Artificial Lift

Prof.Abdus Samad

Department of Ocean Engineering

Indian Institute of Technology Madras, Chennai

Lecture-08 Fluid Properties and Phase Diagram Part-2

Viscosity – why should you study it? Because viscosity indicates resistance to flow, which is the first point to note. Conversely, fluidity is the inverse of viscosity. If a certain fluid has very high viscosity, it will not flow easily. For example, if you have grease and you apply it to a surface, it won't move much; it's like semi-solid grease. Sometimes, liquids like cooking oil will flow, but not too quickly. However, if you have anelene or light oil like petrol, they will flow effortlessly and quickly.

Certain fluids will move quickly on a flat surface, while others won't move at all. Quick movement implies lower viscosity, while no movement suggests very high viscosity. Toothpaste and grease have very high viscosity, but when we talk about oil, it has lower viscosity. Diesel has a higher viscosity than petrol, and water has a viscosity of 1. In terms of oil, it has a slightly higher viscosity than water.

When lubricating a machine element, you typically use long-chain hydrocarbons, not fuel oil like petrol or diesel, because the latter can burn at high temperatures. This is why lubricating oil is commonly used.

So, why should we study viscosity for artificial lifting systems? If you have a fluid with very high viscosity, it won't flow easily. Mechanical arrangements, such as ESP systems or sucker rod pumps, will be necessary. However, if the fluid isn't flowing well, even though the sucker rod pump is operational, it will require significant force and result in high electrical energy consumption.

There are different types of pumps; for example, the ESP (electric submersible pump) won't work effectively if you have very high viscosity. However, some pumps will be very efficient when dealing with high-viscosity fluids. Therefore, you should know the fluid's viscosity, and based on that information, you can select the appropriate pump or artificial lifting mechanism.

First, you need to know how to measure viscosity. While several methods are available, one is the rolling ball viscometer. The rolling ball viscometer operates like this: take a slanted surface, fill it with viscous liquid, and place a ball on it. The ball will not move or roll if the viscosity is very high. However, like water, the ball will slowly move down the surface if the fluid is thin.

There's a formula for this rolling ball viscometer, which includes various parameters: L1 (length), rho 1 (fluid density), rho 2 (ball density), g (acceleration due to gravity), r (radius of the ball), theta (the included angle), v infinity (settling velocity or ball velocity), and eta (viscosity).

Now, let's discuss the forces at play: as the ball moves downward, viscous forces attempt to move it upward, while gravity is acting downward and causing it to move in that direction. Additionally, there's buoyancy force in the equation.

Buoyancy force tries to move the ball upward, while viscous force resists and says, "Hey, don't go." Gravity force, on the other hand, attempts to pull it downward. So gravity and buoyancy forces work in opposite directions, but the ball still moves due to the component of gravity force.

If the fluid has low viscosity, it will move quickly, but if it has very high viscosity, it will move slowly. For example, you can measure the time it takes for the ball to travel a certain distance and calculate its velocity by dividing distance by time. From this velocity, you can determine the viscosity.

You can use this viscosity measurement for artificial lifting and surface production because it reflects the resistance to flow. Viscosity represents the resistance to flow, while fluidity, the opposite of viscosity, indicates how quickly it can flow. Knowing the resistance to flow, you can design your pipe blank system, choose your choke, select your surface separation systems, opt for your artificial lifting system, and determine your valve mechanism based on viscosity.

Next, there are several correlations available for viscosity. One of these correlations is the Ahmed correlation, which provides dead oil viscosity,

- Rolling ball viscometer

$$\eta = [(\rho_1 - \rho_2) \times g \times r^2 \times \sin\theta]/v_\infty$$

API 32, 1.8 to 10 power 7 API, already defined as 4.53 API power 4.53. Additionally, 360 (where T represents the temperature in degrees Fahrenheit) is another constant, denoted as A. This continuous, A, is defined as 10 to the power of 0.43 plus 8.33 API.

