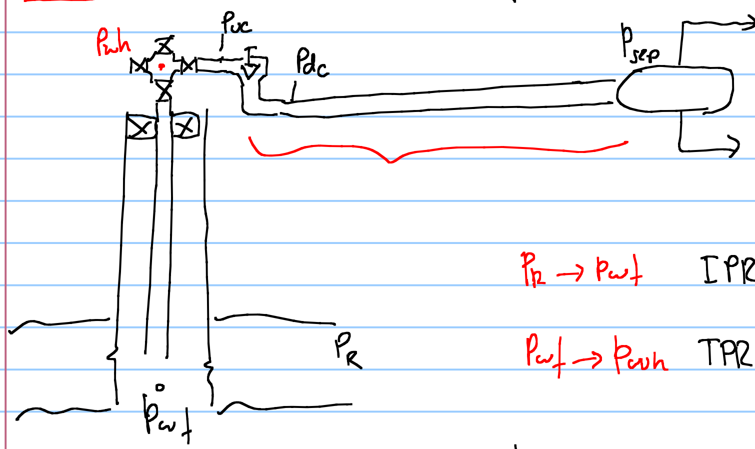
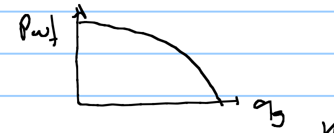
Day 3 04.12.2019 (B2 Tanzania)





$P_R \rightarrow P_{wf}$ IPR equation $q_g = C_R\left(P_R^2 - P_{wf}^2\right)^n$

$P_{wf} \rightarrow P_{wh}$ TPR equation $q_g = C_T\left(\frac{P_{wf}^2}{e^s} - P_{wh}^2\right)^{0.5}$

$P_{uc} \rightarrow P_{dc}$ no equation, simply fix the rate and calculate available pressure upstream and required pressure downstream

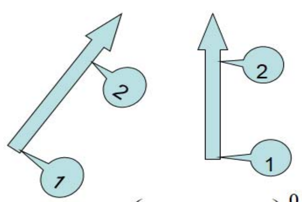
$P_{dc} \rightarrow P_{sep}$ FPR (flowline performance relationship)
assuming horizontal flowline $H = 0$

Tubing flow Equation-Dry gas

$$\boxed{q_{sc} = \left(\frac{\pi}{4}\right)\left(\frac{R}{M_{air}}\right)^{0.5}\left(\frac{T_{SC}}{P_{SC}}\right)\left[\frac{D^5}{\gamma_g f_M Z_{av} T_{av} L}\right]^{0.5}\left(\frac{s e^S}{e^S - 1}\right)^{0.5}\left(\frac{p_1^2}{e^S} - p_2^2\right)^{0.5}}$$

$$\boxed{\frac{s}{2} = \frac{M_g g}{Z_{av} R T_{av}} H = \frac{(28.97)\gamma_g g}{Z_{av} R T_{av}} H}$$

$$q_{gsc} = C_T\left(\frac{p_1^2}{e^s} - p_2^2.\right)^{0.5}$$



$$p_{inlet} = p_1 = e^{s/2}\left(p_2^2 + \frac{q_g^2}{C_T^2}\right)^{0.5} \qquad p_{wh} = p_2 = \left(\frac{p_1^2}{e^s} - \frac{q_g^2}{C_T^2}\right)^{0.5}$$

if $H = 0$ $S = 0$

e^S $e^0 = 1$

$\left(\frac{s e^S}{e^S - 1}\right)^{0.5}$ $S \rightarrow 0$?

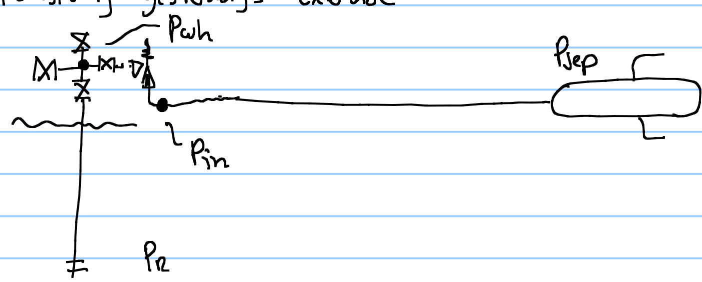
$\frac{0.1}{1-1} \rightarrow \frac{0}{0}$ L'Hopital

$\lim_{S \to 0} \frac{S.e^S}{e^S - 1} = \frac{e^S + e^S.S}{e^S}$

if $S = 0$ $\frac{1 + 0}{1} = 1$

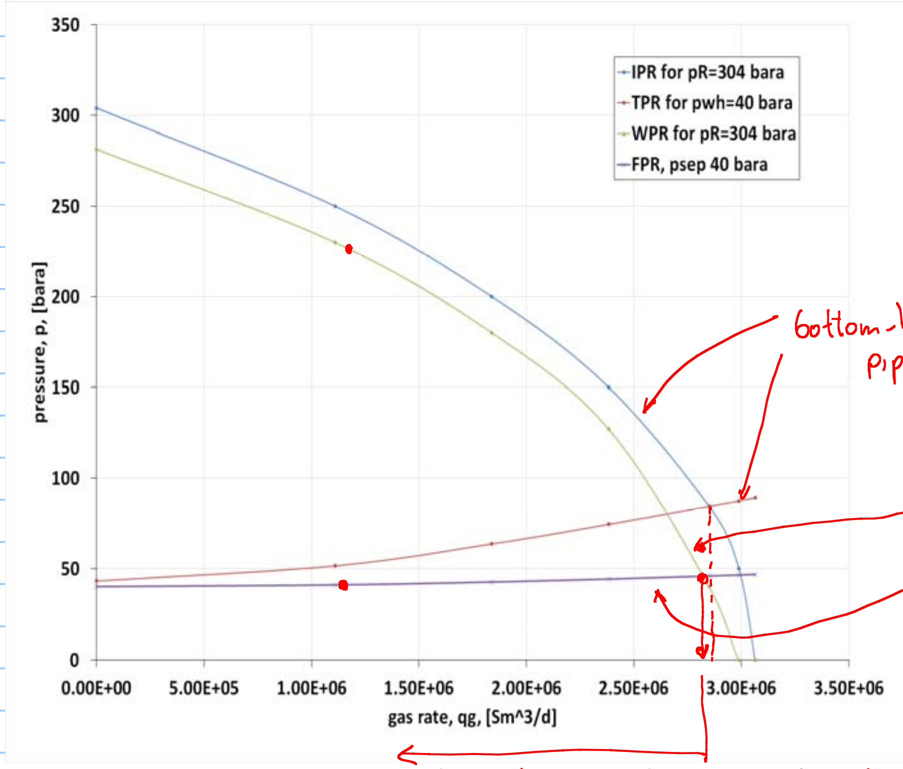
for horizontal flowline $q_g = C_{FL}\left(P_1^2 - P_2^2\right)^{0.5}$

