Artificial Lift

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Lecture-51 Gas Lift Valves and Installation- Part 2

So, every time you are referring to continuous and intermittent gas lift systems. Continuous gas lift is typically used when the productivity index is more than 0.5 barrels per day per psi. Continuous gas lift can also be applied when the productivity index is up to 0.2, but in such cases, people often opt for intermittent gas lift when the productivity is less than 0.5.

Continuous gas lift can be switched to intermittent gas lift as reservoir pressure drops, decreasing productivity index. A periodic gas lift system also results in lower production rates. This is because in an intermittent gas lift system, you allow gas to build up, then inject gas to lift the accumulated liquid. This process pauses the production rate for a period while the liquid column builds up. After some time, you inject gas to remove the accumulated liquid and clean the wellbore. The cycle repeats intermittently, leading to lower productivity compared to continuous gas lift.

The gas injection rate or Gas-to-Liquid Ratio (GLR) influences the potential of gas lift wells. A significant increase in gas injections with a low injection rate generally results in a lower production rate. The production rate is typically reduced when the injection rate is very low. The aim is to find the optimal gas volume for maximum efficiency. Excessive gas injection can hinder efficiency, leading to reduced production rates due to possible annular flow or mist flow effects.

When installing a continuous gas lift system, various formulas can be used. The formula involves wellhead pressure (P_{wh}), which is wellhead gas pressure plus the gradient G_{fa}. G_{fa} includes G_{fa} l and G_{tb}, where G_{tb} is the gradient at depth (d) minus the injection length (l) from the surface. Normally, a difference of approximately 100 psi is maintained between the points of injection and balance. The pressure at the point of injection, the point of balance, the reservoir pressure (P_R), the flowing pressure (Pwf), and the tubing pressure (P_t) are all significant factors in the equation.

To optimize production, it's important to keep wellhead pressure as low as possible, as excessive wellhead pressure can reduce production rates. In contrast to tubing head pressure, which is not impacted by the wellhead pressure, wellhead pressure might result in decreased flow rates. Therefore, it's beneficial to maintain wellhead pressure as low as possible for higher production rates. Casing pressure is another parameter referred to as Pws or surface operating pressure (Pso), and it might also be denoted as P_c. G_{fa} represents the average flowing gradient above the point of injection.

$$P_{wh} + \rho_m g D_{v1} + \rho_f g (D_{v2} - D_{v1}) = P_{ko} + \rho_g g D_{v2}$$

$$D_{v2} = D_{v1} + \frac{P_{ko} - P_{wh} - \rho_m g D_{v1}}{G_f}$$

$$D_{vi+1} = D_{vi} + \frac{P_{ko} - P_{wh} - G_m D_{vi}}{G_f}$$

$$D_{v1} = \frac{P_{ko} - P_{wh}}{g\rho_f} = \frac{P_{ko} - P_{wh}}{G_f}$$

So, this gradient, G_{tb}, is actually below the point of injection. G_{tb} represents the gradient below the point of injection, and 'below' is spelled as 'b l o w' below the point of injection. Here, 'd' is the total wellbore depth, 'l' is the point of injection length from the surface, and 'P w' is the flowing pressure.

This is the basic formula for continuous flow gas lift system, which determines the location of valves. Normally, a gas lift system consists of several valves. One torque valve is used solely for unloading purposes; typically, it is not the operating valve. The bottom-most valve may often serve as the operating valve, but this may not always be the case. When a well is loaded with 0.5 psi per foot of kill fluid to the surface and 800 psi available to the unloading valve, the top valve might be placed at 1600 feet, neglecting the column weight and assuming zero head pressure. However, adjustments must be made accordingly if wellhead pressure and friction are present. Gas column weight should also be considered, as gas has its own density, contributing to weight.

In cases where valves are placed in a well with a fluid level at 3000 feet, the top valve can be positioned at 3000 feet or slightly lower, as needed.

A formula for determining the injection gas rate is provided: It's important to remember this formula, as it may be used in problem-solving exercises.

$$Q_g^s = (TGLR - GLR_F)Q_L$$

- Qg^s volume of gas injection rate, scf/b
- TGLR total gas liquid ratio at point of injection scf/b
- GLRF formation gas liquid ratio

$$TCF = 0.0544\sqrt{\gamma_g T_{vd}}$$

- γg gas specific gravity;
- Tvd temperature at valve depth in R.
- correct volumetric gas injection rate $Q_g^{vd} = Q_g^s \times TCF$

Regarding the types of gas lift installations, there are generally three types: open installation, semi-closed installation, and closed installation. In an open installation, the tubing on the left side does not include a packer, so there is no packer used. In semi-closed installations, the tubing is connected to a packer, and casing is present. The tubing hangs without being fixed to the casing. For semi-closed installations, there is a packer used. In closed installations, there is a packer as well as a valve. In closed installations, reverse flow back to the reservoir is not possible. In open installations, injecting a very high amount of gas can potentially flow back to the reservoir.

