Norwegian University of Science and Technology

TPG4230 – Field development and operations

Spring Semester 2023

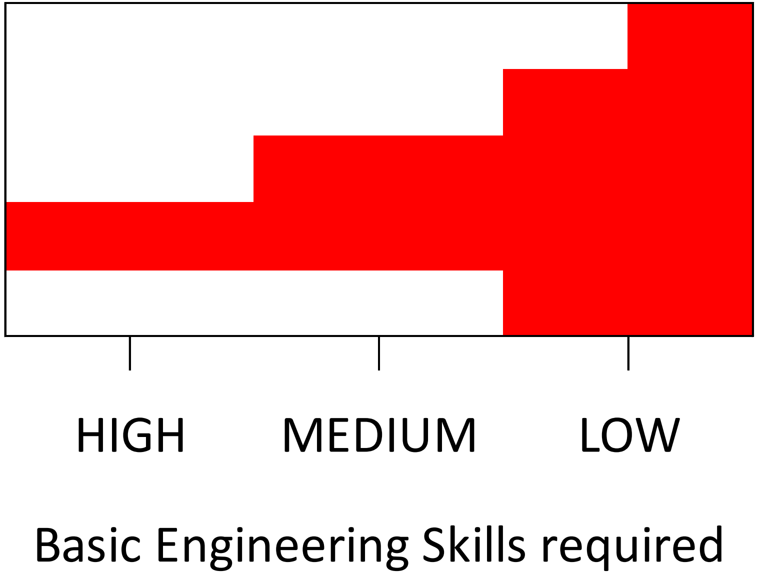
Information

- Lecturer: Assoc. Prof. Milan Stanko (Production Tech) (milan.stanko@ntnu.no). Office 510.
- Teaching assistant: Amin Jelvani Esfahani aminje@stud.ntnu.no
- Lecture schedule (P10)
  - Tuesdays, 13:15-15:00 (theory and exercises)
  - Tuesdays, 15:15-16:00 (session with TA)
  - Fridays, 08:15-10:00 (theory and exercises)
- Course description

Course content

- Field development workflow
  - Lifecycle, production modes, bottlenecking, onshore vs. offshore.
- Field production performance
  - Computation of production profile, production scheduling, extending plateau, production potential, boosting, networks
- Value chain model, cost estimation and NPV calculations
- Dealing with uncertain parameters in Field Development
  - Monte Carlo, Decision and probability trees
- Offshore structures
  - Layout of production systems, Marine loads
- Flow assurance considerations in field development

Goals of the course



- Appreciation, orientation
- Configuration and layout
- Design, dimensioning, simulation
- Troubleshooting, investigative engineering
- Game changer

Course scope

- A selection of topics and petroleum engineering skills needed for the planning, development and operation of oil and gas fields and to understand, model and analyze their production performance
- Topics typically covered in the course (with varying degrees of detail) are: life cycle of a hydrocarbon field, field development workflow, probabilistic reserve estimation, project economic evaluation, offshore field architectures and production systems, reservoir depletion and field performance, production scheduling, flow assurance, flow design of boosting, field processing facilities, export product control and integrated asset modeling

Goals of the course

At the end of the course, the student should be able to:

- Understand the process of planning and developing offshore oil and gas fields and some petroleum engineering aspects that govern the operation of such fields.
- Describe the lifecycle of oil and gas fields, the most common offshore field architectures, describe, understand and explain the functionality of the main components of a production system
- Understand and recognize the decision variables, objectives and constraints involved in field planning
- Perform engineering calculations such as probabilistic estimation of reserves, NPV calculations, flow equilibrium in production systems, flow equilibrium in surface networks, compute production profiles using models of the reservoir and production system, and to analyze applications of subsea boosting

Course scope

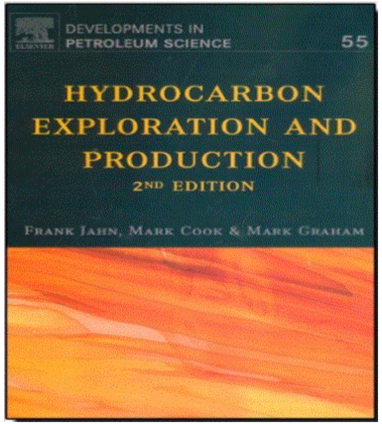
- Practical SI units only (bar, m3), not field units.
- Little focus on exploration and subsurface characterization (geology, geophysics, petrophysics, generation of reservoir realizations)

Information

- Lectures until 25 April (breaking for Easter)
- Consultation time: preferably after class. Try to make an email appointment.
- Reference group – **any volunteers?**
  - Anonymous comment box
- **Use Blackboard and the course progress file to navigate the course**
  - Use the forum for Q&A
  - For group deliveries: Join a group before delivering the exercise (even if one person only!!)

Reference material

- Compendium
- Recommended
- Supplementary
- Hydrocarbon exploration and production (Jahn, Cook and Graham)



Evaluation

- 100% «written» school exam
  - Digital exam in Inspera, most likely using Excel. No written/handwritten material allowed (equations will be provided in the exam papers)
  - Previous years exams
  - Examples 2018, 2020, 2021, 2022
  - Make it nice, easy to understand and follow. When provided, use the Excel template

Evaluation

- Mandatory assignments
  - All assignments must be **approved** to get access to the exam
  - All assignments must be delivered in Blackboard by the deadline
  - Some assignments will be discussed (or solved) in class
  - Individual delivery. Groups of up to 3 people may be allowed for some assignments
  - Nr. of assignments is not yet known, but it is usually 3-4.
  - Let me know early if there is a deadline conflict with other courses
  - Those students that took the course last year and **delivered and approved** the homework, do not have to deliver the obligatory exercises this year. They will be approved. All others must deliver the obligatory exercises.

Teaching

- Flipped classroom
  - Participants watch by themselves pre-recorded videos (ca 45 min) (on Youtube)
  - Live classes every week
    - Discussing further theory, exercises, group work, tutorials on software, Q&A, advanced topics, guest presentations, industry visits?
    - Classes will be recorded, and the recording will be shared on Blackboard

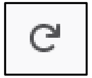
How to watch the pre-recorded videos

- Watching pre-recorded videos (on Youtube):
  - Watch at higher playback speed (1.5x -2x, Milan speaks slow) 😅
  - At certain time stamps (**or at the end of the video**), the videos have embedded links to: other relevant videos, material and quizzes. Example link1 link2
  - It is recommended to go through the complete video and click on the links along the way
  - Pause when needed. Try to summarize what was presented with your own words. Take notes. (with pen and paper or on the pdf)

Quizzes

- Supposed to help you summarize the learnings and consolidate knowledge
- Embedded on videos link2
- No solution key will be given.
- Some quizzes might be given as mandatory assignment

Quizzes

- Known bugs
  - When there is a multiple-choice question, if you want to clear your selection, you have to refresh the page 
  - In some browsers one must scroll down sometimes to see the rest of the quiz and the result code
  - Be patient, give it time to load and process information

Tools

- Excel (+VBA)
- Python (Jupyter Notebook) –using Google Colab
- Hysys (Aspentech, run on ntnu farm) or DWSIM
- IPM (Petex): Prosper, GAP and MBAL

Questions?

Notes for youtube video nr. 1

Field development and operations

Offshore oil and gas production (from fields in Norway)

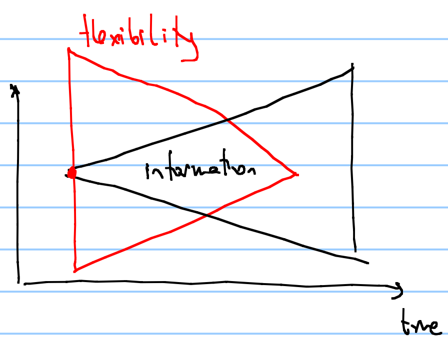
maximize economic value of HC explotation project for shareholders, subjected to technical constraints (eng., petroleum engineering) HSE constraints

define KPI's

- stuck with an existing system
- reduce the impact of system defficiencies
- exploit the advantages
- optimize/"effectivize" production

Decide on main features of field

- → define KPI's for project (Key performance indicator)
- → collect information $
- → define alternatives
- → analyze data, evidence (modeling)
- → choose an alternative



Life-cycle of hydrocarbon field:

Pre-exploration → exploration → Appraisal → field planning → field construction → operations → decommissioning abandonment

discovery

DG0 (Decision gate)

Eriksson process

(5-40)

(3-6)

feasibility studies → concept planning → preengineering

DG1 (BoK) (Beslutning om Konkretisering

DG2 (BoV) → Beslutning om videreføring

DG3 → BoG Beslutning om gjennomføring

→ issue PDO plan for development and operations

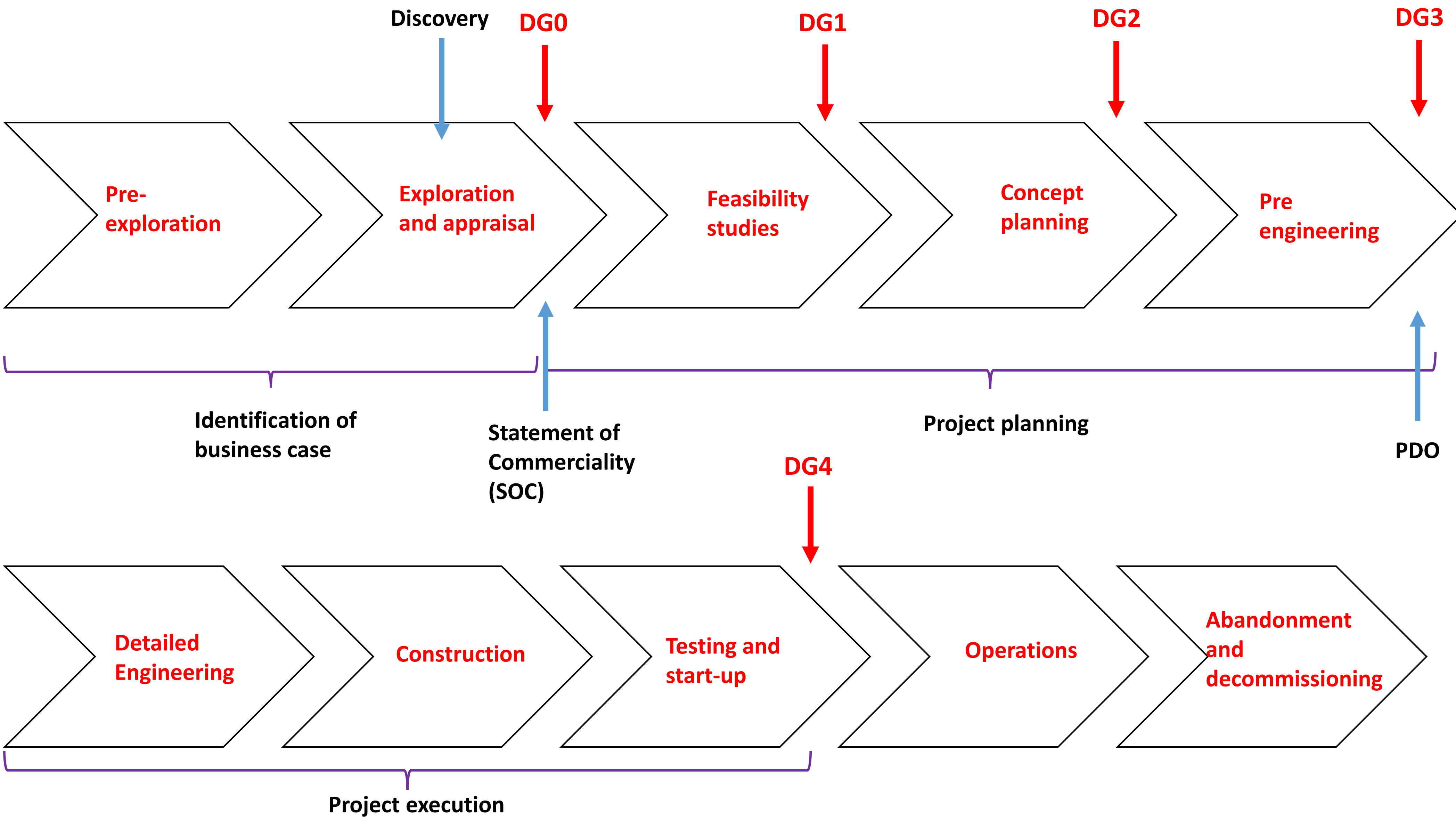
detailed engineering — construction — testing and startup

DG4

Notes for youtube video n. 2

THE FIELD DEVELOPMENT PROCESS

Prof. Milan Stanko (NTNU)


Discovery
DG0
DG1
DG2
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Pre-exploration
Exploration and appraisal
Feasibility studies
Concept planning
Pre engineering
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Statement of Commerciality (SOC)
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PDO
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Detailed Engineering
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Operations
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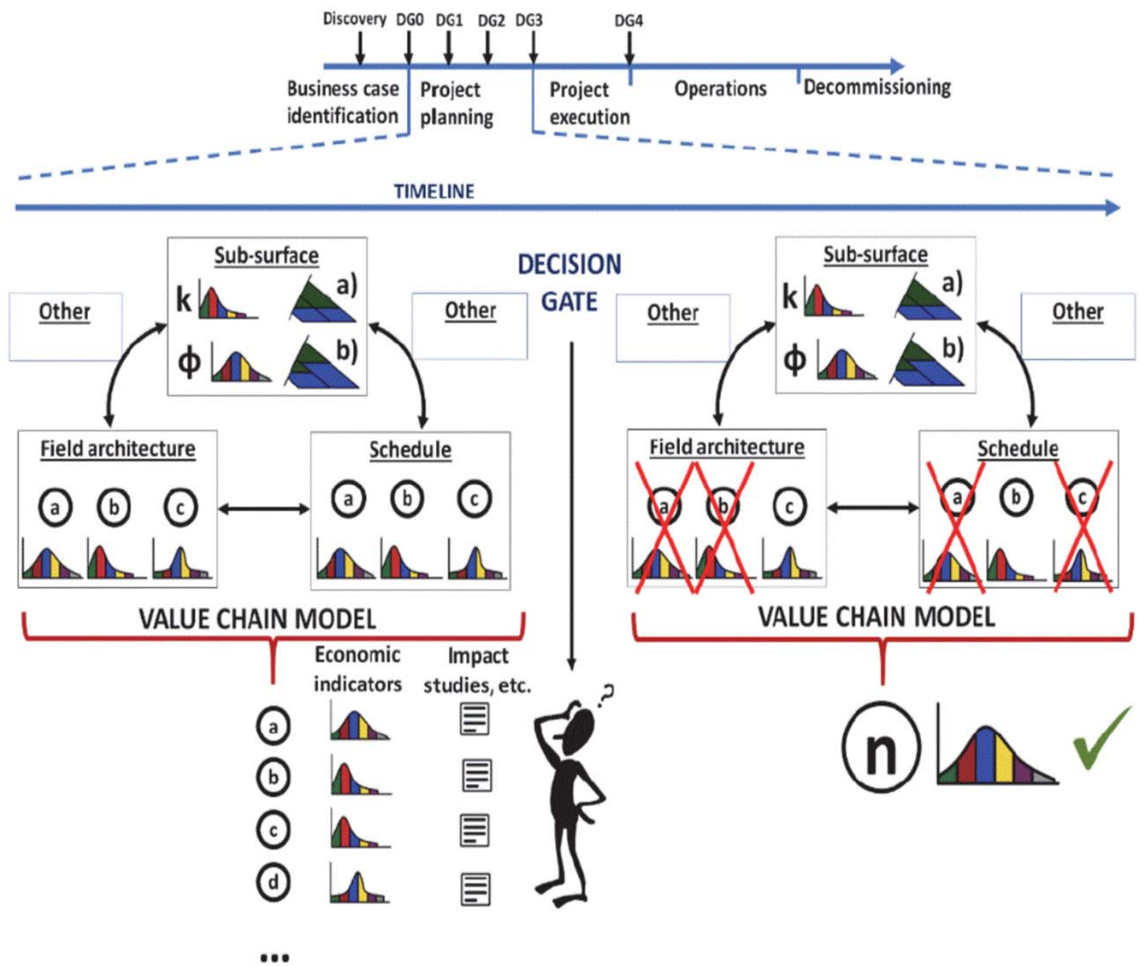
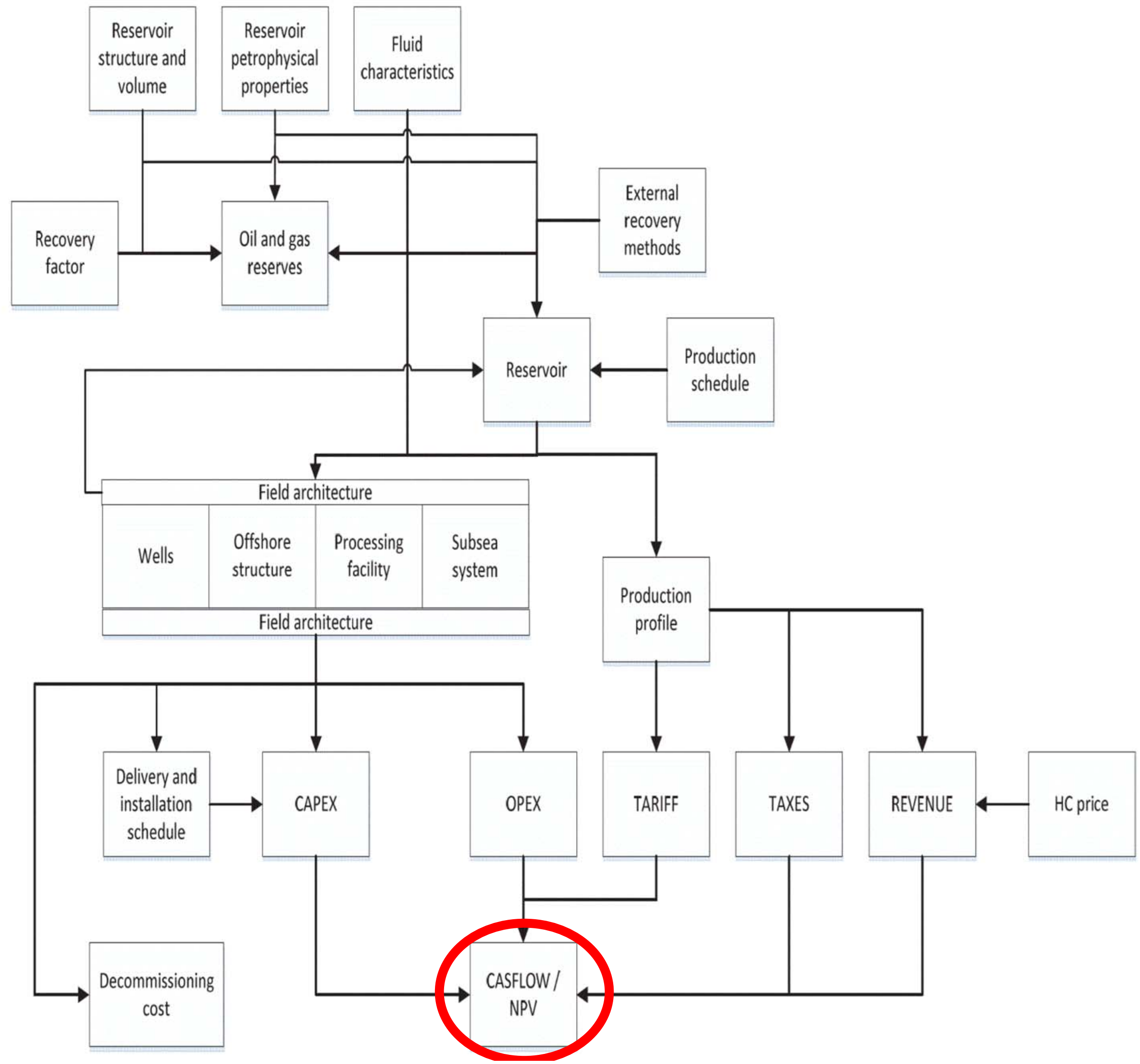
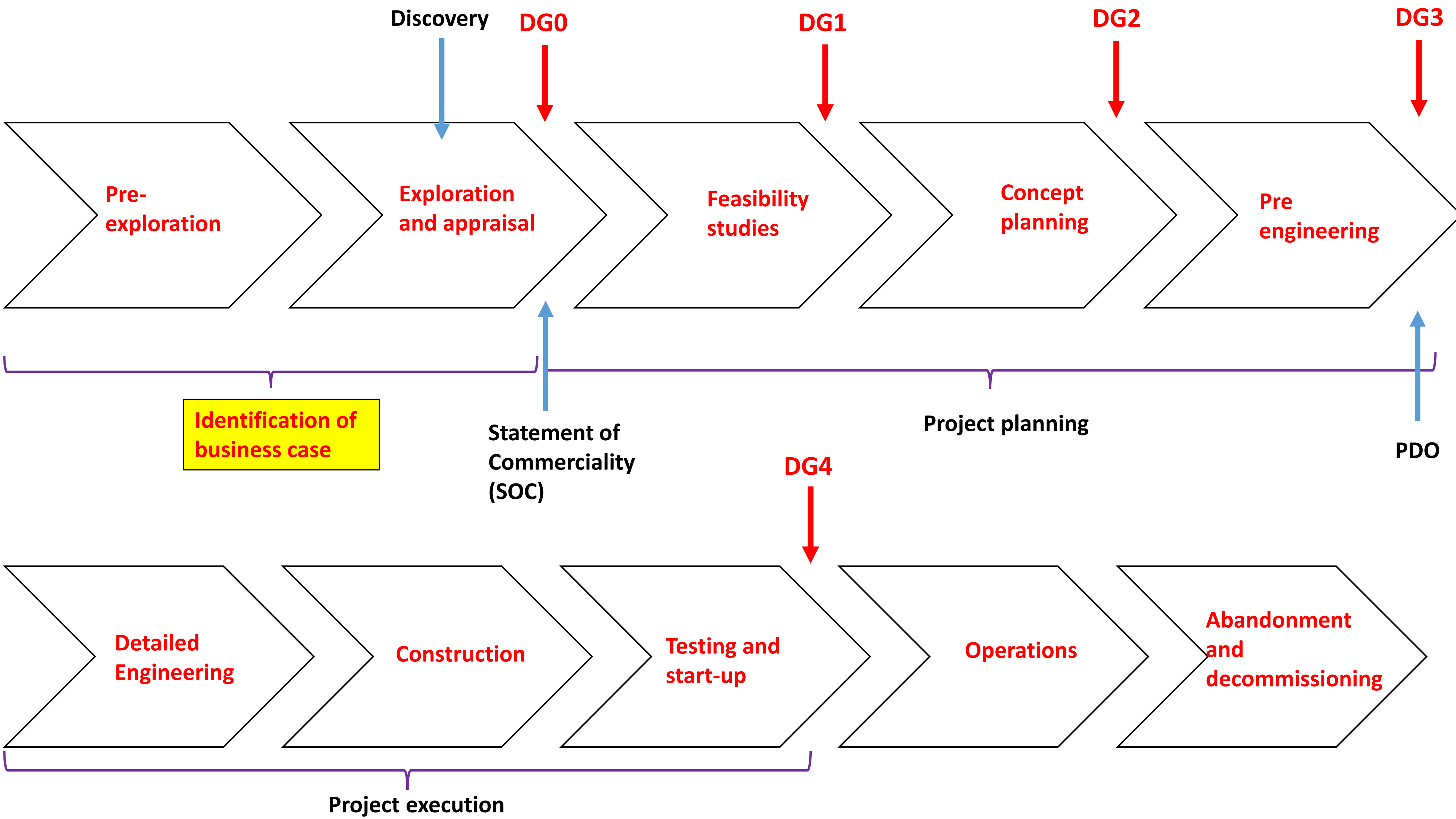
Project execution

During the field development process a model of the value chain is made based on the disciplines involved and populated with information. Initially there are many alternatives and little information. As time progresses and decisions are taken, the model is expanded, there is more information but less flexibility.



Key performance indicators are computed with the value chain model and are used to take decisions in the decision gate process.

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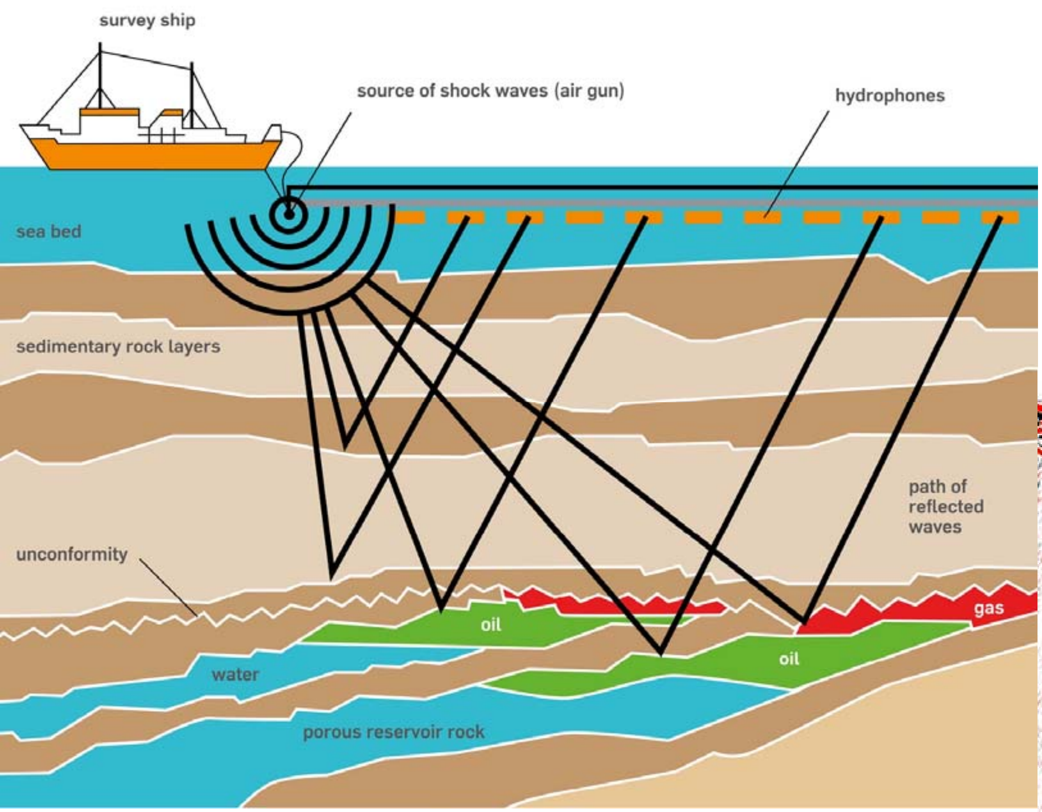
IDENTIFICATION OF BUSINESS CASE

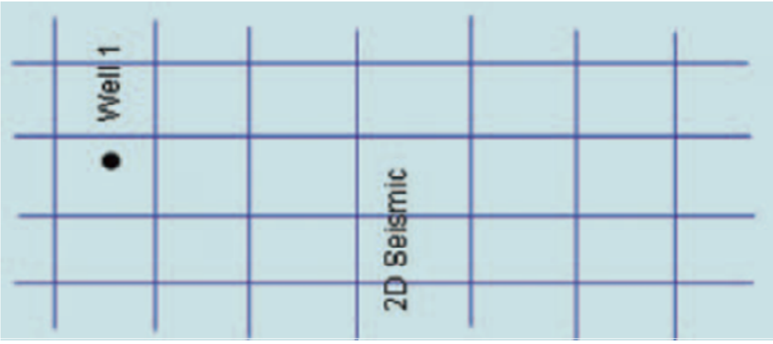
The main goal of this stage is to prove economic potential of the discovery and quantify and reduce the uncertainty in the estimation of reserves.

IDENTIFICATION OF BUSINESS CASE - TASKS

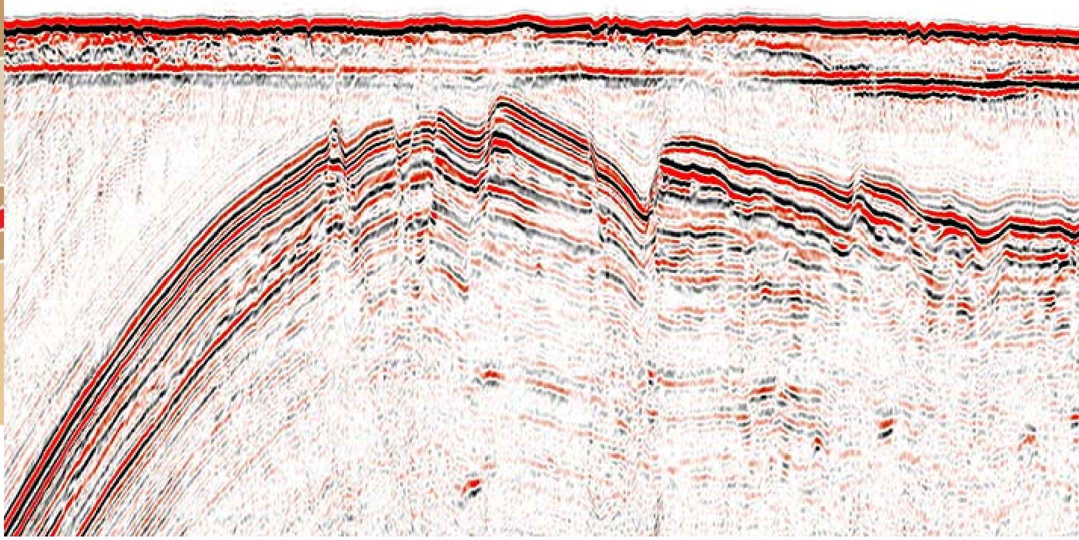
- Pre-exploration – scouting: collecting information on areas of interests. Technical, political, geological, geographical, social, environmental considerations are taken into account. E.g. expected size of reserves, political regime, government stability, technical challenges of the area, taxation regime, personnel security, environmental sensitivity, previous experience in the region, etc.
- Getting pre-exploration access – The exploration license (usually non-exclusive). In the NCS only seismic and shallow wells are allowed. This is usually done by specialized companies selling data to oil companies. Area: 500 Km^2
- Identify prospects.

IDENTIFICATION OF BUSINESS CASE - TASKS





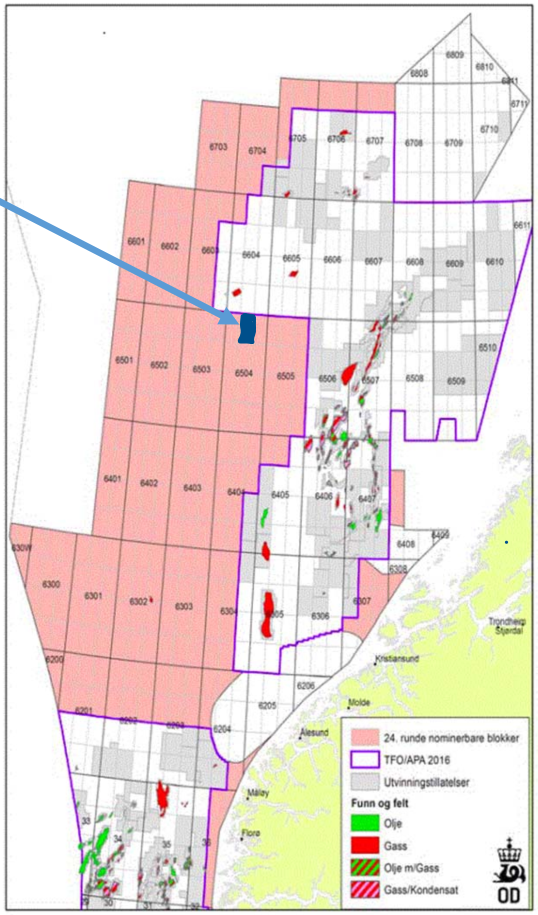
Seismic exploration



[Ref: https://krisenergy.com/company/about-oil-and-gas/exploration/](https://krisenergy.com/company/about-oil-and-gas/exploration/)

IDENTIFICATION OF BUSINESS CASE - TASKS

Ca 500 km^2



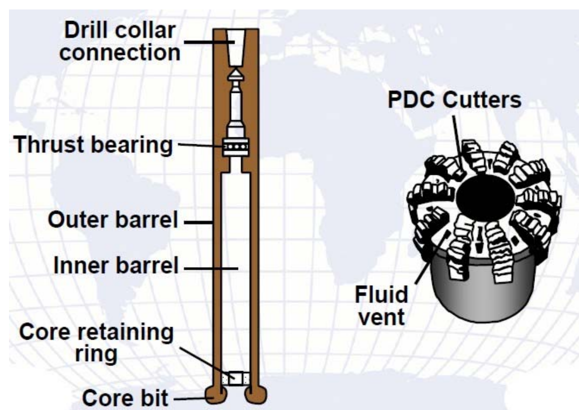
Ref: NPD

- Apply and obtain exclusive production license (6 years, possible to extend for 30 years). In the NCS: Licensing rounds (frontier areas) or Awards in predefined areas (APA). The current fees (if inactive) are 34 000 NOK/km^2 for the first year, 68 000 NOK/km^2 for the second year and 137 000 NOK/km^2 per year thereafter.

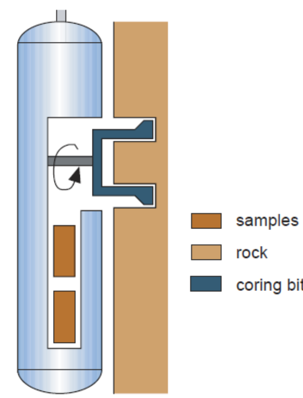
IDENTIFICATION OF BUSINESS CASE - TASKS

- Exploration. Perform geological studies, geophysical surveys, seismic, exploration drilling (Well cores, wall cores, cuttings samples, fluid samples, wireline logs, productivity test).

- Discovery!



Ref: https://www.spec2000.net/09-coremethods.htm



Ref: Hydrocarbon exploration and production, Jahn et al.

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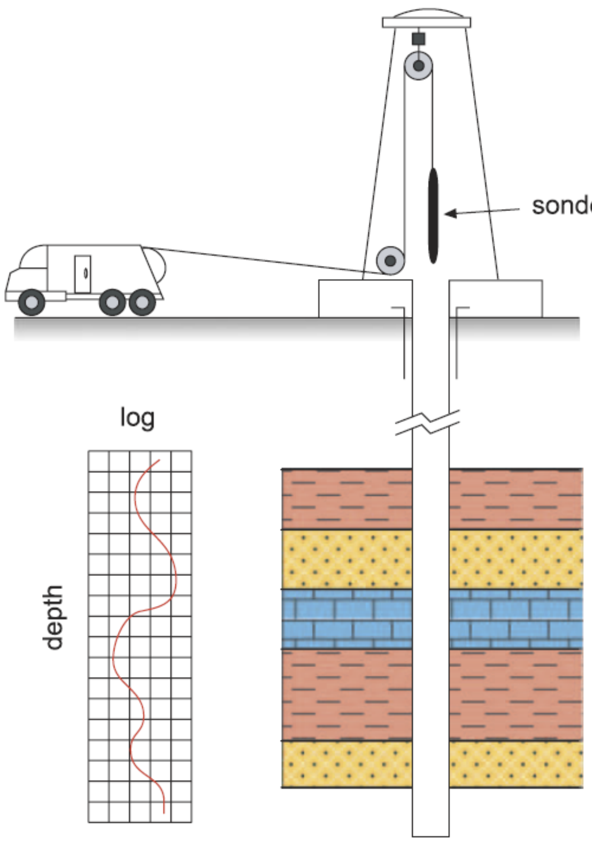

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IDENTIFICATION OF BUSINESS CASE - TASKS

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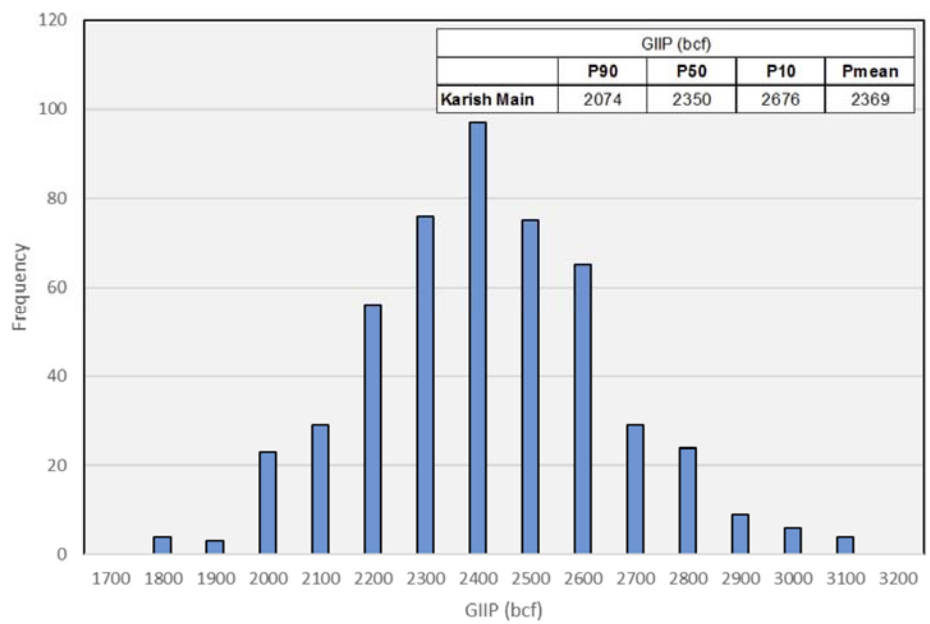
- Discovery!

https://www.youtube.com/watch?v=Qd7F8T0IVXU

IDENTIFICATION OF BUSINESS CASE - TASKS

- Assessment of the discovery and the associated uncertainty. Risk management:
  - **Probabilistic reserve estimation.** Identify and assess additional segments.



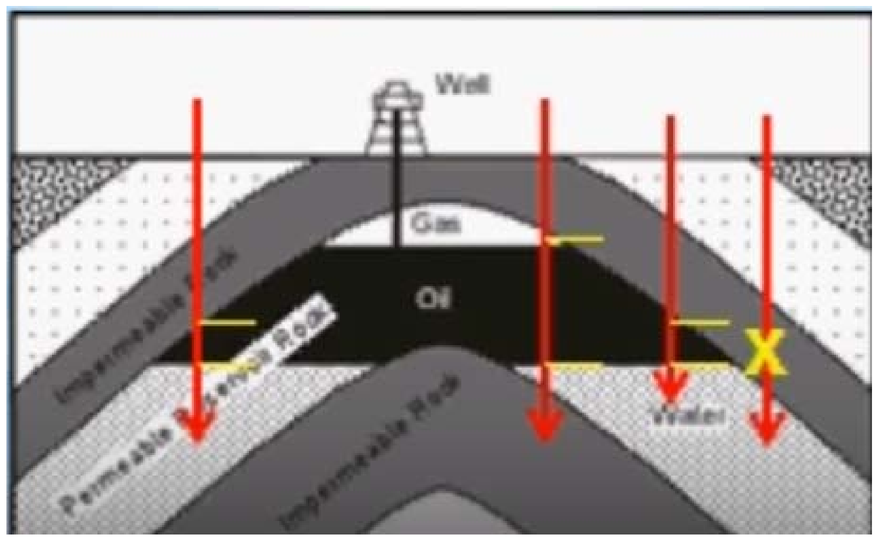
Ref: PDO Karish and Tanin. Energean

IDENTIFICATION OF BUSINESS CASE - TASKS

- Assessment of the discovery and the associated uncertainty. Risk management:
  - **Probabilistic reserve estimation.** Identify and assess additional segments.
  - Perform **simplified economic valuation** of the resources.
  - Field **appraisal** to reduce uncertainty: more exploration wells and seismic to determine for example: fault communication, reservoir extent, aquifer behavior, location of water oil contact or gas oil contact.

IDENTIFICATION OF BUSINESS CASE - TASKS

- Appraisal

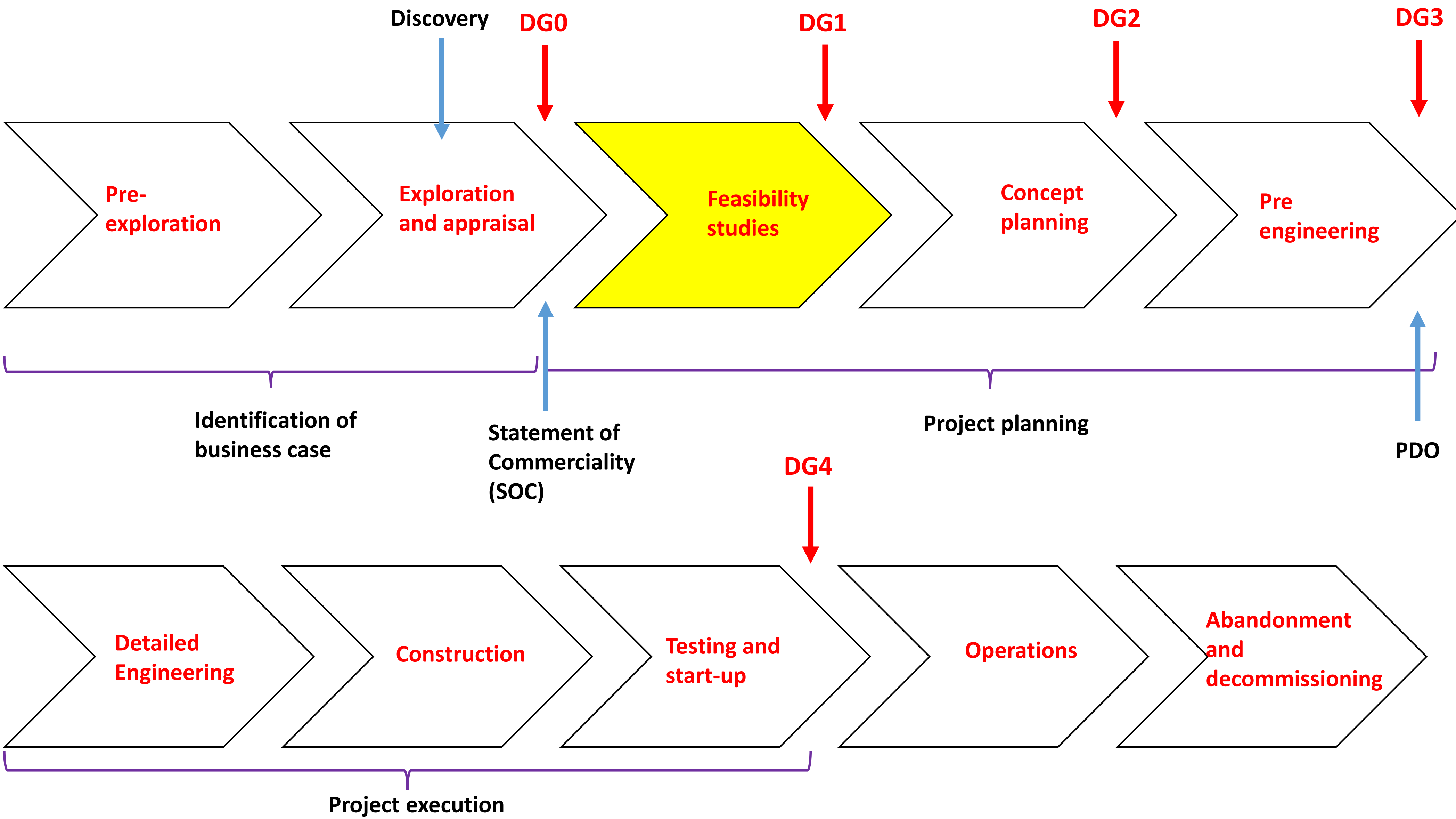


Ref: https://www.youtube.com/watch?v=-e9jjnsquGI

IDENTIFICATION OF BUSINESS CASE - TASKS

DG0:

- Issue a SOC (Statement of Commerciality) and proceed with development.
- Continue with more appraisal
- Sell the discovery.
- Do nothing (wait)
- Relinquish to the government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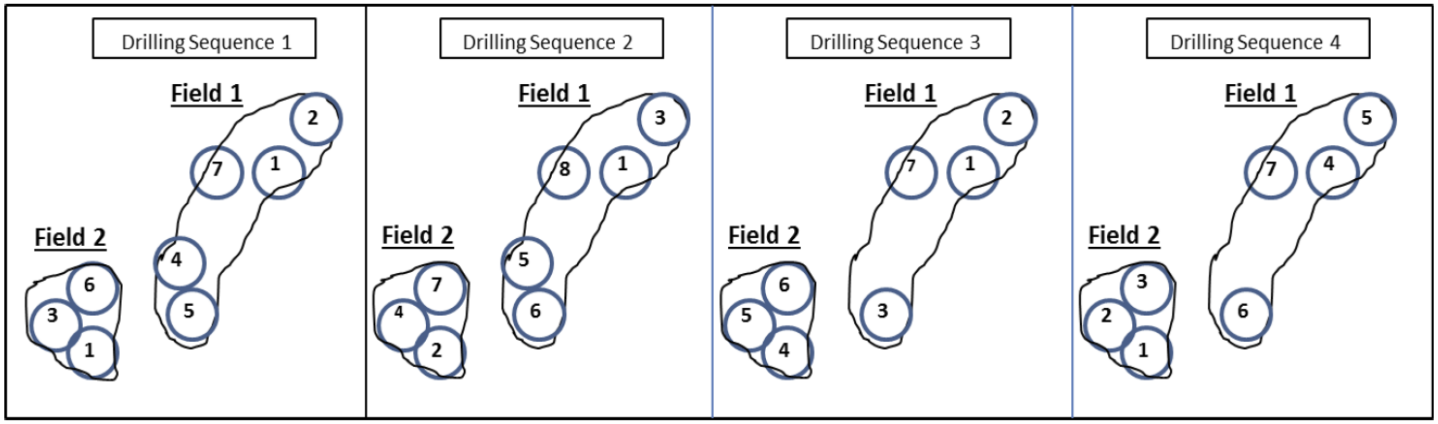
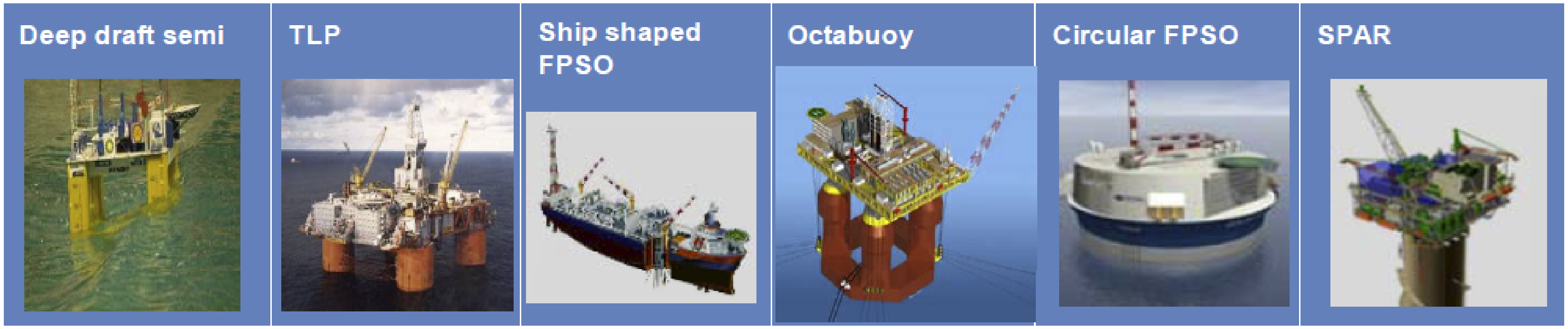
FEASIBILITY STUDIES - TASKS

OBJECTIVE: Justify further development of the project, finding one or more concepts that are technically, commercially and organizationally feasible

- Define objectives of the development in line with the corporate strategy.
- Establish feasible development scenarios.
- Create a project timeline and a workplan.

FEASIBILITY STUDIES - TASKS

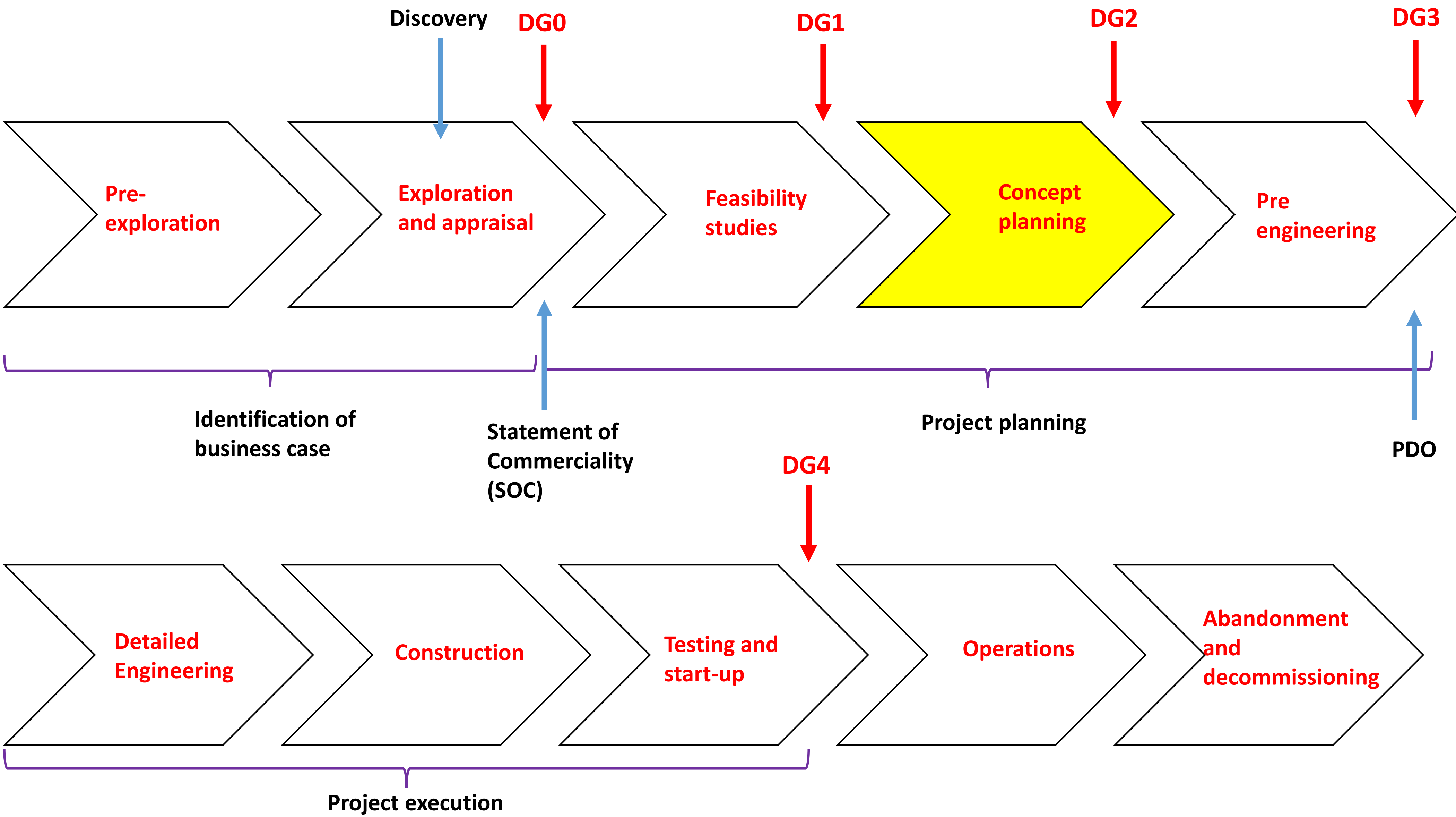




Ref: UTC 2017, Strategies, methods and tools for development of subsea fields, Skogvang and Løken.

FEASIBILITY STUDIES - TASKS

- Identify possible technology gaps and blockers.
- Identify the needs for new technology.
- Identify added value opportunities.
- Cost evaluation for all options (at this stage, cost figures are ±40% uncertain)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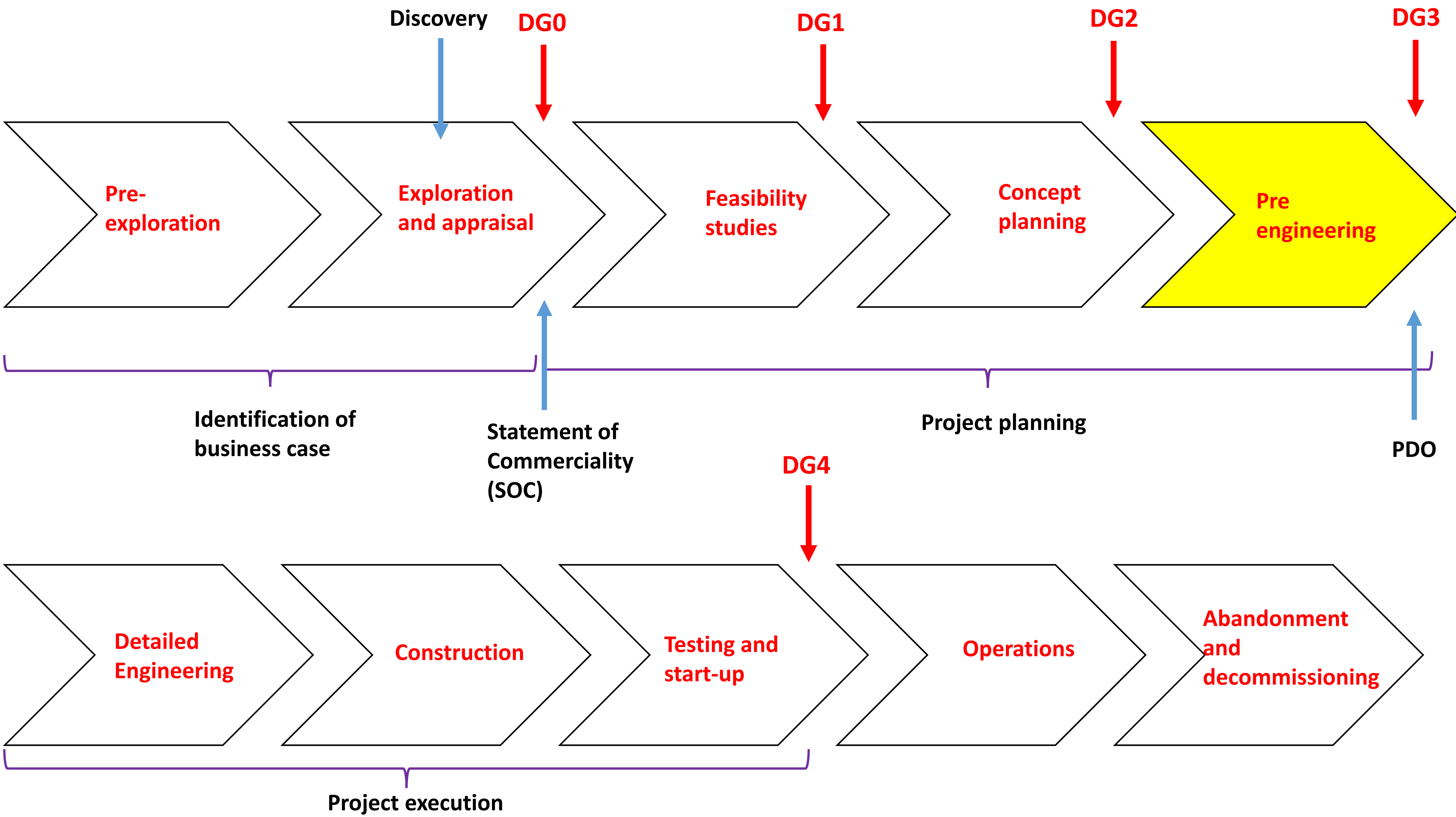
CONCEPT PLANNING - TASKS

OBJECTIVE: Identify development concepts, rank them and select and document a viable concept (Base Case Scenario).

- Evaluate and compare alternatives for development and screen out non-viable options.
- Elaborate a Project Execution Plan (PEP) which describes the project and management system.
- Define the commercial aspects, legislation, agreements, licensing, financing, marketing and supply, taxes.

CONCEPT PLANNING - TASKS

- Create and refine a static and a dynamic model of reservoir. **Define the depletion and production strategy.**
- Define an HSE program
- **Flow assurance evaluation.** Identification of challenges related with fluid properties, multiphase handling and driving pressure.
- Drilling and well planning
- Pre-design of facilities
- Planning of operations, start-up and maintenance
- Cost and manpower estimates of the best viable concept.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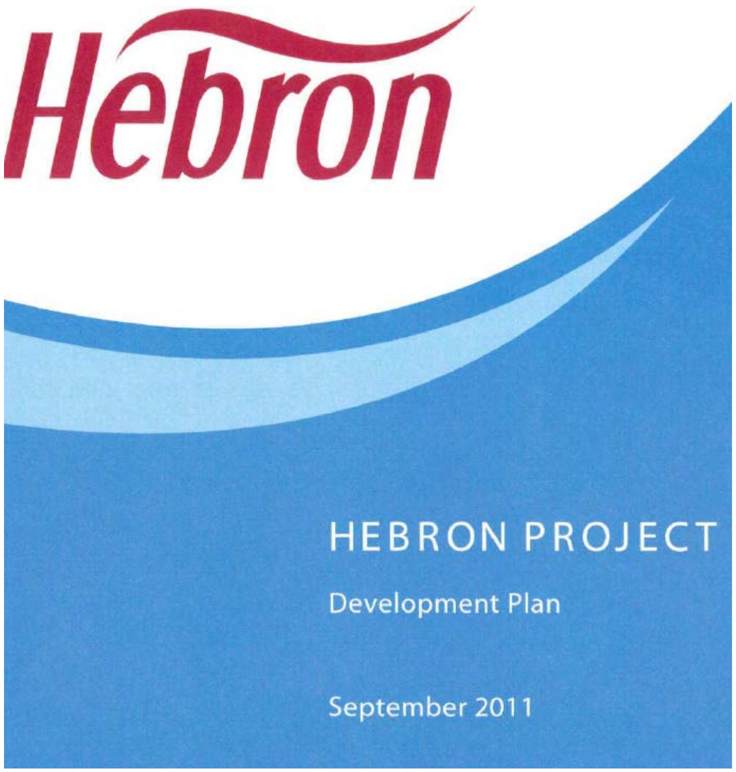
PRE-ENGINEERING - TASKS

OBJECTIVE: Further mature, define and document the development solution based on the selected concept.

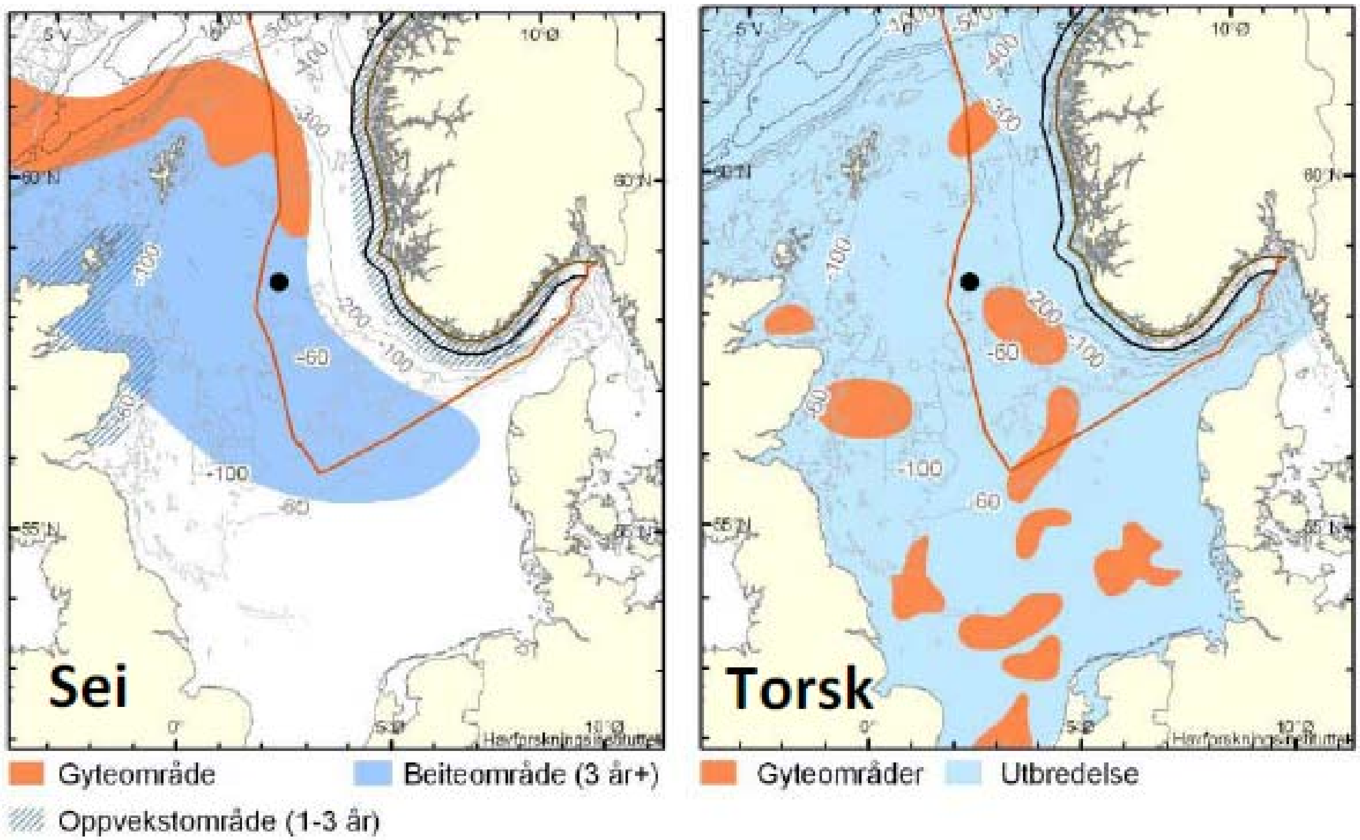
- Selection of the final technical solution. Decide and define all remaining critical technical alternatives.
- Execute Front End Engineering Design (FEED) Studies: determine technical requirements (arranged in packages) for the project based on the final solution chosen. Estimate cost of each package.
- Plan and prepare the execution phase.

PRE-ENGINEERING - TASKS

- Prepare for submission of the application to the authorities.
- Perform the Environmental impact assessment.
- Establish the basis for awarding contracts.
- Issue:
  - Plan for development and operations
  - Plan for installation and operations of facilities for transport and utilization of petroleum (PIO)
  - Impact assessment report

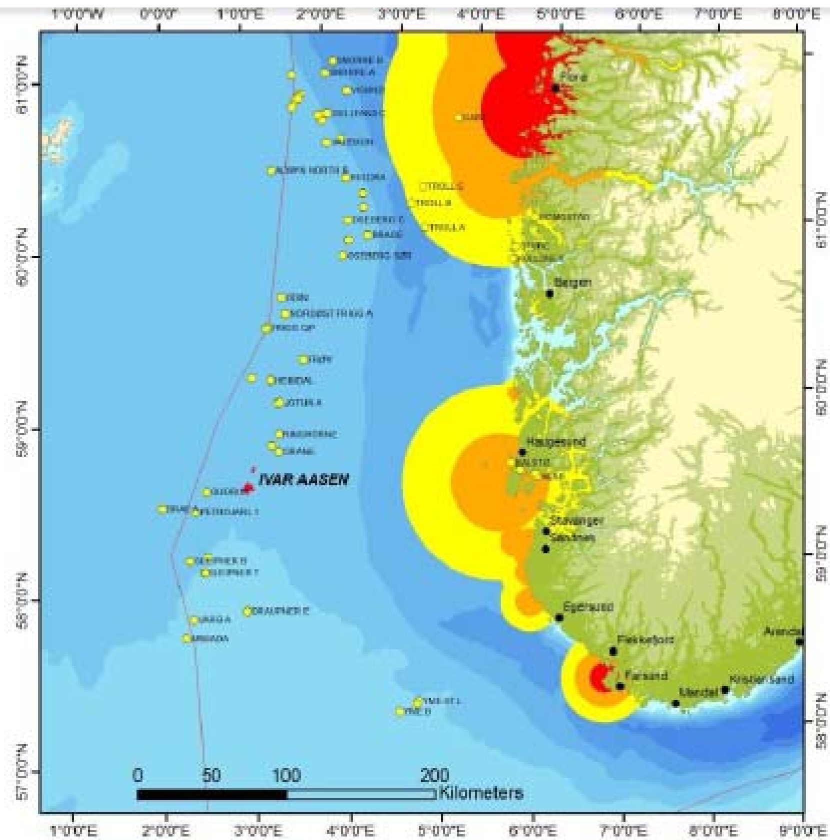


PRE-ENGINEERING - TASKS



Ref: PDO Ivar Aasen. Det Norske

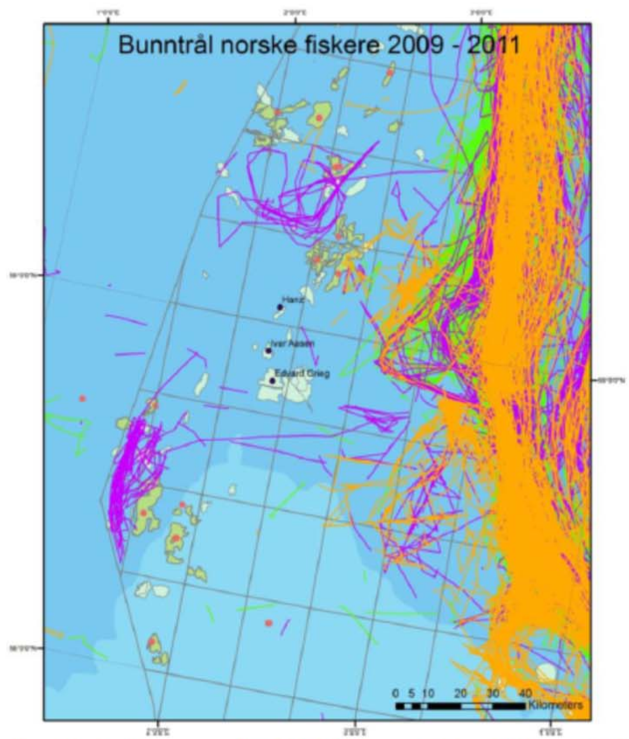
PRE-ENGINEERING - TASKS



Figur 18. Svært viktige (rød), viktige (oransje) og nokså viktige (gule) leveområder for sjøfugl langs kysten av Nordsjøen i hekketiden. Kartet markerer buffersoner rundt de viktige hekkelokalitetene (NINA)

Ref: PDO Ivar Aasen. Det Norske

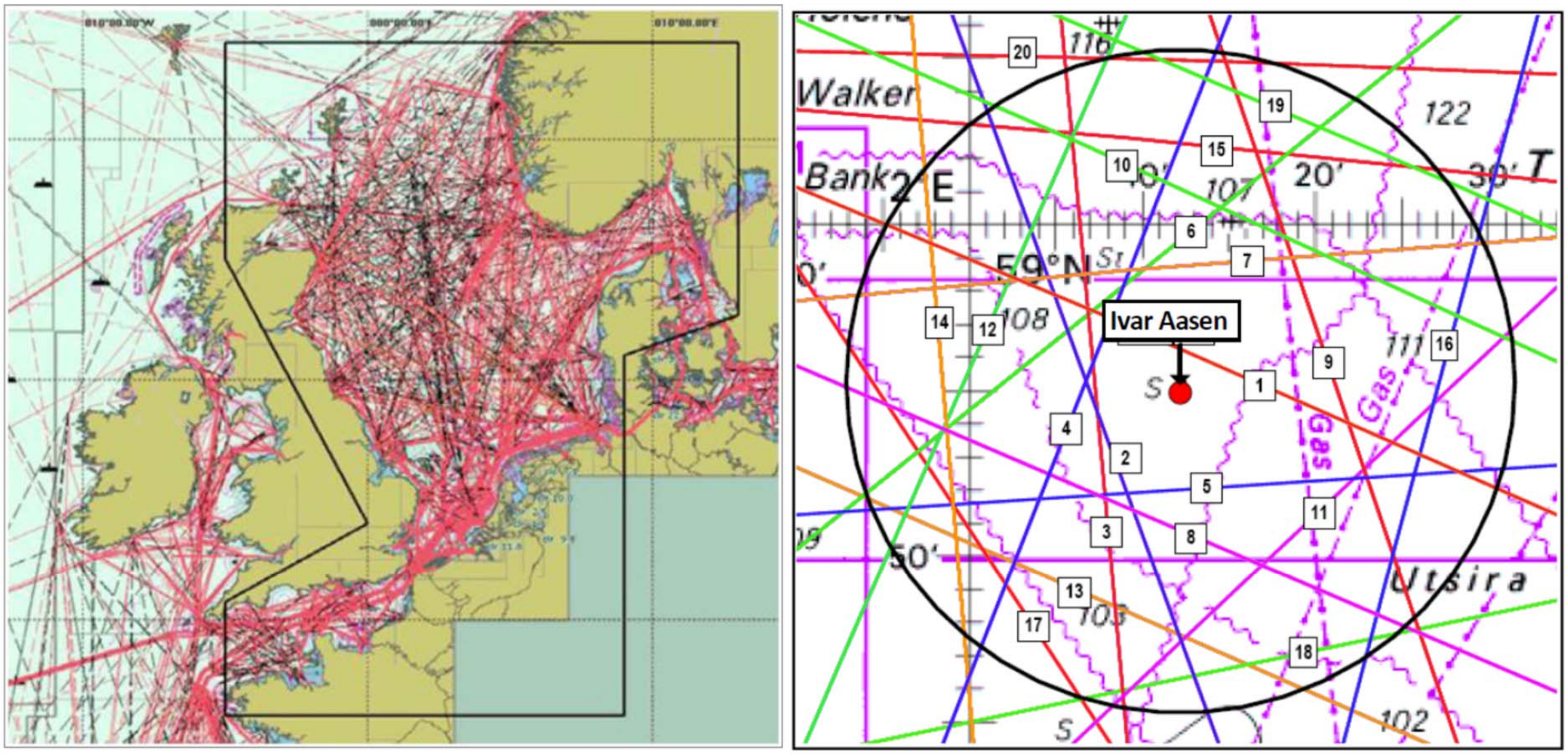
PRE-ENGINEERING - TASKS



Figur 23. Registrert norsk fiskeriaktivitet med bunntrål i området omkring Aasen i 2009 (grønn), 2010 (fiolett) og 2011 (oransje). Figur utarbeidet på grunnlag av data fra Fiskeridirektoratets satellittsporing av større fiskefartøyer

Ref: PDO Ivar Aasen. Det Norske

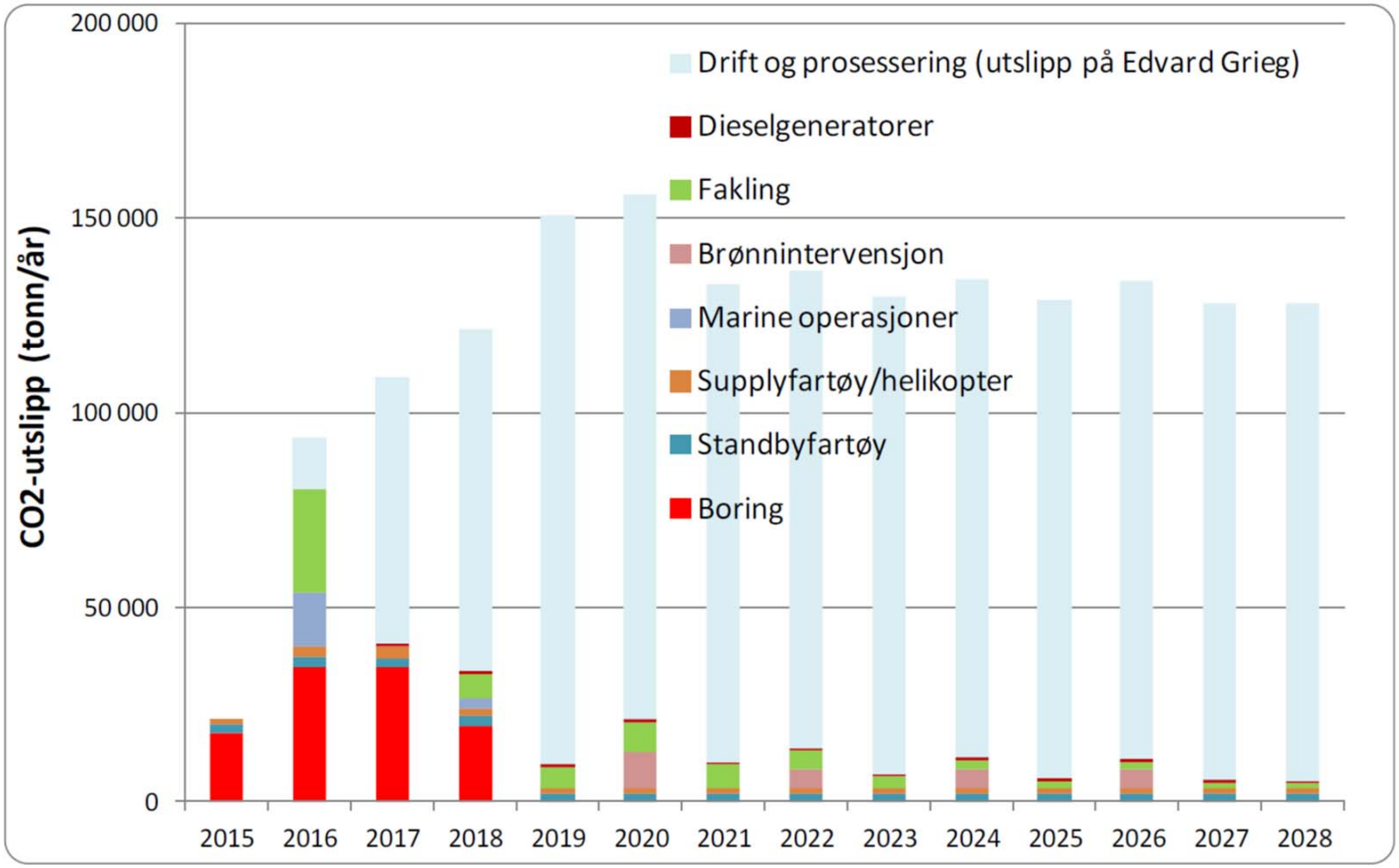
PRE-ENGINEERING - TASKS



Figur 24. Trafikkompleksitet i Nordsjøen (venstre) og skipsleder for handels- og offshorefartøy innenfor en radius på 10 nautiske mil fra Aasen (høyre)

Ref: PDO Ivar Aasen. Det Norske

PRE-ENGINEERING - TASKS



Figur 25. Samlede utslipp av CO_2 fra Aasenfeltet i perioden 2015 – 2028

Ref: PDO Ivar Aasen. Det Norske

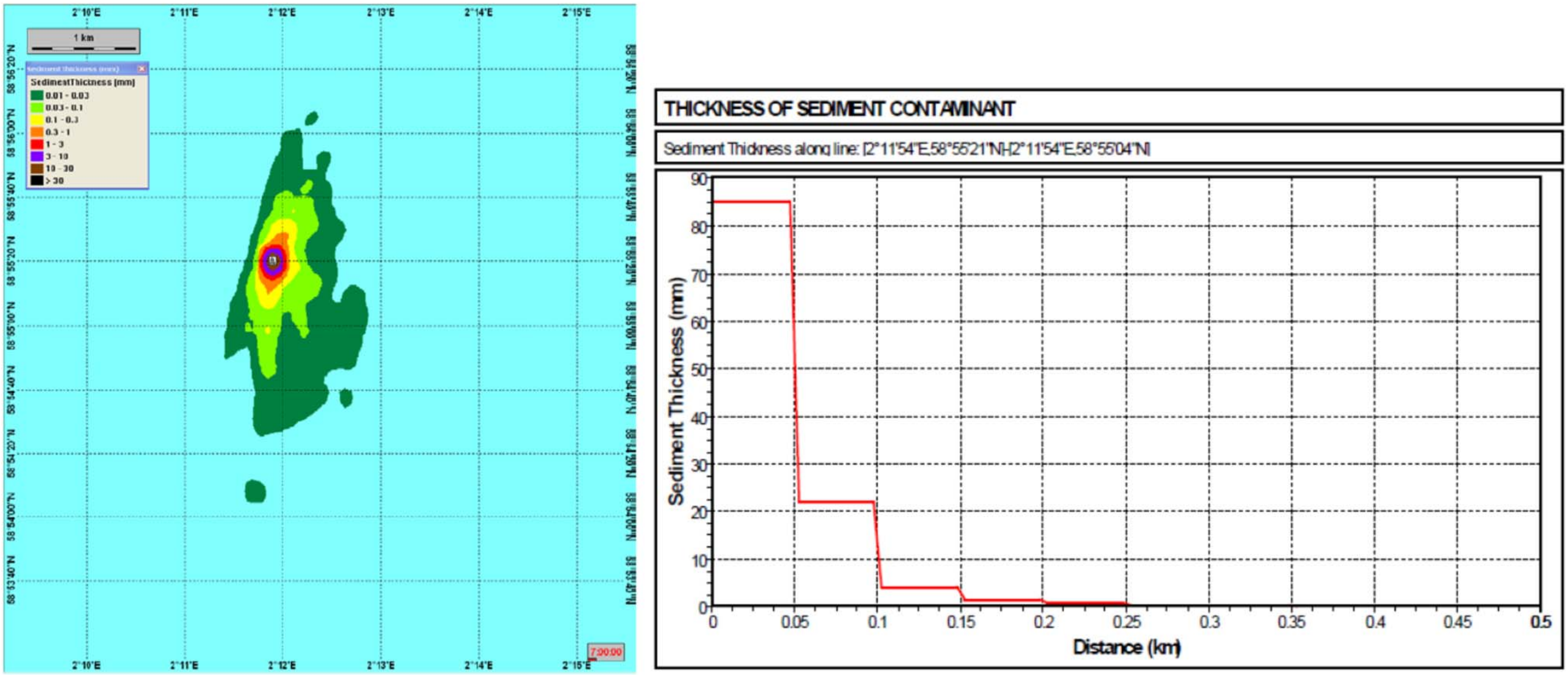
PRE-ENGINEERING - TASKS

Tabell 5-1. Foreløpig oversikt over estimerte mengder kaks for typiske produksjonsbrønner på Aasen, West Cable og Hanz

Seksjon	Borevæske	Boret lengde (m)			Mengde borekaks (tonn)		
		Aasen	**West Cable**	**Hanz**	**Aasen**	**West Cable**	**Hanz**
36”	WBM	88	88	86	70	70	70
26”	WBM	370	370	400	150	150	160
17 ½”	OBM	1 550	1 020	990	310	205	200
12 ¼”	OBM	860	3 890	1 700	90	390	170
8 ½”	OBM	1 390	1 530	90	70	80	5
SUM (avrundet)		**4 300**	**6 900**	**3 300**	**690**	**895**	**605**
SUM WBM kaks					**220**	**220**	**230**
SUM OBM kaks					**470**	**675**	**375**

Ref: PDO Ivar Aasen. Det Norske

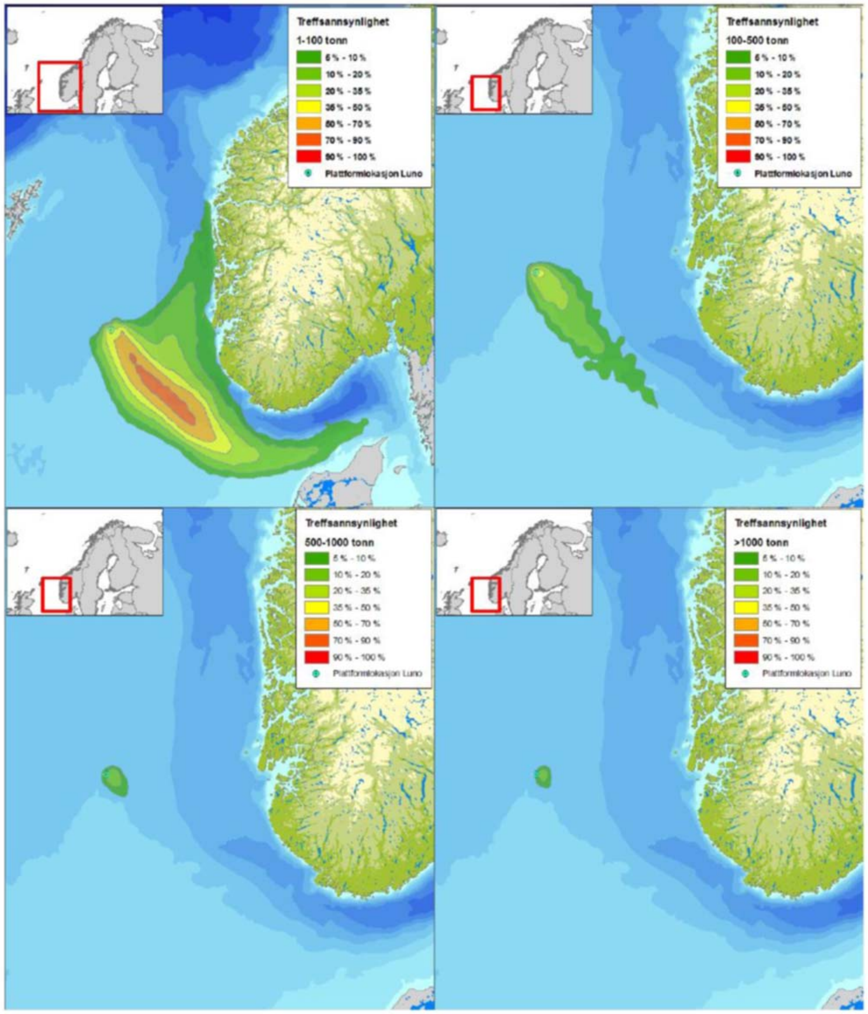
PRE-ENGINEERING - TASKS



Figur 29. Sedimentering ved utslipp av vannbasert kaks ved havbunnen (sommersituasjon)

Ref: PDO Ivar Aasen. Det Norske

PRE-ENGINEERING - TASKS

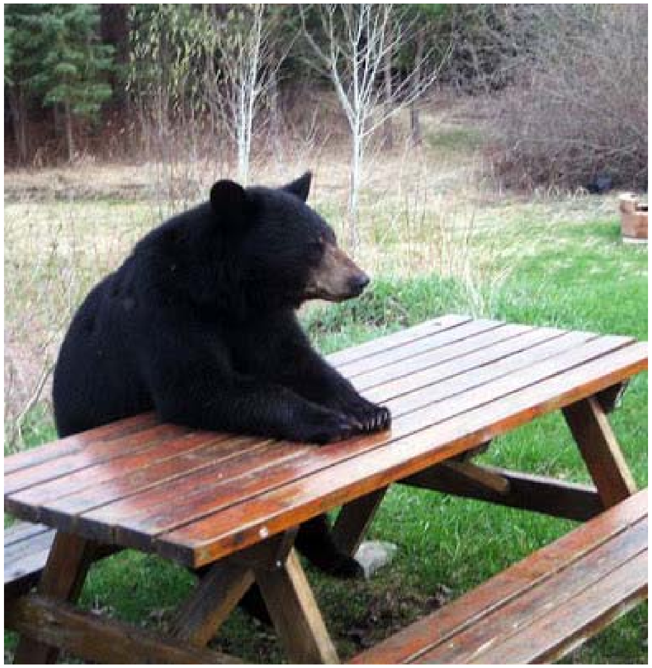


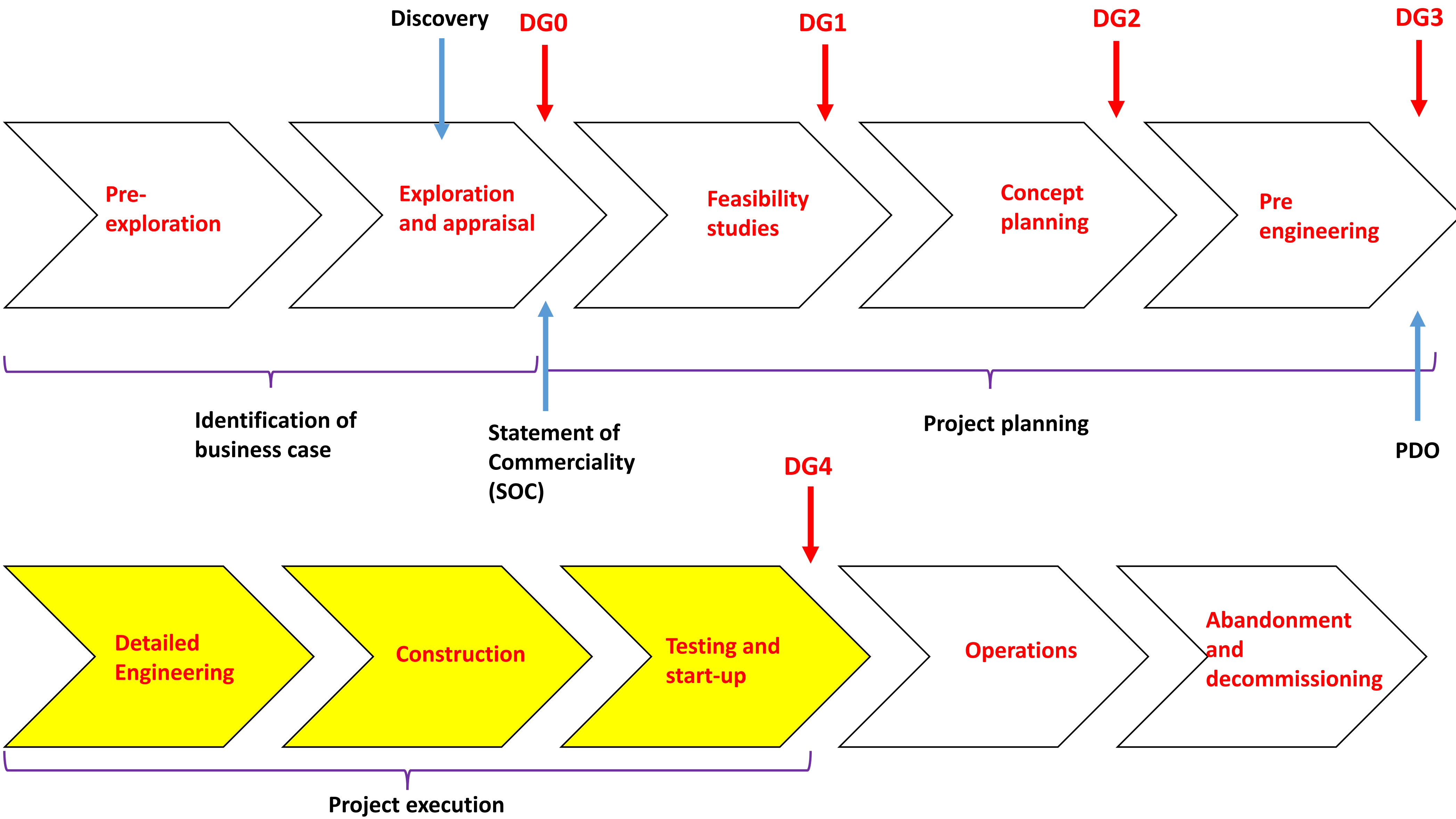
Figur 37. Sannsynligheten for treff av ulike mengdekategorier av olje i 10 × 10 km ruter gitt en sjøbunnsutblåsning fra Aasen/Grieg (helårsstatistikk). Influensområdet er basert på alle utslippsrater og varigheter og deres individuelle sannsynligheter. Merk at det markerte området ikke viser omfanget av et enkelt oljeutslipp, men er det området som berøres i mer enn 5 % av enkeltsimuleringene av oljens drift og spredning (Lundin 2011).

