NTNU – Trondheim
Norwegian University of
Science and Technology

Department of Petroleum Engineering and Applied Geophysics

Examination paper for TPG4230 – Field Development and Operations

Academic contact during examination: Prof. Milan Stanko

Phone: +47 954 40 756

Examination date: June 06, 2016

Examination time (from-to): 09:00-13:00

Permitted examination support material: No Written or handwritten aids permitted. Approved calculator permitted

Other information:

Language: English

Number of pages (front page excluded): 10

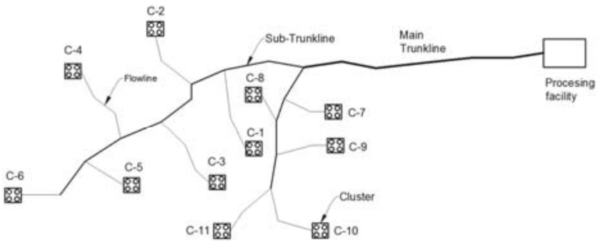
Number of pages enclosed:

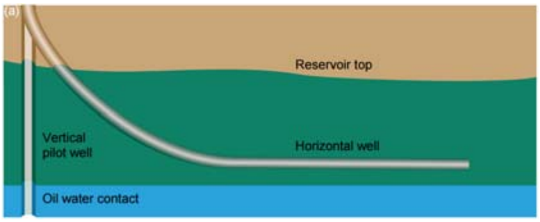
Checked by:

Date Signature

PROBLEM 1 (18 POINTS). Estimation and verification of ESP requirements

The Rio Ariari complex is a field currently under development in the region of “Los llanos” in Colombia. The reservoir has a relatively thin layer (100 ft) containing undersaturated oil (with a bubble point pressure of 45 bara at reservoir temperature, 62 °C) and a very strong bottom aquifer.
The field will be produced with ESP-lifted horizontal wells and using a commingling surface network as the one shown in the figure below.





The wells will be drilled from well pads (clusters) and their production commingled in a flowline and sent further to a sub-trunkline. All sub-trunklines are then merged into the main trunkline that transverses the field and takes the fluids to the main processing facilities.

The Woodgroup company has proposed a unique ESP model (TE7000) with 50 stages which they claim has a wide operational envelope to handle all possible well-to-well and time variations.

1. Your task is, for WELL RA-101, to compute pump requirements (deltap, power) for years 0 and year 4 of production and verify if the pump model proposed by the Woodgroup company **will be able to produce the desired OIL target rate (500 Sm^3/d)**. If the ESP is able to produce the desired rate, estimate graphically the pump frequency required. If not, explain the reasons why the well will not be able to produce the required rate.
2. Explain (sketch) how the pump performance curves change with a higher viscosity.
3. Some engineers have recommended to increase the tubing size to reduce frictional pressure drop in the tubing to meet the target rate. Based on your calculations, what is your opinion about this measure? Will it help in case the pump cannot meet the specified rate?

The following data and assumptions are given:

- Assume that the oil compressibility and GOR can be neglected such as the rate at standard conditions is equal to the rate at local conditions p and T.
- Even though the water cut changes with time, assume that the oil-water mixture has a constant density of 900 [kg/m^3]
- The Water cut (WC) is defined as

$$WC = \frac{q_{\bar{w}}}{q_{\bar{o}} + q_{\bar{w}}}$$

Where $q_{\bar{w}}$ and $q_{\bar{o}}$ are water and oil rates at standard conditions respectively.

- The well inflow can be represented with a linear PI equation:

$q = J \cdot (p_R - p_{wf})$

Where:
q……total liquid rate in Sm^3/d
J……productivity index for total liquid flow **[46.1 $Sm^3/d/bar$]**,
p_R…...reservoir pressure [bara]
p_{wf}…..bottom-hole flowing pressure [bara]

Assume that the productivity index J for liquid is constant with time and that the only factor changing is reservoir pressure.

The table below provides reservoir pressure and water cut (WC) vs year for the two years of interest.

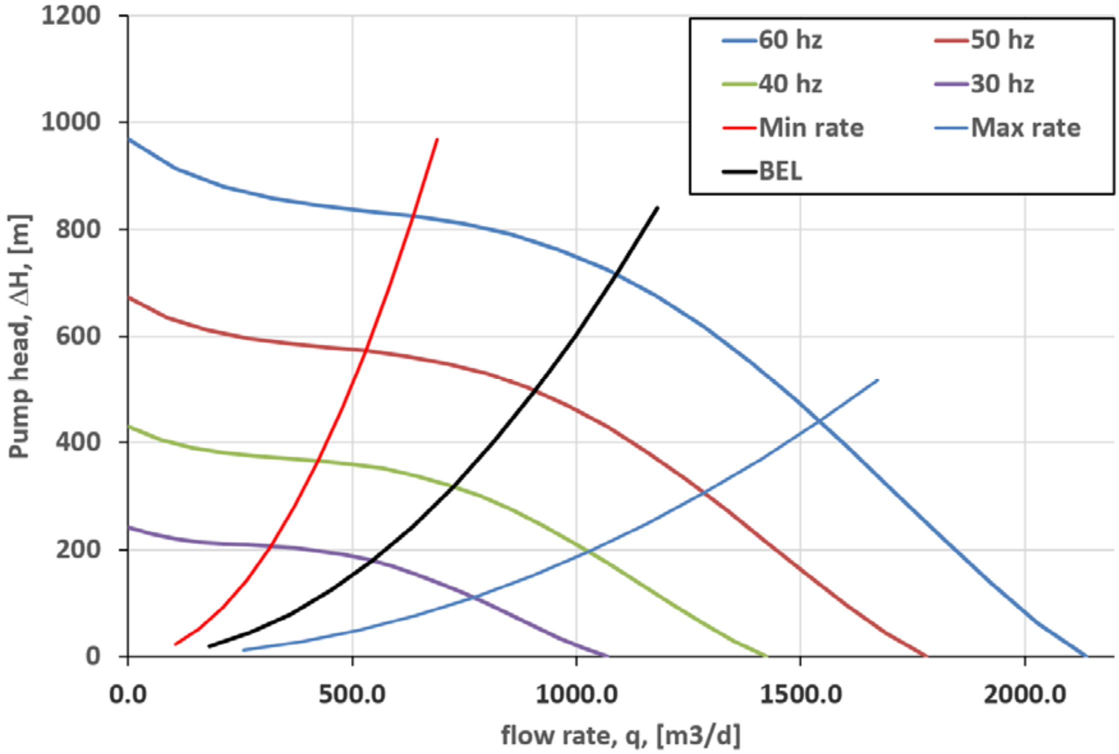
Year [year]	**p_R** [bara]	**WC** [fraction]
0	82.7	0.3
4	68.9	0.5

- Assume that the pressure losses between the bottom-hole and the ESP suction are negligible such as $p_{wf} = p_{suc}$.
- Even though there is a surface network, assume for your study that the wellhead pressure remains constant at a value of 50 bara. Using this assumption, and assuming a constant viscosity of the water and oil mixture, the following expression is provided that gives pressure drop from pump discharge to wellhead vs liquid rate:

$$\Delta p = 6 \cdot 10^{-6} \cdot q^2 + 4.13 \cdot 10^{-4} \cdot q + 66$$

Where:
Δp …tubing pressure drop in bar
q……total liquid rate in Sm^3/d

- The ESP operational map is given in the figure below.



- The pump power [in watts, W] can be estimated with:

$$Power = \frac{q \cdot \Delta p \cdot 1E5}{\eta \cdot 24 \cdot 3600}$$

Where Δp [bara], q in [m^3/d]. Assume a constant pump efficiency (η) of 0.6.

- The pump head [m] is

$$\Delta h = \frac{\Delta p \cdot 10^5}{\rho \cdot g}$$

Where Δp [bara], ρ [kg/m^3] and g = 9.81 [m/s^2]

- The suction pressure of the pump has to be above 45 bara to avoid gas liberation and cavitation in the ESP impeller.

