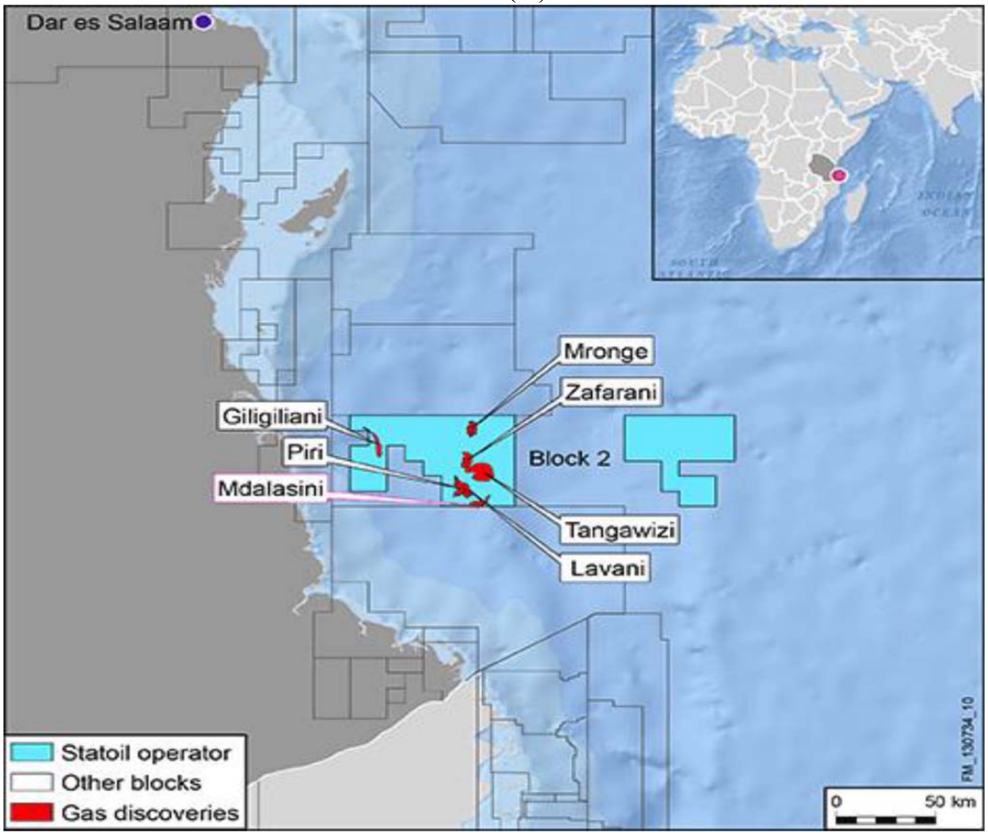
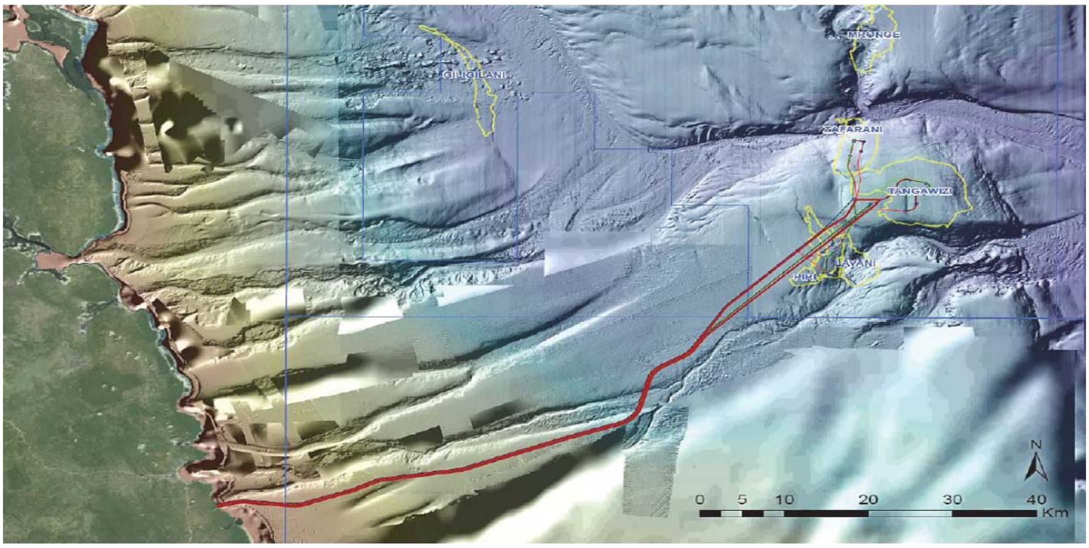
Exercise set 03