Continuous flow application is feasible for open and semi-open installations, but intermittent gas lift systems can be applied to semi-closed or closed installations.

Because in an intermittent case, you need a very high amount of gas quickly. Thus, you must close all this with a packer and a valve. In continuous flow, you are injecting a certain small amount of gas continuously. Open installations can also be used to enhance production rates.

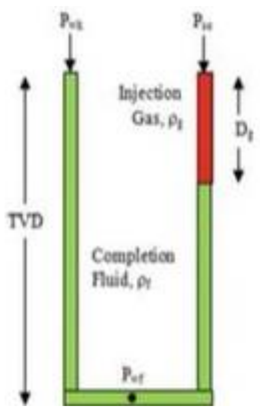
In the unloading process, which is a fundamental part of the gas lift system when you are operating the system, you need to unload. Initially, you drill a hole and kill the wellbore before you start producing. When it is killed, high-density fluid is present inside the wellbore. High-density fluid behaves like this: you have casing and tubing, assuming there is a packer. The entire area will be filled with the same liquid because there are gas lift valves, let's say 1, 2, 3, 4, and initially, all the valves are open. So, in this case, what happens is that, due to the open valves, the kill fluid or high-density fluid fills all this area. There will be no productivity because the density is very high. Reservoir pressure and the total hydrostatic pressure of the kill fluid will be balanced, preventing any fluid from coming in or going out.

Now, when you are unloading a wellbore, you need to remove this kill fluid. How do you do it? Gradually, you inject gas from the surface to remove the fluid from the casing area because you are injecting from the annular area. You inject liquid from this area, gradually removing the annular area fluid. You do this by injecting very high-pressure gas, which displaces the liquid, and the gas goes out.

To illustrate this, they have used a concept similar to a U-tube. Imagine a system like this: you can consider this as the tubing, and this is the casing annular area, while this is the tubing area. You inject gas from the casing side, maintaining casing pressure, and you displace the liquid using your gas. The right-side drawing shows the same process, with gas replacing the liquid.

True Vertical Depth (TVD) is common in the oil and gas industry. Often, we use the terms "measured depth" and "true vertical depth." True vertical depth refers to the actual depth, while measured depth considers the total length. For example, in a wellbore, the total measured depth will be the total length, whereas vertical depth refers to the depth in the vertical direction.

So, flowing pressure (Pwf) is here, and the completion fluid pressure (ρ_f), which is also known as keel fluid, is a high-density fluid. Keel fluid needs to be replaced, and you are applying very high pressure from the surface to remove the keel fluid from the wellbore. Wellhead pressure (P_{wh}) or injection pressure on the surface, and the formula becomes Pso (injection pressure on the surface). This formula is used to calculate the injection pressure (PSO). If ρ_f is high, then Pso will also be high, which means the injection pressure from the surface will be high.



$$P_{so} = P_{wh} + 0.052(\rho_f - \rho_g)D_g$$

Now, let's discuss how the unloading process occurs, as described in Nguyen's book. Initially, imagine the entire wellbore: there is tubing, casing, and the entire space is filled with your completion fluid, which is a high-density liquid. Your hydrostatic column gradient will look like this, and there's a depth (D). For this example, let's assume there are 3 valves: V1, V2, and V3.

Now, what you do is start injecting from the surface. When you inject, you are applying PSO, and your compressor is working to inject gas at high pressure. You gradually inject more and more gas until you reach the first valve, Valve 1. When you inject into Valve 1, bubbling starts, and the flowing pressure changes. Initially, we assume there is no flowing pressure, no production. However, once the flowing pressure appears, you get some drawdown, which initiates productivity, and bubbling creates some production.

