

Exercise set 01

General orientation for delivery:

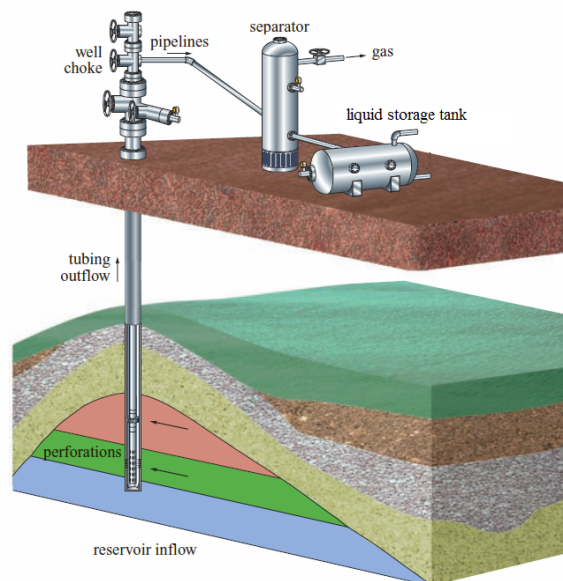
- All answers should be delivered in a pdf report (stating clearly your name). The report should consist of, for each problem, a small description, the methodology, results (on tables and graphs) and short conclusions.
- When converting the word document to pdf make sure to use (in the pdf printer settings) a resolution high enough so figures and plots are still legible.
- Attach all files used to perform your calculations (e.g. Excel files, Hysys files, etc.) when delivering on Itslearning.
- The plots should have a legible and proper size (e.g. 16 pt), axis titles in bold, depicting the variable name, variable symbol and units.

Problem 1: Rough estimation of number of wells required to meet gas contract

A family-owned company has found a small dry gas reservoir in the San Juan Basin. They would like to sell the gas to a local 10 MW power station located a few kilometers away. The power plant requires $80 \times 10^3 \text{ Sm}^3/\text{d}$ of gas and at least a 5 year delivery guarantee to evaluate the proposal.



The company is planning to develop the field using multiple systems of well-choke-pipeline-separator as indicated in the figure below. The pressure of the separators is typically 4 bara. In this arrangement, each well is independent from the others.



You are the youngest son of the president of the company currently studying a year abroad at IPT-NTNU and taking TPG4230. Your father **has asked you to estimate how many wells will they need to meet the 5 year delivery guarantee of 80E3 Sm³/d of gas.**

The following information is available:

-Mathematical expression for Reservoir pressure as a function of cumulative gas production (obtained using dry gas material balance):

$$p_R = 120 \text{ bara} - \left(2.5E - 07 \frac{\text{bara}}{\text{Sm}^3} \right) \cdot G_p$$

-Mathematical expression for single well gas production potential as a function of reservoir pressure (obtained using the dry gas wellhead performance relationship):

$$q_{pp} = \left(5 \frac{\text{Sm}^3 / d}{\text{bara}^2} \right) (p_R)^2 - \left(3E - 11 \frac{\text{Sm}^3 / d}{\text{bara}} \right) p_R - 80 \frac{\text{Sm}^3}{d}$$

Your tasks are:

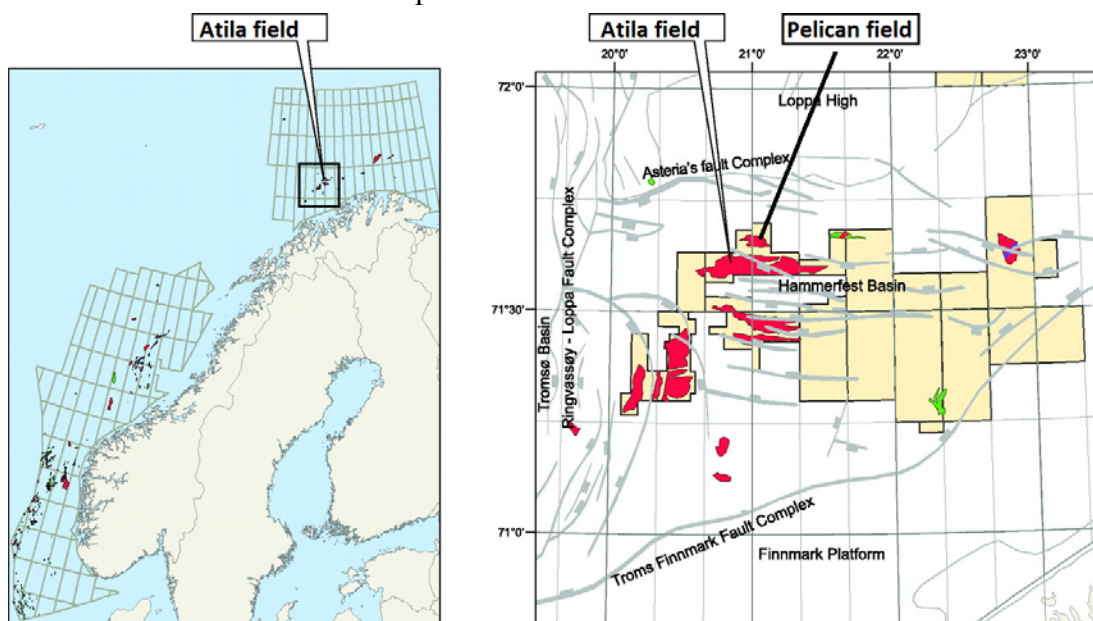
- Estimate the minimum number of wells that have to be drilled to guarantee the supply of 80E3 Sm³/d of gas for at least 5 years.
- Using the number of wells estimated above, calculate the full production profile (plateau+decline period) until reservoir pressure reaches 40 bara. Plot your results in a graph.

Assumptions:

- Assume that a “year” consists of 355 operational days.
- Assume that each well behaves independently from the others.

Problem 2: Preliminary production scheduling studies for a newly discovered offshore gas field

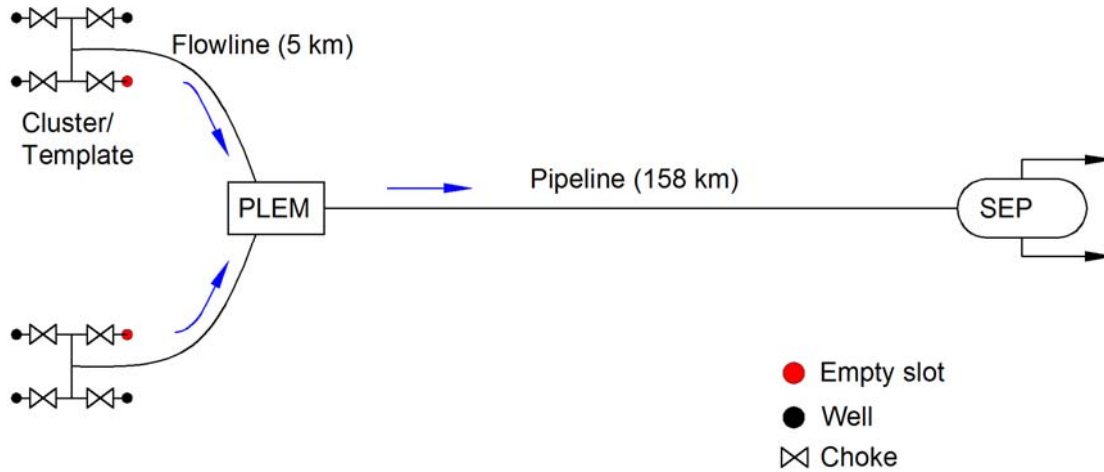
The Atila field is a gas field recently discovered offshore Hammerfest, in the Barents Sea. The initial gas in place is estimated in 2.7E11 Sm³ and the initial reservoir pressure is 276 bara. The field will produce a constant flow rate to a LNG plant on shore in Hammerfest and ship it further to customers in the US and Spain.



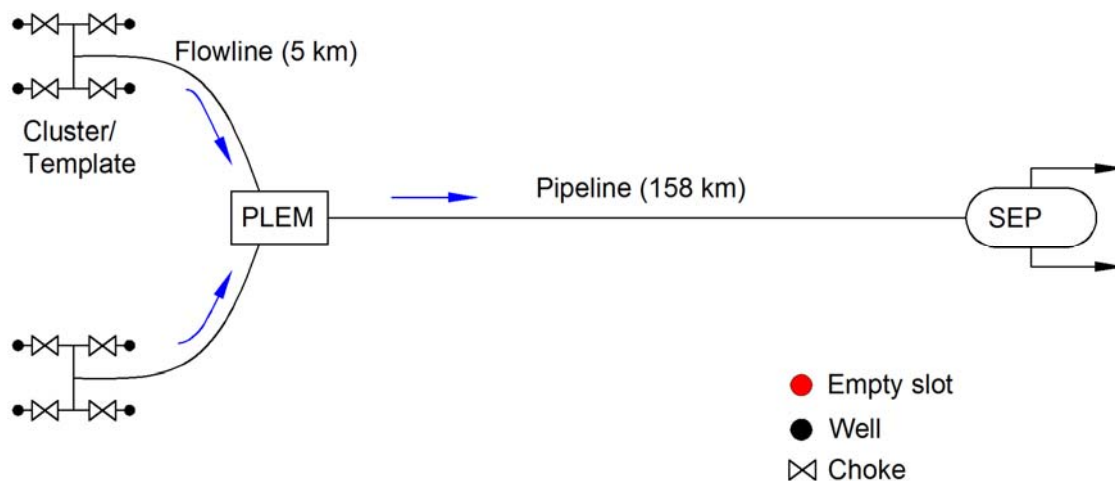
You have to perform a study on production scheduling for the Atila field. **The management wants you to estimate the plateau duration for field production rates of 20E6 Sm³/d, 25E6 and 30E6 Sm³/d and to determine the post-plateau production profile until abandonment. Your results will be used to send a proposal for long-term sales agreement with the customers.**

There are three proposals for producing the field:

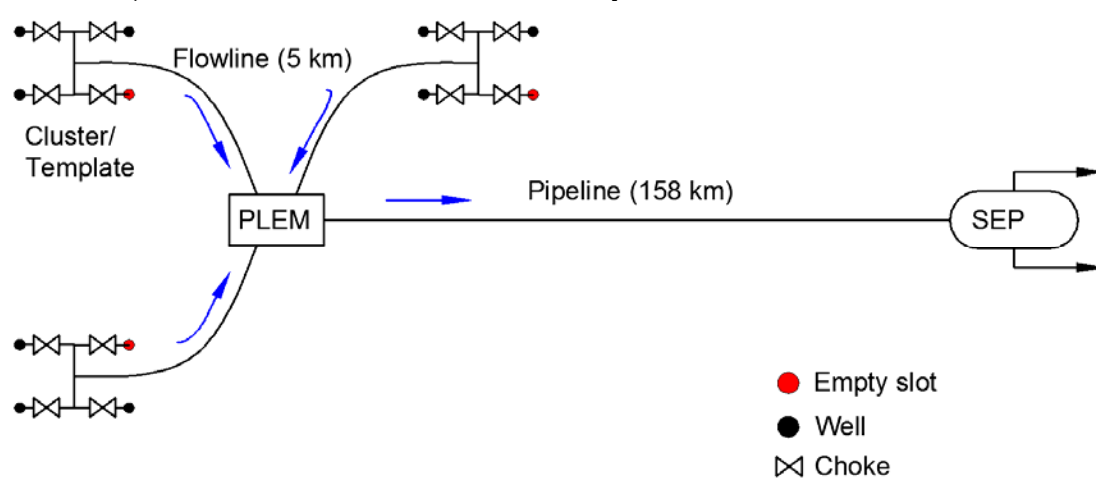
Case a) 6 wells distributed in two templates



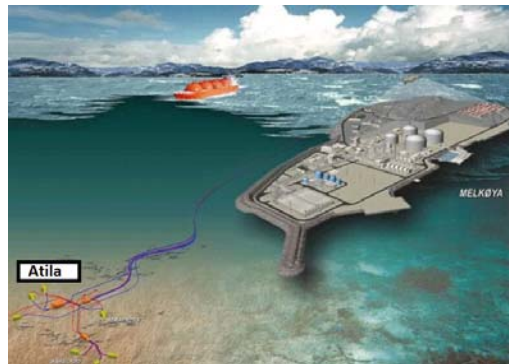
Case b) 8 wells distributed in two templates



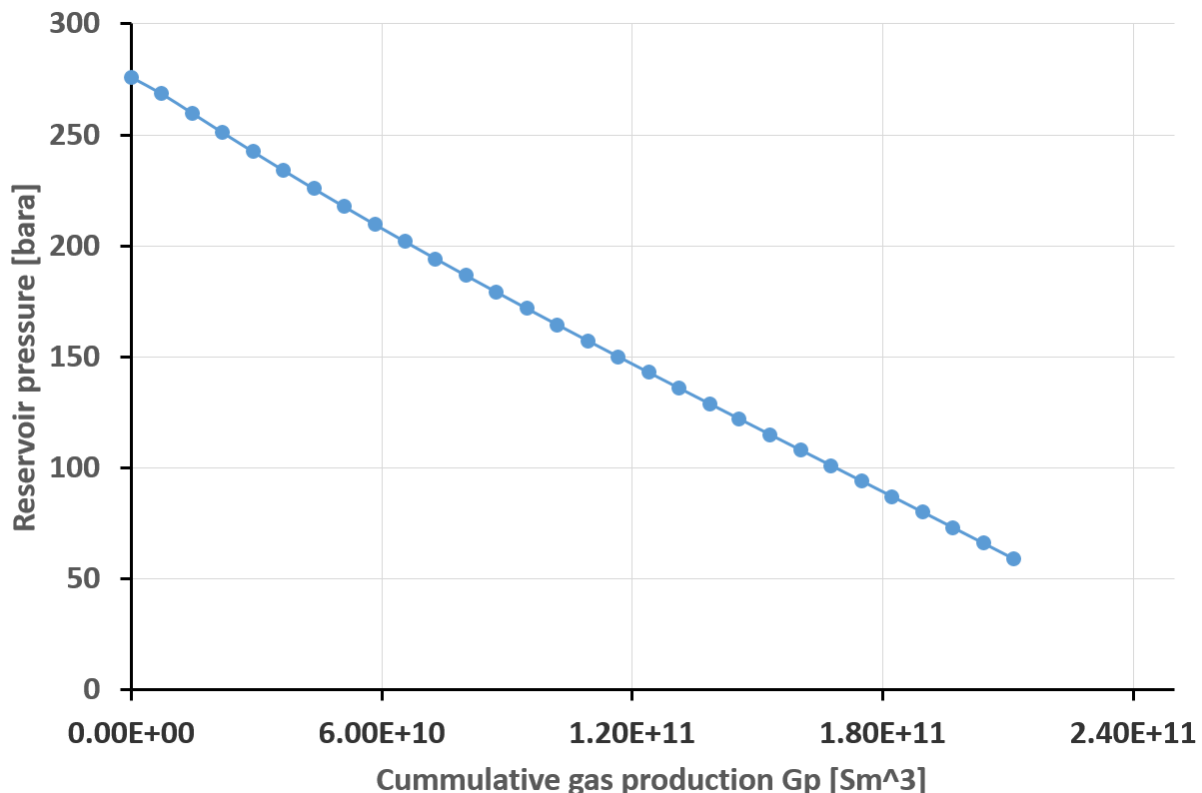
Case c) 9 wells distributed in three templates



