Mandatory Project 3

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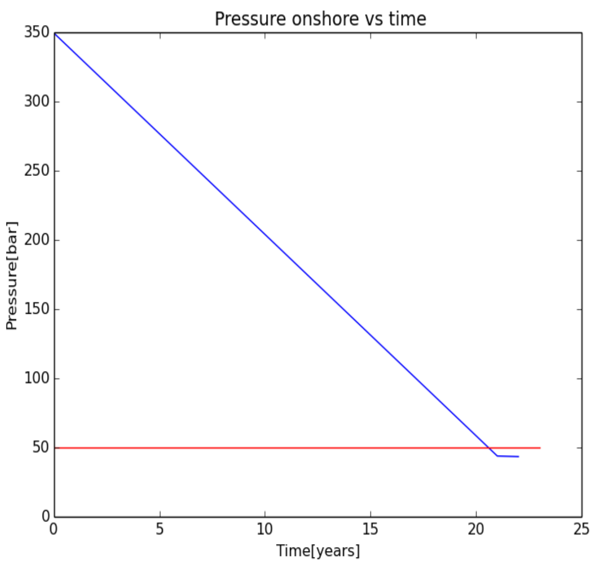


b)

As we can see from the plot we will need to install pressure support between year 21 and 22.

c)

The liquid is neglected since the GOR is large. So we have mainly gas in our pipe. The main uncertainty with this approximation is that we think of the fluid as incompressible and therefore set the density constant in the well and flowline. We know that gas can be a highly compressible so that the density will change for different pressures and temperatures anywhere in the well or flowline.
Also the liquid that is in the well will be more dense, and therefore give more pressure drop than only gas.

d)

To improve the calculations. We could use a different approximation for the friction factor. The Darcy - Weisbach factor has a discontinuity when moving from laminar to turbulent flow. (But we never reach Reynolds numbers under 2300, so it should be okay)

f)

If we choose to install a compressor subsea, we will run into these problems:

- Slugging, a problem of slugging can occur when we have multiphase flow coming from the well. These changes in pressure and force can seriously damage equipment. To tackle this problem we can install a separator which separates the water from the gas and oil. This gives us a simpler flow with less slugging.

- Droplets, even though we have a separator we can get droplets in the gas. When we use a compressor on a fluid which have droplets(with some incompressible parts) the stress on the equipment can become large, and destroy precious gear. Droplets can also lead to a reduction in the effectiveness of the compressor. This problem can be solved by installing a scrubber before the compressor, which takes out some of the liquid.

- Deposits, another problem is chemical deposits which are in the flow. Which under compression will in similar fashion to droplets can destroy equipment. We can solve this by adding chemicals in the flow to dissolve these deposits into liquid or gas. This will ease the stress on the equipment

g)

Installing a compressor subsea is a difficult task but will ultimately bring many benefits:

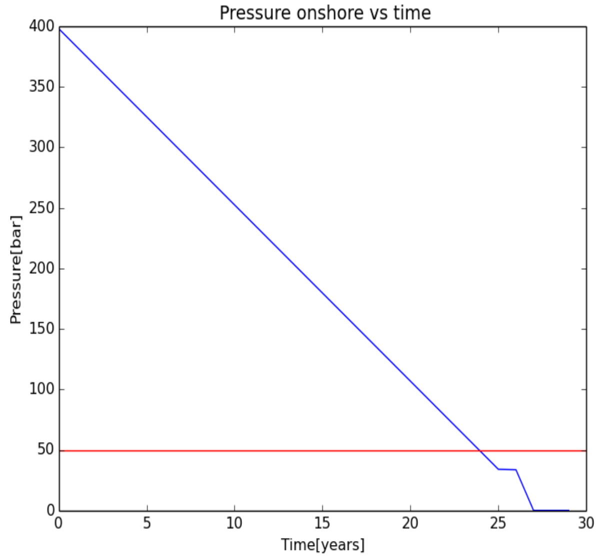
- Placing the compressor closer to the well will make i more effective. This can give the well a longer life and better production. With a subsea compressor it is also possible to transport the hydrocarbons longer.

- Installing anything subsea is always a very difficult task. Just getting electricity down many thousands of meters can be a difficult task. Though it will use less electricity than a topside compressor. Maintenance also becomes a problem subsea. It has to be done by an ROV. While maintenance is much easier offshore.

