Artificial Lift

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Lecture-50 Gas Lift Valves and Installation- Part 1

The force trying to hold the valve open,

$F_o = A_b (P_c - A_p) - A_p P_c$.

Therefore, $P_c (A_b)$ is written as $A_p (P_c + A_p)$,

$P_c A_p = P_d A_b$. Here, $P_{vc} = P_c$.

So, P_{vc} is the pressure in the casing at which the valve will close under operating conditions.

P_{vc} equals P_c, and you should remember this formula and the relationship behind it. I might slightly modify the question in an exam, so it's important to practice to avoid confusion during the actual exam.

Another important term is 'spread,' which is the difference between the opening and closing pressure. ΔP (spread) is defined as,

$\Delta P = (P_d - P_t)(R/(1 - R)) - P_{vc}$

Now, $P_{vc} = P_d$;

therefore,

$\Delta P = (P_d - P_t)(R/(1 - R)) - (1-R)P_d$.

$= (R/(1 - R))\ (P_d - P_t)$,

and this is equivalent to , TEF * $(P_d - P_t)$.

You might recall that TEF, as discussed in a previous lecture,

where TEF = R/(1 - R).

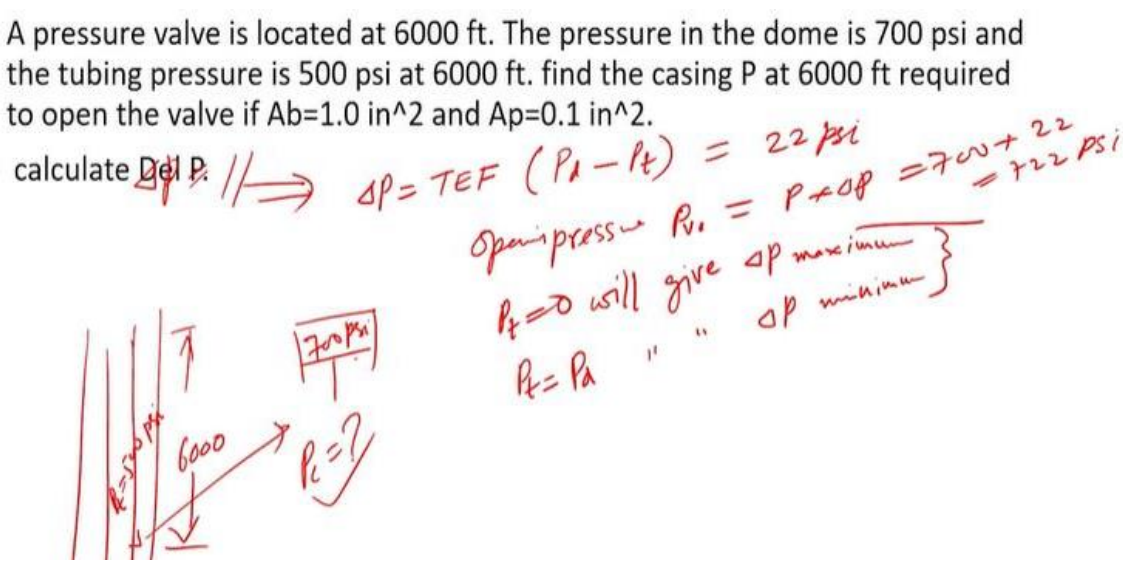
This relationship was covered in the previous lecture. With this formula, we can solve problems. You can use this formula to find other parameters if certain parameters are given. This problem was solved in the last lecture already.

In this problem, a pressure valve is located at a depth of 6000 feet. We have the casing and tubing, assuming there is no packer, and one valve is here. The depth is 6000 feet, not 600 feet. The dome pressure is given as 700 psi, and the tubing pressure is 500 psi (P_t at the injection location). Find the casing pressure at 6000 feet required to open the valve, so you need to find P_c, which has already been solved.

