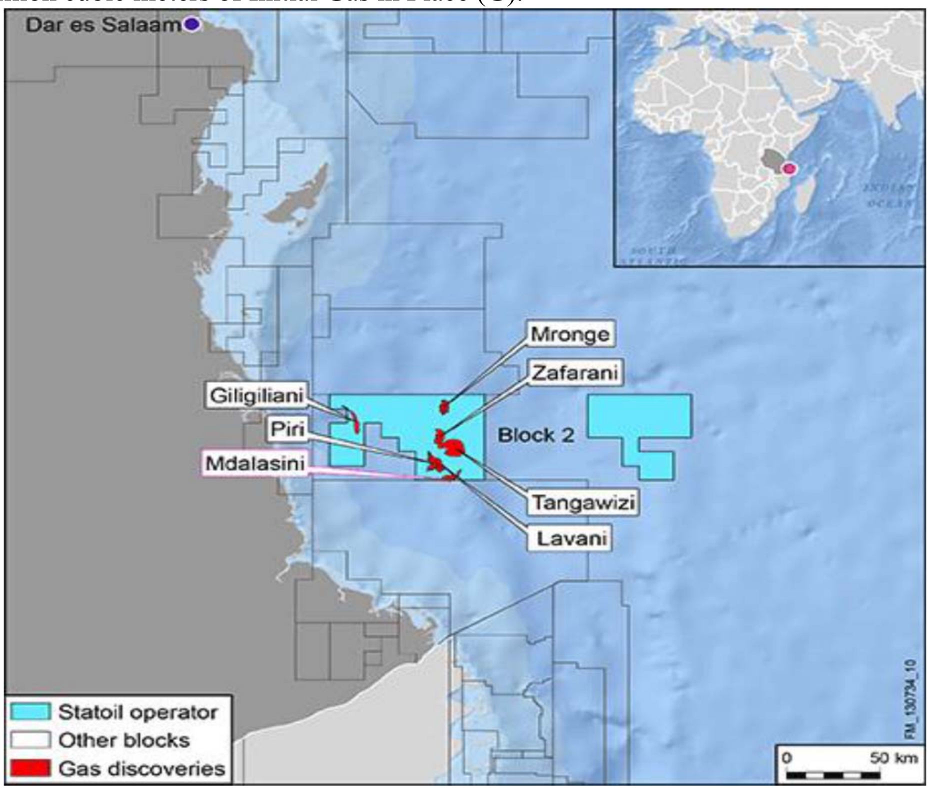
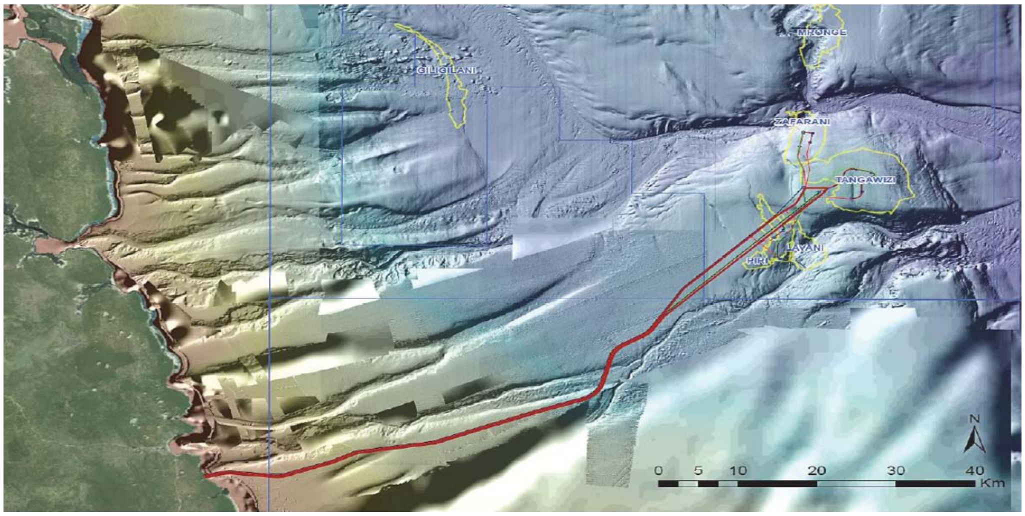
Exercise set (v2)

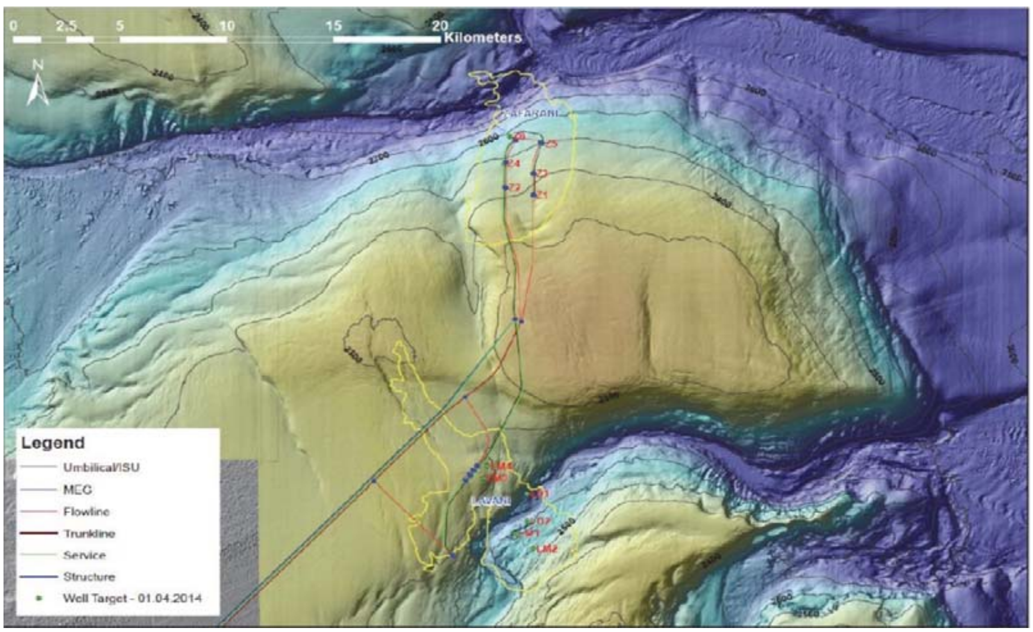
Problem 1: Production scheduling for the dry gas field "Block 2" offshore Tanzania.

Equinor Tanzania is currently operating the license of Block 2 offshore Tanzania with 65% share and ExxonMobil Exploration and Production Tanzania Limited are partners with 35% share. Block 2 comprises of eight discoveries: Zafarani, Lavani, Tangawizi, Mronge, Mdalasini, Giligiliani and Piri as mapped in the figure below. Block 2 covers the area of approximately 5,500 Km^2, lying in water depths between 1,500 to 3,000 m, and the combined discoveries sum up to 0.623 Trillion cubic meters of Initial Gas in Place (G).