- Placing compressors on the seabed is a new invention. The sgard field by Statoil will be the first to have it. This makes it an unsafe investment, and could have many problems. Making it possibly unreliable.

- Electricity to subsea compressor, no problem topside - More difficult to install subsea, and maintenance - Higher and longer production with subsea - Closer the compressor is to the well, the more effective. - Subsea compressor is a new invention. May be unreliable

h)



We can see from the figure when we have a compressor with an extra 50 bar from the start we can extend the production by 3-4 years. Installing the compressor from the start will give us more production and it also will not give us any down time if we have to install the compressor at a later stage in the production.

- Down time while installing compressor, not if installed from start

2

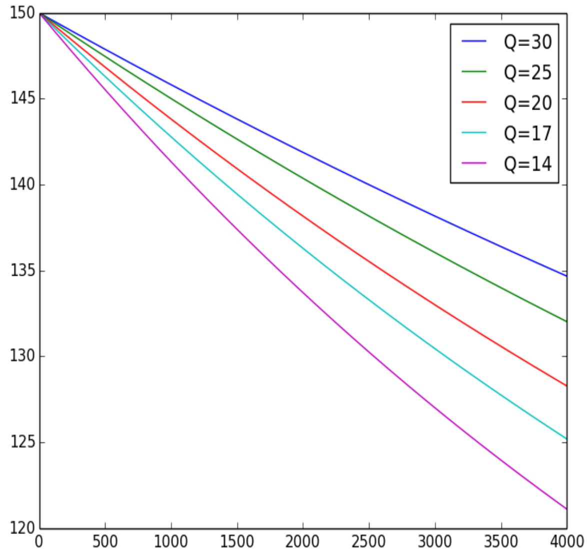
Issues in the flow will be:

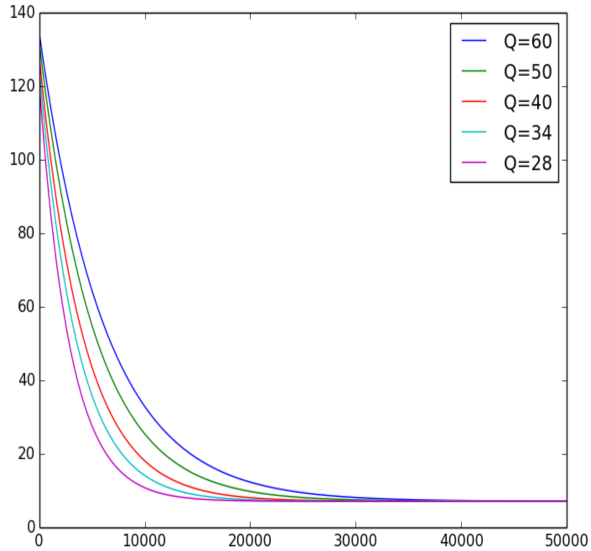
- Slugs
- Hydrates
- wax

In the next sections i will calculate and give ways of tackling these problems

a)

To calculate the temperature I have used equation (57) and not (58) to calculate the temperature drop, since the pressure is constant from reservoir to well and from well to onshore. In the figures we see the temperatures from the reservoir to the well and from the well to onshore. The different plots are for different mass flow rates from the different years.





b)

As we see from the first figure, that we will have high enough temperatures from reservoir to well. But in the second figure, we see that between 1000-2000 m, in the flowline, we hit temperatures low enough so that hydrates will form. The hydrates can be dealt with be adding chemicals to the flow, to stop the hydrates from forming. We can add chemicals like methanol(MeOH or MEG).

If we have a subsea compressor, this will increase the temperature, and will hopefully prevent hydrates from forming.

The hydrates can be prevented from happening if we can avoid low temperatures. This can be done by have sufficiently insulation in the flow line.