SOLUTION

Calculate the total liquid rate for each year using the WC and the oil target rate:

$$q_{\bar{w}} = \frac{WC \cdot q_{\bar{o}}}{1 - WC}$$

$$q_{\bar{w}}^{year\ 0} = 214.3\ Sm^3 / d$$
$$q_{liq}^{year\ 0} = 714.3\ Sm^3 / d$$
$$q_{\bar{w}}^{year\ 4} = 500\ Sm^3 / d$$
$$q_{liq}^{year\ 4} = 1000\ Sm^3 / d$$

Using q_{liq}, calculate p_{wf} from IPR equation:

$$p_{wf} = \cdot\left(p_R - \frac{q_{liq}}{J}\right)$$

$$p_{wf}^{year\ 0} = 67.2\ bara$$
$$p_{wf}^{year\ 4} = 47.2\ bara$$

Using q_{liq}, and p_{wh} = 50 bara, calculate p_{disc} from the expression:

$$p_{dis} = p_{wh} + \Delta p(q_{liq})$$
$$p_{dis}^{year\ 0} = 119.4\ bara$$
$$p_{dis}^{year\ 4} = 122.4\ bara$$

Then the pump deltap is calculated from the expression:

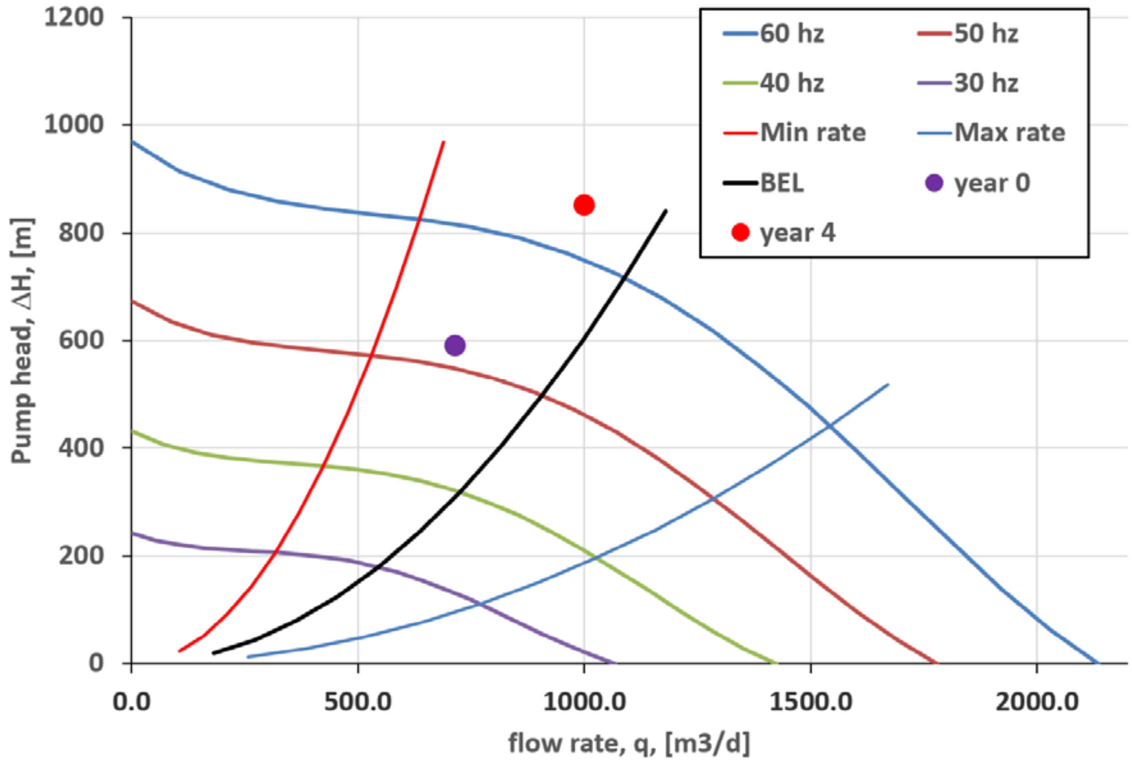
$$\Delta p_{ESP} = p_{dis} - p_{wf}$$

$$\Delta p_{ESP}^{year\ 0} = 52.2\ bara$$
$$\Delta p_{ESP}^{year\ 4} = 75.2\ bara$$

Compute power and head with the provided expressions:

$$P_{ESP}^{year\ 0} = 71.9\ kW$$
$$P_{ESP}^{year\ 4} = 145.1\ kW$$
$$\Delta h_{ESP}^{year\ 0} = 590.7\ m$$
$$\Delta h_{ESP}^{year\ 4} = 851.8\ m$$

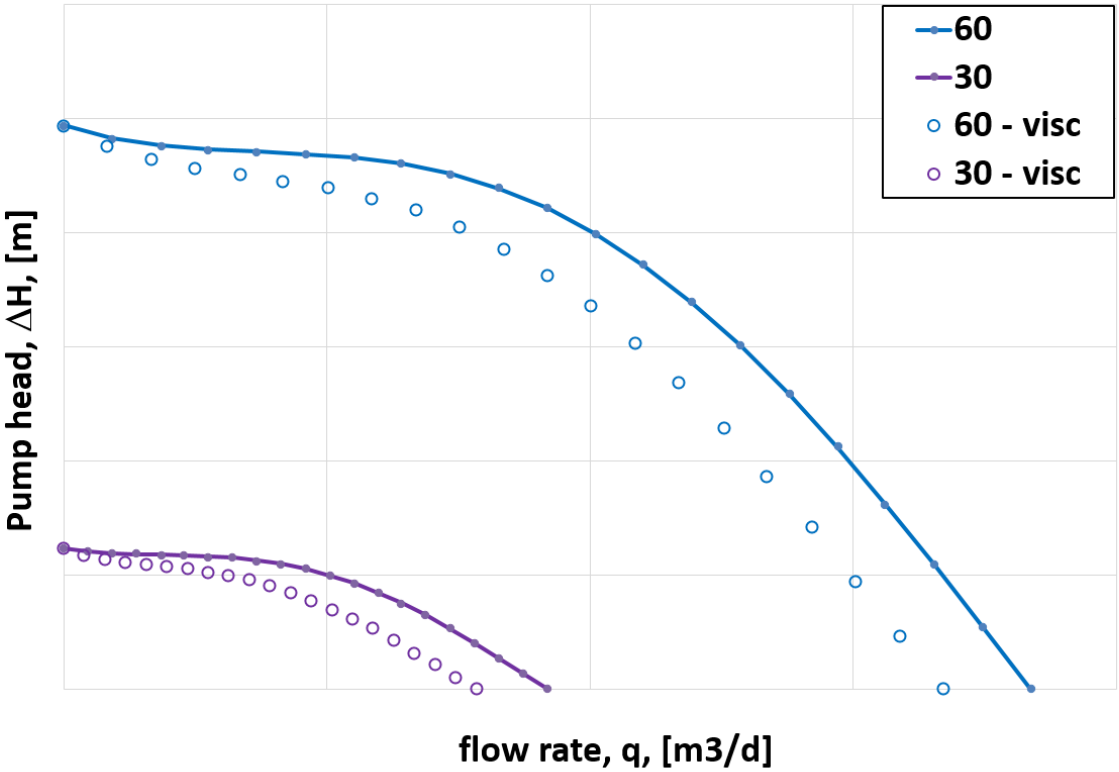
Plotting the points in the ESP performance map:



In year 0, it is possible to produce the target rate. The frequency is 51 hz.

In year 4, it is not possible to produce the target rate. The required frequency would be 63 hz.