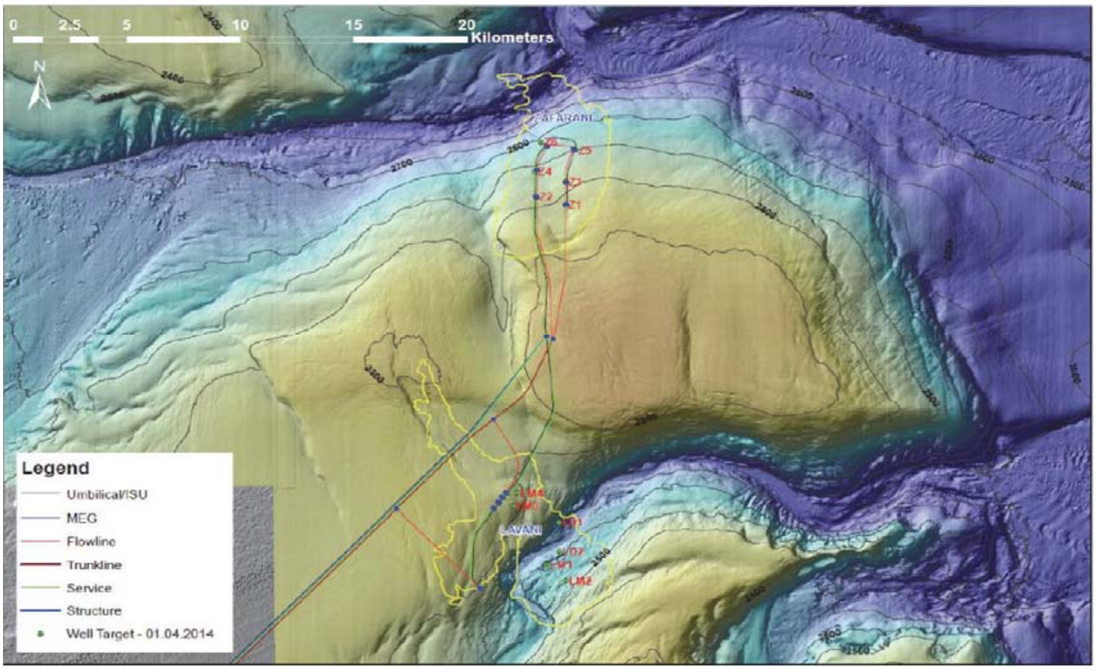
Problem 1: Production scheduling for the dry gas field "Block 2" offshore Tanzania.

Statoil 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.



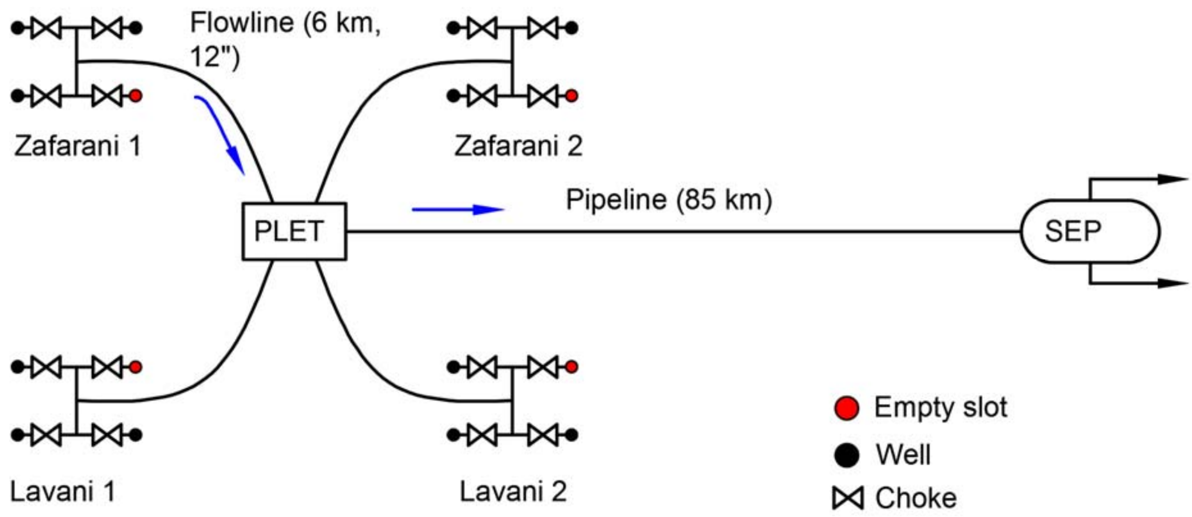


It has been decided that, at an initial stage, only Zafarani and Lavani will be produced. The desired plateau rate is 18 E6 Sm^3/d.