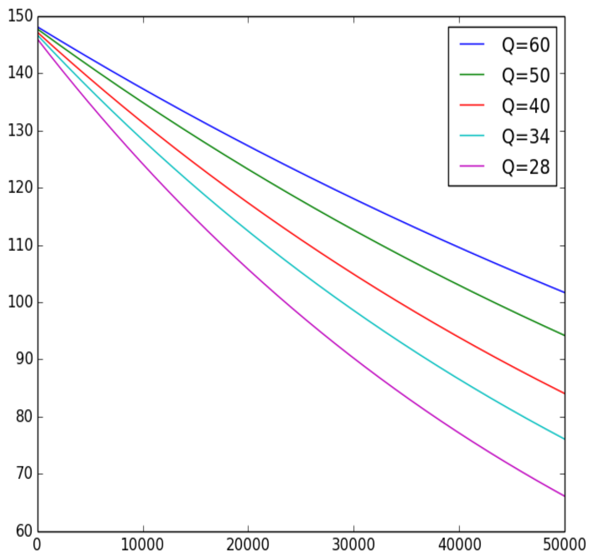
c)

WAT - Wax apperance temperatures In the flowline we will hit temperatures and pressures under WAT. So that wax will form in the flowline. When wax starts to form and the circumference of the line begins to lessen, giving us less fluid flux and therefore less production. We will need to pig the line. Where we start with a smaller pig and increasing the size, so to get all of the wax out from the line. It is also possible to use steam to remove the wax, though this is an expensive venture. Since we have a high GOR, the WAT can be manipulated through separation in the line.

3

The best way to make sure that we do not have hydrates forming. Is to make sure the temperature of the fluid is above the hydrate forming temperature. If a subsea compressor is installed this will give us higher temperatures, which will help in preventing hydrate formation.

4



a)

We see in the figure that when we lower the heat transfer coefficient, which means that the pipe will be more insulated in some way, that we hold a higher temperature. With higher temperature the fluid will be over the hydrate forming domain, so that hydrates will not form. The same with the wax. With higher temperatures we see from the wax appearance curve that wax will not appear.

5

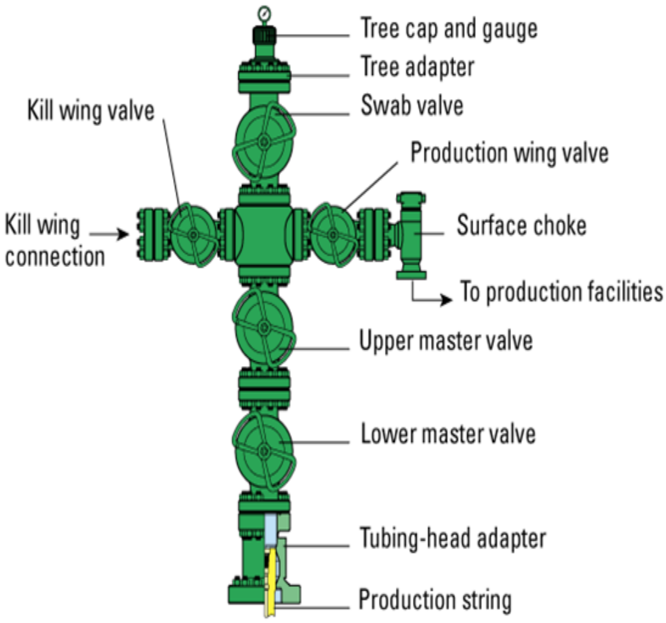
- Slugs can induce vibration, do we have slugs? - At startup we can induce a slug, which can give force to the system? -

6

A subsea x-mas tree is the device that sits on top of the well head, where the hydrocarbons flow from the reservoir. It is basically used to control the flow coming from the reservoir. Its main functions are

- Controls flow from the well, (from picture) in this case with two master valves which can be used to shut the flow completely in case of emergency. These will normally also be hydraulically driven to stay open, so that in if something goes wrong, like the power goes out, the valve will automatically close.
- The x-mas tree, in this case on the left side(picture), has injection points for chemicals. This is used as we know to help control the buildup of wax and hydrates.
- The x-mas tree can also have points for injection back into the well, for old wells to prolong production.
- It has monitoring options to monitor temperature, sand, flow rate, pressure and other things.
- The x-mas tree can also function as a pressure reliever, if the pressure from the reservoir is to high for the system to handle.
- The valve on top is used for intervention to the well. Like putting in wireline to lower down equipment, or to take measurements

Main function of a subsea flow tree: - Control flow of oil and gas out of the well - Control injection in an old field - chemical injection - monitoring(such as pressure, temperature, corrosion, erosion, sand detection, flow rate, flow composition, valve ,choke position feedback) - pressure relief - react to sensors from the well - Wellhead and tree are not the same, tree is on top of wellhead - Many valves - Shutdown of valves(hydraulics maybe) in case of emergency(failsafe needs power to stay open)



References

http://www.croftsystems.net/blog/the-difference-between-a-wellhead-christmas-tree