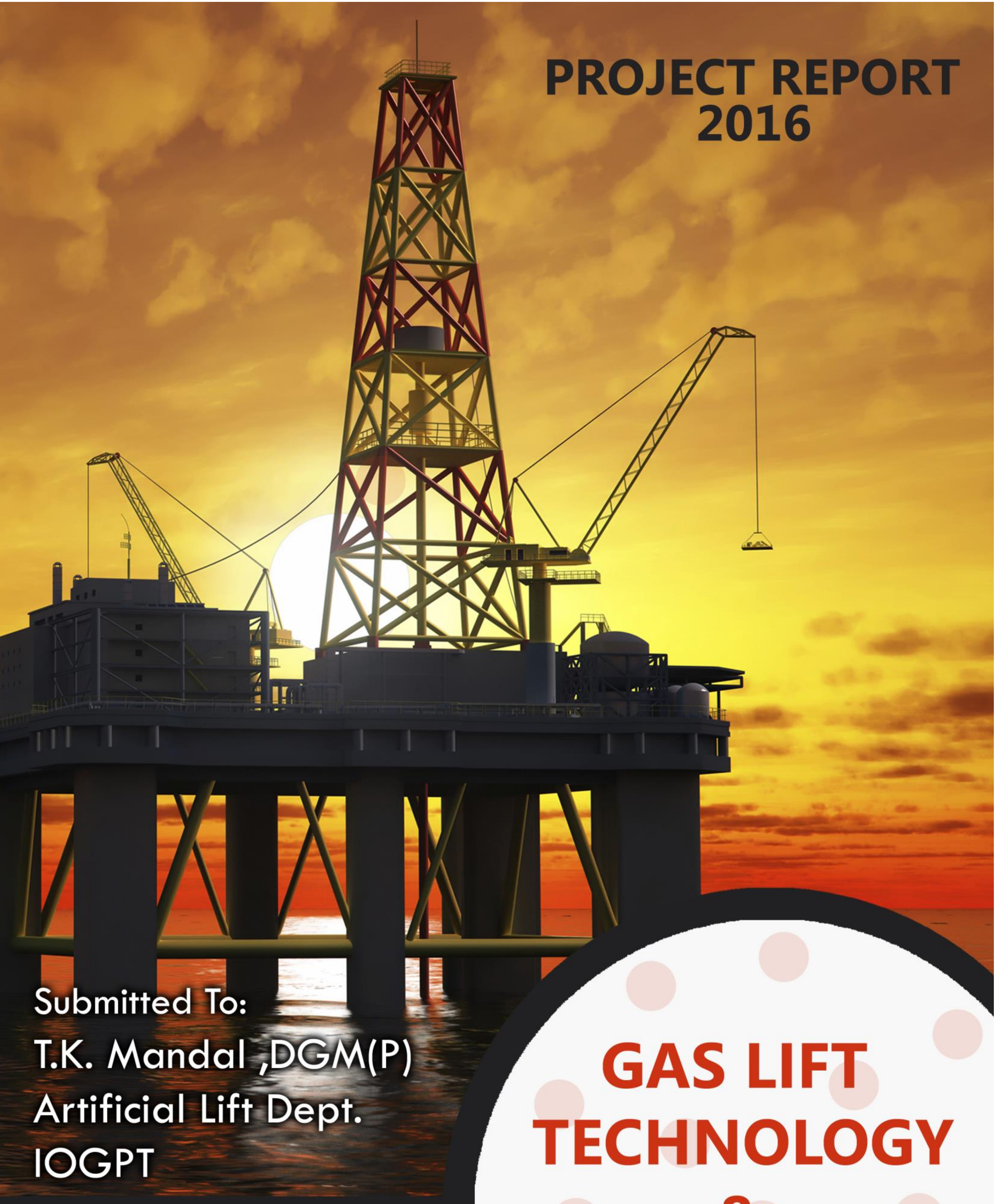

PROJECT REPORT 2016

GAS LIFT TECHNOLOGY & SYSTEM DESIGN

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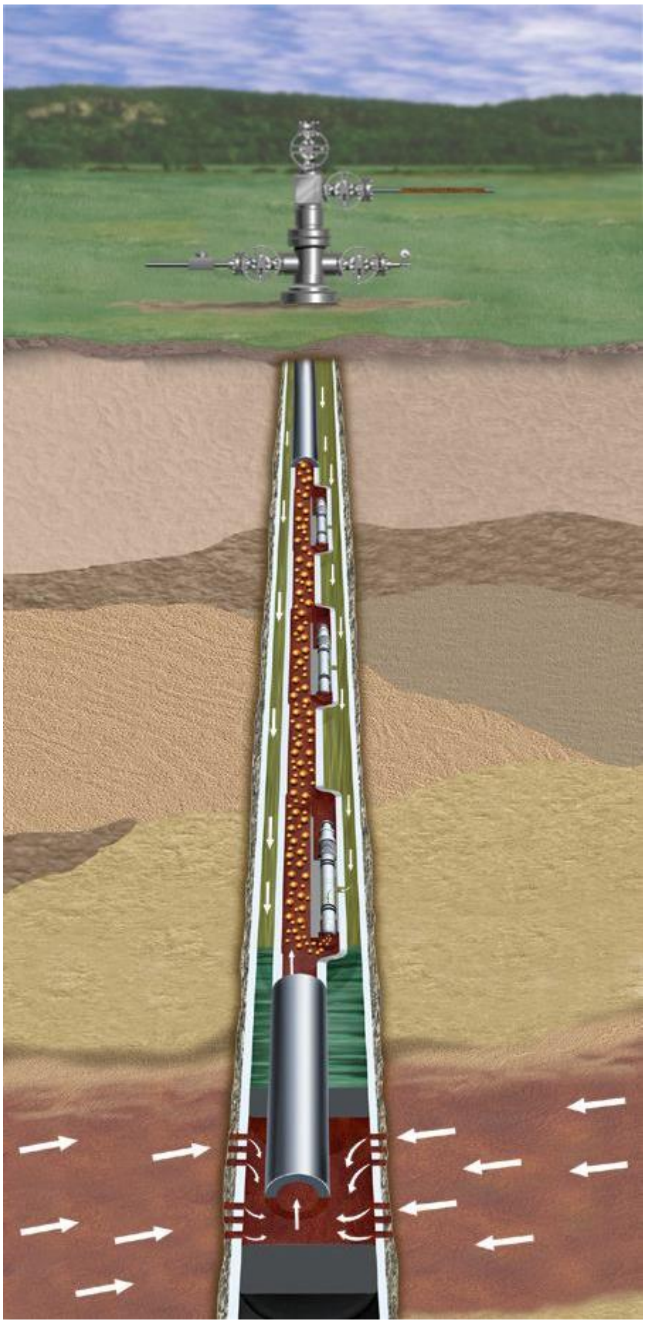
Contents

Chapter 1: Introduction to Gas Lift

1.1 Gas Lift

Gas lift is a method of artificial lift where high pressure gas is injected into the produced fluid column to lift the liquids in non-flowing wells or in flowing wells, to increase production. The purpose behind a gas lift system is to inject relatively high pressure gas into the production string at the deepest point possible. This lightens the fluid column, reducing pressure in the wellbore causing an increase in flow rate.



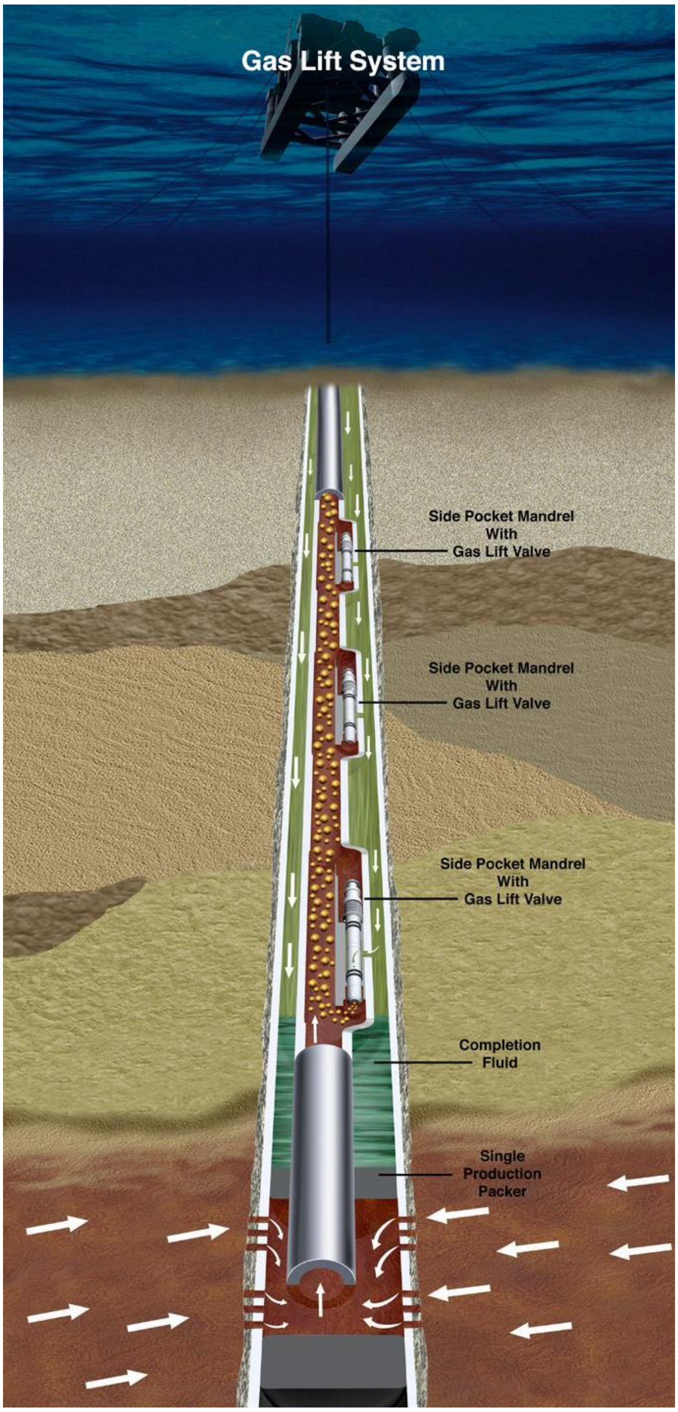
The early method of gas lifting was by U-tubing of liquids around open-ended tubing. The high pressure required to kick off the well and the necessary lowering of the supply pressure after lift had been established made u-tubing inefficient. The fact that the gas went around the end of the tubing meant there was little control of gas usage: therefore, excessive gas was used in most cases. The length of the tubing was not always correct either. (This U-tube method was first used in mines which filled up with water.) Gas lift valves were developed to overcome the deficiencies of U-tubing. Gas lift valves allowed the operator to use all the kick-off pressure, have deeper tubing submergence, and economize on gas usage. With gas lift under control, a number of valves could be run and the well unloaded by letting the gas lift valves control the point of injection. Since the valves could be controlled, lift was possible from greater depths with less pressure.

1.2 Types of Gas Lift

The gas lift method is divided into two distinct classifications: Continuous Flow and Intermittent Flow Systems

CONTINUOUS FLOW - Continuous injection of relatively high pressure gas from the casing into the tubing, maintaining a constant flowing bottomhole pressure.

INTERMITTENT FLOW - Injection of gas from the casing into the tubing on a timed basis as fluid builds up in the tubing. Intermittent flow is usually used in wells with low permeability or low bottomhole pressure where gas supply is scarce.



1.3 Continuous Flow

In continuous flow gas lift, high pressure gas is injected into the fluid stream for the purpose of reducing the density of the vertical liquid column sufficiently enough to allow the formation pressure to lift the fluids to the surface. The continuous flow method is generally applied to higher capacity wells and has been used to produce rates above 50,000 B/D. For continuous flow, the flowing bottomhole pressure must be high enough to support the flowing liquid column.

1.3.1 Applications of Continuous Gas Lift

- To produce wells that will not flow naturally.
- To increase production rates in flowing wells.
- To unload a well that will later flow naturally.

- To remove or unload fluids from gas wells and to keep the gas well unloaded (usually intermittent, but can be continuous).
- To back flow salt water disposal wells to remove sands and other solids that can plug the perforations in the well.
- In water source wells to produce the large volumes of water necessary for water flood operations.

1.3.2 Strengths of Continuous Gas Lift

- Gas lift is the best artificial lift method for handling sand or solid materials. Many wells make some sand even if sand control is installed. The produced sand causes almost no mechanical problem to the gas lift valve since well fluids do not go through gas lift valves; whereas, only a little sand plays havoc with most pumping methods.
- Deviated or crooked holes can be gas lifted with only minor lift problems. This is especially important for offshore platform wells which are directionally drilled. Gas
- lift permits the use of wireline equipment and such equipment is easily and economically serviced. This feature allows for routine repairs through the tubing.
- The normal design leaves the tubing full opening. This permits use of bottomhole surveys, sand sounding and bailing, production logging, cutting paraffin, etc.
- High formation GORs are helpful rather than being a hindrance. Thus in gas lift, less injection gas is required; whereas, in all pumping methods, pumped gas reduces efficiency drastically.
- Gas lift is flexible. A wide range of volumes and lift depths can be achieved with essentially the same well equipment. In some cases, switching to annular flow can also be easily accomplished to handle exceedingly high volumes. The subsurface valves will operate efficiently over a wide range of production rates. It is easy to adjust the circulating gas volume to various wells for changing production rates.
- A central gas lift system can be easily used to service many wells or operate an entire field. Centralization usually lowers total capital cost and permits easier well control and testing.
- Gas lift has a low profile. The surface well equipment is the same as for flowing wells except for injection gas metering. The low profile is usually an advantage in urban and offshore environments.
- Since little extra space is required in the casing and on the well head, it is advantageous for multiple completions or small diameter completions.
- Well subsurface equipment is relatively inexpensive and repair and maintenance of this subsurface equipment is normally low. The equipment is easily pulled and repaired or replaced. Also, major well workovers occur infrequently.
- Installation of gas lift is compatible with subsurface safety valves and other surface equipment. Use of the surface controlled subsurface safety valve with a ¼ -inch control line allows easy shut-in of the well.
- Gas lift will tolerate some bad design assumptions and still work. This is fortunate since the spacing design must usually be made before the well is completed and tested.

1.3.3 Limitations of Continuous Gas Lift

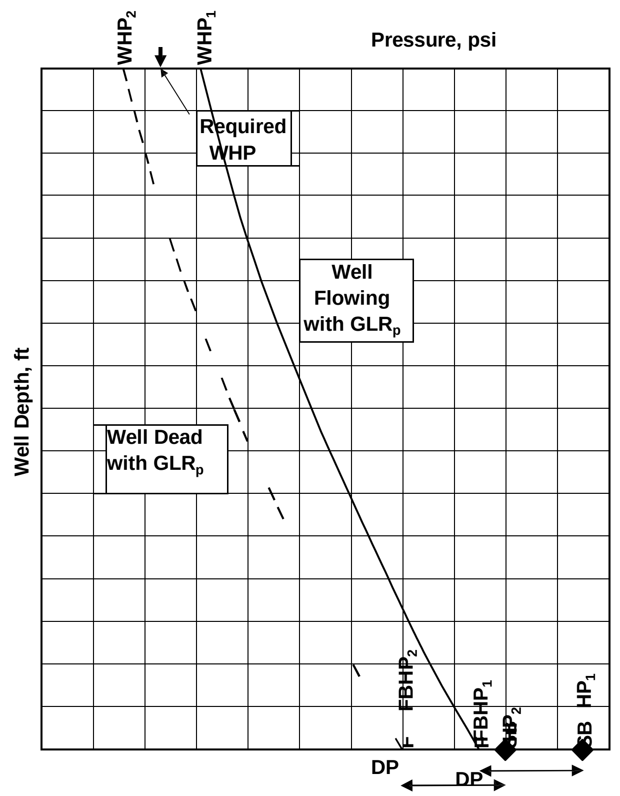
- Relatively high back pressure may seriously restrict production in continuous gas lift. This problem becomes more significant with increasing depths and declining static bottomhole pressures. Thus a 10,000 foot well with a static BHP of 1000 psi and a PI of 1.0 would be difficult to lift with the standard constant flow gas lift system. However, there are some special schemes that could be tried for such wells.
- Gas lift is relatively inefficient, often resulting in large capital investments and high energy operating costs. In the early application of gas lift the lift gas was furnished by gas wells; but the majority of modern gas lift systems use compressors to supply the high pressure lift gas. And, since the cost of compression is an important part of the operating expenses, it is necessary to be concerned with efficient operation of the system.
- The cost of compressors is relatively high and compressors are often long delivery items. The compressor presents space and weight design problems when used on offshore platforms. Also, the cost of the distribution systems onshore may be significant. Increased gas usage also may increase the size of flow lines and separators needed.
- Adequate gas supply is needed throughout the life of the project. If the field runs out of gas or if gas becomes too expensive, one may have to switch to another lift method. In addition, there must be enough gas for easy start-ups.
- Increasing water cut increases the flowing bottom hole pressure with a fixed gas lift pressure. At some water cut, another form of lift, such as ESPs, should be evaluated to increase production by reducing the flowing bottom hole pressure, especially if the produced gas is low.
- Operation and maintenance of compressors can be expensive. Skilled operators and good compressor mechanics are required for successful and reliable operation.
- There is increased difficulty when lifting low gravity (less than 15º API) crude due to greater friction. The cooling effect of gas expansion further aggravates this problem. Also, the cooling effect will compound any paraffin problem.
- Low fluid volumes in conjunction with high water cuts (less than 200 BPD in 2-3/8" OD tubing) become less efficient to lift and frequently severe heading is experienced.
- Good data are required to develop a good design. Such data may not be available and operation continues with an inefficient design that does not produce the well near capacity.

1.4 Principles of Continuous Flow Gas Lifting

1.4.1 Dead wells vs. Gas lifting

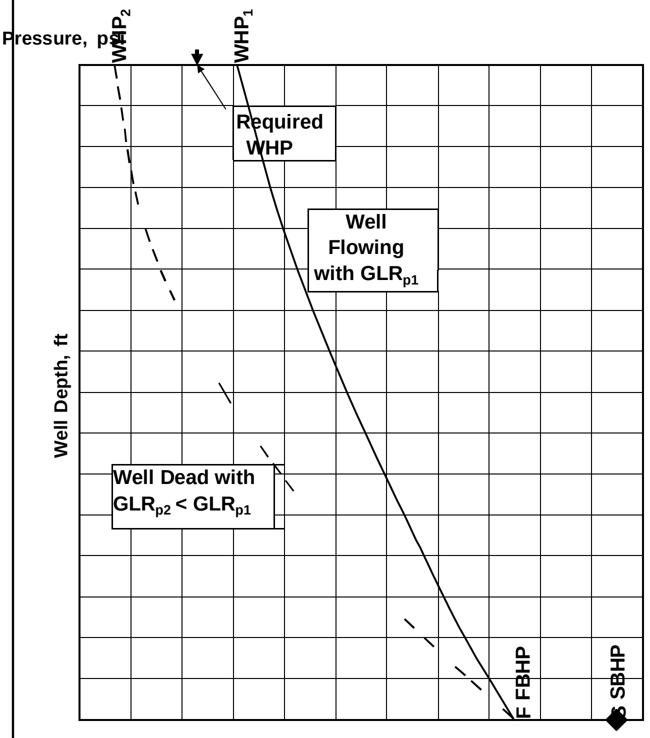
In order to fully understand the mechanism of continuous flow gas lifting, the various reasons why flowing wells cease to flow or die, have to be discussed first. Although there is a great variety of conditions that may lead to a well's dying, most of them can be reduced to two basic causes. These involve (a) the reduction of reservoir or **formation pressure**, and (b) the reduction of **gas content** in the flowing wellstream.

Let us investigate a hypothetical case shown . In the original conditions, the well flowed naturally with a gas-liquid ratio of GLR_p while its static and flowing bottomhole pressures were $SBHP_1$ and $FBHP_1$, respectively. Formation pressure then dropped to $SBHP_2$ and, in order to



How a well dies due to a significant drop in formation pressure.

maintain the same liquid rate, flowing bottomhole pressure had to be reduced to $FBHP_2$, to keep the drawdown at the original level DP. Since it is assumed that the well's liquid and gas production rates did not change, flow with the same production gas-liquid ratio GLR_p must take place in the tubing string. After calculating or plotting the corresponding pressure traverse curve shown in dashed line, it turns out that the well **cannot flow** against the required wellhead pressure WHP. The drop in formation pressure, therefore, can lead to a well's dying, all other parameters being constant.



How a well dies: the effect of decreasing formation gas-liquid ratios.

The second basic case, as shown, involves a reduction of the gas content of the flowing mixture in the tubing string. Even with the original formation and flowing bottomhole pressures, the reduction of the gas-liquid ratio from GLR_{p1} to GLR_{p2} can increase the flowing pressure gradient to such an extent that the well **can no longer flow** against the required wellhead pressure. Reduction of the production gas-liquid ratio can be caused, for example, by an increase in water cut.

