20241105
OUTLINE
-Production engineering overview
-Well construction
-Flow equilibrium

Assoc. Prof. Milan Stanko . 518

Petroleum production engineering

3 languages

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From Wikipedia, the free encyclopedia

CO2 storage
H2
Natural gas
Geothermal

Petroleum production engineering is a subset of petroleum engineering.

Petroleum production engineers design and select subsurface equipment to produce oil and gas well fluids.[1] They often are degreed as petroleum engineers, although they may come from other technical disciplines (e.g., mechanical engineering, chemical engineering, physicist) and subsequently be trained by an oil and gas company.

well - design (1-2)
- operation (20+)
- troubleshooting
- optimization
- intervention

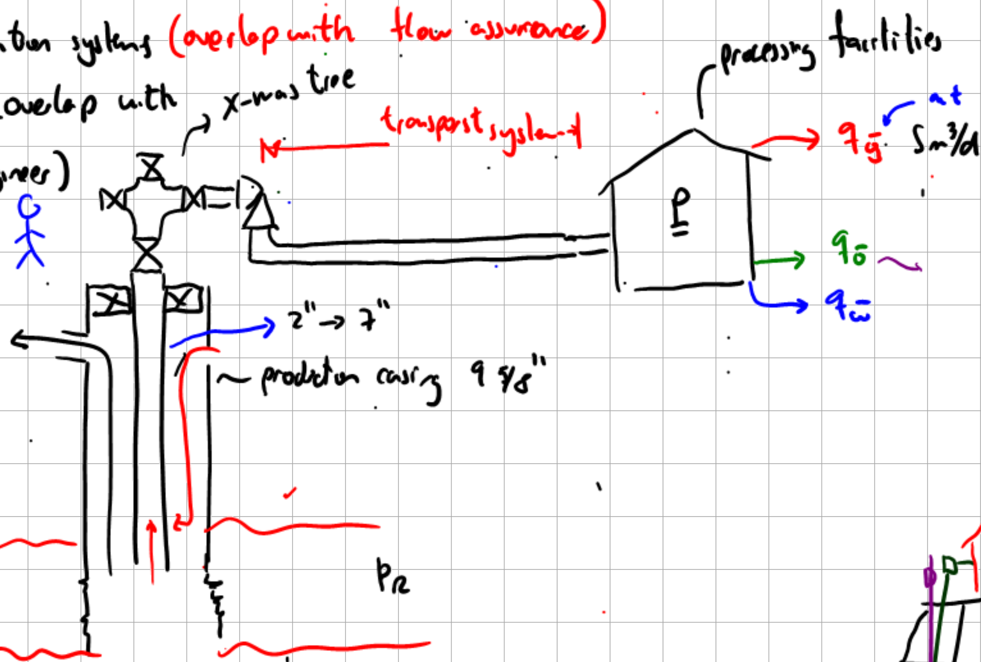
Overview [edit]

Petroleum production engineers' responsibilities include:

1. Evaluating inflow and outflow performance between the reservoir and the wellbore.
2. Designing completion systems, including tubing selection, perforating, sand control, matrix stimulation, and hydraulic fracturing. ↳ well "equipment"
3. Selecting artificial lift equipment, including sucker-rod lift (typically beam pumping), gas lift, electrical submersible pumps, subsurface hydraulic pumps, progressing-cavity pumps, and plunger lift.
4. Selecting (not design) equipment for surface facilities that separate and measure the produced fluids (oil, natural gas, water, and impurities), prepare the oil and gas for transportation to market, and handle disposal of any water and impurities.

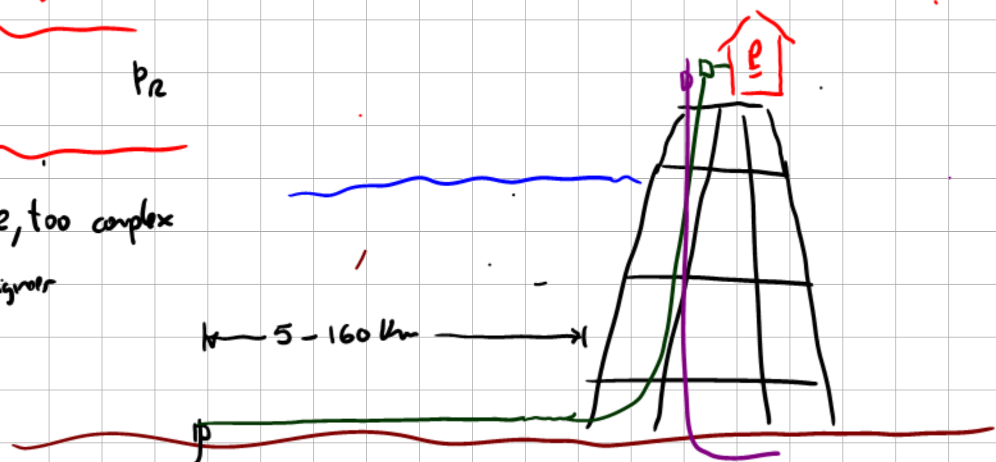
Note: Surface equipments are designed by Chemical engineers and Mechanical engineers according to data provided by the production engineers.

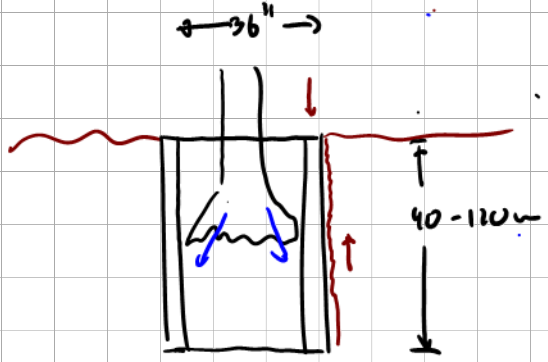
- near wellbore region (overlap with res eng)
- wellbore
- transportation systems (overlap with flow assurance)
- Processing (overlap with facilities engineer)

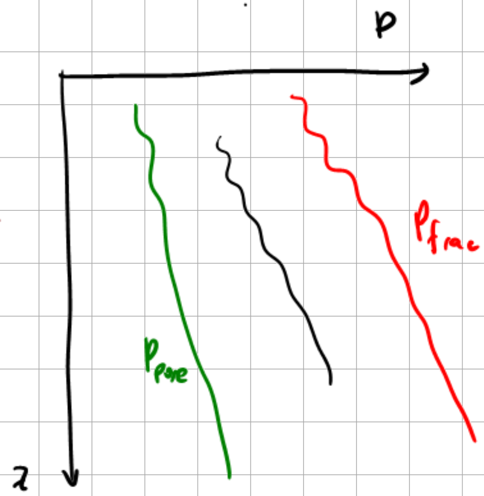


$P_{sc} = 1.01325$ bara
$T_{sc} = 15.56$ °C

if transport system is too large, too complex
flow assurance engineer







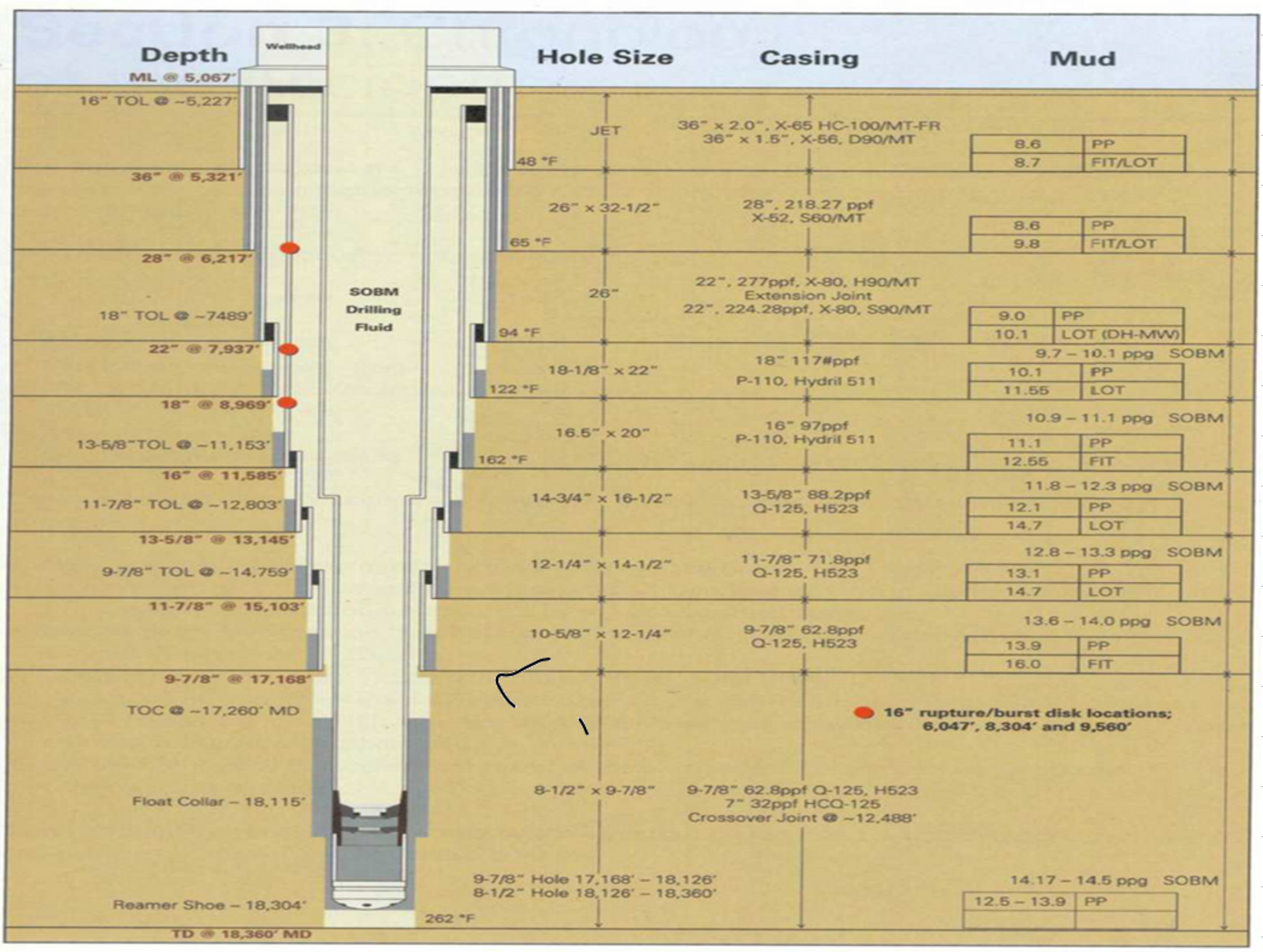
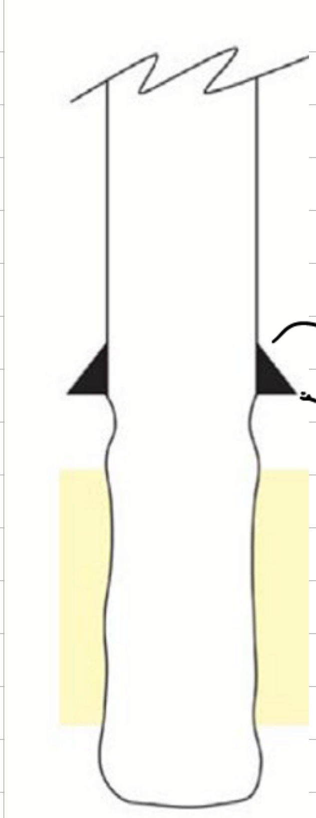


FIGURE 2-2 Final well bore architecture for Macondo well. Source: BP 2010, p. 19. Reprinted with permission; copyright 2010, BP.

calculate total weight of 9 5/8" production casing, of length 2500 m

		29.30
		32.30
		36.00
		38.00
		40.00
		43.50
9 5/8	244.48 lb/ft	47.00
		53.50
		58.40

$$2500\,m \cdot 47\,\frac{lb}{ft} \cdot \frac{1\,ft}{0.3048\,m} \cdot \frac{0.45\,kg}{1\,lb} = 173\ t$$

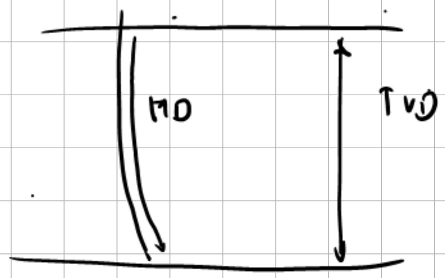


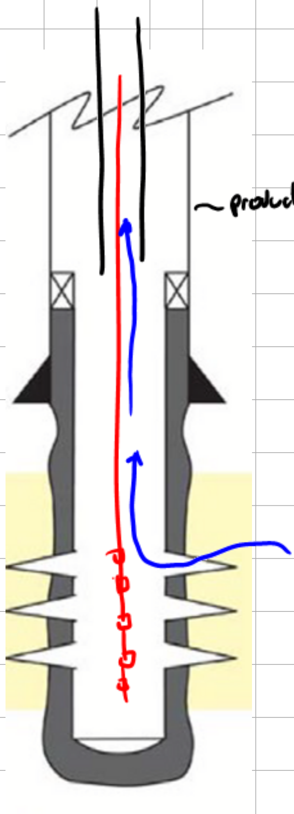
Barefoot

9 5/8" production casing MD, TVD

casing shoe

2500 TVD, 2800 MD





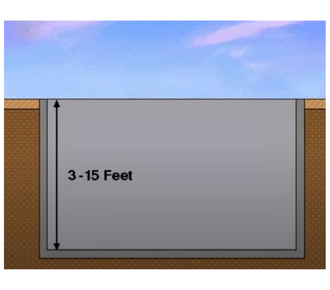
Cemented and perforated liner or casing

Downhole safety valve is used to avoid this!!!

Stanko, v1(2024)

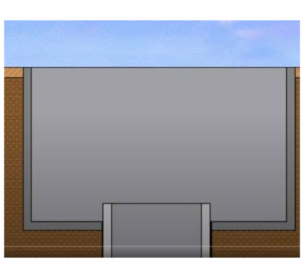
ONSHORE WELL DRILLING (easier to visualize and understand)

Digging the cellar:

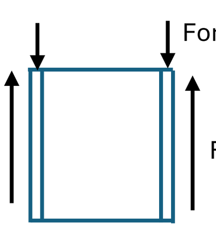


sequence extracted from*

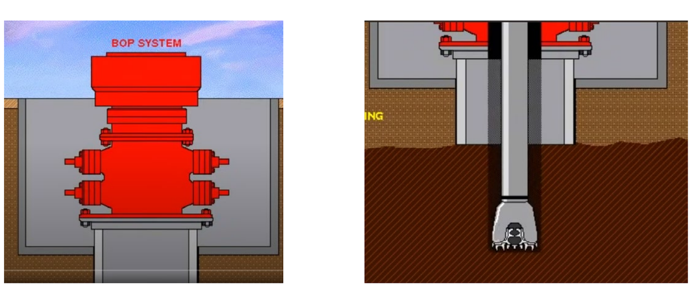
Installing the 36”, 40-120 m conductor (drilled, piled, jetted, etc):



The conductor carries all the well loads (everything inside) and transfers it to the soil

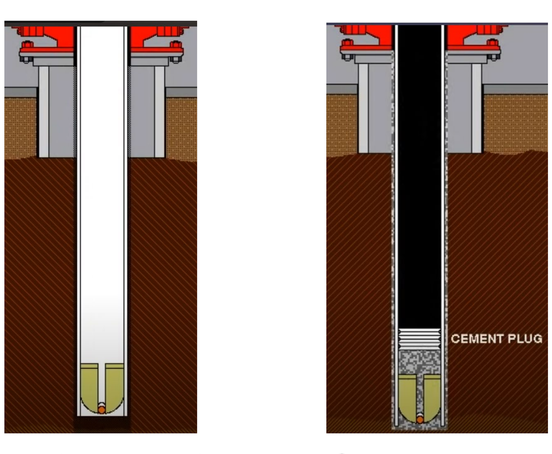


Surface casing (20”):



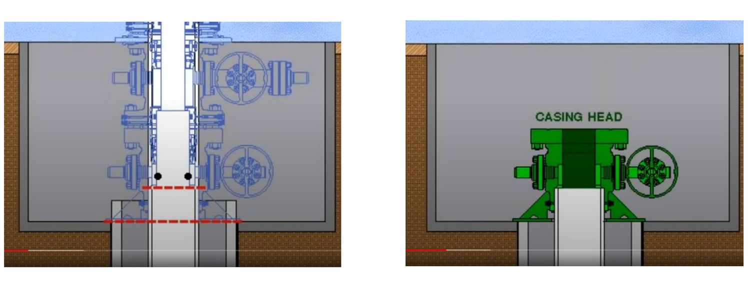
BOP connection

Drilling hole



Running casing

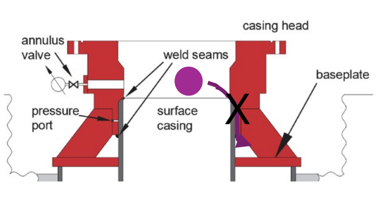
Cementing



Installing casing head

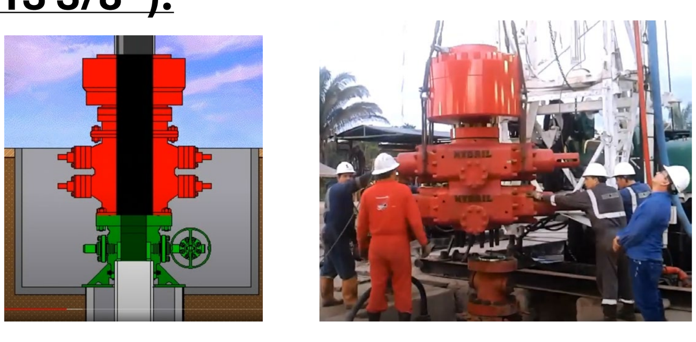
Installing casing head

welding casing head*

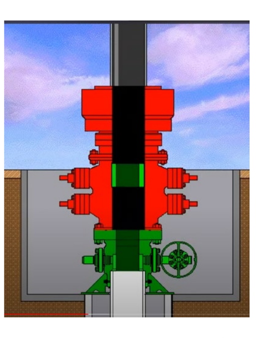


Check weld sealing using the pressure port and a hydraulic pump (the violet dot is high pressure and should not leak out through the welding). **The well is essentially a pressure vessel protecting outside from inside!!**

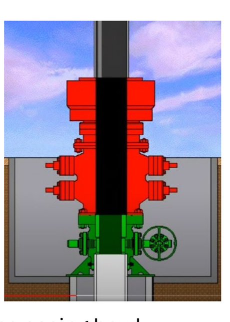
Intermediate casing (13 3/8”):



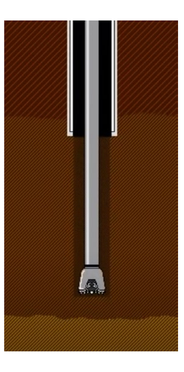
BOP connection (flanged)*



Wear bushing installation

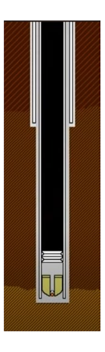


The casing bowl is used as a seal surface later, so it should be protected from scratching with the drill bit and drill string

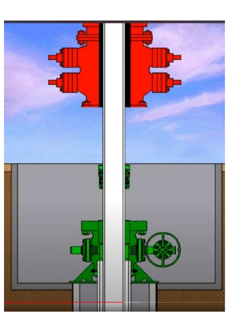


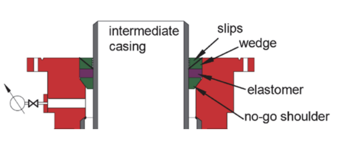
Drilling hole

Running casing (when at the bottom, keep it hanged rig (tension)



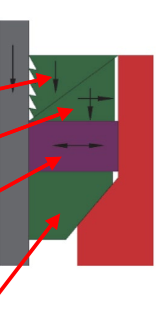
Cementing (either all way to surface or with significant overlap with previous casing)



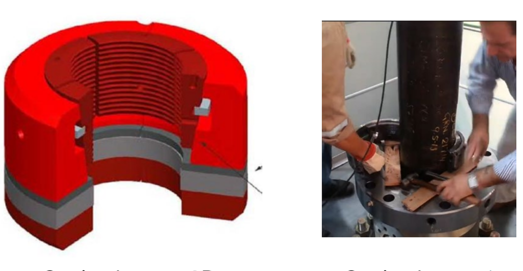


Install casing hanger:

- slips to create attachment between casing and hanger
- wedge: to press the elastomer against no-go shoulder
- elastomer, to expand laterally when pressed and create seal (high pressure above, low pressure below)
- No-go shoulder, to transfer load to casing bowl



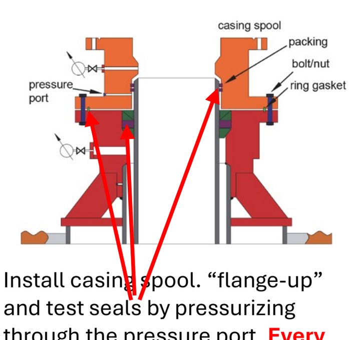
Slip similar to drilling slips*



Casing hanger 3D view

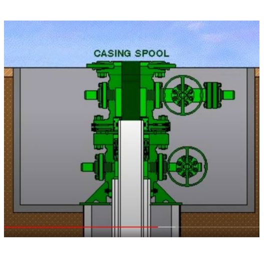
Casing hanger*

Slip marks on casing *

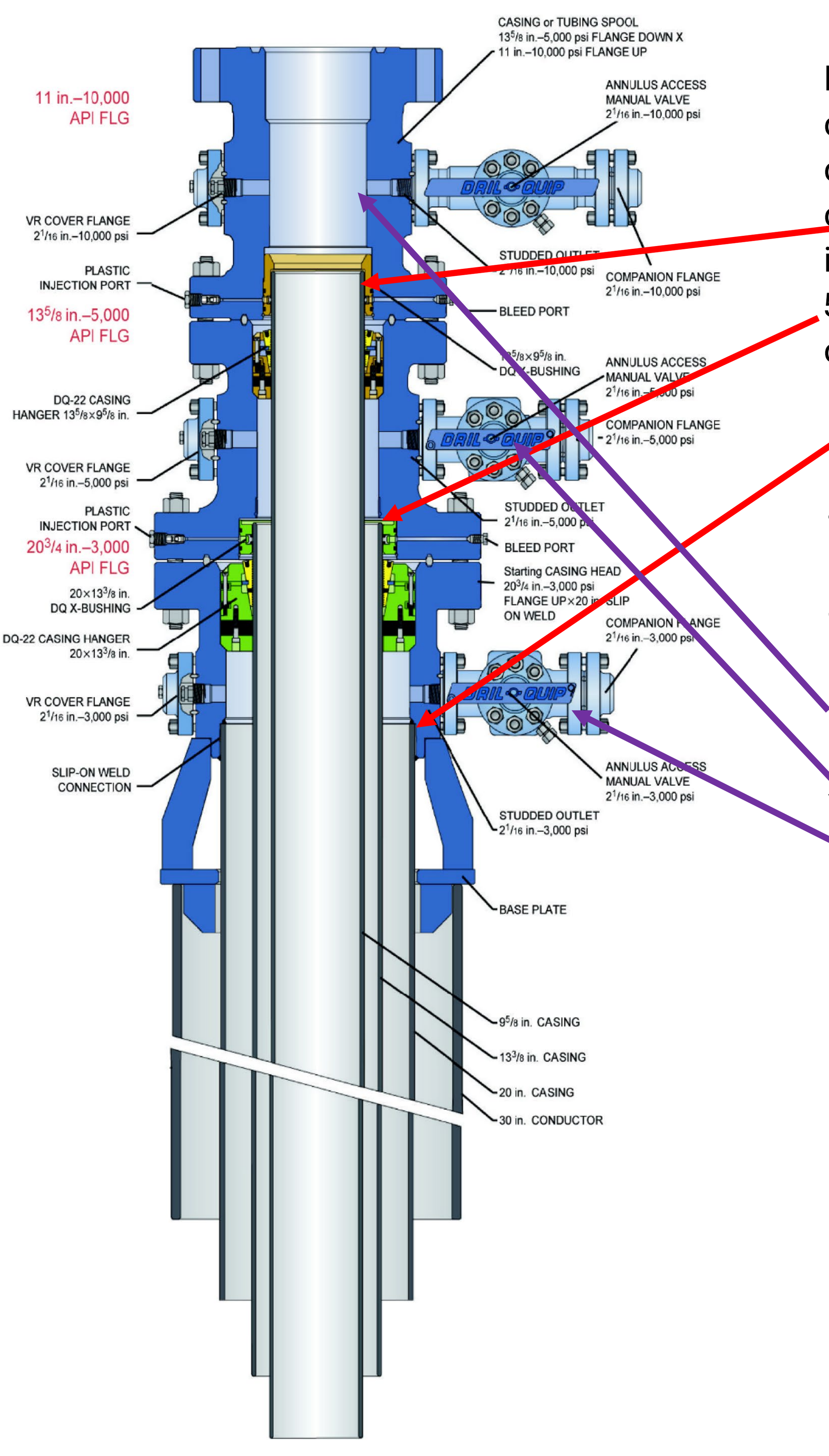


Install casing spool. “flange-up” and test seals by pressurizing through the pressure port. **Every seal should be tested by applying high or low pressure depending where it will have it during normal operation.**

source



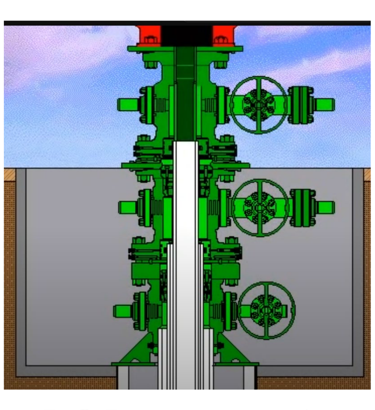
Intermediate casings and production casing (9 5/8”): Repeat process shown above for intermediate casing!



