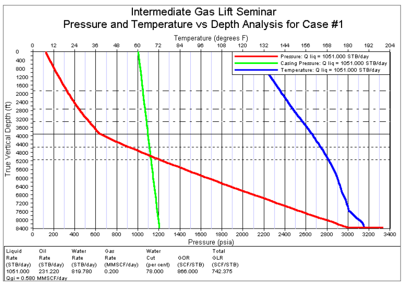


Figure 3

Case #1
Summary & Conclusions

- As figure 2 shows, the fluid level was found at the 4th mandrel. The well has failed to unload to the orifice.
- As figure 3 illustrates, there is sufficient pressure differential at depth to unload to the orifice in mandrel #5.
- Wireline operations confirmed the valve in mandrel #4 was out of pocket, preventing the well from unloading.

Example 8

Case #2

- Well has been severely heading with tubing pressures ranging between 120 - 350 psi. Casing pressures have varied between 900 - 1000 psi.
- Well believed to be multi-point injecting between 2 or more valves.

Case #2
Gas Lift Design

VLV #	MD	TVD	Temp.	TCF	Port	R	TRO
1	1802	1802	105	0.912	3/16"	.094	1005
2	3111	3110	121	0.884	3/16"	.094	995
3	4105	4087	134	0.863	3/16"	.094	980
4	4803	4747	1/4" Orifice Valve from #10				N/A
5	5418	5333	149	0.839	3/16"	.094	960
6	5939	5805	156	0.829	3/16"	.094	945
7	6491	6313	163	0.819	3/16"	.094	930
8	7012	6794	170	0.809	3/16"	.094	920
9	7563	7306	174	0.803	3/16"	.094	910
10	8115	7829	N/A	N/A	3/16"	.094	970

Figure 4

Case #2
Fluid Level Shot

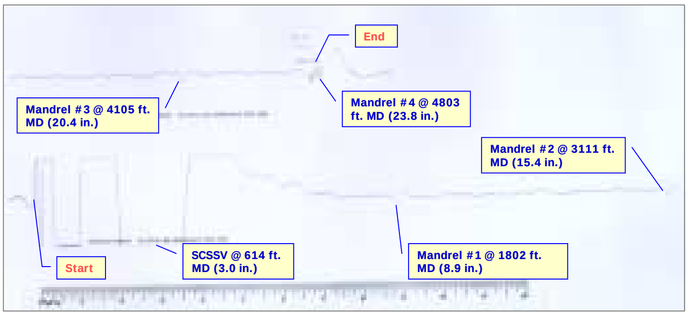


Figure 5

Case #2
Two-Pen Recorder Chart

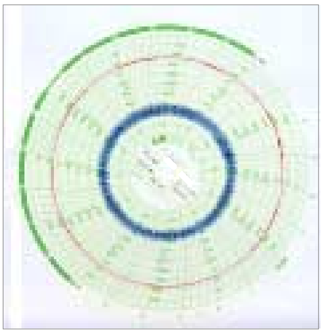


Figure 6

Case #2
Flowing Gradient Survey

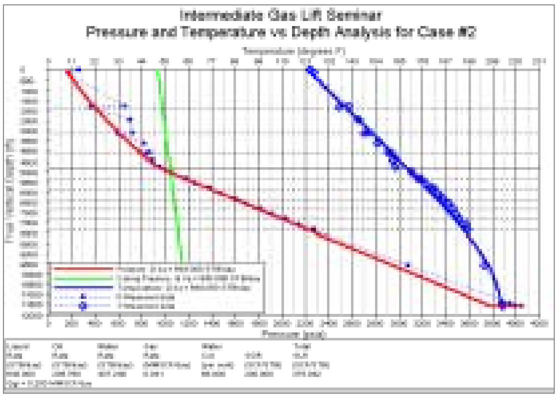


Figure 7

Case #2
Casing Pressure Analysis

VALVE NO	DEPTH TVD	TRO	Pd@60F	Pt	R	1-R	PtR	OP	Tv	TCF	Op Force	Cl Force	
1	1802	1005	911	340	.0940	.9060	32	971	139	.855	912	1065	Closed
2	3110	995	901	587	.0940	.9060	55	995	147	.842	957	1071	Closed
3	4087	980	888	822	.0940	.9060	77	1020	158	.826	1001	1075	Closed
4	4747	1/4" BKO-3 Orifice Valve									N/A	N/A	Open

Figure 8

Case #2
Summary & Conclusions

- As figure 5 illustrates, the well has unloaded to the orifice in mandrel #4.
- Figure 6 is a 2-pen chart showing both tubing and casing heading, typical of multi-point injection and/or un-regulated gas passage due to communication.
- The flowing survey in figure 7 indicates gas passage through valves # 1,2,3 & 4.

