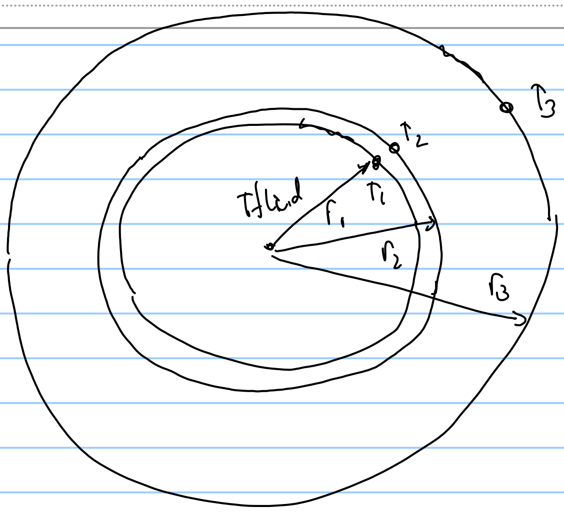
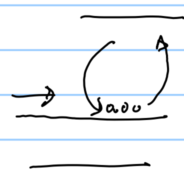


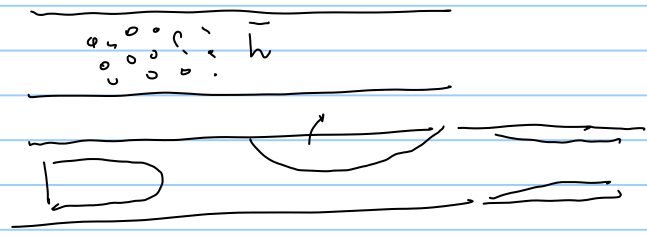
Free convection



Sea bed · Tamb

- forced convection on internal flow

$$\dot{q} = 2\pi r_1 L h_{int} (T_f - T_1)$$



- Conduction in pipe wall

$$\dot{q} = 2\pi L k_{pipe} \frac{(T_1 - T_2)}{\ln\left(\frac{r_2}{r_1}\right)}$$

- Conduction in insulating layer

$$\dot{q} = 2\pi L K_{insulation} \cdot \frac{(T_2 - T_3)}{\ln\left(\frac{r_3}{r_2}\right)}$$

$$\dot{q} = A \cdot h (\Delta T)$$

$$\Delta T = \frac{q}{A \cdot h}$$

- Convection in sea

$$\dot{q} = 2\pi r_3 h_{out} \cdot L (T_3 - T_{amb})$$

in these equations clear the Temperature difference and sum them up:

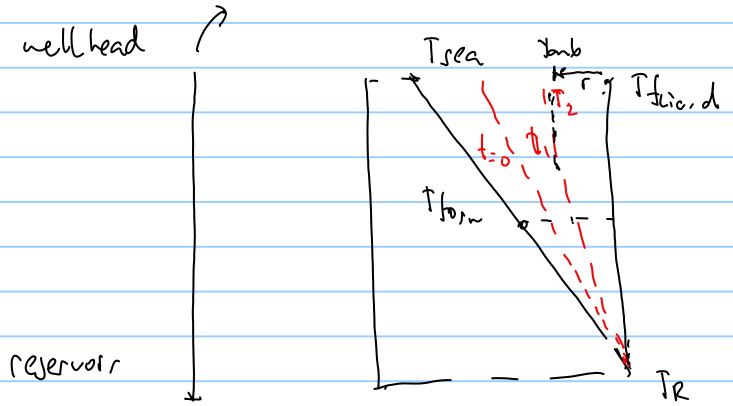
$$(T_f - T_1) + (T_1 - T_2) + (T_2 - T_3) + (T_3 - T_{amb}) = \dot{q} \left(\frac{1}{2\pi r_1 L h_{in}} + \frac{\ln\left(\frac{r_2}{r_1}\right)}{2\pi k_{pipe} L} + \frac{\ln\left(\frac{r_3}{r_2}\right)}{2\pi K_{ins} \cdot L} + \frac{1}{2\pi r_3 \cdot L \cdot h_{out}} \right)$$

overall heat transfer coefficient

$$(T_f - T_{amb}) = \dot{q} \frac{1}{U \cdot 2\pi r_3 \cdot L} = \dot{q} \left(\frac{1}{2\pi r_1 L h_{in}} + \frac{\ln\left(\frac{r_2}{r_1}\right)}{2\pi k_{pipe} L} + \frac{\ln\left(\frac{r_3}{r_2}\right)}{2\pi K_{ins} \cdot L} + \frac{1}{2\pi r_3 \cdot L \cdot h_{out}} \right)$$

$$\frac{1}{U} = \left[\frac{1}{h_{in}\left(\frac{r_1}{r_3}\right)} + \frac{\ln\left(\frac{r_2}{r_1}\right) r_3}{k_{pipe}} + \frac{r_3 \ln\frac{r_3}{r_2}}{k_{ins}} + \frac{1}{h_{out}} \right)$$