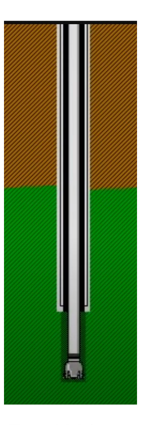
Pressure rating of inner casing higher than outer casing (here production casing 10 000 psi, intermediate casing 5000 psia, surface casing 3000 psia)

The only annulus that might be connected to facilities (for production of injection) is the production casing annulus (A). However, valves and pressure transducers are installed in the others (B,C) to monitor if there are pressure increases (indicates leakages e.g. due to casing hangers seals or cement fails)

Lower completion and tubing:

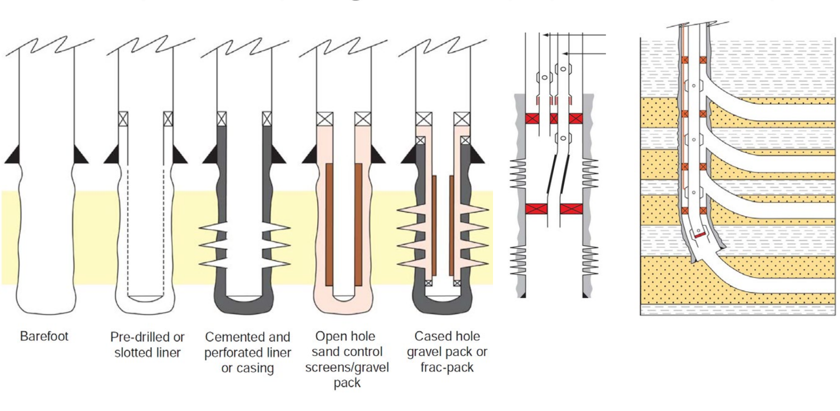


BOP connection (flanged)

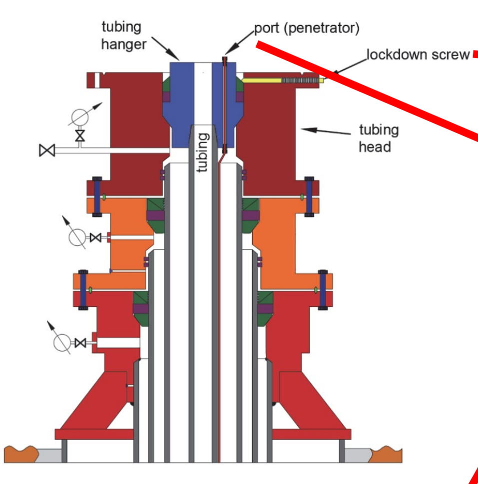


Drilling hole

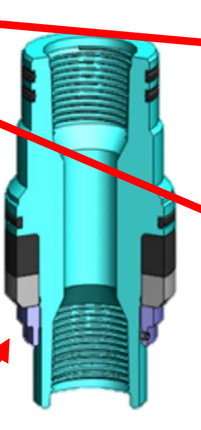
some options (single zone), (multi-zone)



Lower completion. Equipment/materials usually needed: packers (seals), hangers (fix tubulars to casing), drilling (drilling laterals), liners (tubulars that don’t go to surface), perforating gun (establish connection between reservoir and well), cement (isolate reservoir from well).



Run tubing and hang it with tubing hanger



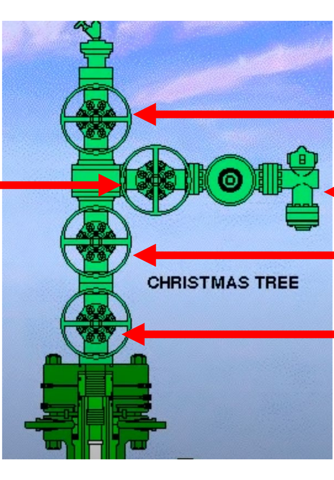
threaded hanger

Lockdown screws are often used to ensure hangers stay in place. When there is thermal expansion of tubing and casing, the hanger could be pushed upwards, releasing the slips and disengaging the seal.

Tubing hanger has “holes” to e.g. chemical injection, pressure gauge, hydraulic lines for subsurface safety valve, etc

Install X-mas tree:

wing valve



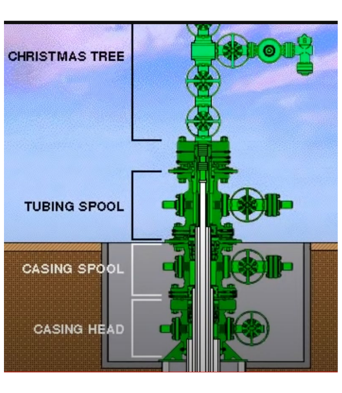
swab valve (to perfom light intervention on well)

Choke (control valve)

upper master valve (remotely operated)

lower master valve (manually operated)

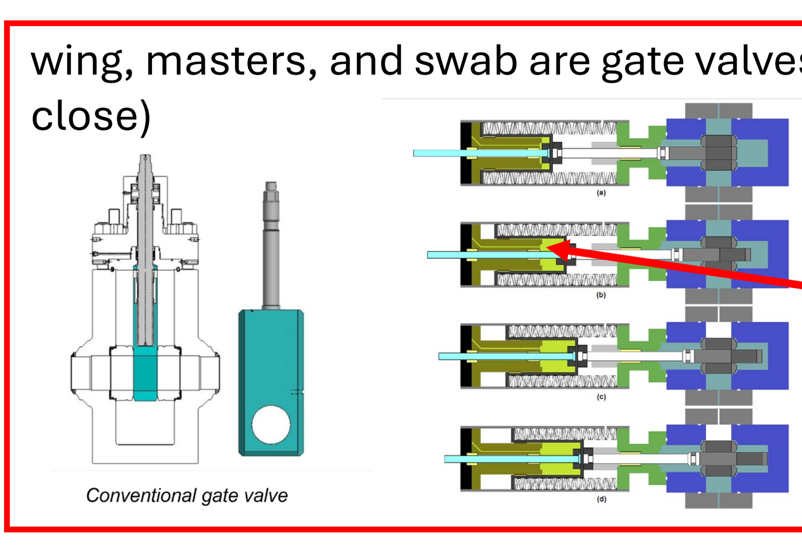
redundancy



X-mas tree

wellhead/ upper completion

wing, masters, and swab are gate valves (only open or close)



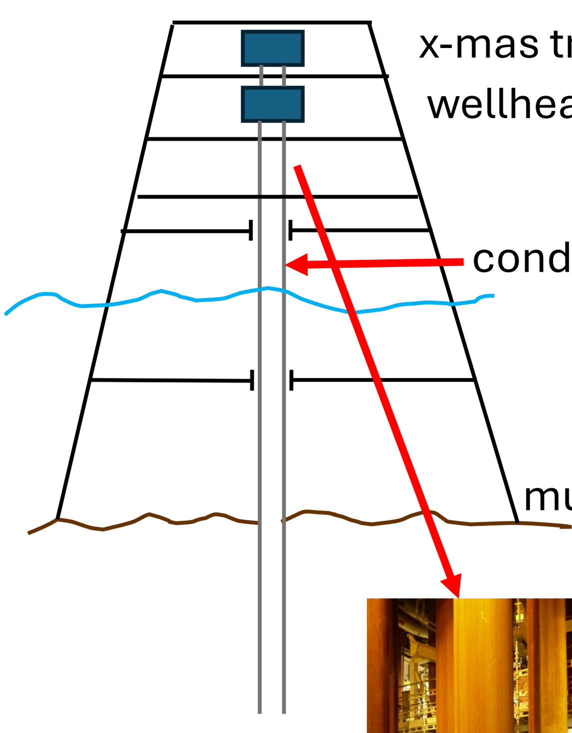
Fail-safe mechanism (closes if hydraulic fluid pressure drops thanks to spring)

annulus master valve

source

PLATFORM WELL DRILLING

similar to onshore drilling, but the conductor is extended above the mudline and into the platform.

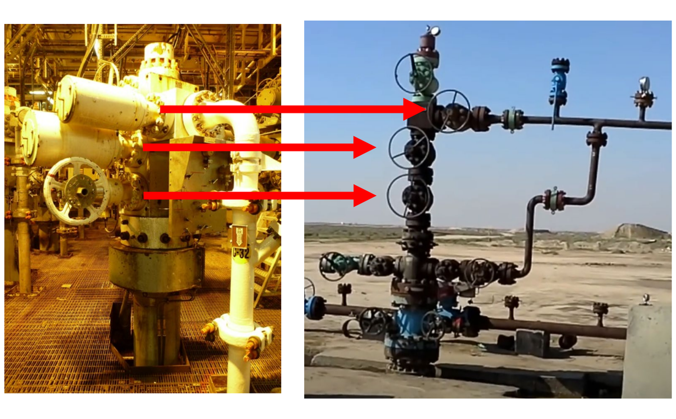


x-mas tree deck

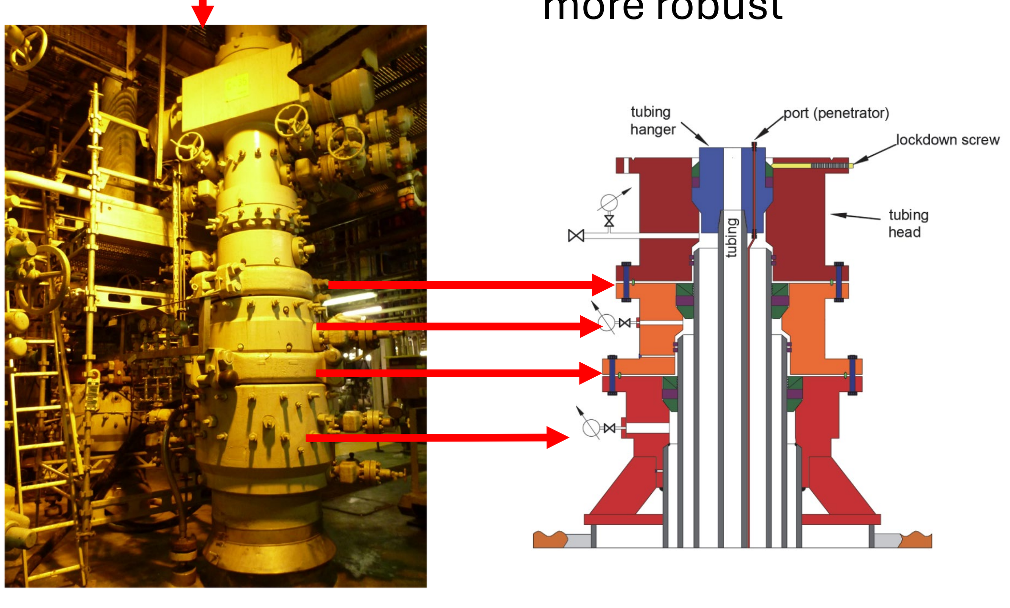
wellhead deck

conductor

mudline

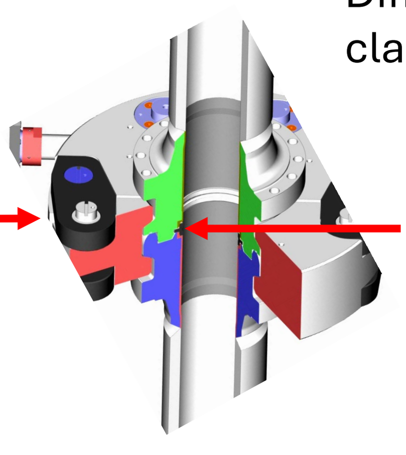


Differences from onshore: x-mas tree is a solid steel block, more robust

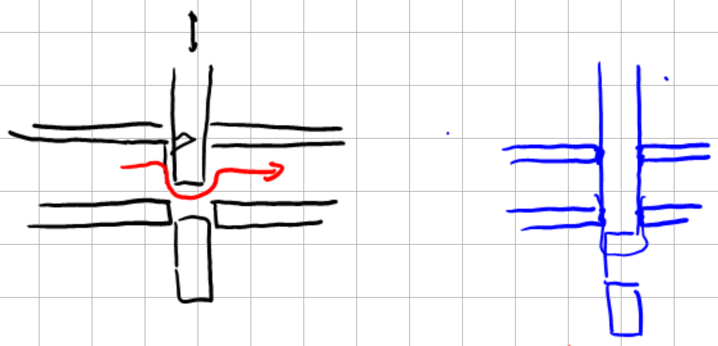


Differences from onshore: less flanges, fast clamp connectors instead (less screws)

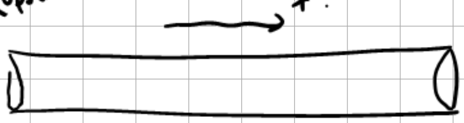
clamp



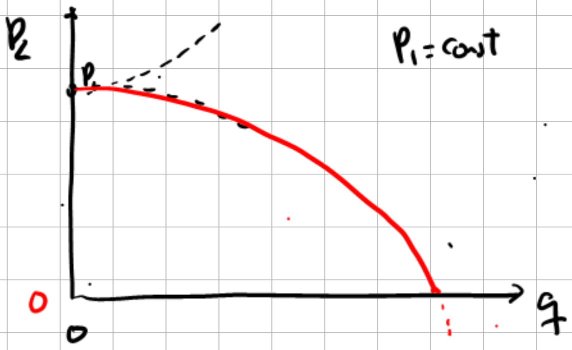
gasket



flow equilibrium:

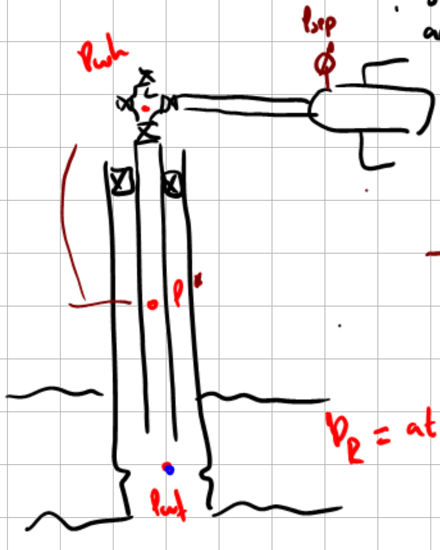


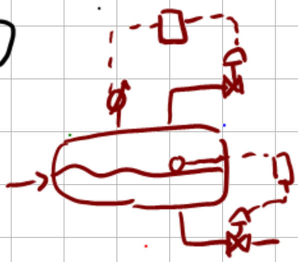
P_1 is fixed, how does P_2 change with q?



$$P_2 = P_1 - \Delta p_{losses}$$

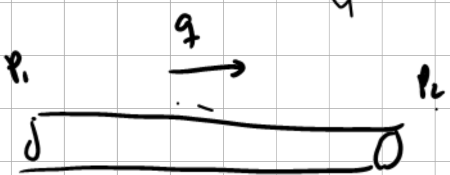
└ hydrostatic, friction, accessories, acceleration





available pressure at pipe exit with fixed upstream pressure

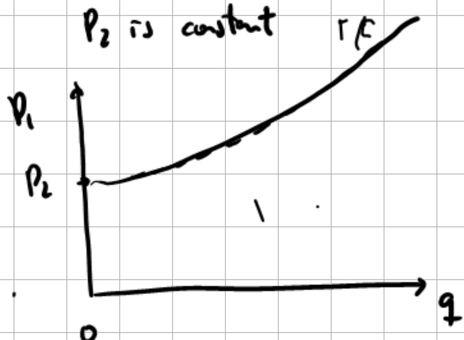
P_R = at a given time is constant

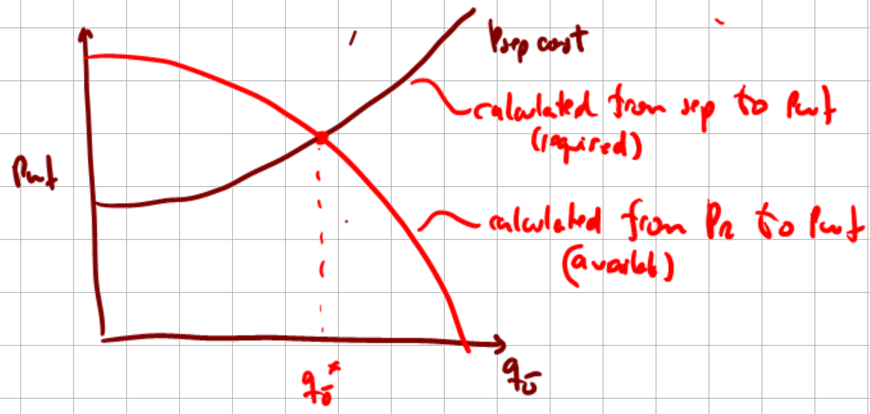


$$P_2 = P_1 - \Delta p$$

$$P_1 = P_2 + \Delta p$$

P_2 is constant




Psep const
calculated from sep to Pwf
(required)
Pwf
calculated from Pr to Pwf
(available)
q_o^*
q_o

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OUTLINE

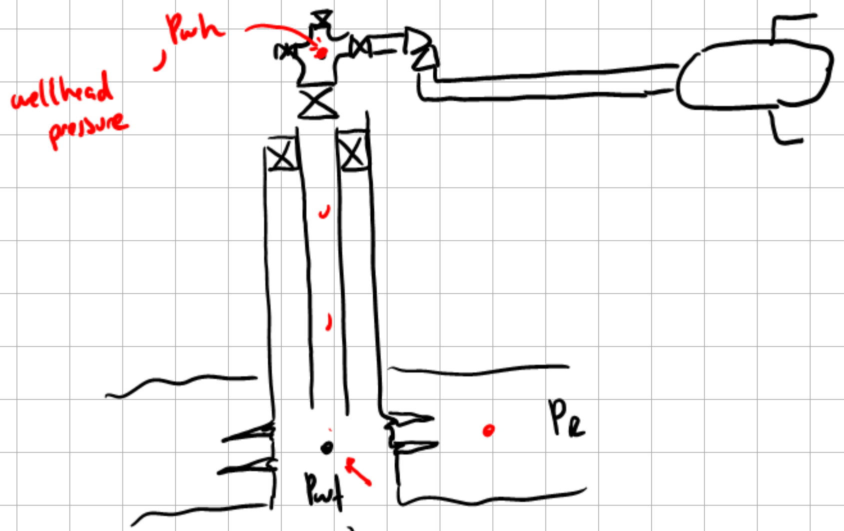
-Flow equilibrium

-Class exercises

-Choke design

-ESP design

-Wellhead compression design



└ flowing bottom-hole pressure { BHP }

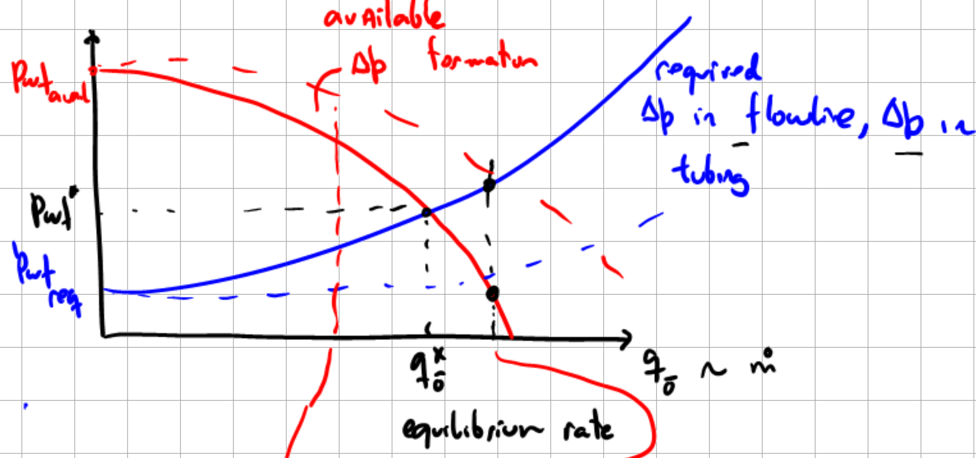
p_{wf} → SPE

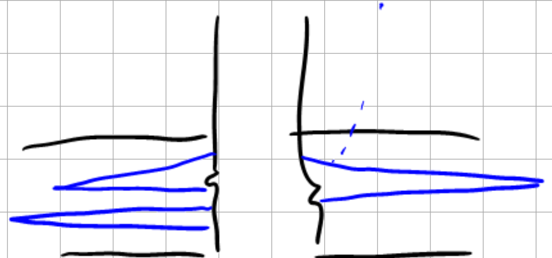
1. pick a point in the system ⇝ typically bottom-hole or wellhead

2. Calculate and plot:
   -available pressure curve at that point, calculated from constant upstream pressure (pR)
   -Required pressure curve at that point, calculated from constant downstream pressure (psep)

3. To find natural flow, find the intersection where pressure from the first curve is equal to the pressure of the second curve

