Artificial Lift

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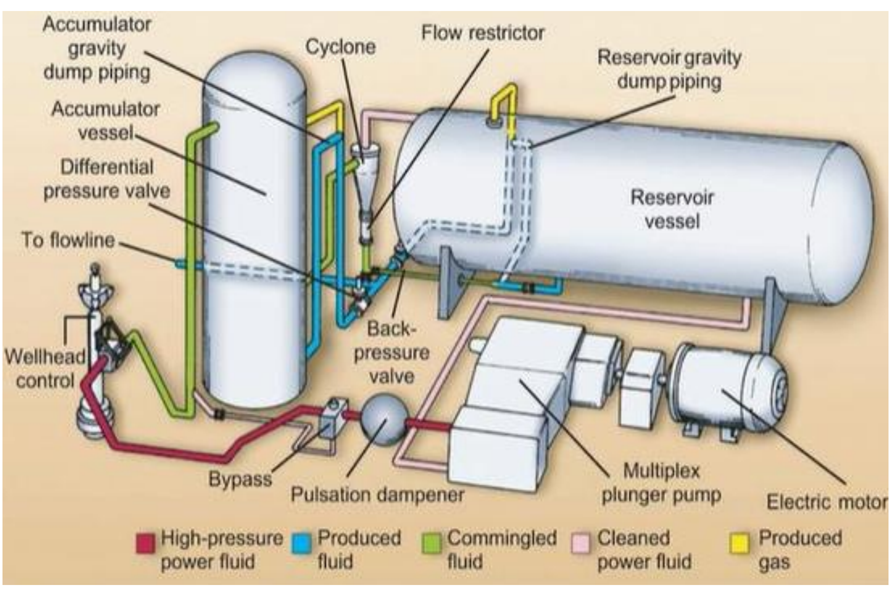
Lecture-36 Progressive Cavity Pump-Part-5

Good morning, today I am going to discuss hydraulic pumping as an artificial lift method. Let's break down the terminology first. 'Artificial lift' refers to the process of artificially raising fluid from a wellbore to the surface. Using hydraulic pumping mechanisms, you can enhance the productivity of the wellbore. In cases where the wellbore contains fluids with gas, sand, or if it's exceptionally deep, a jet pump can be employed. Jet pumps typically have lower efficiency, with only a portion of the pump's efficiency being around 30 percent. When considering the entire system, the efficiency tends to be even lower.

However, jet pumps are still used in the industry due to certain advantages driving their adoption to improve wellbore productivity. They find application in situations like coal bed methane (CBM) systems or dewatering gas well systems. There are two primary types of jet pump systems: hydraulic pumping systems and hydraulic engine pumps or hydraulic piston pumps. We will delve into the details of these systems later on.



For further insights, students can watch the video link I've provided. There are several other videos available that can help them gain a basic understanding of how hydraulic pumping, jet pumps, and hydraulic engine pumps work. Simultaneously, I will discuss various mathematical aspects of jet pumps and how they enhance wellbore productivity.

To better understand how jet pumps can improve productivity, we need to examine the Inflow Performance Relationship (IPR) curve. Keep in mind that when the flowing pressure (Pwf) is high, the flow rate is low in the wellbore. If the difference between Pwf and the reservoir pressure (PR) is substantial, you'll achieve higher productivity. For instance, if Pwf is very high, you'll experience a low flow rate, while a Pwf of zero may result in a production profile like this. By effectively reducing the flowing pressure at the wellbore entry to near zero, while maintaining the reservoir pressure, you can create a substantial drawdown, leading to increased production.

Now, consider a wellbore with a certain liquid column, which generates pressure due to its height, represented as hρg. Because of this, the flowing pressure (Pwf) is high, and Pwf is primarily a result of hρg. If you can remove the fluid column or liquid column, you reduce h while ρg remains constant. As a result, Pwf decreases. A reduced Pwf means you allow more inflow from the reservoir into the wellbore, increasing production. Initially, your productivity is represented on the Outflow Performance Relationship (OPR) or tubing performance relationship or liquid performance relationship curves. Implementing a jet pump can reduce P_{wf}, causing these curves to intersect with the Inflow Performance Relationship (IPR), yielding increased production.