Task 2

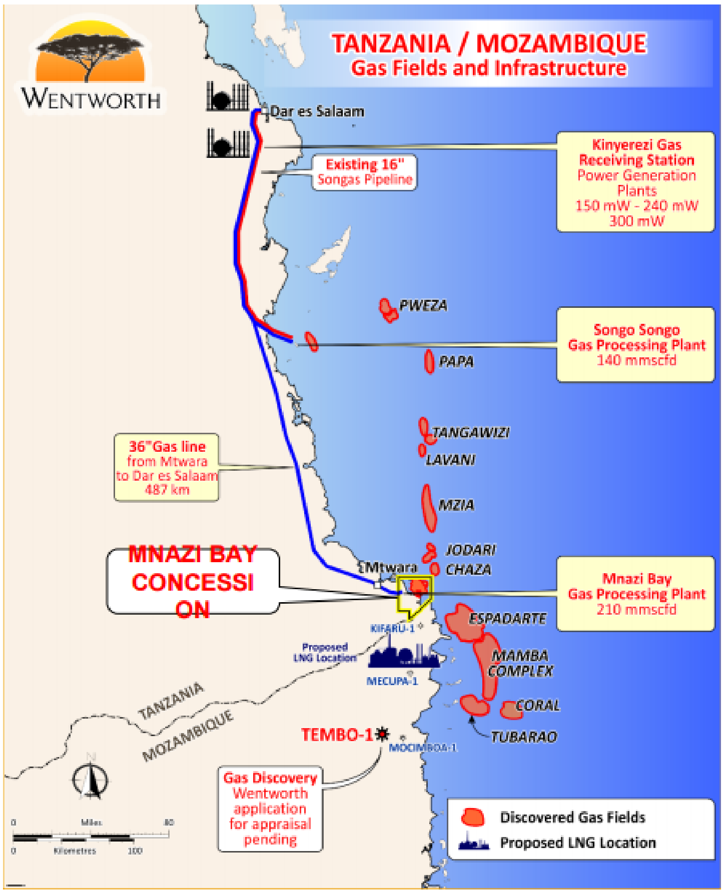


Task 3

Most of the pressure drop in the tubing is due to the hydrostatic column of the fluid (e.g. in year 0, 3.3 bar were due to frictional losses and in year 4, 6.4 bar. Increasing the tubing size will probably reduce further this losses, but it will probably not be enough to make any difference in the ESP operation.

PROBLEM 2. (18 POINTS). Gas field planning.

The Mnazi Bay is a gas field located in the southern-east shores of Tanzania. The field will be produced with standalone vertical wells to a gas processing center (Dehydration and refrigeration). The production will be sent further to feed the main Power plant in Dar es Salaam, a local power plant in Mtwara/Lind and a Urea and Cement plant. The plateau rate is 3.7 E6 Sm^3/d, and the desired plateau duration is 10 years.



1. You first task is **to estimate the minimum number of wells required to meet the 10 years plateau of 3.7 E6 Sm³/d**. The following information is available:
- Assume that a year consists of 355 operational days.
- Analytical expression for **single gas well** production potential (in **Sm³/d)** as a function of cumulative gas production of the field (G_p in **Sm³**):

$$q_{pp} = q_{pp0} - m \cdot G_p = 5.7 \cdot 10^5 - \left(2.4 \cdot 10^{-5} \cdot G_p\right)$$

Assume that all wells are identical and that their production potential depends on the field cumulative production. This yields that the field production potential can be expressed as:

$$q_{ppfield} = N \cdot \left(q_{pp0} - m \cdot G_p\right)$$

Where N is the number of wells.

2. Determine the plateau length with the number of wells chosen in part 1.

3. Propose/derive an analytical expression for the field rate vs time after the plateau period.

4. Compute the cumulative NPV of the project for the plateau period (10 years) considering **only** the revenue from gas sales and the DRILLEX. Use the following data:

-30 E6 USD per well. All wells are drilled during year "0".
-Discount factor of 8%.
-Gas price: 0.11 [USD/ Sm^3]
-The formula for NPV:

$$\mathrm{NPV}(i,N) = \sum_{t=0}^{N} \frac{R_t}{(1+i)^t}$$

Where t is year counter, i is the discount factor (in fraction) and Rt is the cashflow for the year.

SOLUTION

Task 1:

Calculate Gp for a plateau of 10 years:

$$G_{pplateau} = q_{plateau} \cdot N_{op\ days\ in\ a\ year} \cdot 10\, years = 1.31E10\ Sm^3$$

Calculate the production potential for one single well at that cumulative production

$$q_{pp} = 5.7 \cdot 10^5 - \left(2.4 \cdot 10^{-5} \cdot G_{pplateau}\right) = 2.55E05\ Sm^3/d$$

Find out the number of wells by dividing the plateau rate by the production potential :

$$N_{wells} = \frac{3.7 \cdot 10^6}{2.55E05} = 14.52 \approx 15$$

The field production potential becomes:

$$q_{ppf} = N \cdot \left(q_{pp0} - m \cdot G_p\right) = 15 \cdot \left(5.7 \cdot 10^5 - \left(2.4 \cdot 10^{-5} \cdot G_p\right)\right)$$

Task 2:

Using the previous expression, calculate the cumulative production when the field production potential is equal to the plateau rate

$$G_P^* = \frac{1}{m} \cdot \left(q_{pp0} - \frac{q_{ppf}}{N}\right) = \frac{1}{2.4 \cdot 10^{-5}} \cdot \left(5.7 \cdot 10^5 - \frac{3.7E6}{15}\right) = 1.347E10\ Sm^3$$

Obtain the plateau duration by dividing G_P^* by the plateau rate and the number of operational days in a year:

$$Plateau\ \ years = \frac{G_P^*}{q_{plateau} \cdot 355} = 10.26\ years$$

Task 3:

As seen in class, if the production potential of the field is linear with cumulative gas production, and the field is producing always at its production potential, the rate is described by an exponential equation. Using the expression given:

$$q_{pp} = N \cdot \left(-m \cdot G_P + q_{ppo}\right)$$

The gas cumulative production (G_P) is then cleared from it and substituted in Eq. below:

$$G_P = \int_0^t q(t) \cdot dt$$

$$\frac{q_{pp} - N \cdot q_{ppo}}{-N \cdot m} = \int_0^t q_{pp} \cdot dt$$

Rearranging:

$$q_{pp} - N \cdot q_{ppo} = \int_0^t -N \cdot m \cdot q_{pp} \cdot dt$$

Deriving with respect to time to get rid of the integral:

$$\frac{dq_{pp}}{dt} = -N \cdot m \cdot q_{pp}$$

The differential Eq. is solved using separation of variables and evaluated between time end of plateau (potential rate: $q_{plateau}$) and time "t", with a production of $q(t)$:

$$\ln\left(q_{pp}\right)\Big|_{q_{plateau}}^{q(t)} = -N \cdot m \cdot \left(t - t_{plateau}\right)$$

And lastly, by rearranging, the exponential expression is obtained:

$$q(t) = q_{plateau} \cdot e^{-N \cdot m \cdot \left(t - t_{plateau}\right)}$$

Task 4:

Gas production per year is constant: 1.3E+9 Sm^3

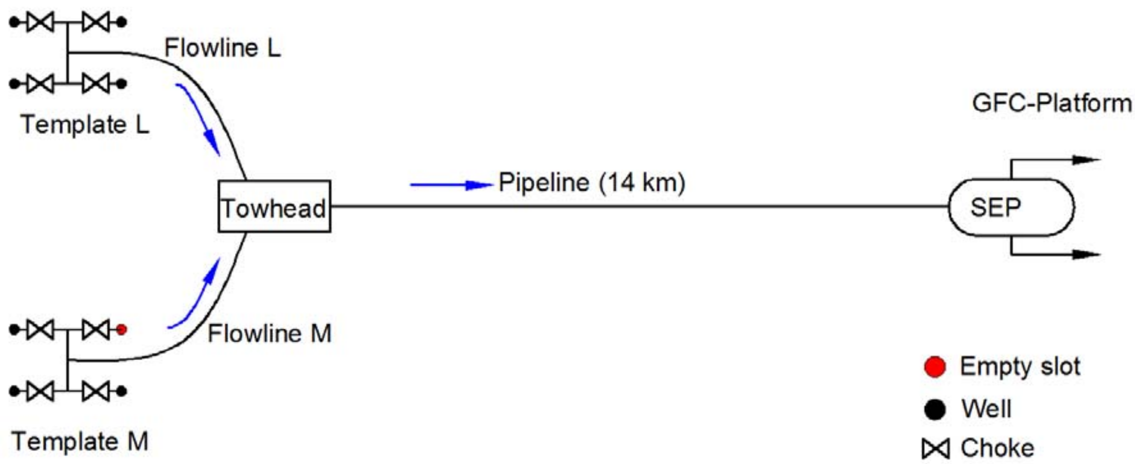
Revenue is constant per year: 144.5E+6 USD (no revenue in year 0, wells haven't been drilled yet)