• If I pick p_{wf} as point of equilibrium

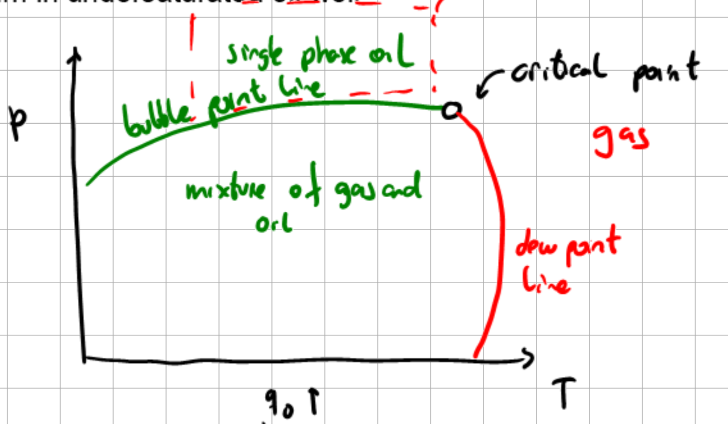




If I want a production rate lower than the eq. rate the options are:
-Bridge the gap between available and required by adding an external equipment

If I want a production rate higher than the eq rate, the options are:
1. Change the available pressure curve (increasing formation permeability), not very easy but can be achieved by e.g. fracking
2. Change the required pressure curve. Increase tubing and flowline size
3. Bridge the gap between required and available by adding an external equipment

-Class exercise, equilibrium in undersaturated oil well



$q_o \downarrow$ $\quad$ $q_o \uparrow$

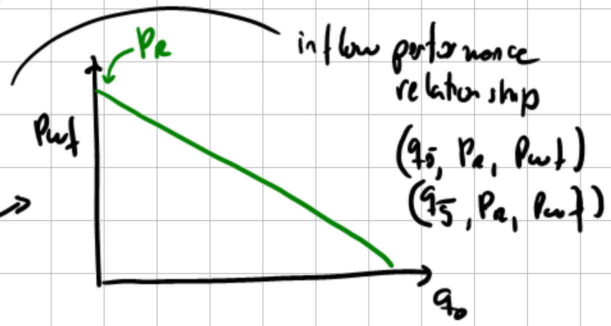
1.) oil in P_R, $P_{wf} \rightarrow P_{wh} \rightarrow P_{sep}$ will be undersaturated

$q_o = q_{\bar{o}}$

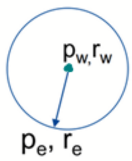
↳ volumetric rate at p, T

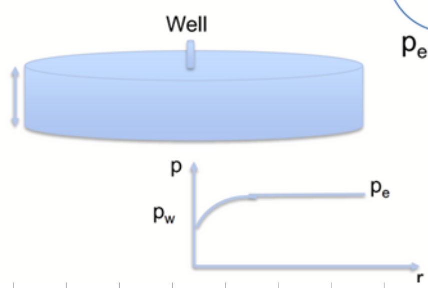
2.) flow $P_R \rightarrow P_{wf}$ Linear IPR

$q_{\bar{o}} = J(P_R - P_{wf})$



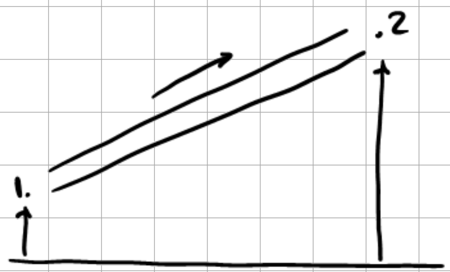
$$Q = \frac{2\pi kh(p_e - p_w)}{\mu \ln(r_e/r_w)}$$





- Q = volume/time production
- p_e = external pressure
- p_w = well pressure
- r_e = external radius
- r_w = well radius
- h = thickness of productive formation

3) flow in tubing : Bernoulli equation



$$\frac{P_1}{\rho g} + z_1 + \cancel{\frac{v_1^2}{2g}} = \frac{P_2}{\rho g} + z_2 + \cancel{\frac{v_2^2}{2g}} + \Delta h_{friction}$$

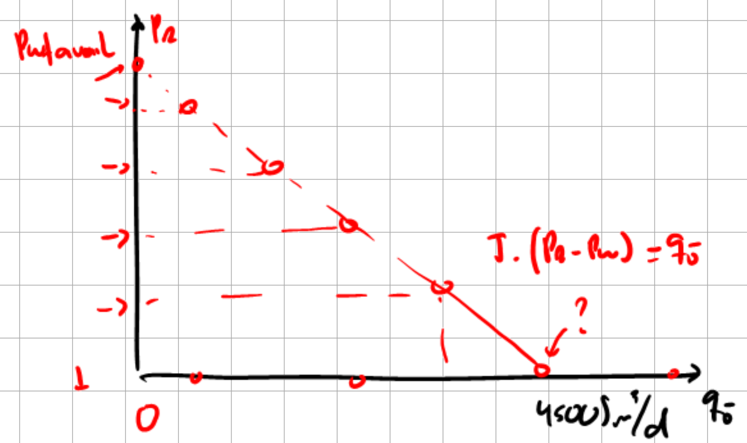
$$\Delta h_f = f \cdot \frac{L}{\phi} \frac{v^2}{2g}$$

$$P_1 - P_2 = \underbrace{(z_2 - z_1)\rho g}_{} + \underbrace{f \frac{L}{\phi} \rho \frac{v^2}{2}}_{\downarrow}$$

$$v = \frac{q}{A}$$

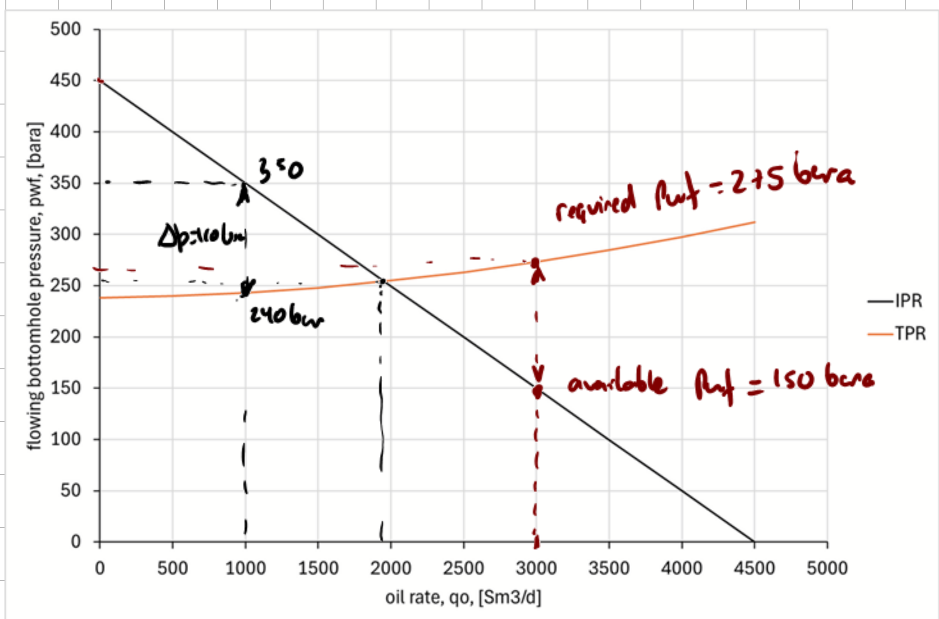
4). Excel VBA

```
Function pressure_drop(q, L, den, visc, teta, roughness, phi)
    'Calculates pressure_drop in bar
    'q, liquid volumetric rate, in m3/d
    'L, pipe length, in m
    'den, liquid density, in kg/m3
    'visc, liquid viscosity, in cP
    'teta, pipe inclination angle from the horizontal in deg
    'roughness, pipe roughness, in m
    'phi, pipe inner diameter, in m
    'defining constants
    Pi = Application.WorksheetFunction.Pi()
    g = 9.81 ' in m/s^2
    'Step 0, convert rate to metric units
    q_ = q / (3600# * 24#) 'changing from m3/d to m3/s
    'Step 1, calculate velocity
    Area = (phi ^ 2) * 0.25 * Pi
    v = q_ / Area
    'Step 2, calculate reynolds number
    Re = Reynolds_f(v, den, visc / 1000, phi) 'visc is required in Pa s, but available in cP
    'Step 3, calculate friction facgtor
    rel_roughness = roughness / phi
    friction_factor = friction_factor_f(Re, rel_roughness)
    'Compute the pressure drop using the Bernoulli equation
    deltap_hydrostatic = 0.00001 * L * Sin(teta * Pi / 180) * den * g
    deltap_frictional = 0.00001 * den * friction_factor * L * 8 * (q_ ^ 2) / ((phi ^ 5) * (Pi ^ 2))
    pressure_drop = deltap_hydrostatic + deltap_frictional
End Function

Function Reynolds_f(v, den, visc, phi)
    'TODO: provide description of function
    'and function input
    Reynolds_f = v * den * phi / visc
End Function

Function friction_factor_f(Re, rel_roughness)
    If Re = 0 Then
        friction_factor_f = 0
    ElseIf Re > 0 And Re < 2300 Then 'laminar flow
        friction_factor_f = 64 / Re
    Else 'turbulent flow
        part1 = -1.8 * (Log((rel_roughness / 3.7) ^ 1.11 + 6.9 / Re) / Log(10))
        friction_factor_f = part1 ^ (1 / -0.5)
    End If
End Function

Function pin_pipe(pout, q, L, den, visc, teta, roughness, phi)
    'function to calculate required pressure at pipe inlet to flow with rate q, against pout
    pin_pipe = pout + pressure_drop(q, L, den, visc, teta, roughness, phi)
End Function

Function pout_pipe(pin, q, L, den, visc, teta, roughness, phi)
    'function to calculate available pressure at pipe outlet to flow with rate q, from pin
    pout_pipe = pin - pressure_drop(q, L, den, visc, teta, roughness, phi)
End Function
```



q_o	P_{wf}
-	-
-	-
-	-
-	-

TPR: tubing performance relationship



Equilibrium conditions

$P_{wf}^* \approx 260$ bara

$q_o^* \approx 1950$ Sm³/d

	IPR (available)	TPR (req)	
pwf - avail	qo	pwf-req	
[bara]	[Sm3/d]	[bara]	
450	0	238	
400	500	240	
350	1000	243	
300	1500	248	
250	2000	255	
200	2500	263	
150	3000	273	
100	3500	285	
50	4000	298	
0	4500	312	
			diff [bar]
254.3	1957.49	254	0

Excel shortcuts:
To access the VBA module
-Alt+F11 (first alt and immediately after F11)
-Activate teh developer tab (File->Options-->Customize Ribbon-->mark Developer).
Click on the "visual basic" button on the developer tab
Freeze cells (ensure they do not shift when we apply the function to other cells): F4
C11
Call function

start typing function and select from the list
Goal seek, to drive a cell to a given value by changing another cell , under DATA tab

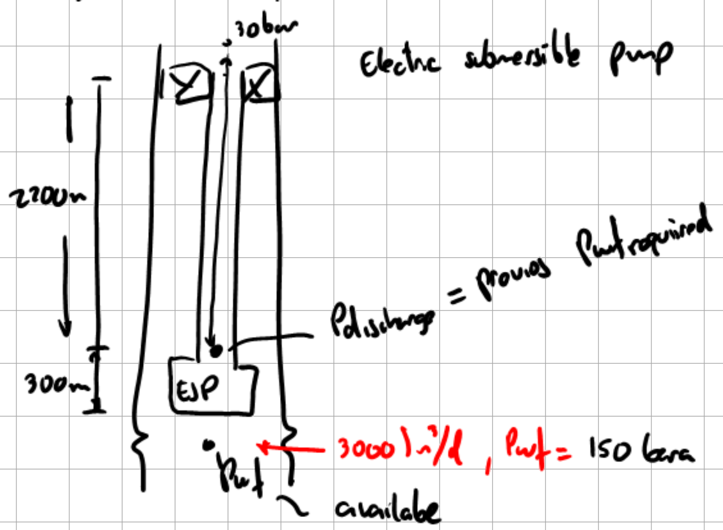
$$q_o = J\left(P_e - P_{wf}\right)$$

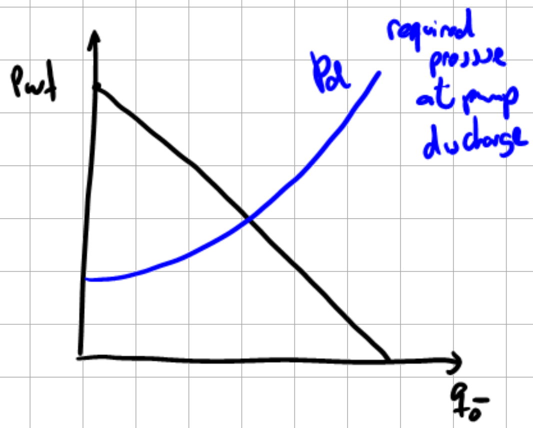
f(q_o)

(30 bar)

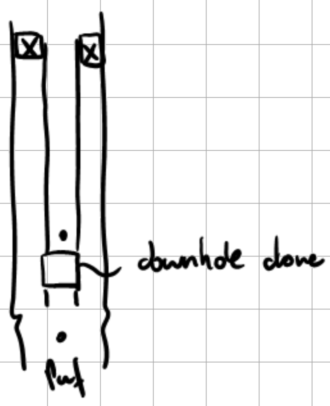
$$\left(P_{wf} - P_{wh}\right) = \rho \cdot g \, \Delta H + f \frac{L}{D} \rho \left(\frac{q_o}{A}\right)^2 \frac{1}{2}$$

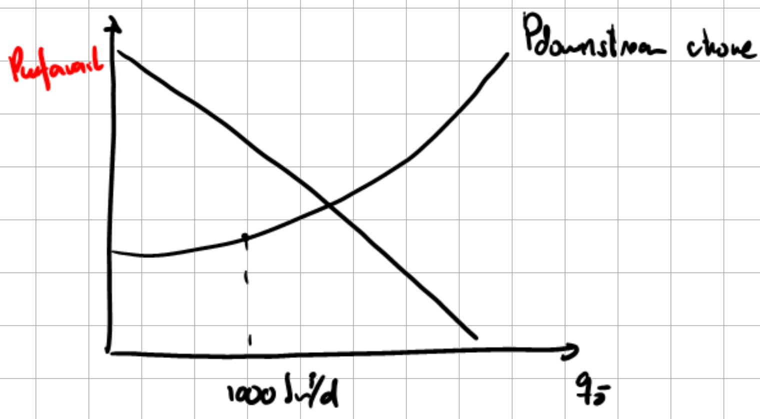
system of two equations and two unknowns, flow equilibrium solves them graphically





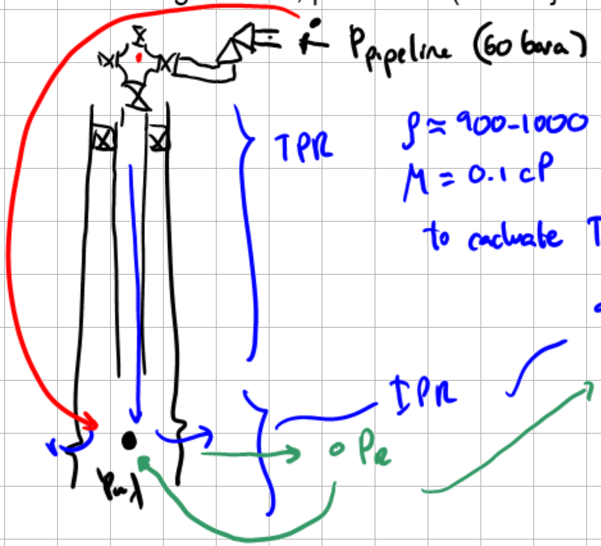
Flow equlibrium analysis can also be used to determine pumping requirements (for exammple downhole pump), but in that case, when the pump is pressent, available pressure at pump suction is pwf, but required pressure at pump discharge is old pwf req,





20241112
OUTLINE
-Guidelines for problem 2 in exercise set 1 (CO2 injector well)
-More details about IPR (derivation of IPR, undersaturated oil, CO2 injector, water injector, effect of wellbore dp, dry gas, saturated oil, composite IPR, horizontal and vertical)

some comments about assignment 1, problem 2 (CO2 injection well):



$\rho \simeq 900\text{-}1000\ kg/m^3$

$\mu = 0.1\ cP$ $\qquad 1\ cP \rightarrow 10^{-3}\ Pa.s$

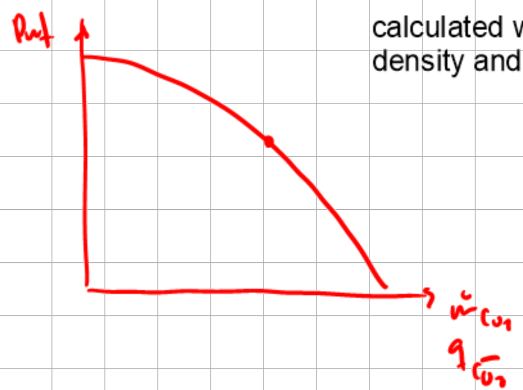
to calculate TPR, one can use the Bernoulli eq.

$q_{CO_2} = J(p_{wf} - p_R)$
at s.c. Sm^3/d

$\dot{m}_{CO_2} = J(p_{wf} - p_e)$
t/d

perform flow equilibrium in this well, at bottom-hole

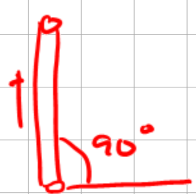
① available pressure curve is calculated from $P_{pipeline}$ (upstream the choke) and includes flow in choke, flow in tubing.



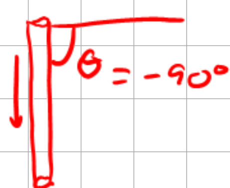
calculated with Bernoulli eq, because the CO2 has a high density and can be considered incompressible

OBS! be careful
the VBA function to calculate Pin Pout uses an angle,

for production θ=90



for injection θ= -90



To calculate pavail at bottom-hole, I should use pout VBA function.

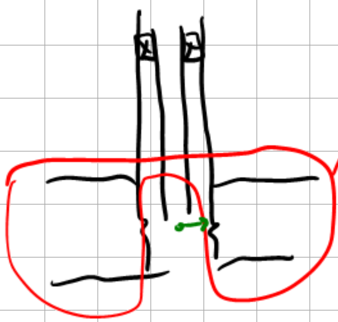
the required p_{wf} is estimated from

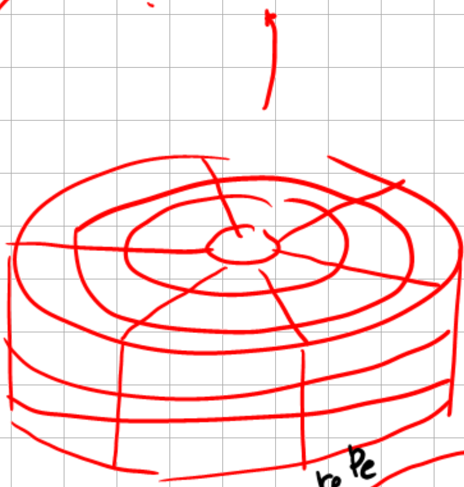
$\dot{m}_{CO_2} = J(p_{wf} - p_R)$ $\qquad p_{wf} = p_R + \frac{\dot{m}_{CO_2}}{J}$

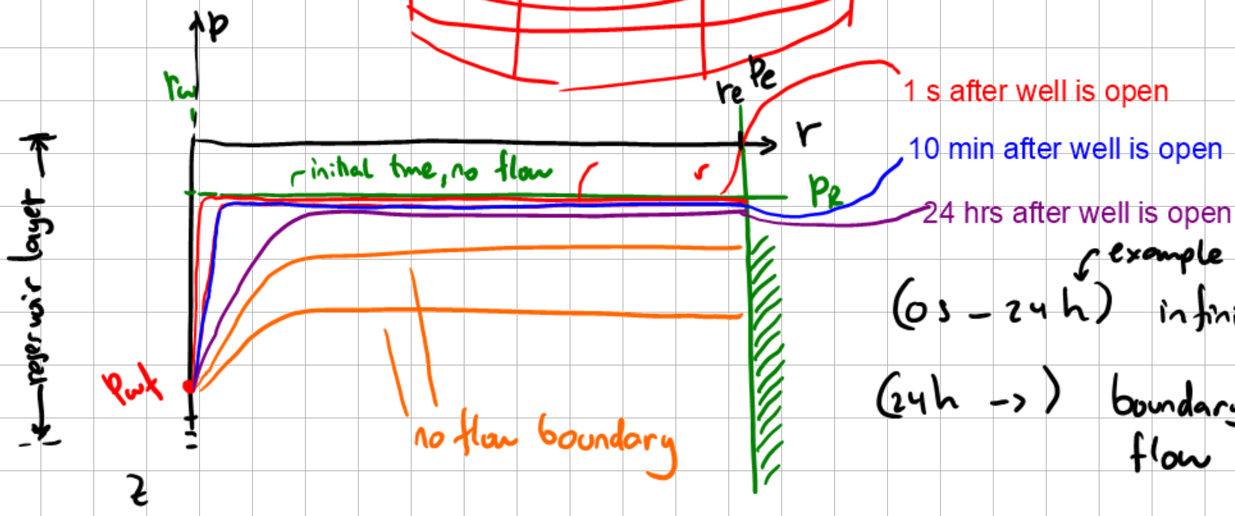
Inflow performance relationship

find a relationship to correct:

$f(q_o, p_{wf}, p_R)$







example!

(0 s – 24 h) infinite acting

(24 h –>) boundary-dominated flow

t_{ss} time to steady state

changes significantly with permeability and fluid properties.

