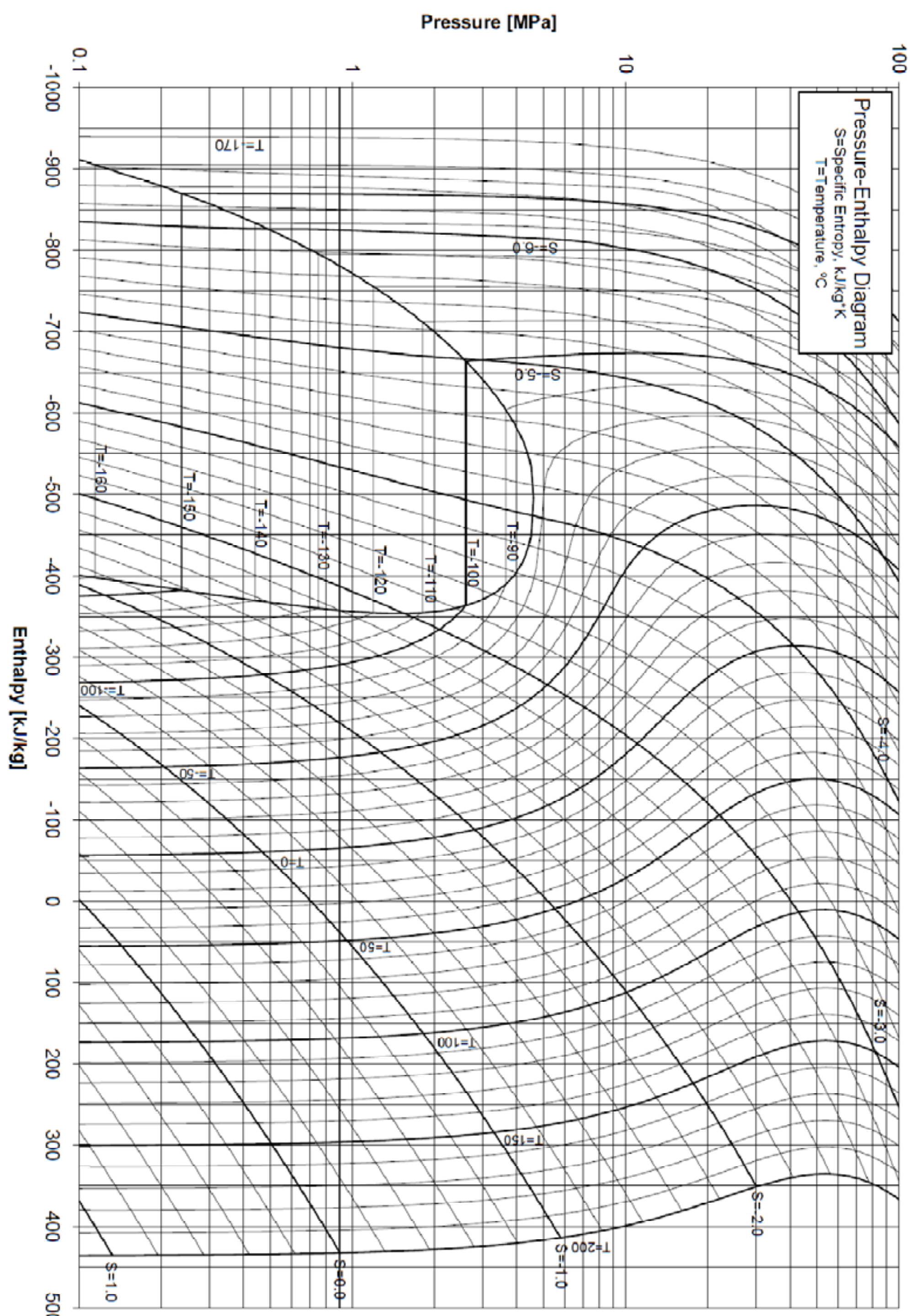
PROBLEM 1 (7 POINTS)