The seabed is characterized by large canyons, and steep inclinations of +4° to +5°. Near onshore angles increase sharply to 20 to 30 degrees. The sea water surface temperature may be approximated to 30 °C, while that in deep water is +3 to +4 °C. The development concept chosen is the subsea tie back to the onshore Liquefied Natural Gas plant. The large-scale seabed topography and the field layout are illustrated in the next figure. Reservoir gas is, in general, very dry.

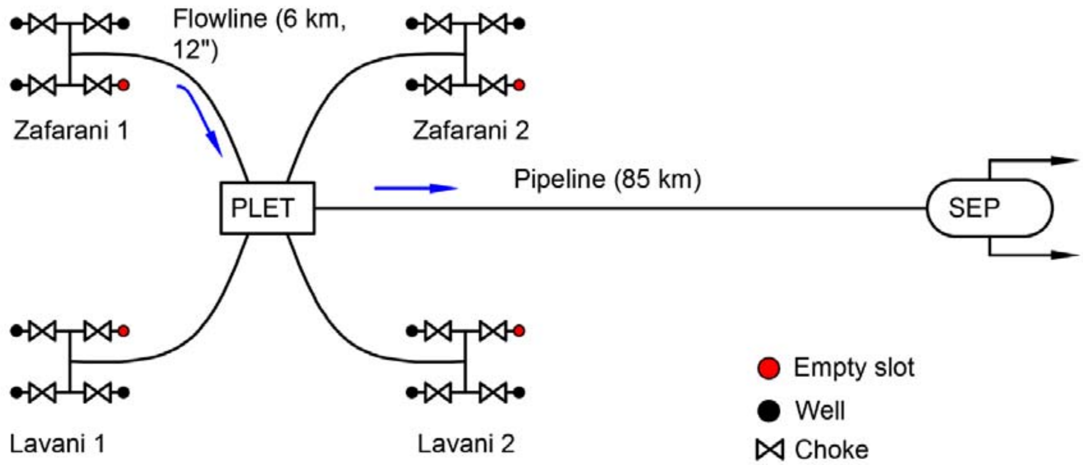




It has been decided that, at an initial stage, only Zafarani and Lavani will be produced. The field will probably be produced in plateau rate.

According to the base case Scenario (BCS) selected for the study, the field is completed subsea with 4 subsea templates (2 for Zafarani and 2 for Lavani), each with 4-slots (well bay). Only three wells are completed in each template. For the purpose of your studies it will be assumed that the templates are symmetrically positioned at 6 km away from the subsea Pipeline Entry Terminal (PLET). You can also assume that, due to reservoir communication, Zafarani and Lavani behave as a single reservoir unit and that a simple gas material balance is good enough to represent its behavior.

Each template is connected by flowline to the PLET where the production streams of all the templates are commingled (combined and mixed). The PLET is on the seabed approximately 85 km from shore and is connected by the main field export pipeline to the slug catcher (separator) on shore.



All wells are identical (in structure and productivity and all other design and operation parameters) and produce from the same reservoir (tank model).
Due to the fact that all wells are identical and symmetrical, it is possible to perform flow equilibrium calculations considering only the flowpath: wellbore-tubing, flowline from template to PLET and pipeline. However, remember to use the appropriate flow rate in each pipe segment.

Task 1: Your main task is to determine the number of wells and field plateau rate that give maximum economic value (NPV). Report plateau duration, number of wells, NPV and ultimate recovery factor for the best solution. Additionally, provide a plot of production profile and discounted cash flow with time.

Task 2: After you have chosen optimal number of wells and plateau duration, evaluate the effect of uncertainties of the gas price (±40% of the value provided), the original gas in place (±20% the value provided) and the CAPEX AND DRILLEX (±40% the value of the base case). Present your results on a table and in a plot using a tornado chart.

Task 3: The multiphase/flow assurance expert working on this project has said that the prediction of the pressure drop in the main transportation pipeline using commercial tools could be extremely unreliable. This is because two very special conditions: hilly profile and the presence of some liquid flowing together with the gas. He says that the error associated with the pressure drop estimation in the pipeline might be off by ±40%. He therefore suggested to perform an experimental campaign to verify and reduce the inaccuracy of the pressure drop models. The experimental campaign costs 5 E06 USD.

Before taking the decision, your manager has asked you to determine what would be the influence of an inaccuracy of 40% in **original pressure drop in the pipeline** on your results.

Guidelines, requirements and useful information

- Assume dry gas flow equations, dry gas tank model material balance, and no condensation in the entire system. Use the pre-programmed VBA functions to calculate flow in tubing, pipeline and flowline (VBA function linep1 or line p2), for the dry gas material balance, for the Z factor and for the IPR. Regarding the IPR, **note**

that it is not possible to find an explicit expression of p_{wf} as when using the low-pressure backpressure equation.

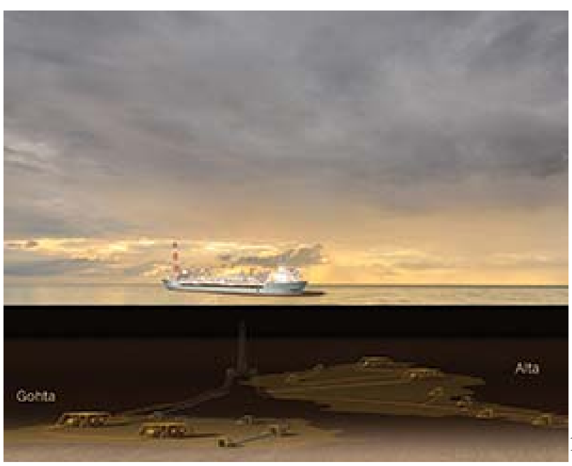
Material balance: $\left(\frac{p_R}{Z_R}\right)=\left(\frac{p_i}{Z_i}\right)\left(1-\frac{G_p}{G}\right)$	Flowline: $q_{gsc}=C_{FL}\cdot\left(p_{in}^2-p_{out}^2\right)^{0.5}$
Inflow equation (valid for all pressure ranges): $q_g=C_R\cdot\left(m(p_R)-m(p_{wf})\right)^n$ Where the m function is : $m(p)=\int_{p_{sc}}^{p}\frac{p}{\mu\cdot Z}dp$	Pipeline equation: $q_{gsc}=C_{pl}\cdot\left(\frac{p_1^2}{e^{S\_pl}}-p_2^2\right)^{0.5}$
Tubing equation $q_{gsc}=C_T\cdot\left(\frac{p_1^2}{e^S}-p_2^2\right)^{0.5}$	User defined function for calculating Z factor: Z=f(P_R, T_R, γ_g)

