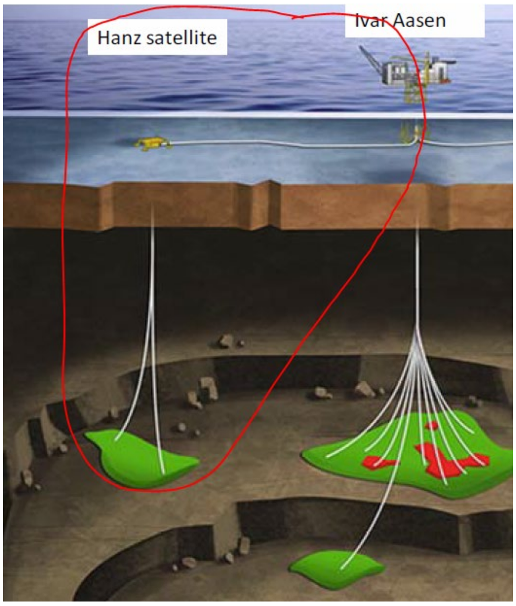
PROBLEM 1 (40 POINTS). Production profile and NPV calculations of the Hanz field

Hanz is a small undersaturated oil reservoir satellite to the Ivar Aasen platform. The initial reservoir pressure of Hanz is 265 bara. The reservoir will be developed using a single oil producer and a pipeline connected to a separator on the platform. The well will be produced in production mode "B", i.e., with open choke. Assume the well does not produce any water.



Task. 1. You are asked to compute the production profile of the reservoir **until the oil flow rate goes below 500 Sm3/d, which is the economic oil flow rate.**

Task 2. Compute the NPV of the development using the equation provided.

Task 3. If there is uncertainty in the initial oil in place volumes of Hanz (a log-normal distribution as given in the "additional information" section), and in the cost figures (a uniform distribution between 20% more and 20% less the base case value). Q**uantify the resulting uncertainty on NPV using probability trees** (use two branches per variable). **Provide the NPV and probability of all end points of the tree.** Sketch the probability tree.

Deliverables:

- Excel file with the solution of the exercise
- A text briefly describing the steps taken to solve this exercise
- A sketch, by hand, PowerPoint, paint, etc. with the sketch of task 3.

ADDITIONAL INFORMATION:

- The times provided in the table represent "end of year".
- Perform your calculations in a yearly basis starting from the end of year "0". Remember that at year "zero", no oil is recovered yet from the field.
- Because you are doing your calculations yearly, at the end of some year the well rate will drop below the minimum economical rate of 500 Sm3/d. **The field is abandoned when this happens, not the year before.**
- Assume that there are 360 operational days in a year.

- Estimate yearly oil production (e.g. of year "i") by assuming that the rate of year "i-1" is constant in the period "i-1"→"i"

The following expression is provided to compute reservoir pressure as a function of cumulative oil production. (VBA function "pressuredecline")

$$p_R = 265 \ - 70 \ \left(\frac{N_P}{N}\right)$$

$$N = 4\ E06\ Sm^3$$

Well Inflow data:

$q_{\bar{o}} = J \cdot (p_R - p_{wf})$ (VBA functions "IPRpwf" and "IPRqo" are provided to compute either oil surface rate or flowing bottom-hole pressure)

J = 60 Sm^3/d/bar

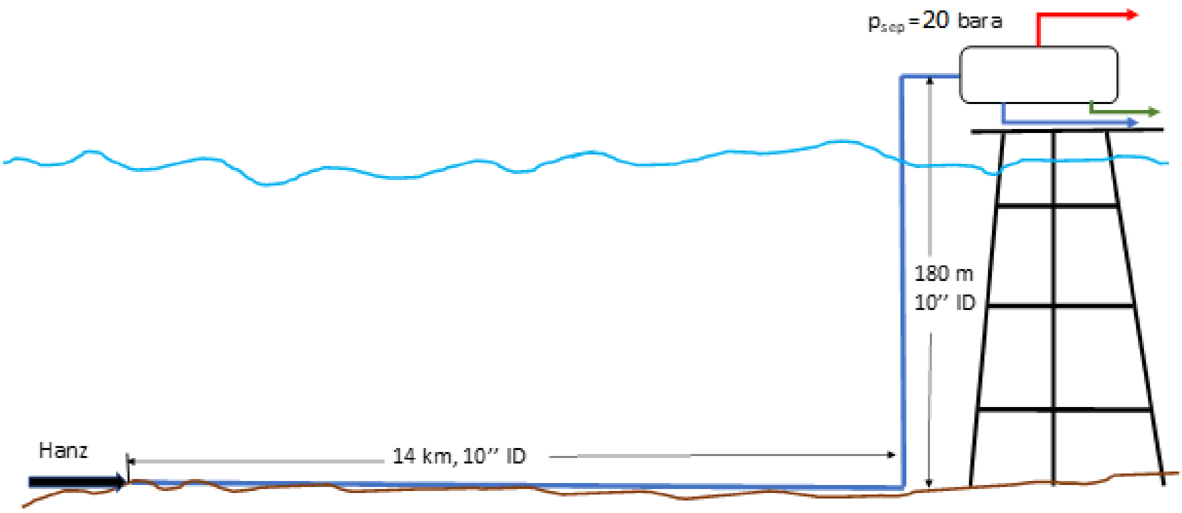
For the pressure drop calculations in the tubing, pipeline and riser assume that there is only oil flowing in the pipes, that the oil is incompressible and neglect the presence of gas. The pressure drop can be calculated with the VBA functions provided, "pout" and "pin".