		ΔGp	Revenue	Cash flow	Discounted cash flow
year	DRILLEX	[sm^3]	[USD]	[USD]	[USD]
0	450.0E+6	000.0E+0	000.0E+0	-450.0E+6	-450.0E+6
1	000.0E+0	1.3E+9	144.5E+6	144.5E+6	133.8E+6
2	000.0E+0	1.3E+9	144.5E+6	144.5E+6	123.9E+6
3	000.0E+0	1.3E+9	144.5E+6	144.5E+6	114.7E+6

4	000.0E+0	1.3E+9	144.5E+6	144.5E+6	106.2E+6
5	000.0E+0	1.3E+9	144.5E+6	144.5E+6	98.3E+6
6	000.0E+0	1.3E+9	144.5E+6	144.5E+6	91.1E+6
7	000.0E+0	1.3E+9	144.5E+6	144.5E+6	84.3E+6
8	000.0E+0	1.3E+9	144.5E+6	144.5E+6	78.1E+6
9	000.0E+0	1.3E+9	144.5E+6	144.5E+6	72.3E+6
10	000.0E+0	1.3E+9	144.5E+6	144.5E+6	66.9E+6
				NPV=	**519.5E+6**

PROBLEM 3 (18 POINTS). Boosting calculations for the Gullfaks South field.

The Gullfaks South field has two subsea templates, L and M. Template L has 4 wells and template M has 3 wells. For the purpose of this exercise, consider that all wells in a given template are identical. The production of the two templates is commingled in a towhead (junction) and transported further with a pipeline to the platform of Gullfaks C.



Given for each template:

- A plot of the available towhead (junction) pressure curve versus total template gas rate (See next page). These curves has been calculated concurrent from reservoir pressure to the junction (including flow in reservoir, flow in tubing and flow in flowline, with open choke).

Given for the pipeline:

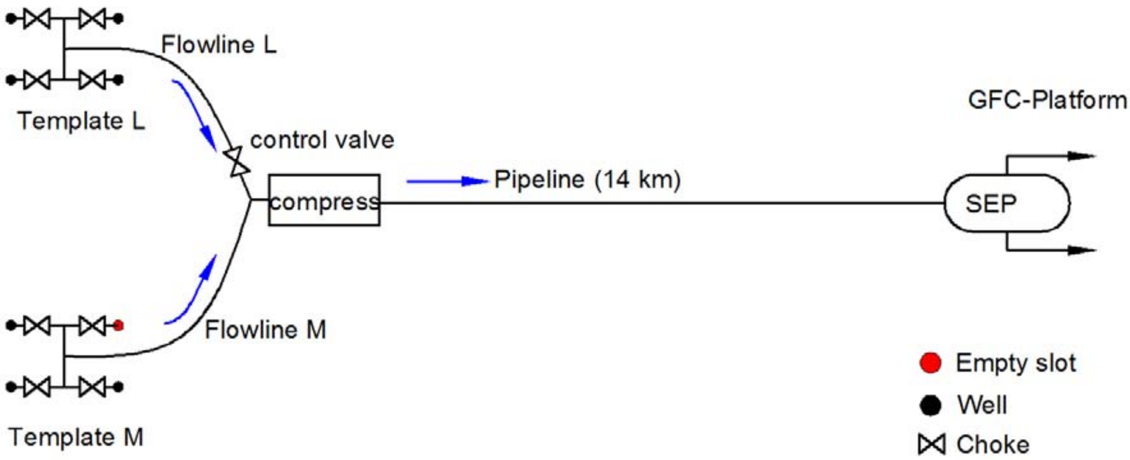
1. A plot of the required junction pressure curve versus pipeline gas rate (See next page). This curve has been calculated countercurrent from separator pressure to the junction (including flow in the pipeline)

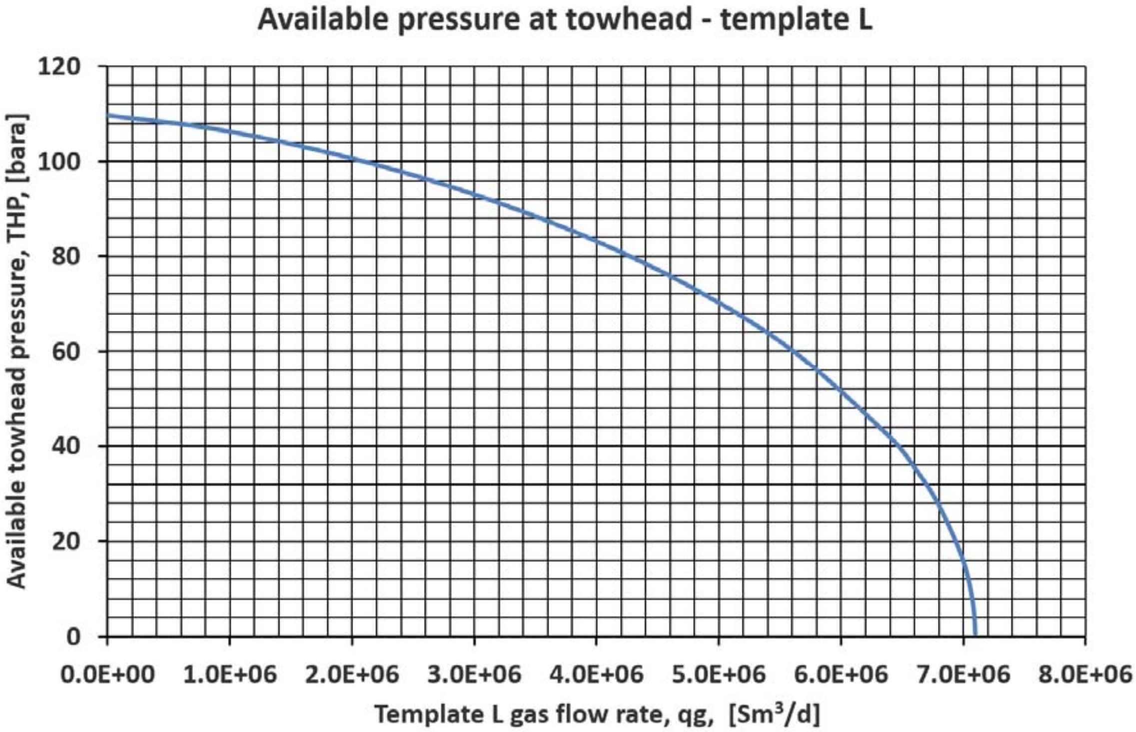
Tasks.