- All wells, templates, and infield flow lines are symmetric in configuration and capacity. Due to the fact that wells are identical, and if the system is symmetric, it is possible to perform flow equilibrium by looking at the path: well (formation), well (tubing), flowline and pipeline, but using different rates (i.e., well rate, template rate, and field rate, correspondingly). The recommended equilibrium point is the wellhead. (upstream and downstream the choke).
- The field produces some associated condensate. The Condensate Gas Ratio (CGR) is 1.5E-4 Sm^3/Sm^3 and it remains constant during the life of the field. Include condensate sales in the revenue profile of the field.
- Due to the change in elevation of the pipeline from subsea to shore, use the tubing equation to represent the pressure drop in the pipeline.
- To calculate revenue, you should compute the production profile until abandonment (field rate of 5 E06 Sm^3/d).
- Remember that to compute the production profile of the field you could use:
  - Flow equilibrium calculations in every time step,
  - Time-step calculations using the production potential curve (q_{pp} vs G_p) as the upper rate bound (as discussed in the class on January 31st). Note that to pursue this option, you have to compute the production potential curve beforehand by running an open choke simulation.
  - The analytical expression of field rate derived from a linear production potential (as discussed in the class on January 31st). Note that to pursue this option, you have to compute the production potential curve beforehand by running an open choke simulation.
- You could use the solution of problem 5 to estimate net present value of revenue. However, remember to add the discounted expenditures and change startup and abandonment time accordingly.
- To find plateau rate and number of wells that give maximum NPV, you have to try different combinations of both. To help you find the best point, it is recommended for you to
  - plot project NPV versus field plateau rate, for a fixed number of wells.
  - plot project NPV versus number of wells, for a fixed field plateau
- To avoid sand production, wells shouldn't produce more than 3 E06 Sm^3/d.

- When varying the number of wells, there should be always the same number of wells in each template (to take advantage of symmetry when doing flow equilibrium). Add and remove templates as needed.
- All wells must be drilled before production startup. The average time required to drill a well is 3 months (4 wells per year). The average cost per well (including perforating, completing, tree and well equipment) is 150 E6 USD. **Note that the number of wells affects might delay the production startup (end of year 5), if there are plans to drill more than 20.**
- OPEX is 120 E06 USD per year
- All CAPEX related to LNG plan, LNG carriers, subsea system is to be paid evenly during the first five years. DRILLEX is paid in the year the well is drilled.
- VBA functions are provided to estimate CAPEX of the LNG plant and CAPEX of the subsea system.
- LNG carriers are needed to take the LNG production from to the market. Each LNG carrier has a capacity of 145,000 m^3 of LNG (equivalent to 86 E06 Sm^3 of produced gas) and can make 22 trips per year. The cost of each LNG carrier is 200 E06 USD. The number of carriers needed depend on the maximum annual gas production.
- Neglect tax and depreciation, and ABEX (abandonment expenditures).

<u>Problem 2:</u> Production scheduling studies for the Alta-Gohta oil field in the Barents Sea.

The offshore Alta-Gohta field (production license operated by Lundin) consists of two separate reservoirs (Alta and Gohta).



[1]

[2]

The reservoir management team of Lundin is evaluating to produce the field with plateau rates between 20-8 E3 Sm3/d from Alta-Gohta. The definitive plateau rate will be decided at a later stage following an economic analysis.

Each reservoir will be produced independently to the FPSO, via a separate pipeline. The oil production potential of each individual reservoir versus its cumulative oil production can be estimated with following expression:

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[1] https://www.oedigital.com/news/446398-northern-lights

[2] Presentation: Lundin i Barentshavet – med fokus på Alta-Gohta. Dag Mustad.

$$q_{pp} = e^{-5.169 \cdot \frac{N_p}{N}} \cdot q_{ppo}$$

Where the values for Alta and Gohta are summarized in the table below:

Reservoir	q_{ppo} [Sm3/d]	N [1E06 Sm3]
Alta	25 E3	45-150
Gohta	8 E3	15-45

Your task is to determine optimum production splitting between Alta and Gohta to achieve maximum plateau duration. Do this for several field plateau rates in the range of interest to Lundin and considering uncertainties in the initial oil in place (N) of the two reservoirs.

Recommendations and suggestions

- Report plateau duration for all field plateau rates considered
- Do your production profile calculation on a 0.5 year basis.
- Provide comments on the effect the assumption of initial oil in place has on field plateau duration and optimum splitting.
- Plot field, Alta and Gohta production profile until the field rate drops to 1.5 E3 Sm3/d
- Assume a year has 355 operational days

<u>Problem 3:</u> Production scheduling calculations for the "Borthne" saturated oil field

A small saturated oil reservoir without gas cap will be produced using an unmanned platform with 4 well slots. The X-mas trees are on the platform. The platform has a separator with a constant pressure of 30 bar. Well are equipped with wellhead chokes to regulate production. The separator is very close to the wellhead and it can be safely assumed that all wells are independent of each other.

Wells will be drilled gradually and will be put into production according to the schedule provided in the excel sheet attached.

It is desirable to produce the platform with a constant rate of 450 Sm3/d. **Your main task** is to determine the plateau duration of the field. Also:

- Estimate (and plot) the choke pressure drop for each year
- Plot the production profile and GOR variation in time
- Plot the oil IPR (curve of p_{wf} vs q_o) for at least five dates, spread evenly in time
- Report the final recovery factor achieved

Suggestions and assumptions

The oil inflow deliverability can be described using the backpressure equation (provided as a VBA function in the excel sheet):

$$q_o = C_R \cdot \left({p_R}^2 - {p_{wf}}^2\right)^n$$

However, for saturated oil, the backpressure coefficient, C_R , will change with depletion depending on the change of mobility of oil and gas around the wellbore. The following equation[3] (provided as a VBA function in the excel sheet) is recommended to compute future C_R

$$C_{new} = C_{old} \cdot \left[\frac{\left(\frac{k_{ro}}{\mu_o \cdot B_o}\right)_{new} \cdot (p_R)_{old}}{\left(\frac{k_{ro}}{\mu_o \cdot B_o}\right)_{old} \cdot (p_R)_{new}}\right]^n$$

The reservoir has been modeled separately in a material balance tool. The results are presented in a table format and depict reservoir pressure, oil saturation, oil relative permeability, gas cumulative production and fluid properties as a function of oil cumulative production. A VBA function (name: "tabinterpol") is provided to interpolate on the table and find values at a particular Np.

Well tubing tables have been computed using Prosper and are provided in the excel sheet. The tubing tables depict bottom-hole pressure as a function of oil rate, gas oil ratio and wellhead pressure. A VBA function (name: TrilinearInterpol) is provided to interpolate on the table (i.e. find required bottom-hole pressure at a particular q_o, GOR and p_{wh})

The initial GOR is the initial solution gas oil ratio, R_{si} . However, for all subsequent time steps it can be estimated with the gas cumulative production and oil cumulative production of the current and previous time step.

A VBA sub is provided in sheet "Data" to apply the GoalSeek to multiple cell sequentially. This might be needed, even in the plateau period, because of the way the tubing table is constructed.

It is recommended for you to compute the production profile post plateau. However, take into account the following:

- After the end of the plateau is reached, oil rates will drop sharply, therefore, it is recommended to reduce the length of the time step or to use a different integration scheme to estimate oil cumulative production.
- The material balance table and tubing table have been generated for a range of input variables (e.g. Np for MB and qo, GOR and pwh for the tubing tables). It might happen that, during your scheduling calculations, such input variables fall out of range. When this happens, stop your calculations.

[3] Well performance, Golan and Whitson, page 178. Compendium, page 45.