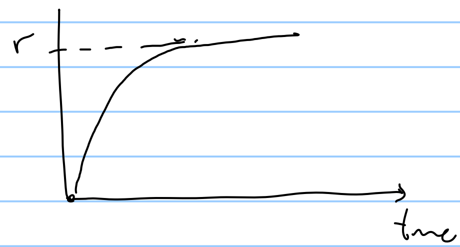
overall heat transfer coefficient referred for outer area



$$\frac{\partial}{\partial t} \neq 0$$

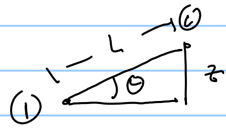
Tamb will be located at an position r that varies with time.!

Ramey - Stanford (1956)



Energy equation in the fluid:

$$\frac{d\dot{q}}{dL} = \dot{m}\left(\frac{dh}{dL} + v\frac{dv}{dL} + \frac{dz}{dL} g\right)$$



$$\frac{z}{L} = \sin(\theta)$$

$$\frac{d\dot{q}}{dL} = \dot{m}\left(\frac{dh}{dL} + \cancel{v\frac{dv}{dL}} + \sin(\theta) g\right)$$

0

- neglecting velocity changes along the pipe ~ heavy oil + water

(p, T) EoS correlation

if liquid

- $dh = C_p(T)\, dT$

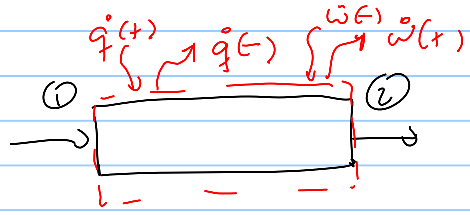
for gas, compressible fluid, Joule thompson

$$dh = C_p(T)\, dT + \mu_J \cdot dp$$

neglect

$$\frac{d\dot{q}}{dL} = \dot{m}\left(C_p \frac{dT}{dL} + \sin\theta\, g\right)$$

$$\dot{q} = 2\pi r_{out} L U_{out} (T_f - T_{amb})$$



$$-2\pi r_{out} U_{out} (T - T_{amb}) = \dot{m} C_p \frac{dT}{dL} + \dot{m} g \sin\theta$$

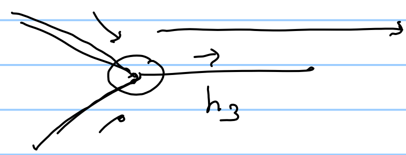
$$\frac{dy}{dx} + ay = C$$

$$\frac{dT}{dL} + T \cdot \frac{1}{A} - \frac{T_{amb}}{A} - \frac{\sin(\theta) \cdot g}{c_p} = 0$$

$$A = \frac{\dot{m} C_p}{2\pi r_{out} \cdot U}$$

$$u \cdot \frac{dT}{dL} + u \cdot T \cdot \frac{1}{A} = u \cdot \left(\frac{T_{amb}}{A} + \frac{\sin(\theta) \cdot g}{c_p} \right)$$

$$u = e^{\frac{x}{A}}$$



$$e^{\frac{x}{A}} \cdot \frac{dT}{dL} + e^{\frac{x}{A}} \cdot T \cdot \frac{1}{A} = e^{\frac{x}{A}} \cdot \left(\frac{T_{amb}}{A} + \frac{\sin(\theta) \cdot g}{c_p} \right)$$

$$\dot{m}_1 h_1 + \dot{m}_2 h_2 = \dot{m}_3 h_3$$

$$\frac{d\left(e^{\frac{x}{A}} \cdot T \right)}{dL} = e^{\frac{x}{A}} \cdot \left(\frac{T_{amb}}{A} + \frac{\sin(\theta) \cdot g}{c_p} \right)$$

$$e^{\frac{x}{A}} \cdot T \Big|_{T_0}^{T(x)} = \left(\frac{T_{amb}}{A} + \frac{\sin(\theta) \cdot g}{c_p} \right) \cdot A \cdot e^{\frac{x}{A}} \Big|_0^x$$