Revisiting yesterdays exercise



$P_R \rightarrow P_{wf} \rightarrow P_{wh}$. available pressure at wellhead

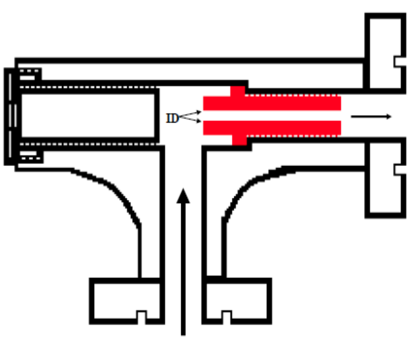
$P_{sep} \rightarrow P_{in}$ required pressure at flowline inlet

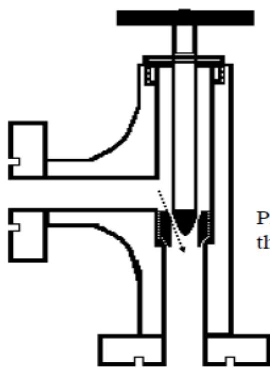


bottom-hole equilibrium, neglecting pipeline

wellhead equilibrium, including pipeline.

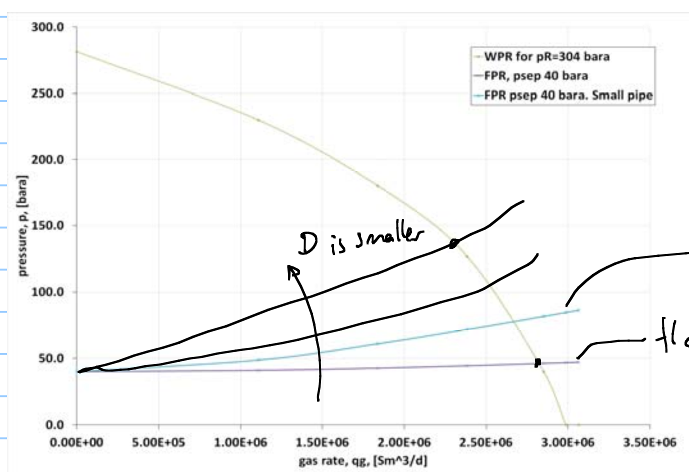
with a choke, p_{wh} is at the upstream and p_{in} is at downstream therefore, I can obtain all rates to the left





it is challenging to operate the choke with high Δp → high velocities → high erosion

"newer" design to avoid excessive erosion



D is smaller

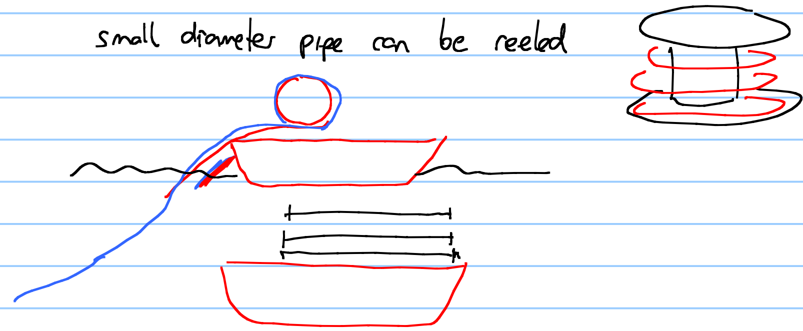
flowline with small pipe

flowline with big pipe

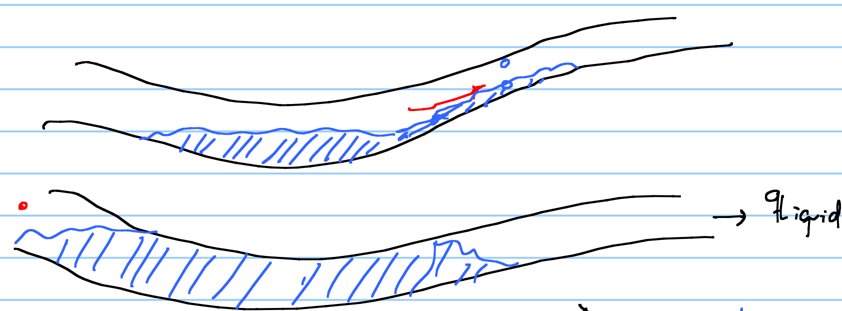
how to decide on flowline diameter?

- provide desired rate → minimize pressure drop
- minimize pipe cost → large pipe is more costly to manufacture
  to transport
  to install

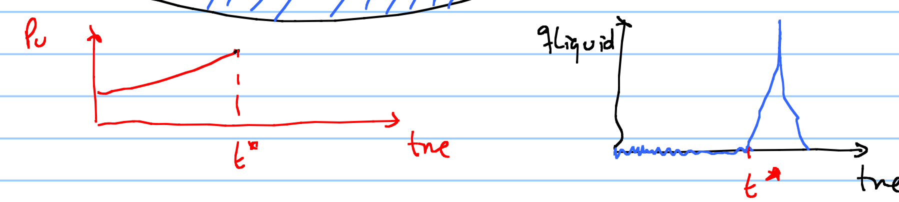
small diameter pipe can be reeled



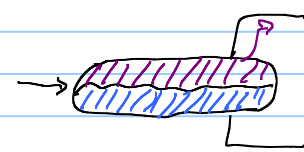
- avoid erosion
- avoid liquid accumulation
  increase v_g reducing ϕ



if slugging cannot be avoided a different type of separator is needed (slugcatcher)