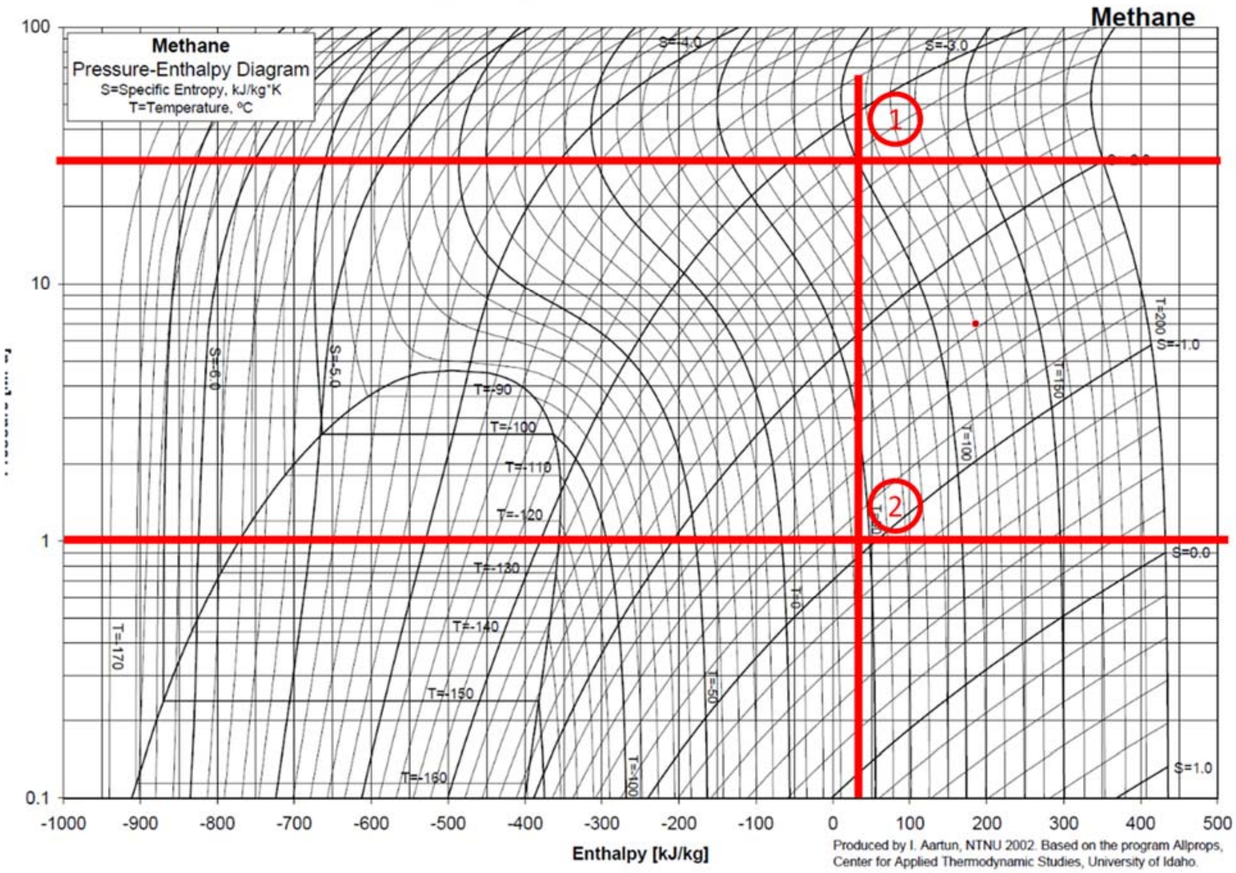
Task 1.1 (4 points). Consider a dry gas well that is choked. The pressure upstream the choke is 300 bara and the pressure downstream the choke is 10 bara. The temperature upstream the choke is 100 C. Consider the gas consists mainly of methane. Estimate the outlet temperature. The pressure enthalpy diagram of Methane is provided next.

Task 1.2 (3 points). Consider two choke models operating with the same conditions indicated in Task 1. However, the two chokes are of slightly different size, and one has a flow of 3E06 Sm3/d, and the other of 3E05 Sm3/d. Indicate how will this affect the outlet temperature.


