Artificial Lift

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Lecture-16 Single and Multiphase Flow-Flow Regimes

Good morning, everybody. We have started discussing multiphase or T-wing flow and its relationship with T-wing performance. In this week's lecture, I have covered single-phase flow and emulsion flow, and today, I will try to cover multiphase flow.

Multiphase flow is essential because handling single-phase flow is relatively easy due to the simplicity of fluid mechanics equations and mathematical correlations. However, simple correlations are insufficient when dealing with multiple phases, such as gas, solids, and liquids. Specialized correlations are required, and multiphase flow significantly impacts the performance of artificial lifting systems.

Why does it affect artificial lifting? For example, let's consider a certain amount of gas present in oil. This gas can enter various pumping systems like sucker rod pumps, electric submersible pumps, or progressive cavity pumps, interfering with their performance. It's important to note that studying multiphase flow in wellbores and normal air-water multiphase flow are different tasks.

In a wellbore, multiple phases are handled due to factors like formation volume, reservoir solution, gas-oil ratio (GLR), and their variation from the subsurface to the surface as pressure and temperature change. Let me illustrate this concept: Imagine a reservoir connected to a wellbore, which is cemented. The wellbore has perforations, and there's tubing connecting the wellbore to the wellhead. The wellhead leads to the production separator. Now, let's discuss the various pressures involved in this system, including reservoir pressure (PR), sand phase completion pressure (PWFS), and flowing pressure (PWF).

Now, you can recall this phase diagram. You've seen the critical point, the dew point line, and the bubble point line. In between, there is a two-phase flow. Two-phase fluid or flow will exist. Here, the dew point represents gas, specifically dry gas, which means no liquid is involved, as I've explained in a previous lecture. Conversely, this area represents the liquid phase.

Considering temperature and pressure, you can observe how fluid properties change based on this phase diagram. For instance, let's denote different sections as A, B, C, and D. Starting with A, the initial fluid is at point A in this phase diagram with temperature (T) and pressure (P). This means it's an entirely single-phase fluid with no gas. If there's any gas, it's already dissolved in the liquid. Therefore, at this stage, you have a single-phase liquid flow, with the oil and gas mixture entering the wellbore as a single phase due to differences in reservoir pressure (PR) and flowing pressure (PWF), also known as drawdown.

As we move from point A to point B, still along the curve ABC, point B may lie on the bubble point line. If it's on the bubble point line, it's still single-phase, but gas bubbles may start forming as you decrease the pressure further. Initially, the pressure was at P1, and now it's at P2, where P1 is more incredible than P2. So, from A, you reach point B, but it's still a single-phase flow up to this level.

Continuing from B to C, once again considering temperature (T) and pressure (P) along the curve ABC, you'll notice that point C is within the two-phase region. This indicates that a certain amount of gas is evolving from the liquid, transitioning from single-phase flow to multiphase flow, creating gas bubbles. Thus, from A to B, there were no bubbles; it was still single-phase. From B to C, you encounter a certain number of bubbles.

Finally, moving from C to D, you're reaching a point where more bubbles form. These bubbles will collide and merge, creating more giant bubbles. These bubbles consist of natural gas or low short-chain hydrocarbons and will continue to generate more bubbles.

After a certain amount of time, if your gas continues to move upward while the pressure fluctuates, with PWF (flowing pressure) increasing and PWH (wellhead pressure) decreasing and considering that reservoir pressure is very high, then as the fluid moves upward, it reaches a point where the wellhead pressure is even lower. This establishes a pressure gradient with lower pressure at the bottom and higher pressure at the top.

Initially, a certain amount of gas would be dissolved in the fluid at the bottom where the pressure is higher.

Some gas comes from the liquid as the fluid ascends and the pressure drops. This process continues as the fluid moves further upward, releasing more gas. When it reaches the top, you have a higher gas concentration. After some time, this leads to the creation of annular flow, where the liquid wets the well and surrounds the gas, forming a central channel. This configuration creates an annular space for the gas.

As the gas content increases and the velocity rises further, the wetting liquid on the walls generates many small bubbles. Initially, gas bubbles were present, progressing from point B to C. Then, more gas bubbles formed from C to D. When moving from D to, say, E, annular flow is established. Finally, you enter a mist flow regime as you approach point F or the wellhead. Here, liquid particles separate and mix with the gas, resulting in mist, not mixed flow.

Its properties change as the fluid travels from the reservoir to the wellhead. However, the fluid properties may differ when considering a mixture of water and gas in normal piping applications. In the context of wellbore applications, the liquid composition is distinct due to variations in reservoir pressure (RS), formation volume factor, and solution gas-oil ratio. This makes multiphase flow in wellbores unique compared to standard air-water multiphase flow. It possesses different viscosity, comprises water-oil mixtures, and may even include sand. In situations with sand, water, oil, and gas, there are three phases involved, with water and oil existing as single phases but with different immiscible states. This complexity results in intricate flow phenomena within the wellbore.