Ref: PDO Ivar Aasen. Det Norske

PRE-ENGINEERING - TASKS

- Wait for the government to study the proposal




Discovery
DG0
DG1
DG2
DG3
Pre-exploration
Exploration and appraisal
Feasibility studies
Concept planning
Pre engineering
Identification of business case
Statement of Commerciality (SOC)
Project planning
PDO
DG4
Detailed Engineering
Construction
Testing and start-up
Operations
Abandonment and decommissioning
Project execution

DETAILED ENGINEERING, CONSTRUCTION, TESTING AND STARTUP

OBJECTIVE: Detailed design, procurement of the construction materials, construction, installation and commissioning of the agreed facilities.

Individual contracts

- Detailed engineering
- Bids, contracts
- Construction, fabrication
- Installation
- Commissioning (Cold or Hot)

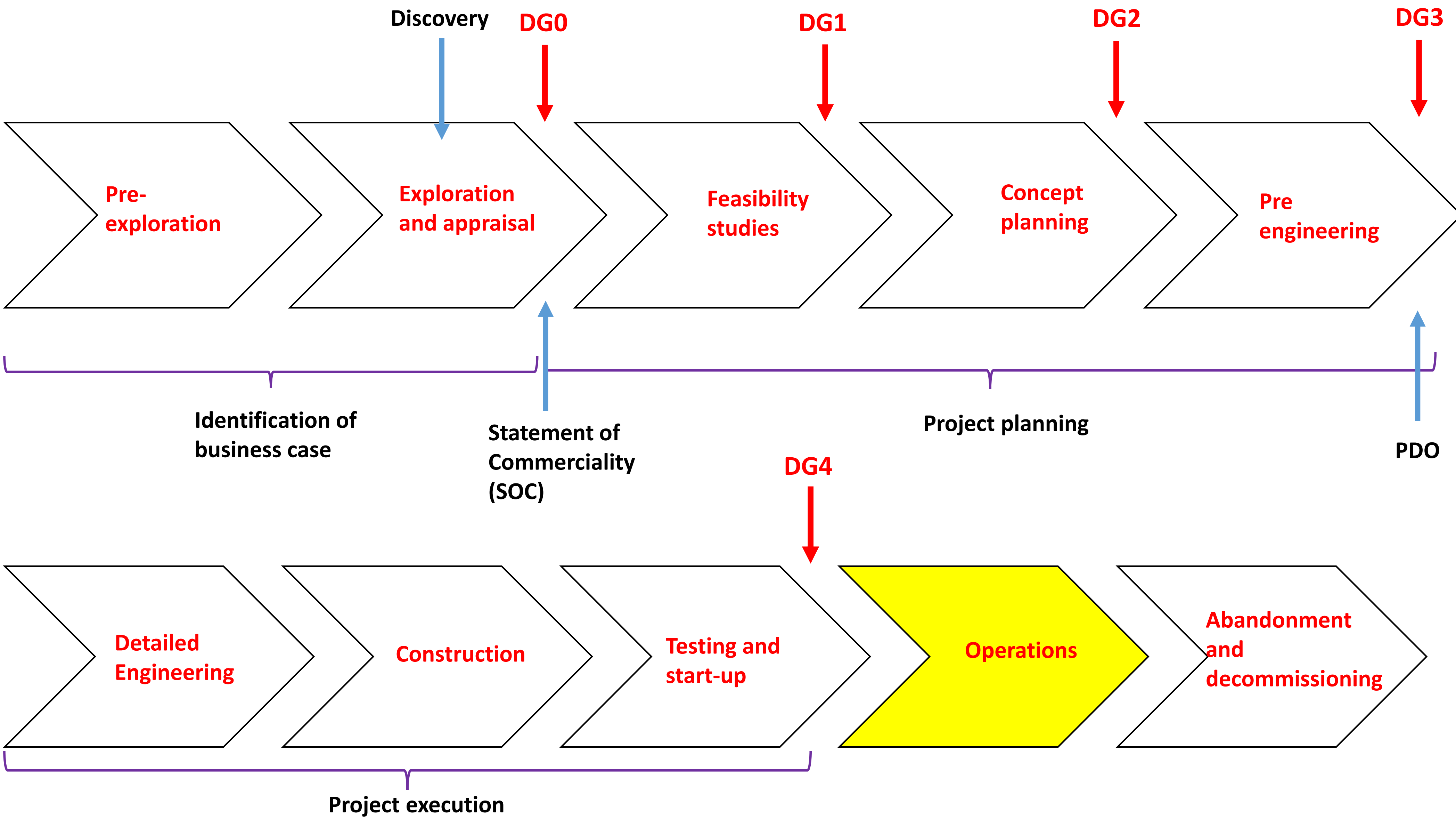
EPCM (Engineering, procurement, construction, and management contract) with one main contractor.

https://www.youtube.com/watch?v=TzLAfzhqVHc

https://www.youtube.com/watch?v=TiWOgTq0YD4

DETAILED ENGINEERING, CONSTRUCTION, TESTING AND STARTUP

- Constructing wells.
- Perform hand over to asset, operations
- Prepare for start-up, operation and maintenance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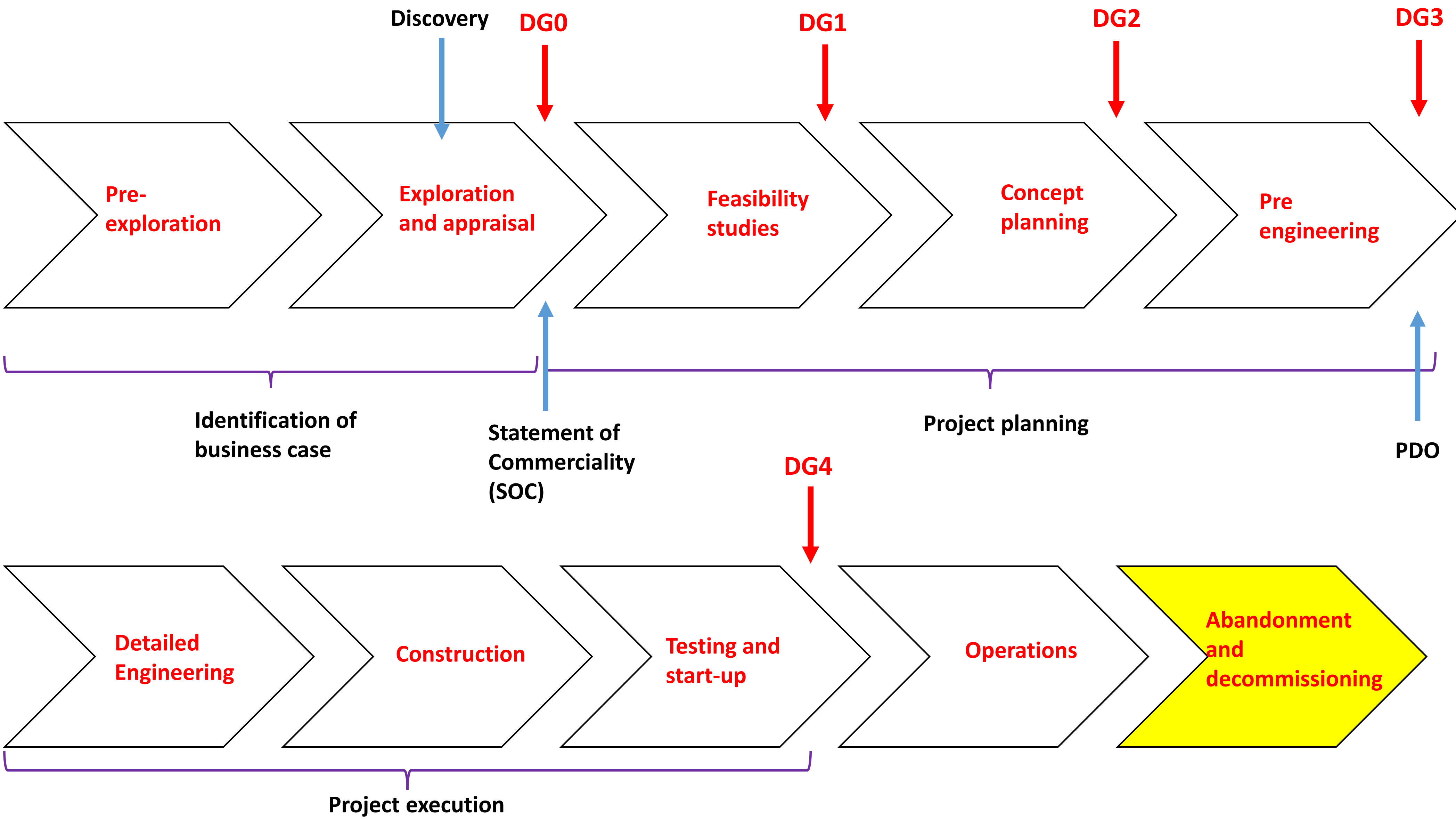
Operations
Abandonment and decommissioning
Project execution

OPERATIONS

- Production startup, Build-up phase, Plateau phase, Decline phase, Tail production, Field shut-down.
- Maintenance.
- Planning Improved Oil recovery methods.
- Allocation and metering.
- De-bottlenecking.
- Troubleshooting.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Operations
Abandonment and decommissioning
Project execution

DECOMISSIONING AND ABANDONMENT

- Engineering “down and clean”: flushing and cleaning tanks, processing equipment, piping.
- Coordinate with relevant environmental and governmental authorities.
- Well plugging and abandonment (P&A)
- Cut and remove well conductor and casing.
- Remove topside equipment.

DECOMISSIONING AND ABANDONMENT

- Removal of the offshore structure: Lifting operations and transport
- Remove or bury subsea pipelines
- Mark and register leftover installations on marine maps
- Monitoring
- Recovery of material: Scrap (steel) and recycling equipment (Gas turbines, separators, heat exchangers, pumps, processing equipment)
- Disposal of residues

DECOMISSIONING AND ABANDONMENT

https://www.youtube.com/watch?v=SLO9uD5Ub_Y

DECOMISSIONING AND ABANDONMENT

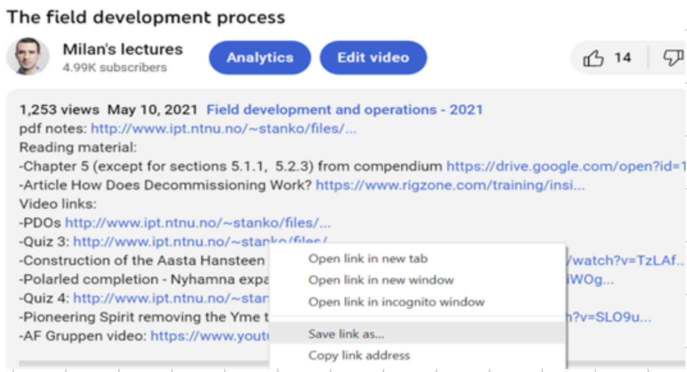
https://www.youtube.com/watch?v=1GA3EIu81rw

Class 17.01.2023

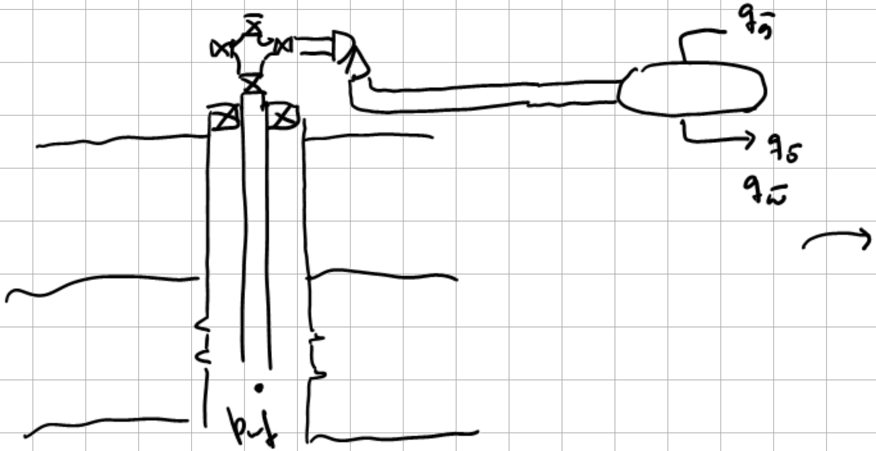
-Remember to register to visit to Verdal
-Missing 1 member of reference group -> will be picked randomly from the student list
-Revisiting quizzes 1-3 (group work)
-Do quiz 4 by yourselves!

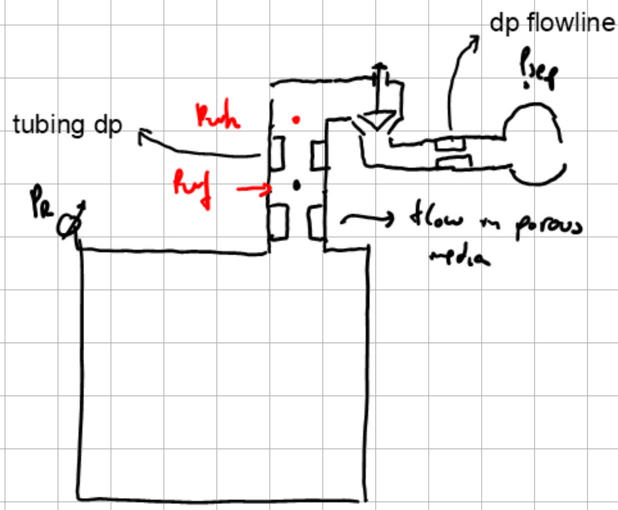
-How to open files provided in Youtube video comments:

right click on link --> "Save as"

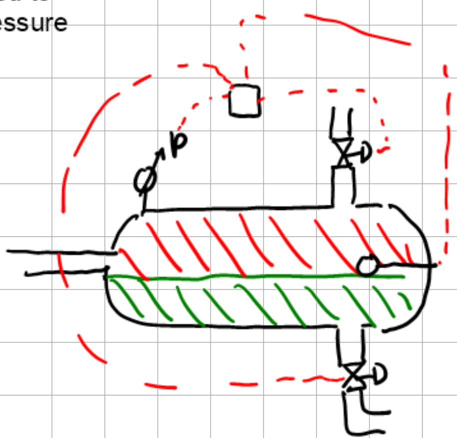


-Mechanical analog of production system





Control system used to keep separator pressure constant

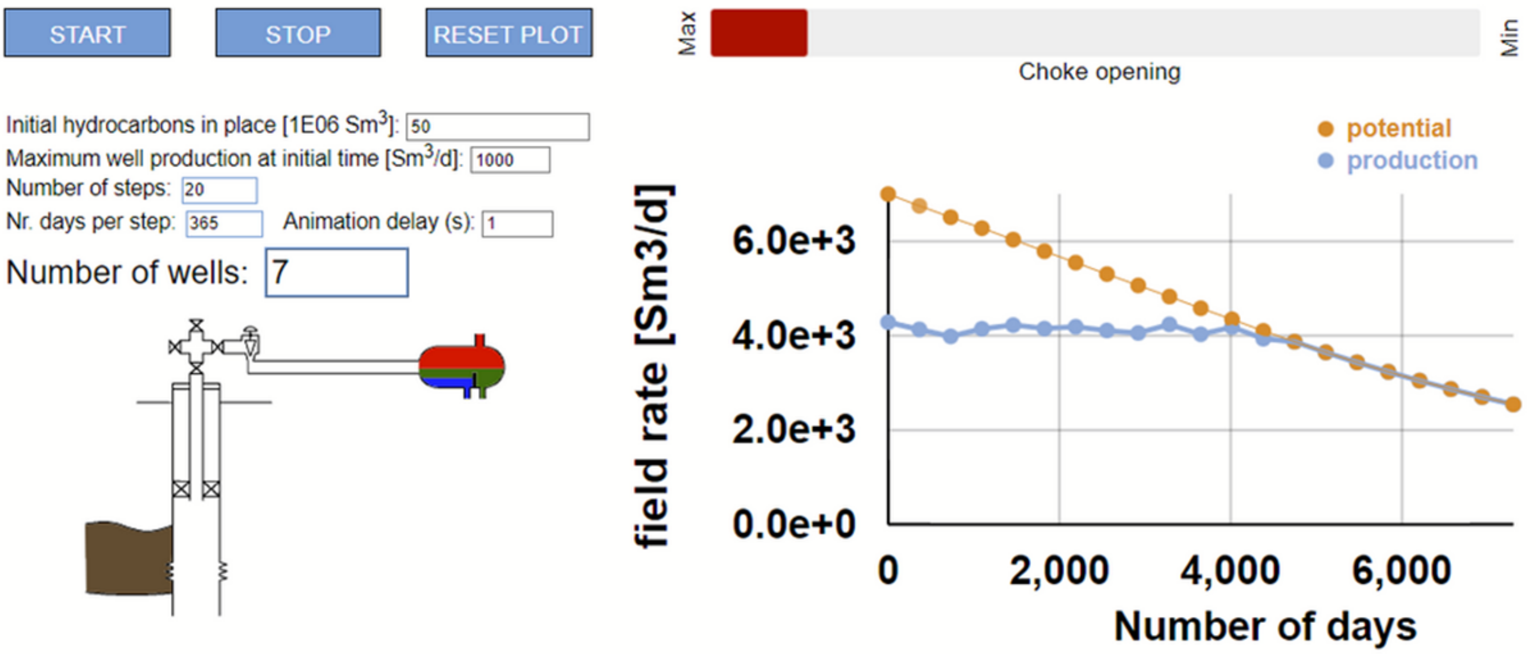


-The flow through the system is dictated by the difference in pressure between reservoir and separator (higher pR-psep gives higher rate and lower pR-psep gives lower rate)
-The pR-psep will be reduced with time due to decline of pR. psep usually remains constant
-The adjustable choke is used to add additional pressure drop to reduce the rate

Play with the Field simulator:
http://www.ipt.ntnu.no/~stanko/Field_Simulator_2.html

Takeaways:
-It is necessary to gradually open the choke to maintain the field rate constant
-Higher plateau rate gives shorter plateau
-Lower plateau rate gives longer plateau
-Plateau ends when the choke is fully open
-Plateau can be extended by adding more wells after the choke is fully open (but it is expensive!!)

Do the quiz!:
http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/2022/Quizzes/Quiz%20Field%20Simulator%202.html



Field development and operations - Quiz Field simulator 2

Use the field simulator to answer the following questions. To start the simulation, modify the input to the left and then click the button that reads "start". During the simulation, the rate of the field is controlled with the red slider (moving to the right or to the left to open or close the choke respectively) and with the number of wells. To reset the simulator, click on the button "reset plot".

1. Using the default values and varying only the choke opening during the simulation, what is (approx.) the plateau duration if we produce a plateau rate of 4000 Sm3/d? TIP: start the simulation with the well choke slider half open.

- ○ 5000 days
- ○ 6000 days
- ○ 2000 days

2. Using the same settings as in question 1, What is (approx.) the plateau duration for a field rate of 5000 Sm3/d?

- ○ 2000 days
- ○ 4000 days
- ○ 500 days

3. Use the same settings as in question 1, but increase the simulation time to 30 steps. During the simulation, after the choke is fully open, increase gradually the number of wells. How many wells (approx.) in total are needed if one wants the field to produce at a plateau rate of 4000 Sm3/d for at least 6000 days?

- ○ 15
- ○ 21
- ○ 10

Once ready submit here your results:

Submit

Submission message

Your result will appear here!

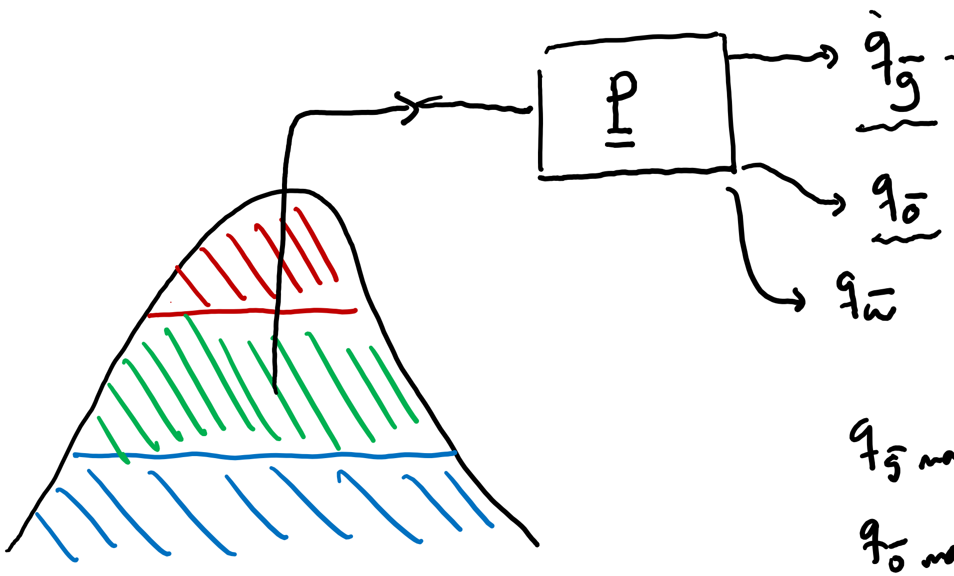
Class 20230120 - OUTLINE

-Bottlenecking

    -Interactive app

    -Heidrun Example

-Introduction to field processing



s.c → $P_{sc} = 1.01325$ bara

$T_{sc} = 15.56\ °C$

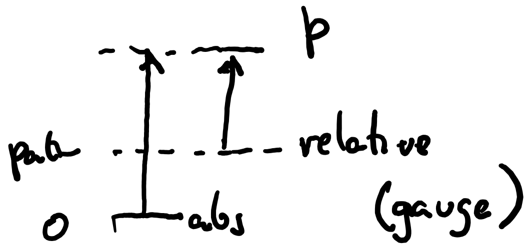
bara

barg

$q_{\bar{g}\,max}$

$q_{\bar{o}\,max}$

$q_{\bar{w}\,max}$



Petroleum components

Non HC
- CO_2
- N_2
- H_2S
- H_2O

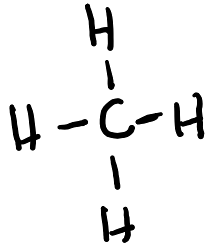
HC
- C_1 } LNG
- C_2
- C_3 } LPG
- C_4
- iC_4
- C_5
- iC_5
- C_6
- ⋮

SCN ↓

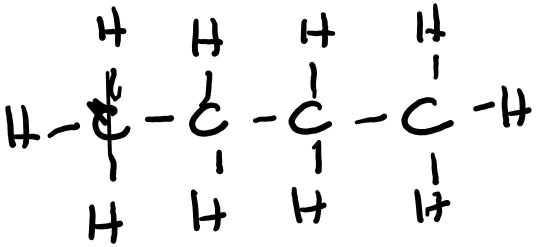
q_g (non HC through iC_4)

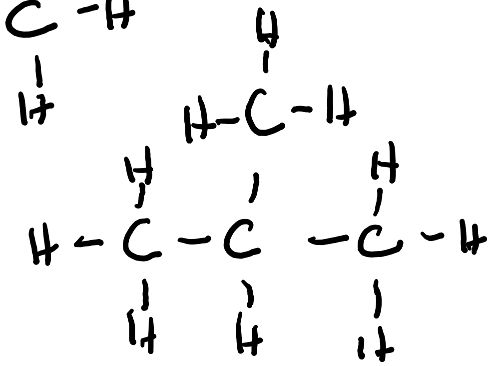
NGL (C_3 through C_5)

q_o (C_4 onward)

CH_4 

ALKANES $C_n H_{2n+2}$





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	⋮
⋮	⋮
	$\Sigma = 1$

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

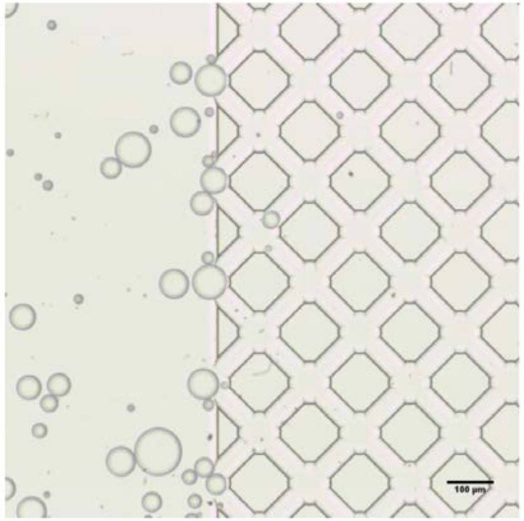
$$x_i, w_i = \frac{\text{mass of component "i"}}{\text{total mass}}$$

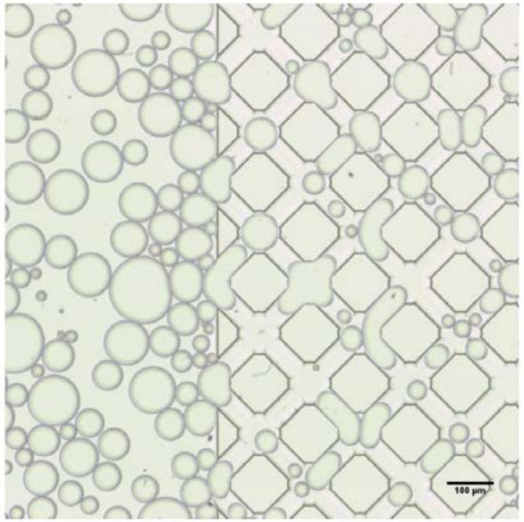
$$w_i = z_i \frac{MW_i}{MW_{mix}}$$

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

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

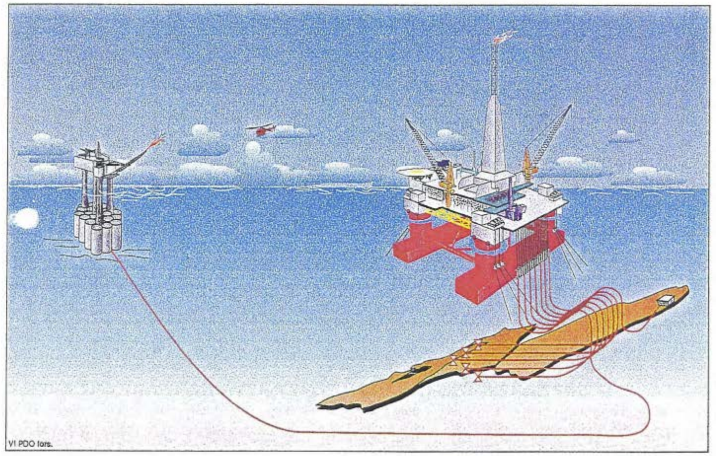
$$q_{\bar{l}} = q_{\bar{o}} + q_{\bar{w}}$$

VISUND

Plan for Development and Operation

PL 120

September 1995



Operator: HYDRO

Partners: STATOIL conoco saga elf

Bottlenecking – play with app

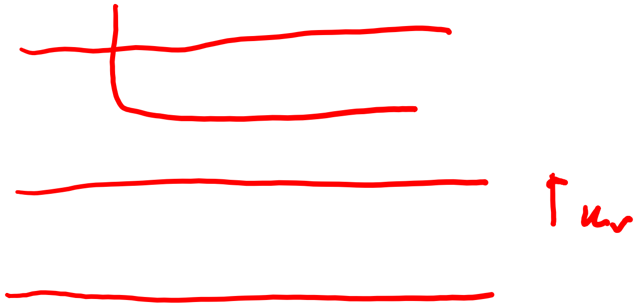
$$WC = \frac{q_{\bar{w}}}{q_{\bar{o}} + q_{\bar{w}}}$$

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

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

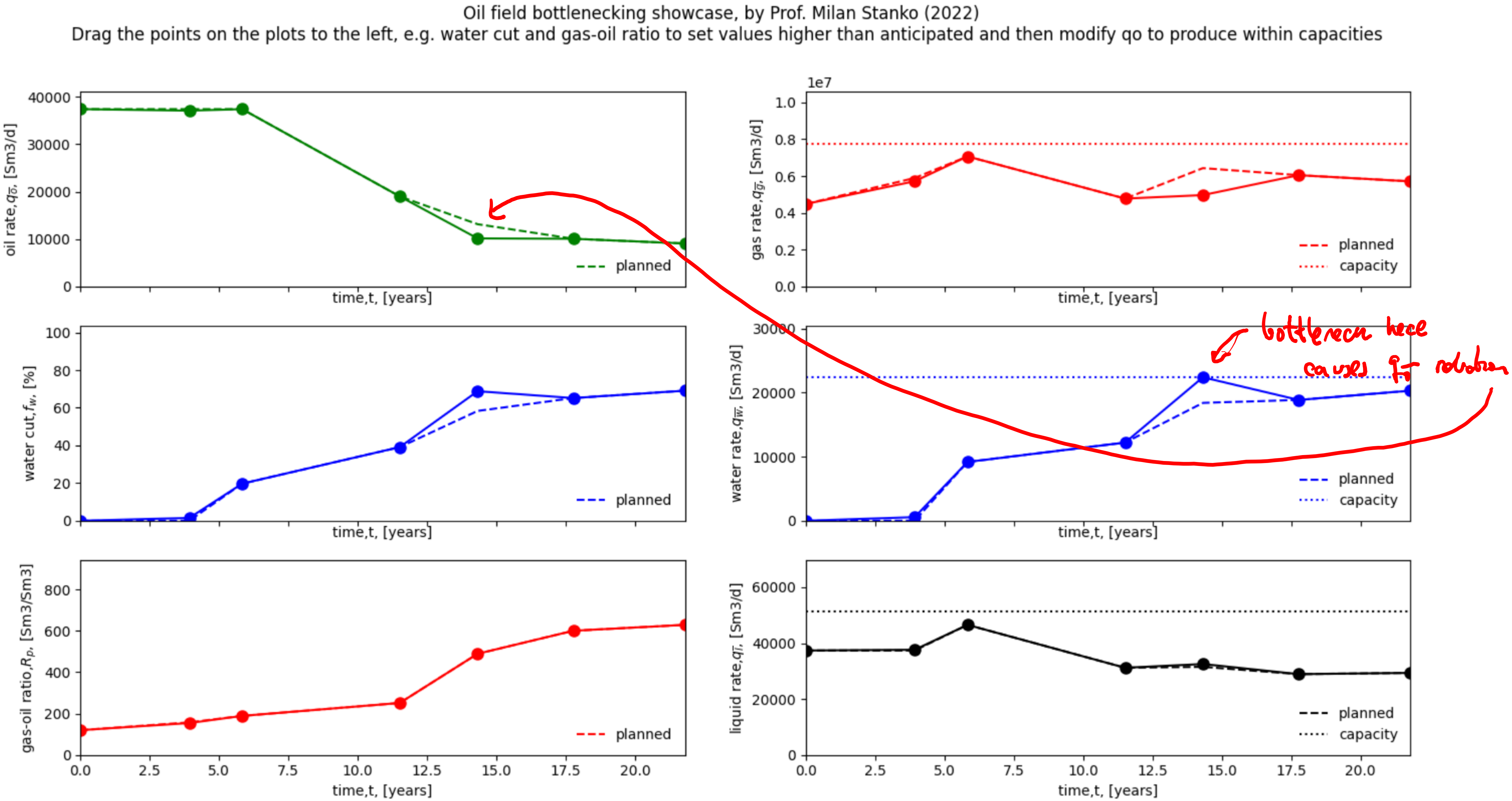
$$q_{\bar{g}} = q_{\bar{o}} \cdot R_p$$

GOR



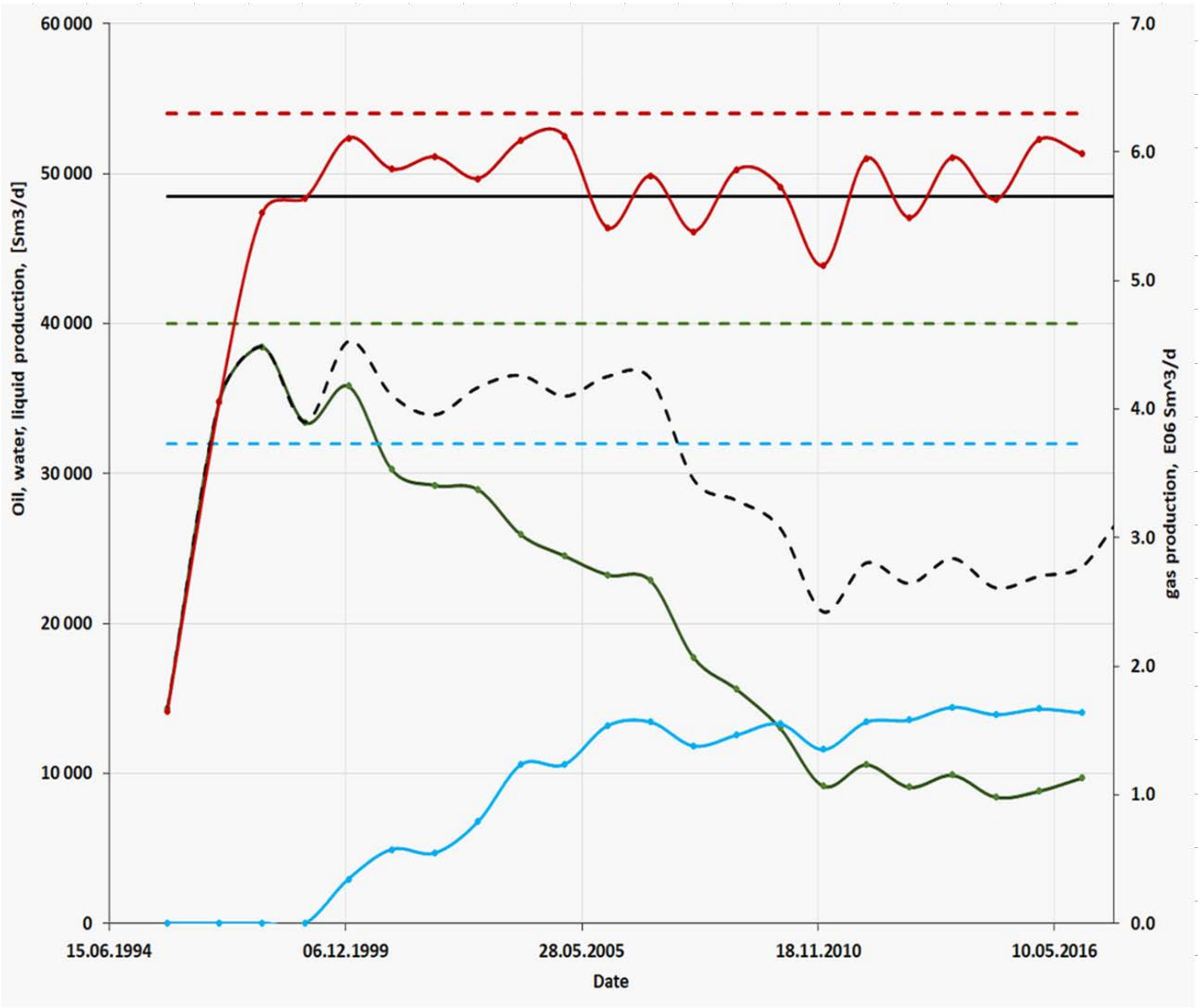
http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/Tools/

Bottlenecking – play with app



Bottlenecking – field example

Bottlenecking – field example

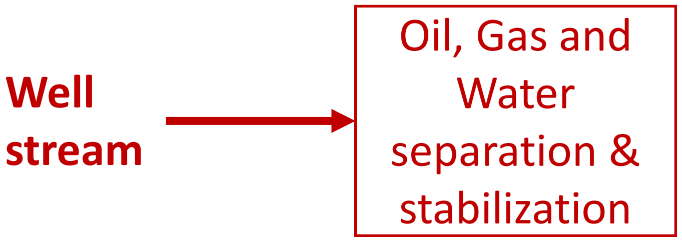


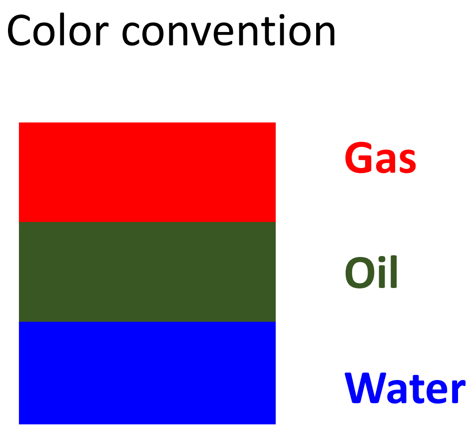
NTNU | Norwegian University of Science and Technology

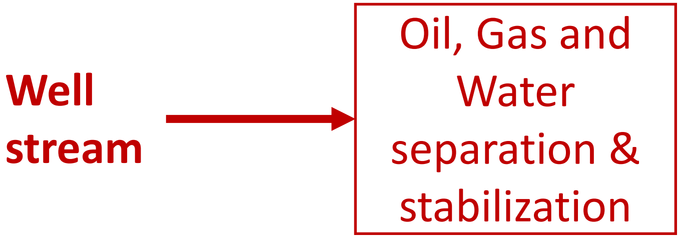
Introduction to oilfield processing

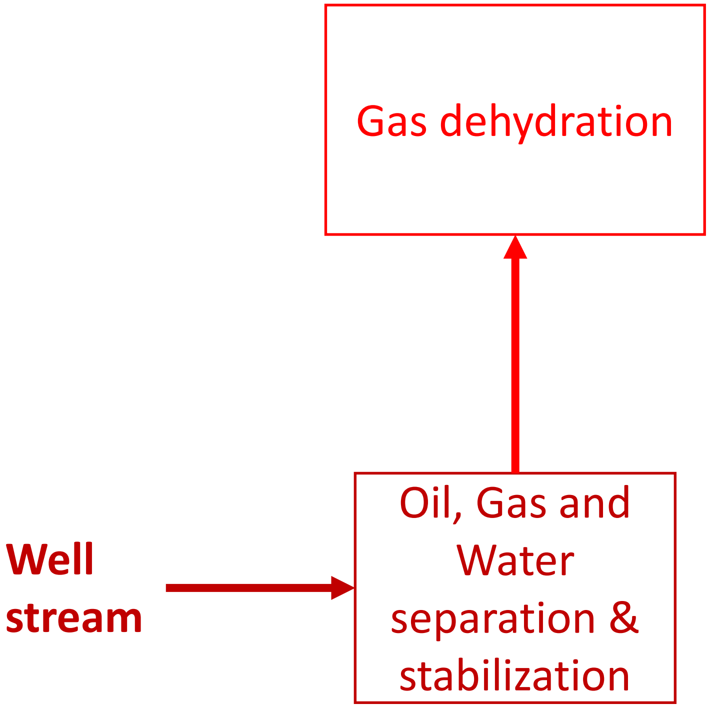
Assoc. Prof. Milan Stanko

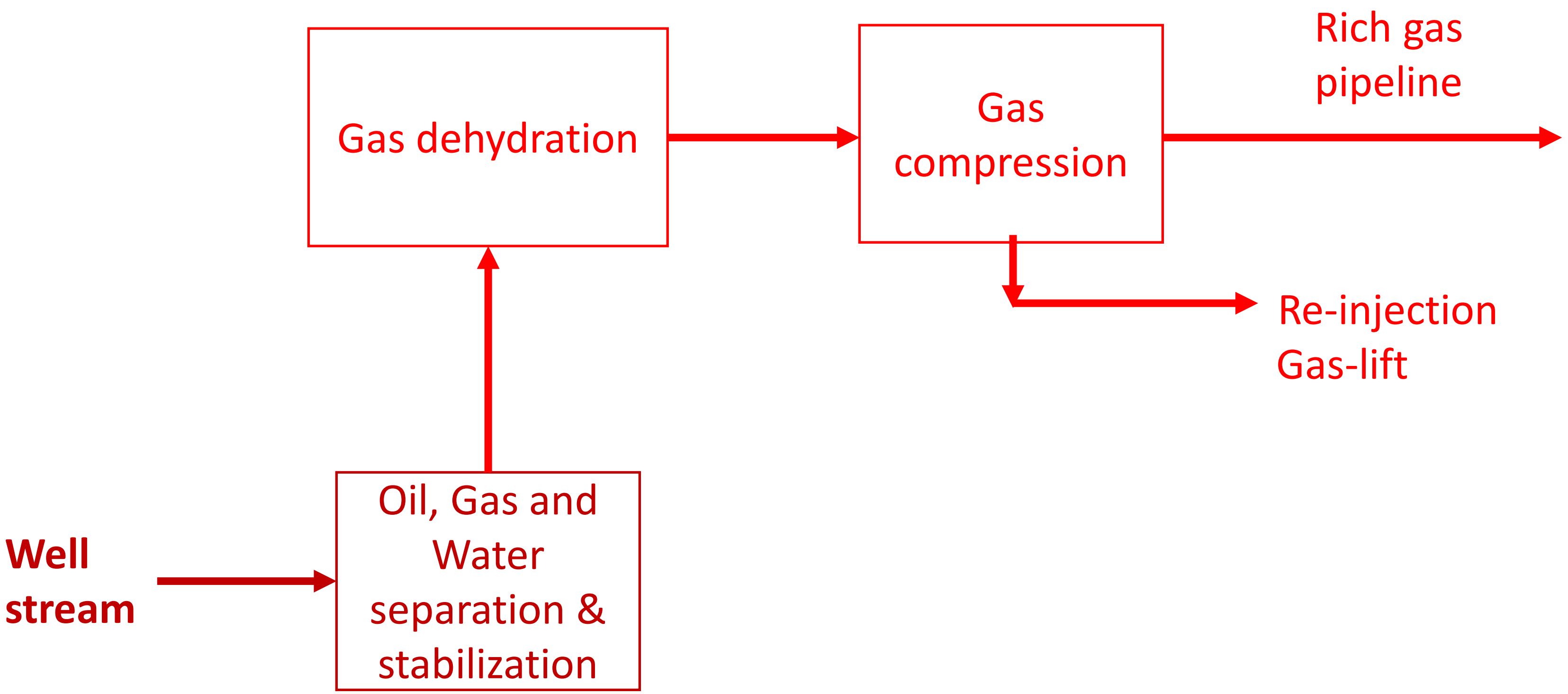
Well stream

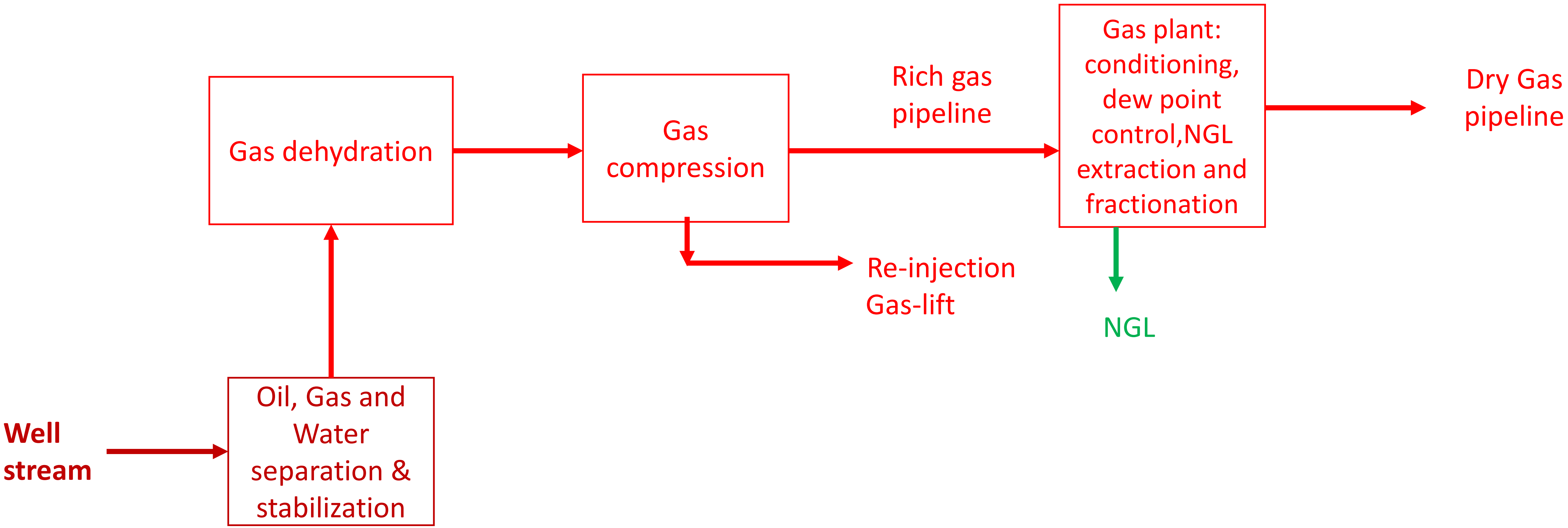

Well stream
Oil, Gas and Water separation & stabilization

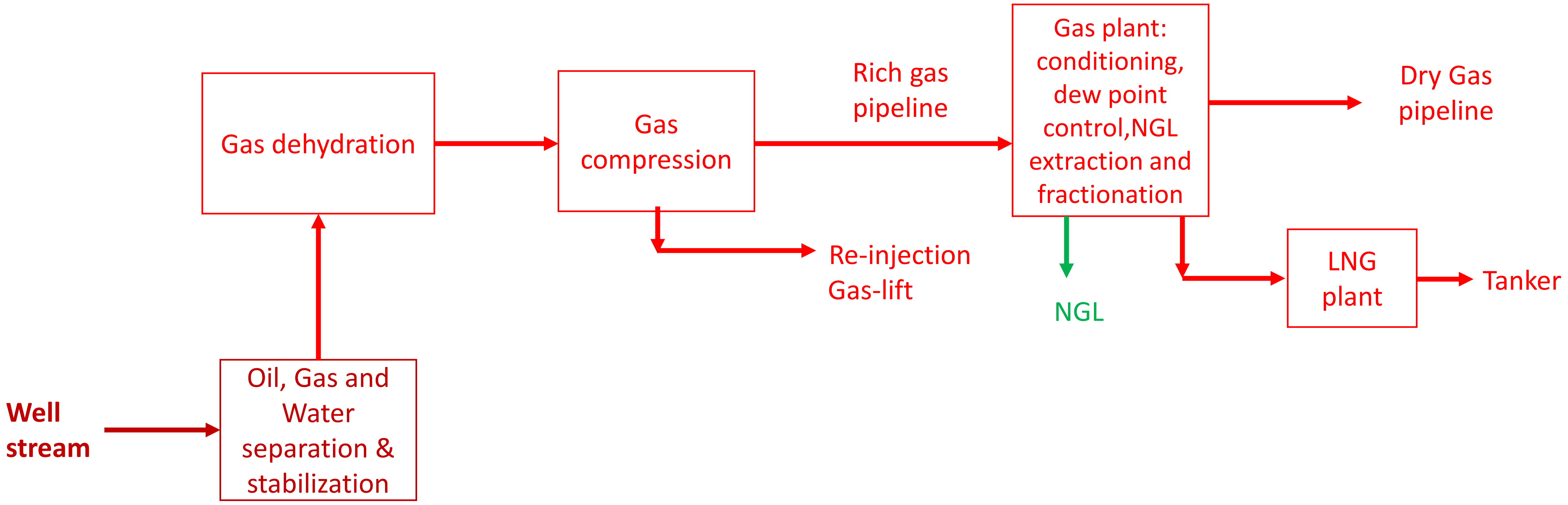

Color convention
Gas
Oil
Water

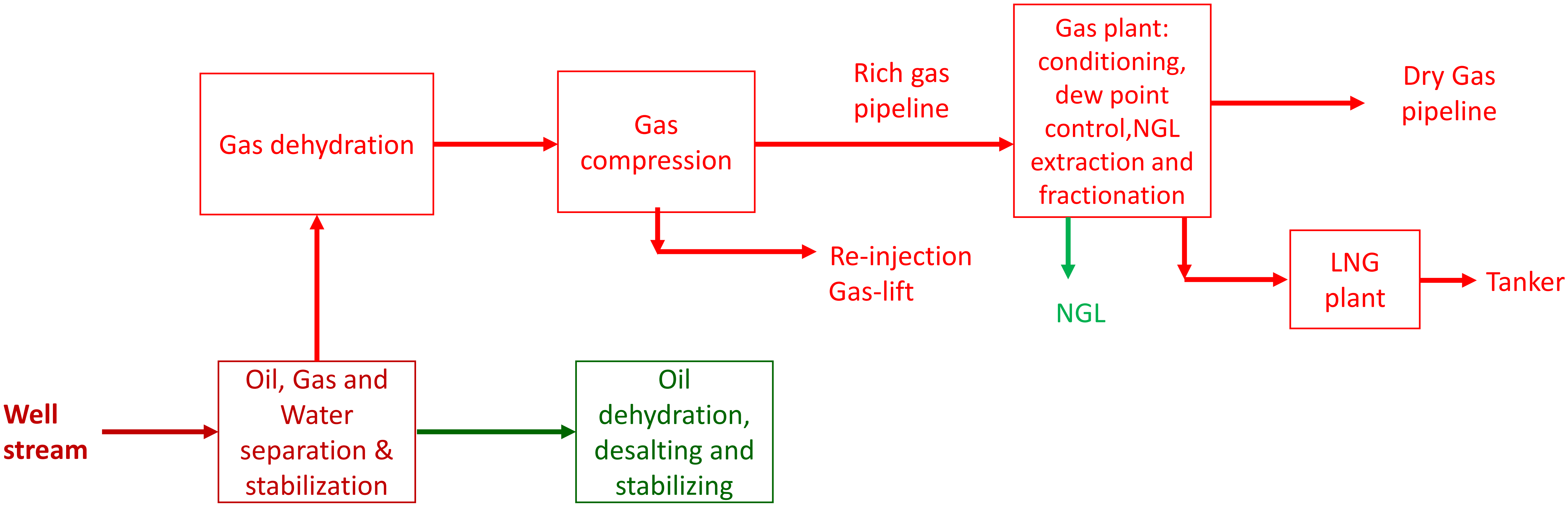

Well stream
Oil, Gas and Water separation & stabilization


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


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


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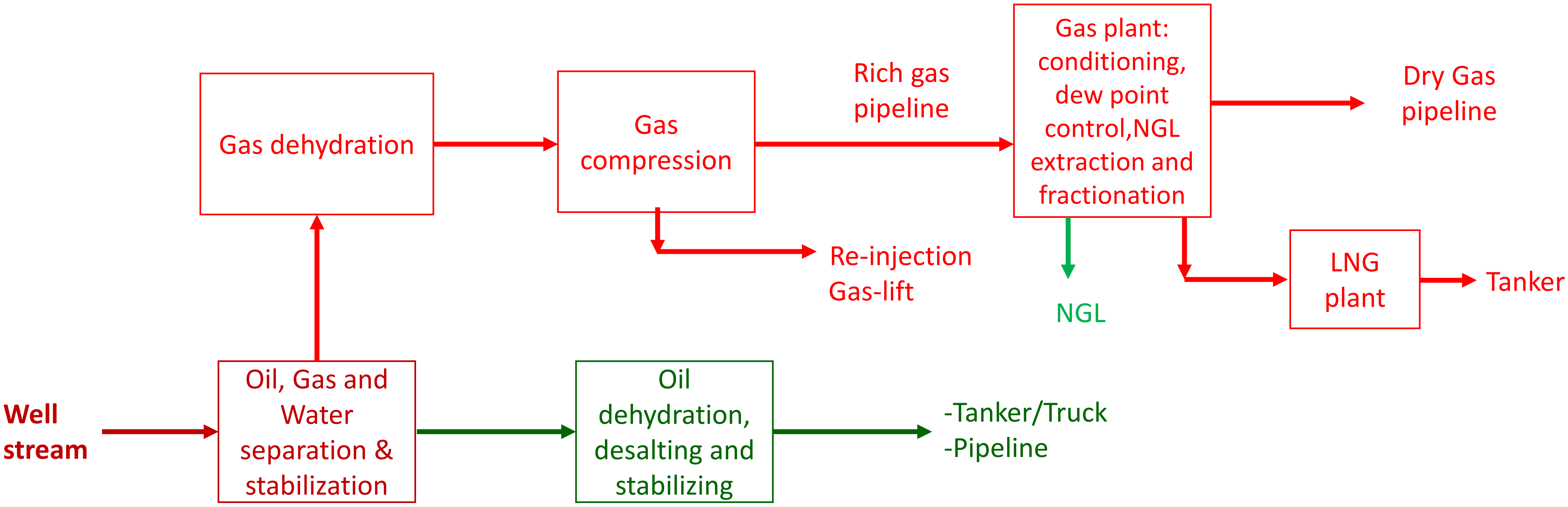
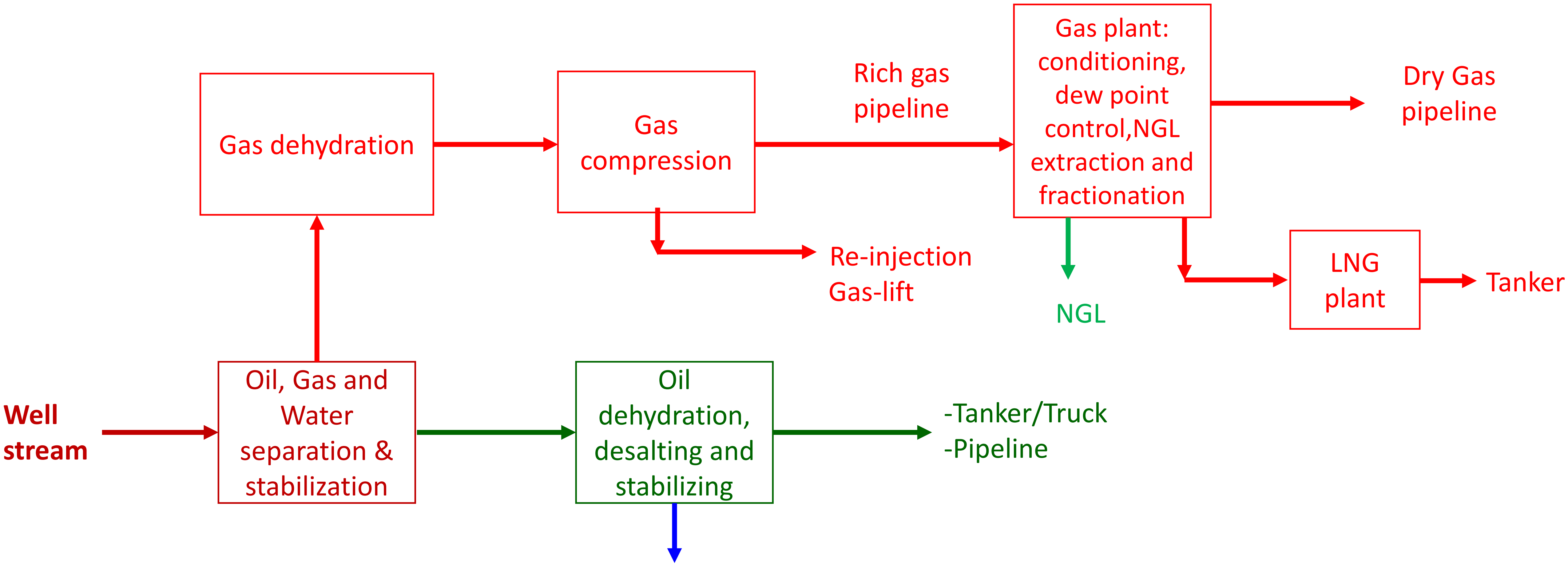
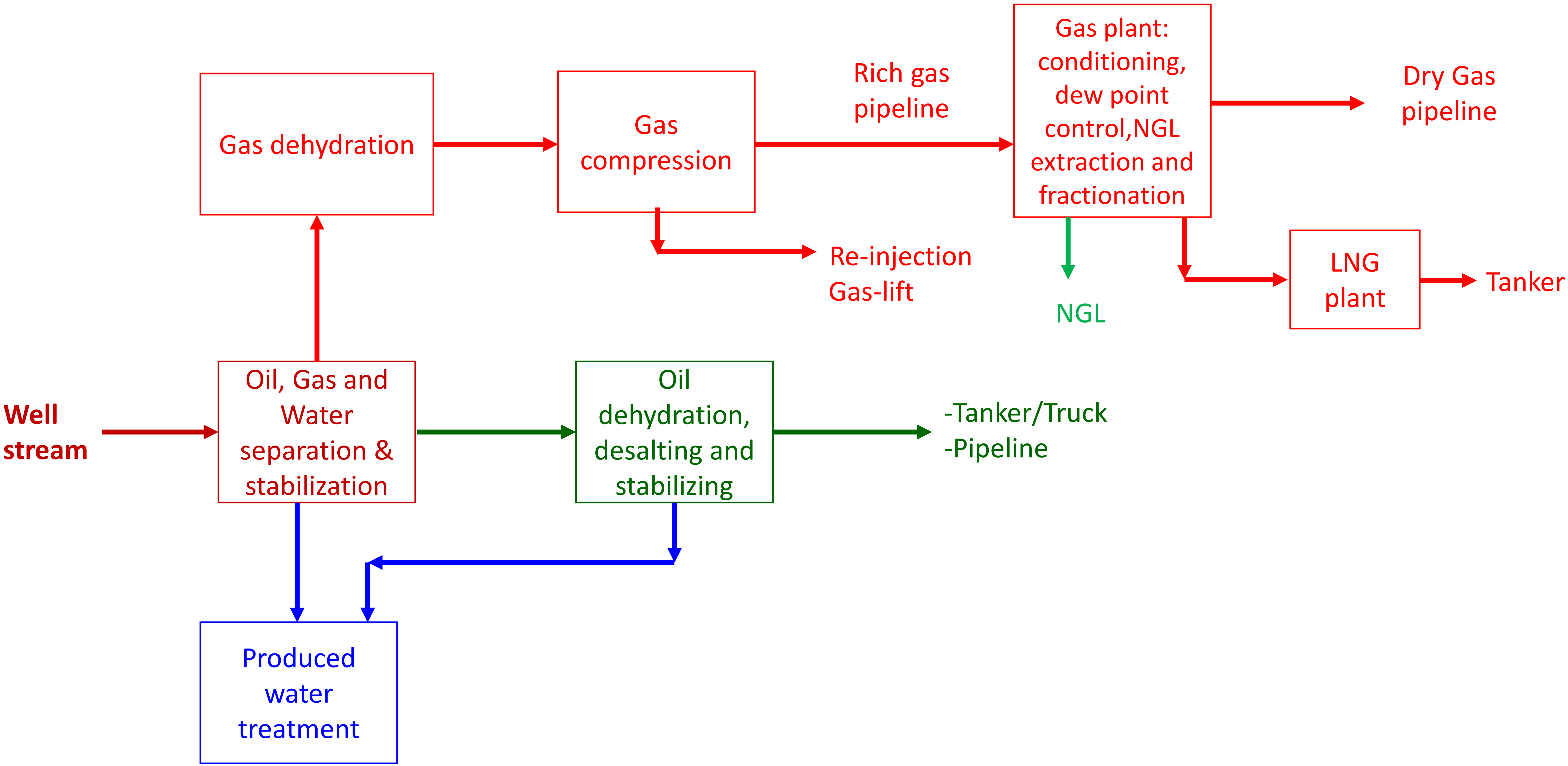
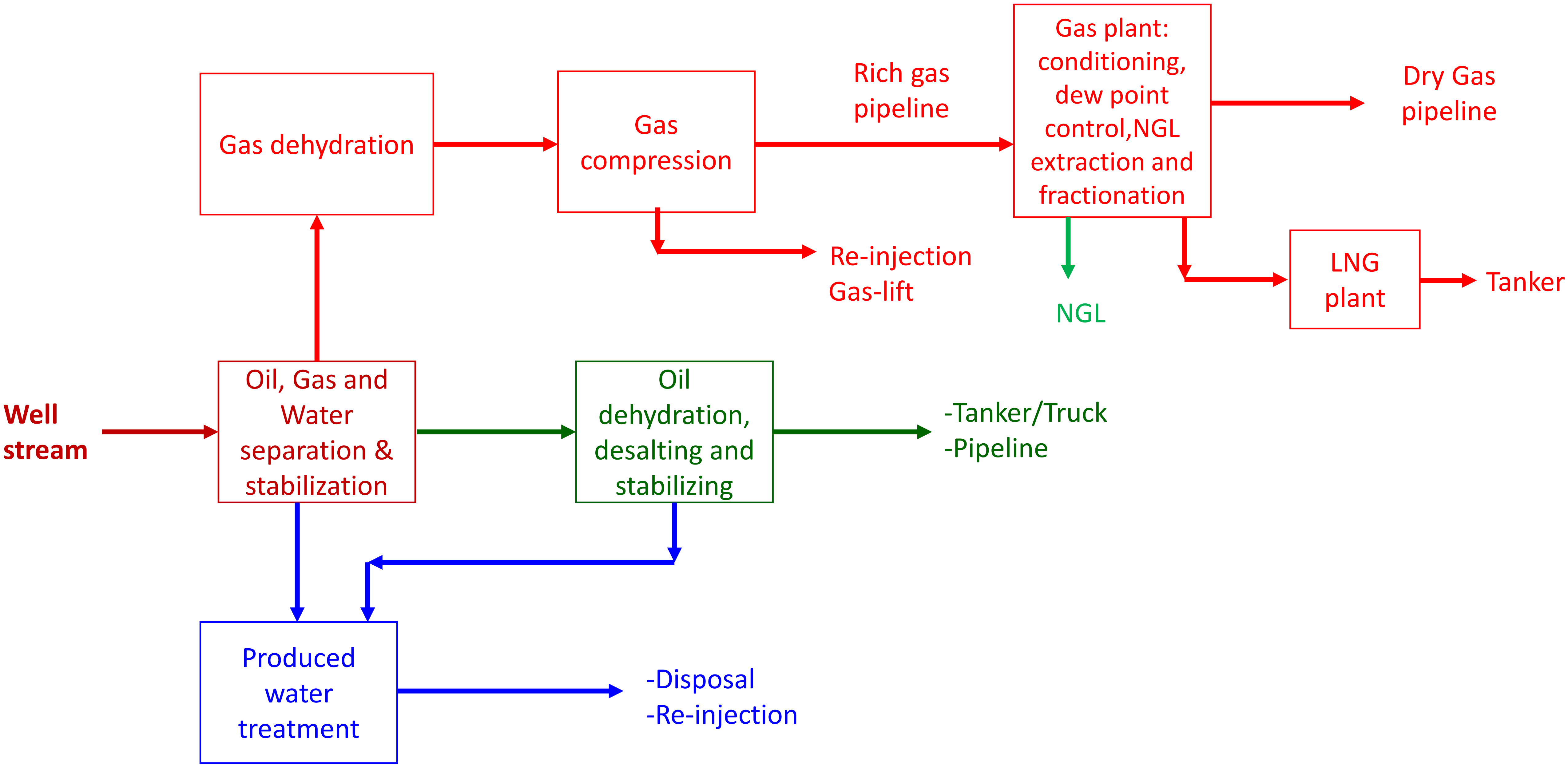
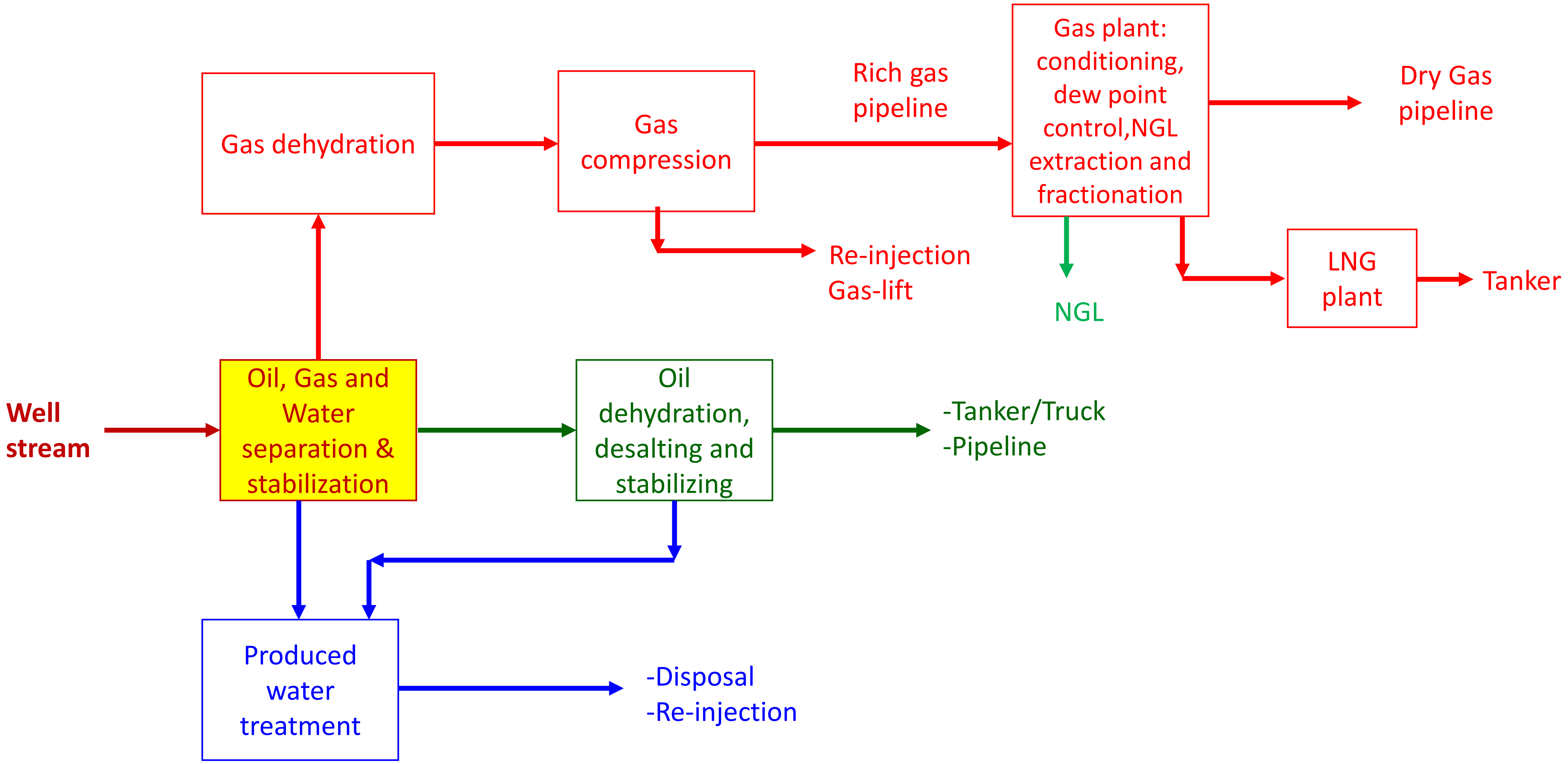
Dry Gas pipeline
Re-injection Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing

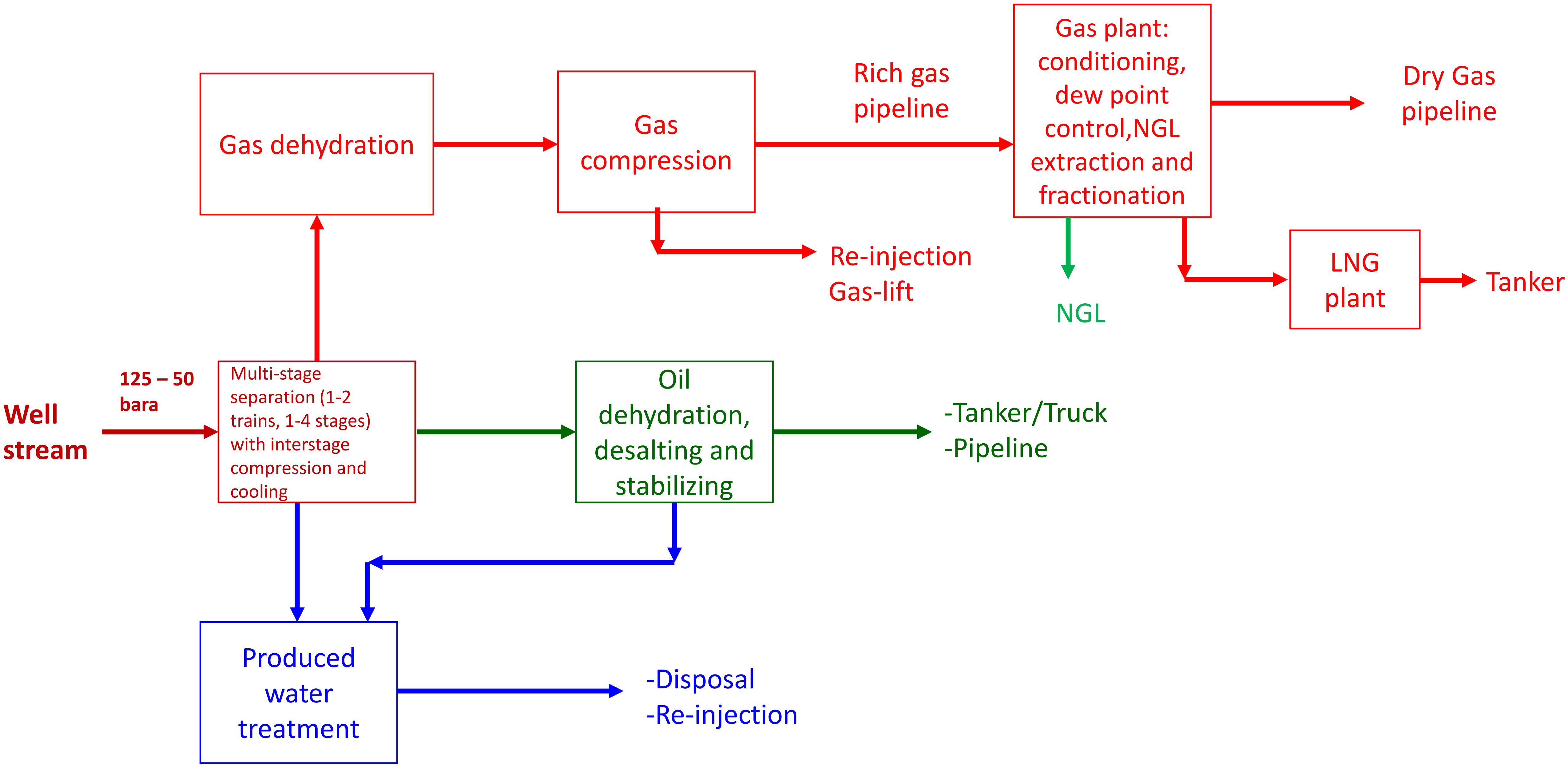

Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing
-Tanker/Truck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

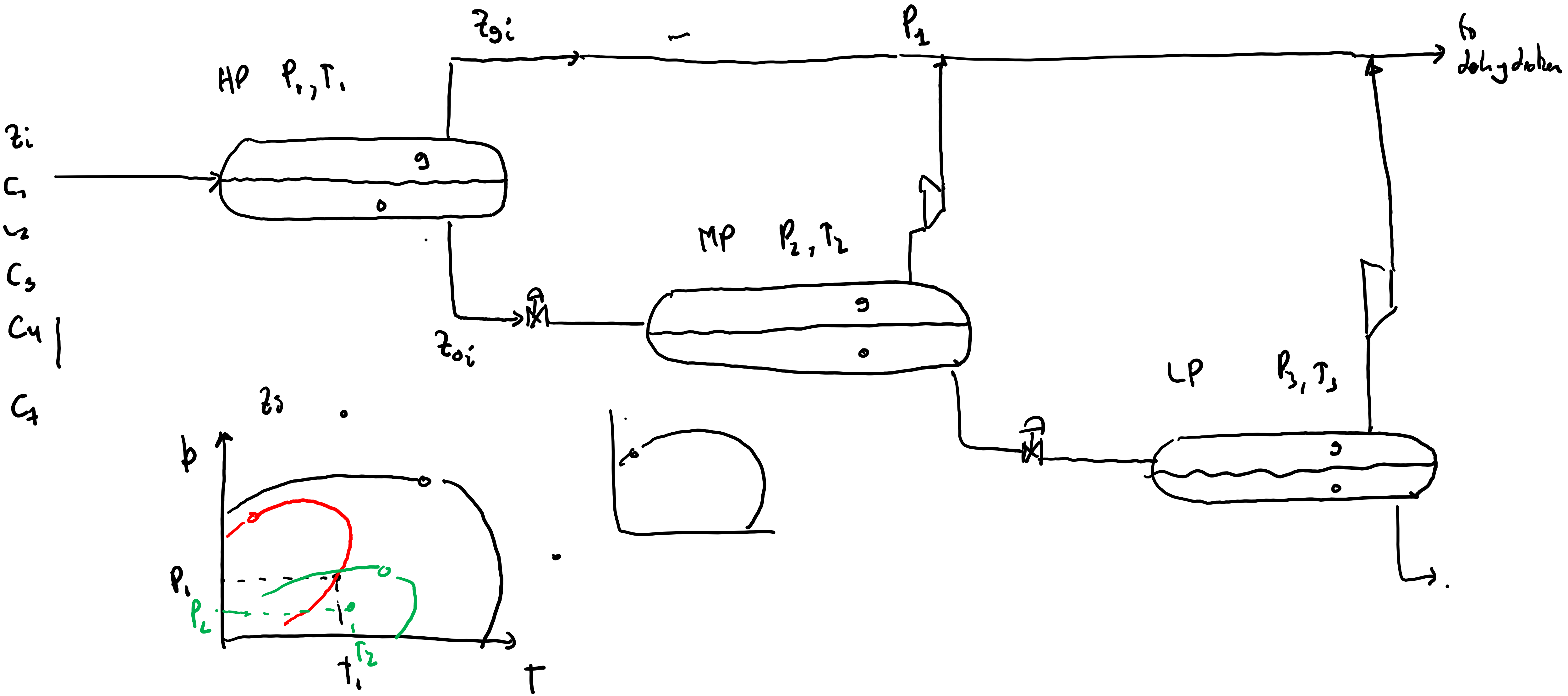

Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing
-Tanker/Truck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


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

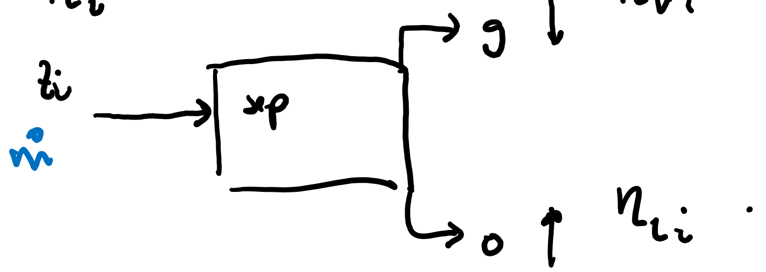

Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-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
125 – 50 bara
Well stream
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

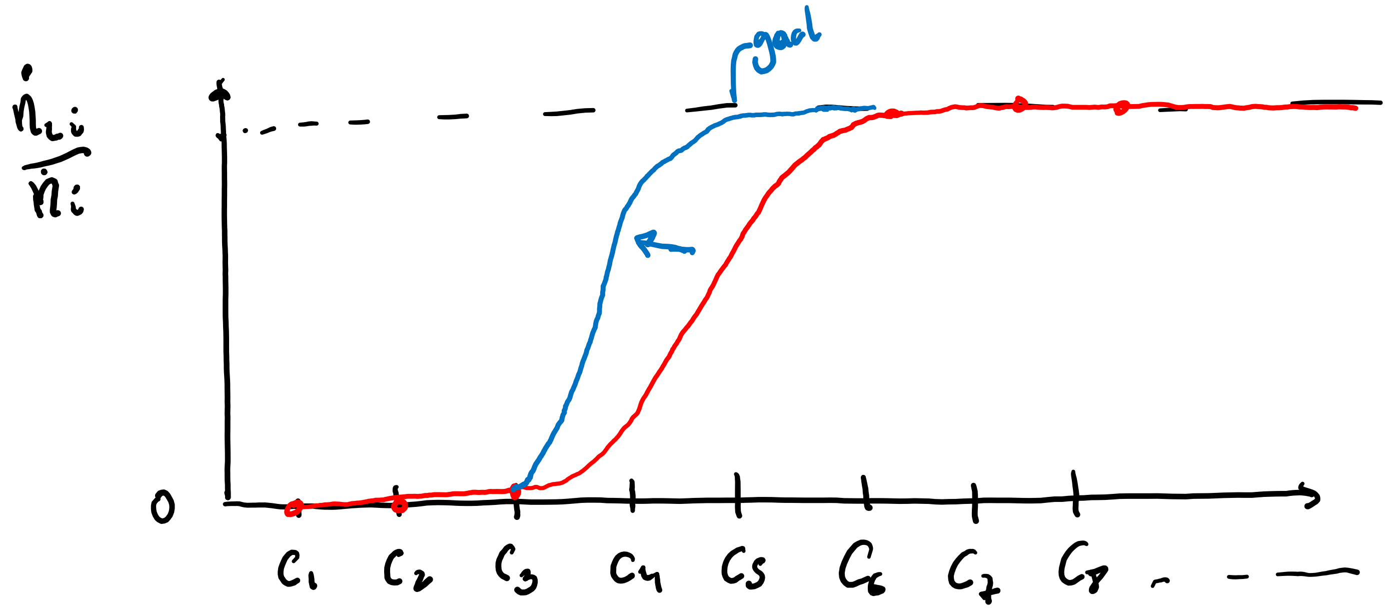


zi
C1
C2
C3
C4
C7
HP P1, T1
zgi
P1
to dehydration
g
o
MP P2, T2
zoi
LP P3, T3
zs
p
P1
P2
T1
T2
T

molar flow → $\dot{n}_i$



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



- "many" separation stages
  2–4
- p_1 (HP) high

  ↑p $\dot{m}$ ↓

  ↑p $\frac{n_{Li}}{n_{vi}}$ ↑
- optimization on top stage pressure

Notes for Youtube video nr. 3

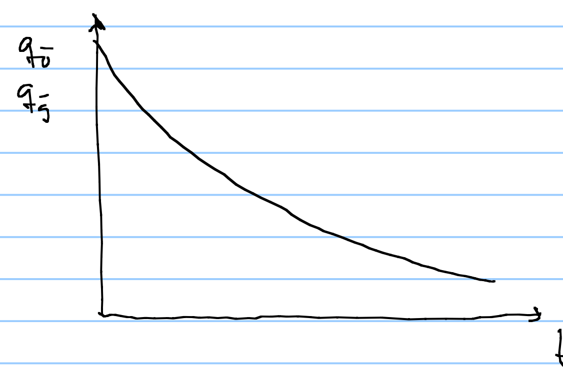
- Field production performance
  - production modes (production scheduling)
  - plateau height vs. plateau length
  - deciding plateau height

production scheduling: deciding / forecasting rates of {oil | gas} and associated products {oil: water; gas: water} during the life of field

two ways to produce a field

Production mode A "plateau production"

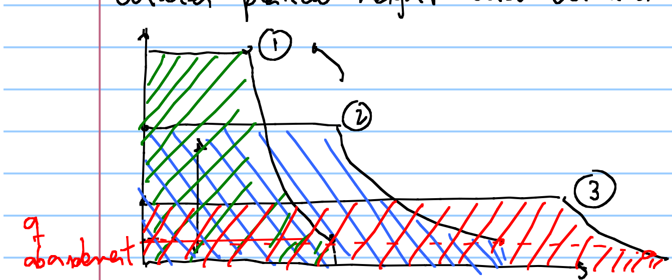
Production mode "B" "decline production"



- typically used for gas fields with a contract
- Big-medium reservoir
- standalone development → requires its own facilities, offshore structure etc.