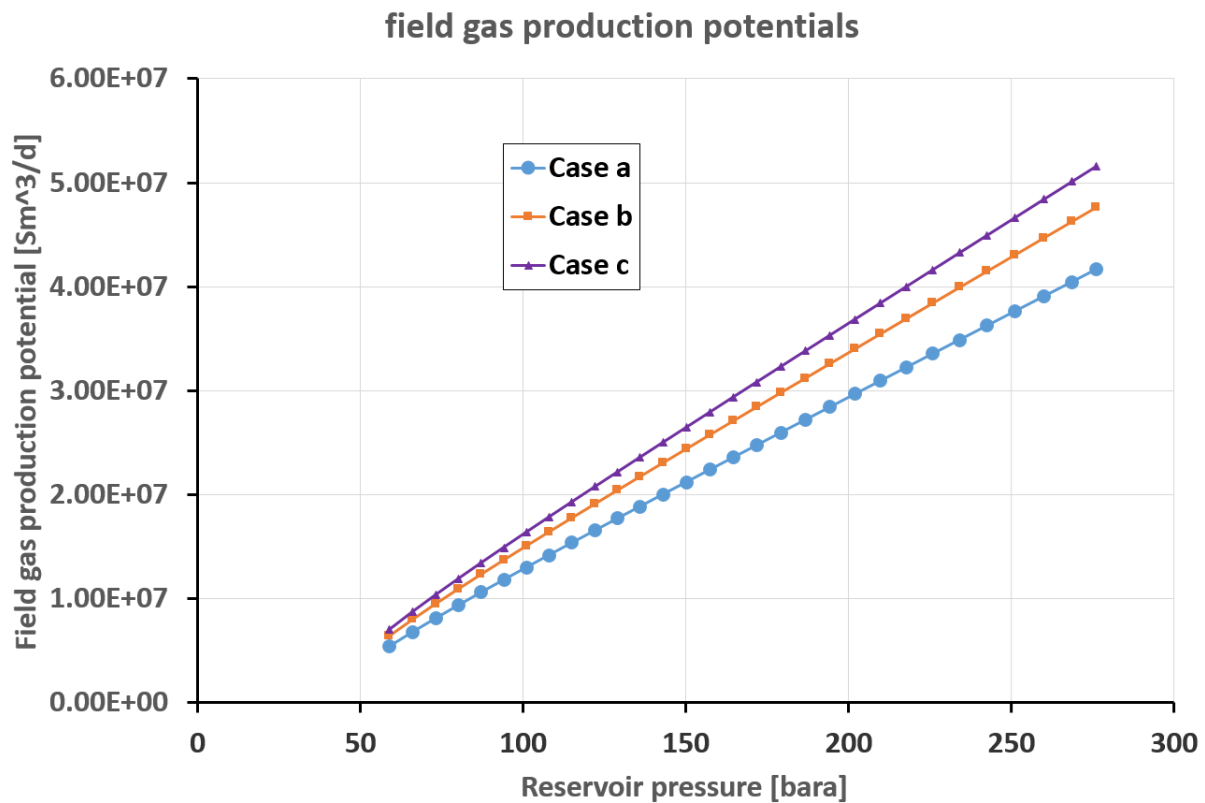
In all cases the field is completed subsea with subsea templates, each with 4-slots (well bay). For each case there is a different number of wells completed on each template. The templates are symmetrically positioned at 5 km away from the subsea Pipeline Entry Module (PLEM). Each template is connected by flow line to the PLEM where the production streams of all the templates are commingled (combined and mixed). The PLEM is on the seabed approximately 158 km from shore and is connected by the main field export pipeline to the slug catcher (separator) on shore. As a first approximation and considering that no data is available at this stage, consider that wells are identical (in structure and productivity and all other design and operation parameters) producing from the same reservoir.



The reservoir engineering department has created a dry gas material balance model of the reservoir and obtained the following behavior of reservoir pressure vs. cumulative gas production:



The production engineering department has calculated the field production potential (wells with fully open choke) for cases a), b) and c) for each reservoir pressure using an approximated model of the production network.



The data points of these two plots are provided in an attached excel file.

Your tasks are:

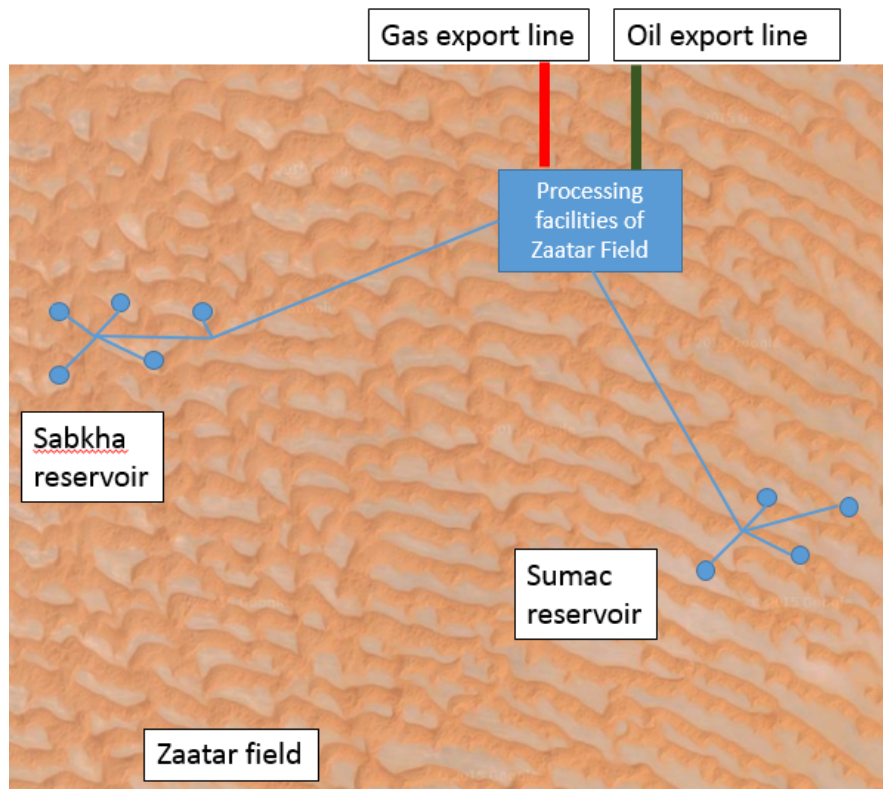
-To compute plateau duration for field production rates of 20E6 Sm³/d, 25E6 and 30E6 Sm³/d and to determine the post-plateau production profile until abandonment for the three proposals for development. Provide the plateau duration in a table and the production profile in plots.

Assumptions:

- Assume that a “year” consists of 355 operational days.
- Perform a linear interpolation in the points given if necessary.

Problem 3: Production scheduling studies for two onshore fields.

The onshore Zaatara field consists of two separate reservoirs (Sabkha and Sumac) that are produced through independent pipelines to the processing facilities. The two oils have very different APIs (Sabkha has 36 API and Sumac has 27 API) and the two oils are blended at the processing facilities. The resulting oil is marketed under the name of Zaatara crude (similar to the Arabian light crude, see the sales specs attached). In order to be accepted for further processing at the refinery, the crude has to have a minimum of 31.8 API.



The reservoir management team of the company proposed to produce 130E3 stb/d from Sabkha and 40E3 stb/d from Sumac to meet a plateau of 170E3 stb/d. The decision was based on some reservoir simulations and on the fact that, at initial conditions, Sabkha can deliver a higher rate than Sumac and because Sabkha has oil of a “better quality”(i.e. higher API) than Sumac.

The total oil production potential of each individual reservoir versus its cumulative oil production can be calculated with the linear expression:

$$q_{pp} = q_{ppo} - m \cdot N_p$$

Where the values for Sabkha and Sumac are summarized in the table below:

Reservoir	q_{ppo} [stb/d]	m [1/d]
Sabkha	250E3	7E-4
Sumac	200E3	5E-4

The producing GOR of each individual reservoirs can be expressed as a function of the cumulative oil production with the polynomial expression:

$$GOR = a \cdot (N_p)^2 - b \cdot N_p + c$$

Where the values for Sabkha and Sumac are summarized in the table below:

Reservoir	a [scf/stb ³]	b [scf/stb ²]	c [scf/stb]
Sabkha	5E-14	5E-8	800
Sumac	1E-14	5E-8	500

Task 1: compute the production profile, API and GOR of the Zaatar field for both the plateau and production decline phase, until the field rate drops to 50 E3 stb/d with the production strategy proposed by the reservoir management group. Report your results in plot(s). Flag periods where the API falls below sale specs.

Assumptions:

-Assume that volumes are additives and that the field API can be calculated with a mass weight average of the Sabkha and Sumac fields.

During the first days of production, the reservoir team realized that the Zaatara crude is actually producing with two degrees API higher than required by specs. They also realized, based on the results of task 1, that the Sabkha reservoir enters in decline much sooner than the Sumac reservoir. In consequence, they now think that the production strategy must be reviewed in order to produce more from Sumac and less from Sabkha.

Task 2: Propose an optimal production strategy to maximize plateau length of the field while ensuring that the API is kept within specs **during the plateau period**. Compute the production profile and API of the Zaatara field for both the plateau and production decline phase, until the field rate drops to 50 E3 stb/d with your new production strategy. Report your results in plot(s) comparing with the base case. Flag periods where the API falls below sale specs.

Task 3: What is the optimal offtake from Sabkha and Sumac that maximizes plateau length if the resulting API wasn't an issue?

Assumptions:

-A year has 355 operational days
-Estimate the resulting API using a mass weight average.

Problem 4: Production system layout of a subsea satellite field;**Field Description**

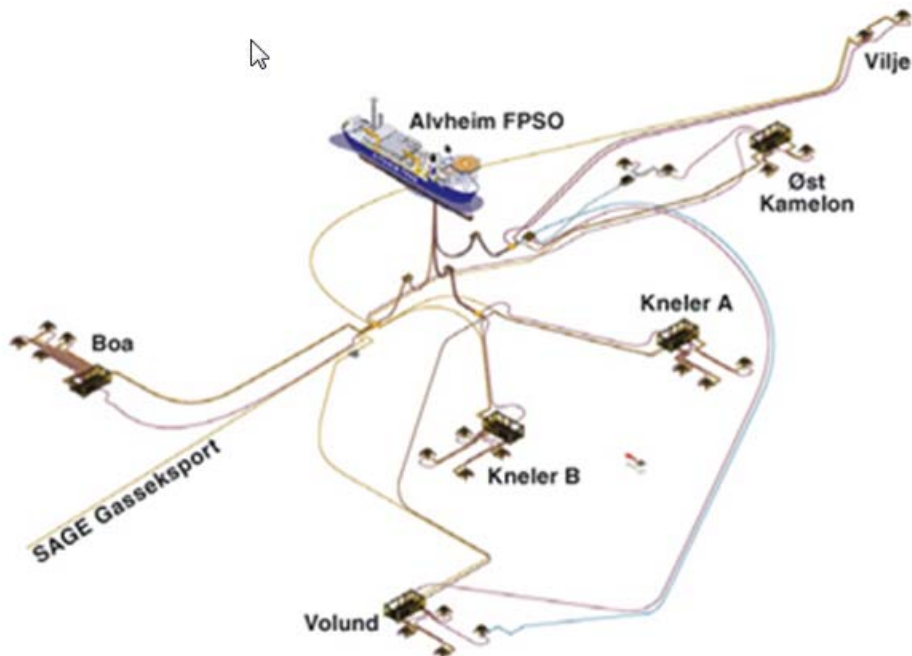
Volund is a subsea oil field, at 130 m water depth, located about 10 kilometers south of the Alvheim FPSO in the central part of the North Sea (see figure). The field, with reservoir depth of 2000 m, is developed as a subsea Satellite field to the Alvheim FPSO (Floating Production, Storage and Offloading 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 manifold 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 vessel. On the vessel there are a one test separator and one production separator train dedicated entirely to the Tolund 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 a development plan you need to perform the following tasks:

1. Propose a simple 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 (Wellhead 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



Exercise set 02

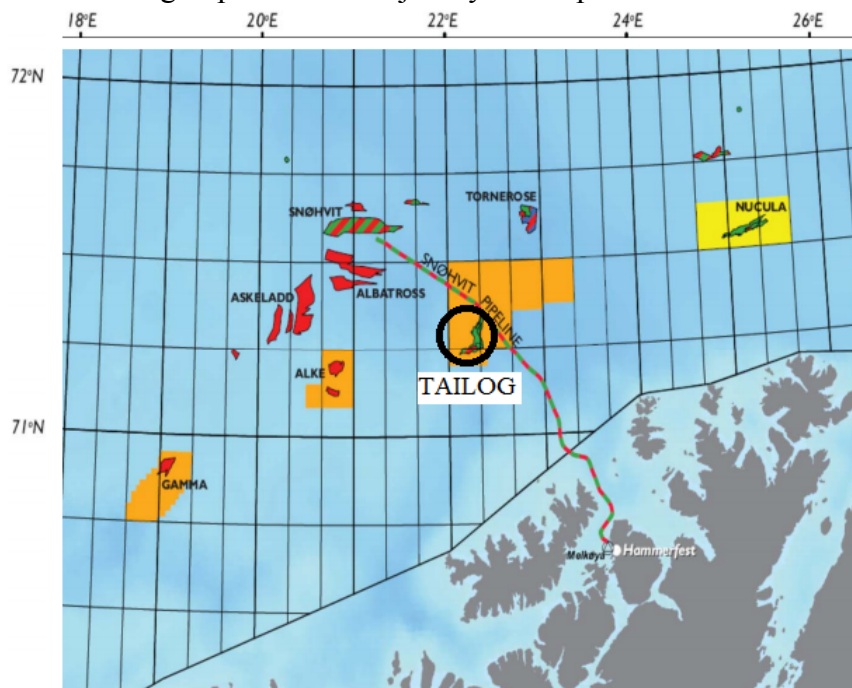
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PROBLEM 1:

Part 1: Probabilistic estimation of Total Recoverable Reserves

The INE company has found two reservoirs in the Barents sea, Realgrunnen and Kobbe, 50 km south of the Snøhvit field and 80 km from the LNG plant of Snøhvit in Hammerfest (Melkøya). The water depth in the area is 360 – 420 metres and, luckily, is an “ice-free” area. The company is evaluating to produce them jointly and baptized the field: “Tailog”.



Both reservoirs contain oil with a thin overlying gas cap. The Realgrunnen formation lies approximately 1100 metres beneath the sea surface, while the Kobbe formation is at approximately 1800 metres depth. The static reservoir pressure is 120 bar for the Realgrunnen and 190 bar for the Kobbe formation.

As part of the early development studies and as required by the Norwegian authorities, your first task is to perform a probabilistic estimation of the total recoverable reserves of the Kobbe reservoir. The subsurface group has provided (in the table below) information on the factors needed to calculate hydrocarbon pore volume, and the reservoir engineering group the formation volume factor (all based on a triangle probability distribution).