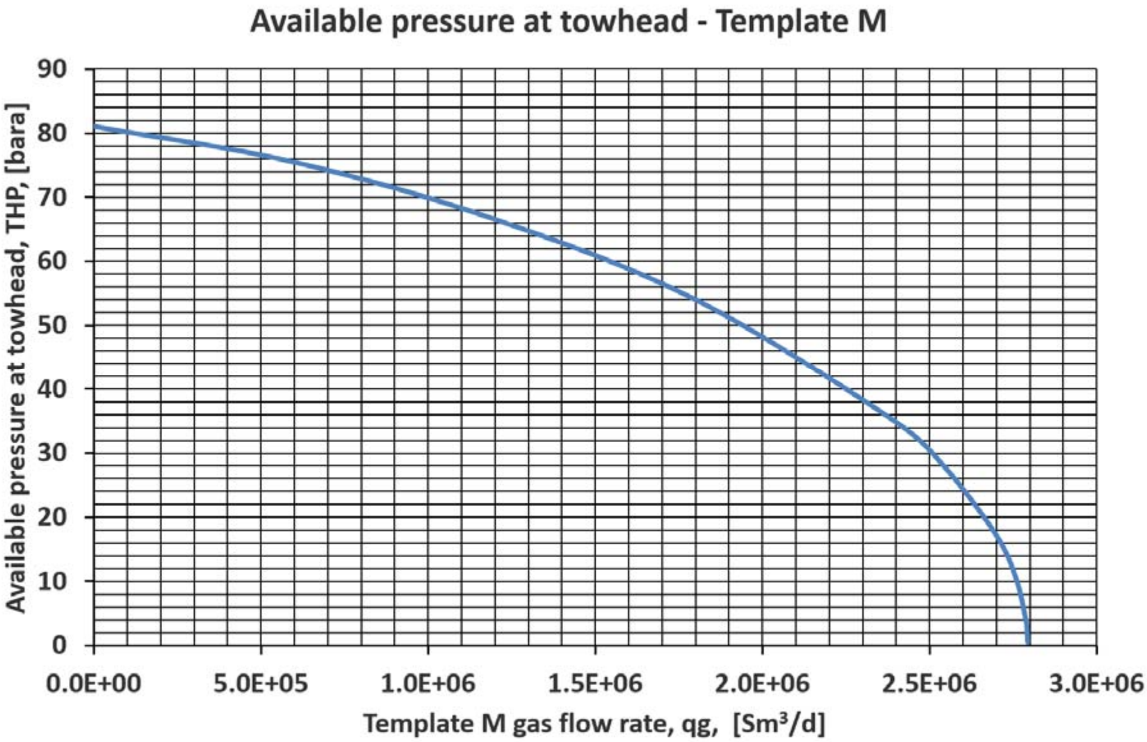
1. If a subsea compressor is installed at the towhead (at the inlet of the pipeline) and the wells have fully open chokes, estimate the pressure increase and the pressure ratio required from the compressor to deliver a total gas rate of 9 E6 Sm^3/d. Estimate the outlet temperature assuming an inlet temperature of 70 C and a polytropic compression exponent (n) of 1.43.

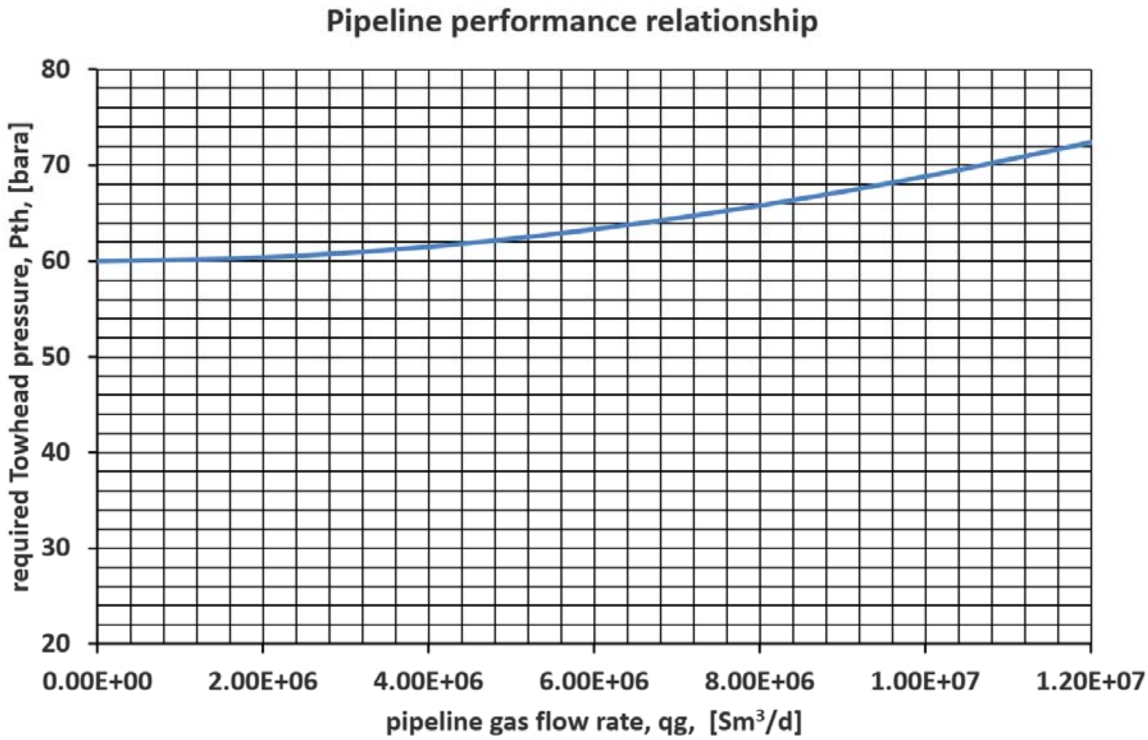
Polytropic expansion, 1 inlet, 2 outlet: $\frac{T_2}{T_1} = \left(\frac{p_2}{p_1}\right)^{\frac{n-1}{n}}$

2. If in case 1 the flow from template L exceeds 6.4 E5 Sm^3/d, there might be wellbore stability problems in the wells. A proposed solution is shown in the figure below, by installing a control valve at the end of the flowline from template L. Is it still possible with this configuration to deliver a total gas rate of 9 E6 Sm^3/d?. If yes, estimate the pressure increase required from the compressor and the pressure drop in the control valve. If not, please explain your answer. **Hint:** fix the rate of template L to be exactly 6.4 E5 Sm^3/d.



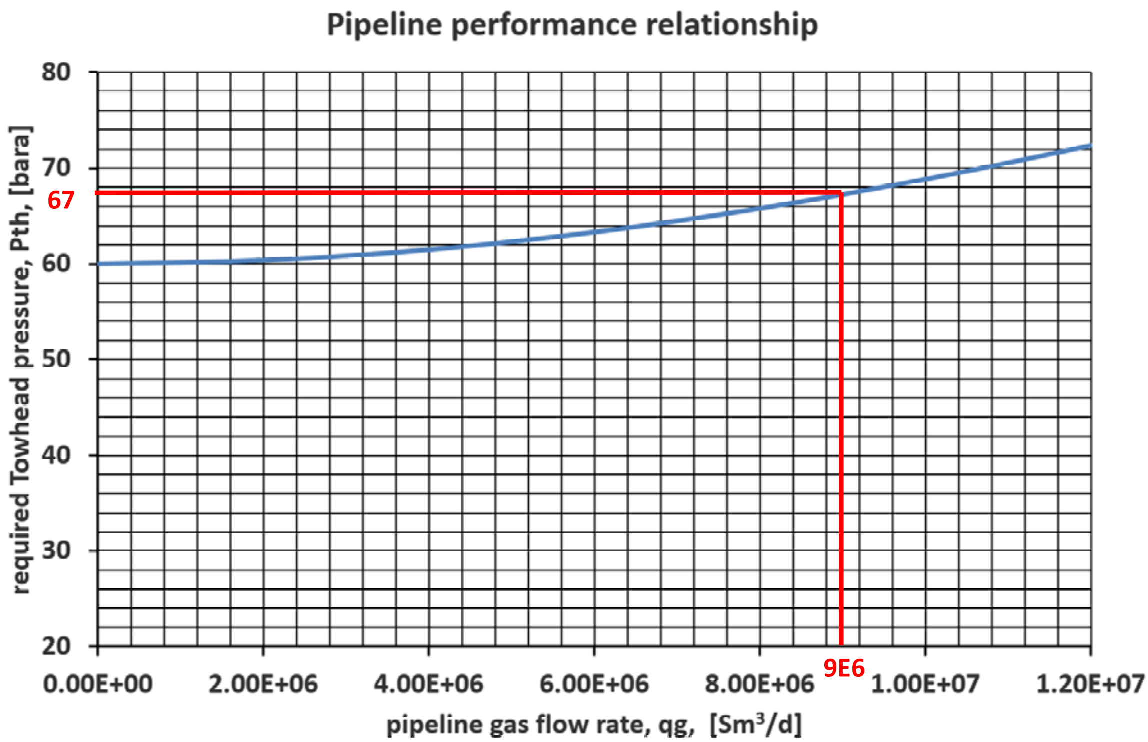

Available pressure at towhead - template L
Available towhead pressure, THP, [bara]
120
100
80
60
40
20
0
0.0E+00
1.0E+06
2.0E+06
3.0E+06
4.0E+06
5.0E+06
6.0E+06
7.0E+06
8.0E+06
Template L gas flow rate, qg, [Sm³/d]