Pressure-Enthalpy Diagram
S=Specific Entropy, kJ/kg*K
T=Temperature, °C
Pressure [MPa]
Enthalpy [kJ/kg]

SOLUTION

Task 1 Locate the inlet on the diagram (point 1)



The outlet of the choke has the same enthalpy than point 1, and we have the pressure, therefore we can locate the outlet point (2)

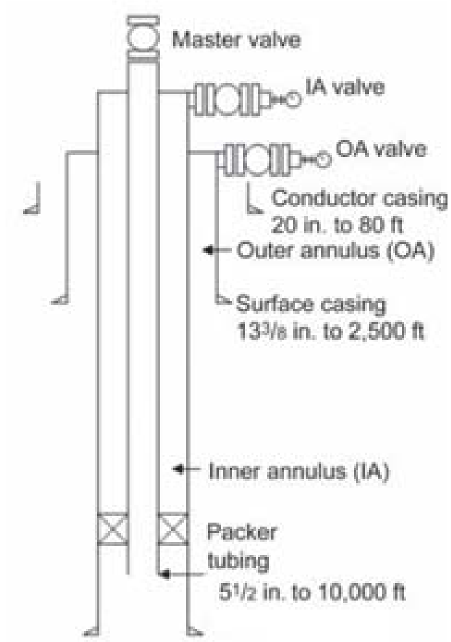
Reading from the chart, the outlet temperature is approximately 42.5 C.

Task 2

Solution: According to the energy conservation equation, the choke process is isenthalpic, thus it is mass flow independent. Therefore if the upstream and downstream pressures are the same and the inlet temperature is also same, both chokes should have the same outlet temperature

PROBLEM 2. (13 POINTS) Multiphase flow pressure drop calculations in a tubing segment

Consider the well shown in the figure below



Task 1. (3 points) Estimate local rates of oil and gas at the wellhead with the provided surface condition rates and the black oil properties.

T [C]	p[bara]	Rs [Sm^3/Sm^3]	rs [Sm^3/Sm^3]	Bo [m^3/Sm^3]	Bg [m^3/Sm^3]
50.0	28	22.6	1.28E-05	1.18	0.0344

qo	[Sm^3/d]	5441
qg	[Sm^3/d]	8.44E+05

Task 2. (2 points) Calculate the no-slip liquid volume fraction considering that there is only oil and gas in flowing through the tubing.

Task 3. (4 points) What is liquid holdup? Why is it different than the no-slip liquid volume fraction?

Task 4. (4 points) Assume that the values obtained in Problem 2.1. have been used to estimate the pressure gradient at the wellhead by the multiphase experts. The value they estimated is dp/dx = 0.03086 bar/m. Estimate the pressure at a location 200 m below in the tubing using the Euler's integration method.

SOLUTION:

Task 1: Local rates:

qo [m^3/d	qg[m^3/d]
6389.6	2.484E+04

Task 2.

The non-slip liquid volume fraction is lamba_l = qo/(gg+qo)

Therefore lamba_l = 0.204

Task 3

Liquid holdup Is the fraction of the cross-section area that is occupied by liquid when there is simultaneous flow of liquid and gas in a pipe.

These two quantities are the same only when the velocities of gas and liquid are same. However, they are often not the same.

Task 4.

consider the problem:

$$y'(t) = f(t, y(t)), \qquad\qquad y(t_0) = y_0.$$

Euler's method for numerical integration is the following:

$$y_{n+1} = y_n + hf(t_n, y_n).$$

Using a step h.