When discussing artificial lift methods in multiphase flow, we encounter various pumping systems such as sucker rod pumps, ESPs (electric submersible pumps), PCPs (progressive cavity pumps), jet pumps, and gas lift systems. Sucker rod pumps, known as beam pumps, are commonly used in well-field applications, featuring a characteristic setup with a rod and a beam. ESPs, on the other hand, typically employ centrifugal pumps. PCPs refer to progressive cavity pumps, while jet pumps utilize high-velocity jets to draw in low-pressure wellbore fluids. Gas lift systems inject gas from the surface, which can take various forms, including hydraulic jet pumps and engine pumps.

In the case of a sucker rod pump operating with the gas present, the gas may obstruct the flow area, potentially leading to fluid pound issues or gas lock interference. For ESPs, the presence of gas can result in vibration, cavitation, and even complete flow cessation. These challenges are related to the gas's interaction with the PCP or electric submersible system.

With a progressive cavity pump (PCP) or a positive displacement pump, PCP can handle a certain amount of gas. However, with higher gas volumes, gas compression can lead to elevated temperatures, posing a challenge for the elastomeric stator and resulting in performance drops due to the increased temperature.

In the gas lift system, gas injection is employed within the wellbore to create a multiphase flow, aiding fluid transport to the surface. While intentionally inducing multiphase flow is beneficial, specific criteria and challenges associated with gas lift systems will be discussed in detail during our lessons.

In hydraulic engine pumps, similar to sucker rod pumps, issues like fluid pound and gas lock can arise when gas is present. Jet pumps, while capable of handling a certain amount of gas, may encounter problems with excessive gas. Gas separators and various techniques may be employed for artificial lift applications to minimize gas interference and facilitate wellbore production.

Regarding flow regimes in multiphase systems, consider a vertical wellbore or pipe. Initially, fluid velocity is low as you move a mixture of air and water from the wellbore to the surface. When there are only small gas bubbles in the liquid, these bubbles create tiny bubbles within the liquid, a phenomenon referred to as bubble flow or bubbly flow.

As you increase the amount of gas, gas particles start colliding with each other, forming larger particles. This phase is called slug flow, where particles become larger due to collisions. Imagine one particle here, another there, and when two particles collide, they merge to form a bigger particle. With more gas particles and void space, collisions continue, causing the transition from bubble flow to slug flow.

With further increases in gas flow, the slug or bubbles begin to collide and break apart, creating highly unstable bubbles. This phase is known as churn flow, characterized by random motion as liquid particles move up and down, introducing increased randomness into the system.

If you continue to increase the gas flow, it results in an annular flow. In this scenario, the liquid coats the inner wall of the tubing or vertical pipe, while the gas forms an inner core. This means the liquid is the continuous phase, while the gas bubbles become the discrete phase. These bubbles are still gas in slug and churn flow, and the constant phase remains liquid. However, as you further increase the fluid velocity or gas volume, the gas forms a central core, and the liquid adheres to the wall, creating a distinct separation where the gas core is not in contact with the wall.

If your gas velocity is very high, it will create a central core. When this central core is formed, the liquid can slide down. If you further increase the gas velocity, what will happen? Gas velocity increases, and the amount of gas also increases. In this case, gas becomes the continuous phase, while liquid particles are broken down into smaller particles, resulting in what's known as mist flow.

Why am I teaching this concept in the context of artificial lifting systems? When working with a gas lift system, your goal should be to create bubble flow, as bubble flow provides higher efficiency for gas lift systems. However, if you create churn or annular flow, you inject a very high amount of gas, but your production rate will decrease.

On the other hand, in gas wells, creating mist flow is very beneficial. When gas velocity is very high, any liquid present in the wellbore will be carried along with the gas. This eliminates the need for any additional pumping mechanisms. So, your objective should be to create mist flow in gas wells. However, if your gas velocity is slightly lower, it can lead to annular flow, which results in liquid being held up. I will explain the concept of liquid held up later on.

It has different applications for various pumping or artificial lifting mechanisms. If you have a bubbly flow or any other type of flow, a centrifugal pump is suitable for handling a small amount of bubbly flow. However, if you encounter slug flow, churn flow, or other types of flow with a higher volume of gas, the centrifugal pump will face significant resistance or hindrance. Centrifugal pumps are typically designed for liquid handling and are not ideal for gas handling. Sucker rod pumps, jet pumps, and other artificial lifting systems are primarily designed for liquid handling, except gas lift systems. In gas lift systems, you inject gas into a fluid column, creating tiny bubbles and achieving bubble flow. Gas lift systems aim to avoid creating slug flow and stay within the bubbly flow region to maximize production.

