Artificial Lift

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Lecture-17 Multiphase Flow-Flow Models

Liquid holdup is when gas, oil, or any liquid (such as oil or water) moves together in a conduit. Due to the higher density of oil or liquid, the denser fluid tends to move downward, while lighter gas attempts to move upward.

Now, if we consider terminal velocity, small liquid particles will gradually descend when the gas velocity is not very high. Imagine a wellbore scenario with a reservoir (P reservoir), flowing pressure (Pwf), and perforations with tubing in place. Let's assume the reservoir pressure is 100 bar and gas is moving upward.

Now, if the gas velocity decreases because the reservoir pressure drops from 100 bar to 50 bar, what occurs next? Initially, you created mist flow, which means that any liquid produced would rise along with the gas. This discussion is specific to a gas well.

Due to reservoir pressure depletion, it drops from 100 bar to 50 bar. As a result, gas velocity decreases, and the liquid particles initially trying to move upward will now attempt to move downward because their terminal velocity may be higher.

With a higher terminal velocity, these particles will move downward, even though gas is trying to push them up due to buoyancy and drag forces. However, the particles' own weight will cause them to move downward. As they move downward, they accumulate, with one particle blocking some space, followed by two, three, four, and so on, until they form a blockage.

When this blockage occurs, consider the initial column pressure. Because the gas column pressure is significantly lower, you have a certain amount of liquid pressure. This column pressure becomes 'P.'

Now, if the reservoir pressure is 50 bar and the column pressure is almost the same, around 50 bar, the reservoir fluid will not attempt to enter the wellbore because the pressure difference is almost zero.

If you can remove this liquid column buildup in the tubing, perhaps through an artificial lifting system or another method, then the liquid and gas will re-enter, and you'll resume production. However, if you don't remove this liquid, your production rate will gradually decrease until it stops completely as the column pressure approaches that of the reservoir. In such a case, production will be very low or almost negligible.

In such a case, you need an artificial lifting system because your production decreases when liquid is held up at the bottom. Therefore, it's essential to understand what liquid holdup is and how to remove it. Artificial lifting systems normally handle a few barrels, whether oil or water, daily. In such scenarios, you might use a sucker rod pump or another artificial lift, which we will discuss later.

However, the challenge is to remove this liquid along with the gas. You need to understand the physical properties and the relevant formulas to do that. There is a formula for liquid holdup given as:

$Hl = v_l / v$

Here, Hl represents liquid holdup, v_l is the liquid phase volume (in cubic feet), and v is the piping area's volume (also in ft^3). This ratio is unitless, representing a fraction.

Now, two other terms come into play: slip and liquid holdup. Slip occurs when gas moves upward, and the liquid phase doesn't follow at the same velocity; instead, it slips downward. The slip formula can describe this slipping phenomenon:

Superficial velocity (V_{sl}) = Q_l / Af

Here, Q_l is the liquid flow rate, and Af represents the flow area for one phase. It's essential to consider the total flow area.

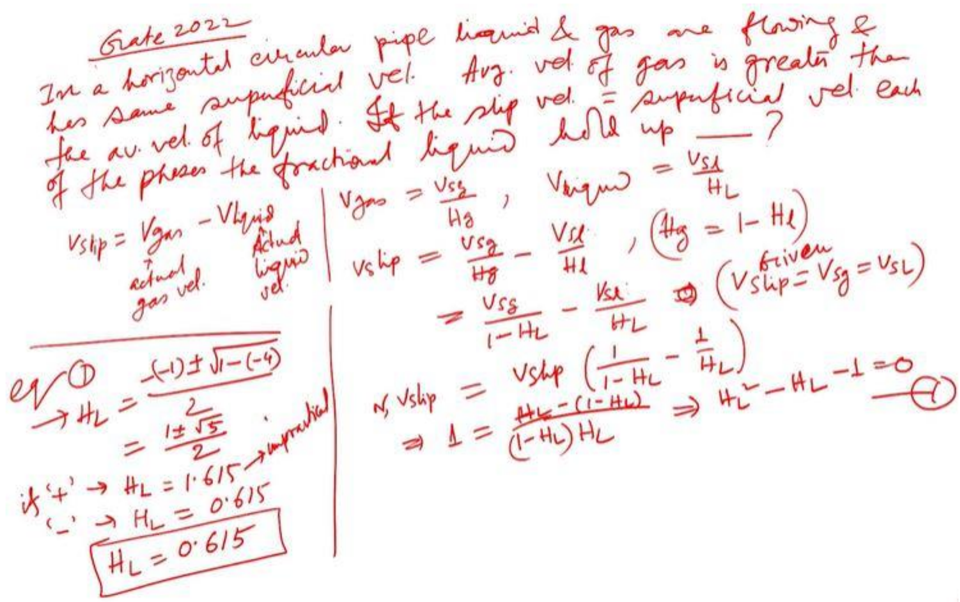
So, this ratio is known as the slip velocity for the liquid. Similarly, you can define the slip velocity for gas as Q_g divided by Af. Now, the gas void fraction is equal to vg divided by v, while the liquid void fraction is represented as v_l or ul divided by v. The total gas void fraction is denoted as alpha g, where alpha g plus H_l equals 1, indicating the total fraction, which must sum up to 1.