In the current problem, you have to calculate ΔP. To calculate ΔP, you need to use the formula,

$\Delta P = TEF\ (P_d - P_t)$,

which results in 22 psi. The opening pressure, Vo, equals P plus ΔP, so 700 plus 22 is 722 psi (P). The maximum spread occurs when P_t equals 0, which results in the maximum ΔP, while the minimum occurs when P_t equals P_d (dome pressure), giving the minimum ΔP.



When the tubing pressure is exactly the same as the dome pressure, it results in the minimum ΔP, and when P_t is 0, ΔP is at its maximum. I previously mentioned two types of valves: unbalanced pressure valves and balanced pressure valves. In unbalanced pressure valves, tubing pressure affects the opening and closing of the valve, but in balanced pressure valves, only casing pressure controls the valve. In a balanced pressure system, the closing and opening pressures are the same as the dome pressure.

The dome is the nitrogen-filled dome in this diagram, and the pressure in the dome is the same as the opening and closing pressures. The spread is always 0, regardless of port size, because Pt doesn't affect it. So, ΔP equals 0 all the time. If the dome pressure is 700 psi and opening and closing occur at 700 psi, the answer will remain the same regardless of the tubing pressure. Tubing pressure, whether it's 400 or 500, doesn't influence the valve's opening and closing. In an exam, I might ask a question like, 'If the dome pressure is 1000 and tubing pressure is 500, what will be the opening and closing pressures?' The tubing pressure doesn't affect the opening and closing valve. Similarly, if I ask about changing the tubing pressure from 400 to 500, it still won't have a significant impact.

$TEF = \frac{R}{1-R}$

$F_o \rightarrow$ opening force

$F_c \rightarrow$ closing force.

$$F_o = F_c$$

$$F_o = P_c (A_b - A_p) + P_c A_p = P_d A_b$$

$$\therefore P_c (A_b - A_p) + P_c A_p$$

$$P_{vc} = P_c$$

$$P_{vc} (A_b - A_p) + P_{vc} A_p = P_d A_b$$

$$\therefore \underline{P_{vc} = P_d}$$

\# Spred: $\Delta P = \frac{P_d - P_t R}{1-R} - P_{vc} \qquad P_{vc} = P_d$

$$\Delta P = \frac{P_d - P_t R}{1-R} - \frac{(1-R) P_d}{1-R}$$

$$= \frac{R}{1-R} (P_d - P_t)$$

$$= TEF (P_d - P_t)$$

The evaluation of gas lift potential is taken from Kermit Brown's book. There are two types of gas lift systems: continuous gas lift systems and intermittent gas lift systems. The port diameter is typically small in a continuous gas lift system, and the gas injection rate is lower. In an intermittent gas lift system, the port diameter is larger, and a larger amount of gas is injected because gas is injected periodically, and you need a higher gas volume in one go. In a continuous gas lift system, the port area is small, and the process creates a bubbly flow.

The purpose of a gas lift valve is to unload fluid from the wellbore and to control the flow. The location of the valve in the flow configuration is influenced by the available gas pressure for unloading, which affects the fluid weight or gradient in the wellbore.

If the wellbore contains only water, be it salty water or plain liquid, or if there is a presence of gas, it will also influence the system. The wellbore inflow performance relationship is another factor that affects the system. If higher wellhead pressure is required, it will impact the flowing pressure, which in turn affects drawdown. Casing fluid load, bottom hole pressure, and well production characteristics are all contributing factors.

Knowing the valve's location is crucial as it allows for the correct setting of the dome pressure at the factory. Especially when selecting a balanced pressure valve, the dome pressure is the sole controlling factor.

The artificial lift system or any artificial lift method can significantly impact your production rate. By understanding the productivity index (IP) or Vogel's curves in the inflow performance relationship, you can visualize the effect on liquid flow rate (q) against flowing pressure (P_{wf}).

