Artificial Lift

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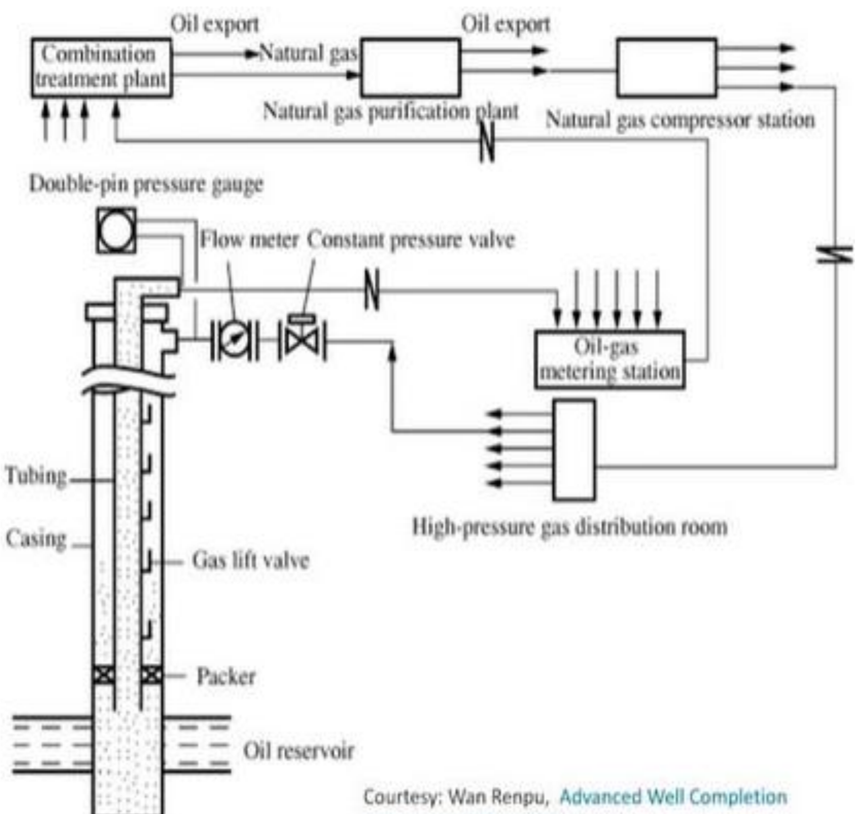
Lecture-48 Gas Lift Basics- Part 1

Good morning, students. Today's lecture is based on Gas Lift. The gas lift system is used as an artificial lifting system, and this technique is primarily used to increase the productivity rate. When wellbore pressure decreases, and reservoir fluid is not moving inside the wellbore or towards the surface, you need an artificial lifting mechanism. By using gas injection techniques, you can increase productivity. In previous lectures, you have seen sucker rod pumps, ESPs, and PCPs. In SRP, you have seen that it is a slow-speed pump suitable for very low fluid flow, like 500, 5 barrels, or 10 barrels.



Courtesy: Wan Renpu, Advanced Well Completion Engineering (Third Edition), 2011

In such cases, you can use SRP systems. ESP is a higher-flow-rate pump, capable of producing, for example, 5000 barrels per day, with an RPM of around 3500. The number of strokes per minute for SRP varies from 5 to 20. PCP, or Progressive Cavity Pump, is suitable for high-viscosity fluids when the oil's viscosity is very high. In the gas lift system, you are injecting gas, making it independent of the oil's viscosity, the gas quantity, or the presence of sand in the wellbore with oil, water, and gas. If you have a high gas-liquid ratio, the gas-to-liquid ratio (GLR), the gas lift system is the appropriate choice.

In the gas lift system, you are injecting gas, so having some gas in the wellbore is acceptable. However, if you have gas and you are using SRP or ESP for pumping, you will encounter difficulties. The gas lift system is versatile because you can pump anywhere from 50 barrels to 2000 barrels with a single gas lift mandrel or gas lift valve mechanism. Using this, you can produce varying amounts of fluid throughout the wellbore's life. In many cases, production engineers install the gas lift mandrel or gas lift valve at the beginning stage so that, later on, you don't have to install the gas lift mandrel or system separately as production depletes or reservoir pressure drops. If you wish to add a gas lift mandrel later, you would need to retrieve the tubing, which can be challenging.

