# Artificial Lift

**Prof.Abdus Samad**

**Department of Ocean Engineering**

**Indian Institute of Technology Madras, Chennai**

## Lecture-52 Plunger Lift and Design

Good morning, everybody. Today, I will be teaching a part of the gas lift system, which includes multiple operating valves. It will also cover the intermittent gas and plunger lift systems. Let's explore why multiple operating valves are necessary. You might wonder why we can't just use a single valve to increase productivity. So, why should we use multiple valves? Why not just one? Let's examine this problem to understand the reasons.

Let's make some initial assumptions: assume wellhead pressure and the constant differential density, which means that the gas surface operating pressure mainly depends on the position of the interface between gas and liquid.

Now, let's consider an operating valve depth of 10,000 feet and a wellhead pressure of 400 psi. The completion fluid has a density of 10 pounds per gallon (PPG). Initially, we assume that the entire wellbore is filled with completion fluid, so its density is the critical factor. The gas density is given as 0.006 PPG (pounds per gallon).

We need to calculate the surface operating pressure ($P_{so}$), the pressure you inject from the surface. The formula for $P_{so}$ is,

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

Substituting the given values, we have $P_{so} = 400 + 0.052 * (10 - 0.006) * 10{,}000$.

This calculation results in a value of 5600 psi.

However, having this high pressure available at the surface, 5600 psi, is impractical. Typically, the surface pressure is around 1500 psi.

Therefore, using multiple valves becomes necessary to manage the pressure effectively. To optimize this system, you first inject gas into a valve near the top of the wellbore. This reduces the hydrostatic pressure of the column. Then, you activate the next valve, further reducing the column's weight, and so on for subsequent valves. This gradual process allows you to start production without requiring an extremely high surface operating pressure (Pso), which is typically limited to around 1500 psi, not the 5600 psi obtained from the calculation with a single valve.

When you have multiple valves in the wellbore, you need to consider the time required to activate each one. For example, in accordance with API RP 11V5, it's recommended to allow 10 minutes for each 50 psi increase in casing pressure up to 400 psi. This means that reaching 1000 psi would take more than two hours, so you need to activate each valve at specified intervals to ensure the system functions correctly.

Keep in mind that in artificial lift techniques, we're only modifying the wellbore, not the reservoir. If you were to modify the reservoir itself, that would fall under enhanced oil recovery techniques. Artificial lift systems focus on optimizing the wellbore conditions for production.

You mentioned 10,000 feet as the operating valve depth regarding the first valve's depth. So, if you want to determine the depth of the first valve from the top, let's call it "d1." Then, you'd also need to calculate the depths for the second and third valves.

You determine the first valve's depth, known as the kick-off pressure (Pko), by applying pressure from the surface. This initiates gas bubbling, and the pressure required for this initial gas injection is termed the kick-off pressure.

You calculate it using the formula: $(P_{ko} - P_{wh}) / (g * \rho_f)$,

where g is the gravitational constant and ρf represents fluid density. People typically assume a fluid density of around 0.45 psi or 0.5 psi for kill fluid, although this value can vary.

For example, if you have a wellhead pressure ($P_{wh}$) of 120 psi and a kick-off pressure of 700 psi, with a kill fluid gradient ($\rho_f$) of 0.45 psi, you can calculate the first valve's depth using this formula to be 1289 feet.

Now, to determine the depth of the second valve, you use another formula. The second valve depth ($D_{v2}$) is equal to the first valve depth ($D_{v1}$) plus the kick-off pressure for the second valve ($P_{ko2}$) minus wellhead pressure ($P_{wh}$), all divided by the mixture density ($\rho_m$) and gravitational constant (g). Since you've introduced gas into the system, you now have a mixture of liquid and gas, so you use the average density ($\rho_m$). The parameters remain the same, with a kill fluid gradient of 0.45 psi.

These calculations allow you to find the depth of the second valve and can be repeated for additional valves.

If the density is given in pounds per gallon, the pressure gradient of the mixture and gas completion fluid (gm) requires a unit conversion factor, which is provided as 0.052. Paying attention to units when solving problems is essential because using incorrect units can lead to incorrect results. Always check the units and perform conversions if necessary when working on problems. You can calculate the depth of the second valve similarly to the first one, and the process can be repeated for the third and fourth valves.

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

The pressure gradient of the mixture of gas and completion fluid inside the tubing: $G_m = g\rho_m$
If the density is in pound per gallon (ppg), then $G_m = 0.052\rho_m$ psi/ft.