-Two types of boundary conditions (@re):

Constant pressure ~ $p_e = \text{const}$

No flow boundary ~ $\left.\frac{dp}{dr}\right|_{@r_e} = \text{const}$

In boundary dominated flow, and in the steady state (pe = constant) or pseudo-steady-state (no flow at re), the time dissapears from the equations, and I can derive IPR using steady-state approximation

Darcy's law

$$v = \frac{k}{\mu}\frac{dp}{dr}$$

$$\int dr = \int \frac{k}{\mu v}\, dp$$

$$v = \frac{k}{\mu}\frac{dp}{dr} \qquad \text{ODE}$$

$$\boxed{\frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} = \alpha \frac{\partial p}{\partial t}} \qquad \text{PDE}$$

IPR equations are:

1)derived from Darcy's law, by applying specific boundary conditions and fluid properties → not accurate

allows to see what are the most important parameters, very important for design

Since it is based on physics it is usually more predictive

2) from field tests → very accurate

Not very predictive in the future

all IPR equations are derived from an equation like this:

$$q_{sc} = C \cdot \int F(p)\,dP$$

fluid properties + rel perm

geometry + rock properties

undersaturated oil well, vertical radial well, no flow boundary

permeability

$$q_{\bar{o}} = \frac{k \cdot h}{\left[ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right] \cdot 18.68} \cdot \int_{p_{wf}}^{p_R} \frac{1}{\mu_o \cdot B_o} dp \approx J\left(P_R - P_{wf}\right)$$

skin

μ

$f(q_{\bar{o}}, P_{wf}, P_R)$

$$v = \frac{k}{\mu}\frac{dP}{dl} \qquad v = \frac{q}{A} \quad q_o$$

$$q_o \sim q_{\bar{o}} \qquad v = \frac{(q_{\bar{o}} \cdot B_o)}{A}$$

similar for:

water injector $q_{\bar{w}} = J\left(P_{wf} - P_R\right)$

CO_2 injector $\dot{m}_{CO_2} = J\left(P_{wf} - P_R\right)$

Horizontal/inclined undersaturated oil well with constant wellbore pressure

$$q_{\bar{o}} = \frac{k_H \cdot h}{18.68 \cdot (\mu_o \cdot B_o)_{@p_{av}} \cdot \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s + s_A\right]}\left[p_R - p_{wf}\right]$$

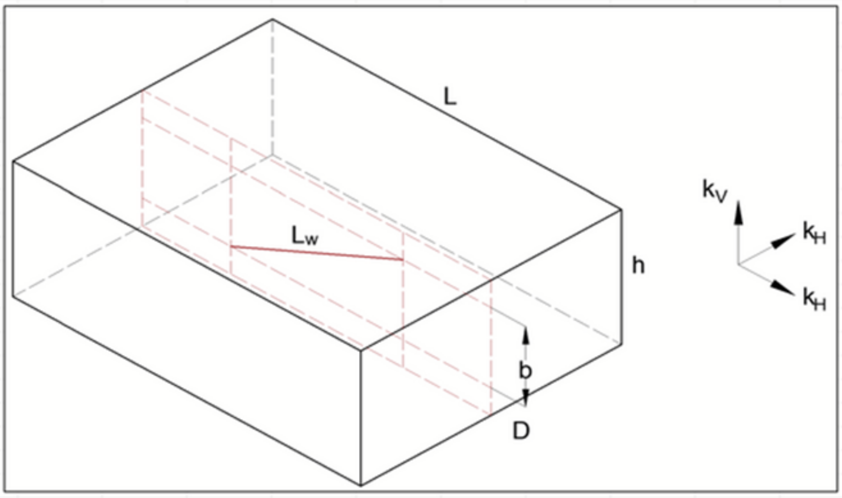
$$q_{\bar{o}} = \frac{k_H \cdot h}{6.22 \cdot (\mu_o \cdot B_o)_{@p_{av}} \cdot \left[\frac{\pi \cdot D \cdot \hat{f}_a}{2 \cdot \bar{L}_w} + \frac{3 \cdot h \cdot \beta}{\hat{L}_w} \cdot \left(\ln\left(\frac{h \cdot \beta}{2 \cdot \pi \cdot \hat{r}_w}\right) + \bar{s}_b\right)\right]}\left[p_R - p_{wf}\right]$$

$$\beta = \sqrt{\frac{k_H}{k_V}} \qquad \bar{L}_w = L_w \cdot \sqrt{1 - \left(\frac{b}{L_w}\right)^2}$$

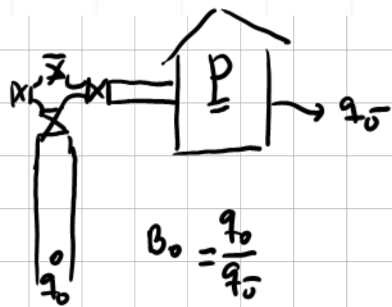
$$\bar{s}_b = \begin{Bmatrix} 0.69 \ \ if \ \ O(b) = O(h) \\ 0 \ \ if \ \ b = 0 \end{Bmatrix} \qquad \hat{L}_w = L_w \cdot \sqrt{1 - \left(\frac{b}{L_w}\right)^2 \cdot (\beta^2 - 1)}$$

$$\hat{r}_w = r_w \cdot \frac{1 + \sqrt{1 + (\beta^2 - 1) \cdot \left(\frac{\bar{L}_w}{\hat{L}_w}\right)^2}}{2}$$

$$\hat{f}_a = \frac{\bar{L}_w}{L} \cdot \left[1 + \left(0.53 \cdot \left(\frac{L}{D}\right)^2 + 1.15 \cdot \left(\frac{L}{D}\right) + 0.164\right) \cdot \left(\frac{1 - \left(\frac{\bar{L}_w}{L}\right)}{0.45 + \left(\frac{\bar{L}_w}{L}\right)}\right)\right]$$



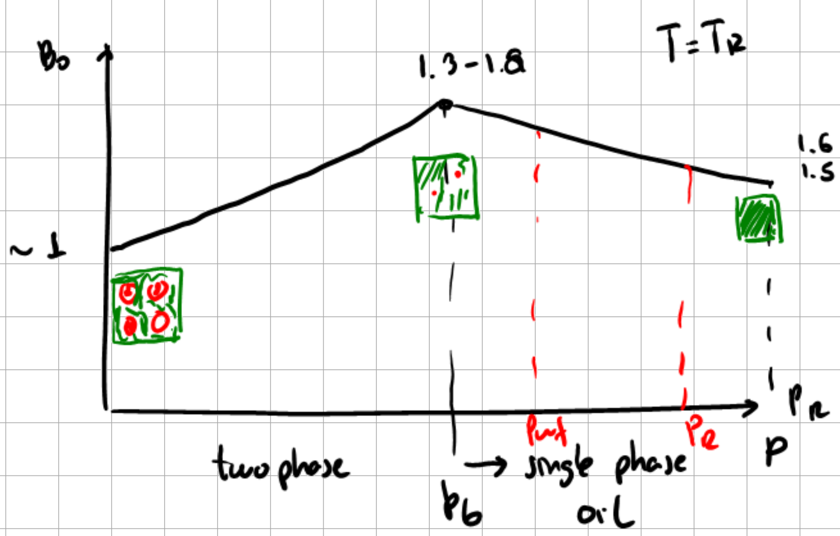
B_o oil volume factor $B_o = \frac{V_{o@p,T}}{V_{\bar{o}}}$

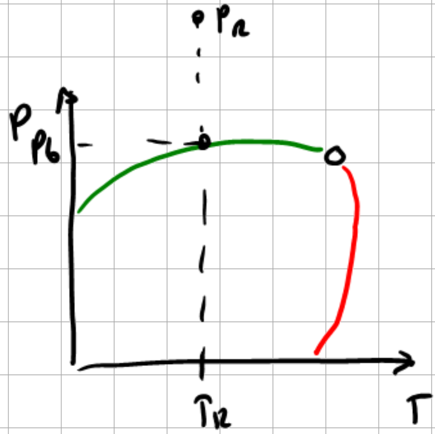


$$B_o = \frac{q_o}{q_{\bar{o}}}$$

-with high p, volume of liquid is reduced $\sim V_{\bar{o}} \downarrow$

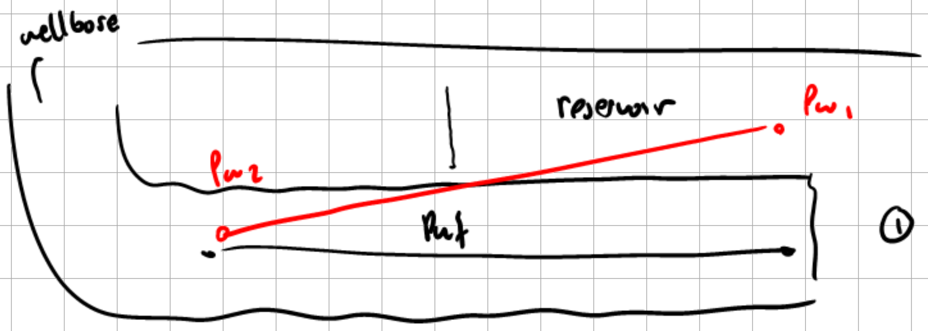
-with high p, gas goes in solution into the oil $\sim V_o \uparrow$ effect nr. 2 wins effect nr. 1





$p_R, p_{wf} \geq p_b$

-Including pressure drop in wellbore (e.g. long horizontal wells):



Bernoulli eq

$q_o = q_{\bar{o}} B_o$

① $p_{w1} - p_{w2} = (z_1 - z_2)\rho g + f \frac{L}{D} \frac{\rho}{2} \left(\frac{q}{A}\right)^2$

+

② $q_{\bar{o}}' = J(p_R - p_{wf})$

+

=

non-linear

dry gas well, vertical radial geometry, no flow boundary

$$q_{\bar{g}} = \frac{k \cdot h}{\left[ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right] \cdot 18.68} \cdot \int_{p_{wf}}^{p_R} \frac{1}{\mu_g \cdot B_g} dp$$

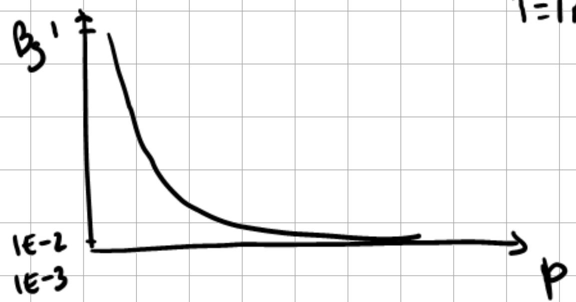
if $P_{wf}, P_R < 120$ bara

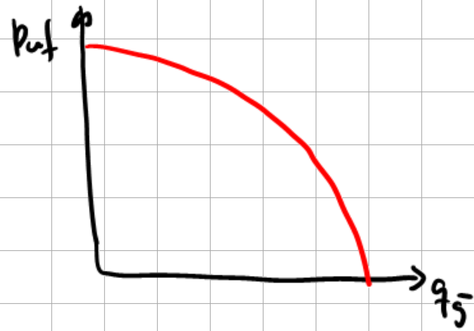
$$q_{\bar{g}} = C_R \left(P_R^2 - P_{wf}^2\right)^n$$

Dry gas back pressure equation

B_g gas volume factor $= \frac{q_g}{q_{\bar{g}}}$

$T = T_R$

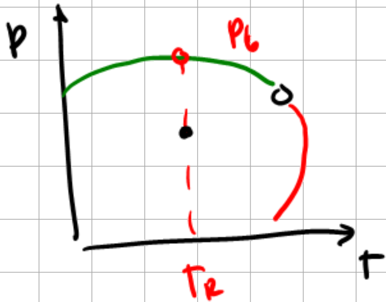


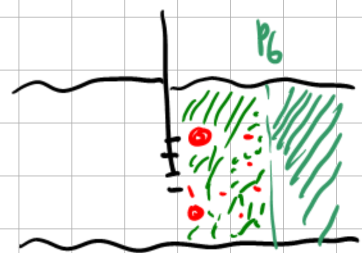


saturated oil, vertical radial well

$$q_{\bar{o}} = \frac{k \cdot h}{18.68 \cdot \left(ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right)} \int_{p_{wf}}^{p_R} \frac{k_{ro}}{\mu_o \cdot B_o} dp$$

$P_{wf} \leq P_b$





single phase flow

Darcy's law $v = \frac{K}{\mu} \frac{dP}{dr}$

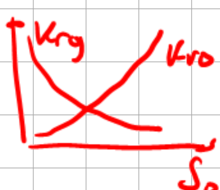
makes IPR non-linear

two-phase flow

$$v = \frac{K \, K_r}{\mu} \frac{dP}{dr}$$

rel. permeability

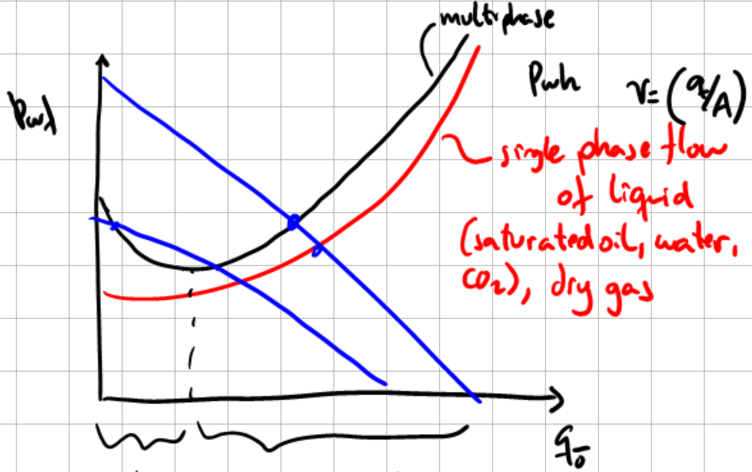
absolute permeability

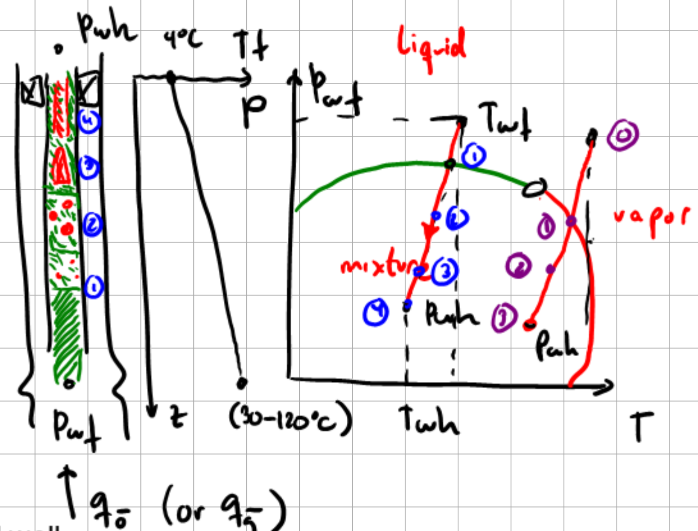


Based on data Vogel eq.

$$q_{\bar{o}} = q_{\bar{o}max}\left(1 - 0.2 \frac{P_{wf}}{P_R} - 0.8 \frac{P_{wf}^2}{P_R^2}\right)$$

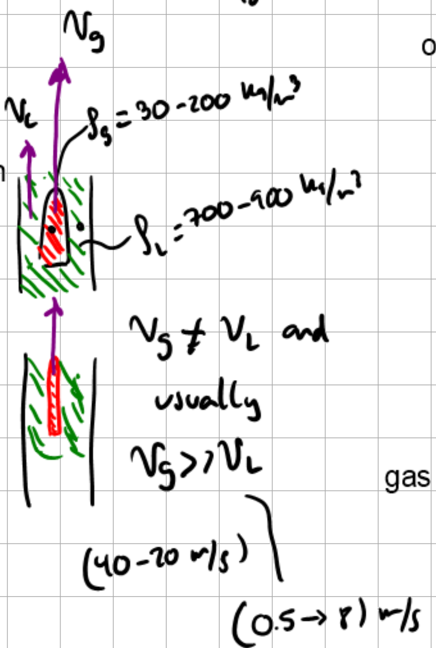
20241113
OUTLINE
-More details about TPR (undersaturated oil, dry gas, multiphase (flow pattern), Integration procedure, tubing tables, couplings, how to choose tubing size)
-Intro to Oil and gas topside processing (BO - Fluid properties)

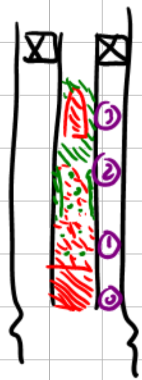




oil well

in this region, gas goes much more quick than liquid, and then the density of the mixture is more similar to the liquid

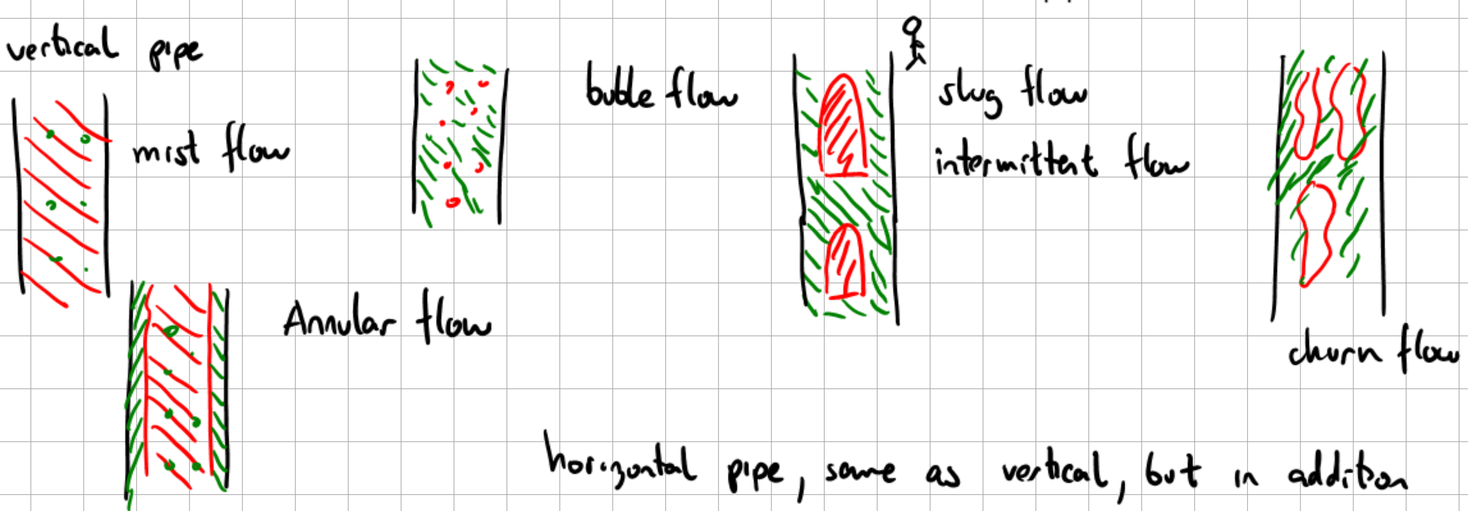




gas well

in multiphase flow, we usually have flow patterns

configuration how gas and liquid arrange themselves in the pipe

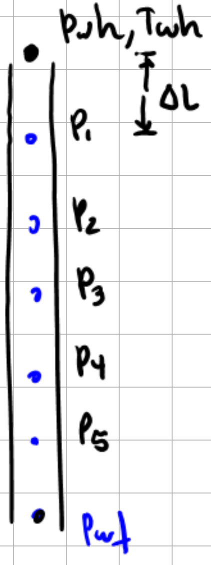


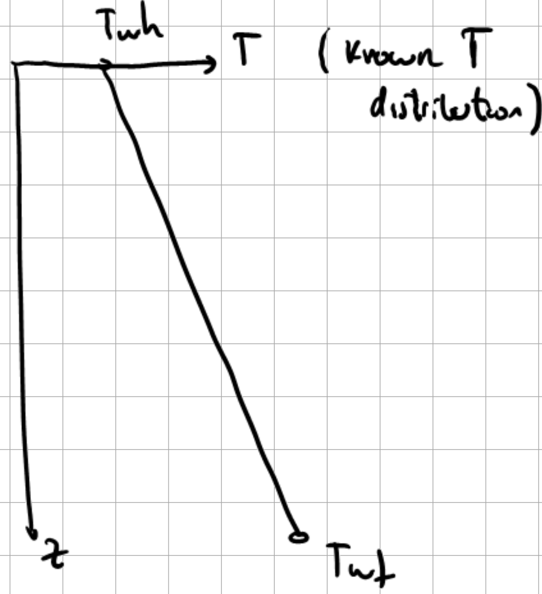
horizontal pipe, same as vertical, but in addition

stratified flow

How do we calculate TPR (tubing performance relationship)?

doing step-wise integration:





1: discretize the pipe in sections

2: Start from the boundary where p is known (P_{wh})

3: Calculate all properties (amounts of oil and gas)

4. Calculate $\frac{dP}{dx}$ at boundary

5: Calculate next point pressure using some integration method

$$\left.\frac{dP}{dx}\right|_{@wh} \qquad P_1 = P_{wh} + \left.\frac{dP}{dx}\right|_{@wh} \cdot \Delta L$$

Euler's method $\left\{ \begin{array}{l} \text{Runge-Kutta} \\ \vdots \end{array} \right.$

6: Calculate all properties of new point

7. Calculate $\frac{dP}{dx}$

8: Repeat!

$\frac{dP}{dx}$ for single phase flow

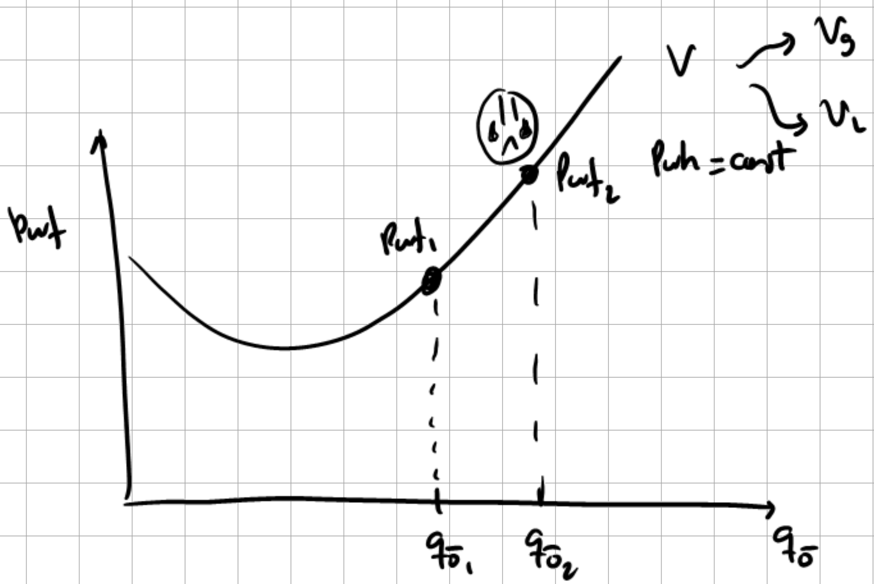
$$\frac{dz}{dx} = \sin\theta$$

$$P_1 - P_2 = \Delta z \cdot \rho \cdot g + f \frac{L}{\Phi} \rho \frac{v^2}{2}$$

$$\frac{dP}{dx} = \sin\theta\, \rho g + \frac{f}{\Phi} \rho \frac{v^2}{2}$$

for multiphase flow $\rho \rightarrow \rho_{mixture} = \rho_{liquid}\, \alpha_L + \rho_g \cdot \alpha_g$

volume fraction



Calculating each point on this curve is computationally expensive!! each point requires integration for dry gas an approximation is $q_g = C_T\left(\frac{p_{wf}^2}{e^S} - p_{wh}^2\right)^{0.5}$

$$C_T = \left(\frac{\pi}{4}\right)\cdot\left(\frac{R}{M_{air}}\right)^{0.5}\cdot\left(\frac{T_{sc}}{p_{sc}}\right)\cdot\left(\frac{D^5}{f_M\cdot L\cdot \gamma_g\cdot Z_{av}\cdot T_{av}}\right)^{0.5}\cdot\left(\frac{S\cdot e^S}{e^S-1}\right)^{0.5}$$

$$S = 2\cdot\frac{28.97\cdot\gamma_g\cdot g}{Z_{av}\cdot R\cdot T_{av}}\cdot L\cdot\cos(\alpha)$$

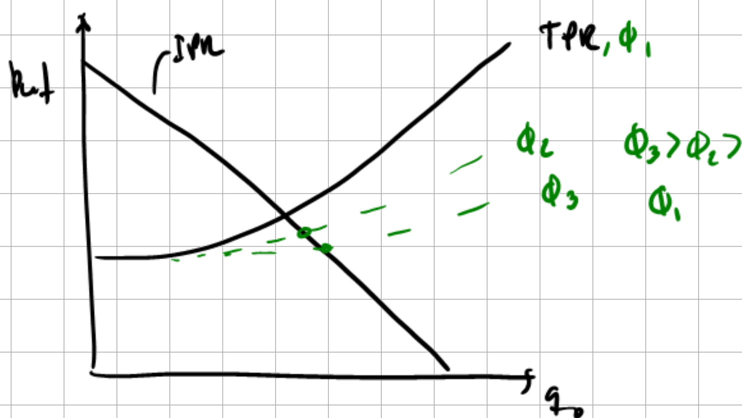
Tubing comes in specific sizes, according to tables, eitehr provided by API, or by other manufacturers (premium tubulars)

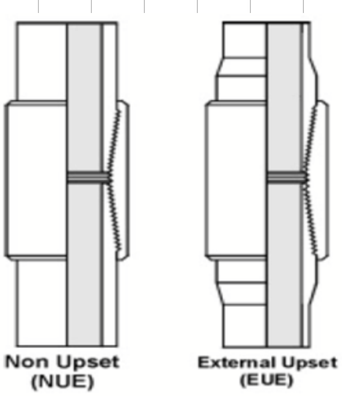
OILProduction.net **API Tubing Table**

material strengh

Tubing Size Nom. in.	Tubing Size OD in.	Nominal Weight T & C Non-Upset lb/ft	Nominal Weight T & C Upset lb/ft	Grade	Wall Thick-ness in.	Inside Dia. in.	Threaded Coupling Drift Dia. in.	Coupling Outside Dia. Non-Upset in.	Coupling Outside Dia. Upset Reg. in.	Coupling Outside Dia. Upset Spec. in.	Col-lapse Resis-tance psi	Internal Yield Pres-sure psi	Joint Yield Strength T & C Non-Upset lb	Joint Yield Strength T & C Upset lb	Capacity Table Barrels per Linear ft	Capacity Table Linear ft per Barrel
3/4	1.05	1.14	1.20	H-40	0.113	0.824	0.730	1.313	1.660		7,200	7,530	6,360	13,300	0.0007	1516.13
				J-55							9,370	10,360	8,740	18,290		
				C-75							12,250	14,120	11,920	24,940		
				N-80							12,710	15,070	12,710	26,610		
1	1.315	1.700	1.800	H-40	0.113	1.049	0.955	1.660	1.900		6,820	7,080	10,960	19,760	0.0011	935.49
				J-55							8,860	9,730	15,060	27,160		
				C-75							11,590	13,270	20,540	37,040		
				N-80							12,270	14,160	21,910	39,510		
1 1/4	1.660	2.300	2.400	H-40	0.125	1.410	1.286	2.054	2.200		5,220	5,270			0.0019	517.79
				H-40	0.140	1.380					5,790	5,900	15,530	26,740	0.0018	540.55
				J-55	0.125	1.410					6,790	7,250			0.0019	517.79
				J-55	0.140	1.380					7,530	8,120	21,360	36,770	0.0018	540.55
				C-75	0.140	1.380					9,840	11,070	29,120	50,140	0.0018	540.55
				N-80	0.140	1.380					10,420	11,810	31,060	53,480	0.0018	540.55
1 1/2	1.900	2.750	2.900	H-40	0.125	1.650	1.516	2.200	2.500		4,450				0.0026	378.11
				H-40	0.145	1.610					5,290		19,090	31,980	0.0025	397.14
				J-55	0.125	1.650					5,790				0.0026	378.11
				J-55	0.145	1.610					6,870		26,250	43,970	0.0025	397.14
				C-75	0.145	1.610					8,990	10,020	35,800	59,960	0.0025	397.14
				N-80	0.145	1.610					9,520	10,680	38,180	63,960	0.0025	397.14

how to choose tubing size:
-Gives most flow (more rate and more USD)
-BUT, cost of the tubing should be taken into account.
-Running tolerances (should enter into casing strings).
-++ Avoid erosion, avoid slugging/liquid loading (very slow liquid velocity), tubing hanger size/load limitations, etc.