Tubing data:

Vertical tubing
Tubing length= 2200 m
Tubing ID = 0.154 m
Tubing roughness = 1.5 E-05 m

Pipeline and riser data:

Pipeline and riser roughness = 1.5 E-05 m



Oil properties:

Density: 861 kg/m^3
Viscosity: 1.03E-03 Pa s

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

$$NPV = NPV_{rev} - C$$

This equation assumes that all expenses are executed at time "zero" (start of production). The net present value of revenue is, discounted from year zero (start of production):

$$NPV_{rev} = \sum_{k=1}^{n} P_o \cdot \frac{\Delta N_{p,k}}{(1+i)^k}$$

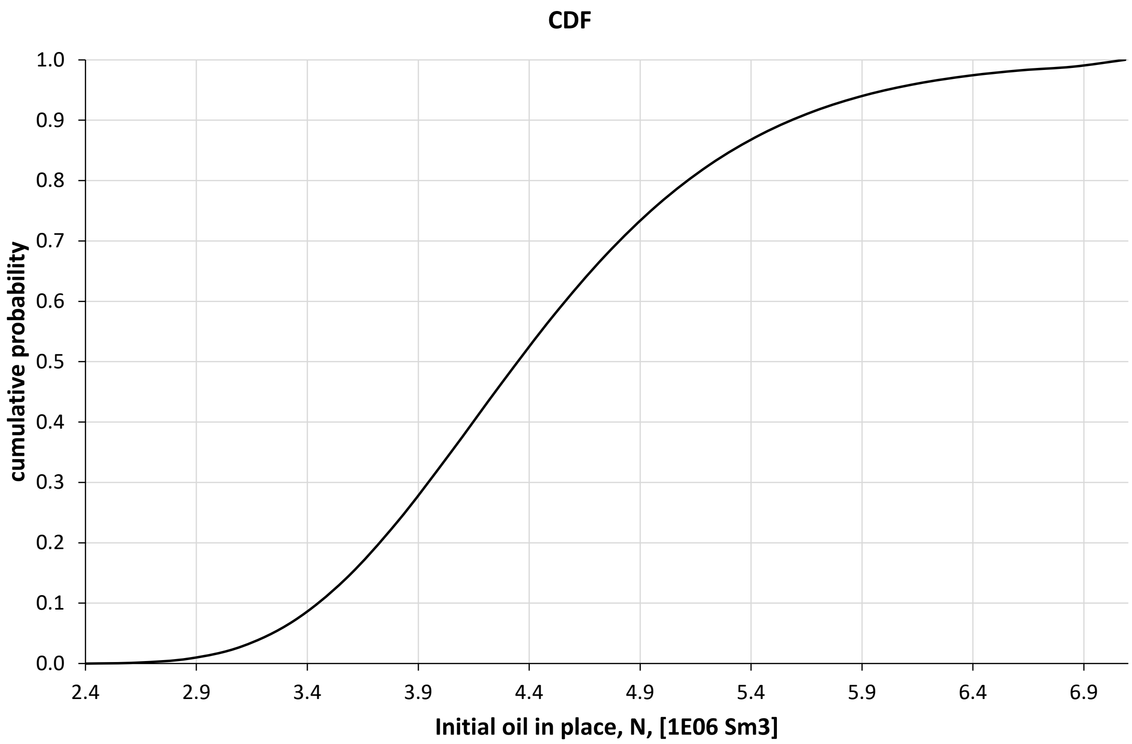
i	Discount rate (use 0.08 1/year)
k	Counter for the number of years
n	Total number of years, unknown
$\Delta N_{p,k}$	Field oil production of year "k"
P_o	price per Sm^3 of oil, [180 USD/Sm^3]

