Surface Facilities for Oil and Gas Handling

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Fluid Properties

So, in the oil and gas industry, the surface pressure can vary, ranging from low to high. You might have observed oil platforms where occasional burning or flaring occurs. This phenomenon is known as flaring, a common practice in the oil and gas sector.

"In certain instances, the industry may have a low amount of gas and often resort to burning it. However, in today's environmental consciousness, regulatory agencies discourage flaring or burning due to the harmful gases it releases. Allowing the atmosphere to absorb these gases is also considered detrimental to the environment.

To address this issue, the recommended approach is to compress the gas and reuse it instead of flaring. By compressing and reusing the gas, the industry can mitigate environmental impact and adhere to sustainable practices."

"In numerous situations, the liquid pressure may be lower, necessitating the use of a pump. Both pumps and compressors become integral components of surface production operations. When pumping, it involves delivering liquid, whereas a compressor primarily deals with gases. A pump transforms a liquid to a gaseous form or reduces its volume.

In such scenarios, compressors can also be employed. In surface production operations, two types of equipment are commonly utilized—pumps for liquid-related tasks and compressors for handling gases."

"There are two main types: centrifugal and positive displacement pumps. The centrifugal type features a high-speed rotating impeller, typically operating at speeds such as 1500 to 3000 rpm. On the other hand, the positive displacement pump, such as the reciprocating pump, involves a continuous up-and-down motion of the piston for fluid delivery."

The choice between centrifugal and positive displacement pumps depends on specific application requirements. Centrifugal pumps excel in high-flow scenarios but have limitations in terms of maximum pressure or compression capabilities. They are known for their ability to handle large volumes of fluid efficiently. However, the development of head or pressure is limited in centrifugal pumps.

On the other hand, positive displacement pumps, including reciprocating and rotary types, offer advantages in situations where precise control over pressure and delivery is crucial. Reciprocating pumps, for example, involve a piston's up-and-down motion, providing a consistent flow and pressure. Positive displacement pumps are generally more suitable for applications that require higher pressure or precise fluid delivery. The choice between the two depends on the specific needs of the surface production operation.

Reciprocating pumps are commonly used in surface production operations due to their efficiency. Positive displacement pumps, including reciprocating types, generally exhibit a lower flow rate but can generate high head or pressure.

When comparing the two types, positive displacement pumps are known for their ability to achieve high pressure development, often expressed as "head." In practical terms, "head" signifies the height to which the pump can deliver liquid against gravity. For example, if we refer to a 10-meter head, it implies the pump can generate enough pressure to lift liquid to a height of 10 meters.

The formula for calculating pressure (P) based on head (h) is

$P = \rho g h$,

where ρ represents the fluid density (e.g., 1000 kg/m^3 for water),

g is the acceleration due to gravity (approximately 9.8 m/s^2),

and h is the head.

So, for a 10-meter head, the pressure would be 10 * 1000 * 9.8, resulting in 98,000 Pascal or 98 kPa. This demonstrates the pump's capacity to provide significant pressure, making positive displacement pumps suitable for applications requiring high head or pressure development.

Now, emphasizing the importance of unit conversions in engineering calculations. The unit of pressure, as you correctly pointed out, is Pascal (Pa), which is equivalent to

Newton per meter square (N/m^2). Proper unit conversions are crucial to avoid errors in calculations and ensure accurate results.

In the context of pumps and compressors, they indeed play a role in imparting energy to fluids. Pumps are devices that add energy to liquids, typically converting electrical energy into mechanical energy to move fluids. Similarly, compressors provide energy to gases, raising their pressure.

Contrastingly, turbines operate in the opposite manner. As you mentioned, wind turbines, for example, harness the kinetic energy from the wind to generate electricity. It's essential to understand these distinctions in energy transfer processes to design and operate systems effectively in various engineering applications.

Absolutely, your understanding is correct. When working with pumps and compressors, the goal is to increase the fluid's energy, leading to changes in pressure, temperature, and volume.

In general terms:

- Pumps are typically associated with liquids, and their primary function is to increase the pressure and flow of liquids.

- Compressors, on the other hand, are used for gases, and their main role is to increase the pressure and reduce the volume of gases.

