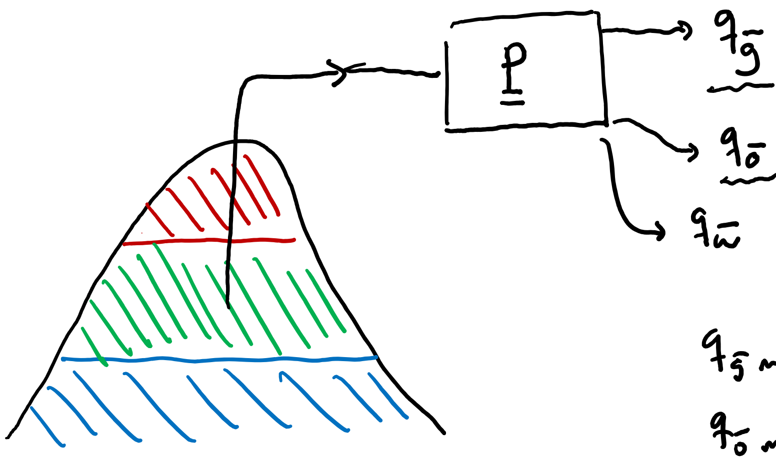
NTNU | Norwegian University of Science and Technology

Introduction to oilfield processing

Assoc. Prof. Milan Stanko



s.c → $p_{sc} = 1.01325$ bara

$T_{sc} = 15.56$ °C

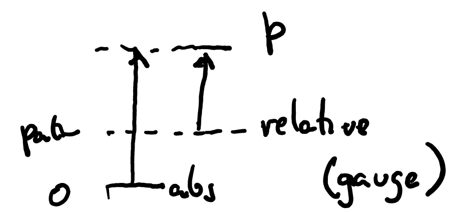
$q_{g\,max}$

$q_{o\,max}$

$q_{w\,max}$

bara

barg



Petroleum components

- Non HC
  - CO_2
  - N_2
  - H_2S
  - H_2O
- HC
  - C_1 } LNG
  - C_2
  - C_3 } LPG
  - C_4
  - iC_4
  - C_5
  - iC_5
  - C_6
  - ⋮

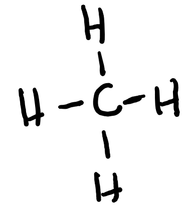
SCN ↓

q_g (from CO_2 through iC_4)

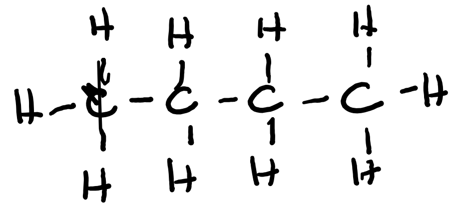
NGL (C_2 – C_5)

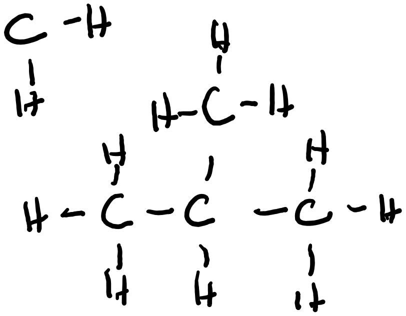
q_o (from C_4 downward)

CH_4



ALKANES C_nH_{2n+2}





LNG – Liquified natural gas

LPG .. Liquified petroleum gas

NGL .. Natural gas liquids

mole fraction z_i

	z_i
C_1	0.1
C_3	0.2
C_8	⋮
⋮	⋮

$\sum_i = 1$

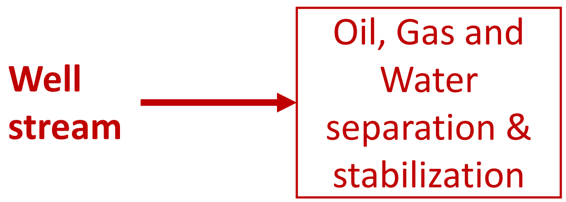
$$z_i = \frac{\text{number of moles of component "i"}}{\text{total number of moles}}$$

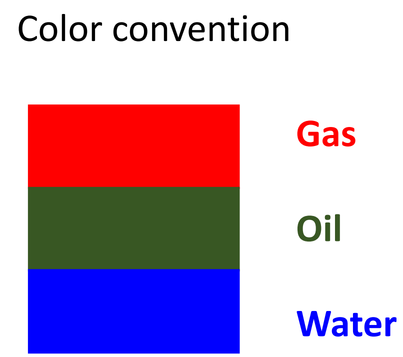
$$x_i, w_i = \frac{\text{mass of component "i"}}{\text{total mass}}$$

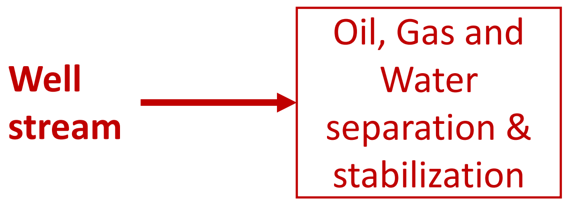
$$w_i = z_i \frac{MW_i}{MW_{mix}}$$

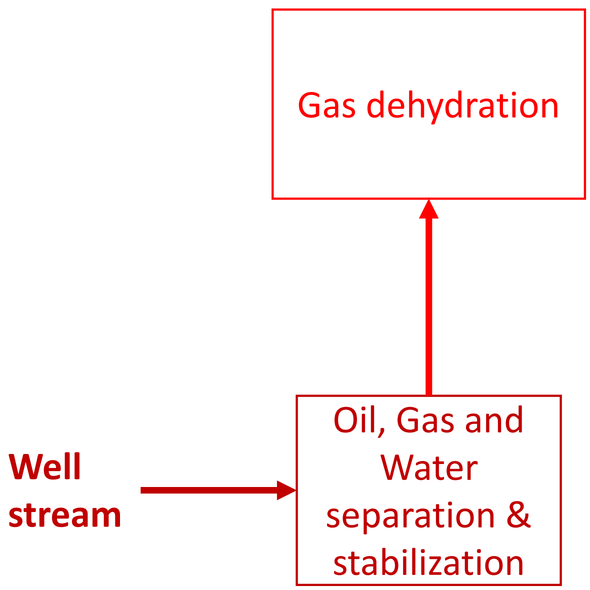
$$MW_{mix} = \sum_{i=1}^{N} z_i MW_i$$

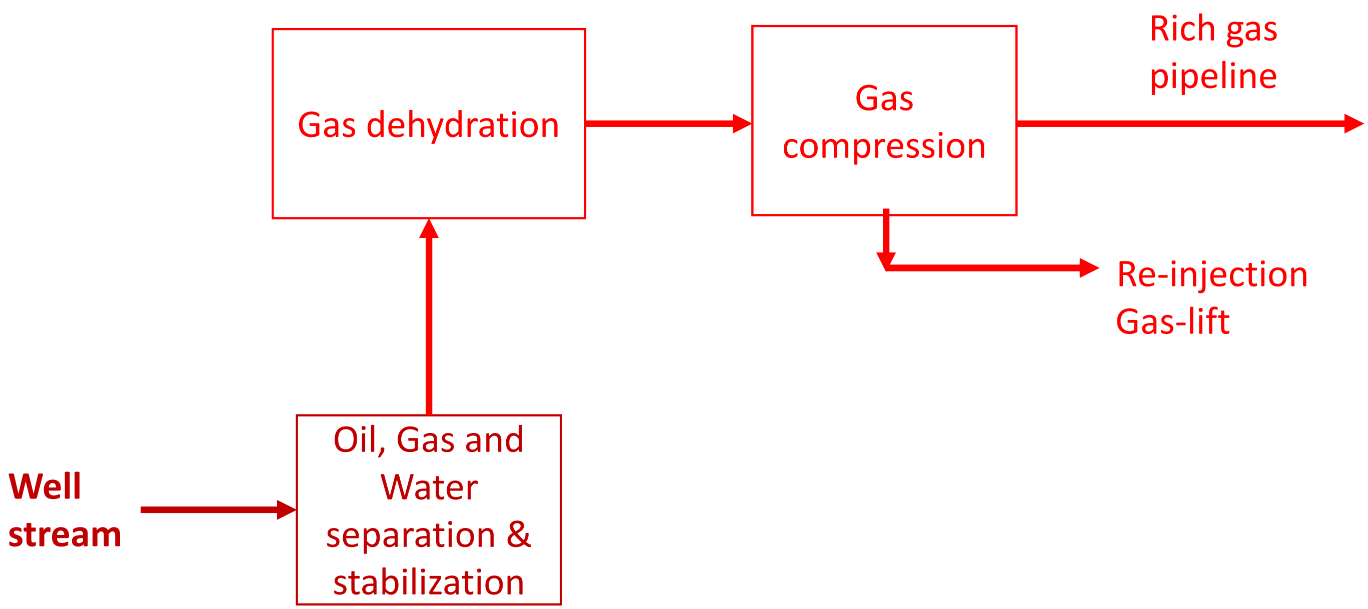
Well stream

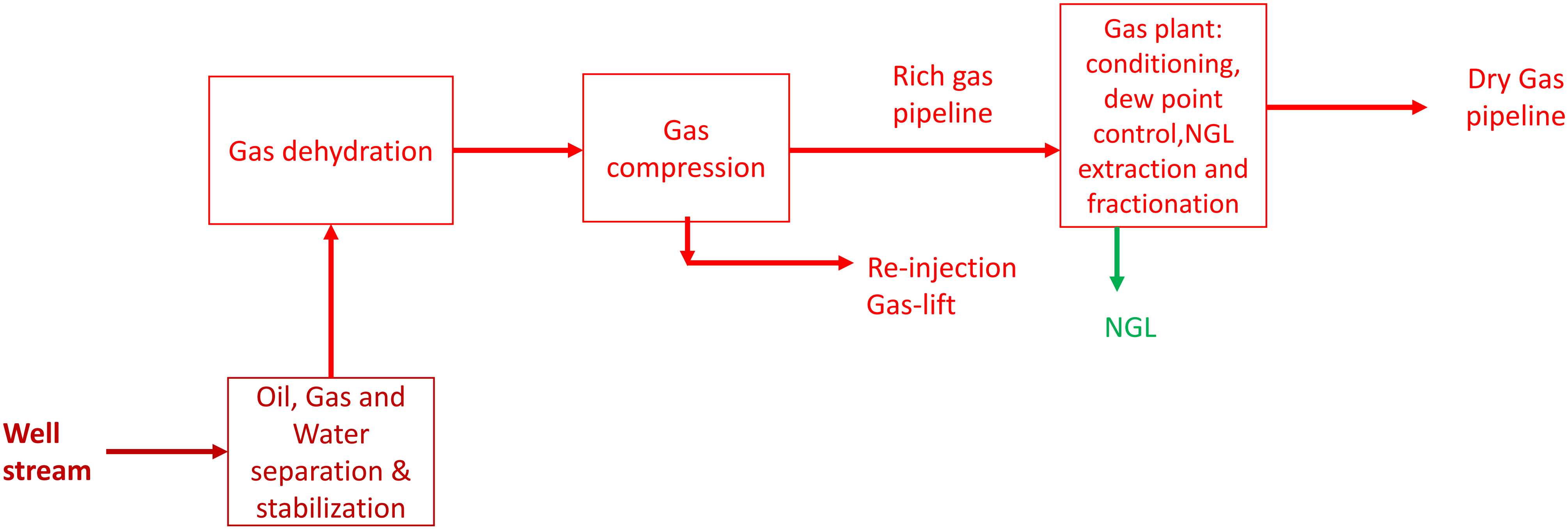

Well
stream
Oil, Gas and
Water
separation &
stabilization

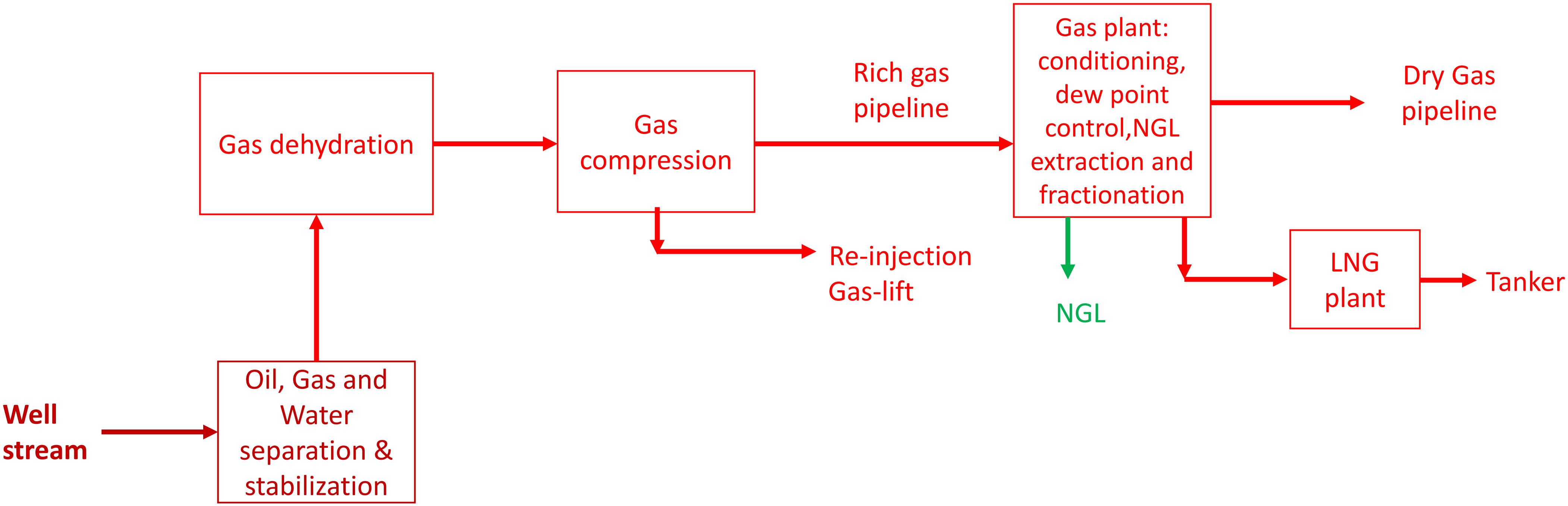

Color convention
Gas
Oil
Water

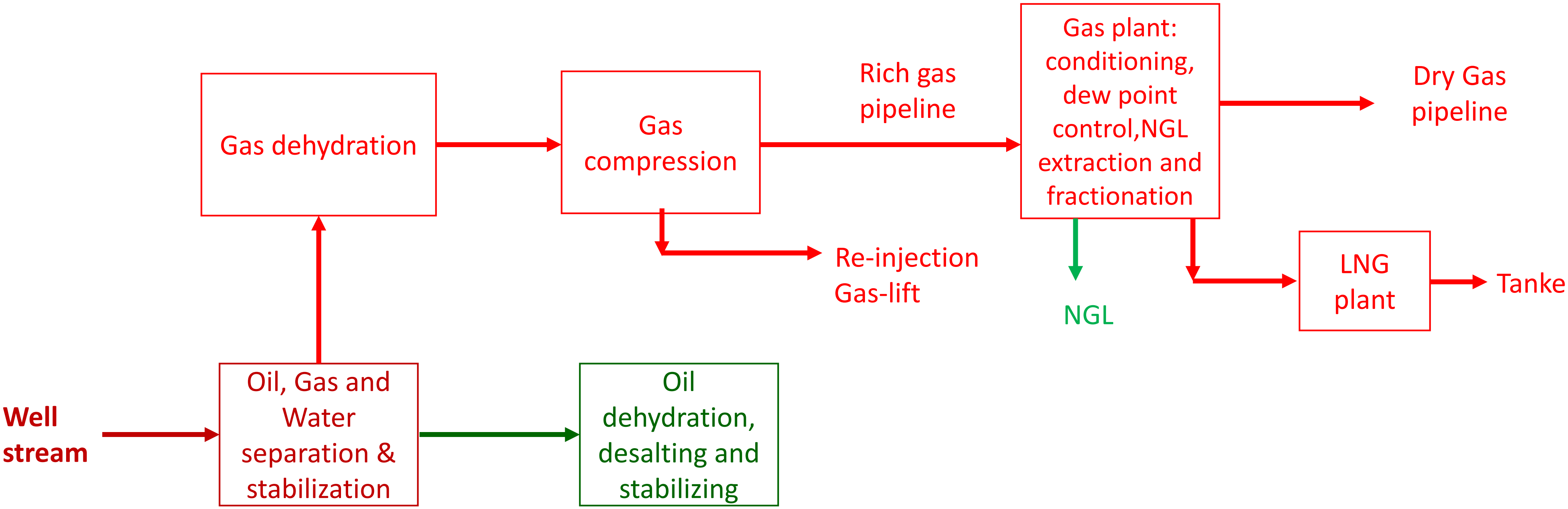

Well stream
Oil, Gas and Water separation & stabilization


Gas dehydration
Well stream
Oil, Gas and Water separation & stabilization


Gas dehydration
Gas compression
Rich gas pipeline
Re-injection
Gas-lift
Well stream
Oil, Gas and Water separation & stabilization


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
Well stream
Oil, Gas and Water separation & stabilization


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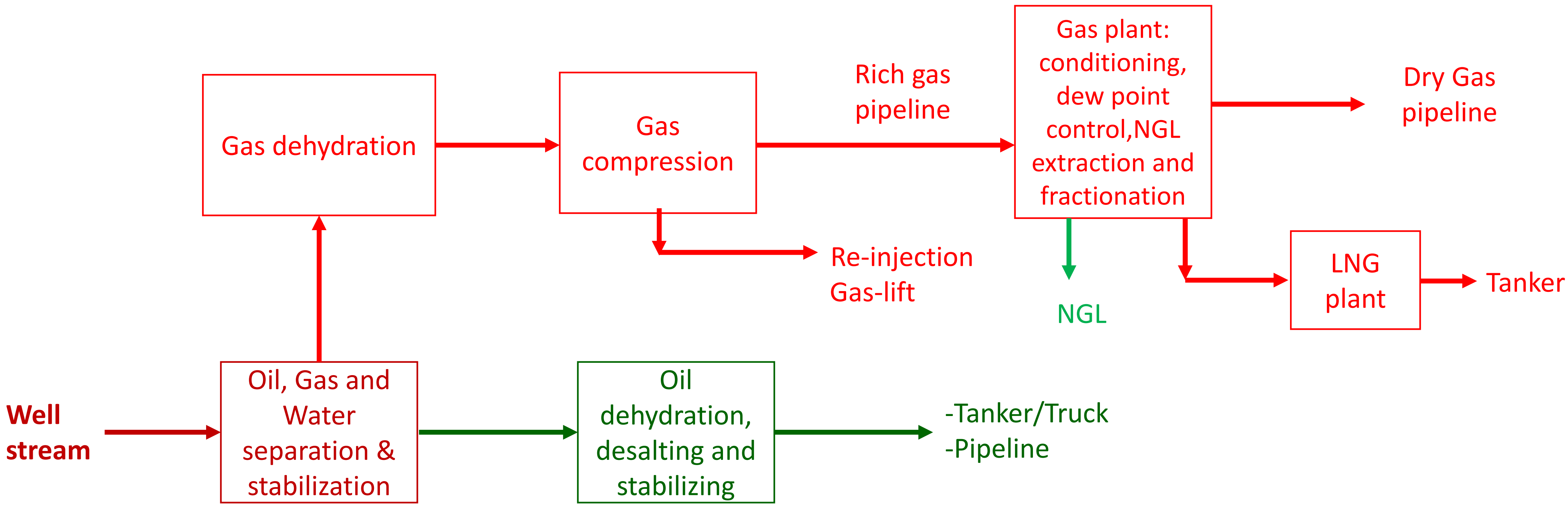
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing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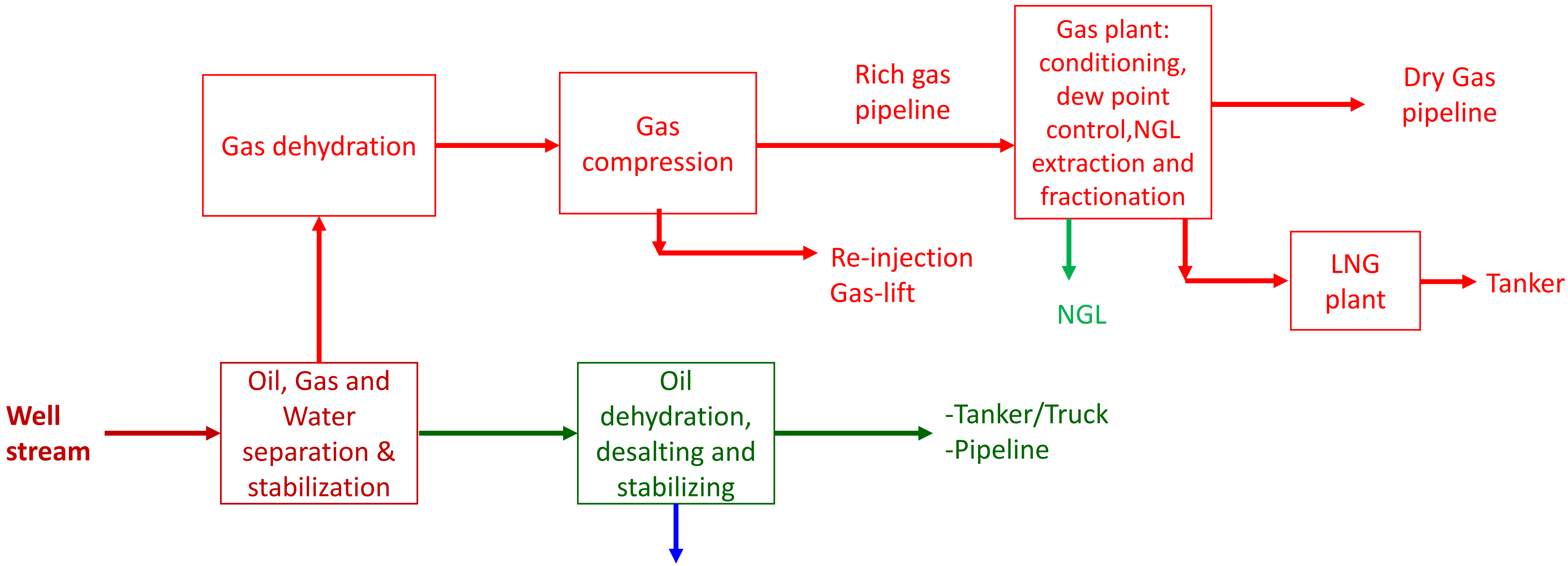
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline