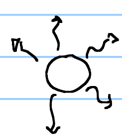


slugging



- avoid excessive cooling

big diameter increases surface area, increases heat transfer



$$\dot{q} = U A (T_f - T_{amb})$$

$\dot{q}$ → heat

U → universal heat tranfer coefficient

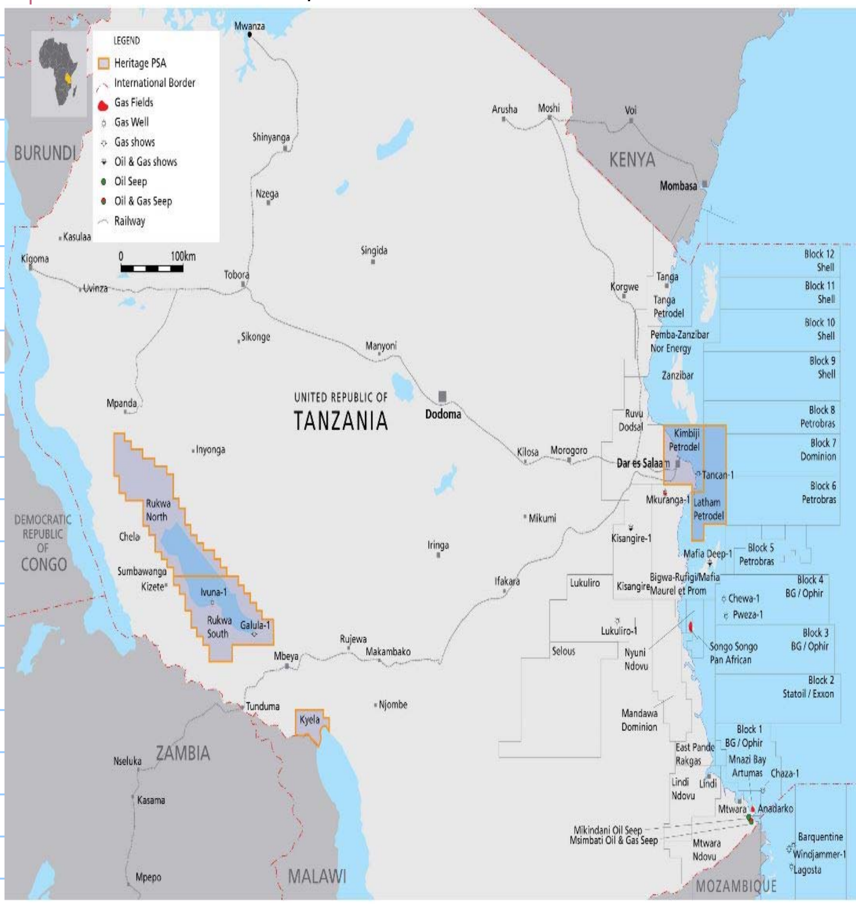
T_f → fluid

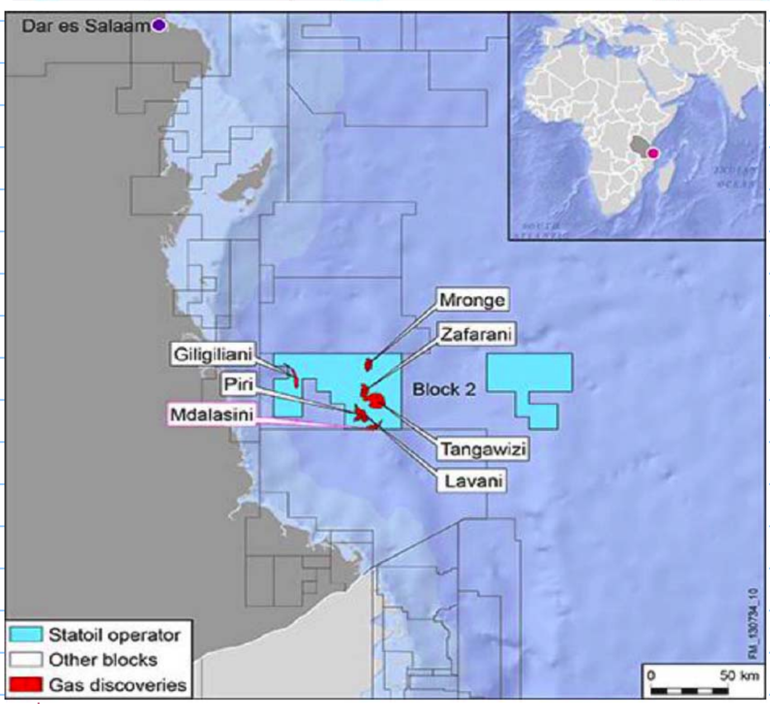
cooling and low temperatures can lead to hydrates, wax

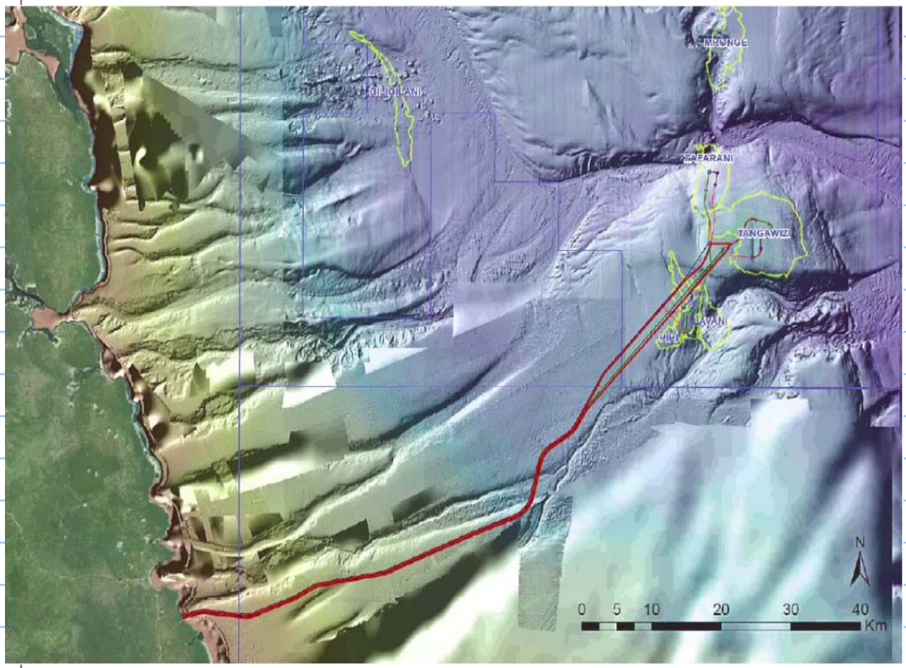
Production scheduling calculations for offshore gas field