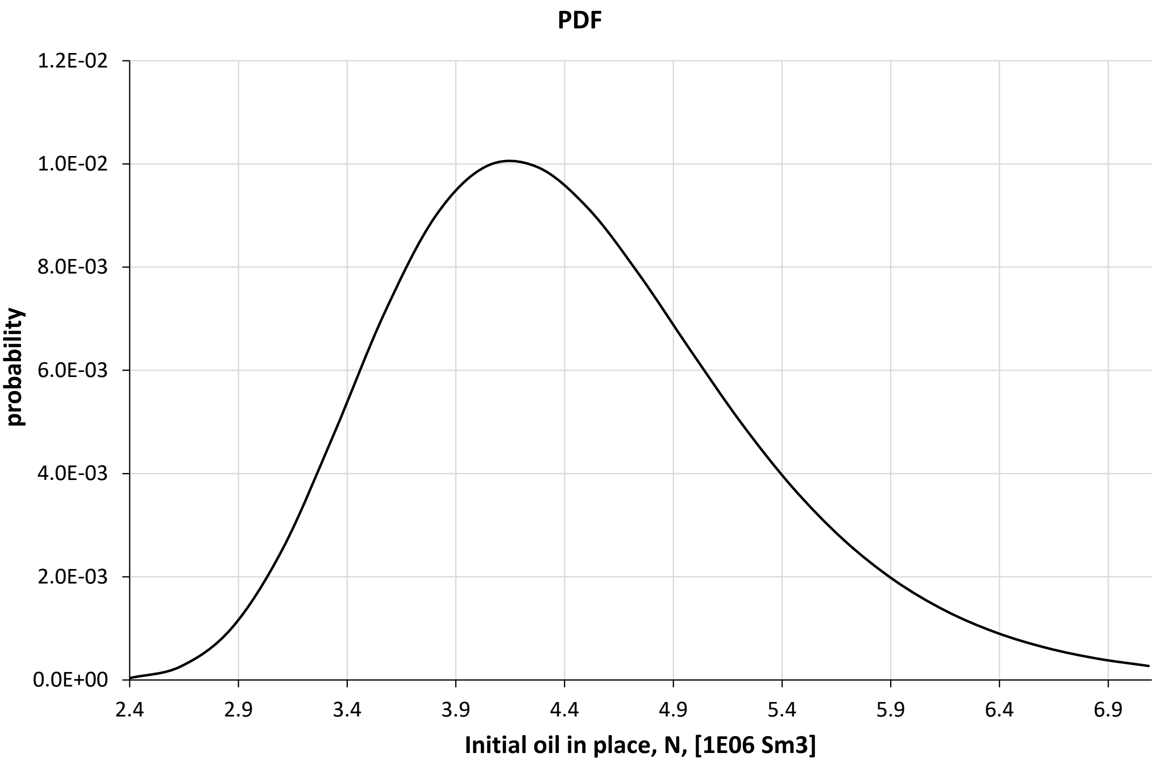
- C is the approximated cost of the development, representing drilling the well, the subsea system and pipeline and topside modifications. Assume equal to 200 million USD.

To capture the effect of uncertainty in the cost, the cost figure of 200 million USD can be multiplied by a factor F, uniformly distributed between 1.2 and 0.8.

$$C_{uncertain} = F \cdot 200$$

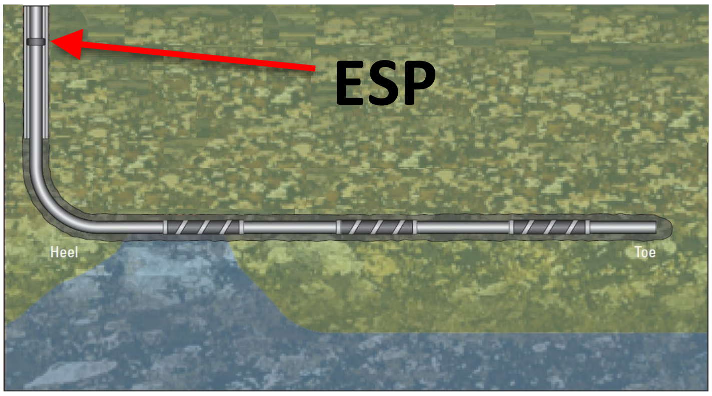
The surface volume in place of oil of the Hanz reservoir exhibits the following cumulative distribution function (cdf) and probability density function (pdf), ranging between 2.4 and 7.1 million Sm^3