Available pressure at towhead - Template M
Available pressure at towhead, THP, [bara]
90
80
70
60
50
40
30
20
10
0
0.0E+00
5.0E+05
1.0E+06
1.5E+06
2.0E+06
2.5E+06
3.0E+06
Template M gas flow rate, qg, [Sm³/d]

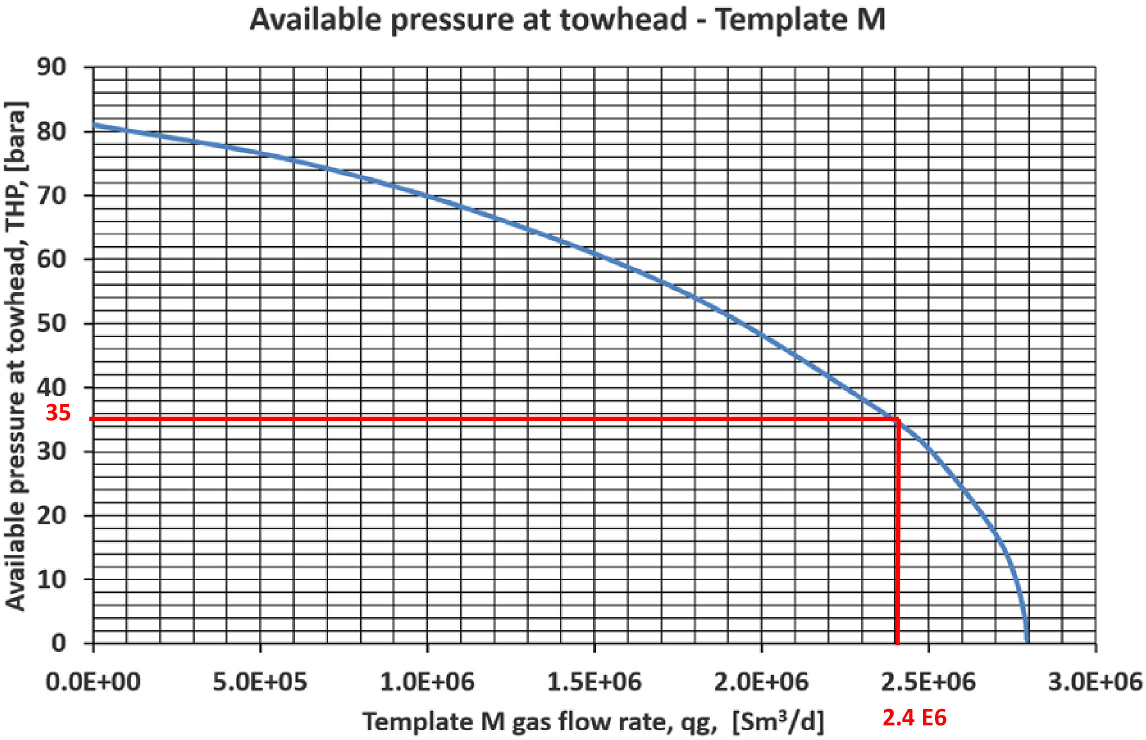


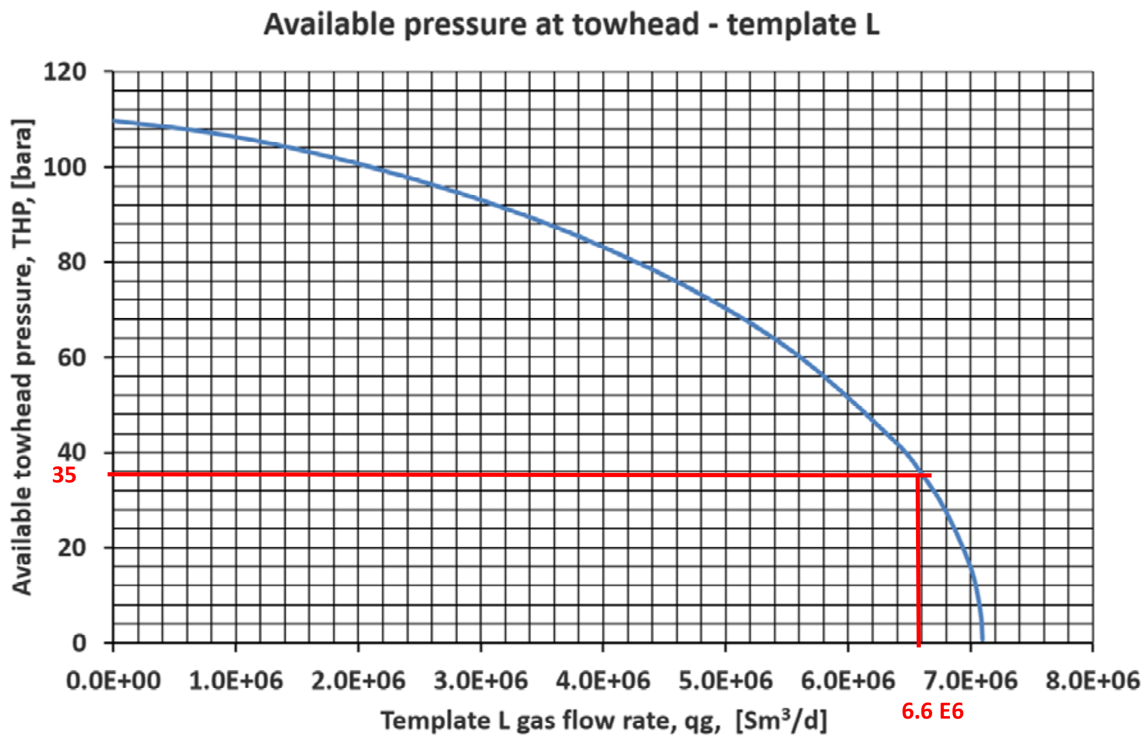
SOLUTION
Task 1:

Obtain the required pressure at the towhead with the PPR for a flow rate of 9 E6 Sm^3/d



67 bara.
Template L and M produce against a common pressure (p suc). The suction pressure to the compressor has to be guessed such that the sum of the flow rates of L and m gives 9E6. After some iterations, the suction pressure is found to be 35 bara.





Then, the deltap of the compressor is $\Delta p = 67 - 35 = 32$ bar

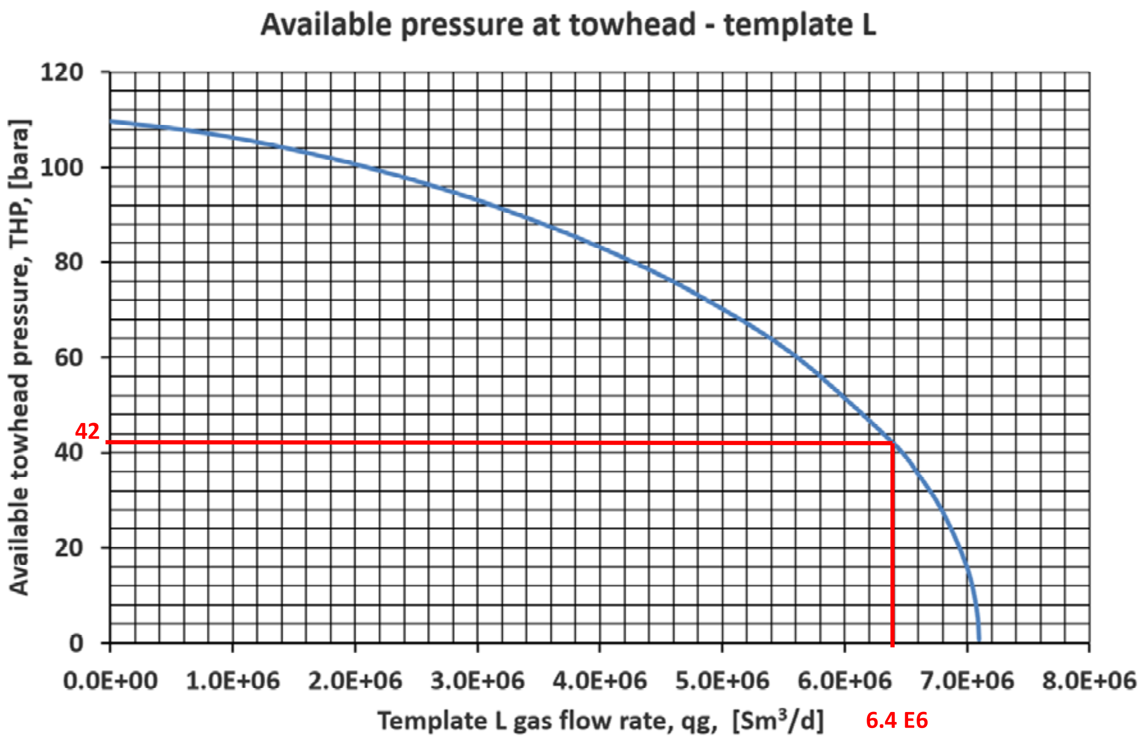
The compressor pressure ratio is: rp=(67/35)= 1.91