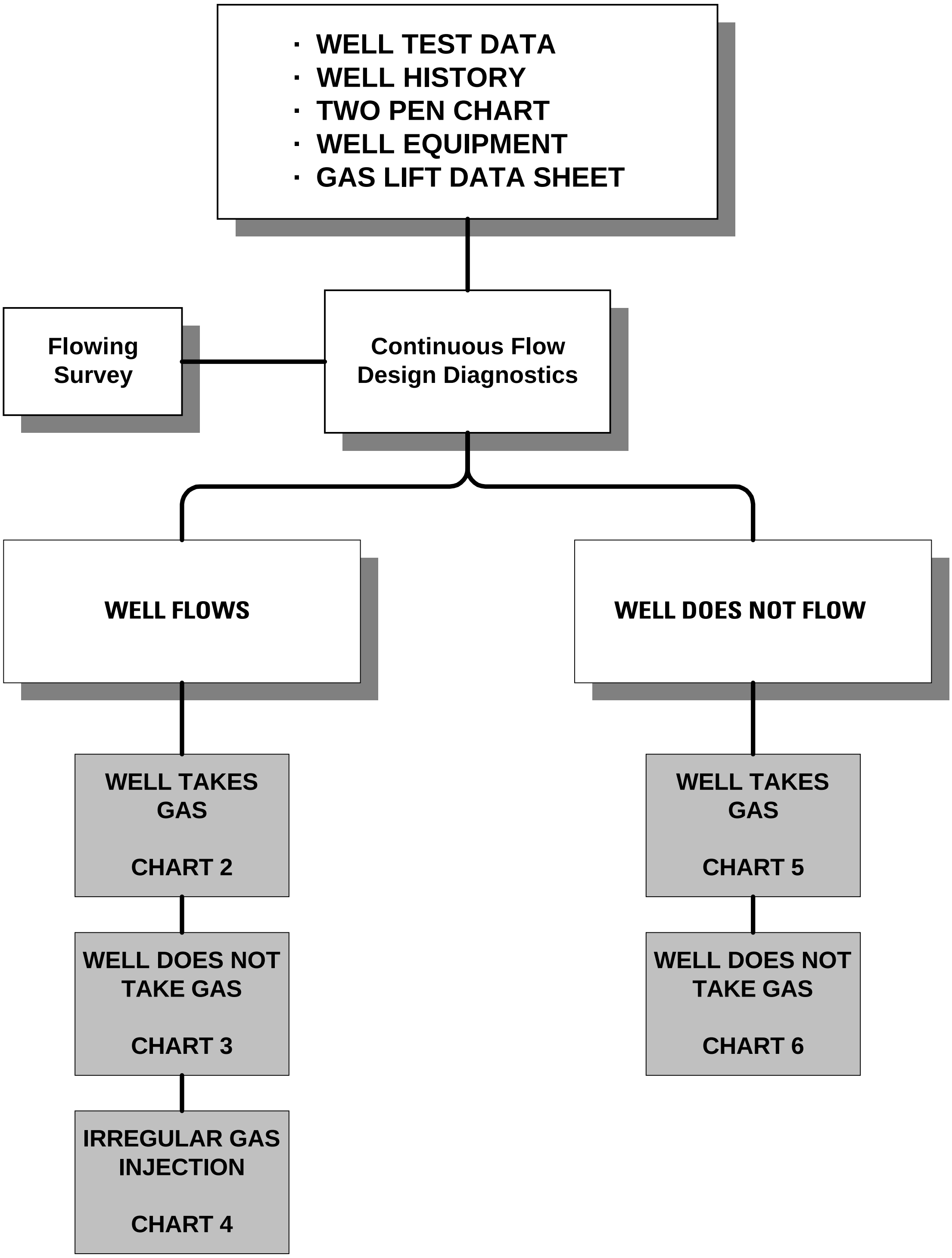
Case #2
Summary & Conclusions

- The casing pressure analysis in figure 8 shows that all unloading valves should be closed at the given pressures and temperatures.
- Well appears to be multi-point injecting through leaking or cut-out valves.
- Appears to be error in bottom three survey points.

Case #2
Summary & Conclusions

- Valves were sent to shop and replaced. The seats in each of the unloading valves were confirmed to be cut out
- After replacing cut-out valves, well was returned to production. Total fluid rate increased by over 150 bbls/d (60 BOPD).
- 4 training sessions were then scheduled for field personnel to better inform them about proper unloading / operating procedures.