It must be obvious that the wells in the previous two examples would return to flowing production if production gas-liquid ratios could be increased sufficiently. This is what happens in continuous flow gas lifting when gas from an outside source is injected into the well. In both examples, if a sufficient amount of lift gas is injected at the well bottom into the flowing wellstream, the total gas-liquid ratio can be increased to such an extent that tubing pressure at the surface attains or exceeds the required wellhead pressure WHP. Under these conditions, the well resumes production at the previous liquid rate.

In summary, continuous flow gas lifting can be considered as an **extension** of the well's flowing life. It is accomplished by continuously injecting a proper amount of lift gas into the upward-moving wellstream to supplement the well's production gas-liquid ratio. The artificially increased gas-liquid ratio reduces the flowing gradient in the tubing string and allows existing formation pressure to lift well fluids to the surface against the wellhead pressure required to move them into the gathering system.

1.4.2 Basic Design of a Continuous Flow Installation

There are two basic operational parameters to be determined when designing a continuous flow gas lift installation: (a) the depth of the **operating valve**, i.e. the point of gas injection, and (b) the **amount of lift gas** to be injected at that point. The exact determination of these quantities varies with several given or assumed parameters detailed below, like surface injection pressure, required wellhead pressure, etc. In the following, a very basic case is considered where all relevant parameters are held constant.

Upcoming graph describes the basic design of a continuous flow gas lift installation for the following conditions:

- the well's desired liquid rate is given,
- the wellhead pressure required to move well fluids to the surface gathering system is known,
- well inflow parameters are available,

- surface injection gas lift pressure is specified, and
- the well's tubing size is given.

With the above parameters given, the two main tasks of the accomplished by the use of a graphical procedure. Design calculations are done in a rectangular coordinate system,

well depth (with zero depth at the top) and the abscissa representing pressure. The use of this coordinate system provides a

way to depict well pressures.

1. First the well's static bottomhole pressure, SBHP, is plotted at total well depth. The **kill fluid** gradient is started from this pressure and is extended towards the surface until it intersects the ordinate axis. The intersection denotes the static liquid level in the well.

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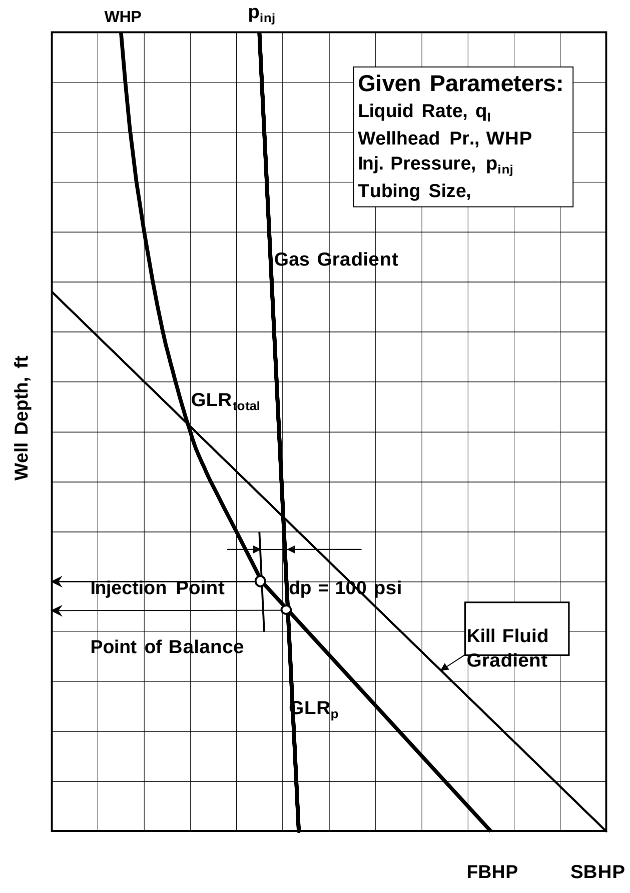


Finding the point of gas injection and the required gas-liquid ratio for continuous flow gas lifting.

2. Since inflow parameters are known, the required flowing bottomhole pressure, FBHP, is found from the desired rate and the **inflow performance relationship** (IPR), as discussed in **Section 2.3**, and is plotted at total well depth.
3. The next task is to plot the injection pressure distribution in the well's annulus starting from the surface operating gas lift pressure. This pressure should be available at the wellsite at all times and must be selected based on compressor discharge pressure, line losses, and an allowance for fluctuating line pressures.
4. Since liquid rate and formation gas-liquid ratio, GLR_p, are known, a pressure traverse starting from the flowing bottomhole pressure, FBHP, can be established. This curve may be calculated from any multiphase flow correlation or may be traced from available flowing gradient curves.
5. The intersection of this curve with the annulus gas gradient curve represents the "**point of balance**" between the tubing and annulus pressure. At this depth, injection pressure in the casing-tubing annulus equals the flowing pressure in the tubing string.
6. The **operating gas lift valve** should be run above the "point of balance" to ensure a pressure differential across the valve during operation. For this reason a parallel to the gas gradient line is drawn at a distance of about 100 psi, the

intersection of which with the flowing tubing pressure defines the depth of the required gas injection point.

7. Now the gas injection requirement is found. For this, the pressure traverse curve that fits between the point of injection and the wellhead pressure should be found, if gradient curves are used. In computer calculations, a trial-and- error procedure can be used to find the proper gas-liquid ratio, GLR_{total}.

8. Injection gas requirement is found by subtracting the amount of gas supplied by the formation, GLP_p, from the total ratio:

$$GLR_{inj} = GLR_{total} - GLR_p$$

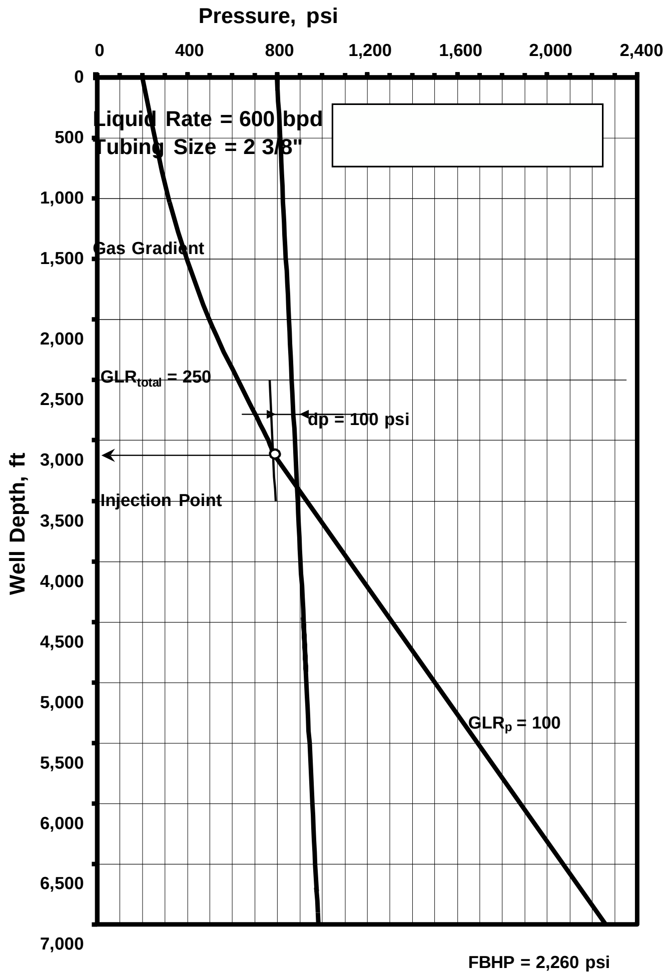
where: GLR_{total} = calculated GLR above the point of gas injection, scf/bbl,
GLR_p = formation GLR, scf/bbl,

Design Considerations

The above procedure results in reliable designs as long as all required parameters are well known. In practice, however, this is not always the case and the following considerations should be taken into account:

- The surface gas injection pressure should be based on the pressure always available at the wellsite. In case of a **fluctuating line pressure**, its minimum value must be taken as the design pressure. This ensures that the required surface injection pressure is available at all times.
- The **pressure differential** across the operating gas lift valve, usually taken as 100 psi, severely affects the well's flowing bottomhole pressure and, consequently, its rate. This is especially true for high-capacity wells with high PIs (productivity indices), where a considerable increase of liquid rates can be achieved if the pressure differential is reduced. [4]
- Due to the well-known calculation errors in vertical multiphase pressure drop predictions, as well as due to fluctuations in well inflow performance, actual injection depths can differ from those found from the above design procedure. In high-capacity wells this can result in production losses, and "**bracketing**" of gas lift valves is recommended. This means that several closely spaced gas lift valves are run close to the design injection depth, allowing to move the injection depth deep enough.
- In high-volume wells, the required gas injection volume can be more than that available at the wellhead. In such cases, lower injection GLRs must be used and the restriction on gas availability may severely limit the liquid rate lifted.
- In continuous flow installations the operating valve must be open at all times and its opening pressure should be set accordingly. Valve setting, therefore, is very critical and should be based on the minimum flowing tubing pressure and, in case of gas charged gas lift valves, on a proper estimate of valve temperature.
- If well inflow performance data are not reliable or unknown, the basic design procedure detailed above cannot be used to find the depth of the operating valve with the proper accuracy.

Example 1.1: Find the point of gas injection and the required gas volume for a well with the following data. Perforation depth is 7,000 ft, where formation pressure is 2,500 psi, the well's PI (productivity index) is 2.5 bpd/psi. The well produces 600 bpd of oil with a formation GLR_p of 100 scf/bbl through a tubing with a 2 3/8" OD and a wellhead pressure of 200 psi. Lift gas of 0.75 relative gravity is injected with a surface injection pressure of 800 psi.



Sample design of a continuous flow gas lift installation for Example 1.1.

Solution

The well's flowing bottomhole pressure is found from the productivity index principle as:

$p_{wf} = p_{ws} – q / PI = 2,500 – 600 / 2.5 = 2,260$ psi.

All graphical constructions will be accomplished , a gradient curve sheet valid for the above conditions. First, the pressure traverse below the point of gas injection is plotted starting from the flowing bottomhole pressure.

Next, calculate and plot the distribution of gas pressure in the annulus. From **Fig. B-1** in **Appendix B**, the static gas gradient for the given injection pressure and gas gravity is found as 26 psi/1,000 ft. Gas pressure at the perforation level is found as:

800 + (26 / 1,000) 7,000 = 982 psi.

A parallel with the gas pressure line, drawn with a pressure differential of dp = 100 psi, intersects the pressure traverse valid below the gas injection at the depth of 3,100 ft, which specifies the required injection point. Using the gradient curve sheet, the pressure traverse connecting the injection point with the specified wellhead pressure can be found. The gas requirement belonging to the proper curve equals 250 scf/bbl, and the injection requirement is found as:

$GLR_{inj} = 250 – 100 = 150$ scf/bbl.

1.4 Intermittent Flow

1.4.1 Introduction

In intermittent gas lift, the liquid in the vertical column is lifted to the surface in a slug or piston form by injecting high pressure gas beneath it. The injected gas expands and displaces the liquid slug, lifting it to the surface. This lift method requires a cyclic operation, thus the term "intermitting gas lift".

Intermittent gas lift should be used at the time when the well's bottomhole pressure can no longer support the vertical flowing gradient, and until an economical production limit is reached. Typically, intermittent lift applies to wells with rather low liquid production and low bottomhole pressure. Under average conditions, intermittent lift will produce rates from 1 to 600 B/D. Wells where intermittent lift is recommended normally have the characteristic of (1) high PI and low BHP or (2) low PI with high BHP. Its use stems from known major pumping problems or where continuous gas lift is already installed or low cost high pressure gas is available.

Thus, when an adequate, good quality, low cost gas supply is available and plans are to lift a relatively shallow, high GOR, low PI or low BHP well with a bad dog-leg that produces same sand; intermittent gas lift would be an excellent choice. Intermittent gas lift has many of the same strengths and limitations as constant flow, and the major factors to be considered are similar.

The amount of production possible from an intermittent system depends on the amount of liquid produced during each cycle and the number of cycles possible per day. Normally, a large ported gas lift valve is used to allow test transfer of gas from casing annulus into the tubing, thus, increasing the fluid velocity and reducing fallback. The volume of gas used during a cycle should be enough to displace the liquids from the depth of injection to the surface. The gas volume can be controlled by a surface time-cycle controller or down hole by the gas lift valve's spread characteristics.

Since intermittent wells produce in a cyclic manner several considerations must be made with respect to surface facilities. Especially, when applied to offshore platforms. Intermittent lift requires a large instantaneous amount of injection gas during the lift cycle. When using a time-cycle controller, a large periodic demand for lift gas is necessary. This can cause a decrease in the lift gas supply pressure if the injection gas flow lines are not large enough. This can affect other gas lift wells on the same system. A choke controlled intermitting system utilizing the downhole spread of a gas lift valve can help to eliminate this problem. Also, once the slug reaches the surface, a large instantaneous fluid and gas volume is produced, the flowline and separator capacities must be large enough to handle the slug or other wells may be affected with high back pressure in addition to the separator being shut in due to a high level or high pressure.

The intermittent gas lift system consists of: (1) a high pressure gas source (either a compressor or a gas well), (2) distribution lines to conduct the high pressure gas to the wellhead, (3) a surface gas controller, (4) gas lift valves and other subsurface equipment, (5) flow lines, and (6) separator and storage facilities.

Each of the components of the system is important and any improperly designed component can seriously affect the efficiency of the entire system.

1.4.1.2 HighPressure Gas Source

Normally, the high pressure gas source will be a compressor system but in some cases, high pressure gas wells are used. For a properly operated system, it is important that a system with sufficient pressure and volume be used.

Intermittent gas lift is inherently difficult to manage since the cyclic nature of intermittent lift creates demands for large volumes of gas for short time spans. If the system is to function efficiently, the high pressure source must be capable of providing these high instantaneous rates. Large distribution lines minimize the problems.

1.4.1.3 Distribution Lines for High Pressure Gas

Here again, the problem of high instantaneous rates are encountered. Careful consideration should be given to looping lines and using the maximum size that can be justified. Large lines create storage and minimal pressure losses.

1.4.1.4 SurfaceGas Controllers

The most common methods of controlling the input gas are: (1) time cycle control, (2) choke control, (3) choke and pressure regulator control and (4) choke and time cycle control.

1.4.1.5 Gas Lift Valves and Other Subsurface Equipment

Most intermittent gas lift wells will contain (1) several gas lift valves and mandrels, (2) a packer and (3) a seating nipple. Should the well be free of sand, a standing valve is normally used in the seating nipple. Provided the formation has very low pressure, a standing valve may be required to prevent the slug from going down instead of up.

1.4.1.6 Flowlines

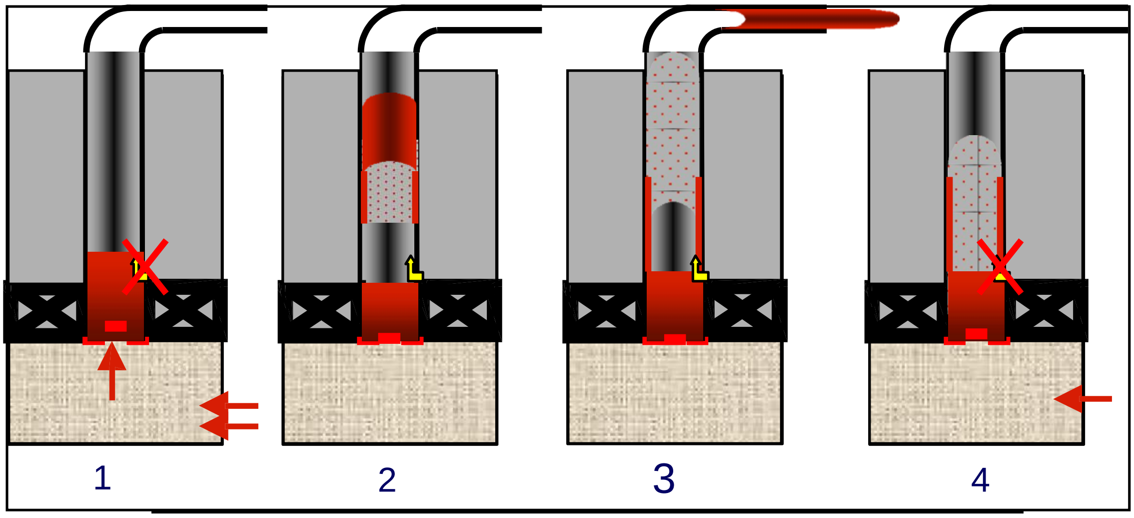
When considering flowlines, it is important to remember that while the intermitting well may be a low producer, the production rate is intermittent and the flow rate may be very high during the few minutes that the intermittent production occurs. For best results, flowlines should be designed to handle the high instantaneous rate. Streamlined flowlines that eliminate all elbows, choke nipples, and sharp turns are also very desirable.

1.4.1.7 Separators and Storage Facilities

The separator must be sized large enough to handle the high instantaneous rates, both fluid and gas. Large discharge valves for both the gas and fluid will assist greatly in this effort.

1.4.2 The Intermitting Cycle

In intermittent gas lift, the liquid in the tubing string is lifted to the surface in a "slug" or piston form by injecting high pressure gas below the slug which expands and displaces the liquid to the surface. This method of lift is a cyclic operation and the cycle can be divided into four periods.



Intermittent lift cycle

1. **Inflow period** - during this period the liquid flows from the formation into the well bore and collects in the tubing above the gas lift valve. The gas lift valve is closed during this period and the tubing pressure is reduced to a minimum to allow the maximum inflow rate.

2. **Lift period** - when sufficient liquid has collected in the tubing, the gas lift valve opens and injects high pressure gas to lift the slug to the surface. Fallback occurs due to liquid coalescing in a film on the wall of the tubing and liquid droplets in the gas slug which lack sufficient velocity to travel to the surface.

3. **Production period** – fluid is produced at the surface. A rapid drop in tubing pressure pulls in gas from the casing. No inflow occurs during this period.

4. **Pressure reduction period** - after the gas lift valve closes and the slug flows through the separator, the lift gas pressure is dissipated and the inflow period begins again. The intermitting cycle is controlled by regulating the frequency of injection, the gas flow rate during injection and total quantity of gas injected during each lift period.

1.4.3 Production Performance

Maximum production from intermittent lift results from optimizing each period of the lift cycle. It is evident that the maximum production is achieved by completing the maximum number of efficient cycles. An efficient cycle means the maximum liquid recovery with an economical gas injection volume.

The two performance parameters of intermittent gas lift are volumetric efficiency

$V.E. = B_t/B_e$

Where B_t = Fluid influx during a cycle,

B_e = Fluid recovered during a cycle

and injected gas-liquid ratio:

$R_i = Q_n/B_t$

Where Q_n is the gas injected per cycle

During the lift period and part of the pressure reduction period the liquid inflow is greatly reduced or stopped completely; therefore, the lift period is optimized by reducing its time to a minimum. The average slug velocity is the controlling factor of the lift period. Field operation has shown that there is a velocity range that results in optimum recovery of liquid. This range is approximately 900 - 1200 ft/min. There are two factors controlling the slug velocity; (1) starting slug size (actually the pressure resulting from the liquid slug plus the tubing back pressure) and (2) the gas injection rate. Both of these factors are controlled by the gas lift valve: the starting slug size by the pressure adjustment and the gas injection rate by the valve port size.

For maximum production, the pressure reduction period should also be reduced to a minimum. The controlling factors are flow line length, size and other restrictions (such as chokes, etc.), separator capacity and operating pressure. The inflow period is optimized by reducing the tubing back pressure to a minimum and installing the operating gas lift valve as deep as possible. The final consideration for maximum production is the cycle frequency. For correct adjustment the well should be cycled as often as the optimum slug size enters the tubing.

1.4.4 Production Capabilities of an Intermitting System

The production capabilities of an intermitting system depend on the following:

1. The starting load
2. Efficiency of Lift
3. Number of cycles per day

1.4.4.1 Starting Load

The starting load is identified as the tubing pressure at the valve when the valve opens and field operation has shown that a starting load of 65-75% of the gas pressure will result in an average slug velocity in the optimum recovery range. The 65% load is a good average for the designer to consider. The upper limits of 75% may be used where surface tubing pressure exceeds 200 psi, or other favorable factors exist such as a large ported valve for high gas delivery rates into the tubing, large flowlines to prevent high tubing head pressure during a cycle and high injection pressures.

The starting load or the tubing pressure at the valve when it opens may be expressed as follows:

P_t = (Load Factor)(P_c)

$P_e = P_t - P_{ts}$

$B_e = ((P_t - P_{ts})/G_s)F_{tb}$

Where B_e = Fluid recovered during a cycle, Bbl

P_e = Pressure of fluid influx, psi

P_t = Tubing pressure at the valve, psi

P_c = Casing pressure at the valve, psi

P_{ts} = Tubing pressure at the surface, psi

F_{tb} = Tubing volume factor, Bbl/ft

G_s = Fluid gradient, psi/ft.