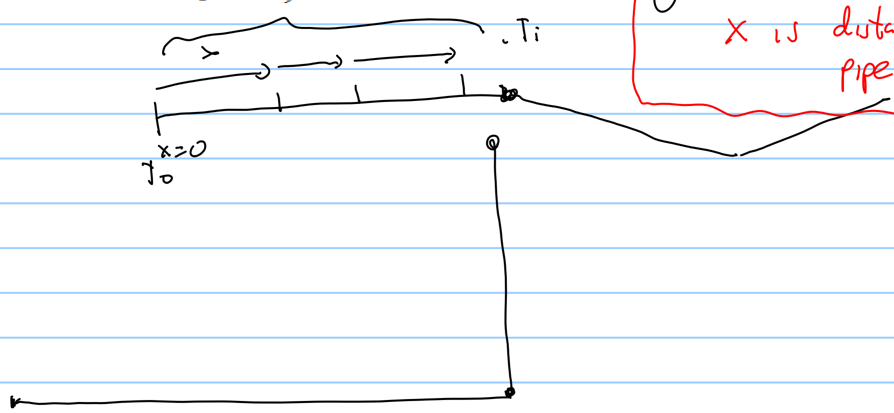
$$e^{\frac{x}{A}} \cdot T(x) - T_0 = \left(\frac{T_{amb}}{A} + \frac{\sin(\theta) \cdot g}{c_p} \right) \cdot A \cdot \left(e^{\frac{x}{A}} - 1 \right)$$

$$T(x) = T_0 \cdot e^{\frac{-x}{A}} + \left(\frac{T_{amb}}{A} + \frac{\sin(\theta) \cdot g}{c_p} \right) \cdot A \cdot \left(1 - e^{\frac{-x}{A}} \right)$$

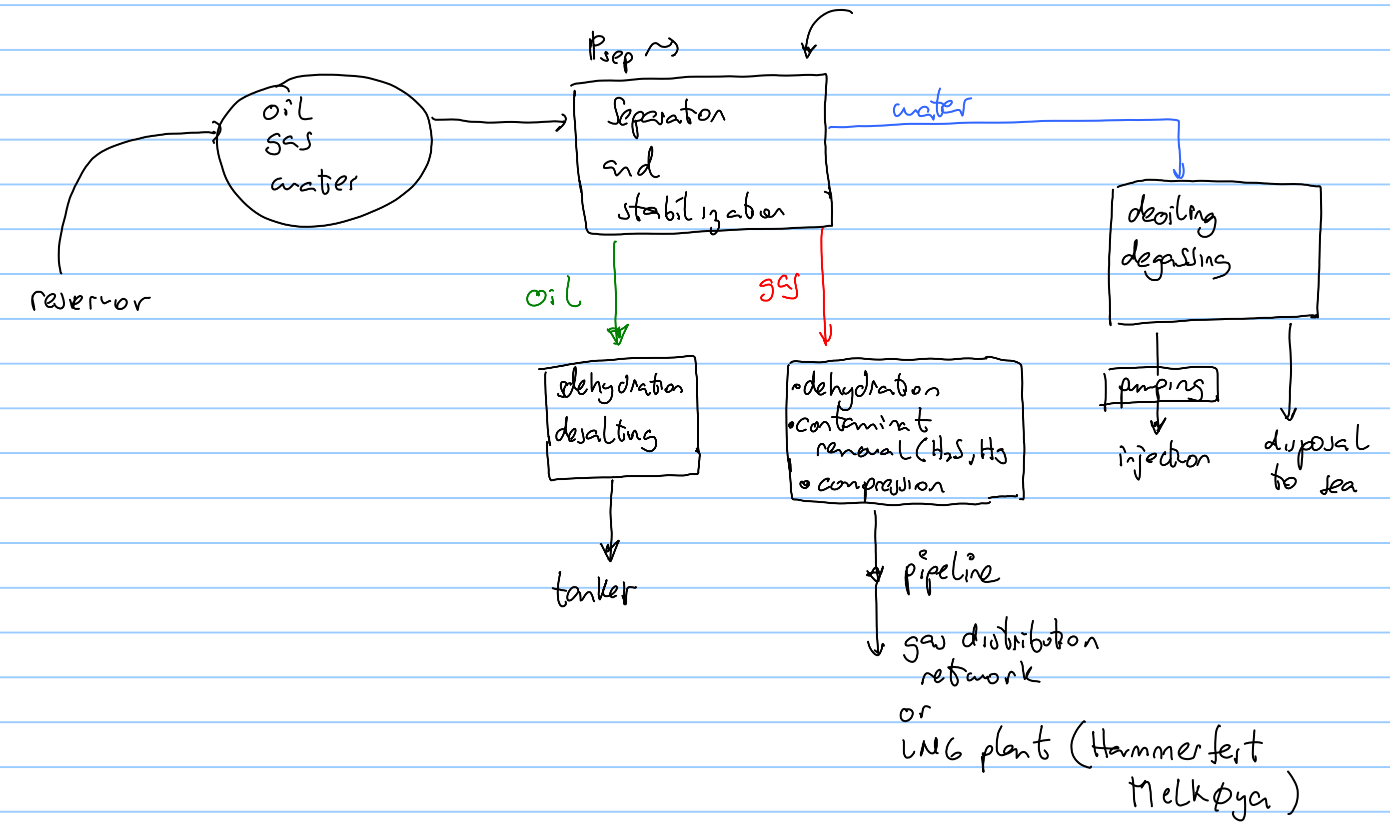
this equation applies for a given pipe segment when U, C_p, θ, $\dot{m}$, r_{out}, remain constant.