<u>Problem 4:</u> Production system layout of the Volund subsea satellite field

<u>Field Description</u>

Volund is a subsea oil field, at 130 m water depth, located about 10 kilometers south of the Alvheim FPSO in the central part of the North Sea (see figure). The field, with reservoir depth of 2000 m, is developed as a subsea Satellite field to the Alvheim FPSO (Floating Production, Storage and Offloading vessel) and is tie-back to floating vessel. The subsea Volund field will have three horizontal subsea oil production wells producing to a subsea production manifold on a template. The wells are satellite to the template and the subsea wellhead are located a short distance from the template. The wellhead/Christmas trees are connected to the template by short pipes sections (Jumpers).

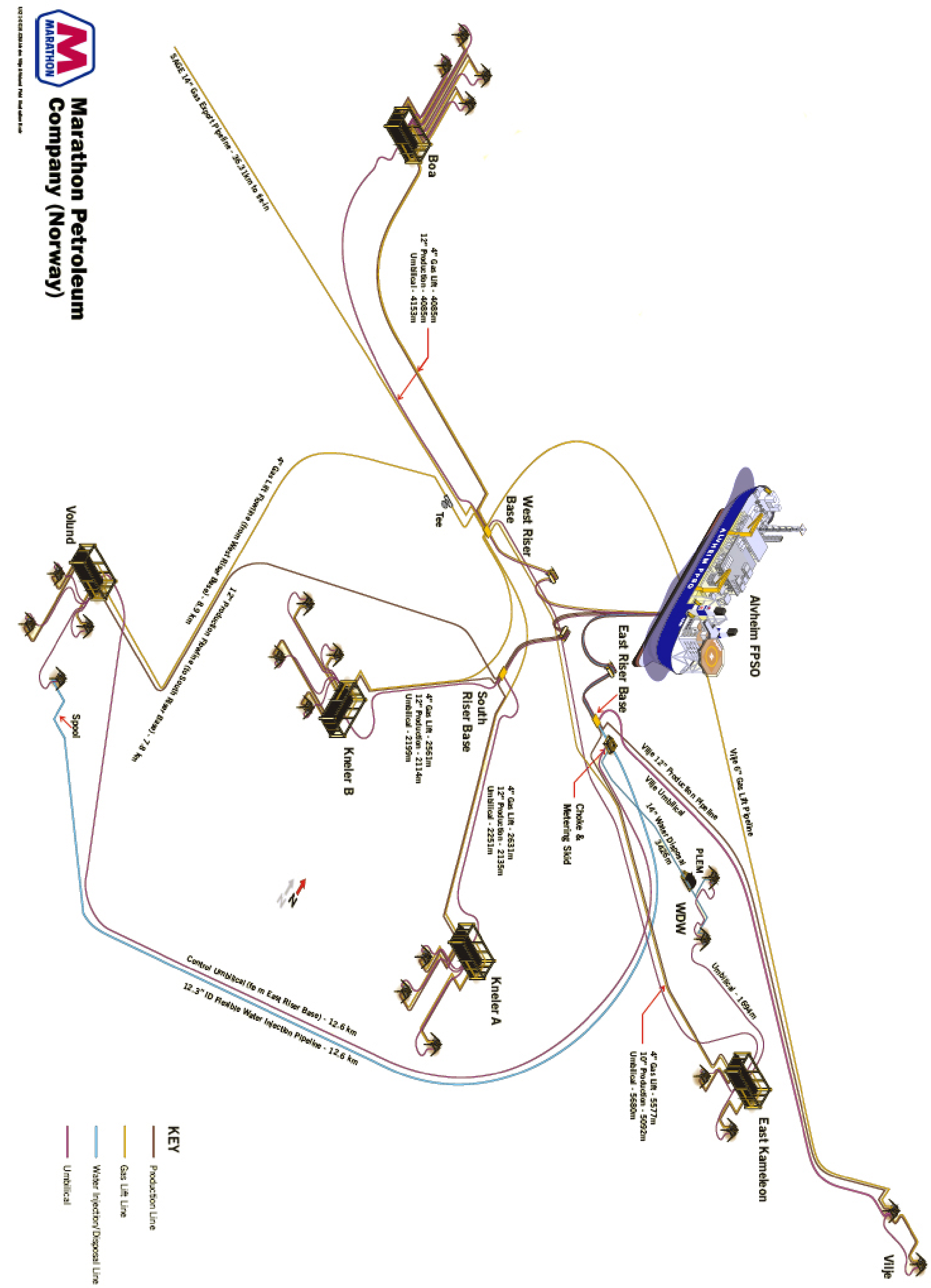
The subsea manifold on the template consists of a test and a production header which are connected by one production line and one test line to the FPSO. On the vessel there is one test separator and one production separator train dedicated entirely to the Volund field. The other fields producing to the vessel (Boa, Kneler B, Kneler A, Øst Kamelon, Vilje), have a separated testing and separation facilities and are not considered in this task.

The well-streams of Volund are commingled in the production header on the subsea template and routed through a pipeline and a flexible riser to the Alvheim FPSO for separation, processing and export. The oil is exported via an offshore buoy-loading to a shuttle tanker (not shown in the figure). The associated rich gas is separated from the condensate liquid and stripped from the NGL (Natural Gas Liquid) on the FPSO. The condensate and stripped liquids are recombined with the exported oil. The dry/lean gas is transported from the Alvheim FPSO to gas pipeline leading to the UK.

As part of preparing the field development plan you need to perform the following tasks:

1. Propose a simplified P&I diagram of the subsea template of Volund production manifold with the production/testing lines to the separators on Alvheim FPSO. Show in your sketch the entire system from the wellhead to the separator. Include suggestions for pigging facilities. The production wells are satellite of the manifold template (Wellheads are not on the template but a distance away).
2. Considering that pigging is not necessary, make suggestions (using a simplified P&I diagram) for an arrangement where the testing of individual wells is done by multiphase meters (MFM) and not by test separator. Address three cases:
   - A surface single multiphase meter (MFM) on the FPSO
   - A single multiphase meter (MFM) in the subsea test manifold
   - A multiphase meter for each subsea well

Show in your diagram the main valves on the wells, the routing valves on the manifold and the arrangement of valves in the FPSO (pig launcher and receiver, separator control valves, etc).