It's essential to distinguish between these terms, and your mnemonic of associating "pump" with liquids and "compressor" with gases is a helpful way to remember their respective functions. This distinction becomes crucial in various engineering applications, where precise control over fluid properties is essential for the overall system performance.

It's a common convention to use the term "pump" for liquid handling systems and "compressor" for air or gas handling systems.

The human heart is indeed a reciprocating pump, characterized by its ability to produce high pressure with a relatively low flow rate. This is essential for maintaining blood circulation in the body.

In oil and gas operations, tubing plays a crucial role in the infrastructure. Tubing is typically a metal pipe or casing that is cemented into the wellbore. It provides structural support and helps in preventing issues related to friction and settlement during the extraction process. Your clarification about the tubing being cemented adds to the understanding of the well construction process in the oil and gas industry.

The importance of tubing and casing in oil and gas well construction is very crucial in this discussion. The annular area between the tubing and casing is a critical space through which fluids flow to the surface.

To summarize:

Casing: This is a metal pipe that is cemented into the wellbore. The cementing process helps secure the casing in place and isolates the wellbore from surrounding formations. The casing provides structural integrity to the well and prevents any unwanted fluid migration.

Tubing: Like casing, tubing is also a metal pipe, but it is not cemented. Tubing is inserted inside the casing, creating an annular space. This space allows for the flow of fluids, such as oil and gas, from the wellbore to the surface. The tubing can be removed for maintenance or repair, and its mobility allows for flexibility in well operations.

Here-by highlighting a crucial aspect of oil and gas production operations, particularly in terms of reservoir and flowing pressures, as well as the significance of kill fluid in maintaining a controlled environment.

Reservoir Pressure: This refers to the pressure within the reservoir itself. It's a key factor in determining the flow of fluids into the wellbore during production.

Flowing Pressure (Tubing Pressure): This is the pressure within the tubing during the production phase. It plays a critical role in allowing or restricting the flow of fluids from the reservoir into the wellbore.

The use of kill fluid becomes vital to control and manipulate the flowing pressure. By adjusting the flowing pressure with kill fluid, operators can create a safe and controlled environment for maintenance or intervention activities. If the flowing pressure is low, it allows for efficient production, but if it is too high and equivalent to reservoir pressure, it can result in unwanted fluid influx into the wellbore.

In terms of managing flowing pressure through the use of kill fluid is a key operational practice that ensures the safety and efficiency of oil and gas production activities, allowing for effective well intervention and maintenance without compromising the integrity of the wellbore.

Explanation of the factors influencing pipe friction and the associated formula for calculating pressure drop due to friction.

Let's break down the key components:

1. Pipe Friction Formula:

$$Pressure\ Drop(\Delta P) = \frac{fL\rho V^2}{2gd}$$

where:

f is the friction factor.

L is the pipe length.

ρ is the fluid density.

V is the fluid velocity.

g is the acceleration due to gravity.

d is the diameter of the pipe.

2. Friction Factor (f):

The friction factor can be obtained from Moody's chart. It takes into account the pipe roughness and fluid velocity. The Reynolds number R_e is an essential parameter in determining the flow regime:

$$R_e = \frac{\rho V d}{\mu}$$

where:

μ is the dynamic viscosity of the fluid.

- If (Re < 2000), the flow is laminar.
- If (Re > 4000), the flow is turbulent.

Understanding the flow regime is crucial because it impacts the calculation of the friction factor, and consequently, the prediction of pressure drop due to pipe friction. Laminar and turbulent flows have different characteristics and behavior, influencing the overall efficiency and energy losses in the fluid transportation system.

Now pipe roughness and its impact on friction factor emphasizes the importance of pipe material and condition in determining pressure losses. This knowledge is fundamental in designing and optimizing fluid transport systems in various engineering applications.

If it is between 2000 to 4000 it will be intermediate or intermediate Reynolds

number. Now, if you go to Moody's diagram Moody's diagram there is another term called fanning friction factor. So, these are almost similar only some factors will be changing. So, in Moody's friction factor if you put Reynolds number here then the friction factor term you can get like this for different Reynolds numbers you can get different friction factor values. And there are some correlation sources available where you can get friction factors whenever you are using them for a field unit.