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

First unloading valve, i = 0 and $D_{v0} = 0$

This allows you to determine the depths of all valves.

One important point to keep in mind is that when activating the valves in a gas lift system, the bottommost valve may not always be the operating valve. In some cases, the valve positioned one or two levels above the bottommost valve can be the operating valve. The selection of the operating valves depends on the specific well conditions and requirements. Engineers can make this decision based on the operational needs.

Another term you'll encounter in gas lift systems is "macaroni installation," which is used in slim hole and ultra-slim hole applications. It involves using slim tubing for gas lift in these ultra-slim holes. Casing sizes in such applications are typically 2 and 3/8 inches, 2 and 7/8 inches, or 3 and 1/2 inches. This narrow casing accommodates the slim tubing, which can be as small as 1 and 1/2 inches when gas lift valves are installed.

So, everything is very narrow and compact. Smaller tubing is called macaroni tubing, which can have gas lift valves. This reduces drilling and completion costs because you only have a slim hole, and instead of redrilling or recompleting, you can use this tubing. Two smaller tubing strings can also run if the casing is slightly wider. For example, with a 3 and a half-inch casing, you can try to insert two 1-inch casings and achieve production.

The use of two tubing strings can be to produce from two different zones. For instance, in a wellbore with one tubing string, you can have one zone perforated for gas or oil production and another zone for a different type of production, such as gas or oil. To obtain production from both zones, you can insert multiple tubing strings.

Small tubing strings can be concentric or parallel. A parallel system is shown in the drawing, but sometimes concentric tubing, where one tube is within another, is also possible. This type of tubing installation is referred to as a macaroni installation. These terms are useful for competitive exams. Competitions often include questions about unfamiliar terms, so it's essential to know that these concepts are relevant to artificial lifting systems.

Now, let's move on to intermittent gas lift systems. Why are they required? Consider a gas well that needs deliquification. In a gas well, the fluid velocity is often very high, leading to mist flow. Due to the high fluid velocity, a small amount of liquid enters the gas well, creating mist. When tiny particles are created, they might settle back into the wellbore with very low velocity. The gas in the well carries this liquid upward. However, if you reduce the fluid or gas velocity, the gas will tend to fall back into the well. When gas flows at high velocity, the terminal velocity of the fluids falling downward becomes lower than the upward velocity of the gas.

Because of the upward velocity of the gas, the fluid is pulled out of the wellbore. However, if you reduce the gas velocity, something interesting happens. Recall that each fluid particle has weight, and a drag force is pulling it up. If the drag force is strong enough, it goes up. But if the weight is slightly higher, it will start sliding back.

So, in the first phase, you have mist flow. The gas velocity decreases as the reservoir pressure is slightly depleted or reduced. A decrease in gas velocity means that the small liquid particles try to come together, forming bigger particles that adhere to the wall. This is known as annular flow, as we discussed in the multiphase flow chapter. But now, let's take another look at it in the context of gas well deliquification.

As you reduce the velocity further, smaller particles combine to form bubbles. These bubbles collide with each other and, as they move downward, they create slug flow. The collision of bubbles and further interactions lead to a gradual downward movement. Eventually, the gas tries to exit the slug area, creating more bubbles. As this happens, the liquid falls back down, stabilizing at the bottom, while the gas continues to move upward. The gas essentially leaves the heavier liquid behind.

In gas well deliquification techniques, this phenomenon is a concern. The liquid falling back to the bottom is why it is referred to as "held up" at the bottom. So, what happens? The pressure at the bottom increases because the liquid column is growing in height, represented as "h" and "$\rho$" being the fluid density. With the increasing height of the liquid column, the flowing pressure (Pwf) rises. The reservoir pressure (PR) remains constant, but the difference between the two becomes very low.

When the difference between Pwf (flowing pressure) and PR (reservoir pressure) is low, which means there's low drawdown, new fluid won't enter the wellbore. In such a scenario, the entry of gas or liquid into the wellbore stops, and no production occurs. To address this, you need to remove the liquid from the wellbore. When you remove the liquid, Pwf decreases, and the reservoir pressure remains constant. This difference, or drawdown, increases. As the drawdown increases, more fluid, whether gas or liquid, enters the wellbore and moves upward.

If the liquid column height is high, it can obstruct this process, preventing the liquid column from rising significantly. When the flowing pressure approaches the reservoir pressure, the fluid or liquid doesn't enter the wellbore. The height of the liquid column remains limited. It might only increase if the reservoir pressure increases due to other factors. In the case of intermittent gas lift systems (IGL) used to address issues like gas slippage, the solution involves injecting gas to remove the liquid column. Removing the liquid column reduces the flowing pressure, and as the difference between Pwf and PR increases, more fluid enters, resulting in increased production.