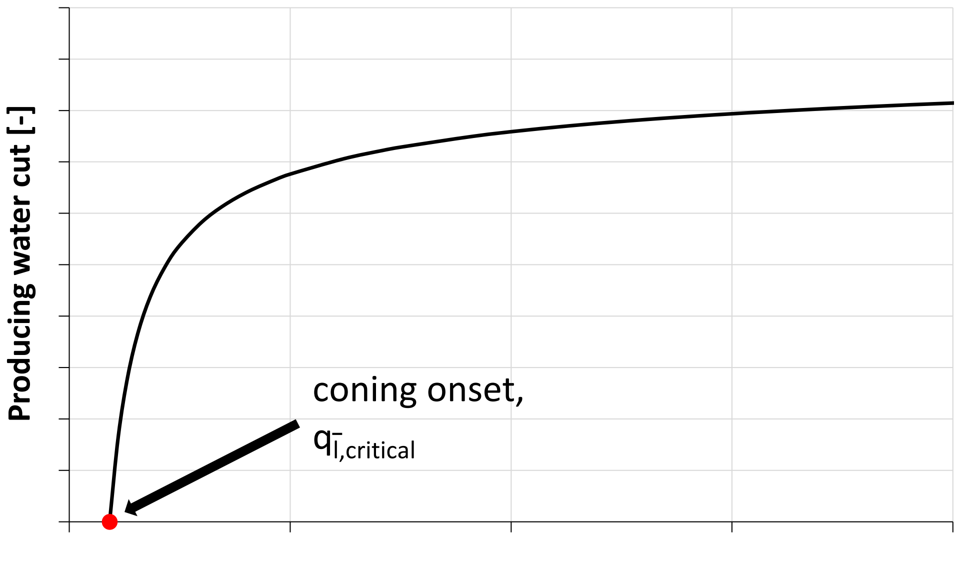

PDF
1.2E-02
1.0E-02
8.0E-03
6.0E-03
4.0E-03
2.0E-03
0.0E+00
probability
2.4
2.9
3.4
3.9
4.4
4.9
5.4
5.9
6.4
6.9
Initial oil in place, N, [1E06 Sm3]

PROBLEM 2 (20 POINTS) – Model-based production optimization of a cluster with 5 ESP-Lifted oil wells in the Rubiales field

Rubiales is a field currently in production in the region of "Los llanos" in Colombia. The reservoir has a thin layer (19 m) containing undersaturated oil and a very strong hydrodynamic bottom aquifer. Wells are ESP-lifted and horizontal like the one shown in the figure below.



Due to the presence of the aquifer, there is coning from the water layer into the wells. The producing watercut of the well is a function of the total liquid rate produced from the well according to the following plot.



The plot is different for each well, and can be approximated with the equation below (given in the attached excel file as a vba function "WC"):

$$WC = f(q_{\bar{l}}) = \begin{cases} if\ q_{\bar{l}} < q_{\bar{l},crit} & WC = 0 \\ if\ q_{\bar{l}} \geq q_{\bar{l},crit} & WC = \dfrac{C \cdot (q_{\bar{l}} - q_{\bar{l},crit})}{1 + (C-1) \cdot (q_{\bar{l}} - q_{\bar{l},crit})} \cdot \dfrac{1}{100} \end{cases}$$

Where WC is output in fraction and $q_{\bar{l}}$ and $q_{\bar{l},crit}$ must be input in Sm^3/d

TASK:
There is a cluster with 5 wells that produce straight to a common small oil-water separator. The data of each well is provided in the excel file attached. You are asked to determine, using model-based production optimization, how much liquid rate must be produced from each well to maximize oil production while keeping the water production below the capacity limit of the separator (1400 Sm^3/d). Deliver the Excel file and a short explanation about how you have solved the problem.

Considerations

- The solution GOR of the oil is small and can be neglected in your calculations
- The producing rate of the well is controlled by adjusting the frequency of the Electric submersible pump. However, instead of modeling the pump, you have been provided with the maximum and minimum liquid rates possible to produce from the well with the ESP.