Your main task is to calculate the production profile for the first 40 years of production from the field. You are asked to perform your analysis on a year basis. Plot the evolution of all relevant pressures in the system (p_R, p_{wf}, p_{wh}, p_{temp}, p_{PLET} and p_{sep}) versus time.

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, use the appropriate rate in each pipe segment.

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 field produces some associated condensate. The Condensate Gas Ratio (CGR) is 1.5E-4 Sm^3/Sm^3.
- Use the tubing equation to represent the pressure drop in the pipeline.

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

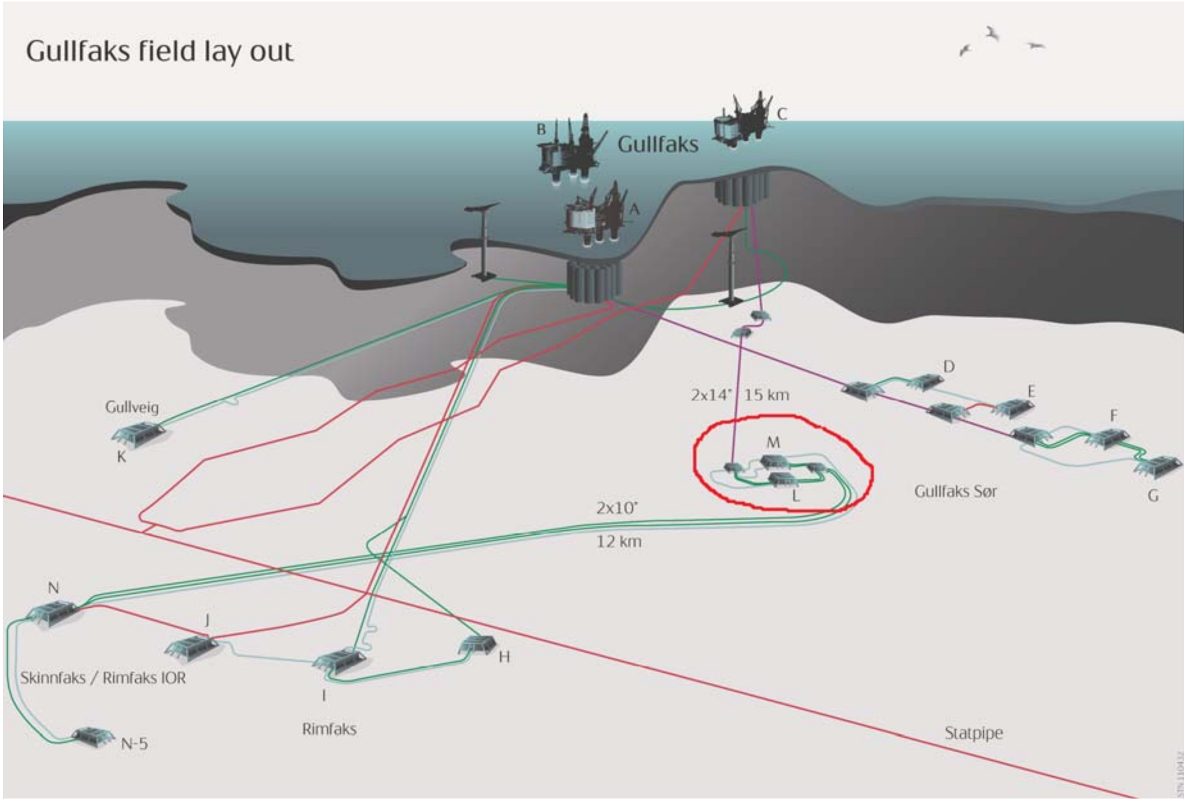
Task 2: Calculate the field production potential curve versus gas cumulative production. Using this curve, determine the plateau length for plateau rates of 20 E06, 15 E06 and 25 E06 Sm^3/d.