Intermittent gas lift systems, or IGL, are commonly used in tubing flow systems with packers and standing valves. In IGL cases, the system is closed. The casing and tubing are properly sealed with a packer, and one or more standing valves are employed within this closed system. Standing valves have limited vertical movement, hence the name "standing valve." There may also be a sitting nipple with a standing valve incorporated into the system.

You would use intermittent gas lift for high or low BHP with low PI (Productivity Index). If PI is higher, indicating higher productivity, you would typically opt for continuous flow gas lift. When using intermittent gas lift, a slug of liquid moves up instead of creating bubbles. In intermittent gas lift, you're not creating bubble flow; you're creating slug flow or ballistic flow.

A continuous gas lift system operates as a steady-state system, continuously producing multiphase flow and moving fluids from near the bottom to the surface.

In an Intermittent Gas Lift (IGL) system, it's unsteady flow. Initially, you allow the accumulation of liquid. Then you inject a high amount of gas, causing a liquid slug to move up to the surface. After that, you stop the gas injection, allowing the liquid column to build up again. This process repeats: build up the liquid column, inject gas, remove the liquid column, and stop. This is how IGL works.

In the continuous gas lift system, gas continuously enters the wellbore and exits, resulting in slug flow. In the intermittent system, you don't create bubble flow. Instead, it operates with slug flow.

In intermittent flow, there is an inner tubing with a packer and a standing valve. You allow a liquid slug to build up. Once the liquid slug reaches a certain level, you inject gas from a gas injection valve. The gas slug pushes the liquid up, and you're not creating any bubbles. This process results in slug flow, where the slug moves upward. After the slug exits, the gas injection is stopped, allowing the column to build up again. You inject gas intermittently, and normally, the gas injection rate is higher but for a shorter period, ensuring that the liquid is removed quickly to prevent fallback issues.

Intermittent gas lift involves continuously sequentially pumping gas, with gas injection alternating. Another technique for removing liquid from the wellbore is the plungerless system. In this case, you may or may not inject gas. Instead, the reservoir pressure is used to remove the liquid from the wellbore. The principle remains the same, and this technique is particularly useful for gas well deliquification. This method is applied in situations with a high gas-oil ratio or a high gas-liquid ratio in a gas well with minimal liquid content. When reservoir pressure decreases, removing the liquid enhances production. This approach is referred to as a free piston or free piston system. It uses a plunger or free piston.

The plunger is not connected to any surface unit; it freely floats from the bottom to the top. Here's how it works: you hold the plunger at the bottom, and a bumper spring temporarily holds it in place. This allows the liquid to build up over the plunger. Once a certain amount of liquid has built up, you remove the plunger, and the reservoir pressure pushes it up to the surface. At the top, a lubricator or catcher holds the plunger and allows more gas and liquid to enter the wellbore from the reservoir.

The wellbore pressure is lower with the plunger up because all the liquid has been removed. In this situation, Pwf is very low, while PR is high, resulting in high drawdown, and fluid will enter the wellbore, leading to production. After some time, the liquid column starts to build up again. You then release the plunger from the top, and it falls down through the liquid. It goes down to the bumper spring, holds it for some time, allows the liquid to build up over the plunger, and then moves it up again. This process continues sequentially. This method is similar to intermittent gas lift but does not rely on injected gas; instead, it uses a mechanical arrangement where the plunger moves up and down.

Plunger lift efficiently removes liquid slugs, reduces back pressure, and prolongs wellbore life. It depends on energy from the reservoir. When the plunger is on top in the lubricator, you need to shorten it so that enough pressure builds up. Once released, this system continues in cycles. The plunger lift system has four cycles: build-up, upstroke, blowdown, and downstroke. During the build-up phase, you hold the plunger at the bottom and allow the liquid to build up over it. Thanks to the bumper spring, the plunger is held in place with a high force.

In this process, you leave the plunger and give it a push. When you leave and push, the entire plunger moves up, and all the liquid goes up with it. As the liquid moves up, it flows through the tubing. This happens during the upstroke phase. During the upstroke phase, the plunger moves up, and gas from the reservoir enters the tubing. The blue-colored liquid moves up and flows through this phase.

Next, it moves to the blowdown stage. In the blowdown stage, the plunger is at the top, and you hold it there for a certain time. During this time, the wellbore is free of liquid. With Pwf lower and reservoir pressure higher, the drawdown is higher, allowing fluid to enter the wellbore and producing gas.