1.4.4.2Efficiency of Lift

Efficiency of lift or volumetric efficiency is the ratio of the recovered load to the starting load. As the slug of fluid moves up the tubing, some of the liquids adhere to the tubing walls and some is entrained as droplets in the gas phase. This lost load is normally referred to as fallback and is primarily dependent on the size of the starting load and depth of the well. Field tests have shown that a fallback of 5% of the starting load per 1000 ft. lift will exist when the load is within the recommended 65-75% range. Therefore, the efficiency may be expressed as:

$$V_E = [1 - \frac{0.05D_v}{1000}]100\,\%$$

The recovered fluid per cycle may be calculated from the equation

$V_E = B_t/B_e$ and $B_t = V_E\ B_e$

where B_t is fluid produced per cycle, Bbl/cycle.

1.4.4.3 Number of Cycles per Day

The maximum number of cycles possible per day is primarily dependent upon the depth of lift and the pressure reduction period. It should be remembered that the complete cycle consists of the inflow period, lift period and pressure reduction period. For design purposes, the minimum time per cycle may be assumed to be three minutes per 1000 feet of lift. Therefore, the maximum cycles per day may be expressed:

N_c (Maximum) = (1440 x 1000)/(3 x D_v) = 480,000/D_v

Where 1440 is minutes per day, 3 is number of minutes per 1000 ft. of lift

D_v is valve depth in feet

Calculation Procedure:

The maximum capacity of an intermitting system may be calculated as follows:

Given: Tubing Size, depth of lift (normally the bottom valve), D_v, Casing pressure at valve, P_c, Tubing back pressure, P_{sp}, and Gradient of produced fluids, G_s

(1) Calculate The fluid influx assuming a 65% load.

$P_t = .65\ P_c$

$B_e = ((P_t - P_{ts})/G_s)F_{tb}$

(2) The efficiency of lift

$$V_E = [1 - \frac{0.05D_v}{1000}]100$$

(3) The recovered fluid per cycle is a function of the starting fluid and volumetric efficiency.

$B_t = E(B_e)$ (Bbls/Cycle)

(4) The maximum number of cycles per day that normally can be expected is a function of depth, assuming all other factors are favorable.

N_c (Maximum) = $(1440 \times 1000)/(3 \times D_v)$

(5) The maximum predicted production may be calculated knowing the recovered fluid per cycle and the maximum number of cycles.

$q_l = N_c\ B_t$ (Bbls/Day)

1.4.5 Gas Lift Valves for Intermitting Use

The primary requirement of the intermitting valves is the ability to pass a large volume of gas. Three categories of valves are primarily used in intermitting gas lift systems. These are (1) pilot operated gas lift valves, (2) injection pressure operated (dome charged) gas lift valves and (3) production pressure operated (fluid sensitive) valves. Other types are used but discussion will be limited to these broad categories.

1.4.5.1 Pilot Operated Valve

The pilot operated valve has a specific application for intermittent lift. It contains a large ported main valve section that is slaved to a pilot section and opens and closes in unison with the pilot. This feature provides the very important advantage that the ball and seat size can be varied as required for the desired spread without affecting the gas passage ability of the valve.

1.4.5.2 Injection Pressure Operated (Dome Charged) Valve

This valve has been widely used for intermitting use. Since the port size affects the gas passage as well as the spread, considerable care must be taken to obtain a balanced design: a port of sufficient size to lift the load but not so large that the valve has excessive spread.

1.4.5.3 Production Pressure Operated (Fluid Sensitive) Valve

The fluid sensitive valve, contrary to the other valves, is a very small-ported valve whose opening and closing is almost totally a factor of tubing pressure. The operation depends on several valve openings to pass the desired amount of gas to lift the intermittent load. This is accomplished when the bottom valve starts the load and as the load passes up the tubing, each successive valve opens. The valves close as the load is lifted to the surface and the pressure reduction period starts.

1.4.6 Injection Gas Requirements

1.4.6.1 Operating Pressure

Intermittent gas lift can be accomplished with a wide range of system pressures with the practical minimum pressure related to depth of lift. The working pressure of available gas lift valves limits the maximum pressure, which is in the order of 1500-2000 psi.

1.4.6.2 Gas Injection Rate

The gas flow rate through the gas lift valve must be high enough to maintain the slug velocity in the optimum range. For maximum efficiency and cycle frequency, normally a large ported valve is required.

1.4.6.3 Gas Volume Required per Cycle

Two phase slug flow is complex; so it is difficult to calculate the total gas volume exactly. An estimate can be obtained using the following assumptions: At the moment the slug arrives at the surface, the tubing is filled with gas at a pressure equal to the average between the starting slug head and the valve close pressure.

This may be expressed as:

$Q_n = P_{tf} V_t/P_a$

Where Q_n = Injected gas required during interval, ft^3

P_{tf} = Average of Starting Load and Valve Close Pressure

$= (P_{vc} + P_t)/2 + 14.7$ psia

V_t = Volume of tubing (ft^3) from depth of valve (D_v) less the length of the starting fluid head

$= [D_v - (B_e/F_{tb})]\ F_{tv}$

P_a = Atmospheric pressure

It would be more correct to include the effect of temperature and compressibility but since the basis for the calculation is approximate, this is not necessary unless extreme temperatures or pressures are involved.

1.4.6.4 Gas Liquid Ratio

The injected gas liquid ratio is the gas injected per cycle divided by the recovered fluid per cycle.

$R_i = Q_n/B_t$

Where Q_n is injection gas liquid ratio (ft3/bbl)

1.4.7 Control of Injection Gas

The final control of the intermittent lift cycle is accomplished by integrating the characteristics of the surface controller and the gas lift valve. The amount of injection gas on each cycle is (1) that amount of gas stored in the casing annulus between the gas lift valve opening and closing pressure plus (2) that amount injected into the annulus at the surface while the gas lift valve was open. Therefore, we must carefully consider the characteristics of both the gas lift valve and the surface controller.

1.4.7.1 Control of Injection Gas by the Gas Lift Valve

A review of the force balance equation for a gas lift valve follows:

When the valve is closed: $P_d = P_c - F_{ts}(P_c - P_t)$
When the valve is open: $P_d = P_c$

Where: $F_{ts} = A_s/A_b$

From the equations, it can be seen that the gas lift valve is responsive to both the casing and tubing pressure when closed but responsive to the casing pressure only when open.

Example A
Given:
P_d = 700 psi at the valve
P_t = 400 psi at the valve
F_{ts} = .166 (NM14 w/.25" port)

Find:
P_c required to open the valve,
P_c when valve closes,
Spread

Pc required to open the valve:

$$P_d = P_c - F_{ts}(P_c - P_t)$$
$$P_c = (P_d - F_{ts} P_t)/(1 - F_{ts})$$
$$= [700 - .166(400)]/.834$$
$$= 760$$

Pc when the valve closes:

$P_d = P_c$ (when the Valve is open)
P_c = 700 psi

The spread is the difference in the casing pressure at the point where the valve opens and closes or:

Spread = 760 - 700 = 60 psi

The minimum amount of gas injected when the valve opens is that amount stored in the annulus at 760 psi less that volume stored at 700 psi where the valve closes. Examine the parameters for a valve with a port of .375" when all pressure conditions remain the same:

Example B

Given: P_d 700 psi at the valve
P_t = 400 psi at the valve
F_{ts} = .367(NM14 w/.375" port)

Find: P_c required to open the valve
P_c when valve closes
Spread

P_c required to open the valve:

$P_c = [P_d - F_{ts} P_t]/[1 - F_{ts}]$
$= [700 - .367(400)]/0.633$
$= 874$ psi

Pc when valve closes:

$P_c = P_d$
$P_c = 700$ psi

The spread is now 874 - 700 = 174 psi

Examples A and B illustrate the effect of the change in port size; therefore the tubing effect – (A_s/A_b) –factor, F_{ts}. Should choke control be desired, where most of the gas for the cycle will be stored in the annulus, the use of the proper F_{ts} factor is very important. Provided time cycle control is used, the F_{ts} is not critical but should be no larger than that for choke control.

Gas volume stored in the annulus at the start of cycle

$V_1 = P_c V_a D_v/P_a$
where: V_a = Unit annular volume ft3/ft
P_a = Atmospheric pressure, psia
P_c = Casing pressure when valve opens

Gas volume remaining in the annulus at the end of lift

$V_2 = P_{vc} V_a D_v/P_a$
where: P_{vc} = Valve closing pressure or Casing pressure when valve closes

The difference represents the minimum gas volume injected.

$Q_s = V_1 - V_2$
$Q_s = (P_c - P_{vc}) (V_a D_v/P_a)$

Including a temperature correction:

$Q_s = (P_c - P_{vc})\ (V_a\ D_v/P_a)(T_s/T_a)$

where: T_s = Standard temperature 520°R

T_a = Average annulus temperature, °R

Rearranging and substituting an average annulus temperature of 580°R and atmospheric pressure of 14.7 psia:

$P_c - P_{vc} = Q_s\ (14.7)(580)/(V_a\ D_v\ 520)$

$P_c - P_{vc} = 16.4\ Q_s/(V_a\ D_v)$

The volume of gas stored in the annulus, Q_s, should be 75% of the gas required to affect the lift cycle. Therefore:

$Q_s = 0.75\ Q_n$

where: Q_n may be obtained from R_i

$Q_n = R_i \times B_t$

V_a may be found earlier. P_c is normally a known value and P_t is a function of P_c (65 - 75% load factor). Therefore, F_{ts} may be calculated:

$F_{ts} = (P_c - P_{vc})/(P_c - P_t)$

P_t may also be calculated from:

$B_e = B_t/V_E$

$P_t = (B_e\ G_s/F_{tb})\ (P_{sp})$

1.4.7.2 Control of Injection Gas by the Surface Controller

Several types of controllers are used to complement the injection gas controlled by the gas lift valve. The two most commonly used are the time cycle controller and choke.

1.4.7.2.1 Time Cycle Control

The time cycle control method transfers the major part of the intermitting lift cycle control to the surface. This control consists of a clock driven pilot, which opens and closes a diaphragm actuated valve on the gas supply line. The pilot can be adjusted to inject gas for a specific time and close the gas supply for a specific time. During the injection time the annulus pressure increases until the force balance on the gas lift valve is satisfied. At this point, the valve opens and the lift starts. The gas injection will continue until the time cycle controller closes and the annulus pressure drops to the close pressure of the gas lift valve. The volume of gas injected is that controlled by the spread of the gas lift valve plus the gas injected from the time the gas lift valve opens until the surface timer closes.

During the time pilot "off" time the annulus pressure remains at the gas lift valve close pressure and so lift cannot occur until the pilot starts the next gas injection into the casing.

The optimum adjustment of the time cycle control method is accomplished when:

1. The gas volume injected is reduced to the minimum necessary for efficient lift.

2. The set time interval between cycles corresponds to the time required to inflow the efficient sized liquid slug.

The time cycle control offers the advantage of a major part of the control at the surface and the disadvantage of a high instantaneous gas flow demand on the high pressure gas distribution system. Also the time cycle control has two interdependent adjustments making it more difficult to adjust.

1.4.7.2.2 Choke Control

The choke control method utilizes the well's inflow performance and the gas lift valves operational characteristics to control the intermitting lift cycle. This surface control consists of an adjustable choke or "flow control valve" on the gas supply line. This choke is adjusted to allow the gas to flow into the annulus at a steady rate. During the liquid inflow period, the gas lift valve is closed and the tubing pressure at the valve increases. The annulus pressure is also increasing and when the two pressures reach the level set by the force balance equation, the gas lift valve opens and starts the lift cycle. The flow capacity of the gas lift valve must exceed the gas flow rate through the choke. Otherwise, no decrease in the annulus pressure will occur and the gas lift valve will not close.

The optimum adjustment of the choke control method is accomplished when the choke is adjusted so that the annulus pressure buildup coincides with the liquid inflow rate from the formation, and the design casing and tubing pressures are reached at the same time.

The injected gas volume is controlled by the spread of the gas lift valve and the proper selection of gas lift valve tubing effect factor.

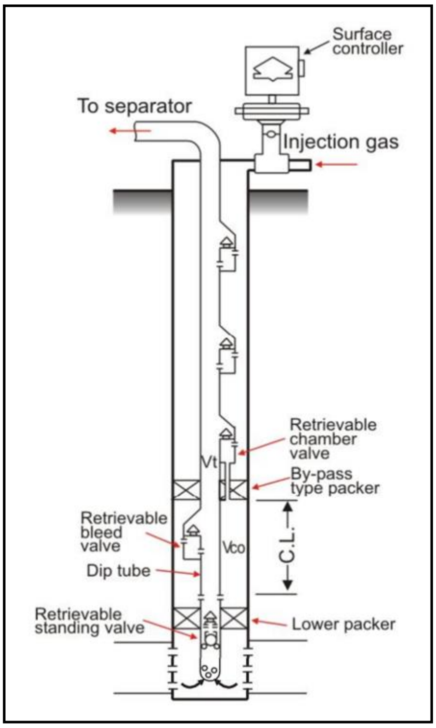
The choke control method has the advantage of steady demand on the gas supply system and a single function adjustment. The cycle frequency is controlled by the well. A disadvantage is the operational efficiency depends on a more exact installation design and a predictable operation of the gas lift valves. It should be noted that a system designed for choke control can be operated by a time cycle controller.

1.4.8 Chamber Lift

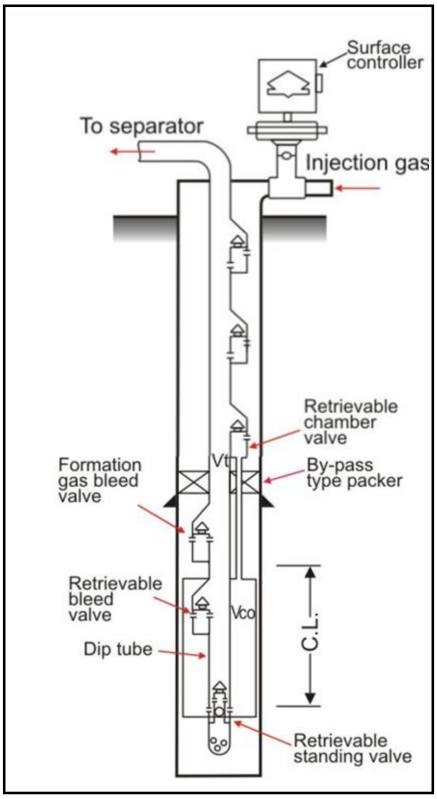
A chamber installation is a special type of intermitting gas lift installation that uses an enlarged section called a "chamber" at the bottom of the tubing string. The purpose of this chamber is to collect the maximum quantity of fluid in the well bore with the minimum fluid pressure at the formation. This system is useful in increasing the production rate from a low pressure reservoir.

The physical chamber design is usually tailored to the particular well and may be formed by using a large section of tubing or by installing two packers and using the casing itself. Since this enlarged section does not permit the installation of a gas lift valve at the bottom of the chamber, the valve is installed above the chamber and a "dip tube" is used to inject the gas beneath the fluid. A standing valve at the bottom of the chamber is a necessary part of the system.

Regardless of physical configuration, chambers can be classified in two types. In the Type I the gas is injected into the annular space between the dip tube and the chamber.



Type I – Two Packer Chamber Installation



Type II – Insert Chamber Installation

In Type II the gas is injected down the dip tube.

The length of the chamber in either type should be calculated so that the maximum fluid head that occurs during the lift cycle is approximately 65% of the lift gas pressure. This condition occurs in the Type I chamber when all the fluid has been transferred from the annular space in the chamber into the dip tube and the tubing. The volume of fluid in the tubing and dip tube that produces the required fluid head can be equated to the volume of the annular space in the chamber, which determines the optimum chamber length. The following equation is used to calculate the chamber length of a Type I chamber:

$$L_{c1} = \frac{0.65 P_{vc} A_t}{G_s (A_c - A_d + A_t)}$$

where: L_{cl} = Chamber Length – ft

P_{vc} = Close Pressure of Chamber Valve - psi

A_c = Internal Cross-Sectional Area of Chamber - in^2

A_d = External Cross-Sectional Area of Dip Tube - in^2

A_t = Internal Cross-Sectional Area of Tubing - in^2

G_s = Static Gradient - psi/ft.

In the Type II chamber, the maximum fluid head occurs when the fluid has been transferred from the chamber into the tubing. The equation for calculating the optimum chamber length of a Type II chamber is:

$L_{c2} = 0.65\ P_{vc} A_t/(G_s\ A_c)$

If the chamber of either type is too short, the fluid recovery will be reduced. If it is too long, the gas consumption will be excessive because it will be necessary to initiate the lift cycle before the chamber is full. The Type I chamber requires a "Bleed Port" in the top of the dip tube to allow the gas trapped in the chamber to escape during the fluid feed-in. The bleed port should be approximately 1/16" in diameter in most cases. If the formation gas-fluid ratio is high it may be advantageous to use a differential valve instead of a bleed port.

If the well is loaded during shut-in periods, it will require unloading valves. These valves should be spaced from the surface the same as a standard installation. The last unloading valve should be within sixty feet (two joints) of the chamber valve.

1.4.8.1 Chamber Valve Specifications

Since the liquid head pressure effect on the pilot valve is not present in a chamber installation, the tubing effect factor for the chamber valve should be the minimum available. The force balance equation can be used to determine the closing pressure of the chamber valve using this F_{ts} and the operating separator pressure (P_{sp}) as the tubing pressure.

1.4.9 Operation of Intermitting Lift System

The following section gives a brief discussion of the installation procedure, unloading operation, and well adjustment.

1.4.9.1 Installation

An accurate tubing tally should be made so that the valves can be installed at the joint nearest to the designed depth. A standing valve is an integral part of an intermitting gas lift installation and may be installed before the seating nipple is lowered in the well or it may be run on wire line. The seating nipple is installed in the tubing string below the bottom valve and the bottom valve is spaced immediately above the packer. However, if the running diameter of the mandrel is close to the drift diameter of the casing, two joints of tubing should be run between the packer and bottom mandrel to prevent binding against the casing wall. The mandrels should be handled carefully while they are being installed in the tubing string and should be guided through the well head fittings. Once the mandrels are inside the casing below the tubing head, the tubing may be lowered at any desired rate. Mandrels are usually marked so that the operator can tell which end of the Mandrel to run in the upward direction.

1.4.9.2Unloading Operation

During the unloading operation, well liquids are being transferred through the gas lift valves from the casing to the tubing. Because of this, the well should be kicked off slowly so that the well fluids won't damage the gas lift valves. A good cycle for unloading is obtained with two to four minute gas injections each 20 to 30 minutes. The casing pressure is frequently erratic during this procedure, so an odd-looking pressure chart is not a cause for alarm. In most wells, twenty-four (24) hours or less will clear the annular space of fluid.

1.4.9.3Well Adjustment

After the well is unloaded, it should be adjusted for the maximum liquid production with a minimum gas-liquid ratio. The design calculations provide a good initial adjustment but the fine adjustment requires production testing.

Complete testing instrumentation is necessary to exactly evaluate the operation of the system. The most useful single instrument is the pressure recorder with two elements to record the tubing and casing pressure simultaneously. The analysis of these charts can provide information on the well adjustment and valve operation.

1.4.10 Data Required for an Installation Design

In order to design a continuous gas lift installation, the following data is needed:

1. Completion information like depth of mid-perforations, deviation profile of the well, tubing size, casing size, flow configuration, downhole restrictions like SSSV,
2. Reservoir information* like static bottomhole pressure, productivity index or inflow performance relationship,
3. Fluid information like specific gravities of produced oil, water, and gas, formation gas-oil ratio*, water cut*, injection gas gravities, and
4. Operating information like production rate*, flowing wellhead pressure, injection gas pressure at the wellhead*, available injection gas quantity*, flowing temperature profile*, and type of gas lift valve.

The information marked with an asterisk * vary with time, so depending on the time-horizon over which the installation needs to operate, changes to the marked data items over that time horizon need to be considered in the design.

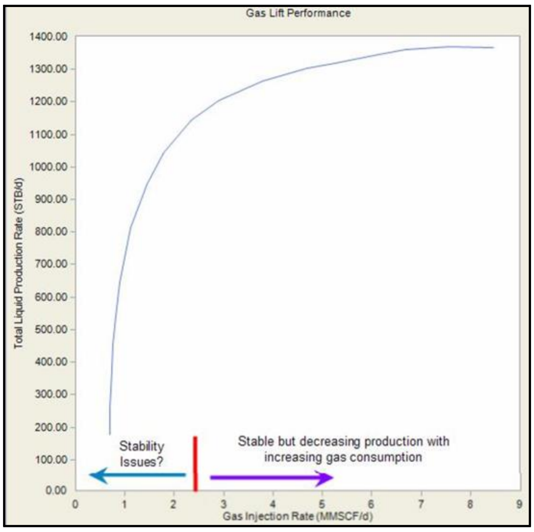
1.4.11Design Problems

There are three types of installation design problems:

1. Valve spacing, sizing and pressure setting need to be determined for an existing well that needs to be converted to gas lift,
2. Valve spacing needs to be determined for a well that is projected to require gas lift at a later date, i.e. design with limited information, and
3. Valve sizing and pressure setting need to be determined for a well with existing mandrels.