			Net to Gross	Oil Saturation	Oil Formation Volume Factor
	Rock volume (V_R)	Porosity(ϕ)	N_{TG}	$S_o=(1-S_w)$	B_o
	bbl	fraction	fraction	fraction	Res bbl/stb
Min (a)	2.00E+09	0.18	0.3	0.80	1.35
Mode (c)	2.30E+09	0.24	0.4	0.85	1.45
Max (b)	2.50E+09	0.30	0.5	0.90	1.60

There is disagreement within the company with respect to which ultimate recovery factor (F_{RU}) distribution to employ. A senior reservoir engineer A says that an optimistically skewed triangle distribution should be employed as shown in the table below. Another senior reservoir engineer B says that a more conservatively skewed triangle distribution should be used as shown in the table below.

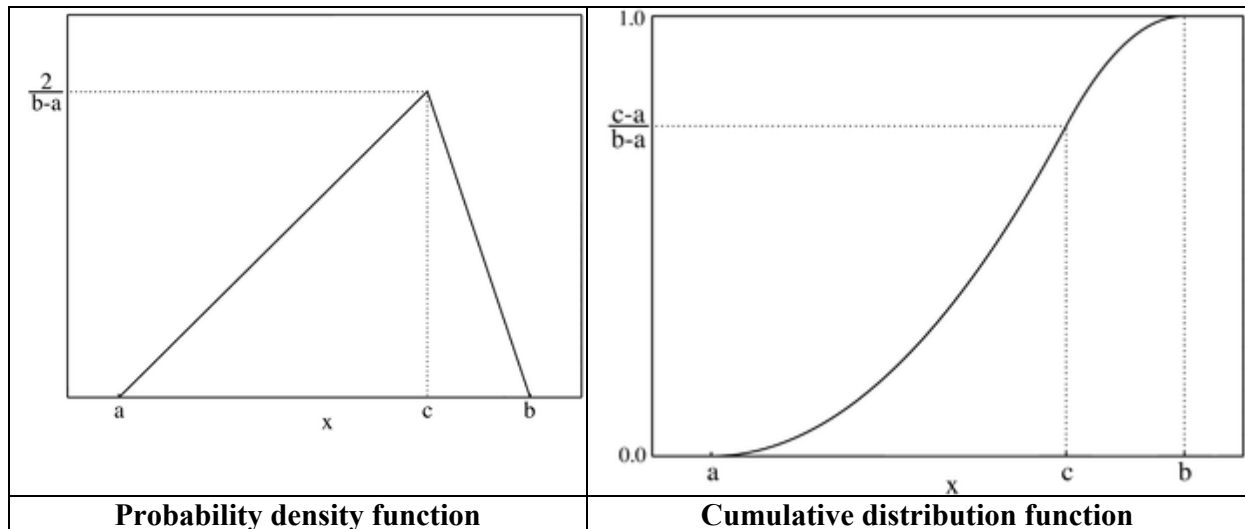
Reservoir engineer	Min(a)	Mode(c)	Max(b)
A	0.35	0.57	0.65
B	0.35	0.42	0.65

Assumptions and extra information:

Use the following equation to calculate total recoverable reserves (TRR):

$$TRR = N_{PU} = N \cdot F_{RU} = \frac{V_R \cdot \phi \cdot (1 - S_w) \cdot (N_{TG})}{B_o} \cdot F_{RU}$$

All the input information given is uncertain and reported as a triangular distribution (Min, Mode, Max). The details of the triangular distribution are shown below:



The probability density function is described by the following piecewise function:

$$f(x|a, b, c) = \begin{cases} \frac{2(x-a)}{(b-a)(c-a)} & \text{for } a \leq x \leq c \\ \frac{2(b-x)}{(b-a)(b-c)} & \text{for } c \leq x \leq b \\ 0 & \text{otherwise} \end{cases}$$

If a probability U is randomly chosen between the interval $(0,1)$, the value of the variable (X) can be calculated using the following piecewise function:

$$\begin{cases} X = a + \sqrt{U(b-a)(c-a)} & \text{for } 0 < U < F(c) \\ X = b - \sqrt{(1-U)(b-a)(b-c)} & \text{for } F(c) \leq U < 1 \end{cases}$$

Where: $F(c) = (c-a)/(b-a)$

Tasks:

-Perform a Monte Carlo Simulation Study (using 6000 simulations) to obtain the expected value of the Total Recoverable Oil Reserves. Report the outcome as:

- Expected value (Mean or Average)
- Median (P50) , P10, P90
- Expectation curve for the Total Recoverable Oil Reserves (Plot of Cumulative Probability)

The study should be performed separately for both F_{RU} distributions provided (senior reservoir engineer A and B). How different are the values estimated?. Is there any difference in the expectation curves for TRR?

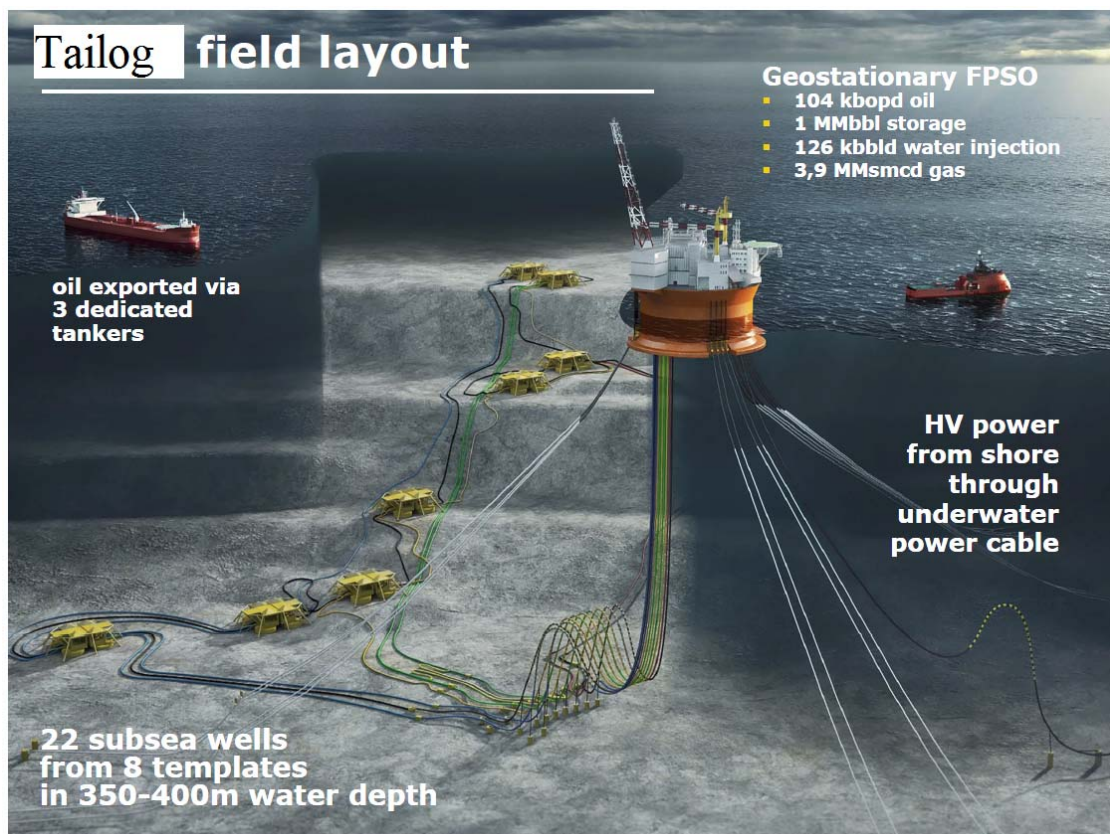
Part 2:

Time has passed and the INE company is conducting a study on feasible development scenarios as a pre-step to select the best case and prepare the Plan for Development and Operations.

The field will be produced in plateau mode with 100 000 stb/d of oil and a total recoverable reserve estimated of 180 E6 stb. The average producing GOR (gas-oil ratio) is 1600 scf/stb and WC (water cut) is 20%.

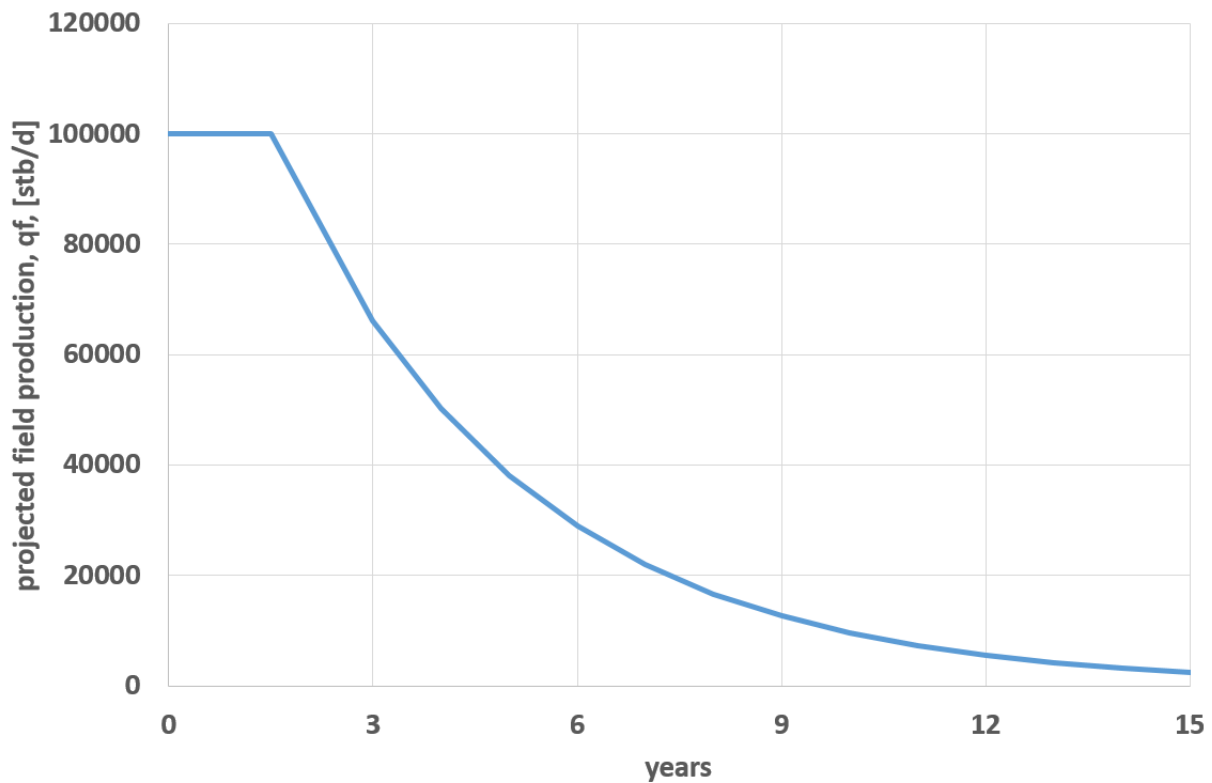
Your main task is to perform a simplified economical evaluation (NPV calculations) of the two scenarios currently under consideration to develop the field:

Alternative 1: Subsea wells in templates and production to Sevan (circular) FPSO with risers



In this development alternative, the field will be produced for 15 years. The oil will be distributed to the market using tankers. All the produced water will be reinjected for pressure support. The gas will be reinjected into the Kobbé reservoir because, at the moment, there is no solution to distribute it to the market.

The figure below shows the expected production profile for this field development strategy.



The field will be developed with 22 wells, 11 oil producers, 2 gas injectors and 9 water injectors. The wells are subsea, perforated from 8 templates: 4 for production wells, 3 for water injection wells and 1 for gas injection.

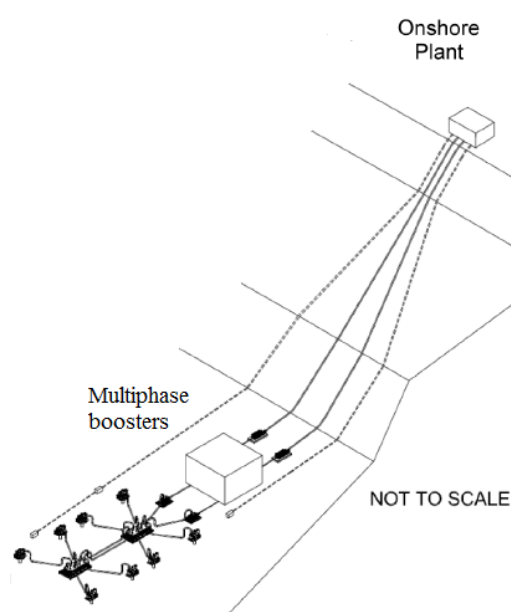
All wells will be drilled in a period of 4 years (with an average duration of drilling and completing of 2 months). The average cost per well (including perforating, completing and well equipment) is 150 E6 USD (in 2016 dollars). Usually there is a constant annual increase of 5% on this value.

The annual operating cost (OPEX) is 200 E6 USD (in 2016 dollars).

The cost of the Sevan type FPSO is 1.1 E9 USD (in 2016 dollars), it will be commissioned upfront at the beginning of the project and the total time until delivery on site is 4 years.

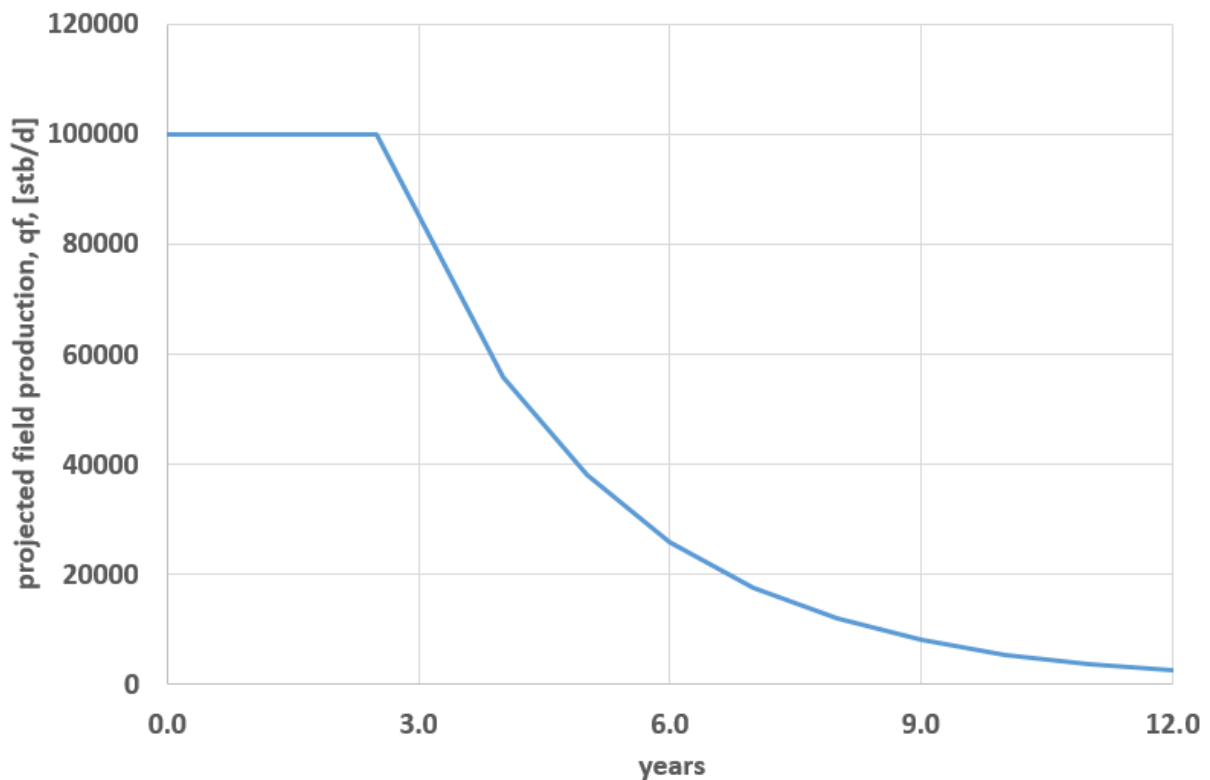
Other CAPEX costs like materials and installation of the risers, umbilicals and subsea manifolds can be neglected in this alternative.