- produce as much as possible as early as possible
- satellite developments to existing fields that use existing infrastructure

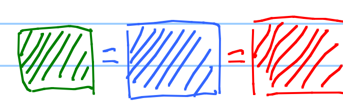
in mode "a" there is a relationship between plateau height and duration



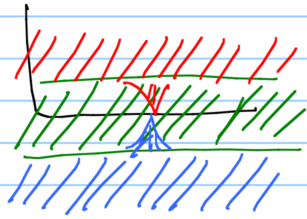
$$N_p = \int_0^t q(t)\,dt$$

↳ cumulative production

until abandonment N_{pu}



- for gas, plateau height / length is given by contract
- for oil/gas → there is a requirement by authorities to reach certain RF



higher rates can cause high GOR
high WC
sand production

to define plateau rate an economic analysis must be made

higher plateau → higher revenue

NPV ⇝ net present value

$$NPV = \sum_{i=1}^{N} \frac{\underbrace{CF_i}_{\text{cash flow} = \text{revenue} - \text{expenses}}}{(1+c)^i}$$

year

↳ discounting rate (5% → 15%)
0.05 – 0.15

$\Delta Q_{p_i} \cdot P_o^i$ production of oil/gas in year i

$$\underbrace{NPV}_{} = \underbrace{\text{Expenses}}_{\text{wells, processing facilities, platform}}^{(1-5)} + \frac{\Delta Q_p^5 \cdot P_o^5 - OPEX^5}{(1+0.07)^5} + \frac{\Delta Q_p^6 \, P_o^6 - OPEX^6}{(1+0.07)^6} + \ldots$$

start production

due to discounting, it makes sense to produce as much as possible, as early as possible

year	$DF = \frac{1}{(1+c)^i}$
1	0.93457944
2	0.87343873
3	0.81629788
4	0.76289521
5	0.71298618
6	0.66634222
7	0.62274974
8	0.5820091
9	0.54393374
10	0.50834929
11	0.4750928
12	0.44401196
13	0.41496445
14	0.38781724
15	0.36244602

if plateau rate is higher → bigger processing facility
→ bigger offshore structure
→ more wells

"expenses" become very negative

but also revenues become bigger

for HC fields, plateau rate is usually decided by doing an economic evaluation and sensitivity analyses

exceptions { • Blending of crude

Rules of thumb for first iteration on plateau rate

for oil: 10% of N_{pu} per year

ultimate cumulative production (at abandonment)

TRR → total recoverable reserves

Example 180E06 stb → N initial oil in place (OOIP)

$$N_{pu} = \underbrace{R_{Fu}}_{(0.3-0.5)} \cdot N$$

$$N_{pu} = 0.4 \; 180E06 \text{ stb}$$

$$N_{pu} = 72E06 \text{ stb}$$

$$q_{plateau} = \frac{N_{pu} \cdot 0.1}{\text{Nr. producing day in year}} = \frac{72E06 \cdot 0.1}{0.9 \cdot 365} \approx 21900 \text{ stb/d}$$

[Sm^3/d]

[stb/d]

↳ 95% uptime (0.95 . 365)

for gas (2-5)% of G_{pu}

Q is either oil or gas
N is for oil
G is for gas

Class 20230124 - OUTLINE

-Simulating a separation train in Hysys
-How do a horizontal and vertical separator look like?

HYSYS Example

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

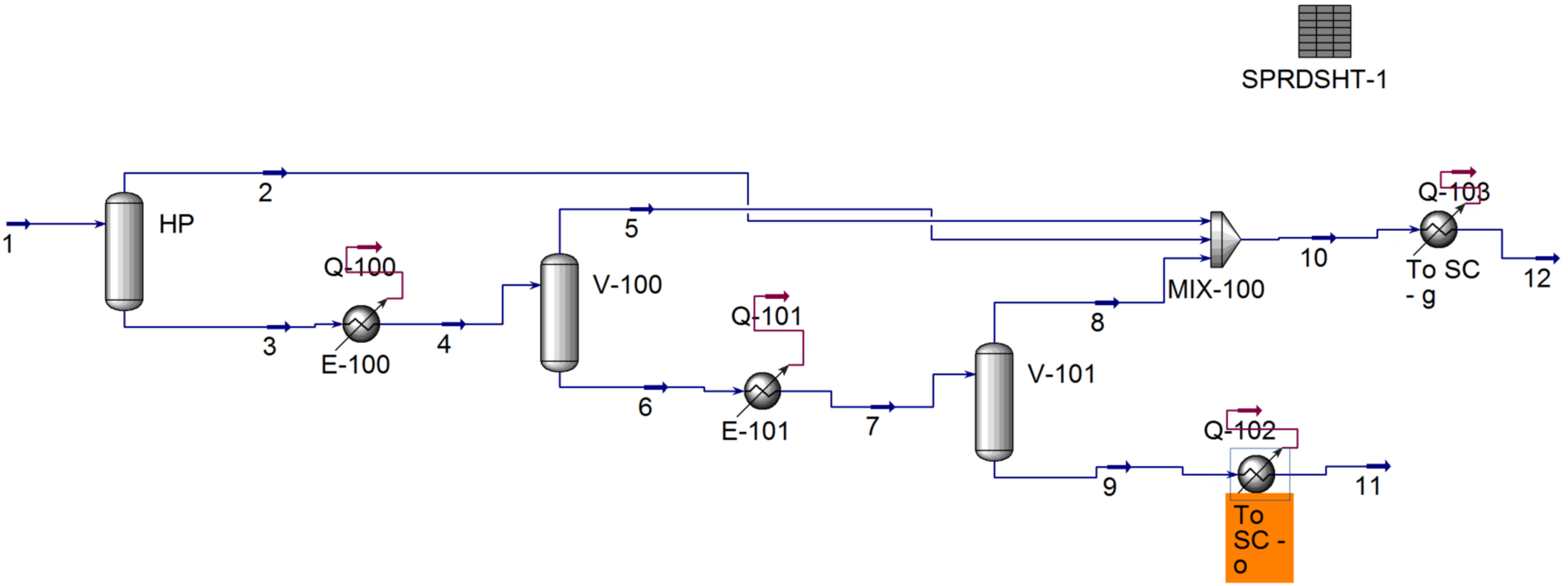
Total mass flow: 27 000 kg/h

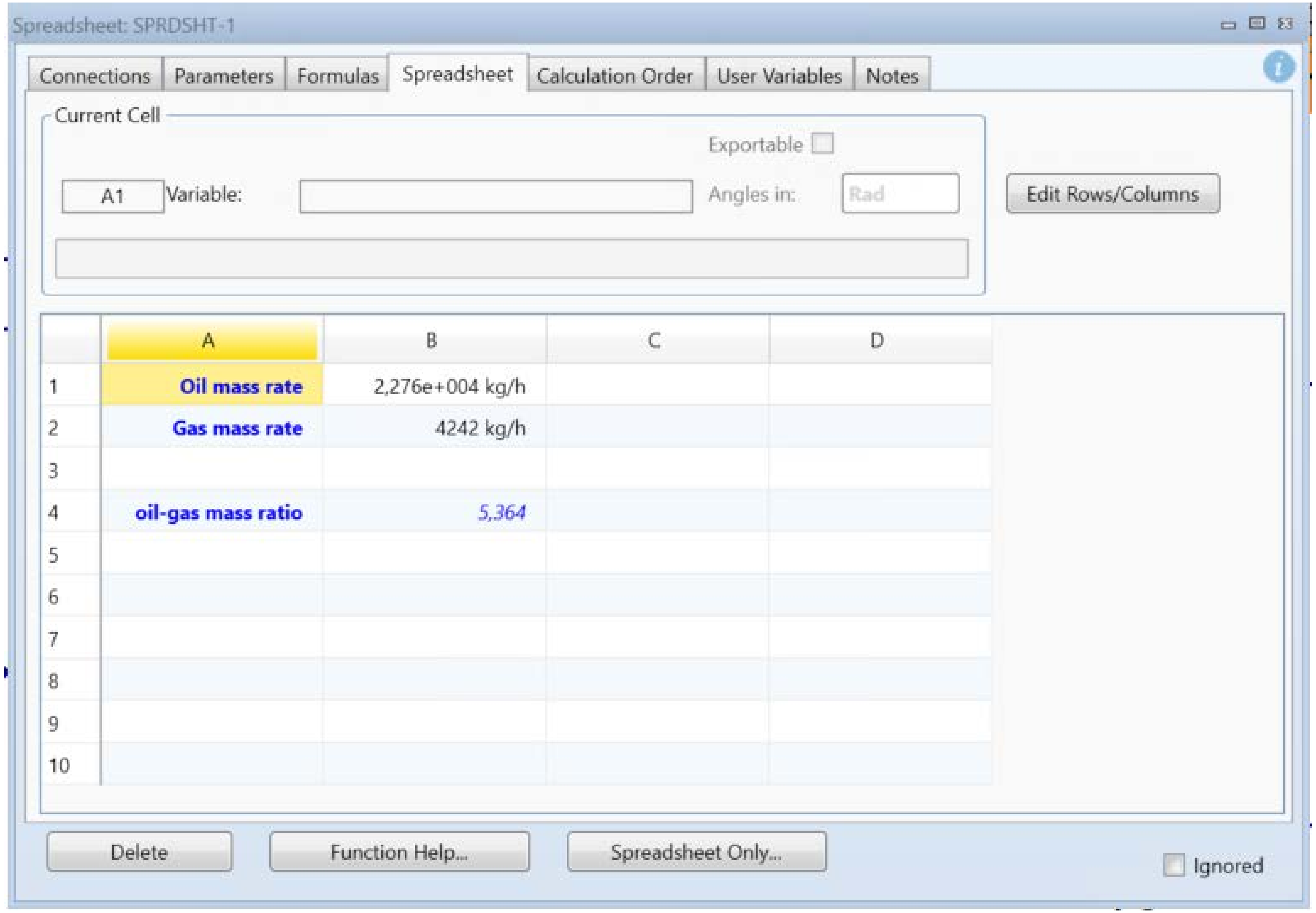
$$\dot{m} = q_{\bar{o}} \cdot \rho_{\bar{o}} + q_{\bar{g}} \cdot \rho_{\bar{g}} + q_{\bar{w}} \, \rho_{\bar{w}} = q_{\bar{o}}\left(\rho_{\bar{o}} + GOR \cdot \rho_{\bar{g}} + \frac{wc}{1-wc}\, \rho_{\bar{w}}\right)$$

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

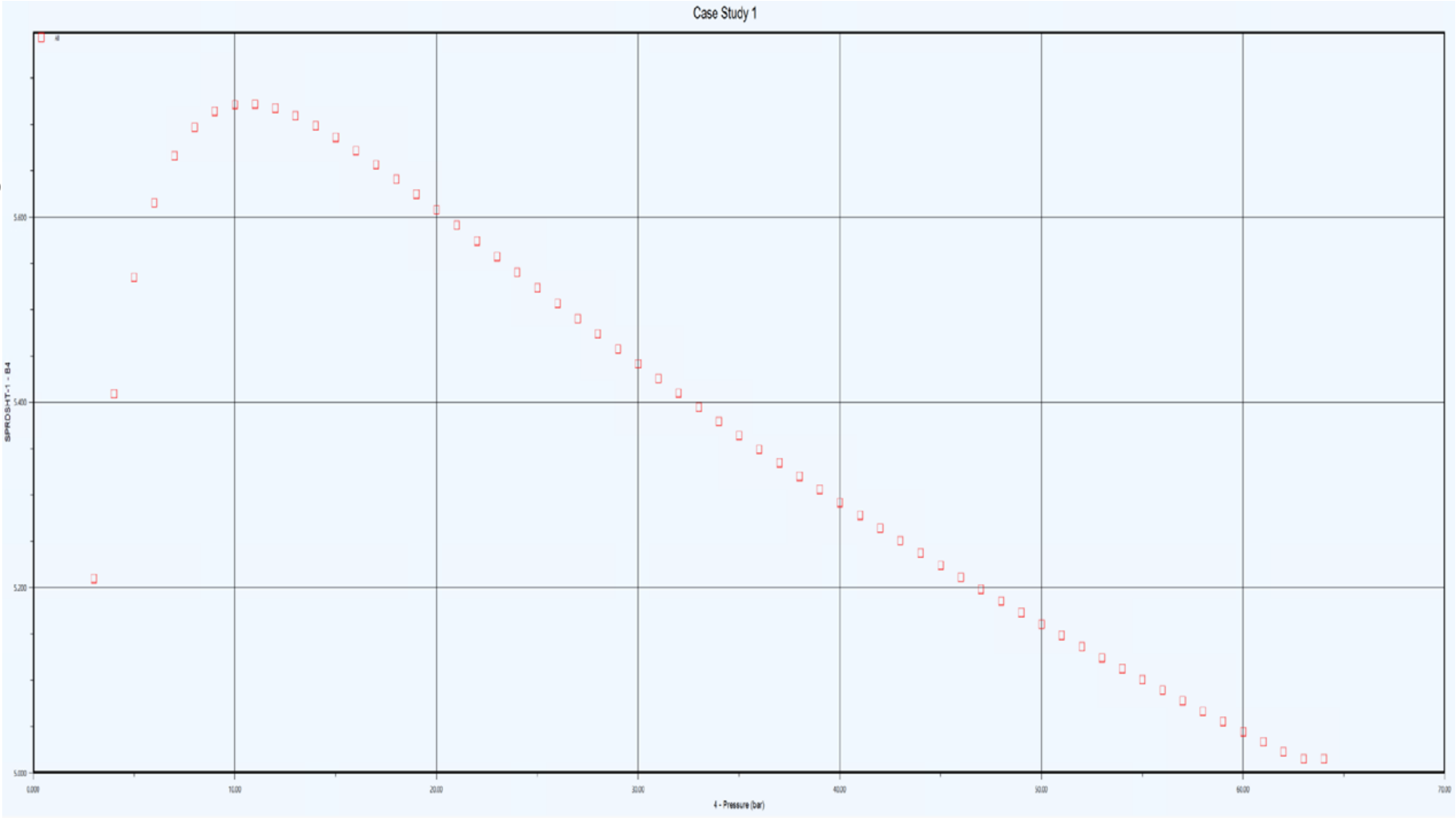

Spreadsheet: SPRDSHT-1
Connections
Parameters
Formulas
Spreadsheet
Calculation Order
User Variables
Notes
Current Cell
Exportable
A1
Variable:
Angles in:
Rad
Edit Rows/Columns
A
B
C
D
Oil mass rate
2,276e+004 kg/h
Gas mass rate
4242 kg/h
oil-gas mass ratio
5,364
Delete
Function Help...
Spreadsheet Only...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

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

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

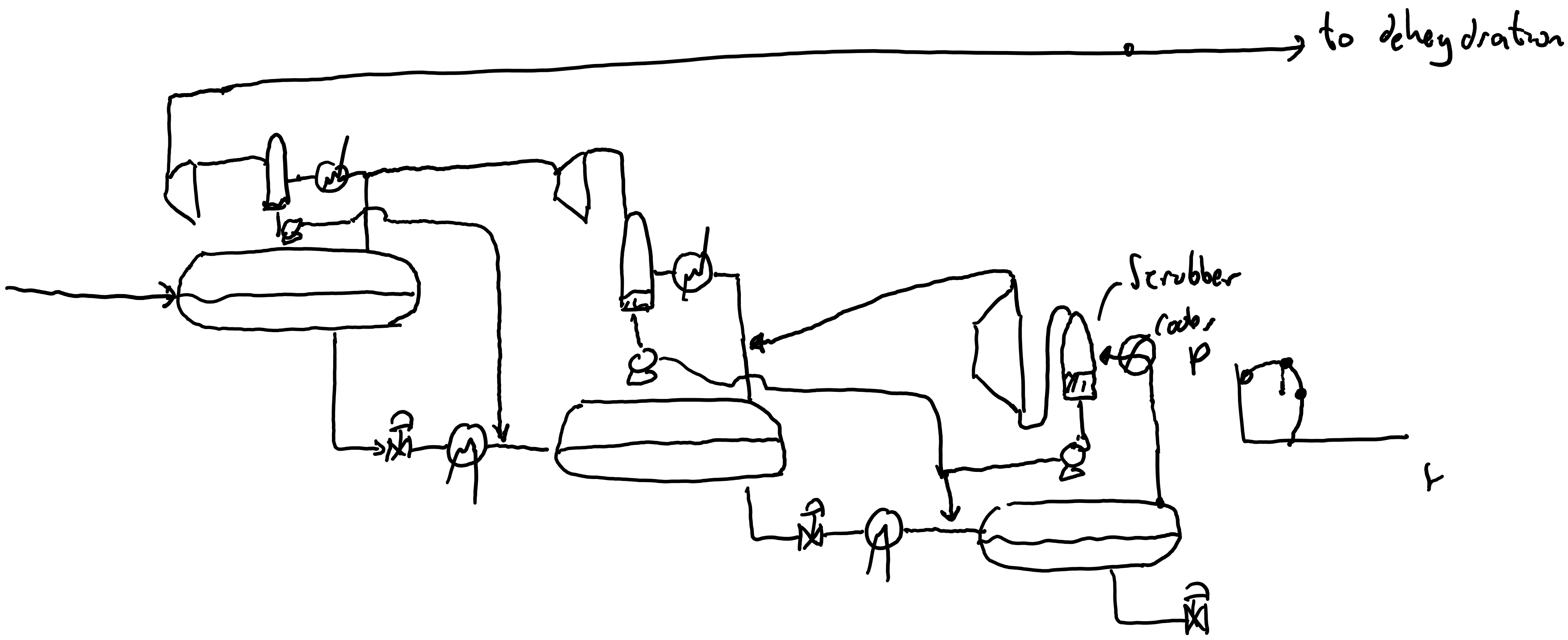
$$\text{abs}\, \frac{(\overset{\text{base}}{5.6} - \overset{\text{new}}{5.75})}{\underset{\text{base}}{5.6}} \times 100 = 2.6\%$$

Ratio between oil mass rate/gas mass rate

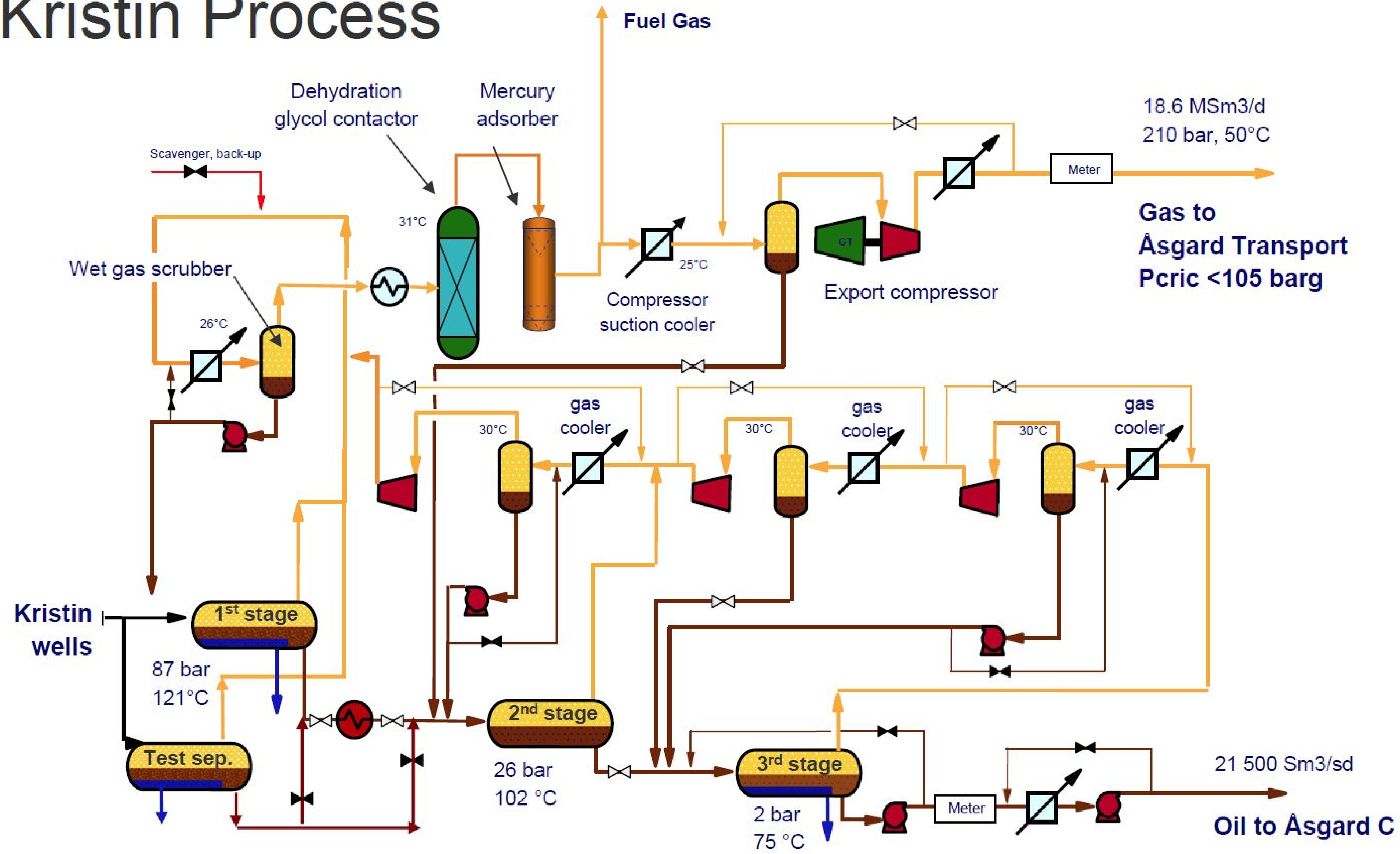


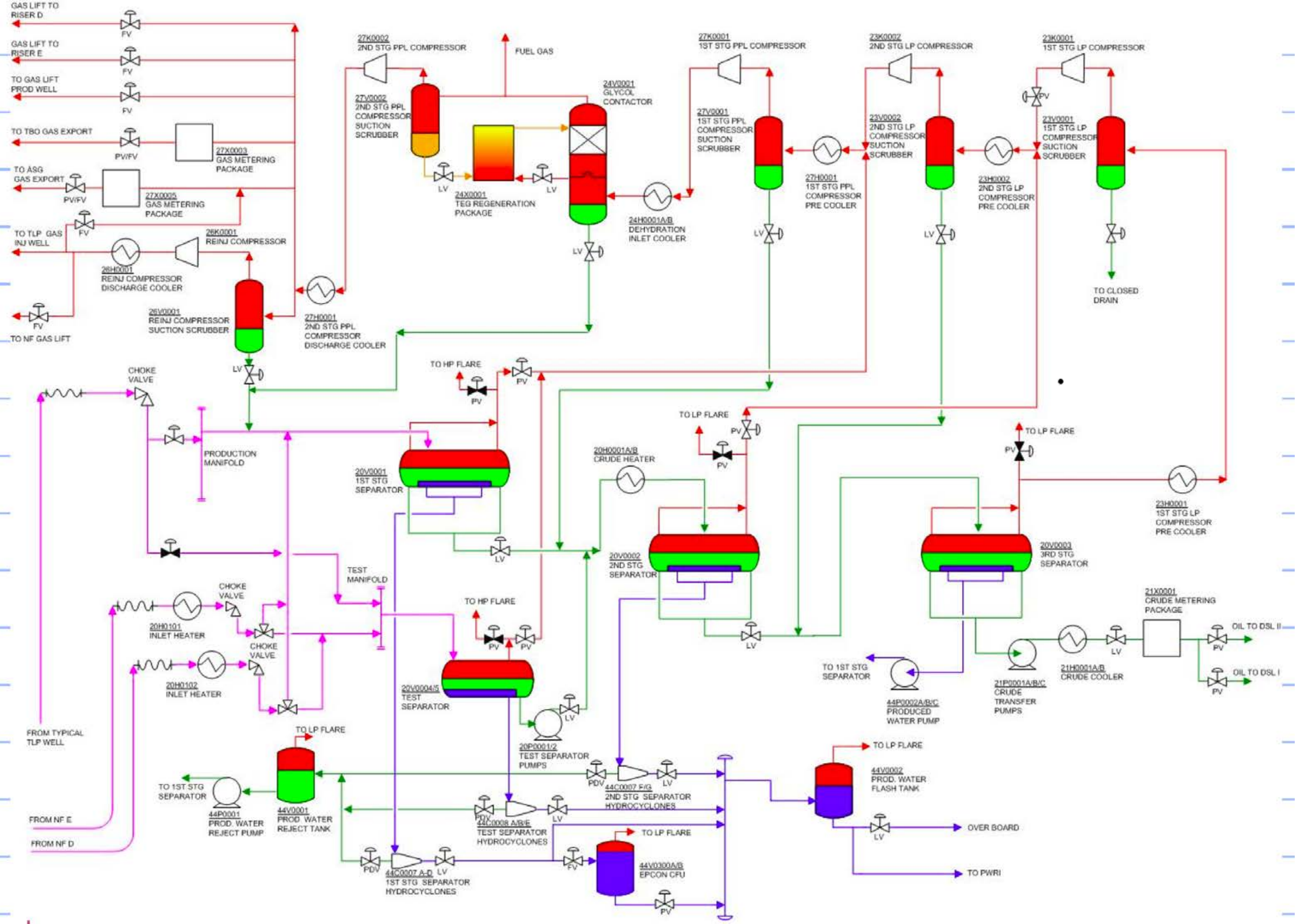
Pressure of medium stage separator (MP), bara

How does the separation process looks like in reality:

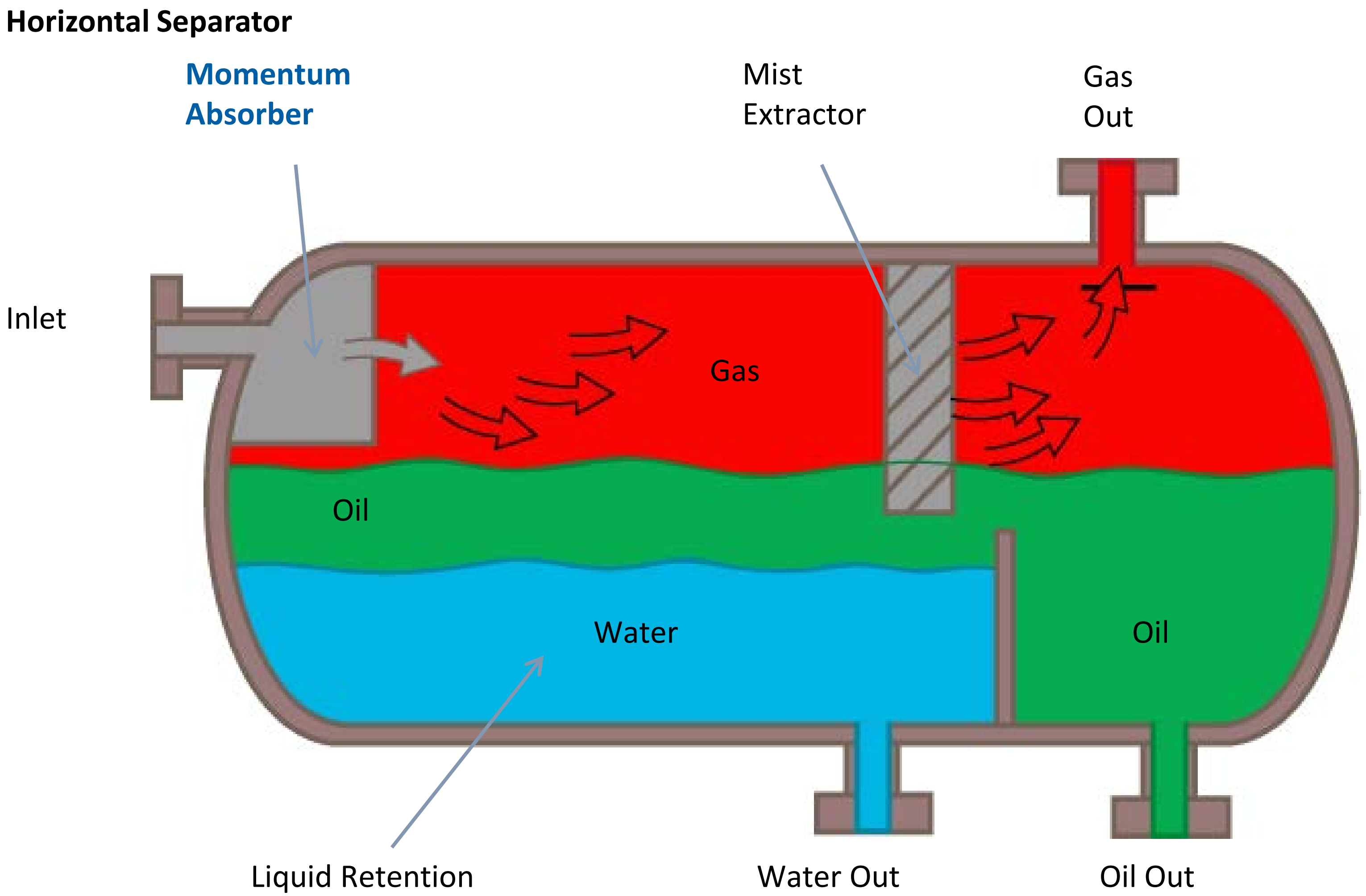


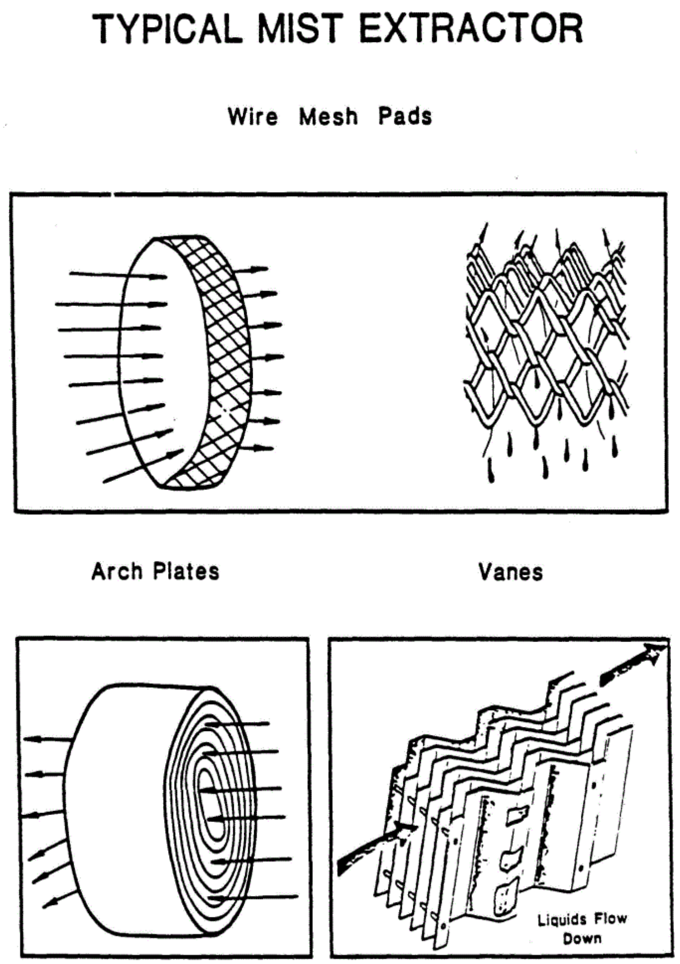
Kristin Process



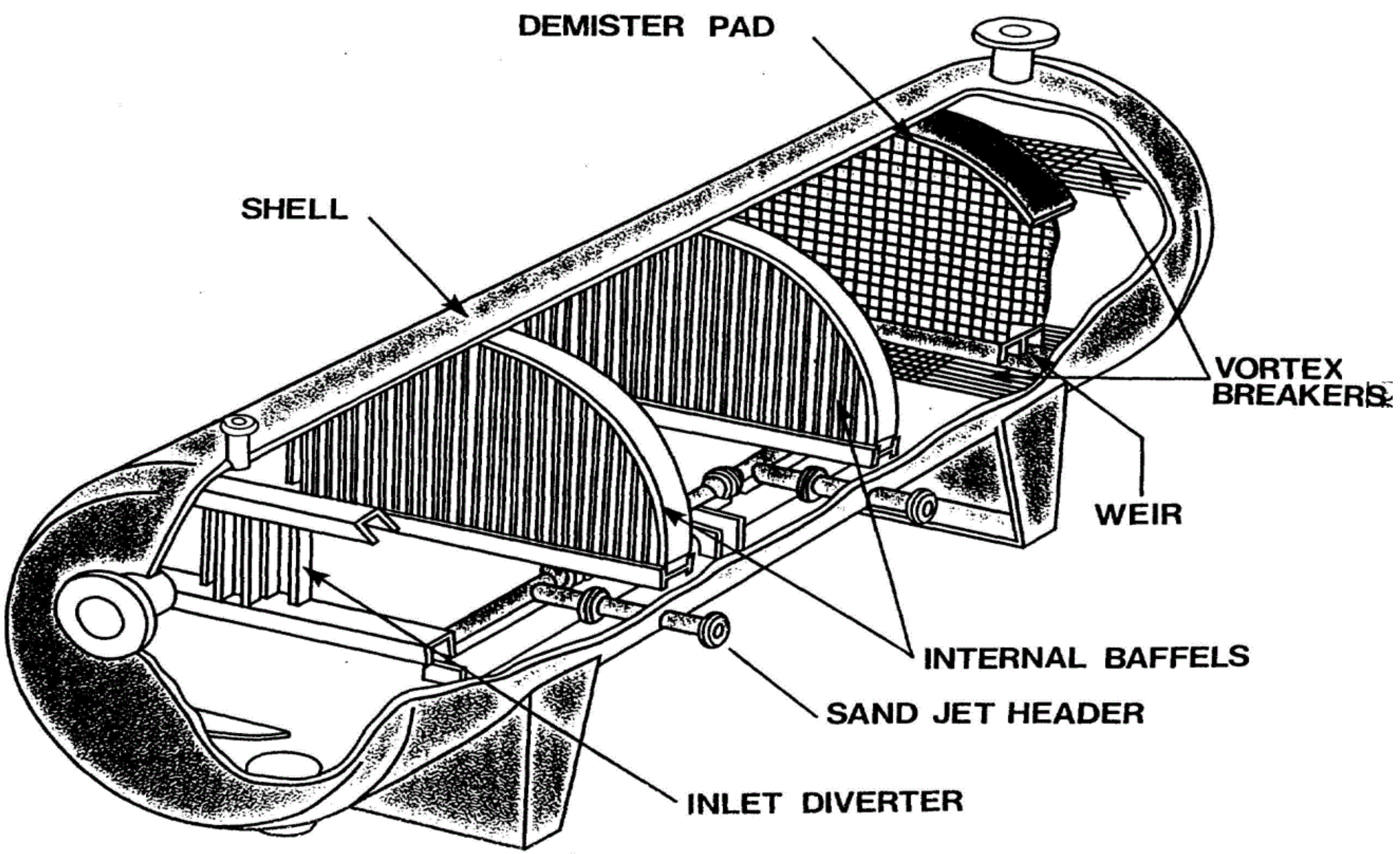

GAS LIFT TO RISER D
GAS LIFT TO RISER E
TO GAS LIFT PROD WELL
TO TBO GAS EXPORT
TO ASG GAS EXPORT
TO TLP GAS INJ WELL
TO NF GAS LIFT
FV
PV/FV
27X0003 GAS METERING PACKAGE
27X0005 GAS METERING PACKAGE
26K0001 REINJ COMPRESSOR
26H0001 REINJ COMPRESSOR DISCHARGE COOLER
26V0001 REINJ COMPRESSOR SUCTION SCRUBBER
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
20V0001 1ST STG SEPARATOR
TO LP FLARE
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
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

Horizontal separator

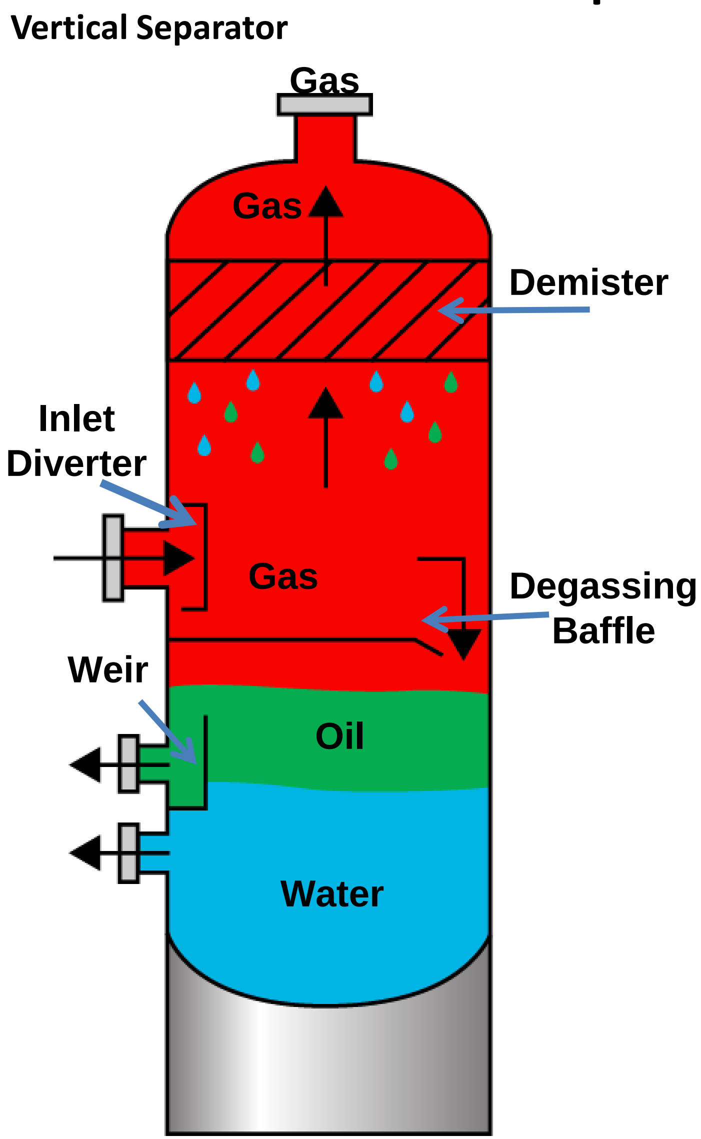


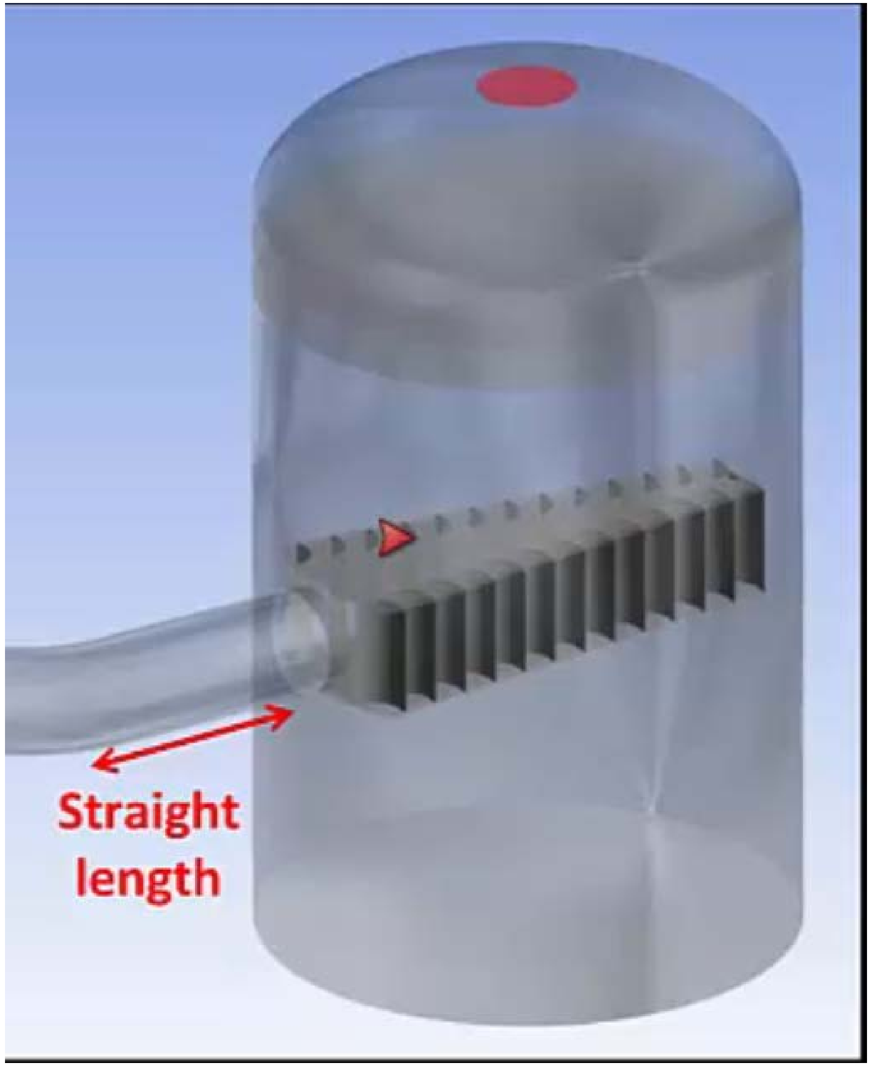


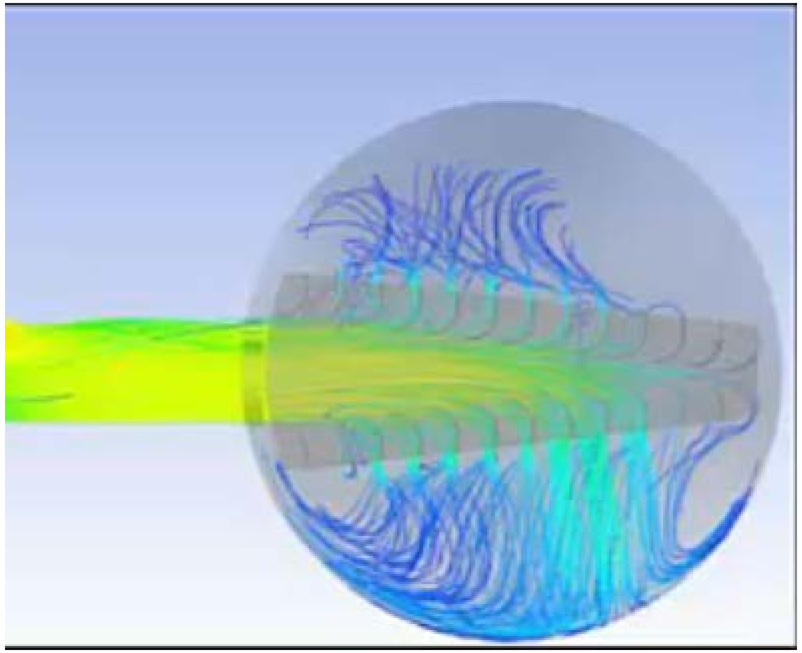
Horizontal separator



Vertical separator







OUTLINE: 27.01.2023

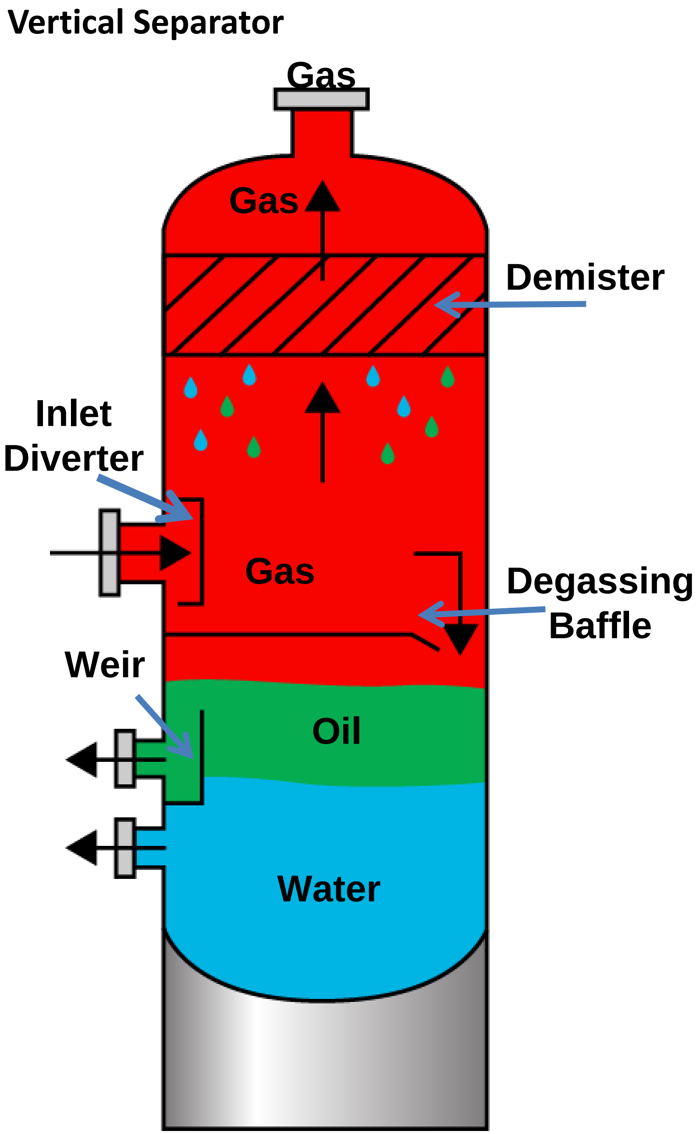
- Example of (simple) sizing horizontal gas-oil separator

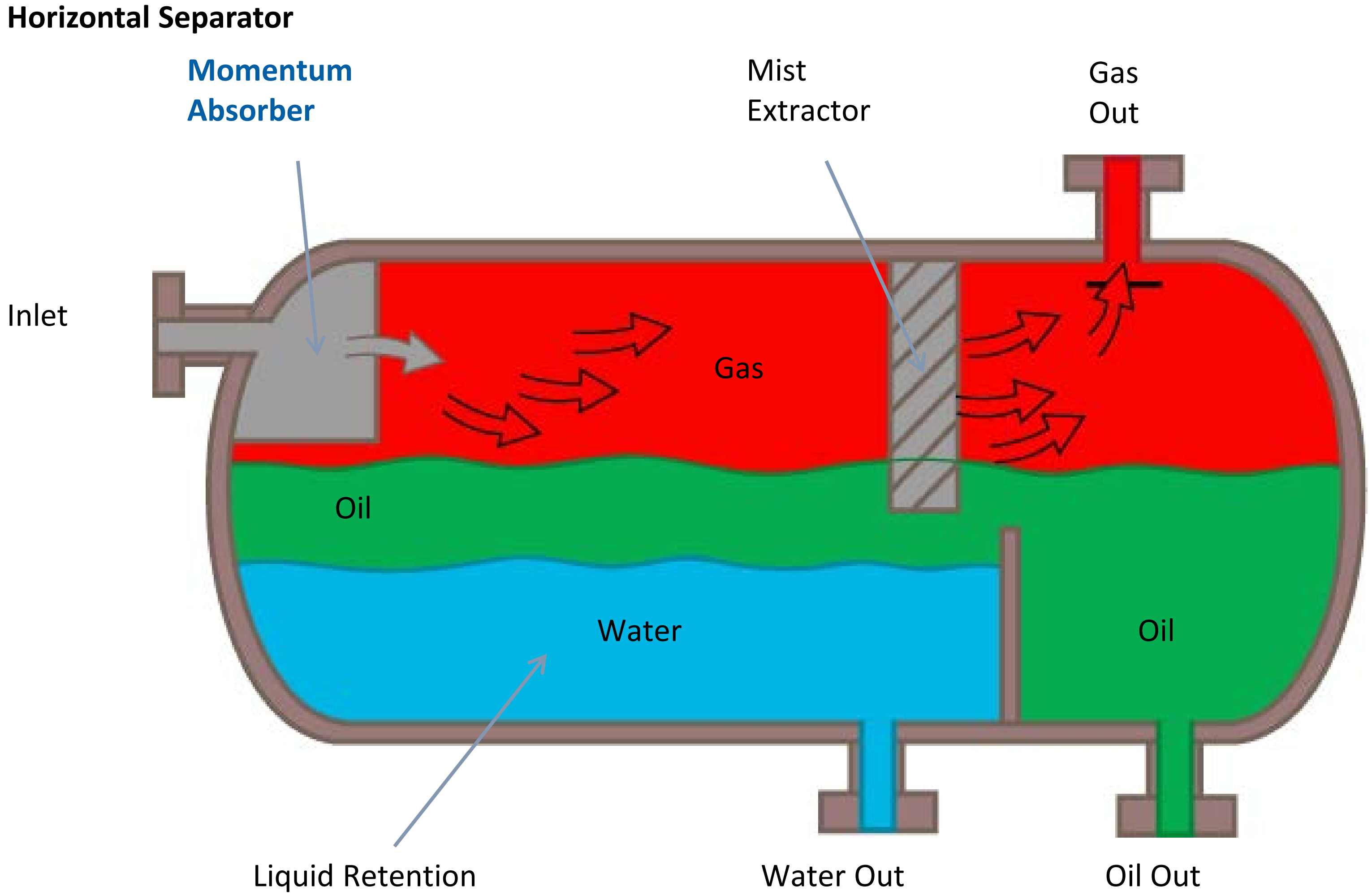
Separation design theory

Find separator dimensions such as:

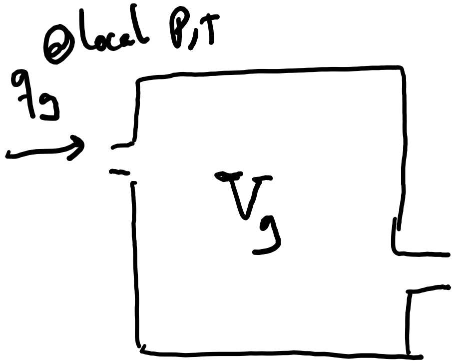
Residence time > separation time

Residence time

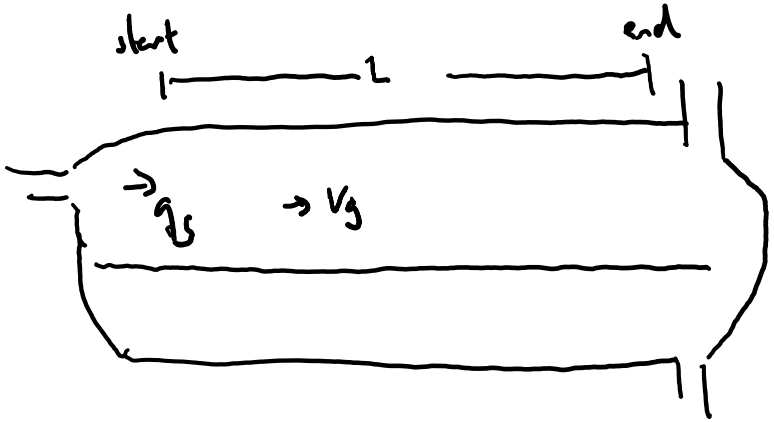




Residence time (gas)



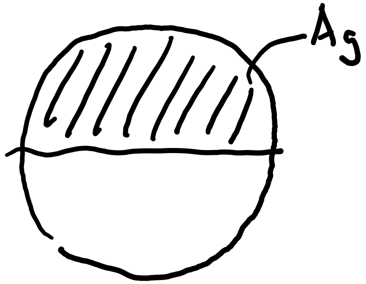
$$t_{res\,g} = \frac{V_g}{q_g}$$



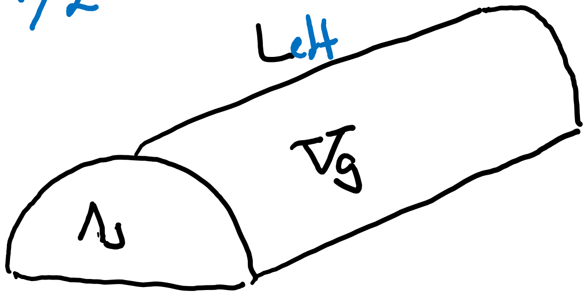
$$V_g = \frac{q_g}{A_g}$$

$$t_{res\,g} = \frac{L}{V_g}$$

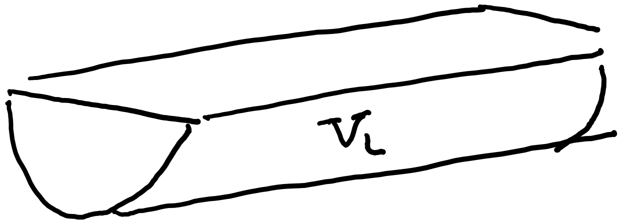
$$t_{res\,g} = \frac{A_g L}{q_g} = \frac{V_g}{q_g}$$



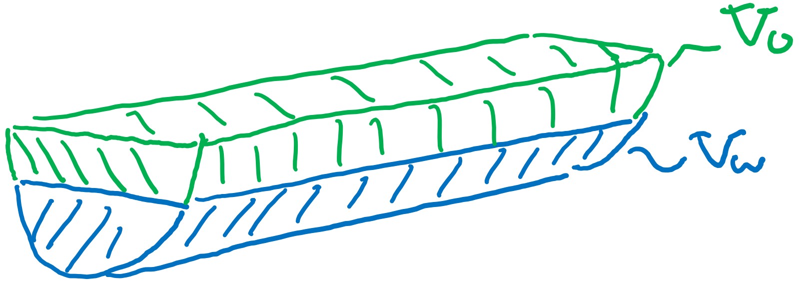
$$\frac{ID^2 \cdot \pi}{4} \Big/ 2$$



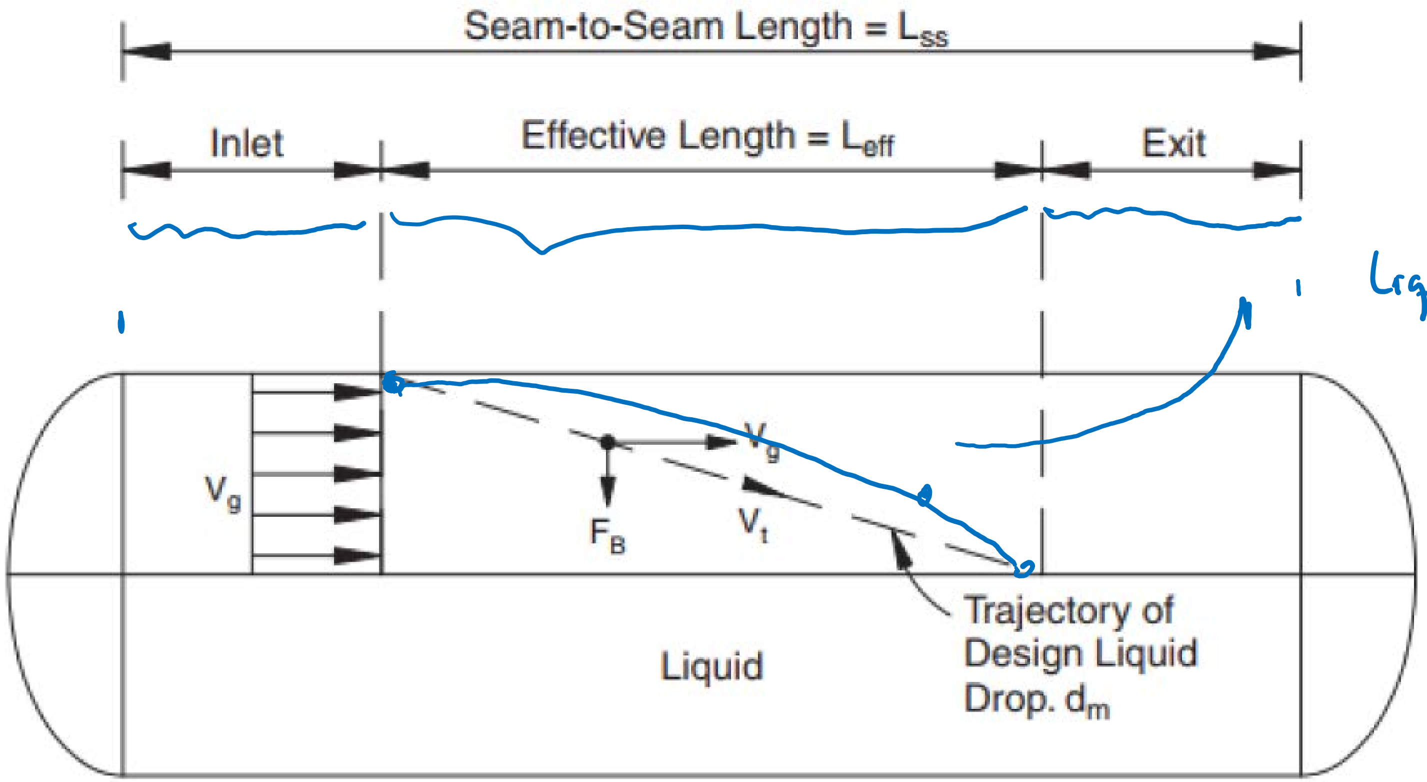
for liquid



or, two liquid phases



Separation time - gas



Legend:

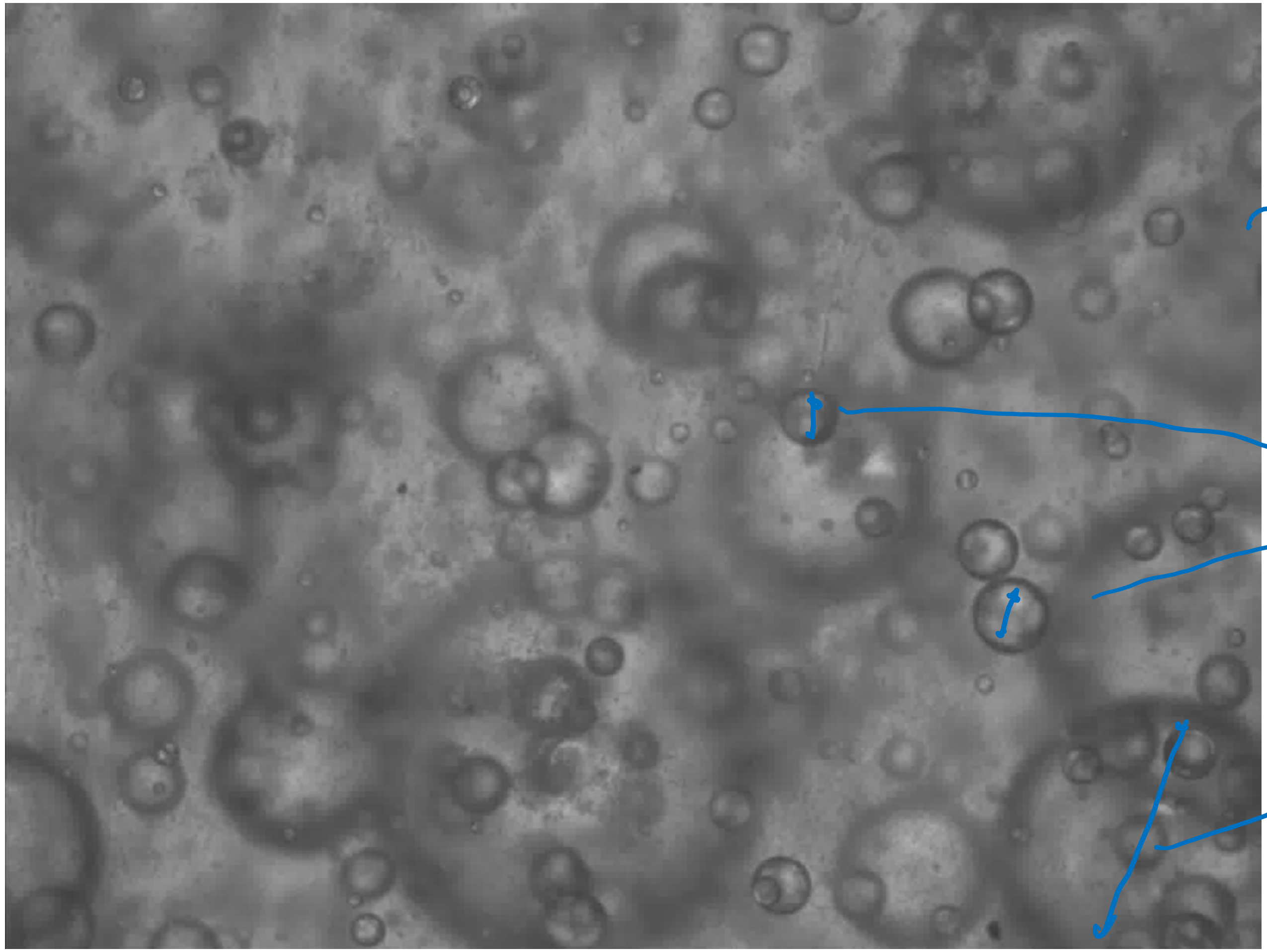
V_g = Average Gas Velocity = $\frac{Q}{A}$

V_t = Terminal or Setting Velocity Relative to Gas

F_B = Buoyant Force

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

Separation time – droplet size distribution



d = 1E01-1E02 um

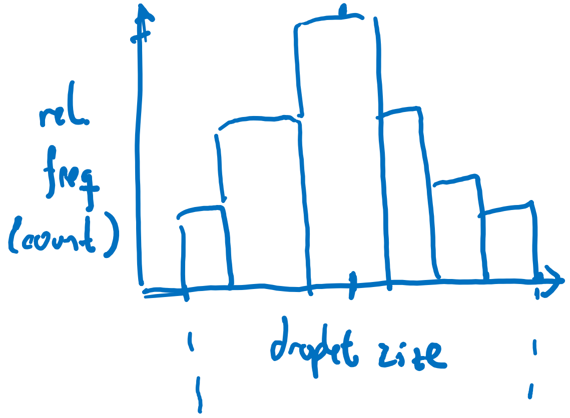
10 – 100 E-6 m

dispersion

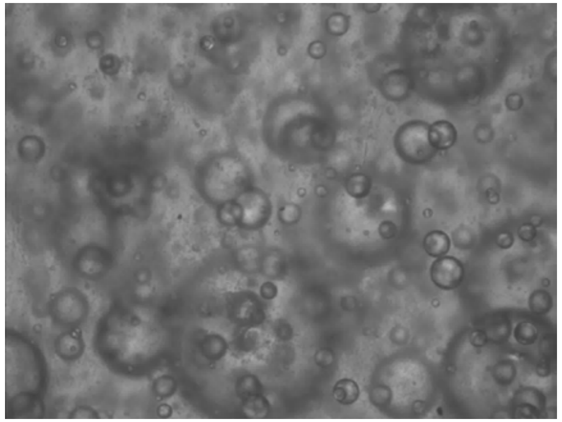
characterize the dispersion

	count	rel. freq
min	N_1	N_1/Σ
d_1	N_2	N_2/Σ
d_2	N_3	N_3/Σ
d_3	N_4	
d_4	N_5	
max	N_6	
	ΣN	

frequency analysis



Separation time – droplet size distribution

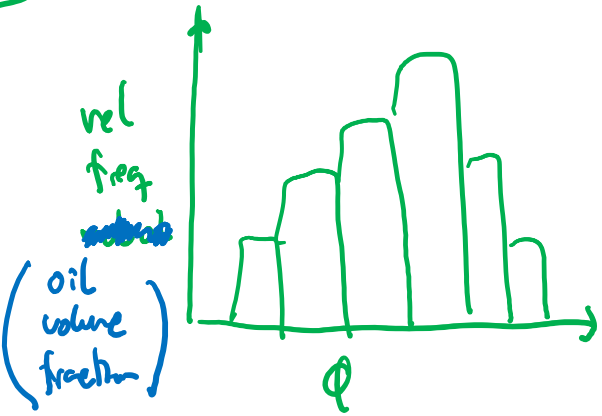


d = 1E01-1E02 um

another approach (volume based)

size class

d	Count	total Volume	rel freq
d_{min}	N_{min}	$\boxed{N_{min} \cdot \frac{4\pi r_{min}^3}{3}}$	$\square / \square$
d_1	N_1		
d_2	N_2	$N_2 \cdot \frac{4\pi r_2^3}{3}$	
⋮	⋮	⋮	
d_{max}	N_{max}	$N_{max} \frac{4\pi r_{max}^3}{3}$	
		$\boxed{\Sigma V}$	

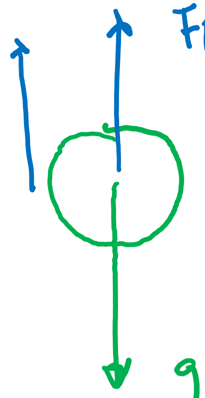


Separation time = settling time

if conservative $\phi_{droplet} = \phi_{min}$

falling time – settling time

$F_b = g \cdot V_d \cdot \rho_g$



$\rho_g V_d^2 \, 0.5 \, C_d A_p$

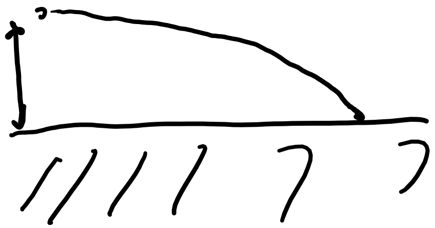
$\frac{\pi \phi_p^2}{4}$

$g \cdot V_d \cdot \rho_d$

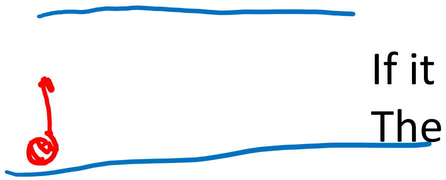
$\Sigma F = 0$

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

$\frac{\phi_{sep}}{2}$



$$t_{settling\ time} = \frac{\phi_{sep}/2}{V_s}$$

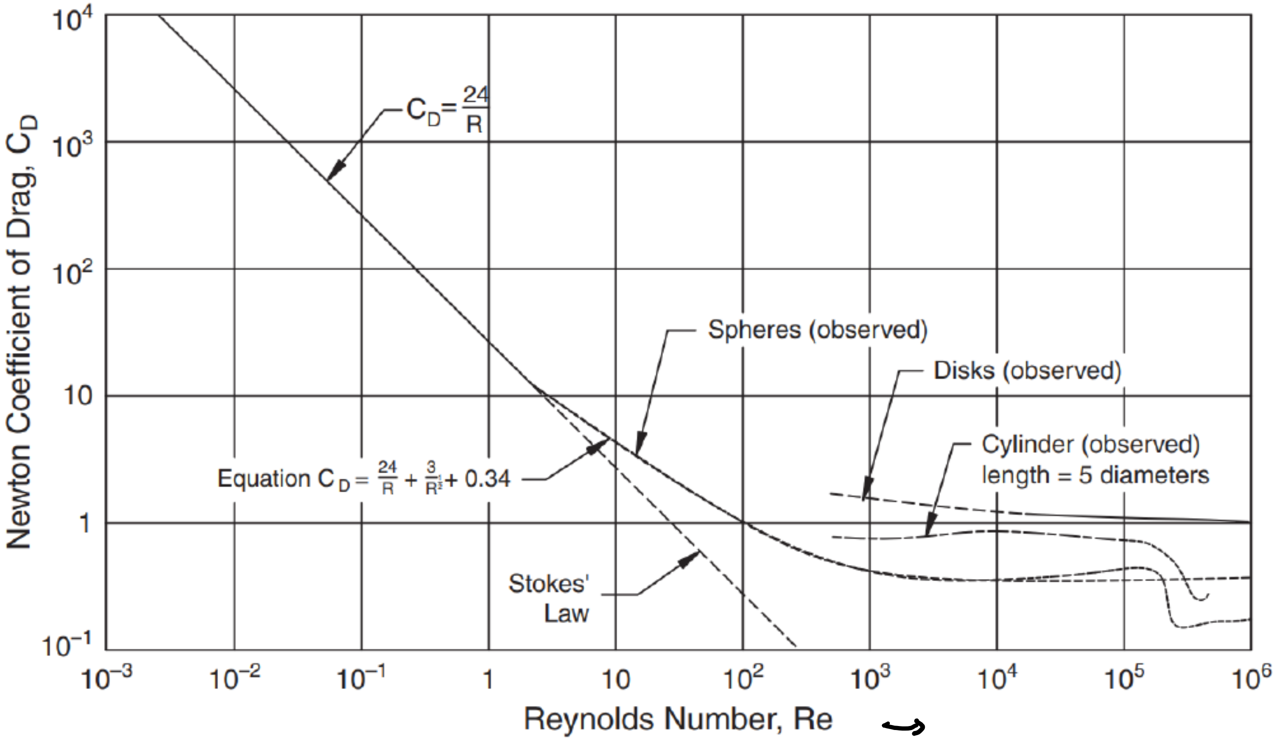


If it is a bubble of gas in oil, the direction of drag is opposite,
Then it should be (denf-dend)

Separation time = settling time

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

surrounding fluid



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

Case ①

Liquid droplet in gas

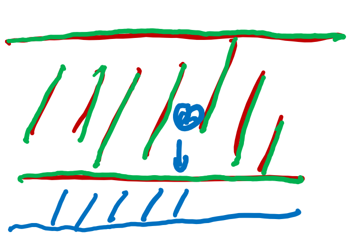
$\mu_f \downarrow$

$v_s \uparrow$

$Re_p \uparrow$

Case ②

droplet of water in oil



$\mu_f \uparrow$

$v_s \downarrow$

$Re \downarrow$

Case 2

Case 1

Separation time = settling time

the calculation of v_s is implicit ! because $C_D = f(v_s)$

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

$f(v_s)$

1 assume v_s
2 calculate Re
3 calculate C_D
4 calculate v_s
5 repeat

GAS

$$t_{resid} \geq t_{settling}$$

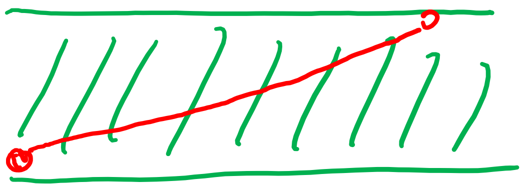
$$\frac{\frac{L \cdot \phi_{sep}^2 \pi}{8}}{q_{gas}} \geq \frac{\frac{\phi_{sep}}{2}}{v_s}$$

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

Oil separation time

API 12 J

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



is very fast

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

$\frac{V_o}{q_o} = t_{res,o} \geq t_{retention\ oil}$

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

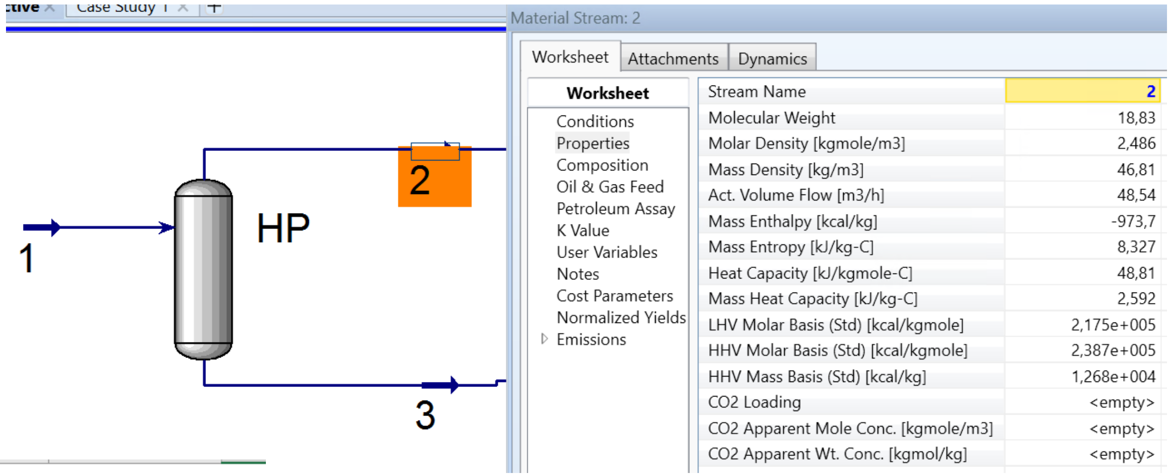
API spec 12J

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

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:

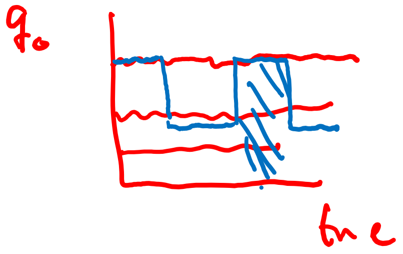
Dsep	[m]	0.9
Vsettling (oil in gas)	[m/s]	0.1567
tsep (oil in gas)	[s]	2.87
L_eff_min (tres>tsetl)	[m]	0.1
Lsep (eff)	[m]	2.1
tres_liq	[s]	61.38
Lss/D	[-]	3.3
L_eff_max (slenderness ratio)	[m]	2.7

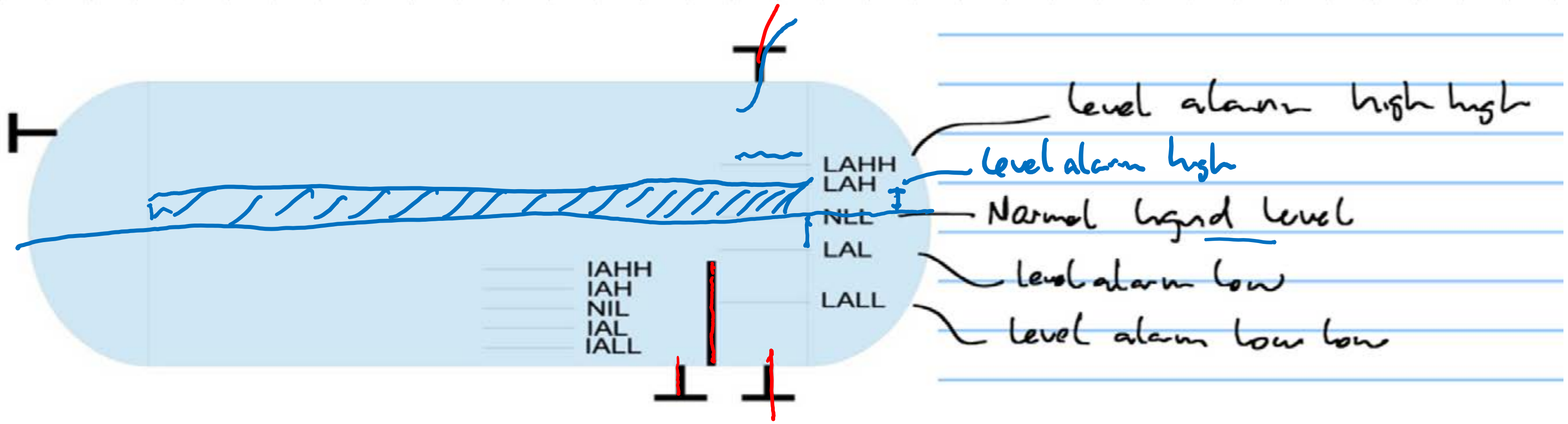
This separator is oversized for gas, but it is properly sized for the liquid