Gas dehydration
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Dry Gas pipeline
Re-injection
Gas-lift
NGL
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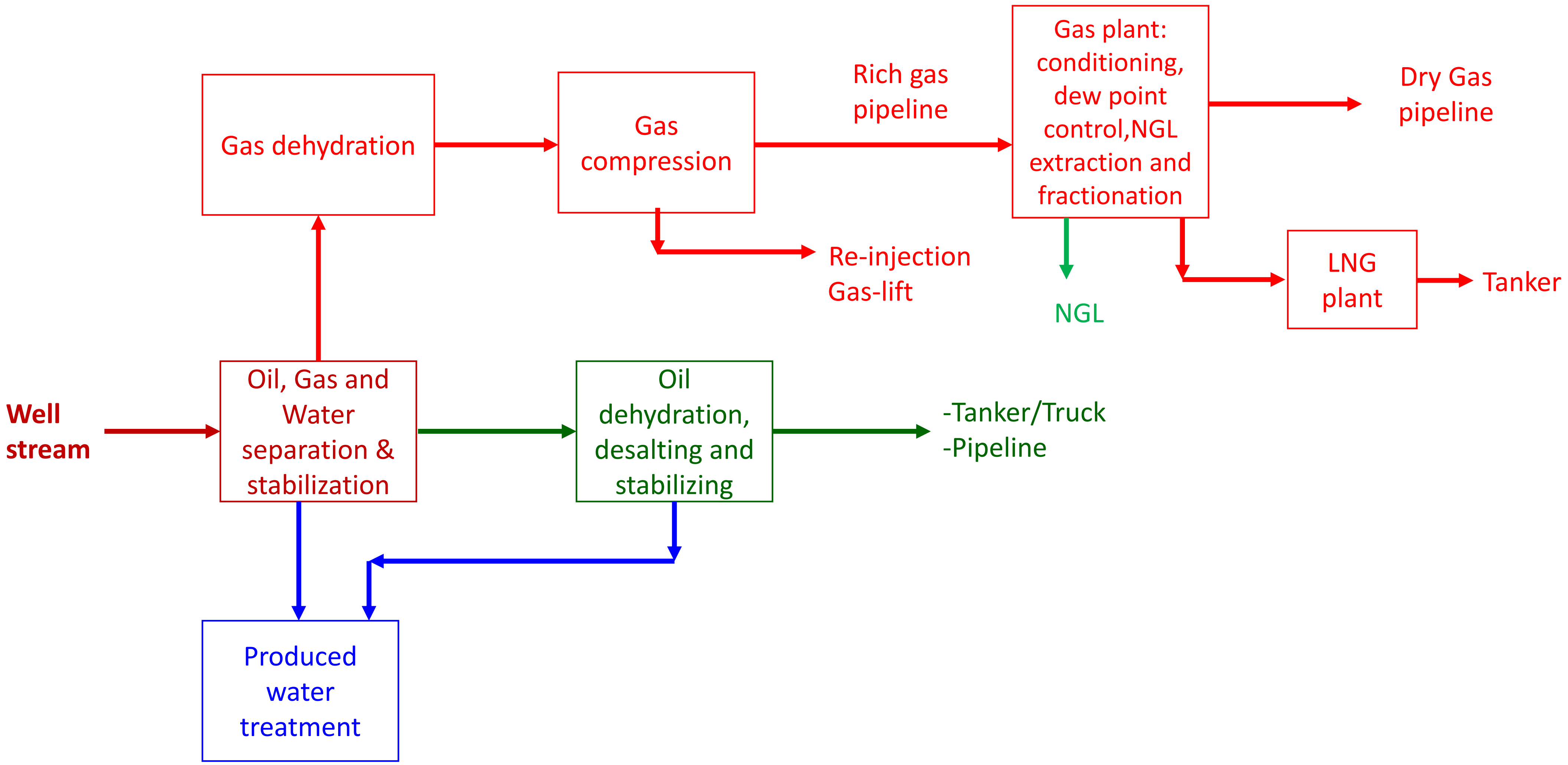
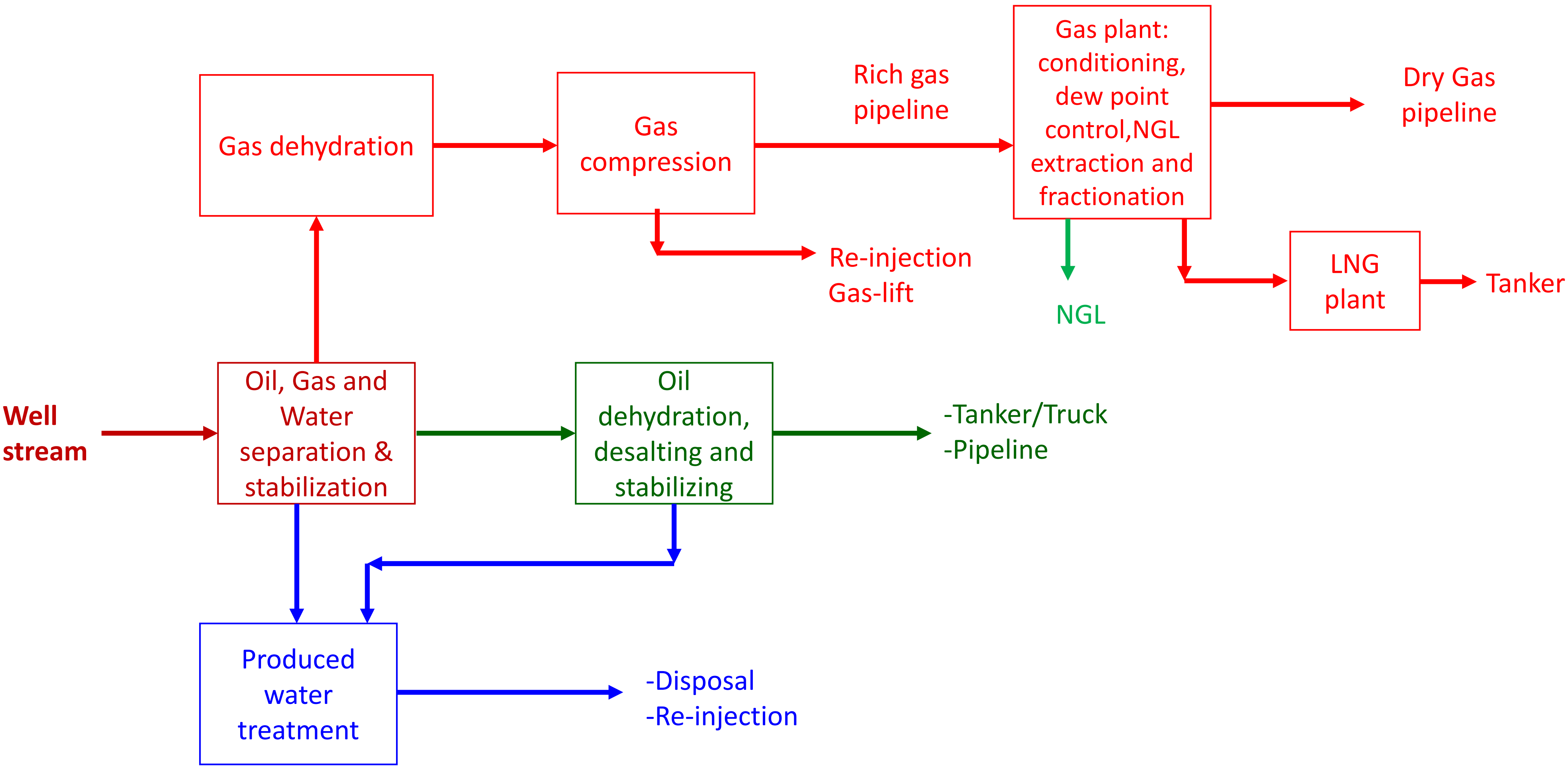
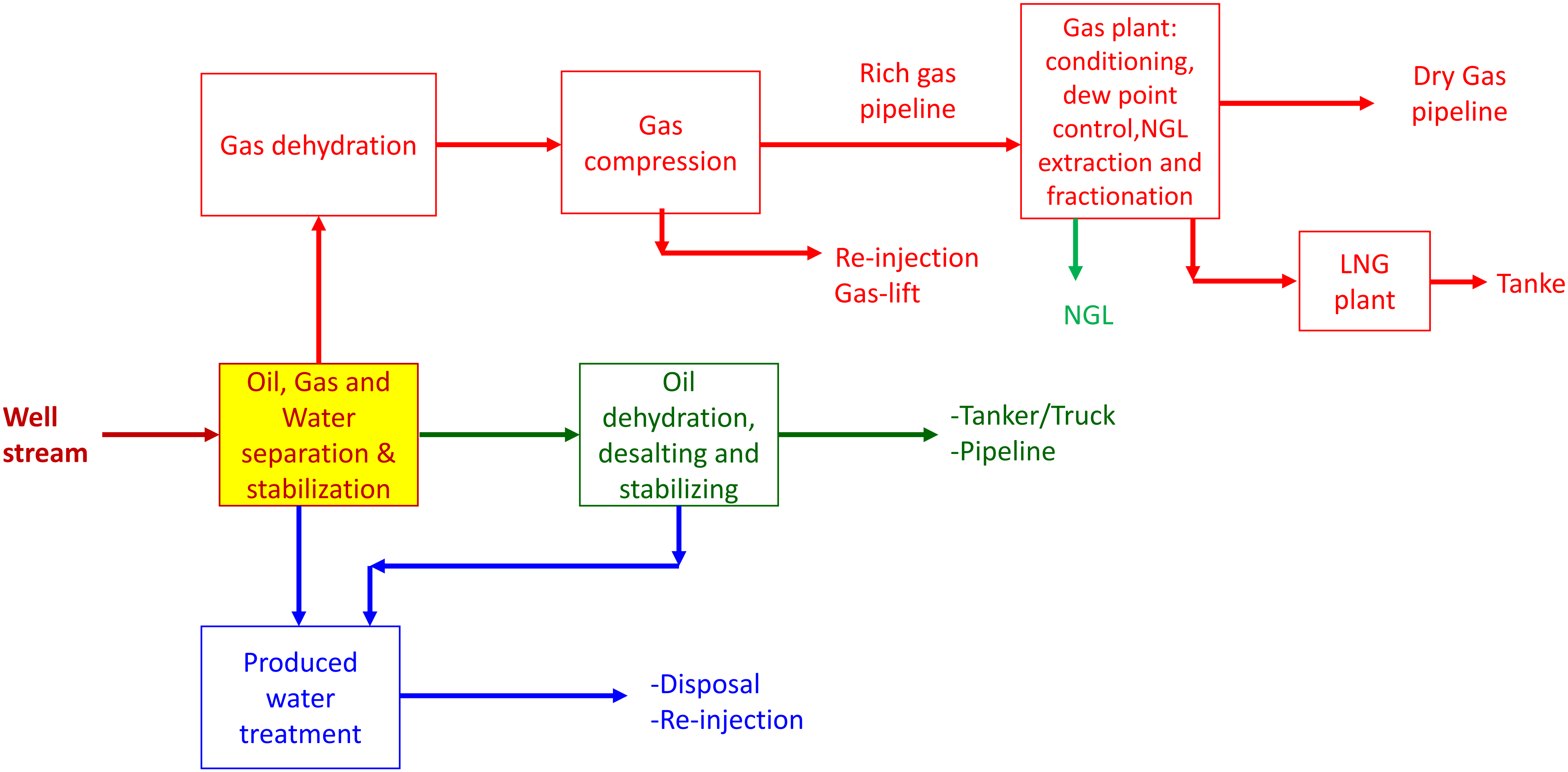
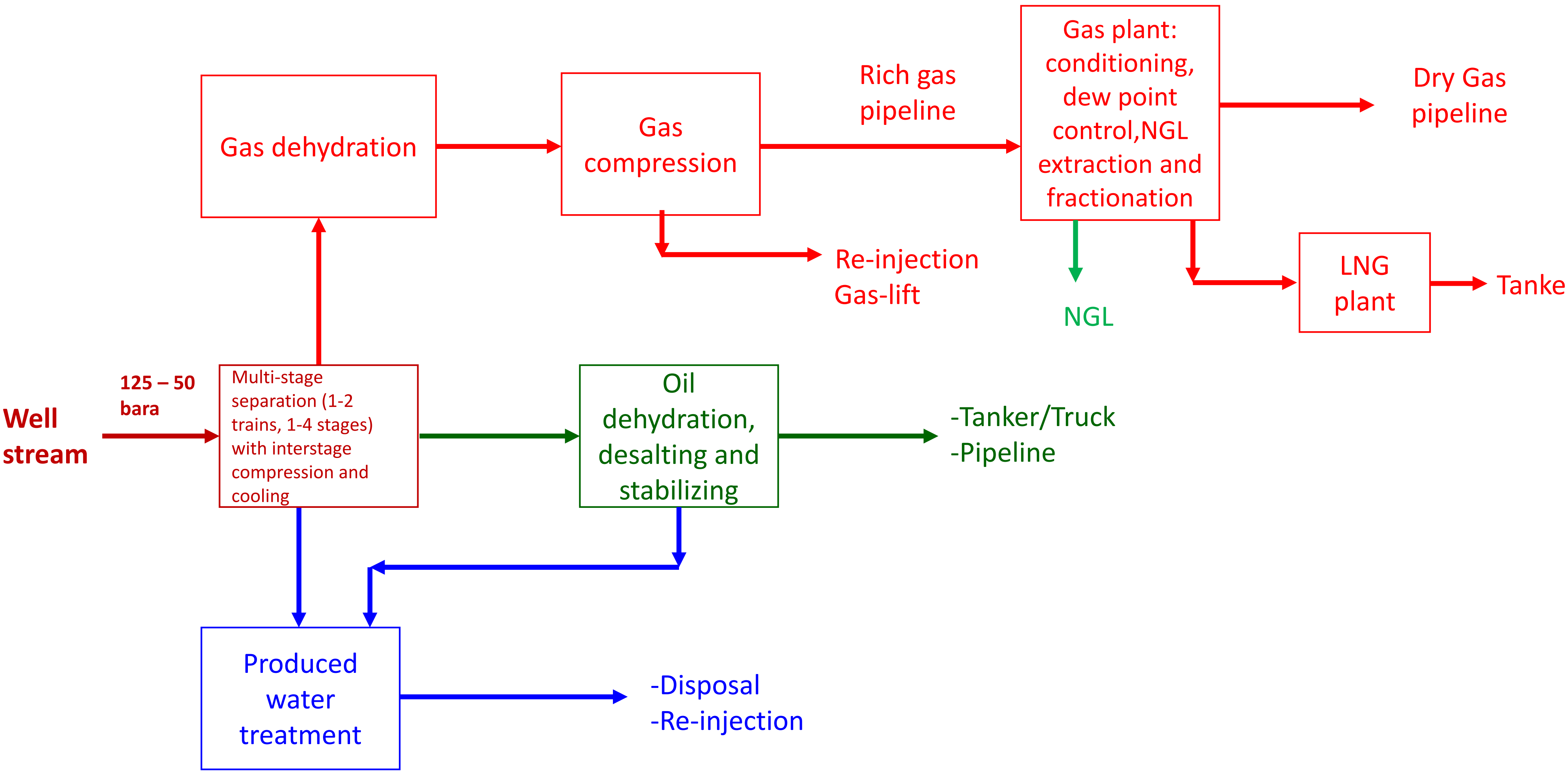
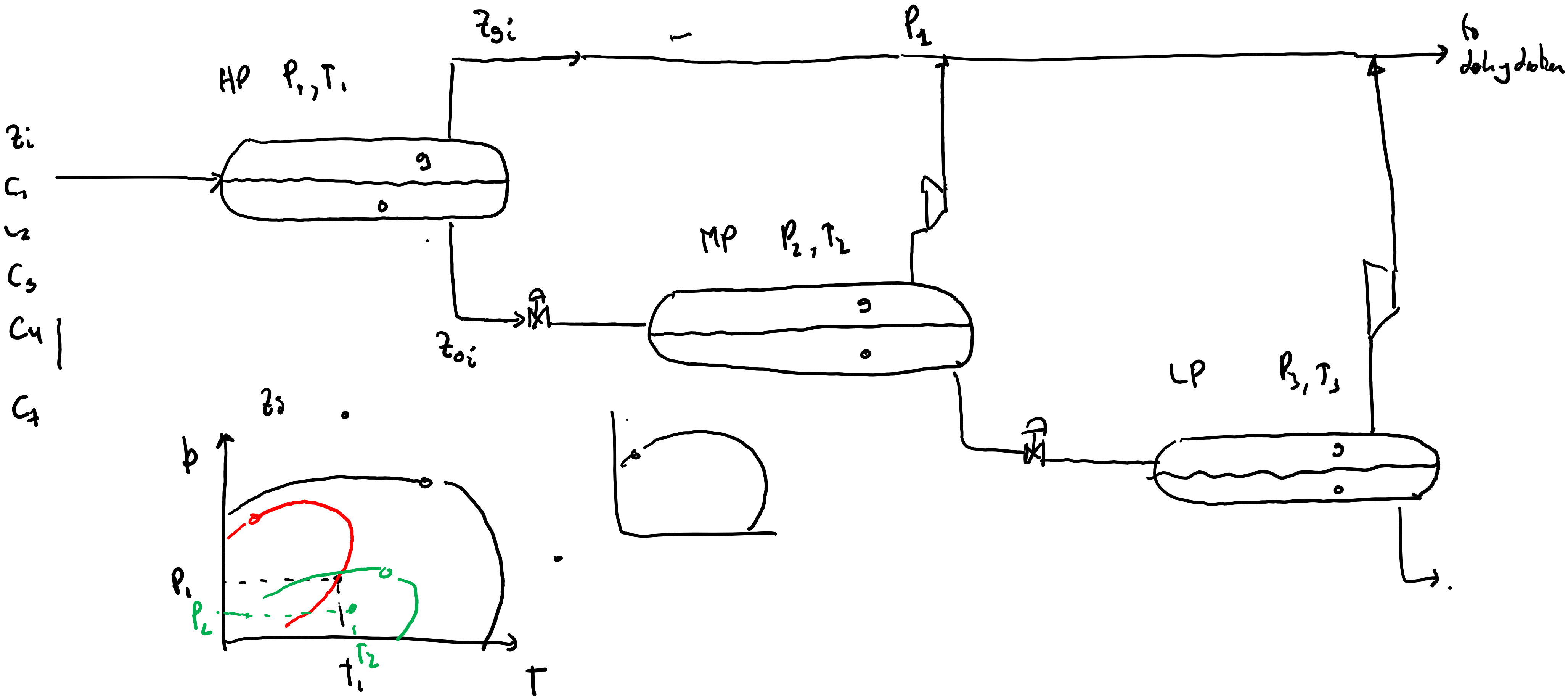
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline


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

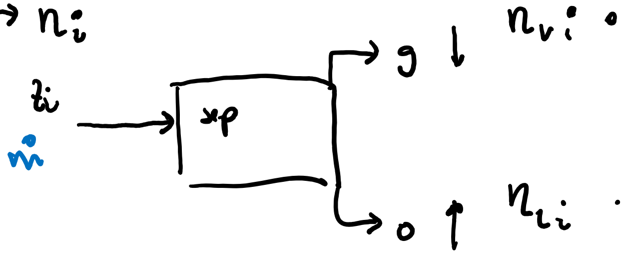

Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing
-Tanker/Truck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