GAS LIFT TROUBLESHOOTING FLOWCHART



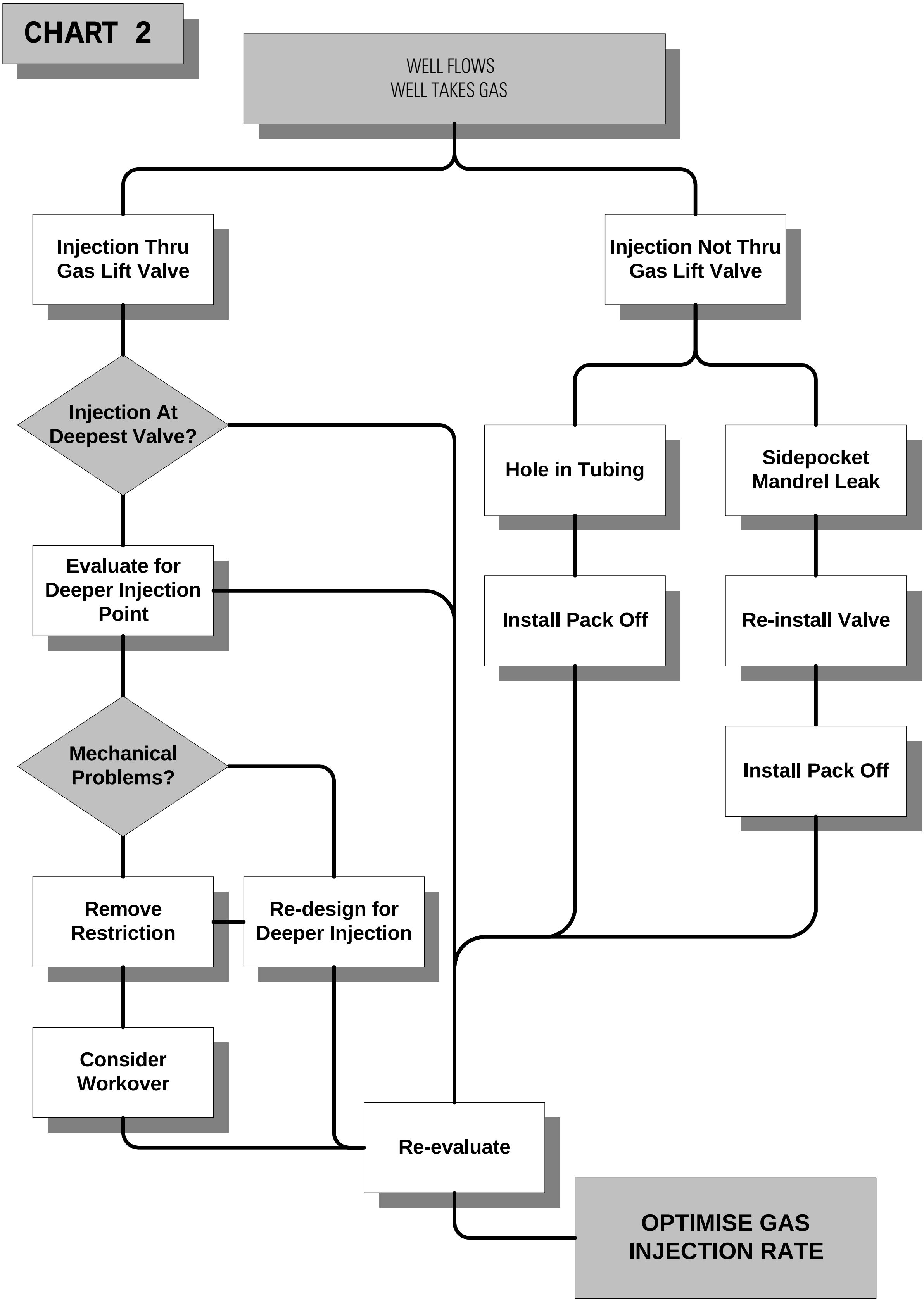