Some time ago, we conducted experiments on bubble flow. In cases where slug flow or churn flow had already formed due to sudden changes in fluid velocity or composition (e.g., air and water), we designed a system to break the slugs. This breaking of slugs resulted in bubble flow. We conducted these experiments in collaboration with the Abu Dhabi Petroleum Institute, and I believe we also published a paper on this research.

Flow regimes for horizontal pipes: Now, let's consider a horizontal pipe like this. Initially, you have a very low flow velocity, with low liquid and gas velocities. In this case, what occurs in a horizontal pipe is the formation of two distinct layers: one is a liquid layer, and the other is a gas layer. This phenomenon is known as stratified flow. The denser fluid, the liquid, occupies the bottom layer, while the upper portion contains the gas. Stratified flow occurs when the flow velocity is low, providing sufficient time for liquid particles to settle. You may recall the formula for particle settlement, which involves the terminal velocity (Vt). When more time is available due to the low flow velocity, particles settle more rapidly. Consequently, because the flow velocity is low and turbulence is minimal, liquid particles settle at the bottom while gas particles rise, resulting in two separate flow zones.

Next, when you slightly increase the flow velocity, the gas velocity also increases. In this situation, a wavy flow pattern emerges. In wavy flow, both liquid and gas are present. The gas, attempting to pass over the liquid, interacts with the liquid surface, creating small ripples that gradually grow into waves. This is why it's referred to as wavy flow.

If you increase the velocity further, gas will still be present, and gas bubbles will become entrained. This flow pattern is known as slug flow, characterized by the creation of gas slugs. Gas and liquid move together in this state, albeit with potentially different velocities.

It moves on to annular flow, increasing gas velocity further, leading to liquid soaking the pipe wall while gas flows through the central core. This pattern is referred to as annular flow. Similar to vertical pipes with high gas velocity, liquid covers the upper and lower walls in this scenario, while gas establishes its path in the center.

Next, we have a bubbly flow. When gas velocity is further increased, liquid particles form smaller particles within the liquid. In this case, you obtain very small liquid particles mixed with gas, creating a bubbly flow pattern. This description applies to horizontal pipes.

In vertical pipes, stratified flow does not typically occur because you don't form two distinct layers. Notably, these flow regimes depend on factors such as piping dimensions, friction, and fluid properties. Various scientists have conducted tests with different pipe diameters, such as 5.1 centimeters and 3 centimeters, revealing various flow regimes. You may encounter single or multiple flow regimes in wellbores, or some flow regimes may not be present. Nonetheless, these are the fundamental concepts of flow regimes in horizontal and vertical pipes. In cases of low flow velocity with a gas-liquid mixture, stratified flow may occur, while very high flow velocities can lead to mist flow. Bubbly flow can be observed when there's a low amount of gas and a high amount of liquid.

In vertical wells, you may observe bubbly flow with a very small amount of gas and mist flow with a very high amount of gas. However, not all wellbores exhibit these properties. Therefore, I will categorize them into two parts: vertical and horizontal.

Whether vertical or horizontal, flow regimes in tubing exhibit different flow velocities for gas and liquid. A plot of superficial gas velocity against superficial liquid velocity, shown on a logarithmic scale, will roughly look like this:

- In the case of low flow velocities for gas and liquid, you will typically observe stratified flow, represented by this region on the graph.
- When there's a slightly higher flow velocity, wave flow patterns emerge.
- Further increasing the liquid flow velocity leads to plug flow.
- Beyond that, higher liquid velocities can result in slug flow.
- If the liquid flow increases even further while gas flow remains lower, you can expect to see bubbly flow.
- Additionally, you will encounter mist flow if you have a wave pattern and high gas velocity with low liquid velocity.
- Finally, with a substantial amount of liquid, annular flow can occur.

It's worth noting that this curve is an approximation, and changes in piping dimensions and other properties may lead to slight variations. Nevertheless, the overall shape remains similar. For instance, you'll encounter stratified flow at lower velocities for both gas and liquid. As you increase gas velocity slightly, you'll observe wave flow, followed by mist flow with further increases. When superficial liquid velocity is raised, annular flow becomes possible, and if you continue moving upwards, you'll reach bubbly flow.

Now, consider a vertical wellbore. In a vertical wellbore, you can draw a similar figure depicting superficial gas and liquid velocities. I'll explain what 'superficial' means later. In this case, at low velocities, you typically encounter bubble flow. Here, the gas amount is low, but the liquid volume is higher, resulting in bubble flow with dispersed bubbles. As you progress, you encounter annular mist flow, followed by slug or churn flow, and finally, annular flow. This describes the flow pattern in a vertical wellbore.

Now, when dealing with inclined wellbores, the fluid behavior will be a combination of characteristics from both vertical and horizontal flow patterns. The dominance of either vertical or horizontal flow behavior depends on various factors. The explanation provided here offers a general concept to help you understand how flow regimes change when fluid liquid velocity or gas velocity is altered.