Marathon Petroleum
Company (Norway)
Boa
4" Gas Lift - 4085m
12" Production - 4085m
Umbilical - 4153m
West Riser
Base
Tee
Alvheim FPSO
East Riser Base
South
Riser Base
Volund
Spool
Kneler B
Kneler A
Choke &
Metering Skid
PLEM
WDW
East Kameleon
Vilje
KEY
Production Line
Gas Lift Line
Water Injection/Disposal Line
Umbilical

Problem 5:

During class (January 31st), it was demonstrated that **if** the production potential is a straight line, then an analytical expression of the production profile can be derived:

$for\ t < t_p \qquad q_f = q_{p,f}$

$for\ t \geq t_p \qquad q_f = q_{p,f} \cdot e^{-m\cdot(t-t_p)}$

Where

$$t_p = \left(\frac{q_{ppo}}{q_{p,f}} - 1\right) \cdot \frac{1}{m}$$

The net present value of the project is the sum of all cash flows from time zero to field abandonment discounted with time. Cash flows are often calculated and discounted in a discrete manner, e.g. on a year basis, e.g.:

$$f_{NPV} = \sum_{k=1}^{N} \frac{Rt_k}{(1+i)^k}$$

Where:

i	Discount rate (a value usually given in 1/year)
k	Counter for the number of years
N	Total number of years
Rt_k	Cash flow of year "k"

However, theoretically, it is also possible to perform continuous discounting[4]:

$$f_{NPV} = \int_0^{t_{end}} Rt(t) \cdot e^{-i\cdot t} dt$$

Your tasks are:

1. Calculate an analytical expression for the net present value **considering revenue only** by using the following expression:

$$NPV_{rev} = \int_{t_{start}}^{t_{end}} q_f(t) \cdot P_o \cdot e^{-i\cdot t} dt$$

Where:

- $q_f(t)$ is the analytical expression of field production profile presented earlier
- P_o is the oil price (e.g. USD/Sm3), assumed constant in time.

[4] https://www.investopedia.com/terms/c/continuouscompounding.asp; http://financialmanagementpro.com/continuous-discounting/

2. Calculate an analytical expression of the recovery factor, assuming that the initial amount of hydrocarbons in place is Q.

Problem 6:

An oil reservoir has been discovered in the Barents Sea, 310 km from Hammerfest. Seismic data and a few exploration wells have been drilled that provide enough information to perform an initial reserve estimation and economic valuation.

The company is currently in the business identification phase (leading to DG0) and it will decide if:

1) To go forward with the development
2) To drill some more appraisal wells and get more information about the areal extension of the reservoir. The cost of the appraisal well campaign is 150 million USD. The campaign could have two outcomes:
   a. If the appraisal wells gives a positive indication of hydrocarbons, It will confirm the minimum value of the rock volume currently used.
   b. If the appraisal wells give a negative indication of hydrocarbons, the minimum rock volume must be reduced to 6 E09 bbl.

- To help the company to take the decision, you have to perform a probabilistic estimation of the value of the project (NPV). Use your results to decide if it worth or not if to perform the appraisal campaign. You are considering employing a probability tree together with the Monte Carlo or Latin-Hypercube sampling methods.

- Evaluate the effect of the oil price has on your results (varying uniformly in the range 30-70 USD/bbl)

Additional information

You can do your calculations in Excel or Python.

For estimating the economic value of the project, you must use the following simplified expression[5] of NPV (in million USD)

$$NPV = P_o \cdot F_D \cdot N_{pu} - C$$

Where:

- P_o is the price per barrel of oil [USD/bbl].
- C is the approximated cost of the development, mainly representing facilities and wells [in million USD]. It will be assumed that the cost is a function of the maximum oil rate produced. It is given by the equation:

$$C = \frac{N_{pu} \cdot F_{outake}}{uptime} \cdot 11826 + 2002$$

  - Where F_{outake} is an outake factor representing how much of the total recoverable reserves is recovered per year in the plateau period. According to the discussion in class, assume that this value is uniformly distributed between 0.05-0.15
  - Uptime is the number of operational days per year. Use 350 days.
  - There is usually high uncertainty associated to C (usually ±40% during the business identification phase). To capture this uncertainty, it is recommended to multiply C by a factor F, which is uniformly distributed between 0.6-1.4.

- F_D is a discounting factor [-], representing that reserves are recovered and discounted gradually within a period of time, instead of at time zero.

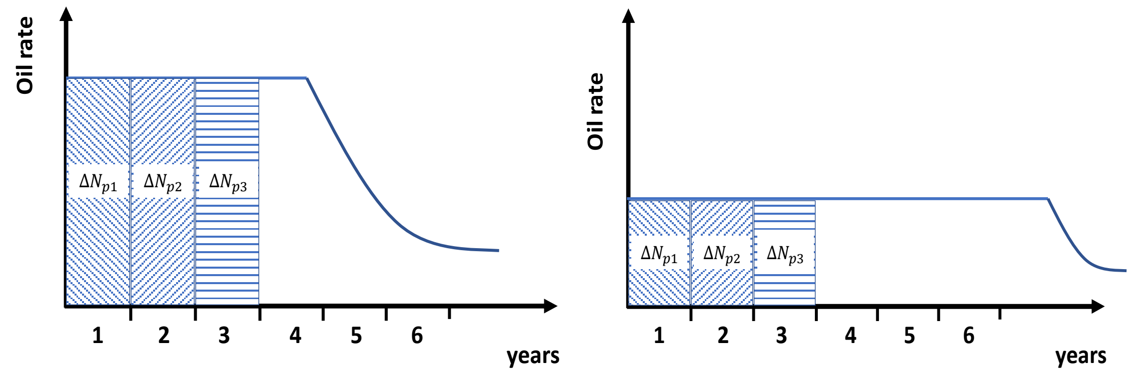
$$NPV_{revenue} = \sum_{i=1}^{N} \frac{\Delta N_{pi} \cdot P_o}{\left(1+d_f\right)^i} = \frac{\Delta N_{p1} \cdot P_o}{\left(1+d_f\right)^1} + \frac{\Delta N_{p2} \cdot P_o}{\left(1+d_f\right)^2} + \frac{\Delta N_{p3} \cdot P_o}{\left(1+d_f\right)^3} + \cdots$$

$$N_{pu} \cdot P_o \cdot F_D = \frac{\Delta N_{p1} \cdot P_o}{\left(1+d_f\right)^1} + \frac{\Delta N_{p2} \cdot P_o}{\left(1+d_f\right)^2} + \frac{\Delta N_{p3} \cdot P_o}{\left(1+d_f\right)^3} + \cdots$$

$$F_D = \frac{1}{N_{pu} \cdot P_o} \left[\frac{\Delta N_{p1} \cdot P_o}{\left(1+d_f\right)^1} + \frac{\Delta N_{p2} \cdot P_o}{\left(1+d_f\right)^2} + \frac{\Delta N_{p3} \cdot P_o}{\left(1+d_f\right)^3} + \cdots \right]$$

This value will depend on the plateau rate of the field:

[5] This expression has been derived from the full NPV equation, assuming that all expenses are executed in year zero ("0") and that the discounted revenue can be approximated by multiplying the total recoverable reserves by the oil price and a "discounting" factor



and on the discounting rate.

It is recommended for you to use the results of exercise 1 and/or exercise 5 to determine a suitable value range.

- N_{pu} is the ultimate cumulative oil production [in Million stb] (or total recoverable reserves). Only oil is recovered from this field (due to lack of gas transport infrastructure).