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

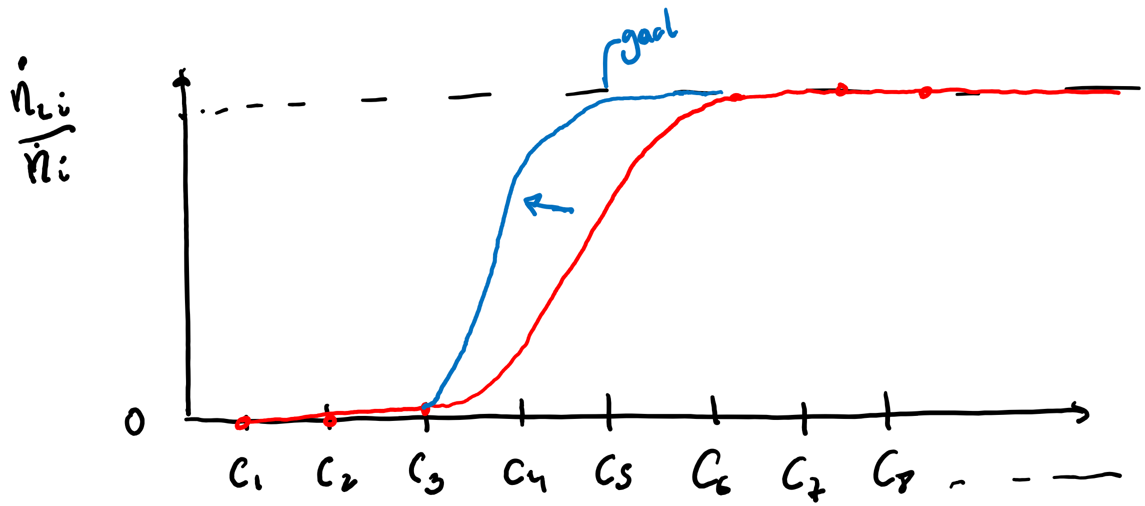

Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
125 – 50 bara
Multi-stage separation (1-2 trains, 1-4 stages) with interstage compression and cooling
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline
Produced water treatment
-Disposal
-Re-injection


zi
C1
C2
C3
C4
C7
HP P1, T1
zgi
P1
to dehydration
MP P2, T2
zoi
LP P3, T3
p
P1
P2
T1
T2
T

molar flow → $\dot{n}_i$

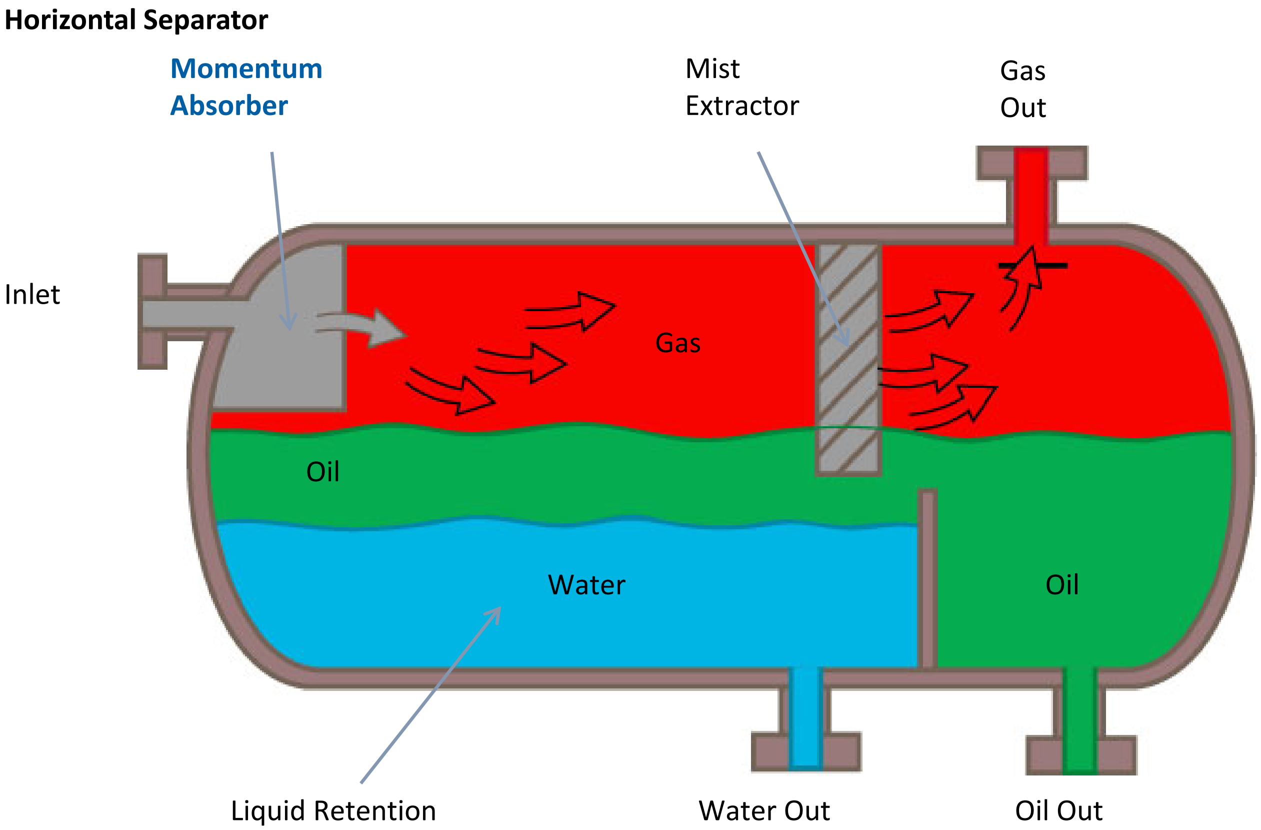


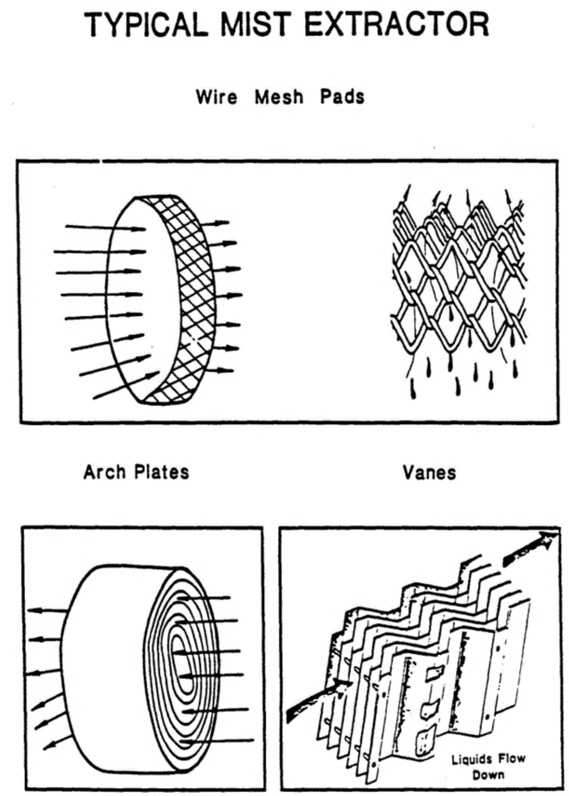
$$\frac{\dot{n}_{vi}}{\dot{n}_i} \quad \frac{\dot{n}_{Li}}{\dot{n}_i} = 1$$



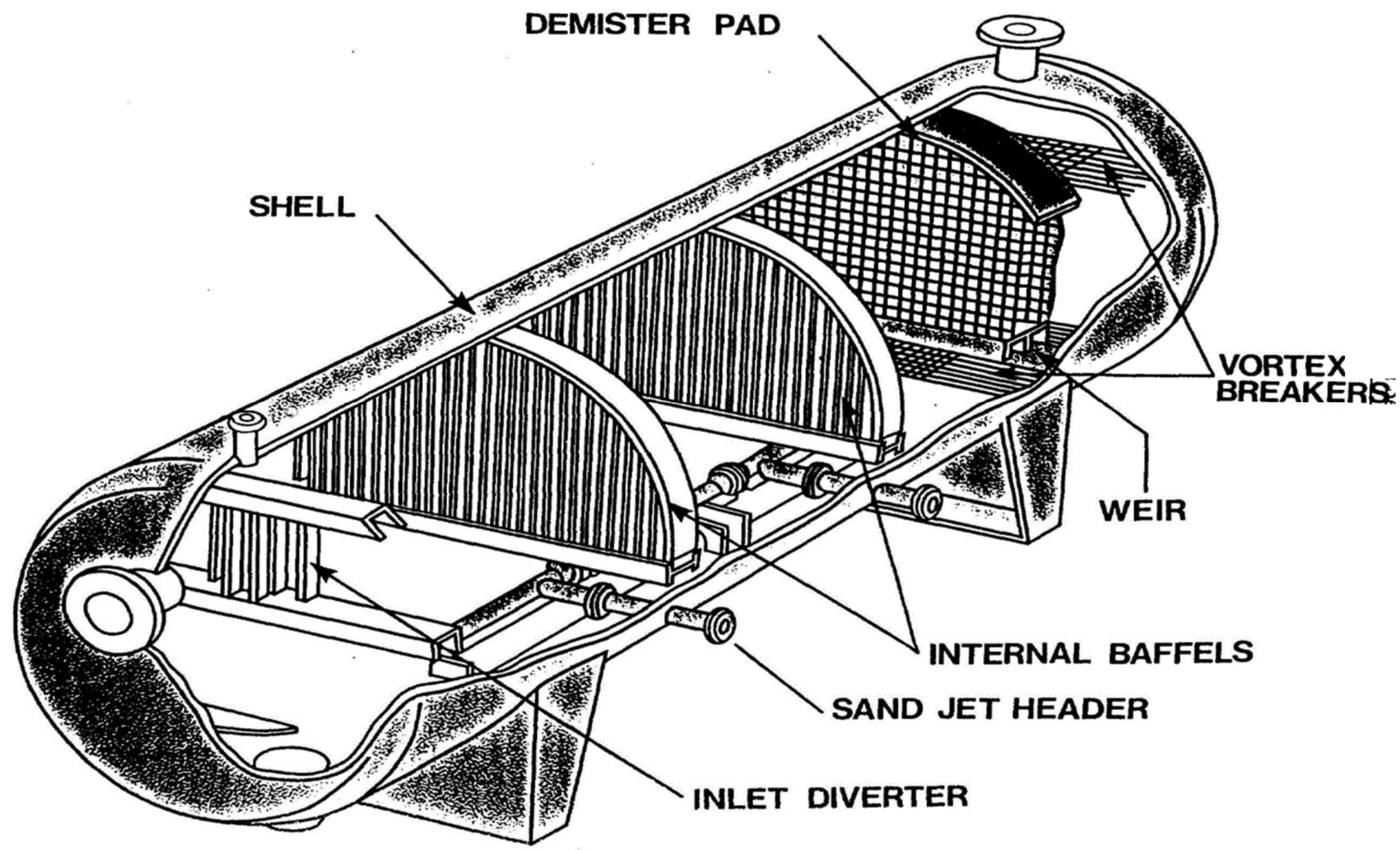
- "many" separation stages
  2–4
- P_1 (HP) high
  ↑ p $\dot{n}_i$ ↓
  ↑ p $\frac{n_{Li}}{n_{vi}}$ ↑
- optimization on top stage pressure

Horizontal separator



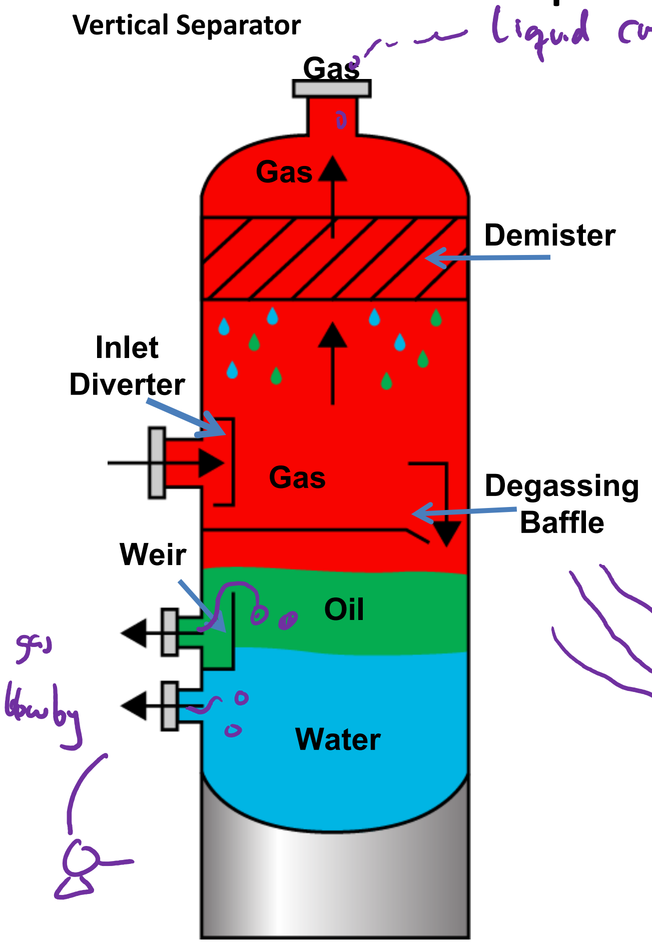


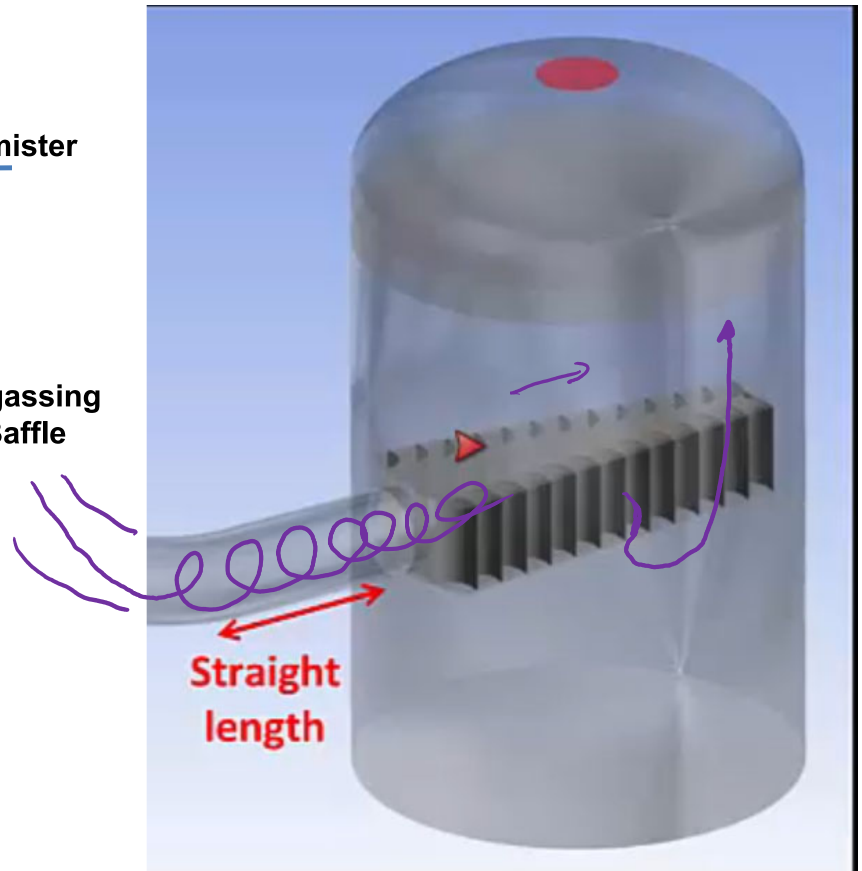
Horizontal separator

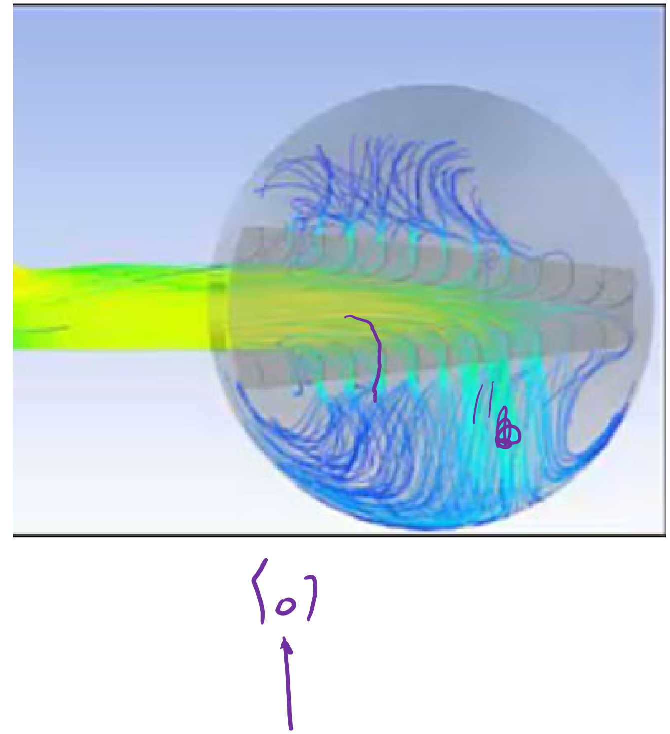


Vertical separator

liquid carry over







HYSYS Example

Problem 3[1]

Task 1. Using Hysys[2] simulate a separation train with tree stages (details given below). The total mass flow of hydrocarbons is: 27 000 kg/h. The composition of the stream is given below.

Data

Component	Mole Fraction
Nitrogen	0.003672
CO2	0.001092
Methane	0.429256
Ethane	0.046897
Propane	0.029618
i-butane	0.014919
n-butane	0.009325
i-pentane	0.008446
n-pentane	0.005030
Hexanes	0.018433
Heptanes	0.041418
Octanes	0.049891
Nonanes	0.038403
Decanes	0.303600

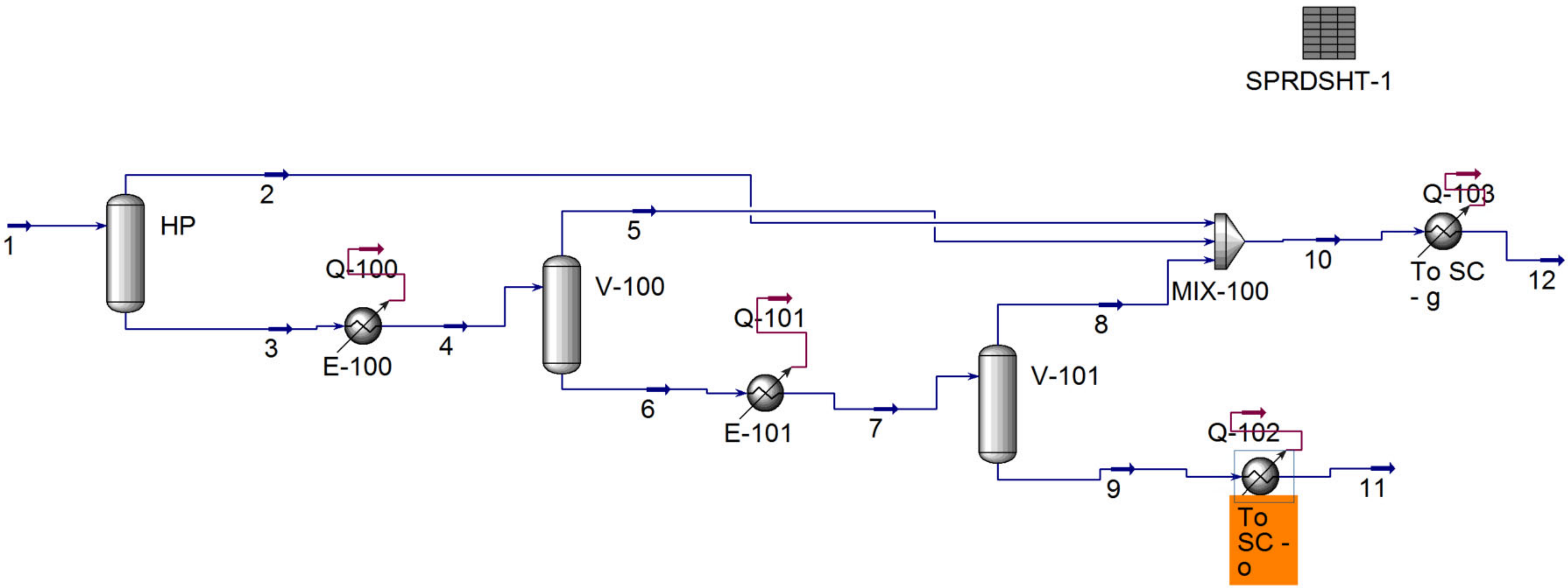
Total mass flow: 27 000 kg/h

$$\dot{m} = q_o \cdot \rho_o + q_g \cdot \rho_g + q_w \rho_w = q_o \left(\rho_o + GOR \cdot \rho_g + \frac{wc}{1-wc} \rho_w\right)$$

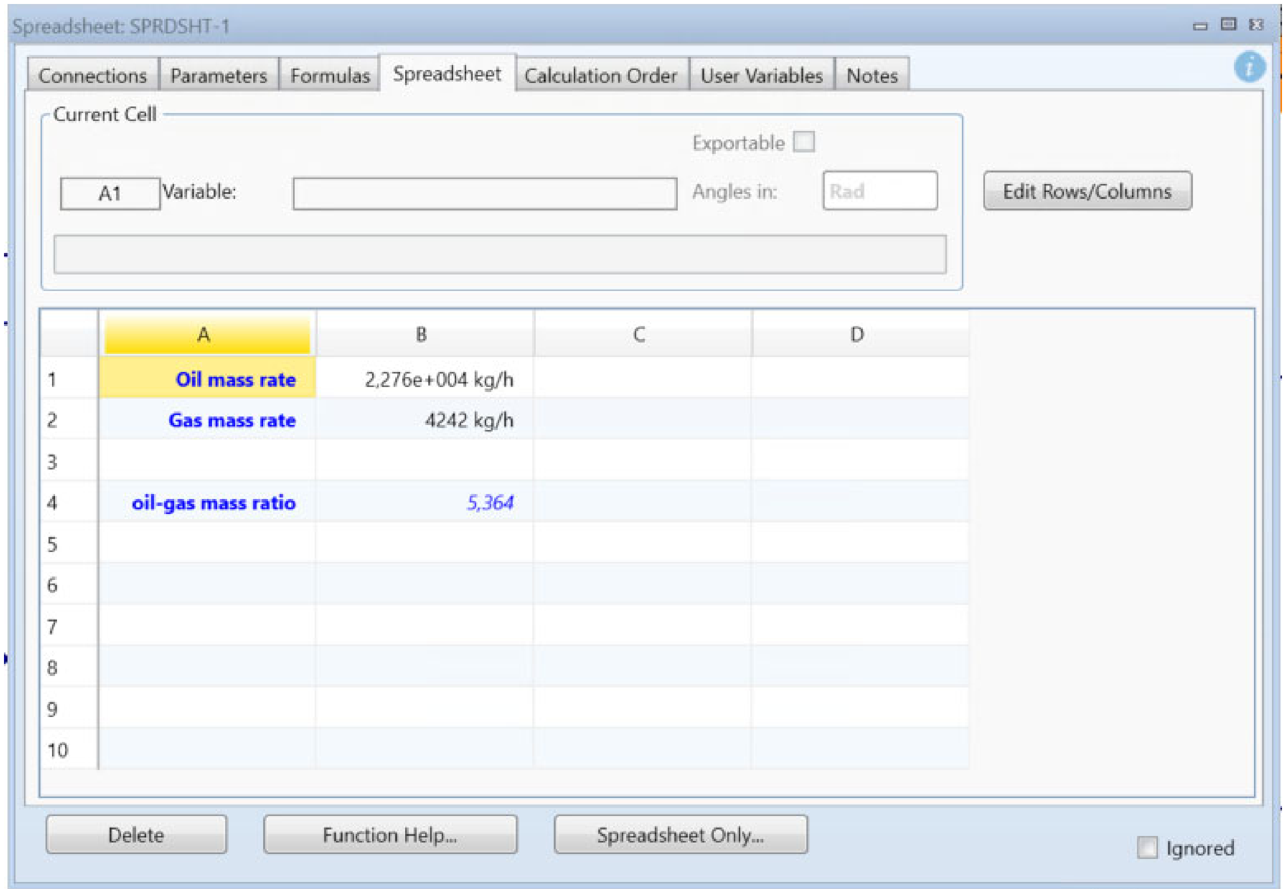
Separation Stage	Pressure (bara)	Temperature (C)
Stage 1	65	75
Stage 2	20	65
Stage 3	2	60
Standard Conditions	1.01325	15.66

Tasks:

- Simulate the system in Hysys
- Perform a sensitivity study on the 2nd stage separation pressure to maximize oil production