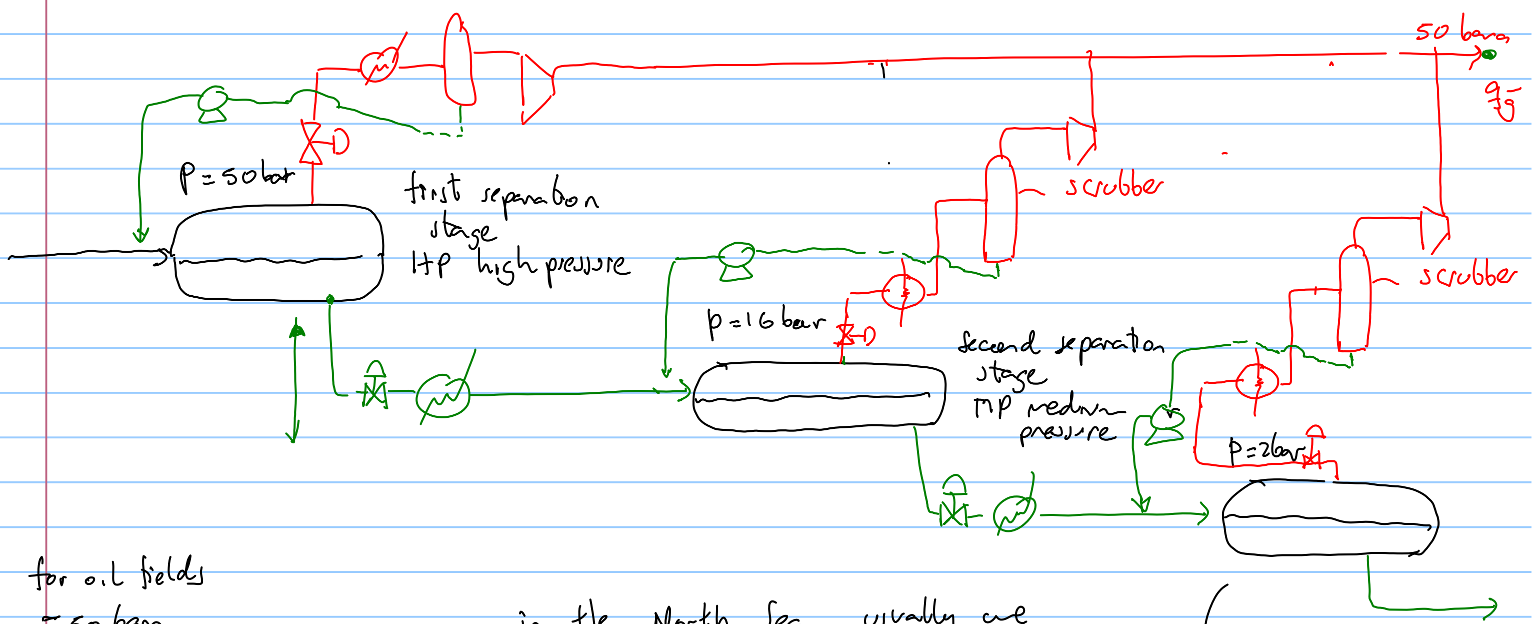
U

x is distance ALONG pipe.