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

Other design considerations

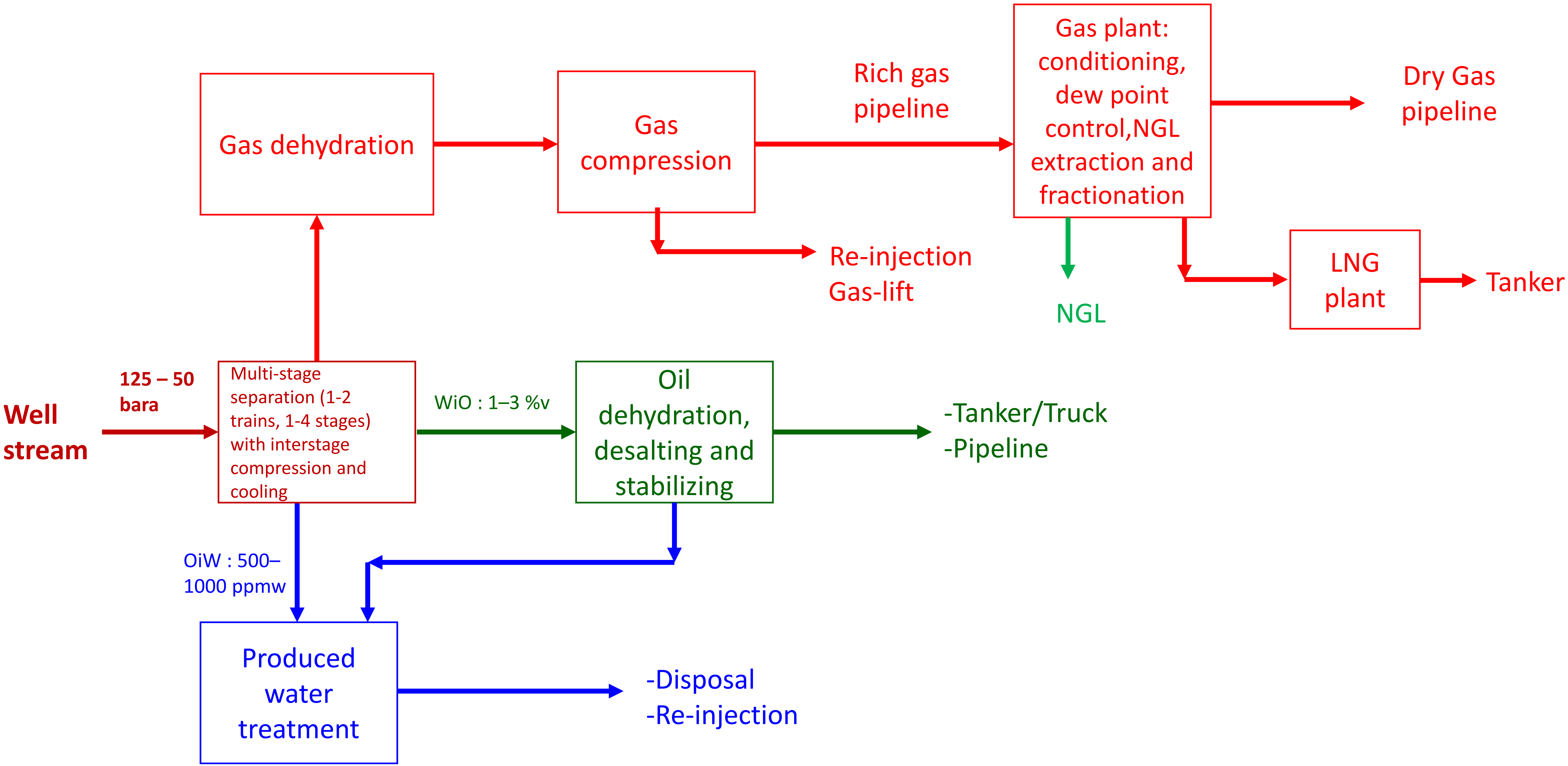
- 3 phases (gas, oil and water)
- Internals
- Inlet and outlet section
- Structural design
- Additional space for transient flow (slugs)
- ++

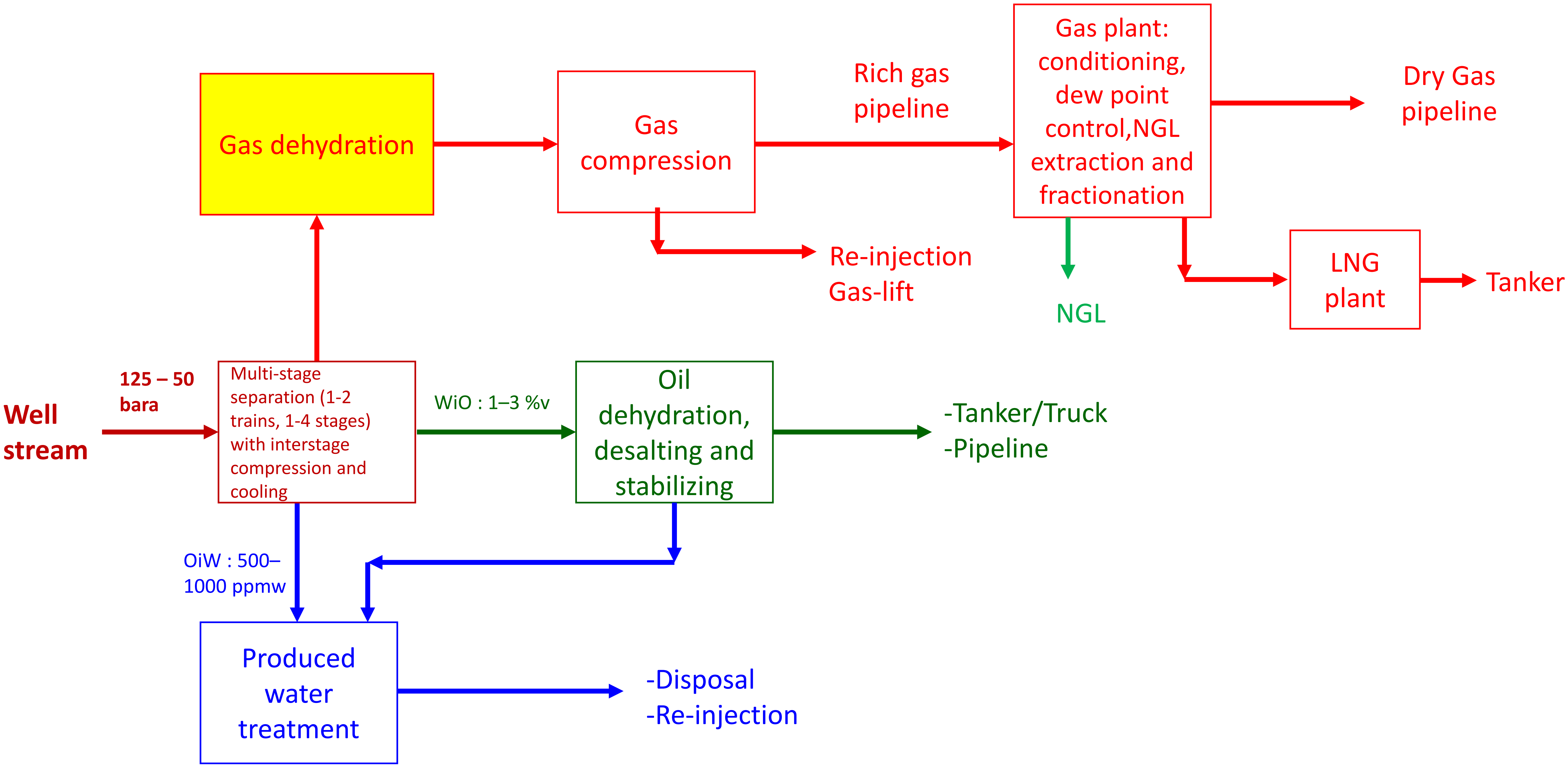




OUTLINE: 27.01.2023

- Other topside processing equipment
- Quiz 5


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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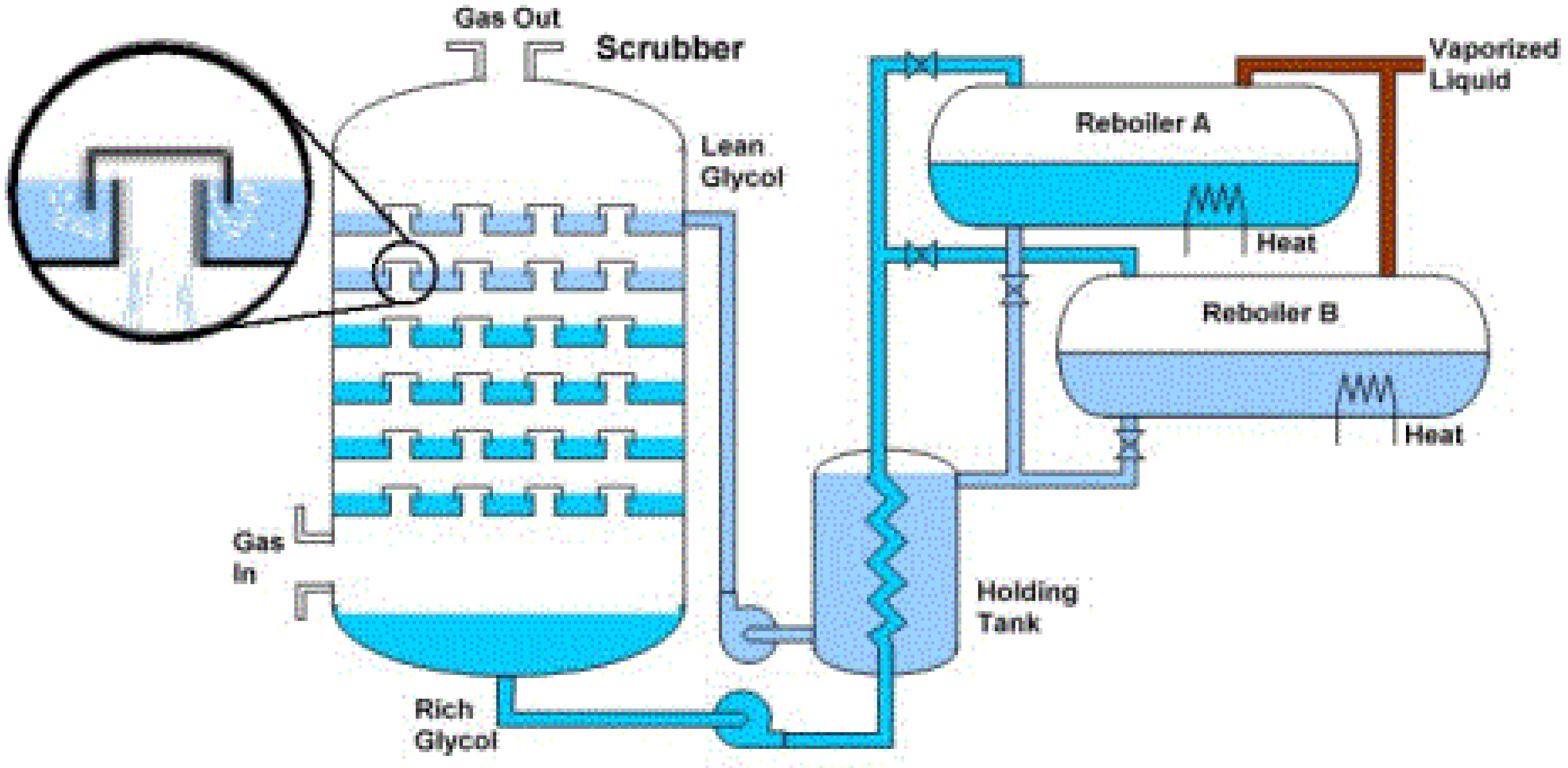
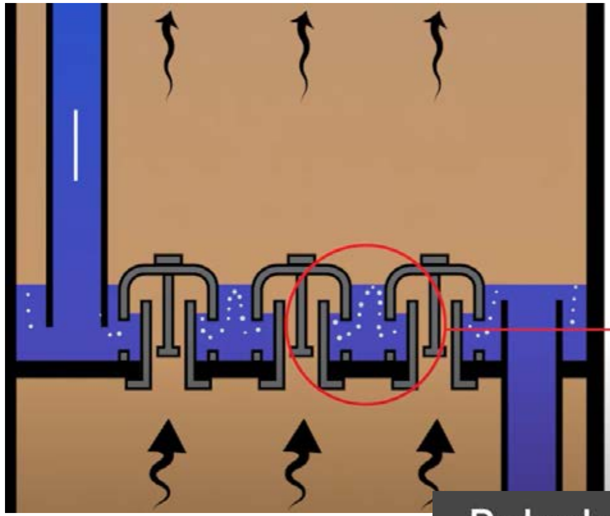
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection

TEG dehydration



Youtube links for TEG dehydration

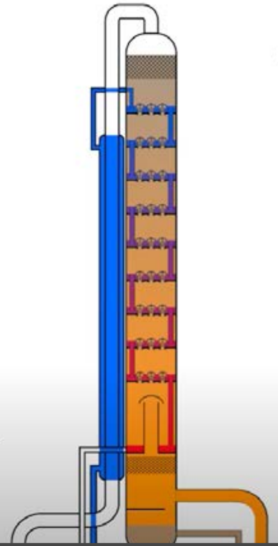
- Inside a gas dehydration tower: https://www.youtube.com/watch?v=_f7q8gWf8fg
- Gas dehydration unit: https://www.youtube.com/watch?v=kTtiqTeTZ0I



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

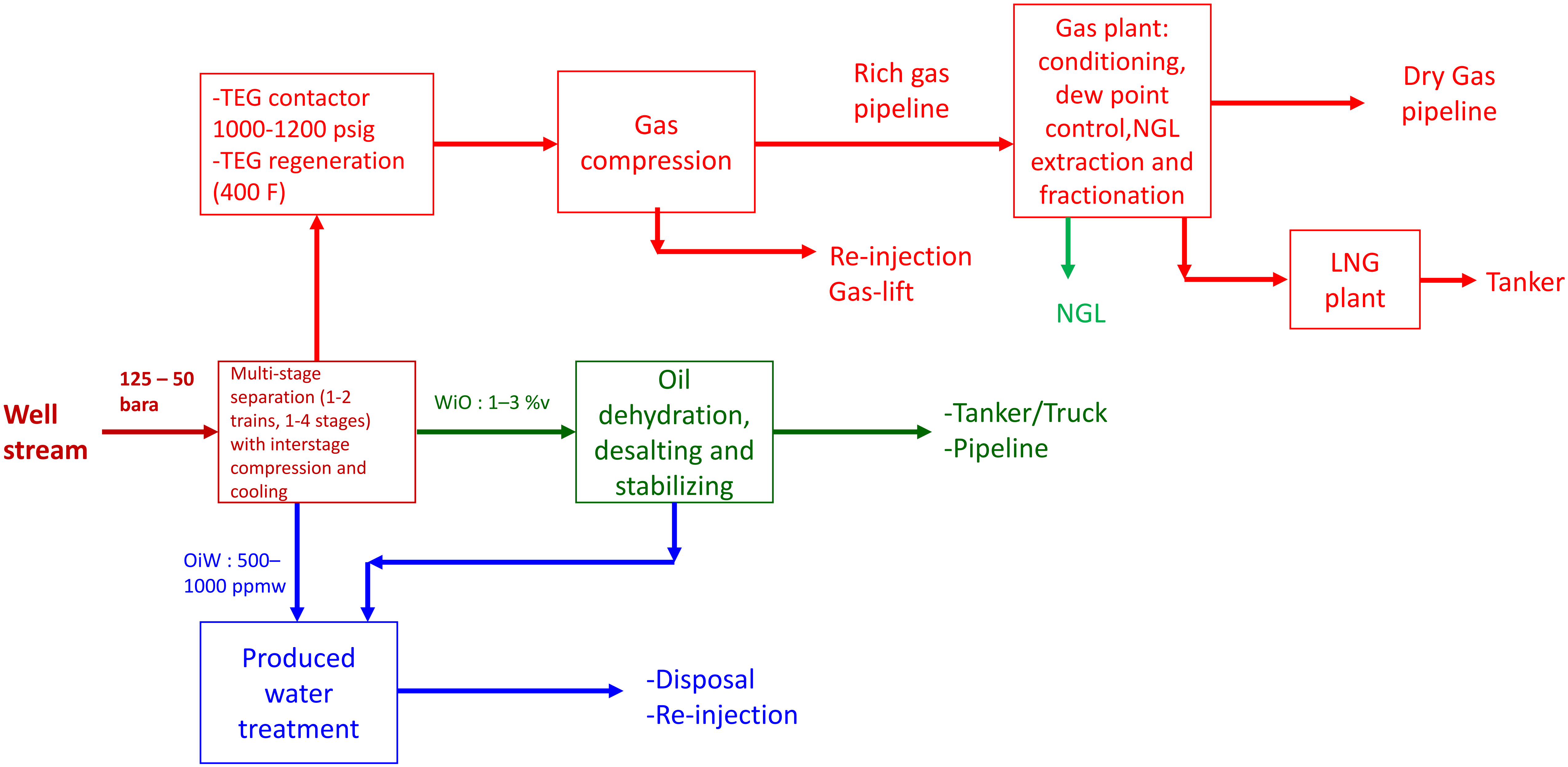
1. Glycol moves through **contactor tower**, absorbing the moisture from the natural gas becoming WET GLYCOL.

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)
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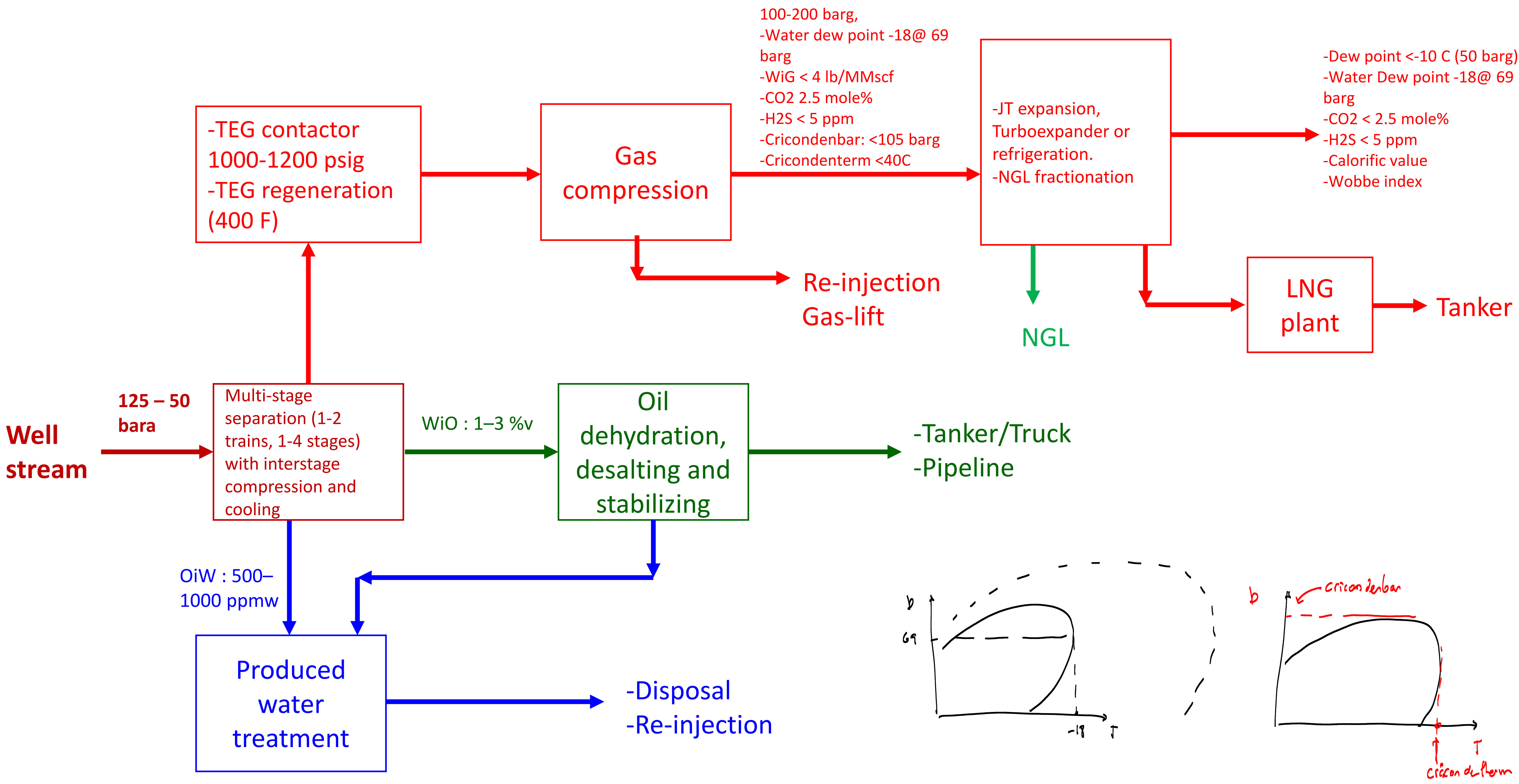
-Pipeline
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection



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)
Gas compression
-JT expansion, Turboexpander or refrigeration.
-NGL fractionation
Re-injection
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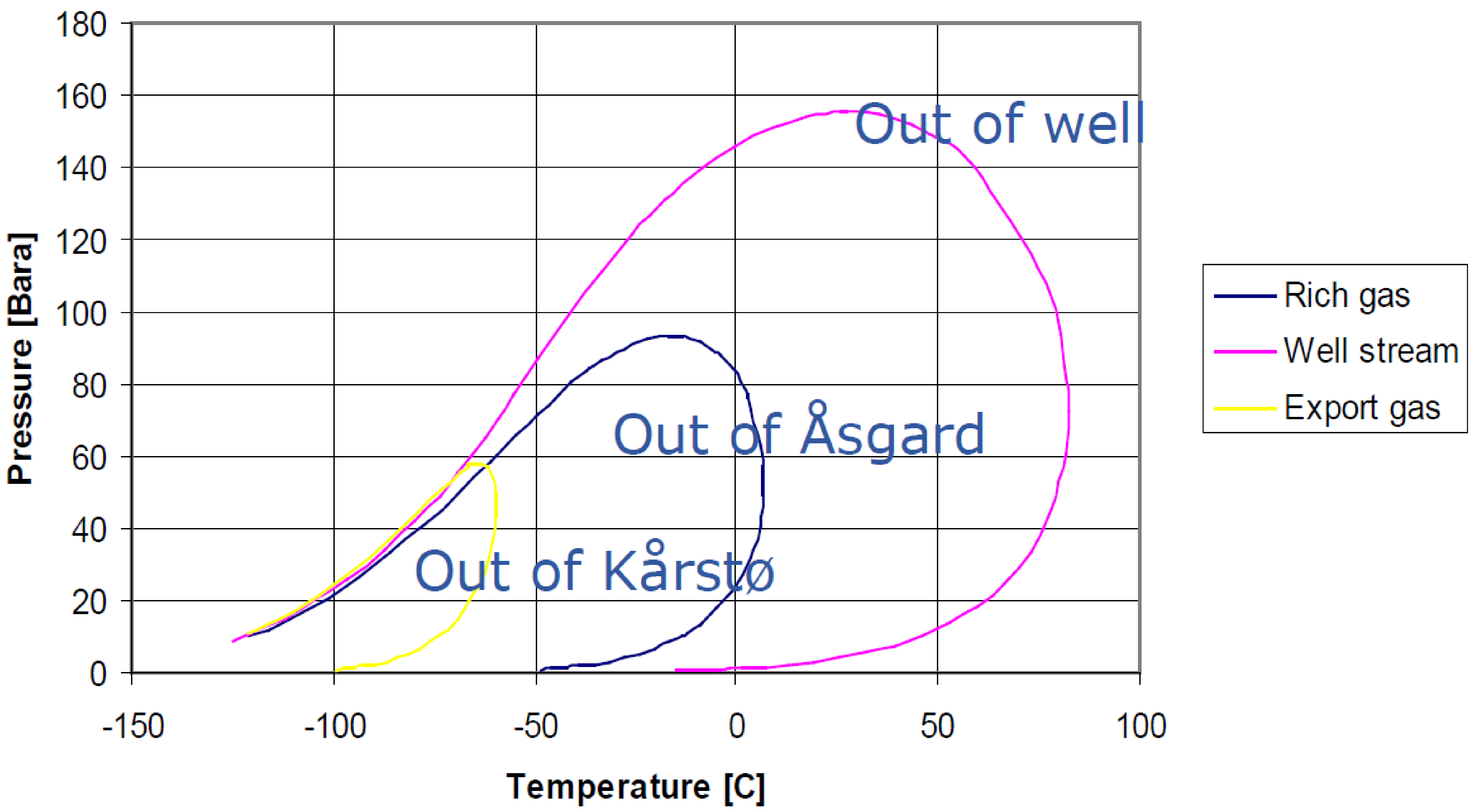
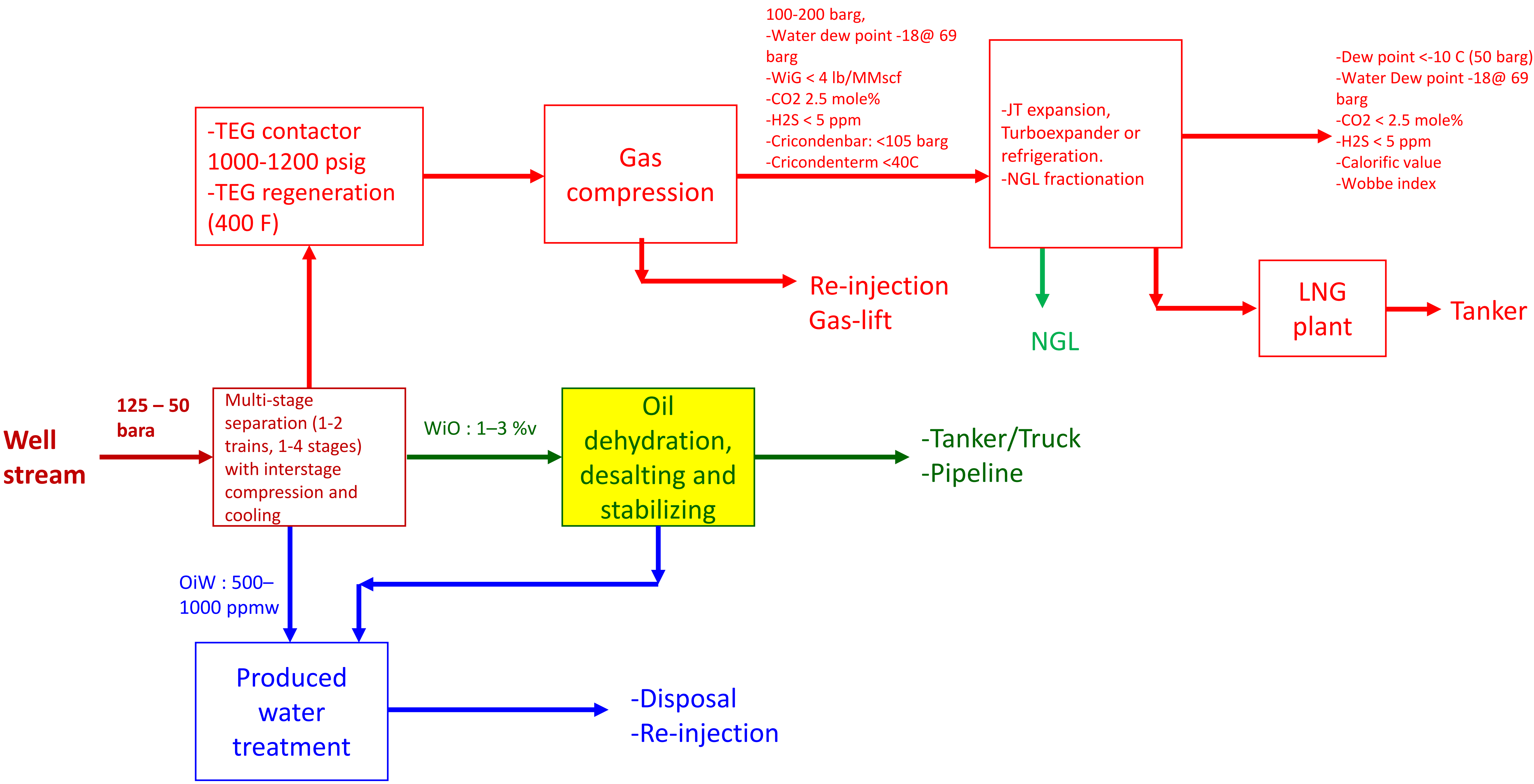
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection
p
69
-18
T
p
cricondenbar
T
cricondentherm

Hydrocarbon phase behaviour





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OiW : 500–1000 ppmw
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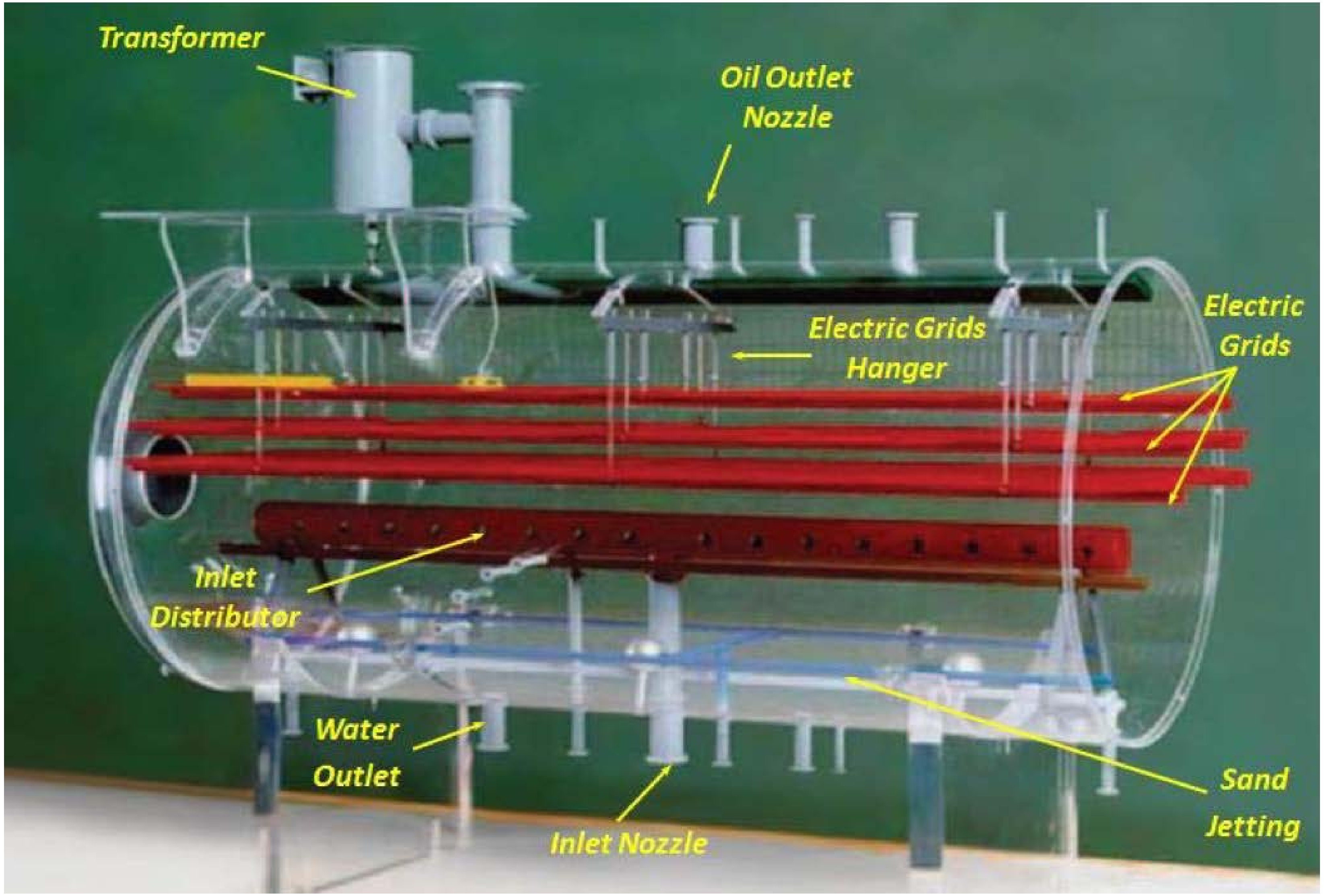
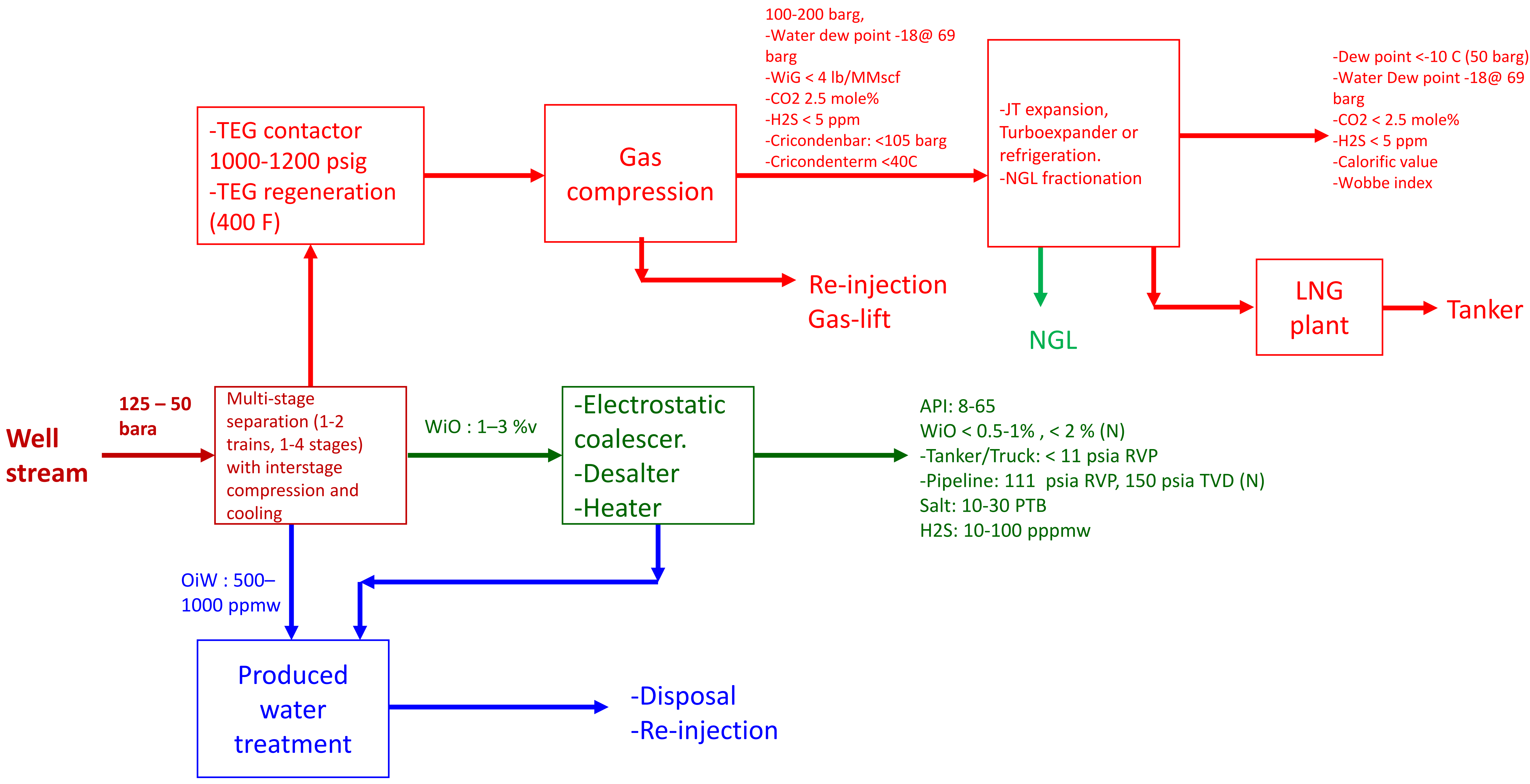
Electrostatic coalescer





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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

H_2S: 10-100 pppmw

$$API = \frac{141.5}{\gamma_{\bar{o}}} - 131.5$$

$\bar{o}$ standard conditions

$$\gamma_{\bar{o}} = \frac{\rho_{\bar{o}}}{\rho_{\bar{w}}}$$

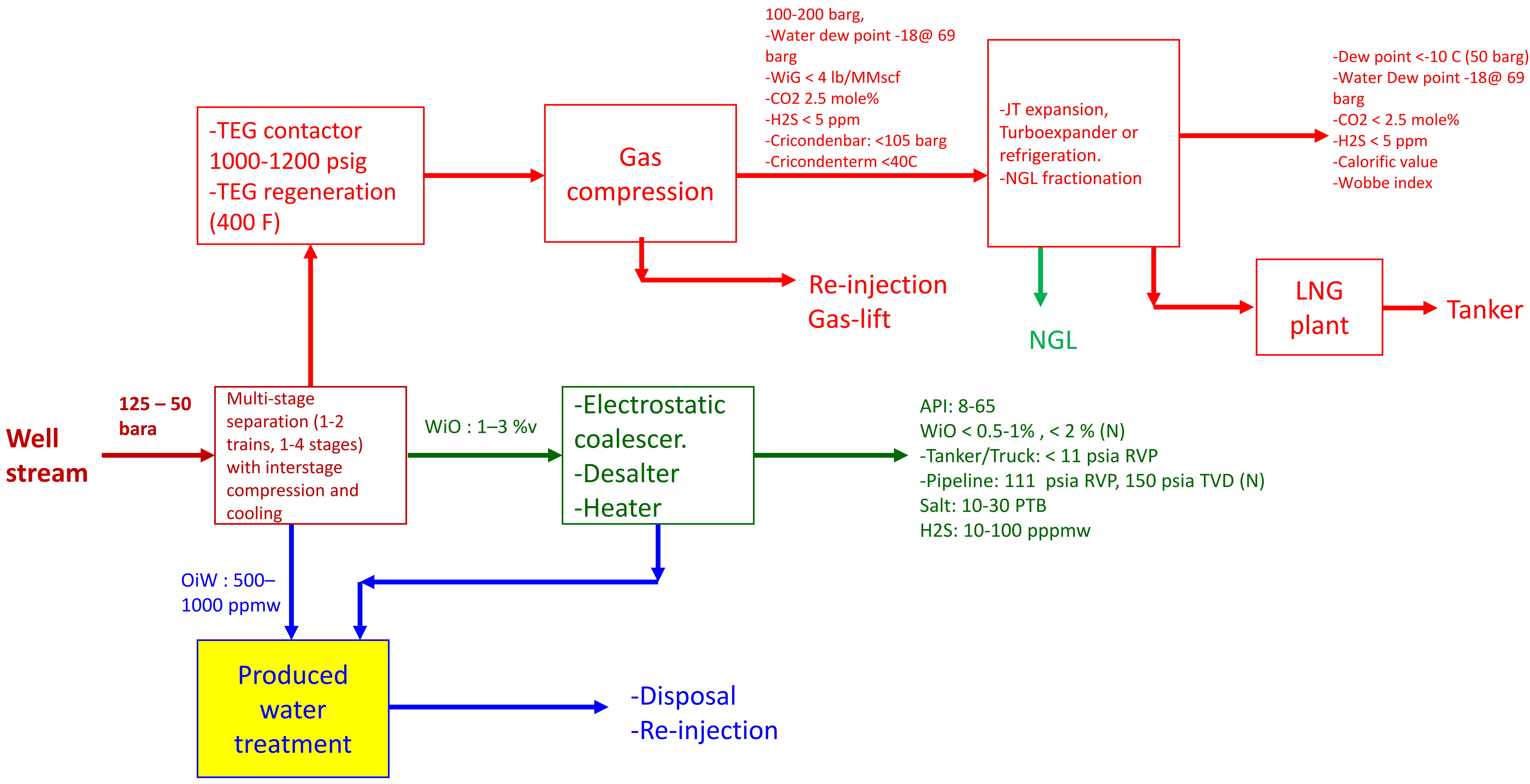
700-900 kg/m^3

1000 kg/m^3

Reid vapor pressure

TVD true vapor pressure

PTB pounds per thousand barrels



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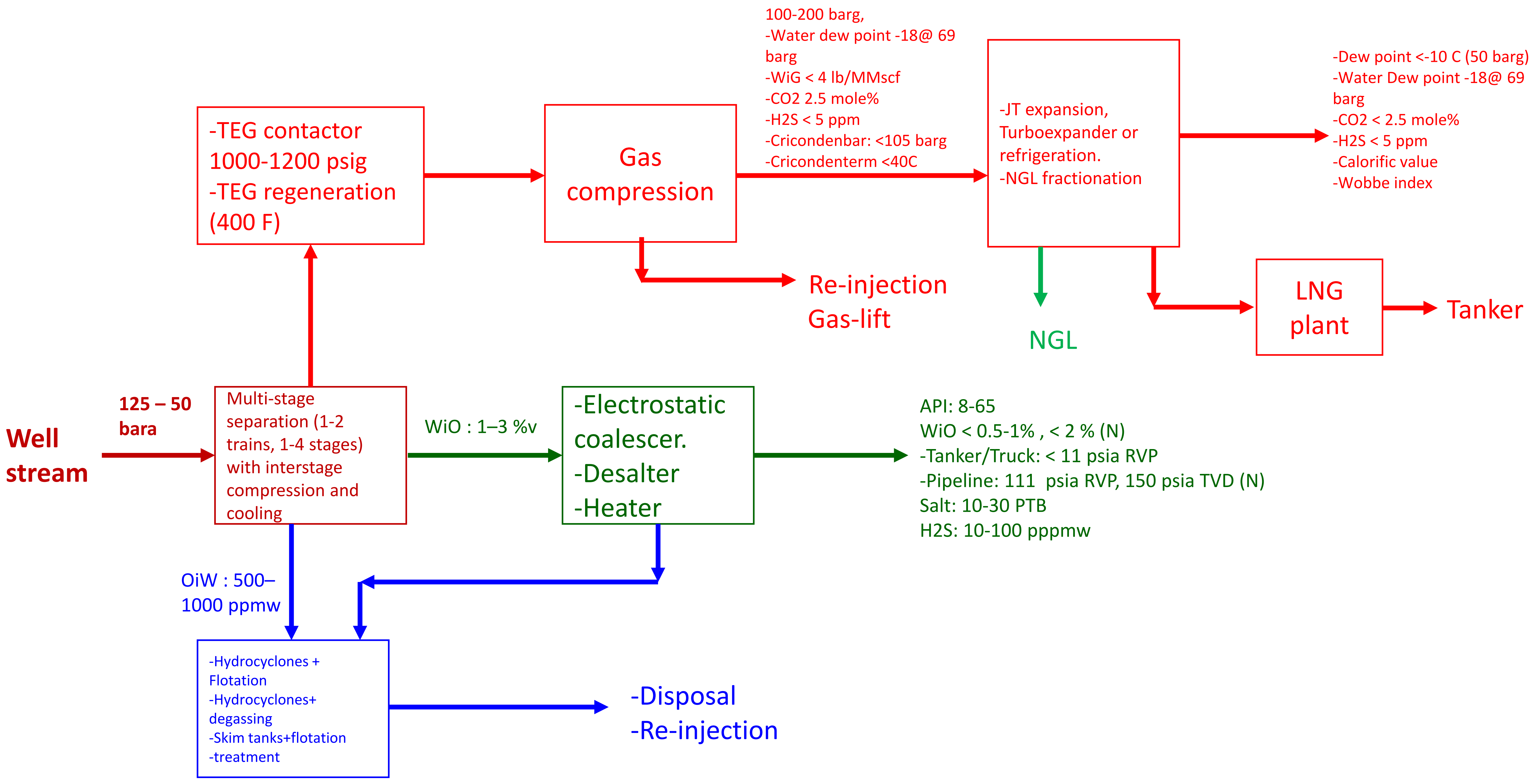
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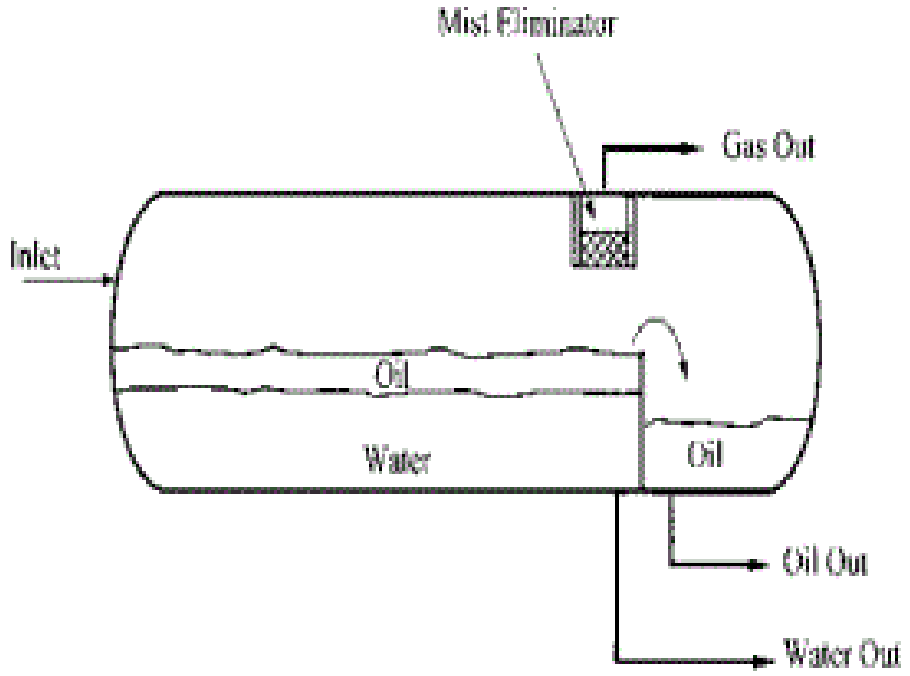
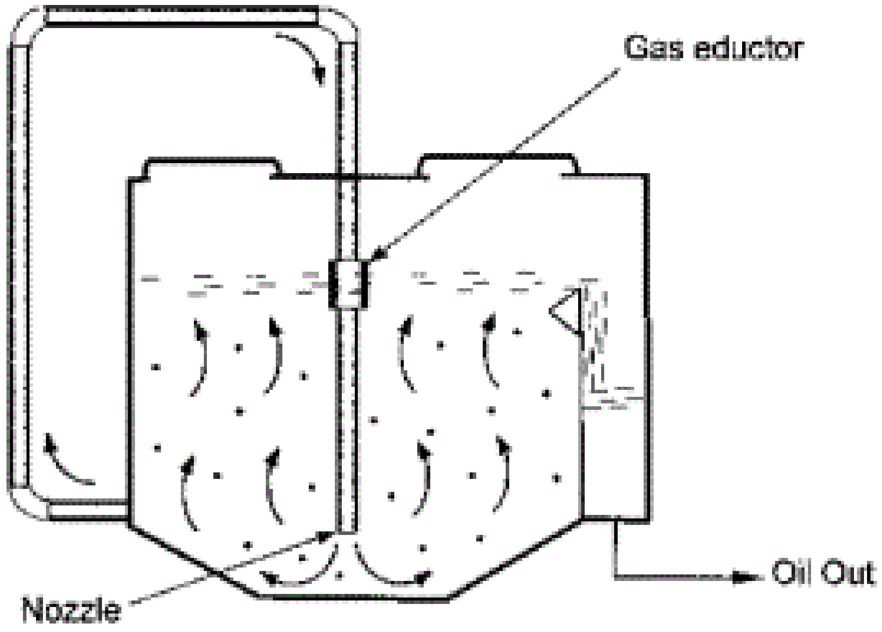
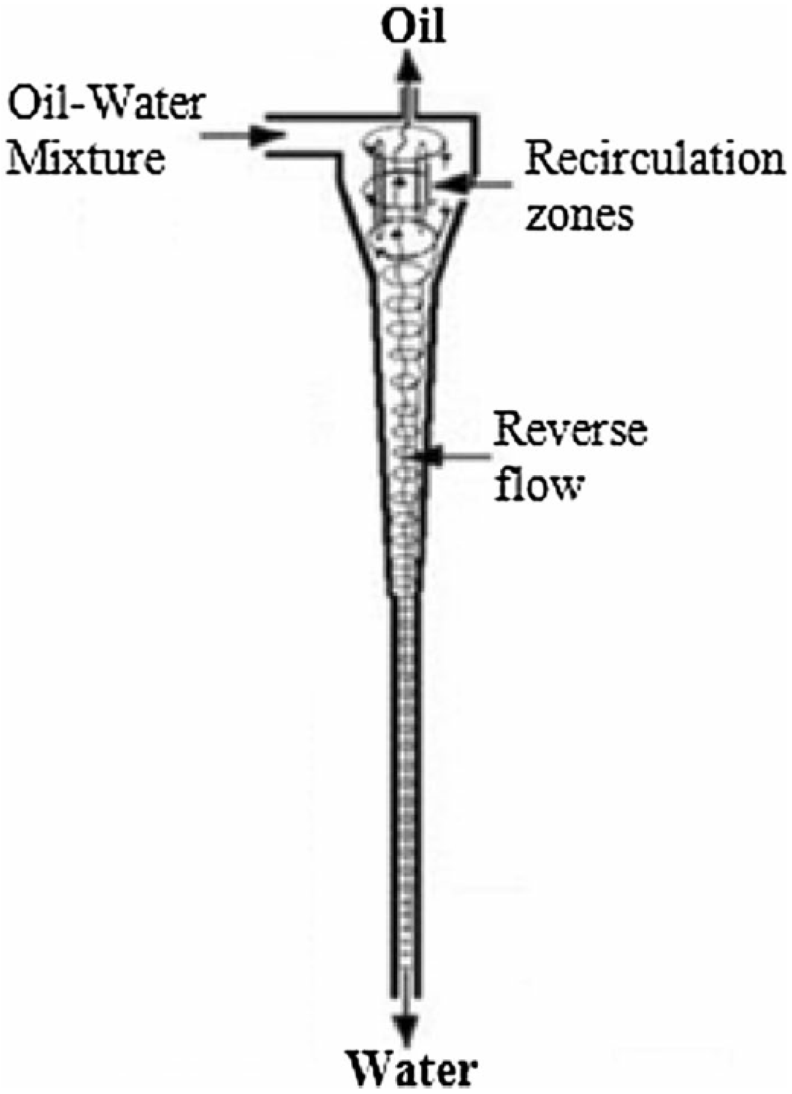
-Pipeline: 111 psia RVP, 150 psia TVD (N)
Salt: 10-30 PTB
H2S: 10-100 pppmw
OiW : 500–1000 ppmw
-Hydrocyclones + Flotation
-Hydrocyclones+ degassing
-Skim tanks+flotation
-treatment
-Disposal
-Re-injection

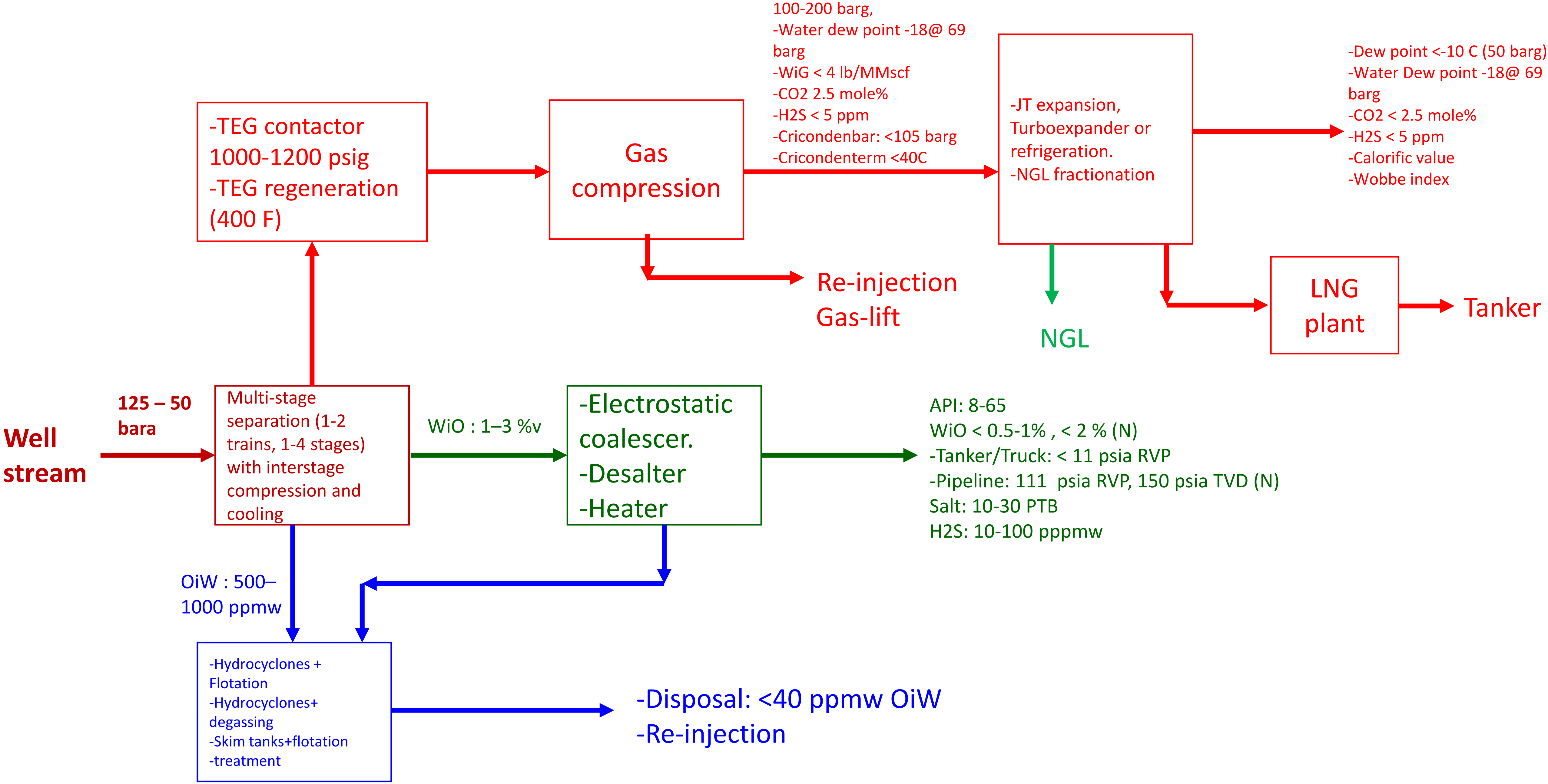
Skim tank + flotation unit





Hydrocyclone





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,
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LNG plant
Tanker
WiO : 1–3 %v
-Electrostatic coalescer.
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API: 8-65
WiO < 0.5-1% , < 2 % (N)
-Tanker/Truck: < 11 psia RVP
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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: <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

Field development and operations - Quiz 5

1. Which of the following statements is false?

- ○ Field production mode A is always followed by mode B
- ○ A field could be produced using mode B and then mode A
- ○ Production mode B is typically used for standalone projects
- ○ In production mode A, the wellhead choke is opened gradually

2. Using the data in the facts website of the NPD, and assuming that the field produced a constant rate during all days of the month, what was the oil rate produced by the Alvheim field in October 2021? (input just the number is Sm3/d, without the digits after the decimal point and without rounding)

Answer:

3. Using the excel sheet given, and the simplified expression to calculate NPV, determine the field plateau rate that gives the highest NPV (assume 350 operational days in a year)

- ○ Ca 9000 Sm3/d
- ○ Ca 4000 Sm3/d
- ○ Ca 12000 Sm3/d

4. A while ago, Milan made an Excel file that shows the production profile of field in the NCS using data from the npd website. Using the data in the excel sheet, compute a range for the initial gas in place of the Snohvit field using the rule of thumb discussed in class. Assume an uptime of 95%, and ultimate recovery factor of 85%. Select the closest from the list below.

- ○ 1.6 E11 - 4.1 E11 Sm3
- ○ 6.2 E11 - 8.5 E11 Sm3
- ○ 0.8 E11 - 1 E11 Sm3

Once ready submit here your results:

Submit

MENU — FACTPAGES — NORWEGIAN PETROLEUM DIRECTORATE — NPD

WELLBORE LICENCE BAA FIELD DISCOVERY COMPANY SURVEY FACILITY TUF STRATIGRAPHY 31.01.2023 - 01:31

- Attributes
- > Page view
- ∨ Table view
  - Overview
  - Status
  - Operators
  - Owners
  - Licensees
  - ∨ Production
    - ∨ Saleable
      - **Monthly - by field**
      - Yearly - by field
      - Monthly - total
      - Yearly - total

Table – Monthly - by field

Export: EXCEL XML CSV

Field (Discovery)	Year	Month	Net - oil [mill Sm3]	Net - gas [bill Sm3]	Net - NGL [mill Sm3]	Net - condensate [mill Sm3]	Net - oil equivalents [mill Sm3]	Produced water in field [mill Sm3]	NPDID information carrier
ALBUSKJELL	1996	11	0.00428	0.01558	0.00156	0.00000	0.02142	0.00000	43437
ALBUSKJELL	1996	12	0.00416	0.01668	0.00159	0.00000	0.02243	0.00000	43437
ALBUSKJELL	1997	1	0.00334	0.01180	0.00124	0.00000	0.01638	0.00000	43437
ALBUSKJELL	1997	2	0.00366	0.01370	0.00146	0.00000	0.01882	0.00000	43437
ALBUSKJELL	1997	3	0.00414	0.01713	0.00169	0.00000	0.02296	0.00000	43437
ALBUSKJELL	1997	4	0.00393	0.01559	0.00164	0.00000	0.02117	0.00000	43437
ALBUSKJELL	1997	5	0.00367	0.01589	0.00156	0.00000	0.02111	0.00000	43437
ALBUSKJELL	1997	6	0.00335	0.01598	0.00148	0.00000	0.02081	0.00000	43437
ALBUSKJELL	1997	7	0.00358	0.01550	0.00154	0.00000	0.02062	0.00000	43437
ALBUSKJELL	1997	8	0.00420	0.01879	0.00200	0.00000	0.02498	0.00000	43437
ALBUSKJELL	1997	9	0.00510	0.01678	0.00180	0.00000	0.02368	0.00000	43437

initial fluids in place

for Alvheim N oil $N_p(t)$

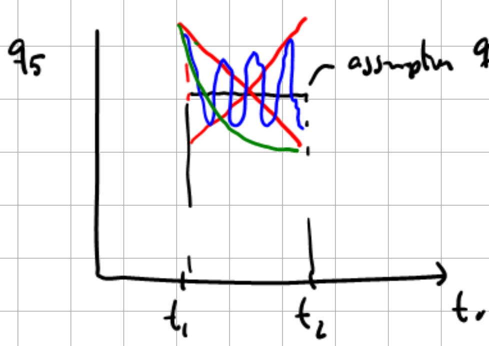
G gas

$\mathbb{C}$

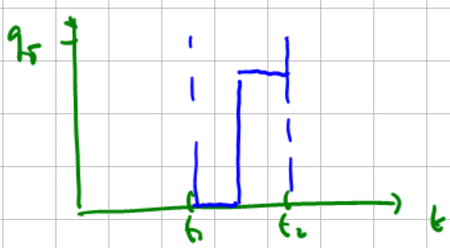
ΔN_p — how much has been produced in a period

for October 2021, Alvheim produced $\Delta N_p = 0.19628\ E06\ Sm^3$

q_o Sm^3/d



$$q_s = \frac{0.19628\ E06\ Sm^3}{31} = 6331\ Sm^3/d$$



Rules of thumb

$$N_{pu} = \int_0^{t_{final}} q_{o_{field}}\, dt$$

$$q_o = \frac{N_{pu} \cdot \overset{0.1}{F}}{N_{day\ in\ year}}$$

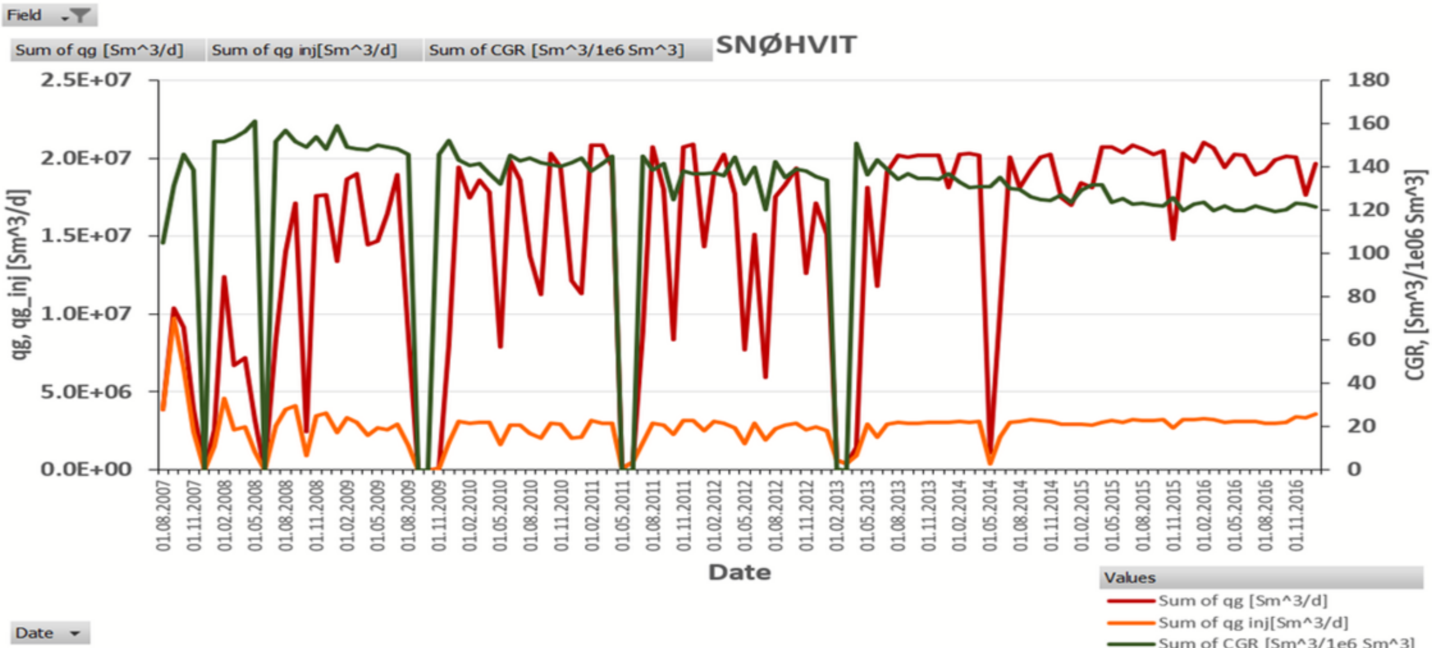
$$q_g = \frac{G_{pu}\, \overset{0.02-0.05}{F}}{N_{day\ in\ year}}$$

$$G_{pu} = \frac{q_g \cdot N_{days/year}}{F}$$

F

$N_{day\ in\ year} = 0.95 \cdot 365 = 346.75$ days

from NPD, $q_{g_{field}} \cong 20E06\ Sm^3/d$



$$G_{pu} = \frac{20E6 \cdot 346.75}{0.02} = 3.46\ E11\ Sm^3$$

$$G = \frac{G_{pu}}{0.85} = 4.08E11\ Sm^3$$

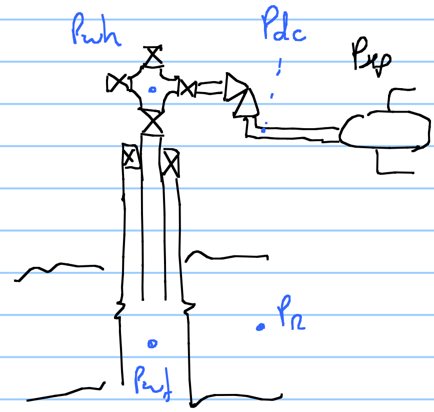
$$\frac{G_{pu}}{G} = F_{RU}$$ ultimate recovery factor

Youtube video: Intro to Excel VBA functions and sub

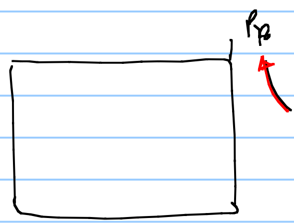
There were no notes for this video

Youtube video: modeling dry gas systems

Simplified dry gas production system



Reservoir model



Dry gas material balance

$$P_R = P_{Ri} \frac{z_R}{z_i} \left(1 - \underbrace{\frac{G_p}{G}}_{R_F}\right)$$

$G_p = f(q_g)$, $q_g = f(t)$

G: uncertain value

R_F recovery factor

z: gas deviation factor

$z = f(P_r, T_r)$, $P_r = \frac{P_R}{P_c}$, $T_r = \frac{T_R}{T_c}$

$P_c, T_c = f(\text{gas composition})$

MB dry gas equation is implicit

- Given RF, assume P_R
- with P_R compute z_R
- verify that $\varepsilon = P_R - \frac{P_{Ri}\, z_R}{z_i}(1 - R_F) = 0 \leq$ Tolerance
- if not,

3.3.2 Z-Factor Correlations. Standing and Katz[4] present a generalized Z-factor chart (**Fig. 3.6**), which has become an industry standard for predicting the volumetric behavior of natural gases. Many empirical equations and EOS's have been fit to the original Standing-Katz chart. For example, Hall and Yarborough[21,22] present an accurate representation of the Standing-Katz chart using a Carnahan-Starling hard-sphere EOS,

$$Z = \alpha p_{pr}/y, \qquad (3.42)$$

where $\alpha = 0.06125\,t\,\exp[-1.2(1-t)^2]$, where $t = 1/T_{pr}$.

The reduced-density parameter, y (the product of a van der Waals covolume and density), is obtained by solving

$$f(y) = 0 = -\alpha p_{pr} + \frac{y + y^2 + y^3 - y^4}{(1-y)^3} - (14.76t - 9.76t^2 + 4.58t^3)y^2 + (90.7t - 242.2t^2 + 42.4t^3)y^{2.18+2.82t}, \qquad (3.43)$$

with

$$\frac{df(y)}{dy} = \frac{1 + 4y + 4y^2 - 4y^3 + y^4}{(1-y)^4} - (29.52t - 19.52t^2 + 9.16t^3)y + (2.18 + 2.82t)(90.7t - 242.2t^2 + 42.4t^3) \times y^{1.18+2.82t}. \qquad (3.44)$$

The derivative $\partial Z/\partial p$ used in the definition of c_g is given by

$$\left(\frac{\partial Z}{\partial p}\right)_T = \frac{\alpha}{p_{pc}}\left[\frac{1}{y} - \frac{\alpha p_{pr}/y^2}{df(y)/dy}\right]. \qquad (3.45)$$

Equation approximation to Z chart

to predict T_c, P_c we will use

Sutton correlations

Sutton[7] suggests the following correlations for hydrocarbon gas mixtures.

$$T_{pcHC} = 169.2 + 349.5\gamma_{gHC} - 74.0\gamma_{gHC}^2 \qquad (3.47a)$$

and

$$p_{pcHC} = 756.8 - 131\gamma_{gHC} - 3.6\gamma_{gHC}^2. \qquad (3.47b)$$

$$\gamma_g = \frac{Mw_{gas}}{Mw_{air}\ (28.97)}$$

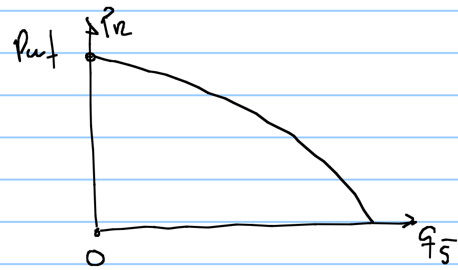
$$Mw_{gas} = \sum_{i=1}^{N} z_i Mw_i$$

$P_R \rightarrow P_{wf}$ IPR equation low pressure dry gas equation

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

← backpressure exponent
laminar $n \sim 1$
turbulent $n \to 0.5$

inflow coefficient $\{ T_R, k, h, s$ (skin factor)



- pseudo-steady state regime (boundary dominated flow)
page 37 of compendium

- $P_{wf} \rightarrow P_{wh}$ Dry gas tubing equation

$$q_{\bar{g}} = C_T\left(\frac{P_{wf}^2}{e^S} - P_{wh}^2\right)^{0.5}$$

elevation coefficient (hydrostatic losses)

tubing coefficient (friction losses)

$q_{\bar{g}} = 0$ $P_{wf} = P_{wh}\, e^{S/2}$

Page 156, Appendix A of compendium

$$q_{sc} = \left(\frac{\pi}{4}\right)\cdot\left(\frac{R}{M_{air}}\right)^{0.5}\cdot\left(\frac{T_{sc}}{p_{sc}}\right)\cdot\left(\frac{D^5}{f_M\cdot L\cdot\gamma_g\cdot Z_{av}\cdot T_{av}}\right)^{0.5}\cdot\left[\left(p_{wf}^2 - p_t^2\cdot e^S\right)\cdot\left(\frac{S}{e^S-1}\right)\right]^{0.5}$$

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

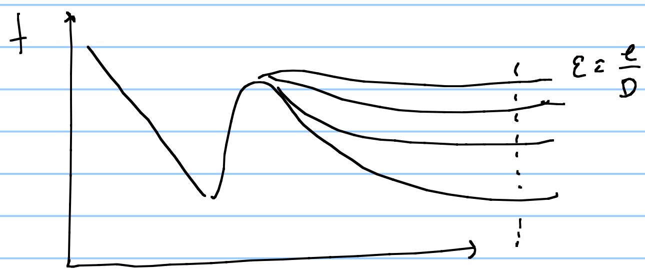
$$S = 2\cdot L\cdot C_a = 2\cdot\frac{M_g}{Z_{av}\cdot R\cdot T_{av}}\cdot L\cdot g\cdot\cos(\alpha)$$

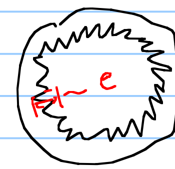
Comments about tubing equation

$T_{av} \rightarrow \frac{T_{wf} + T_{wh}}{2}$ An estimate of T_{wh} is needed to compute C_T

$z_{av} \rightarrow \frac{z_{wf} + z_{wh}}{2}$

f_M friction factor





$Re = \frac{v \rho D}{\mu}$

$v = f(q_{local})$ for gas $v \uparrow\uparrow$ ρ is low compared to liquid

q_{local} $f(\rho)$

liquid v - [0.5 - 4] m/s

gas v - [5 - 40] m/s

μ_g is << μ_L

Re_g >>

always in fully turbulent regime

$f_M = f(\varepsilon)$ however $e = f(C.D)$ due to manufacturing

Choke equation for dry gas: (page 166)

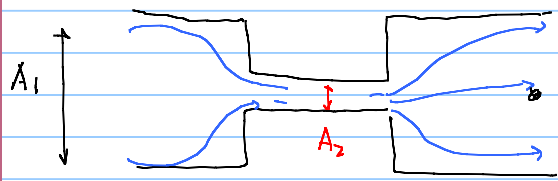
"opening" tuning factor $\frac{R_u}{MW_g}$ $k = \frac{c_p}{c_v}$

$$q_{\bar{g}} = \frac{p_1 \cdot T_{sc} \cdot A_2 \cdot C_d}{p_{sc}} \cdot \sqrt{2 \cdot \frac{R}{Z_1 \cdot T_1 \cdot M_w} \cdot \frac{k}{k-1} \cdot \left(y^{\frac{2}{k}} - y^{\frac{k+1}{k}}\right)}$$

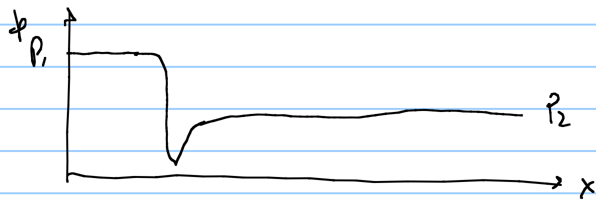
$p_{sc} = 1.01325$ bara

$T_{sc} = 15.56\ °C$

$y = \frac{p_2}{p_1}$ (downstream)/(upstream)



if $y > y_c \simeq (0.6)$, there is critical flow at the throat



if $y > y_c$ $q_{\bar{g}} = q_{\bar{g}_c} =$

$$q_{\bar{g}} = \frac{p_1 \cdot T_{sc} \cdot A_2 \cdot C_d}{p_{sc}} \cdot \sqrt{2 \cdot \frac{R}{Z_1 \cdot T_1 \cdot M_w} \cdot \frac{k}{k-1} \cdot \left(y_c^{\frac{2}{k}} - y_c^{\frac{k+1}{k}}\right)}$$

in blue

if $y < y_c$

$$q_{\bar{g}} = \frac{p_1 \cdot T_{sc} \cdot A_2 \cdot C_d}{p_{sc}} \cdot \sqrt{2 \cdot \frac{R}{Z_1 \cdot T_1 \cdot M_w} \cdot \frac{k}{k-1} \cdot \left(y^{\frac{2}{k}} - y^{\frac{k+1}{k}}\right)}$$

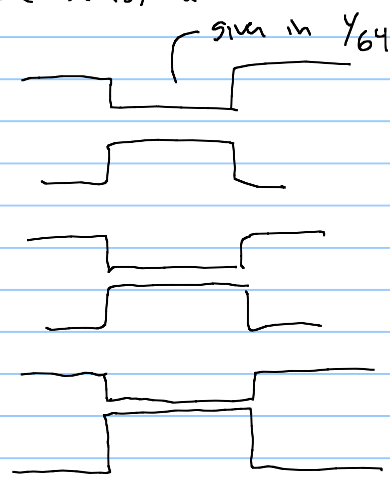
in red

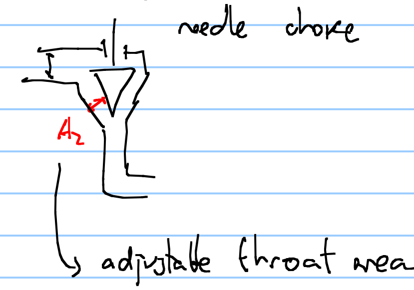
with p_1 = constant

(flow is "choked", critical flow)

in onshore fields, bean chore are often used

offshore often adjustable chokes are used





→ P_{sep} flowline → tubing equation can be used for flowline

horizontal flowline, the tubing equation simplifies to

$$q_{\bar{s}} = C_{FL}\left(P_{dc}^2 - P_{sep}^2\right)^{0.5}$$

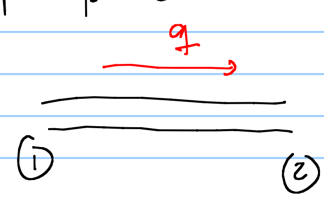
$S=0$ (L'Hopital)