Now, concerning slip velocity, this is the superficial velocity for gas, and this is the superficial velocity for liquid. The slip velocity equals the actual velocity of gas minus the velocity of the liquid, represented as ug minus ul. Let's solve a problem to understand this concept better.

This question is from the GATE exam in 2022. The question goes like this: In a horizontal circular pipe, liquid and gas flow with the same superficial velocity. What can be said about the average velocity of gas? The average velocity of the gas is greater than the average velocity of the liquid. Additionally, the slip velocity is equal to the superficial velocity.

If the slip velocity is equal to the superficial velocity for each of the phases, it implies fractional liquid holdup. Now, let's solve a multiphase problem that appeared in the 2022 GATE exam. The problem statement goes as follows: In a horizontal circular pipe, both liquid and gas flow at the same superficial velocity. Interestingly, the average velocity of the gas is greater than the average velocity of the liquid. We need to find the fractional liquid holdup when the slip velocity equals the superficial velocity for each phase.

To solve this problem, we'll start with the slip velocity equation:



So, this concludes the solution to this problem. In the exam, I may present similar issues and sometimes provide values. Now, when you're dealing with multiphase flow, there are two types of solutions: the homogeneous model and the separated model. The homogeneous model may seem easier, but 'easier' doesn't mean it's very simple, just like 2 plus 2 equals 4.

There are several correlations, one of which is the Poitman and Carpenter correlation. Let's delve into this correlation. The formula is taken from Guo and Ghalambor's Petroleum Production Engineering book (2007). The formula is as follows: pressure drop equals $(\bar{\rho} + \bar{K}) / (\bar{\rho} * \Delta H / 144)$.

The values in the formula are as follows:

- ΔΨ: ΔΨ is the average mixture density in lb/ft^3.
- $\bar{K}$: $\bar{K}$ is a parameter we will discuss later.
- ΔH: ΔH represents the depth increment in feet.
- 144: This is a constant.

To calculate $\bar{K}$, refer to the friction factor and oil flow rate (STB per day). F2F (fanning friction factor), M (the total mass associated with 1 STB of oil), and D (the tubing diameter, also in feet) are all involved in the calculation.

The value $\bar{\rho}$ is calculated as $(\rho_1 + \rho_2) / 2$, where ρ_1 and ρ_2 are the mixture densities at the top tubing segment.

LB divided by FT^3, and ρ_2 at the bottom is again in the same unit, LB/FT^3. The term ρ is defined as M divided by Vm, where M is given as follows: M = γo * GOR * ρair / γg, where:

- γo is the oil-specific (SP) gravity, which is 1 for fresh water.
- GOR is the gas-oil ratio.
- ρair is the air density.

- γg is the gas-specific gravity (gas gravity).

Poettmann and Carpenter (1952) a simplified gas-oil-water three phase flow model

$$\Delta p = \left(\bar{\rho} + \frac{\bar{k}}{\bar{\rho}}\right)\frac{\Delta h}{144}$$

$$\bar{k} = \frac{f_{2F} q_o^2 M^2}{7.4137 \times 10^{10} D^5}$$

$$\bar{\rho} = \frac{\rho_1 + \rho_2}{2}$$

$$\rho = \frac{M}{V_m}$$

$$M = 350.17(\gamma_o + WOR\,\gamma_w) + GOR\rho_{air}\gamma_g$$

$$V_m = 5.615(B_o + WOR\,B_w) + (GOR - R_s)\left(\frac{14.7}{p}\right)\left(\frac{T}{520}\right)\left(\frac{z}{1.0}\right)$$

Guo et al. Petroleum Prod.Engg. Book, 2007

$$f_{2F} = 10^{1.444 - 2.5\log(D\rho v)}$$

$$(D\rho v) = \frac{1.4737 \times 10^{-5} M q_o}{D}$$

Vm is the volume mixture associated with 1 STB of oil, and Bo is the formation volume factor. WR represents the producing water-oil ratio, Bw is the formation volume factor of water, and R is the solution gas-oil ratio. P is the density pressure, T is the temperature in Rankine, and Z is the compressibility factor.

The compressibility factor has a unit of lower density in lbm per cubic feet, ρair in lbm/cubic feet, and γg is gas-specific gravity (1 per air). Vm is the volume mixture associated with 1 STB of oil, and Bo is the formation volume factor (unit: rb/stb, reservoir barrel divided by stock tank barrel). Bw is the formation volume factor of water, typically around 1. Rho insitu represents the in-situ pressure (unit: psi), and Z is the compressibility factor, which depends on specific P and T conditions.

The term 'f,' which we've seen in the K formula, represents the Fanning friction factor (F2F). This factor can be found using the formula F2F = 10^(1.44 + 2.5 * log(d * ρ * V)), a formula developed by Gou and Ghalambor, the authors of this book. The Potomac company provided this formula to avoid using a chart for F2F. In this formula, 'D' represents the tubing diameter, 'V' is the velocity, and 'ρ' is the density. The Reynolds number, if written, can be represented as * ρ * V' in the top term.