Let's summarize some crucial points:

1. Conversion Factors:

When working with different unit systems, it's essential to be mindful of conversion factors. Using the SI unit system simplifies calculations and avoids the need for additional conversion factors.

2. Friction Factor Values:

The friction factor (f) typically falls within the range of 0.002 to 0.003 for common scenarios. It's crucial to keep this value low to minimize pressure drop and optimize the efficiency of fluid transportation systems.

3. Pipe Characteristics:

Diameter: Narrow pipes can result in higher pressure drop, especially if the fluid velocity is high.

Roughness: Lower pipe roughness is desirable to reduce friction factor and subsequently pressure drop.

4. Pipe Orientation:

Whether the pipe is horizontal or vertical doesn't significantly impact the calculation of pressure drop due to friction. The primary considerations are the pipe diameter, roughness, length, and fluid velocity.

5. Optimizing Pressure Drop:

To minimize pressure drop, efforts should focus on reducing friction factor (lowering pipe roughness), using wider pipes when possible, and managing fluid velocity. Long pipe lengths can contribute to pressure drop, so minimizing unnecessary pipe length is beneficial.

Understanding these factors is crucial for engineers involved in designing fluid transport systems, as it allows them to make informed decisions to optimize efficiency and minimize energy losses.

Additional factors that can influence fluid flow characteristics, including the relationship between flow rate, pipe diameter, and fluid velocity, as well as the impact of sand particles in the fluid. Let's summarize these points:

1. Flow Rate and Pipe Diameter:

In a narrow pipe with a high flow rate, the fluid velocity increases. This increased velocity contributes to higher friction and can result in a greater pressure drop.

2. Pipe Diameter (d):

Changes in pipe diameter affect fluid friction. Larger diameter pipes generally exhibit lower fluid velocities and reduced friction, contributing to lower pressure drops.

3. Gravity (g):

The acceleration due to gravity (g) remains constant, but its impact on fluid flow becomes significant in vertical pipes. However, in the context of the given formula,(g) does not directly affect the friction factor or pressure drop.

4. Sand Settlement:

The presence of sand particles in the fluid introduces additional considerations. The movement of sand in the fluid is influenced by fluid velocity.Terminal velocity is reached when the upward fluid drag force on the sand particle equals the downward gravitational force. For small sand particles, the terminal velocity is lower than for larger particles.

These factors collectively emphasize the complexity of fluid flow dynamics and the need for careful consideration in system design. Engineers must account for variables like pipe diameter, flow rate, and the presence of particles to optimize fluid transport systems and minimize potential issues such as pressure drop and sand settlement.

Important considerations in oil and gas operations, particularly in managing sand particles in the wellbore and understanding different oil classifications. Let's summarize the key points:

1. Sand Settlement in Wellbore:

The size of sand particles and fluid velocity play crucial roles in the movement of sand in the wellbore.

Higher fluid velocities are effective in carrying away smaller sand particles, preventing their deposition and potential blockages in the wellbore.

2. Terminal Velocity of Sand:

Terminal velocity, the speed at which the upward fluid drag force equals the downward gravitational force on a sand particle, depends on the particle size.

Smaller particles have lower terminal velocities, making it easier for fluid flow to carry them away.

3. Fluid Property - Live Oil vs. Dead Oil:

Live Oil: Oil taken directly from the wellbore, maintaining the same pressure and temperature as the wellbore conditions. All volatile components are retained.

Dead Oil: Oil without volatile components, typically maintained at standard conditions (14.7 psi and 60 degrees Fahrenheit).

4. Standard Conditions:

Standard conditions refer to the industry-standard pressure (14.7 psi) and temperature (60 degrees Fahrenheit) used for measurements and comparisons. This provides a consistent reference point for fluid properties.

Understanding and managing these factors are critical for efficient oil and gas production. Controlling sand movement, classifying oil types, and working with standard conditions contribute to safe and effective operations in the oil and gas industry.

This is called standard condition or stock tank condition. Stock tank condition also means a surface condition where no volatile component is there. You start a big tank where you store crude oil. You have already removed all the volatile components so that it will be safe. If you have lots of volatile components and it is open to the atmosphere then volatile components will be polluting the environment.If you are removing all volatile components and you are storing that is called dead oil. Dead does not mean that it does not have any heating value. Heating value means you are burning any fuel wood coal or oil. So, it will give lots of heat. That is called heating value how much heat you are getting from 1 gram of or 1 kg of fuel.