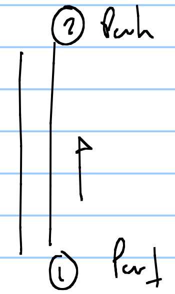
VBA Visual basic for applications

for pipe equations in VBA

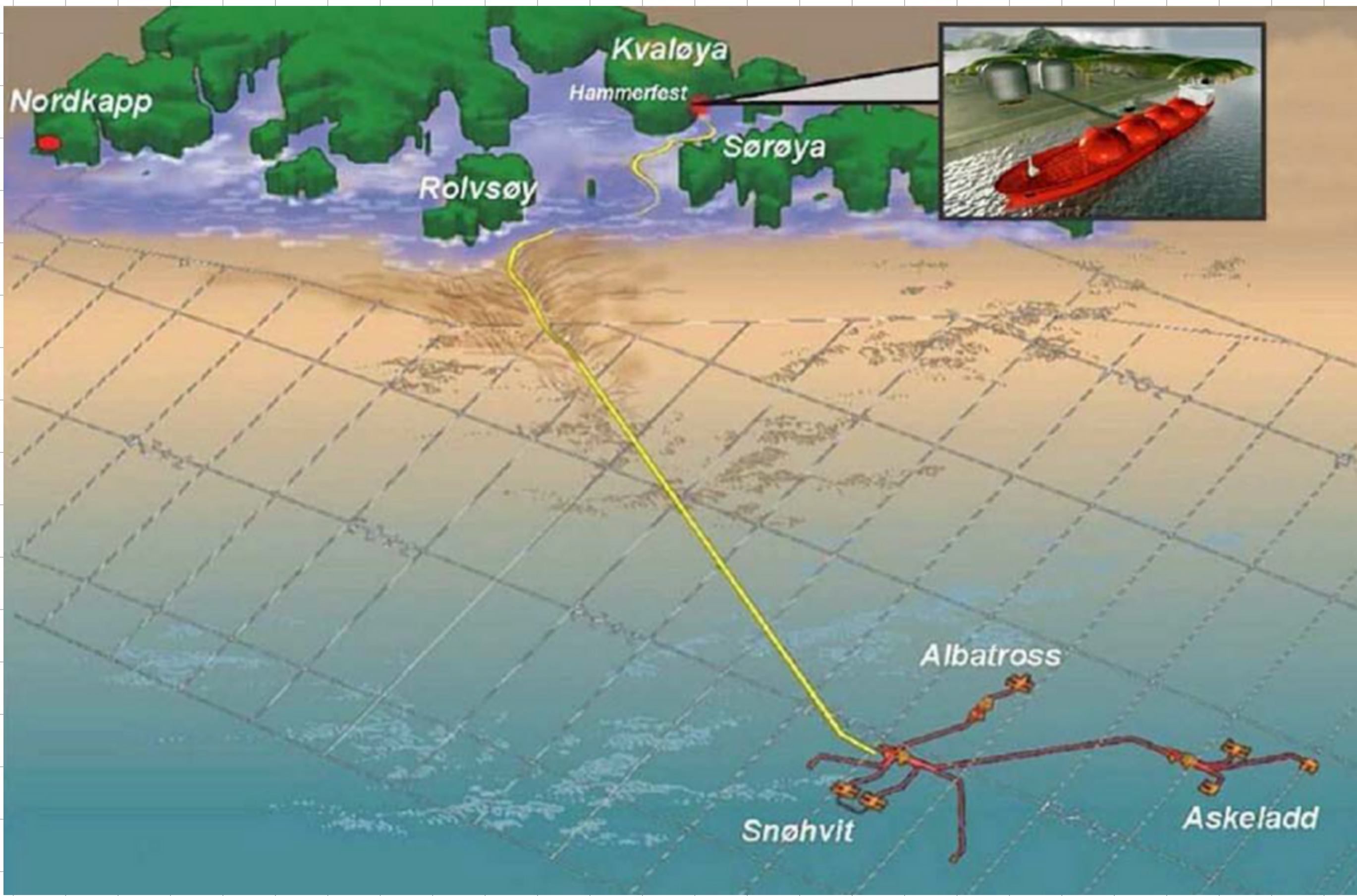
1 is upstream

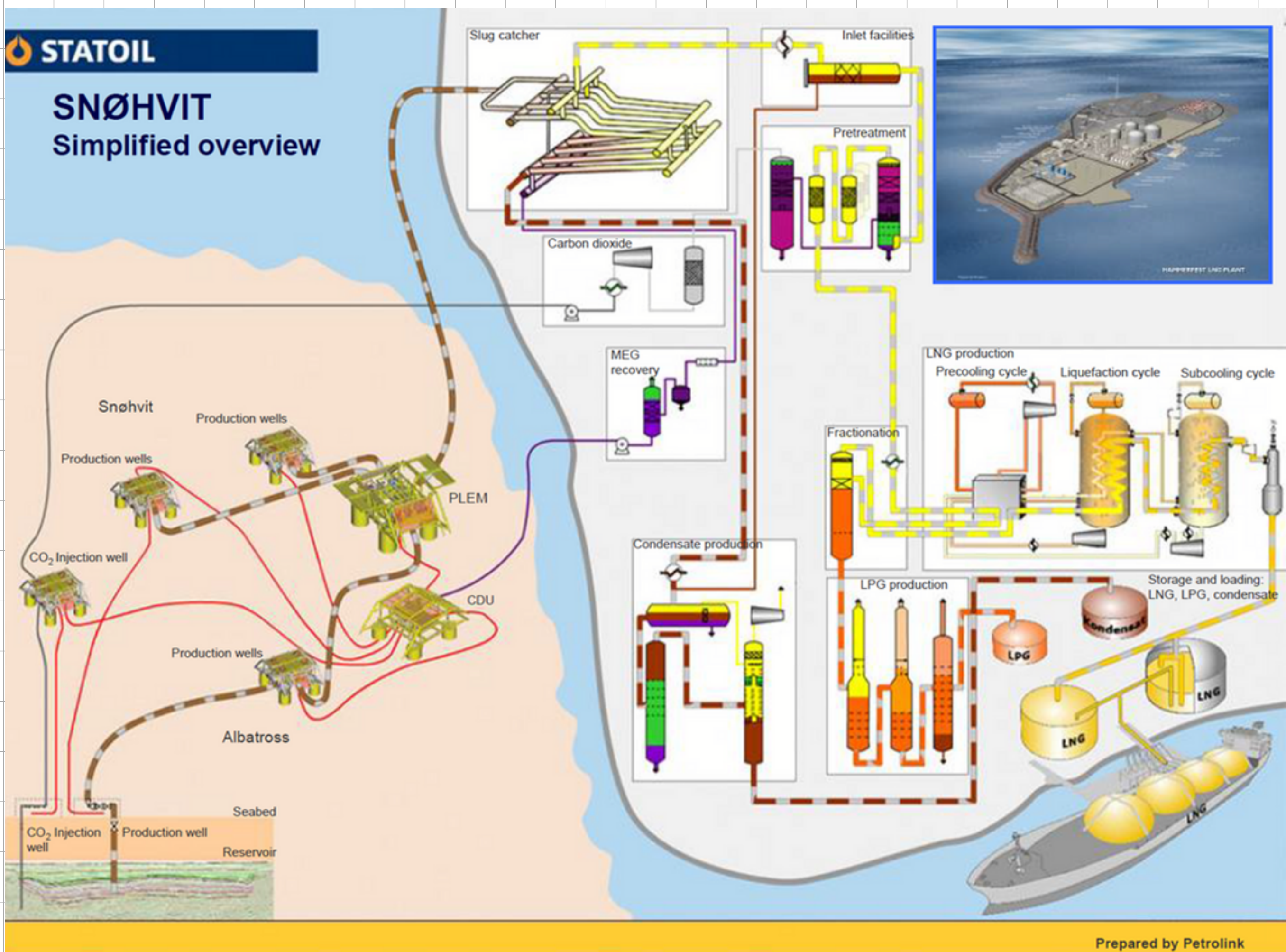
2 is downstream





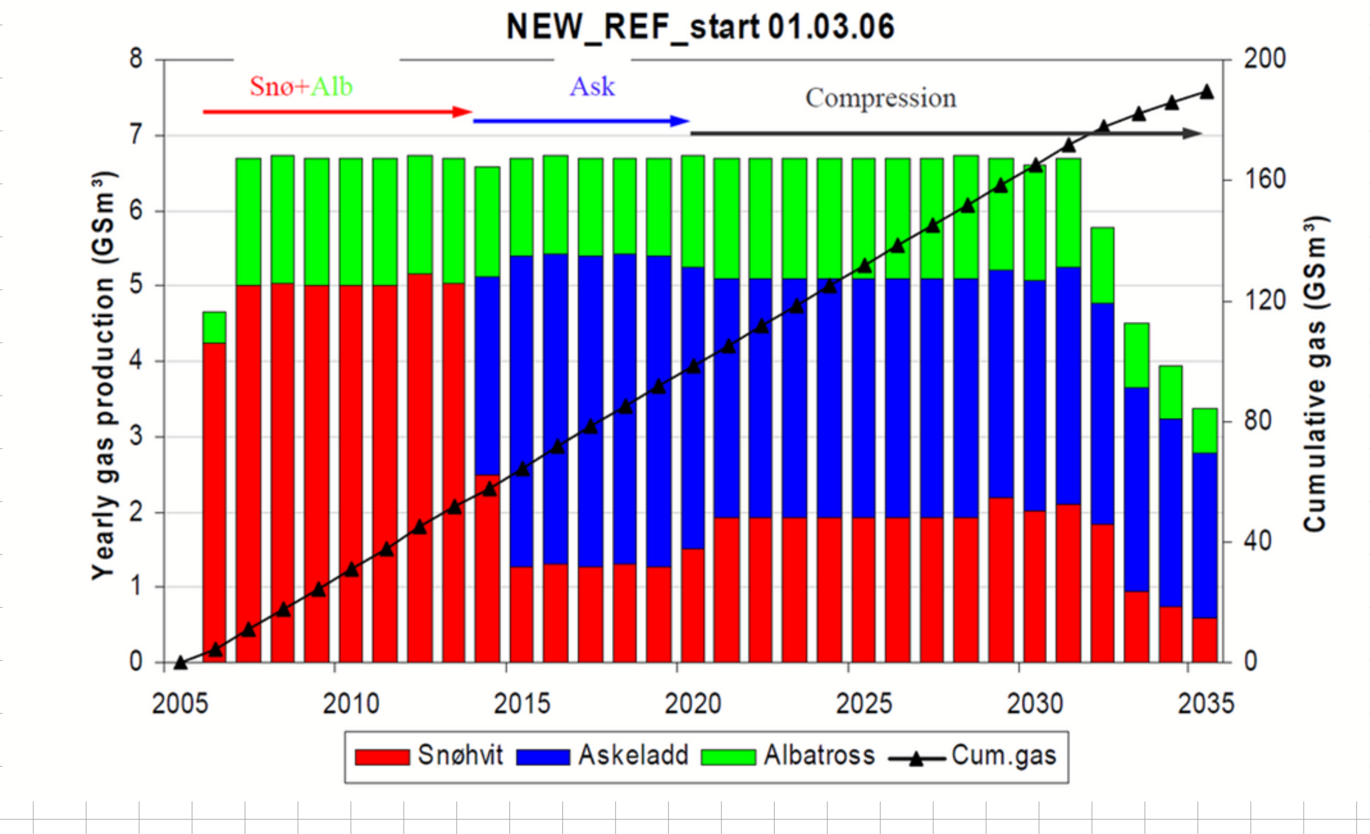
Outline, class 20230203:
-Re-cap on Excel VBA, equations for modeling dry gas systems
-Production scheduling - class exercise for the Snøhvit field



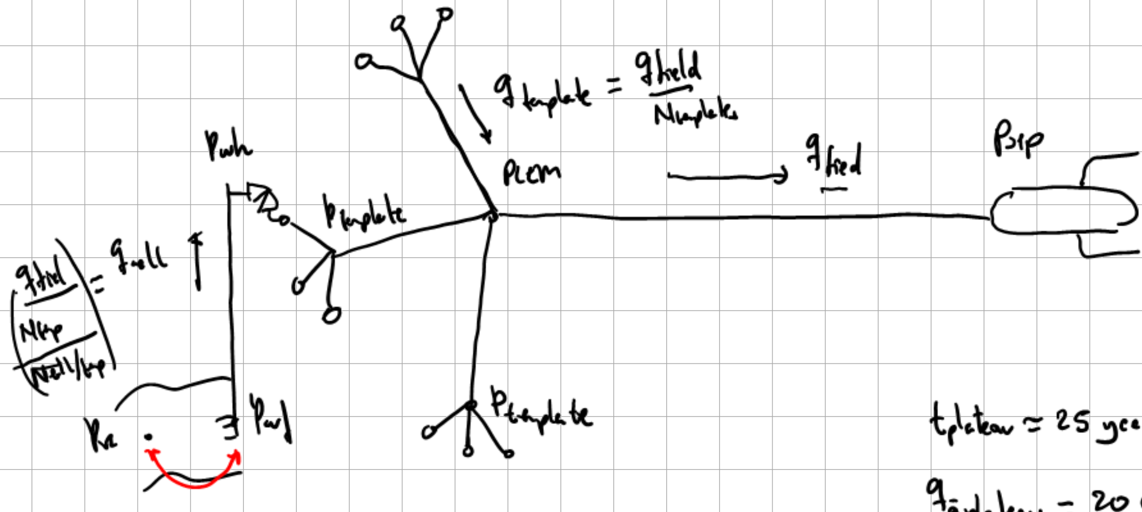


Slugcatcher: https://www.youtube.com/watch?v=xY4WdJLal_0

Production profile (20,8mill. Sm³/sd – 6,7 GSm³/år)



Goal: perform production scheduling calculations for the Snøhvit field, i.e. 1) determine plateau duration, 2) determine post-plateau production



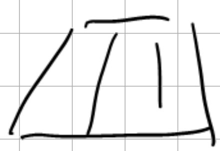
$t_{plateau} \simeq 25$ years desired

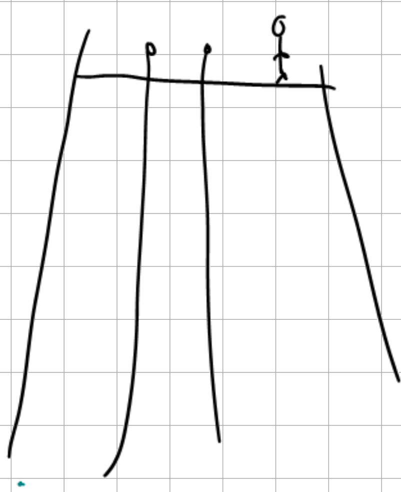
$q_{g\,plateau} = 20\text{E}06\ Sm^3/d$

Assumptions: all wells are identical and the production network is symmetric

G (IGIP), Initial gas in place	270E+09	[Sm3]
Annual production volume (in plateau), in fraction of G	0.027	[-]
Production days per year (uptime)	365	[day]
T_R, reservoir temperature	92	[°C]
p_{Ri}, initial reservoir pressure	276	[bara]
C_R, inflow backpressure coefficient	1000	[Sm3/bar^2n]
n, inflow backpressure exponent	1	[-]
C_t, Tubing flow coefficient (2100 MDx0.15 ID m)	4.03E+04	[Sm3/bar]
S, Tubing elevation coefficient	0.155	[-]
C_{FL}, flowline coefficient from template-PLEM (5000x0.355 ID	2.83E+05	[Sm3/bar]
C_{PL} Pipeline coefficient from PLEM-Shore (158600x0.68 ID m)	2.75E+05	[Sm3/bar]
Separator (slug catcher) pressure	30	[bara]
Gas molecular weight (Methane)	16	[kg/kmole]
Gas specific gravity	0.55	[-]
Gas density at Sc	0.67	[kg/m^3]
Number of templates	3	
Number of wells	9	
Desired plateau duration	20	[years]
qfield	20.0E+6	[Sm^3/d]
Field gas rate for abandonment (1/3 of plateau rate)	6.67E+06	[Sm^3/d]

Comment: in this case, we assume the number of wells remains constant in time. This is often the case in subsea developments. However, in onshore fields and offshore fields with dry X-mas trees, the drilling rig is often available to drill additional wells during the life of the field to prolong plateau, production and increase recovery factor. For these cases, it would be better to add a column with number of producer per year to determine the "drilling schedule"





The strategy is to input the rate and make pressure drop calculations along the system.
-first, from reservoir to wellhead (cocurrent). This is the available pressure, we will use IPR and TPR
-then, to avoid computing choke pressure drop, and to avoid doing assumptions about choke opening, we move countercurrent from separator to template. WE will use pipeline and flowline equations

time (end of year	q_{field}	ΔG_p	G_p	R_f	Z	p_R	q_{well}	p_{wf}	p_{wh}	p_{temp}	p_{plem}	p_{sep}	q_{temp}	Δ_{pchoke}	p_{temp}/p_{wh}	q_{pp}
[years]	[Sm^3/d]	[Sm^3]	[Sm^3]	[-]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bar]	[-]	[Sm3/d]
0	20.0E+6		000.0E+0	0.000	0.967	276	2.2E+6	271.9	245.5	82.1	78.7	30.0	6.7E+6	163		

Comments1: the drawdown is very small, this could be the case if the formation is very productiive and it has big thickness

Comment2: pressure drop in the tubing is small. Do a rough quality check to compare against the hydrostatic pressure drop for single phase gas and single phase water

Choke dp is positive, then it is possible to flow!

$\Delta p_{tubing} = 26$ bara

$\Delta p_{hydro} + \Delta p_{friction}$

$\rho_{fluid} \cdot g \, \Delta h + \rho_{fluid} f \frac{L}{\phi} \frac{v^2}{2}$

9.81

please check

1000 10 3000 ~

3E7 Pa → 300 bara

gas 100 - 200 kg/m^3

~ 30 bar

Future steps:

pR goes down in time, pwf is a function of qwell and pR, if pR goes down then pwf also. The same logic applies for pwh

pplem is a function of qfield and psep, both are constant during plateau, so pplem is also constant. The same logic applies to ptemp

Class 20230207 : Continuation of Snøhvit exercise - Production scheduling of subsea gas field

Just for fun, On year 0, we calculated the maximum field gas production, by usin gthe solver to change rate until dp choke = 0, this gave around 52 E06 Sm3/d

to move to the second year, we need to estimate production of year 1 to calculate Gp

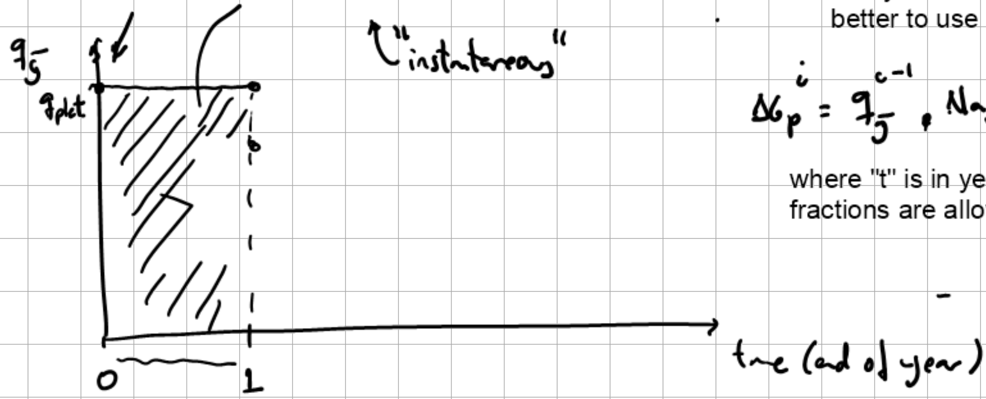
It can be estimated in two ways:

Assuming the rate remains constant through the year:

This is good for plateau, but can give poor results for the decline phase (overprediction)

$$\Delta G_p^i = q_j^{i-1} \cdot N_{days/year}$$

"instantaneous"



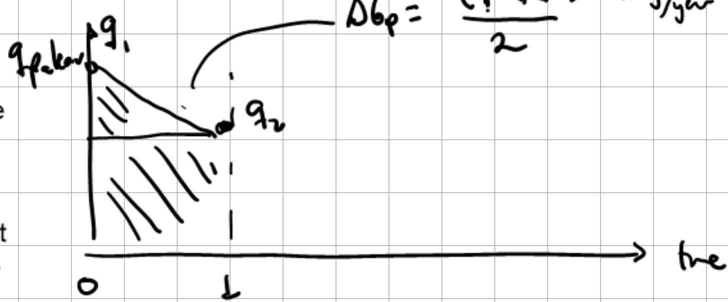
This is valid if the timestep is one year!!! it if different, it is better to use

$$\Delta G_p^i = q_j^{i-1} \cdot N_{days/year} \cdot (t^i - t^{i-1})$$

where "t" is in years(year fractions are allowed)

if rates are changing from year to year, it is better to use a trapezoidal approximation. However, here the rate of qi must be initially assumed and later verified with pressure drop calculations. (as it was done for qi-1, was calculated with initial pR)

$$\Delta G_p^i = \frac{(q^i + q^{i-1})}{2} N_{days/year} \cdot (t^i - t^{i-1})$$



cumulative field production is calculated with:

$$G_p^i = \sum_{k=1}^{i} \Delta G_p^k$$

Rectangular approximation

AVERAGE =(C25)*B4*(B26-B25)

	A	B	C	D
1	**Snohvit Gas Field, Prof. Michael Golan, Prof. Milan Stanko**			
2	G (IGIP), Initial gas in place	270E+09	[Sm3]	
3	Annual production volume (in plateau), in fraction of G	0.027	[-]	
4	Production days per year (uptime)	365	[day]	
5	T_R , reservoir temperature	92	[°C]	
6	p_{Ri}, initial reservoir pressure	276	[bara]	
7	C_R, inflow backpressure coefficient	1000	[Sm3/bar^2n]	
8	n, inflow backpressure exponent	1	[-]	
9	C_t, Tubing flow coefficient (2100 MDx0.15 ID m)	4.03E+04	[Sm3/bar]	
10	S, Tubing elevation coefficient	0.155	[-]	
11	C_{FL}, flowline coefficient from template-PLEM (5000x0.355 ID m)	2.83E+05	[Sm3/bar]	
12	C_{PL} Pipeline coefficient from PLEM-Shore (158600x0.68 ID m)	2.75E+05	[Sm3/bar]	
13	Separator (slug catcher) pressure	30	[bara]	
14	Gas molecular weight (Methane)	16	[kg/kmole]	
15	Gas specific gravity	0.55	[-]	
16	Gas density at Sc	0.67	[kg/m^3]	
17	Number of templates	3		
18	Number of wells	9		
19	Desired plateau duration	20	[years]	
20	qfield	20.0E+6	[Sm^3/d]	
21	Field gas rate for abandonment (1/3 of plateau rate)	6.67E+06	[Sm^3/d]	
22				
23		time (end of year)	q_{field}	ΔG_p
24		[years]	[Sm^3/d]	[Sm^3]
25		0	20.0E+6	
26		1	20.0E+6	B25)

Calculating Gp

time (end of year)	q_{field}	ΔG_p	G_p
[years]	[Sm^3/d]	[Sm^3]	[Sm^3]
0	20.0E+6		000.0E+0
1	20.0E+6	7.3E+9	=E25+D26

This is the recovery factor for year 1, is it within the rule of thumb for plateau production mentioned in previous lectures?

time (end of year)	q_{field}	ΔG_p	G_p	R_f
[years]	[Sm^3/d]	[Sm^3]	[Sm^3]	[-]
0	20.0E+6		000.0E+0	0.000
1	20.0E+6	7.3E+9	7.30E+09	0.027

Rule of thumb . in plateau, yearly outtake (ΔG_p)

$$0.027 \le \frac{\Delta G_p^{year}}{G_{pu}} \le 0.05$$

$$\frac{\Delta G_p}{G \cdot R_{fu}}$$

assuming $R_{fu} = 0.8$

$$R_{fu} \cdot 0.027 \le \frac{\Delta G_p^{year}}{G} \le 0.05\, R_{fu}$$

Yes, it is within the range

To calculate reservoir pressure

use the z from the year before

$$p_R = p_{Ri} \frac{z_R}{z_{Ri}} \left(1 - R_F\right)$$

To avoid an implicit calculation, we will use the ZR of the previous year. (assuming pressure does not change much from year to year)

time (end of year)	q_{field}	ΔG_p	G_p	R_f	Z	p_R
[years]	[Sm^3/d]	[Sm^3]	[Sm^3]	[-]	[-]	[bara]
0	20.0E+6		000.0E+0	0.000	0.967	276
1	20.0E+6	7.3E+9	7.30E+09	0.027	0.963	269

Then, as we have done earlier, do pressure calculations of pwf, pwh, pplem, ptemp and calculate dp choke.

Repeat for all years

time (end of year)	q_{field}	ΔG_p	G_p	R_f	Z	p_R	q_{well}	p_{wf}	p_{wh}	p_{temp}	p_{plem}	p_{sep}	q_{temp}	Δ_{pchoke}
[years]	[Sm^3/d]	[Sm^3]	[Sm^3]	[-]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bar]
0	20.0E+6		000.0E+0	0.000	0.967	276	2.2E+6	271.9	245.5	82.1	78.7	30.0	6.7E+6	163
1	20.0E+6	7.3E+9	7.30E+09	0.027	0.963	269	2.2E+6	264.4	238.4	82.1	78.7	30.0	6.7E+6	156
2	20.0E+6	7.3E+9	1.46E+10	0.054	0.957	260	2.2E+6	255.5	229.9	82.1	78.7	30.0	6.7E+6	148
3	20.0E+6	7.3E+9	2.19E+10	0.081	0.953	251	2.2E+6	246.6	221.4	82.1	78.7	30.0	6.7E+6	139
4	20.0E+6	7.3E+9	2.92E+10	0.108	0.948	242	2.2E+6	237.8	213.0	82.1	78.7	30.0	6.7E+6	131
5	20.0E+6	7.3E+9	3.65E+10	0.135	0.944	234	2.2E+6	229.2	204.8	82.1	78.7	30.0	6.7E+6	123
6	20.0E+6	7.3E+9	4.38E+10	0.162	0.941	226	2.2E+6	220.7	196.7	82.1	78.7	30.0	6.7E+6	115
7	20.0E+6	7.3E+9	5.11E+10	0.189	0.937	218	2.2E+6	212.4	188.7	82.1	78.7	30.0	6.7E+6	107
8	20.0E+6	7.3E+9	5.84E+10	0.216	0.935	210	2.2E+6	204.3	180.8	82.1	78.7	30.0	6.7E+6	99
9	20.0E+6	7.3E+9	6.57E+10	0.243	0.932	202	2.2E+6	196.2	173.0	82.1	78.7	30.0	6.7E+6	91
10	20.0E+6	7.3E+9	7.30E+10	0.270	0.931	194	2.2E+6	188.3	165.3	82.1	78.7	30.0	6.7E+6	83
11	20.0E+6	7.3E+9	8.03E+10	0.297	0.929	187	2.2E+6	180.5	157.7	82.1	78.7	30.0	6.7E+6	76
12	20.0E+6	7.3E+9	8.76E+10	0.324	0.928	179	2.2E+6	172.7	150.0	82.1	78.7	30.0	6.7E+6	68
13	20.0E+6	7.3E+9	9.49E+10	0.351	0.927	172	2.2E+6	165.1	142.5	82.1	78.7	30.0	6.7E+6	60
14	20.0E+6	7.3E+9	1.02E+11	0.379	0.927	164	2.2E+6	157.5	134.9	82.1	78.7	30.0	6.7E+6	53
15	20.0E+6	7.3E+9	1.10E+11	0.406	0.926	157	2.2E+6	149.9	127.3	82.1	78.7	30.0	6.7E+6	45
16	20.0E+6	7.3E+9	1.17E+11	0.433	0.927	150	2.2E+6	142.4	119.7	82.1	78.7	30.0	6.7E+6	38
17	20.0E+6	7.3E+9	1.24E+11	0.460	0.927	143	2.2E+6	134.9	112.0	82.1	78.7	30.0	6.7E+6	30
18	20.0E+6	7.3E+9	1.31E+11	0.487	0.928	136	2.2E+6	127.4	104.2	82.1	78.7	30.0	6.7E+6	22
19	20.0E+6	7.3E+9	1.39E+11	0.514	0.929	129	2.2E+6	119.8	96.2	82.1	78.7	30.0	6.7E+6	14
20	20.0E+6	7.3E+9	1.46E+11	0.541	0.931	122	2.2E+6	112.3	88.1	82.1	78.7	30.0	6.7E+6	6
21	20.0E+6	7.3E+9	1.53E+11	0.568	0.933	115	2.2E+6	104.7	79.6	82.1	78.7	30.0	6.7E+6	-2
22	20.0E+6	7.3E+9	1.61E+11	0.595	0.935	108	2.2E+6	97.0	70.8	82.1	78.7	30.0	6.7E+6	-11
23	20.0E+6	7.3E+9	1.68E+11	0.622	0.937	101	2.2E+6	89.2	61.4	82.1	78.7	30.0	6.7E+6	-21
24	20.0E+6	7.3E+9	1.75E+11	0.649	0.940	94	2.2E+6	81.2	51.0	82.1	78.7	30.0	6.7E+6	-31
25	20.0E+6	7.3E+9	1.83E+11	0.676	0.943	87	2.2E+6	73.0	39.0	82.1	78.7	30.0	6.7E+6	-43
26	20.0E+6	7.3E+9	1.90E+11	0.703	0.946	80	2.2E+6	64.5	22.9	82.1	78.7	30.0	6.7E+6	-59
27	20.0E+6	7.3E+9	1.97E+11	0.730	0.950	73	2.2E+6	55.6	#VALUE!	82.1	78.7	30.0	6.7E+6	#######
28	20.0E+6	7.3E+9	2.04E+11	0.757	0.953	66	2.2E+6	45.9	#VALUE!	82.1	78.7	30.0	6.7E+6	#######
29	20.0E+6	7.3E+9	2.12E+11	0.784	0.957	59	2.2E+6	35.0	#VALUE!	82.1	78.7	30.0	6.7E+6	#######
30	20.0E+6	7.3E+9	2.19E+11	0.811	0.962	52	2.2E+6	21.0	#VALUE!	82.1	78.7	30.0	6.7E+6	#######
31	20.0E+6	7.3E+9	2.26E+11	0.838	0.966	44	2.2E+6	######	#VALUE!	82.1	78.7	30.0	6.7E+6	#######
32	20.0E+6	7.3E+9	2.34E+11	0.865	0.971	37	2.2E+6	######	#VALUE!	82.1	78.7	30.0	6.7E+6	#######

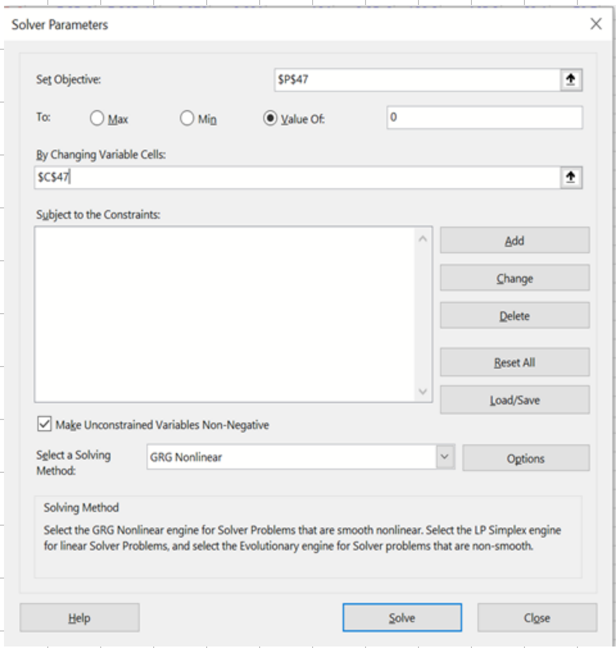
plateau ends here

To determine exactly when plateau ends, I need to use a custom timestep (not yearly). I will use the solver for this. For year 21, change the time, to get dp choke = 0

time (end of year)	q_{field}	ΔG_p	G_p	R_f	Z	p_R	q_{well}	p_{wf}	p_{wh}	p_{temp}	p_{plem}	p_{sep}	q_{temp}	Δ_{pchoke}
[years]	[Sm^3/d]	[Sm^3]	[Sm^3]	[-]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bar]
0	20.0E+6		000.0E+0	0.000	0.967	276	2.2E+6	271.9	245.5	82.1	78.7	30.0	6.7E+6	163
1	20.0E+6	7.3E+9	7.30E+09	0.027	0.963	269	2.2E+6	264.4	238.4	82.1	78.7	30.0	6.7E+6	156
2	20.0E+6	7.3E+9	1.46E+10	0.054	0.957	260	2.2E+6	255.5	229.9	82.1	78.7	30.0	6.7E+6	148
3	20.0E+6	7.3E+9	2.19E+10	0.081	0.953	251	2.2E+6	246.6	221.4	82.1	78.7	30.0	6.7E+6	139
4	20.0E+6	7.3E+9	2.92E+10	0.108	0.948	242	2.2E+6	237.8	213.0	82.1	78.7	30.0	6.7E+6	131
5	20.0E+6	7.3E+9	3.65E+10	0.135	0.944	234	2.2E+6	229.2	204.8	82.1	78.7	30.0	6.7E+6	123
6	20.0E+6	7.3E+9	4.38E+10	0.162	0.941	226	2.2E+6	220.7	196.7	82.1	78.7	30.0	6.7E+6	115
7	20.0E+6	7.3E+9	5.11E+10	0.189	0.937	218	2.2E+6	212.4	188.7	82.1	78.7	30.0	6.7E+6	107
8	20.0E+6	7.3E+9	5.84E+10	0.216	0.935	210	2.2E+6	204.3	180.8	82.1	78.7	30.0	6.7E+6	99
9	20.0E+6	7.3E+9	6.57E+10	0.243	0.932	202	2.2E+6	196.2	173.0	82.1	78.7	30.0	6.7E+6	91
10	20.0E+6	7.3E+9	7.30E+10	0.270	0.931	194	2.2E+6	188.3	165.3	82.1	78.7	30.0	6.7E+6	83
11	20.0E+6	7.3E+9	8.03E+10	0.297	0.929	187	2.2E+6	180.5	157.7	82.1	78.7	30.0	6.7E+6	76
12	20.0E+6	7.3E+9	8.76E+10	0.324	0.928	179	2.2E+6	172.7	150.0	82.1	78.7	30.0	6.7E+6	68
13	20.0E+6	7.3E+9	9.49E+10	0.351	0.927	172	2.2E+6	165.1	142.5	82.1	78.7	30.0	6.7E+6	60
14	20.0E+6	7.3E+9	1.02E+11	0.379	0.927	164	2.2E+6	157.5	134.9	82.1	78.7	30.0	6.7E+6	53
15	20.0E+6	7.3E+9	1.10E+11	0.406	0.926	157	2.2E+6	149.9	127.3	82.1	78.7	30.0	6.7E+6	45
16	20.0E+6	7.3E+9	1.17E+11	0.433	0.927	150	2.2E+6	142.4	119.7	82.1	78.7	30.0	6.7E+6	38
17	20.0E+6	7.3E+9	1.24E+11	0.460	0.927	143	2.2E+6	134.9	112.0	82.1	78.7	30.0	6.7E+6	30
18	20.0E+6	7.3E+9	1.31E+11	0.487	0.928	136	2.2E+6	127.4	104.2	82.1	78.7	30.0	6.7E+6	22
19	20.0E+6	7.3E+9	1.39E+11	0.514	0.929	129	2.2E+6	119.8	96.2	82.1	78.7	30.0	6.7E+6	14
20	20.0E+6	7.3E+9	1.46E+11	0.541	0.931	122	2.2E+6	112.3	88.1	82.1	78.7	30.0	6.7E+6	6
20.71790385	20.0E+6	5.2E+9	1.51E+11	0.560	0.932	117	2.2E+6	106.9	82.1	82.1	78.7	30.0	6.7E+6	0

I then continue with yearly steps afterwards.

To find out the decline rates, I use the solver in each year to change the field rate until the DP choke is equal to zero



20.71790385	20.0E+6	5.2E+9	1.51E+11	0.560	0.932	117	2.2E+6	106.9	82.1	82.1	78.7	30.0	6.7E+6	0
21	19.6E+6	2.1E+9	1.53E+11	0.568	0.933	115	2.2E+6	105.0	80.8	80.8	77.4	30.0	6.5E+6	0

To repeat for all the years below I use the button at the top

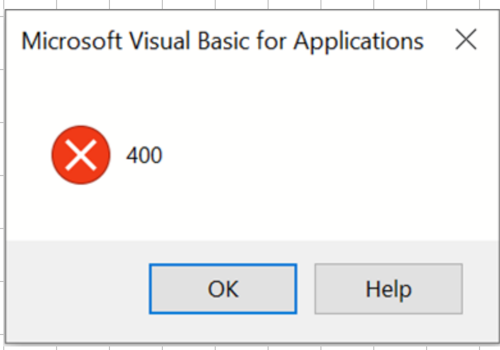
Run GoalSeek to make dp choke = 0 by changing qfield

START row	48
END row	69

This button triggers a VBA routine that runs GoalSeek repeatedly to find field rates during decline

```
Sub GoalSeekVBA()
    sheetname = "Data_res_well_network"
    startRow = Worksheets(sheetname).Cells(18, 9).Value
    endRow = Worksheets(sheetname).Cells(19, 9).Value
    Dim sh As Worksheet
    Set sh = ThisWorkbook.Sheets(sheetname)
    Dim target As Long
    target = 0#
    For i = startRow To endRow
        OBJTAG = "P" & i
        VARTAG = "C" & i
        sh.Range(OBJTAG).GoalSeek Goal:=target, ChangingCell:=Range(VARTAG)
    Next
End Sub
```

This might happen:



It managed to solve until year 28, but not afterwards. This is because of this VALUE error

20.71790385	20.0E+6	5.2E+9	1.51E+11	0.560	0.932	117	2.2E+6	106.9	82.1	82.1	78.7	30.0	6.7E+6	0
21	19.6E+6	2.1E+9	1.53E+11	0.568	0.933	115	2.2E+6	105.0	80.8	80.8	77.4	30.0	6.5E+6	0
22	18.2E+6	7.2E+9	1.60E+11	0.594	0.935	108	2.0E+6	98.1	75.7	75.7	72.6	30.0	6.1E+6	0
23	16.9E+6	6.6E+9	1.67E+11	0.619	0.937	102	1.9E+6	91.9	71.2	71.2	68.4	30.0	5.6E+6	0
24	15.7E+6	6.2E+9	1.73E+11	0.642	0.939	96	1.7E+6	86.2	67.0	67.0	64.4	30.0	5.2E+6	0
25	14.5E+6	5.7E+9	1.79E+11	0.663	0.941	90	1.6E+6	80.9	63.2	63.2	60.8	30.0	4.8E+6	0
26	13.5E+6	5.3E+9	1.84E+11	0.683	0.944	85	1.5E+6	76.0	59.6	59.6	57.5	30.0	4.5E+6	0
27	12.5E+6	4.9E+9	1.89E+11	0.701	0.946	81	1.4E+6	71.4	56.4	56.4	54.4	30.0	4.2E+6	0
28	11.6E+6	4.6E+9	1.94E+11	0.718	0.948	76	1.3E+6	67.2	53.4	53.4	51.6	30.0	3.9E+6	0
29	20.0E+6	4.2E+9	1.98E+11	0.733	0.950	72	2.2E+6	54.6	#VALUE!	82.1	78.7	30.0	6.7E+6	#######
30	20.0E+6	7.3E+9	2.05E+11	0.760	0.954	65	2.2E+6	44.7	#VALUE!	82.1	78.7	30.0	6.7E+6	#######
31	20.0E+6	7.3E+9	2.13E+11	0.787	0.958	58	2.2E+6	33.5	#VALUE!	82.1	78.7	30.0	6.7E+6	#######
32	20.0E+6	7.3E+9	2.20E+11	0.814	0.962	51	2.2E+6	18.7	#VALUE!	82.1	78.7	30.0	6.7E+6	#######
33	20.0E+6	7.3E+9	2.27E+11	0.842	0.967	44	2.2E+6	######	#VALUE!	82.1	78.7	30.0	6.7E+6	#######

If one assumes a too high well rate, then the value under the square root might be negative and Excel fails

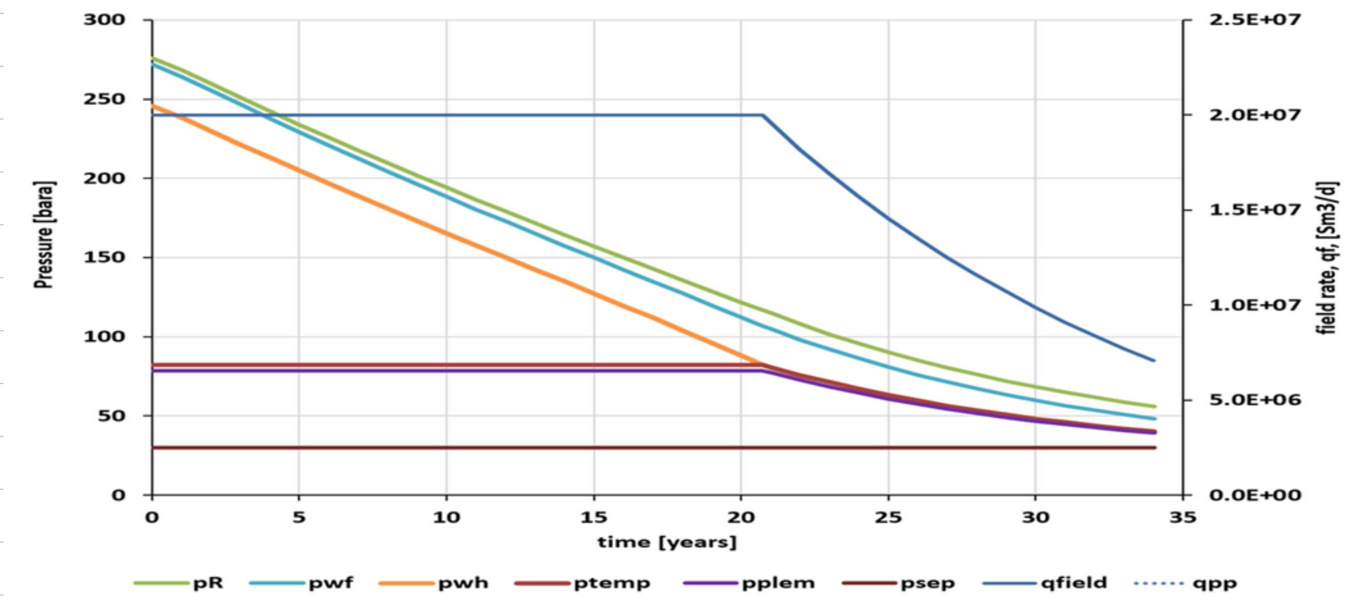
$$q_g = C_T\left(\frac{p_{wf}^2}{e^s} - p_{wh}^2\right)^{0.5}$$

$$p_{wh} = \sqrt{\frac{p_{wf}^2}{e^s} - \underbrace{\left(\frac{q_g}{C_T}\right)^2}_{<}}$$

To solve this, I change the guess for field rate from 20 E06 Sm3/d to 5 E06 Sm3/d for year 29 and onwards and re-run the button

SUCESS!!

time (end of year)	q_{field}	ΔG_p	G_p	R_f	Z	p_R	q_{well}	p_{wf}	p_{wh}	p_{temp}	p_{plem}	p_{sep}	q_{temp}	Δ_{pchoke}
[years]	[Sm^3/d]	[Sm^3]	[Sm^3]	[-]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bar]
0	20.0E+6		000.0E+0	0.000	0.967	276	2.2E+6	271.9	245.5	82.1	78.7	30.0	6.7E+6	163
1	20.0E+6	7.3E+9	7.30E+09	0.027	0.963	269	2.2E+6	264.4	238.4	82.1	78.7	30.0	6.7E+6	156
2	20.0E+6	7.3E+9	1.46E+10	0.054	0.957	260	2.2E+6	255.5	229.9	82.1	78.7	30.0	6.7E+6	148
3	20.0E+6	7.3E+9	2.19E+10	0.081	0.953	251	2.2E+6	246.6	221.4	82.1	78.7	30.0	6.7E+6	139
4	20.0E+6	7.3E+9	2.92E+10	0.108	0.948	242	2.2E+6	237.8	213.0	82.1	78.7	30.0	6.7E+6	131
5	20.0E+6	7.3E+9	3.65E+10	0.135	0.944	234	2.2E+6	229.2	204.8	82.1	78.7	30.0	6.7E+6	123
6	20.0E+6	7.3E+9	4.38E+10	0.162	0.941	226	2.2E+6	220.7	196.7	82.1	78.7	30.0	6.7E+6	115
7	20.0E+6	7.3E+9	5.11E+10	0.189	0.937	218	2.2E+6	212.4	188.7	82.1	78.7	30.0	6.7E+6	107
8	20.0E+6	7.3E+9	5.84E+10	0.216	0.935	210	2.2E+6	204.3	180.8	82.1	78.7	30.0	6.7E+6	99
9	20.0E+6	7.3E+9	6.57E+10	0.243	0.932	202	2.2E+6	196.2	173.0	82.1	78.7	30.0	6.7E+6	91
10	20.0E+6	7.3E+9	7.30E+10	0.270	0.931	194	2.2E+6	188.3	165.3	82.1	78.7	30.0	6.7E+6	83
11	20.0E+6	7.3E+9	8.03E+10	0.297	0.929	187	2.2E+6	180.5	157.7	82.1	78.7	30.0	6.7E+6	76
12	20.0E+6	7.3E+9	8.76E+10	0.324	0.928	179	2.2E+6	172.7	150.0	82.1	78.7	30.0	6.7E+6	68
13	20.0E+6	7.3E+9	9.49E+10	0.351	0.927	172	2.2E+6	165.1	142.5	82.1	78.7	30.0	6.7E+6	60
14	20.0E+6	7.3E+9	1.02E+11	0.379	0.927	164	2.2E+6	157.5	134.9	82.1	78.7	30.0	6.7E+6	53
15	20.0E+6	7.3E+9	1.10E+11	0.406	0.926	157	2.2E+6	149.9	127.3	82.1	78.7	30.0	6.7E+6	45
16	20.0E+6	7.3E+9	1.17E+11	0.433	0.927	150	2.2E+6	142.4	119.7	82.1	78.7	30.0	6.7E+6	38
17	20.0E+6	7.3E+9	1.24E+11	0.460	0.927	143	2.2E+6	134.9	112.0	82.1	78.7	30.0	6.7E+6	30
18	20.0E+6	7.3E+9	1.31E+11	0.487	0.928	136	2.2E+6	127.4	104.2	82.1	78.7	30.0	6.7E+6	22
19	20.0E+6	7.3E+9	1.39E+11	0.514	0.929	129	2.2E+6	119.8	96.2	82.1	78.7	30.0	6.7E+6	14
20	20.0E+6	7.3E+9	1.46E+11	0.541	0.931	122	2.2E+6	112.3	88.1	82.1	78.7	30.0	6.7E+6	6
20.71790385	20.0E+6	5.2E+9	1.51E+11	0.560	0.932	117	2.2E+6	106.9	82.1	82.1	78.7	30.0	6.7E+6	0
21	19.6E+6	2.1E+9	1.53E+11	0.568	0.933	115	2.2E+6	105.0	80.8	80.8	77.4	30.0	6.5E+6	0
22	18.2E+6	7.2E+9	1.60E+11	0.594	0.935	108	2.0E+6	98.1	75.7	75.7	72.6	30.0	6.1E+6	0
23	16.9E+6	6.6E+9	1.67E+11	0.619	0.937	102	1.9E+6	91.9	71.2	71.2	68.4	30.0	5.6E+6	0
24	15.7E+6	6.2E+9	1.73E+11	0.642	0.939	96	1.7E+6	86.2	67.0	67.0	64.4	30.0	5.2E+6	0
25	14.5E+6	5.7E+9	1.79E+11	0.663	0.941	90	1.6E+6	80.9	63.2	63.2	60.8	30.0	4.8E+6	0
26	13.5E+6	5.3E+9	1.84E+11	0.683	0.944	85	1.5E+6	76.0	59.6	59.6	57.5	30.0	4.5E+6	0
27	12.5E+6	4.9E+9	1.89E+11	0.701	0.946	81	1.4E+6	71.4	56.4	56.4	54.4	30.0	4.2E+6	0
28	11.6E+6	4.6E+9	1.94E+11	0.718	0.948	76	1.3E+6	67.2	53.4	53.4	51.6	30.0	3.9E+6	0
29	10.7E+6	4.2E+9	1.98E+11	0.733	0.950	72	1.2E+6	63.4	50.7	50.7	49.1	30.0	3.6E+6	0
30	9.9E+6	3.9E+9	2.02E+11	0.748	0.952	68	1.1E+6	59.8	48.2	48.2	46.8	30.0	3.3E+6	0
31	9.1E+6	3.6E+9	2.06E+11	0.761	0.954	65	1.0E+6	56.6	45.9	45.9	44.7	30.0	3.0E+6	0
32	8.4E+6	3.3E+9	2.09E+11	0.773	0.956	62	931.0E+3	53.6	43.9	43.9	42.8	30.0	2.8E+6	0
33	7.7E+6	3.1E+9	2.12E+11	0.785	0.958	59	855.8E+3	50.9	42.0	42.0	41.0	30.0	2.6E+6	0
34	7.1E+6	2.8E+9	2.15E+11	0.795	0.959	56	785.2E+3	48.4	40.4	40.4	39.5	30.0	2.4E+6	0



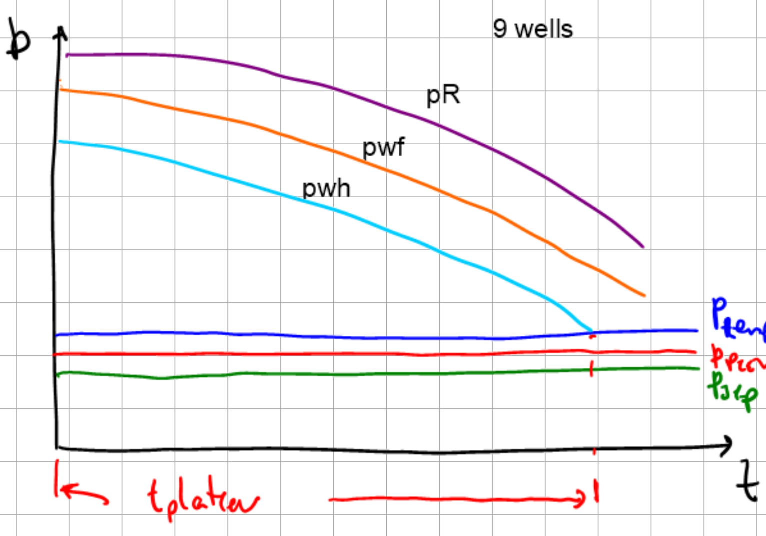
Study the following cases:
-Smaller G --> plateau is shorter
-higher plateau rate --> plateau is shorter
-Lower plateau rate -->plateau is longer
-Add 3 more wells (one extra per template, to keep symmetry) - 12 in total --> gives one additional year in plateau -- Not much considering the investment, but I might be obliged to do this due to contractual obligations

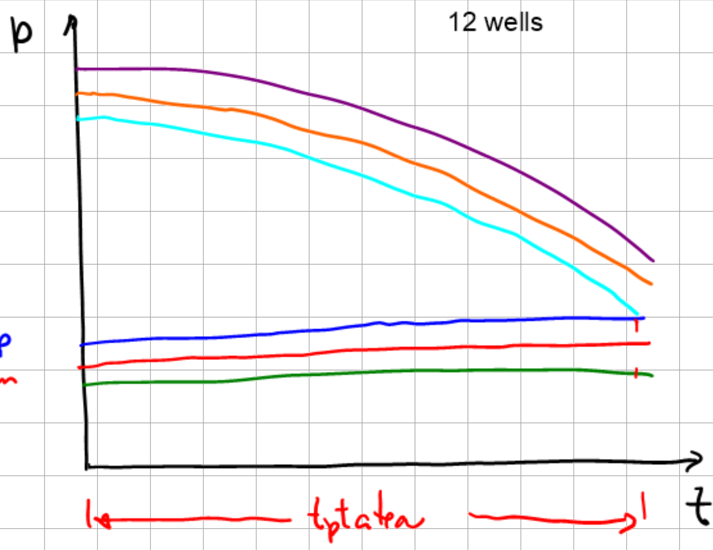
Why adding more wells (while keeping same field plateau rate) gives longer plateau?

$$q_g = C_R \left(p_R^2 - p_{wf}^2\right)^n$$

$$p_{wf} = \sqrt{p_R^2 - \left(\frac{q_g}{C_R}\right)^{1/n}}$$

-The rate per well is smaller
-pwf is closer to pR
-pwh is closer to pwf
-The intersection between pwh-ptemp occurs later in time





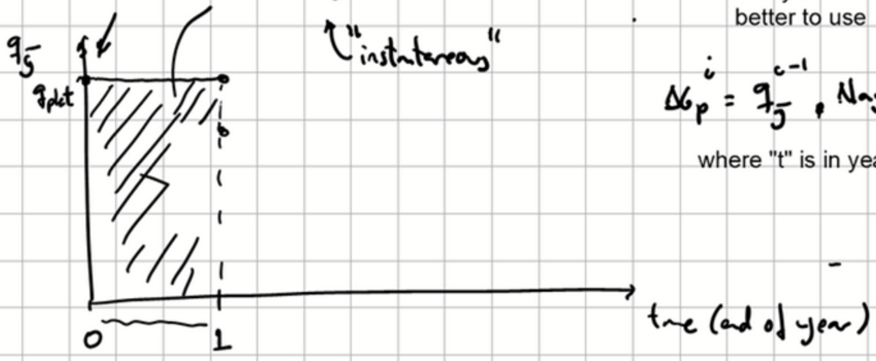
More cases to test:
-Well with poor productivity (CR is low) --> leads to shorter plateau
-Change the method to estimate deltaGp

Assuming the rate remains constant through the year:

This is good for plateau, but can give poor results for the decline phase (overprediction)

$$\Delta G_p^{i} = q_{\bar{J}}^{i-1} \cdot N_{days/year}$$

"instantaneous"



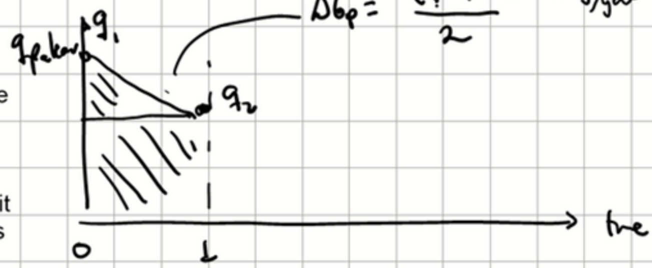
This is valid if the timestep is one year!!! it if different, it is better to use

$$\Delta G_p^{i} = q_{\bar{J}}^{i-1} \cdot N_{days/year} \cdot (t^{i} - t^{i-1})$$

where "t" is in years

if rates are changing from year to year, it is better to use a trapezoidal approximation. However, here the rate of qi must be initially assumed and later verified with pressure drop calculations. (as it was done for qi-1, was calculated with initial pR)

$$\Delta G_p^{i} = \frac{(q^{i} + q^{i-1})}{2} N_{days/year} \cdot (t^{i} - t^{i-1})$$



fx =0.5*(C25+C26)*B4*(B26-B25)

	B	C	D
	20.0E+6	[Sm^3/d]	
/3 of plateau rate)	6.67E+06	[Sm^3/d]	
	time (end of year)	q_{field}	ΔG_p
	[years]	[Sm^3/d]	[Sm^3]
	0	20.0E+6	
	1	20.0E+6	=0.5*(C25+
	2	20.0E+6	7.3E+9

We see that the DP choke in decline is not exactly zero, but slightly positive.

time (end of year) [years]	q_{field} [Sm^3/d]	ΔG_p [Sm^3]	G_p [Sm^3]	R_f [-]	Z [-]	p_R [bara]	q_{well} [Sm^3/d]	p_{wf} [bara]	p_{wh} [bara]	p_{temp} [bara]	p_{plem} [bara]	p_{sep} [bara]	q_{temp} [Sm^3/d]	Δp_{choke} [bar]
0	20.0E+6		000.0E+0	0.000	0.967	276	2.2E+6	271.9	245.5	82.1	78.7	30.0	6.7E+6	163
1	20.0E+6	7.3E+9	7.30E+09	0.027	0.963	269	2.2E+6	264.4	238.4	82.1	78.7	30.0	6.7E+6	156
2	20.0E+6	7.3E+9	1.46E+10	0.054	0.957	260	2.2E+6	255.5	229.9	82.1	78.7	30.0	6.7E+6	148
3	20.0E+6	7.3E+9	2.19E+10	0.081	0.953	251	2.2E+6	246.6	221.4	82.1	78.7	30.0	6.7E+6	139
4	20.0E+6	7.3E+9	2.92E+10	0.108	0.948	242	2.2E+6	237.8	213.0	82.1	78.7	30.0	6.7E+6	131
5	20.0E+6	7.3E+9	3.65E+10	0.135	0.944	234	2.2E+6	229.2	204.8	82.1	78.7	30.0	6.7E+6	123
6	20.0E+6	7.3E+9	4.38E+10	0.162	0.941	226	2.2E+6	220.7	196.7	82.1	78.7	30.0	6.7E+6	115
7	20.0E+6	7.3E+9	5.11E+10	0.189	0.937	218	2.2E+6	212.4	188.7	82.1	78.7	30.0	6.7E+6	107
8	20.0E+6	7.3E+9	5.84E+10	0.216	0.935	210	2.2E+6	204.3	180.8	82.1	78.7	30.0	6.7E+6	99
9	20.0E+6	7.3E+9	6.57E+10	0.243	0.932	202	2.2E+6	196.2	173.0	82.1	78.7	30.0	6.7E+6	91
10	20.0E+6	7.3E+9	7.30E+10	0.270	0.931	194	2.2E+6	188.3	165.3	82.1	78.7	30.0	6.7E+6	83
11	20.0E+6	7.3E+9	8.03E+10	0.297	0.929	187	2.2E+6	180.5	157.7	82.1	78.7	30.0	6.7E+6	76
12	20.0E+6	7.3E+9	8.76E+10	0.324	0.928	179	2.2E+6	172.7	150.0	82.1	78.7	30.0	6.7E+6	68
13	20.0E+6	7.3E+9	9.49E+10	0.351	0.927	172	2.2E+6	165.1	142.5	82.1	78.7	30.0	6.7E+6	60
14	20.0E+6	7.3E+9	1.02E+11	0.379	0.927	164	2.2E+6	157.5	134.9	82.1	78.7	30.0	6.7E+6	53
15	20.0E+6	7.3E+9	1.10E+11	0.406	0.926	157	2.2E+6	149.9	127.3	82.1	78.7	30.0	6.7E+6	45
16	20.0E+6	7.3E+9	1.17E+11	0.433	0.927	150	2.2E+6	142.4	119.7	82.1	78.7	30.0	6.7E+6	38
17	20.0E+6	7.3E+9	1.24E+11	0.460	0.927	143	2.2E+6	134.9	112.0	82.1	78.7	30.0	6.7E+6	30
18	20.0E+6	7.3E+9	1.31E+11	0.487	0.928	136	2.2E+6	127.4	104.2	82.1	78.7	30.0	6.7E+6	22
19	20.0E+6	7.3E+9	1.39E+11	0.514	0.929	129	2.2E+6	119.8	96.2	82.1	78.7	30.0	6.7E+6	14
20	20.0E+6	7.3E+9	1.46E+11	0.541	0.931	122	2.2E+6	112.3	88.1	82.1	78.7	30.0	6.7E+6	6
20.71790385	20.0E+6	5.2E+9	1.51E+11	0.560	0.932	117	2.2E+6	106.9	82.1	82.1	78.7	30.0	6.7E+6	0
21	19.6E+6	2.0E+9	1.53E+11	0.568	0.933	115	2.2E+6	105.1	80.8	80.8	77.4	30.0	6.5E+6	0
22	18.2E+6	6.9E+9	1.60E+11	0.593	0.935	108	2.0E+6	98.4	76.0	75.7	72.6	30.0	6.1E+6	0
23	16.9E+6	6.4E+9	1.67E+11	0.617	0.937	102	1.9E+6	92.5	71.8	71.2	68.4	30.0	5.6E+6	1
24	15.7E+6	5.9E+9	1.73E+11	0.639	0.939	96	1.7E+6	87.0	67.9	67.0	64.4	30.0	5.2E+6	1
25	14.5E+6	5.5E+9	1.78E+11	0.659	0.941	91	1.6E+6	81.9	64.3	63.2	60.8	30.0	4.8E+6	1
26	13.5E+6	5.1E+9	1.83E+11	0.678	0.943	86	1.5E+6	77.2	61.0	59.6	57.5	30.0	4.5E+6	1
27	12.5E+6	4.7E+9	1.88E+11	0.696	0.945	82	1.4E+6	72.8	57.9	56.4	54.4	30.0	4.2E+6	2
28	11.6E+6	4.4E+9	1.92E+11	0.712	0.947	78	1.3E+6	68.8	55.2	53.4	51.6	30.0	3.9E+6	2
29	10.7E+6	4.1E+9	1.96E+11	0.727	0.949	74	1.2E+6	65.2	52.6	50.7	49.1	30.0	3.6E+6	2
30	9.9E+6	3.8E+9	2.00E+11	0.741	0.951	70	1.1E+6	61.8	50.3	48.2	46.8	30.0	3.3E+6	2
31	9.1E+6	3.5E+9	2.04E+11	0.754	0.953	67	1.0E+6	58.7	48.2	45.9	44.7	30.0	3.0E+6	2
32	8.4E+6	3.2E+9	2.07E+11	0.766	0.955	64	931.0E+3	55.9	46.3	43.9	42.8	30.0	2.8E+6	2
33	7.7E+6	2.9E+9	2.10E+11	0.777	0.956	61	855.8E+3	53.3	44.6	42.0	41.0	30.0	2.6E+6	3
34	7.1E+6	2.7E+9	2.12E+11	0.787	0.958	58	785.2E+3	51.0	43.0	40.4	39.5	30.0	2.4E+6	3
35	6.5E+6	2.5E+9	2.15E+11	0.796	0.959	56	719.0E+3	48.9	41.6	38.9	38.1	30.0	2.2E+6	3

This is because the rectangular approximation is overpredicting produced gas volumes in decline, and therefore reservoir pressure is declining faster than what it actually is

Using the button to drive choke dp to zero by changing field rate during the decline phase:

time (end of year)	q_{field}	ΔG_p	G_p	R_f	Z	p_R	q_{well}	p_{wf}	p_{wh}	p_{temp}	p_{plem}	p_{sep}	q_{temp}	Δ_{pchoke}
[years]	[Sm^3/d]	[Sm^3]	[Sm^3]	[-]	[-]	[bara]	[Sm^3/d]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm^3/d]	[bar]
0	20.0E+6		000.0E+0	0.000	0.967	276	2.2E+6	271.9	245.5	82.1	78.7	30.0	6.7E+6	163
1	20.0E+6	7.3E+9	7.30E+09	0.027	0.963	269	2.2E+6	264.4	238.4	82.1	78.7	30.0	6.7E+6	156
2	20.0E+6	7.3E+9	1.46E+10	0.054	0.957	260	2.2E+6	255.5	229.9	82.1	78.7	30.0	6.7E+6	148
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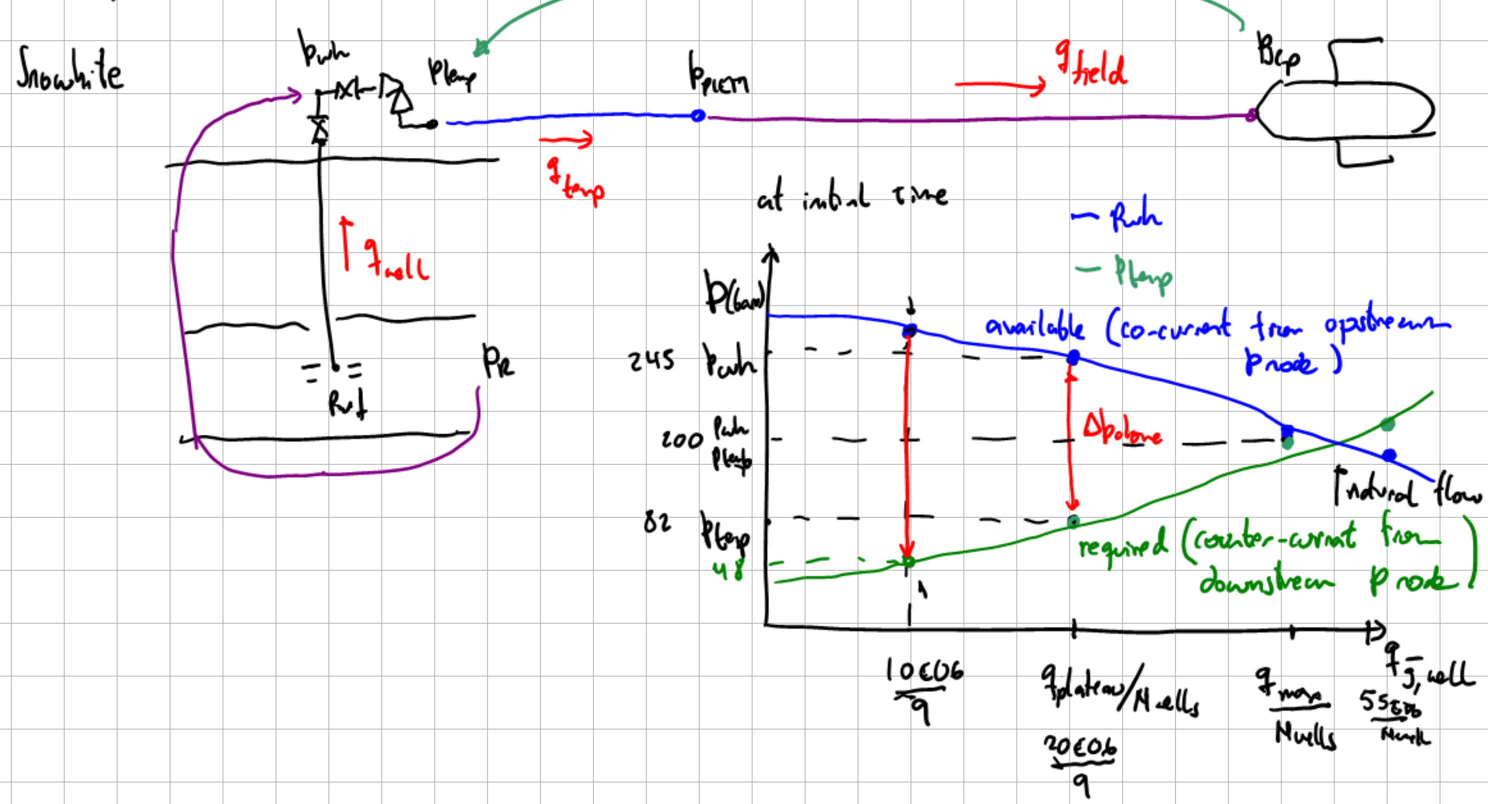
7	20.0E+6	7.3E+9	5.11E+10	0.189	0.937	218	2.2E+6	212.4	188.7	82.1	78.7	30.0	6.7E+6	107
8	20.0E+6	7.3E+9	5.84E+10	0.216	0.935	210	2.2E+6	204.3	180.8	82.1	78.7	30.0	6.7E+6	99
9	20.0E+6	7.3E+9	6.57E+10	0.243	0.932	202	2.2E+6	196.2	173.0	82.1	78.7	30.0	6.7E+6	91
10	20.0E+6	7.3E+9	7.30E+10	0.270	0.931	194	2.2E+6	188.3	165.3	82.1	78.7	30.0	6.7E+6	83
11	20.0E+6	7.3E+9	8.03E+10	0.297	0.929	187	2.2E+6	180.5	157.7	82.1	78.7	30.0	6.7E+6	76
12	20.0E+6	7.3E+9	8.76E+10	0.324	0.928	179	2.2E+6	172.7	150.0	82.1	78.7	30.0	6.7E+6	68
13	20.0E+6	7.3E+9	9.49E+10	0.351	0.927	172	2.2E+6	165.1	142.5	82.1	78.7	30.0	6.7E+6	60
14	20.0E+6	7.3E+9	1.02E+11	0.379	0.927	164	2.2E+6	157.5	134.9	82.1	78.7	30.0	6.7E+6	53
15	20.0E+6	7.3E+9	1.10E+11	0.406	0.926	157	2.2E+6	149.9	127.3	82.1	78.7	30.0	6.7E+6	45
16	20.0E+6	7.3E+9	1.17E+11	0.433	0.927	150	2.2E+6	142.4	119.7	82.1	78.7	30.0	6.7E+6	38
17	20.0E+6	7.3E+9	1.24E+11	0.460	0.927	143	2.2E+6	134.9	112.0	82.1	78.7	30.0	6.7E+6	30
18	20.0E+6	7.3E+9	1.31E+11	0.487	0.928	136	2.2E+6	127.4	104.2	82.1	78.7	30.0	6.7E+6	22
19	20.0E+6	7.3E+9	1.39E+11	0.514	0.929	129	2.2E+6	119.8	96.2	82.1	78.7	30.0	6.7E+6	14
20	20.0E+6	7.3E+9	1.46E+11	0.541	0.931	122	2.2E+6	112.3	88.1	82.1	78.7	30.0	6.7E+6	6
20.71790385	20.0E+6	5.2E+9	1.51E+11	0.560	0.932	117	2.2E+6	106.9	82.1	82.1	78.7	30.0	6.7E+6	0
21	19.6E+6	2.0E+9	1.53E+11	0.568	0.933	115	2.2E+6	105.1	80.8	80.8	77.4	30.0	6.5E+6	0
22	18.2E+6	6.9E+9	1.60E+11	0.593	0.935	108	2.0E+6	98.4	75.9	75.9	72.8	30.0	6.1E+6	0
23	17.0E+6	6.4E+9	1.67E+11	0.617	0.937	102	1.9E+6	92.4	71.5	71.5	68.7	30.0	5.7E+6	0
24	15.8E+6	6.0E+9	1.73E+11	0.639	0.939	96	1.8E+6	86.8	67.5	67.5	64.8	30.0	5.3E+6	0
25	14.7E+6	5.6E+9	1.78E+11	0.660	0.941	91	1.6E+6	81.6	63.7	63.7	61.3	30.0	4.9E+6	0
26	13.7E+6	5.2E+9	1.83E+11	0.679	0.943	86	1.5E+6	76.8	60.3	60.3	58.1	30.0	4.6E+6	0
27	12.7E+6	4.8E+9	1.88E+11	0.697	0.945	82	1.4E+6	72.4	57.1	57.1	55.1	30.0	4.2E+6	0
28	11.8E+6	4.5E+9	1.93E+11	0.714	0.947	77	1.3E+6	68.3	54.1	54.1	52.3	30.0	3.9E+6	0
29	10.9E+6	4.1E+9	1.97E+11	0.729	0.949	73	1.2E+6	64.5	51.5	51.5	49.8	30.0	3.6E+6	0
30	10.1E+6	3.8E+9	2.01E+11	0.743	0.951	70	1.1E+6	61.0	49.0	49.0	47.5	30.0	3.4E+6	0
31	9.4E+6	3.6E+9	2.04E+11	0.756	0.953	66	1.0E+6	57.7	46.7	46.7	45.4	30.0	3.1E+6	0
32	8.7E+6	3.3E+9	2.08E+11	0.769	0.955	63	963.4E+3	54.8	44.7	44.7	43.5	30.0	2.9E+6	0
33	8.0E+6	3.0E+9	2.11E+11	0.780	0.957	60	889.2E+3	52.1	42.8	42.8	41.8	30.0	2.7E+6	0
34	7.4E+6	2.8E+9	2.13E+11	0.790	0.958	57	819.4E+3	49.6	41.2	41.2	40.2	30.0	2.5E+6	0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Class 20230210 - Outline

-Abandonment rate
-Flow equilibrium (nodal analysis)
-Measures to prolong plateau
 -Subsea boosting/compression

Flow equilibrium / Nodal analysis



at initial time, when $\Delta p_{choke} = 0$ we obtained

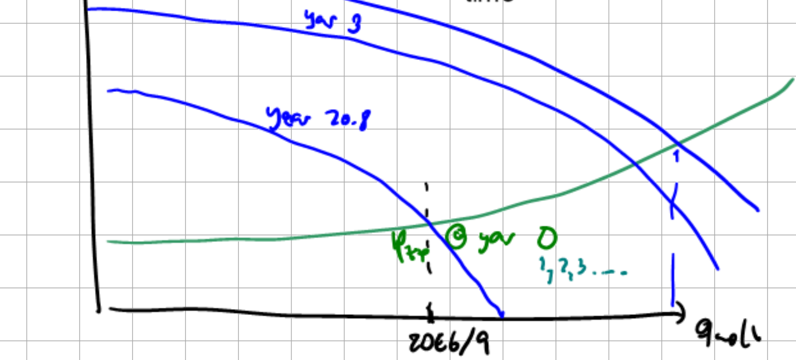
$$q_{field} \simeq 52\ E06\ Sm^3/d$$

If I want to have an intersection to the right of the natural flow point, I have a few options:
-Modify the available pressure curve (IPR "improvement", increase tubing size)
-Modify the required pressure curve (increase pipeline/flowline diameter, add parallel pipes)
-Add an element to bridge the pressure difference --> pump, compressor

How do the available and required pressure curves change with time?

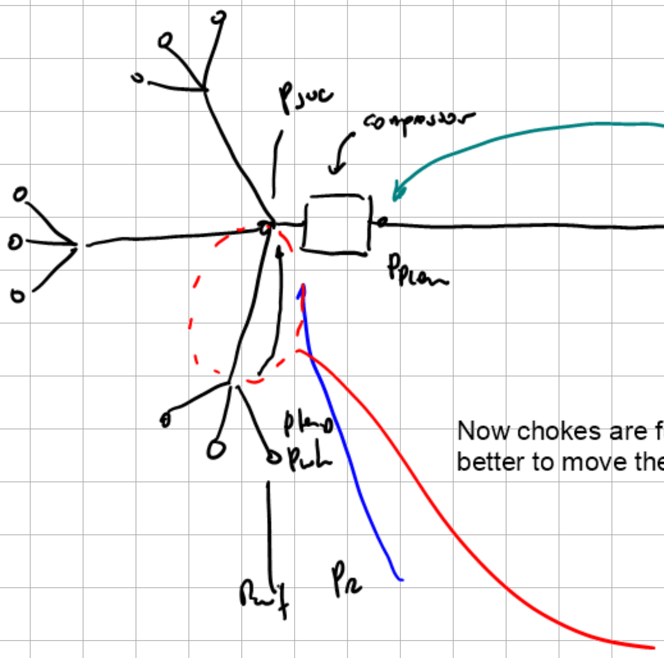
In this case only the available pressure curve is changing in time, because pR is changing in time

Measures to prolong plateau:
-Same as above
-Add more wells

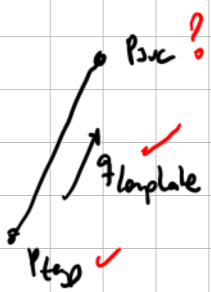


At the end of the plateau, we will try to prolong it with a compressor, since modifying the available and required pressure curves is too expensive

To add a compressor, we will place it at the plem, since it is only one for all wells, cheaper, easy to install and more convenient



Now chokes are fully open. Since I placed the compressor in the plem, it is better to move the equilibrium point to this location.



flowline
VBA
type P1
line P2
choke q

		k (Cp/Cv)	1.299	
SUBSEA COMPRESSION				
P_{suc} [bara]	P_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]
76.1	78.7			2.6
66.8	78.7			11.9
56.7	78.7			22.0
45.3	78.7			33.4
31.1	78.7			47.5
#VALUE!	78.7			#VALUE!
#VALUE!	78.7			#VALUE!
#VALUE!	78.7			#VALUE!

the DP compressor numbers look reasonable

← $q_{template}$ is too high for the pressure at P_{temp}

$\sqrt{(\ )}$ negative

$$P_{plem} = \sqrt{P_{lem}^2 - \left(\frac{q_{temp}}{C_{fl}}\right)^2}$$

the only option is to reduce the rate !!

then plateau ends

- The discharge temperature of the compressor has to be below 140 C to avoid problems in the seals of the compressor, avoid structural integrity issues in the pipeline and avoid vaporization of the hydrate inhibitor.
- The maximum power per compressor is 11 MW.
- The minimum temperature possible to achieve in the inlet cooler is 20 C.
- The minimum suction pressure to the compressor is 15 bara.
- Assume that the compressors operate with a polytropic efficiency of 70%.
- The gas temperature at the inlet of the compressor station is 67 C.

I reduce Ffield until $p_{suc} = 15$ bar

We should continue our production profile calculations until we reach abandonment rate

$CF^i = Revenue^i - OPEX^i$

when $CF < 0$ end of life of field

- To calculate revenue, you should compute the production profile until abandonment (field rate of 5 E06 Sm³/d). To compute the production profile you have to use flow

21	20.0E+6	7.3E+9	1.53E+11	0.568	0.933	115	2.2E+6	104.7	79.6	79.6	78.7	30.0	6.7E+6	0
22	20.0E+6	7.3E+9	1.61E+11	0.595	0.935	108	2.2E+6	97.0	70.8	70.8	78.7	30.0	6.7E+6	0
23	20.0E+6	7.3E+9	1.68E+11	0.622	0.937	101	2.2E+6	89.2	61.4	61.4	78.7	30.0	6.7E+6	0
24	20.0E+6	7.3E+9	1.75E+11	0.649	0.940	94	2.2E+6	81.2	51.0	51.0	78.7	30.0	6.7E+6	0
25	20.0E+6	7.3E+9	1.83E+11	0.676	0.943	87	2.2E+6	73.0	39.0	39.0	78.7	30.0	6.7E+6	0
26	19.5E+6	7.2E+9	1.90E+11	0.703	0.946	80	2.2E+6	65.1	27.4	27.4	76.8	30.0	6.5E+6	0
27	17.5E+6	6.7E+9	1.96E+11	0.728	0.949	74	1.9E+6	58.9	25.5	25.5	70.2	30.0	5.8E+6	0
28	15.7E+6	6.0E+9	2.02E+11	0.750	0.952	68	1.7E+6	53.3	23.8	23.8	64.4	30.0	5.2E+6	0
29	14.1E+6	5.4E+9	2.08E+11	0.770	0.955	62	1.6E+6	48.4	22.3	22.3	59.3	30.0	4.7E+6	0
30	12.6E+6	4.9E+9	2.13E+11	0.788	0.958	58	1.4E+6	44.0	21.1	21.1	54.8	30.0	4.2E+6	0
31	11.3E+6	4.4E+9	2.17E+11	0.804	0.961	54	1.3E+6	40.1	20.1	20.1	50.9	30.0	3.8E+6	0
32	10.1E+6	3.9E+9	2.21E+11	0.819	0.963	50	1.1E+6	36.6	19.2	19.2	47.5	30.0	3.4E+6	0
33	9.1E+6	3.5E+9	2.25E+11	0.832	0.965	46	1.0E+6	33.6	18.4	18.4	44.6	30.0	3.0E+6	0
34	8.1E+6	3.1E+9	2.28E+11	0.843	0.967	43	903.5E+3	30.9	17.8	17.8	42.1	30.0	2.7E+6	0
35	7.3E+6	2.8E+9	2.31E+11	0.854	0.969	40	808.9E+3	28.6	17.3	17.3	40.0	30.0	2.4E+6	0
36	6.5E+6	2.5E+9	2.33E+11	0.863	0.971	38	724.0E+3	26.6	16.8	16.8	38.2	30.0	2.2E+6	0

SUBSEA COMPRESSION

p_{suc} [bara]	p_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]	h_{suc} [kJ/kg]	s_{suc} [kJ/kg K]	$T_{dis,isen}$ [C]	s_{disc} [kJ/kg K]	$h_{dis,isen}$ [kJ/kg]	$\eta_{adiabatic}$ (eff) [-]	m [kg/s]
76.1	78.7			2.6							155.7E+0
66.8	78.7			11.9							155.7E+0
56.7	78.7			22.0							155.7E+0
45.3	78.7			33.4							155.7E+0
31.1	78.7			47.5							155.7E+0
15.0	76.8			61.8							151.5E+0
15.0	70.2			55.2							136.0E+0
15.0	64.4			49.4							122.1E+0
15.0	59.3			44.3							109.5E+0
15.0	54.8			39.8							98.2E+0
15.0	50.9			35.9							88.0E+0
15.0	47.5			32.5							78.9E+0
15.0	44.6			29.6							70.7E+0
15.0	42.1			27.1							63.3E+0
15.0	40.0			25.0							56.7E+0
15.0	38.2			23.2							50.7E+0

Let's try to estimate compression power and outlet temperature

How do we estimate compression power ?

$$\cancel{\dot{Q}} + \dot{w} + \dot{m}(\cancel{e_{in}}) - \dot{m}\, e_{out} = 0$$

h

Power $\rightarrow \dot{w} = \dot{m}\,\underbrace{(h_{out} - h_{in})}$

Watt

$\dot{m} \rightarrow q_{g\,field}\,[Sm^3/d] \cdot \rho_g$

for liquid

$C_p(T_{out} - T_{in})$

gas

p also affect h

so using this expression is innacurate

h thermodynamic property

(p, T)

$p_{in}, p_{out}, T_{in}, T_{out}$?