SPRDSHT-1
1
HP
2
3
Q-100
E-100
4
5
V-100
6
Q-101
E-101
7
V-101
8
9
MIX-100
10
Q-103
To SC
- g
12
Q-102
To
SC -
o
11


Spreadsheet: SPRDSHT-1
Connections
Parameters
Formulas
Spreadsheet
Calculation Order
User Variables
Notes
Current Cell
Exportable
A1
Variable:
Angles in:
Rad
Edit Rows/Columns
A
B
C
D
Oil mass rate
2,276e+004 kg/h
Gas mass rate
4242 kg/h
oil-gas mass ratio
5,364
Delete
Function Help...
Spreadsheet Only...
Ignored

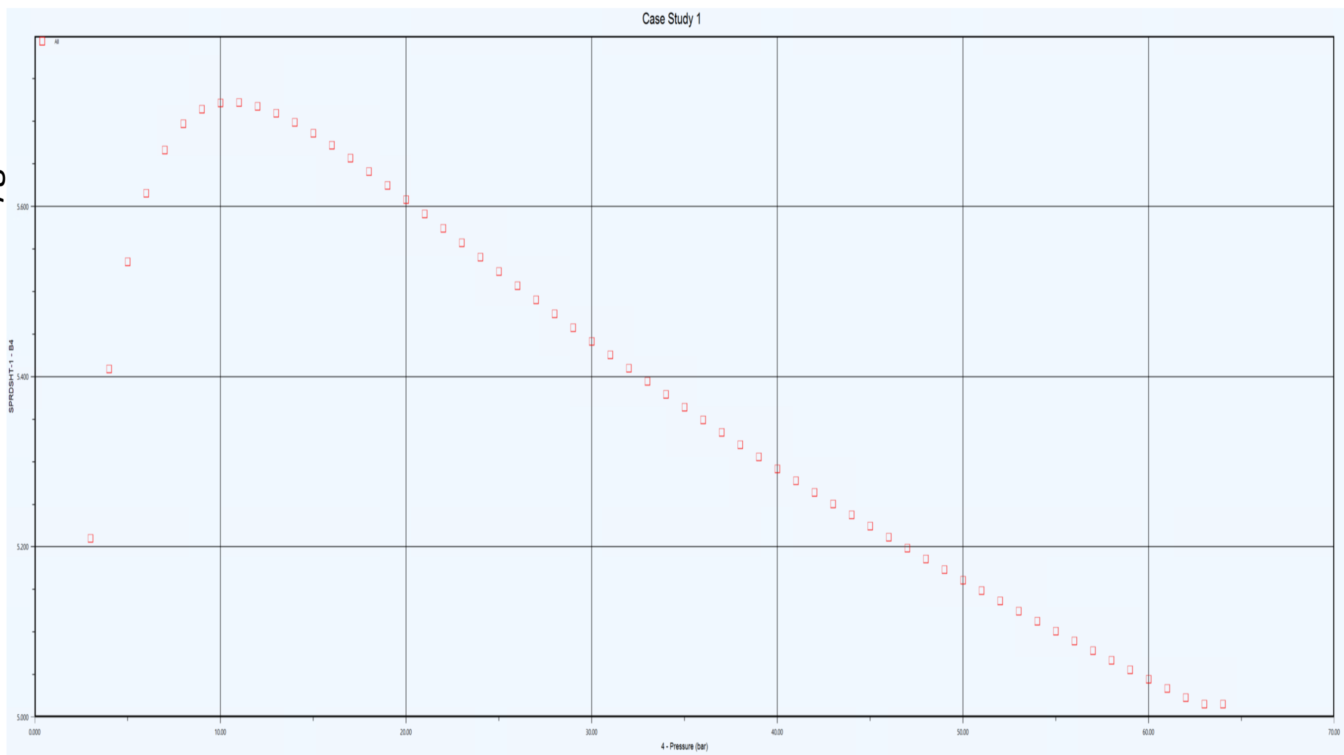
$p_{mp} = 20$ bara $\qquad \frac{\dot{m}_o}{\dot{m}_g} = 5.6$

$p_{mp} = 10$ bara $\qquad \frac{\dot{m}_o}{\dot{m}_g} = 5.75$

base $\quad$ new

$$\text{abs}\left(\frac{5.6 - 5.75}{5.6}\right) \times 100 = 2.6\%$$

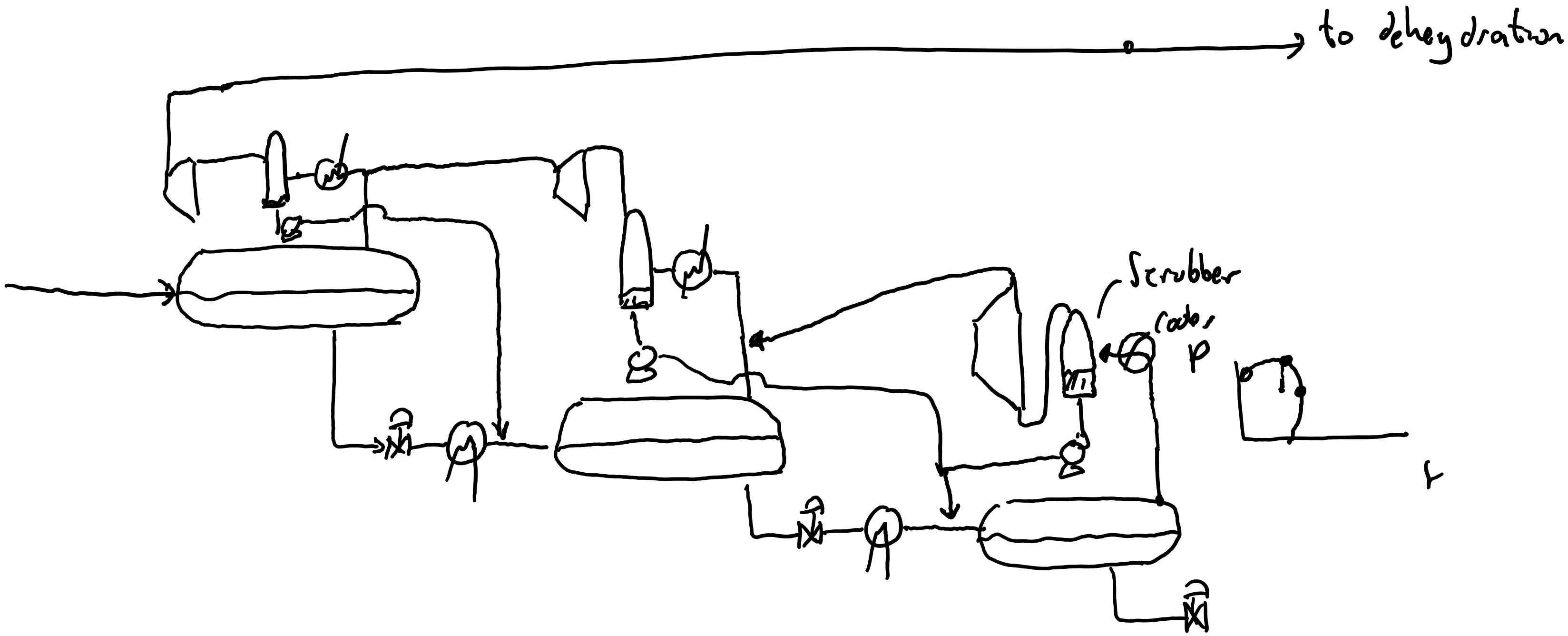
base



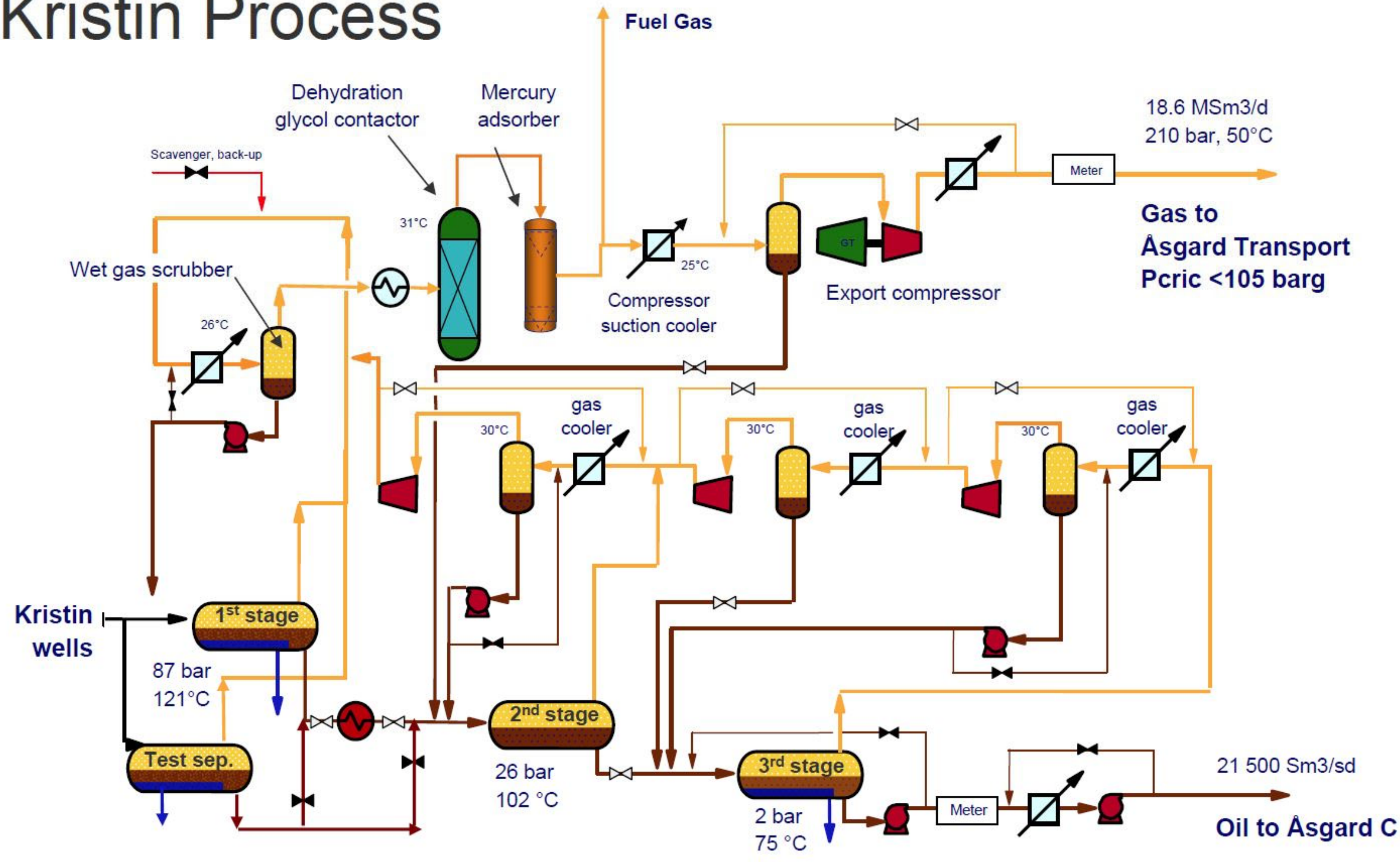
Ratio between oil mass rate/gas mass rate

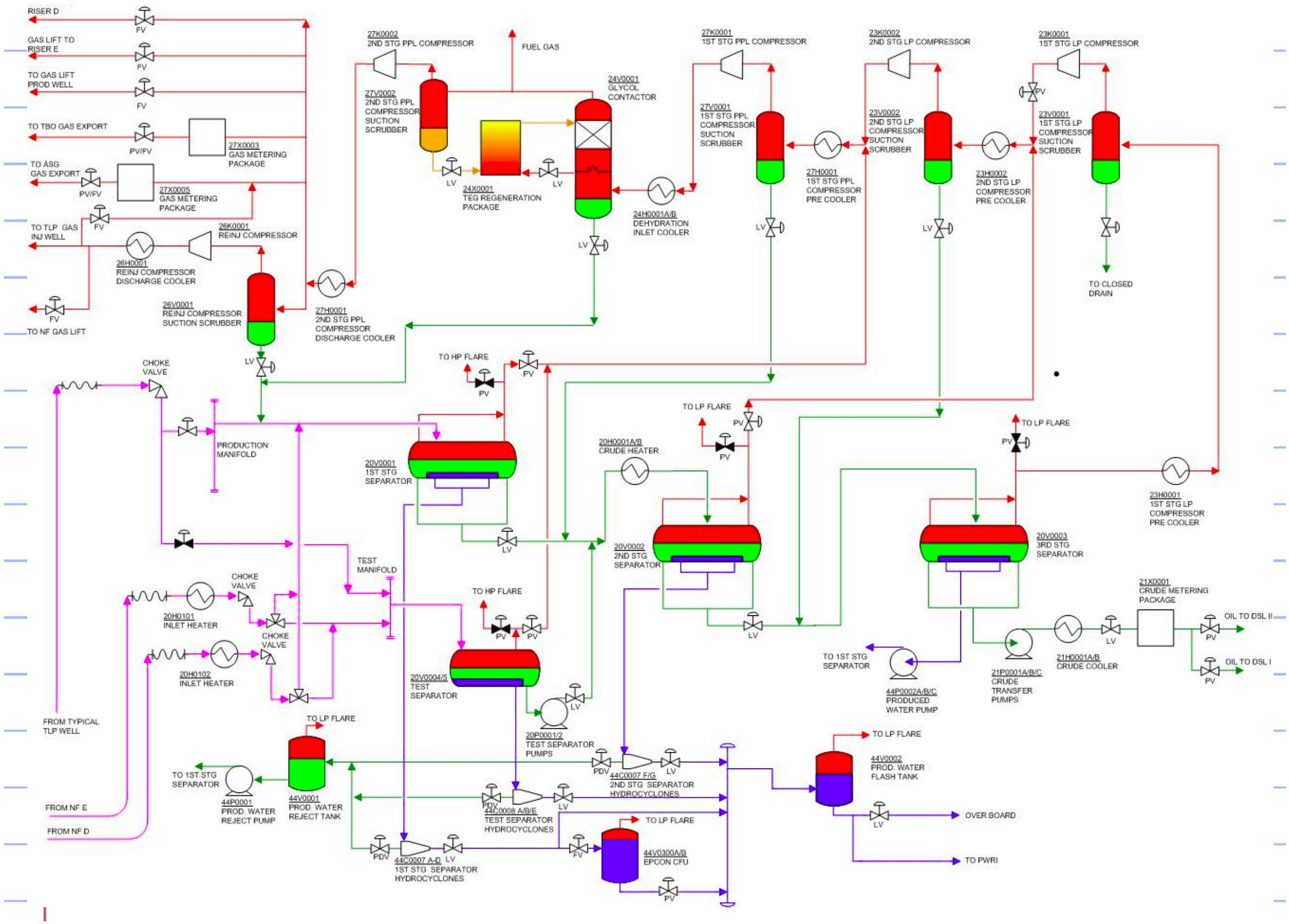
Pressure of medium stage separator (MP), bara

How does the separation process looks like in reality:



Kristin Process




RISER D
GAS LIFT TO RISER E
TO GAS LIFT PROD WELL
TO TBO GAS EXPORT
TO ÅSG GAS EXPORT
TO TLP GAS INJ WELL
TO NF GAS LIFT
27X0003 GAS METERING PACKAGE
27X0005 GAS METERING PACKAGE
26K0001 REINJ COMPRESSOR
26H0001 REINJ COMPRESSOR DISCHARGE COOLER
26V0001 REINJ COMPRESSOR SUCTION SCRUBBER
27H0001 2ND STG PPL COMPRESSOR DISCHARGE COOLER
27K0002 2ND STG PPL COMPRESSOR
27V0002 2ND STG PPL COMPRESSOR SUCTION SCRUBBER
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
TO HP FLARE
TO LP FLARE
CHOKE VALVE
PRODUCTION MANIFOLD
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
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
FROM TYPICAL TLP WELL
FROM NF E
FROM NF D
44P0001 PROD. WATER REJECT PUMP
44V0001 PROD. WATER REJECT TANK
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

- Example of (simple) sizing horizontal gas-oil separator

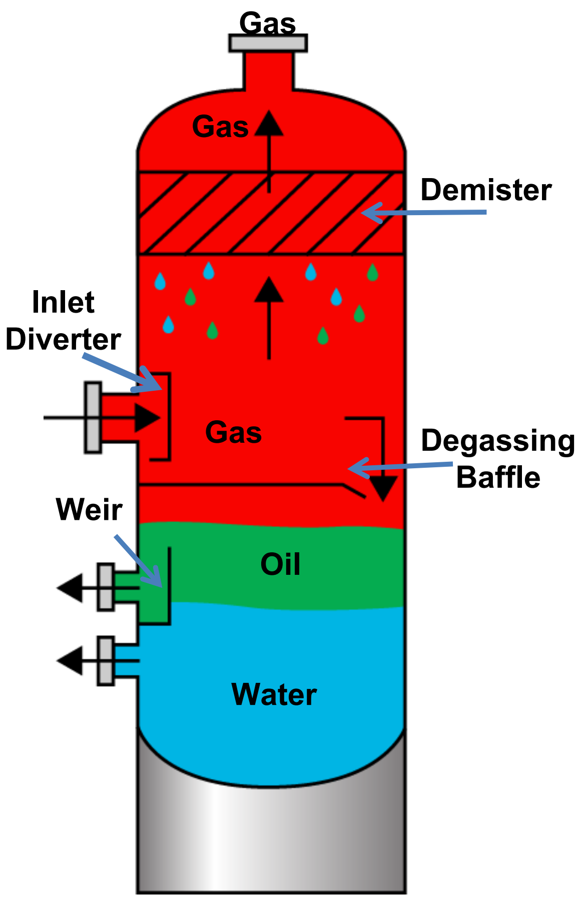
Separation design theory

Find separator dimensions such as:

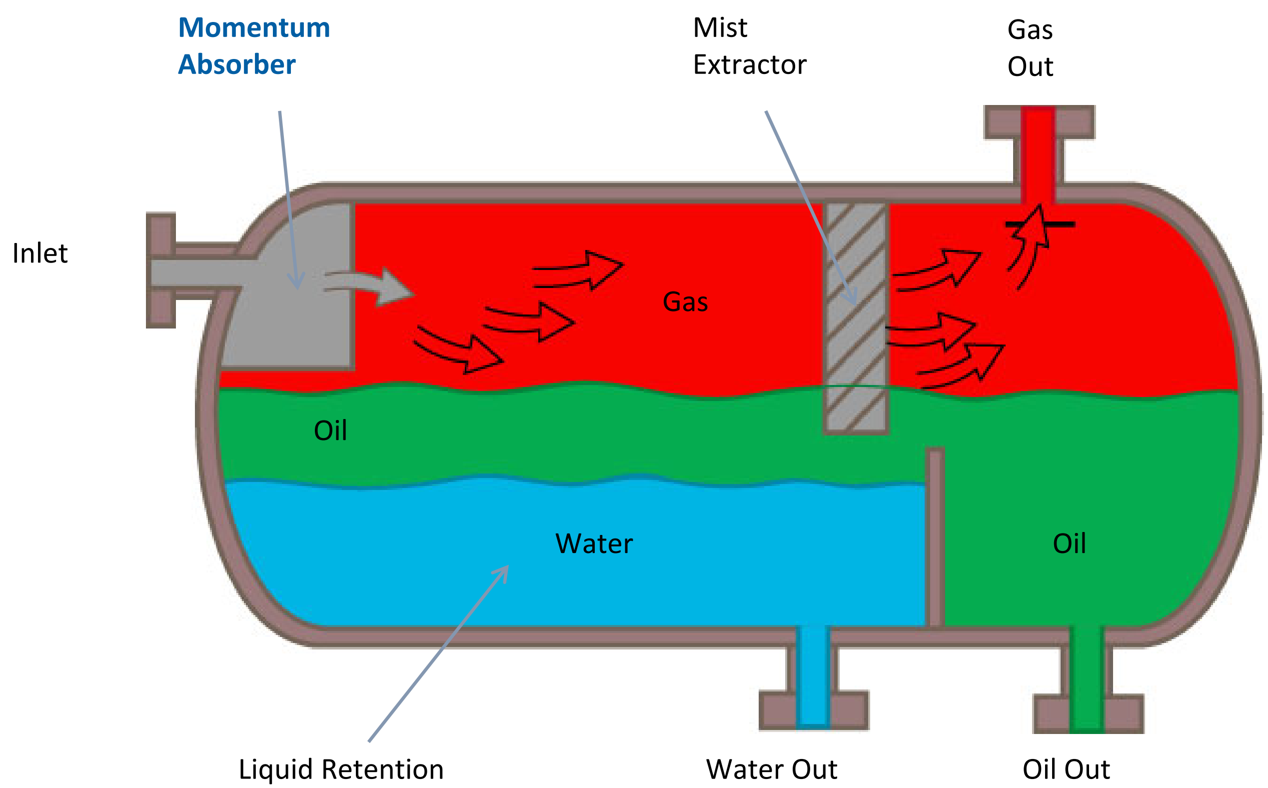
Residence time > separation time

Residence time

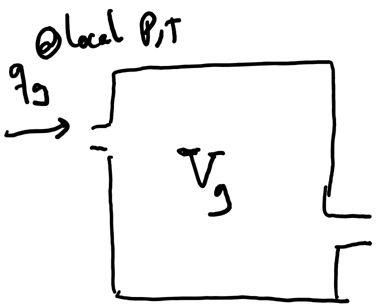
Vertical Separator



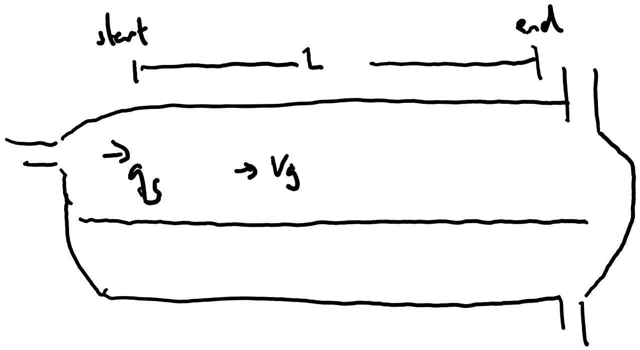
Horizontal Separator



Residence time (gas)