The outlet temperature is

$$T_2 = T_1 \cdot \left(r_p\right)^{\frac{n-1}{n}} = \left(70 + 273.15\right) \cdot \left(1.91\right)^{\frac{1.43-1}{1.43}} = 417.14K = 143.99\ C$$

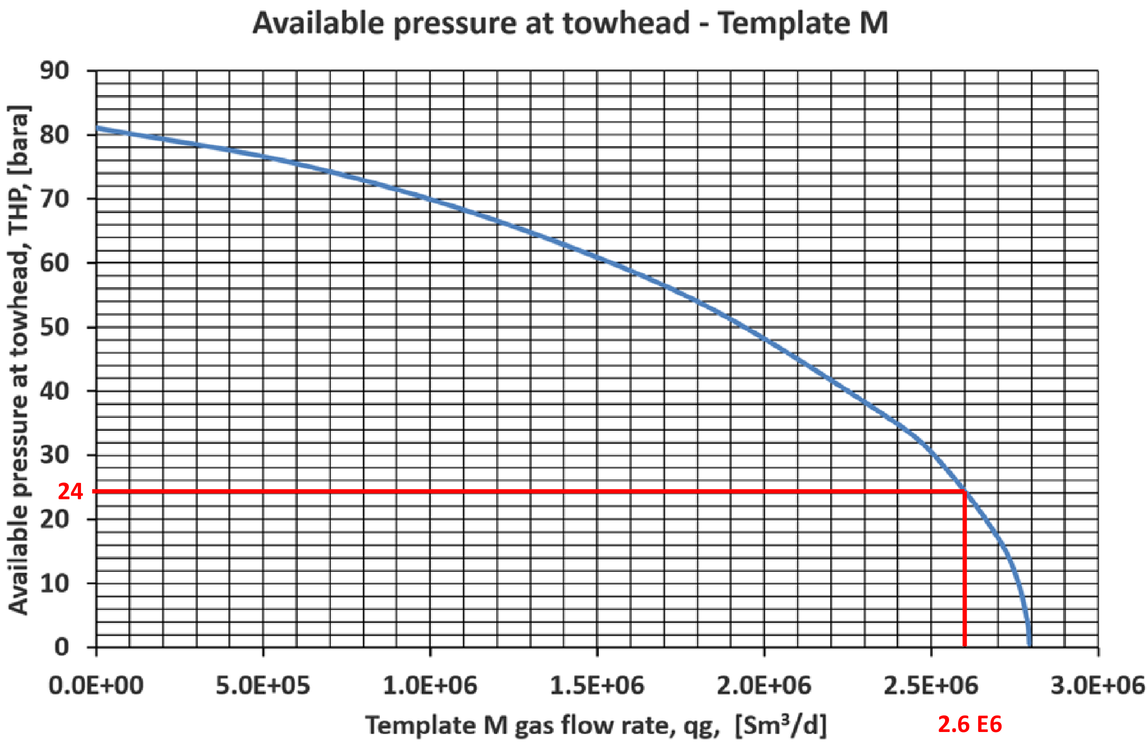
Task 2:

The flowrate of template L exceeds the limit of 6.4 E6 Sm^3/d, thus it has to be choked. As recommended in the problem statement, lets fix 6.4 E6 Sm^3/d in template L.



The available pressure is 42 bara. This is the pressure upstream the choke.

The rest of the flow (2.6 E6 Sm^3/d) has to come from template M. In order to deliver that rate the available pressure downstream the choke (at the suction of the compressor) has to be 24 bara).