Alternative 2: Subsea wells in templates and production to shore using multiphase boosters



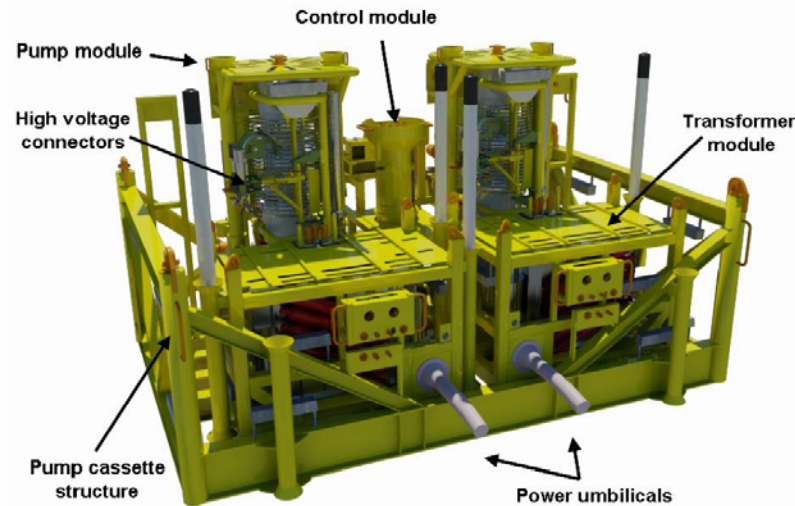
In this development alternative, the field will be produced for 12 years. The oil gas and water will be transported to shore using two multiphase boosters and the processing will take place onshore. The gas will be processed in the LNG plan in Melkøya and sold further to customers in Spain and in the US.

The figure below shows the expected production profile for this field development strategy. The plateau has been extended slightly with the usage of subsea boosters and the recovery has been accelerated in 3 years.



The field will be developed with 20 wells, 11 oil producers, and 9 water injectors. The wells are subsea, perforated from 7 templates: 4 for production wells and 3 for water injection wells. As water is required to be injected into the formation and provide pressure support a Subsea Raw Seawater Injection (SRSWI) unit will be installed. The approximate cost of the unit is 100 E6 USD (in 2016 dollars).

SRSWI Pump Cassette



Other relevant data:

- Cost of umbilicals (manufacturing, transport, laying and installation) and power lines: 100 E6 USD
- Cost of Pipelines from boosting station to shore (design, manufacturing, transport, laying and installation): 150 E6 USD
- Subsea pumps (design manufacturing, testing, deployment and installation): 150 E6 USD per each pump
- Cost of onshore processing plant: 180 E6 USD
- The annual operating costs (OPEX) is 200 E6 USD

All costs are given in 2016 dollars.

Your tasks are:

Prepare a Gantt chart with the timeline of the most relevant events (i.e. drilling of wells, deployment of FPSO, construction of processing facilities, production startup, etc) for each development alternative.

Calculate the annual revenues, DRILLEX, CAPEX, OPEX, total cost, cash flow, the discounted cash flow, and NPV **of the two development alternatives** for the Tailog field. Based on your calculations, which one is the best alternative?. Present your results on a table and plot revenues, expenses, discounted cash flow and cumulative NPV vs. time (not on the same plot).

Perform a sensitivity analysis on the total cumulative NPV of the project considering the following variations

- $\pm 30\%$ variation in the oil price
- $\pm 30\%$ variation in the well cost price

- $\pm 30\%$ variation in the Sevan FPSO price
- $\pm 30\%$ variation in the OPEX
- Delay of the production startup in 1 and 2 years.

Plot your results in a spider plot for both development alternatives.

How would you include uncertainty in your NPV calculations?

General assumptions for your calculations

- Neglect the buildup period of the plateau (i.e. assume that all wells enter in production at the same time).
- Oil price: 40 USD/stb
- Gas price: 2 USD/E3 scf
- Assume that all CAPEX are executed during the first two years of the projects.
- Assume that the project starts in 2016.
- Employ a yearly discount rate of 8%

Suggestions and recommendations:

- Calculate the cumulative production of each year using the trapezoidal method.
- Extract the values of the production profile plot using the following datathief application: <http://arohatgi.info/WebPlotDigitizer/>
- The cost values given are purely referential and should be used cautiously. If an inconsistency is detected or you have obtained information from a trustworthy source, feel free to modify the input.

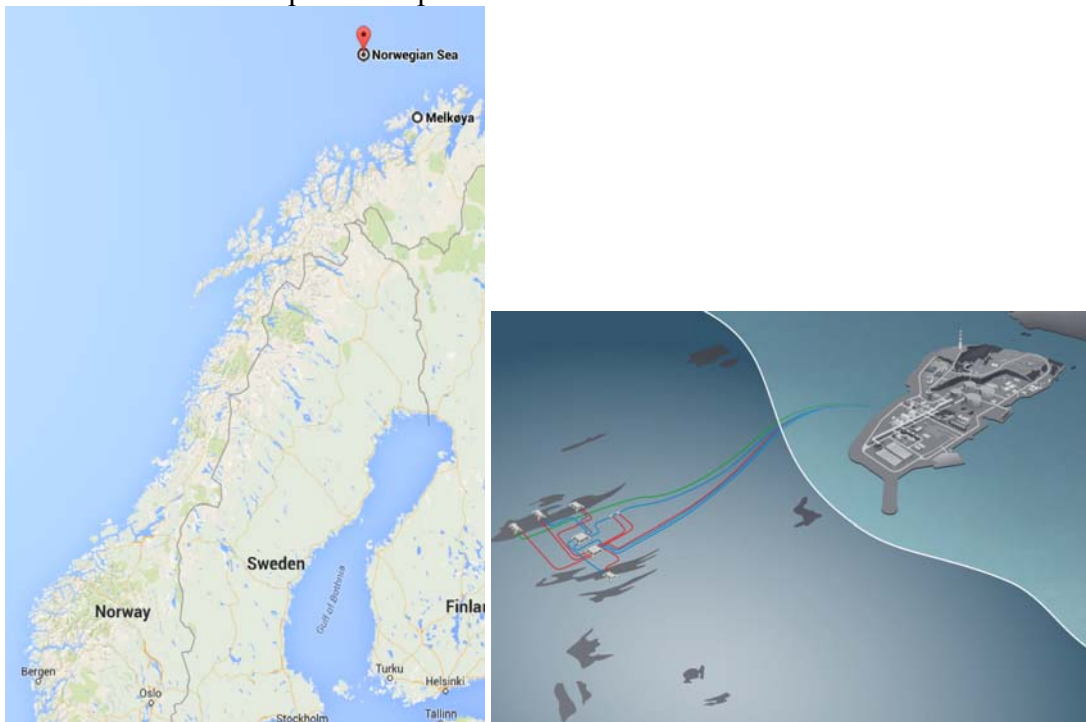
Exercise set 03

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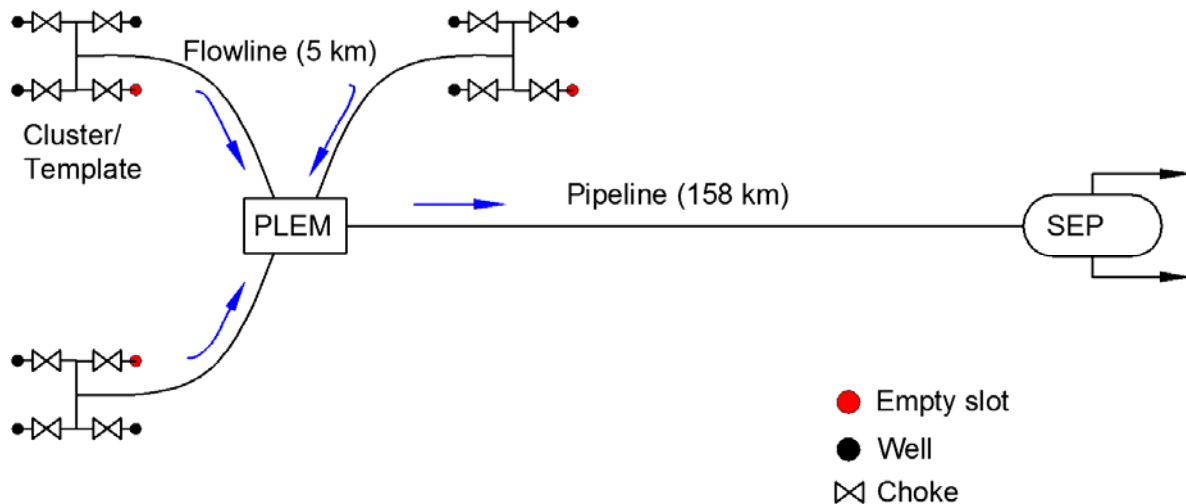
PROBLEM 1: Determining optimum number of wells to maximize NPV

The Atila East is an offshore gas field located in the Barents sea 158 km from Hammerfest currently under development. The field will be developed with the “subsea to beach” concept. The gas production will be taken by a LNG plant and transported further in LNG carrier to customers in US and Spain. The plateau rate of the field has been set to 20E6 Sm³/d.



According to the base case Scenario (BCS) selected for the study, the field is completed subsea with three subsea templates, each with 4-slots (well bay). Only three wells are completed in each template. The templates are symmetrically positioned at 5 km away from the subsea Pipeline Entry Module (PLEM). Each template is connected by flow line to the PLEM where the production streams of all the templates are commingled (combined and mixed). The PLEM is on the seabed approximately 158 km from shore and is connected by the main field export pipeline to the slug catcher (separator) on shore.

All the wells are identical (in structure and productivity and all other design and operation parameters) and produce from the same reservoir (tank model).



Your company (Liotats) wishes to analyze the impact of the number of wells in the NPV of the project (as explained by Haldorsen, see the “additional information” section below) These are your tasks:

- Using the attached excel spreadsheet calculate the plateau length of the field and production profile (until the field gas rate reaches a minimum economical rate of 5 E06 Sm³/d) for the following cases:

Case N	Nwells	Ntemplates
1	6	2
2	8	2
3 (BCS)	9	3
4	12	3
5	12	4
6	15	5
7	16	4
8	18	6
9	24	6

In order to keep symmetry, assume that every template is symmetrically positioned from the PLEM and that every template has the same number of wells.

- Use the NPV calculation template (attached excel sheet) to estimate the total NPV of each project by inputting the yearly gas outtake, the drilling costs and the number of years. Assume that only 5 wells can be drilled per year and that production starts after the LNG plant is installed (year 7). Plot the cumulative NPV vs time for all cases (each one in a separate chart).
- Plot:
 - Ultimate recovery factor vs number of wells.

- b. NPV vs number of wells.
- c. Breakeven time vs number of wells

Do the plots follow the trend described by Haldorsen? Why?.

Based on these plots, and knowing that a plateau of 22 years is required, choose the optimum number of wells to use and justify your answer.

- 4. When comparing cases 4 and 5. What is best? To have the same number of wells but with more templates or with less templates?.

Assumptions in the solution approach:

- Assume dry gas flow equations, dry gas tank model material balance, and no condensation in the entire system
- All wells, templates, and infield flow lines are symmetric in configuration and capacity
- You may use the uploaded VBA calculators (Flow, Mbal, Zfact)
- The cost of each well (drilling, completion, equipment, etc.) is 180 E6 USD. Assume that this value doesn't change with time. Maximum 5 wells can be drilled per year.
- OPEX: 120 E6 USD per year (from year 7). Assume that this value doesn't change with time.
- The field produces some associated condensate. The revenue from condensate sales should be included in the NPV calculation. The Condensate Gas Ratio (CGR) is 1.5E-4 Sm³/Sm³.

Atila gas Field (Base Case Data)		
G=IGIP	270.00E+09	Sm3
Production days per year	365	day
T _R	92	oC
Pi, initial Res pressure	276	bara
C, inflow Back pressure coefficient	1000	Sm3/bar^2n
n, backpressure, exponent	1	
Ct, Tubing coefficient (2100 MDx0.15 ID m)	4.03E+04	Sm3/bar
Elevation coeff, S	0.155	
C _{FL} Flowline Template-PLEM (5000x0.355 ID m)	2.83E+05	Sm3/bar
C _{PL} Pipeline PLEM-Shore (158600x0.68 ID m)	2.75E+05	Sm3/bar
Separator (slug catcher) pressure	30	bara
Gas molecular weight (Methane)	22	kg/kmole
Gas specific gravity	0.76	Gas specific gravity
Number of template	3	
Number of wells	6	
Desired plateau	20	years
q _{field}	20.0E+6	[Sm^3/d]

<p>Material balance:</p> $p_R = p_i \left(\frac{z_R}{z_i} \right) \left(1 - \frac{Gp}{G} \right)$	<p>Horizontal Pipeline and flowline equation Horizontal</p> $q_{sc} = C_{FL} (p_m^2 - p_{out}^2)^{0.5}$
<p>Inflow equation:</p> $q_{gsc} = C_R (p_R^2 - p_{wf}^2)^n$	<p>User define function for calculating Z factor: Z factor: $Z=f(P_R, T_R, \gamma_g)$</p>
<p>Tubing equation</p> $q_{gsc} = C_T \left(\frac{p_{in}^2}{e^s} - p_{out}^2 \right)^{0.5}$	

Additional information:

Taken from the article: «Choosing between rocks, hard places and a lot more: the economic interface” by Helge Haldorsen.

Plateau rate

Several plateau rates for a field should be tried (Fig. 21a). The number of wells should be varied for each choice of plateau rate to see how the NPV (Fig. 21b) and the recovery factor (Fig. 21c) are affected. Even if the recovery factor often increases as the number of wells is increased, a case of diminishing return is often evidenced (Fig. 21c). This is due to the fact that the last ‘new’ wells do not produce enough oil to pay for the added expense of including

them (perhaps the whole development concept must be changed from a ship to a GBS as the number of wells goes from 18 to 45). A plot of NPV against the number of wells and/or the plateau rate will often exhibit a maximum value (Fig. 21b). A plot of the recovery factor (at a fixed time, for a fixed number of wells) against plateau rate will demonstrate if rate sensitivity is a problem (Fig. 21d). If this is the case, the number of wells may be increased, which in turn will increase costs, and the search continues.