Live oil means all the components are there. So, live oil, dead oil the same dead oil will not have the volatile component and it will be taken at standard conditions. Stock tank I already defined the stock tank oil as dead oil. So, you are maintaining the temperature of 14.7 or surface condition at 60 degrees Fahrenheit. Then dead oil live oil some other term will be their SCF stock standard cubic feet. Standard cubic feet means the same condition you are creating like 14.7 psi 16 degrees Fahrenheit pressure and stand. So, whenever you are saying standard SCF. You are maintaining the standard condition which is 14.

7 psi 60 degrees Fahrenheit. Oil compressibility compressibility defines we should know how much compressibility happens like gas compressibility compressibility l I t y . Compressibility gas will be like 160 just an approximate idea minus 6 psi inverse . So, compressibility means 1 by pressure there is compressibility oil if you compress them with 16 * 10^- 6 psi. Water if you compress it will be like 3* 10^- 6.

So, if you see gas compression is very high. And whenever you are talking about fluid property. You have to remember units also unit plus fluid probably both. So, fill units like stock tank barrels will be using R_b . Sometimes they use reservoir barrels. Reservoir barrel million standard cubic feet million they do not put single mother they will be assuming in a mega. Dead oil I will I already defined SCF defined stock tank condition means 14.

7 psi and 60 degrees Fahrenheit. So, you should remember this term length normally we specify in feet or inch not meter or other unit volume gallon barrel cubic feet area feet square pressure psi ok. Viscosity C_p temperature degree Fahrenheit degree Rankine, not centigrade mass normally it will be pound. So, remember the conversion unit also. So, you find any source and you just try to remember how they are converting and what are the different fill units Many other units also will be their barrel or not written anything here.

So, a barrel also should be included barrel. So, they specify as a BBL or blue barrel. So, blue barrel terms are also very unique previous days the barrels were used to store alcohol and other chemicals in this storing and oil industry they were trying to find some barrels for measurement. So, they use their barrel chemical industry barrel and this is one barrel two barrel three barrel. So, the color of the barrel was blue. So, that is why they are saying blue barrel whenever there is a specified unit.

So, sometimes there will be like BBL small l or BBL or sometimes barrel per day sometime they will like BBL per day or day or BOPD barrel of oil per day or BWPD or BPD all same barrel of oil per day barrel water per day BPD barrel per day. So, there I think there is no standard thing. So, many authors will be writing small BPD many will be writing capital BPD many BOPD capital.

So, many ways they are writing. So, all are valid. Phase diagram Whenever you are talking about oil and gas coming from a well boat to the surface every time pressure change is happening and during pressure change your volatile component will go out. So, you have to know the phase diagram . So, the phase diagram is like this reservoir pressure for oil and gas a temperature curve will be like this and there will be one point called the critical point critical point is called the dew point temperature bubble point is bubble point BUBBLB bubble point line this is dew point line ok. So, initially, you get certain oil and gas at this point A-ok. Then when you are taking the oil and oil or fluid to the surface the pressure will be changing pressure will be going down right when pressure is going down actually you are moving towards this maybe at the end on the surface after the oil head you

got pressure at B from pressure A to pressure B when it reaches to pressure B you see this it crossed bubble point when it is crossing it was gas this is a gas area this is a liquid area this is gas area.

At low when you reduce pressure it becomes a phase liquid plus gas. So, you entered into the liquid plus gas zone ok? So, when you enter into the liquid plus gas zone means whatever liquid you have. So, that liquid releases some amount of gas. So, you are getting two-phase because you cross the bubble point line.

You reduce further pressure after a certain time lowering pressure let us say at the surface it may create a whole gas actually if you cross the dew point line. So, first, you have to check that is your position in the phase diagram then you change the pressure from the reservoir to the wellhead to the separator. So, every time you will be releasing a certain amount of gas ok. So, whenever you are releasing gas you are going towards your dead oil situation ok. So, if in a certain situation, it can create complete gas in certain situation gas will completely go out from your liquid.

So, in that case, you get dead oil and you will get separate gas, but if you are working in between this liquid zone and gas zone that bubble point and dew point line then you have both fluids.