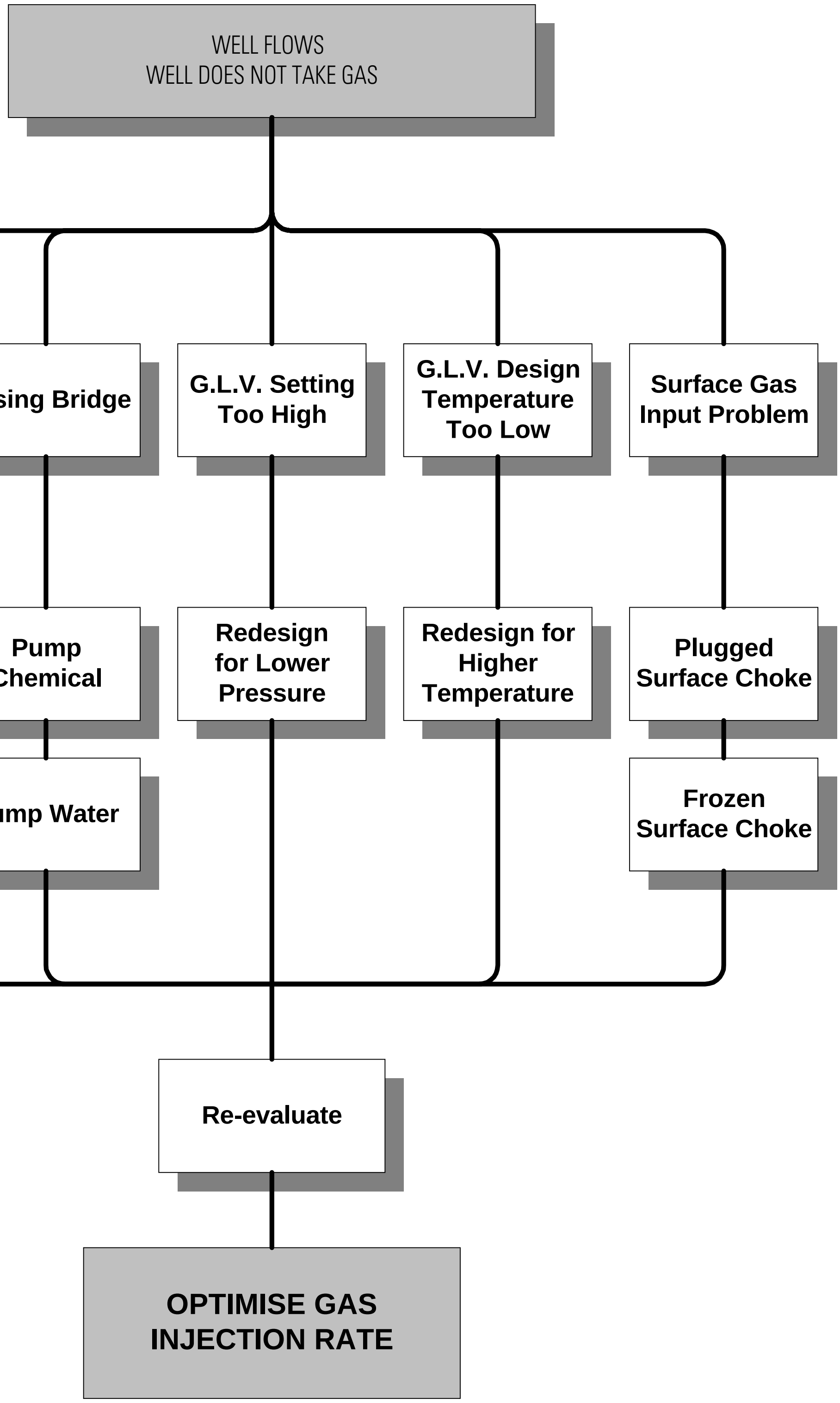