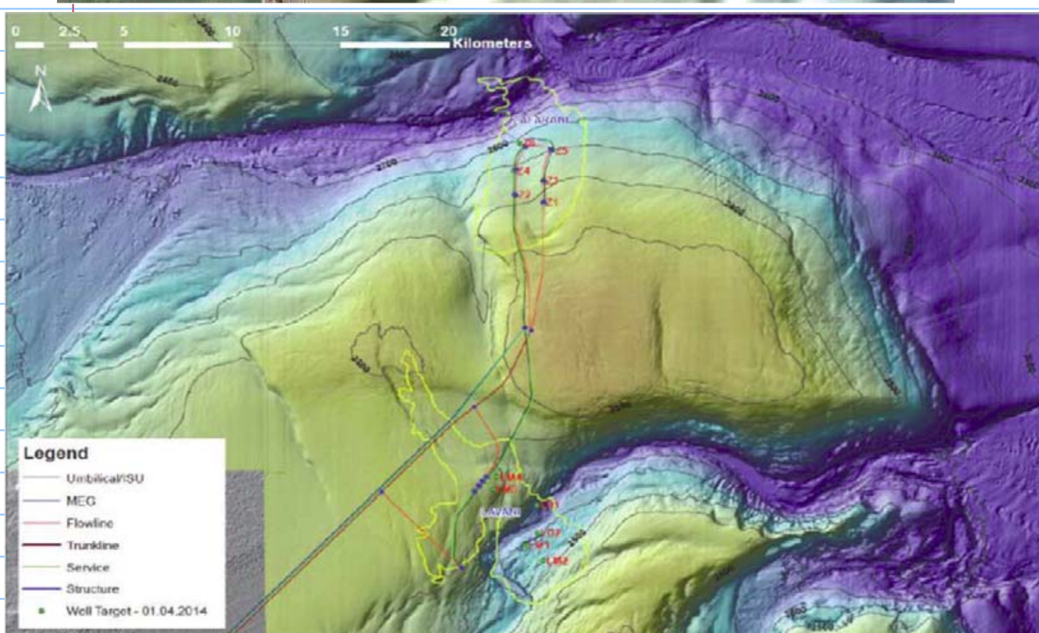
estimating q_{field} vs time (very important for revenue calculations
cost estimation
NPV calculations

Case: Block 2 offshore Tanzania



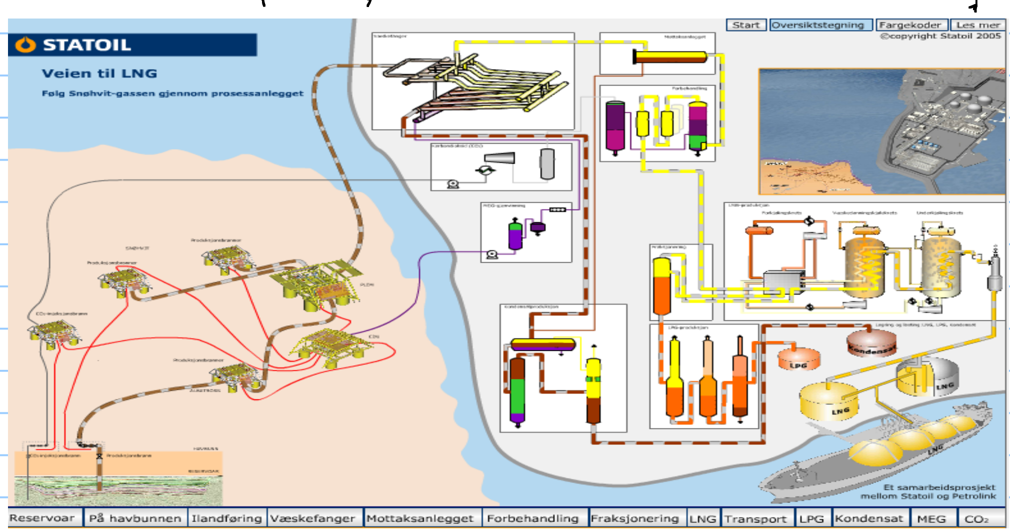


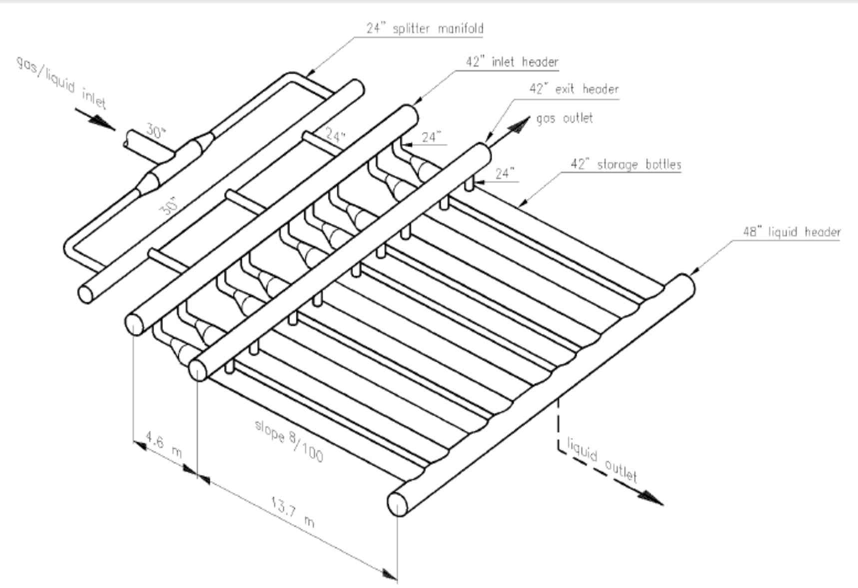


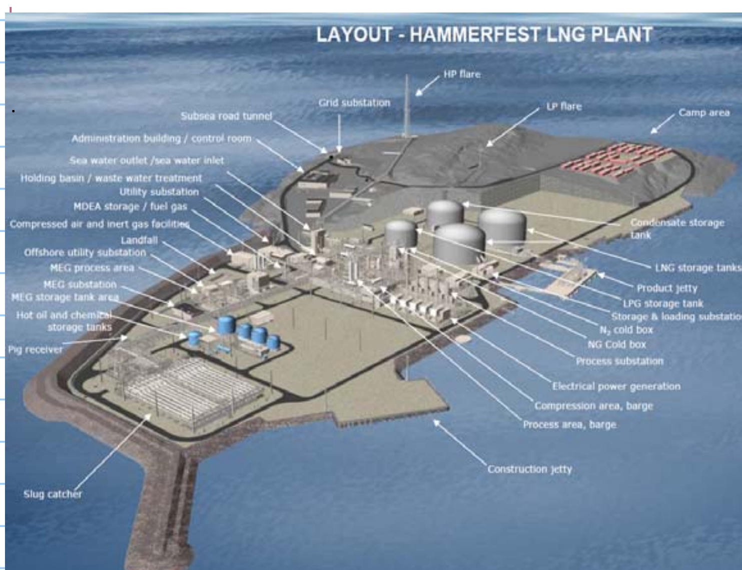


in Norway there is a field very similar to B2, SnøHvit (Snowhite)

Subsea to beach : subsea wells, no platform, no offshore structure and a long transportation pipeline to shore



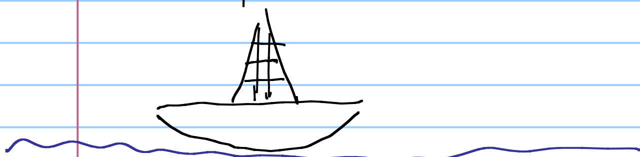

24" splitter manifold
42" inlet header
42" exit header
gas/liquid inlet
gas outlet
30"
24"
24"
24"
30"
42" storage bottles
48" liquid header
slope 8/100
4.6 m
13.7 m
liquid outlet