Sometimes, I give assignments to students and ask them to use this formula to calculate values. In such cases, some terms may be unknown while others are known, and students must understand how to solve for the unknowns.

Some terms need explanation: R_s represents the solution gas-oil ratio, P stands for pressure, P_B denotes bubble point pressure, and mu_OB signifies saturated oil viscosity. Saturated oil viscosity is the viscosity at the point when bubbling starts. The pressure formula is also provided here. When managing temperature and pressure in a way that they are above the bubble point pressure, it means the fluid is unsaturated, requiring more oil or gas to become saturated.

Ahmed, 1989

Dead oil

$$\boxed{\mu_{od} = \left(0.32 + \frac{1.8 \times 10^7}{API^{4.53}}\right)\left(\frac{360}{t + 200}\right)^A}$$

$$A = 10^{\left(0.43 + \frac{8.33}{API}\right)}$$

Sat oil

$$\mu_{ob} = 10^a \mu_{od}^b$$

$$a = R_s(2.2 \times 10^{-7} R_s - 7.4 \times 10^{-4})$$

$$b = \frac{0.68}{10^c} + \frac{0.25}{10^d} + \frac{0.062}{10^e}$$

$$c = 8.62 \times 10^{-5} R_s$$

$$d = 1.10 \times 10^{-3} R_s$$

$$e = 3.74 \times 10^{-3} R_s$$

unsat oil

$$\mu_o = \mu_{ob} + 0.001(p - p_b)(0.024\mu_{ob}^{1.6} + 0.38\mu_{ob}^{0.56})$$

So, in essence, saturated oil is like this: you take a certain amount of oil and gas mixture at a specific pressure and temperature, and when you reduce pressure, bubbling starts. At the moment bubbling starts, you assume that the liquid is saturated. However, it is considered unsaturated if it can absorb more gas at the same temperature and pressure. If you have a certain fluid with free gas above it, it is unsaturated.

The equation is quite extensive, making it challenging to remember. So, what will I do in the exam? I will provide some correlations but leave certain parts missing. If you haven't practiced, you might find it difficult. Therefore, it's better to practice with problems based on my provided formula.

Now, let's discuss one correlation for oil viscosity with respect to pressure, denoted as mu. It looks like this:

Yes, viscosity typically decreases when you reduce pressure to the bubble point pressure. Then, when gas is released, viscosity goes up. At dead oil conditions, dead oil exhibits higher viscosity. However, when you take a fluid above the bubble point condition, reducing pressure will cause viscosity to decrease. This happens because the molecules have more space, creating less resistance to flow. As a result, viscosity decreases. When bubbling starts and free gas is released from the liquid, viscosity increases, reaching its maximum at dead oil, corresponding to 14.7 psi and 60 degrees Fahrenheit surface conditions.

Now, let's move on to the next topic: oil compressibility. Oil compressibility involves taking a certain amount of fluid mixture from the reservoir, checking the surface, and observing how the fluid volume changes due to pressure changes.

$$c_o = -\frac{1}{V}\left(\frac{\partial V}{\partial p}\right)_T$$

So, for this reason, it is inversely proportional to pressure and remains constant at a specific temperature, following an isothermal condition. Compressibility changes because atoms become more compact and closer to each other at high pressure. When you release pressure, the atoms have more space and resonance, increasing volume. This phenomenon is called compressibility. If we represent compressibility graphically, it looks like this: on the y-axis, we have psi inverse, and on the x-axis, we have pressure (p). Compressibility remains relatively constant until it reaches the bubble point pressure (p_b). When you reduce pressure beyond the bubble point, compressibility increases significantly because a large amount of gas is released.

At dead oil conditions, it exhibits maximum compressibility.