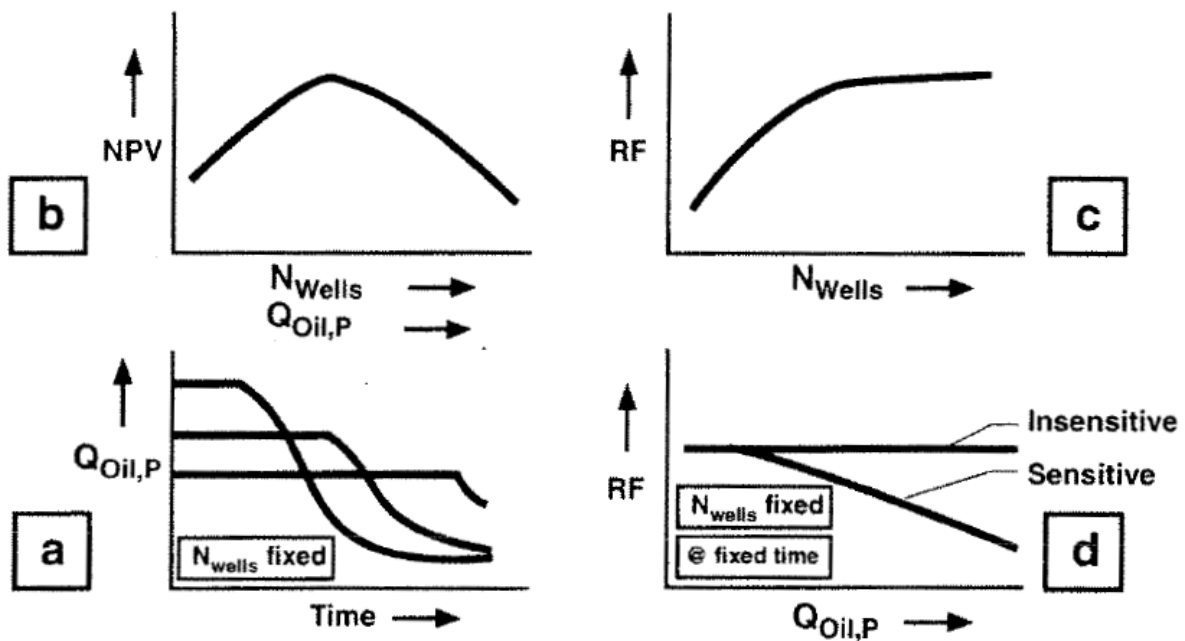
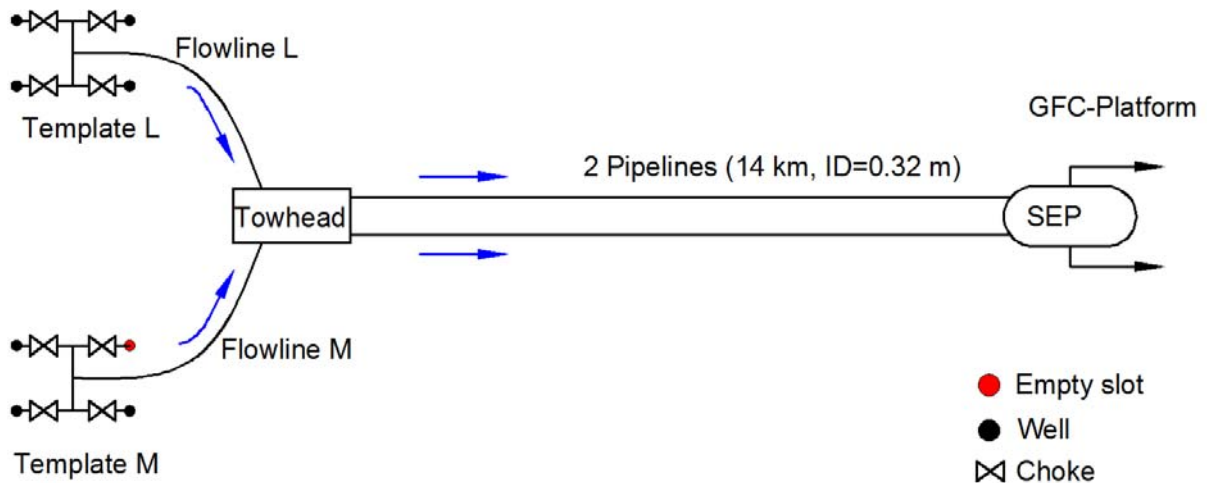
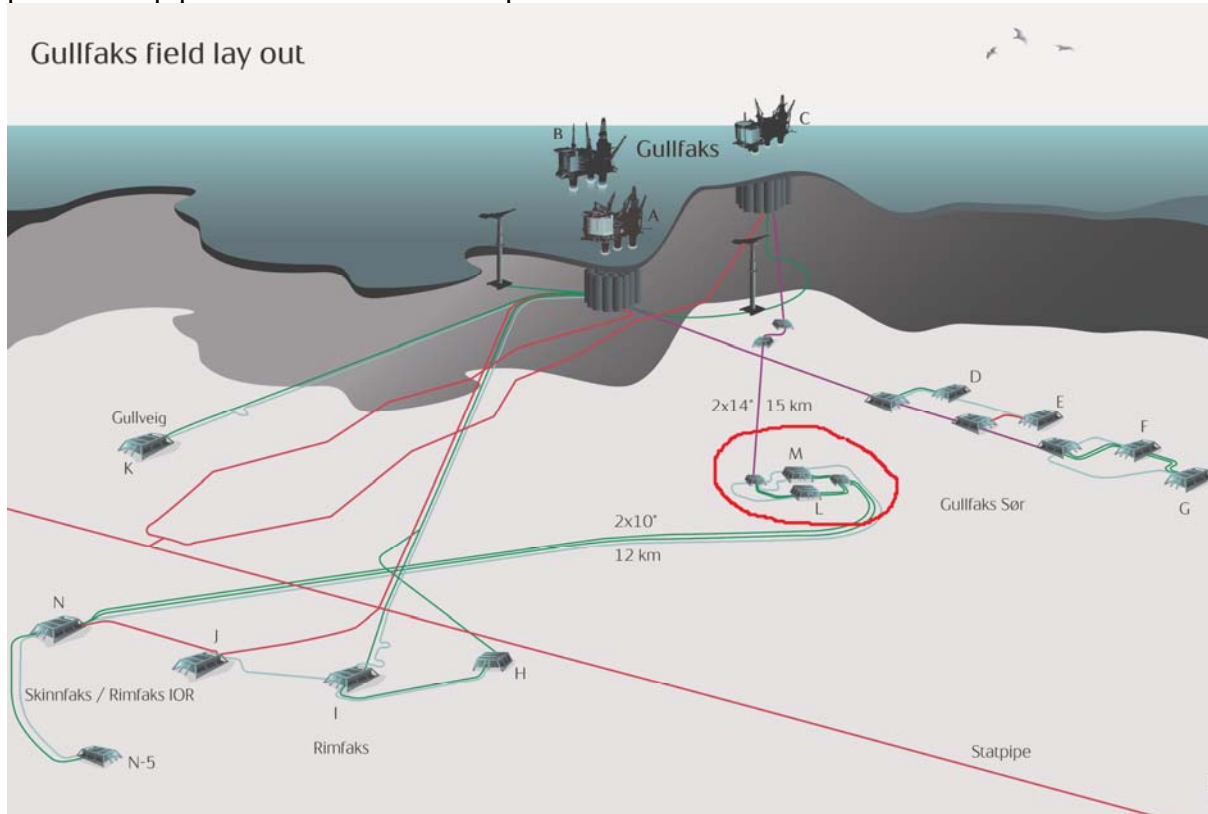


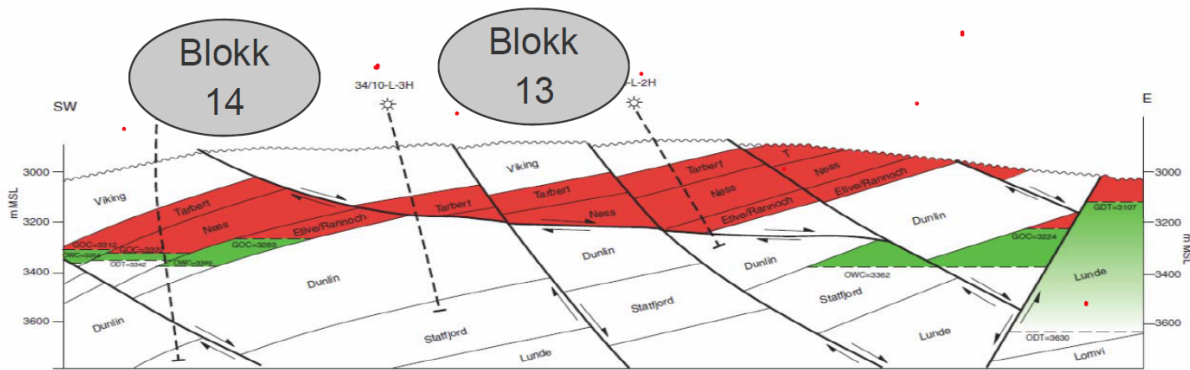
Fig. 21. Optimization methodology.

PROBLEM 2:

Two reservoir units in Gullfaks South field (Block 13 and Block 14) have been producing oil and gas since 1999 by two subsea templates (Template L and M). The production is commingled in a manifold (called “Towhead”) and is transported further using two identical production pipelines to the Gullfaks C platform.



Due to the depletion of the oil layer in the formations, the wells from templates M and L have been recompleted in 2009 to produce liquid rich gas. The liquid comes from gas condensate in one formation and from mobile liquid oil in the bottom of the reservoir of the other formation. From 2009, the field is produced in plateau mode with a total rate of 10 E6 Sm³/d.



Your main task is to develop an excel sheet to calculate the length of the production plateau and compute post plateau production profile. The reservoir and production management team will employ these results later to: 1. Tune the resistance coefficients to reproduce historic production data and 2. Analyze the impact of introducing subsea compression.

Being a preliminary study, considerable simplification assumptions will be used:

- The gas is dry, its depletion and recovery characteristics can be modeled by reservoir tank model
- The flow in the wells and the pipeline can be represented by isothermal flow equations.
- Consider that all wells in each template are identical (i.e. produce the same, so it is necessary to model only one well).
- Wells are equipped with wellhead chokes to adjust the rate when required.

The table below (given in the the attached excel sheet) contain all the data necessary to run your calculations.

Gullfaks South L-M satellite system	East Tank	West Tank		
Pre-compression Phase, ignores liquid production (Start Jan 2009)	L-Template	M-Template		
	Fault Block 13	Fault Block 14		
	Brent Formation	Brent Formation		
G=GIIP-Gas cap (31 December 2008)	54.2E+9	17.5E+9	Sm3	
Daily Plateau production rate (per template)-Precompression mode			Sm3/d	
Wells per template (Pre compression)	4	3		
Production days per year	328	330	day	
T _R	128	112	°C	
P _i , initial Res pressure (01 Jan 2009)	240	210	bara	
C, inflow Back pressure coefficient	1000	700	Sm3/bar ²ⁿ	
n, backpressure, exponent	0.8	0.8		
Tubing MD	3515	2800		
Tubing TVD	3100	2500		
C _t , Tubing coefficient 7" (ID=6.094")	38152,4	41163	Sm3/bar	
Elevation coeff Tubing, S	0.43	0.34		
C _{FL} 12".Template-to-Towhead (ID=) Spool	1403054	1397663	Sm3/bar	
C _{PL} Pipeline 14" Towhead-to-GFC 14000m (ID=0.32m)	148220	148220	Sm3/bar	
Separator pressure GFC (Inlet Sep)			60 bara	
Gas molecular weight (Methane)	19	19	kg/kmole	
Gas specific gravity	0.66	0.66	Gas specific gravity	

Conduct a plateau length analysis and determine the production profile (until a minimum economical rate of 2 E6 Sm³/d) for two scenarios:

- The plateau production of each template is calculated at the end of year 2008 by running an open choke network simulation and using the split factors (as explained in the class of 16.02.2016, page 10). The plateau rate of each template remains constant while deltap choke

> 0. Once Δp choke becomes < 0 for one of the templates, the production of the other template has to be increased to compensate (and obtain $10 \text{ E6 Sm}^3/\text{d}$). When both chokes are negative, the produced rate will be the hydraulic equilibrium rate of the network (lower than $10 \text{ E6 Sm}^3/\text{d}$). In other words, the production of each template can be modified towards the end of the plateau such that the plateau length is prolonged.

b. The plateau production of each template is calculated yearly by running an open choke network simulation for each year and using the split factors (as explained in the class of 16.02.2016, page 10). When both chokes are negative, the produced rate will be the hydraulic equilibrium rate of the network (lower than $10 \text{ E6 Sm}^3/\text{d}$).

Plot (in Excel) the results of your calculations and the change of pressure in the important nodes of the system versus time. Indicate on the plot the end of the plateau. (Important pressure nodes are reservoirs, bottom-holes, wellheads, pressure drop across the choke, template pressure, at the towhead and separator).

Plot the field gas production profile and the template gas production profile for the complete life of the asset.

PROBLEM 3: Model-based production allocation on a multi-layer gas well

Background

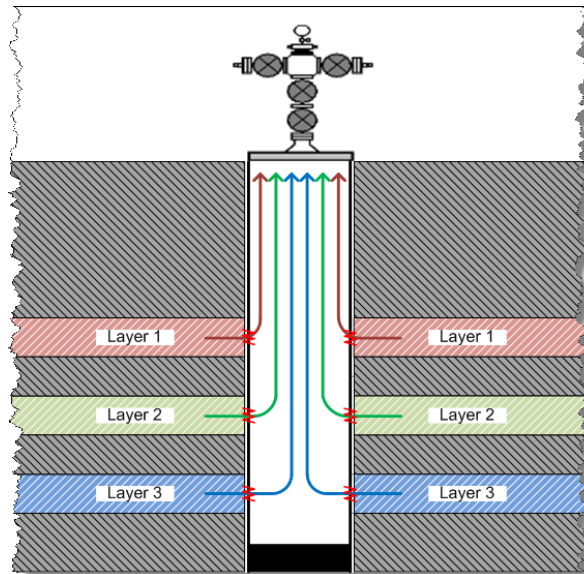
You have been asked for your expert advice to solve a problem on production allocation on a dry gas well from the San Juan area, New Mexico, US.



The well is the Dunavant 1-15 U 4 from the “Ignacio Blanco” Field. The well is producing **at a constant gas flow rate of $180 \text{ E3 Sm}^3/\text{d}$** from three formations (3 layers) that have different ownerships:

Layer Name Company	FRUITLAND COAL	WATERISLAND COAL	SAN JUAN
BP	30 %	70 %	10 %
Chesapeake energy corp.	40 %	10 %	40 %
Marathon	30 %	20 %	50 %

Each layer has its own properties, permeability, porosity, reservoir pressure, deliverability, etc. The vertical separation between the layers is pertinent and has to be considered. The well architecture is as follows:



Tasks:

You are asked to determine: 1). what fraction of the total gas flow rate is coming from each layer and 2). What fraction of the total gas flow rate corresponds to each company.

Solving Suggestions

- Transform the three layer well in an equivalent downhole network (consider from reservoirs until wellhead).

Information provided

Inflow performance of the layer (backpressure equation)

$$q_{gsc} = C_R (p_R^2 - p_{wf}^2)^n$$

Tubing equation (for each vertical segment)

$$q_{gsc} = C_T \left(\frac{p_{in}^2}{e^s} - p_{out}^2 \right)^{0.5}$$

All relevant data is given in the attached excel sheet.