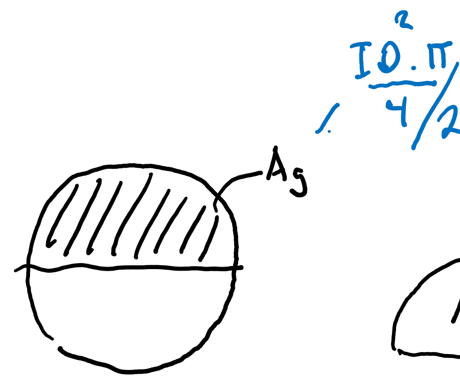
$$t_{res_g} = \frac{V_g}{q_g}$$

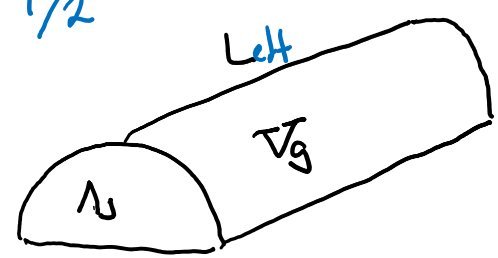


$$v_g = \frac{q_g}{A_g}$$

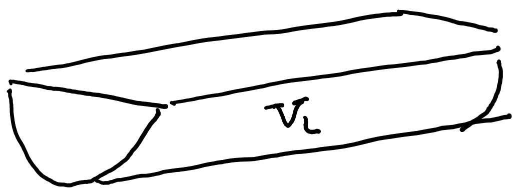
$$t_{res_g} = \frac{L}{v_g}$$

$$t_{res_g} = \frac{A_g L}{q_g} = \frac{V_g}{q_g}$$

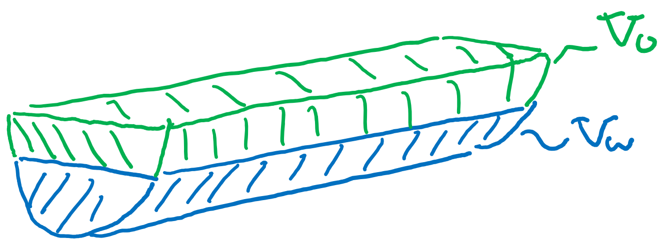




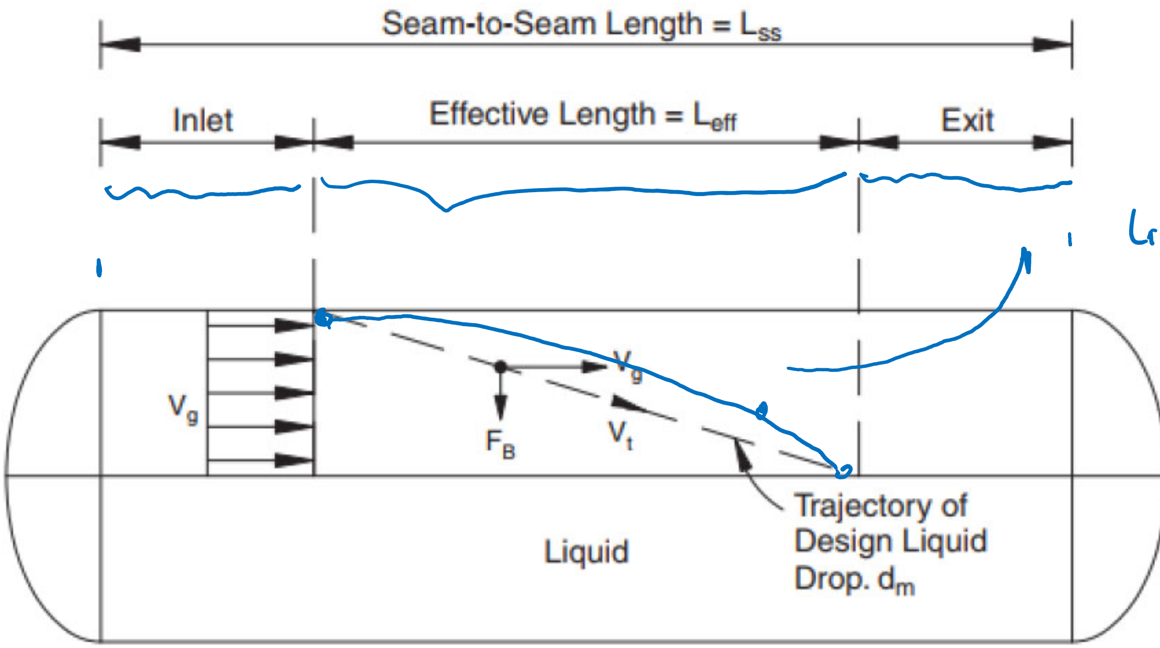
for liquid



or, two liquid phases



Separation time - gas



Liquid carry over
droplet does not
manage to reach
the liquid layer
before the gas
exits

Legend:

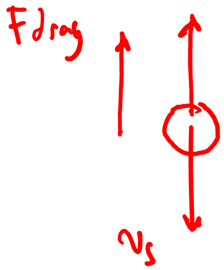
V_g = Average Gas Velocity = $\frac{Q}{A}$

V_t = Terminal or Setting Velocity Relative to Gas

F_B = Buoyant Force

Separation time = settling time

how to estimate v_s



$\rho_f V_d \cdot g$ (bouyancy) (gas)

$m \cdot g$ (weight)

$\rightarrow (\rho_p - \rho_f) V_d \, g$

$F_{drag} = \frac{1}{2} \rho_f \cdot A_d \cdot C_d \, v_s^2$

$A_d = \frac{\pi d_d^2}{4}$; C_d: drag coefficient

$\Sigma F = 0$

assumed! (smallest possible, more conservative)

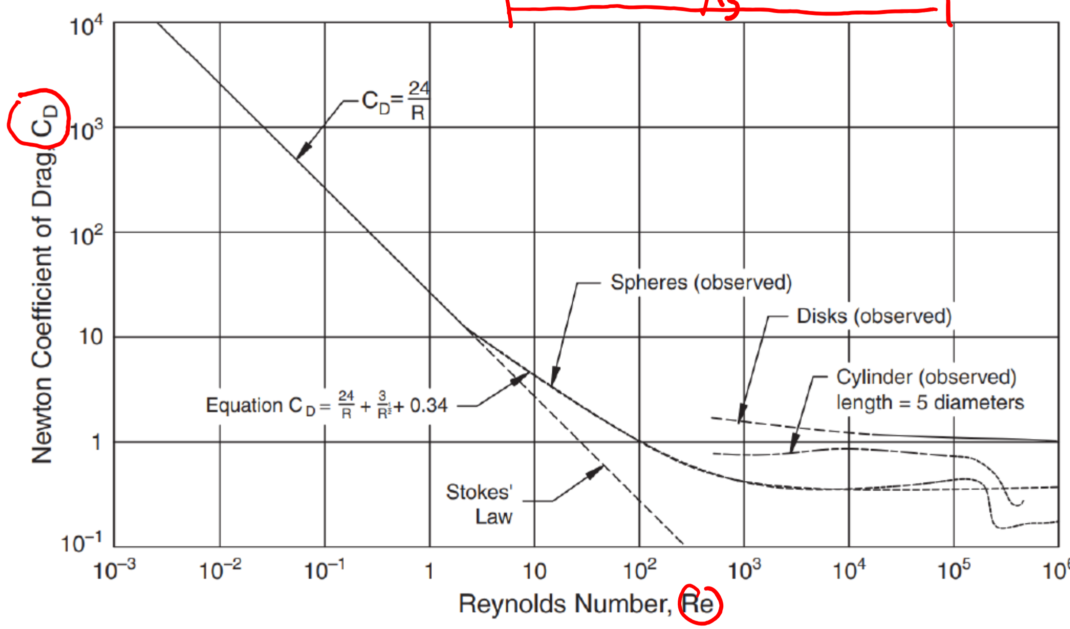
$$v_d = v_s = \sqrt{\frac{4 \, d_d \, g}{3 \, C_D} \, \frac{(\rho_d - \rho_f)}{\rho_f}}$$

(d_d: ? ; ρ_d: ρ_{oil} ; ρ_f: ρ_{gas} ; C_D: ?)

If it is a bubble of gas in oil, the direction of drag is opposite,
Then it should be (denf-dend)

Separation time = settling time

$$C_D = f(\mathrm{Re}),\ \ \mathrm{Re} = \frac{\rho_f v_s d_p}{\mu_f}$$

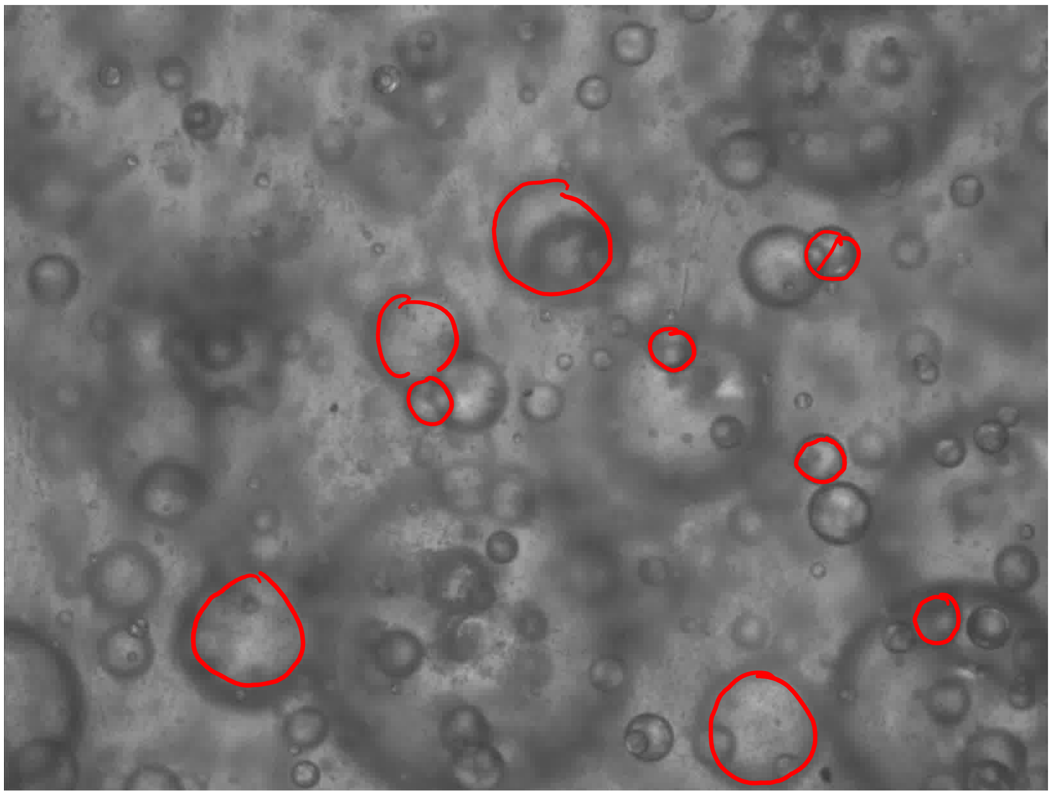


Laminar Flow	$\mathrm{Re} < 2$	$C_D = \frac{24}{\mathrm{Re}}$
Transition Flow	$2 \le \mathrm{Re} < 2 \cdot 10^5$	$C_D = \frac{24}{\mathrm{Re}} + \frac{3}{\sqrt{\mathrm{Re}}} + 0.34$
Turbulent	$2 \cdot 10^5 < \mathrm{Re}$	0.2

case ① oil droplet in gas
$\mu_g \downarrow$
$\mathrm{Re}_d \uparrow$

case ② water droplet in oil
oil in water
$\mu_o \uparrow$
$\mathrm{Re} \downarrow$

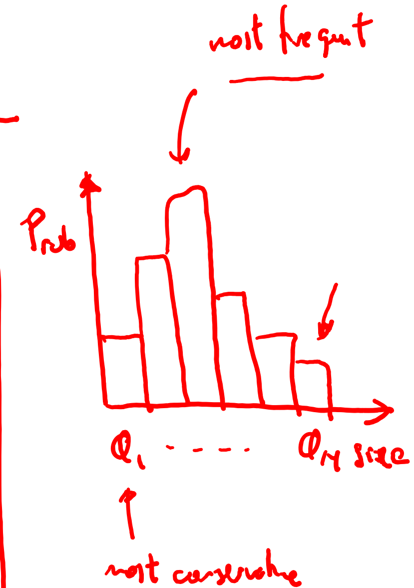
Separation time – droplet size distribution



10 -100 μm (1E-6 m)

d = 1E01-1E02 um

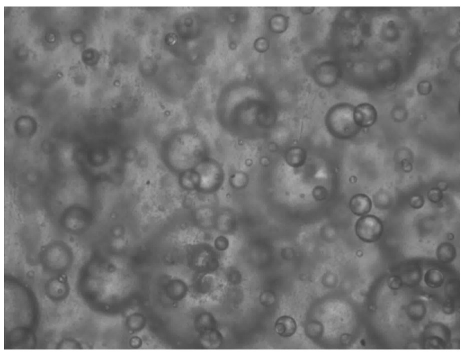
d	Count		Probability
min d_1	n_1		n_1/N
d_2	n_2	4	n_2/N
d_3	n_3	3	⋮
d_4	n_4		⋮
⋮	⋮		
max d_N	n_N		n_N/N

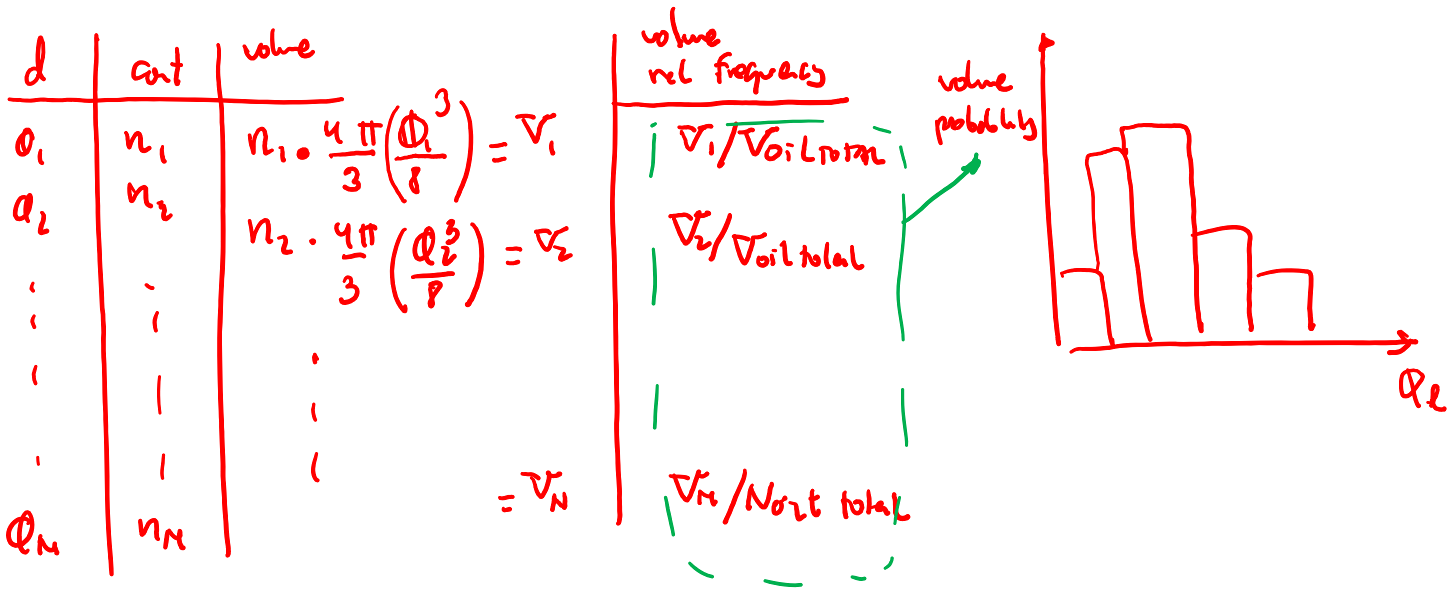


Separation time – droplet size distribution

d = 1E01-1E02 um

(volume based)





The calculation of V_s is implicit! (because $C_D = f(V_s)$)

$$V_s = \sqrt{\frac{4\, d_p\, g}{3\, C_D} \frac{(\rho_d - \rho_f)}{\rho_f}}$$

$$Re = \frac{\rho_f \cdot d_p \cdot V_s}{\mu_f}$$

1. assume V_s
2. calculate Re
3. Calculate C_D
4. Calculate V_s
5. check if $V_{s\,calc} = V_{s\,assumed}$

not → back to 1

yes → solution

The same equation can be used for

-Bubles of gas in liquid

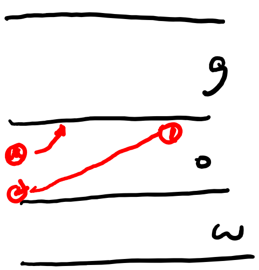
-droplets of liquid in liquid

BUT if the droplet/bubble is going up, the order of the density difference must be changed.

Oil separation time

API spec 12J

Crude API	Retention Time (min)
>30	1
20 - 30	1 - 2
10 - 20	2 - 4



So, experience-based values are often used instead (see table above)

Separation time = settling time

for droplet of oil in gas :

$t_{residence} \geq t_{settling}$

$$\frac{L_{eff}\, \phi_{sep}^2\, \pi}{4 \cdot q_{sep}} \geq \frac{\phi_{sep}/2}{v_s}$$

assuming liquid level is at half separator

$$L_{eff}\, \phi_{sep} \geq \frac{4 \cdot q_{sep}}{v_s \cdot \pi}$$

Simple Calculation example

-Design an oil-gas horizontal separator (Leff and ID) for the first stage of the Hysys problem provided earlier
-oil droplet size: 150 um
-Slenderness ratio (Lss/D): 3-4 (assume Lss=Leff+D)
-Max ID: 4.5 m
-Max Leff: 20 m

Crude API	Retention Time (min)
>30	1
20 - 30	1 - 2
10 - 20	2 - 4

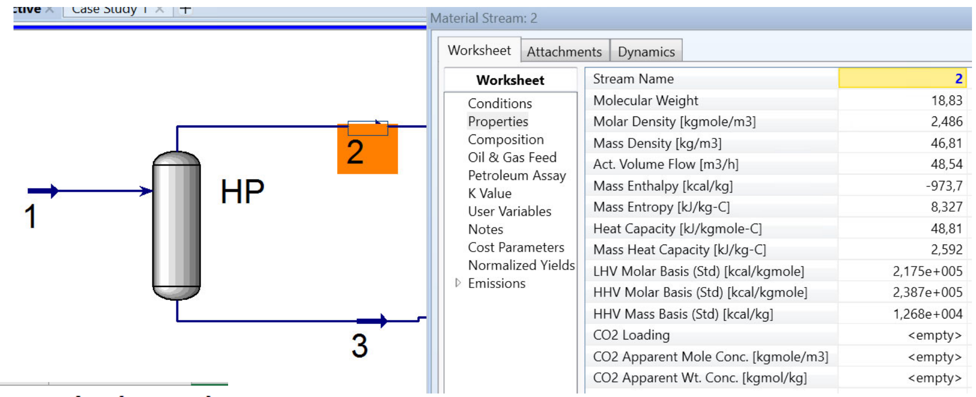
API spec 12J

Simple Calculation example

http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/2023/Class_files/Simple_Separator_sizing_exercise.xls

Use hysys to get properties and rates of oil and gas

$$q_g = \frac{\dot{m}_g}{\rho_g}$$



Simple liquid-gas horizontal separator sizing, Prof. Milan Stanko (NTNU)		
API	[-]	92.07
deno	[kg/m3]	631.2
deng	[kg/m3]	46.8
viscg	[Pa s]	1.44E-05
qg	[m3/s]	1.35E-02
qo	[m3/s]	1.09E-02
ddroplet	[m]	1.50E-04

Convention: red is input, blue is calculated

Oil API is unrealistically high, this is because we have neglected components heavier than C10 in our Hysys simulation

Simple Calculation example

1. tresgas >= tsepgas

Calculate settling velocity of oil in gas, use VBA function

AVERAGE | =vterminal(C4;C5;C6;C9)

	A	B	C
1	Simple liquid-gas horizontal separator sizing, Prof. Milan Sta		
2			
3	API	[-]	92.07
4	deno	[kg/m3]	631.2
5	deng	[kg/m3]	46.8
6	viscg	[Pa s]	1.44E-05
7	qg	[m3/s]	1.35E-02
8	qo	[m3/s]	1.09E-02
9	ddroplet	[m]	1.50E-04
10			
11	Dsep	[m]	0.9
12			
13	Vsettling (oil in gas)	[m/s]	=vterminal(C4;

Vsettling (oil in gas)	[m/s]	0.1567

```
Function vterminal(denp, denf, viscf, dp)
    'returns dispersed phase terminal velocity, m/s
    'Denp density of the dispersed phase, kg/m3
    'denf density of the continuous phase, kg/m3
    'viscf, viscosity of the continuous phase, Pa s
    'dp diameter of the dispersed phase, m
    If denp > denf Then
        a = 1
    Else
        a = -1
    End If
    'assume fully turbulent initially
    Cd_ = 0.2
    vp_prev = 1
    tol = 0.1
    residual = 1
    i = 0
    Do While residual > tol Or i < 1000
        vp = ((4 / 3) * 9.81 * (dp / Cd_) * (a * (denp - denf) / denf)) ^ 0.5
        residual = (vp - vp_prev) * 100 / vp_prev
        Re = Reynolds(dp, denf, viscf, vp)
        Cd_ = DragCoeff_Cd(Re)
        vp_prev = vp
        i = i + 1
    Loop
    vterminal = vp
End Function
Function DragCoeff_Cd(Re)
    'Re Reynolds number defined as denf*vp*dp/viscf Where p is disersed phase and f is fluid
    If Re < 2 Then
        DragCoeff_Cd = 24 / Re
    ElseIf Re >= 2 And Re < 200000# Then
        DragCoeff_Cd = (24 / Re) + (3 / (Re ^ 0.5)) + 0.34
    Else
        DragCoeff = 0.2
    End If
End Function

Function Reynolds(dp, denf, viscf, vp)
    'Reynolds number of dispersed phase
    'returns Reynolds number of dispersed phase
    'vp dispersed phase terminal velocity, m/s
    'Denp density of the dispersed phase, kg/m3
    'denf density of the continuous phase, kg/m3
    'viscf, viscosity of the continuous phase, Pa s
    Reynolds = denf * vp * dp / viscf
End Function
```

Simple Calculation example

$$L\,\phi_{sep} \geq \frac{4 \cdot q_{gas}}{v_s \cdot \pi}$$

if ϕ_{sep} is given | then $$L_{eff} \geq \frac{4 \cdot q_{gas}}{v_s \cdot \pi\,\phi_{sep}}$$

Dsep	[m]	0.5
Vsettling (oil in gas)	[m/s]	0.1567
tsep (oil in gas)	[s]	1.60
L_eff_min (tres>tsetl)	[m]	0.2

```
Function L_eff_min(qg, vdroplet, dsep)
    'Minimum required separator effective length assuming half the separator is filled
    'qg gas volumetric rate, m3/s
    'vdroplet, m/s
    'dsep, separator diameter
    Pi = Atn(1) * 4
    L_eff_min = qg * 4 / (Pi * vdroplet * dsep)
End Function
```

Because the rate of gas is so low, almost any small separator works (oil separates very quickly from gas)

2. treso >= tsep_oil

Crude API	Retention Time (min)
>30	1
20 - 30	1 - 2
10 - 20	2 - 4

```
Function tres_liquid(L_eff_sep, dsep, qo)
    'Liquid residence time in s
    'L_eff_sep, separator effective length, m
    'dsep, separator diameter, m
    'qo, oil volumetric rate, m3/s
    Pi = Atn(1) * 4
    tres_liquid = L_eff_sep * Pi * (dsep ^ 2) * 0.125 / (qo)
End Function
```

Assuming Leff, then

Lsep (eff)	[m]	2.1
tres_liq	[s]	18.94

NOT ENOUGH

Lsep (eff)	[m]	7.0
tres_liq	[s]	63.15

Oil separates sucessfully!