Regardless of the design problem, a design procedure must ensure that gas is injected at the deepest point possible, and it is injected at a single point in the well. To accomplish this, the design procedure must account for injection and production flow characteristics and valve operating characteristics so that an upper valve can not be opened while gas is being injected at a deeper point.

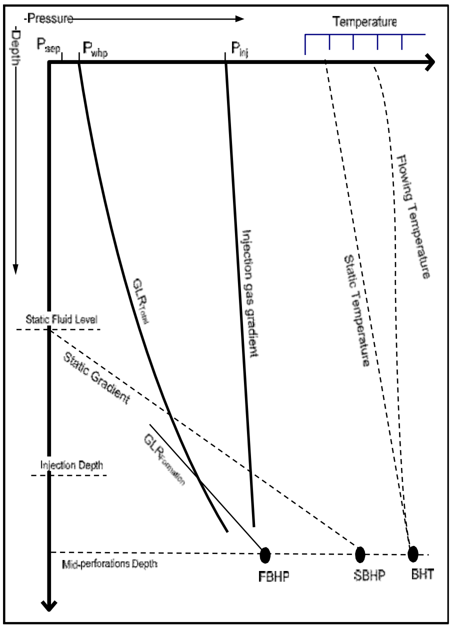
When better information is available, the first step is determination of the production flow rate and corresponding injection gas quantity required. This step can be performed by preparing a gas lift performance curve using a Nodal Analysis package like WellFlo:



When an unlimited quantity of injection gas is available, inject a high enough quantity to avoid stability issues. Select a point on the flattening part of the curve at the smallest injection quantity possible. Avoid selecting an injection gas quantity in the steeper slope area because a small fluctuation in injection gas quantity may induce tubing heading leading to installation instability as described elsewhere.

Once the liquid production rate and lift gas injection rate values are selected for an installation, several gradients need to be prepared which are used in graphical designs discussed later.

a. Create a pressure versus depth plot and mark a line at the mid-perforations depth.
b. Plot the injection gas pressure gradient from the surface operating injection pressure.
c. From inflow performance, calculate *FBHP* required to produce the design liquid rate, and mark it at the mid-perforations depth along with *SBHP*.
d. Plot flowing the gradient curve for the design rate and *formation* GLR from the *FBHP* until it crosses the injection gas gradient line less total pressure drop value.



e. Plot the flowing gradient curve for the design rate and *Total* GLR (=*Injection* + *Formation* GLR) from the wellhead pressure until it crosses the *formation* GLR curve plotted in the previous step. This curve represents the design gradient curve and its intersection with the *Formation* GLR line represents the injection depth necessary to produce the design rate with the design injection rate.
f. Plot the static fluid gradient for the well completion (or kill) fluid from *SBHP* upwards until it crosses the depth axis. This depth is the Static Fluid Level (SFL).
g. Plot static the temperature gradient line from mean surface temperature at zero depth to the bottomhole temperature at the mid-perforations depth.
h. Also, plot the flowing temperature gradient which is considerably higher than the static temperature gradient. Flowing temperature values are needed to determine valve setting pressures at surface temperatures in the test rack.

1.5 Comparison of Continuous and Intermittent Flow Systems

CONDITION	CONTINUOUS FLOW	INTERMITTENT
Production Rate (bbl/day)	100 – 75,000	Up to 500
Static BHP (psi)	> 0.3 psi/ft	< 0.3 psi/ft
Flowing BHP (psi)	> 0.08 psi/ft	150 psi and higher
Injection gas (scf/bbl)	50 – 250 per 1000 ft of lift	250 – 300 per 1000 ft of
Injection Pressure (psi)	> 100 psi per 1000 ft of lift	< 100 psi per 1000 ft of lift
Gas injection rate	Larger volumes	Smaller volumes

1.6 Common Gas Lift Operational Issues

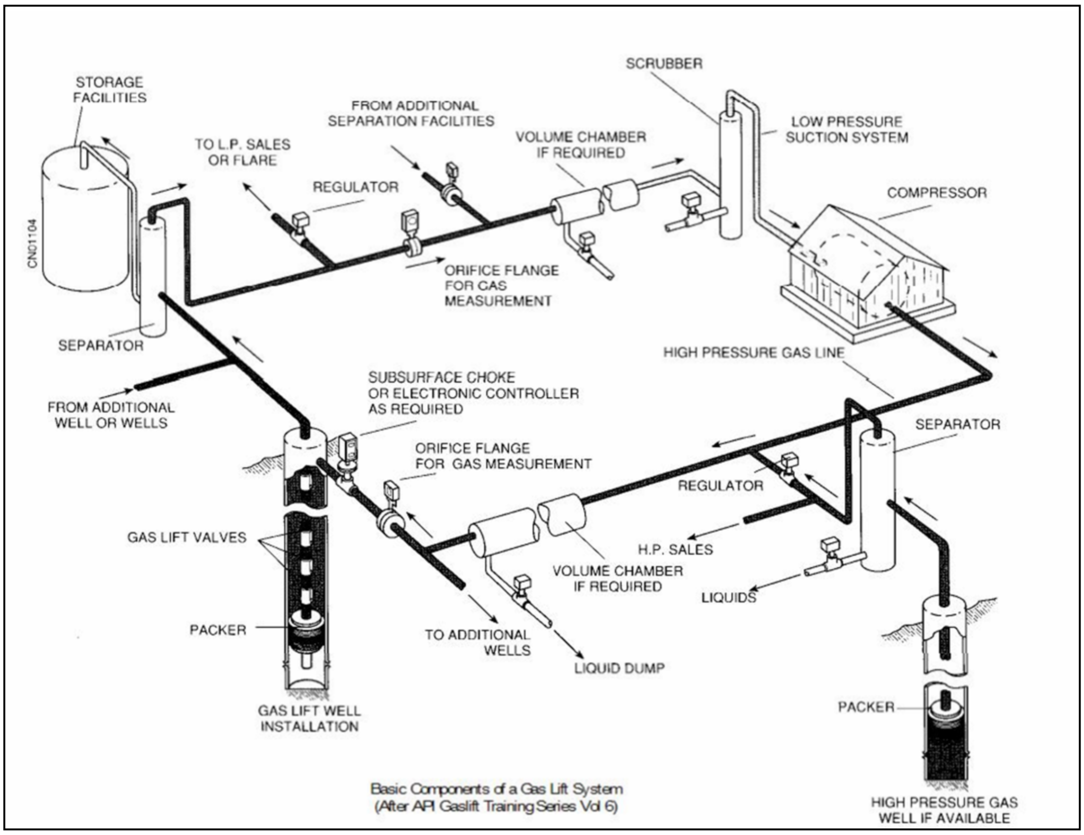
Also there are some potential problems with gas lift that must be resolved as identified below:

- Freezing and hydrate problems in injection gas lines.
- Corrosive injection gas.
- Severe paraffin problems.
- Fluctuating suction and discharge pressures.
- Wireline problems.
- Dual artificial lift frequently results in poor lift efficiency.
- Changing well conditions, especially decline in BHP and PI.
- Deep high volume lift
- Valve interference – multi-pointing

Chapter 2: Gas Lift Installations /Equipment

2.1 Introduction

The components of a gas lift system consist of a source of high pressure gas distribution lines to conduct the gas to the well head, surface controls, subsurface gas lift equipment and other subsurface equipment, flow lines, separation and storage equipment. The efficiency of the gas lift system depends on proper engineering of all these components.



Basic Components of a Gas Lift System (After API Gaslift Training Series Vol 6)

Closed rotative gas lift system

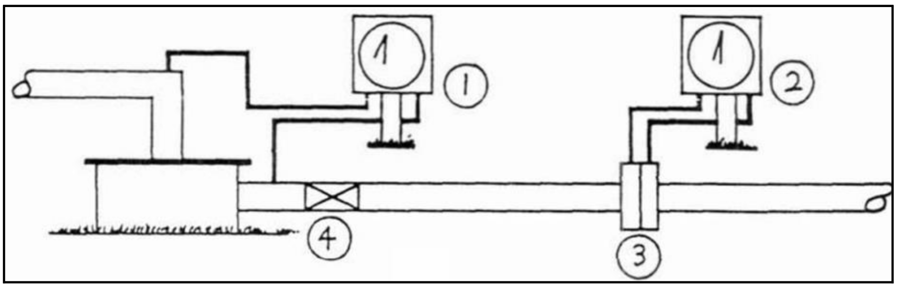
The portion of the system which we will be most concerned about is the subsurface gas lift equipment or the gas lift valve and mandrel; and they are detailed in subsequent sections.

The amount of other subsurface equipment will vary a great deal depending on the location and type of well. Nearly always, the installation will consist of a packer and usually some type of seating nipple near the bottom of the tubing. If the installation is for intermittent lift, a standing valve is usually used in the bottom seating nipple. Other type seating nipples may also be used for installing subsurface safety valves and other controls.

Separation and storage usually consist of a separator and tank facilities, but only the separator is of importance to gas lift operations. The separator must be large enough to handle the production requirements. For intermittent lift, the production rate requirement is the instantaneous rate when the slug hits the separator. Also of importance is the ability of the separator to rapidly dispel the liquids. Should these requirements not be met, the tendency is for the pressure relief valve to open and blow fluids to the air.

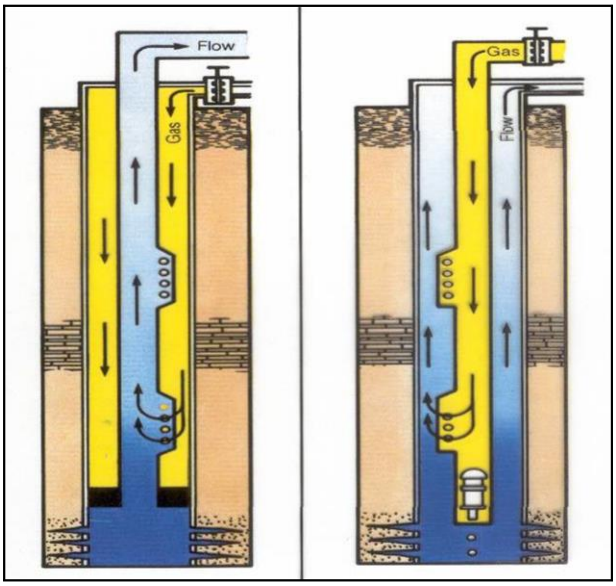
Surface controls may be simple or complex depending upon whether continuous lift or intermittent lift and the degree of control desired by the operator. The sketch below indicates some important considerations for surface equipment.

1. Two pen recorder to indicate and record casing and tubing pressures.
2. Orifice meter to measure injection volume.
3. Orifice Run.
4. Surface Control - May be choke: intermitter, regulator or combination.



Typical surface equipment for a gas lift installation

2.2 Types of Gas Lift Installations



Continuous gas lift completion configurations

A gas lift installation can be configured for tubing flow or annular flow as shown in the schematic. In the tubing flow installation (diagram at left), gas is injected down the casing-tubing annulus through a gas lift valve and into the tubing whereas in the annular flow configuration (diagram at right), gas is injected down the tubing through a gas lift valve and into the casing-tubing annulus.

2.3 Gas Lift Mandrels

Mandrels are used in gas-lift, chemical injection, and waterflood applications to lower flow-control devices into the wellbore. The mandrels have threaded connections and form an integral part of the tubing string. Mandrels provide an offset location away from the full-bore drift ID of the tubing and in this location, a gas lift valve or other flow-control device is installed, thus permitting post-completion operations without impediment.

Mandrels are manufactured to accommodate 5/8", 1" and 1-1/2" gas lift valves and variety of thread and material options. The mandrels may be divided into conventional and retrievable types depending on how gas-lift valves (or other flow-control devices) are installed or removed.

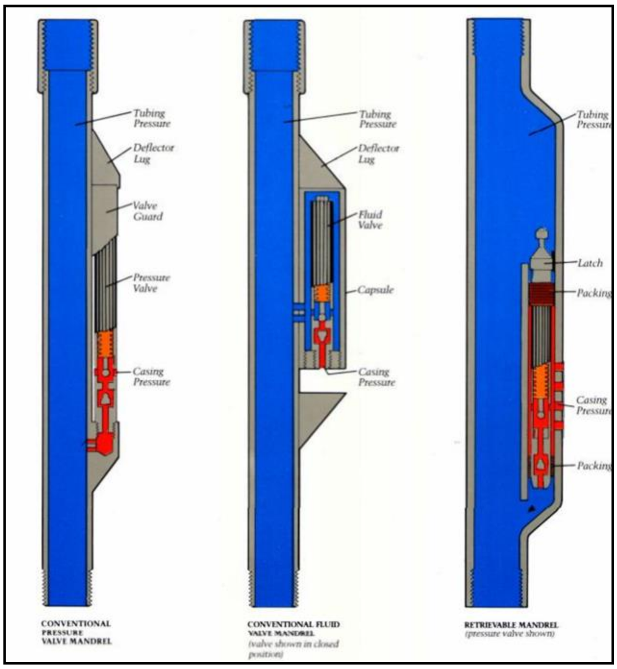
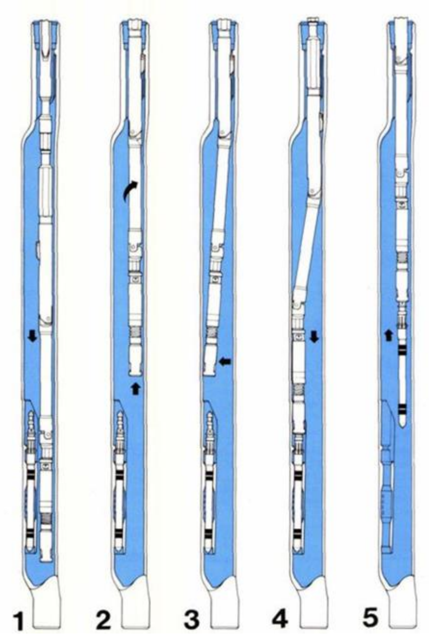


Illustration of conventional and side pocket gas lift mandrels

Conventional gas-lift mandrels are equipped with external lugs to receive gas-lift and orifice valves. The valve is installed at the surface in the mandrel before lowering the mandrel as a part of the tubing completion string. External guards are attached to the OD of the mandrels, surrounding the valves and providing protection during tubing running and pulling operations.

Several types of retrievable mandrels are available but the most common is the side pocket mandrel. The side pocket is offset from the bore of the tubing, allowing full tubing drift for well-servicing operations through the mandrel, without restriction. The side pocket encompasses profiles and sealed bores to land a flow-control device. Gas-lift and other flow-control devices are installed in the side pocket using a kickover tool, which is run into the well, using standard wireline techniques as shown in the figure below.



1. The tool is run below the mandrel. Since the tool is locked in a rigid position, it cannot kick over accidentally.
2. The operator slowly raises the positioning tool until the key of the tool engages the orienting sleeve in the mandrel. Further upward movement causes the positioning tool to rotate until the key enters the slot. When the key reaches the top of the slot, the operator receives an indication on the weight indicator.
3. The positioning tool is now properly oriented. The operator pulls an additional strain on the line (200 lbs. above the free weight of tools and line). This strain forces the pivot arm to swing out and lock in position. The valve or pulling tool is now located just above the pocket or latch.
4. Once the tool is locked in the offset position, a valve may be installed or removed with the internal `V shape of the mandrel accurately guiding the tools.
5. Removal of the tool is accomplished when the shear pin is sheared as the key reaches the top of the slot. This action allows the trigger to glide freely out of the slot and thru tubing. When the pivot arm reaches the small upper section of the mandrel, it snaps back and locks into the rigid position; thus, there is no drag on the tool or valve as it is removed from the well.

Retrieval of a gas lift valve from a side pocket mandrel using a kickover tool

Most of these mandrels include an integral orienting sleeve that aligns the kickover tool and flow-control device above the pocket for precise installation in straight and deviated wellbores. Mandrels that do not have orienting sleeves should only be installed in straight wellbores. Such mandrels also feature a tool guard at the top of the pocket. The tool guard deflects tools larger than the pulling/running tool back into the tubing bore to prevent damage to the valve latch.

In tubing flow gas-lift operations, injection gas from the casing-tubing annulus enters the opposing mandrel ports, travels through the gas lift valve, and enters the tubing string. Mandrels with alternate port configuration that allows gas to enter from tubing for annulus flow operation are also available. The packing on the flow-control device seals the bore above and below the ports and isolates the production and injection pressures.

Side pocket mandrels usually have an oval profile wherein the pocket is usually welded longitudinally. For exceptional conditions, round cross-sectional profile mandrels are also available that have pockets machined from solid bar stock.

2.1.1 Installation Procedures for Gas Lift Mandrels

1. Handling of Mandrels
   - Mandrels should be slung with two slings. There should be one sling on either side of the major O.D. of the mandrel. This keeps the mandrel well balanced.
   - When in transport insure belly of mandrel is down. This puts the center of gravity to bottom.
   - Ensure all thread protectors are in place before moving mandrel.
   - Cover injection ports on mandrel before transport. This will keep any foreign objects out of the ports.

2. Installation of Mandrels
   - The bottom of the mandrel has the gas injection ports closest to it.
   - Mandrels should be numbered and the setting depth should be recorded on the mandrel
   - Calculate running depth of mandrel. Design depths are TVD and should be converted to MD's.
   - Ensure mandrel ports are uncovered before running them in the hole.
   - Space out mandrels to the nearest 30 foot joint

3. Torque Specification
   - As per recommendations for the specific thread

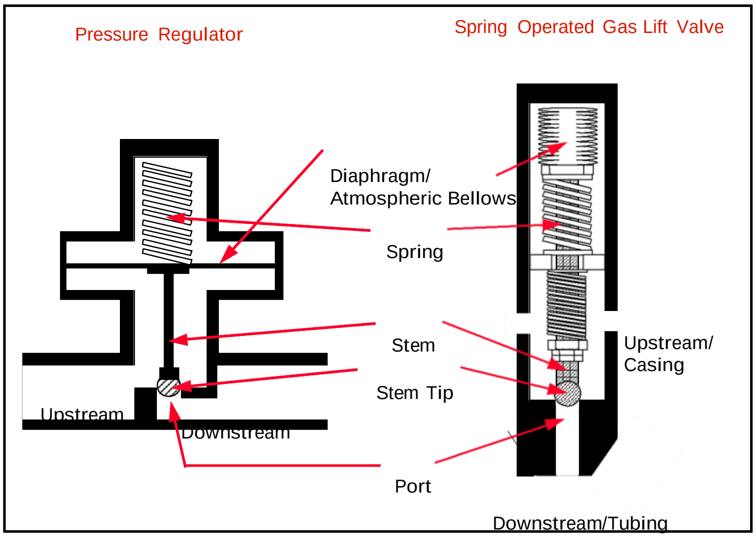
4. Pressure Testing Procedure
   - With the flow device in the mandrel a pressure test can be done in the tubing, (the velocity checks close) but an annular test will be open to the tubing through the flow device
   - Set plug in tubing, pressure test tubing to required pressure.
   - Pressure test down annulus (expect to see pressure on tubing due to flow direction of orifice)

Gas lift mandrel installation procedures

2.4 Valve Classification and Selection

The gas lift valve may be of several types depending on the specific application. The function of the valve is to regulate injection pressure into the tubing. For intermittent lift, the requirement is to inject a large volume of gas as rapidly as possible. For continuous flow, the requirement is to regulate the gas into the tubing continuously. Normally, a back check becomes an integral part of the valve to prevent liquids from going back into the injection side once unloaded.

An understanding of the mechanics of a gas lift valve is essential to properly design or trouble shoot installations. Gas lift valves are basically downhole pressure regulators wherein force exerted by a confined pressure or a spring is countered by injection and production pressures to control the opening through which injection occurs. The basic valve includes a bellows, a chamber (dome) formed by one end of the bellows and the wall and end of the valve, and a port that is opened or closed by a ball attached at the end of the stem. The ball at the end of the stem tip is larger than the port and is finely matched (lapped) to the seat portion of the port forming a seal.