Processing of hydrocarbon fluids ~> equipment on platform





(3rd separation stage
LP low pressure

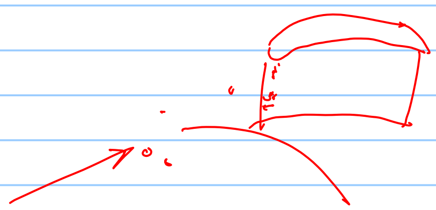
for oil fields
≈ 50 bara
for low GOR
oils

in the North Sea usually we
use 3 stages

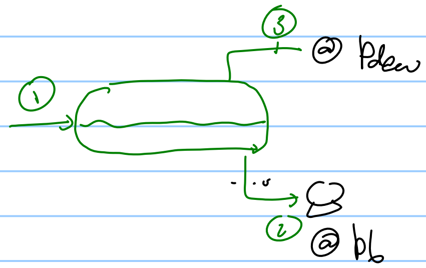
it can be down to 20 bara

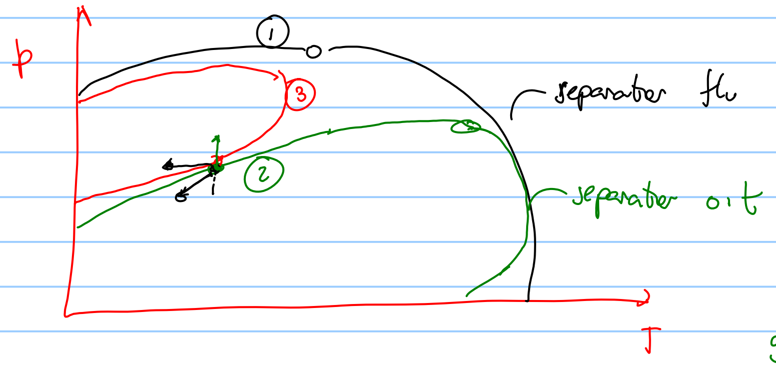
for gas
higher than 50 bara

compressor can only work with
gas (dry)