$\rho \rightarrow \Delta p$ efficient

$\rho \rightarrow \Delta T$ inefficient

what is the best compression process we can perform?

$$\frac{\dot{w}_{ideal}}{\dot{w}_{real}} = \eta_{adiabatic}$$

$$\dot{W}_{real} = \frac{\dot{W}_{ideal}}{\eta_{adiabatic}} \qquad 0.5 \le \eta_{adiabatic} \le 0.8$$

isoentropic $\quad s_{in} = s_{out}$

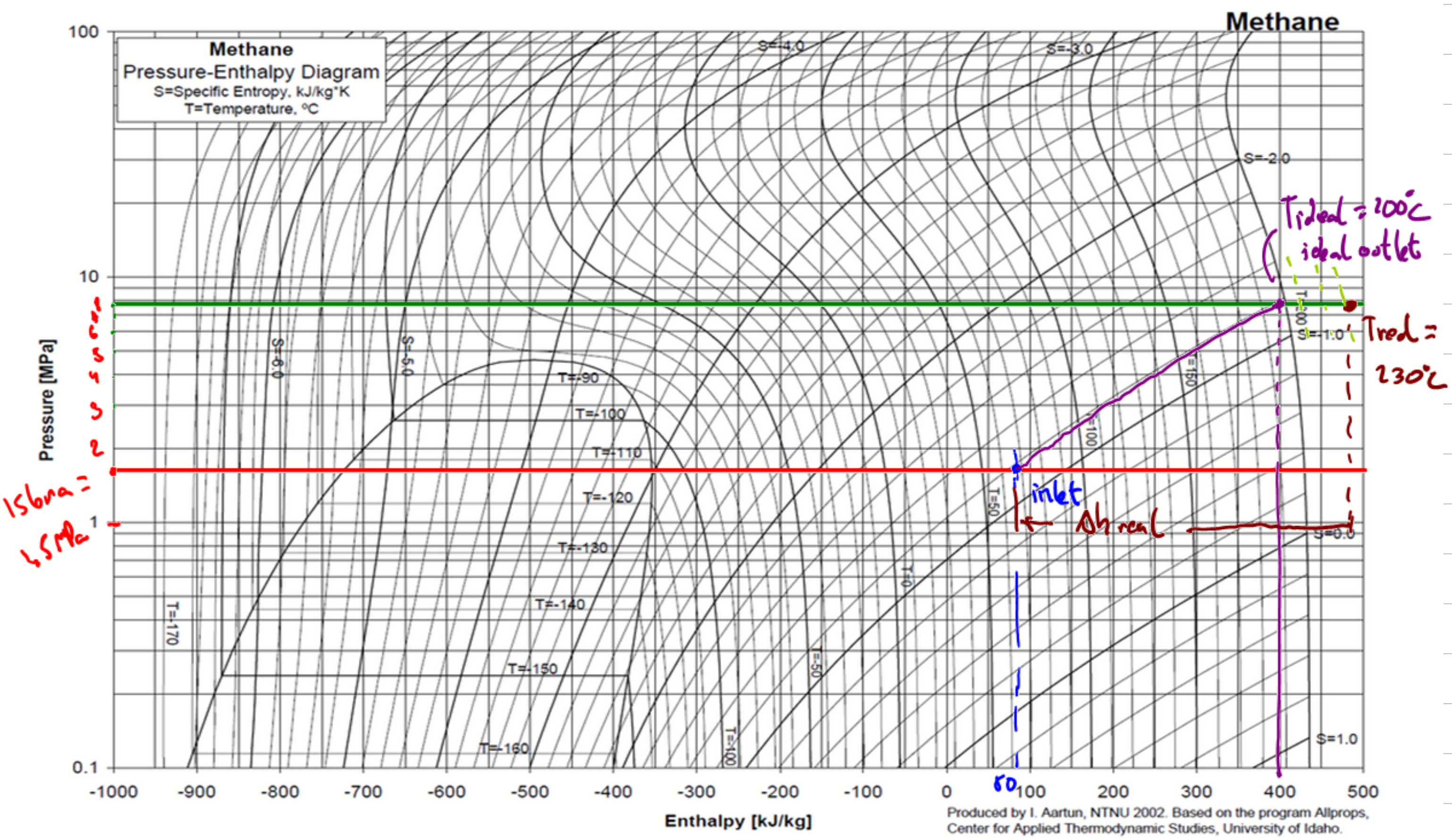
SUBSEA COMPRESSION

P_{suc} [bara]	P_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]	[k
76.1	78.7			2.6	
66.8	78.7			11.9	
56.7	78.7			22.0	
45.3	78.7			33.4	
31.1	78.7			47.5	
15.0	76.8			61.8	
15.0	70.2			55.2	
15.0	64.4			49.4	

Let's do the analysis for this year

$p_{in} = 15$ bara $\quad T_{in} = 67\ ^\circ C$

$p_{out} = 76.8$ bara



$$\Delta h_{ideal} = (h_{out} - h_{in}) = 400 - 80 \text{ kJ/kg} = 320 \text{ kJ/kg}$$

$$\dot{W}_{real} = \frac{\dot{W}_{ideal}}{\eta_{adiabatic}}$$

$$\cancel{\dot{m}}(h_{out} - h_{in}) = \frac{\cancel{\dot{m}}(h_{out_s} - h_{in})}{\eta_{adiabatic}}$$

$$\Delta h_{real} = \frac{\Delta h_{ideal}}{\eta_{adiabatic}}$$

SUBSEA COMPRESSION

p_{suc} [bara]	p_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]	[k
76.1	78.7			2.6	
66.8	78.7			11.9	
56.7	78.7			22.0	
45.3	78.7			33.4	
31.1	78.7			47.5	
15.0	76.8			61.8	
15.0	70.2			55.2	
15.0	64.4			49.4	

the T_{out} is too high (230°C)
a cooler is need

$$\dot{W}_{real} = 151.5\ kg/s \frac{(320\ kJ/kg)}{\eta_{adiabatic}}$$

$$\eta_{adiabatic} = 0.7$$

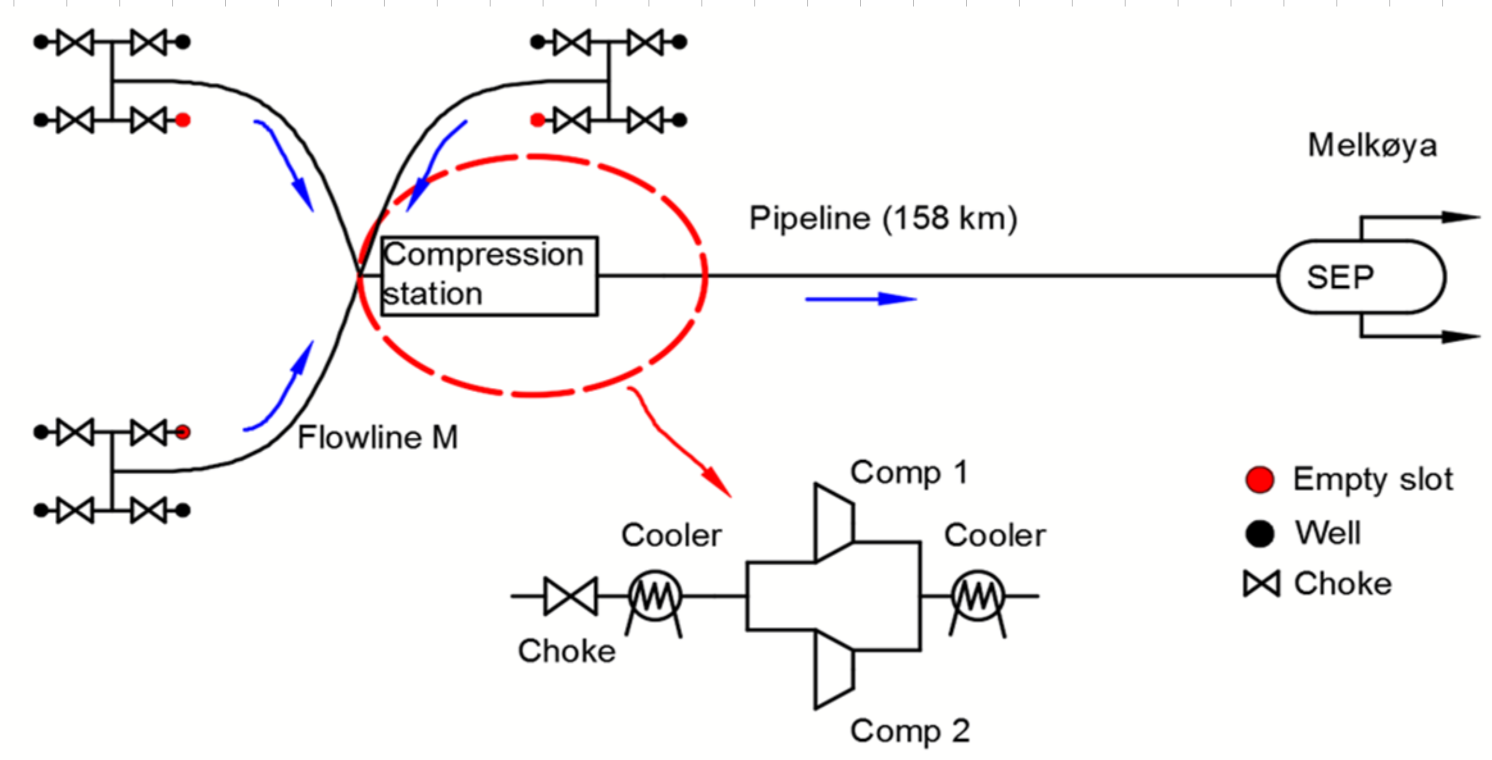
$$\dot{W}_{real} = 69257\ kJ/s = 69\ MW$$

this is too much!! 3 compressor stations (2x 11 MW) would be needed

what can be done?

Reduce the rate, this will reduce the dP and also the dh

Class 20230214
Outline
-Solving the Snøhvit production scheduling exercise considering a subsea compressor
-General comments about boosters



Reduce qgfield due to max power limit

k (Cp/Cv)	1.299
START row	57
END row	61
Max power [MW]	22

SUBSEA COMPRESSION

p_{suc} [bara]	p_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]	h_{suc} [kJ/kg]	s_{suc} [kJ/kg K]	$T_{dis,isen}$ [C]	s_{disc} [kJ/kg K]	$h_{dis,isen}$ [kJ/kg]	$\eta_{adiabatic}$ (eff) [-]	m [kg/s]	P_{comp} [MW]
76.1	78.7	67		2.6						0.7		
66.8	78.7	67		11.9						0.7		
56.7	78.7	67		22.0						0.7		
45.3	78.7	67		33.4						0.7		
31.1	78.7	67		47.5						0.7		
15.0	76.8	67		61.8	-4586	10.346				0.7		
15.0	70.2	67		55.2						0.7		
15.0	64.4	67		49.4						0.7		
15.0	59.3	67		44.3						0.7		
15.0	54.8	67		39.8						0.7		
15.0	50.9	67		35.9						0.7		
15.0	47.5	67		32.5						0.7		
15.0	44.6	67		29.6						0.7		
15.0	42.1	67		27.1						0.7		
15.0	40.0	67		25.0						0.7		
15.0	38.2	67		23.2						0.7		

I use the twodiminterpolation function on the table located in the sheet "gas enthalpy table"

```
Function TwoDimInterpol(x1 As Double, x2 As Double, col As Integer, Matrix As Range, OrderX As Integer, OrderY As Integer)
    'function to perform two-dimensional linear interpolation in tables
    'INPUT:
    '-x1 value for the first variable which the property is required (e.g.: Pressure)
    '-x2 value for the second variable which the property is required  (e.g.: Temperature)
    '-col: column number (integer) in which the property is located (e.g.: 3)
    'Matrix: table organized in the following manner:

    '   x1      x2   PROP1  PROP2  PROP3  PROP4
    ' value  value  value  value  value  value
    ' value  value  value  value  value  value
    ' value  value  value  value  value  value
    ' value  value  value  value  value  value
    '-OrderX use digit 0 if X values are organized in descending manner, 1 if X values are ascending
    '-OrderY use digit 0 if Y values are organized in descending manner, 1 if Y values are ascending

    'Reading the dimensions of the matrix
    'Number of rows
    m = Matrix.Rows.Count
    'Number of columns
    n = Matrix.Columns.Count

    'Checking is value x1 is within the Matrix ranges
    If OrderX = 1 Then
        If x1 < Matrix(1, 1) Or x1 > Matrix(m, 1) Then
            Err = 1
        End If
    Else
        If x1 > Matrix(1, 1) Or x1 < Matrix(m, 1) Then
            Err = 1
        End If
    End If
    'Checking is value x2 is within the Matrix ranges
    If OrderY = 1 Then
        If x2 < Matrix(1, 2) Or x2 > Matrix(m, 2) Then
            Err = 1
        End If
    Else
        If x2 > Matrix(1, 2) Or x2 < Matrix(m, 2) Then
            Err = 1
        End If
    End If
    'If values are not in the matrix range return a message
```

A	B	C	D
p [bara]	T [C]	h [kJ/kg]	s [kJ/kg K]
10	-10	-4759.64	9.94221
10	0	-4737.06	10.0264
10	10	-4714.36	10.1081
10	20	-4691.49	10.1874
10	30	-4668.45	10.2647
10	40	-4645.21	10.3401
10	50	-4621.77	10.4138
10	60	-4598.1	10.4859
10	70	-4574.19	10.5567
10	80	-4550.02	10.6261
10	90	-4525.6	10.6943
10	100	-4500.9	10.7614

In class, we tried to guess Tdisc_isen such that s_suc=s_disc using the solver. This worked well, however, solver didn't work well when we wanted to reduce the rate to bring the power down to 22 MW AND at the same time guess Tdis_isen such that s_suc=s_disc. So, we used a different approach. The isentropic discharge temperature will be calculated using the following expression:

in K, not in °C

$$\frac{T_{out,isen}}{T_{in}} = (r_p)^{\frac{k-1}{k}} \qquad k = \frac{C_p}{C_v}$$

ideal gas

isentropic process

rp is pressure ratio between discharge and suction.

$$T_{out,is} = T_{in}\,(r_p)^{\frac{k-1}{k}}$$

This equation is programmed in VBA with the name "Tout". After finding this temperature, I then use table interpolation with pdis and Tdisc_isen to find hdis_isen and s_dis_isen.

k (Cp/Cv) 1.299

SUBSEA COMPRESSION

p_{suc} [bara]	p_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]	h_{suc} [kJ/kg]	s_{suc} [kJ/kg K]	$T_{dis,isen}$ [C]	s_{disc} [kJ/kg K]	$h_{dis,isen}$ [kJ/kg]	$\eta_{adiabatic}$ (eff) [-]
76.1	78.7	67		2.6						0.7
66.8	78.7	67		11.9						0.7
56.7	78.7	67		22.0						0.7
45.3	78.7	67		33.4						0.7
31.1	78.7	67		47.5						0.7
15.0	76.8	67	5.12	61.8	-4586	10.346	222.3	VALUE N	VALUE I	0.7
15.0	70.2	67		55.2						0.7
15.0	64.4	67		49.4						0.7
15.0	59.3	67		44.3						0.7
15.0	54.8	67		39.8						0.7
15.0	50.9	67		35.9						0.7
15.0	47.5	67		32.5						0.7
15.0	44.6	67		29.6						0.7
15.0	42.1	67		27.1						0.7
15.0	40.0	67		25.0						0.7
15.0	38.2	67		23.2						0.7

The value error is because the maximum value in the table is 200 C. I decide to reduce the field rate to 17 E06 (200 C at the discharge is too high

These are very similar, good!

SUBSEA COMPRESSION

p_{suc} [bara]	p_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]	h_{suc} [kJ/kg]	s_{suc} [kJ/kg K]	$T_{dis,isen}$ [C]	s_{disc} [kJ/kg K]	$h_{dis,isen}$ [kJ/kg]	$\eta_{adiabatic}$ (eff) [-]
76.1	78.7	67		2.6						0.7
66.8	78.7	67		11.9						0.7
56.7	78.7	67		22.0						0.7
45.3	78.7	67		33.4						0.7
31.1	78.7	67		47.5						0.7
36.4	68.7	67	1.89	32.3	-4605	9.819	120.5	9.821	-4487	0.7

I then calculate the compression power by using the expression:

$$\dot{w}_{real} = \dot{m} \frac{\Delta h_{ideal}}{\eta_{adiabatic}}$$

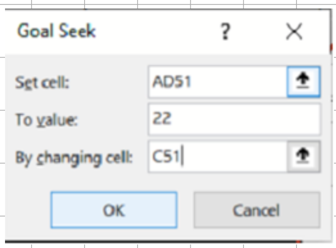
h_{suc} [kJ/kg]	s_{suc} [kJ/kg K]	$T_{dis,isen}$ [C]	s_{disc} [kJ/kg K]	$h_{dis,isen}$ [kJ/kg]	$\eta_{adiabatic}$ (eff) [-]	m [kg/s]	P_{comp} [MW]	h_{disc} [kJ/kg]	T_{disc} [C]	$h_{disc,tal}$ [kJ/k
					0.7	155.7E+0				
					0.7	155.7E+0				
					0.7	155.7E+0				
					0.7	155.7E+0				
					0.7	155.7E+0				
-4605	9.819	120.5	9.821	-4487	0.7	132.3E+0	=AC51*(AA51-W51)/(AB51*1000)			

SUBSEA COMPRESSION

p_{suc} [bara]	p_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]	h_{suc} [kJ/kg]	s_{suc} [kJ/kg K]	$T_{dis,isen}$ [C]	s_{disc} [kJ/kg K]	$h_{dis,isen}$ [kJ/kg]	$\eta_{adiabatic}$ (eff) [-]	m [kg/s]	P_{comp} [MW]
76.1	78.7	67		2.6						0.7	155.7E+0	
66.8	78.7	67		11.9						0.7	155.7E+0	
56.7	78.7	67		22.0						0.7	155.7E+0	
45.3	78.7	67		33.4						0.7	155.7E+0	
31.1	78.7	67		47.5						0.7	155.7E+0	
36.4	68.7	67	1.89	32.3	-4605	9.819	120.5	9.821	-4487	0.7	132.3E+0	22.2E+0
18.3	70.2	67		51.9						0.7	136.0E+0	
18.1	64.4	67		46.4						0.7	122.1E+0	

By reducing the field rate to 17E06 Sm3/d I brought down the compression power to a feasible value.

I use the goal seek to change the rate to bring power to 22 MW



I then apply the CELL formulas for the other years

SUBSEA COMPRESSION

p_{suc} [bara]	p_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]	h_{suc} [kJ/kg]	s_{suc} [kJ/kg K]	$T_{dis,isen}$ [C]	s_{disc} [kJ/kg K]	$h_{dis,isen}$ [kJ/kg]	$\eta_{adiabatic}$ (eff) [-]	m [kg/s]	P_{comp} [MW]
76.1	78.7	67	1.03	2.6	-4638	9.360	69.6	9.359	-4633	0.7	155.7E+0	1.1E+0
66.8	78.7	67	1.18	11.9	-4631	9.445	80.1	9.441	-4604	0.7	155.7E+0	5.8E+0
56.7	78.7	67	1.39	22.0	-4622	9.549	93.7	9.544	-4567	0.7	155.7E+0	12.2E+0
45.3	78.7	67	1.74	33.4	-4612	9.688	113.2	9.686	-4514	0.7	155.7E+0	22.0E+0
31.1	78.7	67	2.53	47.5	-4600	9.909	148.0	9.927	-4417	0.7	155.7E+0	40.8E+0
36.5	68.6	67	1.88	32.1	-4605	9.818	120.2	9.819	-4488	0.7	132.2E+0	22.0E+0
18.4	70.2	67	3.82	51.9	-4589	10.219	190.1	10.265	-4293	0.7	136.0E+0	57.6E+0
18.1	64.4	67	3.56	46.3	-4589	10.229	182.6	10.269	-4312	0.7	122.1E+0	48.3E+0
17.9	59.3	67	3.32	41.4	-4588	10.237	175.1	10.268	-4331	0.7	109.5E+0	40.3E+0
17.7	54.8	67	3.10	37.1	-4588	10.244	168.1	10.271	-4348	0.7	98.2E+0	33.7E+0
17.5	50.9	67	2.91	33.4	-4588	10.251	161.7	10.270	-4364	0.7	88.0E+0	28.2E+0
17.4	47.5	67	2.74	30.2	-4588	10.257	155.7	10.273	-4379	0.7	78.9E+0	23.6E+0
17.2	44.6	67	2.59	27.4	-4588	10.262	150.4	10.275	-4392	0.7	70.7E+0	19.8E+0
17.1	42.1	67	2.47	25.0	-4588	10.267	145.5	10.275	-4404	0.7	63.3E+0	16.6E+0
17.0	40.0	67	2.36	23.0	-4588	10.272	141.3	10.274	-4414	0.7	56.7E+0	14.1E+0
16.9	38.2	67	2.27	21.4	-4588	10.276	137.5	10.279	-4423	0.7	50.7E+0	11.9E+0

field rate should be reduced in these years. I use the button

Reduce qgfield due to max power limit

Reduce qgfield due to max power limit

k (Cp/Cv) 1.299

START row	50
END row	57
Max power [MW]	22

SUBSEA COMPRESSION

p_{suc} [bara]	p_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]	h_{suc} [kJ/kg]	s_{suc} [kJ/kg K]	$T_{dis,isen}$ [C]	s_{disc} [kJ/kg K]	$h_{dis,isen}$ [kJ/kg]	$\eta_{adiabatic}$ (eff) [-]	m [kg/s]	P_{comp} [MW]
76.1	78.7	67	1.03	2.6	-4638	9.360	69.6	9.359	-4633	0.7	155.7E+0	1.1E+0
66.8	78.7	67	1.18	11.9	-4631	9.445	80.1	9.441	-4604	0.7	155.7E+0	5.8E+0
56.7	78.7	67	1.39	22.0	-4622	9.549	93.7	9.544	-4567	0.7	155.7E+0	12.2E+0
45.3	78.7	67	1.74	33.4	-4612	9.688	113.2	9.686	-4514	0.7	155.7E+0	22.0E+0
40.9	73.6	67	1.80	32.8	-4609	9.748	116.4	9.750	-4502	0.7	144.0E+0	22.0E+0
36.9	69.0	67	1.87	32.2	-4605	9.812	119.9	9.814	-4489	0.7	133.1E+0	22.0E+0
33.2	64.8	67	1.95	31.6	-4602	9.874	123.6	9.879	-4477	0.7	122.9E+0	22.0E+0
29.8	60.9	67	2.04	31.0	-4599	9.931	127.7	9.942	-4463	0.7	113.4E+0	22.0E+0
26.8	57.3	67	2.14	30.5	-4596	10.002	132.1	10.009	-4449	0.7	104.5E+0	22.0E+0
24.0	54.0	67	2.25	30.1	-4594	10.066	137.0	10.076	-4434	0.7	96.2E+0	22.0E+0
21.4	51.1	67	2.38	29.7	-4592	10.124	142.3	10.143	-4418	0.7	88.5E+0	22.0E+0
19.1	48.4	67	2.53	29.3	-4590	10.190	148.1	10.212	-4400	0.7	81.4E+0	22.0E+0
20.9	44.6	67	2.14	23.7	-4591	10.137	132.0	10.155	-4442	0.7	70.7E+0	15.1E+0
20.6	42.1	67	2.05	21.6	-4591	10.144	128.1	10.161	-4451	0.7	63.3E+0	12.7E+0
20.3	40.0	67	1.97	19.7	-4591	10.151	124.7	10.165	-4458	0.7	56.7E+0	10.7E+0
20.0	38.2	67	1.91	18.2	-4590	10.157	121.7	10.174	-4465	0.7	50.7E+0	9.1E+0

I could increase the field rate in these years (the suction pressure is above 15 bara and teh compression power is below 22 MW). I use goalseek again

Reduce qgfield due to max power limit

k (Cp/Cv) 1.299

START row	58
END row	59
Max power [MW]	22

SUBSEA COMPRESSION

p_{suc} [bara]	p_{disch} [bara]	T_{suc} [C]	r_p [-]	Δ_p [bar]	h_{suc} [kJ/kg]	s_{suc} [kJ/kg K]	$T_{dis,isen}$ [C]	s_{disc} [kJ/kg K]	$h_{dis,isen}$ [kJ/kg]	$\eta_{adiabatic}$ (eff) [-]	m [kg/s]	P_{comp} [MW]
76.1	78.7	67	1.03	2.6	-4638	9.360	69.6	9.359	-4633	0.7	155.7E+0	1.1E+0
66.8	78.7	67	1.18	11.9	-4631	9.445	80.1	9.441	-4604	0.7	155.7E+0	5.8E+0
56.7	78.7	67	1.39	22.0	-4622	9.549	93.7	9.544	-4567	0.7	155.7E+0	12.2E+0
45.3	78.7	67	1.74	33.4	-4612	9.688	113.2	9.686	-4514	0.7	155.7E+0	22.0E+0
40.9	73.6	67	1.80	32.8	-4609	9.748	116.4	9.750	-4502	0.7	144.0E+0	22.0E+0
36.9	69.0	67	1.87	32.2	-4605	9.812	119.9	9.814	-4489	0.7	133.1E+0	22.0E+0
33.2	64.8	67	1.95	31.6	-4602	9.874	123.6	9.879	-4477	0.7	122.9E+0	22.0E+0
29.8	60.9	67	2.04	31.0	-4599	9.931	127.7	9.942	-4463	0.7	113.4E+0	22.0E+0
26.8	57.3	67	2.14	30.5	-4596	10.002	132.1	10.009	-4449	0.7	104.5E+0	22.0E+0
24.0	54.0	67	2.25	30.1	-4594	10.066	137.0	10.076	-4434	0.7	96.2E+0	22.0E+0
21.4	51.1	67	2.38	29.7	-4592	10.124	142.3	10.143	-4418	0.7	88.5E+0	22.0E+0
19.1	48.4	67	2.53	29.3	-4590	10.190	148.1	10.212	-4400	0.7	81.4E+0	22.0E+0
17.0	46.0	67	2.70	29.0	-4588	10.269	154.4	10.283	-4382	0.7	74.7E+0	22.0E+0
15.2	43.9	67	2.90	28.7	-4586	10.340	161.3	10.354	-4361	0.7	68.6E+0	22.0E+0
15.0	41.5	67	2.77	26.5	-4586	10.346	156.9	10.356	-4372	0.7	61.5E+0	18.8E+0
15.0	39.5	67	2.63	24.5	-4586	10.346	152.0	10.351	-4385	0.7	55.1E+0	15.8E+0

Plateau production

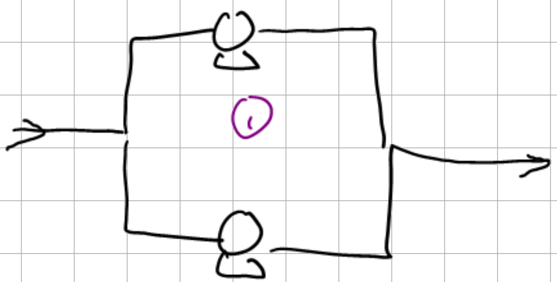
Decline: power-constrained operation

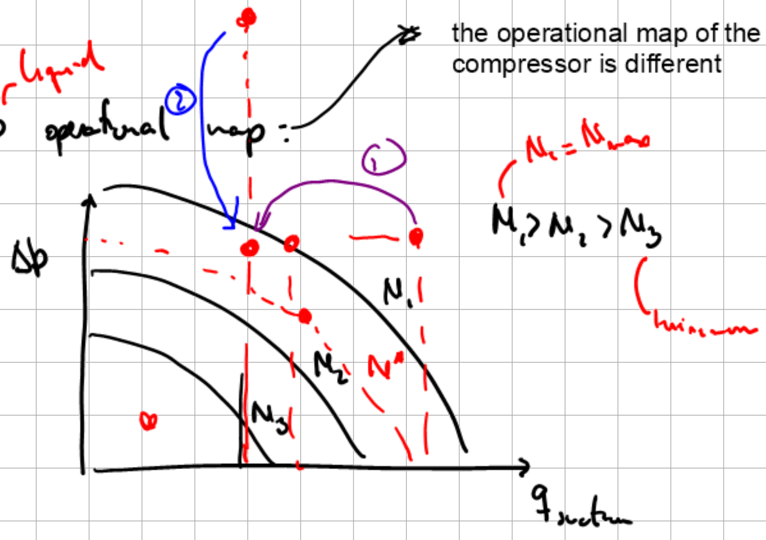
Decline: operation constrained by suction pressure

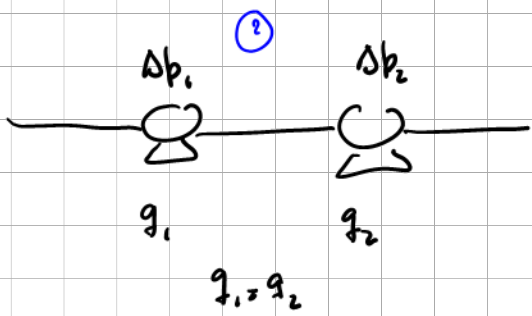
Try it by yourselves: Assume Tsuction is reduced to 20 C and repeat the calculations. What differences do you find?

Other things that should be taken into account when considering compressor (boosting):
-Outlet temperature. It might be that the temperature is too high. Cooling can be used.
-Operational map (q, DP should fall inside the map), if not, I can change the model, or use parallel/series configuration

Pump (liquid) operational map: → the operational map of the compressor is different





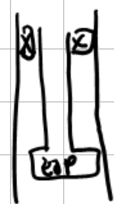


$\Delta p_1 + \Delta p_2 = \Delta p_{total}$

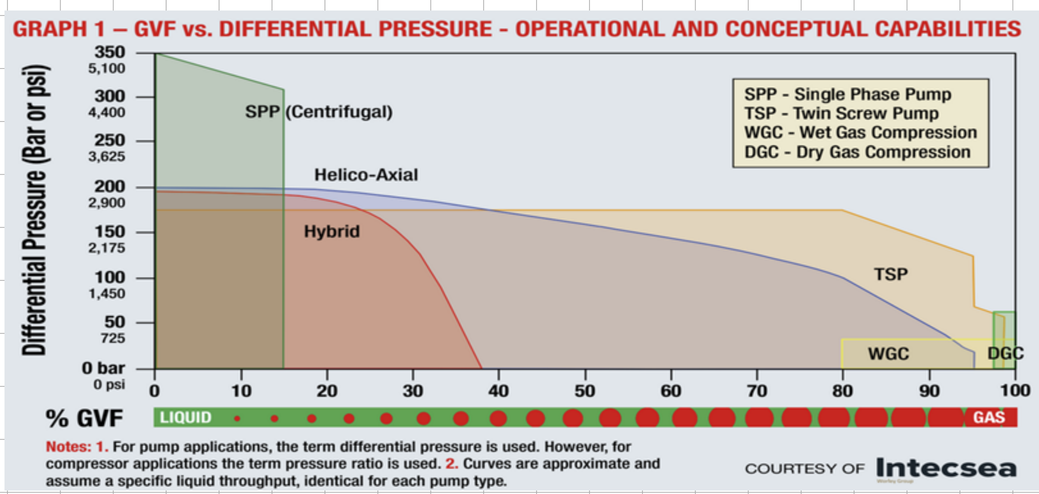
Bridging the pressure difference between required & available:

Boosters → outside of well → GVF gas volume factor $\frac{q_g}{q_L + q_g} = GVF$ @ suction

→ inside of well → ESP electric submersible pump

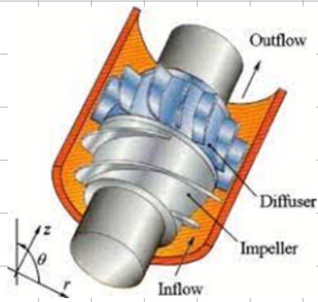


Available boosting technology:
https://www.offshore-mag.com/resources/maps-posters/document/14185956/2020-worldwide-survey-of-subsea-processing



Twin screw pump:
https://www.youtube.com/watch?v=5DksnUU-o6o

Helico-axial pump (popular for oil fields):



Section 2.3.3. in Milan's compendium.
The method used for the analysis of the Snowhite subsea compresor can be used for other fluids, the only difference is that the p-h behavior of the fluid is different:

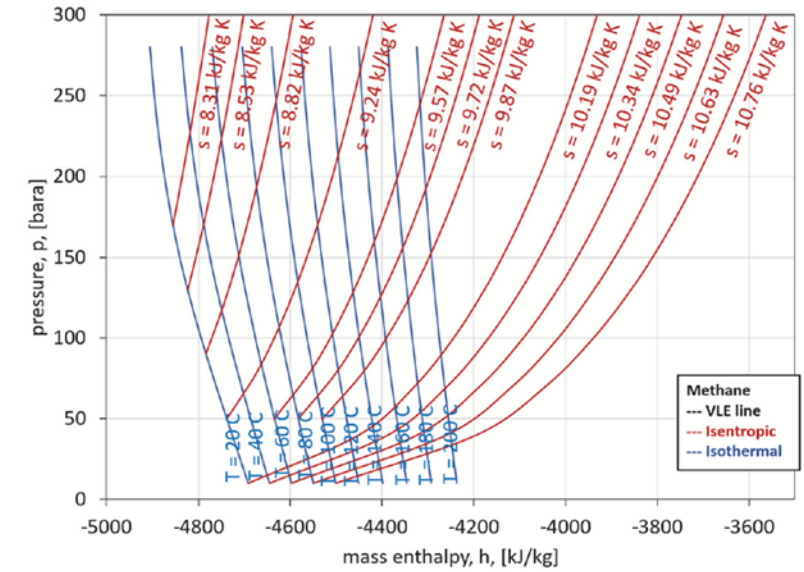


FIGURE 2-36. PRESSURE-ENTHALPY DIAGRAM FOR METHANE DEPICTING LINES OF ISO-TEMPERATURE AND ISO-ENTROPY

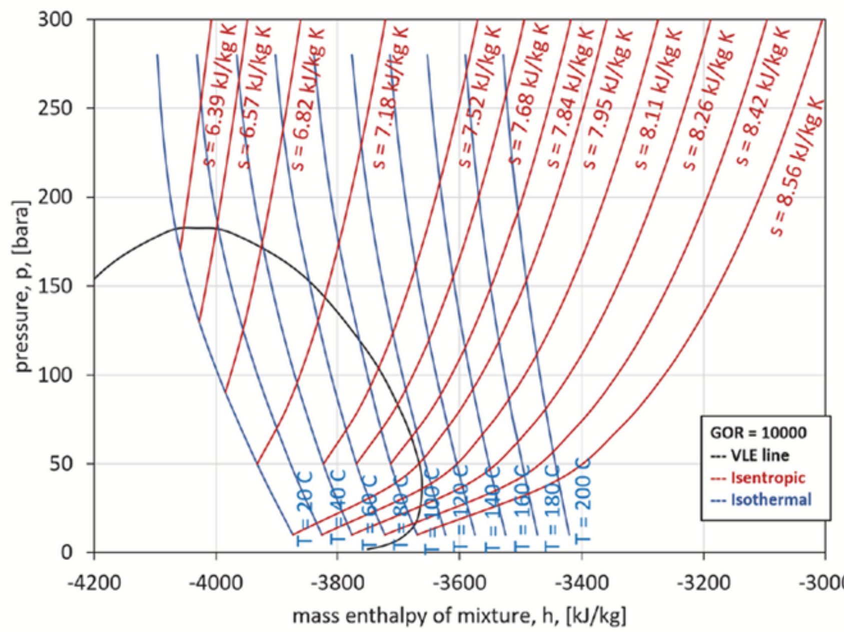


FIGURE 2-35. PRESSURE-ENTHALPY DIAGRAM FOR AN OIL WITH GOR=10 000 DEPICTING LINES OF ISO-TEMPERATURE AND ISO-ENTROPY

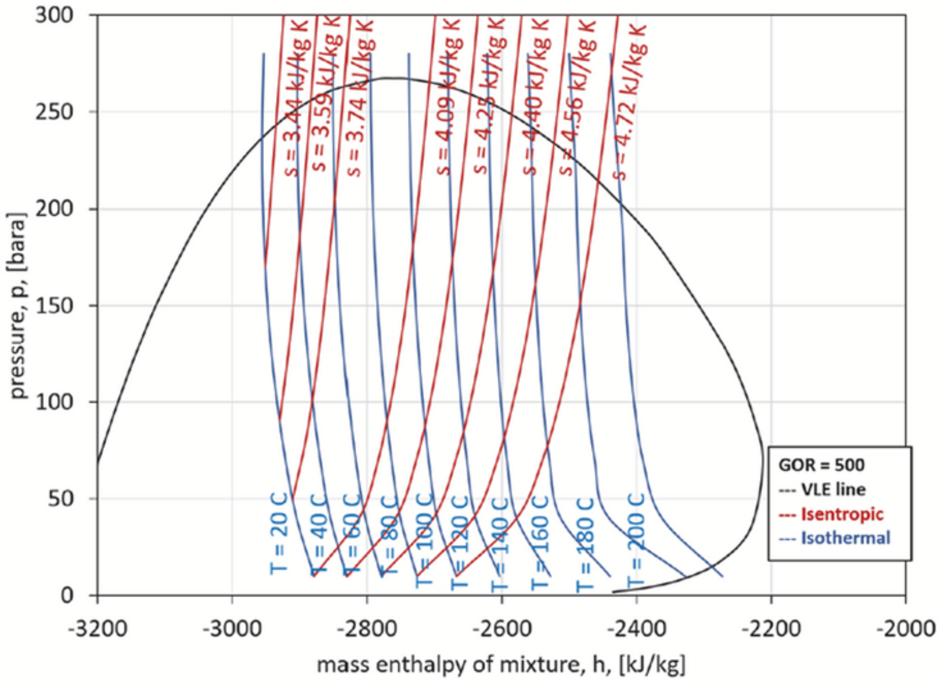


FIGURE 2-34. PRESSURE-ENTHALPY DIAGRAM FOR AN OIL WITH GOR=500 DEPICTING LINES OF ISO-TEMPERATURE AND ISO-ENTROPY

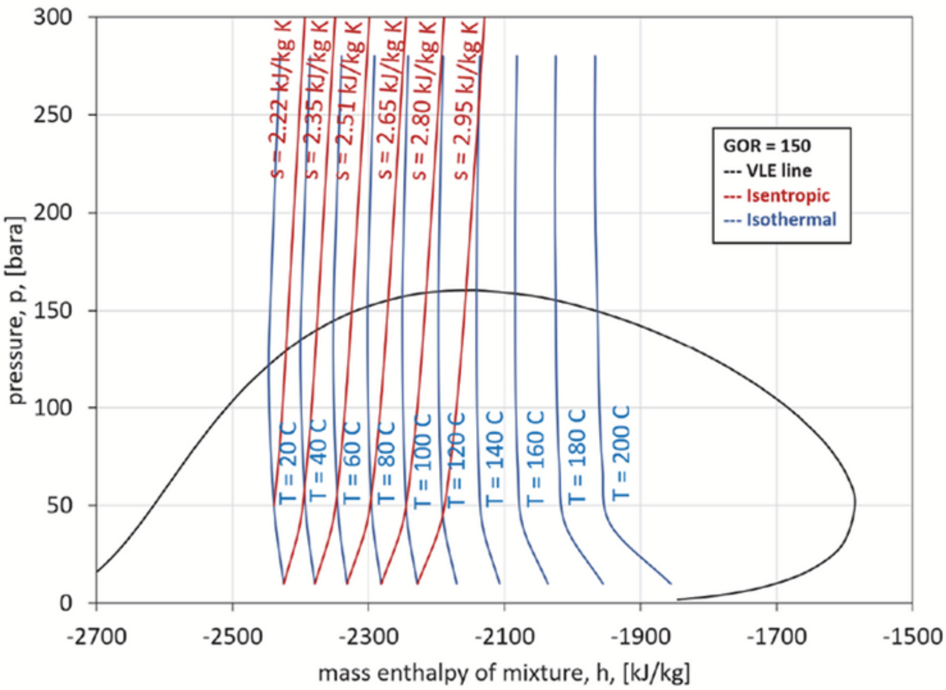


FIGURE 2-33. PRESSURE-ENTHALPY DIAGRAM FOR AN OIL WITH GOR = 150 DEPICTING LINES OF ISO-TEMPERATURE AND ISO-ENTROPY

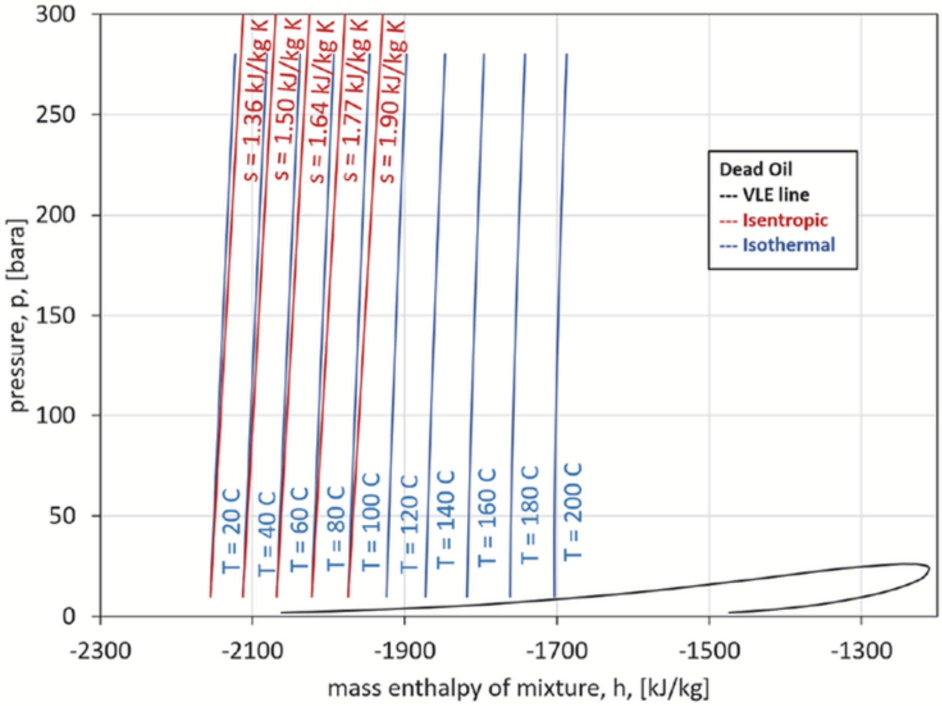


FIGURE 2-32. PRESSURE-ENTHALPY DIAGRAM FOR A DEAD OIL DEPICTING LINES OF ISO-TEMPERATURE AND ISO-ENTROPY

Observations: more oil-like, the iso-entropy lines are more vertical. This means that if the psuc, Tsuc and pdisc are the same, the ideal Dh is smaller than for an oil-like fluid than for a gas-like fluid (less work required to boost)

NTNU – Trondheim
Norwegian University of
Science and Technology

Class 20230217

Outline

-Approaches to generate production profiles

-Estimation of project economic indicators

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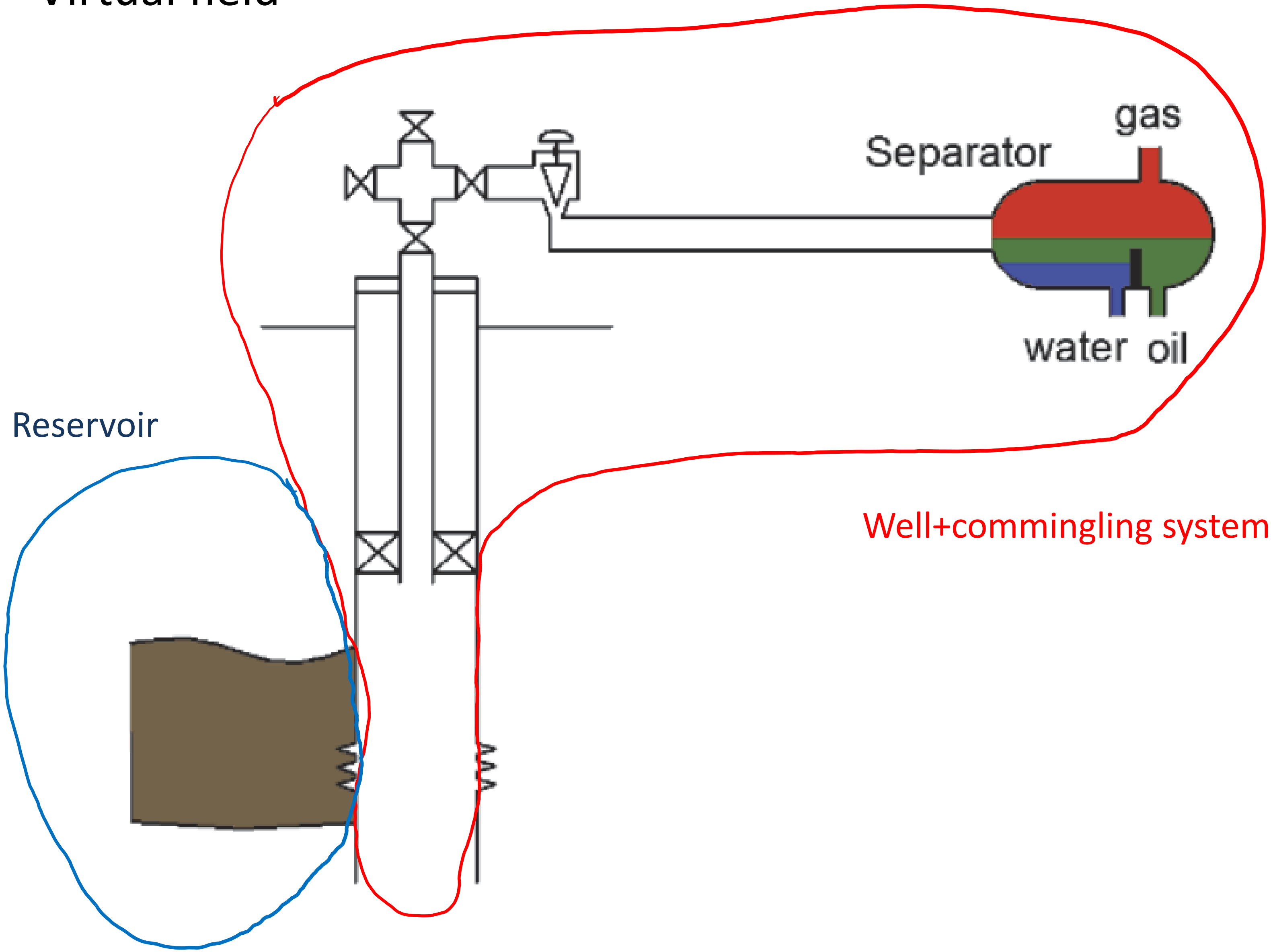
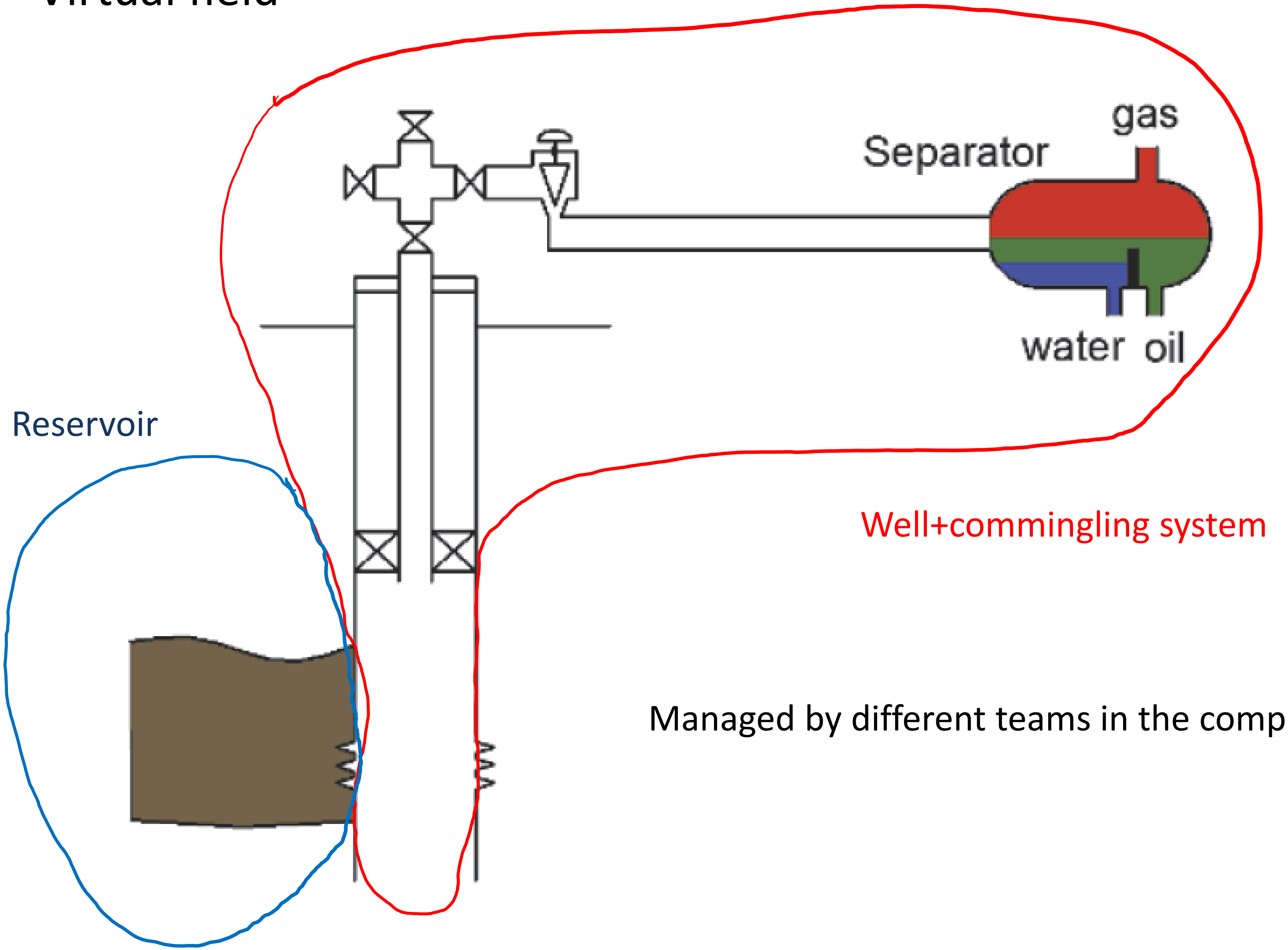
Norwegian University of
Science and Technology

Approaches to generate production profiles

Virtual field

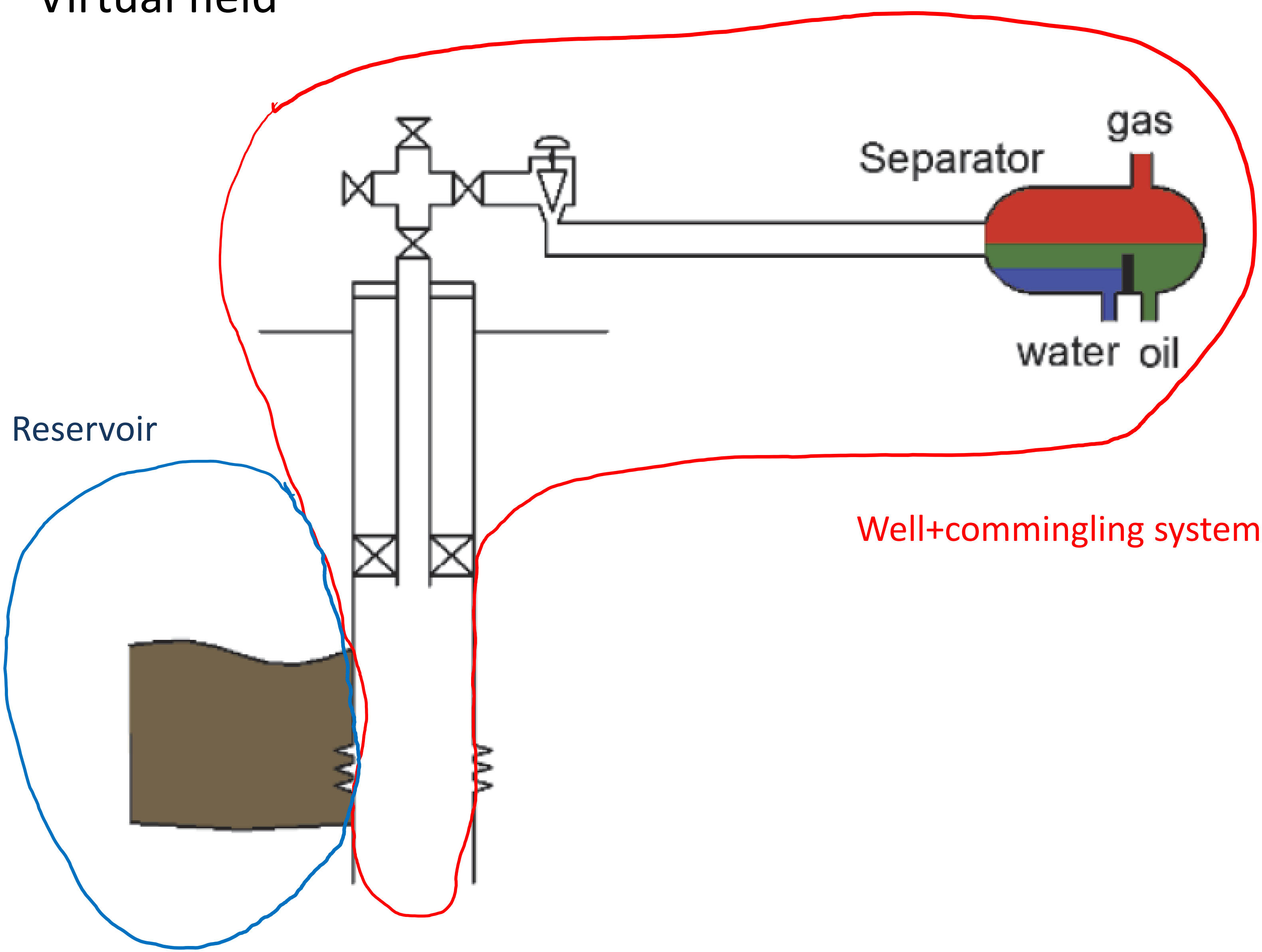


Virtual field



Managed by different teams in the company

Virtual field



Reservoir model

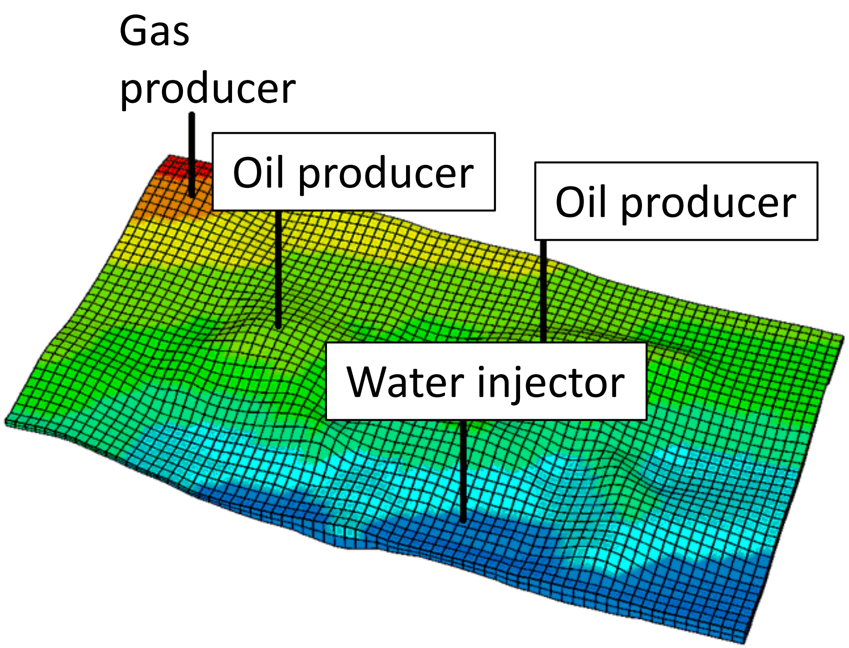
Alternatives to generate production profiles

-Reservoir only
-Reservoir + network (coupled)

Reservoir modeling alternatives

-Material balance + IPR equation (what we did in the Snowhite exercise)
-Decline (type) curves – assuming a trend of qfield versus time (e.g. exponential)
-Reservoir simulation

Reservoir model

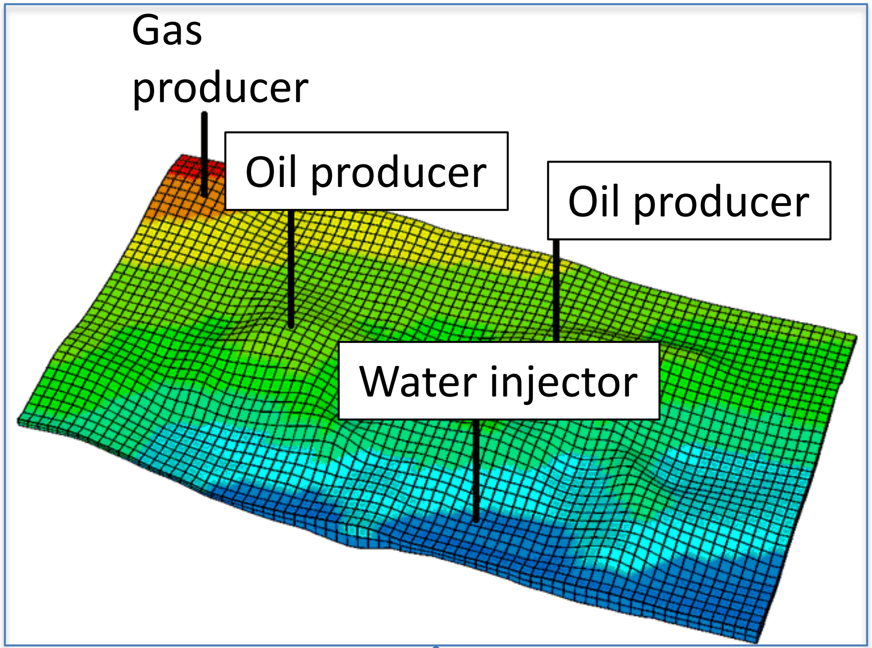


- 3D computer representation of a petroleum reservoir
- Computes the **variation** of the pressures, saturations and other properties **with time** when fluids are retrieved from or injected into the domain
- Captures the flow in porous media in the reservoir, thermal effects, thermodynamic flashing

Reservoir model

Boundary conditions (t):
-Well target rate q_w (t) and $p_{wf\,min}$(t)

INPUT



OUTPUT

- Boundary properties p_{wf}(t), q_w (t)
- Block variables (t)
- Well variables (t)

INPUT

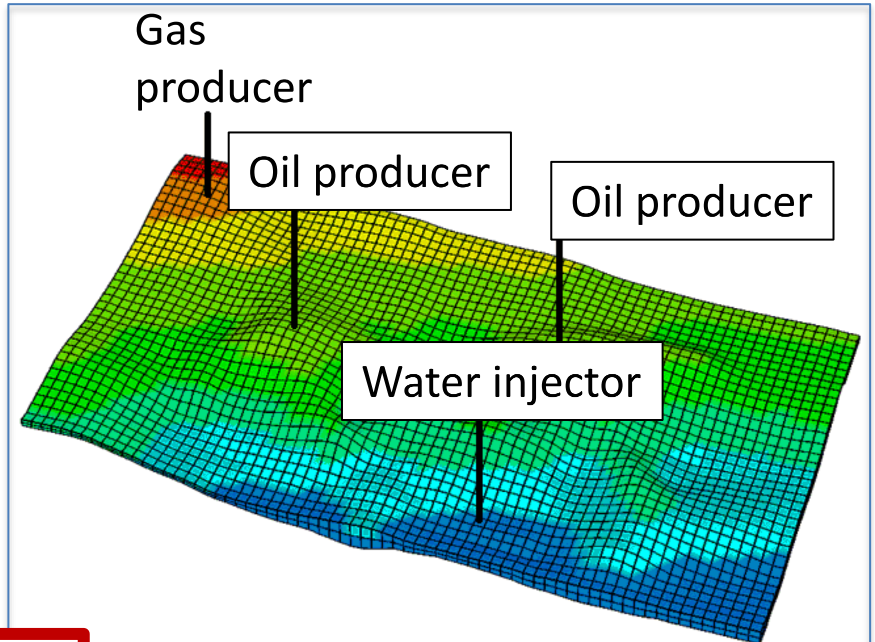
- Reservoir / system properties (Porosity, saturations, permeability, EOS, fluid composition, reservoir temperature, initial reservoir pressure)
- Well locations
- **Well status (t)**

Usually variables constant for the whole simulation time or on-off (no regulation)

Reservoir model

Boundary conditions (t):
-Well target rate q_w (t) and $p_{wf\ min}$(t)

INPUT



OUTPUT

- Boundary properties p_{wf} (t), q_w (t)
- Block variables (t)
- Well variables (t)

A GOOD GUESS(ES) FOR pwfmin is required!!

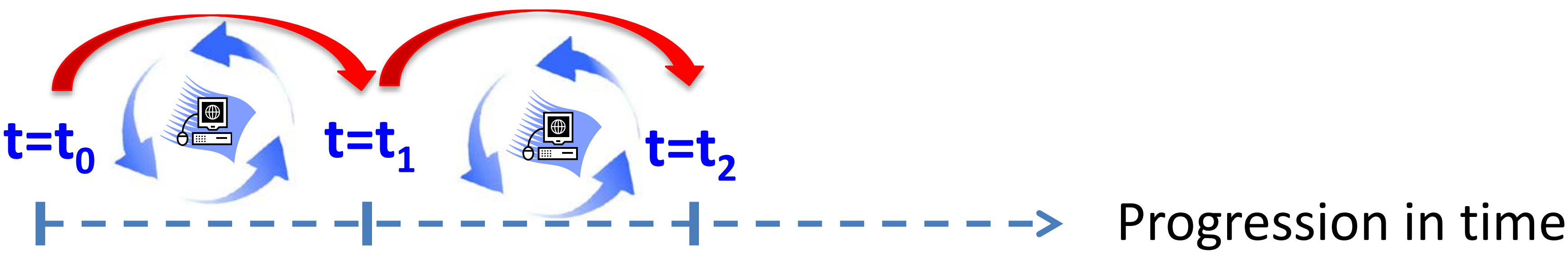
INPUT

- Reservoir / system properties (Porosity, saturations, permeability, EOS, fluid composition, reservoir temperature, initial reservoir pressure)
- Well locations
- **Well status (t)**

Usually variables constant for the whole simulation time or on-off (no regulation)

Operating mode

Reservoir model

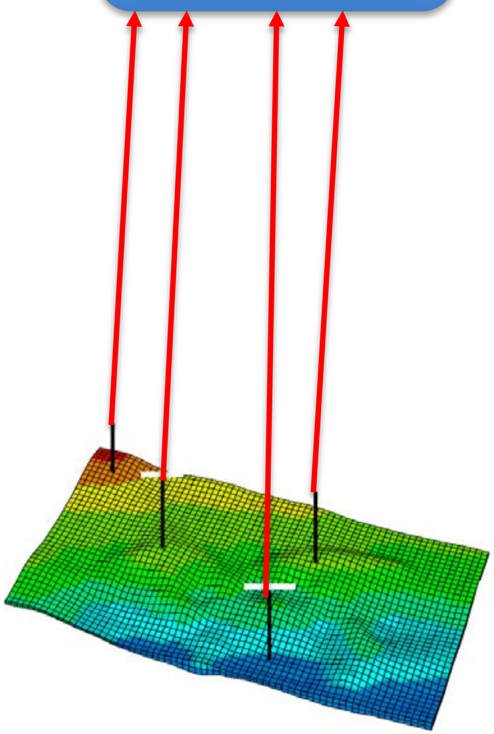


Input file - Example

Network model

Network model characteristics

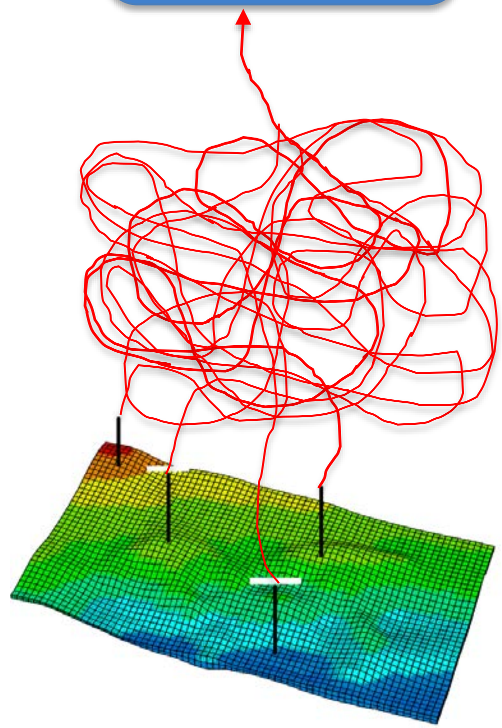
Separator pressure, p_{SEP}



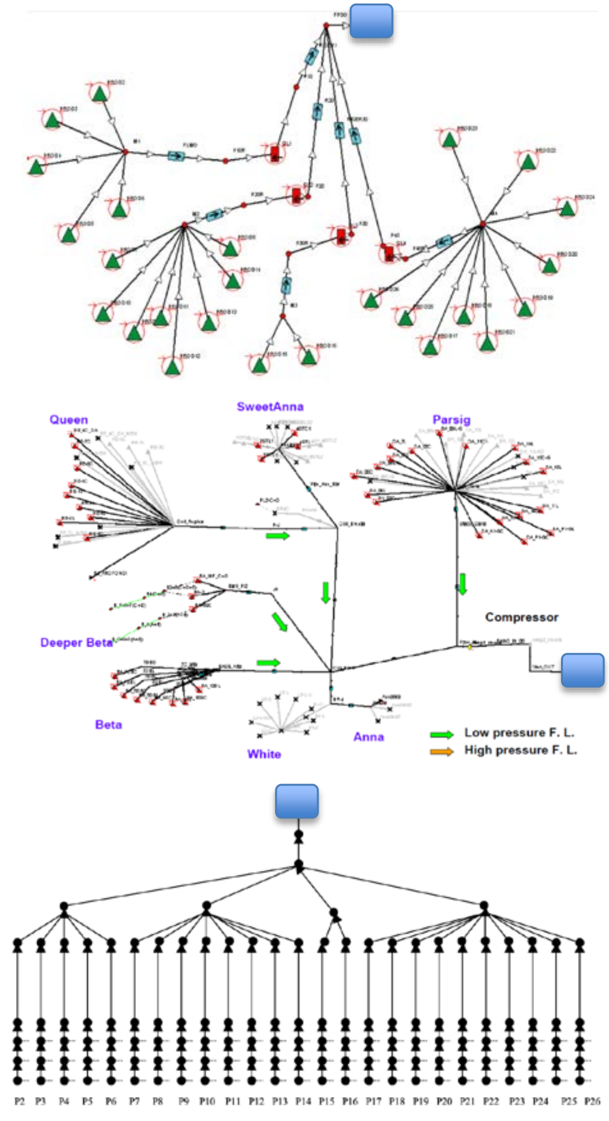
Reservoir pressure, p_R

VS.

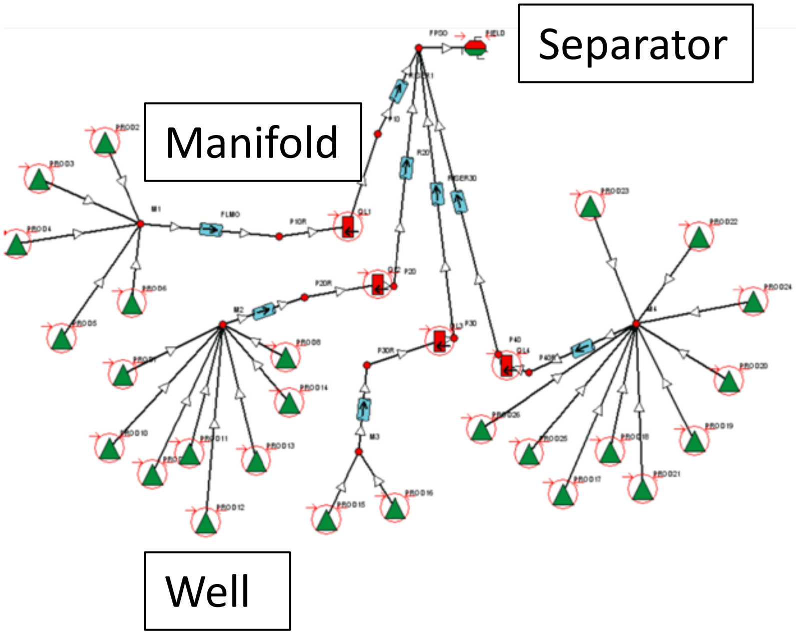
Separator pressure, p_{SEP}



Reservoir pressure, p_R



Network model

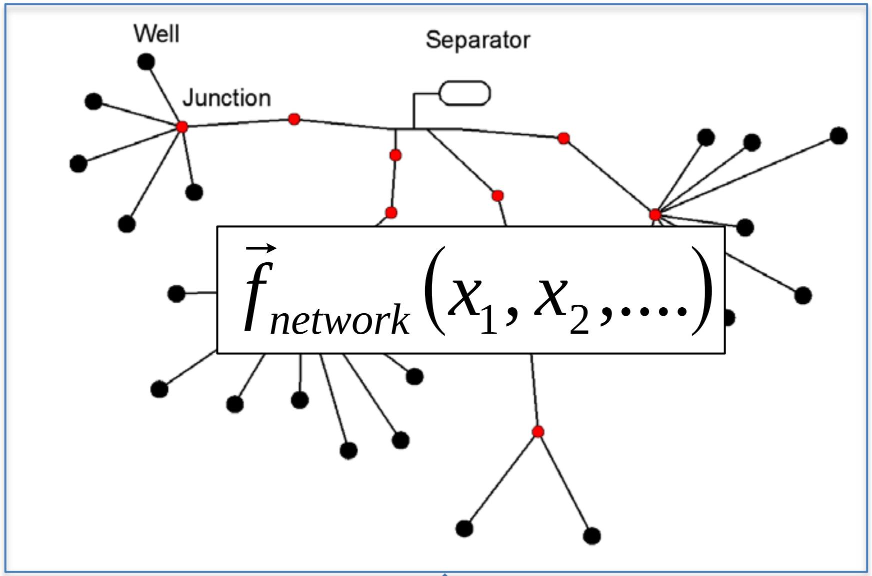


- Steady state (for a given condition in time), 1D Computer representation of a petroleum production network (wells, pipelines, equipment)
- Computes the pressure and temperature profiles in each flowline, the flow rate of each well, the conditions upstream and downstream of equipment
- Captures the single phase/multiphase flow along the production system, from the wells until the processing facilities

Network model – v1

Boundary conditions for injectors or producers:
-Well Inflow performance relationship (IPR)

INPUT



OUTPUT

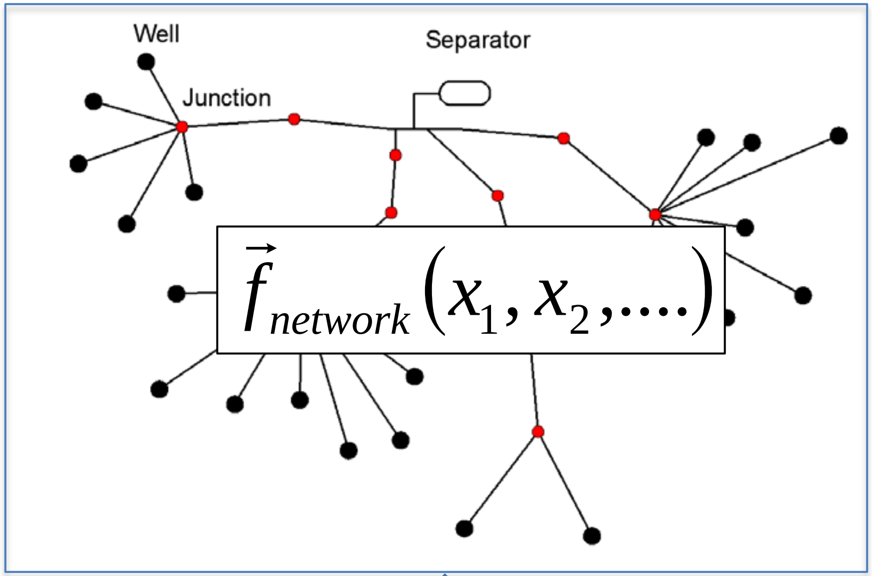
- **Well flow rates**
- Pressure and temperature along the system

INPUT

- System Properties (pipe dimensions, layout, fluid composition, EOS, separator pressure, ambient temperature)
- **Adjustable variables:** choke opening, well routing, Inflow control valves, gas lift injection rate, diluent injection rate, pump frequency, compressor.

These usually vary during the life of the field.

Network model – v1 variation (requires an "optimizer")



Boundary conditions for injectors or producers:

-Well Inflow performance relationship (IPR)

Desired well rates

-Adjustable variables will be changed to achieve well rates

INPUT

OUTPUT

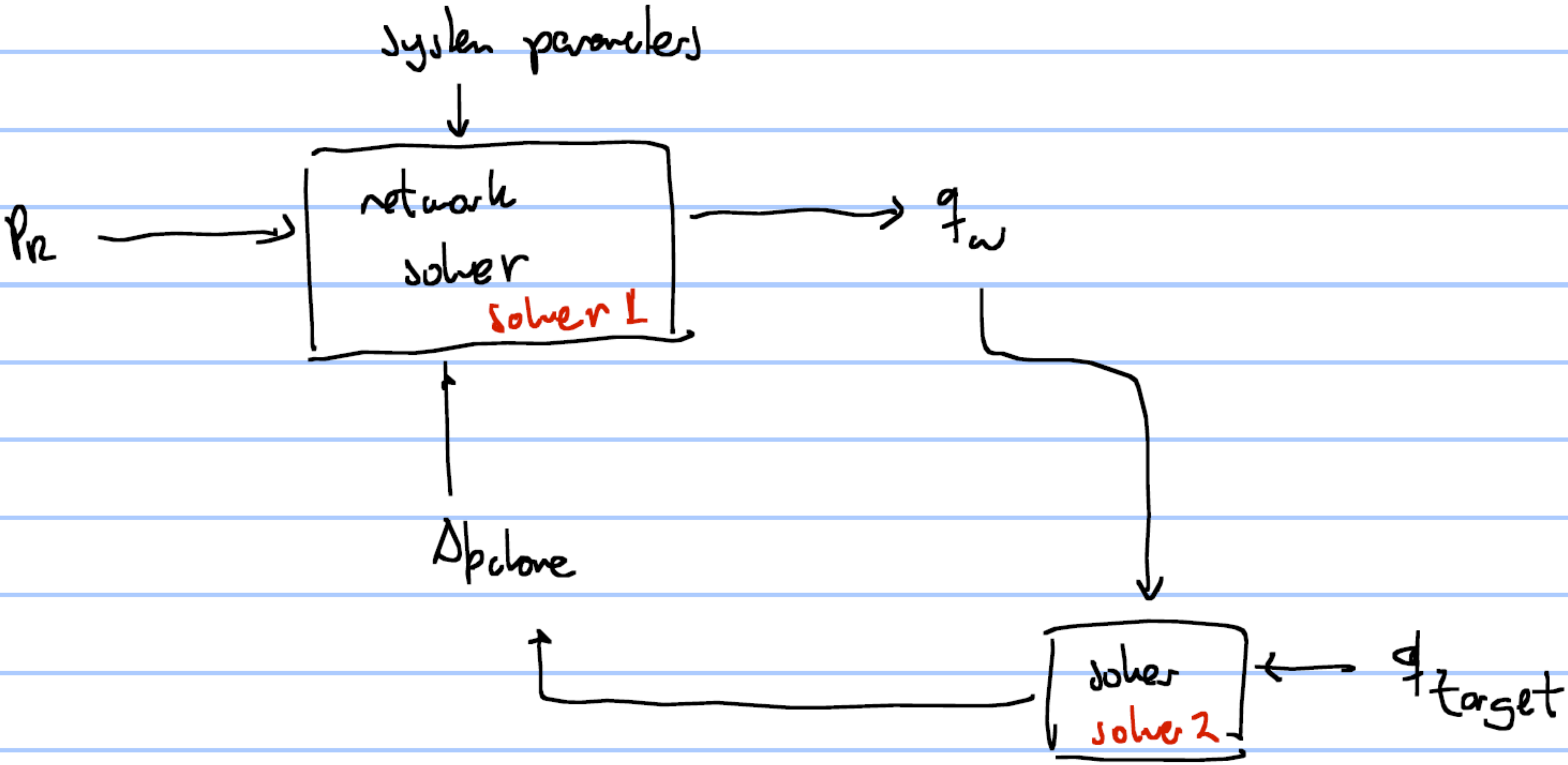
- **Well flow rates**
- Pressure and temperature along the system

INPUT

- System Properties (pipe dimensions, layout, fluid composition, EOS, separator pressure, ambient temperature)
- **Adjustable variables:** choke opening, well routing, Inflow control valves, gas lift injection rate, diluent injection rate, pump frequency, compressor.

These usually vary during the life of the field.

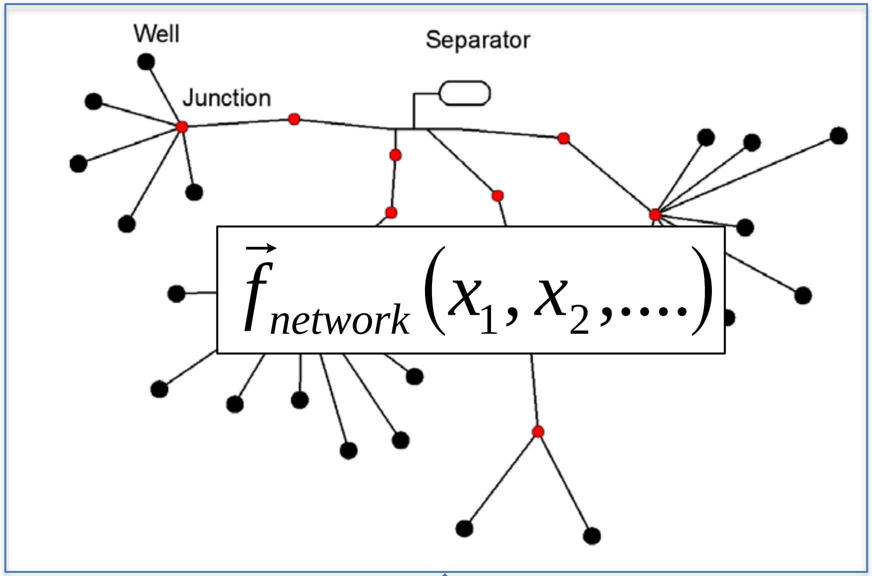
Network model – v1 variation (requires an "optimizer")



Network model – v2

Boundary conditions for injectors or producers:
Desired well rates

INPUT



OUTPUT

- Pressure and temperature along the system
- Pressure at the boundaries

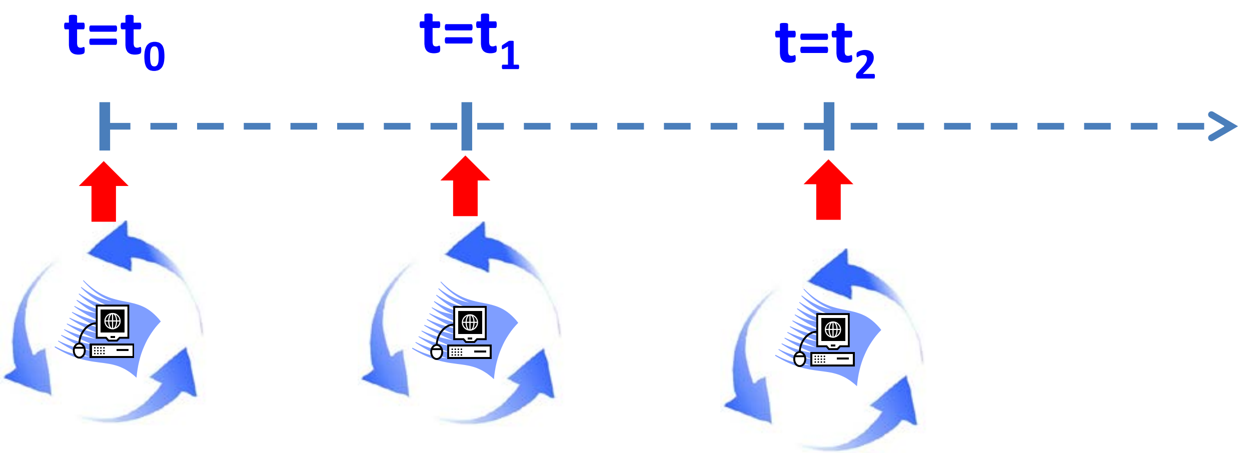
INPUT

- System Properties (pipe dimensions, layout, fluid composition, EOS, separator pressure, ambient temperature)
- **Adjustable variables:** choke opening, well routing, Inflow control valves, gas lift injection rate, diluent injection rate, pump frequency, compressor.

These usually vary during the life of the field.

Operating mode

Network model



For a given time step

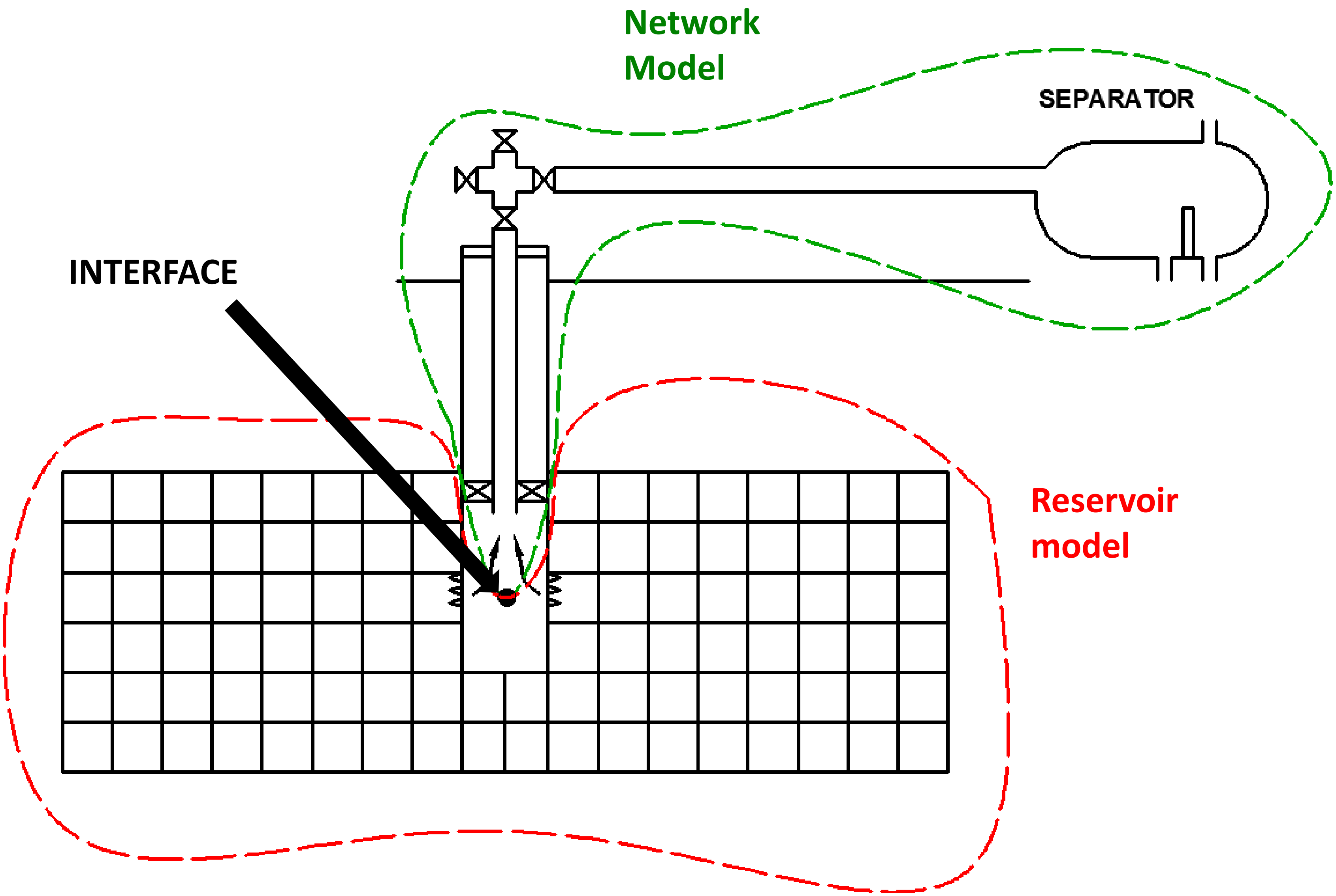
Coupling:

Connecting reservoir and network model to achieve consistency at the interface.