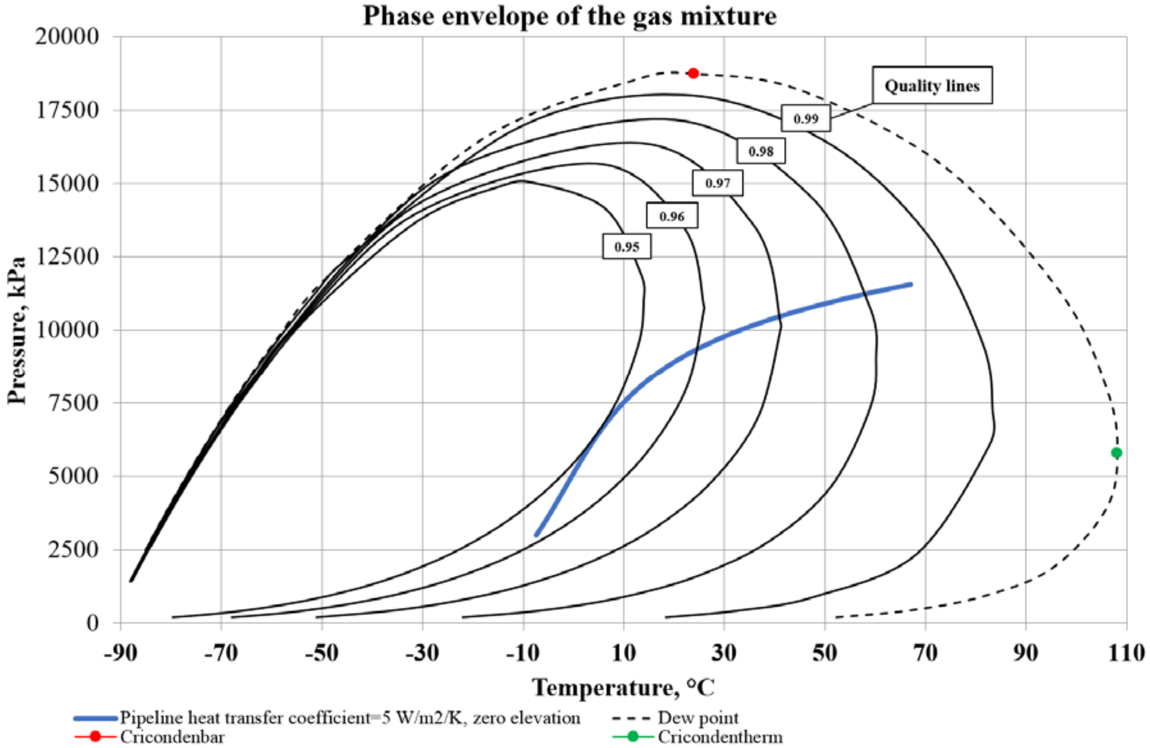


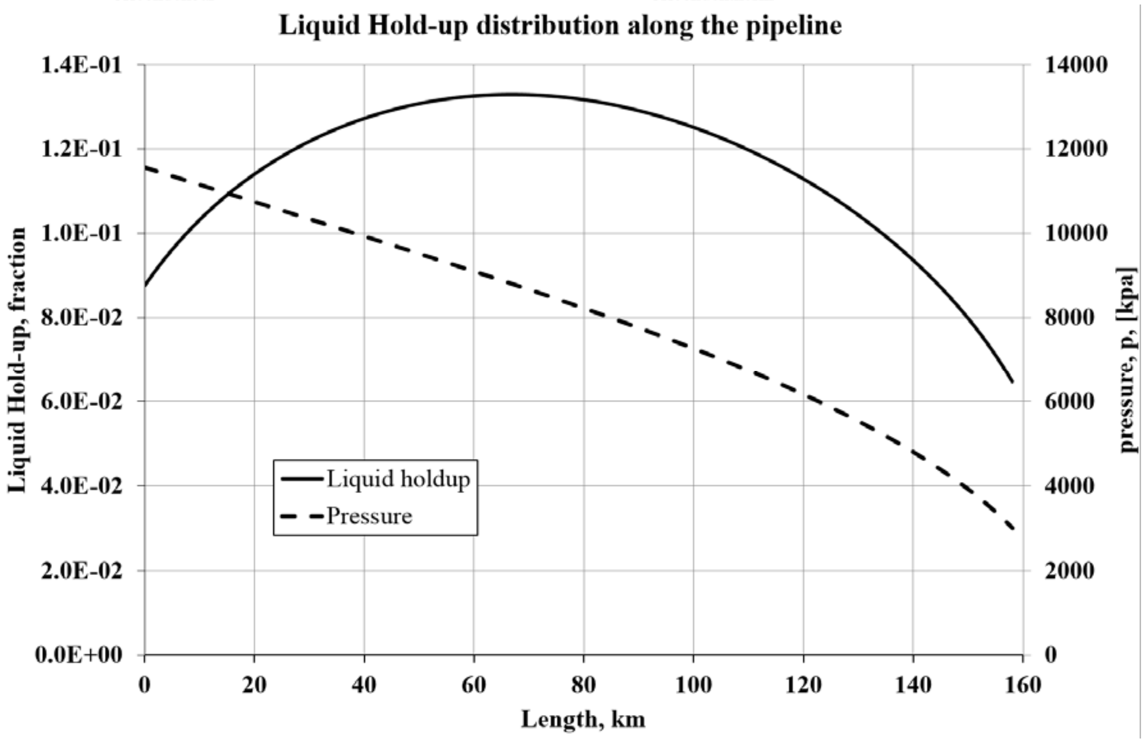
Deltap choke = 42-24 = 18 bar

Deltap compressor = 67 – 24 = 43 bar.

PROBLEM 4. (6 POINTS).

The 158 km, 678 mm ID pipeline that takes the fluids from the Snowhite field to shore (Melkøya LNG plant) has been modeled in Hysys (total mass flow rate 80 000 kg/hr). The analysis is steady-state and a simplified horizontal pipeline profile has been used. The results are shown in the plots below:





1. Calculate, for pipeline position 100 km the superficial and real gas and liquid velocities (m/s). Assume that the density of gas at that point is 74 kg/m^3 and the density of liquid is 611 kg/m^3.

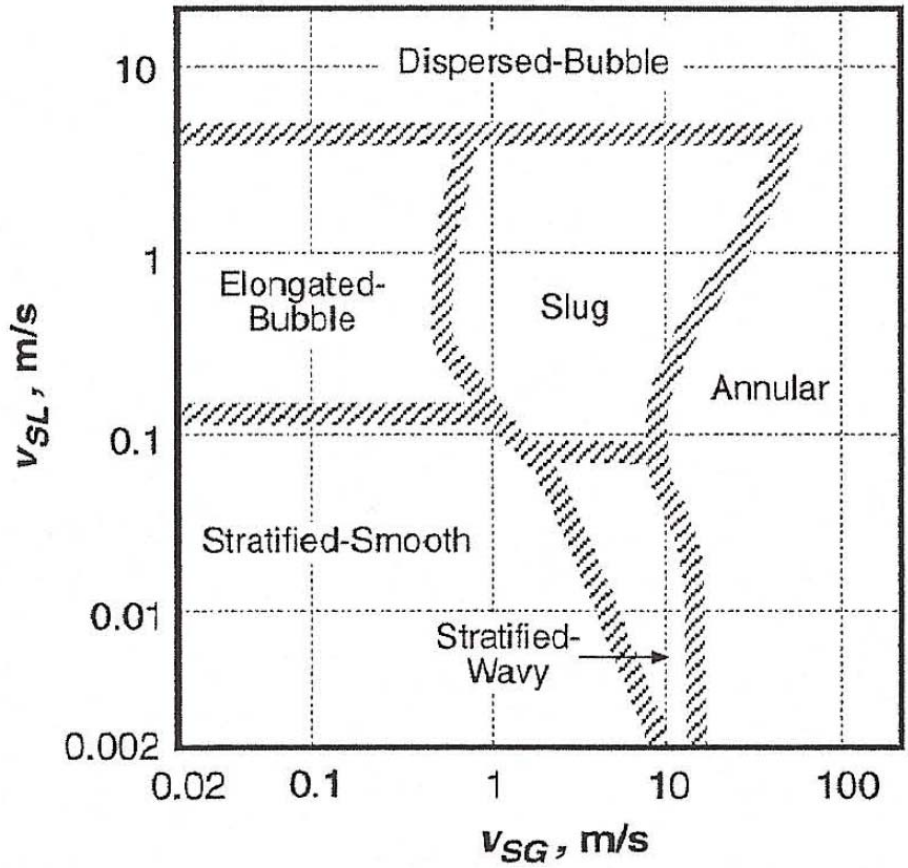
2. Using the superficial velocities and the flow pattern map determine what is the flow pattern of the multiphase mixture at the point of interest.
3. Please provide an explanation for the holdup profile shown.

Some useful definitions are given below:

- Superficial velocity: local volume rate of a phase divided by pipe cross section area.
- The mass fraction in a saturated mixture that is vapour is called quality, and denoted by X :

$$X = \frac{\dot{m}_g}{\dot{m}_g + \dot{m}_L}$$

- The Liquid holdup is the cross sectional area occupied by the liquid divided by the total pipe cross sectional area.
- Flow pattern map for horizontal pipe:



SOLUTION

From the second plot, at 100 km, p = 7300 kPa and Hl = 0.125.

From the first plot, at p = 7300 kPa, the quality is X = 0.95.

Calculate gas mass flow rate and liquid mas flow rate at the location of interest:

$$\dot{m}_g = X \cdot \dot{m}_T = 0.95 \cdot 80000\ kg/hr \cdot \frac{1\ hr}{3600\ s} = 21.11\ kg/s$$

$$\dot{m}_l = (1-X) \cdot \dot{m}_T = 0.05 \cdot 80000\ kg/hr \cdot \frac{1\ hr}{3600\ s} = 1.11\ kg/s$$

With the densities provided, calculate the local volumetric rates of gas and liquid

$$q_g = \frac{\dot{m}_g}{\rho_g} = \frac{21.11\ kg/s}{74\ kg/m^3} = 0.285 m^3/s$$

$$q_l = \frac{\dot{m}_l}{\rho_l} = \frac{1.11\ kg/s}{611\ kg/m^3} = 0.001818 m^3/s$$

The superficial velocities are calculated dividing by the cross section area:

$$u_{sg} = \frac{q_g}{A} = \frac{0.285\ m^3/s}{0.361 m^2} = 0.79 m/s$$

$$u_{sl} = \frac{q_l}{A} = \frac{0.001818\ m^3/s}{0.361 m^2} = 0.005 m/s$$

The real velocities:

$$u_g = \frac{q_g}{A \cdot (1-H_L)} = \frac{0.79 m/s}{0.875} = 0.9 m/s$$

$$u_l = \frac{q_l}{A \cdot H_L} = \frac{0.005 m/s}{0.125} = 0.04 m/s$$

Task 2.

Stratified Smooth

Task 3.

The holdup depends on two factors:

-The amount of liquid and gas that exist at that particular p and T in the pipe and
-The multiphase flow dynamics (the gas and the liquid travel at different velocities thus the cross section area that they occupy is also different)

It can be seen from the first graph that there is liquid condensation from the gas between 0-100 km, and then from 100- 150 km there is liquid evaporation to the gas. This explains the general trend why the holdup increases and then decreases. However, the holdup starts to decrease much earlier, at km. 70 even though the liquid is still condensing from the gas. This might be due to the second explanation. Due to the dynamics of multiphase flow, the liquid begins to travel faster and the holdup begins to decrease.