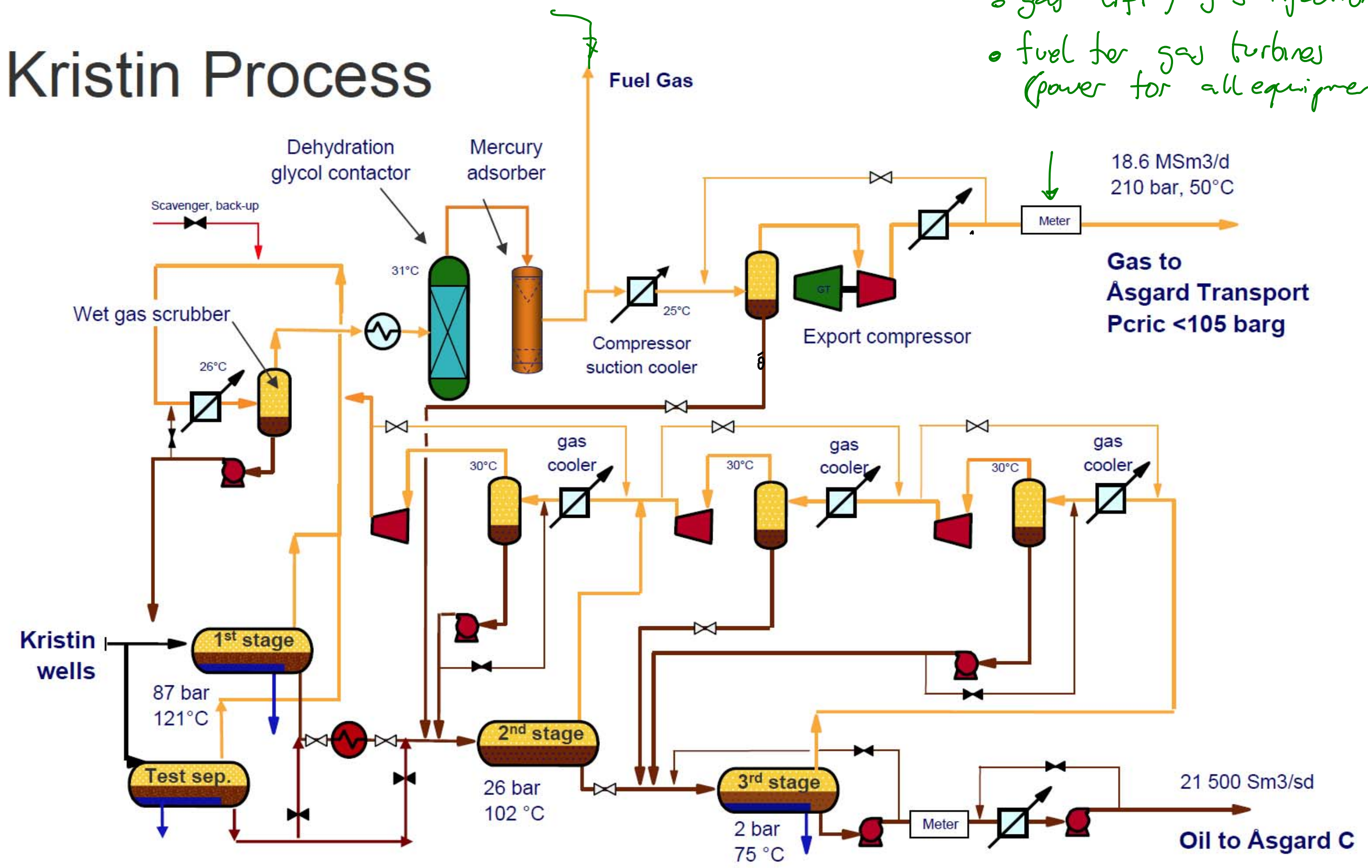


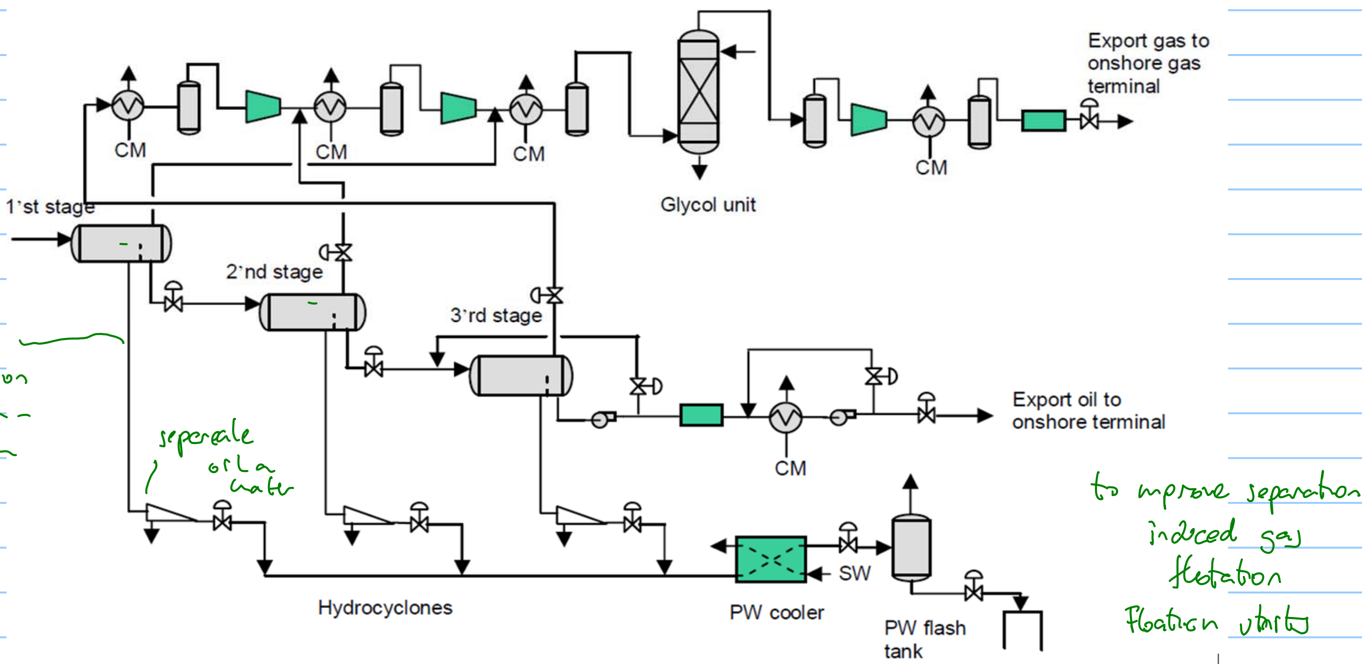
in every separation stage





gas can be used for
- gas lift, gas injection
- fuel for gas turbines (power for all equipment)





OiW concentration 1000ppm – 500ppm

seperate oil a water

to improve separation induced gas flotation

Flotation units

Typical processing capacities of an oil field: $q_{\bar{o}}$: 8000 Sm^3/d – 50000 Sm^3/d