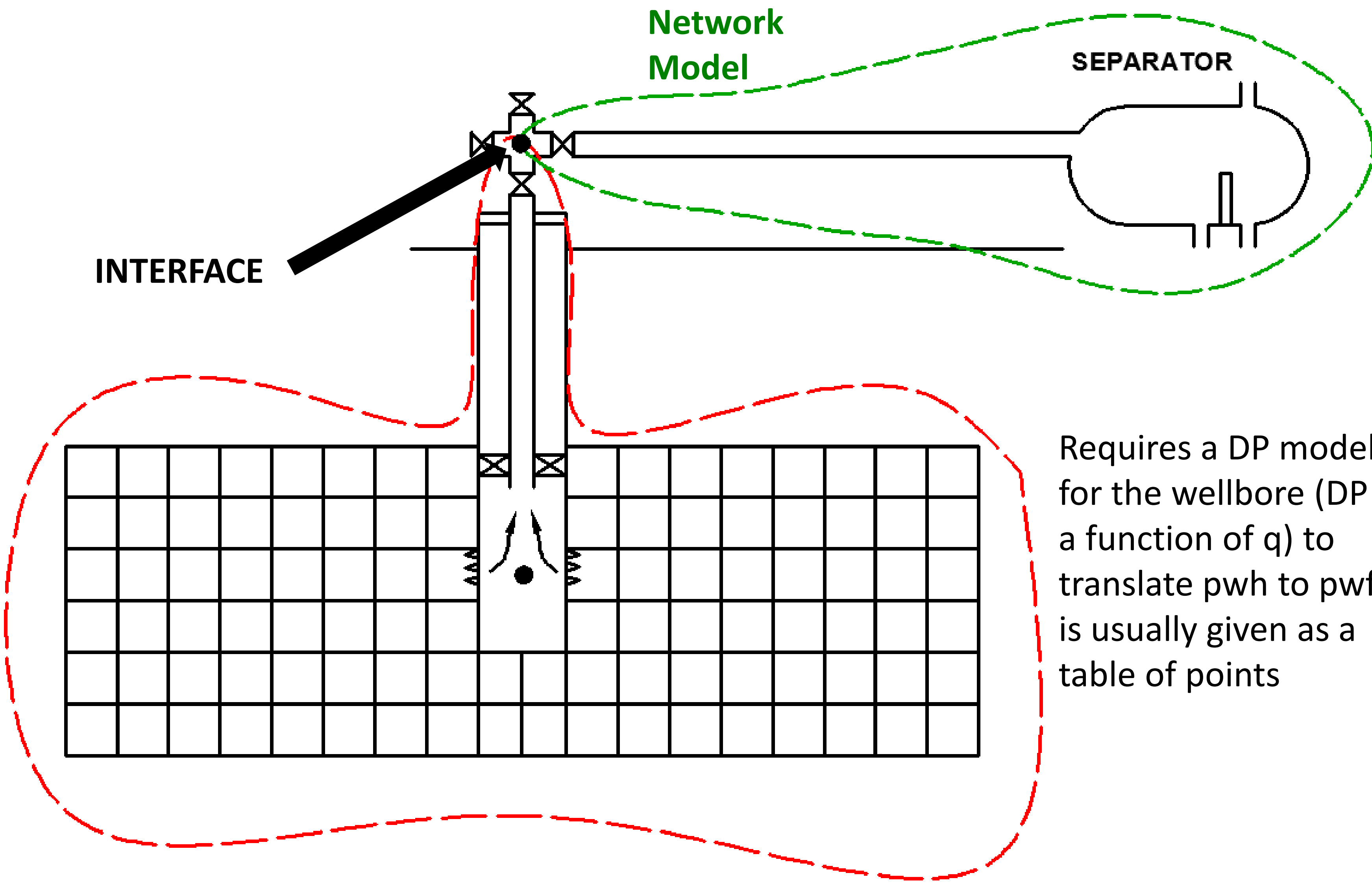
Or, equivalently:

- Will I be able to produce the reservoir rates through the well and network?
- Find realistic values for p_wfmin

Model's Interface: well's bottomhole



Model's Interface: wellhead



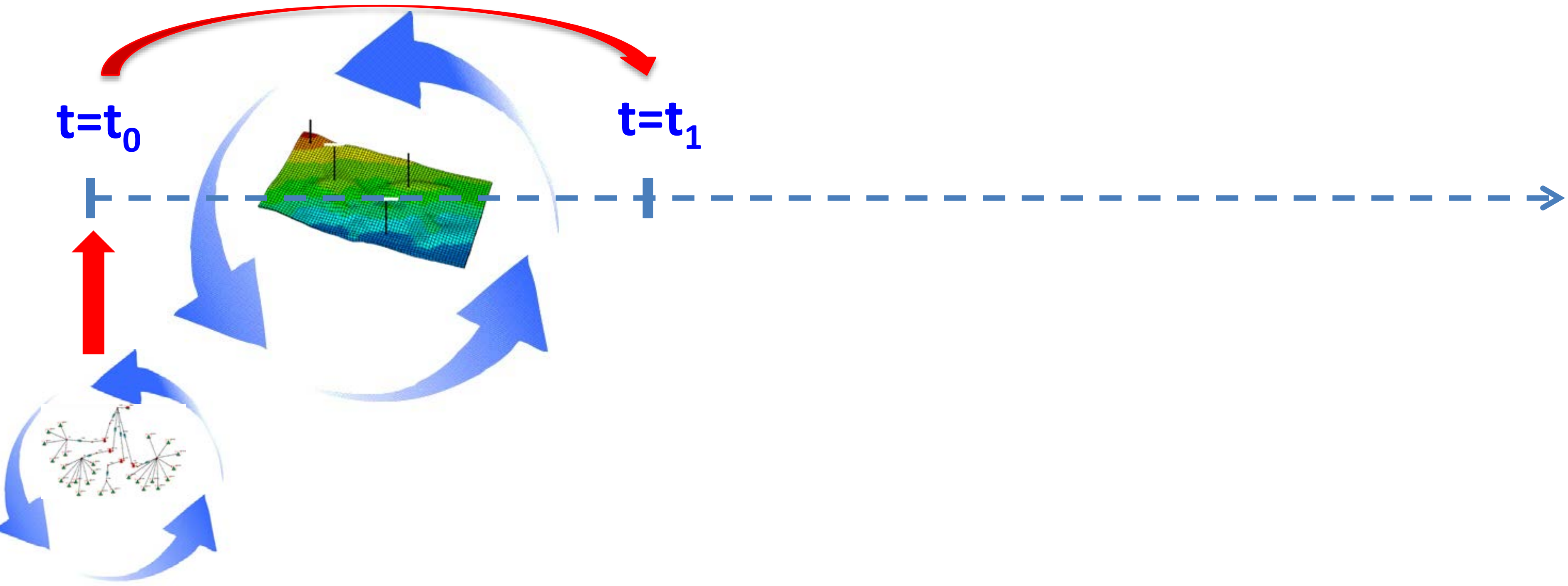
Requires a DP model for the wellbore (DP as a function of q) to translate pwh to pwf. It is usually given as a table of points

Integration strategies

- **Explicit**

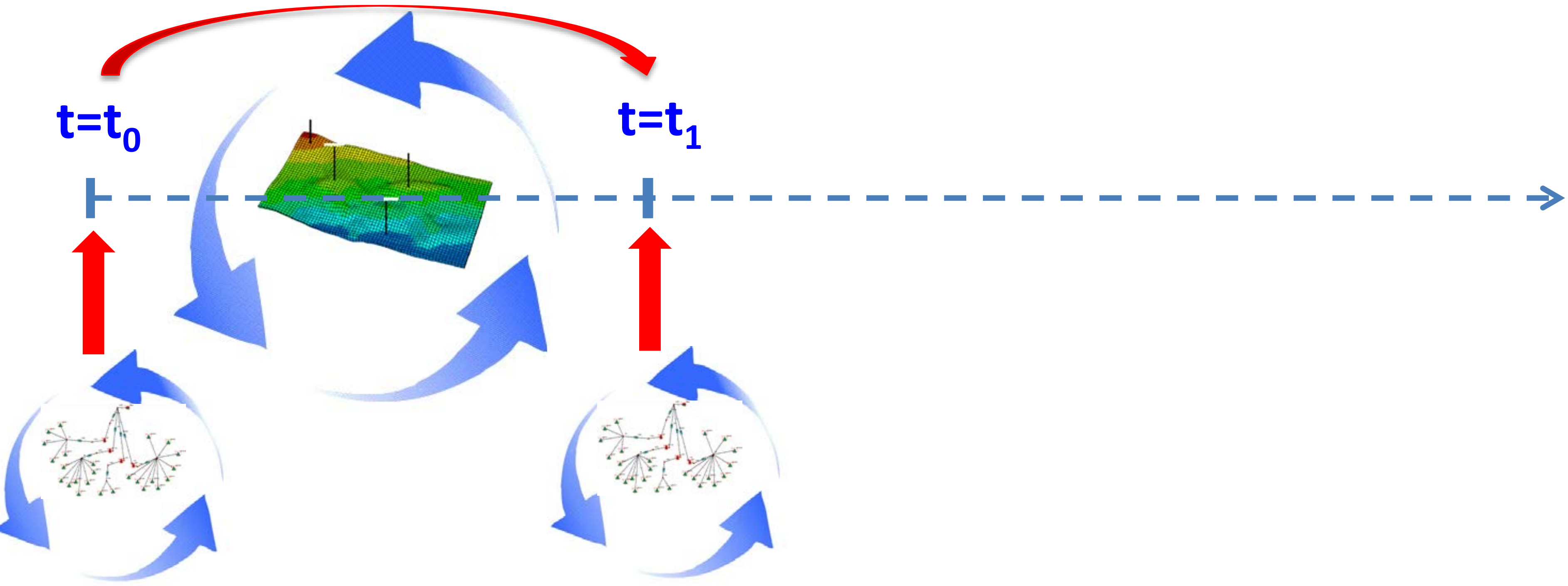
Integration strategies

- **Explicit**



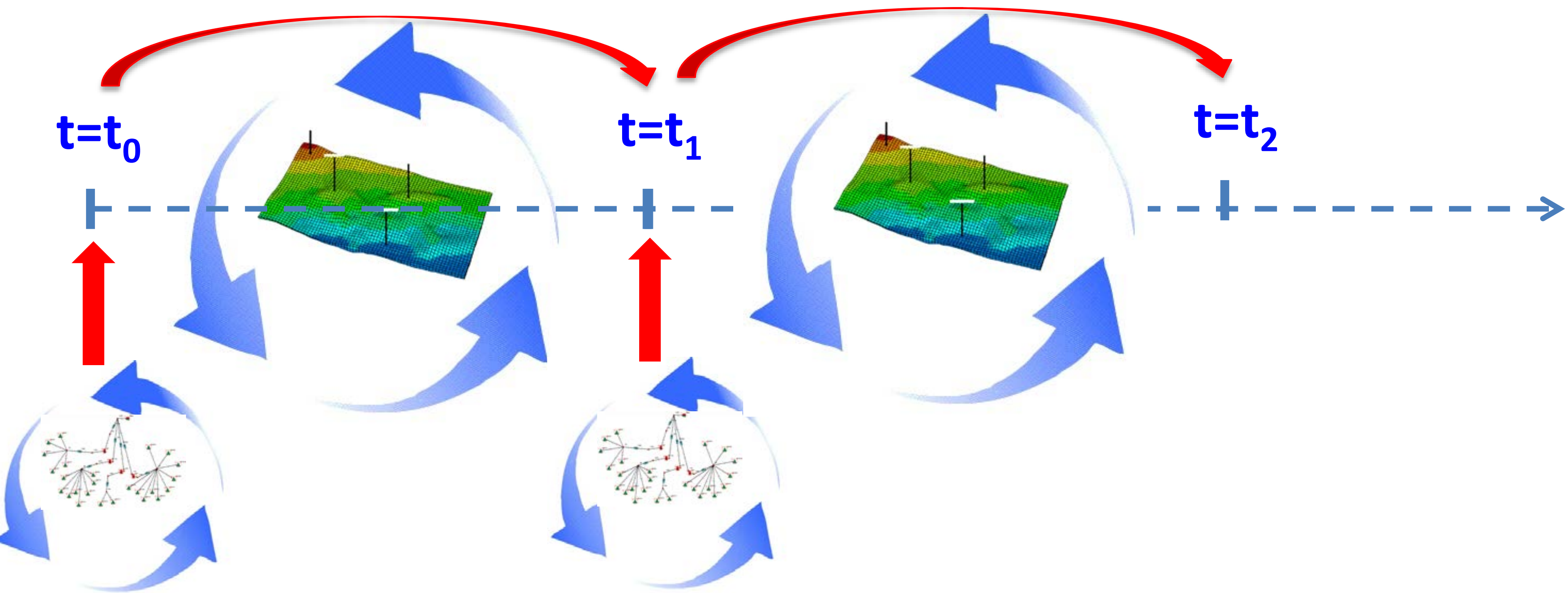
Integration strategies

- **Explicit**



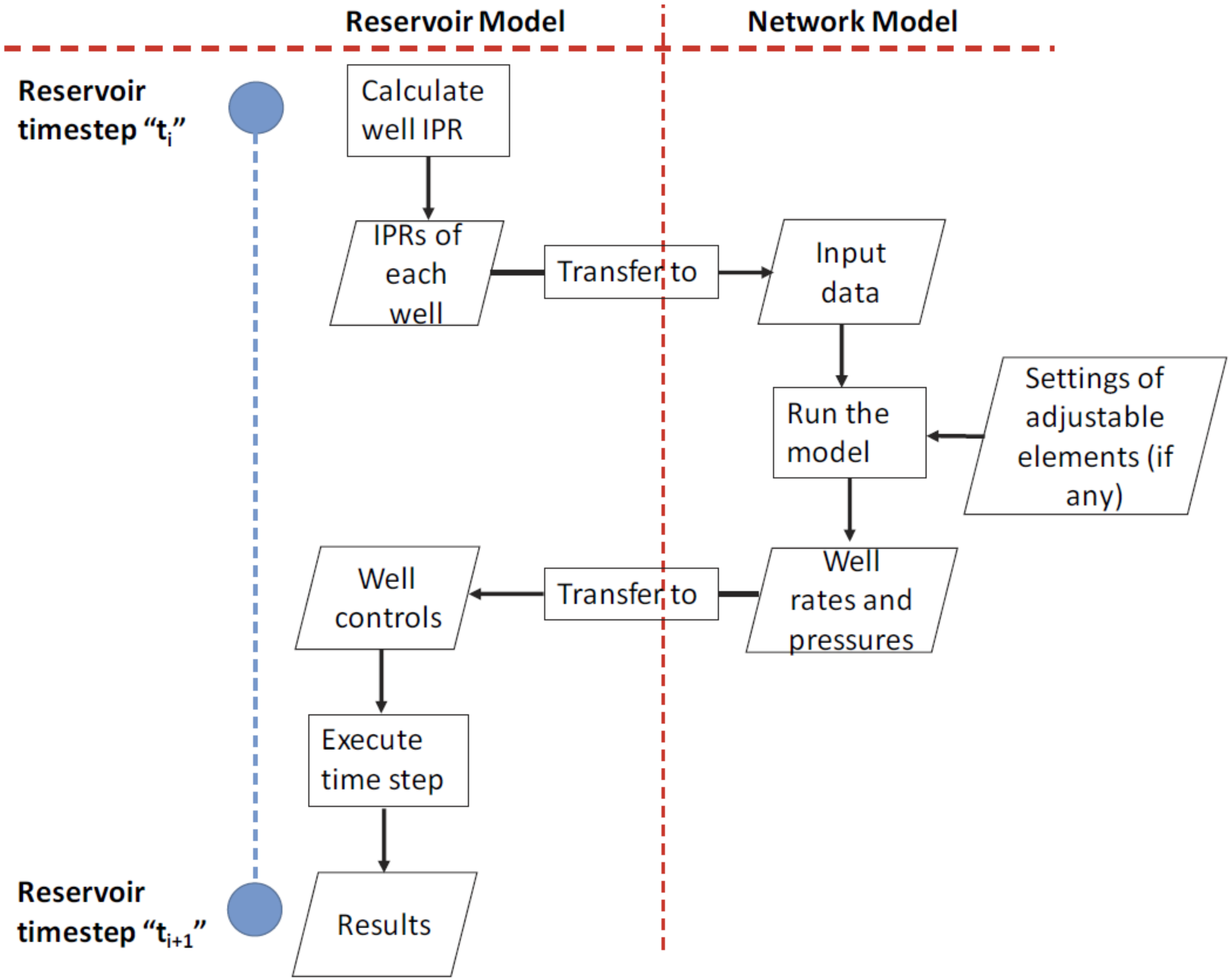
Integration strategies

- **Explicit**

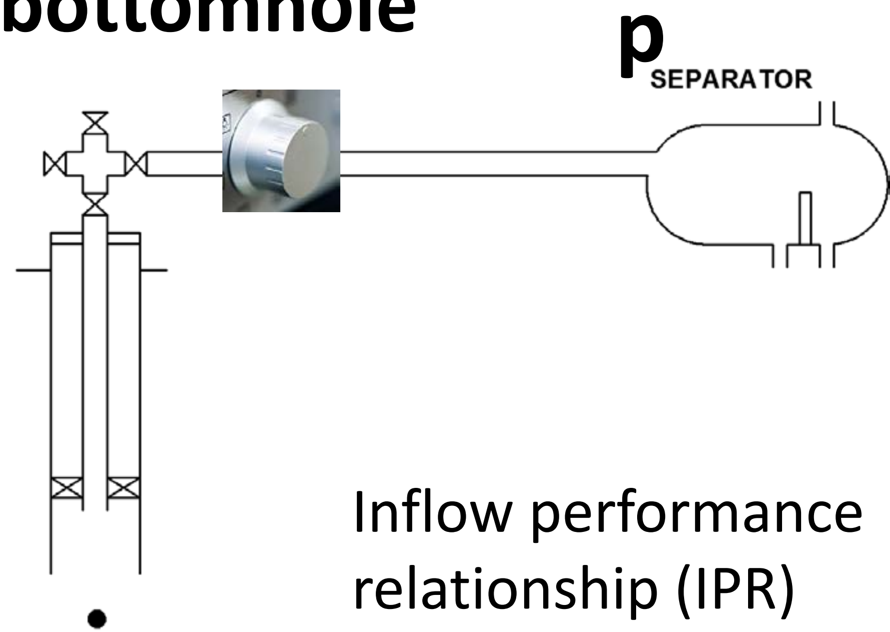


Integration strategies

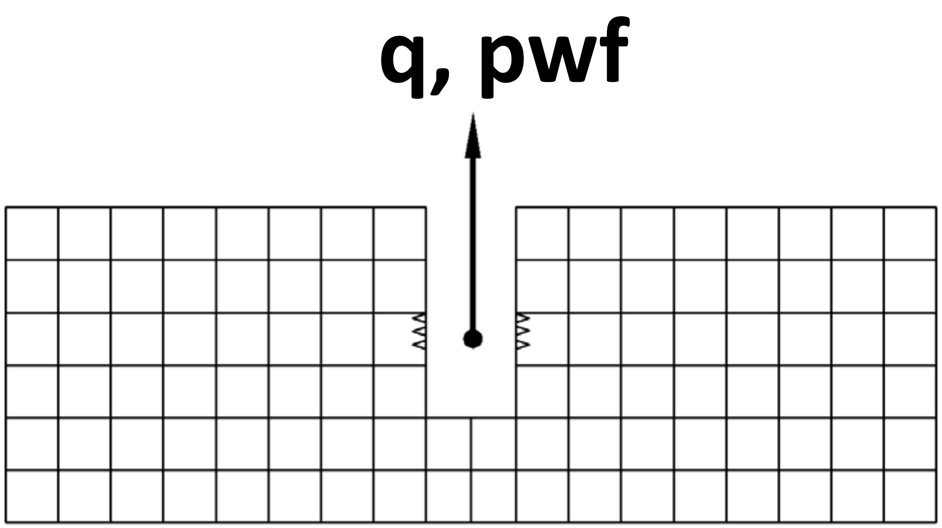
- **Explicit**

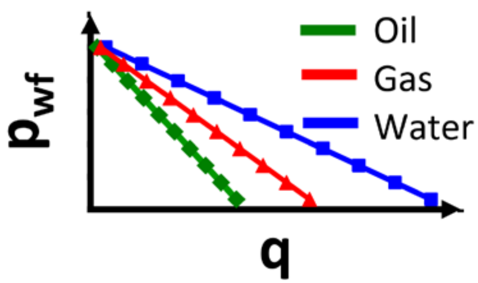


Model's Interface: well's bottomhole



Inflow performance relationship (IPR)



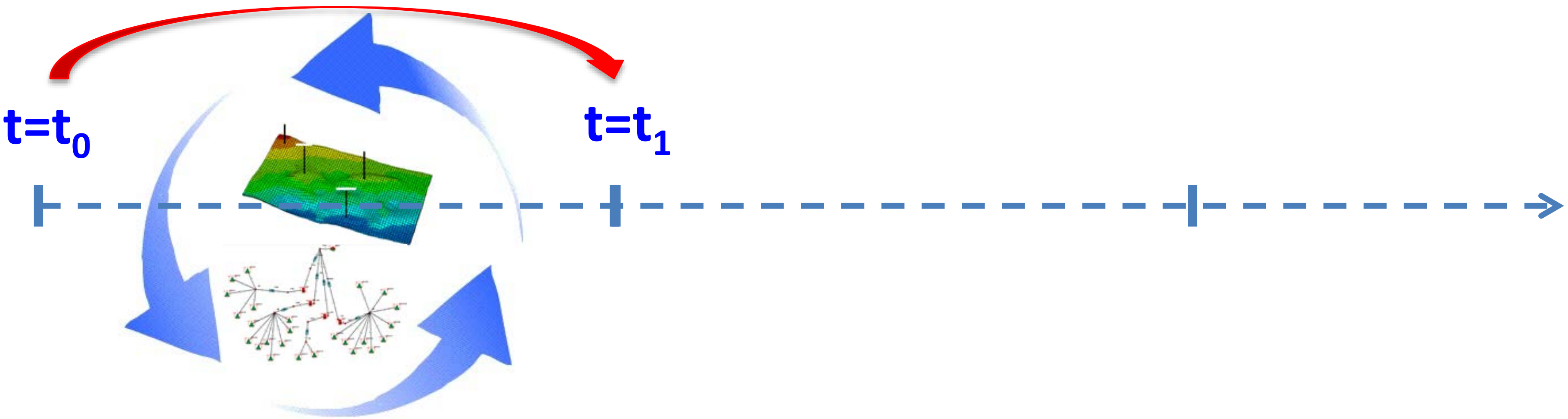


Explicit integration strategy

- Possible to integrate software from different providers
- IPR generation is required (by reservoir simulator or by the network simulator)
- Can lead to numerical instabilities. A small time-step might be required

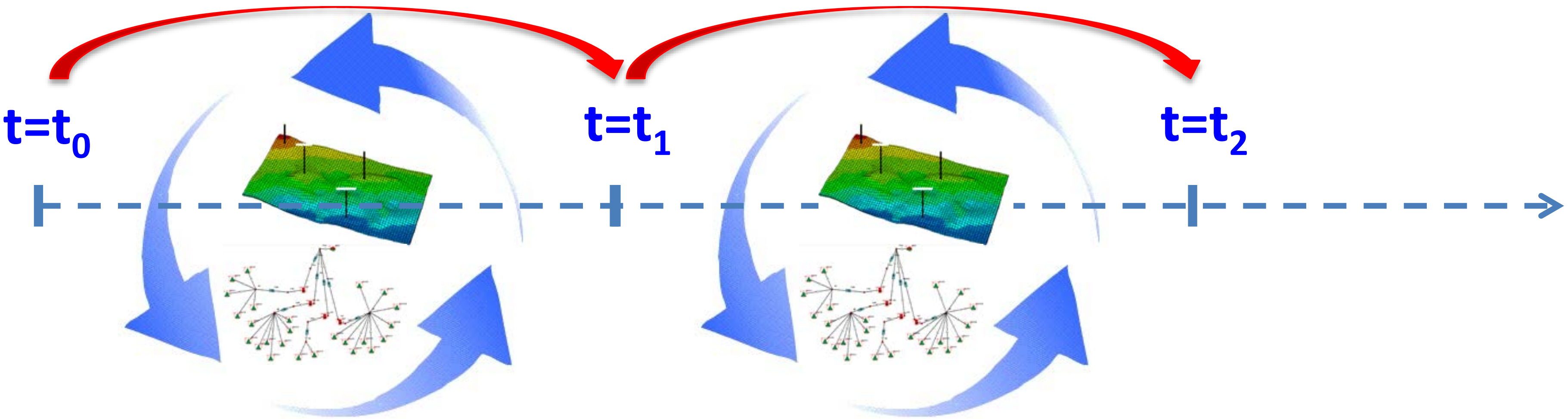
Integration strategies

- **Implicit**



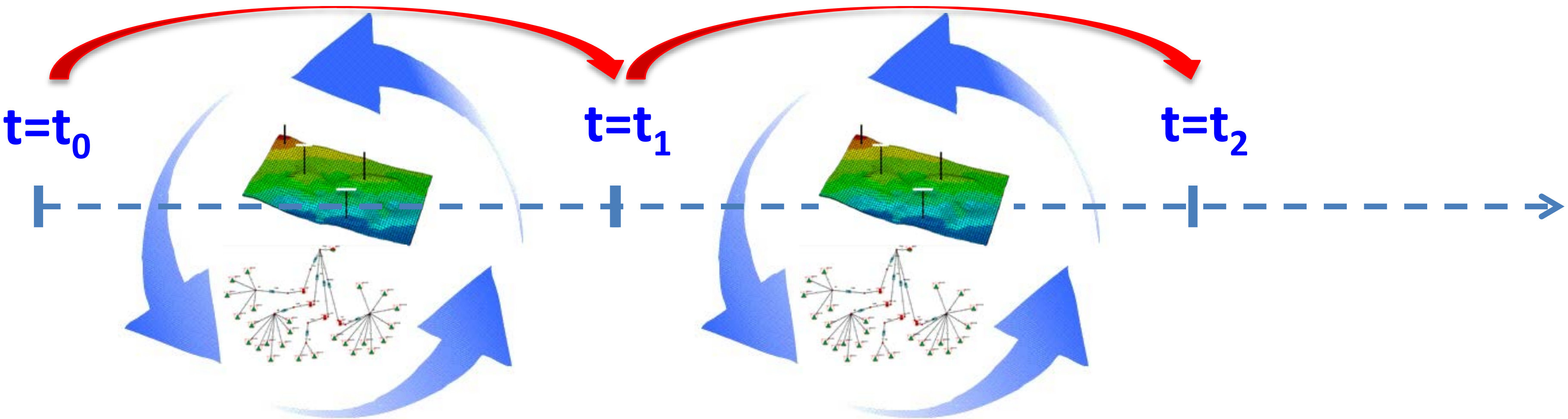
Integration strategies

- **Implicit**



Integration strategies

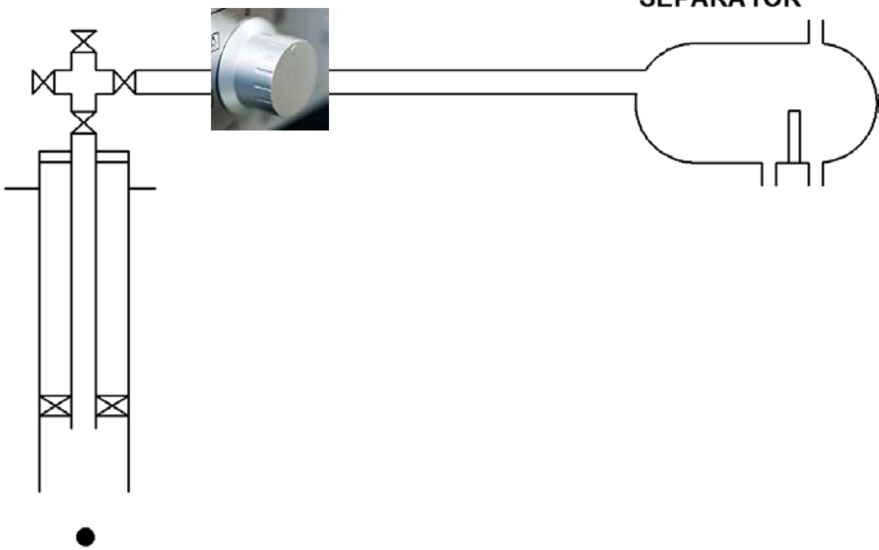
- **Implicit**



Here an IPR might not be needed

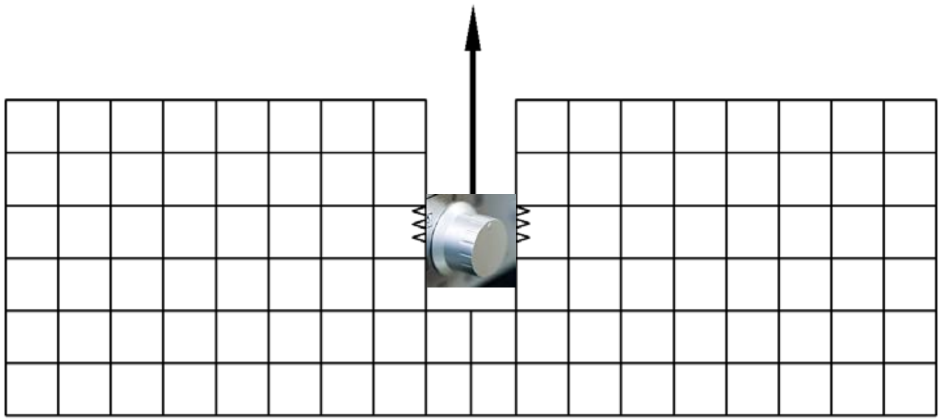
Model's Interface: well's bottomhole

$p_{SEPARATOR}$



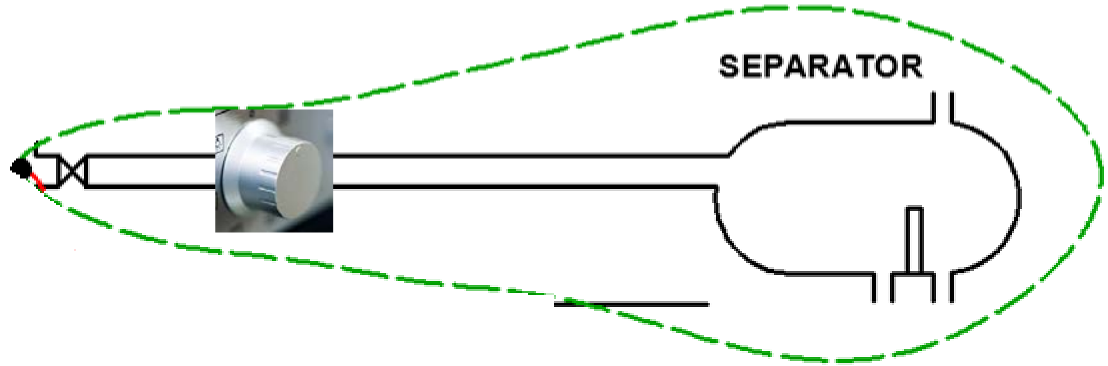
q, pwf

q, pwf

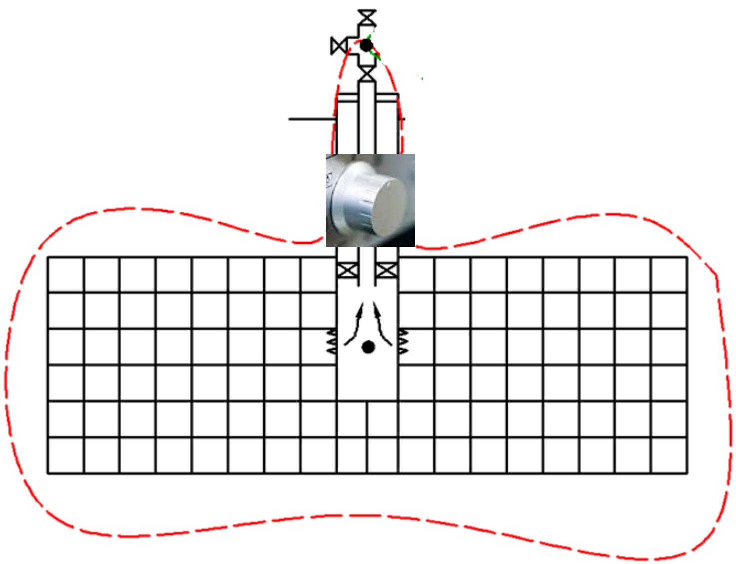


Model's Interface: wellhead

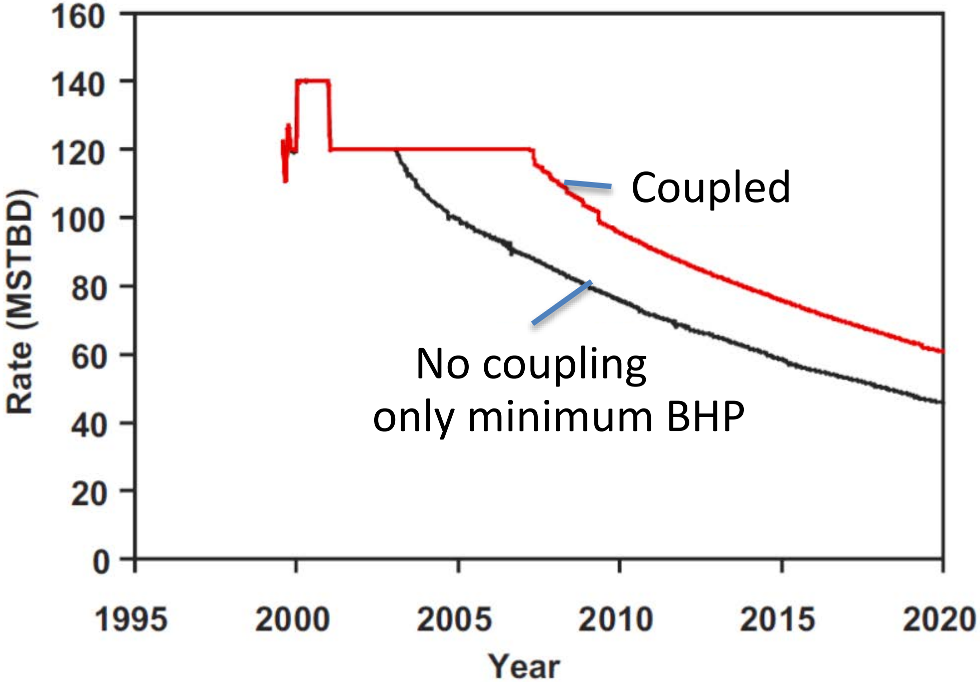
q

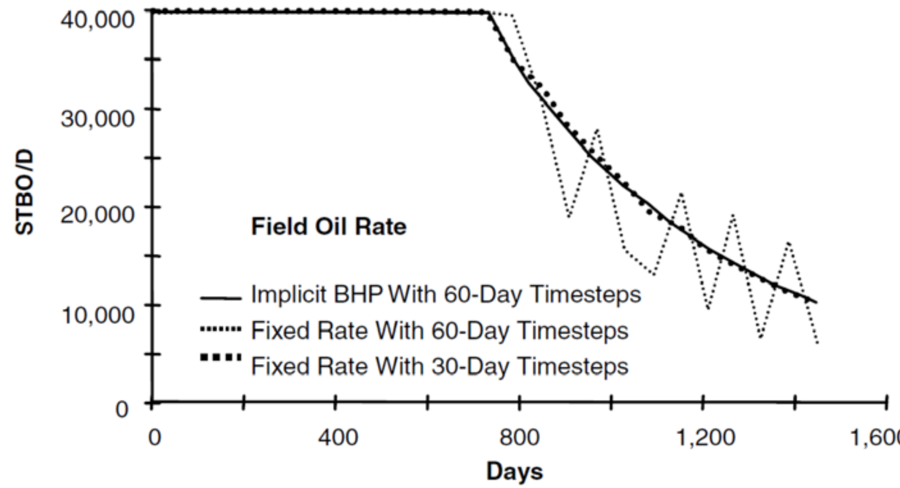


q, pwh



Examples from the literature





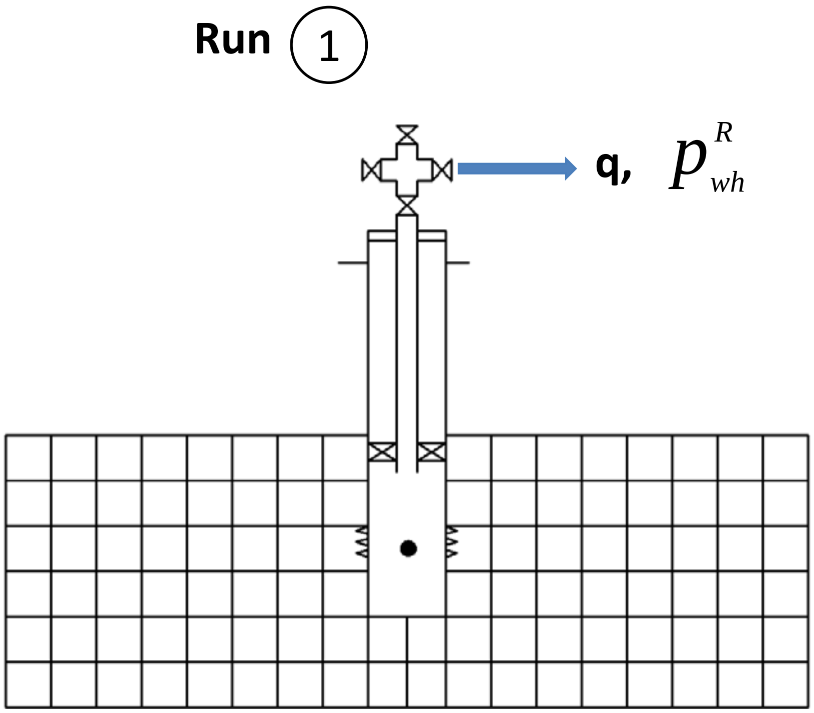
Solution instability from SPE 71120

From Al-Shaalan, 2002

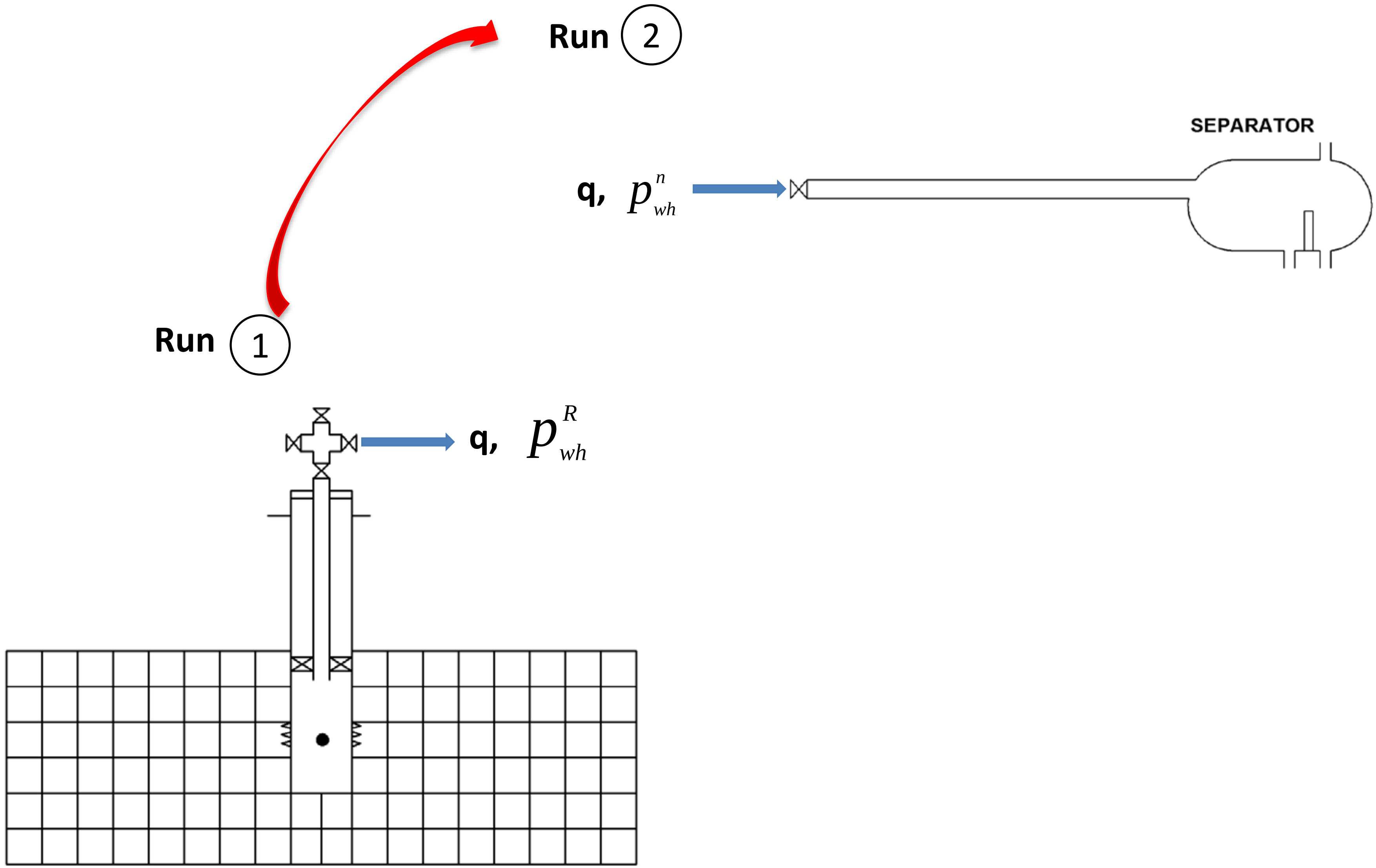
Implicit integration strategy

- Difficult to integrate software from different providers (for efficient solving, the source code should be integrated)
- IPR generation is not required
- More numerically stable, bigger time-steps can be used

Coupling strategy for choked wells



Coupling strategy for choked wells

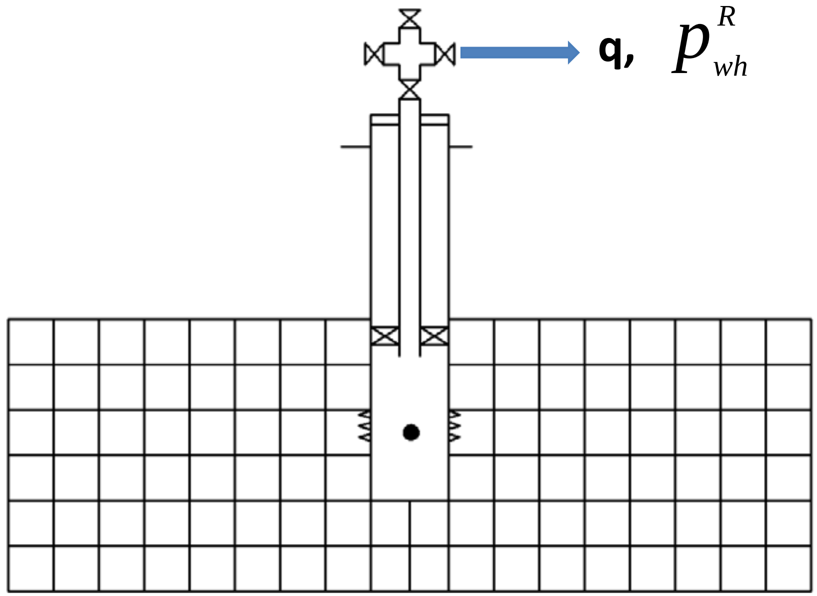


Coupling strategy for choked wells

Run 2

q, p_{wh}^{n}

Run 1



q, p_{wh}^{R}

If $p_{wh}^{R} > p_{wh}^{n}$

- Well is choked, proceed to next reservoir time step

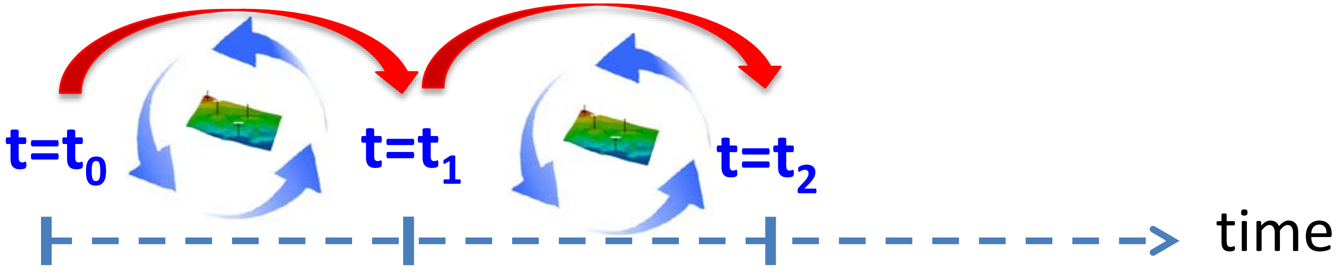
Integration strategies

- **Loose coupling with bottom-hole coupling –most typical**

Integration strategies

- **Loose coupling with bottom-hole coupling –most typical**

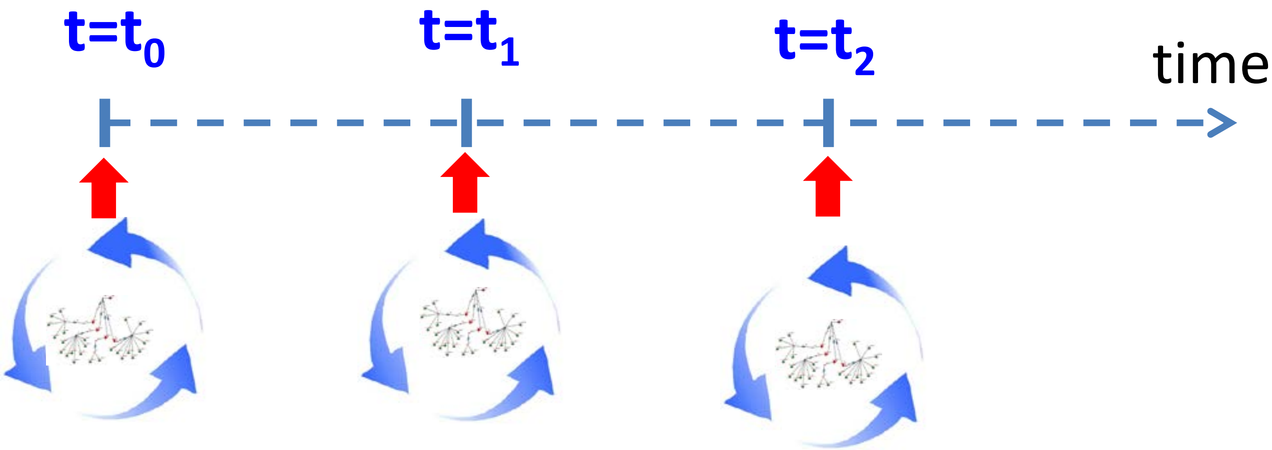
1. Assume p_{wfmin}
2. Run reservoir simulation



Obtain profiles of q(t), p_{wf} (t), IPR (t)

Loose coupling with bottom-hole coupling

3. Run network simulation with IPR(t) from step 2



4. Verify if $q_{network}(t) == q_{reservoir}(t)$. If not, provide $p_{wf}(t)$ as $p_{wfmin}(t)$ and repeat from step 1

Loose coupling integration strategy

- Easy to integrate software from different providers
- Practical for use for different engineering teams
- More time-consuming – several iterations are typically required to converge on a solution

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Net present value: KPI typically used to evaluate and decide on projects and to compare development alternatives

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

Discounted cash flow (DCF) method

- Calculated on a yearly basis:
  - Typically end of year OR mid-year

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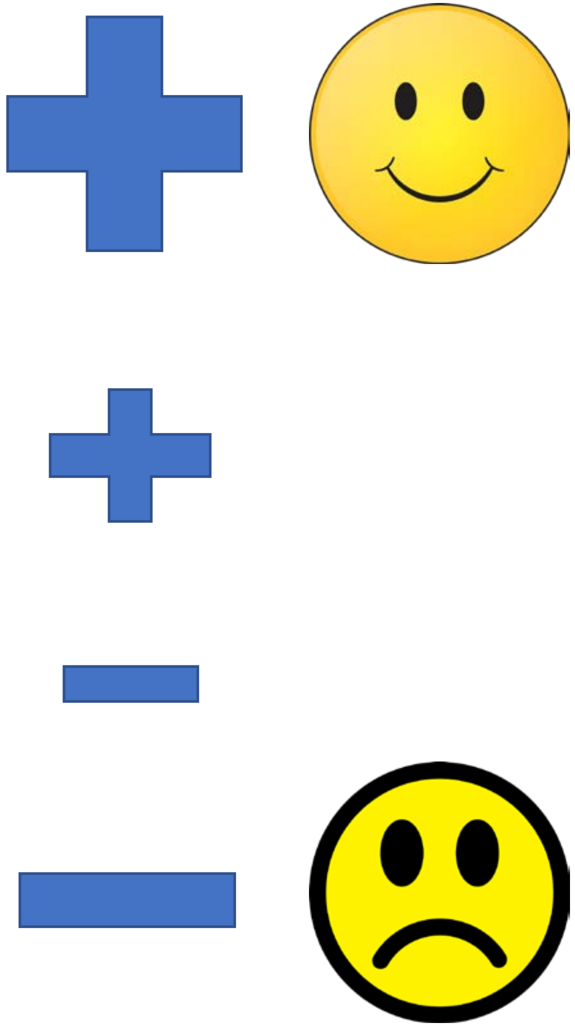


Discounted cash flow (DCF) method

- Calculated on a yearly basis:
  - Typically end of year OR mid-year

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

In currency of year «t»

Net present value

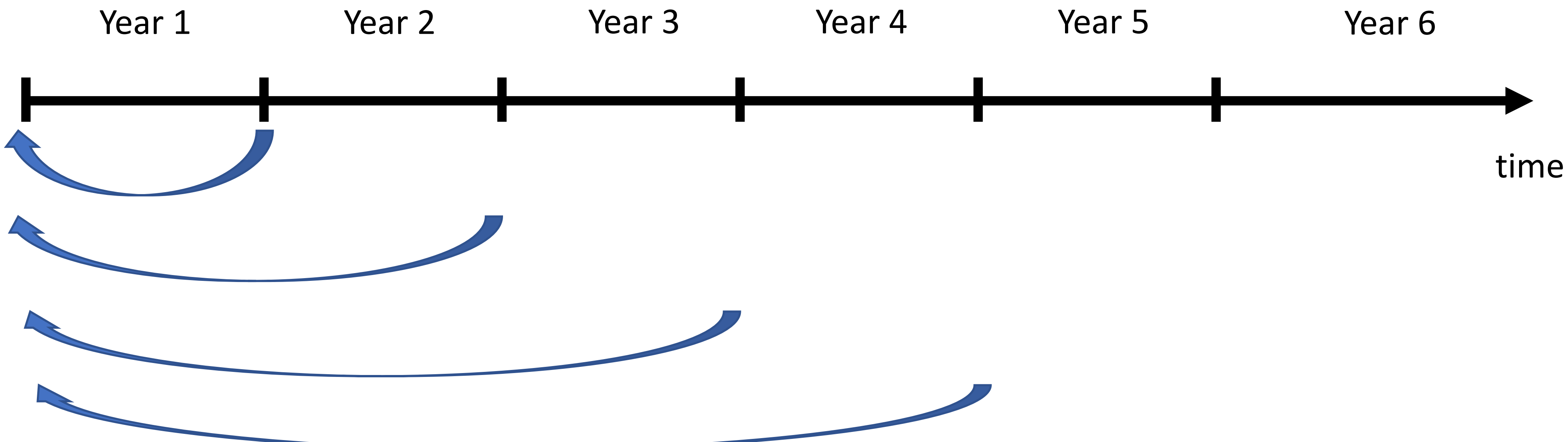
$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

To convert currency in year «t» to currency of year 0 (reference year)

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

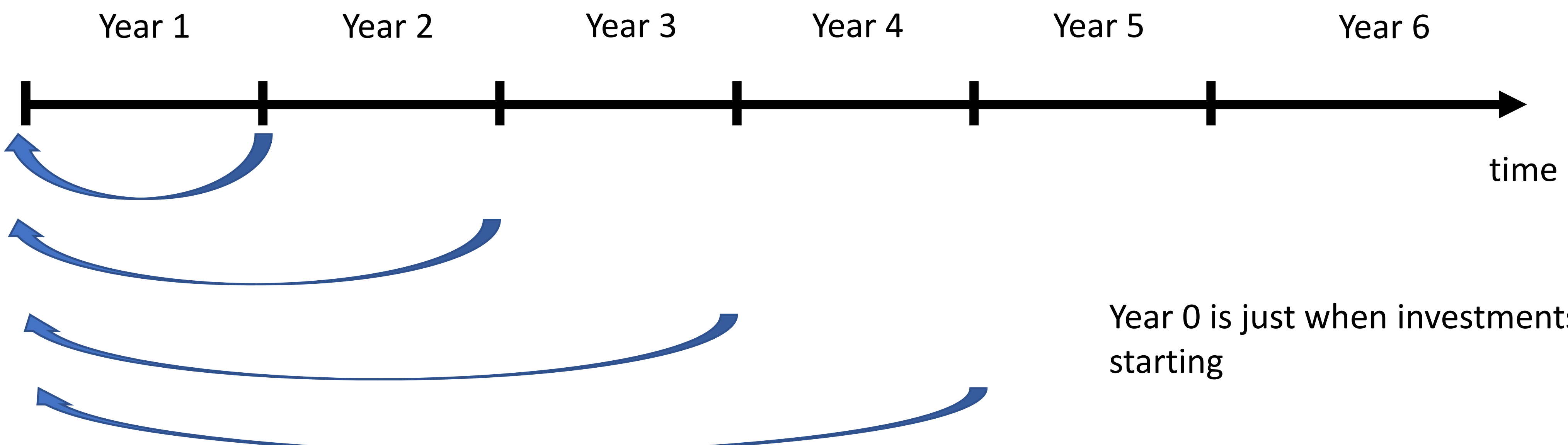
To convert currency in year «t» to year 0 (reference year)



Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

To convert currency in year «t» to year 0 (reference year)



Year 0 is just when investments are starting

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

- Typically: 7-12%, based on operator's past experience
- Should be better than investing the capital on other financial instruments

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$Revenue_t$:

- Sales of oil and gas (yearly production * price per volume)
- Tariffs to other companies for using your infrastructure (e.g. processing fluids for tie-backs)

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$Revenue_t$:

- Sales of oil and gas (yearly production * price per volume)
- Tariffs to other companies for using your infrastructure (e.g. processing fluids for tie-backs)

- Assuming 50 USD/bbl, a field with 150 kstbd, for a year this gives 7.5 E09 USD (20E06 USD per day)

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$Revenue_t$:

- Sales of oil and gas (yearly production * price per volume)
- Tariffs to other companies for using your infrastructure (e.g. processing fluids for tie-backs)

- Assuming 50 USD/bbl, a field with 150 kstbd, for a year this gives 7.5 E09 USD (20E06 USD per day)
- Assuming a gas price of 0.66 USD/m3 (Feb 2023), and a production of 20E06 Sm3/d, this gives for a year 4.8 E09 USD (13 E06 USD per day)

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$Revenue_t$:

- Sales of oil and gas (yearly production * price per volume)
- Tariffs to other companies for using your infrastructure (e.g. processing fluids for tie-backs)

- Usually assumed constant
- If gas, it is usually negotiated as part of a delivery contract

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$Revenue_t$:

- Sales of oil and gas (yearly production * price per volume)
- Tariffs to other companies for using your infrastructure (e.g. processing fluids for tie-backs)

During early years (4-8) there is no revenue!! (field doesn't exist)

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

The biggest expenses occur at the beginning, when there is a lot of construction and drilling

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Exploration costs

All exploration costs are, as a starting point, deductible and may be off-set against profits from production.

Moreover, companies may claim an annual cash refund of the tax value of direct and indirect exploration costs under ordinary petroleum tax and special tax (this amounts to 78% of such costs), with the exception of finance costs, with the amount of the refund limited to the tax value of the net tax losses. This is an alternative to carrying the losses forward.

Source: oil and gas taxation in Norway. Deloitte

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

A deductible for taxes is **an expense that a taxpayer or business can subtract from adjusted gross income**, which reduces their income, thereby reducing the overall tax they need to pay.

https://www.investopedia.com › ... › Tax Deductions

Deductible Definition, Common Tax and Business Deductibles

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Examples:

- Well plugging
- Removal of flowlines, pipelines offshore structure
- Cleaning
- monitoring

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Are often neglected as they are deductible and they occur late in the life of the field (heavily discounted)

Abandonment costs

Abandonment costs are deductible when the costs are actually incurred. Accounting provisions made in order to meet future abandonment costs are not deductible.

Source: oil and gas taxation in Norway. Deloitte

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Capital allowances for investments made in productions facilities and pipelines and installations which are part of such production facilities and pipelines are calculated on a straight line basis over six years at a rate of 16.66% per year from the date the capital expenditure was incurred. The capital allowances are granted both when calculating the basis for ordinary petroleum tax and special tax.

Source: oil and gas taxation in Norway. Deloitte

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Examples:

- Drilling vessel renting (daily rate)
- Drilling materials (tubulars, cement, mud, completion, wellhead)
- Test during drillin (DST, logging, pressure tests, sampling)
- X-mas tree
- Drilling tools
- Salaries, insurance

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

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- Drilling materials (tubulars, cement, mud, completion, wellhead)
- Test during drillin (DST, logging, pressure tests, sampling)
- X-mas tree
- Drilling tools
- Salaries, insurance

- Cost per well:

30-180 E06 USD (offshore)

10-15 E06 (onshore)

Example

Source: Karish-Tanin PDO

Table 8-4: Drilling tangibles cost estimate

Item	Source	Cost (US$)
Wellhead	TechnipFMC quotation 7/4/17	362,500
Conductor	LR data based on planned 2017 well	320,000
20" Casing	Tenaris quotation 31/3/17	722.56/m
13-5/8" Casing	Tenaris quotation 31/3/17	342.76/m
9-5/8" Casing	Tenaris quotation 31/3/17	204.80/m
9-5/8" 13 Cr Casing	Tenaris quotation 31/3/17	956.00/m
Float equipment, etc. (full set)	LR data based on planned 2017 well	366,000
Total		**6,617,464.00**

Table 8-5: Completion tangibles cost estimate

Item	Source	Cost (US$)
Well test equipment	LR data based on planned 2017 well	1,015,000
SSTT	Expro quotation 10/4/17	750,000
OHGP	LR data based on planned 2017 well	925,000
Upper completion	LR data based on planned 2017 well	625,000
Xmas Tree	TechnipFMC quotation 7/4/17	4,738,682
FMC Installation costs	TechnipFMC quotation 7/4/17	1,300,000

Example

Table 8-6: Total calculated drilling costs – 3 Karish Main development wells

Certainty level	Total days	Total Services Spread rate (US$ mln)	Total Rig rate (US$ mln)	Drilling tangibles (US$ mln)	Completion tangibles (US$ mln)	Total Drillex (US$ mln)
P90	379	95.22	94.75	24.82	35.07	248.86
P50	277	55.68	55.40	19.86	28.06	159.00
P10	241	36.33	36.15	14.89	21.04	108.41

Source: Karish-Tanin PDO

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Examples:

- Engineering studies
- Processing facilities (separators, pumps, compressors, heat exchangers, control system, injection, oil, water and gas treatment
- Offshore structure (cost of platform or vessel, living quarters, power source, helideck)
- Subsea system (template, flowlines, pipelines, risers, umbilicals, metering)
- Export system
- Salaries, insurance

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

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- Offshore structure (cost of platform or vessel, living quarters, power source, helideck)
- Subsea system (template, flowlines, pipelines, risers, umbilicals, metering)
- Export system
- Salaries, insurance

There is usually a payment schedule for CAPEX over a few years for big items (FPSO, subsea equipment etc)

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Examples:

- Engineering studies
- Processing facilities (separators, pumps, compressors, heat exchangers, control system, injection, oil, water and gas treatment
- Offshore structure (cost of platform or vessel, living quarters, power source, helideck)
- Subsea system (template, flowlines, pipelines, risers, umbilicals, metering)
- Export system
- Salaries, insurance

- Total cost:

-O (1E09) USD

Examples:

-O(1E06) USD per km of subsea pipeline

-FPSO 200 – 3000 1E06 USD

Examples

Table 6-6 CAPEX Estimation Example (2007 Data)

1. Subsea Equipment Cost

Subsea Trees		Unit	Cost
Subsea Tree Assembly		**3**	**$4,518,302**
(each)	5-inch × 2-inch 10-ksi vertical tree assembly	1	included
	Retrievable choke assembly	1	included
	Tubing hanger 5-in. 10 ksi	1	included
	High-pressure tree cap	1	included
	5-in. tubing head spool assembly	1	included
	Insulation	1	included
Subsea Hardware			
Subsea Manifold			
	(EE trim)	1	$5,760,826
Suction Pile			
	Suction pile for manifold	1	$1,000,000
Production PLET		2	$3,468,368
Production Tree Jumpers		3	$975,174
Pigging Loop		1	$431,555
Production PLET Jumpers		2	$1,796,872
Flying Leads			$1,247,031
	Hydraulic flying lead SUTA to tree		
	Electrical flying lead SUTA to tree		
	Hydraulic flying lead SCM to manifold		
	Electrical flying lead SUTA to manifold		
Other Subsea Hardware			
Multiphase Flow Meter		1	$924,250

Source: Yong Bai, Qiang Bai, Subsea engineering Handbook.

Examples

Table 6-6 CAPEX Estimation Example (2007 Data)—cont'd

1. Subsea Equipment Cost

	Subsea Trees	Unit	Cost
Umbilicals			
Umbilical			$11,606,659
	25,000ft Length		
Risers			
Riser			$6,987,752
	Prod. 8.625-in. × 0.906-in. × 65 SCR, 2 × 7500 ft		
Flowlines			
Flowline			$4,743,849
	Dual 10-in. SMLS API 5L X-65, flowline, 52,026 ft		
	Total Procurement Cost		**$54,264,324**
2. Testing Cost			
Subsea Hardware FAT,EFAT			$27,132,162
Tree SIT & Commissioning			$875,000
Manifold & PLET SIT			$565,499
Control System SIT			$237,786
	Total Testing Cost		**$28,810,447**
3. Installation Cost			
Tree	3 days × $1000k per day		$3,000,000
Manifold & Other hardware			$48,153
Jumpers	(1 day per jumper + downtime)		$32,102
ROV Vessel Support			$1,518,000
Other Installation Cost			$862,000
Pipe-lay	52,0260ft		$43,139,000

Source: Yong Bai, Qiang Bai, Subsea engineering Handbook.

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Examples:

- Salaries
- Insurance
- Maintenance
- Equipment
- Well intervention
- Power consumption
- Production chemicals (MEG, inhibitors)
- Pigging
- Transportation and export

- Heavily depends on the size and type of facility
- It often dictates when to abandon (CF becomes negative)

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Examples:

- Salaries
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- Power consumption
- Production chemicals (MEG, inhibitors)
- Pigging
- Transportation and export

- Heavily depends on the size and type of facility
- It often dictates when to abandon (CF becomes negative)

$$\text{Annual OPEX} = [A(\%) \times \text{cumulative CAPEX}(\$)] + \left[B\left(\frac{\$}{\text{bbl}}\right) \times \text{production}\left(\frac{\text{bbl}}{\text{year}}\right)\right]$$

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

Should be adjusted by inflation

$$
\left.\begin{array}{l} DRILLEX_t \\[2em] CAPEX_t \\[2em] OPEX_t \end{array}\right\}
$$

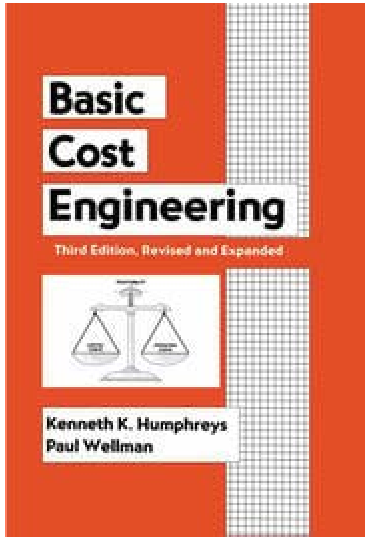
Function of number of wells, maximum production rates of oil, gas and water, development concept, type of fluids etc.

Cost estimation – expected accuracy

- For DG1, +-40%
- For DG2, +-30%
- For DG3, +-20%

Costing

- It is a profession and a discipline
- Internal company databases (based on previous projects)
- Provided by contractors and suppliers
- Commercial software
- Depending on the desired accuracy, can take significant time



$$C_2 = C_1\left(\frac{S_2}{S_1}\right)^n$$

C_1 = cost of equipment of capacity S_1

C_2 = cost of equipment of capacity S_2

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

- Petroleum tax
- CO2 tax (in 2022 NOK 1.65 NOK/Sm3 gas)

The Norwegian petroleum tax system is based on the taxation of the entity rather than taxation of specific petroleum assets.

Neutral tax system

The petroleum taxation system is intended to be neutral, so that an investment project that is profitable for an investor before tax is also profitable after tax. This ensures substantial revenues for the Norwegian society and at the same time encourages companies to carry out all profitable projects.

To ensure a neutral tax system, only the company's net profit is taxable, and losses may be carried forward in the company tax. Special tax value of losses is reimbursed at the tax settlement, the year after it accrued. Neutral properties in the tax system are also important when defining investment based tax deductions.

Sources:
oil and gas taxation in Norway. Deloitte
https://www.norskpetroleum.no/en/economy/petroleum-tax

Ordinary corporate tax	Special tax
Operating income (norm prices for oil)	Operating income (norm prices for oil)
- Operating expenses	- Operating expenses
- Linear depreciation for investments (6 years)	- Depreciation for investments (100 %)
- Exploration expenses, R&D and decom.	- Exploration expenses, R&D and decom.
- Environmental taxes and area fees	- Environmental taxes and area fees
- Net financial costs	- Calculated ordinary tax
- (Loss carry forward)	
= Corporation tax base (22 %)	**= Special tax base (71,8 %)**

The Petroleum Price Council is responsible for setting norm prices, which it does after collecting information from the companies and holding meetings with them. The norm price system applies to various types and qualities of petroleum. For gas, the actual sales prices are used.

Source: https://www.norskpetroleum.no/en/economy/petroleum-tax

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

- CO2 tax (in 2022 NOK 1.65 NOK/Sm3 gas)

Net present value

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

- CO2 tax (in 2022 NOK 1.65 NOK/Sm3 gas)

Example:

- Considering gas turbine efficiency 1 MWh/257 Sm3 gas (TPG4245 – H2022).
- For a field with 30 MW, in a year this represents 262 800 MWh, which represents 67 E06 Sm3 of gas.
- This will be taxed with ca 111 E06 USD.

Net present value - Royalties

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

$$Expenses_t = DRILLEX_t + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

- Used in some countries
- % from the production, not the profit!!

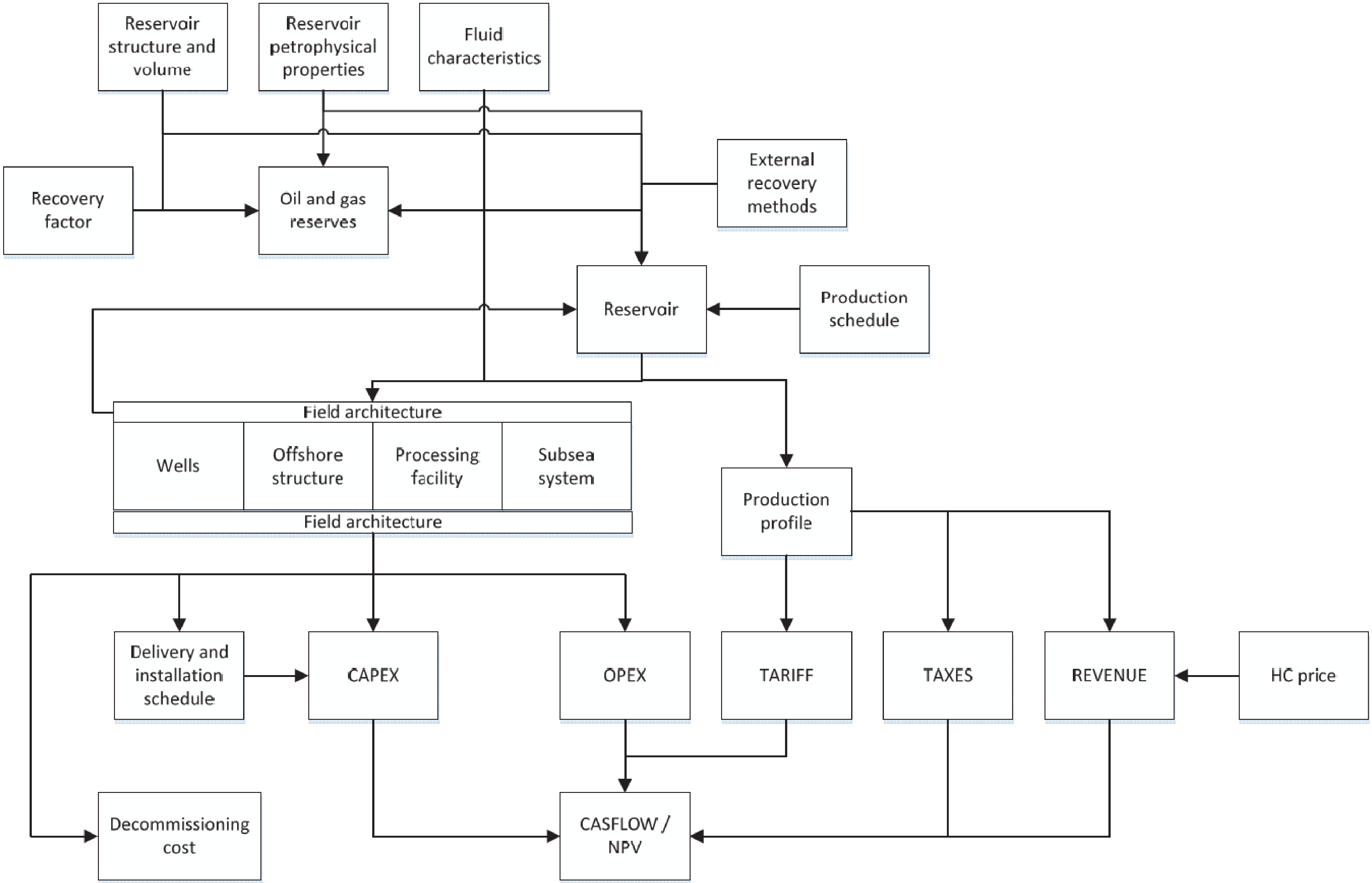
Net present value calculation- Who does what:

- Production profiles of oil, gas and condensate: petroleum engineers
- CAPEX: cost engineers (or suppliers) with input from facilities engineers, marine engineers
- DRILLEX: cost engineers (or suppliers) with input from drilling engineers
- Gas and oil prices: Market analyst
- Tax, Inflation, Exchange rate, discount rate: Finance department

Net present value calculation- Who does what:

- Production profiles of oil, gas and condensate: petroleum engineers
- CAPEX: cost engineers (or suppliers) with input from facilities engineers, marine engineers
- DRILLEX: cost engineers (or suppliers) with input from drilling engineers
- Gas and oil prices: Market analyst
- Tax, Inflation, Exchange rate, discount rate: Finance department

- Highly affected by the development strategy
- All are interconnected!!
- Take time to generate. If there are changes, it takes time to get new values


Reservoir structure and volume
Reservoir petrophysical properties
Fluid characteristics
External recovery methods
Recovery factor
Oil and gas reserves
Reservoir
Production schedule
Field architecture
Wells
Offshore structure
Processing facility
Subsea system
Field architecture
Production profile
Delivery and installation schedule
CAPEX
OPEX
TARIFF
TAXES
REVENUE
HC price
Decommissioning cost
CASFLOW / NPV

Example:

Higher production rates→

bigger separators and compressors→

more weight→

bigger offshore structure

NPV estimation

Source: Hebron field PDO

Table 13.4-1: Hebron Platform Development Capital and Operating Estimates

Year	Capital Costs ($M CAD))						Operating Costs ($MCAD)
	Pre-Production				Drilling	Total	
	Proj. Admin.	Topsides	GBS	OLS			
2010	68	12	13	0		93	1
2011	174	394	240	0		807	9
2012	244	704	291	12		1252	11
2013	216	698	391	36		1340	14
2014	290	643	444	107		1484	20
2015	327	409	234	69		1039	36
2016	256		175	0	82	513	65
2017					222	222	157
2018					236	236	147
2019					242	242	148
2020					242	242	174
2021					242	242	159
2022					218	218	159
2023					189	189	159
2024					215	215	179
2025							159
2026							161
2027							164
2028							187
2029							176
2030							196
2031							194
2032							210
2033							190
2034							188
2035							186
2036							202
2037							182
2038							181
2039							179
2040							197
2041							180
2042							180
2043							180
2044							187
2045							176
2046							592
TOTAL	$ 1,575	$ 2,861	$ 1,788	$ 224	$ 1,887	$ 8,334	$ 5,883

CF versus time

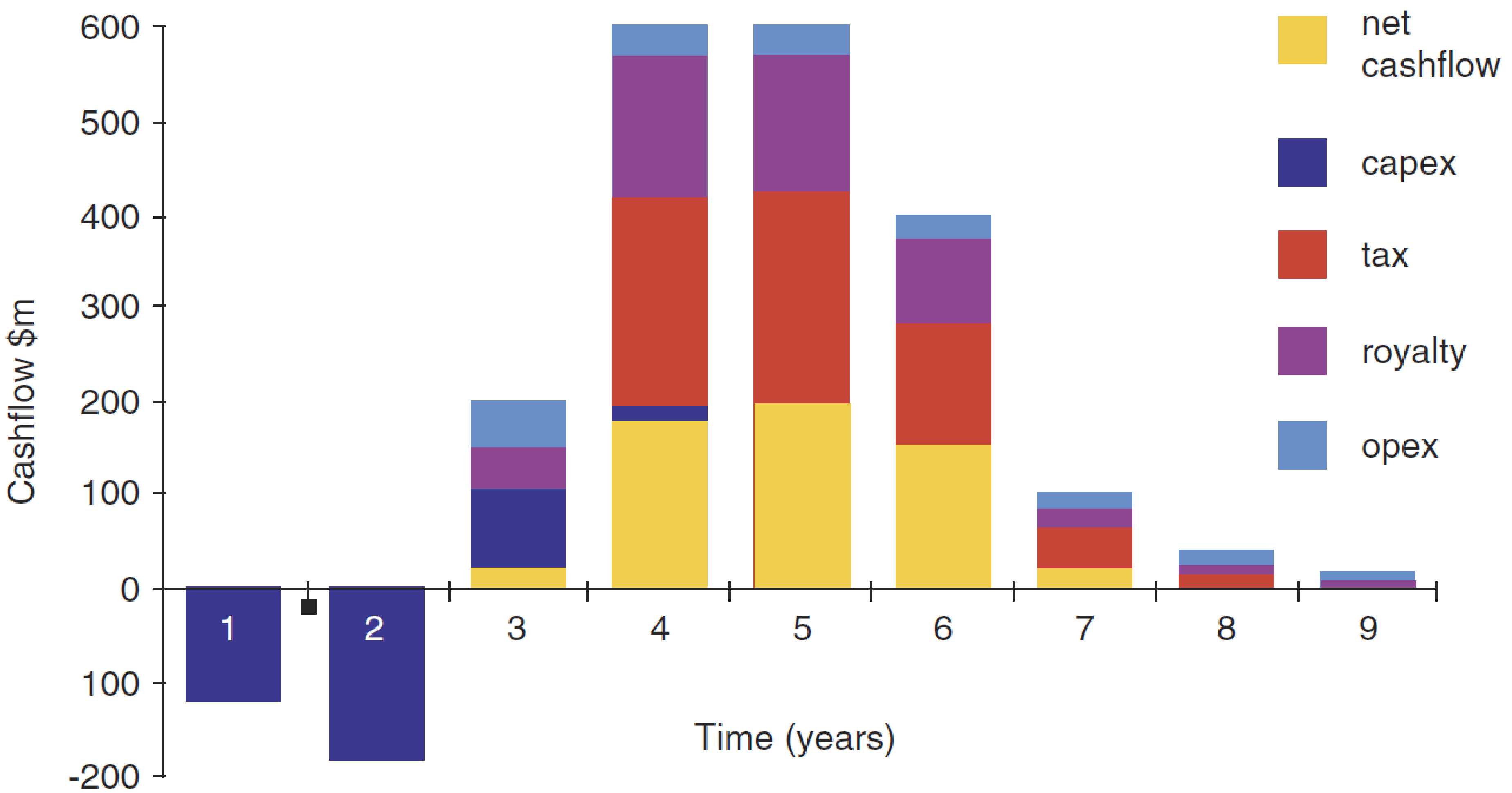
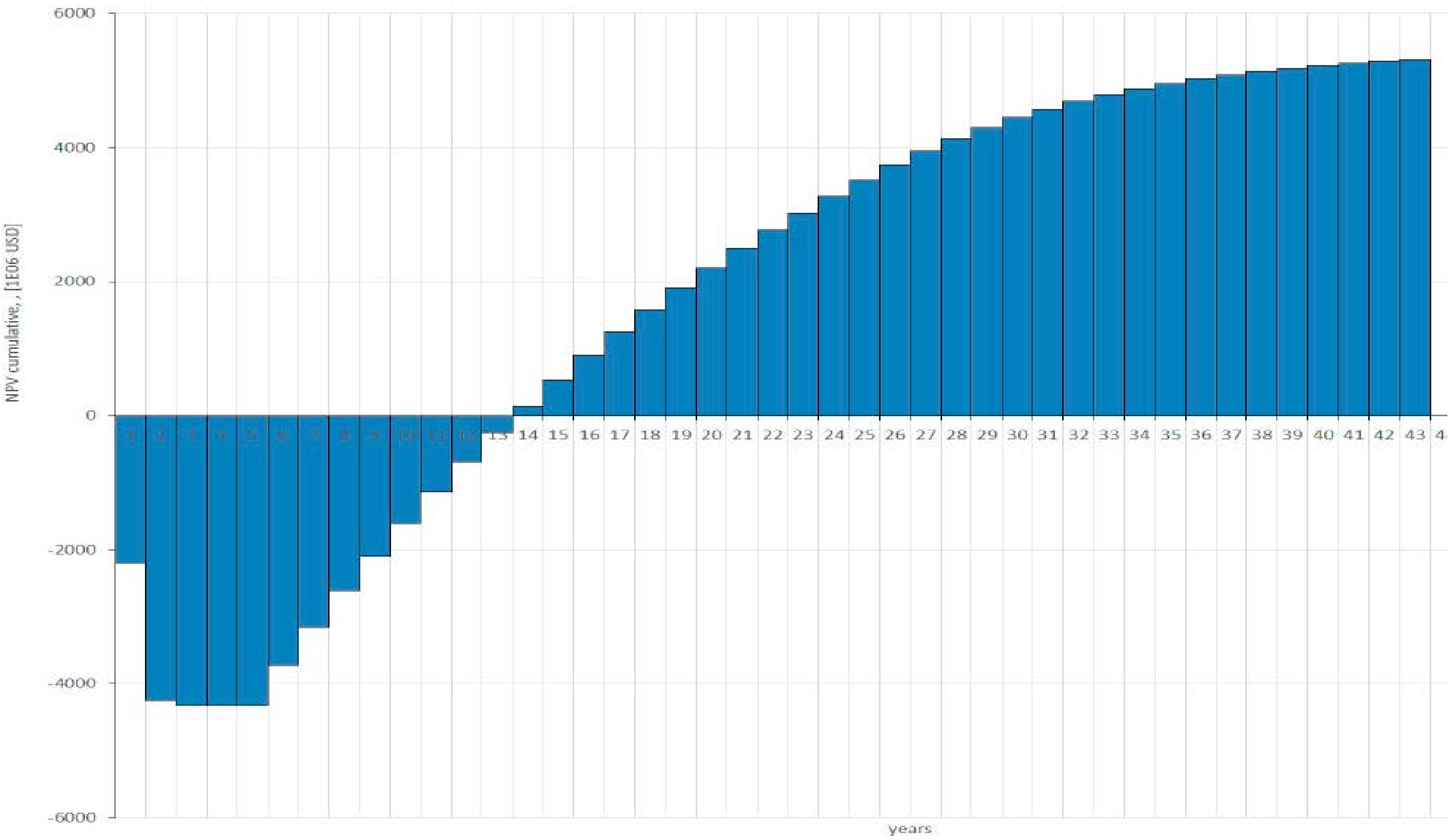


Figure 14.5 Components of a project cashflow.