Now, let's discuss the specific gravity of gas. When talking about the specific gravity of gas, we need to know the molecular weight of the gas or its apparent molecular weight. This apparent molecular weight is often referred to as the air molecular weight, which is approximately 28.97. Natural gas or gas from a wellbore typically consists of multiple components rather than single-component fluid. Therefore, we need to determine the percentage of each element and its respective molecular weight. To calculate the apparent molecular weight (MWa), you can use the formula:

Apparent Molecular Weight,

$$MW_a = \sum_{i=1}^{Nc} y_i MW_i$$

Here, Nc represents the number of components, yi is the fraction of each component, and Mwi is the molecular weight of each component. This formula is available in the AMET 989 reference.

Gas viscosity is another important factor to consider. Like oil, gas has its viscosity, affecting its ability to flow. However, gas viscosity is generally lower than liquid viscosity because gas molecules are lighter. Gas viscosity typically falls in the 0.01 to 0.03 poise range, indicating very low viscosity.

Despite its low viscosity, it's crucial to understand the viscosity formula because even small changes in viscosity can significantly impact the performance of an entire system when designing it. One formula for gas viscosity involves kinematic viscosity (V_g), which can be expressed as $V_g = \mu_g / \rho_g$, and it's important to take note of the units involved. Any errors in unit conversions can lead to problems.

Gas viscosity is measured in poise or centipoise (cP), with one centipoise equivalent to water viscosity. Kinematic viscosity is measured in centistokes (cSt), but dynamic viscosity (μ) is commonly used for all calculations in the oil and gas industry. To calculate dynamic viscosity from kinematic viscosity, you can use the formula,

Kinematic
visc

$$\nu_g = \frac{\mu_g}{\rho_g}$$

$$\mu_g = \frac{\sum (\mu_{gi} y_i \sqrt{MW_i})}{\sum (y_i \sqrt{MW_i})}$$

Where μ_g is gas viscosity, V_g is kinematic viscosity, and ρ_g is gas density. In cases involving multiple components, you can use this formula for gas viscosity: gas viscosity = (percentage of component 1 * molecular weight) / (square root of the sum of the percentage molecular weights squared).

Visualizing the relationship between viscosity and pressure in a graphical plot would appear as a curve, with viscosity (μ) on the y-axis and pressure (psi) on the x-axis. In general, viscosity is represented by the dynamic viscosity term (μ), and this is commonly used in the oil and gas industry.

Viscosity behaves in a specific manner. If you increase pressure, viscosity tends to increase as well. Why does this happen? Gas molecules are not closely packed like liquid ones; they are more spread out. So when you increase pressure, the gas molecules come closer together, leading to more collisions. Due to Brownian motion, gas molecules experience numerous random crashes as they move about. An increase in crashes results in higher viscosity.

Likewise, increasing temperature also leads to higher viscosity. Why? Because raising the temperature means you are providing more energy to the particles, causing them to move much faster. Faster motion translates to increased collisions, which, in turn, results in higher viscosity. Therefore, viscosity is essentially a function of pressure and temperature.

Now, let's discuss the compressibility factor of gas. An ideal gas would have a compressibility factor (Z) of 1. However, the compressibility factor Z is typically less than 1 when dealing with natural gas or other gases. The term used for this is the compressibility factor, Z factor, or deviation factor. It indicates how much a gas deviates from the behavior of an ideal gas.

An ideal gas, in theory, exhibits perfection with a compressibility factor (Z) of 1. However, in practical applications, Z is not equal to 1. The formula derived from the ideal gas law, PV = nRT, can be expressed as PV = ZnRT, where 'n' represents the number of molecules. It is crucial to pay attention to units, as incorrect unit conversions can lead to calculation errors.

$$z = \frac{V_{actual}}{V_{ideal\ gas}}$$

$$pV = nzRT$$

For instance, if you use pressure in psi, volume in cubic feet, and temperature in degrees Rankine, the value of the gas constant 'R' will be 10.73. Changing units will result in a different 'R-value. Therefore, it's essential to remember that the value of 'R' depends on the chosen units. When conducting calculations, always verify the units used to ensure accurate results.