Construction considerations

$$\frac{L_{ss}}{D} \in (3-4)$$

$$L_{ss} = L_{eff} + D$$

$$3 \leq \frac{L_{eff} + D}{D} \leq 4$$

Current design does not work!!

Dsep	[m]	0.5
Vsettling (oil in gas)	[m/s]	0.1567
tsep (oil in gas)	[s]	1.60
L_eff_min (tres>tsetl)	[m]	0.2
Lsep (eff)	[m]	7.0
tres_liq	[s]	63.15
Lss/D	[-]	15.0

Modifying Leff and D until all constraints are satisfied:

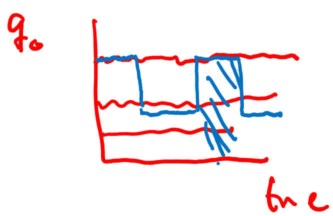
Dsep	[m]	0.9
Vsettling (oil in gas)	[m/s]	0.1567
tsep (oil in gas)	[s]	2.87
L_eff_min (tres>tsetl)	[m]	0.1
Lsep (eff)	[m]	2.1
tres_liq	[s]	61.38
Lss/D	[-]	3.3
L_eff_max (slenderness ratio)	[m]	2.7

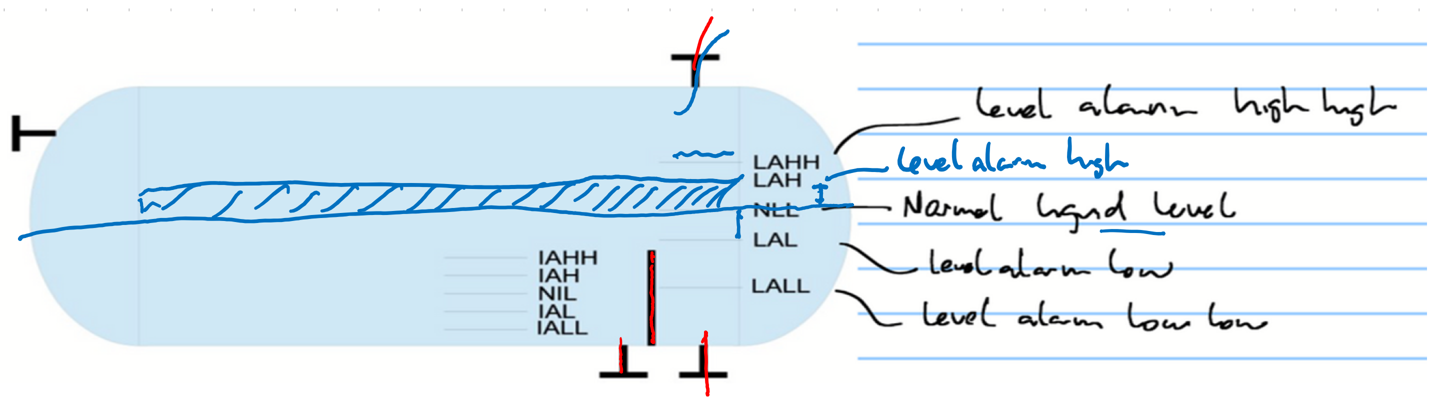
This separator is oversized for gas, but it is properly sized for the liquid

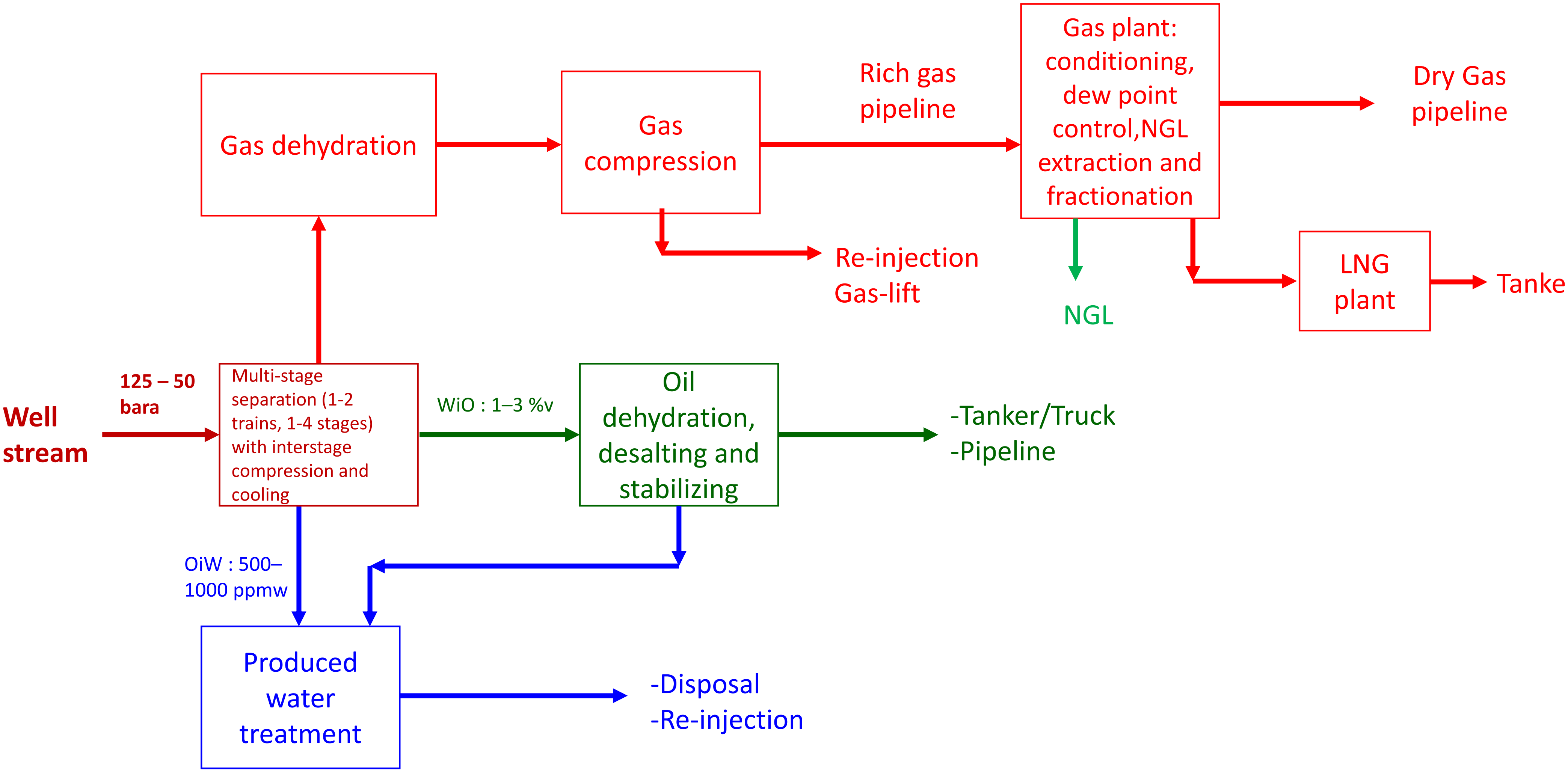
Inverse problem → geometry, calculate max flow rates of oil and gas

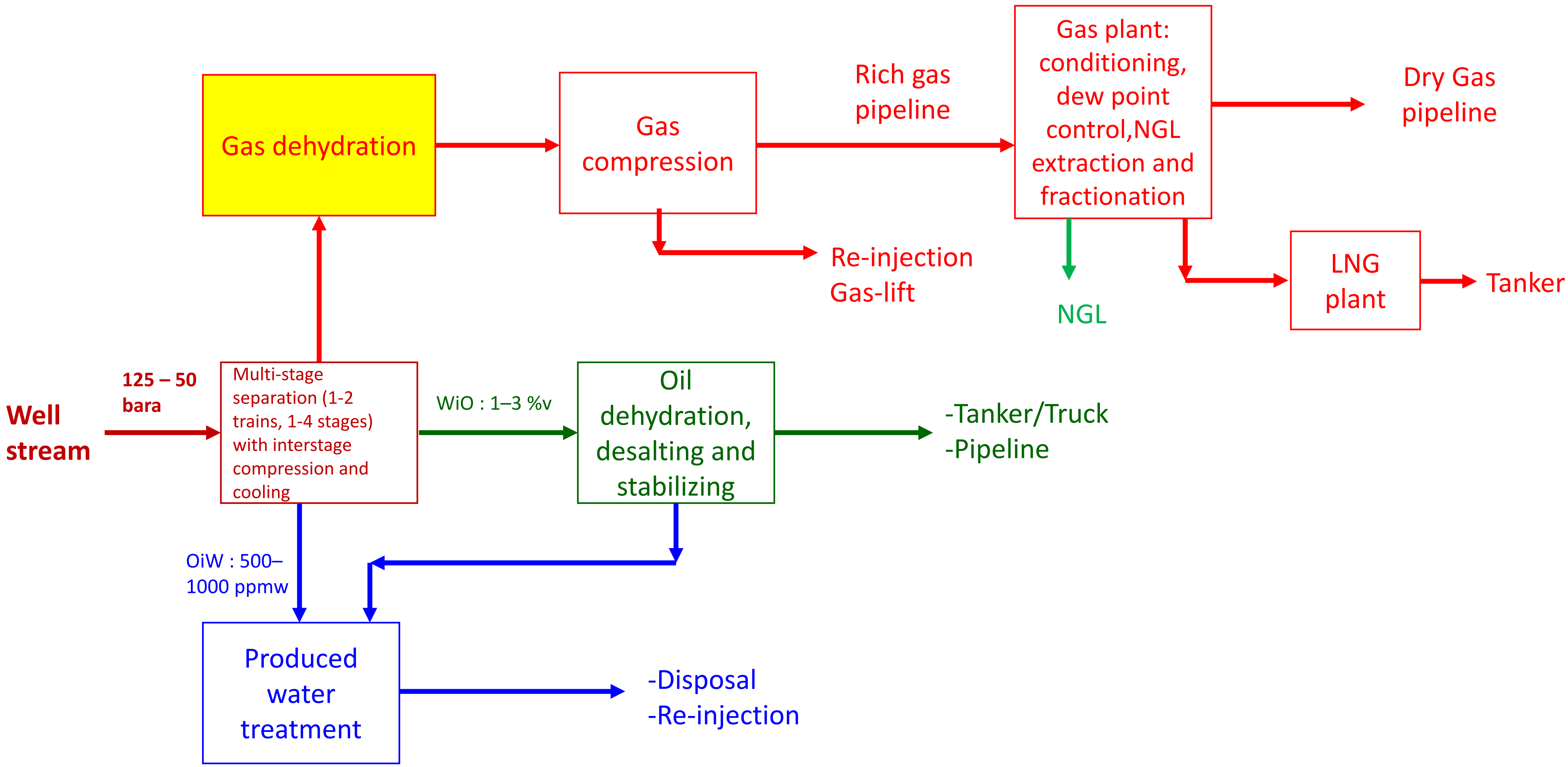
Other design considerations

- 3 phases (gas, oil and water)
- Internals
- Inlet and outlet section
- Structural design
- Additional space for transient flow (slugs)
- ++






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
125 – 50 bara
Well stream
Multi-stage separation (1-2 trains, 1-4 stages) with interstage compression and cooling
WiO : 1–3 %v
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection


Gas dehydration
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WiO : 1–3 %v
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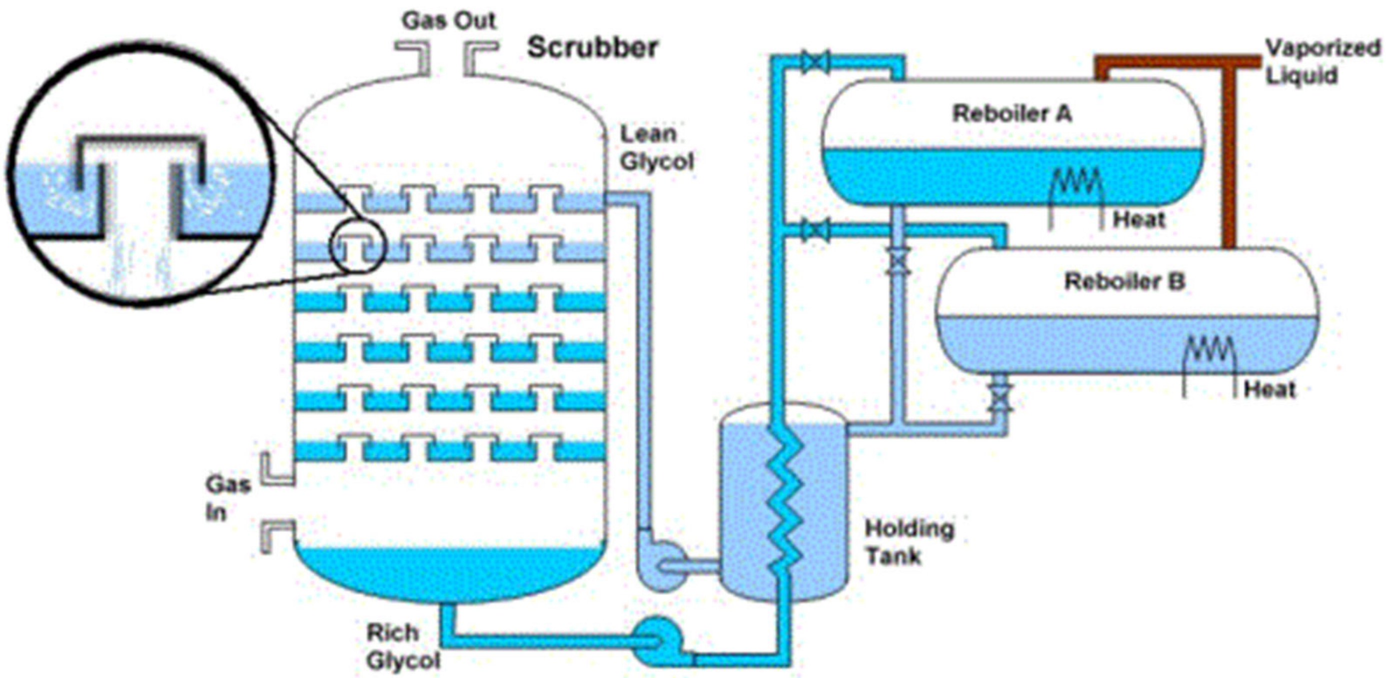
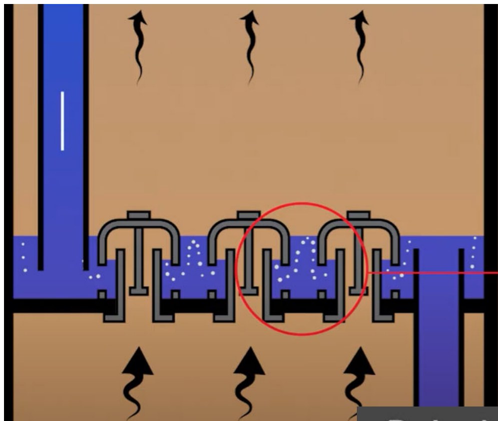
TEG dehydration



Youtube links for TEG dehydration

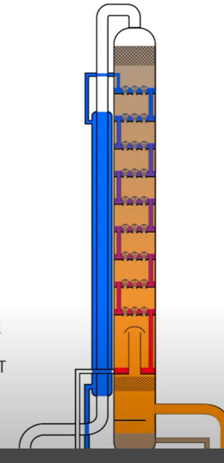
- Inside a gas dehydration tower: https://www.youtube.com/watch?v=_f7q8gWf8fg
- Gas dehydration unit: https://www.youtube.com/watch?v=kTtiqTeTZ0I



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



GAS DEHYDRATION

Wet Glycol OUT

Dry Glycol IN

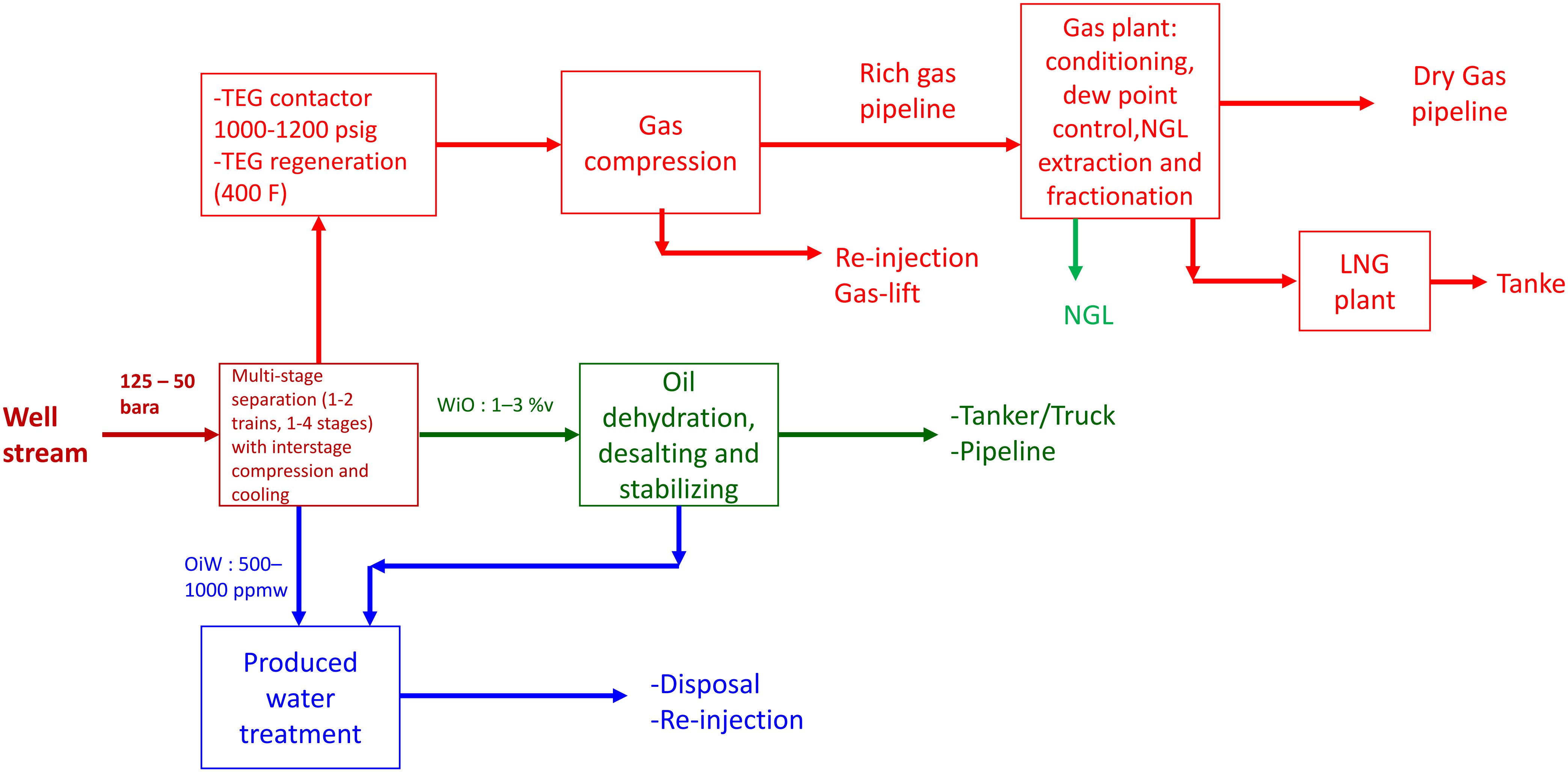
1. Glycol moves through **contactor tower**, absorbing the moisture from the natural gas becoming WET GLYCOL.