LAYOUT - HAMMERFEST LNG PLANT
HP flare
Grid substation
LP flare
Camp area
Subsea road tunnel
Administration building / control room
Sea water outlet /sea water inlet
Holding basin / waste water treatment
Utility substation
MDEA storage / fuel gas
Compressed air and inert gas facilities
Landfall
Offshore utility substation
MEG process area
MEG substation
MEG storage tank area
Hot oil and chemical storage tanks
Pig receiver
Condensate storage tank
LNG storage tanks
Product jetty
LPG storage tank
Storage & loading substation
N_2 cold box
NG Cold box
Process substation
Electrical power generation
Compression area, barge
Process area, barge
Construction jetty
Slug catcher

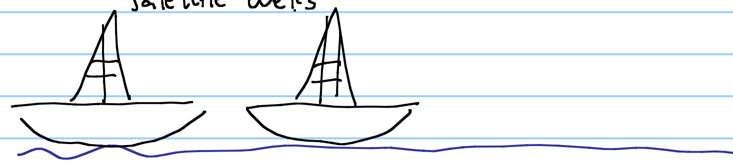
Subsea layout

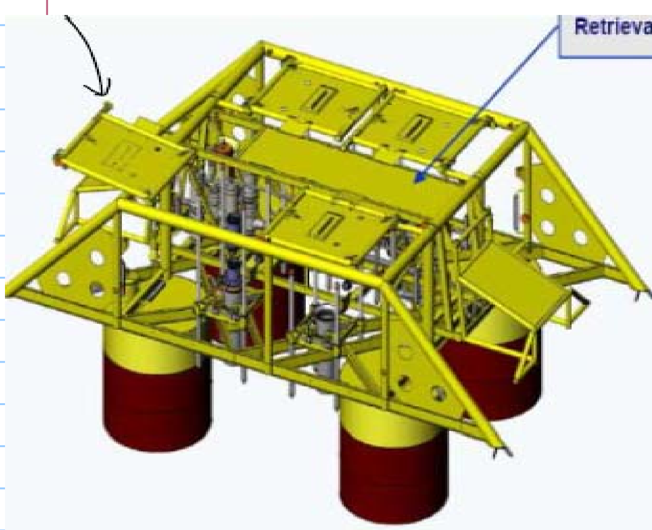
typically, wells are arranged in templates

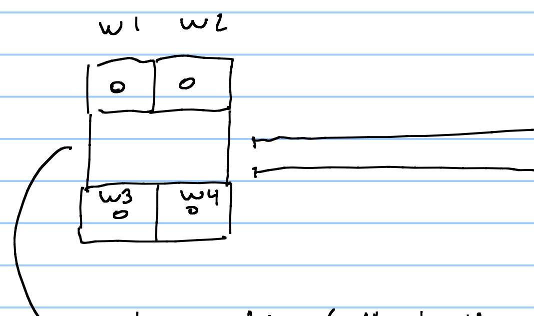
4-slot template



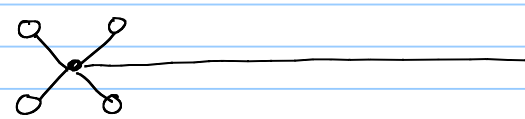
satellite wells



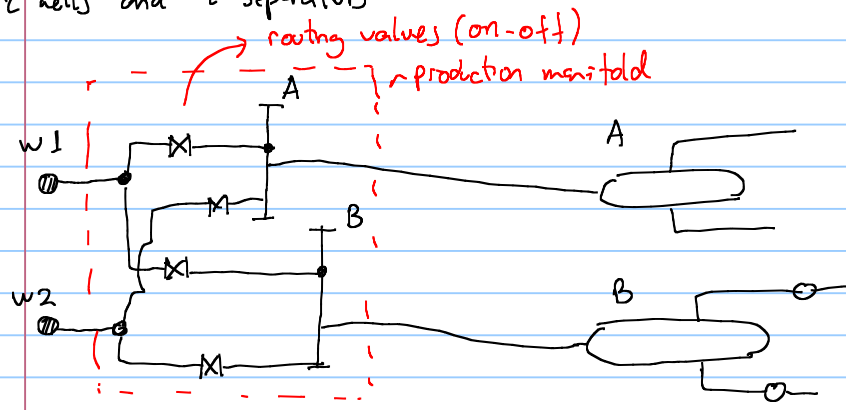




production manifold (collects the production of wells)



2 wells and 2 separators

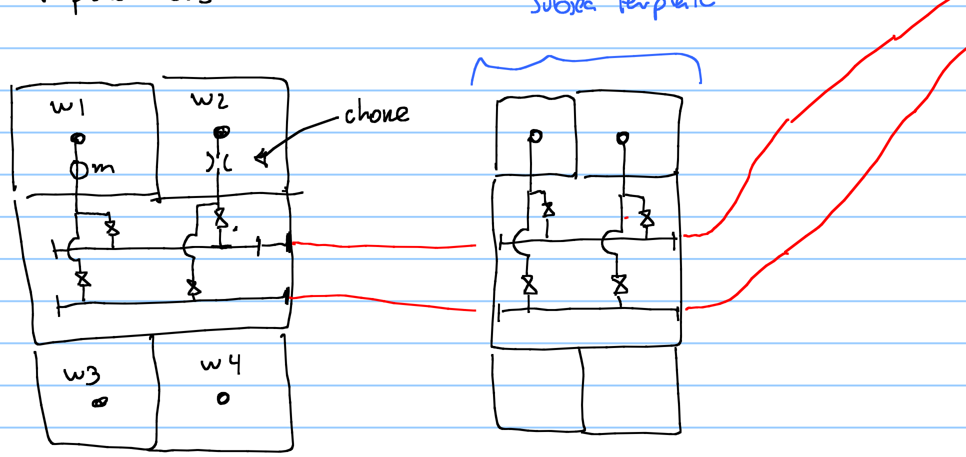


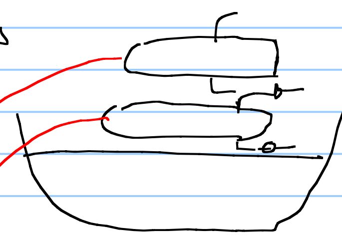
to have the option to send production from w1 to A or to B

include a header for each destination

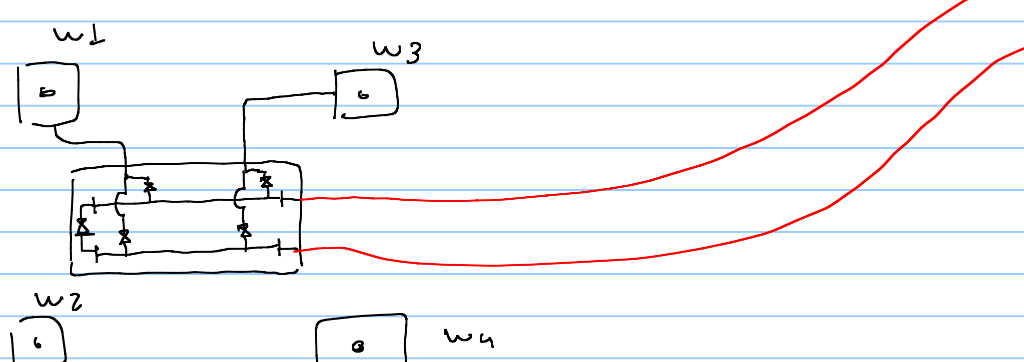
Reasons to use a production manifold : for well testing (allocation)
↳ to find out how much is the well producing and split production and revenue among partners
to improve models (production (reservoir history matching))

subsea, we have the same arrangement of headers, routing valves, and pipes for template wells