The ultimate cumulative oil production is $N_{pu} = N \cdot F_R$, where

- F_R is the ultimate recovery factor [-]. Assume this value can vary uniformly between 0.2-0.4 (the reservoir has very low pressure).
- N is the initial oil in place [stb], estimated by the expression:

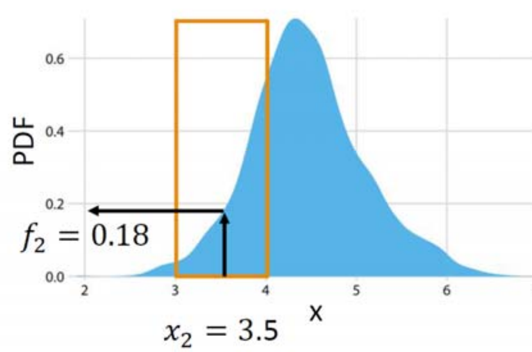
$$N = \frac{V_R \cdot \phi \cdot S_o \cdot N_{tg}}{B_o}$$

Where:

- V_R Rock volume [bbl], uniformly distributed between 8-15 E03 million bbl
- ϕ porosity [-], uniformly distributed between 0.09-0.29
- S_o oil saturation [-], uniformly distributed between 0.8-0.9
- N_{tg} Net to gross [-], uniformly distributed between 0.3-0.5
- B_o Oil formation volume factor [bbl/stb], uniformly distributed between 1.08-1.25

If needed, you could discretize the cumulative probability distributions (for example of N) using the procedure described below[6]:

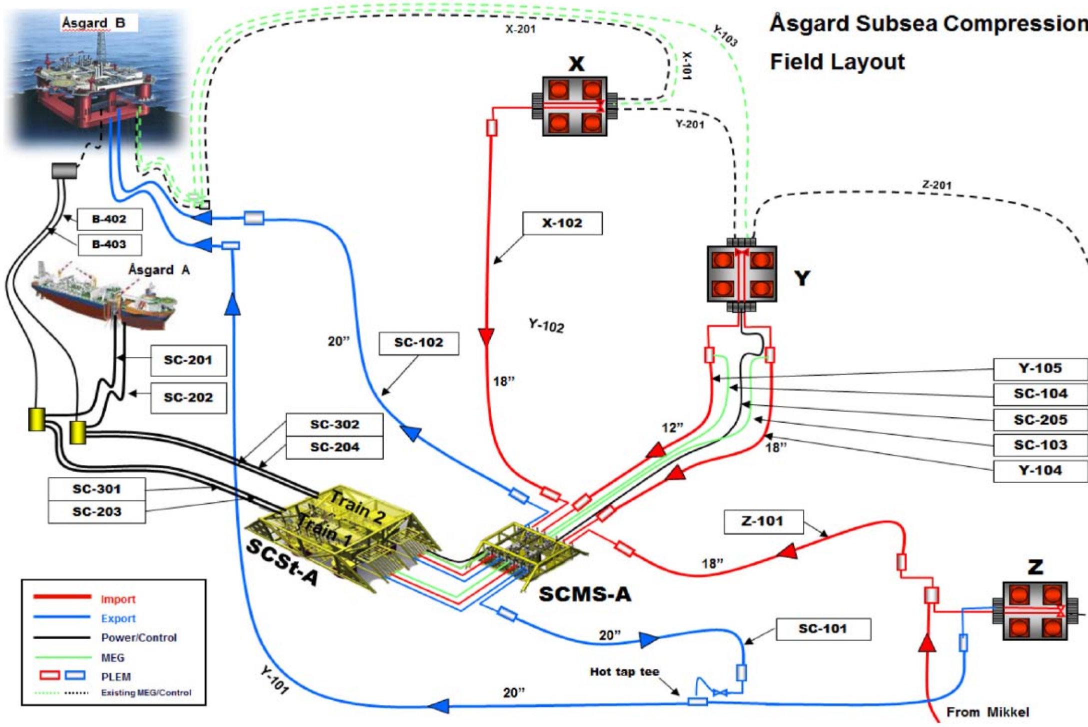
- Discretize the value range into N intervals.
- Use the mid-value of interval i as the discrete value x_i.
- Calculate the probability density f_i using the PDF, $f_i = f(x_i)$.
- Normalize f_i to get the probability for x_i, $P_i = \frac{f_i}{\sum_{i=1}^{N} f_i}$.

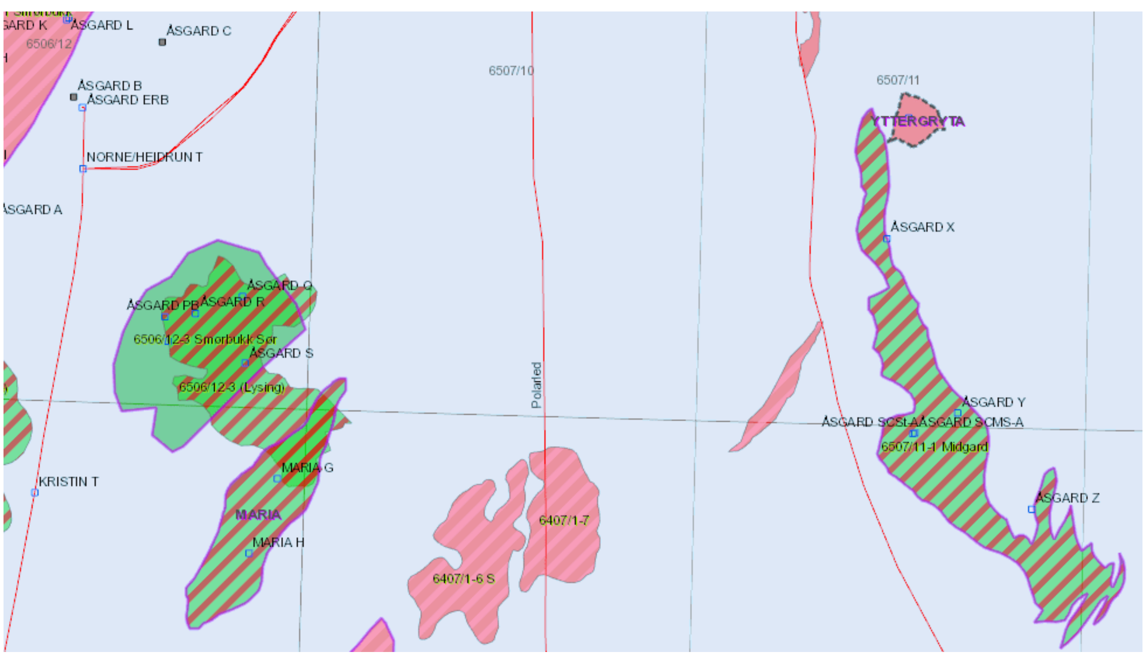


[6] Slide taken from course of Reidar Bratvold, Aojie Hong.