In our case, $y = p(x)$, $y' = \dfrac{dp}{dx}$, point "0" is at a depth of 0 m,

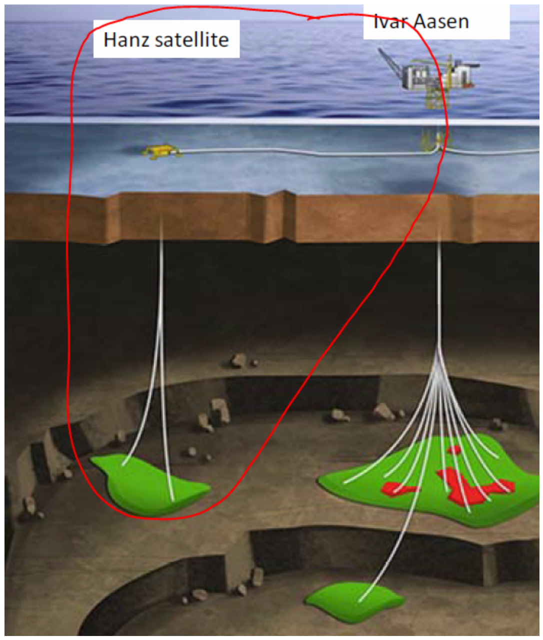
Using a step of h= 200 m the pressure at a depth of 200 m is:

$$p(200\ m) = p(0\ m) + 200\ m \cdot \left(0.03086\,\frac{bar}{m}\right) = 28\,bara + 6.17\ \ bara = 34.2\,bara$$

PROBLEM 3 (6 POINTS).

Hanz is a small undersaturated oil reservoir satellite to the Ivar Aasen platform. The reservoir will be developed using one single oil producer and a flowline connected to the platform. The flowline from the Xmas tree to the platform exhibits a very low pressure drop, thus, as a first approximation, the wellhead pressure can be safely assumed to have a constant value of 50 bara.

The well will be produced with open choke. The well doesn't produce any water.



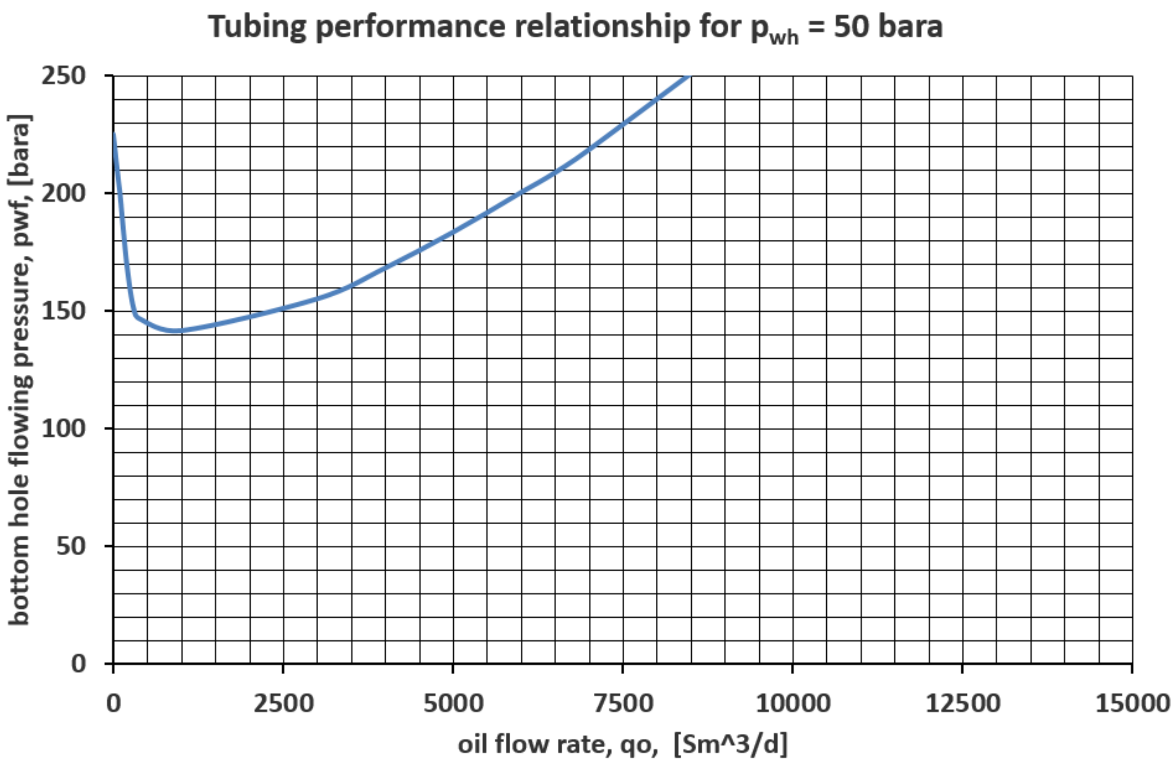
The IPR of the well is provided:

$$q_{\bar{o}} = J \cdot (p_R - p_{wf})$$

J = 60 Sm^3/d/bar

With p_R= 200 bara.