From there, you continue injecting and activating the second valve, Valve 2. When you activate Valve 2, Valve 1 is closed. Initially, all the valves are open, but when Valve 1 is injected with gas, it closes, and then it progresses to Valve 2. Again, when it goes to Valve 3, Valve 2 is closed. In this case, Valve 3 serves as the operating valve. It's worth noting that Valve 3, or the lowermost valve, may not always be the operating valve, but in this example, it is shown as the operating valve, and the entire column becomes green in the last picture. Green indicates the creation of a multiphase flow with many bubbles, reducing the pressure throughout the column and increasing production.

So, your flowing pressure (P_{wf}) is reduced, and the drawdown increases. Reservoir pressure (reservoir pressure) remains constant; it cannot be changed. Sometimes, people inject steam or implement water flooding.

So, these methods are meant to modify your reservoir, not the wellbore. In our case, with the artificial lift system, we are not attempting to alter the reservoir pressure; we assume the reservoir pressure remains constant. However, in tertiary or enhanced recovery systems, people inject gas or liquid to modify reservoir pressure or reservoir fluid properties. In those cases, they are not changing the wellbore system but modifying the reservoir.

Both systems are different. In our case, we are changing wellbore properties and wellbore fluid properties. We modify the flowing pressure using artificial lifting techniques. Enhanced recovery systems do not alter the wellbore system but focus on changing the reservoir.

You can observe that when you start injecting gas, the first valve receives gas, creating many bubbles and reducing hydrostatic pressure. As hydrostatic pressure drops, the flowing pressure (P_{wf}) decreases. When P_{wf} decreases, it creates a difference and generates drawdown. The decreased P_{wf} allows extra fluid to enter. Continuously injecting gas from the surface reaches the second valve, and as the first valve closes, the second valve receives more gas. The entire column's weight further reduces, resulting in more drawdown and more fluid entering. The lower hydrostatic column gradually allows even more fluid to enter, increasing production.

However, if you aim for too much production and increase gas flow rate excessively, it may not optimize production. Instead, it could reduce the production rate. You must find the optimal production rate and the ideal valve depth to achieve the best production. Attempting to extract too much production can create various flow issues, such as annular flow, bubble flow, mist flow, or other types of flow, which can disrupt the entire system.

There is a formula to calculate valve locations. In the formula, 'd' represents the valve's depth location, 'P_{wh}' is the wellhead pressure, 'ρ_m' is the mixture density, 'g' is the gravitational constant, 'd_v' is the valve one location, 'ρ_f' is the fluid density, 'g_k' is the valve two location, and 'P_{ko}' stands for the kick-off pressure location. Using this formula and others, you can determine different valve locations.

Two options are available when discussing your gas lift compression system: dissipating compressors and centrifugal compressors. Normally, centrifugal compressors have a lower pressure ratio, which means they can compress lower amounts of gas. If you need to compress a high volume of gas with a high compression ratio, reciprocating compressors are a better choice. Both types can be used simultaneously or in series, one after the other. Centrifugal compressors can handle a large volume of air, which is then compressed in several stages. I will discuss the details of how the compressor works later on.

So, a reciprocating compressor operates much like a piston in a sucker rod pump that we've seen before. It has a valve arrangement for pumping fluid. A typical reciprocating compressor will have valves, similar to a sucker rod pump, and a piston that moves back and forth, just as in a sucker rod pump. Sucker rod pumps have different terminologies like traveling valve and standing valve, whereas in a reciprocating compressor, you have one valve opening in one direction and another valve opening in the opposite direction. Let's call them V_1 and V_2. When the piston is moving in one direction, V_2 is closed, and V_1 is open. When the piston moves in the opposite direction, the valve operation reverses. This continuous movement delivers high-pressure gas to your system.

However, a single-piston cylinder will not be sufficient. You need a multiple-piston-cylinder arrangement for proper compression. For example, you first compress a high volume of gas to obtain a lower volume, then compress it again to get an even smaller volume. In between these compression stages, you must consider the ideal gas law, PV equals RT, where 'P' is pressure, 'V' is volume, 'T' is temperature, and 'R' is a constant. When compressing gas, you're changing the pressure and volume, which also alters the temperature, generating a significant amount of heat. To prevent excessive heat generation, you need an inter-stage cooling system. Normally, multi-cylinder systems are used for this purpose. With multiple intercooling stages, you can achieve an efficient system.

If you opt for centrifugal compressors, these work similarly to centrifugal pumps, which you might be familiar with. However, a centrifugal compressor delivers air or natural gas instead of delivering liquid as in a centrifugal pump. As you compress natural gas at a high rate, it generates high temperatures. Therefore, you must dissipate heat and compress it in stages, one by one, to achieve proper compression.