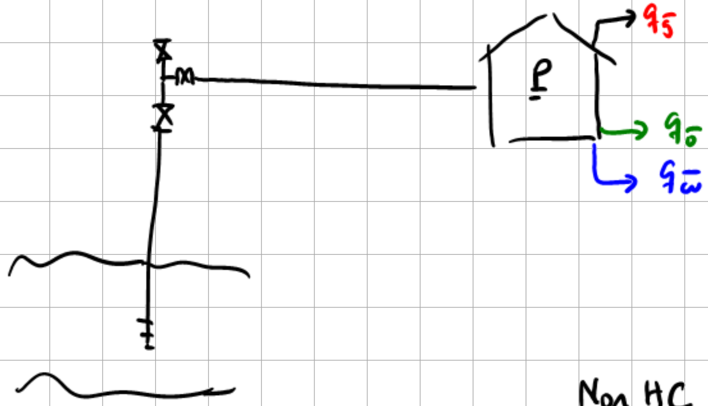




coupling machine: https://www.youtube.com/watch?v=PWt9k7mYBoI

running tubing in well kvitebjørn https://www.youtube.com/watch?v=_vq4hnXQKGw

Topside processing: function is to prepare oil and gas for export and water for discharge



a reservoir stream is defined by providing the composition (mole fraction) of each molecule

	z_i (mole fraction)
N_2	0.02
CO_2	0.05
H_2O	
C_1	0.8
C_2	0.2
	⋮

number of moles of a molecule/divided by total number of moles

$$z_i = \frac{n_i}{n_{TOTAL}}$$

n_i: substance i

Hydrocarbons are made of molecules

Non HC:
- H_2O → produced water
- N_2
- CO_2
- H_2S

HC:
- C_1
- C_2
- C_3
- C_4
- C_5
- C_6
- C_7
- C_8
- ⋮
- C_{100}

LNG: C_1, C_2

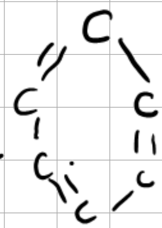
LPG: C_3, C_4

export gas: N_2 … C_4

NGL: C_3 … C_5

export oil: C_5 … C_{100}

aromatic



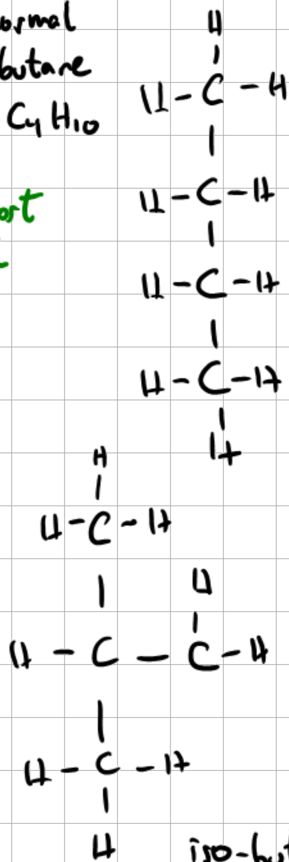
Alkanes C_nH_{2n+2}

CH_4

C_2H_6

normal butane

nC_4H_{10}



iso-butane

iC_4H_{10}

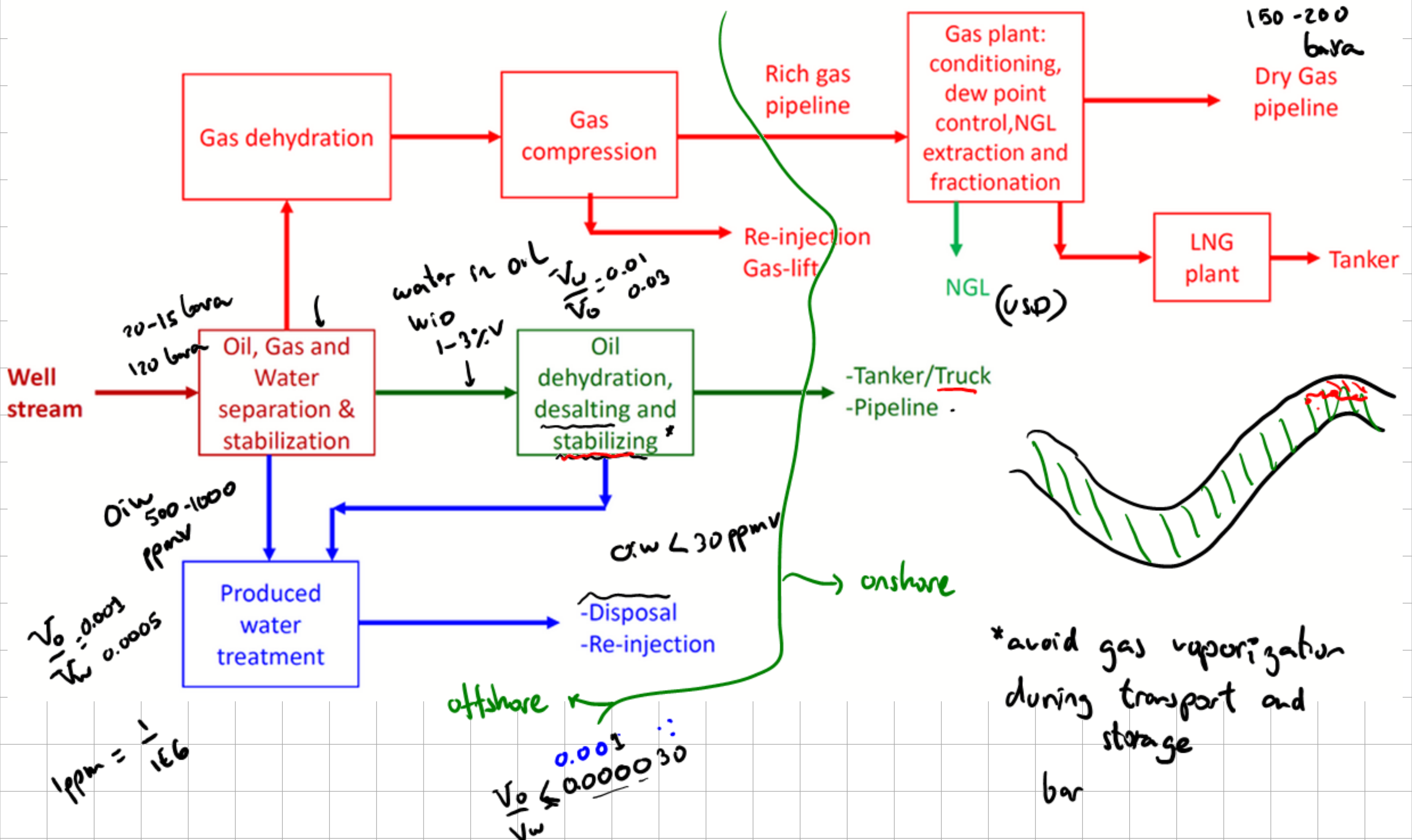
usually above C4, it refers to a whole family of molecules that have the same formula, but different configuration, and different properties

LNG Liquified natural gas

LPG Liquified petroleum gas (grilling)

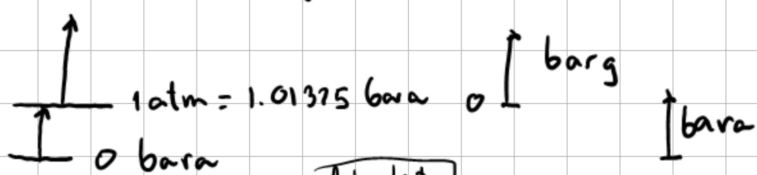
NGL Natural gas liquids

20241119
OUTLINE
-Basics about topside processing
-Orientation about the exam

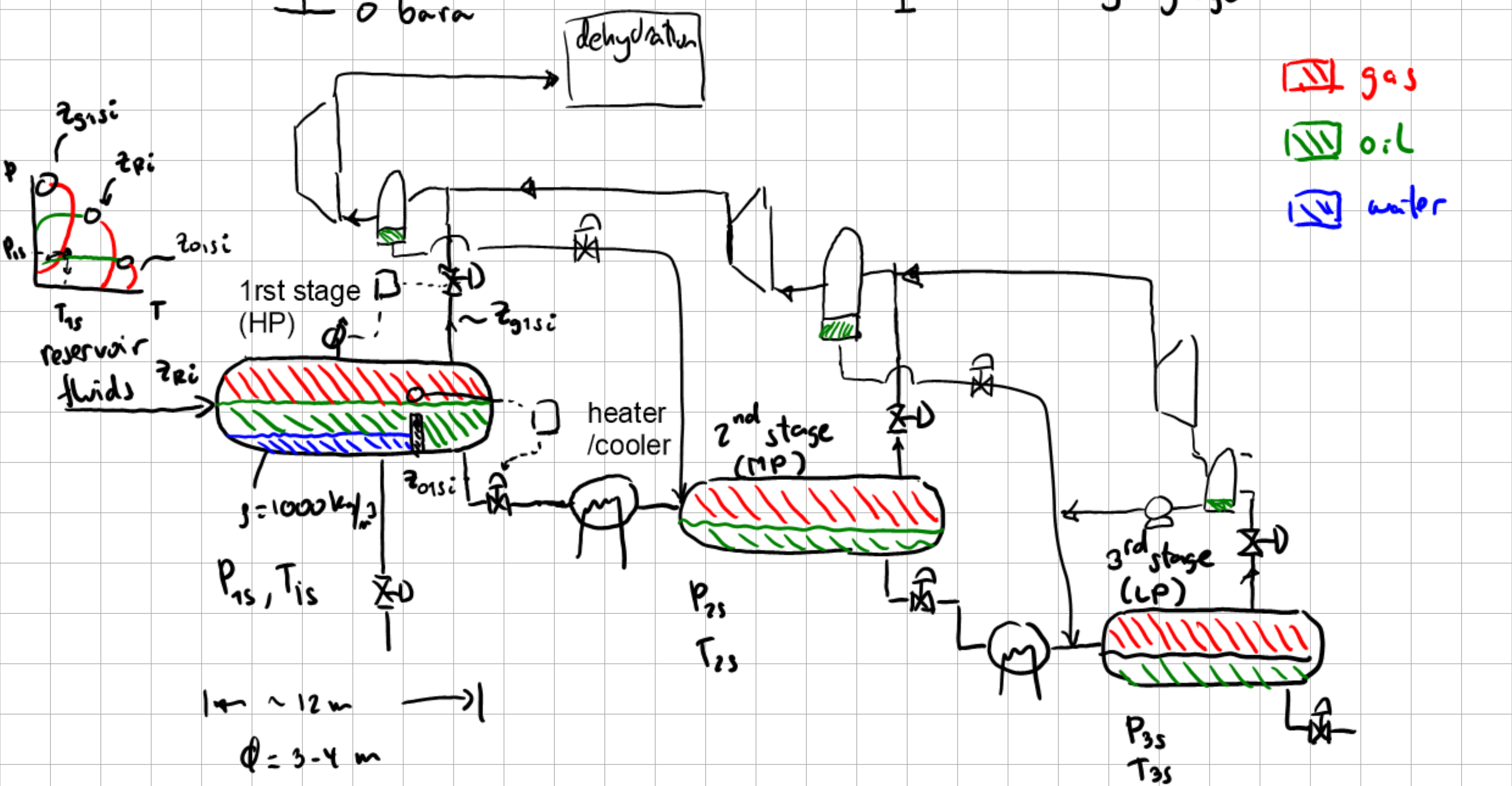


*avoid gas vaporization during transport and storage

bar

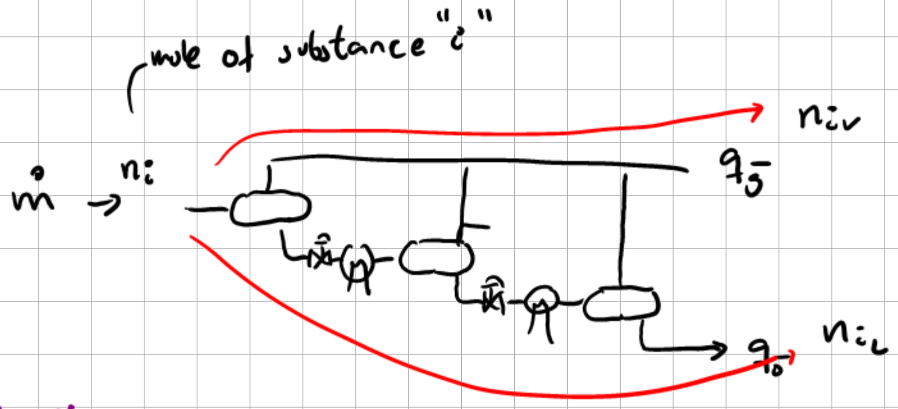


a: absolute
g: gauge

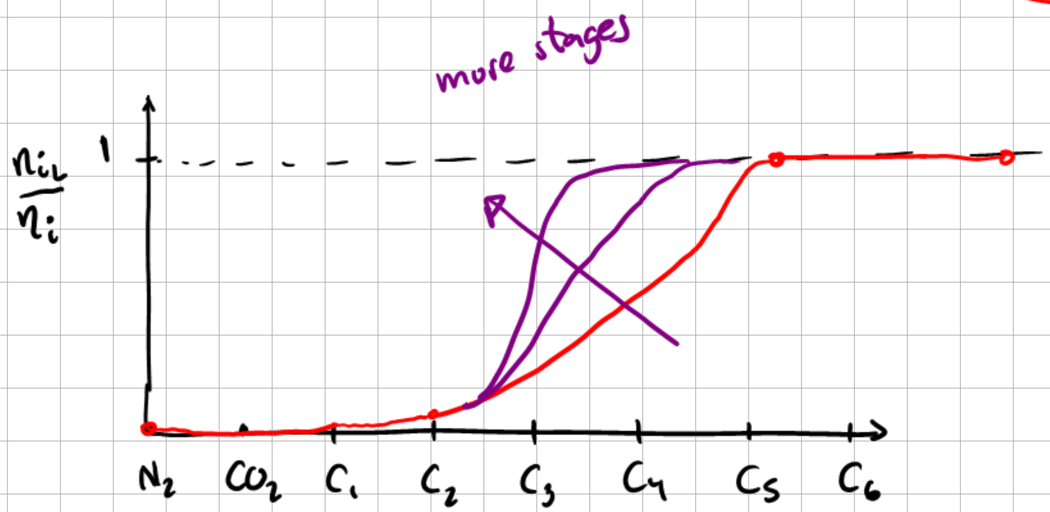


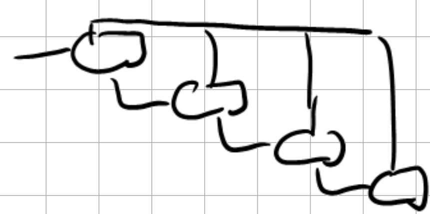
typically in the North Sea: 1-4 stages
1-2 trains

If a lot of gas: vertical separator



$n_i = n_{iL} + n_{iv}$





The purpose of the multi-stage separation process is to:
-Physically separate oil-gas-water
-"convince" molecules to remain in the oil $\rightsquigarrow$ $q_{\bar{o}} \uparrow$ $\downarrow$ GOR

Usually molecules are more willing to stay in the oil if:
-P1p is high (But is is disadvantage because then the required pressure is higher to flow)
-p mp and Tmp can be modified to obtain more oil and lower GOR

GOR gas-oil ratio $\frac{q_{\bar{g}}}{q_{\bar{o}}}$ $\frac{Sm^3/\cancel{d}}{Sm^3/\cancel{d}} = \left[Sm^3/Sm^3 \right]$

in the US $[scf/stb]$

Imagine a field with the following characteristics:

$$\left.\begin{array}{l} q_{\bar{o}} = 15000 \ Sm^3/d \\ GOR = 150 \ Sm^3/Sm^3 \end{array}\right\} \begin{array}{l} q_{\bar{g}} = q_{\bar{o}} \cdot GOR \\ q_{\bar{g}} = 2.25E06 \ Sm^3/d \end{array}$$

$$q_{HC} = q_{\bar{o}} + q_{\bar{g}} = 2.265E6 \ Sm^3/d$$

the revenue : $q_{\bar{o}} \cdot P_o + q_{\bar{g}} \cdot P_g = q_{\bar{o}}(P_o + GOR \cdot P_g)$

$P_o = 60 \ USD/bbl \simeq 377 \ USD/Sm^3$ $\quad P_g \approx 1 \ USD/Sm^3$ (but earlier $0.1 \ USD/Sm^3$)

Revenue $q_{\bar{o}} \cdot P_o + q_{\bar{g}} \cdot P_g$

$$(15000 \cdot 377 + 2.25E6 \cdot 1)$$

$$(5655000 + 2250000) \text{ USD/d}$$

if one manages to reduce the GOR to e.g. GOR = 130 Sm^3/Sm^3

with multistage separation

$$q_{\overline{HC}} = 2.265E06 = q_{\bar{o}}(1+130)$$

$$q_{\bar{o}} = 17290 \ Sm^3/d$$

Revenue:

$$q_{\bar{o}} \cdot P_o + q_{\bar{g}} \cdot P_g$$

$$(17290 \cdot 377) + (17290 \cdot 130 \cdot 1)$$

$$[6518358 + 2.247700] \text{ USD/d}$$

Exam information (only the production part):

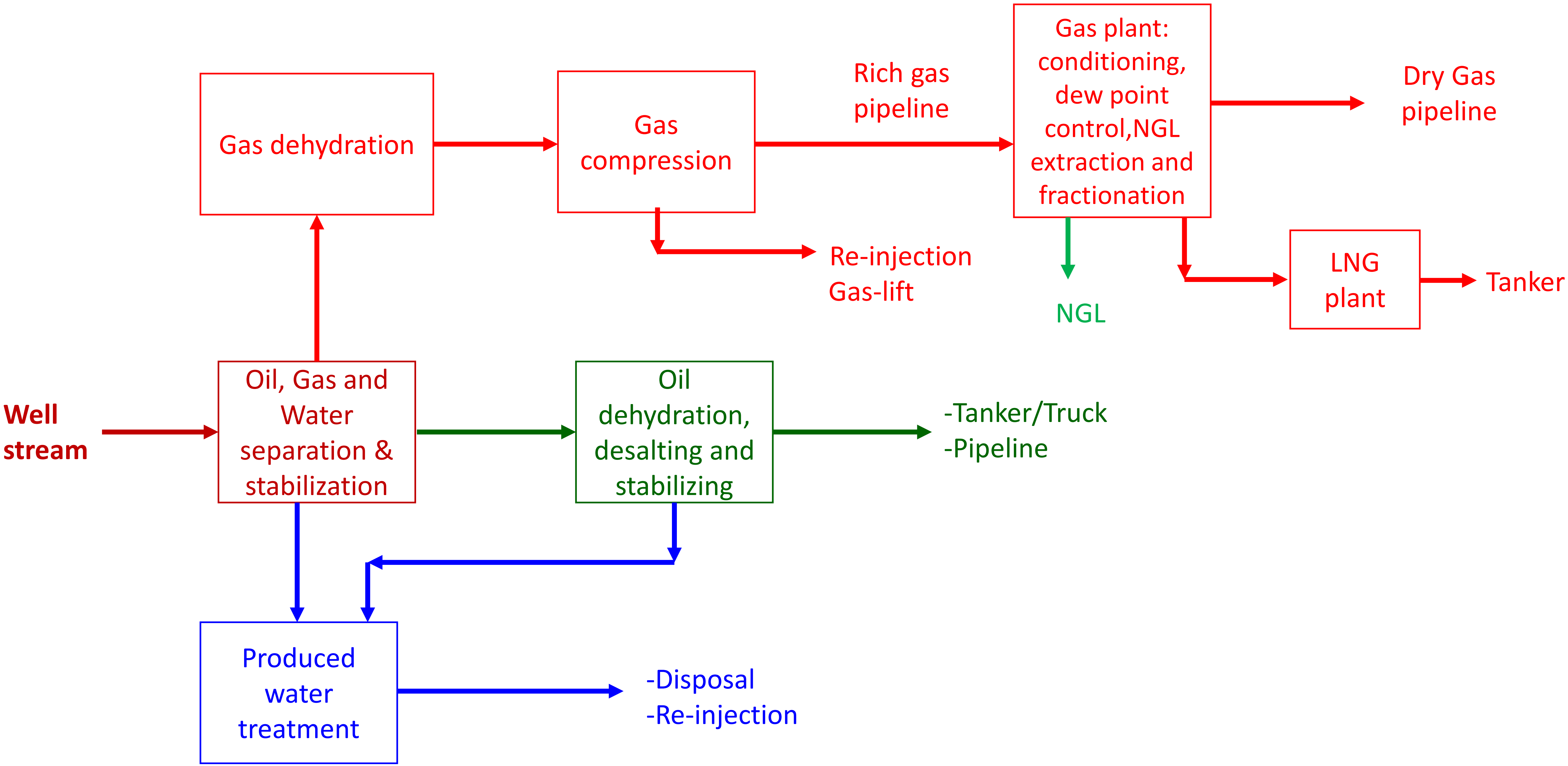
-1 Problem (15 POINTS). Calculation problem with 3 tasks (each 5 POINTS) - Need a calculator.
Flow equilibrium+ Dry gas equations. To study consider downhole and wellhead equilibrium!!!
Equations will be given in the exam
-Milan corrects considering procedure+results.