Exercise set 04

General orientation for delivery:

- All answers should be delivered in a pdf report (stating clearly your name). The report should consist of, for each problem, a short description, a clear description of the methodology used to solve the problem, some calculation examples, results (on tables and graphs) and discussion of the results, analysis and conclusions.
- If you have done the exercise in cooperation with another student, please state it clearly at the beginning of the report. No identical text, format of figures, charts, tables, layout, excel sheet layout are allowed. Each student should have ownership of her/his own excel sheet.
- Students are encouraged to make observations, extra calculations, etc. outside of the scope of the exercise.
- When converting the word document to pdf make sure to use (in the pdf printer settings) a resolution high enough so figures and plots are still legible.
- Attach all files used to perform your calculations (e.g. Excel files, Hysys files, etc.) when delivering on Itslearning. The excel files should be constructed in a way that anyone can understand it and modify it easily.
- The plots should have a legible and proper size (e.g. 16 pt), axis titles in bold, depicting the variable name, variable symbol and units.
- Design your Sheet such that user define input can be change and the results of the sheet will be changes automatically.

PROBLEM 1: Generation of BO properties and Estimating well IPR with test data

The Prudhoe bay field is a large oil field on Alaska's North Slope. The field has been producing since 1977 and it is currently producing around half a million barrels per day.



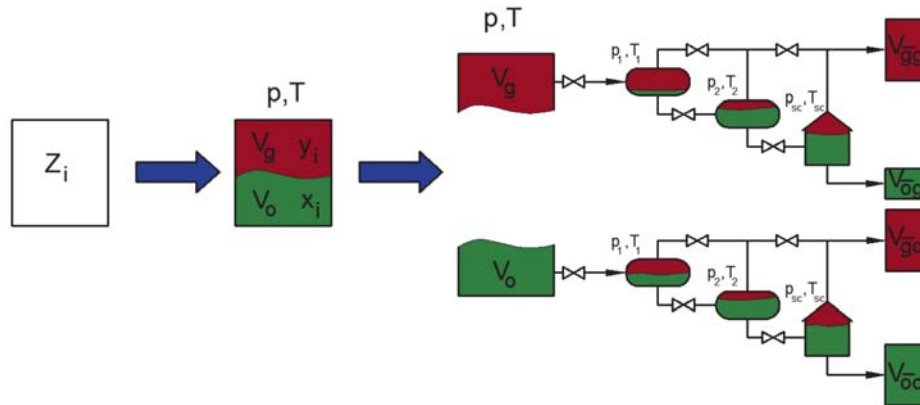
The field has 1330 wells, from which 591 are naturally flowing. The wells shut-in pressure is 166 bara (corresponding to a reservoir pressure of 400 bara). The wells are arranged in production modules that provide protection and insulation to the Christmas trees from the harsh arctic environment. The various modules are connected through flowlines to the main three gathering centers of the field (GC-1, GC-2 and GC-3).



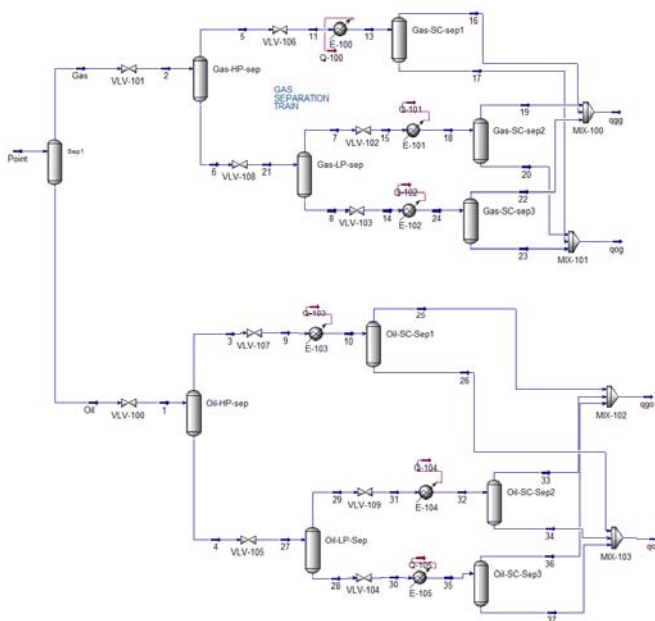
You are a production engineer in the field responsible for Well P2-15. You have been asked to perform the following tasks:

-Generate a table of BO properties (B_o , B_g , R_s , r_s , μ_o , μ_g) for the fluid composition of Well P2-15 using the attached Hysys file for pressures from 200 bar to 80 bar (in 20 bar increments) and a fixed temperature of 100 °C and 80 °C. Plot the BO properties versus pressure for a fixed temperature and quality control if they make sense. These tables will be used later by your fellow engineers to populate a Prosper model.

Comments: BO tables have to be generated using the procedure explained in class:



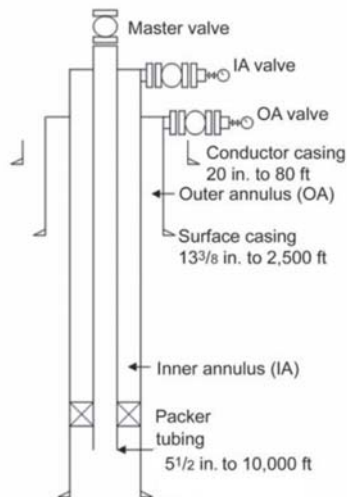
A Hysys file is provided with the composition and the surface process existing in the field (a high pressure separator and a low pressure separator). Most BO properties are calculated in a “Hysys spreadsheet” (indicated with a read arrow in the figure). Double click to access them.



	Mole Fractions
Nitrogen	0.0037
CO2	0.0011
Methane	0.4325
Ethane	0.0472
Propane	0.0297
i-Butane	0.0149
n-Butane	0.0093
i-Pentane	0.0083
n-Pentane	0.0050
n-Hexane	0.0183
n-Heptane	0.0411
n-Octane	0.0495
n-Nonane	0.0381
22-Mpropane	0.0002
n-Decane	0.3012

- Well P2-15 has been tested recently giving a wellhead pressure of 80 bara, $q_o = 1272 \text{ Sm}^3/\text{d}$, $\text{GOR}=146.2 \text{ Sm}^3/\text{Sm}^3$. With the data measured and the well layout provided below, estimate the flowing bottom-hole pressure. Use the value calculated to estimate the productivity index of the formation J , $q_o = J \cdot (p_R - p_{wf})$.

A typical well completion of the producing wells in the Prudhoe Bay is shown below:



Suggestions:

-Use the procedure shown in class (20160223) to calculate the bottom-hole pressure departing from the wellhead. Use 5 intervals and Euler’s method for explicit numerical integration. Use Hysys as a compositional fluid property calculator. Assume that the fluid temperature distribution is known a priori and goes linearly from 100 °C at reservoir conditions to 20 °C at the wellhead.

The standard conditions density of the oil is 721.4 kg/m³

The standard conditions density of the gas is 0.8721 kg/m³

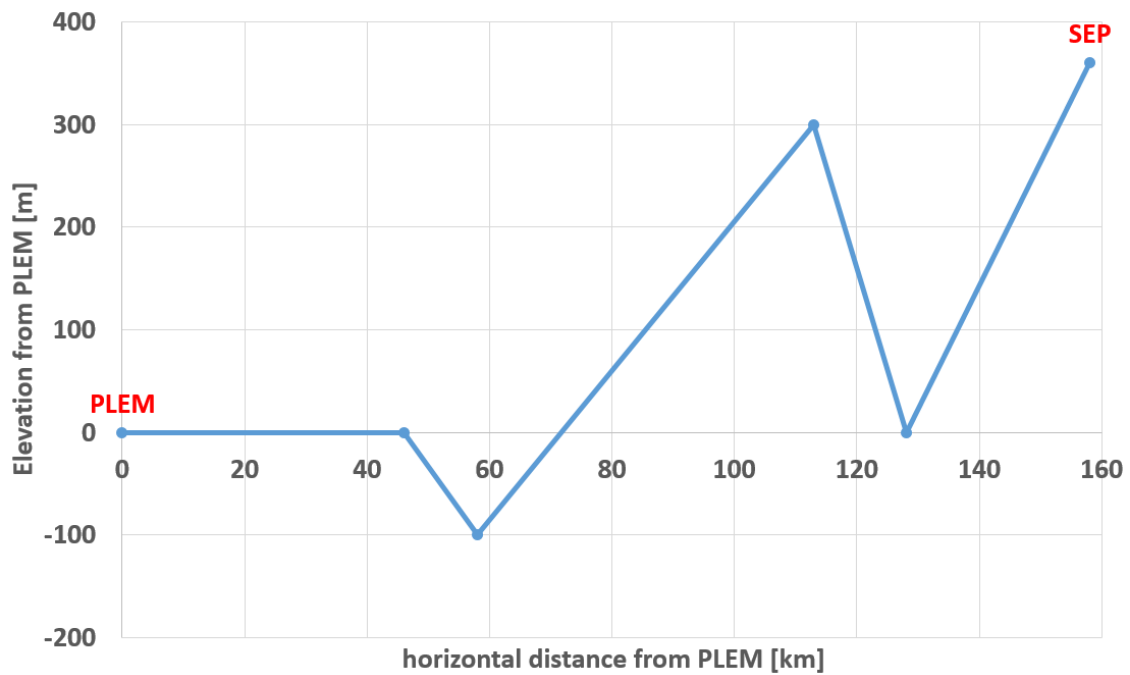
PROBLEM 2: Simplified flow assurance analysis of the Snøhvit pipeline

The main purpose of this exercise is to analyze the hydraulic performance of the main Snøhvit gas line considering the full composition of the gas:

Component	Mole %
Nitrogen	2.525
Carbondioxide	5.262
Methane	81.006
Ethane	5.027
Propane	2.534
i-Butane	0.4
n-Butane	0.83
i-Pentane	0.281
n-Pentane	0.308
Hexanes	0.352
Heptanes	0.469
Octanes	0.407
Nonanes	0.203
Decanes	0.397

You are asked to perform a more realistic simulation of the flow condition along the 158 km pipeline extending from the PLEM to the slug catcher using the software HYSYS. Include the real elevation profile of the pipeline (see the graph below).

Pipeline profile



Real pipeline elevation profile (referenced relative to PLEM position)

X	Y	
[km]	[m]	
0	0	PLEM
46	0	
58	-100	
113	300	
128	0	
158	360	SEP

Using the following data:

Molar flow	[kgmol/h]	36829.34		
Pout (Slug catcher pressure)	[bara]	30		
Tin pipeline	[C]	67		
Tsea	[C]	6		
Pipe ID	[in]	26.7		
Pipe OD (Including insulation)	[in]	30		
Overall pipeline heat transfer coefficient	[W/m ² K]	0.5	1.5	5

Conduct the simulations considering three values of overall pipeline heat transfer coefficient (HTC) as listed in the pipeline data set.

Tasks:

- Tabulate and plot pressure, temperature and liquid holdup along the pipeline for each of the 3 cases of thermal insulation specifications.
- Plot the phase envelope (P-T diagram) of the gas mixture illustrating the saturation lines (bubble and dew point lines) and the quality lines inside the two-phase region (0.01, 0.02, 0.03, 0.04, 0.05, 0.1, 0.2). Indicate in your plot the following:
 - Cricondenbar and Cricondentherm points
 - The region with retrograde condensate behavior (if any)
 - Plot the p-T along the pipeline on top of the P-T diagram for the three different thermal insulations. Detect if there is any condensate retrograde behavior.

For the insulation of $5 \text{ W/m}^2 \text{ K}$, calculate 5 points of the required PLEM pressure curve (keeping separator pressure constant) and plot them versus surface gas rate.

Solving suggestions

- Remember that Hysys performs its calculations co-current. This means that you provide a pplem pressure, Tplem temperature, and a molar rate at the inlet of the pipe, and Hysys calculates the gas flow rates at the exit of the separator and the separator pressure. However, we now that separator pressure has to be 30 bara. In order to force Hysys to reach this value, it is necessary to use an ADJUST.

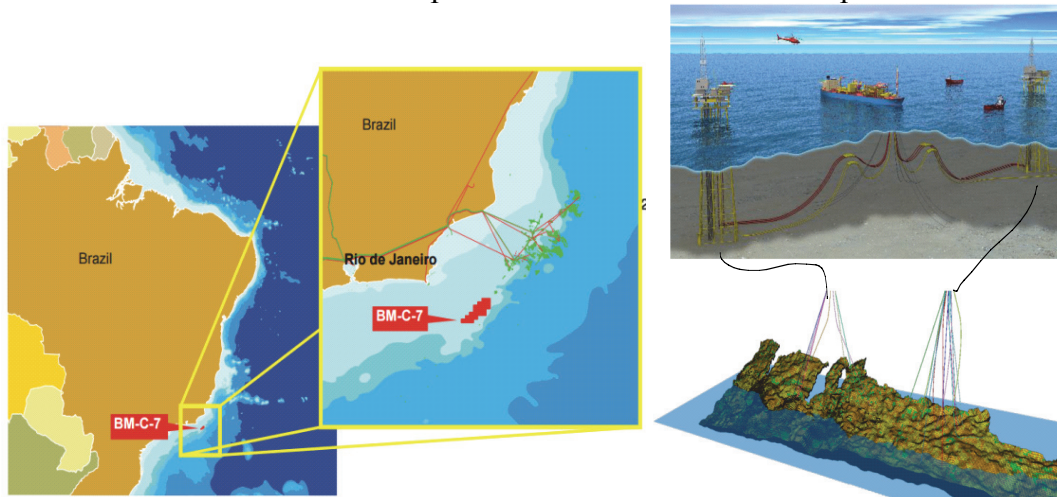
Exercise set 05

General orientation for delivery:

- All answers should be delivered in a pdf report (stating clearly your name). The report should consist of, for each problem, a short description, a clear description of the methodology used to solve the problem, some calculation examples, results (on tables and graphs) and discussion of the results, analysis and conclusions.
- If you have done the exercise in cooperation with another student, please state it clearly at the beginning of the report. No identical text, format of figures, charts, tables, layout, excel sheet layout are allowed. Each student should have ownership of her/his own excel sheet.
- Students are encouraged to make observations, extra calculations, etc. outside of the scope of the exercise.
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- The plots should have a legible and proper size (e.g. 16 pt), axis titles in bold, depicting the variable name, variable symbol and units.
- Design your Sheet such that user define input can be change and the results of the sheet will be changes automatically.

PROBLEM 1: ESP design and verification with output from reservoir simulator

Peregrino is the largest oil field operated by Statoil outside of Norway. The field is located 85 km offshore Brazil in the Campos Basin at about 100 water depth.