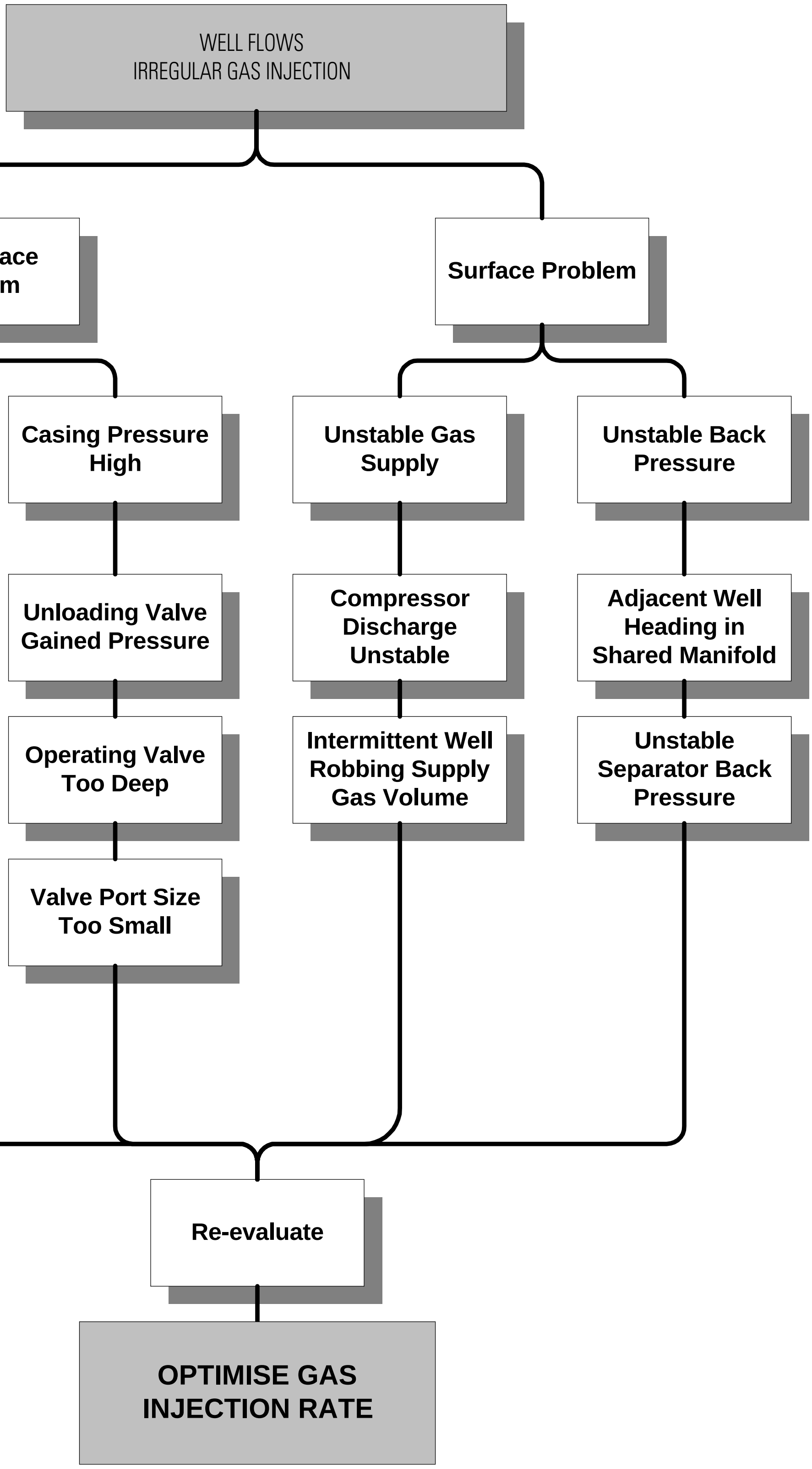
CHART 2
WELL FLOWS
WELL TAKES GAS
Injection Thru Gas Lift Valve
Injection Not Thru Gas Lift Valve
Injection At Deepest Valve?
Hole in Tubing
Sidepocket Mandrel Leak
Evaluate for Deeper Injection Point
Install Pack Off
Re-install Valve
Mechanical Problems?
Install Pack Off
Remove Restriction
Re-design for Deeper Injection
Consider Workover
Re-evaluate
OPTIMISE GAS INJECTION RATE