Removing liquid using your jet pump can achieve even higher production levels. This is reflected in the increasing flow rate (Q) from A to B. When you change from point 1 to 2, or from 1.1 to 0.2, P_{wf} changes accordingly. This adjustment provides assistance to your wellbore, allowing the flow rate to increase from A to B. As P_{wf} decreases from A' to B', the flow rate increases from A to B. This hydraulic pumping system enables enhanced production.

Now, take a look at this figure I obtained from Petrowiki, which provides a clear illustration. In this diagram, you can see a wellbore with a wellhead controller. High-pressure fluid is pumped into the wellbore, effectively increasing productivity. I will explain how this process works in more detail shortly. Imagine a wellbore where the injection of high-pressure fluid results in increased production. The green color represents the production fluid.

Now, as you store the fluids, you proceed with separation. After separation, you reserve the fluids in a tank like this one. The yellow line represents the gas line. When you produce fluids and reduce the pressure, some gas may separate from the liquid or oil. This gas must be managed separately, whether directed to a sales line or injected into a wellbore. However, the liquid portion you obtain from the wellbore, which may include water and oil, must be processed further.

On the surface, you must separate the oil for refining, while the water can either be disposed of or reserved for reinjection into the wellbore. The same water can be reinjected repeatedly, but you must separate the oil and water before doing so. You cannot reintroduce the same produced fluid into the wellbore, as it would result in a loss of productivity. This liquid is then passed through a high-pressure pump driven by an induction motor. The induction motor is connected to a coupling and gearbox. The high-pressure pump itself is often a multiplex plunger pump or reciprocating pump.

When the reciprocating pump generates flow, it typically produces a pulsating flow. We will discuss how to reduce pulsating flow later on. To address this issue, a pulsation dampener is employed. The pulsation dampener helps mitigate the fluctuations in pressure and flow. For example, in a sucker rod pump, production is achieved when the piston moves upward, while no production occurs during the downward stroke. By placing a pressure sensor here, you can observe high pressure during the upward stroke and no pressure during the downward stroke, and this pattern repeats.

So, you're experiencing pressure pulses, similar to a sucker rod pump where there's a rod involved. When the piston moves up, you get high pressure, and when the piston moves down, you get low pressure. This high and low pressure cycle creates a pulsating flow that cannot be directly used in your jet pump. To reduce these pulsations, you need to employ a pulsation dampener. A pulsation dampener typically consists of a chamber filled with nitrogen and a membrane. The nitrogen compresses and absorbs the pulses, providing a smoother output. The high-pressure fluid then continues into your wellbore.

When it reaches the wellbore, the wellbore fluid may either mix with the high-pressure fluid you're injecting (referred to as power fluid) or remain separate. In many cases, these fluids mix, while in others, they remain distinct. I've taken this picture from a Weatherford brochure, which illustrates their system. Weatherford manufactures and sells systems like the one depicted here.

The picture illustrates a separated system and a storage system. Fluid is injected into the wellbore from storage, and production is subsequently obtained from the wellbore. Inside the wellbore, you'll find a jet pump, hydraulic engine pump, or hydraulic piston pump connected to perforations. Fluid enters through these perforations, while power fluid is supplied from within. The power fluid flows out and passes through a mixing chamber where it combines with wellbore fluid. This combined mixture is then lifted to the surface. Below this paragraph, you can see another picture from the same document.

So, there's one nozzle here, and another nozzle here. I'm shading the metal part of the nozzle, not the hollow part. High-pressure fluid flows through this nozzle. When you change the cross-section, like from P_1 to P_2, Q_1 to Q_2, and d_1 to d_n, the pressure will reduce while the flow rate increases. Thus, Q_2 will be lower than Q_1, and the flow rate will be the same, but the fluid velocity will change, with V_2 being higher than V_1.

Why do I say the flow rate will be the same? If we consider mass flow rate

($m_1 = \rho_1 Q_1$ and $m_2 = \rho_2 Q_2$),

and ρ_1 is constant, then Q_1 and Q_2 will remain constant. However, if we calculate velocity

(velocity = Q/A),

when the area changes

(area = $\pi D^2/4$),

the velocity will increase when passing through a nozzle because the area is reduced due to the decreased diameter. This change in area leads to a change in velocity.