Wet Glycol = “Rich” Glycol
Glycol entrained with water

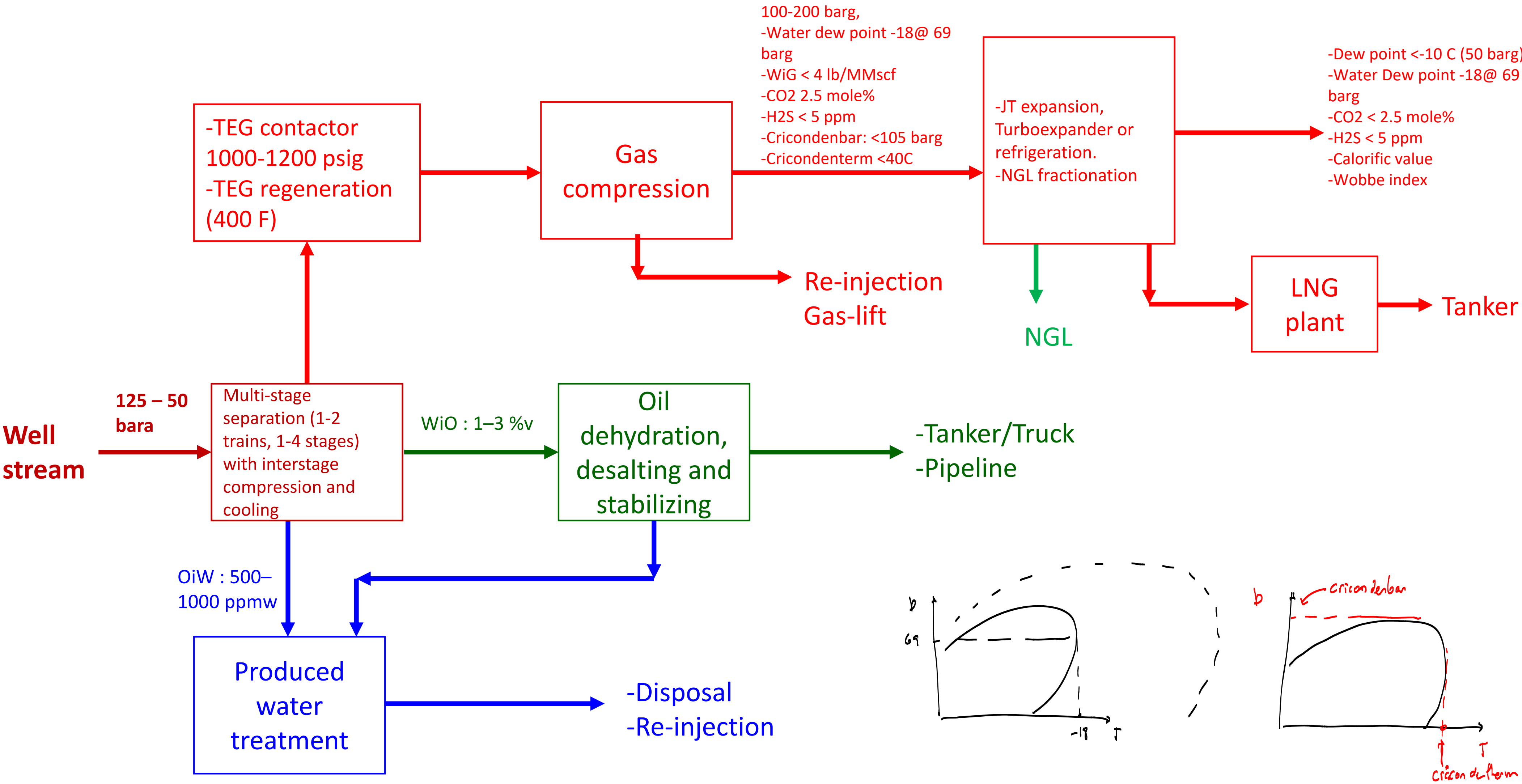
Dehydration Unit Sizes

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).



-TEG contactor
1000-1200 psig
-TEG regeneration
(400 F)
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
125 – 50
bara
Multi-stage
separation (1-2
trains, 1-4 stages)
with interstage
compression and
cooling
WiO : 1–3 %v
Oil
dehydration,
desalting and
stabilizing
-Tanker/Truck
-Pipeline
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)
-Water Dew point -18@ 69 barg
-CO2 < 2.5 mole%
-H2S < 5 ppm
-Calorific value
-Wobbe index
Re-injection
Gas-lift
NGL
LNG
plant
Tanker
Well
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125 – 50
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Multi-stage separation (1-2 trains, 1-4 stages) with interstage compression and cooling
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1000 ppmw
Produced
water
treatment
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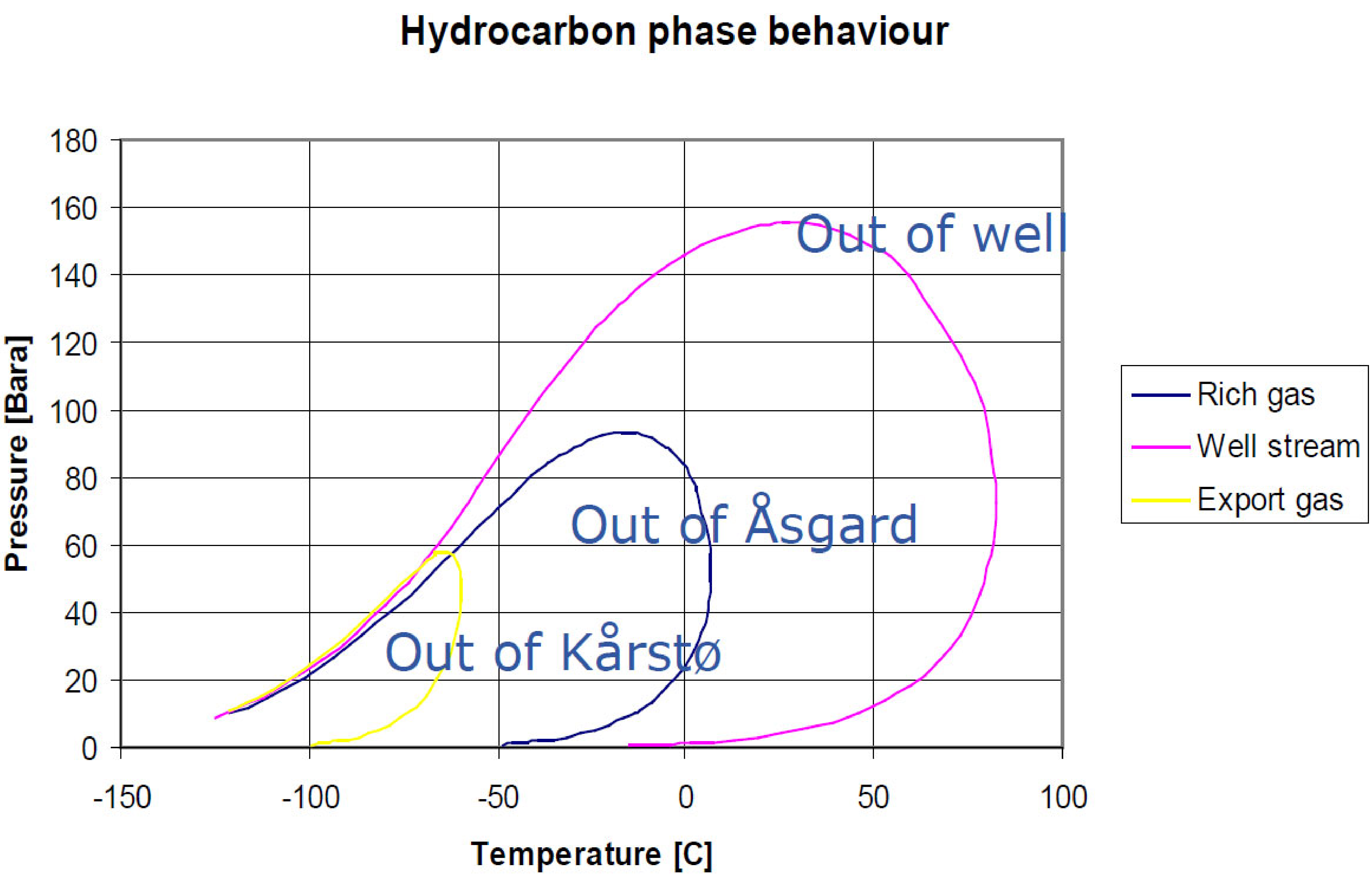
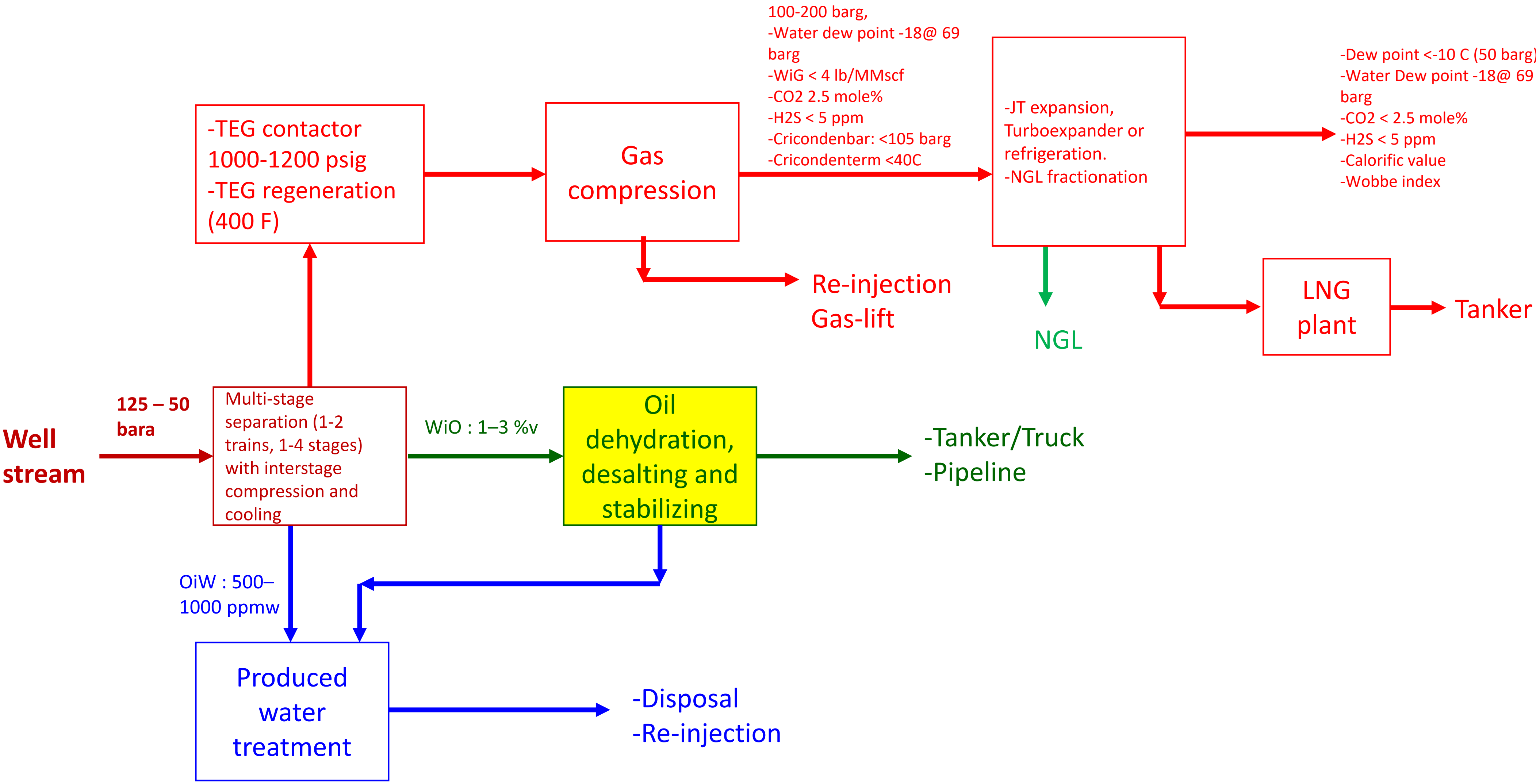

Hydrocarbon phase behaviour
Pressure [Bara]
180
160
140
120
100
80
60
40
20
0
-150
-100
-50
0
50
100
Temperature [C]
Out of well
Out of Åsgard
Out of Kårstø
Rich gas
Well stream
Export gas



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
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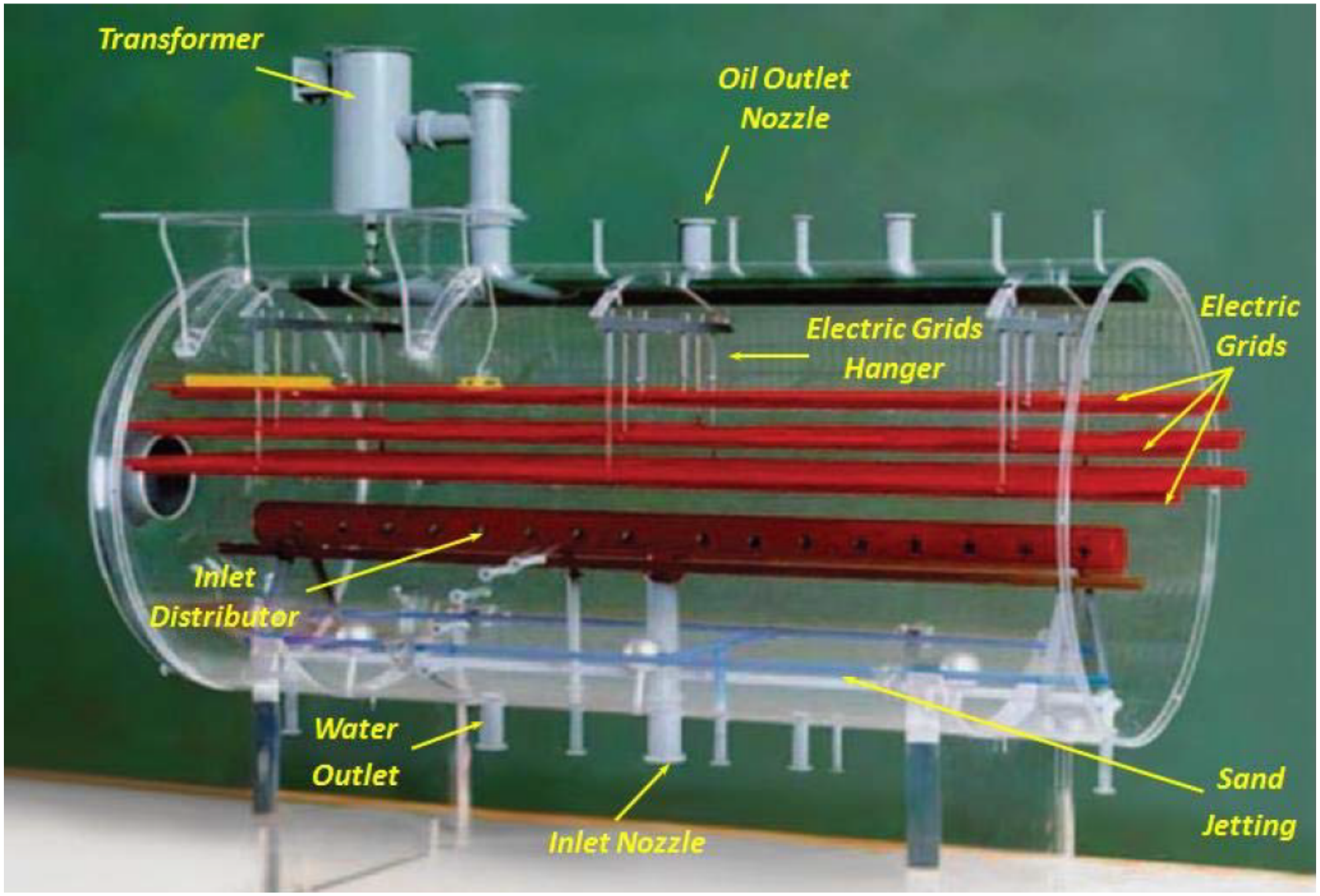
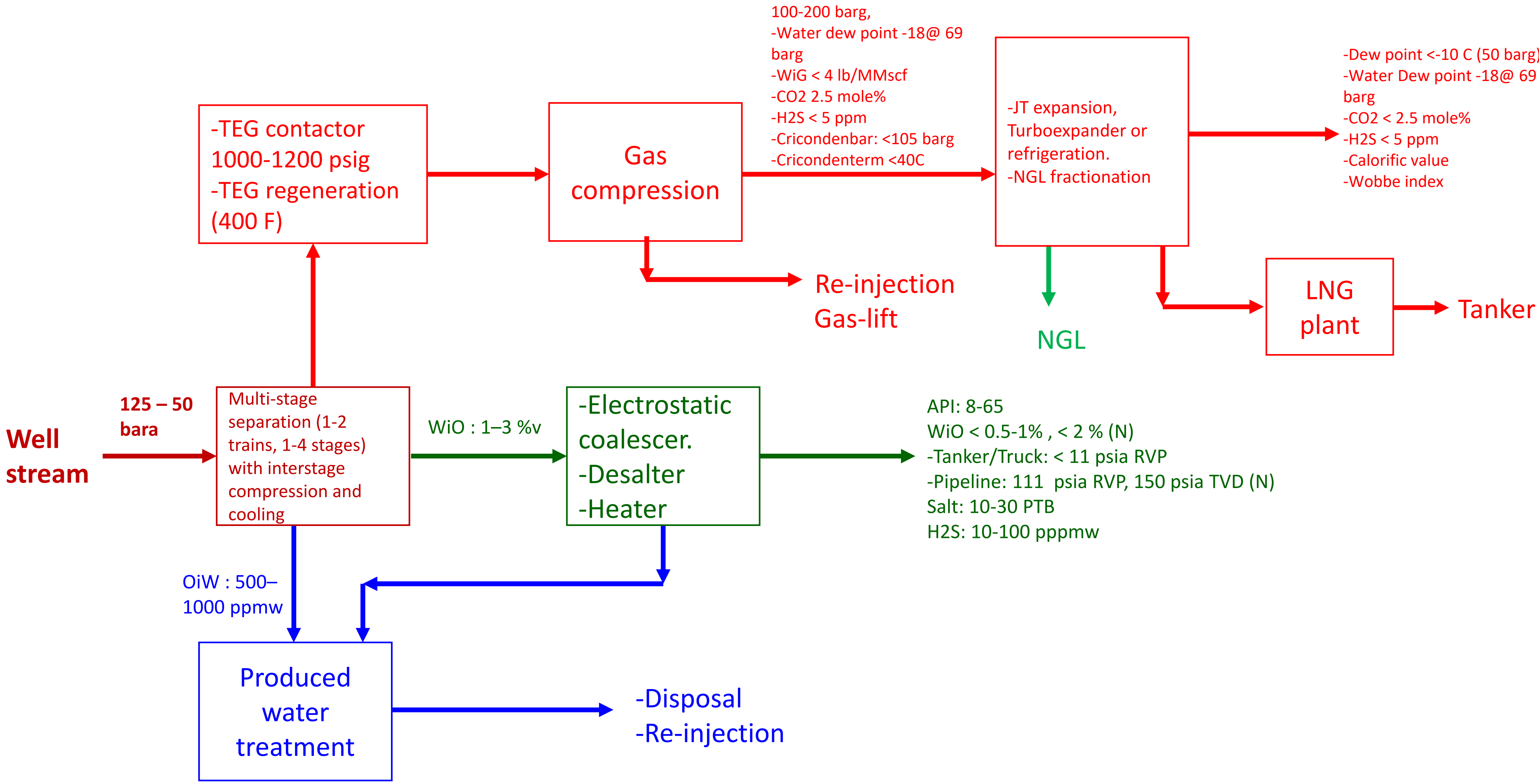
-Wobbe index
LNG plant
Tanker
WiO : 1–3 %v
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection

Electrostatic coalescer





100-200 barg,
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Re-injection
Gas-lift
NGL
LNG plant
Tanker
125 – 50 bara
Well stream
Multi-stage separation (1-2 trains, 1-4 stages) with interstage compression and cooling
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