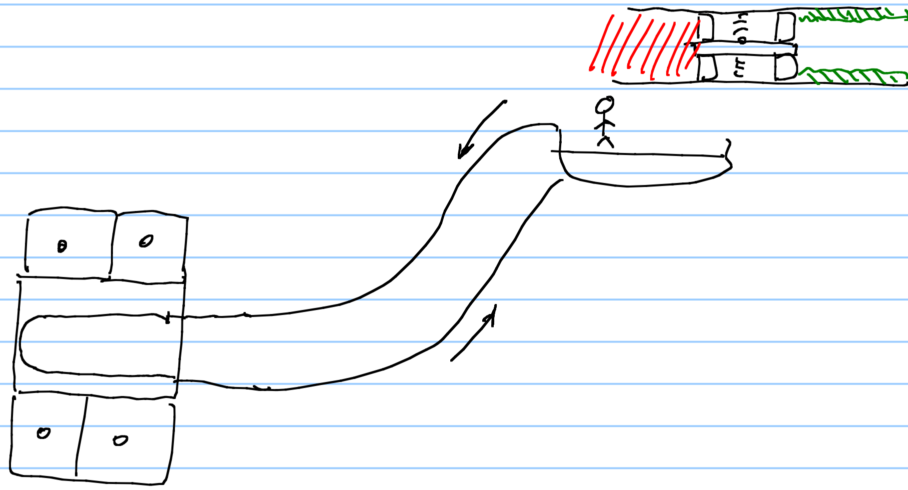




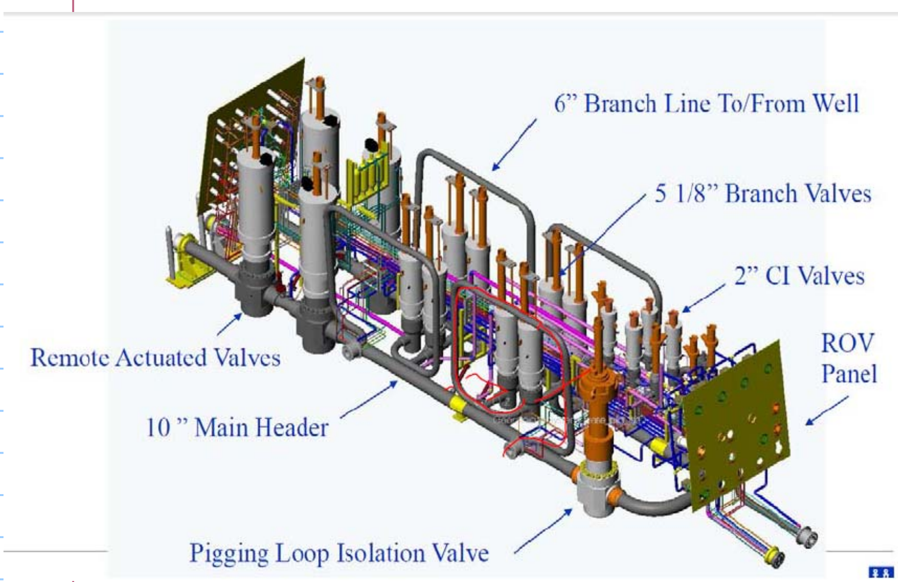
what happens when you have satellite wells?

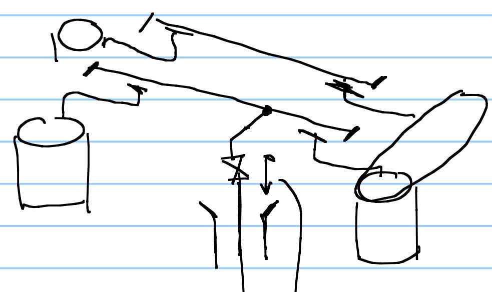


some reasons to have two flowlines:
- to meter rates topside (test separator)
- to use 2 separators and smaller pipelines (operational flexibility)
- to perform pigging.
  - inspection and monitoring pipe thickness
  - evacuate liquid e.g used hydrostatic pressure test
  - remove wax accumulations

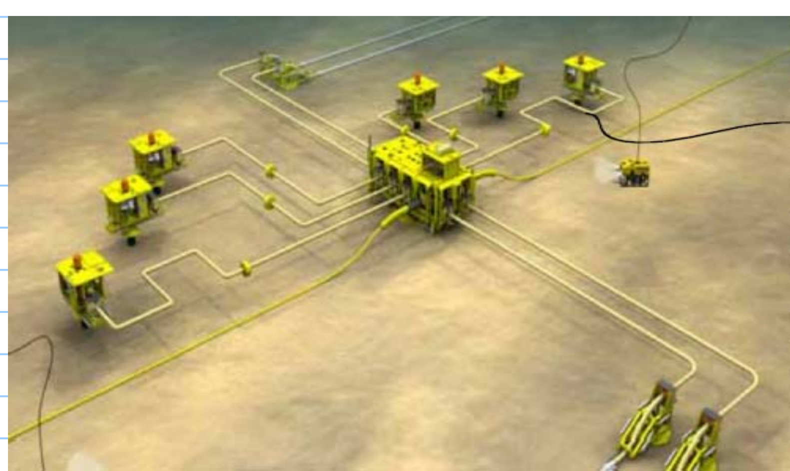


manifold module of 4 well subsea template

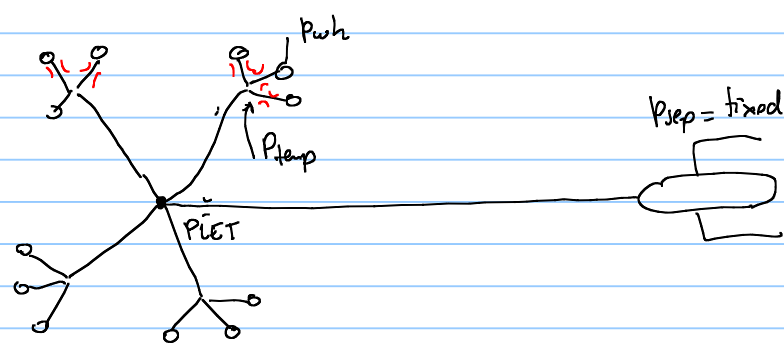




cooling and warming up of well



B2 problem (12 wells)



a long term gas contract produced mode A

$G = 311\,E\,9\ Sm^3$

set equilibrium point = choke

- All well are identical
- All template are identical
- All template are located symmetrical and same distance from PLET