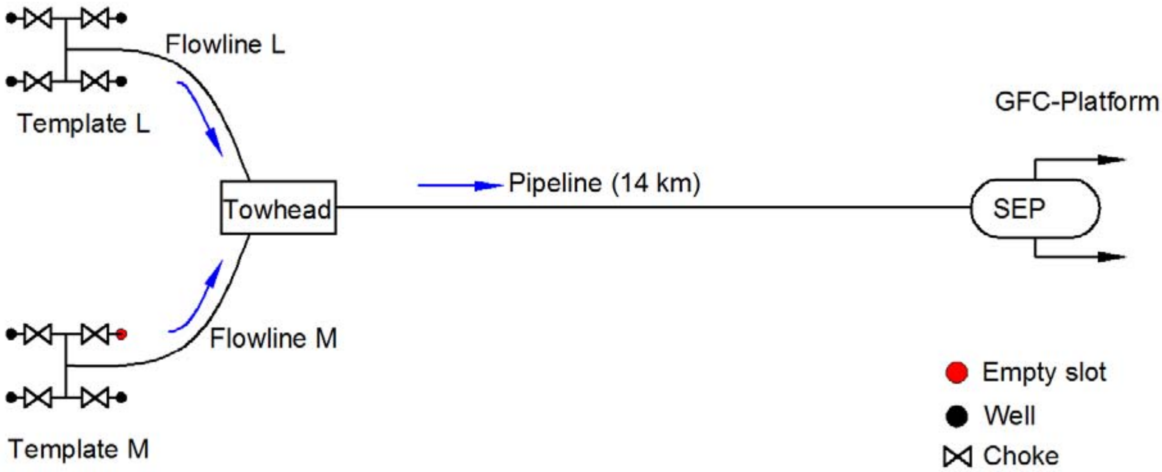
Task 3: The multiphase/flow assurance expert working on this project has said that the prediction of the pressure drop in the main transportation pipeline using commercial tools (e.g. Olga®) could be extremely unreliable. This is because two very special conditions: hilly profile and the presence of some liquid flowing together with the gas. He says that the error associated with the pressure drop estimation might be of ±20%. He therefore suggested to perform an experimental campaign in the large scale multiphase loop of SINTEF (http://sintefloops.com/?page_id=962) in Trondheim 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 20% in the prediction of the pressure drop in the production profile of the Block 2 field. Specifically on the duration of the plateau. **Your task is then to add 20% to the original pressure drop in the pipeline and calculate the production profile again. Discuss your results.**

<u>Problem 2:</u> Production network calculations for the Gullfaks South field.

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). Template L has 4 wells and template M has 3 wells. For the purpose of this exercise, consider that all wells in a given template are identical (**However, the production of one well in the L template is not the same as the production of one well in the M template**). The production of the two templates is commingled in a towhead (junction) and transported further with a pipeline to the platform of Gullfaks C.

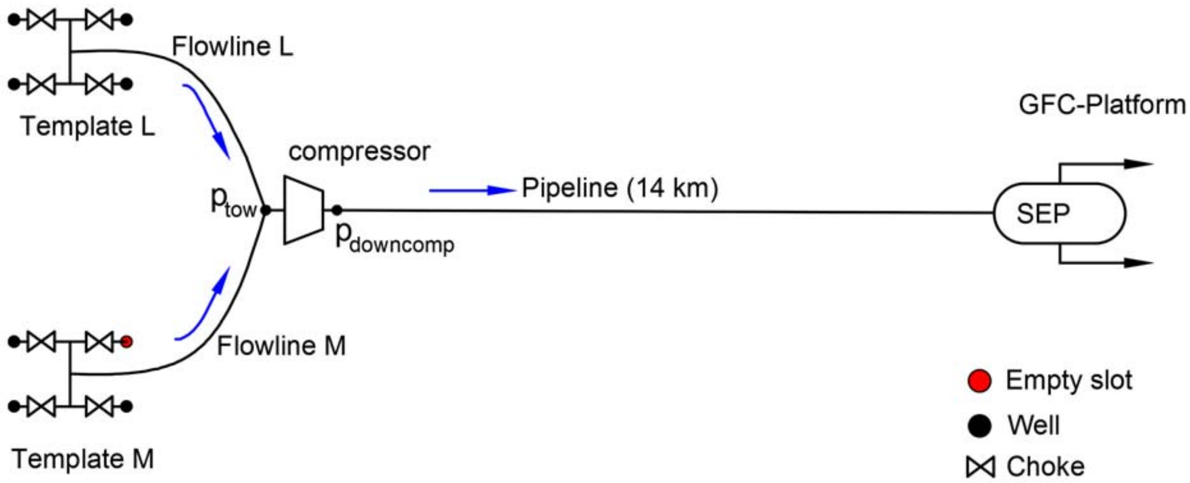




The field have been producing oil and gas since 1999. Due to the depletion of the oil layer in the formations, the wells from templates M and L have been recompleted in 2009 to produce liquid rich gas. The liquid comes from gas condensate in one formation and from mobile liquid oil in the bottom of the reservoir of the other formation. From 2009, the field is produced in plateau mode with a total rate of 10 E6 Sm^3/d.