The tubing performance relationship (required flowing bottom-hole pressure at constant wellhead pressure of 50 bara) is provided in the figure below.



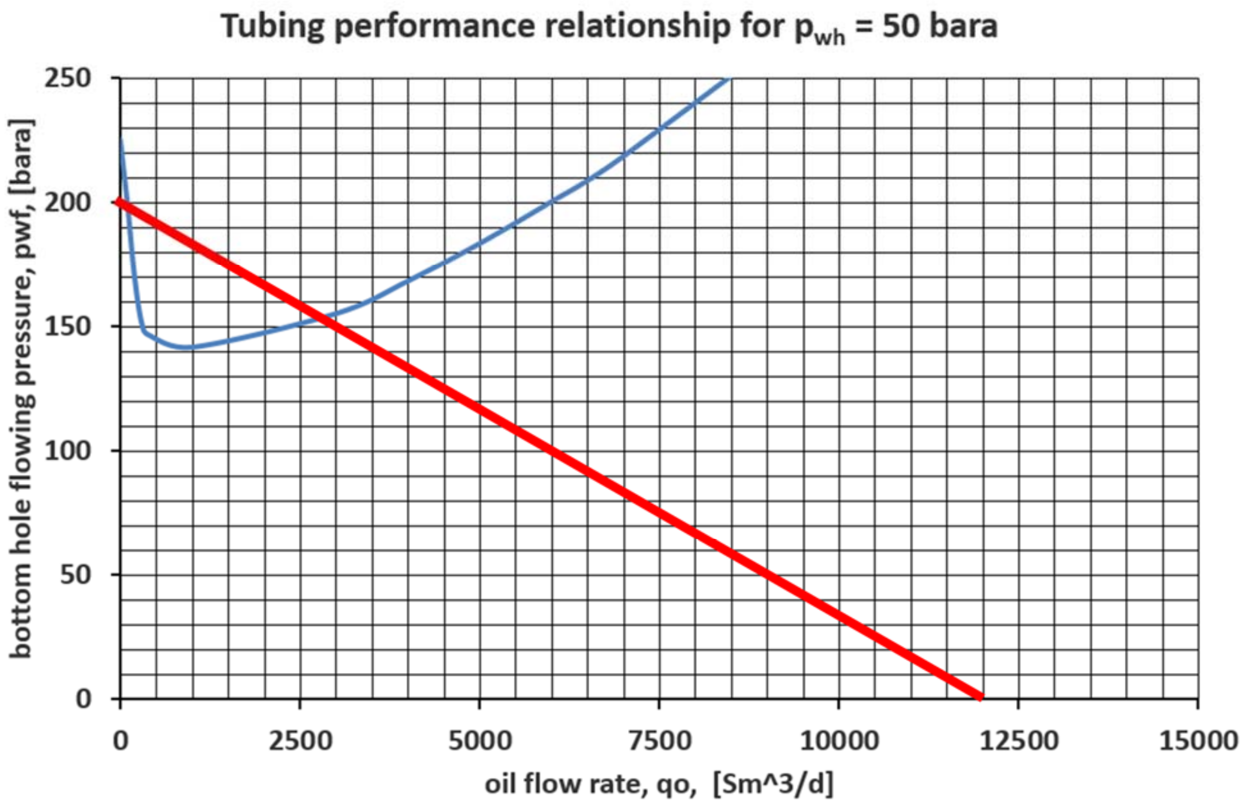
Task 1. Is is possible for the well to produce 4000 Sm3/d by natural flow? If not, estimate the pressure boost required by the ESP pump located downhole.

Solution

Plot the IPR on top of the TPR to find out the well rate (flow equilibrium at the well bottom-hole).