Hagedorn–Brown correlation

$$\frac{dP}{dz} = \frac{g}{g_c}\bar{\rho} + \frac{2f_F\bar{\rho}u_m^2}{g_c D} + \bar{\rho}\frac{\Delta(u_m^2)}{2g_c\Delta z}$$

US field unit

$$144\frac{dp}{dz} = \bar{\rho} + \frac{f_F M_t^2}{7.413 \times 10^{10} D^5 \bar{\rho}} + \bar{\rho}\frac{\Delta(u_m^2)}{2g_c\Delta z},$$

$$\bar{\rho} = y_L\rho_L + (1 - y_L)\rho_G,$$

$$u_m = u_{SL} + u_{SG},$$

$$N_{vL} = 1.938\, u_{SL}\sqrt[4]{\frac{\rho_L}{\sigma}}$$

$$N_{vG} = 1.938 u_{SG}\sqrt[4]{\frac{\rho_L}{\sigma}}$$

$$N_D = 120.872 D\sqrt{\frac{\rho_L}{\sigma}}$$

$$N_L = 0.15726\,\mu_L\sqrt[4]{\frac{1}{\rho_L\sigma^3}},$$

Guo et al. P

So, the formula for the 'd * ρ * V' term will look like this: M represents the total mass, Q is the oil flow rate, and D is the tubing diameter. This is how you calculate the pressure drop for homogeneous flow using the Poettmann and Carpenter equation. There are many other equations available, but because this is not our multiphase course focused on artificial lifting systems, we're providing these basic formulas to give you an idea. Understanding the formulas associated with basic calculations when considering homogeneous flow is essential.

Homogeneous flow assumes that particles are very small and mix uniformly. However, in cases where particles exhibit behavior like slug flow, plug flow, or other non-uniform flows, you cannot use this approximation. Although this formula is very simplified, it is still widely used in the oil field for fluid calculations.

As we mentioned earlier, we have the homogeneous flow model and the separated flow model. The separated flow model provides more accurate results but is much more complex, as manual calculations can be challenging. Nevertheless, it's essential to understand how to develop and calculate results using the separated flow model.

In the separated flow model, the pressure gradient (del p/del z) is determined by the following factors:

- g/gc (acceleration due to gravity)
- ρbar^2 (average density)
- 2ff (two-phase friction factor)
- ρf (density of the fluid)
- u (velocity)
- Vm^2 (volume mixture)
- gc/d (gravitational constant divided by the tubing diameter)
- U^2m * del (velocity term U squared times del)

If you're working with field units, you'll need to include the 144 constant and other necessary terms for field unit conversions. Additionally, for ρ (density), you'll calculate YL, PN, Y minus YL, and GL.

$$dz = \cos\phi \, dL$$

$$\rho = \frac{29 \gamma_g p}{zRT}$$

$$v = \frac{4 q z}{\pi D_t^2} \frac{P T}{T P}$$

So, one term is Um, where Um represents the mixture velocity, and its unit is feet per second. For ρ and ρbar, you can calculate them as YL and PL, where PL stands for liquid density, and its unit is lbm per ft^3, and ρg represents gas density, measured in lbm/ft^3. We also have terms like USL and USG, denoting superficial velocity for liquid and gas, respectively.

You'll need to calculate the liquid and gas velocity numbers using all these formulas. These are referred to as liquid velocity number and gas velocity number, respectively.

Additionally, there's the pipe diameter number. Hagedorn and Brown developed charts based on these numbers, such as CNL, which is a log-log plot. Another critical factor is the holdup factor (NLV * P^0.1 * CNL / NGV^0.575 * PA^0.1 * N * D).

From these charts, you can calculate pressure drop. Additionally, we have the concept of liquid holdup and the liquid viscosity number.

We've covered multiphase flow for liquid and gas, liquid-liquid flow, and single-phase liquid flow. Moving on to single-phase gas flow, the equation is as follows: del P / (ρg / gc) * dz = fm * V^2 * (dl^2 / gc) * dt. Here, dz equals cos theta * dl, where L represents the piping length, and cos theta is the angle of the pipe from the vertical position. ρ represents density, which is 29 times γg. P insitu denotes pressure, ZRT represents the universal gas constant RT, Z is the compressibility factor, T is temperature, and ν is calculated as 4qZpT / (πDt^2TP).

$$\frac{dP}{\rho} + \frac{g}{g_c} dZ + \frac{f_M v^2 dL}{2 g_c D_i} = 0$$

If you have the values for these terms, you can calculate the actual single-phase gas flow. Throughout this lecture, we've explored the distinctions between vertical and horizontal pipes.

In vertical pipe flow, the physics will differ from horizontal flow. Additionally, the behavior of various artificial lift systems will vary depending on factors such as gas, the quantity of liquid, or the creation of multiphases or emulsions. If you have a significant emulsion, it may lead to increased viscosity-related issues and higher electrical power consumption for pumping. Conversely, abundant gas could result in failures within your ESP system, sucker rod pumping system, or other pumping systems. When discussing different artificial lifting systems, we will explore how gas can impact your pumping system and the overall production economics.

******Thank you very much*****