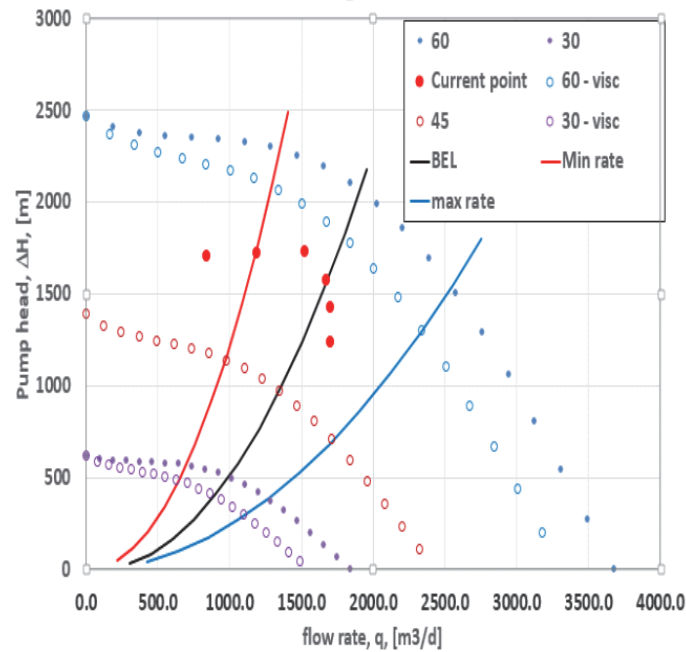


The field is developed with two fixed platforms from which wells are drilled and completed. There are 40 producing wells in total. The production is taken to an FPSO where the processing takes place. The separated water is transported back to the platforms and injected in the lower part of the formation.

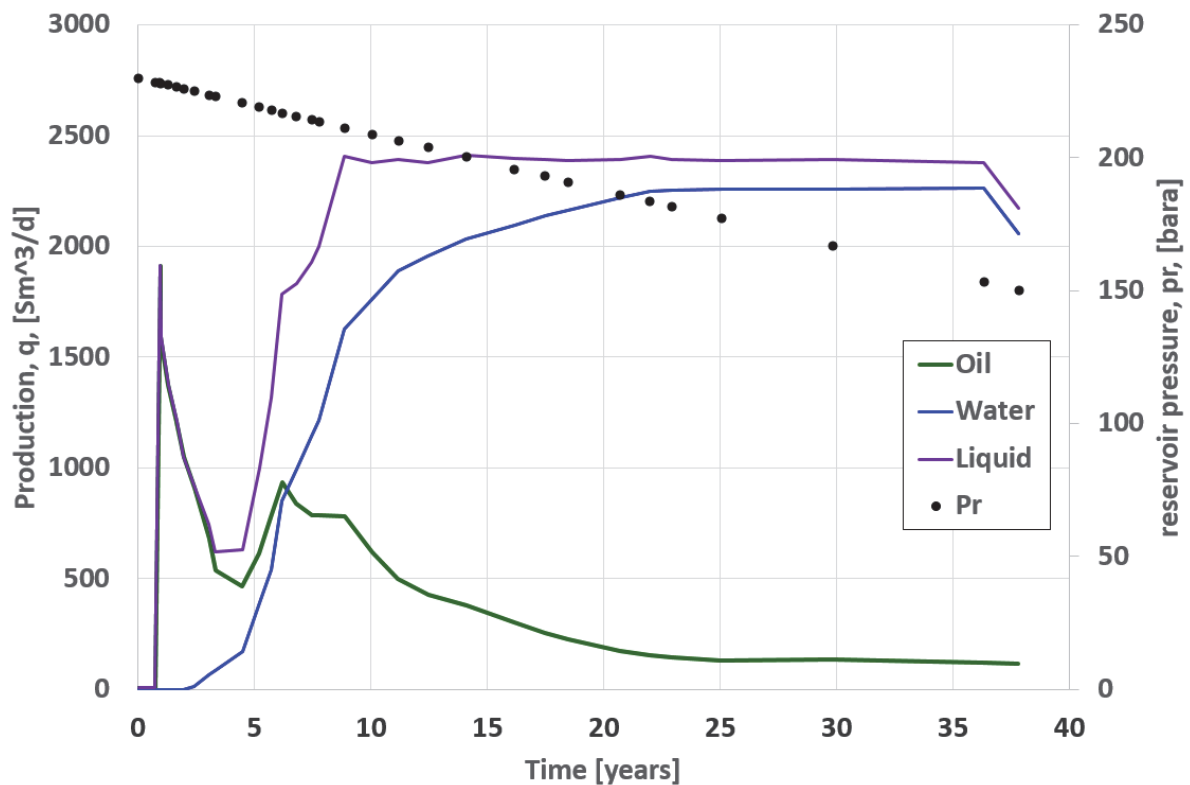
The wells are deviated with ESPs installed in them. The wells are classified in low, medium and high producers.

A particular ESP model has already been suggested by a manufacturer (Baker Hughes) based on the well layout and production rates desired.

On the 15th of march, 2016 you have attended a training session about ESP design analysis and verification session using Excel. The analysis was made assuming a fixed reservoir oil rate of 1700 Sm³/d with no associated water produced. There were two approaches used for the analysis: one excluding the ESP model and one including the ESP model. The instructor has given you the two excel sheets for future use.



Recently, reservoir engineers have run the reservoir model and have obtained a more trustworthy approximation of the production profile of the well and the evolution of reservoir pressure:



Your task is to verify if the ESP proposed by the manufacturer will be able to produce the rate predicted by the reservoir simulator for times: 1 , 3 , 5.2, 10 and 22 years. If it is not

possible to deliver the rate, try to make adjustments to the rate so it will fall inside the operational envelope of the pump. Identify limiting factors. If you are using the excel solver to adjust automatically the rate, please specify clearly the objective, constraints and variables.

If you are given budget to change something in the well, is there something in particular that you will prioritize to meet the reservoir production goals?.

Plot the operational points (both original rates from the reservoir simulator and corrected rates) overlapped in the ESP operational map. Determine ESP operational frequency, suction pressure, required power for each year listed above.

Calculate the emulsion viscosity of the oil and water mixture for each one of the years listed above. Is there any trend?

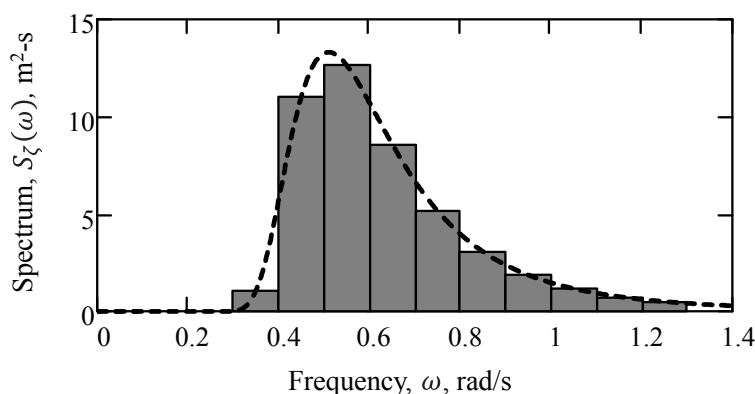
Provide your final recommendations if the ESP is adequate to deliver the desired rate or not.

Assumptions:

- Use one of the excel sheets given by the instructor (whichever you prefer). The well layout, J, pump curves, are the same as before.
- Assume maximum pump power = 730 Hp
- Assume pump efficiency is constant and equal to 60%.
- The output data from the reservoir simulator is provided in the last tab (“Production data” in the excel files used for ESP analysis.
- Assume that the total liquid productivity index (J) of the formation remains constant with time.

PROBLEM 2: Wave energy spectrum and time domain wave record

A wave energy spectrum obtained from 20 min sample of instrumentally recorded wave data in the Troll field (position 60° 45' 21.12" N 3° 38' 22.98" E) is given in the figure below. The spectrum has been simplified to a column type diagram with frequency steps of $\Delta\omega_i=0.1$ rad/s, and the values are given in the table. This sea state is formed by long crested deep-water waves.



ω	S_{ζ}
rad/s	$m^2 \cdot s$
0.35	1.1
0.45	11.1
0.55	12.6
0.65	8.6
0.75	5.2
0.85	3.1
0.95	1.9
1.05	1.2
1.15	0.8
1.25	0.5

Tasks:

1. Find the wave surface elevation amplitude for each wave component
2. Find and plot the wave elevation function corresponding to the first, fourth and eighth wave component (0.35, 0.65 and 1.05 rad/s).

3. Then, find and plot the resulting wave surface elevation by adding the contribution of all the harmonic wave components for time steps such as: 0,1,2 ... 300s.
 - Generate random values for the phase angle ε_i among all wave components. To do so, it is possible to use excel functions as follow: =RAND()*2*Pi()

Useful equations:

Wave surface elevation for an “i” harmonic component: $\zeta_i(x, t) = \zeta_{ai} \sin(\omega_i * t + \varepsilon_i)$

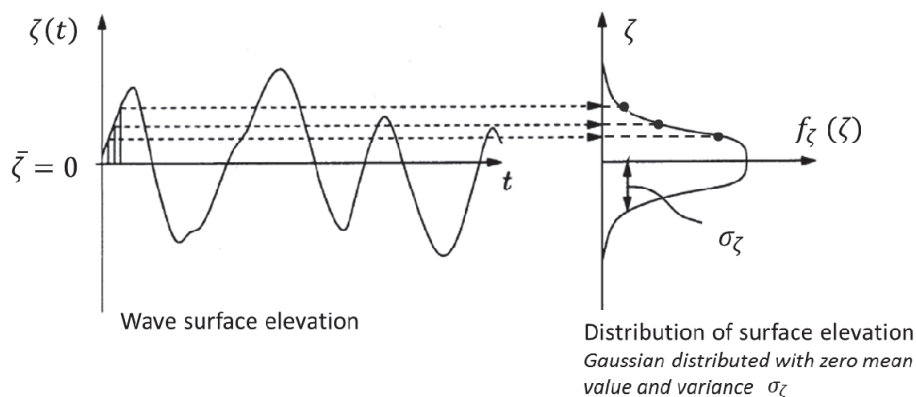
Total wave surface elevation: $\bar{\zeta}(x, t) = \sum_{i=1}^N \zeta_{ai} \sin(\omega_i * t + \varepsilon_i)$

Wave energy spectrum: $\frac{1}{2} \zeta_{ai}^2(\omega_i) \triangleq S_{\zeta}(\omega_i) \Delta\omega_i$

$$\frac{E}{\rho g} = \sum_{i=1}^N \frac{1}{2} \zeta_{ai}^2(\omega_i) \triangleq \sum_{i=1}^N S_{\zeta}(\omega_i) \Delta\omega_i$$

PROBLEM 3: Wave energy spectrum and time domain wave record

The total surface elevations in the previous Ex 1 is assumed to be Gaussian distributed, which means that the expected mean value will be zero and the variance equal to σ_{ζ}^2 , and they are considered to be constant during the whole time interval. This is illustrated in the figure below.



Tasks:

Using the data of wave surface elevation for time steps from 0,1,2...300s, find:

- Statistical calculations:

1. The mean value of wave surface elevation, $\bar{\zeta}$
2. The variance of the surface elevation, σ_{ζ}^2
3. The limit of the highest 1/3 of wave heights, $h_{1/3}$
4. The significant wave height, H_s

- Distributions:

1. Probability density function of wave elevations, $f_{\zeta}(\zeta)$ (Gaussian distribution)
2. Probability density function of wave heights, $f_H(H)$ (Rayleigh distribution)
3. Cumulative distribution function of wave heights, $F_H(H)$

Useful equations:

$$H_s = 4 \sigma_\zeta \quad h_{1/3} = 4 \sigma_\zeta \sqrt{\frac{\ln(3)}{2}}$$

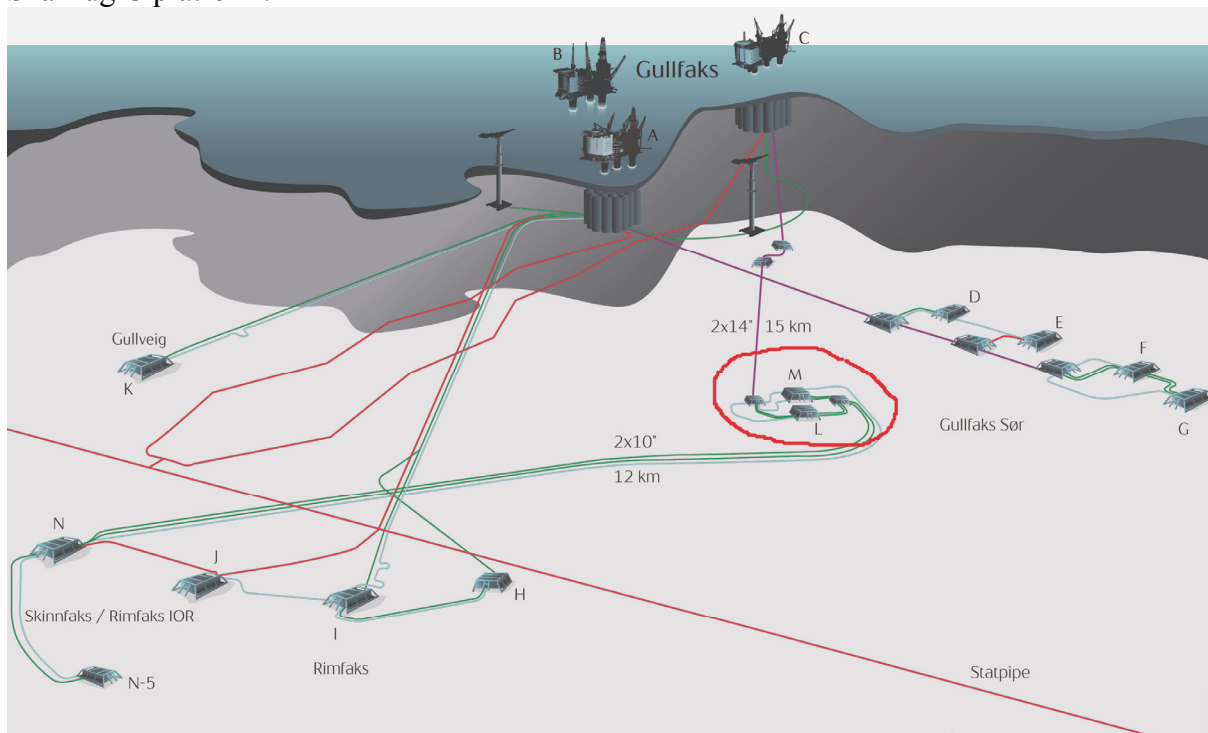
$$f_\zeta(\zeta) = \frac{1}{\sigma_\zeta \sqrt{2\pi}} \exp \left[-\left(\frac{\zeta}{\sigma_\zeta \sqrt{2}} \right)^2 \right]$$