CHART 3



WELL FLOWS
WELL DOES NOT TAKE GAS
Failed Gas Lift Valve
Casing Bridge
G.L.V. Setting Too High
G.L.V. Design Temperature Too Low
Surface Gas Input Problem
Change Out Valve
Pump Chemical
Redesign for Lower Pressure
Redesign for Higher Temperature
Plugged Surface Choke
Pump Water
Frozen Surface Choke
Re-evaluate
OPTIMISE GAS INJECTION RATE

CHART 4


WELL FLOWS
IRREGULAR GAS INJECTION
SubSurface Problem
Surface Problem
Casing Pressure Low
Casing Pressure High
Unstable Gas Supply
Unstable Back Pressure
Hole in Tubing
Unloading Valve Gained Pressure
Compressor Discharge Unstable
Adjacent Well Heading in Shared Manifold
Unloading Valve Lost Pressure
Operating Valve Too Deep
Intermittent Well Robbing Supply Gas Volume
Unstable Separator Back Pressure
Valve Port Fluid Cut
Valve Port Size Too Small
Leaking Sidepocket Mandrel
Re-evaluate
OPTIMISE GAS INJECTION RATE

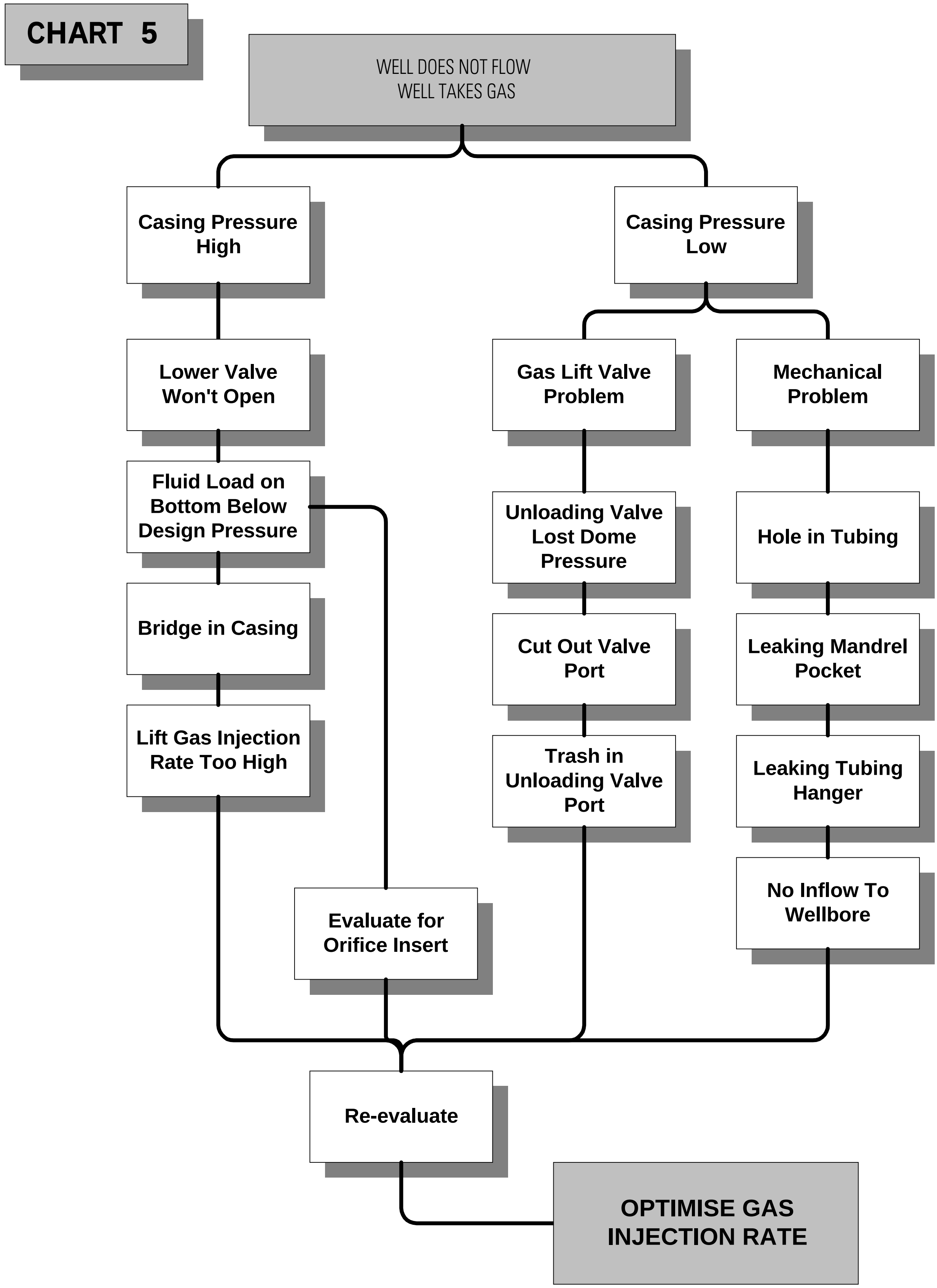


CHART 5
WELL DOES NOT FLOW
WELL TAKES GAS
Casing Pressure High
Casing Pressure Low
Lower Valve Won't Open
Gas Lift Valve Problem
Mechanical Problem
Fluid Load on Bottom Below Design Pressure
Unloading Valve Lost Dome Pressure
Hole in Tubing
Bridge in Casing
Cut Out Valve Port
Leaking Mandrel Pocket
Lift Gas Injection Rate Too High
Trash in Unloading Valve Port
Leaking Tubing Hanger
No Inflow To Wellbore
Evaluate for Orifice Insert
Re-evaluate
OPTIMISE GAS INJECTION RATE