When fluid passes through a nozzle, velocity increases, resulting in a decrease in pressure. I'll explain later how this reduction in pressure works. In this nozzle, fluid flows at very high velocity, creating low pressure, which, in turn, sucks in another fluid, increasing productivity. I'll explain how this process works later.

This information is also from the same Weatherford document, aiming to provide insight into jet pump size and flow rate criteria. Jet pumps excel in handling corrosion because anti-corrosive agents can be added to the power fluid pumped from the surface. They also efficiently handle gases, solids, high-density fluids, and thick fluids since they pump high-pressure fluid from the surface. Adjusting fluid temperature can modify fluid density and other properties. Jet pumps are easy to service, usually requiring maintenance on the jet nozzle, which can be retrieved and fixed in the wellbore bottom. They can have multiple cylinder types, including electric cylinders, and are also suitable for offshore applications.

If you look at the operating range, it can extend up to 20,000 feet, whereas PCPs and other systems may struggle to handle such depths. However, jet pumps can manage it. They can also withstand high operating temperatures because the jet pump system, including the nozzle, is entirely made of metal, making it suitable for high-temperature, high-pressure wellbores (HPHT) of up to 260 degrees Celsius.

Jet pumps can operate within a volume range of 300 to 1,000 barrels per day and even go as high as 35,000 barrels per day, allowing for substantial production rates. Tubing sizes can vary from one and a half inches to three inches. Narrower tubing sizes result in lower flow rates, as seen with 400 barrels per day, whereas larger sizes enable higher daily production volumes.

Jet pumps are suitable for deep wells, high-solid-content fluids (including sand), high gas content, and corrosive fluids. The inclusion of anti-corrosive agents can mitigate the corrosive effects of the injected power fluid from the surface.

Subsea production is also possible, and it can handle high production volumes. Jet pumps are designed with short and compact bodies, facilitating retrieval and wireline operations since only the nozzle part needs to be removed or replaced. Their operational lifespan is notably long, with approximately four years, in contrast to the four to six months typically associated with PCPs. The surface equipment includes a multiplex pump with a power range of 60 to 625 horsepower, and it can be powered by an electric motor or a multi-cylinder IC engine, though it's not a compressor system since it generates high pressure.

However, jet pumps have some limitations. Their efficiency is relatively low, ranging from 10 to 30 percent, and they require a high rate of power fluid, nearly double that of production fluid. This means a significant volume of fluid must be pumped, and handling high pressure on the surface can pose challenges, including issues related to pipes and safety. Space constraints can also be problematic, as jet pumps demand a considerable amount of space. Additionally, they face potential failure issues, such as cavitation, especially at high velocities when sand particles can erode the jet pump's metal surfaces.

This combination can lead to cavitation and erosion; if corrosive fluid is present, erosion and corrosion will compound your problems.

The hydraulic engine or piston pump is related to the sucker rod pump. The mechanism and design are such that you introduce high-pressure fluid to operate a reciprocating engine. It's similar in concept to a steam engine, where high-pressure steam is supplied to drive a piston, resulting in reciprocating motion that is transformed into rotation. Older trains, such as the Darjeeling or Ooty trains, and even some heritage trains, were powered by steam engines. These engines have found similar applications in the hydraulic engine of piston pumps.

In this setup, high-pressure fluid is used to actuate a piston system. The reciprocating motion generated by the piston is transmitted through a shaft or rod, commonly known as a sucker rod. This arrangement includes a plunger assembly, similar to the bottom hole assembly found in a sucker rod pump, complete with a traveling valve (TV) and standing valve (SV). By using a small reciprocating shaft to drive the sucker rod pump, you can replace the need for a lengthy sucker rod.

In this setup, you don't have a long rod; you only have high-pressure fluid that operates your reciprocating engine. The reciprocating engine is connected to your reciprocating shaft, causing the shaft to move up and down. This reciprocating action is applied to your plunger assembly or bottom-hole assembly, similar to a standard sucker rod pump, resulting in production. The advantage here is that you can reach any depth without needing an extended rod, beam, or hydraulic motor with balancing masses and other associated equipment.