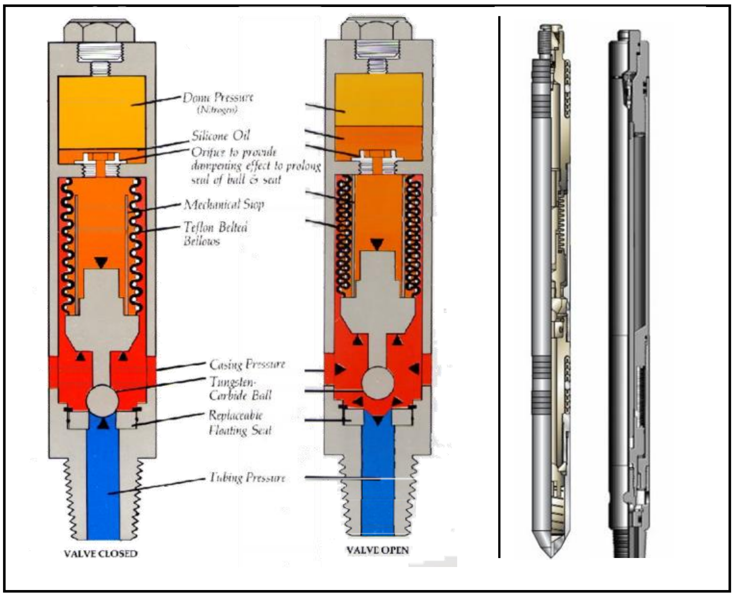
Comparison of IPO gas lift valve to surface pressure regulator

Although the design and configuration of gas lift valves are many, based on the internal construction, they may be divided into two categories: (1) Pressure charged and (2) spring loaded. In a pressure-charged valve, the force opposing injection and production pressures is provided solely by a dome charge and the spring is absent. On the other hand, in a spring-loaded valve a spring provides all (or almost all) of the opposing force.

Two opposing forces are at work in the pressure charged valve. The nitrogen charge located inside the bellows acts on the three-ply bellows to hold the ball on seat thereby keeping the valve in a closed position. This closing force is opposed by two opening forces: the injection gas pressure and the production pressure. When these combined opening forces exceed the nitrogen charge, the valve opens, and injection gas flows into the production string if injection pressure is higher than the production pressure. Pressure charged valves are classified based on which of the two counter pressures –injection or tubing – exerts on the larger area thereby dominating the valve-opening action. If the injection pressure acts on the external side of the bellows and the production pressure acts over the area of the valve port as shown in the figure below then the valve is called an Injection Pressure Operated (IPO) gas lift valve. Conversely when the production pressure acts on the external side of the bellows, i.e., larger area, then the valve is called a Production Pressure Operated (PPO) gas lift valve.

2.4.1 Injection Pressure Operated (IPO) Valve

The IPO valve is primarily controlled by the injection pressure. The components include a dome, a bellows assembly, a ball and seat and a check valve. When comparing this valve to a pressure regulator during the operation, the bellows assembly acts as the diaphragm, the dome charge (generally nitrogen) is the spring or loading element and the stem is the transmission element. In addition, there is a ball and seat. Nitrogen is used to pressure charge the bellows because besides being a non-reactive inert gas, it reacts to pressure and temperature in a predictable manner. This is important in valve operations



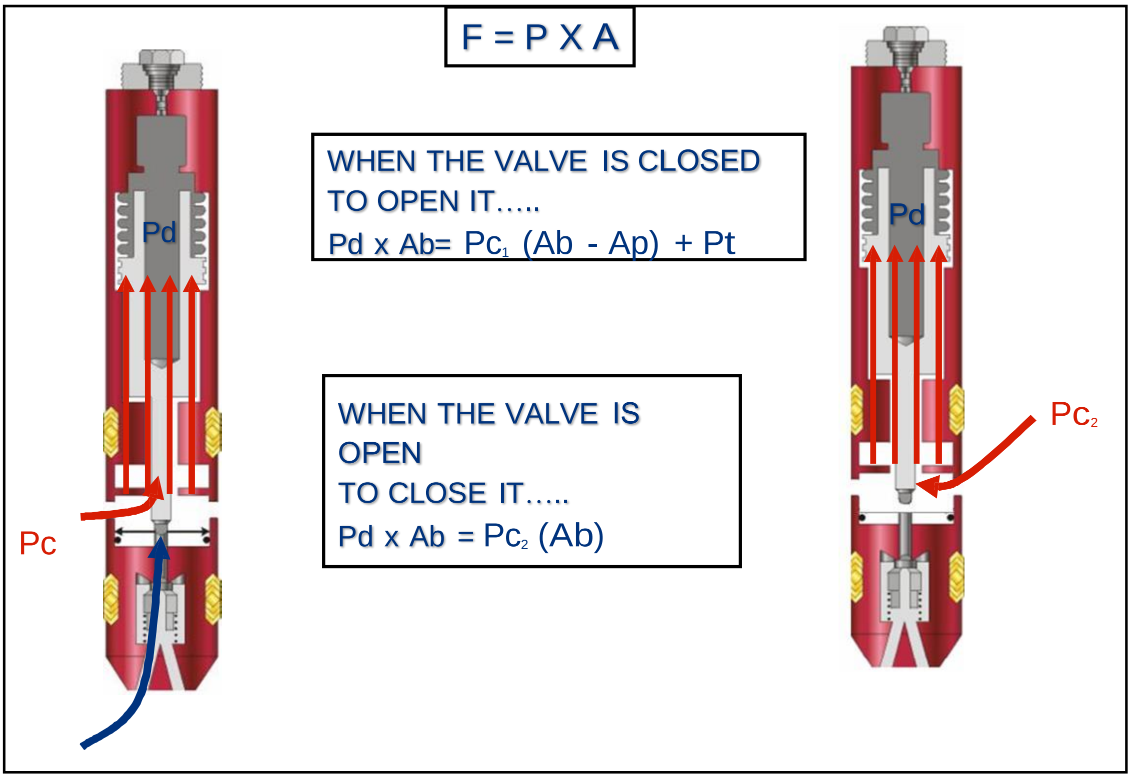
Injection Pressure Operated (IPO) gas lift valve

because any change in temperature caused by operating depth or production rate, effects the opening and closing pressure of the valve. The primary opening force is the injection or upstream pressure acting on the area of the bellows, less the area of the port. The secondary opening force is the production or downstream pressure acting on the area of the port. When the combination of the two opening forces is greater than the single closing force, the valve opens. Once the valve opens, the stem area is exposed to injection pressure. At this time the injection pressure is working on both the area of the bellows and the area of the port so only injection pressure is holding the valve open. In order to close the valve, the injection pressure has to be lowered to a value equal to or less than the dome pressure. The valve is considered "unbalanced" as it opens at one pressure and closes at another. The difference between the two pressures is referred to as "spread". Valves that have the same OD typically have the same bellows size, i.e., same A_b. Therefore, a valve with a larger port size has larger spread, (i.e. a larger injection drop needs to be taken to close a larger ported valve).

The normal application of an injection pressure operated valve is in single wells where the casing pressure can be controlled by an input choke. Injection pressure operated valves with nitrogen-charged bellows are temperature affected. Since the valve is primarily controlled by injection pressure, the operating pressure of each successive lower valve is set below the operating pressure of the valve above to allow the upper valve to close.

<u>Force Balance for an IPO Valve:</u>

- The closing force is provided by nitrogen pressure acting on the area of the bellows and supplied via stem to the ball,
- The opening force is a combination of tubing pressure acting on the ball over the area of the port and casing pressure acting on the outside of the bellows.



Pt

UNBALANCED VALVE

Force balance for an IPO gas lift valve

$$F_c = p_d A_b \qquad \ldots\ldots \text{ Closing Force}$$

$$F_o = p_{inj}(A_b - A_p) + p_{prod} A_p \qquad \ldots\ldots \text{ Opening Force}$$

where p_d = bellows or dome-charge pressure ,
p_{inj} = injection pressure,
p_{prod} = production pressure,
A_b = bellows area,
A_p = port area.

Just before the valve opens, the two forces are equal:

$$F_c = F_o$$

$$p_d A_b = p_{inj}(A_b - A_p) + p_{prod} A_p \qquad \ldots\ldots \text{ Substituting from above}$$

$$p_d = p_{inj}(1 - A_p / A_b) + p_{prod}(A_p / A_b) \quad \ldots\ldots \text{ Dividing by } A_b$$

$$p_d = p_{inj}(1 - R) + p_{prod} R \qquad \ldots\ldots \text{ where } R = A_p / A_b$$

$p_d = p_{vc} = p_{inj}$ … … where p_{vc} = valve closing pressure

The difference between the valve opening pressure and closing pressure is referred to as the *valve spread*. Injection pressure when the valve opens is given by $(p_d - p_{prod})/(1 \quad R)$.

$$\text{So, } \textit{Valve spread} = (p_d - p_{prod})/(1-R) - p_d$$

$$= R(p_d - p_{prod})/(1-R)$$

Another useful term is *Test Rack Open Pressure*, p_{tro}, which refers to the injection pressure required to open a valve when no production pressure is applied. By substituting, p_{prod} equal to zero in the equation below:

$$p_d = p_{tro}(1-R) + p_{prod}(=0)\text{, so}$$

$$p_{tro} = p_d/(1-R)$$

Advantages	Disadvantages
Large range of applications for both continuous as well as intermittent applications	Temperature sensitivity requires accurate anticipation of operating temperatures
Most commonly used valve so operators are highly familiar with design procedure and performance	To keep upper valves closed and compensate for temperature, design of a string must be based on decreasing injection pressure resulting in lower injection depths.
Higher gas passage capability	Requires relatively constant injection pressures
Due to injection pressure sensitivity, design tolerates uncertainties in tubing pressure conditions resulting in forgivable and controllable designs.	May require higher injection pressure to reach optimal injection depth, or higher gas volumes to produce from a suboptimal depth
Easier to troubleshoot since surface measurement of injection pressure may provide indication of injection depth.	

2.4.2 Production Pressure Operated Valve

In the configuration of a Production Pressure Operated (PPO) valve, the components of the bellows, stem, seat and check valve, are all present. The forces acting on the valve are reversed. The production pressure is directed to the bellows area, less the area of the port, and the injection pressure is routed to the area of the port. This results in the primary opening force being the production pressure as this pressure acts on the larger area. The closing force may be a spring or a charged bellows. When using a spring as the closing force, the PPO valve is not temperature sensitive. PPO valves are manufactured in several configurations. There is the PPO that is bellows operated. Another type is the spring loaded PPO, having a spring as the closing force and no bellows charge. This valve has the advantage of not being temperature sensitive. This type of valve is considered balanced as the valve essentially opens and closes at the same pressure setting. Because of high sensitivity to the production pressure this valve is also called a *Fluid valve*.

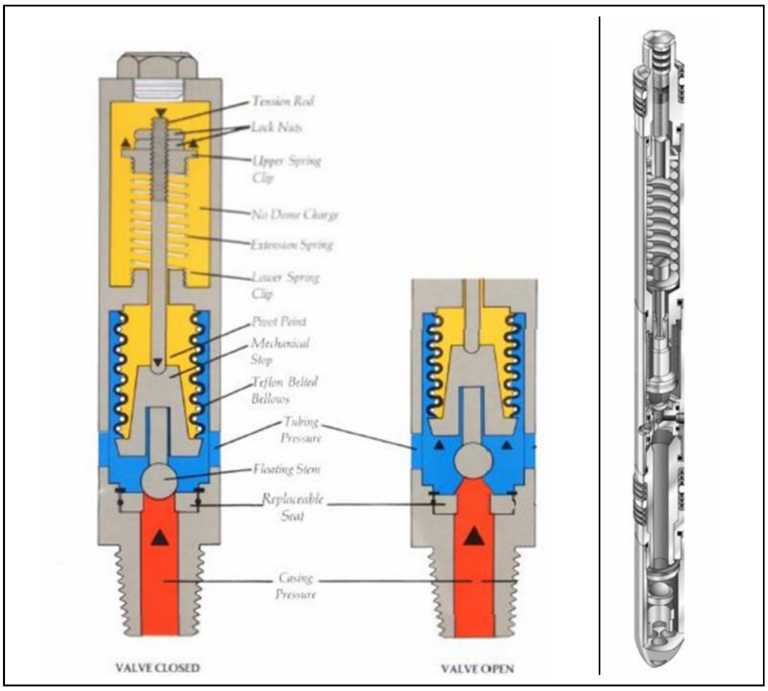


Illustration of Production Pressure Operated (PPO) gas lift valve

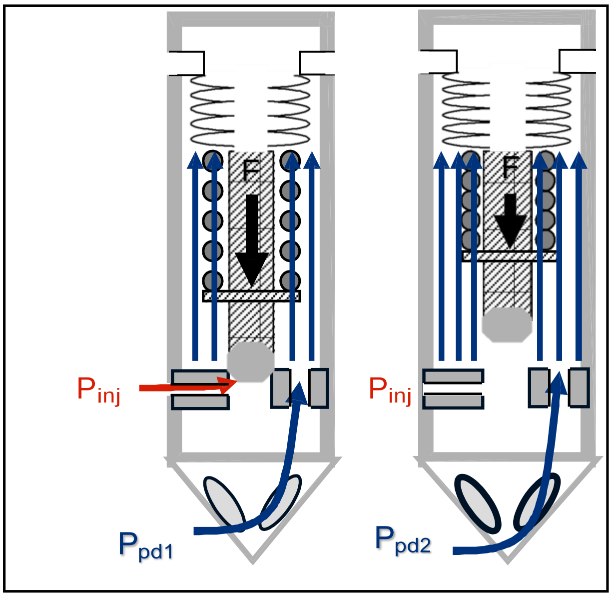
This valve is most suitable for dual applications where two strings of valves must operate simultaneously in a common annulus. If IPO valves are used, then drops in injection pressure may cause inefficient operation due to interference. PPO valves on the other hand operate on the same injection pressure making deeper and predictable injection possible.

Force Balance for a PPO Valve:

- The closing force is provided by the spring tension,
- The opening force is a combination of production pressure acting on the outside of the bellows and the injection pressure acting on the ball over the area of the port,

•

Force balance for PPO gas lift valve



$$F_c = F_s = p_{st} A_b \qquad \text{… … Closing Force}$$

$$F_o = p_{prod}(A_b - A_p) + p_{inj} A_p \qquad \text{… … Opening Force}$$

where p_{st} = spring tension,
p_{inj} = injection pressure,
p_{prod} = production pressure,
A_b = bellows area,
A_p = port area.

Just before the valve opens, the two forces are equal:

$$F_c = F_o$$

$$p_{st} A_b = p_{prod}(A_b - A_p) + p_{inj} A_p \qquad \text{… … Substituting from above}$$

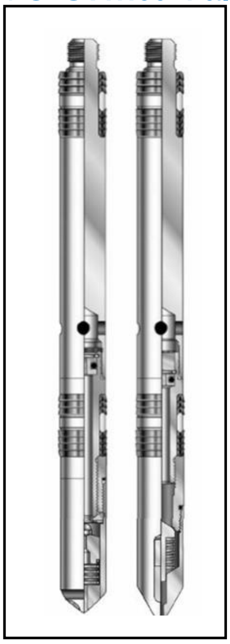
$$p_{st} = p_{prod}(1 - A_p / A_b) + p_{inj}(A_p / A_b) \qquad \text{… … Dividing by } A_b$$

$$p_{st} = p_{prod}(1 - R) + p_{inj} R \qquad \text{… … where } R = A_p / A_b$$

Advantages	Disadvantages
Used in continuous flow application only	Poor gas passage ability requires multiple injection points.
Insensitive to the injection pressure making it highly suitable for installations with fluctuating injection supply line pressures.	Design is not as forgiving as IPO design. Because of high sensitivity to production pressure, changes in surface production pressure from design may cause serious problems.

Suitable for common annulus dual completions since the control is completely from the production side and the injection pressure can be maintained constant.	Harder to troubleshoot since control almost completely from the production side.
Maximum injection pressure is available at the bottom most valve.	Requires closer mandrel spacing resulting in needing more mandrels.
Temperature insensitive because spring tension does not vary with temperature.	More mandrels may lead to multipoint injection.

2.4.3 Orifice Valves



Orifice valves are used for the operating valve position and they do not contain either a bellows or spring element. The size of the orifice and pressure differential across the valve control injection gas throughput. Spring-loaded check valves prevent flow from production to the injection side.

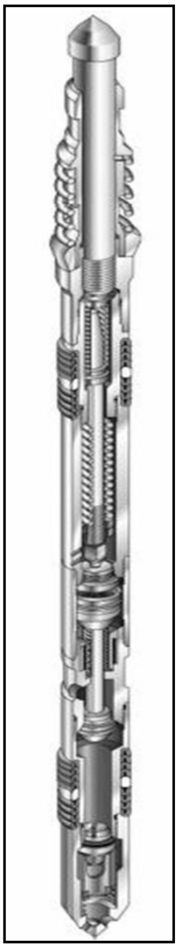
Because of the significant injection pressure drop that occurs, the orifice valves provide a good indication of operating from the desired depth. They cost considerably less than unloading valves because of the absence of bellows or spring elements. They can be used to establish communication between tubing and annulus during circulation operations.

2.4.4 Dummy Valves

Dummy valves are essentially isolation valves that can be used to block the mandrel's injection ports. Typical applications are

- Sealing off the pocket of a side-pocket mandrel, preventing communication between casing and tubing,
- Blanking off the tubing for production until gas-lift valves are required
- Pressurizing the tubing
- Isolating tubing and casing flow during single-alternative production and for test purposes during multi-point water- or gas-injection floods

2.4.5 Pilot Valves



Pilot valves are the most applicable operating valve type for intermittent gas lift installations, due to their controlled, snap-acting opening and large port for passage of a large amount of gas in a short period of time. Advantages of pilot valves include the following:

- Available in dome charge and spring loaded versions
- Large main port power section for efficient intermittent lift application
- Controlled Spread for optimal gas usage
- Excellent choice for intermittent and chamber lift installations
- Spring loaded model- no temperature effect
- Snap acting power section for quick injection response

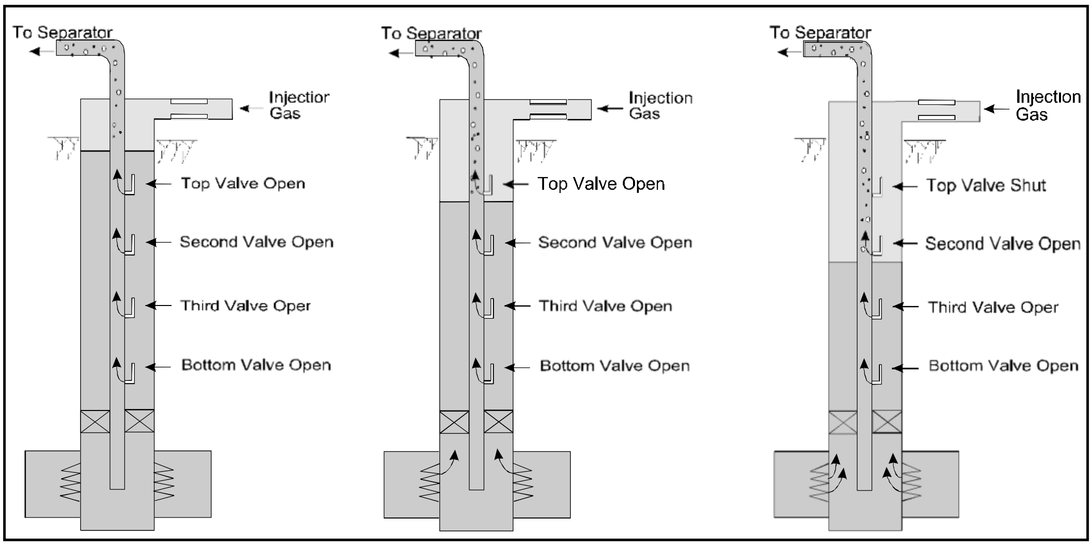
Disadvantages include:

- Poor choice in continuous flow applications
- More moving parts
- Sandy production affects run life

Chapter 3: Unloading of Wells using Gas Lift

Proper understanding of the unloading sequence is essential to the successful design of a gas lift installation. After a well is completed or worked over, the fluid level in the casing and tubing is usually at or near the surface. The injection pressure available to unload the well is usually not sufficient to unload the fluids to the desired depth of gas injection. This is because the pressure caused by the static fluid column in the well at the desired depth of injection is greater than the available injection pressure at the desired depth of injection. In such a case, a series o unloading valves is installed in the well. These valves are designed to use the available gas pressure to unload the well until the desired depth of gas injection is reached. The following figures illustrate a gas lift installation under various stages of the unloading process.