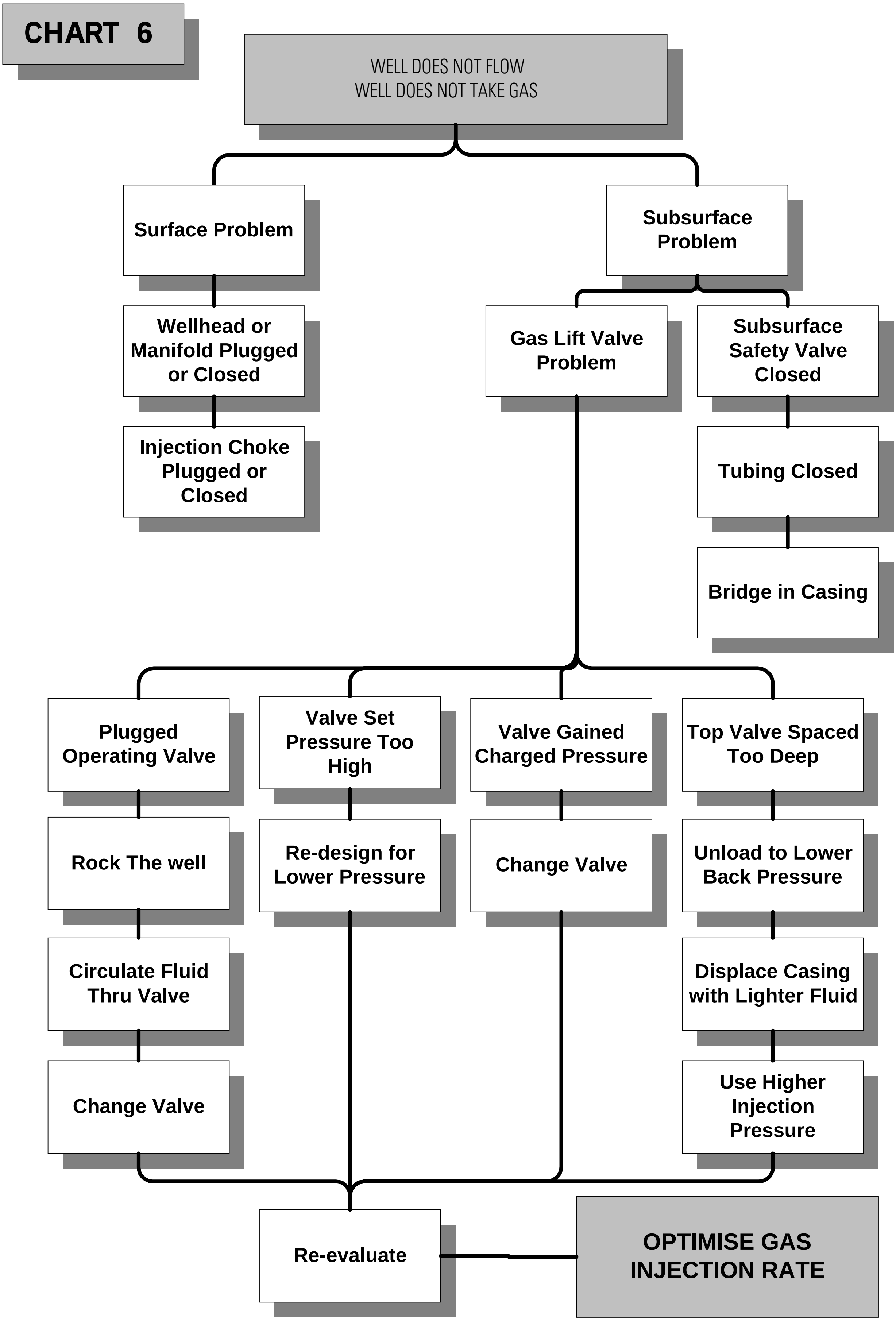


CHART 6
WELL DOES NOT FLOW
WELL DOES NOT TAKE GAS
Surface Problem
Subsurface Problem
Wellhead or Manifold Plugged or Closed
Injection Choke Plugged or Closed
Gas Lift Valve Problem
Subsurface Safety Valve Closed
Tubing Closed
Bridge in Casing
Plugged Operating Valve
Valve Set Pressure Too High
Valve Gained Charged Pressure
Top Valve Spaced Too Deep
Rock The well
Re-design for Lower Pressure
Change Valve
Unload to Lower Back Pressure
Circulate Fluid Thru Valve
Displace Casing with Lighter Fluid
Change Valve
Use Higher Injection Pressure
Re-evaluate
OPTIMISE GAS INJECTION RATE

8. Reference Charts and Tables

8. Reference Charts and Tables

CHAPTER OBJECTIVE: This section contains reference charts, tables and graphs regularly used for gas lift design calculations.