The flow rate is at its maximum when the flowing pressure is zero, indicating a high drawdown. Conversely, when the flowing pressure approaches reservoir pressure (P_R), the drawdown is minimal, resulting in a low flow rate.

Artificial lift can increase drawdown. For instance, if a wellbore is fully loaded with liquid and an Electric Submersible Pump (ESP) is employed to remove the liquid, the lower pressure created by the ESP compared to the hydrostatic pressure increases the drawdown. This results in a shift in the outflow performance relationship (OPR) such that it intersects with the inflow performance relationship (IPR). As a result, production is enhanced, and the flowing pressure is reduced, moving from Pwf0 to P_{wf1}.

When you remove some liquid, the weight of the hydrostatic column is reduced, and consequently, the flowing pressure (P_{wf}) also decreases. As P_{wf} decreases, the difference between P_R (reservoir pressure) and P_{wf} increases. With both values increasing, more fluid will flow into the wellbore, resulting in a higher production rate or flow rate.

The picture on the right shows that initially, with a gas-liquid ratio of 1, it did not intersect with your Inflow Performance Relationship (IPR) curve. Then, after implementing a particular artificial lifting system, the flow rate and P_{wf} shifted. Once you introduce a more efficient artificial lifting system, the flow rate increases further, possibly reaching q_1 or q_2 and P_{wf1} or P_{wf2}. Gradually, P_{wf}, or flowing pressure, decreases, while flow rate increases, leading to greater productivity.

This book, 'Artificial Lifting Methods' by Niue (Springer), provides a comprehensive explanation using the IPR relationship and gas injection rates. The vertical axis represents depth, while the horizontal axis depicts pressure, including surface pressure (wellhead pressure) and casing pressure. Surface operating pressure (SOP) is the operating pressure on the surface. In the wellbore, the pressure and gradient vary, and as a result, different pressure values (p_1, p_2, p_3, p_4) correspond to different depths (d_1, d_2). This variation in depth results in a changing pressure profile. The hydraulic gradient inside the tubing follows a curve that corresponds to the changing depths and pressures.

You can see that the blue line does not touch the top portion of the y-axis, indicating that the reservoir pressure is insufficient to push the fluid up to the surface. As a result, the liquid level only reaches a certain level, and it doesn't reach the wellhead, even though the wellhead is above. The pressure from the reservoir is insufficient. In such cases, you attempt to inject gas. You draw the Inflow Performance Relationship (IPR) curve with flowing pressure on the y-axis and just the opposite, with P_{wf} by q in reverse order. So, the IPR curve becomes like this, showing P_{wf} and q.

Now, the curve looks like this. As a result, you achieve a significantly higher bottom liquid rate, as shown in the bottom-left corner. They've changed it like this, with changes in q and P_{wf}.

P_{wf} becomes much higher, resulting in increased production. Without this adjustment, you won't get any production. You need to lower P_{wf} to achieve higher production or flow rates. That's where gas injection comes into play. When you change P_{wf}, you'll notice changes in flow rates. With gas injection, your P_{wf} decreases, leading to a higher flow rate.

There are two terms to consider: 'point of balance' and 'point of injection.' The 'point of balance' is represented by the vertical line pso, which essentially depicts casing pressure from the surface. When you inject gas, you need extra pressure from the surface for the gas to enter. This extra pressure opens the valve, allowing for production. The 'point of balance' is where liquid and gas are in balance, but no production occurs. As you increase pressure further, your production rate begins. This point is the 'point of injection,' where you draw one curve showing multiphase flow or the injection of a significant amount of gas.

You might see the figure as P_{wf} was initially here and now it's here, and you're injecting at this point. The gradient changes as you reach the same point but with a lower gradient due to multiphase flow. This results in increased production. Changing P_{wf} means changing drawdown, which, in turn, means more fluid enters the wellbore. However, your hydrostatic pressure, from the top to the point of injection, is reduced. The result is increased production, and P_{wf} is altered.