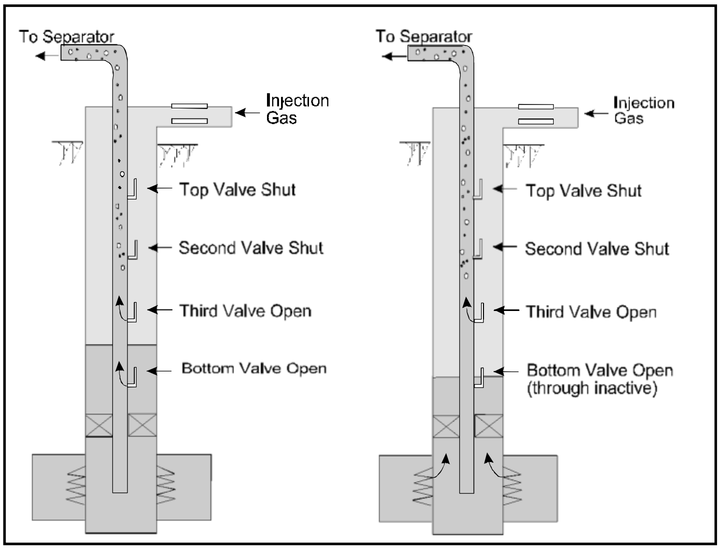
In the beginning, as shown in the left most schematic, the wellbore is full of kill fluid. The kill fluid level, which is the same in the annulus and tubing, can be determined by dividing the static reservoir pressure by the (static) kill fluid gradient when a standing valve is not placed at the bottom of the tubing. All valves are open as the annulus and tubing pressure exceeds the valve opening pressures. As the gas is injected in the annulus, fluid from the annulus is transferred into the tubing through all valves by a simple U-tubing action. No reservoir fluids enter the wellbore because the fluid column in the tubing exerts pressure higher than the static bottomhole pressure.



The middle schematic shows the top valve being uncovered, and gas begins entering the tubing through this valve while lower valves continue to U-tube the kill fluid from annulus into tubing. As more gas enters the tubing, the resulting reduced density of fluids causes reduced tubing pressure at all valve stations and against perforations. At some point, when the fluid column in the tubing exerts a pressure lower than the static bottomhole pressure, reservoir fluid influx occurs. The first valve remains open until the second valve is uncovered.

The right most schematic shows the fluid level in the annulus below the second valve. At this time, initially injection occurs from both the top valves. Injection pressure decreases due to the increased valve throughput and the tubing pressure decreases due to decreased fluid density. Both the decreases cause the top valve to close. The third and fourth valves continue to transfer fluids from the annulus into the tubing. The bottomhole pressure continues to drop resulting in increasing influx from the formation.

In the following figure, the left-most schematic shows the fluid level below the third valve in the annulus as injection continues. At some point, the second valve closes while injection continues from the third valve and U-tube-transfer continues from the bottom-most fourth valve. The flowing bottomhole pressure continues to drop throughout this process resulting in higher influx from the formation.



If sufficient injection pressure is available then this U-tubing process continues until the bottom valve is uncovered and injection begins from that position. In this case, the bottom valve becomes the operating valve.

However, the schematic in the middle shows a condition where injection pressure is not sufficient to uncover the fourth valve, i.e. tubing pressure is higher than the injection pressure at the fourth valve. In this situation, even though the bottom valve is open no injection occurs from that location and the third valve becomes an operating valve until well conditions change.

Chapter 4: Injection Pressure Operated (IPO) Installation Design

Injection Pressure Operated or IPO installation designs use unbalanced pressure charged valves that open and close at different injection pressure values. In order to close a valve, the injection pressure must be lowered below the closing pressure of the valve. So, in order to prevent valve interference – or multi-point injection – valves must be designed to operate at a surface injection pressure which is lower than the valve above. This requirement causes loss of operating injection pressure which is major draw-back of this design.

There are several design methods used for valve spacing depending on availability of information, type of valve, and preference of designer. Most designs are similar with slight modifications on how or when safety factors are applied. Two are discussed below: Constant Pressure Drop method and P_{tmax}-P_{tmin} method.

4.1 Constant Pressure Drop Design Method

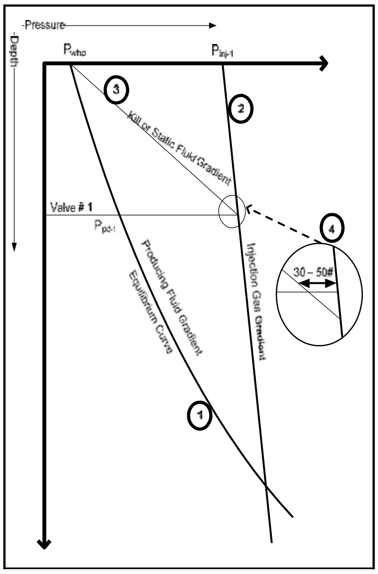
Step 1: Once the design injection and production rate combination is selected, a producing gradient curve is prepared and plotted on a pressure versus depth diagram starting at the operating wellhead pressure.

Step 2: Next, the injection gas gradient is prepared and plotted.

Step 3: Plot the static fluid (also called kill fluid) gradient line from the flowing well head pressure, P_{whp}.

Step 4: The first valve depth is determined at the depth where the pressure difference between the injection gas gradient and the static fluid gradient line is at least 30 psi. This differential ensures that the injection pressure is higher than the production pressure when the valve is uncovered during the unloading operation, allowing injection.

An adjustment in the valve spacing is often necessary to avoid adding smaller tubing joints (pup joints). Actual setting depth can easily vary by 25 ft. The 30-psi differential taken above provides deviation of about 64 ft for 0.465 psi/ft static gradient. (=30/0.465)



Step 5: In order to calculate the second valve depth, a fixed amount of pressure drop is taken from the surface injection pressure. And it is assumed that the second valve will operate with this lowered injection pressure. This fixed pressure drop ensures that when the operation is transferred to the second valve at this lower injection pressure value, the upper valve closes. The gas gradient line is plotted using this lowered injection pressure.

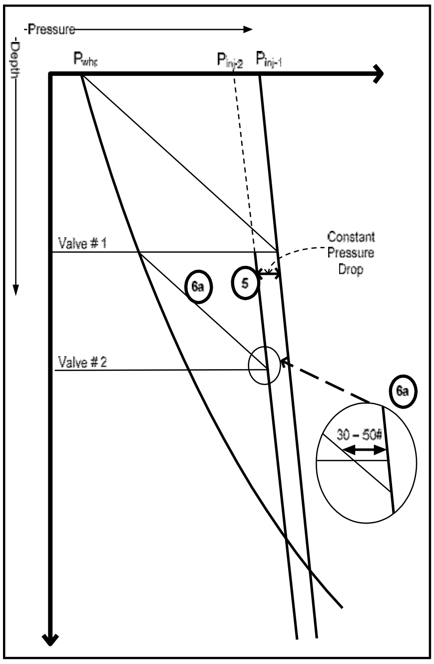
This pressure drop value may be constant for all valve positions or it can be adjusted based on valve and port combination as shown in table below. If the pressure drop is selected based on port size, then perform sizing calculations as described in Step 8 below.

A pressure drop greater than the below recommendation is required when data quality is poor. Also, if the gas injection is possible at the bottom-most depth then higher pressure drops should be taken:

Valve OD (in.)	Port Size (in.)	Safety Factor (psi)
5/8"	1/8"	10
	5/32"	15
	3/16"	20
1"	1/8"	5
	3/16"	10
	1/4"	15
	5/16"	20
1 ½"	3/16"	5

Valve OD (in.)	Port Size (in.)	Safety Factor (psi)
	$\frac{1}{4}$"	10
	$\frac{5}{16}$"	15
	$\frac{3}{8}$"	20
	$\frac{7}{16}$"	25

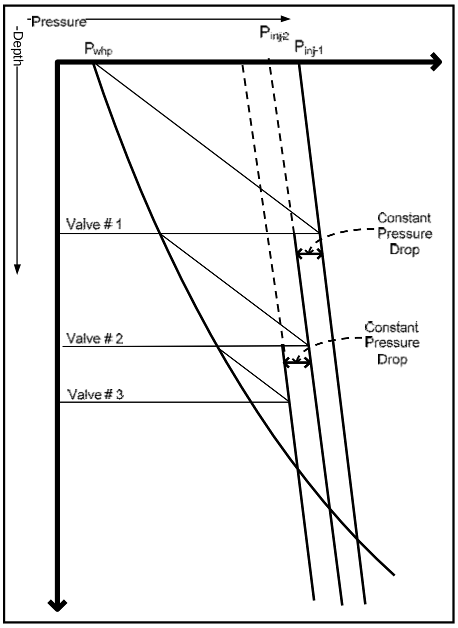
Step 6: The second valve depth is determined at the depth where the pressure difference between the reduced injection gas gradient and the static fluid gradient line is at least 30 psi as before.



Step 7: This process is repeated until one of the following conditions occur indicating the bottom-most valve depth:

- The pressure drop between injection pressure and the minimum production pressure is insufficient. In this case set the operating valve depth at the previous location. It is a good design practice to add one or more valves/mandrels to accommodate for future changes in the operating conditions.
- The maximum possible depth is reached below which injection is not possible, e.g. packer. In this case, set the operating valve one tubing joint above the packer to permit tubing cutting and jarring should need arise during workover at a later date.
- Spacing between successive valve positions is too small. Recommended minimum limit on spacing range from 250 ft for a high

productivity index well with accurate data to 500 ft for a low productivity index well with poor data.



Step 8: Valve Sizing at each valve location: Generally 1" valves are selected where gas injection rates are relatively low (< 750 MCFD). 1½" valves are selected for higher rate wells (> 2000 BPD).

Determine the liquid production rate (Q_l) possible from each valve location: Plot a gradient curve from the production pressure at a valve location to the mid-perforations depth. If the projected bottomhole pressure is less than the reservoir pressure then use inflow performance relationship to determine liquid flow rate, otherwise use the unloading rate, e.g. 200 bpd. If no inflow is possible then the gradient curve could be replaced with a static (kill fluid) gradient line and $GLR_{formation}$ is considered to be zero. Otherwise use a gradient curve for the flow rate and $GLR_{formation}$.

Determine injection gas quantity: Find a gradient curve that will pass through P_{whp} and the production pressure on design gradient curve. Gas-liquid ratio for this gradient curve will indicate the GLR_{total}. Total injection gas quantity at a valve station is determined by:

$$Q_{g\text{-}inj} = Q_l \ (GLR_{total} - GLR_{formation})$$

Determine port size that passes the injection gas quantity by using either Thornhill Craver equation or true valve performance.

Step 9: Valve pressure setting: Once a valve and valve port size is determined, using force balance equations for IPO valves; dome charge pressure and test rack opening pressures are calculated at the valve depth temperature. The test rack open pressure is calculated at the base surface temperature (normally 60º F) by applying a temperature correction factor for the Nitrogen gas which is charged inside the dome.

For the operating valve location, an orifice valve is used when the operating injection gas requirement is higher. If an IPO valve is used, then it is commonly set at a substantially lower pressure than the other valves. This procedure, referred to as *flagging*, causes the surface injection pressure to be below the operating pressure of the upper valves and it provides an indication that the well is operating from the bottom-most position – once the possibility of a tubing leak or other malfunction has been ruled out.

4.2 P_{tmax}-P_{tmin} Design Method

The Constant Casing Pressure Drop method relies on proper selection of pressure drop values at each valve location. Too small a value is likely to result in a greater possibility of valve interference depending on the port size being used, whereas too large a value of pressure drop will result in loss of lift energy and may cause operation at a shallower depth resulting in inefficient lift. The Pt_{max}-Pt_{min} method provides a rational way of selecting injection an pressure drop that falls in between the two extremes of pressure drop values. This is important where available operating injection pressure is low and/or mandrels are widely spaced.

Once a valve size is determined at any location, its *Production Pressure Effect Factor*, P_{PEF}, is available from the manufacturer's catalog for the valve-port combination:

$$P_{PEF} = A_p/(A_p - A_b)$$

At any location, the largest production pressure (under flowing conditions) would not exceed a straight line drawn from the wellhead pressure and the injection pressure at the next location below. If we know the maximum production pressure at any location and if we know the P_{PEF} of the valve at that location; the amount of effective reopening pressure caused by the potential increase in production pressure is given by:

$$\Lambda P = (Pt_{max} - Pt_{min}) \times P_{PEF}$$

The first four steps in graphical design are same as before.

Step 1: Once the design injection and production rate combination is selected, prepare a producing gradient curve and plot on a pressure versus depth diagram starting at the operating wellhead pressure.

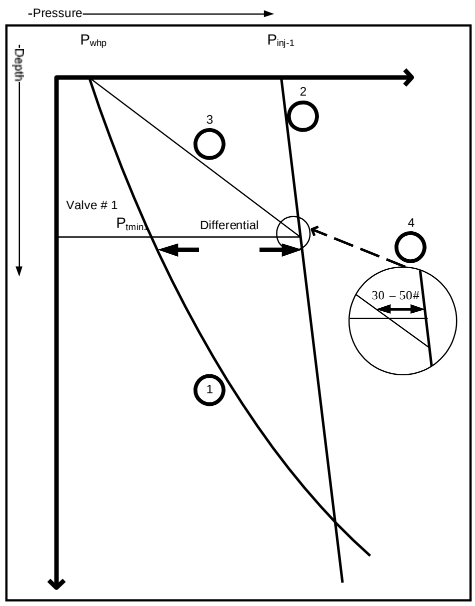
Step 2: Next prepare and plot the injection gas gradient.

Step 3: Plot the static fluid (also called kill fluid) gradient line from the flowing well head pressure, P_{whp}.

Step 4: The first valve depth is determined at the depth where the pressure difference between the injection gas gradient and the static fluid gradient line is at least 30 psi. This differential ensures that the injection pressure is higher than the production pressure when the valve is uncovered during unloading operation allowing injection.

An adjustment in the valve spacing is often necessary to avoid adding smaller tubing joints (pup joints). Actual setting depth can easily vary by 25 ft. The 30-psi differential taken above provides deviation of about 64 ft for 0.465 psi/ft static gradient. (=30/0.465)

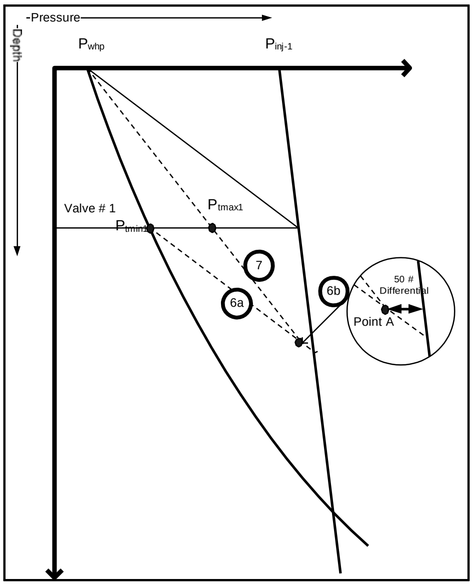
Production pressure at this valve depth from the gradient curve is designated as Pt_{min1}. This is the minimum production pressure at this valve location based on the flow conditions for the gradient curve.



Step 5: Valve sizing is performed next. Calculate required injection gas quantity using process discussed in Step 8 of the Constant Pressure Drop design for an IPO design. Determine the *smallest* port size that passes desired injection gas quantity by using either Thornhill Craver equation or a true valve performance Once a port size is known, determine the production pressure effect, P_{PEF1}, from the manufacturer catalog.

Step 6: Plot a static gradient line from the production pressure at valve number 1 and determine a point (called Point A) where the pressure difference between the injection gas gradient and the static fluid gradient line is 50 psi.

Step 7: Connect ‘Point A’ to the surface production pressure with a straight line. The intersection of this line and the first valve line is the maximum production pressure or Pt_{max1}.



Step 8: Determine effective reopening pressure caused by the potential increase in production pressure from Pt_{min1} to Pt_{max1}.

$$\Delta P_1 = (Pt_{max1} - Pt_{min1}) \text{ x } P_{PEF1}$$

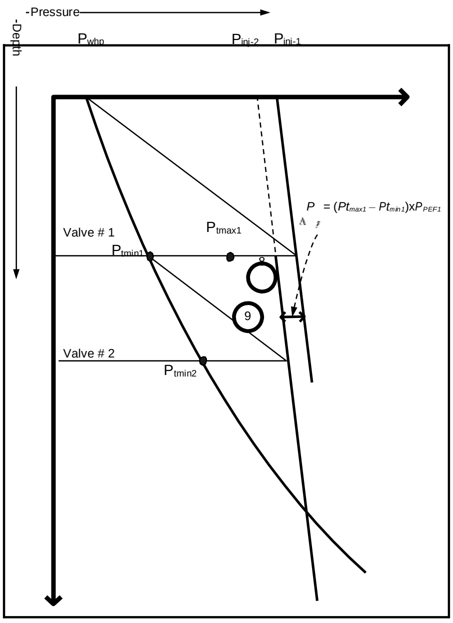
This is the injection pressure drop required to be taken to space the second valve in order to keep the first valve closed while second opens. So surface injection pressure for spacing the second valve is:

$$P_{inj\text{-}2} = P_{inj\text{-}1} - \Lambda P_1 = P_{inj\text{-}1} - (Pt_{max1} - Pt_{min1}) \text{ x } P_{PEF1}$$

Plot a gas gradient line from surface with $P_{inj\text{-}2}$.

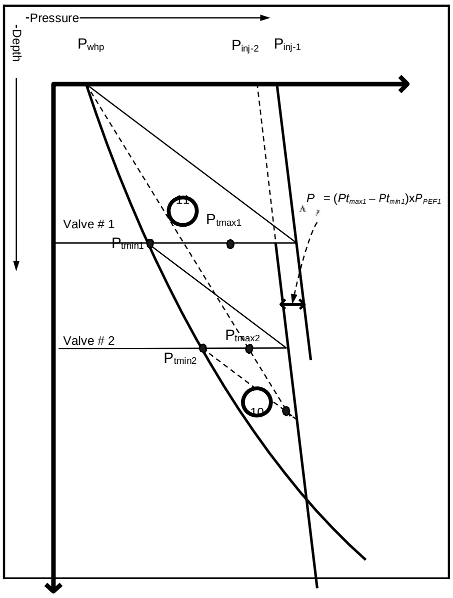
Step 9: Plot static fluid line from the Pt_{min1} at the first location. Similar to step 4 above, the second valve depth is determined; this is at the depth where the pressure difference between the injection gas gradient and the static fluid gradient line is at least 30 psi.

The minimum production pressure at this valve depth from the gradient curve is designated as Pt_{min2}. Perform a valve sizing to determine port size and associated P_{PEF2}.



Step 10: As in step 6 for valve number 1, plot a static gradient line from the Pt_{min2} at valve number 2, and determine a point (called Point A) where the pressure difference between the injection gas gradient and the static fluid gradient line is 50 psi.

Step 11: As in step 7, connect 'Point A' to the surface production pressure with a straight line. The intersection of this line and the second valve line is Pt_{max2} for valve location number 2.



Step 12: Determine effective reopening pressure caused by the potential increase in production pressure from Ptmin2 to Ptmax2.

$$\Delta P_2 = (Pt_{max2} - Pt_{min2}) \text{ x } P_{PEF2}$$

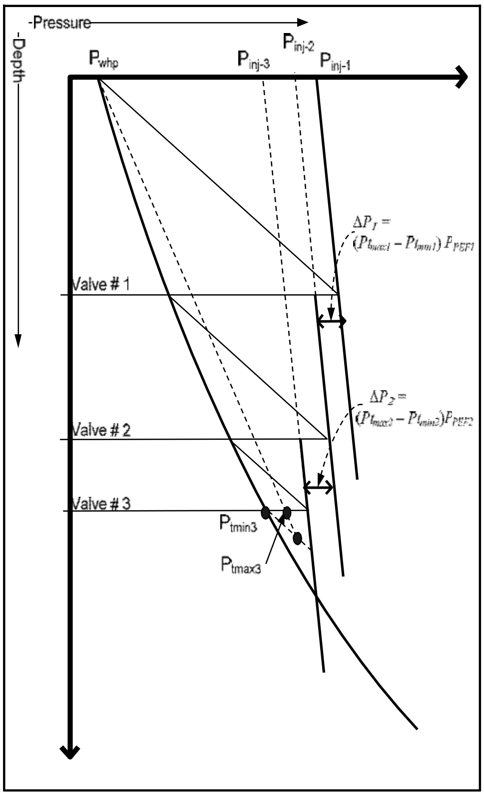
This is the injection pressure drop required to be taken to space the third valve in order to keep the second valve closed while third valve opens. So surface injection pressure for spacing the third valve is:

$$P_{inj\text{-}3} = P_{inj\text{-}2} - \Delta P_2 = P_{inj\text{-}2} - (Pt_{max2} - Pt_{min2}) \times P_{PEF2}$$

Plot a gas gradient line from surface with $P_{inj\text{-}3}$.

Step 13: Repeat steps 9 through 12 until one of the following conditions occur indicating that the bottom-most valve depth has been reached:

- Pressure drop between injection pressure and the minimum production pressure is insufficient. In this case set the operating valve depth at the previous location. It is a good design practice to add one or more valves/mandrels to accommodate for future changes in the operating conditions.
- The maximum possible depth is reached below which injection is not possible, e.g. packer. In this case, set the operating valve one tubing joint above the packer to permit tubing cutting and jarring should need arises during workover at a later date.
- Spacing between successive valve positions is too small. Recommended minimum limit on spacing range from 90 ft for a high productivity index well with accurate data to 500 ft for a low productivity index well with poor data.