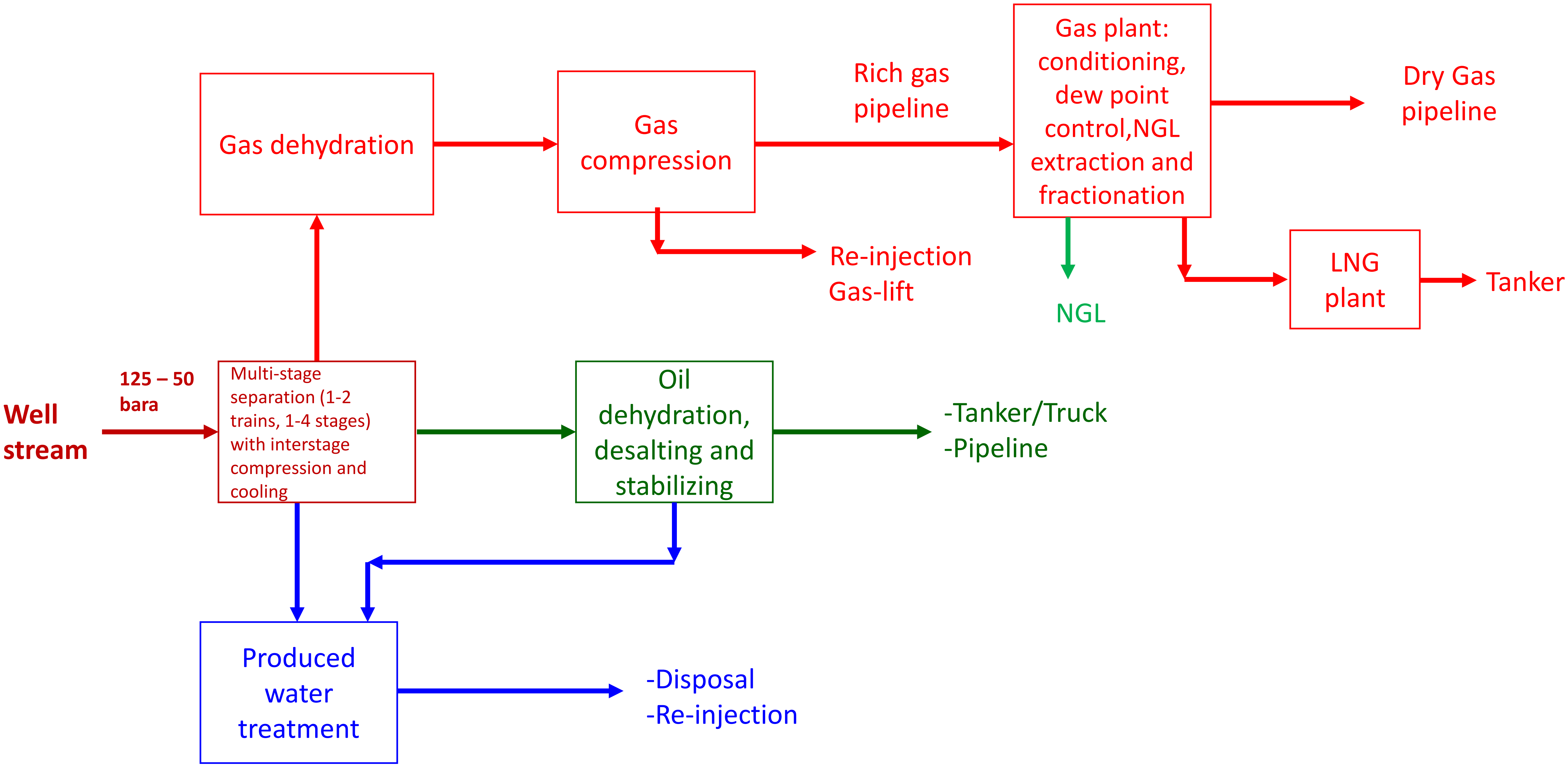
-1 question (5 POINTS): Theory+Sketching question

NTNU | Norwegian University of Science and Technology

Introduction to oilfield processing

Assoc. Prof. Milan Stanko


Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline
Produced water treatment
-Disposal
-Re-injection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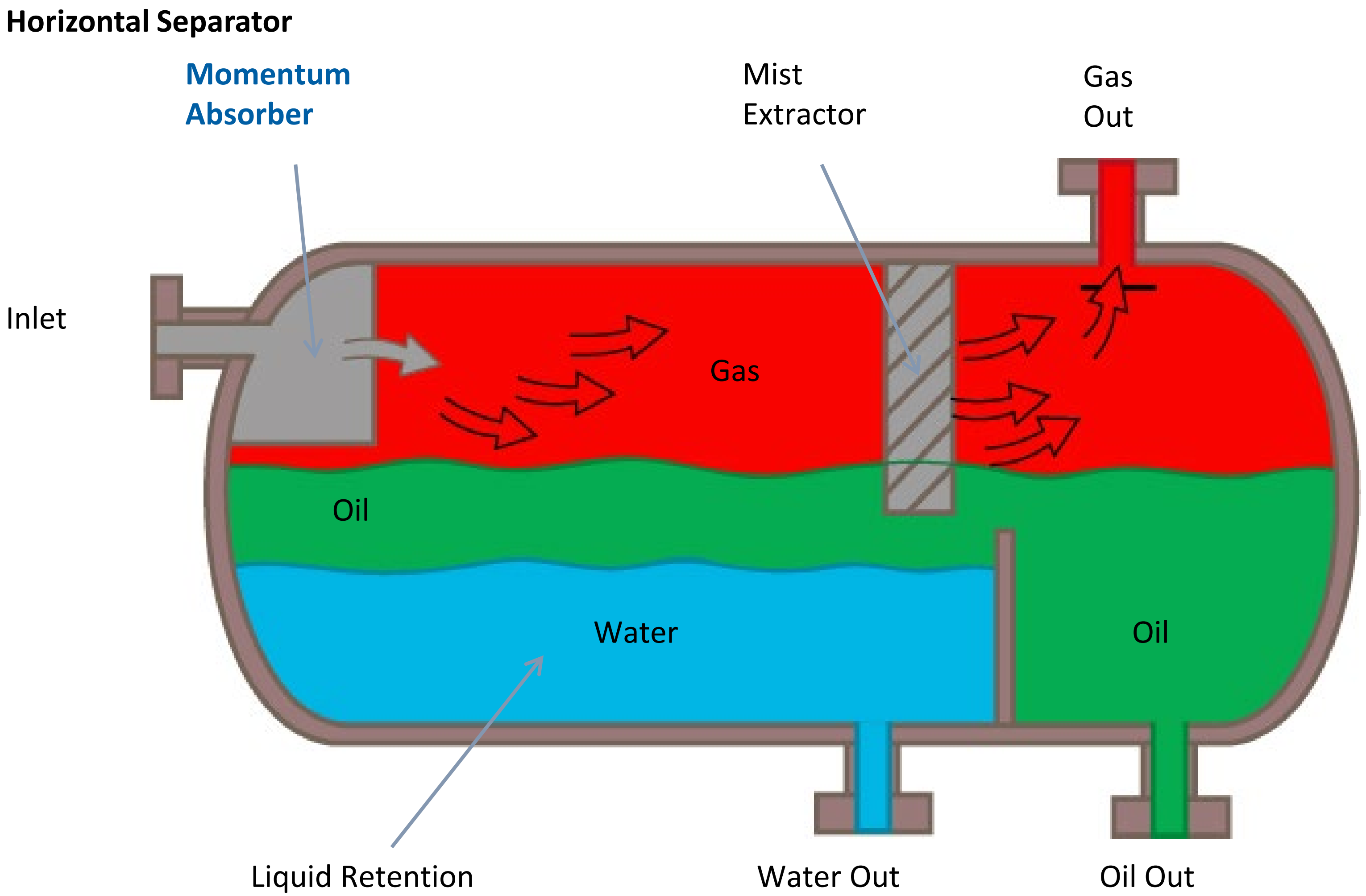
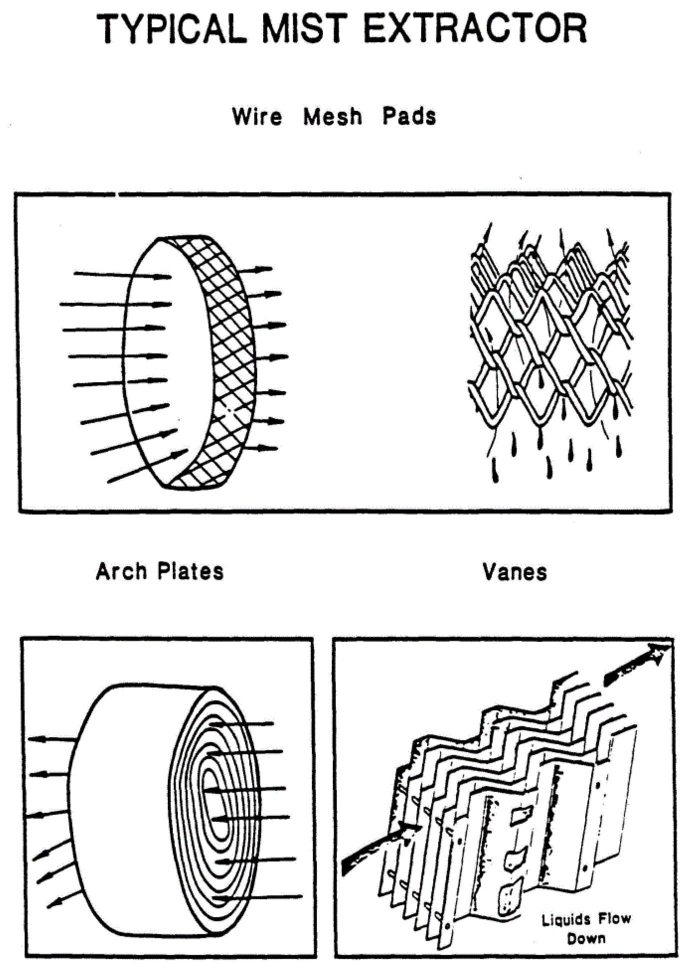
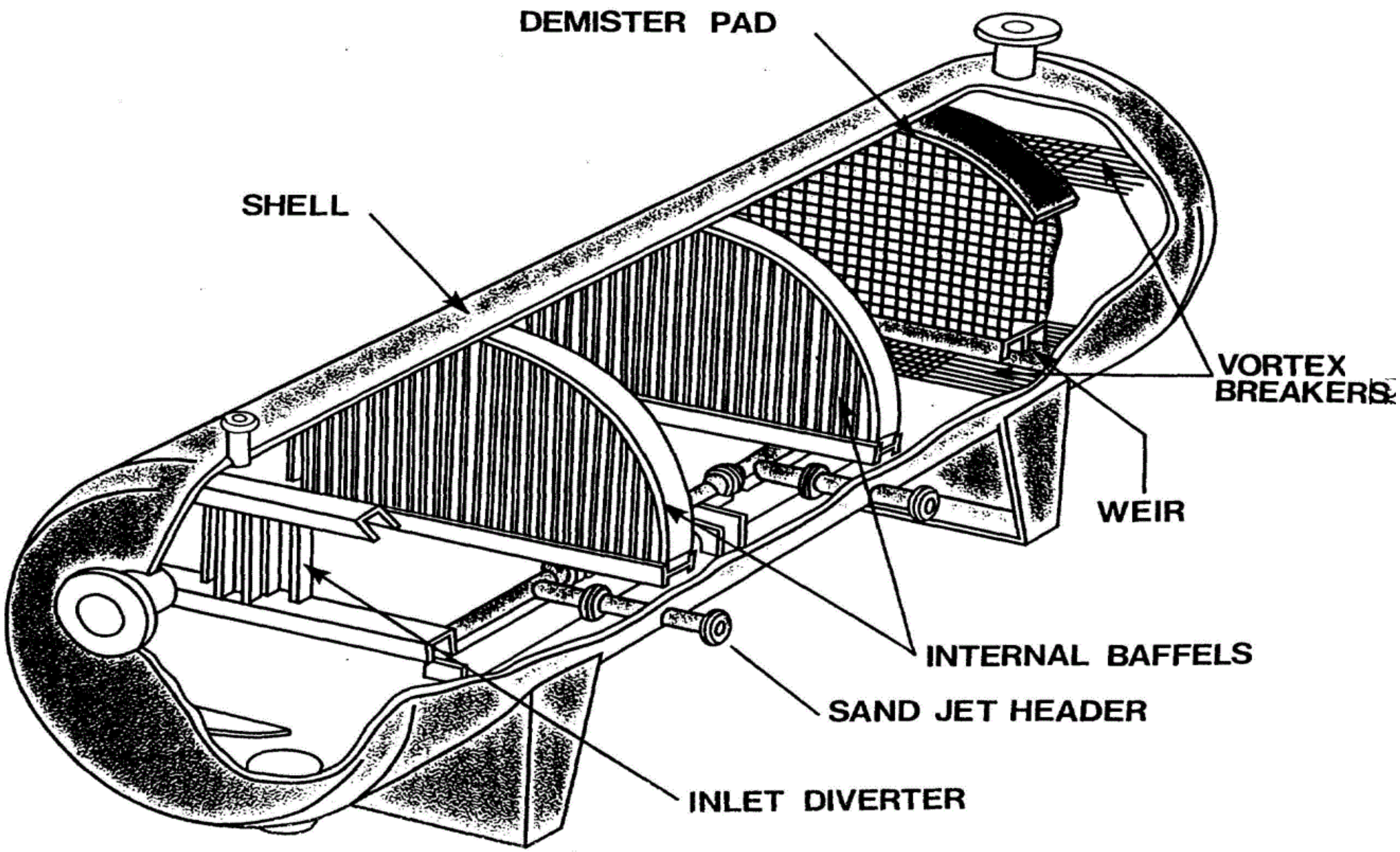
Horizontal separator