You only require a surface pumping unit, a reciprocating engine, and a plunger assembly. However, the production rate will be lower than that of a hydraulic jet pump. The hydraulic jet pump can achieve higher production rates, whereas this system functions similarly to a simple reciprocating sucker rod pump.

Nevertheless, like the sucker rod pump, the hydraulic engine pump faces challenges related to gas and sand. Gas and sand issues are the same as those encountered by the SRP (sucker rod pump) or beam pump. However, on the positive side, it can be used in long wellbores and deviated wellbores.

I've mixed both positive and negative aspects. On the positive side, this system can pump long and deviated wells. However, there are disadvantages, including low formation pressure. Separated tubing is required in the wellbore, one for hydraulic fluid pumping and another for extracting production fluid. This means two separate tubing or flow paths are necessary to transport fluid from the wellbore to the surface. I will explain later how the hydraulic piston pump involves two tubing and two separate components.

Additionally, you do not mix your produced fluid and power fluid in this system. When you do not mix produced fluid and power fluid, the same power fluid can be reused without treatment. In contrast, with a jet pump, where produced fluid and power fluid are mixed, surface separation is required, and power fluid treatment is necessary each time.

You can see two artificial lifting mechanisms for high volume in these two pictures. Gas lift has a very high volume and a lift depth of 16,000 feet with a volume flow rate of 30,000. On the other hand, ESP (Electric Submersible Pump) provides a higher volume than hydraulic jet pumps. Hydraulic jet pumps have a higher volume, but the volume flow rate is much lower if you look at hydraulic engine pumps. However, they can reach greater depths. Hydraulic jet pumps quickly experience a decrease in volume flow rate. In contrast, hydraulic engine pumps have a lower volume but maintain it for longer depths. When it comes to low volume artificial lift, reciprocating hydraulic pumps are a viable option. PCP (Progressing Cavity Pump) offers a lower volume compared to reciprocating engine pumps, while reciprocating rod pumps provide slightly higher volume for greater water or fluid depths.

Plunger lift has the lowest volume flow rate. If we compare all the artificial lift methods, we find that gas lift has the highest production rate, while plunger lift has the lowest. It's worth noting that there may be many more artificial lifting systems in development, but these are the most common ones that we can use for depth and flow rate comparisons.

Regarding power fluid, as I mentioned earlier, in the case of a jet pump, your fluids are mixed. However, in the hydraulic engine pump, the fluids do not mix. Let me explain how it works. We have the casing and tubing. The casing is cemented, and there are perforations in the casing. The tubing is placed here, and let's use a packer to seal the annular space, preventing any flow through the annular region. Now, I need to inject power fluid through this tubing. My pump, the jet pump, is located here. The wellbore fluid flows through this tubing, and the jet pump introduces high-pressure fluid. These two fluids mix and move through this system. You then extract the fluid and subject it to power fluid conditioning. Conditioning involves properly separating the fluid obtained from the wellbore. After that, you create a high-pressure pump, and the high-pressure pump injects the fluid.

So, in this case, this is called the open power fluid option, where open power fluid means that fluid from the wellbore and your pump fluid, or power fluid, are mixed together. This is referred to as an open fluid option. On the other hand, there is the closed fluid option, with open power fluid (OPF) and closed power fluid (CPF) options. In the closed power fluid option, you have a wellbore similar to the casing, and then you have one tubing, with another tubing located here, and you have one pump. Power fluid is introduced through this tubing, and the power fluid returns here. On the surface, you re-inject it. There's no need for further conditioning because it doesn't mix with the wellbore fluid. However, what happens to your wellbore fluid? Wellbore fluid enters the wellbore tubing, and from the tubing, you obtain wellbore fluid like this. This is your separator. Wellbore fluid, for hydraulic engine pump, piston pump, plunger pump, hydraulic plunger pump, or piston pump, whatever you name it, that pump will have power fluid—this is power fluid—coming from the surface. It goes through the pump but doesn't mix; it goes back up to the surface and circulates like this. When it comes to wellbore fluid, it goes like this and enters the separator. Wellbore fluid doesn't mix with power fluid. Life is easier because you only have power fluid circulating without mixing with anything. You don't need to separate the power fluid. However, both fluids mix together in an open fluid application, such as for a jet pump. In such cases, you first have to separate and condition them before introducing them into your wellbore as power fluid.