Step 14: Valve pressure setting: Once a valve and valve port size is determined at each valve location, dome charge pressure and test rack opening pressures are calculated using force balance equations for IPO valves.

These values are at the valve depth temperature. The test rack open pressure is calculated at the base surface temperature (normally 60º F) by applying temperature correction factor for the Nitrogen gas which is charged inside dome.

For the operating valve location, orifice valve is used when operating injection gas requirement is higher. If an IPO valve is used, then it is commonly set at a substantially lower pressure than the other valves. This procedure, referred to as *flagging*, causes the surface injection pressure to be below the operating pressure of the upper valves and it provides indication that the well is operating from the bottom-most position – once the possibility of a tubing leak or other malfunction has been ruled out.

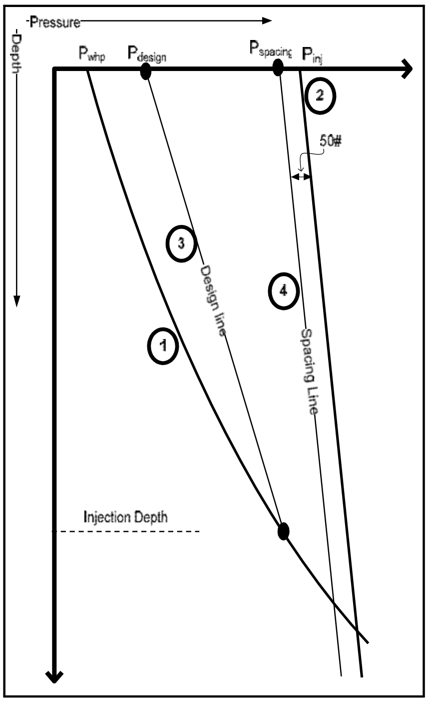
Chapter 5: Production Pressure Operated (PPO) Installation Design

Production Pressure Operated or PPO installation designs use balanced valves (also called fluid valves) that open and close at the same injection pressure value because they are more sensitive to the production pressure. Because the production pressure influences valve opening and closing actions, ideally this design would require accurate estimates of production information.

In order to close a valve, the production pressure must be lowered below the closing pressure of the valve. So in order to prevent valve interference – or multi-point injection – valve's closing pressure is calculated using a production pressure that is higher than the operating or closing pressure of the valve below. This design does not require taking any drop in injection pressure like IPO design so it utilizes full injection pressure throughout, however higher closing production pressure values results in closer valve spacing.

Step 1: After selecting design injection and production rate combination, plot a design flowing gradient curve on a pressure versus depth diagram starting at operating wellhead pressure.

Step 2: Prepare and plot injection gas gradient curve beginning at design injection pressure.



Step 3: Plot a *design line* which will be used to space the unloading valves. Because a PPO valve opens on production pressure, the unloading valves must be spaced

at a higher production pressure than the design producing gradient curve. This prevents the upper valves from opening after the production pressures approach the design flowing gradient. The design line begins at a following pressure on the surface:

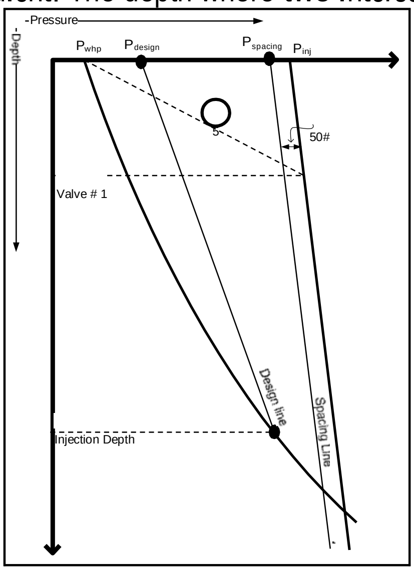
$$P_{design} = P_{whp} + 0.25(P_{inj} - P_{whp})$$

The point at the other end of the design line is the expected point of gas injection for the operating conditions.

Plot the design line by connecting P_{design} and the point on the design gradient at the injection depth.

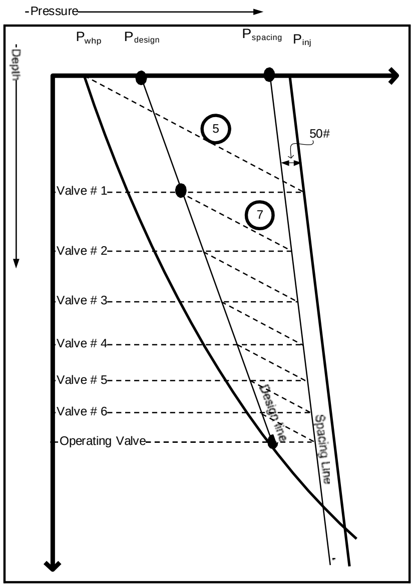
Step 4: Plot a *spacing line* beginning at a surface pressure value 50 psi less than the design injection pressure and parallel to the injection gas gradient. The valve will be spaced from this line. The 50 psi differential ensures that transfer is made to the next lower valve before current valve closes.

Step 5: Plot static gradient line corresponding to the kill fluid (or completion fluid) gradient beginning at the design wellhead pressure until it crosses the injection gas gradient. The depth where two intersect is the top valve depth.



Step 6: Valve sizing is performed next. Calculate required injection gas quantity using process discussed in Step 8 of the Constant Pressure Drop design for an IPO design. Determine the *smallest* port size that passes desired injection gas quantity by using either Thornhill Craver equation or a true valve performance. Once a port size is known, determine the A_p/A_b ratio for the valve-port combination from the manufacturer catalog.

Step 7: Spacing for Valve # 2 onwards: Plot static gradient corresponding to kill or completion fluid beginning at the pressure on the design line at preceding valve depth until it crosses the *spacing* line. The depth where two intersect is the next valve depth. Size the valve per instructions in Step 6.



Step 8: Repeat step 7 until one of the following conditions occur indicating that the bottom-most valve depth has been reached:

- Pressure drop between injection pressure and the minimum production pressure is insufficient. In this case set the operating valve depth at the previous location. It is a good design practice to add one or more valves/mandrels to accommodate for future changes in the operating conditions.
- The maximum possible depth is reached below which injection is not possible, e.g. packer. In this case, set the operating valve one tubing joint above the packer to permit tubing cutting and jarring should need arises during workover at a later date.
- Spacing between successive valve positions is too small. Recommended minimum limit on spacing range from 90 ft for a high productivity index well with accurate data to 500 ft for a low productivity index well with poor data.

Step 9: Valve setting pressure calculations: Since the valve opens and closes at the same pressure, the test rack open pressure (P_{tro}) is calculated using force balance equation for the PPO valves:

$$P_{tro} = P_{pd} + \frac{A_p / A_b}{(1 - A_p / A_b)} P_{inj}$$

P_{pd} for each position (except for the operating valve) is determined from the design line at each valve depth whereas P_{inj} is read from the injection gradient line at each valve depth. P_{tro} is rounded to the nearest 5 psi.

For the operating valve, because this is production pressure sensitive valve the valve needs to stay open as the well depletes. Therefore the bottom valve is flagged by setting it to open at a much lower production pressure than that presented by the design flowing gradient.

Often times, an IPO valve is selected in the bottom position. This precaution prevents the injection gas from being bled-off in the event of gas shut-off. The injection pressure sensitivity of an IPO valve would close this valve with drop in injection pressure. If an IPO valve is selected, the valve setting should be done using procedure described for an IPO installation.

Another option for the bottom operating valve is to use an orifice valve.

Chapter 6: Design Bias or Discussion on Various Safety Factors

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.

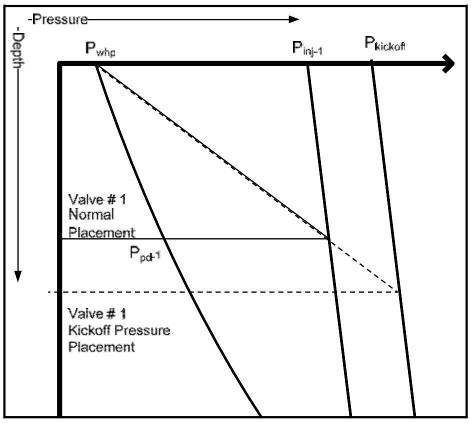
With this in mind, it is often desirable to incorporate various forms of “design bias” into gas lift designs. This bias is used to ensure that the design is successful in accomplishing the above stated objective. That is, to ensure that the unloading valves are closed when the well is lifting from the 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.

7.1 Top Valve Depth Selection

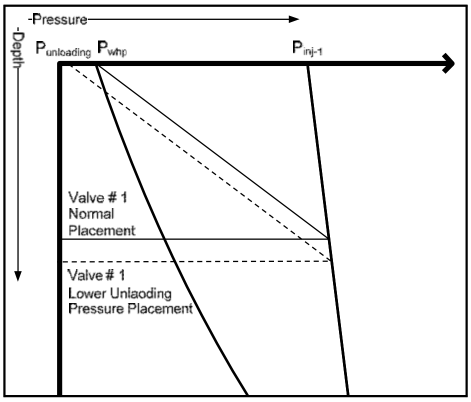
The preceding design discussions for the first valve assumes that during the unloading process,

a) Normal (design) injection pressure is available, and
b) The well is unloaded against the design wellhead pressure.

Often a small capacity compressor or another source is available that can provide higher than the design injection pressure for shorter duration and lower rates to allow unloading until the first valve depth. This higher pressure is referred to as the kickoff pressure. Such a kickoff injection pressure allows deeper first valve placement as shown in the following figure.



While unloading, a lower wellhead pressure value can be used if the unloading fluid could be diverted to another lower pressure facility. Even if kill fluid is to be diverted to the same separation equipments, flow rates during unloading are low enough to justify smaller – or almost no – pressure drop in the flowline or header meaning a lower unloading pressure equal to separator pressure. Following figure shows, how a lower unloading wellhead pressure allows deeper first valve placement:



When both higher kickoff pressure and lower unloading pressure are available, the deepest first valve placement results.

6.2 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 rationale 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. Hence, 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.

6.3 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.

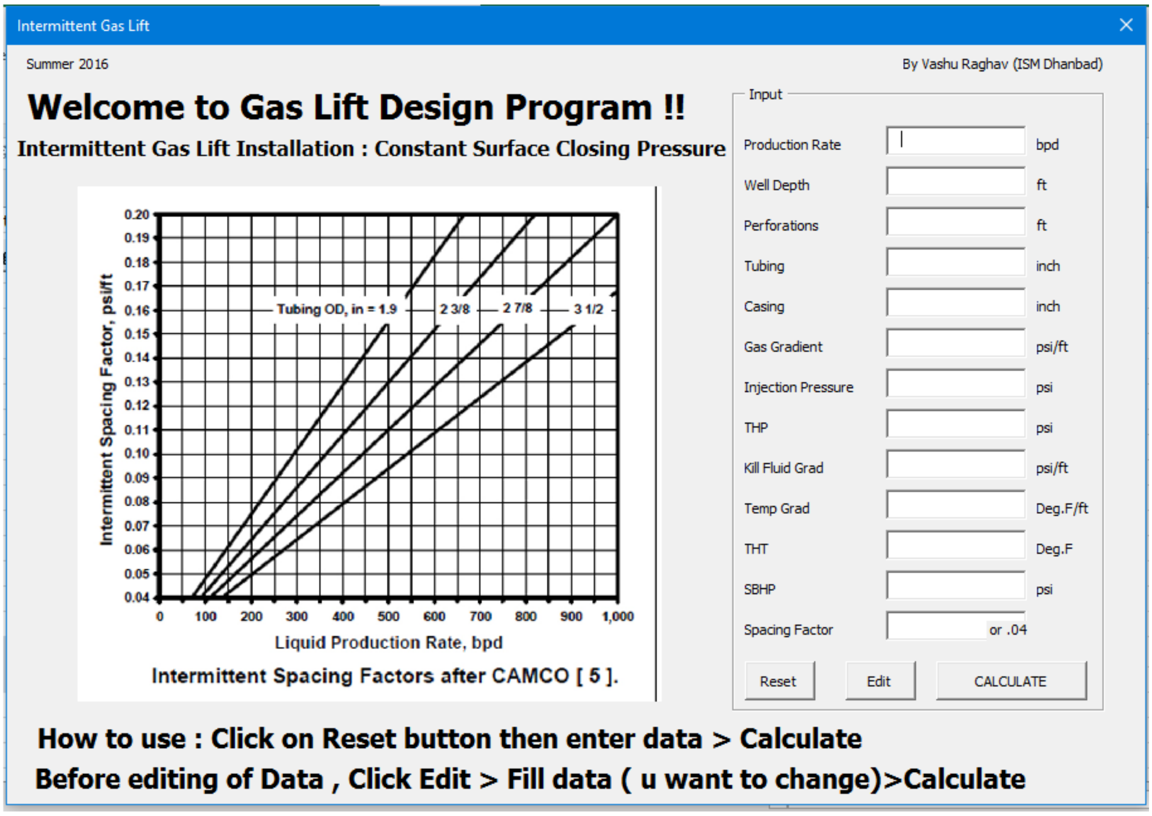
- Selection of flowing gradient – The selection of the flowing gradient curve can serve as yet another form of bias. Often, engineers will select a flowing gradient that is “heavier” (or further to the right) than what is anticipated. In most cases, this requires increasing either the water cut or rate 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 drawdown 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.

VBA EXCEL PROGRAM

Intermittent Gas Lift System Design

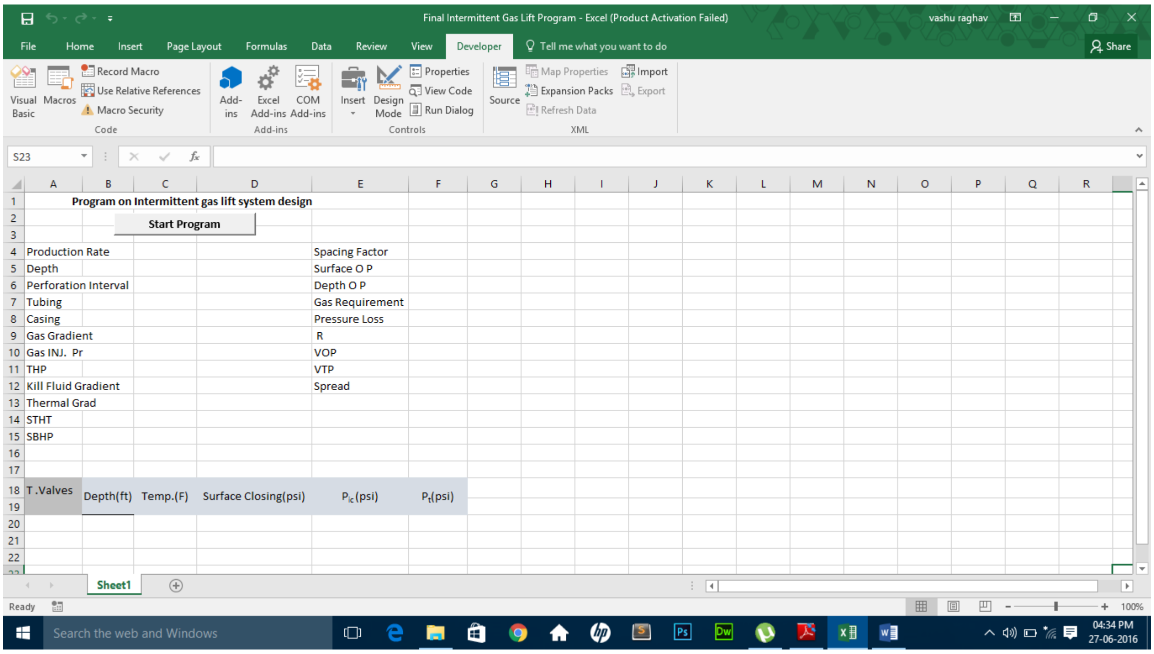
This software is made in Virtual Basic Application (VBA) of Microsoft Excel 2016. It is used to design intermittent gas lift installation system, based on **Constant Surface Closing Pressure** procedure. A common design procedure for installations with single-point gas injection uses a constant surface closing pressure for all valves in the unloading valve string.



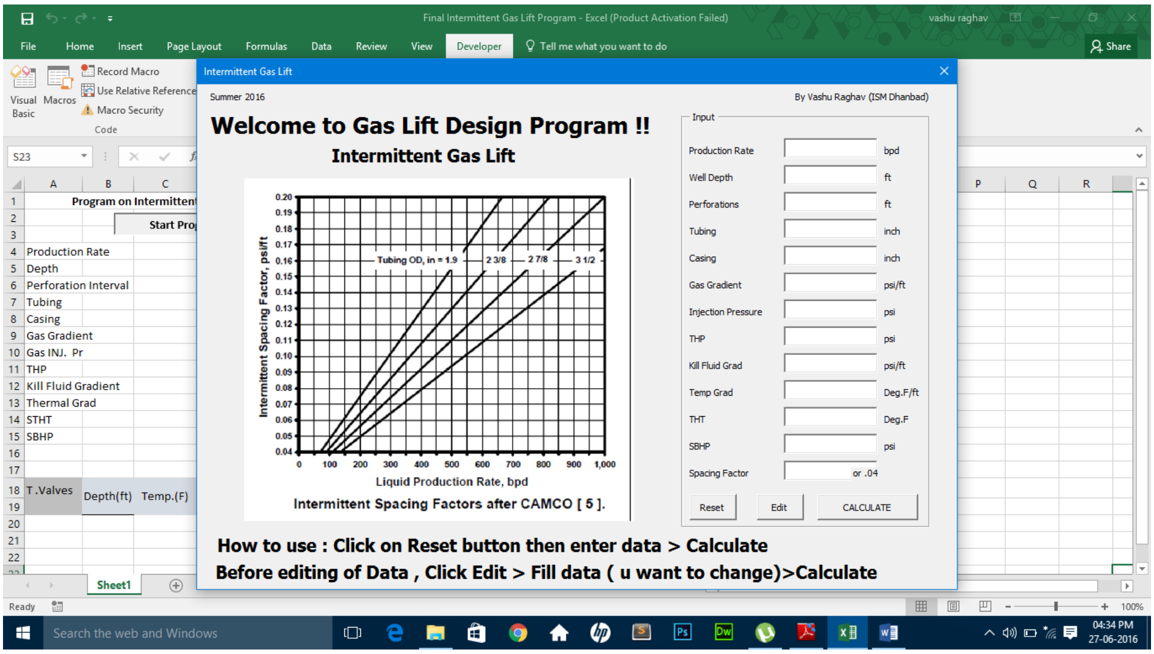
"EXCEL VBA Program" MANUAL

1. Open the program in MS Excel.

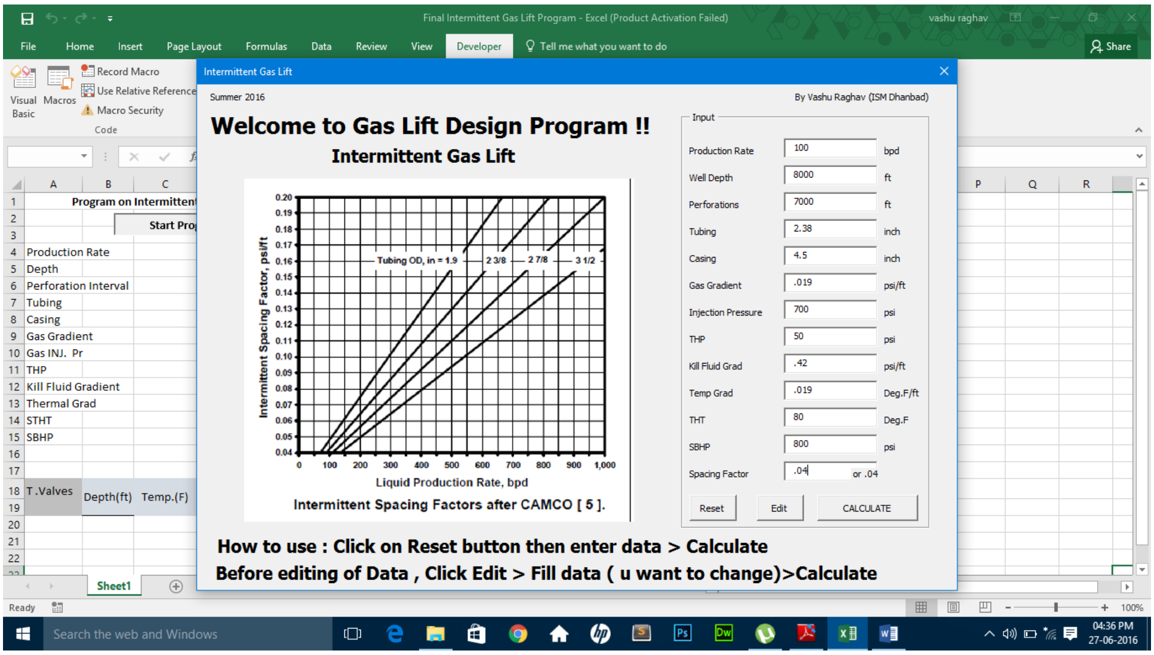
2. Click on "Start Program" button to run the program.