2-5% of TRR produced anually

$TRR = G \cdot \underbrace{R_{Fo}}_{0.8} = 311 \cdot 0.8\ 1E09 = 248\,E09$

$q_{plateau} = \dfrac{TRR \cdot 0.02}{N_{day\ in\ year}} = \dfrac{248\,E09 \cdot 0.02}{365}$

$q_{plateau} = 13.6\,E6\ Sm^3/d$

calculate $q_w = \dfrac{q_{field}}{N_w}$

compute available pressure at P_{wh}

$P_R - P_{wf}$ IPR equation with q_w

$P_{wf} \rightarrow P_{wh}$ TPR equation with q_w

compute required pressure downstream the choke (P_{temp})

$P_{sep} \rightarrow P_{PLET} \rightarrow$ pipeline equation with q_{field}

$PLET \rightarrow P_{temp} \rightarrow$ flowline equation with $q_{temp} = \dfrac{q_{field}}{N_{temp}}$

- verify $P_{wh} > P_{temp}$? $\xrightarrow{\text{if yes}}$ production is possible by choking

  $\xrightarrow{\text{if not}}$ production is not possible, rate must be reduced

IPR TPR FPR PPR (pipeline performance relationship)

time	P_R	P_{wf}	P_{wh}	P_{temp}	P_{plet}	P_{sep}
→ 0						
1						

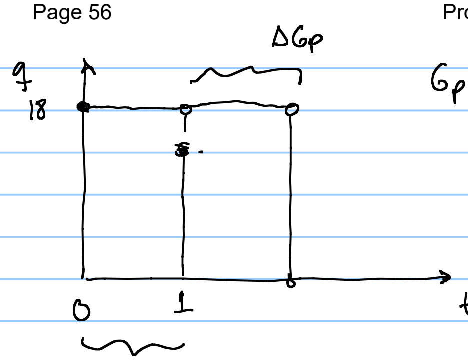
time 0 years means first day of year 1

time 1 years means first day of year 2

$P_R = P_{Ri} \dfrac{z_R}{z_{Ri}} \left(1 - \dfrac{G_p}{G}\right)$?

RF

to calculate G_p for $t = 1$ i assume production remained constant from $t = 0 \rightarrow t = 1$



$$G_{p_2} = \Delta G_{p_1} + \Delta G_{p_2}$$

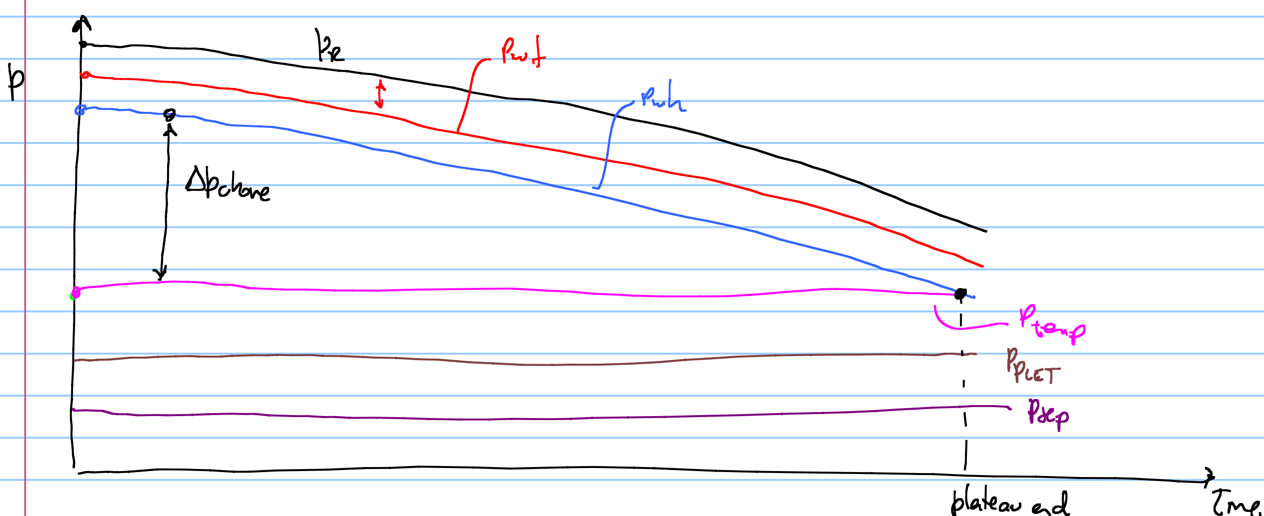
$$\Delta G_p = q_{field\,(t=0)} \cdot \Delta t \quad N_{days/year}$$

$$\left[Sm^3/\cancel{d}\right] \quad \left[\cancel{years}\right] \quad \left[\cancel{d}/\cancel{year}\right]$$