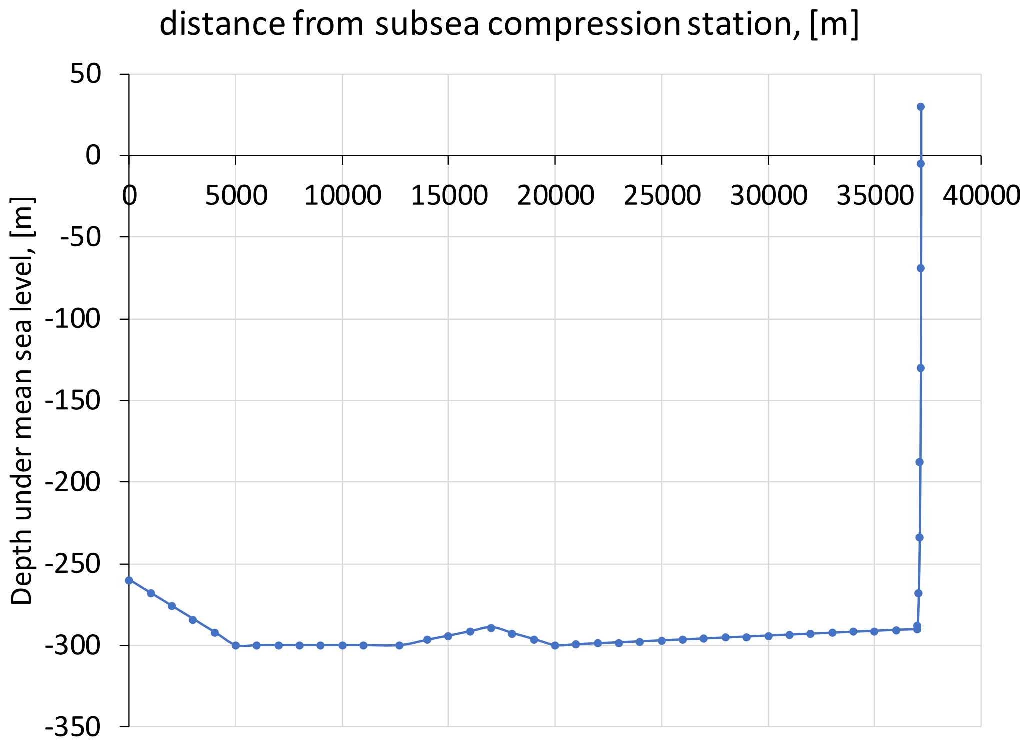
Problem 7:

The Åsgard Subsea Compression Project (SCSt) is installed at a water depth of 260 meters. It is connected to a subsea manifold station (SCMS-A) routing all flow from the wells of Midgard and Mikkel to the gas processing facilities on the semi-sub of Åsgard B, that is about 40 km away.



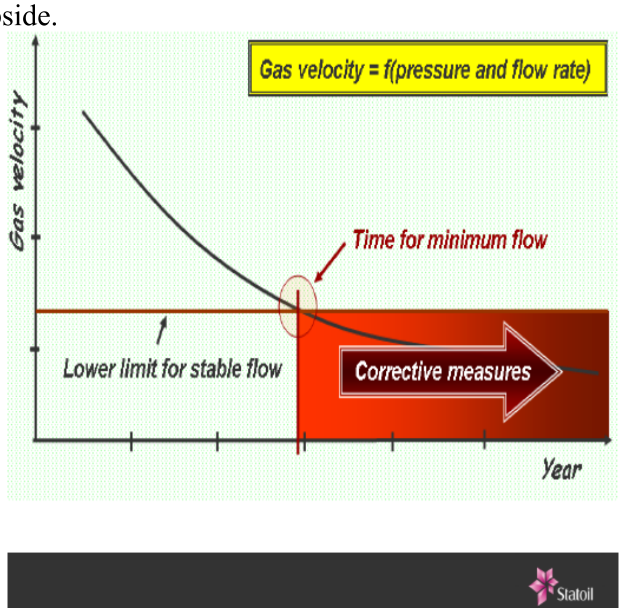


A total rate of 21 E06 Sm3/d of gas flows through the compression station. As indicated in the figure, the discharge is split to two pipelines of 20” (SC-101/Y-101 and SC-102). You can assume that both flowlines are identical and each carries a rate of gas of 10.5 E06 Sm3/d. The approximate elevation profile from the SCMS-A to Åsgard B is given below:



The subsea compressor station has been installed to:

1. Improve recovery from Mikkel and Midgard by adding energy to the fluid and bridge the difference between the required pressure at the discharge and the available pressure at the suction of the compressor station.
2. Also, in gas transportation lines with liquids, it often occurs that if gas rate drops too much, there will be accumulation of liquid in the pipeline. This liquid will eventually block sections of the pipeline, causing pressure surges, and liquid ultimately will be pushed to the topside facilities, which then receives slugs of liquids and gas. This phenomenon is extremely detrimental to the proper operation of the first stage separators topside.



Your main task is as follows:

1. Calculate, using excel, the steady-state pressure and temperature drop along the pipeline (in the sheet "Data" of the provided excel file). Determine if there is a risk for hydrate formation in the pipe. If there is, estimate the proper amount of MEG (in weight% and rate) to inject to avoid it[7]. To calculate the amount of MEG you need to estimate the maximum amount of free water that can be present in the pipeline[8].
   - What is the typical "lifecycle" of MEG on an offshore oil and gas field? Provide some comments regarding MEG recovery, make up and disposal.
   - If MEG injection is required, list what repercussions will this have on the field design.
   - What operational problems can MEG cause in the production system?

Additional information

- **Suggested procedure to estimate temperature drop in the pipeline:**

The energy equation is applied to a pipe section neglecting changes in potential and kinetic energy, i.e.:

$$(h_{in} - h_{out}) \cdot \dot{m} = \dot{Q}$$

For every interval in the pipeline, starting from the discharge of the compressor (co-current calculation), the enthalpy at the exit of the interval can be computed using the equation above. The heat transfer is computed using the temperature difference between the temperature at the inlet of the interval (T_{in}) and the environment (T_{amb}), the overall heat transfer coefficient (U), the pipe inner diameter (ϕ) and the length of the interval (L):

$$\dot{Q} = (T_{in} - T_{amb}) \cdot U \cdot \pi \cdot \phi \cdot L$$

The overall heat transfer coefficient is 180 W/m2 K.[9]

Once the outlet specific enthalpy of the section is calculated at the exit of the pipe interval an interpolation on the PVT table must be performed to find the corresponding outlet temperature that gives such enthalpy. One way to do this in excel is:

1. Guess a temperature at the end of each interval (column D) and calculate the enthalpy by 1) interpolating on the table (using the VBA function "TwoDimInterpol" in column E) and by using the energy balance (apply the VBA function "enthalpy_out" in column H).
2. Then use the solver (or Goalseek) to make both columns equal (drive the error in column "I" to zero).[10] You can do this simultaneously for all intervals or sequentially, starting from the interval closest to the compression station. Use a good initial seed, solver is very sensitive to it.

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[7] The estimation of a new hydrate line with different amounts of MEG is provided in plot "P_T_Hydrate", and the data is on the PVT sheet.

[8] Assume that all water comes from condensation from the gas

[9] This number has been calculated assuming that the pipe is unburied and has no insulation and that the external convective coefficient with the water on the seabed is 200 W/m2 K.

[10] This is already pre-programmed for you in the macro button "solve" on the sheet called "Data". Only specify Start row and end row in cells H7 and H8.