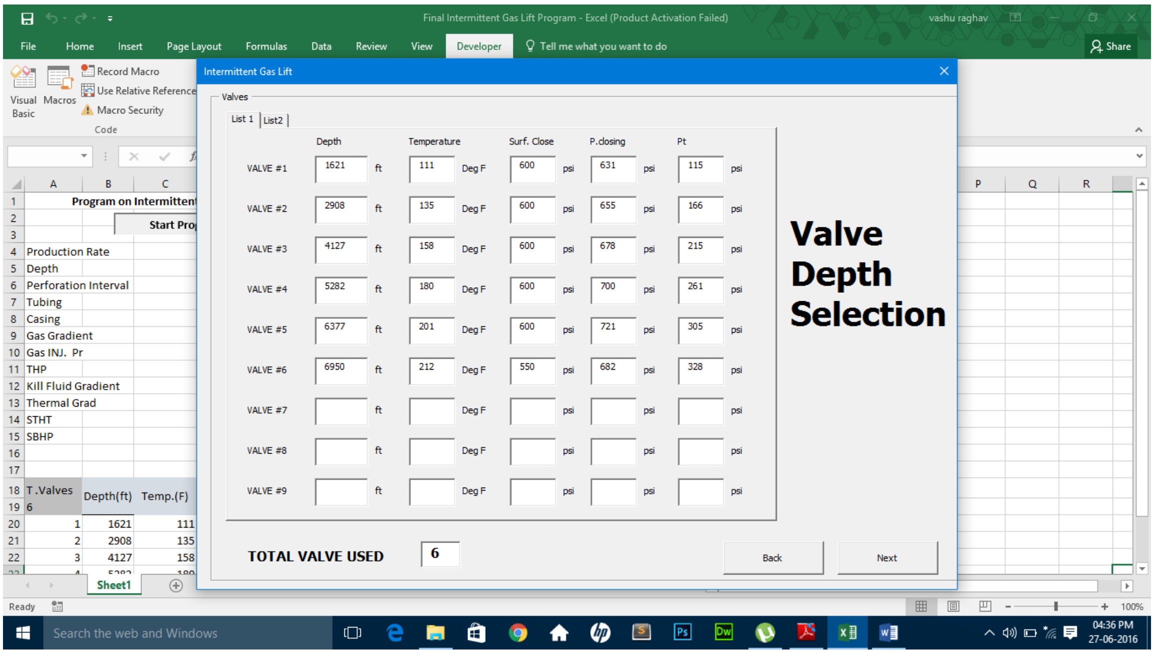
3. Welcome to Intermittent Gas Lift window will appear.



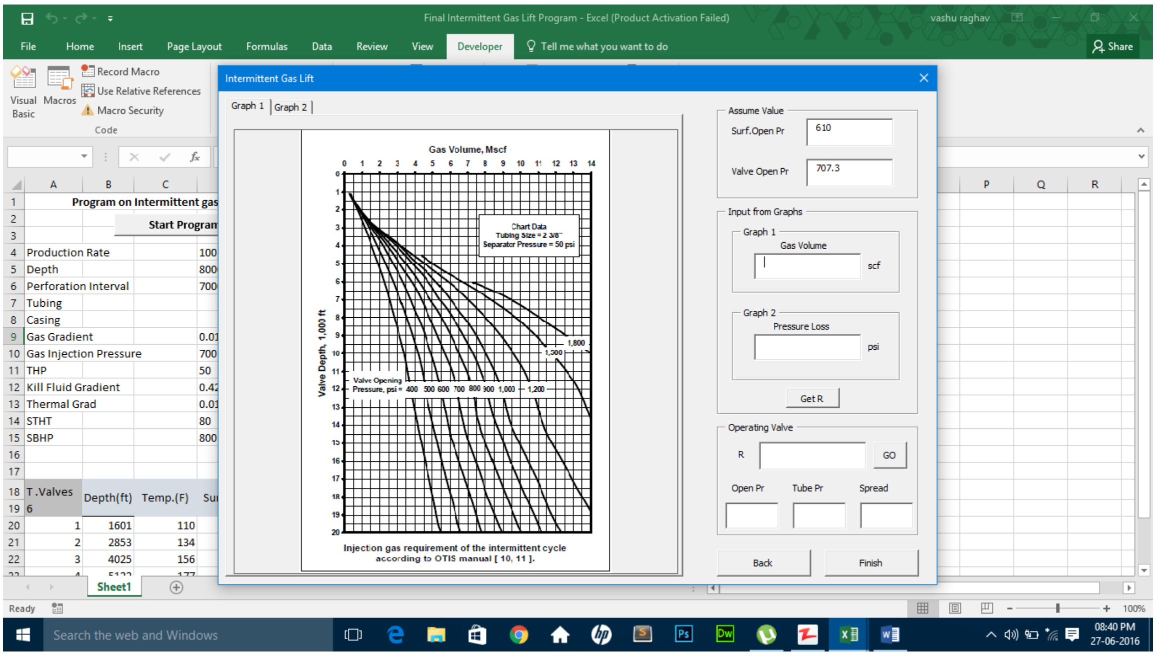
4. Click on “Reset” button and then fill up all the column.



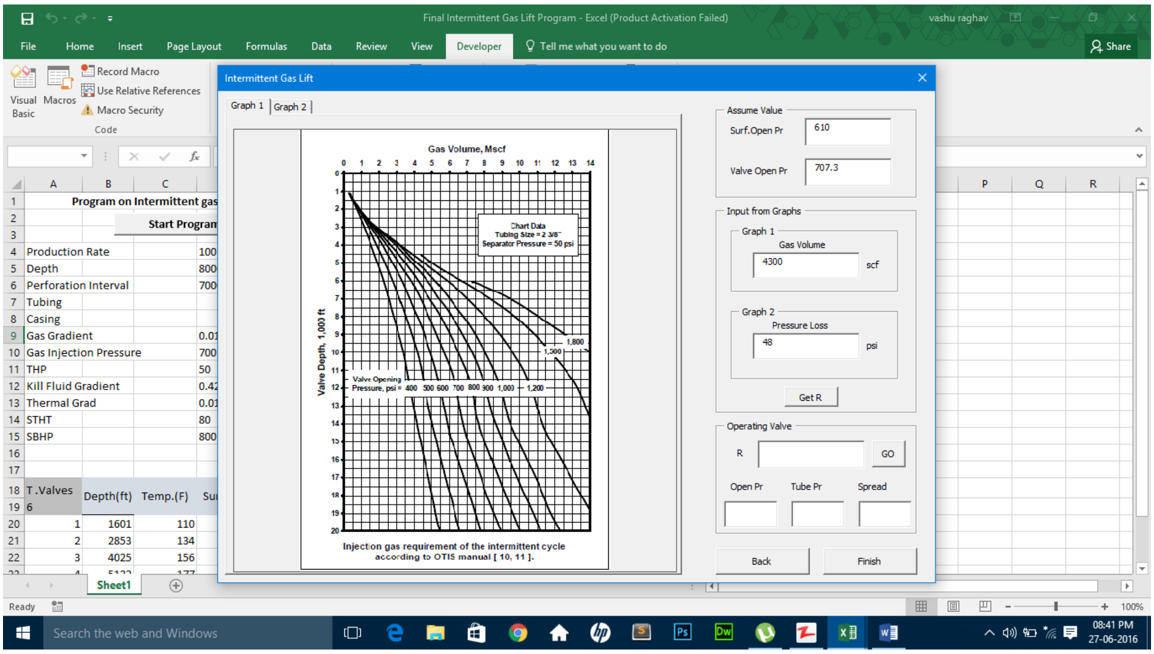
5. Click “Calculate” button then Valve Depth Selection Window will appear.



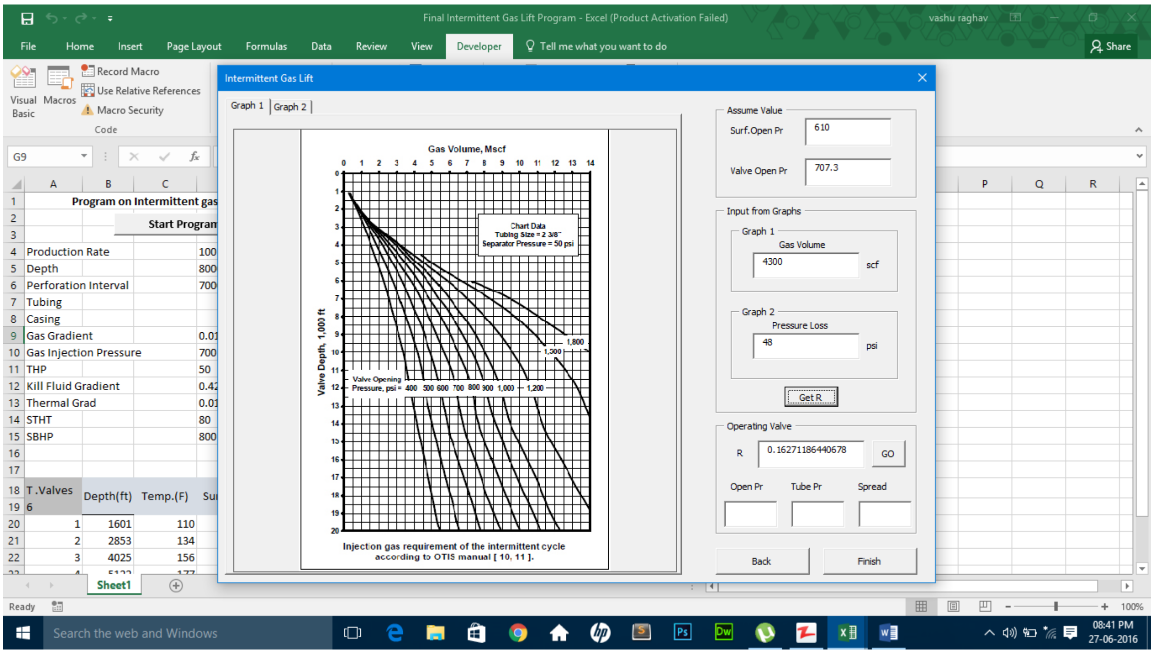
6. Click “Next” then Operating Valve Window will appear.



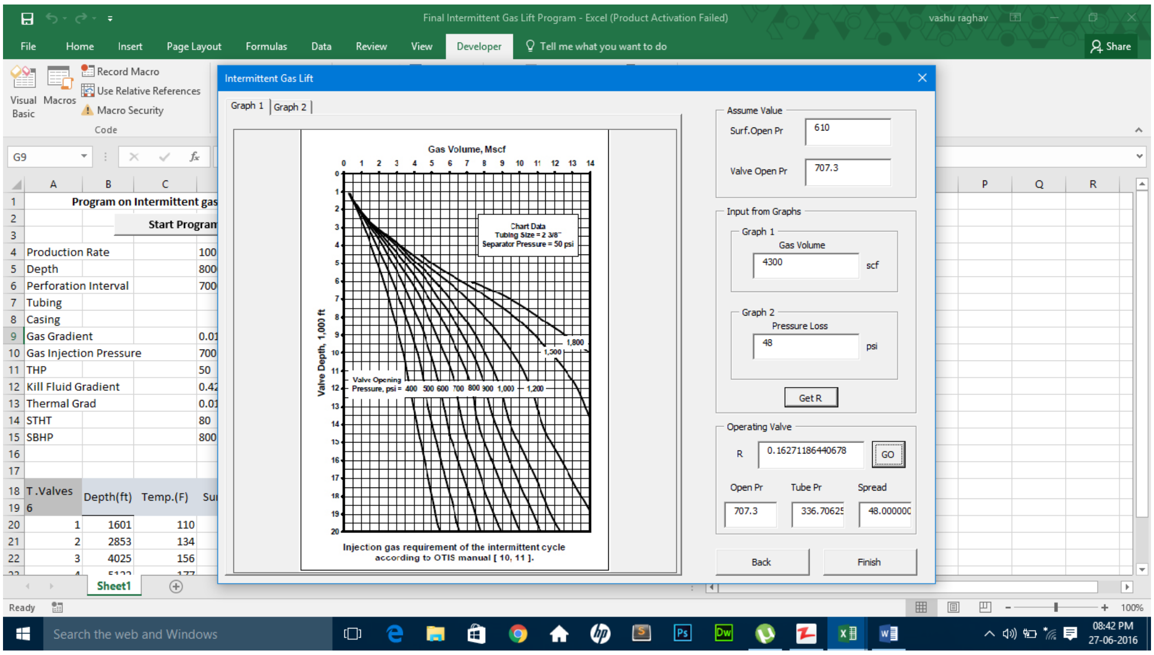
7. Fill up the Gas Volume and Pressure Loss column from Graph 1 & Graph 2 respectively and then Click “Get R” button.



8. R value will be shown in Operating valve frame.



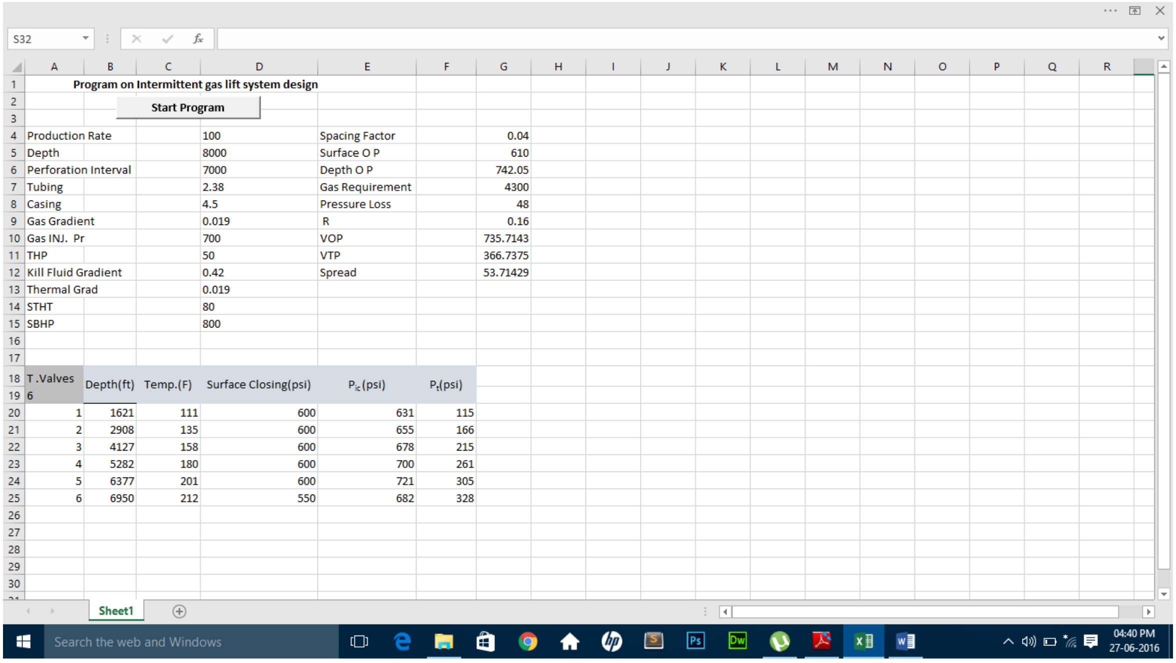
9. If you have R near by the calculated R in operating valve frame, then input that value and click “GO” button.



10. Hence the opening pressure , tubing pressure and spread will be appear in their respective column.
11. If the spread is near by to Pressure Loss then your reading are correct, but if it is different then change the Surf. Open Pr. by 10 psi in assume value frame and Repeat from Step7.
12. Click “Finish” button the program.

13. An excel sheet of the data will appear

14. Print out the excel sheet.



Program on Intermittent gas lift system design

Start Program

Production Rate	100	Spacing Factor	0.04
Depth	8000	Surface O P	610
Perforation Interval	7000	Depth O P	742.05
Tubing	2.38	Gas Requirement	4300
Casing	4.5	Pressure Loss	48
Gas Gradient	0.019	R	0.16
Gas INJ. Pr	700	VOP	735.7143
THP	50	VTP	366.7375
Kill Fluid Gradient	0.42	Spread	53.71429
Thermal Grad	0.019		
STHT	80		
SBHP	800		

T .Valves 6	Depth(ft)	Temp.(F)	Surface Closing(psi)	P_{ic}(psi)	P_t(psi)
1	1621	111	600	631	115
2	2908	135	600	655	166
3	4127	158	600	678	215
4	5282	180	600	700	261
5	6377	201	600	721	305
6	6950	212	550	682	328

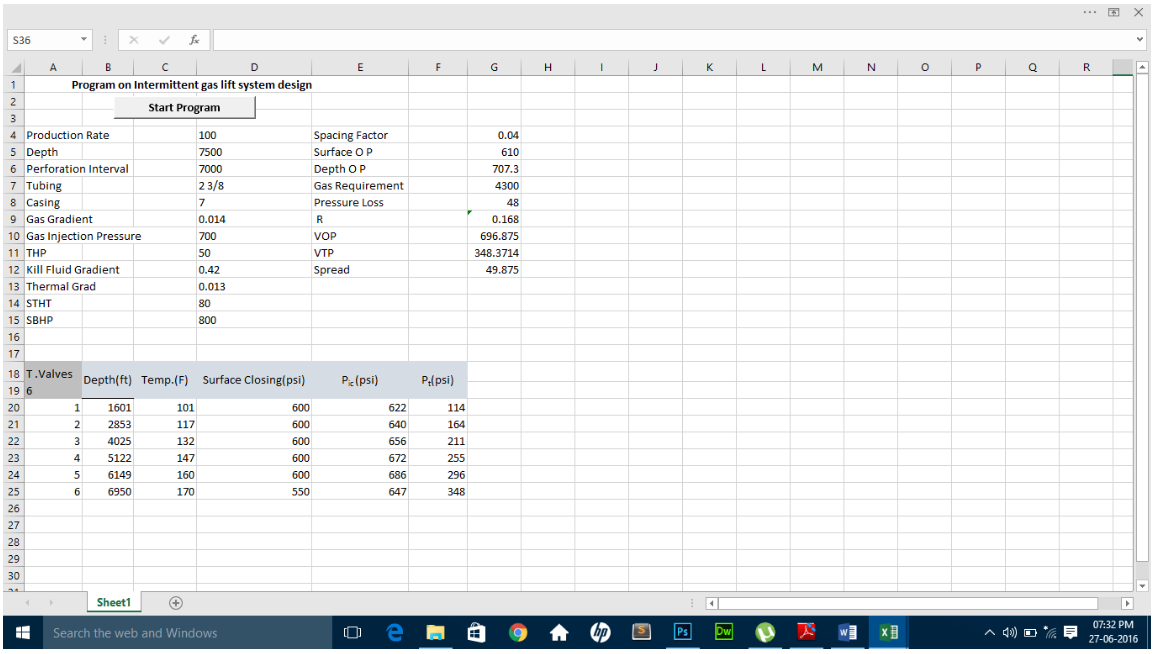
Problem Solution by this “Excel VBA Program”

Design an intermittent installation lifting off bottom for the well with the data given below.

Production = 100 bpd
Casing Size = 7”
Tubing Size = 2 3/8”
Temperature Gradient = 0.013 ºF/ft
Static Bottomhole Pressure = 800 psi
Wellhead Pressure = 50 psi

Well Depth = 7,500 ft
Available Injection Pressure = 700 psi
Depth of Perforations = 7,000 ft
Gas Gradient = 0.014 psi/ft
Wellhead Temperature = 80ºF
Load Fluid Gradient = 0.42 psi/ft

Output



Program on Intermittent gas lift system design

Start Program

Production Rate	100	Spacing Factor	0.04
Depth	7500	Surface O P	610
Perforation Interval	7000	Depth O P	707.3
Tubing	2 3/8	Gas Requirement	4300
Casing	7	Pressure Loss	48
Gas Gradient	0.014	R	0.168
Gas Injection Pressure	700	VOP	696.875
THP	50	VTP	348.3714
Kill Fluid Gradient	0.42	Spread	49.875
Thermal Grad	0.013		
STHT	80		
SBHP	800		

T .Valves 6	Depth(ft)	Temp.(F)	Surface Closing(psi)	P_{ic}(psi)	P_t(psi)
1	1601	101	600	622	114
2	2853	117	600	640	164
3	4025	132	600	656	211
4	5122	147	600	672	255
5	6149	160	600	686	296
6	6950	170	550	647	348

References

1. The Technology of Artificial Lift Method (Volume 2a) – K.E Brown
2. Artificial Lift Manual, Artificial Lift Department, IOGPT
3. Gas Lift Manual, Artificial Lift Department, IOGPT
4. Gas Lift Manual – Gabor Takacs
5. http://www.homeandlearn.org – Excel VBA Programming