Currently, **it is year 2017**, and the production has started to decline. Reservoir pressure of Blocks 13 (template L) and 14 (Template M) are 145 and 102 bara respectively. These are your tasks:

1. Calculate the natural flow rate by performing flow equilibrium in the network. Consider wellhead chokes fully open.
2. If a subsea compressor is installed at the towhead (at the inlet of the pipeline) and the wells have fully open chokes, estimate the pressure increase and the pressure ratio required from the compressor to deliver a total gas rate of 9 E6 Sm^3/d.



3. If in case 2 the flow from template L exceeds 6.4 E6 Sm^3/d, there might be wellbore stability problems in the wells due to the low pressure of the formation. A proposed solution is to use the wellhead choke of template L, to choke back the production of that template. Is it still possible with this configuration to deliver a total gas rate of 9 E6 Sm^3/d?. If yes, estimate the pressure increase required from the compressor and the pressure drop in the control valve. If not, please explain your answer. **Hint:** fix the rate of template L to be exactly 6.4 E6 Sm^3/d.

<u>Problem 3:</u> Production scheduling studies for two oil fields in Saudi Arabia.

The onshore AFK field (operated by Saudi Aramco) consists of two separate reservoirs (Abu Hadriya and Khursaniyah) that are produced through independent pipelines to the processing facilities in Ras Al Khair. The two oils have very different APIs (Abu-Hadriya has 36 API and Khursaniyah has 27 API) and the two oils are blended at the processing facilities. The resulting oil is marketed under the name of Berri crude (similar to the Arabian light crude, see the sales specs attached). In order to be accepted for further processing at the refineries abroad, the crude has to have a minimum of 31.8 API.

Arabian Light

		Reference ID
Origin:	Saudi Arabia	
Synonyms:	Berri	

Data from OGJ 99 were originally published in 1991 as part of a series entitled "Export Crudes for the '90s".

API Gravity		
	33.4	OGJ 99
	31.8	ESD 92

The reservoir management team of the company proposed to produce 130E3 stb/d from Abu-Hadriya and 40E3 stb/d from Khursaniyah to meet a plateau of 170E3 stb/d. The decision was based on some reservoir simulations and on the fact that:

- At initial conditions, Abu-Hadriya can deliver a higher rate than Khursaniyah and
- Abu-Hadriya has oil of a "better quality"(i.e. higher API) than Khursaniyah.

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 Abu-Hadriya and Khursaniyah are summarized in the table below:

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

Task 1: compute the production profile and API of the AFK 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 the production rates are additives and that the field API can be calculated with a rate weight average of the Abu Hadriya and Khursaniyah fields:

$$API_{FIELD} = \frac{q_{ABU} \cdot API_{ABU} + q_{KHUR} \cdot API_{KHUR}}{q_{FIELD}}$$

Remember that (as derived in class, page 112 of the class notes), if the production potential is a straight line, it is possible to use the exponential expression for the post plateau period:

$$q_{field}(t) = q_{plateau} \cdot e^{-m \cdot (t - t_{plateau})}$$

Where $t_{plateau}$ is the plateau duration in days, t is in days.

IT IS NOW 2 YEARS INTO PRODUCTION and the reservoir team realized that the AFK 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 Abu Hadriya reservoir enters in decline much sooner than the Khursaniyah reservoir. In consequence, they now think that the production strategy must be reviewed in order to produce more from Khursaniyah and less from Abu Hadriya.

Task 2: Propose a reviewed production strategy to maximize plateau length of the field while ensuring that the API is kept within specs **during the remaining plateau duration**. Compute the production profile and API of the AFK 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. **Take into account that the field has been previously produced for two years.**

Task 3: What is the optimal offtake from Abu Hadriya and Khursaniyah that maximizes plateau length if the resulting API wasn't an issue?. **Take into account that the field has been previously produced for two years.**

Assumptions:
-A year has 355 operational days