- **Suggested procedure to estimate pressure drop in the pipeline:**

To estimate pressure distribution in the pipe, for each pipeline interval, starting from separator pressure (counter current calculation), use a simple first order integration:

$$p_{in} = p_{out} + L \cdot \left.\frac{dp}{dx}\right|_{p_{out},T_{out}}$$

This equation is programmed in VBA under the name "pin"

The pressure gradient is estimated using the drift flux model:

$$\frac{dp}{dx} = -\left[\rho_g \cdot y_g + \rho_l \cdot (1 - y_g)\right] \cdot g_x - \frac{1}{2 \cdot d}\left[f_g \cdot \rho_g \cdot v_g \cdot v_{sg} + f_l \cdot \rho_l \cdot v_l \cdot v_{sl}\right]$$

Where y_g is the gas void fraction, that is the fraction of the cross section area occupied by the gas. To estimate this quantify, the following equation is used[11]:

$$y_g = \frac{\lambda_g + 1 - \left[(\lambda_g + 1)^2 - 4 \cdot {\lambda_g}^2\right]^{0.5}}{2 \cdot \lambda_g}$$

λ_g is the non-slip gas volume fraction:

$$\lambda_g = \frac{v_{sg}}{v_{sg} + v_{sl}}$$

v_{sg}, v_{sl} are the superficial velocities of gas and liquid, respectively, that are the local rate of gas (q_g) and liquid (q_l) divided by the pipe cross section (A_p):

$$v_{sg} = \frac{q_g}{A_p}$$

$$v_{sl} = \frac{q_l}{A_p}$$

v_g and v_l are the real gas and liquid velocities, defined by:

$$v_g = \frac{v_{sg}}{y_g}$$

$$v_l = \frac{v_{sl}}{(1 - y_g)}$$

To avoid convergence issues when performing your calculations in the excel sheet, it is recommended to assume a pressure in all locations in the pipe (column C) and then, after the temperature distribution is found, calculate the actual pressure using the VBA function in column «S». Then, both columns (C and S) must be same. You can use simple substitution to make them equal.

- Depression of hydrate formation temperature with MEG. The reduction in the hydrate formation temperature (at a given pressure) when adding MEG (in Celsius) is estimated with the Hammerschmidt equation:

$$\Delta T = \left(\frac{2000 \cdot W}{62 \cdot (100 - W)} - 32\right) \cdot \frac{1}{1.8}$$

Where W is the weight percent of inhibitor in the liquid.

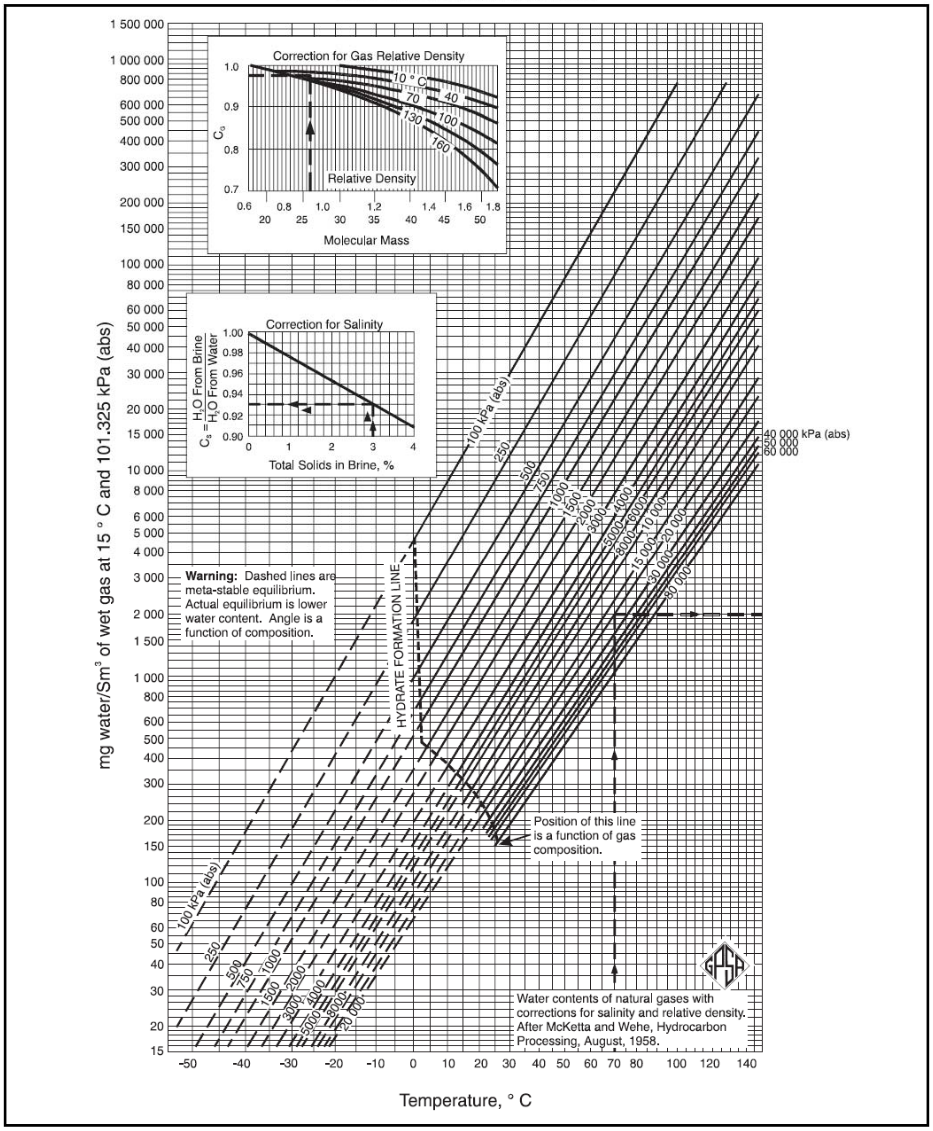
This equation has been programmed in a VBA function called "deltaT".

- The amount of water dissolved in the Gas can be estimated with the McKetta and Wehe Chart.

[11] Anand Nagoo, 2013, PhD thesis, Pipe Fractional Flow Theory: Principles and Applications

FIG. 20-4

Water Content of Hydrocarbon Gas



20-5

This chart gives you the ratio (r_{sw}) between surface water (in kg) and surface gas volume (in 1E06 Sm3) as a function of gas specific gravity, pressure and temperature. This means, if you fully saturate a gas with water at a specific pressure and temperature[12], and you take that gas to standard conditions, it will give you the r_{sw} ratio between surface water and surface gas.

The maximum amount of free water in the pipeline will usually occur at the end of the pipeline, where pressure and temperature are lowest. Therefore, it is recommended for you to find the r_{sw} at reservoir conditions and at the end of the pipeline. The difference

[12] this means the gas cannot take any more water and any extra water added will be free water

between the two multiplied by the standard conditions gas rate will give you the existing free water at that location.
The VBA function “rsw_kg_MCM” is provided instead of reading manually on the graph.

- Interpolate on the property table provided in the sheet “PVT” to find the required fluid properties (e.g. enthalpy, viscosities, densities and mass fraction). To interpolate use the VBA function “TwoDimInterpol”