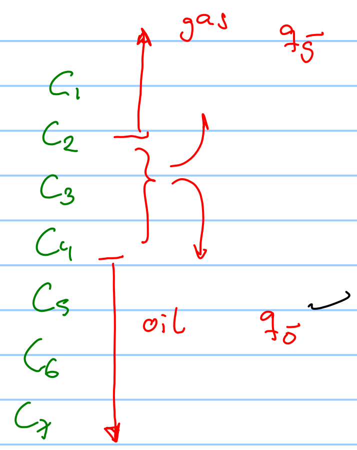
$q_{\bar{g}}$ = 1.5 – 8.5 E6 Sm^3/d

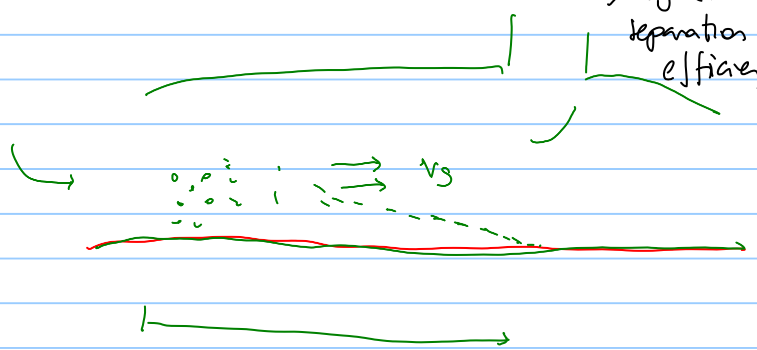
$p_{HP} \approx 50$ bara

number of stages : 3
number of trains : 1-2

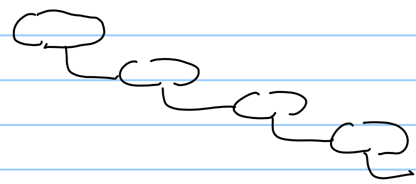
How processing facilities affect the field design process?

- Pressure of 1st stage separator
  - high pressures gives better liquid recovery
  - high pressures reduce production rates from reservoir
  - high pressure ⇝ gas occupies less volume; v_g are less ⇝ less Δp ↳ higher separation efficiency





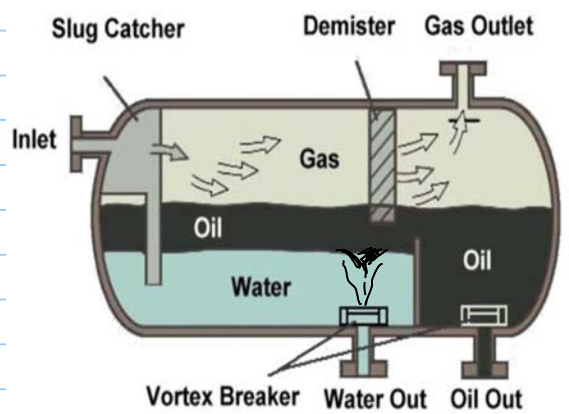
more separation stages also improve liquid recovery



Usually for oil p_{HP} is 50 bara or less

Usually for gas p_{HP} can be higher 50 bara

Separators are three phase separator (most of the water is separated in the first stage)



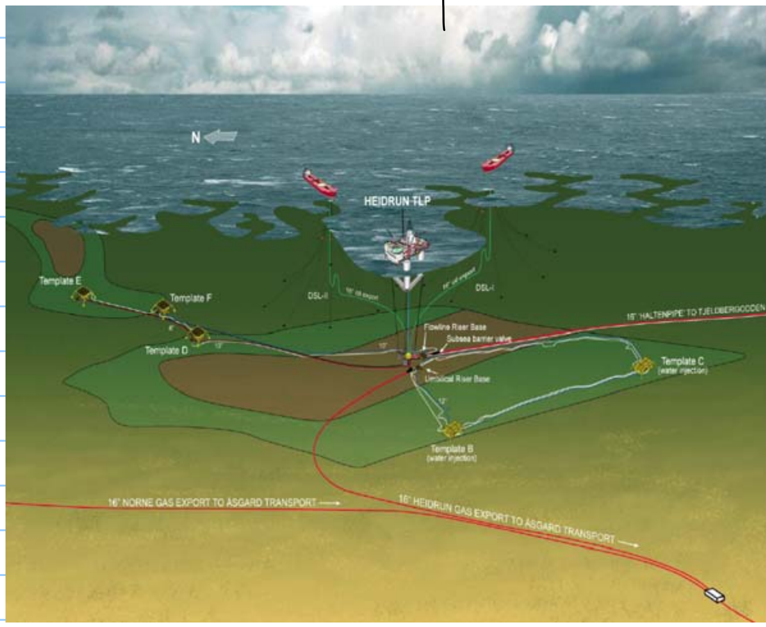
facilities have maximums of : processing capacity of gas { dehydration unit, compressor }