So, they will install a gas lift mandrel at the beginning stage, especially in offshore wellbores. This is done so that later, when production decreases, you can enhance production using the gas lift system. The gas lift system involves a wellbore, casing and cementing it. Then, a tubing is inserted, and a packer is placed. The packer prevents wellbore fluids from passing through the annular area. As I explained in previous lectures, the tubing, casing, and cementing are standard components. Please review the basics.

The casing should have perforations in the oil or gas zone. Perforations are made in various patterns. The reservoir allows oil or gas to flow, and water or sand may also be present, depending on the effectiveness of sand control mechanisms. Sometimes, when producing oil, water can also enter the wellbore due to various mechanisms. If liquid, in the form of oil or water, enters the wellbore, you need to pump it. Even if gas enters, you must continue pumping because stopping gas inflow is not possible.

On the surface, there is a wellhead, denoted as 'WH.' The system separates the components from the wellhead, and then the fluids are transported, whether by wagon, ship, or pipeline, to refineries. Gas is also obtained from the separator in a gas injection system. This gas can be injected through the annular area using a gas lift mandrel or gas lift valve system. You'll have gas lift valves to inject small bubbles, enhancing productivity. When injecting gas from the surface, a compressor is needed. A compressor is a must-have.

The source of the gas is the gas obtained after separation. This gas can be injected and used for production. Any excess gas obtained after production can be sent to customers. When compressing gas and managing multiple wellbores, a manifold is used to distribute gas to different wellbores. There may be various wellbores, such as Wellbore 1, Wellbore 2, and Wellbore 3, each with its own gas injection criteria.

Let's say Wellbore 1 requires 250 PSI pressure, while Wellbore 2 may need 500 PSI pressure. Different wellbores may require varying levels of pressure. Your manifold will control and distribute the gas to different wellbores. Each wellbore might have its own compression system. Sending compressed gas to different wellbores can result in higher productivity.

This entire lecture is based on the book 'Technology for Artificial Lifting Methods' by the author Kermit Brown, Volume 2A. It's in Chapter 3, and I believe it's Volume 2A, as indicated in the book. If we look at the gas lift system, there are two main components: the subsurface part, located below the surface, which includes the gas lift mandrel and gas lift valve mechanism. On the surface, there are the compression system and separator systems. Let's understand how it works. You have a compressor system here; from the compressor, the gas goes to the high-pressure gas distribution room.

The gas is distributed and sent to various wellbores in this distribution room. You may have multiple wellbores where the compressed gas is sent. You have one large compression system to handle this. The gas enters the tubing, which is surrounded by casing that has been cemented. There are perforations, and liquid, gas, or oil can enter through them. Our primary goal is to produce oil, not water or sand.

When a completion engineer works on the well, they aim to complete it to maximize oil production while minimizing water or sand. To avoid mixing oil and water, engineers perforate only the oil zone. In some cases, both oil and water may be present together. In such cases, you must address this on the surface.

If you're producing more water, remember that water doesn't generate revenue; it costs you money to separate and manage it on the surface. So, your funds will be wasted if you're producing excess water. It's best to avoid producing water because it needs to be separated and disposed of, which can lead to various challenges. It's better to focus on oil production, as oil is profitable.

Similarly, if you're producing gas, it's still beneficial because gas can be a source of income. You're obtaining oil due to gas injection, and the same gas is sent to the surface. This process yields both oil and gas. The oil and gas are then directed to the oil and gas metering station, and from there, they go to the treatment area. The oil, water, and gas are separated at the treatment area. The treated gas is sent to the export line, and natural gas is returned to the system.

Some of the gas can be sold, while the rest might need to be reinjected. This creates a continuous cycle. Normally, you don't inject air because if oxygen, which is present in air, mixes with hydrocarbons or natural gas, it can create a combustible mixture, posing a significant danger. Therefore, it's crucial to avoid introducing oxygen.

Now, there are two types of gas lift systems: intermittent and continuous. The continuous system is used when there's a significant amount of liquid in the wellbore, and reservoir pressure is high. In this case, gas is injected continuously to maintain continuous oil production and higher productivity.

On the other hand, intermittent flow is employed in situations like gas wells with liquid held up. In a gas well, mist flow is created to ensure that any liquid present is broken down into very small particles that move with the gas, preventing liquid accumulation at the bottom. However, if the reservoir pressure depletes and flow rates decrease, mist formation may not occur, and instead, small bubbles might be formed.

So, slowly bubbles will slide down, accumulating at the bottom. As they accumulate, it affects the flowing pressure, denoted as Pwf. When the flowing pressure decreases, it may not push the fluid upward because the liquid buildup creates hydrostatic pressure, preventing the entry of oil, gas, or water.