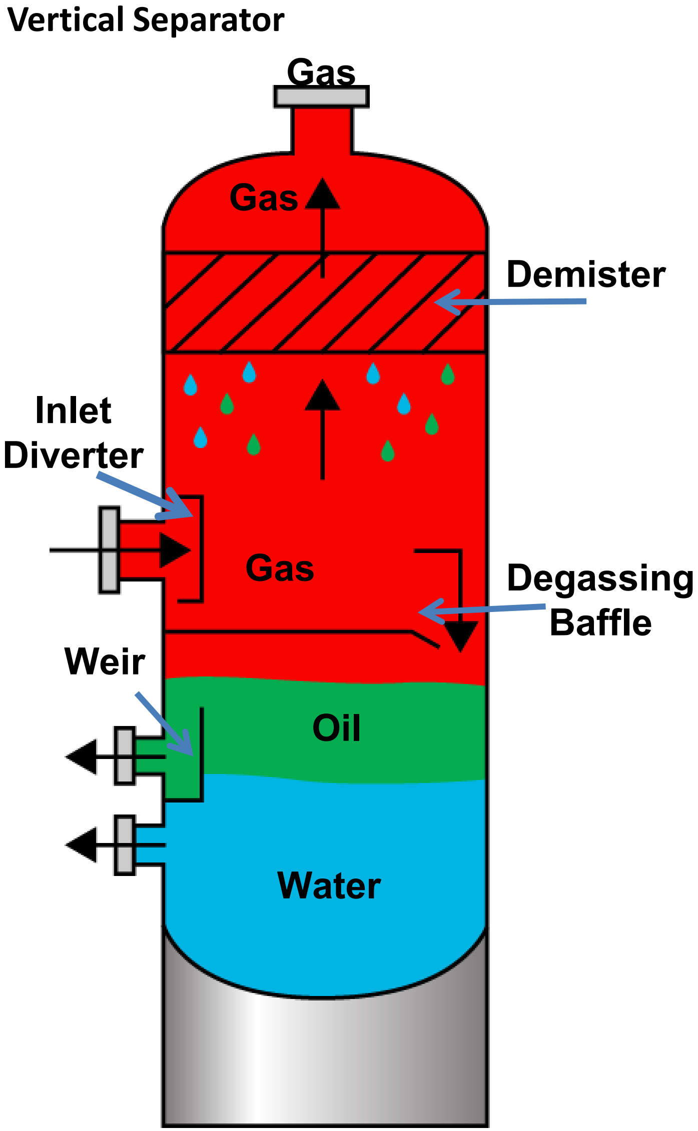


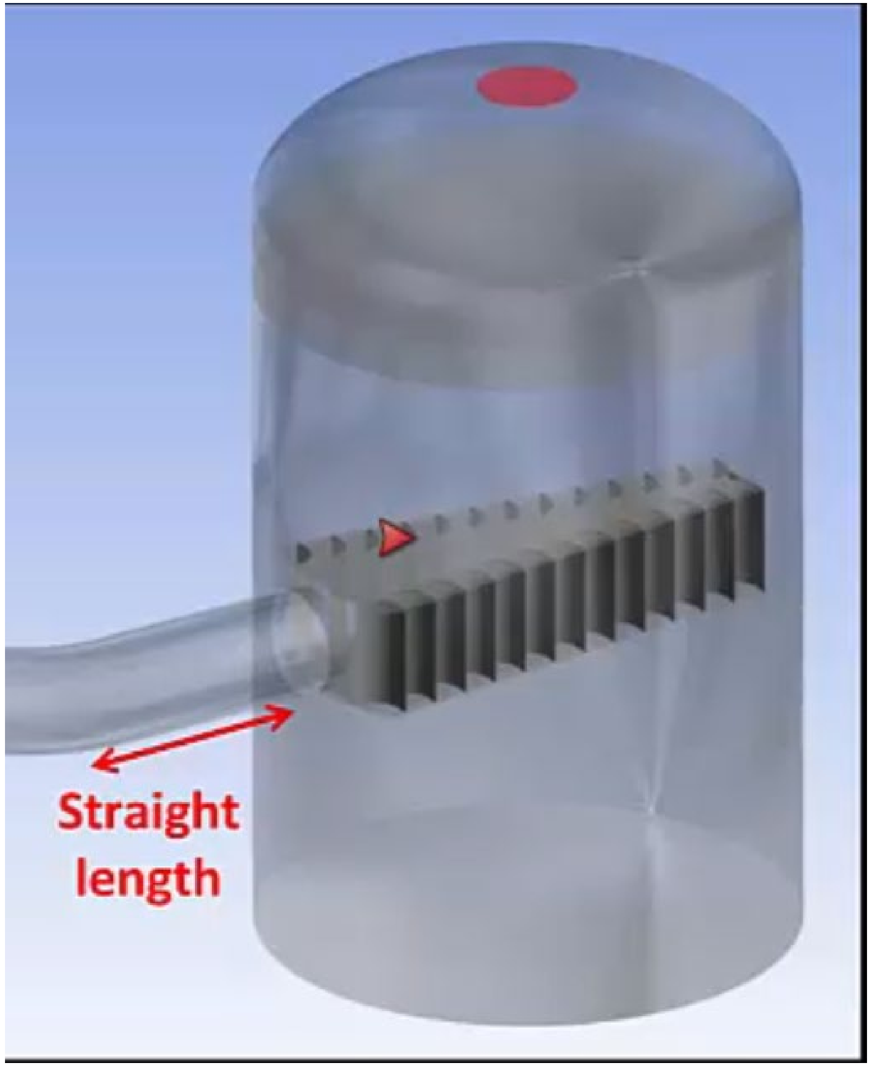


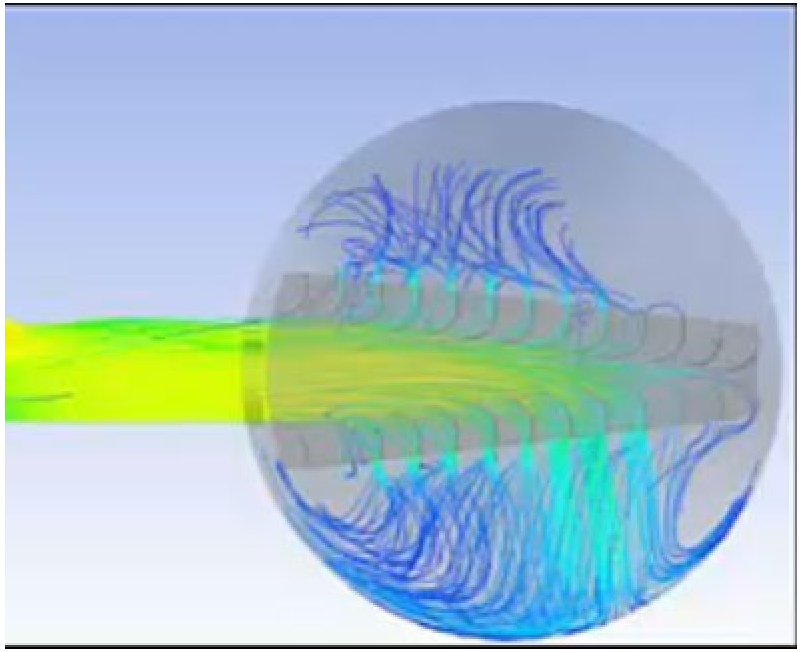
Horizontal separator



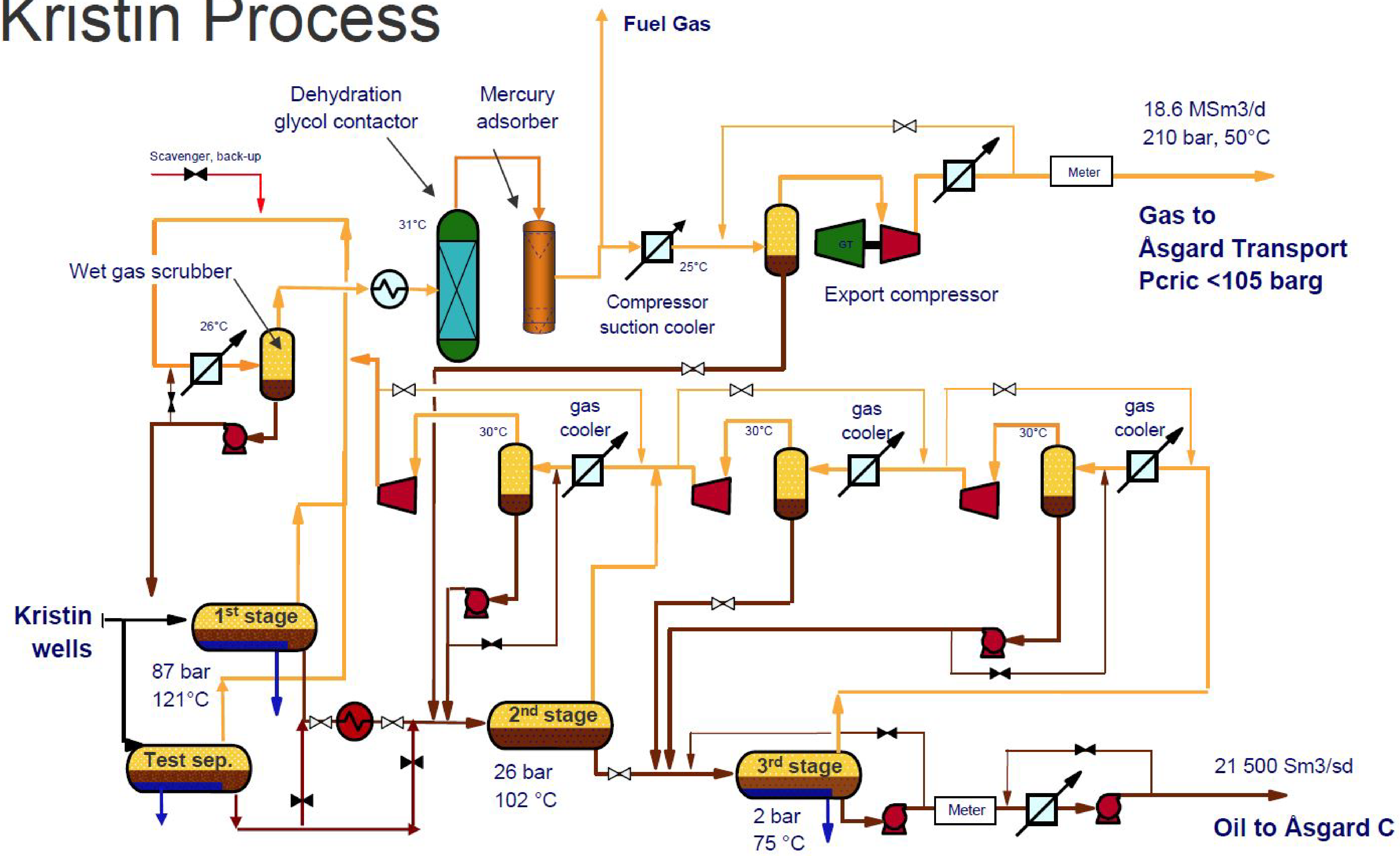
Vertical separator

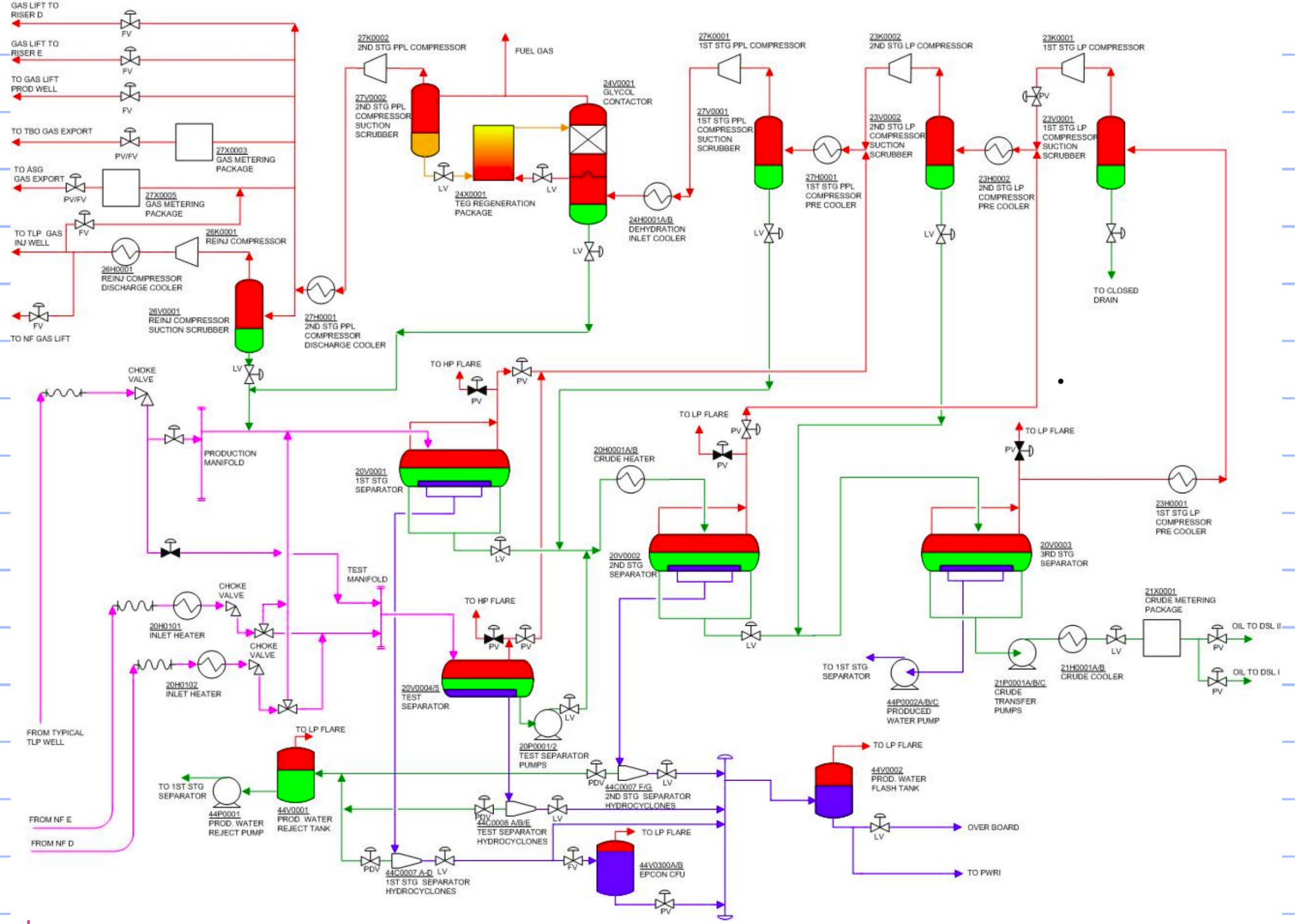


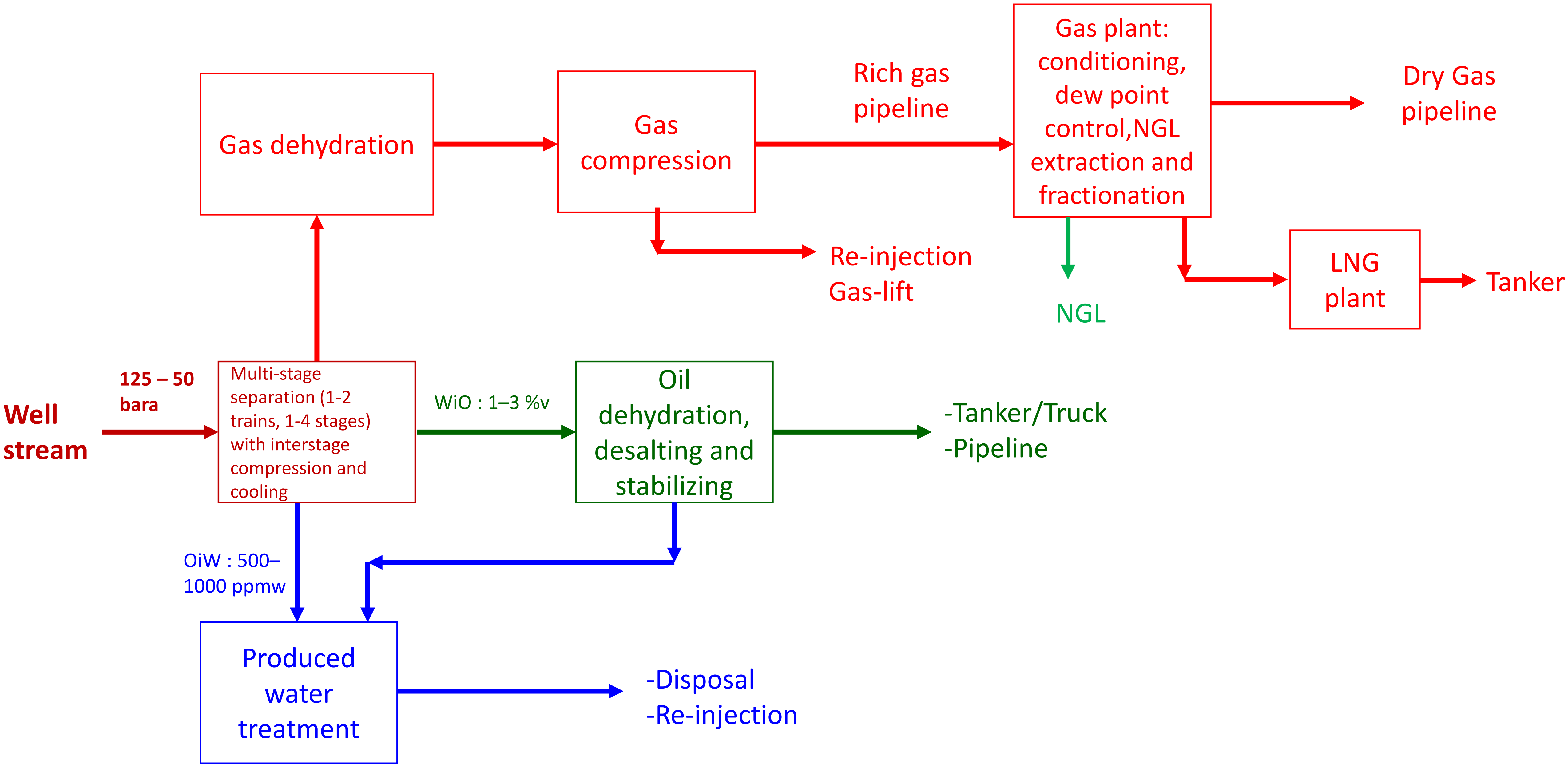




Kristin Process




GAS LIFT TO RISER D
GAS LIFT TO RISER E
TO GAS LIFT PROD WELL
TO TBO GAS EXPORT
TO ASG GAS EXPORT
TO TLP GAS INJ WELL
TO NF GAS LIFT
FV
PV/FV
27X0003 GAS METERING PACKAGE
27X0005 GAS METERING PACKAGE
26K0001 REINJ COMPRESSOR
26H0001 REINJ COMPRESSOR DISCHARGE COOLER
26V0001 REINJ COMPRESSOR SUCTION SCRUBBER
27K0002 2ND STG PPL COMPRESSOR
27V0002 2ND STG PPL COMPRESSOR SUCTION SCRUBBER
27H0001 2ND STG PPL COMPRESSOR DISCHARGE COOLER
FUEL GAS
24X0001 TEG REGENERATION PACKAGE
24V0001 GLYCOL CONTACTOR
24H0001A/B DEHYDRATION INLET COOLER
27K0001 1ST STG PPL COMPRESSOR
27V0001 1ST STG PPL COMPRESSOR SUCTION SCRUBBER
27H0001 1ST STG PPL COMPRESSOR PRE COOLER
23K0002 2ND STG LP COMPRESSOR
23V0002 2ND STG LP COMPRESSOR SUCTION SCRUBBER
23H0002 2ND STG LP COMPRESSOR PRE COOLER
23K0001 1ST STG LP COMPRESSOR
23V0001 1ST STG LP COMPRESSOR SUCTION SCRUBBER
TO CLOSED DRAIN
LV
PV
CHOKE VALVE
PRODUCTION MANIFOLD
TO HP FLARE
TO LP FLARE
20V0001 1ST STG SEPARATOR
20H0001A/B CRUDE HEATER
20V0002 2ND STG SEPARATOR
20V0003 3RD STG SEPARATOR
23H0001 1ST STG LP COMPRESSOR PRE COOLER
TEST MANIFOLD
20H0101 INLET HEATER
20H0102 INLET HEATER
20V0004/5 TEST SEPARATOR
20P0001/2 TEST SEPARATOR PUMPS
FROM TYPICAL TLP WELL
FROM NF E
FROM NF D
21X0001 CRUDE METERING PACKAGE
OIL TO DSL II
OIL TO DSL I
21H0001A/B CRUDE COOLER
21P0001A/B/C CRUDE TRANSFER PUMPS
TO 1ST STG SEPARATOR
44P0002A/B/C PRODUCED WATER PUMP
44V0001 PROD. WATER REJECT TANK
44P0001 PROD. WATER REJECT PUMP
PDV
44C0007 F/G 2ND STG SEPARATOR HYDROCYCLONES
44C0008 A/B/E TEST SEPARATOR HYDROCYCLONES
44C0007 A-D 1ST STG SEPARATOR HYDROCYCLONES
44V0300A/B EPCON CFU
44V0002 PROD. WATER FLASH TANK
OVER BOARD
TO PWRI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Tanker
125 – 50 bara
Well stream
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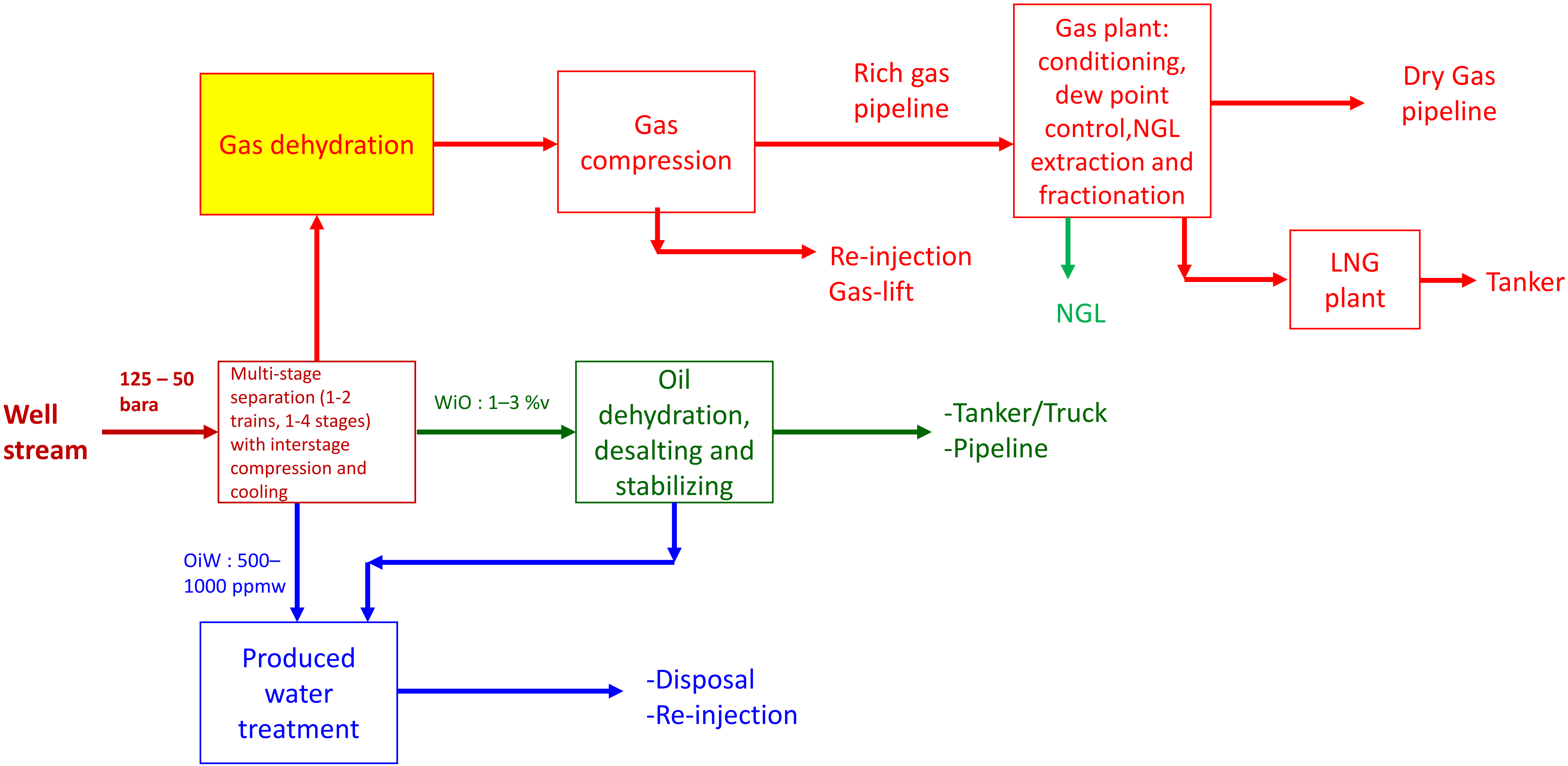
WiO : 1–3 %v
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection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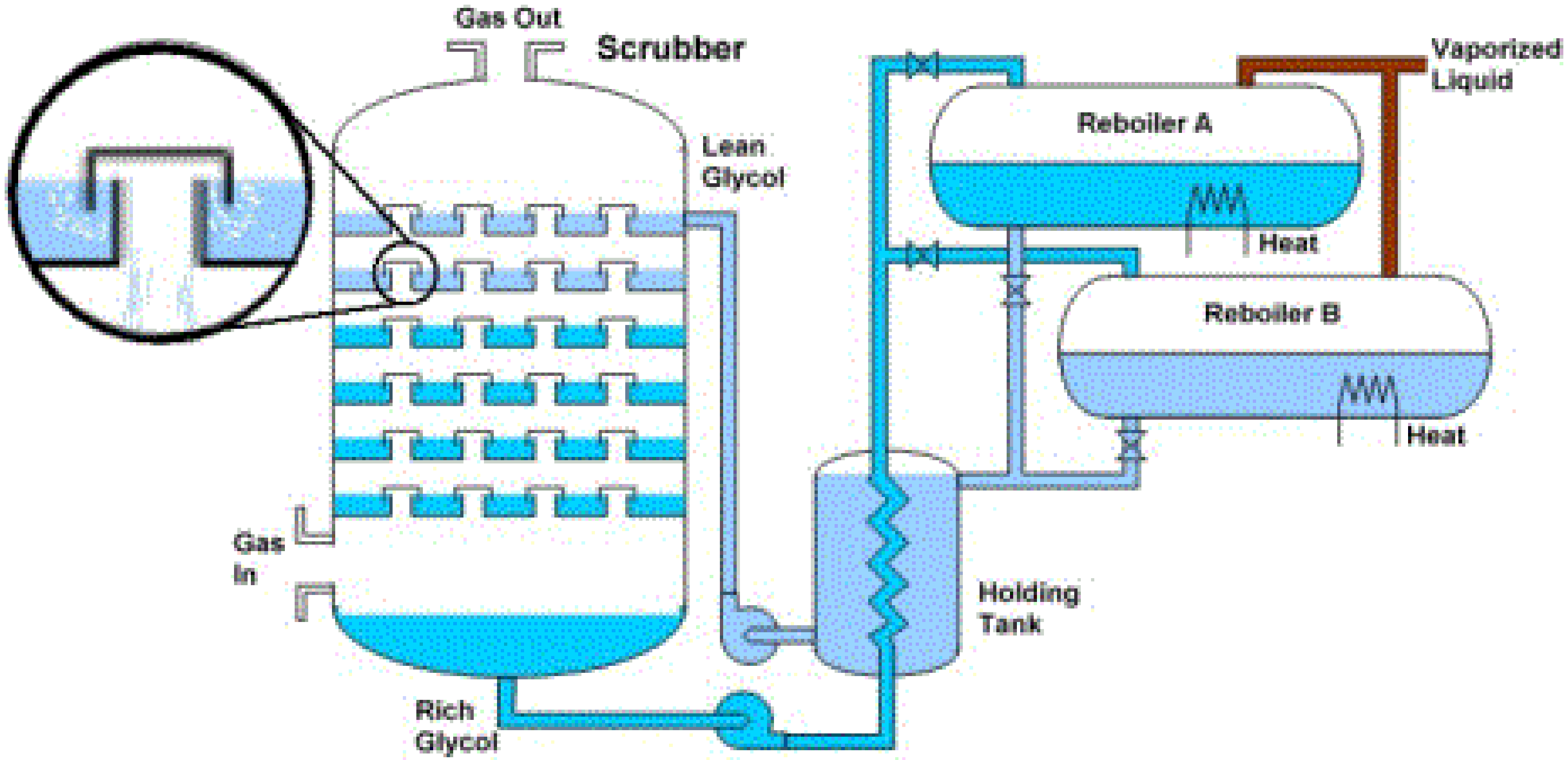
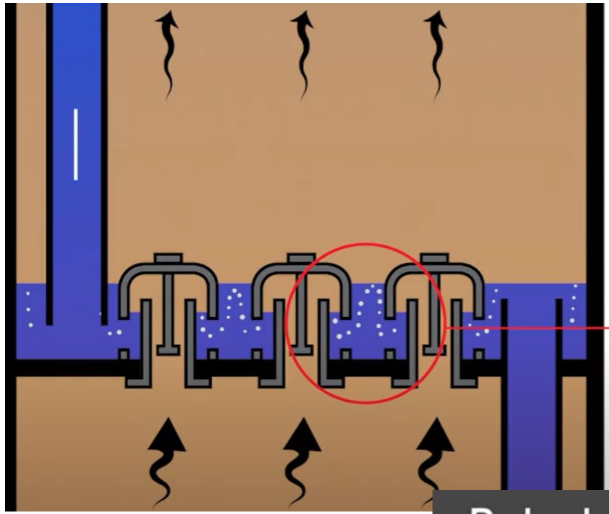
TEG dehydration



Youtube links for TEG dehydration

- Inside a gas dehydration tower: https://www.youtube.com/watch?v=_f7q8gWf8fg
- Gas dehydration unit: https://www.youtube.com/watch?v=kTtiqTeTZ0I



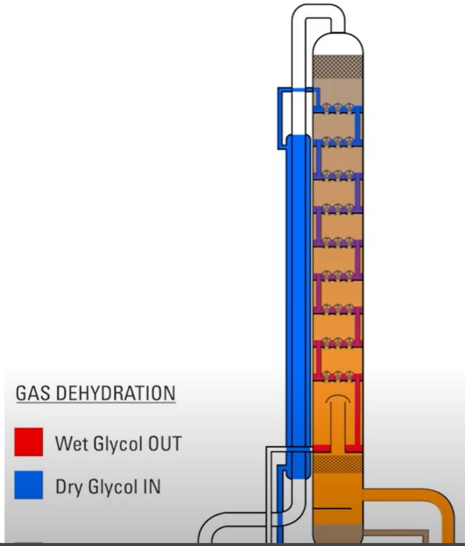
Gas

comes into contact with the

triethylene glycol

Water vapors entrained in the gas are absorbed in the TEG

The glycol is then removed from the gas



1. Glycol moves through **contactor tower**, absorbing the moisture from the natural gas becoming WET GLYCOL.

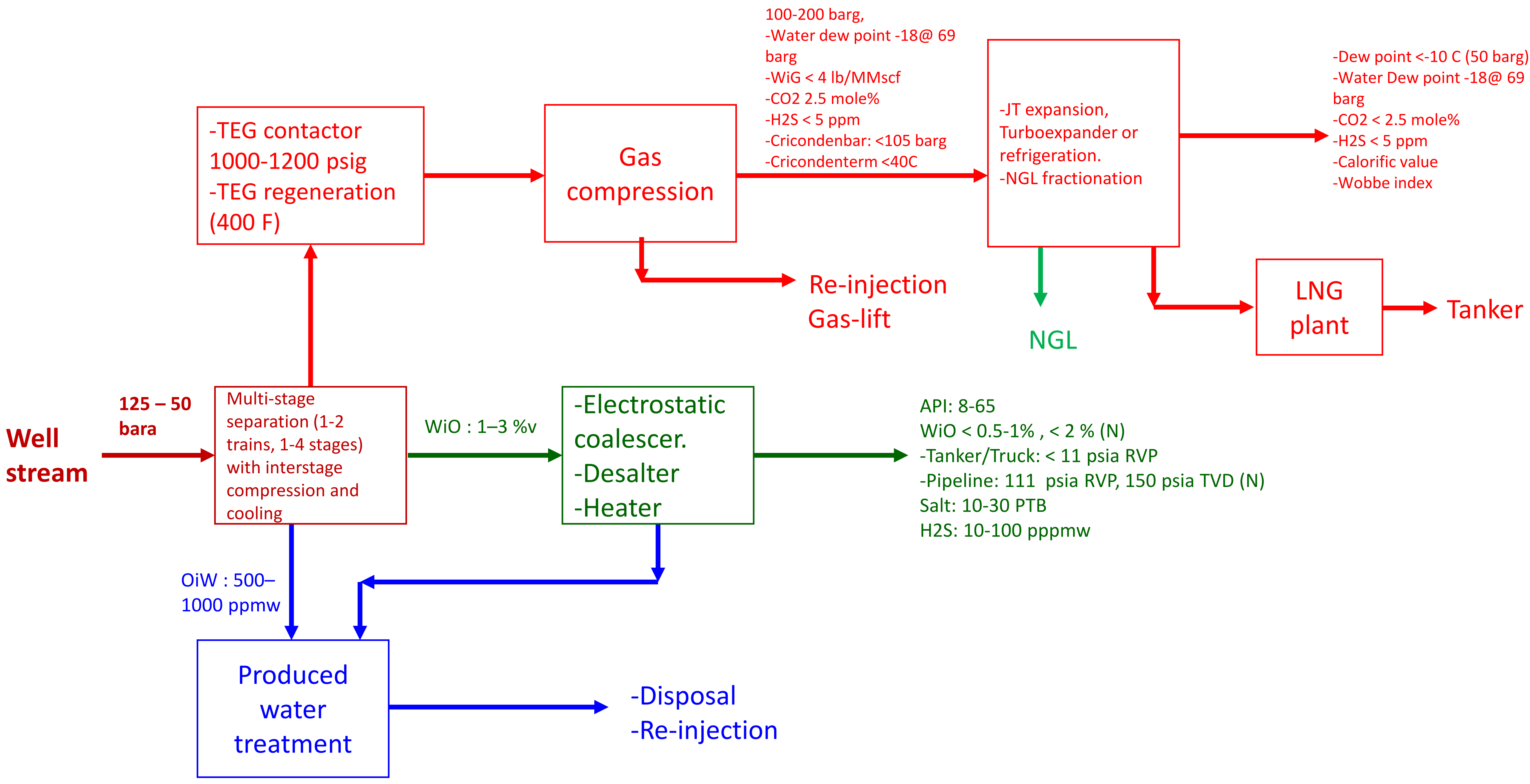
Wet Glycol = "Rich" Glycol

Glycol entrained with water

Dehydration Unit Sizes

Dehydration units vary in size depending on **gas flow**.