processing capacity of water { cyclones }

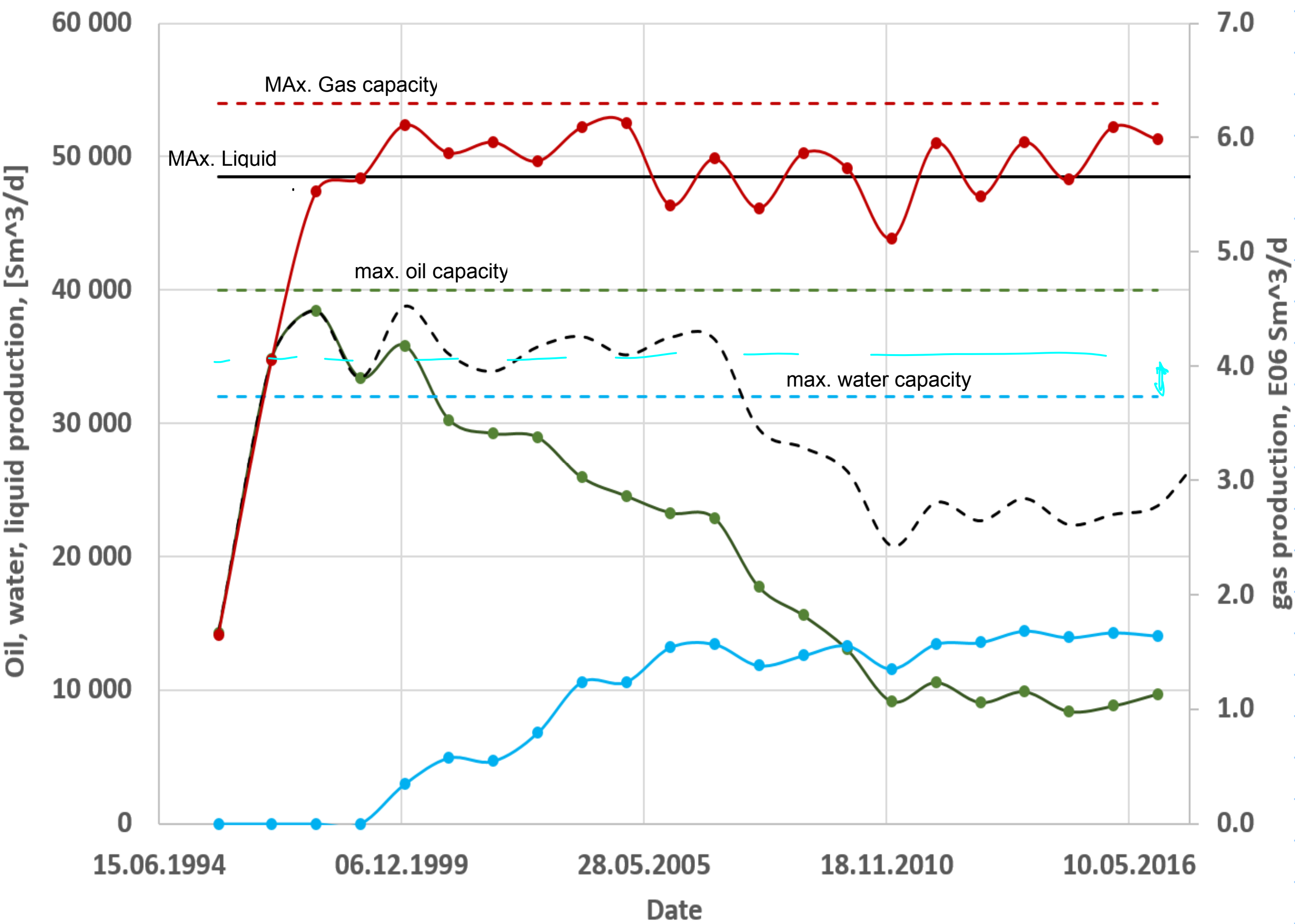
If at any point in time, i reach one of these capacities, there is no choice but to choke back production!

processing capacity of liquid { separator capacity, separator level }

Let's look at the production profile of Heidrun:



In Heidrun it looks like gas is at its maximum capacity, thus it migh indicate that the production of the field had to be choked back.



Increasing the capacity of the processing facilities costs money, bigger capacity, bigger size, more weight and more space on the platfo
The optimal capacity should be studied using an economic analysis to choose capacity values that do not increase significantly capex b
still give high NPV.