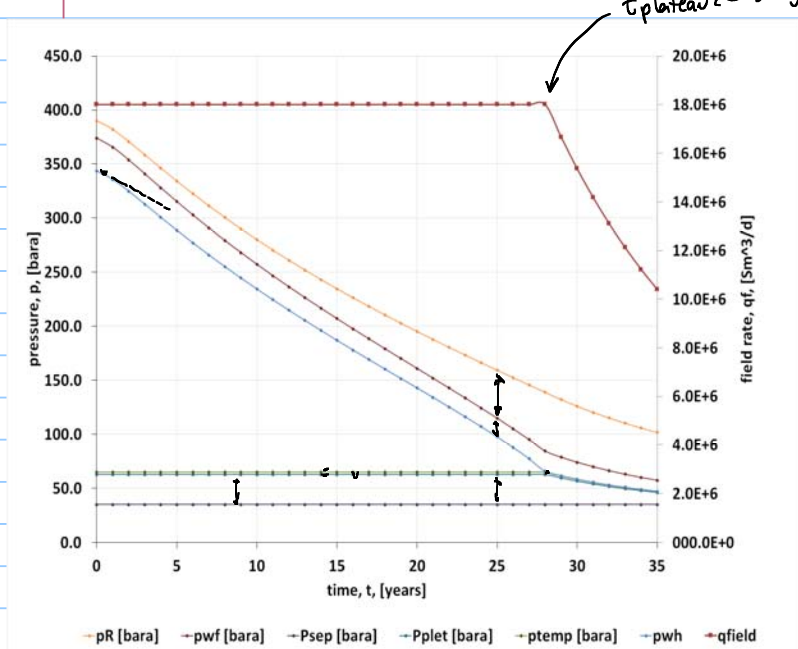
$$G_p = \sum_{i=0}^{N} \Delta G_p$$

usually the company doesn't operate all day in year

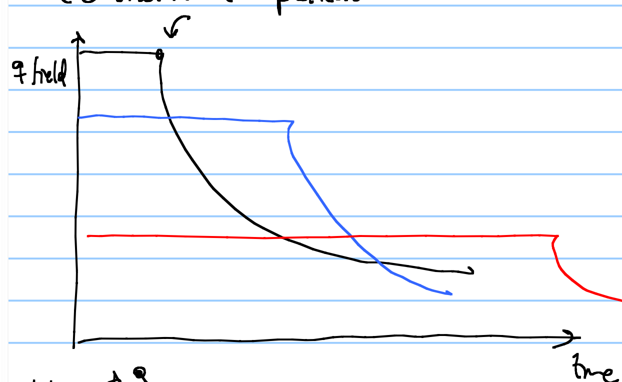
uptime = N producing days in a year < 365

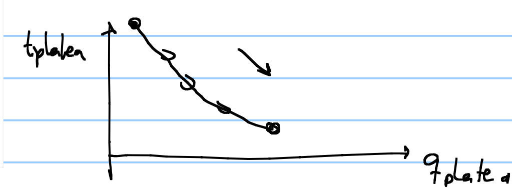


tplateau ~ 28 years



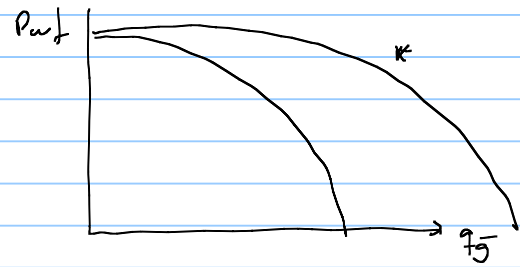
usually the higher the plateau rate, the shorter the plateau





How to extend the plateau?

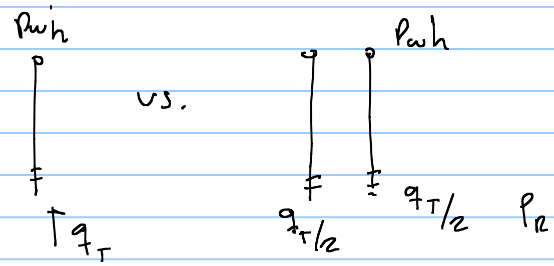
- make available pressure higher or make it decline "slower"
  - P_R ~ pressure support to reservoir injection? → for oil water/gas; for gas not feasible
  - "enhance" IPR



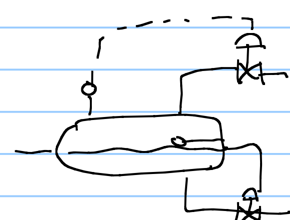
stimulation
fracking
acidizing (cleaning pores)

  - Increase tubing size. if oil reservoir { pumping in well artificial lift; gas lift }

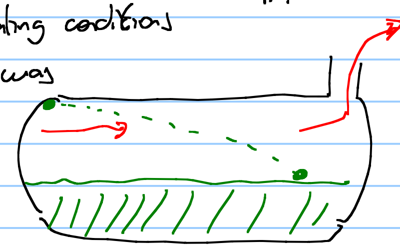
  - Increase N_w → lower rate per well, lower pressure drop in formation and in tubing therefore higher P_{wh}



- making required pressure lower plateau?
  - lower P_{sep} → change separator set



might not be desirable because it changes operating conditions for which equipment was designed



if P_{sep} is reduced v_g ↑

high pressure   low pressure

$$\dot{m}_g = \dot{m}_g$$

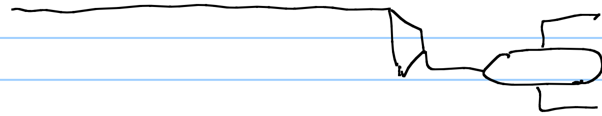
$$\rho_g \, q_g = \rho_g \cdot q_g$$

P is high ρ is also high   P is low, ρ_g is low

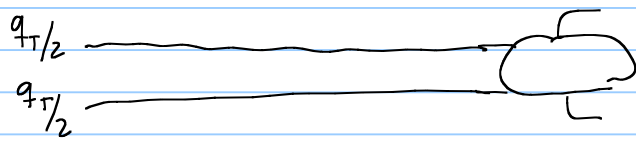
q_g for low pressure is higher than q_g for high pressure

$$v_g = \frac{q_g}{A_{sep}}$$

- add a compressor before separator



- increase pipeline diameter
- increase flowline diameter
- add another pipeline



- homework repeat calculations for plateau rate of 25E06 Sm^3/d

NPV calculations (Net present value): Sum expenses and revenue of project and refer all to a common date

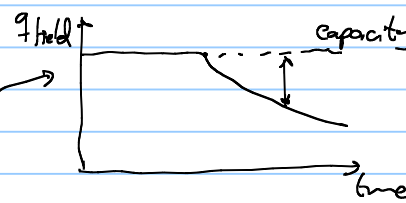
operational expenditures (OPEX) (–) occur after field starts producing
- salaries
- power consumption
- maintenance of equipment
- well intervention
- insurance
- chemical usage { biocide, corrosion inhibitor, hydrate, wax
- transportation

field "X"

(–) occur during first years

capital expenditures {CAPEX}
- drilling, completing wells (DRILLEX)
- processing facilities (separators, gas turbine, compressors, pumps, control system)
- offshore structure
  ↳ FPSO, GBS, Jackup
- subsea system
- engineering studies
- export system → pipeline, tankers

revenue ? (+)
sales of hydrocarbons { oil, gas
rental of processing capacity



Cash flow calculation

time	CAPEX	DRILLEX	OPEX	Revenue [USD]	Cash flow
0	$\boxed{-}$	0	0	0	$\Sigma (+)(-)$
1	$\boxed{-}$	$\boxed{-}$	0	0	
2	$\boxed{-}$	$\boxed{-}$	0	0	
3	$\boxed{-}$	$\boxed{-}$	0	0	
4	$\boxed{-}$	$\boxed{-}$	0	0	
5	0	0	$\boxed{-}$	$\boxed{+}$	
	0	0	(−)	$\boxed{+}$	
	0	0	(−)	$\boxed{+}$	
	0	0	(−)	$\boxed{+}$