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

$$API = \frac{141.5}{\gamma_o} - 131.5$$

o standard conditions

$$\gamma_o = \frac{\rho_o}{\rho_w}$$

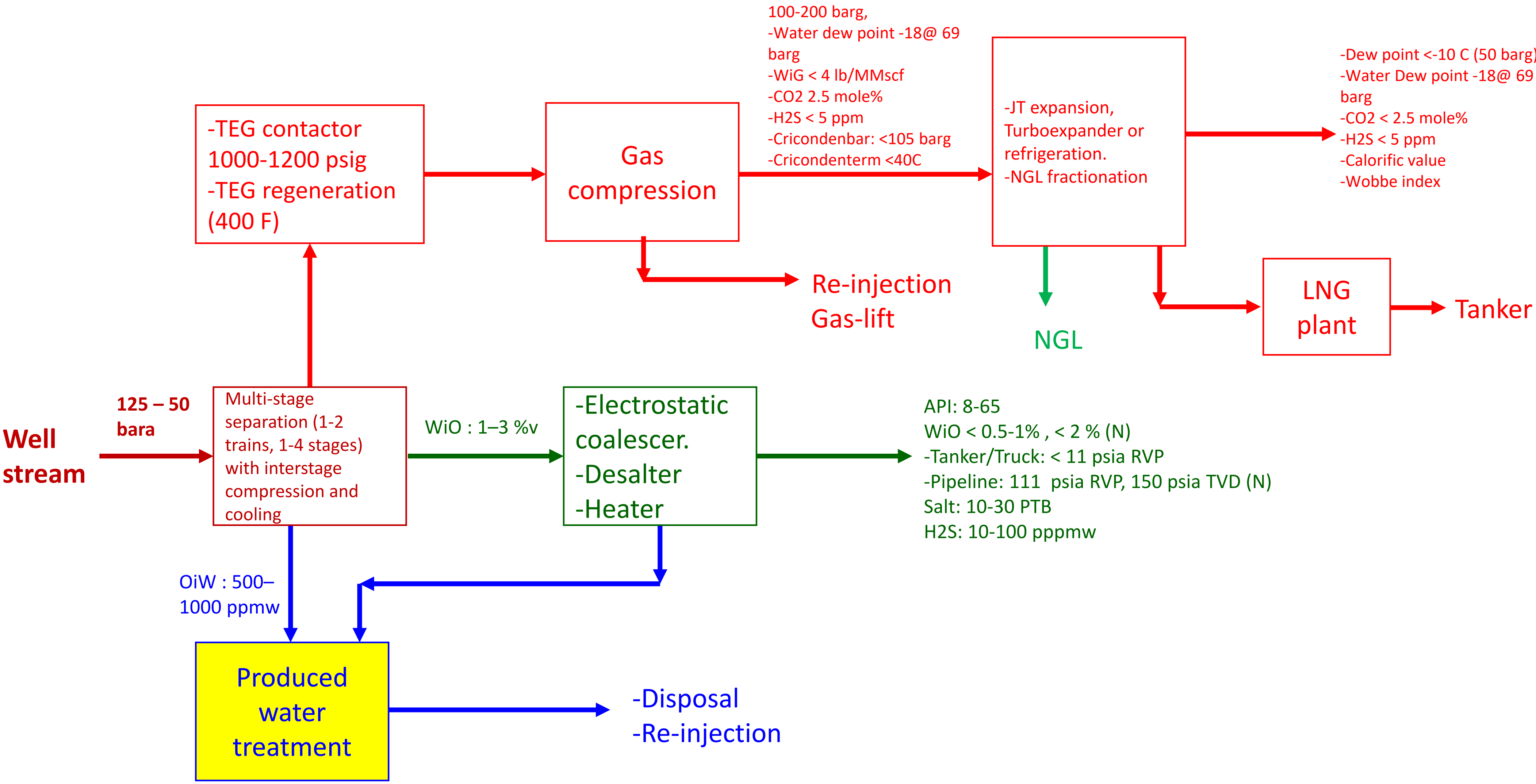
ρ_o: 700-900 kg/m^3

ρ_w: 1000 kg/m^3

RVP: Reid vapor pressure

TVD: true vapor pressure

PTB: pounds per thousand barrels



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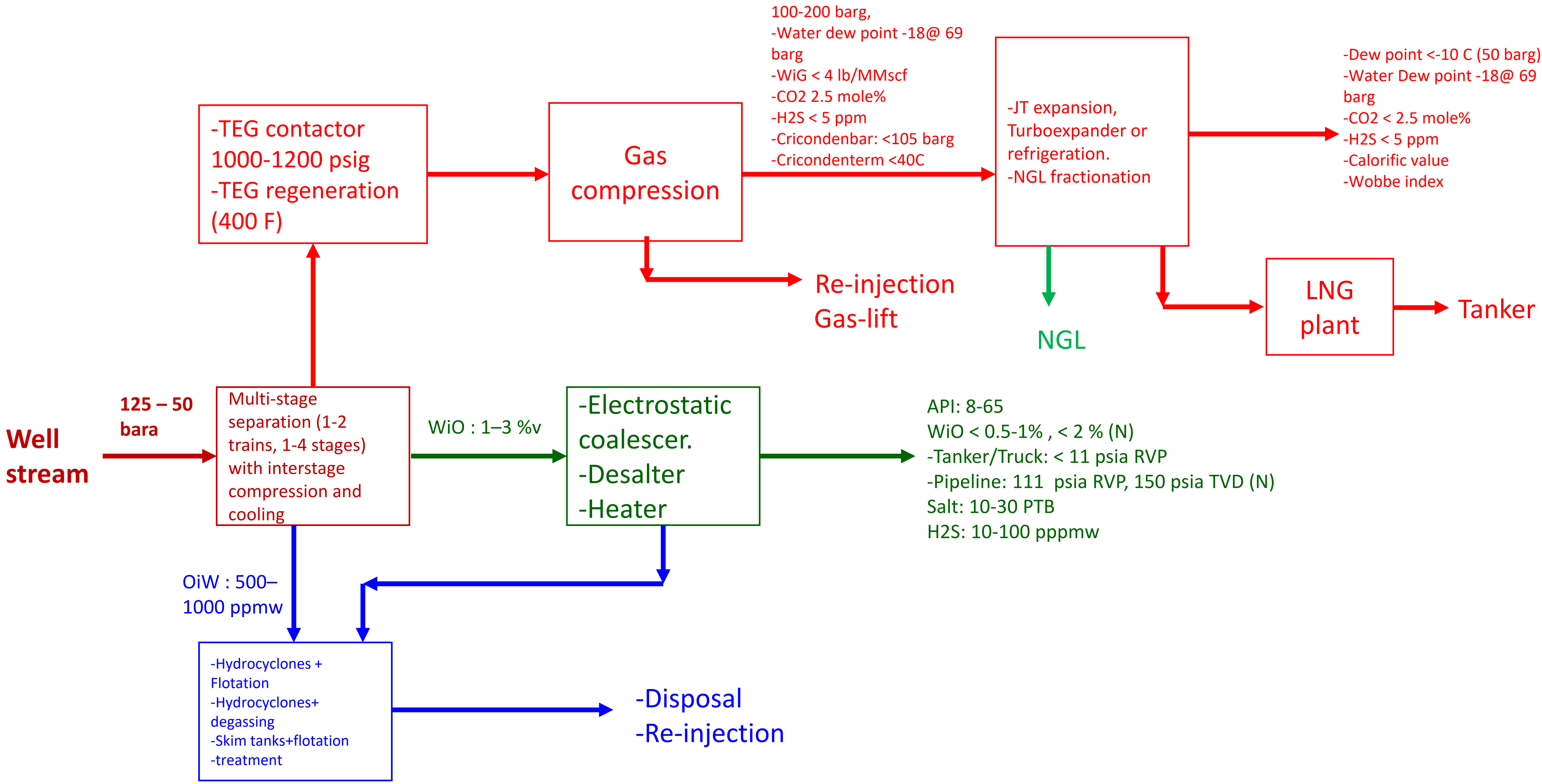
-Disposal
-Re-injection



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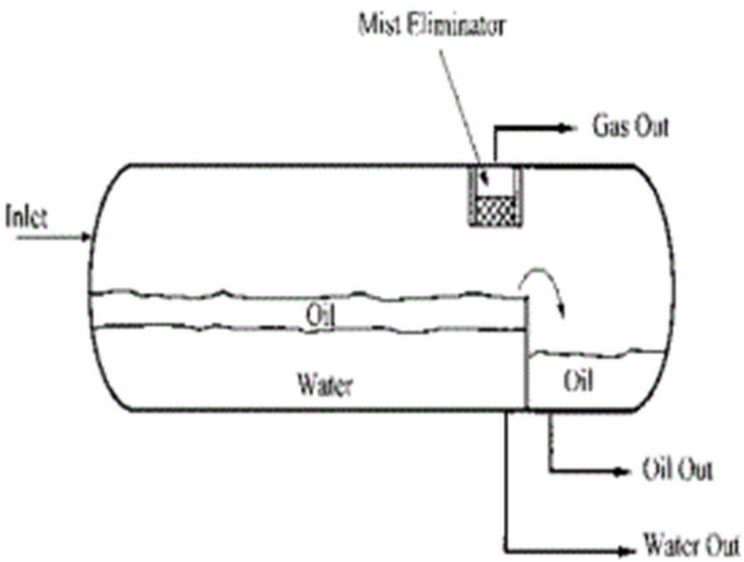
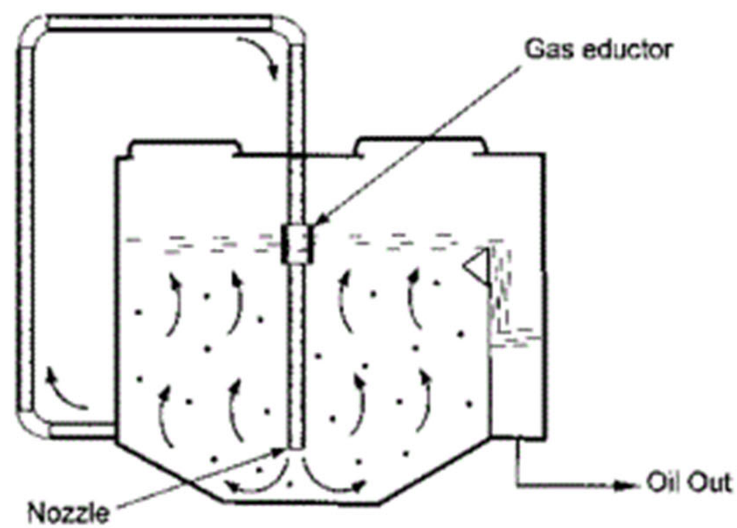
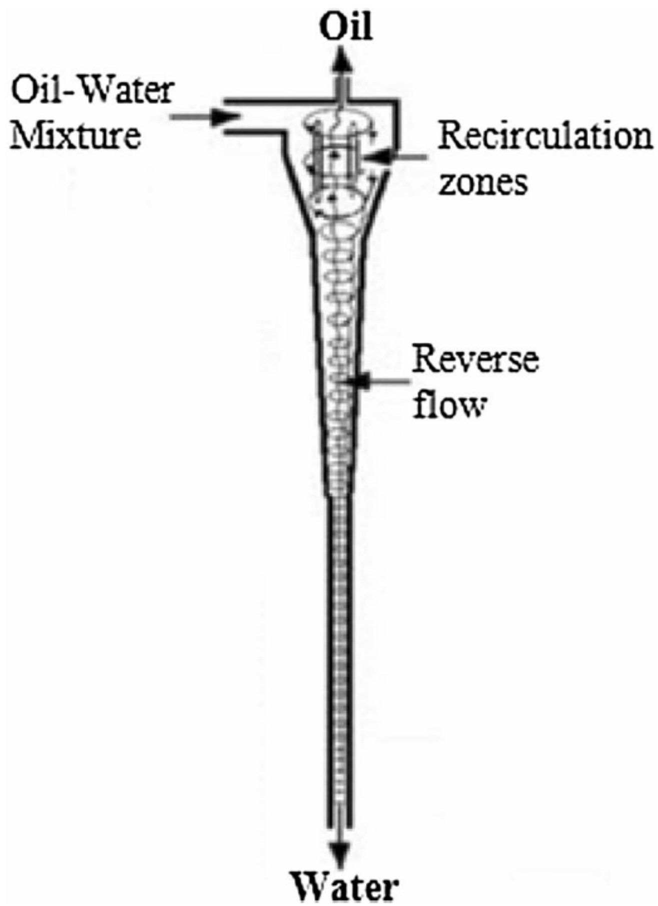
-Heater
API: 8-65
WiO < 0.5-1% , < 2 % (N)
-Tanker/Truck: < 11 psia RVP
-Pipeline: 111 psia RVP, 150 psia TVD (N)
Salt: 10-30 PTB
H2S: 10-100 pppmw
OiW : 500–1000 ppmw
-Hydrocyclones + Flotation
-Hydrocyclones+ degassing
-Skim tanks+flotation
-treatment
-Disposal
-Re-injection

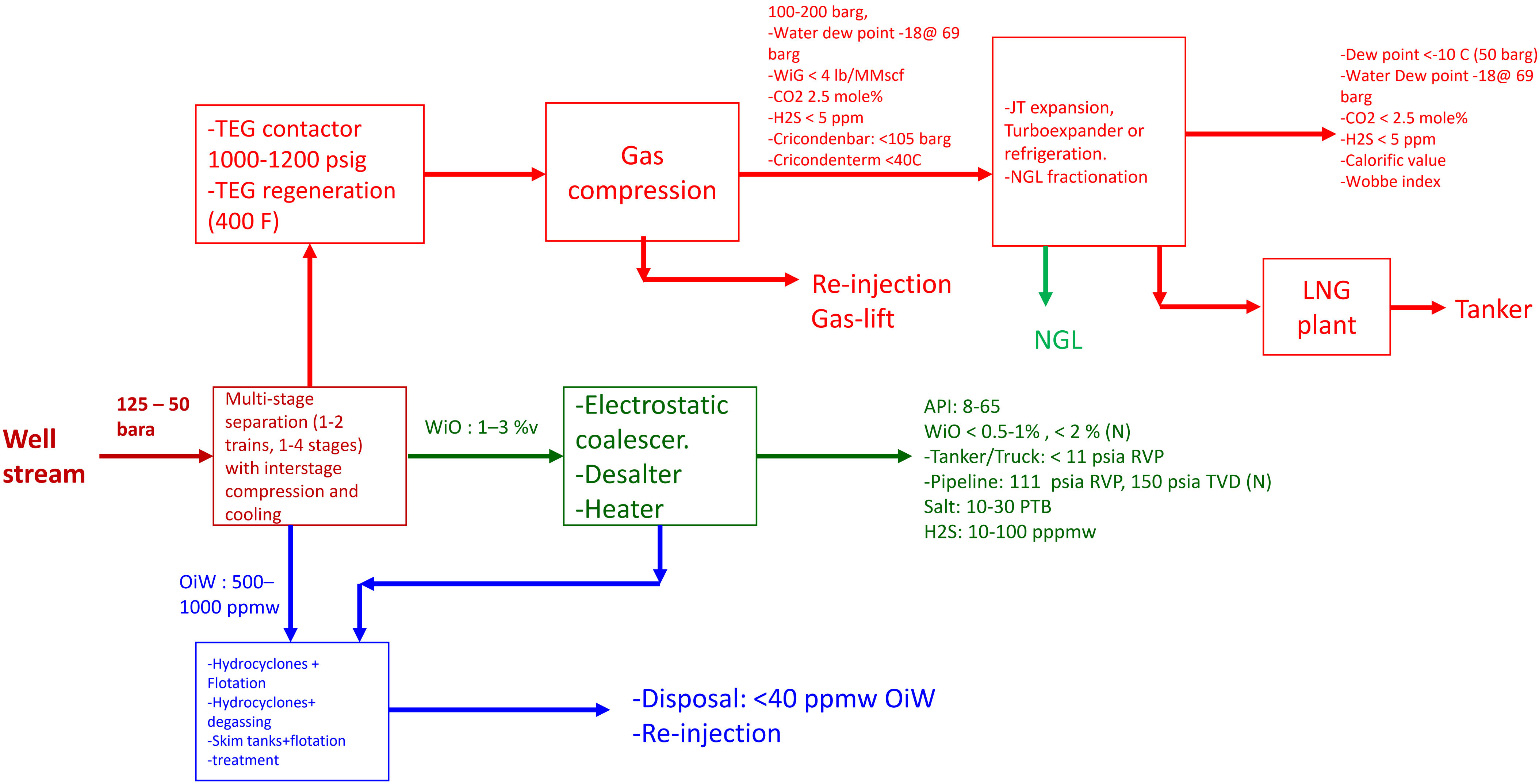
Skim tank + flotation unit





Hydrocyclone





-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)
-Water Dew point -18@ 69 barg
-CO2 < 2.5 mole%
-H2S < 5 ppm
-Calorific value
-Wobbe index
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
125 – 50 bara
Multi-stage separation (1-2 trains, 1-4 stages) with interstage compression and cooling
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

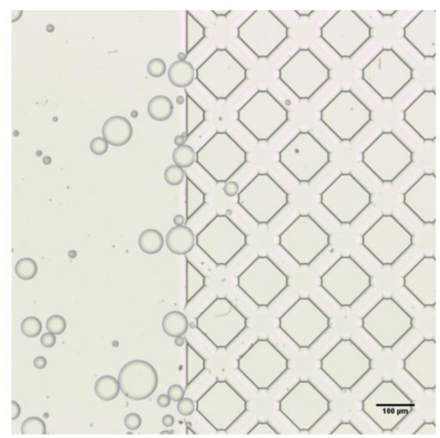
Water knockout : https://www.youtube.com/watch?v=wQ1A8w9Ouy4

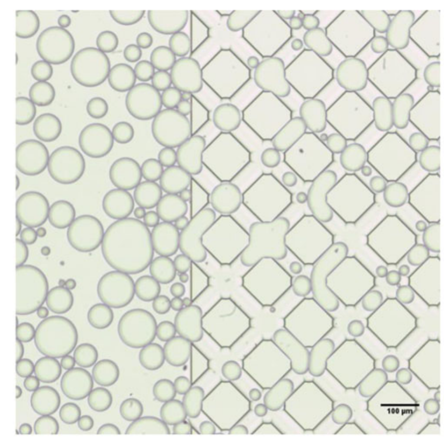
Walkthrough an oil and gas platform in the UK . https://www.youtube.com/watch?v=UrWTMCgHr6s

Bottlenecking

Bottlenecking - reasons

- Processing facility «capacity» is reached
  - Separation capacity (residence times)
  - Capacity of rotating equipment (pumps/compressors)
  - Water Treatment capacity
  - Water injection – Plugging of injectors
  - Sand production/wellbore stability



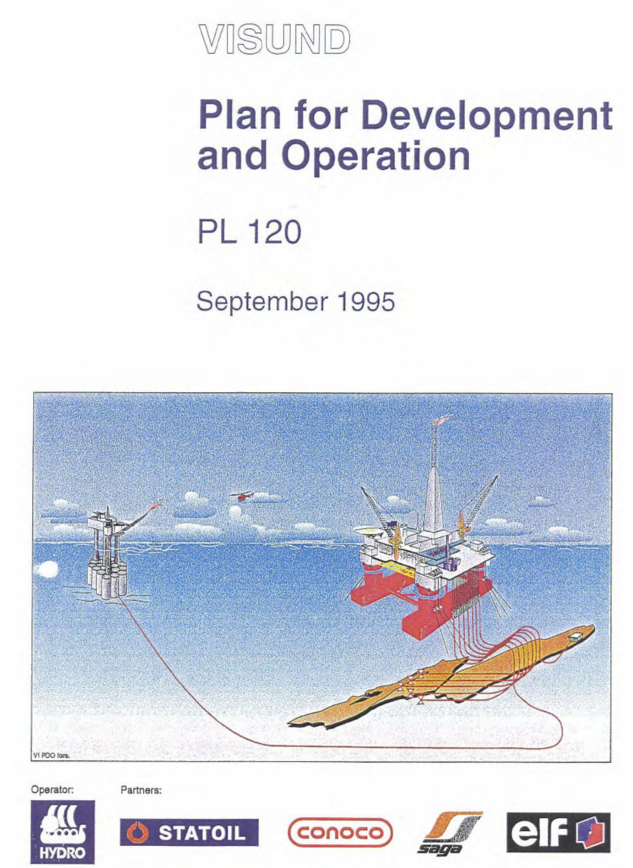


Processing capacity in PDO

Process Categories	Capacities
Oil production	16,000 Sm³/sd
Liquid production	28,000 Sm³/sd
Water production	15,000 Sm³/sd
Water injection	18,000 Sm³/sd
Utsira water production	15,000 Sm³/sd
Gas production initially (excl. fuel gas)	10 MSm³/sd
Gas injection	10 MSm³/sd
Export gas production	13 MSm³/sd

Table 1-2 Process Capacities

$$q_l = q_o + q_w$$



Bottlenecking – play with app

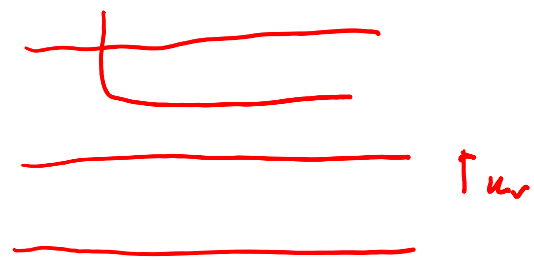
$$WC = \frac{q_{\bar{w}}}{q_{\bar{o}} + q_{\bar{w}}}$$

$$q_{\bar{w}} = f(q_{\bar{o}}, WC)$$

$$q_{\bar{w}} = \left(\frac{WC}{1-WC}\right) q_{\bar{o}}$$

$$q_{\bar{g}} = q_{\bar{o}} \cdot R_p$$

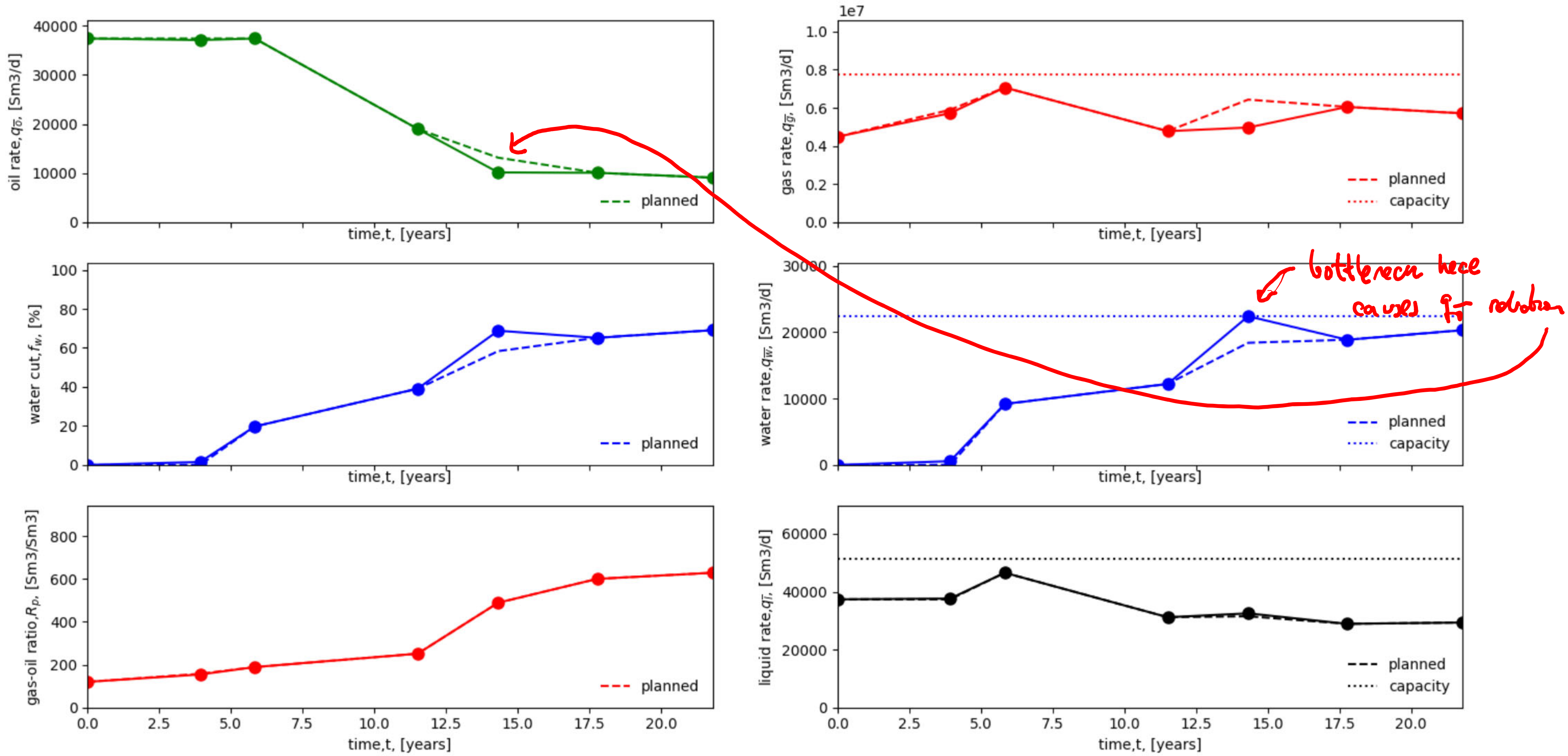
R_p → GOR



http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/Tools/

Bottlenecking – play with app

Oil field bottlenecking showcase, by Prof. Milan Stanko (2022)
Drag the points on the plots to the left, e.g. water cut and gas-oil ratio to set values higher than anticipated and then modify qo to produce within capacities



Bottlenecking – field example

Bottlenecking – field example