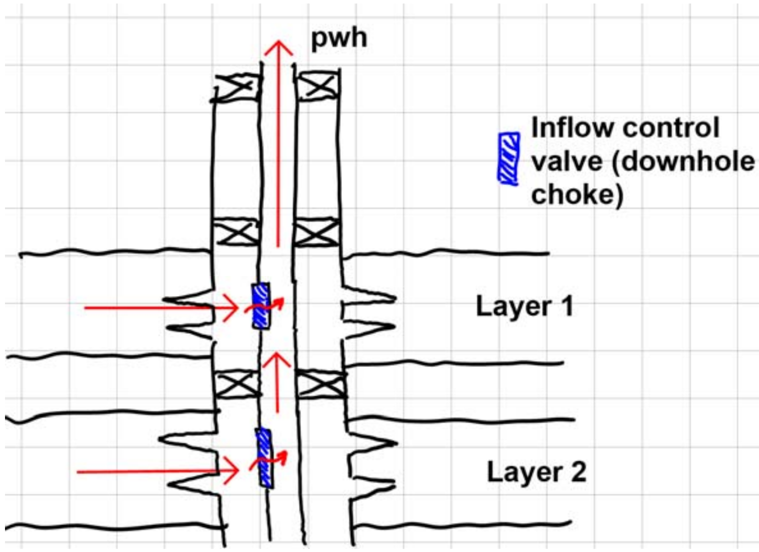
The rate is equal to 2750 Sm^3/d. therefore it is not possible to produce the rate of 4 000 Sm3/d by natural flow.

If a pump is installed bottom-hole (at the inlet of the tubing) then, reading from IPR, the pwf (suction pressure of the pump) is 135 bara. Reading from TPR (dischare pressure of the pump) gives pdis = 167 bara. Therefore, delta P = 167 – 135 = 32 bar



PROBLEM 4 (20 POINTS)

Consider a gas well producing from two layers as shown in the figure below. The well is equipped with downhole inflow control valves (chokes) that regulate the production from each layer.



Task 1. (10 points) If one desires to produce a total rate from the well of 150 000 Sm3/d, split in layer 1: 50 000 Sm3/d and from layer 2: 100 000 Sm3/d, at a wellhead pressure of 10 bara, **calculate the deltap across the inflow control valves of each layer to achieve this**.

Task 2. (10 points) Calculate the flow from the well, and from each layer, if the downhole chokes are fully open and wellhead pressure is 10 bara.

The table below provides the inflow properties of each layer

	pR [bara]	C [Sm3/bar2n]	n
Layer 1	200	2010	0.52
Layer 2	250	1150	0.54

The table below provides the information of the tubing (from wellhead to layer 1).

	CT [Sm3/d/bar]	s
Tubing	2.09E+03	0.58

Neglect the pressure drop along the tubing segment between layers 1 and 2 ($p_{wf1} = p_{wf2} = p_{wf}$).

Solution

Task 1

A counter current calculation is made from wellhead to the bottom-hole (in front of layer 1) using the tubing equation, with wellhead pressure equal to 10 bara and well rate equal to 150 000 Sm3/d. This gives

Pwf = 96.8 bara

Using the IPR for layer 1, fixing the rate, a pwf1 is obtained

Pwf1 = 198.8 bara

Therefore, the choke of layer 1 must provide

Deltap choke 1 = 198.8 – 96.8 = 102 bar

Using the IPR for layer 2, fixing the rate, a pwf2 is obtained

Pwf2 = 242.1

Therefore, the choke of layer 2 must provide

Deltap choke 2 = 242.1 – 96.8 = 145.3 bar

Task 2

A value of pwf is assumed. (198.8 bara). With that, and the TPR equation, the rate of the well is found.

With the value of pwf and the IPR of layer 1, the rate of layer 1 is found 1.

With the well rate and the rate of layer 1, the rate of layer 2 is found (q2 = qwell- q1)

With the rate of layer 2 and the IPR of layer 2, the pwf is also found.

Then the pwf assumed is varied (using solver) until the pwf assumed is equal to the pwf found with the IPR from layer 2.