Moving on to density refers to the spacing between gas particles, typically spread far apart. When pressure is increased, these particles come closer together, causing an increase in density. Both temperature and pressure, especially at high values, significantly impact density. If you consider the same volume, an increase in pressure will lead to an increase in density.

Now, let's delve into the formula for gas density, which can be expressed as ρg = m / V. In this formula, MW represents the apparent molecular weight, P is the pressure in psi, Z is the compressibility factor, as you're already familiar with R (the universal gas constant), and T stands for Rankine temperature. If we assume the molecular weight of air to be 9, the gas density (ρg) can be calculated as 2.7 * γg * ρ * P * Z * T.

Moving on to the gas formation volume factor (Fvf), it's essential to consider how gas behaves when transitioning from the wellbore to the surface. In this context, we assume that the substance remains a gas both in reservoir conditions and at the surface. As illustrated, the volume change follows a pattern, especially for dry gas.

$$\rho_g = \frac{m}{V} = \frac{MW_a p}{zRT}$$

Air mol wt: 29

$$\rho_g = \frac{2.7\gamma_g p}{zT}$$

When dealing with problems related to the formation volume factor, it's crucial to determine whether the context involves oil or gas. Understanding the compressibility due to pressure and temperature changes is key. The compressibility factor (Cg), in the case of gas, is defined similarly to oil as the inverse of pressure (1/V) multiplied by the change in volume per unit change in pressure (Δv/ΔP), with a negative sign indicating a decrease in volume due to pressure.

$$c_g = -\frac{1}{V}\left(\frac{\partial V}{\partial p}\right)_T$$

These concepts are indispensable for artificial lifts. When moving a specific volume of fluid to the surface, various properties such as phase, volume, density, and viscosity change. For instance, when designing a Progressive Cavity Pump (PCP), you may initially assume it will handle single-phase liquid. However, due to phase changes caused by alterations in pressure and temperature, the introduction of gas can lead to PCP failure.

$$B_g = 0.00504\frac{zT}{p} \quad = V_{res}/V_{sc}$$

So, if your PCP or Progressive Cavity Pump starts failing, your production will be hampered, and you'll spend more money than generating oil or gas. Alternatively, you might use a Sucker Rod Pump, which could perform well initially. However, at a later stage, you might discover issues related to excessive gas or changes in viscosity. These changes could be due to various factors like water influx or increased wellbore sand. Such alterations in fluid properties can lead to issues where the fluid fails to get lifted or the Sucker Rod Pump becomes blocked.

When it comes to ESP systems, they may not perform optimally with high-viscosity fluids. If, for some reason, you end up with significantly higher viscosity or a change in viscosity – for instance, from 20 API to 30 API – the same artificial lift system may no longer work effectively. Therefore, it's crucial to thoroughly understand the fluid's properties in the wellbore and the reservoir properties. This knowledge informs the selection or design of the appropriate artificial lift mechanism, ultimately enhancing your production. Neglecting these fundamental aspects – such as fluid properties and reservoir characteristics – can lead to issues where an initially selected artificial lift system works for a limited time, but as conditions change, productivity suffers, and fluid properties evolve.

Once again, you'd need to change the entire artificial lifting system. When such changes are necessary, they tend to be very expensive. Consider, for instance, an inaccessible wellbore, perhaps in a desert, forest, or a horizontal wellbore. Workover or intervention operations can be exceedingly costly in such scenarios. Therefore, it's crucial to install an artificial lifting or pumping system in a way that ensures it runs for an extended period without the need for interventions or workovers. Your expenses will increase significantly Whenever you need to perform a workover or intervention. These procedures entail stopping fluid production, reworking the wellbore, and reinstalling the artificial lifting system, all of which come at a high cost. Hence, before selecting or designing any artificial lift system, you must thoroughly understand the fluid properties, reservoir characteristics, wellbore production processes, and surface separation requirements. A comprehensive understanding of these factors is essential before making decisions regarding artificial lift systems.