Nitrogen Temperature Correction Factors for Temperature in Fahrenheit

° F	Ct	° F	Ct	° F	Ct	° F	Ct	° F	Ct	° F	°Ct
61	0.998	101	0.919	141	0.852	181	0.794	221	0.743	261	0.698
62	0.996	102	0.917	142	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

Nitrogen Temperature Correction Factors for Temperature in Celsius

° C	Ct	° C	Ct	° C	Ct	° C	Ct
16	0.998	51	0.879	86	0.786	121	0.710
17	0.994	52	0.876	87	0.783	122	0.708
18	0.991	53	0.873	88	0.781	123	0.706
19	0.987	54	0.870	89	0.779	124	0.704
20	0.983	55	0.868	90	0.776	125	0.702
21	0.979	56	0.865	91	0.774	126	0.701
22	0.976	57	0.862	92	0.772	127	0.699
23	0.972	58	0.859	93	0.769	128	0.697
24	0.968	59	0.856	94	0.767	129	0.695
25	0.965	60	0.853	95	0.765	130	0.693
26	0.961	61	0.850	96	0.763	131	0.691
27	0.958	62	0.848	97	0.760	132	0.689
28	0.954	63	0.845	98	0.758	133	0.688
29	0.951	64	0.842	99	0.756	134	0.686
30	0.947	65	0.839	100	0.754	135	0.684
31	0.944	66	0.837	101	0.752	136	0.682
32	0.940	67	0.834	102	0.749	137	0.680
33	0.937	68	0.831	103	0.747	138	0.678
34	0.933	69	0.829	104	0.745	139	0.677
35	0.930	70	0.826	105	0.743	140	0.675
36	0.927	71	0.823	106	0.741	141	0.673
37	0.923	72	0.821	107	0.739	142	0.671
38	0.920	73	0.818	108	0.737	143	0.670
39	0.917	74	0.816	109	0.734	144	0.668
40	0.914	75	0.813	110	0.732	145	0.666
41	0.910	76	0.810	111	0.730	146	0.665
42	0.907	77	0.808	112	0.728	147	0.663
43	0.904	78	0.805	113	0.726	148	0.661
44	0.901	79	0.803	114	0.724	149	0.659
45	0.898	80	0.800	115	0.722	150	0.658
46	0.895	81	0.798	116	0.720	151	0.656
47	0.892	82	0.795	117	0.718	152	0.654
48	0.888	83	0.793	118	0.716	153	0.653
49	0.885	84	0.791	119	0.714	154	0.651
50	0.882	85	0.788	120	0.712	155	0.649

Camco Valve Specifications

Type	A_b - Effective Bellows Area (sq in.)	Port Size (in.)	A_p - Area of Port With Bevel (sq in.)	A_p / A_b	$1-(A_p / A_b)$	$PPEF = \frac{A_p / A_b}{1-(A_p / A_b)}$
R-20	0.77	3/16	0.029	0.038	0.962	0.040
		1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
		3/8	0.113	0.147	0.853	0.172
		7/16	0.154	0.200	0.800	0.250
		1/2	0.200	0.260	0.740	0.351
R-28	0.77	1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
R-25	0.77	3/16	0.029	0.038	0.962	0.040
		1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
Rp-6 **	0.77	1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
		3/8	0.113	0.147	0.853	0.172
		7/16	0.154	0.200	0.800	0.250
		1/2	0.200	0.260	0.740	0.351
RPB-5 **	0.77	1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
		3/8	0.113	0.147	0.853	0.172
		7/16	0.154	0.200	0.800	0.250
RMI	0.65	1/4	0.051	0.078	0.922	0.085
		5/16	0.079	0.122	0.878	0.139
		3/8	0.113	0.174	0.826	0.211
		7/16	0.154	0.237	0.763	0.311
		1/2	0.200	0.308	0.692	0.445
BK	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104
		1/4	0.051	0.165	0.835	0.198
		5/16	0.079	0.255	0.745	0.342
BK-1	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104
		1/4	0.051	0.165	0.835	0.198
		5/16	0.079	0.255	0.745	0.342
		3/8	0.113	0.365	0.635	0.575
BKR-5	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104
		1/4	0.051	0.165	0.835	0.198
BKF-6	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104
		1/4	0.051	0.165	0.835	0.198
J-20	0.77	3/16	0.029	0.038	0.962	0.040
		1/4	0.051	0.066	0.934	0.071
		5/16	0.079	0.103	0.897	0.115
		3/8	0.113	0.147	0.853	0.172
		7/16	0.154	0.200	0.800	0.250
		1/2	0.200	0.260	0.740	0.351
JR-20	0.77	1/8	0.013	0.017	0.983	0.017
		3/16	0.029	0.038	0.962	0.040
		1/4	0.051	0.066	0.934	0.071
J-40	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104
		1/4	0.051	0.165	0.835	0.198
		5/16	0.079	0.255	0.745	0.342
		3/8	0.113	0.365	0.635	0.575
JR-40	0.31	1/8	0.013	0.042	0.958	0.044
		3/16	0.029	0.094	0.906	0.104