In a unit this size, flow rates can be **a few million cubic feet** per day (MMCFD).



100-200 barg,
-Water dew point -18@ 69 barg
-WiG < 4 lb/MMscf
-CO2 2.5 mole%
-H2S < 5 ppm
-Cricondenbar: <105 barg
-Cricondenterm <40C
-Dew point <-10 C (50 barg)
-Water Dew point -18@ 69 barg
-CO2 < 2.5 mole%
-H2S < 5 ppm
-Calorific value
-Wobbe index
-TEG contactor 1000-1200 psig
-TEG regeneration (400 F)
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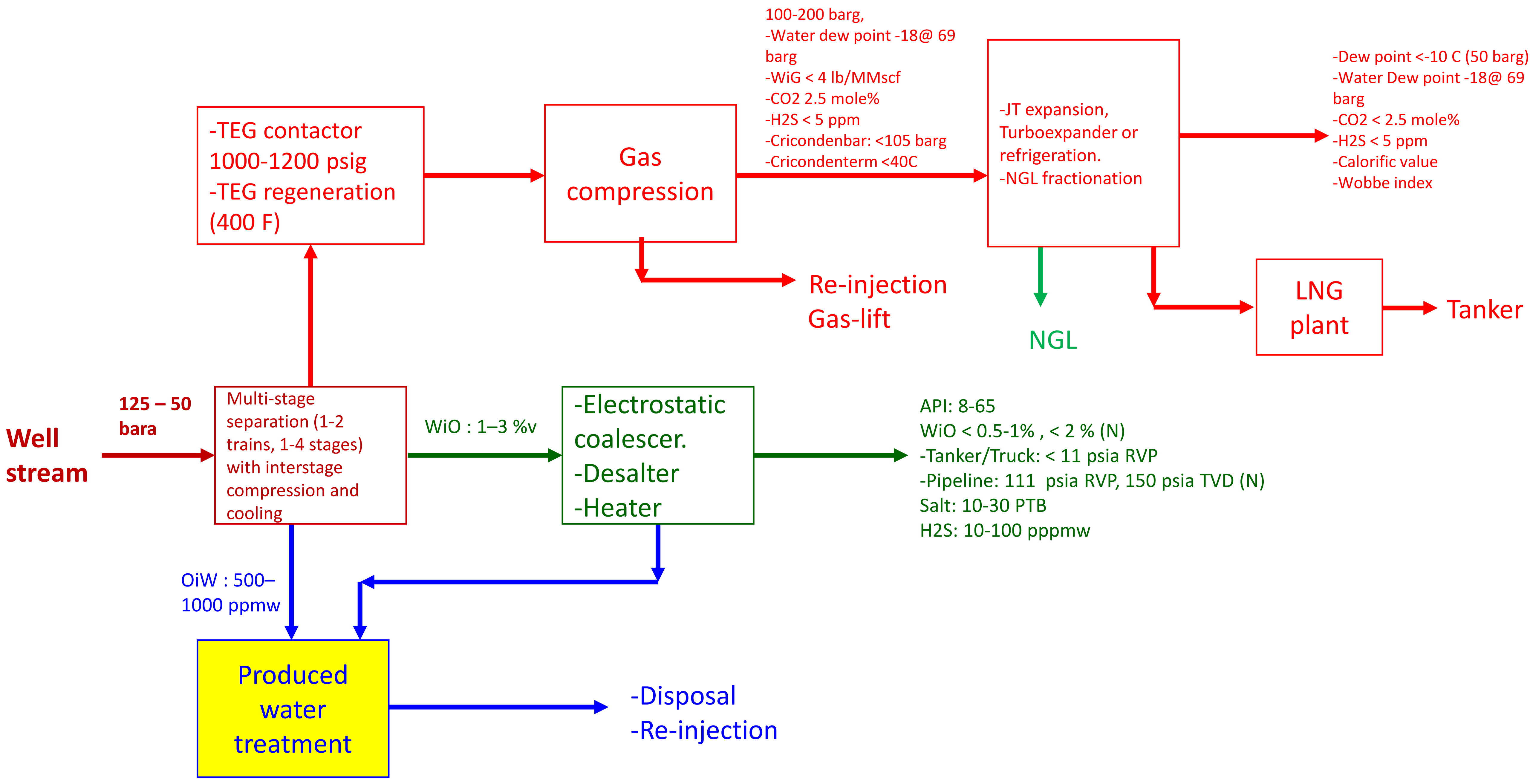
WiO : 1–3 %v
-Electrostatic coalescer.
-Desalter
-Heater
API: 8-65
WiO < 0.5-1% , < 2 % (N)
-Tanker/Truck: < 11 psia RVP
-Pipeline: 111 psia RVP, 150 psia TVD (N)
Salt: 10-30 PTB
H2S: 10-100 pppmw
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection



-TEG contactor 1000-1200 psig
-TEG regeneration (400 F)
Gas compression
100-200 barg,
-Water dew point -18@ 69 barg
-WiG < 4 lb/MMscf
-CO2 2.5 mole%
-H2S < 5 ppm
-Cricondenbar: <105 barg
-Cricondenterm <40C
-JT expansion, Turboexpander or refrigeration.
-NGL fractionation
-Dew point <-10 C (50 barg)
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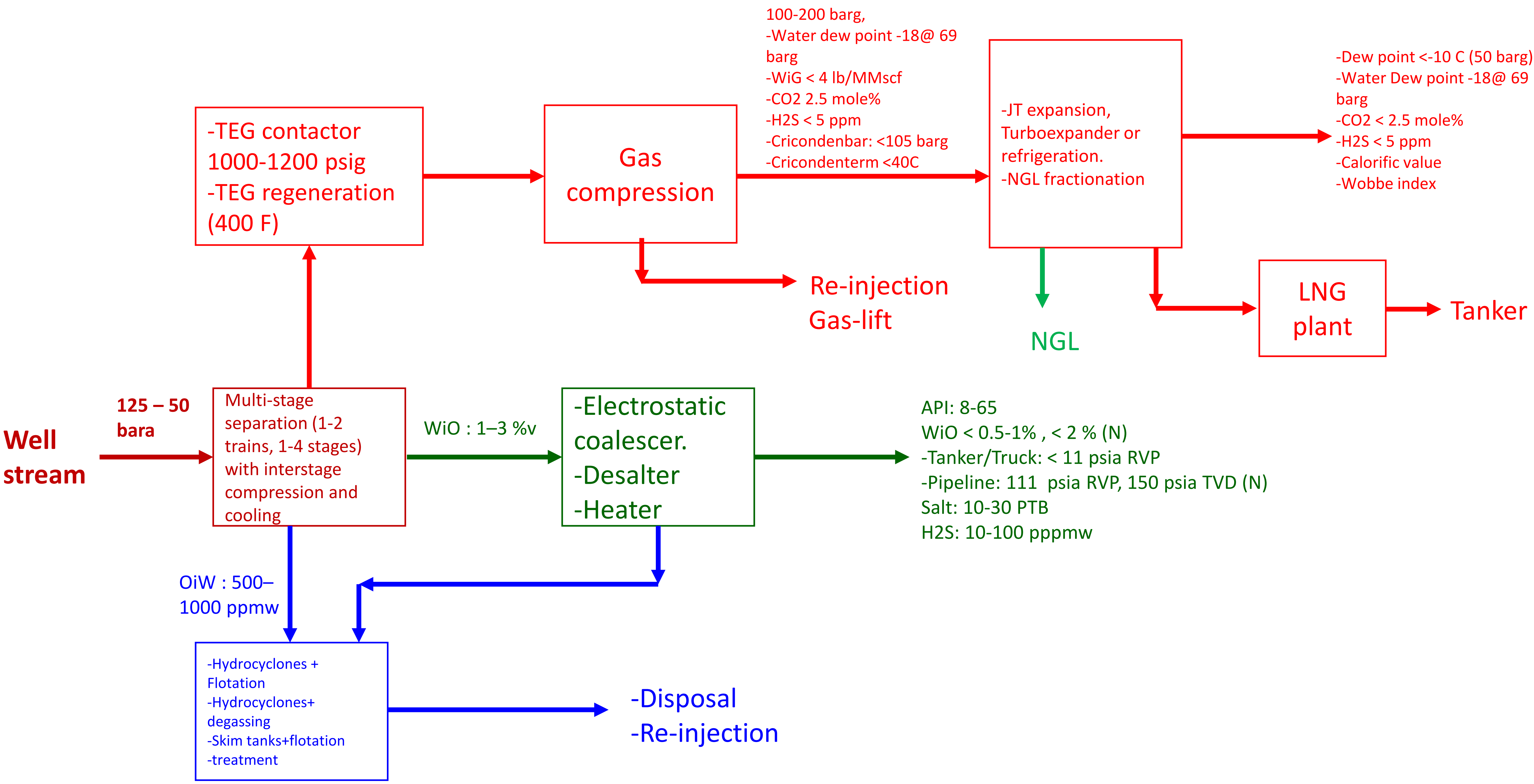
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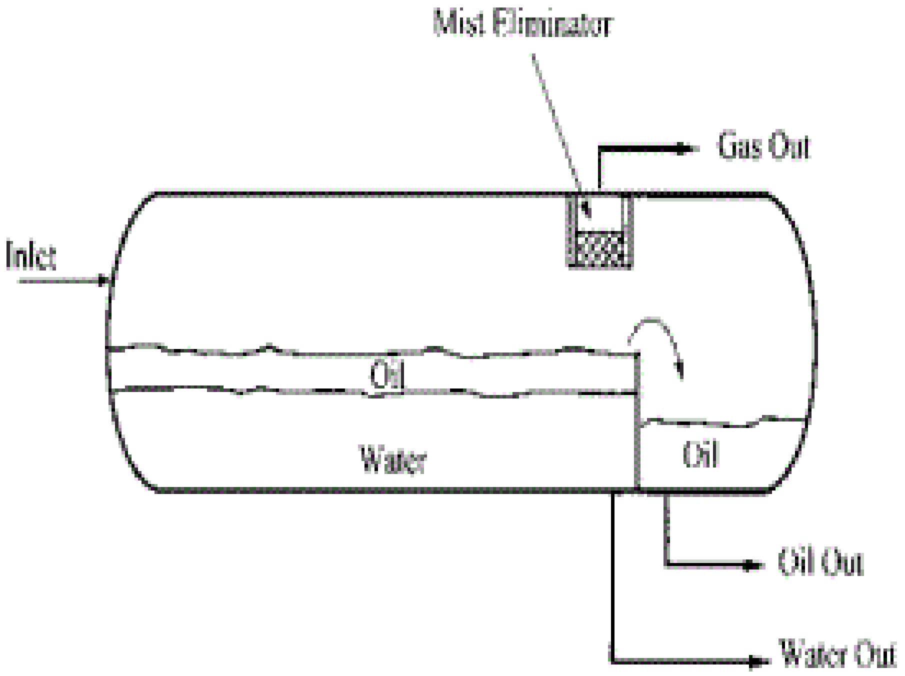
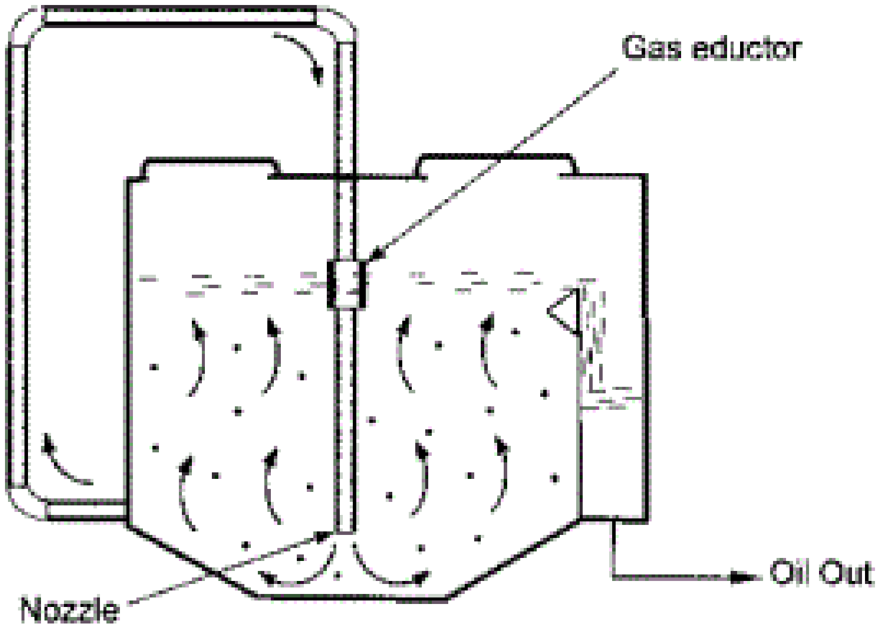
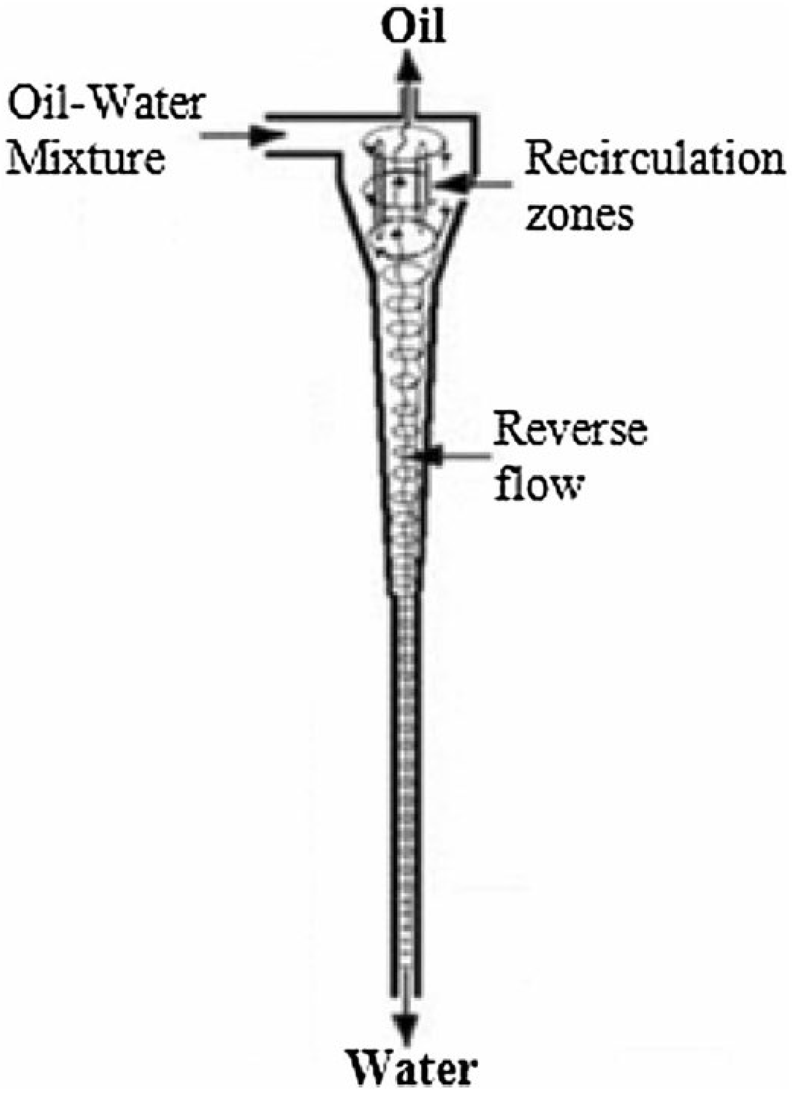
Salt: 10-30 PTB
H2S: 10-100 pppmw
OiW : 500–1000 ppmw
-Hydrocyclones + Flotation
-Hydrocyclones+ degassing
-Skim tanks+flotation
-treatment
-Disposal
-Re-injection

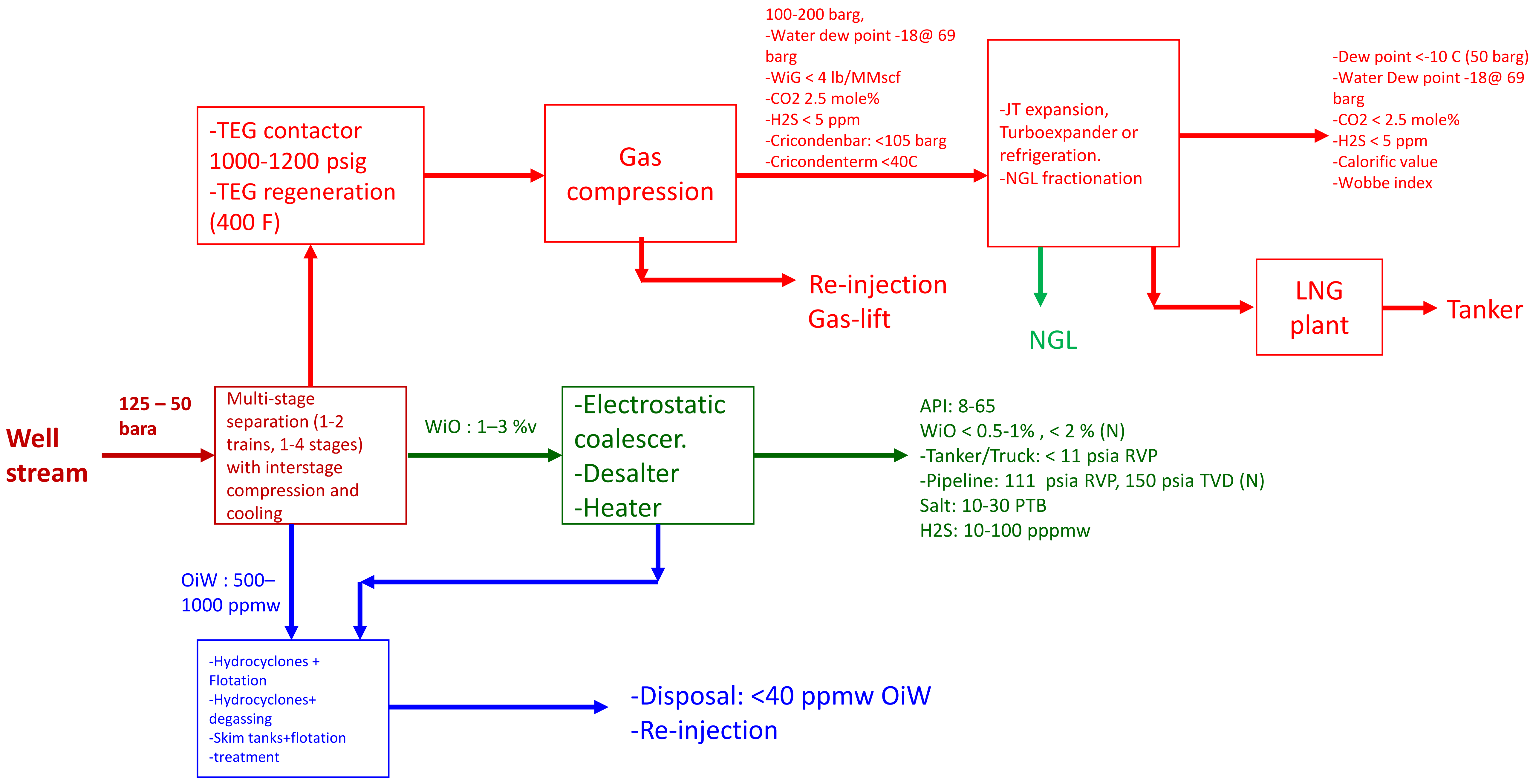
Skim tank + flotation unit





Hydrocyclone





Well stream
125 – 50 bara
Multi-stage separation (1-2 trains, 1-4 stages) with interstage compression and cooling
-TEG contactor 1000-1200 psig
-TEG regeneration (400 F)
Gas compression
Re-injection
Gas-lift
100-200 barg,
-Water dew point -18@ 69 barg
-WiG < 4 lb/MMscf
-CO2 2.5 mole%
-H2S < 5 ppm
-Cricondenbar: <105 barg
-Cricondenterm <40C
-JT expansion, Turboexpander or refrigeration.
-NGL fractionation
NGL
LNG plant
Tanker
-Dew point <-10 C (50 barg)
-Water Dew point -18@ 69 barg
-CO2 < 2.5 mole%
-H2S < 5 ppm
-Calorific value
-Wobbe index
WiO : 1–3 %v
-Electrostatic coalescer.
-Desalter
-Heater
API: 8-65
WiO < 0.5-1% , < 2 % (N)
-Tanker/Truck: < 11 psia RVP
-Pipeline: 111 psia RVP, 150 psia TVD (N)
Salt: 10-30 PTB
H2S: 10-100 pppmw
OiW : 500–1000 ppmw
-Hydrocyclones + Flotation
-Hydrocyclones+ degassing
-Skim tanks+flotation
-treatment
-Disposal: <40 ppmw OiW
-Re-injection

Other links

Water knockout : https://www.youtube.com/watch?v=wQ1A8w9Ouy4

Walkthrough an oil and gas platform in the UK . https://www.youtube.com/watch?v=UrWTMCgHr6s