In such a case, you need to remove the accumulated water. If you don't remove it, production will be halted. To remove a small amount of deposited water, let's say 5 barrels or 10 barrels per day, you can use a plunger lift system. The plunger lift system involves a catcher and a plunger. As the liquid column builds up and reaches a certain level above the plunger, you inject high-pressure gas from the bottom of the plunger. The high-pressure gas causes the plunger to move upward, carrying the entire liquid column with it and delivering the liquid, effectively removing it from the wellbore. This process helps remove liquid from the wellbore, with gas aiding in moving the plunger. This process can be done intermittently, not continuously; you don't continuously move the plunger up and down. You may perform this operation once or twice a day, creating high pressure to move the plunger and expel the collected liquid. This process is called intermittent flow gas lift.

In continuous gas lift, no plunger moves up and down to remove liquid. Instead, gas is continuously injected to maintain production.

In the gas lift valve, when gas is injected, it passes through a small nozzle, creating small bubbles. As these bubbles take up space within the column filled with liquid (such as water), the overall liquid volume in that height is reduced. This reduction in volume leads to a decrease in average density. Initially, the column is filled with entirely liquid (denoted as P_2), but due to the introduction of gas bubbles, it becomes a porous column, and the total liquid weight is reduced. When the liquid weight is reduced, it affects the flowing pressure (P_{wf}) while the reservoir pressure (P_r) remains unchanged. The difference between P_{wf} and P_r increases due to the gas injection.

So, more liquid will enter the elbow, and with more liquid entering, the production rate increases. However, if you don't inject gas, the weight of the entire liquid column will be very high, nearly equal to the reservoir pressure, and the flowing pressure. In such a case, fluid won't enter your wellbore. To enhance production, you remove as much of the liquid column as possible so that more liquid can come from the reservoir. Gas bubbles play a crucial role in creating a bubbly flow.

If you recall the multiphase flow lecture, I mentioned that bubble flow is beneficial. Creating a mist flow with very small particles won't be as helpful. Mist flow would require injecting a high amount of gas from the surface, which may not always be feasible. Injecting too little gas would only create small bubbles, which aren't very effective. To optimize production, the right amount of gas should be injected.

Ideally, The flow should be bubbly or Taylor bubble flow, not wavy or unsteady. Now, where to inject the gas? When injecting gas from the surface, start by injecting it into the top valve to create small bubbles. As the bubbles move upward, you'll notice that the pressure is higher in the lower portion (section 1) and lower in the upper portion (section 2) due to the difference in column height. More column height means more pressure, and the bubbles will get compressed in the lower section. However, as they move up, they expand due to the lower pressure.

As bubbles travel from the bottom to the top of the column, they increase in size, displacing more fluid. The average density at the bottom is higher, while at the top, it's lower. Injecting gas into the top valve first reduces the weight of the column, and gradually injecting gas into the lower valves further reduces the hydrostatic pressure, increasing production rates.

The lowest valve isn't always the operating valve. The operating valve can be different based on field conditions and requirements. Flexibility is a key feature of gas lift systems, allowing production rates to range from 1,000 barrels per day to 50 barrels per day. You can effectively change the oil production rate by controlling the gas injection rate and the operating valve.

But other artificial lifting systems may not offer as much flexibility as gas lift. Gas lift is known for its high degree of flexibility, making it a commonly used method in the oil and gas industry. While sucker rod pumps (SRP) are widespread, gas lift systems are favored for their ability to provide higher productivity rates. SRP is commonly used for lower flow rates, but its productivity rate is significantly lower, resulting in a very low daily barrel production. In contrast, gas lift systems can achieve very high daily production rates.

You should remember some theories regarding gas lift, such as the gas lift mandrel. The mandrel is like a pocket created in the tubing during installation where you can install the gas lift valves. The valves can be pre-installed or inserted later using wireline methods, but in many cases, gas lift valves are installed at the beginning stage. This gas lift mandrel or pocket contains the gas lift valve. I will explain how the entire system works later. Gas lift mandrels are installed in the tubing string and come in two primary types: conventional and side pocket types.