Problem 4.2, Prof. Milan Stanko (NTNU)					**Inflow performance relationship (IPR)**		
	pR [bara]	**C [Sm3/bar2n]**	**n**				
Layer 1	200	2010	0.52				
Layer 2	250	1150	0.54				
	Cf [Sm3/d/bar]	**s**			**Tubing performance relationship (TPR)**		
Tubing	2.09E+03	0.58					

$$q_g = c(p_R^2 - p_{wf}^2)^n$$

$$p_{wh} = p_2 = \left(\frac{p_1^2}{e^s} - \frac{q_g^2}{C_T^2}\right)^{0.5}$$

	pwh [bara]	pwf1 [bara]	qwell [Sm3/d]	q1 [Sm3/d]	q2 [Sm3/d]	pwf2 (from IPR) [bara]	error [bar]
	10	198.8	3.10E+05	4.99E+04	2.61E+05	198.8	0.0

Problem 5 (6 POINTS). A test was performed to an oil well. One test point was gathered and is presented in the table below:

p_{wf} [bara]	q_o [Sm3/d]	q_g [Sm3/d]	q_w [Sm3/d]
241	2256	284 256	1289

Current reservoir pressure is 302 bara. The initial bubble point pressure of the reservoir was 400 bara.

Propose an IPR equation for oil, gas and water for this well and estimate the parameters to the equation. Justify your choice.

Proposed solution:

Due to the fact that no information about the reservoir is provided, and only test data is available, and it's a saturated oil reservoir, one option is to use Vogel's (V=0.2) or Fetkovich's (V=0) equation:

$$q_{\bar{o}} = q_{\bar{o},max}\left[1 - V \cdot \frac{p_{wf}}{p_R} - (1 - V) \cdot \left(\frac{p_{wf}}{p_R}\right)^2\right]$$

If using Vogel, then substituting the test point (pwf=241 bara, pR=302 bara, qo=2256 Sm3/d), gives qomax = 6817 Sm3/d.

If using Fetkovich, then substituting the test point (pwf=241 bara, pR=302 bara, qo=2256 Sm3/d), gives qomax= 6211 Sm3/d.

The gas and water IPR are found by multiplying the oil IPR by the GOR (126) and water cut (0.36)

Problem 6 (8 POINTS).

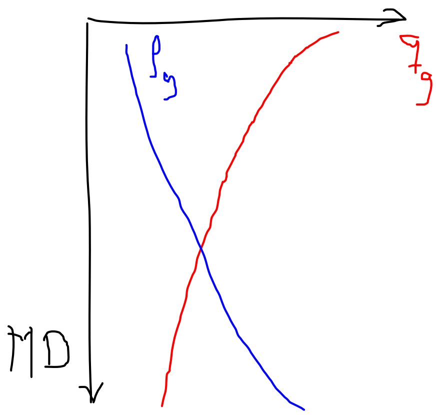
a) (3 points) Make a sketch showing how the local gas rate varies with measured depth (MD) in a well producing dry gas. Sketch from bottom-hole to wellhead. Explain the behavior plotted.

b) (5 points) Explain briefly what are the considerations that must be taken into account when selecting tubing diameter. In which situations is the profile of local gas rate versus measured depth useful?

Solution

a) The local rate of gas is increasing from bottom.hole to wellhead due to the fact that the pressure Is decreasing (gas expands), and the density is reduced.

$$\dot{m}_g = \rho_g \, q_g = q_g \cdot \rho_g$$

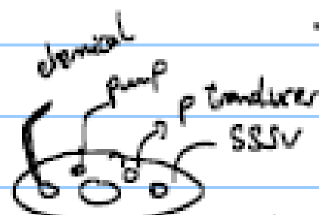


b)

tubing diameter selection

$\rho = \frac{p}{RT}$

- maximize rate ↑ ID $ ↓ Δp
- minimize cost ↑ ϕ ↑ $
- fit production casing
- depends on tubing hanger (structural limitations and space)
- erosion $v_g \leq v_{erosional}$ *
- liquid loading/slugging $v_g \geq v_{loading\ velocity}$ *



The profile of local gas rate versus depth is useful e.g. to calculate the local gas velocity and evaluate if there will be risk of erosion or liquid loading in any tubing location.