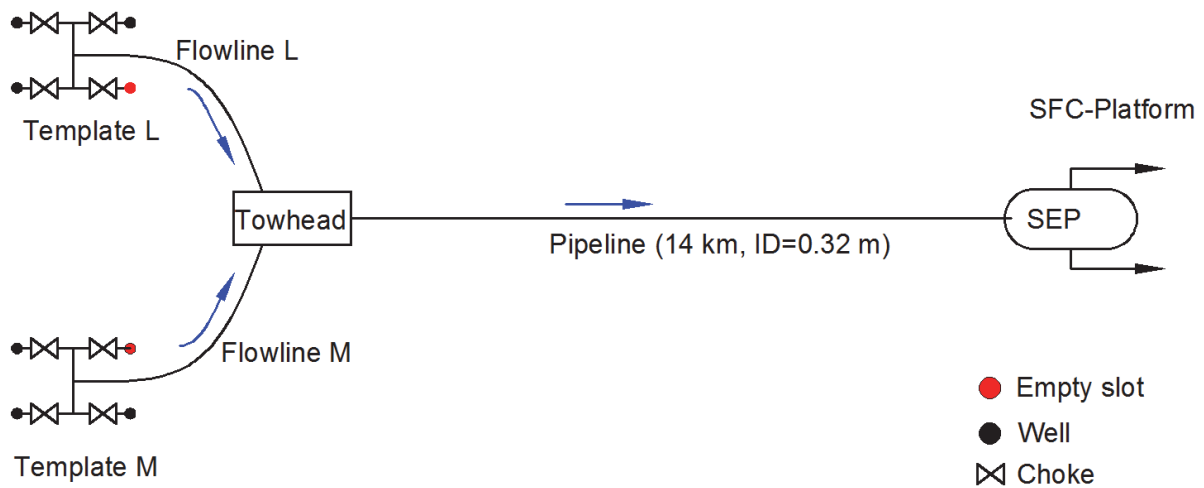
$$f_H(H) = \frac{H}{4\sigma_\zeta^2} \exp \left[-\left(\frac{H}{\sigma_\zeta \sqrt{8}} \right)^2 \right]$$

$$F_H(H) = 1 - \exp \left[-\left(\frac{H}{\sigma_\zeta \sqrt{8}} \right)^2 \right]$$

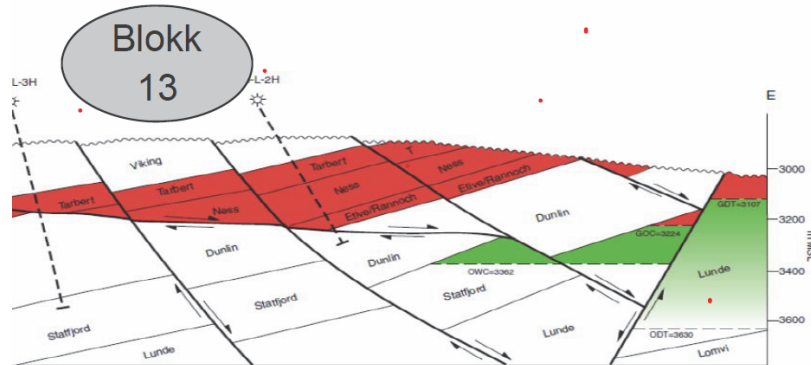
PROBLEM 4: SUBSEA GAS COMPRESSION DESIGN FOR THE SKAFLUG FIELD

A reservoir unit in the Skaflug South field (Block 13) have been producing oil and gas since 1999 by two subsea templates (Templates L and M). The production is commingled in a manifold (called “Towhead”) and is transported further using one production pipeline to the Skaflug C platform.





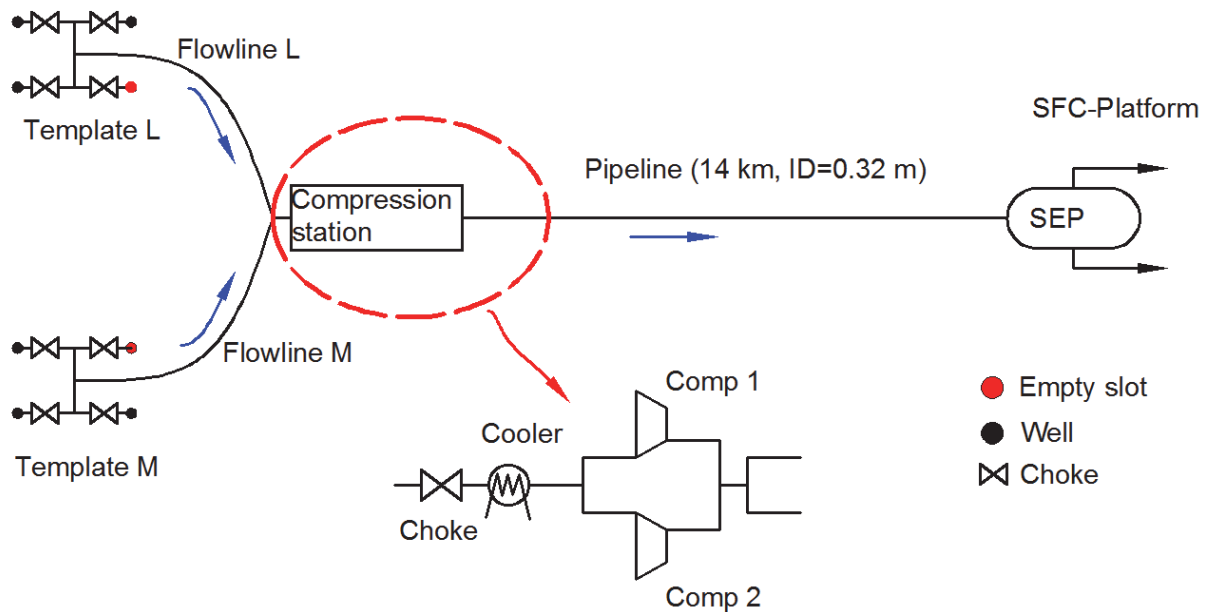
Due to the depletion of the oil layer in the formations, the wells from templates M and L have been recompleted in 2009 to produce liquid rich gas. From 2009, the field is produced in plateau mode with a total rate of 10 E6 Sm³/d.



The production profile of the field and the length of the plateau departing from 2009 have been estimated by another engineer and the results are available in the attached excel file. The plateau duration is 7.6 years.

Your task is to conduct an analysis to evaluate the impact of using subsea compression to maintain plateau production after the natural plateau end is reached. Your main task is to expand the excel sheet that your friend developed to calculate the length of the production plateau in the compression period and compute post plateau production profile (when operationally, due to compressor constraints, it is not possible to maintain plateau production any longer).

The proposed layout for the installation of the compressor (suggested by Aker solutions) is shown in the figure below:



The compression station has a choke valve, a cooler and two identical compressors in parallel. In normal operating conditions, the choke is fully open. Some operational constraints are the following:

- The discharge temperature of the compressor has to be below 150 C to avoid problems in the seals of the compressor, avoid structural integrity issues in the pipeline and avoid vaporization of the hydrate inhibitor.
- The maximum power per compressor is 5.5 MW.
- The maximum temperature drop in the cooler is 30 C.
- The minimum suction pressure to the compressor is 20 bara.
- Assume that the compressor operates with a polytropic efficiency of 70%.
- The gas temperature at the inlet of the compressor station is 80 C.

The German company MAN has already proposed a specific compressor model to use in the system. The compressor map, measured for test conditions is also included in the excel sheet.

Being a preliminary study, considerable simplification assumptions will be used:

- The gas is dry, its depletion and recovery characteristics can be modeled by reservoir tank model
- The flow in the wells and the pipeline can be represented by isothermal flow equations.
- Wells are operating with fully open choke during the compression period.
- All wells, templates, and infield flow lines are symmetric in configuration and capacity.

If, during your analysis, the operating point falls outside the operational map of the compressor, consider the following options:

- Use the valve at the inlet of the compressor station as a choke valve to drop the inlet pressure and increase the compression ratio
- Use the cooler

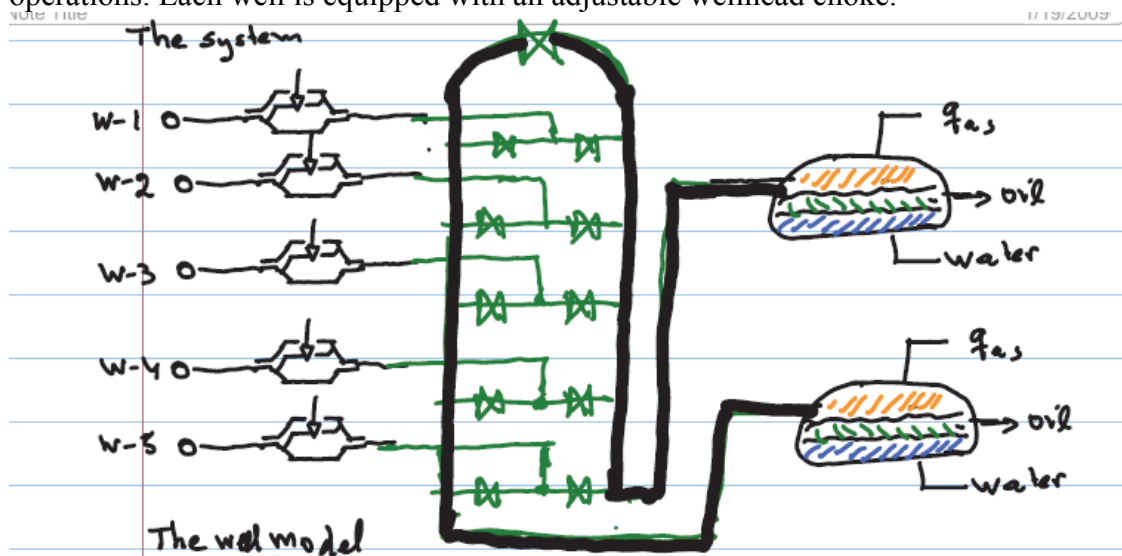
Some specific tasks are:

- Compute and plot the field gas production profile, deltaP compressor, compression ratio, suction pressure for the complete life of the asset.
- Determine when (in which compressor years) the cooler is required.
- Estimate the rotational speed of the compressor and the required compressor power for each compressor year.
- Plot the operational points on top of the compressor map (for test conditions).

As a last task, your company is evaluating eliminating the cooler from the system to avoid potential plugging problems. Compute the production profile considering that there is no cooler and issue a recommendation on the matter.

PROBLEM 5: MODEL-BASED PRODUCTION OPTIMIZATION OF A 5 WELL PRODUCTION SYSTEM PRODUCING TO TWO SEPARATORS

The cluster illustrated in the figure below consists of 5 wells and two production separators. Each well has the option to produce either to separator 1 or 2 by opening and closing the relevant valves. The crossover valve (the valve at the top) is closed during normal operations. Each well is equipped with an adjustable wellhead choke.



Because of the routing valves there are actually 32 (2⁵) possible operating configurations depending if the wells produce to separator 1 or 2. All configurations as listed in the table below:

Case No=	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
Well																																
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
2	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2
3	1	1	1	1	2	2	2	2	1	1	1	1	2	2	2	2	1	1	1	1	2	2	2	2	1	1	1	1	2	2	2	2
4	1	1	2	2	1	1	2	2	1	1	2	2	1	1	2	2	1	1	2	2	1	1	2	2	1	1	2	2	1	1	2	2
5	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2

Each separator has a maximum processing capacity of water and gas, as indicated in the table below:

Sep	Sep	Sep	Sep	sep	sep
1	1	1	2	2	2
qo	qg	qw	qo	qg	qw
Sm3/D	Sm3/D	Sm3/D	Sm3/D	Sm3/D	Sm3/D
	250.0E+3	400		200.0E+3	380

After attending a conference about optimization, your manager has asked you to evaluate if there is a particular choke opening and routing configuration that yields maximum oil production while fulfilling the operational constraints.

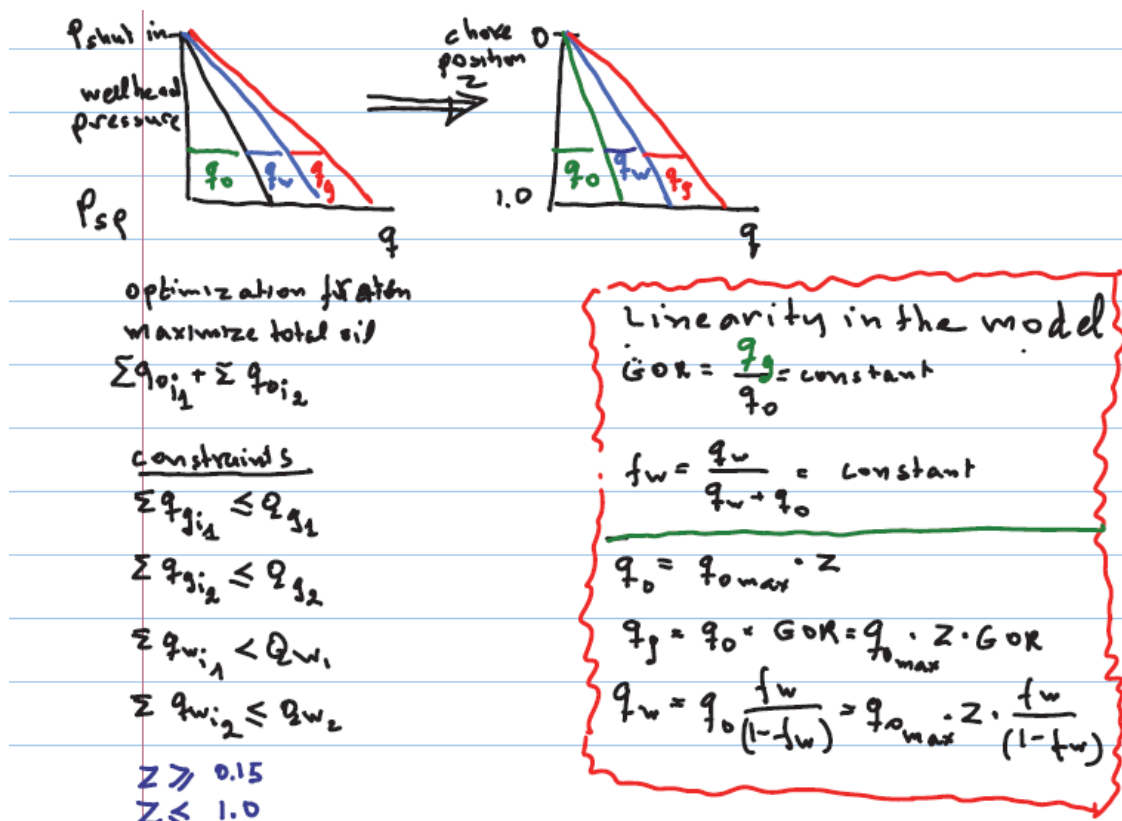
Your main task is to to setup a model of the system and to execute optimization on it to maximize oil production by changing choke opening and well routing, while honouring the operational constraints (separator handling capacity and maximum and minimum choke opening).

Specific Tasks:

1. Use optimization in excel (using the excel solver) to determine the maximum oil production subject to the listed constraints for 5 routing configurations (selected arbitrarily by you from the table).
2. Comment on which of the separator constraints should get priority if there is a budget to slack only one of the constraints on each separator.

Assumptions:

The production engineers of the field have determined that, due to the fact that wells are very close to the separator, the production of the well (oil, gas and water) can be represented by a linear model that depends on the choke opening (z) of each well as indicated in the figure below. $Z=1$ represents a fully open choke while $Z=0$ represents a fully closed choke.



The data for each well is summarized in the table below.

Well	$q_{\max o}$ Sm ³ /D	f_w fraction	GOR Sm ³ /m ³
1	636	0.20	142
2	795	0.43	214
3	477	0.31	267
4	636	0.47	356
5	318	0.10	249

And the chokes can be operated only in the following range:

Choke constraints		
Z min	0.15	Fraction-Choke opening
Zmax	1	Fraction-Choke opening