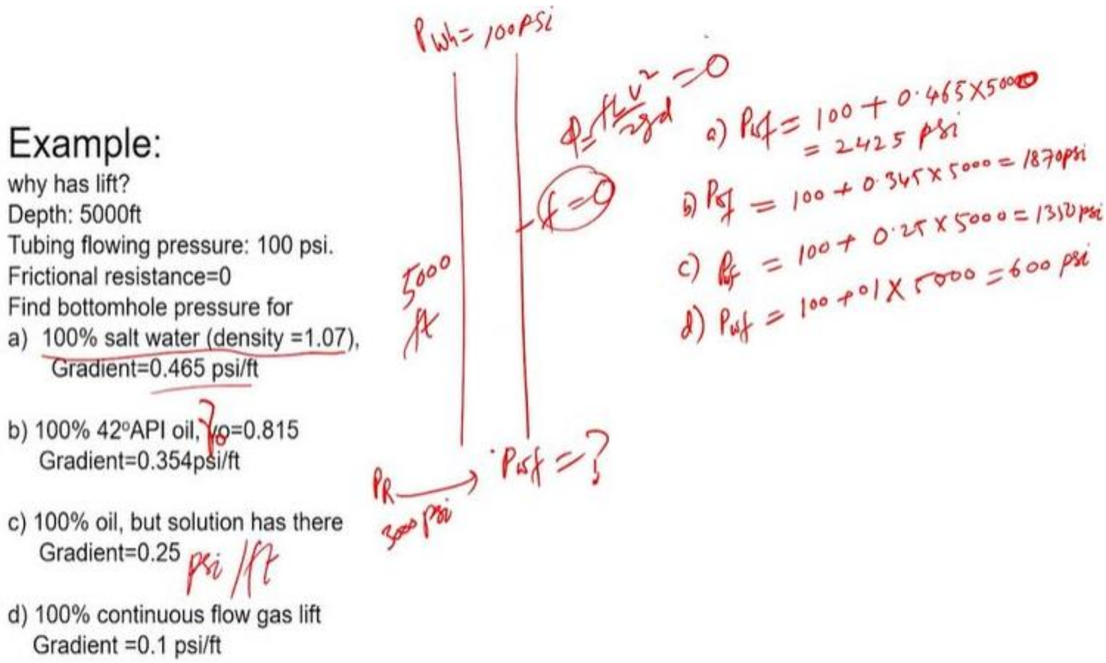
The conventional type involves assembling everything first and then inserting the tubing, whereas the side pocket mandrel is designed to allow the installation of gas lift valves and other downhole components using wirelines. Different types of valves are available, but we cannot discuss them in this lecture due to time limitations.

Examples include casing pressure-operated valves, pressure valves, unbalanced bellow valves, balanced pressure valves, throttling pressure valves, fluid-operated valves, and combination valves. While we won't cover all types in this course, we will discuss a few.

For illustration, let's consider an example from Karmit Brown's book to understand how the gas lift system works. In this example, we have a wellbore with a depth of 5000 feet, and the tubing's flowing pressure is 100 psi.

Frictional resistance (f) is assumed to be 0. Therefore, there will be no fluid friction ($fLV^2/2GD$)

ΔP (pressure drop) is also considered to be 0 because f is 0. We need to determine the wellhead pressure (P_{WH}) requirement, which is 100 psi. However, we need to find the flowing pressure for this wellbore.



If you are pumping water in the same wellbore, your flowing pressure requirement is 2425 psi. This means that P_R (reservoir pressure) must be more than P_{WF} for the fluid to flow from the reservoir to the wellbore. For case A, PR must be 2424 psi or more, while the flowing pressure (P_{WF}) should be 2425, assuming there is no fluid friction. If fluid friction is present, then the reservoir pressure must be even higher, taking friction into account.

In case C, 100 percent oil is assumed, but there is solution gas in the oil, which reduces the gradient to 0.25. In this case, P_{WF} would be 100 psi (wellhead pressure) + 0.25 * 5000 feet, resulting in a flowing pressure of 1350 psi. The presence of some gas reduces the flowing pressure.

In case D, it's a continuous gas lift system, which changes the pressure gradient to 0.1 psi. In this case, P_{WF} would be 100 psi (wellhead pressure) + 0.1 * 5000 feet, resulting in a flowing pressure of 600 psi. You can see how the flowing pressure changes for the same reservoir pressure, such as 3000 psi. In case 1, there's a pressure difference of around 500 psi (3000 - 2425), leading to lower flow rates. In case D, the pressure difference is 2200 psi (3000 - 600), resulting in significantly higher flow rates. This illustrates how a gas lift system can enhance productivity when there is solution gas or continuous gas injection.