During the blowdown stage, you get gas production, but some liquid also accumulates in the tubing. As liquid accumulates, you release the plunger, and it sits on the bumper spring. Again, you allow the liquid column to build up. This cycle continues, resulting in production.

The difference between intermittent gas lift and plunger lift is that in intermittent gas lift, gas pushes the liquid, and there is no interface between gas and liquid, which can lead to liquid falling back in long wellbores. In plunger lift, the mechanical separation between gas and liquid, created by the plunger, leads to better performance. In some cases, gas can assist with the process. Injecting gas from the surface while the plunger is held at the bottom can increase the efficiency of the entire system.

The same explanation is written here. Initially, the control valve is closed, and the plunger is at the bottom, allowing the liquid column to build up. The plunger is seated on top of the bumper spring. Gas production is lower because a shut-in valve is closed, causing surface casing pressure to increase. All pressures increase because the reservoir pushes all the fluid in the wellbore. Tubing pressure also increases due to the hydrostatic pressure caused by the liquid column. After some time, fluid entry becomes very low. At this point, you release the plunger, and it moves up due to the lower pressure. As the casing pressure reaches a desired value, the control valve of the air sink opens. This valve reduces the upper pressure when opened.

In this system, only lower pressure, which is the reservoir pressure, is present. Lower pressure pushes the valve upward. The liquid slug rises at about the same speed as the plunger. Plunger and tubing have some small gap, so some fluid may leak back. Maintaining a tight seal could cause too much friction, so a certain amount of gap is maintained for efficiency.

The efficiency of the plunger lift system depends on the amount of liquid falling back. Gas also leaks upward. When you push the plunger using gas, gas moves through the small gap between the plunger and tubing, while liquid tries to fall down. Both contribute to lower efficiency. Practical plunger systems have clearance to reduce friction.

The plunger moves upward during the upstroke, and gas in the annular space expands and enters the production tubing. The upstroke stage ends when the plunger is caught at the lubricator. The next stage is the blowdown stage. In the blowdown stage, the plunger is at the top. In this stage, gas and fluids flow freely, but some liquid may slowly fall back, gradually increasing Pwf. As liquid accumulates in the tubing, gas velocity slows down, liquid enters the wellbore, and gas rate drops. Surface pressure flattens.

The downstroke stage follows, where the control valve is closed, and you allow the plunger to fall back. You catch it for a certain time, allow the liquid column to build up again, and then release it. The buildup stage involves wasting energy by excessively lifting the plunger, which can increase the average water column pressure.

So, the system can be optimized to determine whether a longer or shorter stage is preferable. Monitoring pressure and flow rate responses during the plunger cycle is crucial. The cycle includes the buildup, upstroke, blowdown, and downstroke stages. During the buildup stage, the plunger is held at the bottom, and the liquid column is allowed to build up.

During the upstroke stage, tubing pressure will decrease because the valve is open, allowing the gas and liquid above the plunger to escape. The upper pressure is lower during this phase, causing the tubing pressure to drop. Casing pressure will also decrease during the upstroke stage. In the blowdown stage, when you catch the plunger at the top, casing pressure will decrease slightly, but tubing pressure will remain relatively stable because the wellbore is producing at a fixed pressure. Initially, there is no liquid accumulation, but it gradually develops, causing the pressure to increase. During the downstroke, tubing pressure increases. Higher tubing pressure results in lower production, and lower tubing pressure leads to higher production. In the blowdown stage, you can achieve higher production.

Remember these terms: GAPL and PAGL. GAPL stands for Gas Assisted Plunger Lift, and PAGL is Plunger Assisted Gas Lift. PAGL involves continuous gas lift assisted by a continuously running plunger. GAPL is a gas injection-assisted plunger lift system that supplements the reservoir drive. These are two distinct terms, so don't confuse them.

In intermittent gas lift (IGL), plunger applications do not involve gas injection. In intermittent gas lift applications, there is no plunger. People often try to combine intermittent and plunger lift applications, both intermittent gas lift applications. In purely intermittent applications, there is no plunger and no interface between liquid and gas. In plunger lift applications, there is an interface involving a plunger. The plunger reduces the injection gas requirement of IGL by 30 to 70 percent, depending on factors such as plunger construction, depth of lift, injection gas pressure, adjustment of injection gas volume, and wellbore plunger installation. This improvement enhances performance.

Thank you very much for listening to this lecture.