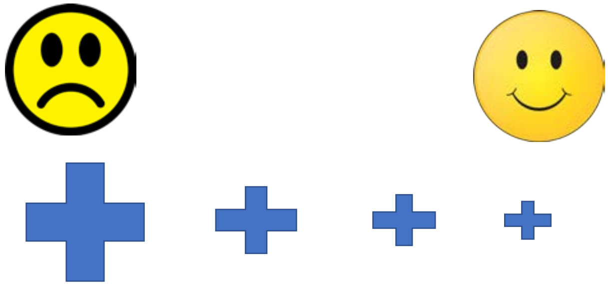
Source: Frank Jahn, Mark Cook, Mark Graham. Hydrocarbon Exploration and Production

NPV versus time



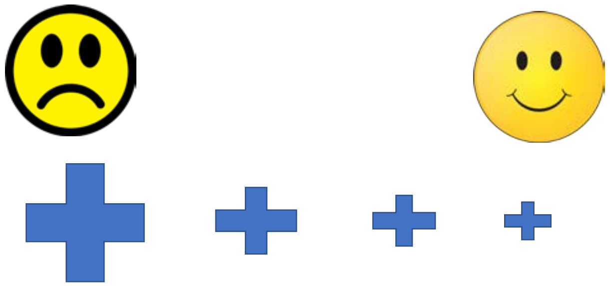
Other KPIs used

- Break-even price → oil price that give NPV = 0

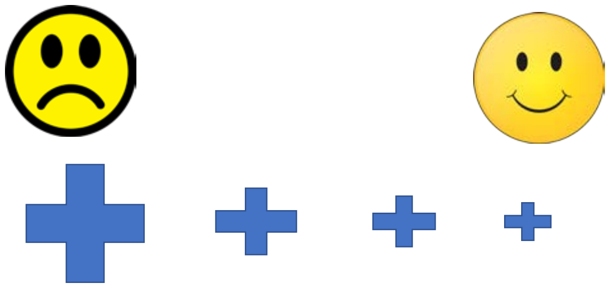


Other KPIs used

- Break-even price → oil price that give NPV = 0

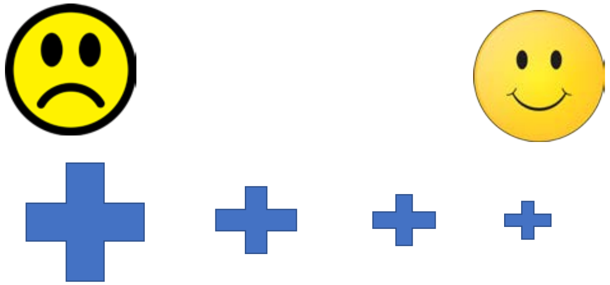


- NPV break-even→ time when NPV = 0

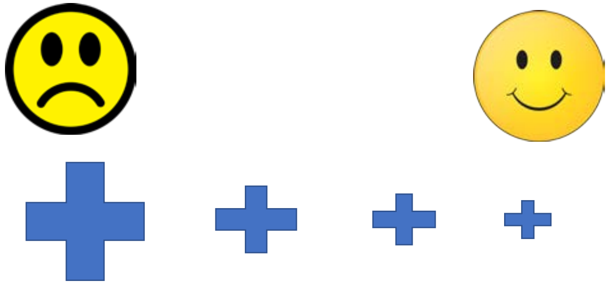


Other KPIs used

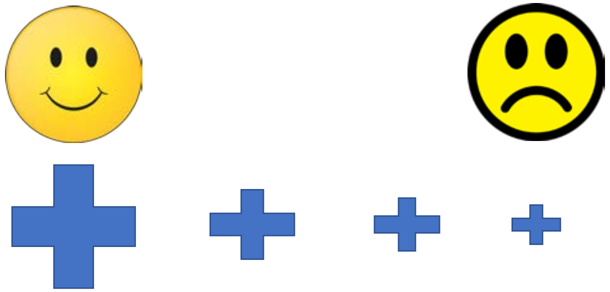
- Break-even price → oil price that give NPV = 0



- NPV break-even→ time when NPV = 0

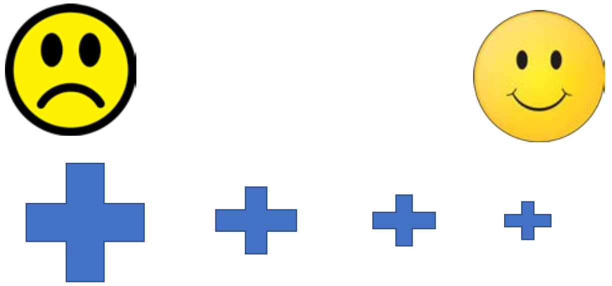


- Internal rate of return (IRR) → discount rate for which NPV = 0

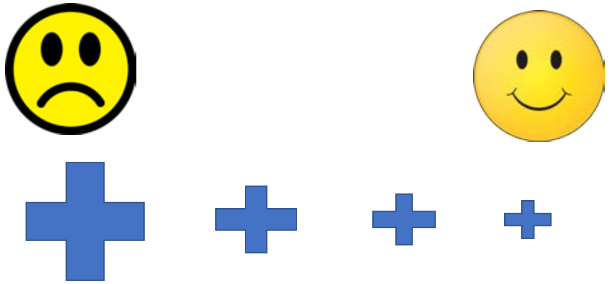


Other KPIs used

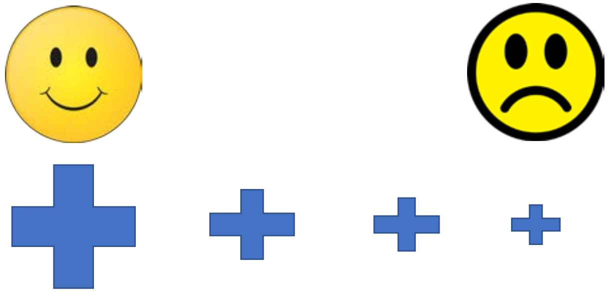
- Break-even price → oil price that give NPV = 0



- NPV break-even→ time when NPV = 0



- Internal rate of return (IRR) → discount rate for which NPV = 0



- OTHERS…

Standards

INTERNATIONAL STANDARD

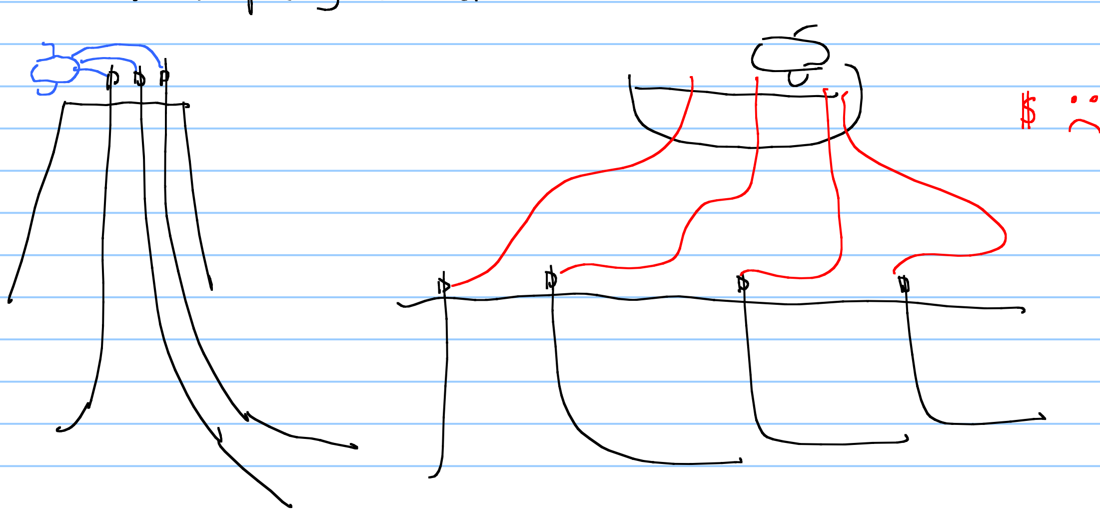
ISO 15663

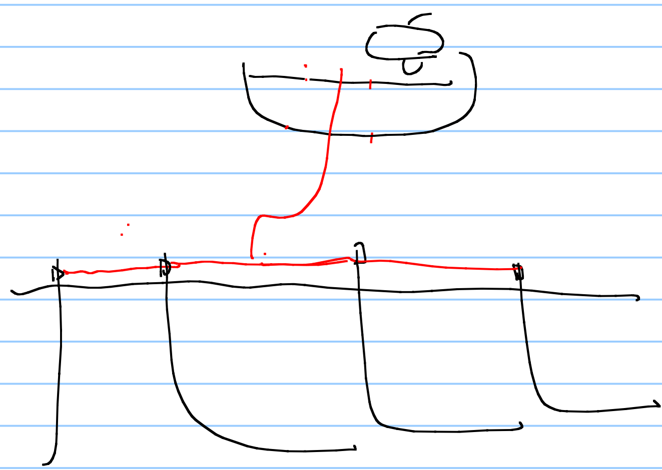
First edition
2021-02

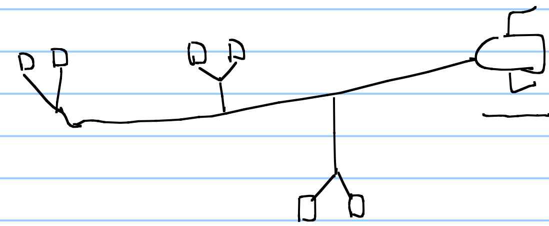
Petroleum, petrochemical and natural gas industries — Life cycle costing

Industries du pétrole et du gaz naturel — Estimation des coûts globaux de production et de traitement

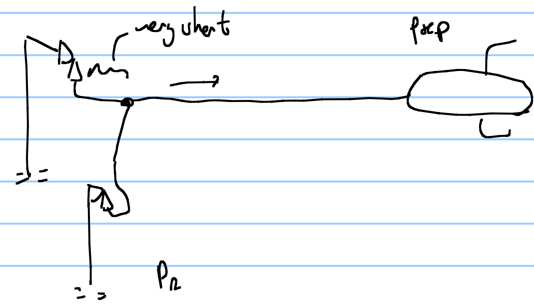
- Networks collection of pipes, flowline, pipeline, valves, pumps, take the fluids from wells to the processing facilities.







Example: 2 Dry gas wells

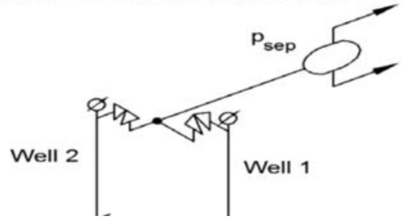


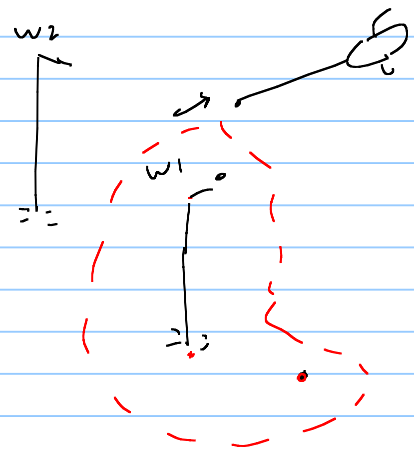
open choke $\Delta p_{c_1} = 0$ $\Delta p_{c_2} = 0$

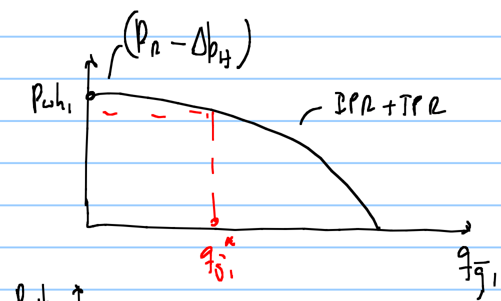
	Equations	Nr equations		Nr unknowns	
IPR	$q_{g_1} = C_{R_1}\left(p_{R_1}^2 - p_{wf_1}^2\right)^{n_1}$ $q_{g_2} = C_{R_2}\left(p_{R_2}^2 - p_{wf_2}^2\right)^{n_2}$	2		4	
TPR	$q_{g_1} = C_{T_1}\left(\frac{p_{wf_1}^2}{e^{s_1}} - p_{wh_1}^2\right)^{0.5}$ $q_{g_2} = C_{T_2}\left(\frac{p_{wf_2}^2}{e^{s_2}} - p_{wh_2}^2\right)^{0.5}$	2	4	2	6
PPR	$q_{g_1} + q_{g_2} = C_{PL}\left(p_j^2 - p_{sep}^2\right)^{0.5}$	1	5	1	7
	$\Delta p_{c_1} = 0$ $p_{wh_1} = p_j$	1	6	0	7
	$\Delta p_{c_2} = 0$ $p_{wh_2} = p_j$	1	7	0	7

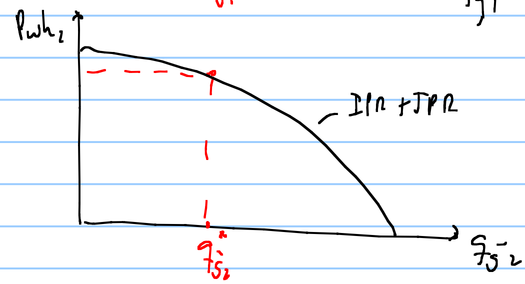
PROBLEM 4 (18 POINTS). Network solving. (2017) exam

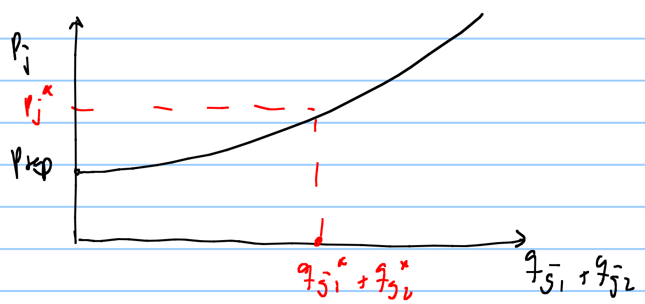
Consider the gas field with two wells, a manifold a pipeline and a separator shown in the figure below. The wellhead of the wells are very close to the junction so it can be safely assumed that the wellhead pressure and junction pressure are equal when the choke is open.











approach nr. 1

1: assume $q_{g_1}^*$ $q_{g_2}^*$

2: Read $p_{wh_1}^*$, $p_{wh_2}^*$, p_j^*
(WPR$_1$) (WPR$_2$) (PPR)

3: Verify $p_{wh_1}^* = p_{wh_2}^* = p_j^*$ — not

yes

$q_{g_1}^*$, $q_{g_2}^*$ are solution

approach nr. 2

1: assume $p_j^* = p_{wh_1}^* = p_{wh_2}^*$

2: Read $q_{g_1}^*$ (WPR$_1$), $q_{g_2}^*$ (WPR$_2$),
$q_{pipeline}^*$ (PPR)

3. Verify

$q_{g_1}^* + q_{g_2}^* = q_{pipeline}^*$ — not

yes

solution

first iteration $p_j = 50$ bara

$q_{g_1}^* = 1.2\text{E}06$ Sm³/d

$q_{g_2}^* = 1.57\text{E}06$ Sm³/d + 2.77 E6 Sm³/d $\varepsilon = 0.97$ 1E06 Sm³/d

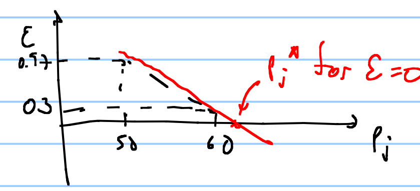
$q_{pipeline}^* = 1.8\text{E}06$ Sm³/d 1.8 E06 Sm³/d

2nd $p_j = 60$ bara

$q_{pipeline}^* = 2.3\text{E}06$ Sm³/d 2.3 E06 Sm³/d $\varepsilon = 0.3$ 1E06 Sm³/d

$q_{g_2}^* = 1.45\text{E}06$ Sm³/d + 2.60 E06 Sm³/d

$q_{g_1}^* = 1.15\text{E}06$ Sm³/d



$$\frac{\varepsilon_1 - \varepsilon_2}{p_{j_1} - p_{j_2}} = \frac{\varepsilon_1 - 0}{p_{j_1} - p_j^*}$$

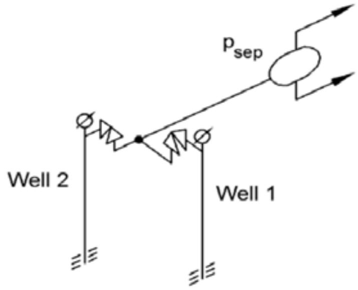
$p_j^* = \sim$

Youtube video: Solving dry gas networks in Excel

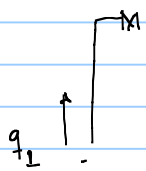
Exercise: using data from Problem 4 of the Exam 2017:

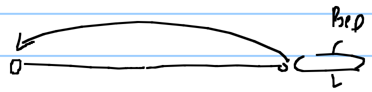
PROBLEM 4 (18 POINTS). Network solving.

Consider the gas field with two wells, a manifold a pipeline and a separator shown in the figure below. The wellhead of the wells are very close to the junction so it can be safely assumed that the wellhead pressure and junction pressure are equal when the choke is open.



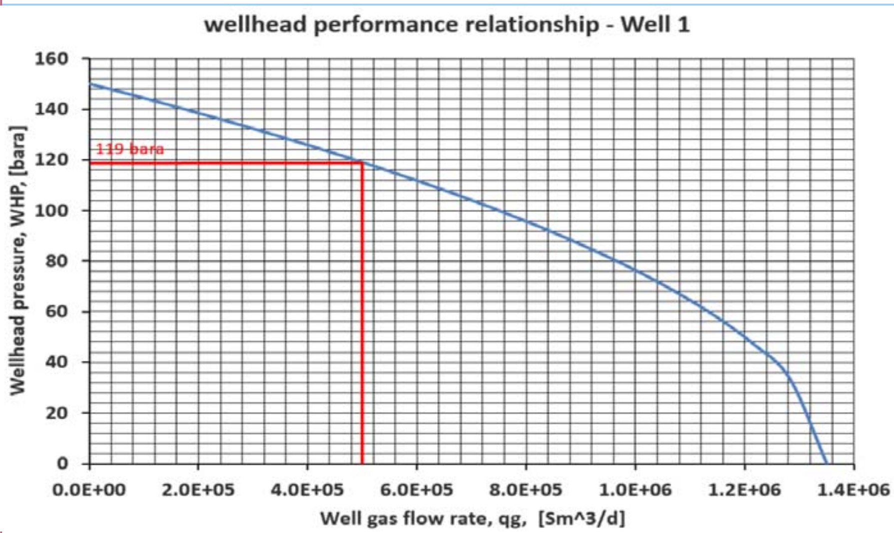
Will it be possible to produce 0.5 E06 Sm3/d from each well? if so, what is the choke deltap required in each well?

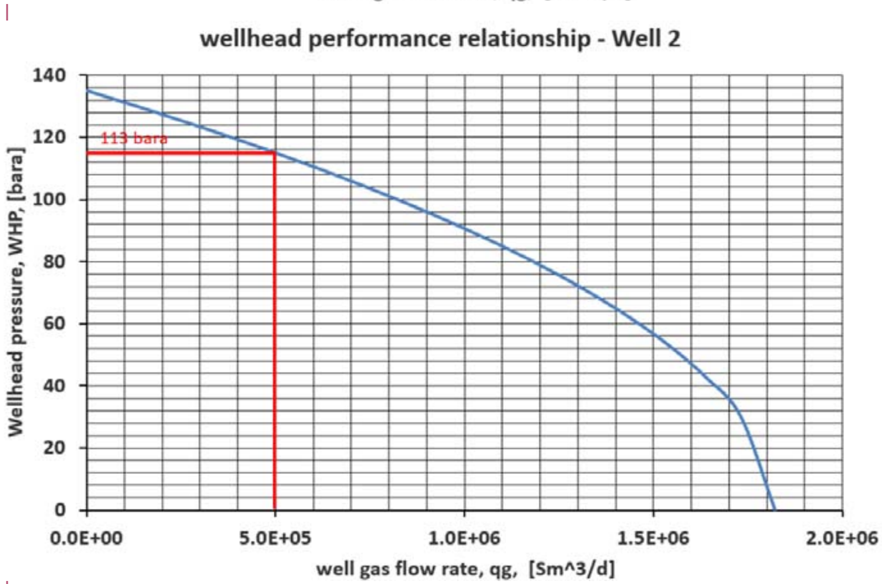


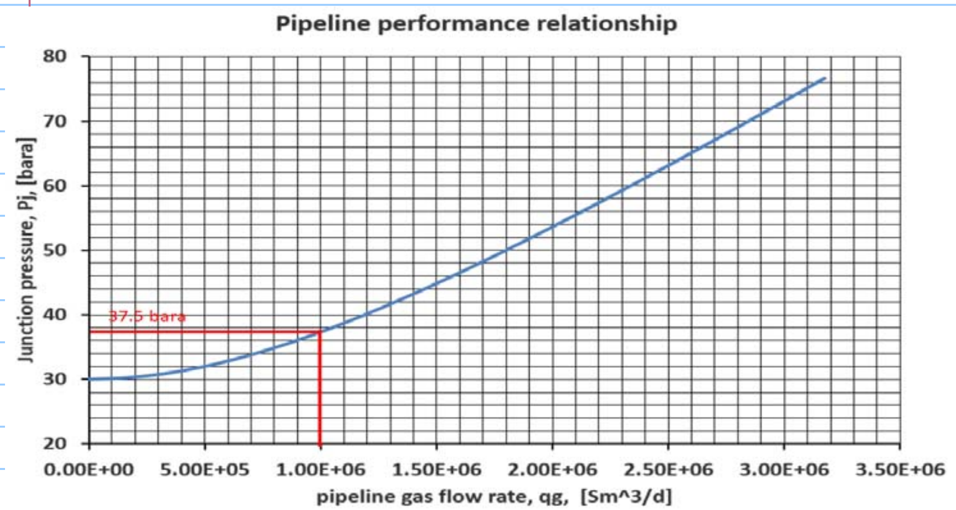


verify $\Delta p > 0$ then q_1 is feasible

if $\Delta p < 0$ then q_1 is no feasible



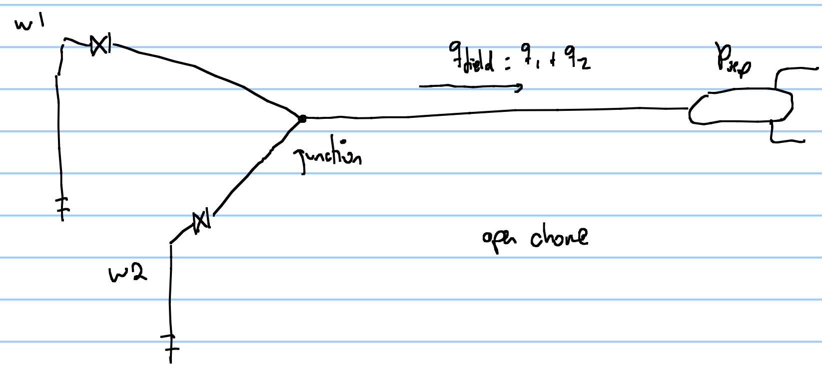




Deltap_choke1 = 119 - 37.5 = 81.5 bara
Deltap_choke2= 113-37.5 = 75.5 bara

Yes, it is possible to produce 0.5 E06 Sm3/d from well 1 and 2.

Exercise on Dry gas network using Excel



we have to assume either $\overline{q_1}, \overline{q_2}$

OR: P_{wf1}, P_{wf2} ← $P_{wf} < P_R$

↳ we prefer to assume P_{wf} because I know the upper bound

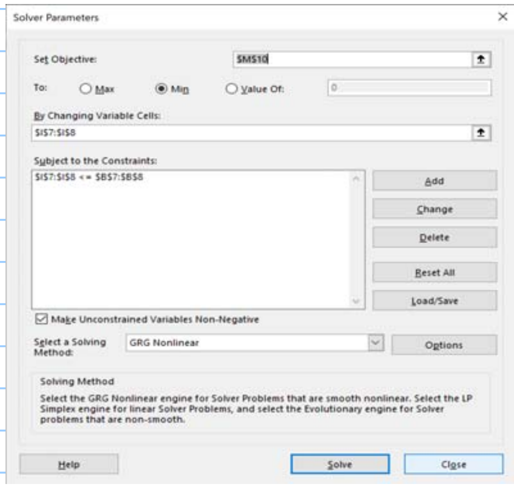
$$q = C_R \left(P_R^2 - P_{wf}^2\right)^n$$

$$P_{wf} = \sqrt{\underbrace{P_R^2 - \left(\frac{q}{C_R}\right)^{1/n}}_{\text{i don't know } q_{max}\text{, and can give problems in eq.}}}$$

objective variable:

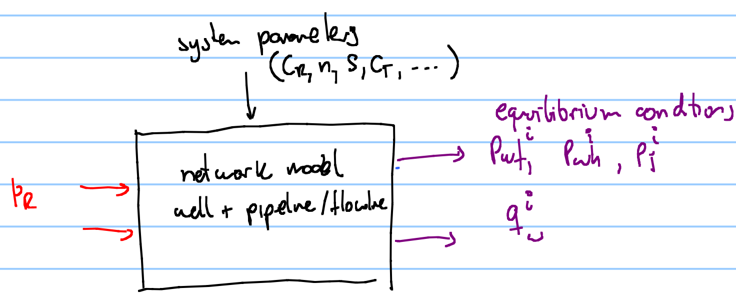
$$\left(P_{j_{av}} - P_{j_1}\right)^2 + \left(P_{j_{av}} - P_{j_2}\right)^2 + \left(P_{j_{av}} - P_{j_{sep}}\right)^2$$

		IPR		Tubing		Flowline						
Component Name	p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	pjunc	error
	[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bara]	(bara^2)
W_1	120	52	0.8	0.13	7680	8673		38	1.02E+05	33	31	1E-0
W_2	120	40	0.75	0.11	8600	7563		34	4.95E+04	31	31	9E-1
Pipeline						14080	28.6		1.51E+05		31	2E-0
										Average=	31	4E-0



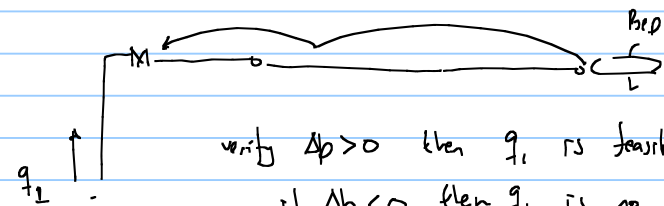
If solver is not available

Activate solver → excel menu → options
↓
Add in
↓
"go"
↓
tick on "solver"
or "problem solver"



solving the network
with choke

• option 1, fixing rates
(option usually not available in commercial software)

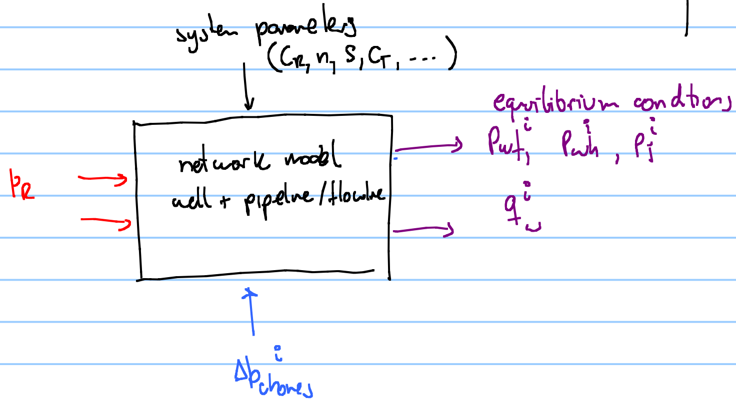


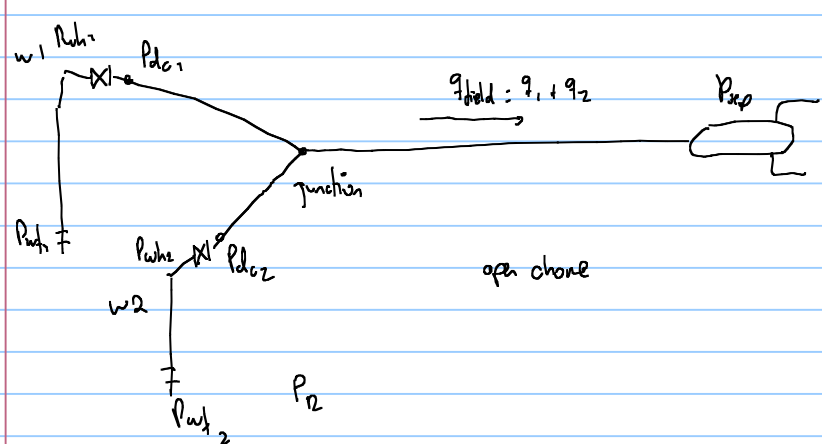
verify $\Delta p > 0$ then q_1 is feasible
if $\Delta p < 0$ then q_1 is no feasible

for example, it is desirable to produce
$$\begin{cases} q_1 = 80000 \ Sm^3/d \\ q_2 = 40000 \ Sm^3/d \end{cases}$$

		IPR		Tubing		Flowline							
Component Name	p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc
	[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]
W_1	120	52	0.8	0.13	7680	8673		69	8.00E+04	64	33	31	30
W_2	120	40	0.75	0.11	8600	7563		66	4.00E+04	63	32	30	30
Pipeline						14080	28.6		1.20E+05				30

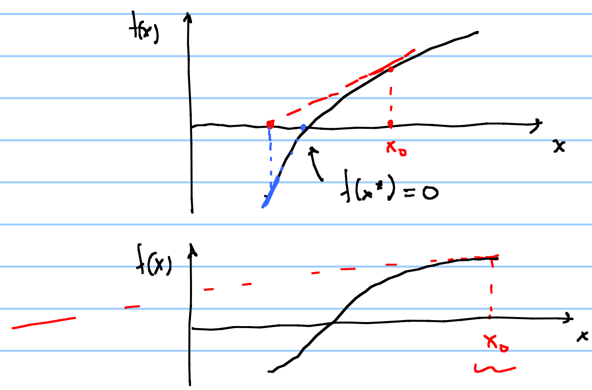
• option 2 : include the choke "model" → 2 options
- Δp_{choke}. ← this option will be discussed next
- choke opening $\Delta p_{choke} = f(q_g, Opening, p_1)$





open choke

	IPR			Tubing	Flowline								
p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc	error
[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]	(bara^2)
120	52	0.8	0.13	7680	8673		42	9.92E+04	38	5	33	30	3E-10
120	40	0.75	0.11	8600	7563		39	4.84E+04	36	5	31	30	1E-09
					14080	28.6		1.48E+05				30	3E-09
									Average=			30	4E-09

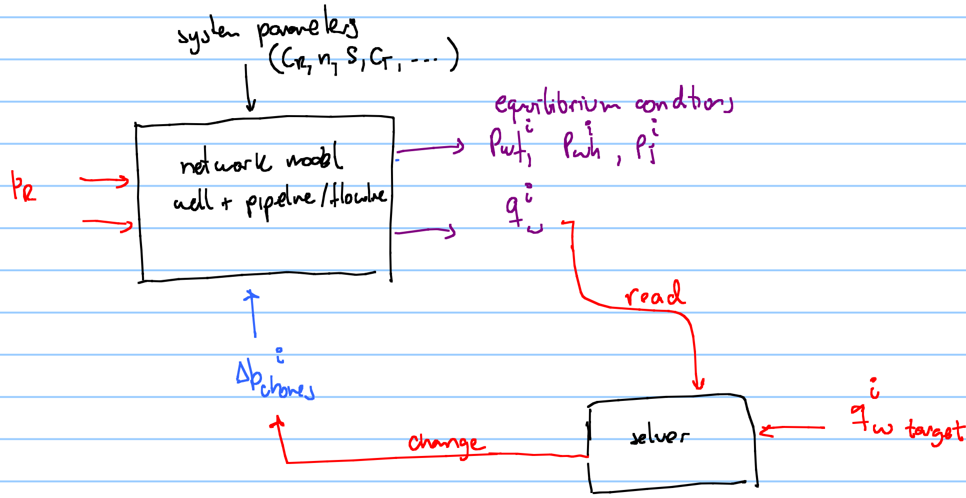


-- step 1
--- step 2

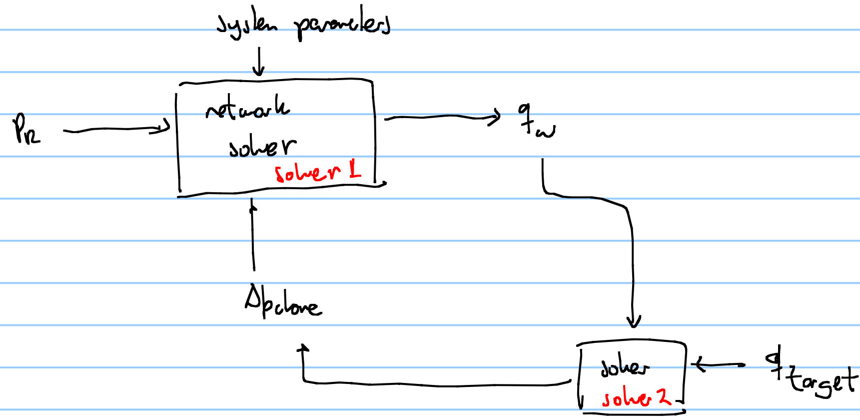
for derivative based solver it is necessary to give a good initial seed

	IPR			Tubing	Flowline								
p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc	error
[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]	(bara^2)
120	52	0.8	0.13	7680	8673		57	9.01E+04	52	20	32	30	1E-09
120	40	0.75	0.11	8600	7563		54	4.44E+04	51	20	31	30	8E-10
					14080	28.6		1.35E+05				30	4E-09
									Average=			30	6E-09

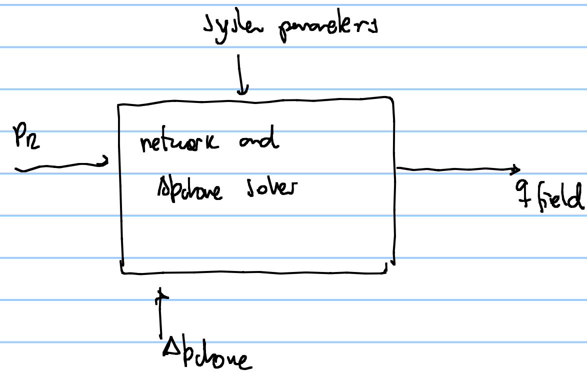
- How to use this model to find Δp_{choke} such that $q_1 = 80000 \ Sm^3/d$
  $q_2 = 40000 \ Sm^3/d$



in excel it is not possible to have two levels of solver



"Merging the two solvers"



objective variable :

$$\left(P_{j_{av}} - P_{j_1}\right)^2 + \left(P_{j_{av}} - P_{j_2}\right)^2 + \left(P_{j_{av}} - P_{j_{sep}}\right)^2$$

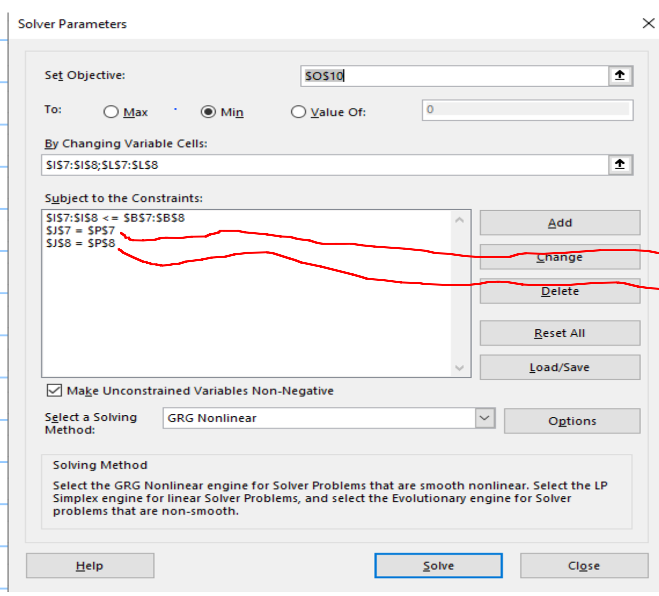
variables

changing P_{wf_1}

P_{wf_2}

$\Delta p_{choke\,1}$

$\Delta p_{choke\,2}$



constraints

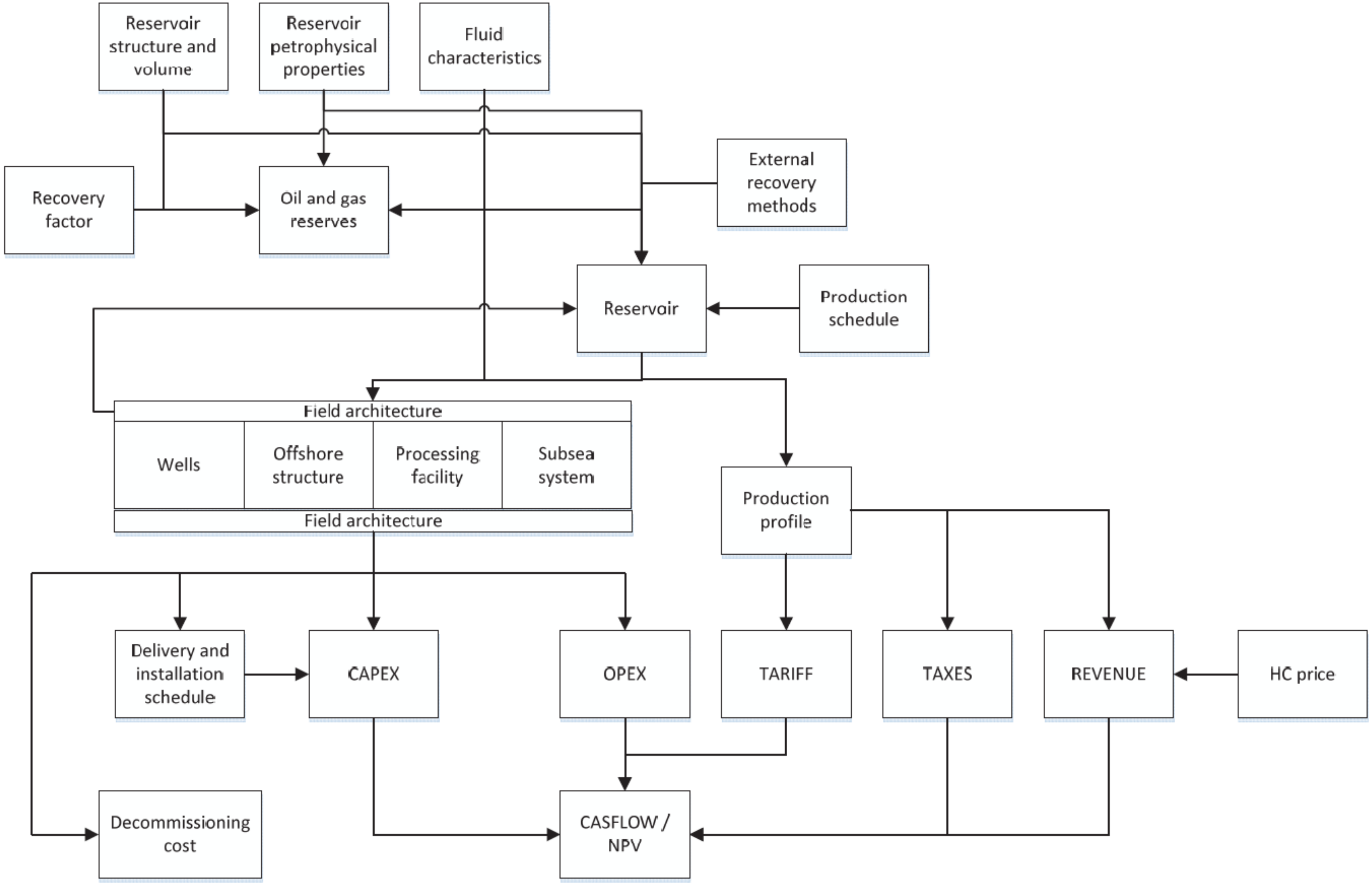
$q_1 = q_{1\,target}$

$q_2 = q_{2\,target}$

	IPR		Tubing		Flowline									
p_R	C	n	S	Ct	Cfl	psep	pwf	qwell	pwh	dpchoke	pdc	pjunc	error	qtarget
[bara]	[Sm^3/bar^2n]			[Sm^3/bar^2]	[Sm^3/bar^2]	[bara]	[bara]	[Sm^3/d]	[bara]	[bar]	[bar]	[bara]	(bara^2)	[Sm3/d]
120	52	0.8	0.13	7680	8673		69	8.00E+04	64	33	31	30	9E-11	80000
120	40	0.75	0.11	8600	7563		87	3.00E+04	82	52	30	30	5E-11	30000
					14080	28.6		1.10E+05				30	7E-12	
									Average=			30	2E-10	

Class 20230221
Outline:
-NPV calculations - effect of uncertainty and optimal production and drilling schedule
-Exercise: CO_2 Injection scheduling for the "Snøhvit" field

Handling uncertainty



Handling uncertainty – from the standard

Industry practices:

- **Typical sensitivity analysis is performed changing inputs for CAPEX (e.g. +-15% and +-30%), product price (e.g. +-10% and +-20%), production start delay (e.g. 1 year). Results are calculated for NPV and IRR**
- **For production impact, worst and best production cases are performed**
- **Probabilistic approach with quantitative analysis very complex to be performed and very seldom used (for giant project only in case).**
  - **The results is a probabilistic curve for NPV and IRR using risked CAPEX and schedule, production, prices and discount rate as input**
  - **Deterministic NPV with P< P50 indicates good probability to achieve the deterministic result**
- **Sensitivity for CO2 tax scenarios is also performed**

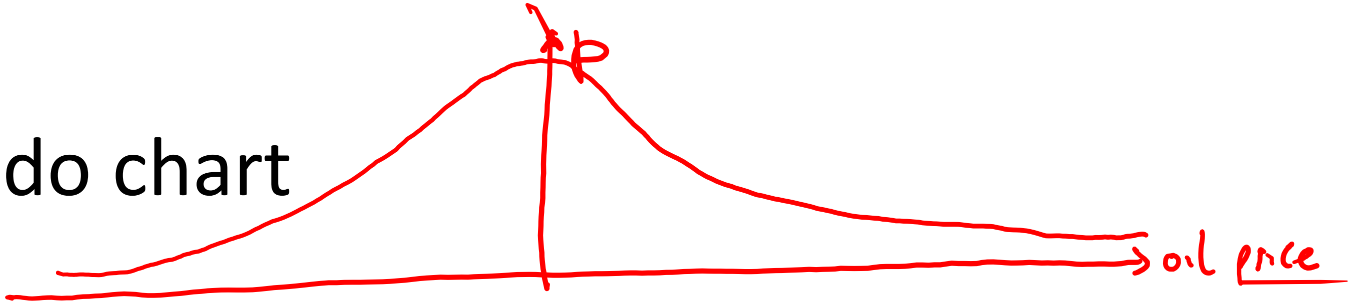
Source: ISO 15663:2021 course, 9 June 2021

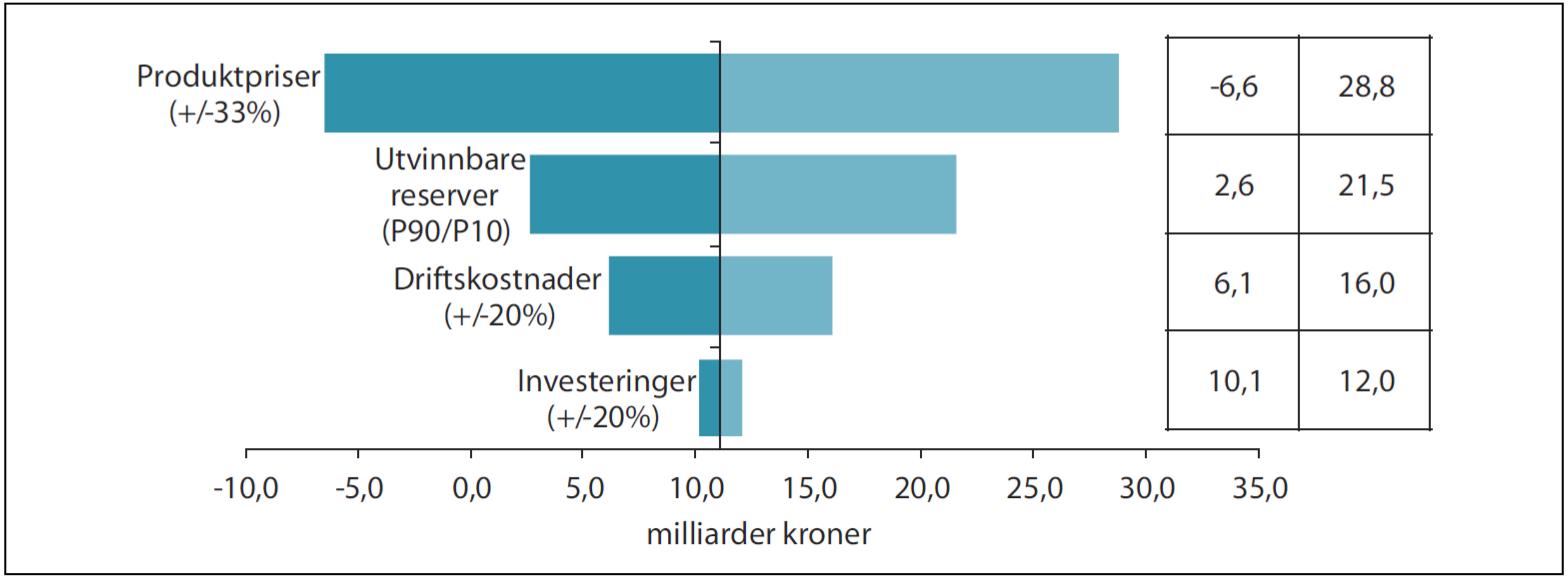
Sensitivity analysis

Varying one at a time: «Ceteris paribus» principle

Sensitivity analysis

Tornado chart





Figur 2.3 Sensitivitetsanalyser

Source: Proposisjon til Stortinget: Utbygging og drift av Aasta Hansteen-feltet

Sensitivity analysis

Spider plots

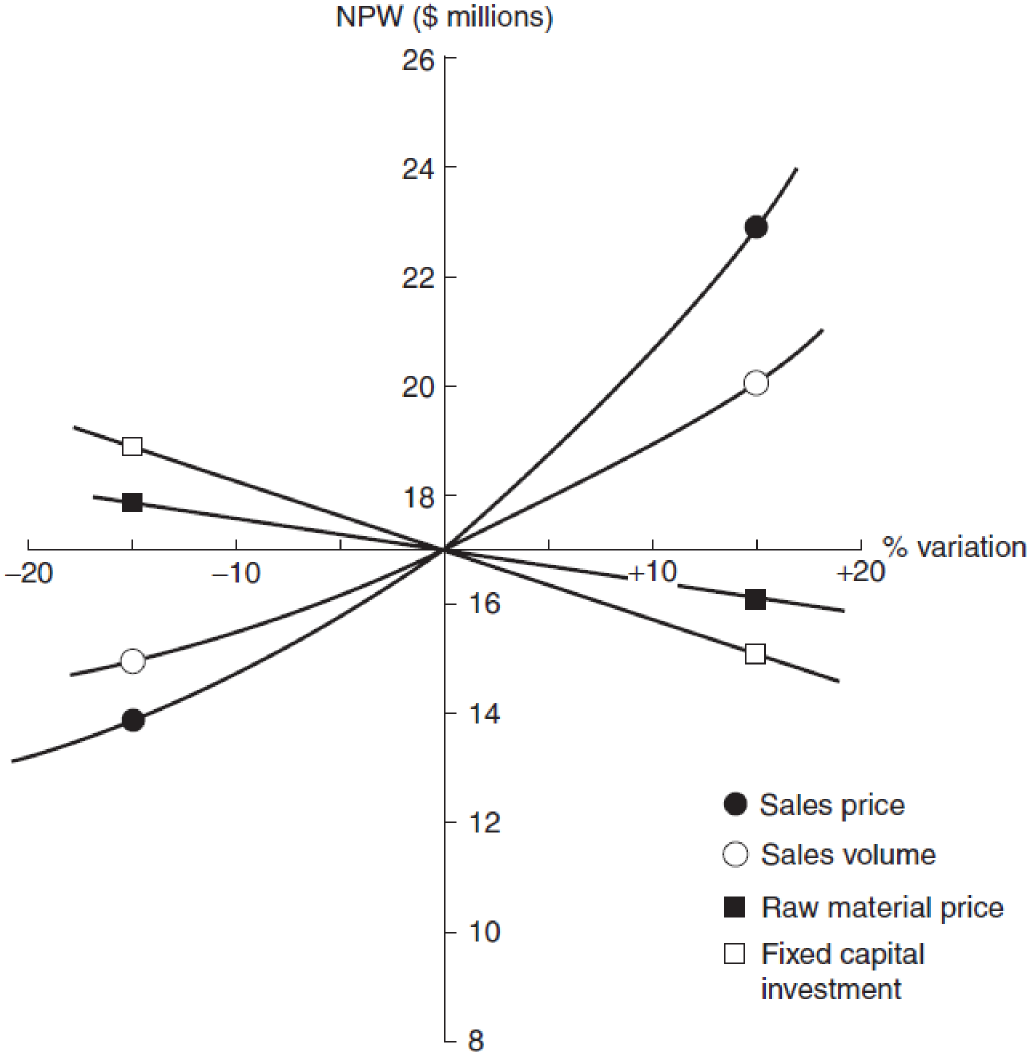


FIG. 9-14 Strauss plot.

Sensitivity analysis - defficiencies

- There could be uncertainties that occur simultaneously
- Probability of occurrence?

Field development goal

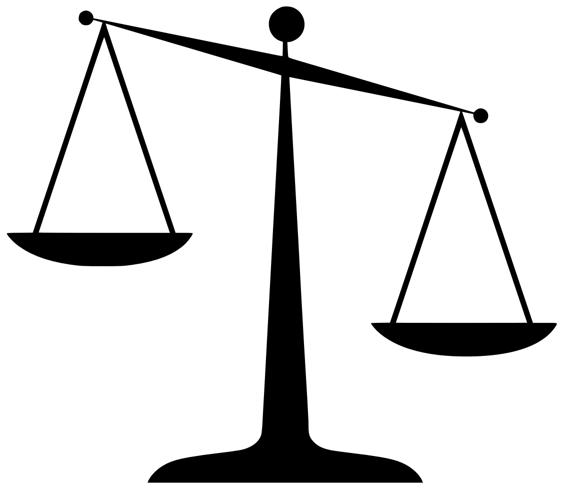
Find field design to maximize NPV

Field development goal

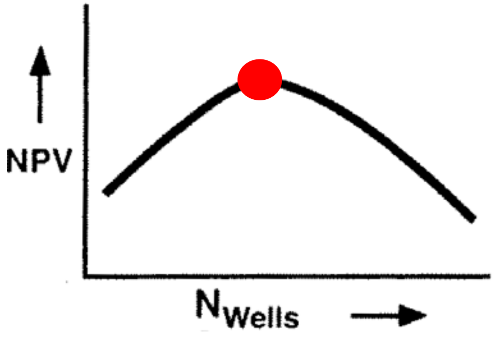
Find field design to maximize NPV

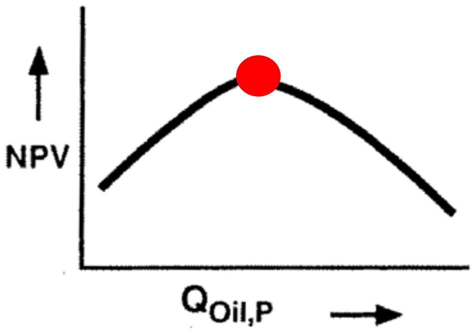
There is an optimal production scheduling and drilling schedule that maximize NPV

Action	Advantages	Disadvantages
Higher HC rates during early times	Gives higher revenue	Gives higher cost (CAPEX, OPEX)
Drill more wells	Allows for higher rates, extends field life	Gives higher cost (DRILLEX, CAPEX, OPEX)



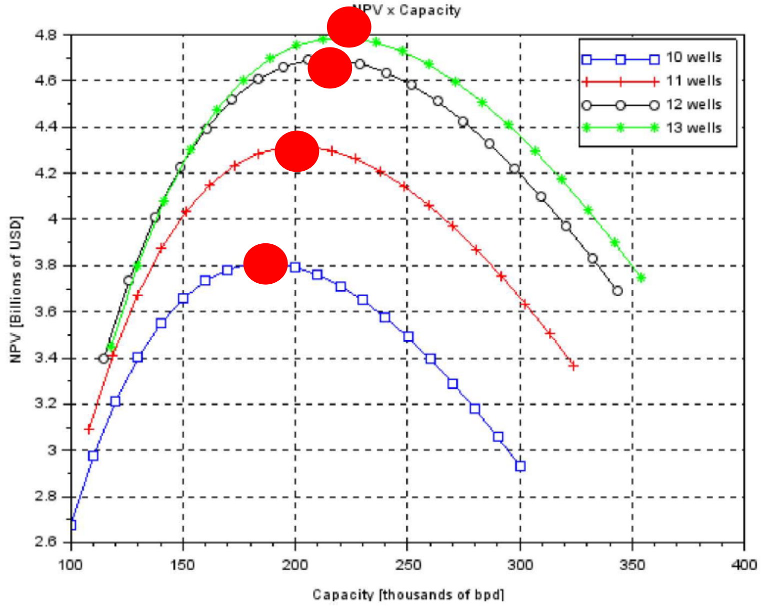
Variation of NPV with plateau rate and number of wells:





Choosing between rocks, hard places and a lot more: the economic interface

Helge Hove Haldorsen

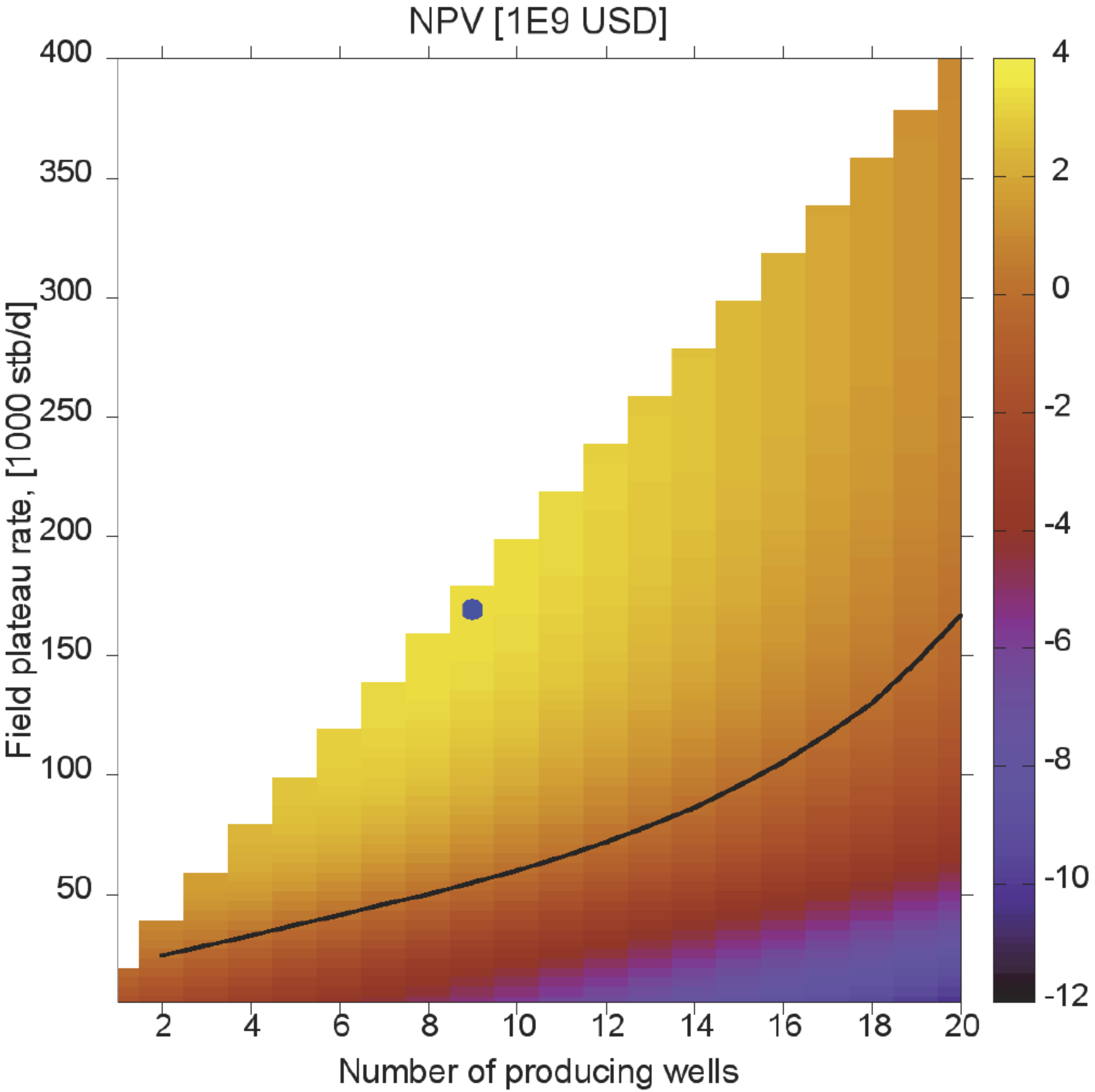


OTC-28898-MS

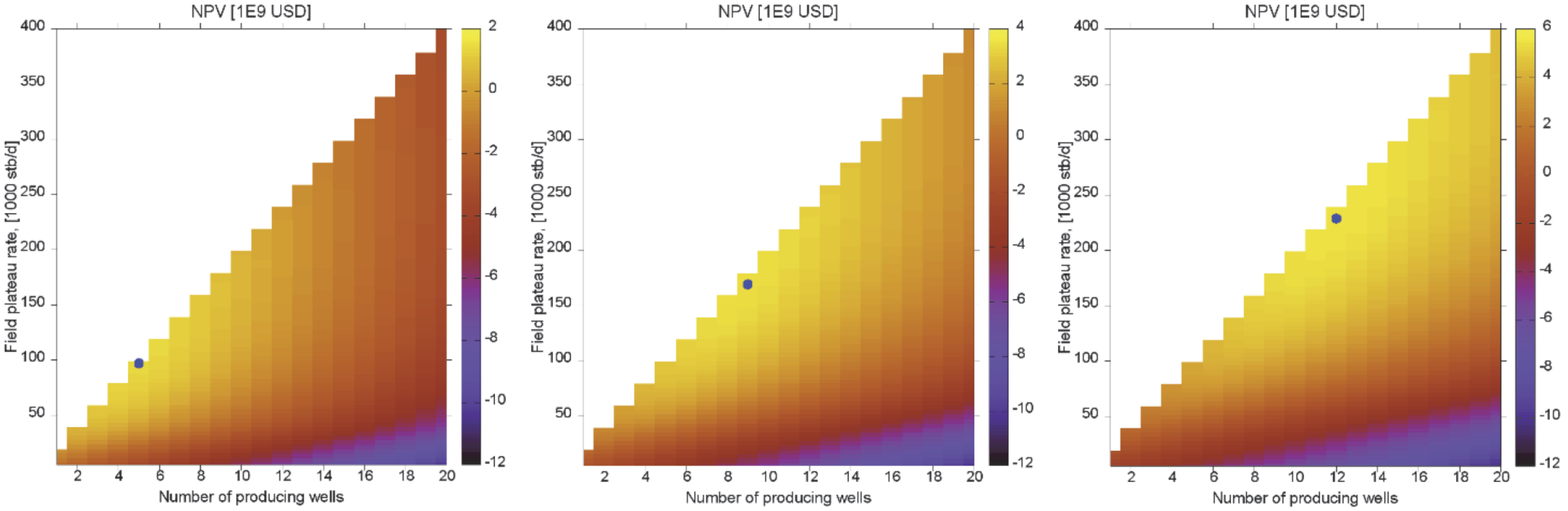
A Cost Reduction Methodology for Offshore Projects

G. C. Nunes, Rio Petroleo Consulting Group; A. H. da Silva and L. G. Esch, Universidade do Estado do Rio de Janeiro

Example from Milan's Compendium section 5.2.3.



Effect of uncertainties



a) N= 0.6·base

b) N= base

c) N= 1.4·base

NPV calculations for the Snøhvit field

Gas price	0.10	[usd/Sm^3]	
Discount rate	5	[%]	
LNG plant CAPEX	160	usd/ Sm^3/c	(paid in years 1 and 2)
Well cost	100	[1E06 USD]	(4 wells maximum per year)
LNG carrier cost	200	[1E06 USD]	(each carrier has a capacity of 145000 Sm3 LNG, or 86E06 Sm3 og gas, can do 22 trips in a year, amount paid evenly during the first two years)
Subsea manifold cost	20	[1E06 USD]	
Pipeline and umbilicals	500	[1E06 USD]	(paid in years 1 and 2)
OPEX	200	[1E06 USD]	(paid anually when production starts)
N manifolds	3		
field plateau rate	2.00E+07	[Sm3/d]	
ΔG_p (plateau)	7.30E+09	[Sm^3]	
Cost LNG plant	3200	[1E06 USD]	
Nr of LNG carriers required	4		
Cost of LNG carriers	800	[1E06 USD]	

NPV [1E06 U: 1046

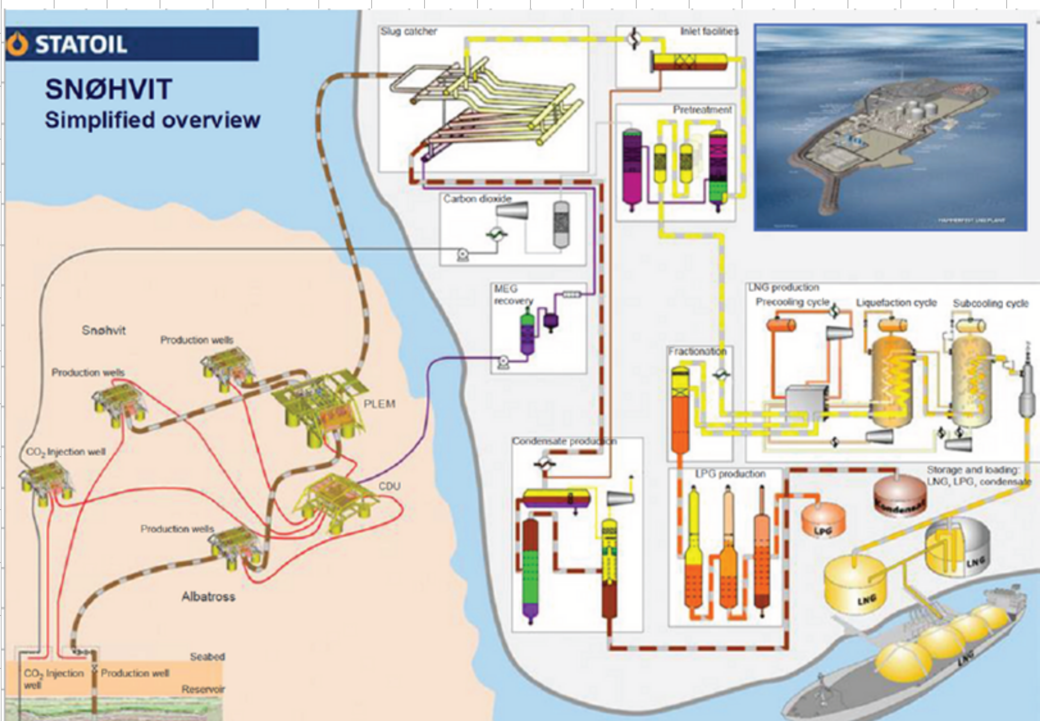
		CAPEX												
				Subsea										
	End of yea	Nwells	DRILLEX	Pipeline & umbilicals	Manifolds	LNG Plant	NG vessel	TOTAL CAPEX	Yearly gas offtake	Revenues	OPEX	Cash flow	Discounted cash flow	NPV
	[-]	[-]	[1E06 USD]	[1E06 USD]	[1E06 USD]	[1E06 USD]	1E06 USD	IE06 USD	[Sm^3]	[1E06 USD]	[1E06 USD]	1E06 USD	[1E06 USD]	[1E06 USD]
	1	4	400	250	60	1600	400	2710	0.00E+00	0	0	-2710	-2581	-2581
	2	4	400	250	0	1600	400	2650	0.00E+00	0	0	-2650	-2404	-4985
	3	1	100	0	0	0	0	100	0.00E+00	0	0	-100	-86	-5071
	4	0	0	0	0	0	0	0	0.00E+00	0	0	0	0	-5071
PROD START-->	5	0	0	0	0	0	0	0	0.00E+00	0	0	0	0	-5071
	6	0	0	0	0	0	0	0	7.30E+09	730	200	530	395	-4675
	7	0	0	0	0	0	0	0	7.30E+09	730	200	530	377	-4299
	8	0	0	0	0	0	0	0	7.30E+09	730	200	530	359	-3940
	9	0	0	0	0	0	0	0	7.30E+09	730	200	530	342	-3598
	10	0	0	0	0	0	0	0	7.30E+09	730	200	530	325	-3273
	11	0	0	0	0	0	0	0	7.30E+09	730	200	530	310	-2963
	12	0	0	0	0	0	0	0	7.30E+09	730	200	530	295	-2668
	13	0	0	0	0	0	0	0	7.30E+09	730	200	530	281	-2387
	14	0	0	0	0	0	0	0	7.30E+09	730	200	530	268	-2119
	15	0	0	0	0	0	0	0	7.30E+09	730	200	530	255	-1864
	16	0	0	0	0	0	0	0	7.30E+09	730	200	530	243	-1622
	17	0	0	0	0	0	0	0	7.30E+09	730	200	530	231	-1390
	18	0	0	0	0	0	0	0	7.30E+09	730	200	530	220	-1170
	19	0	0	0	0	0	0	0	7.30E+09	730	200	530	210	-960
	20	0	0	0	0	0	0	0	7.30E+09	730	200	530	200	-761
	21	0	0	0	0	0	0	0	7.30E+09	730	200	530	190	-570
	22	0	0	0	0	0	0	0	7.30E+09	730	200	530	181	-389
	23	0	0	0	0	0	0	0	7.30E+09	730	200	530	173	-217
	24	0	0	0	0	0	0	0	7.30E+09	730	200	530	164	-52
	25	0	0	0	0	0	0	0	7.30E+09	730	200	530	157	104
	26	0	0	0	0	0	0	0	7.30E+09	730	200	530	149	253
	27	0	0	0	0	0	0	0	7.15E+09	715	200	515	138	391
	28	0	0	0	0	0	0	0	6.64E+09	664	200	464	118	510
	29	0	0	0	0	0	0	0	6.17E+09	617	200	417	101	611

Recommendation: perform NPV calculations for Snøhvit, using the Excel file provided earlier, and the sheet "NPV_Calc"

-Exercise: CO_2 Injection scheduling for the "Snøhvit" field. the procedure used for production scheduling can be used for injection scheduling also.

340m

water depth

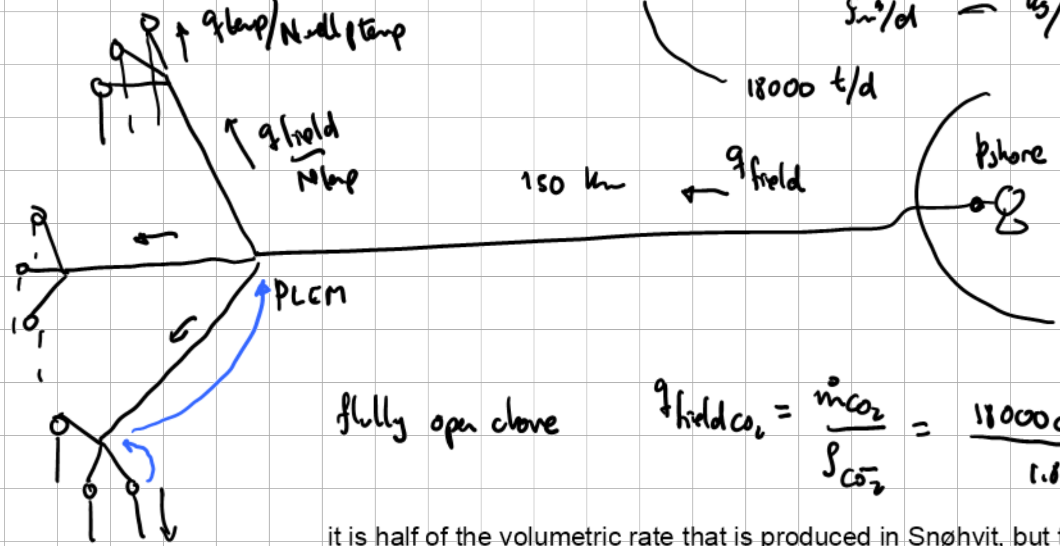


Fictitious Snøhvit CO2 injection field based on the real field

18E06 kg/d $\rho_{CO_2} = 1.86$ kg/m^3

Sm^3/d — kg/d

18000 t/d



$$q_{field\,CO_2} = \frac{\dot{m}_{CO_2}}{\rho_{CO_2}} = \frac{18000000}{1.86} = 9.6E06 \text{ Sm}^3/\text{d}$$

it is half of the volumetric rate that is produced in Snøhvit, but the density is 3 times bigger

For this case, the equilibrium point will be at shore, since the wellhead chokes are fully open. We will do counter current calculations from reservoir to shore

For flow in tubing, flowline and pipelines, we can use the dry gas tubing equation but with CO2 properties

$$q_{sc} = \left(\frac{\pi}{4}\right)\cdot\left(\frac{R}{M_{air}}\right)^{0.5}\cdot\left(\frac{T_{sc}}{p_{sc}}\right)\cdot\left(\frac{D^5}{f_M\cdot L\cdot\gamma_g\cdot Z_{av}\cdot T_{av}}\right)^{0.5}\cdot\left[\left(p_{wf}^2 - p_t^2\cdot e^S\right)\cdot\left(\frac{S}{e^S-1}\right)\right]^{0.5}$$

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

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

The main difference is that S is negative,(alpha is downwards) and pwf and pwh must switch places (flow goes from pwh to pwf)

$$C_T \ [\text{Sm}^3/\text{d}/\text{bar}] \longrightarrow [\text{t/d}/\text{bar}]$$

Another change is that the flow coefficients are calculated for volumetric flow at standard conditions, and we are working with mass flow, so we must multiply it by standard conditions density of CO2

injectivity index

$$q_{well} = J\left(P_{wf} - P_R\right) \qquad P_{wf} = P_R + \frac{q_{well}}{J}$$

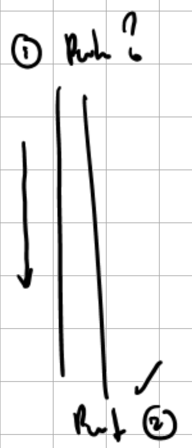
$$q_{well} = C_R\left(P_R^2 - P_{wf}^2\right)^n$$

Since CO2 has high density, the IPR used is linear (like if it were a liquid). --> taken from TPG4245

J here is the injectivity index and must be in units of mass flow/pressure

Field rate [t/d]	Cumulative inj [t]	delta Cum inj [t]	pR [bara]	TR [C]	ZR [-]	Well rate [t/d]	pwf [bara]	Twf [C]	pwh [bara]	Twh [C]	DP choke [bara]	ptemp [bara]	Ttemp [C]	template rate [t/d]	pplem [bara]	Tplem [C]	pshore [bara]	Tshore [C]
18000	0	0	300.0	92	0.626	2000	308	45	120.6	4	0	120.6	4	6000	121.0	4	92.8	10

-For pwh we use the tubing equation, pwh is 1 and pwf is 2.
-for pplem we use the flowline equation, ptemp is 2 and pplem is 1.
-for pshore we use the inclined flowline equation (same tubing equation), pshore is 1 and pplem is 2.
the pressure at the wellhead is greater than the pressure at the bottom-hole, but flow is from wellhead to bottom-hole, how is this possible?
when the line is horizontal, (from plem to temp), the pressure at the plem is greater than at the template., which is consistent



$$P_{wf} = P_{wh} - \Delta p_H - \Delta p_f$$

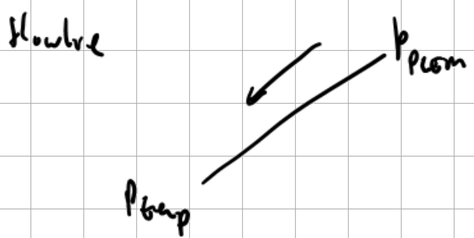
no flow

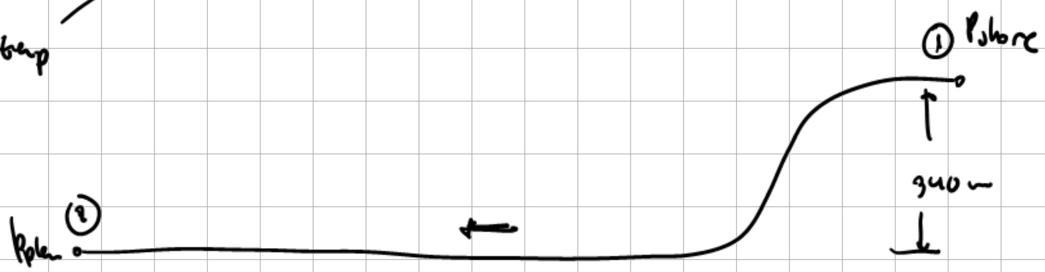
$$P_{wf} = P_{wh} - \Delta p_H \quad \text{but} \quad \Delta p_H = -$$

assuming water $\rho = 1000\ kg/m^3$

$q_w = 0$ $\quad P_{wh} = 100$ bar

$$p_{wf} = 100 + \rho \cdot \Delta H \cdot g$$



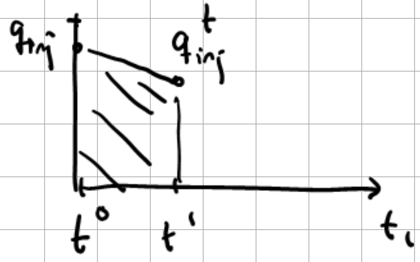


This is because, for downward flow, the hydrostatic component adds to the pressure at the top. In our calculations the pressure drop due to friction is smaller than the pressure increase due to the hydrostatic component. This is because the viscosity of CO2 is small., but the density is big

Estimating yearly injection amounts of CO2

ΔG_p

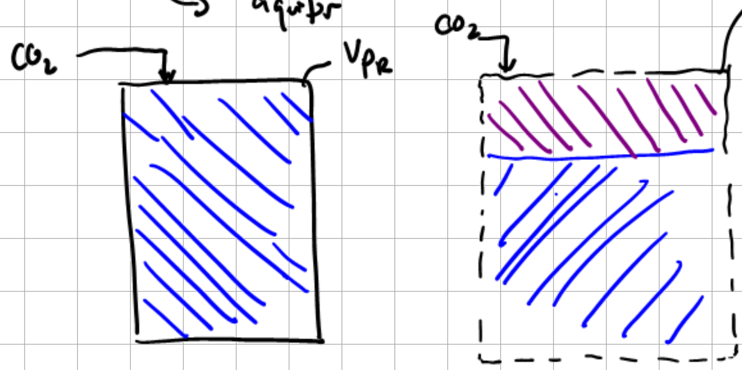
$$\Delta G_{inj}^{t} = \frac{\left(q_{field}^{t} + q_{field}^{t-1}\right)}{2} \cdot \overbrace{\left(t^{t} - t^{t-1}\right)}^{years} \cdot \overbrace{uptime}^{\text{Nr operational day / years}}$$



Material balance for CO2 storage

CO_2 storage → depleted gas reservoir

↳ aquifer



$$p_R \cdot V_{R,CO_2} = n_{CO_2} \cdot R_u \cdot Z_R \, T_R$$

$$V_{R,CO_2} = \frac{n_{CO_2} \cdot R_u \cdot Z_R \, T_R}{p_R}$$

$$n_{CO_2} \propto G_{inj}$$

$$V_{R,CO_2} = V_{pR} \cdot \underbrace{c_e}_{c_f + c_w} \cdot (p_R - p_{Ri})$$

$$V_{R,CO2} = \frac{n_{inj} \cdot R \cdot Z_R \cdot T_R}{p_R}$$

$$V_{R,CO2} = c_e \cdot V_{T,i} \cdot (p_R - p_{Ri})$$

$$\frac{n_{inj} \cdot R \cdot Z_R \cdot T_R}{c_e \cdot V_{T,i} \cdot p_R} = (p_R - p_{Ri})$$

$$p_R{}^2 - p_{Ri} \cdot p_R - \frac{m_{inj} \cdot \bar{R} \cdot Z_R \cdot T_R}{c_e \cdot V_{T,i}} = 0$$

$$p_R = \frac{p_{Ri} \pm \sqrt{p_{Ri}{}^2 + 4 \cdot \frac{m_{inj} \cdot \bar{R} \cdot Z_R \cdot T_R}{c_e \cdot V_{T,i}}}}{2}$$

The physical solution is the positive, then

$$p_R = \frac{p_{Ri} + \sqrt{p_{Ri}{}^2 + 4 \cdot \frac{m_{inj} \cdot \bar{R} \cdot Z_R \cdot T_R}{c_e \cdot V_{T,i}}}}{2}$$

We will use ZR from the previous time, to avoid implicit calculations the function ZfacStanding cannot be used for CO2, then we need to use another technique to estimate Z.

We will do interpolation in a table, since the process in the reservoir is isothermal.

A	B	C	D
T	[C]	92	
den_sc	[kg/m3]	1.8682	
p	deng	Z - data	
[bara]	[kg/m3]		
1.0132	1.5	0.9974	
11.013	16.4	0.9721	
21.013	32.2	0.9463	
31.013	48.9	0.9200	
41.013	66.6	0.8930	
51.013	85.4	0.8656	
61.013	105.6	0.8377	
71.013	127.2	0.8093	
81.013	150.4	0.7805	
81.013	150.4	0.7805	
81.013	150.4	0.7805	
91.013	175.5	0.7516	
101.01	202.6	0.7227	
111.01	231.7	0.6942	
121.01	263.0	0.6668	
131.01	296.2	0.6410	
141.01	330.9	0.6176	
151.01	366.3	0.5975	
161.01	401.5	0.5813	
171.01	435.5	0.5691	
181.01	467.5	0.5611	
191.01	497.2	0.5567	
201.01	524.4	0.5555	
211.01	549.2	0.5568	
221.01	571.7	0.5603	
231.01	592.1	0.5654	
241.01	610.8	0.5719	
251.01	627.9	0.5794	

Data | CO2_PVT | PT_Diagram_CO2

Properties taken from the website of NIST https://webbook.nist.gov/cgi/cbook.cgi?ID=C124389&Mask=4

ERROR in the Excel spreadsheet, the Aquifer pore volume VporeR [m3] should be 1.80E+10

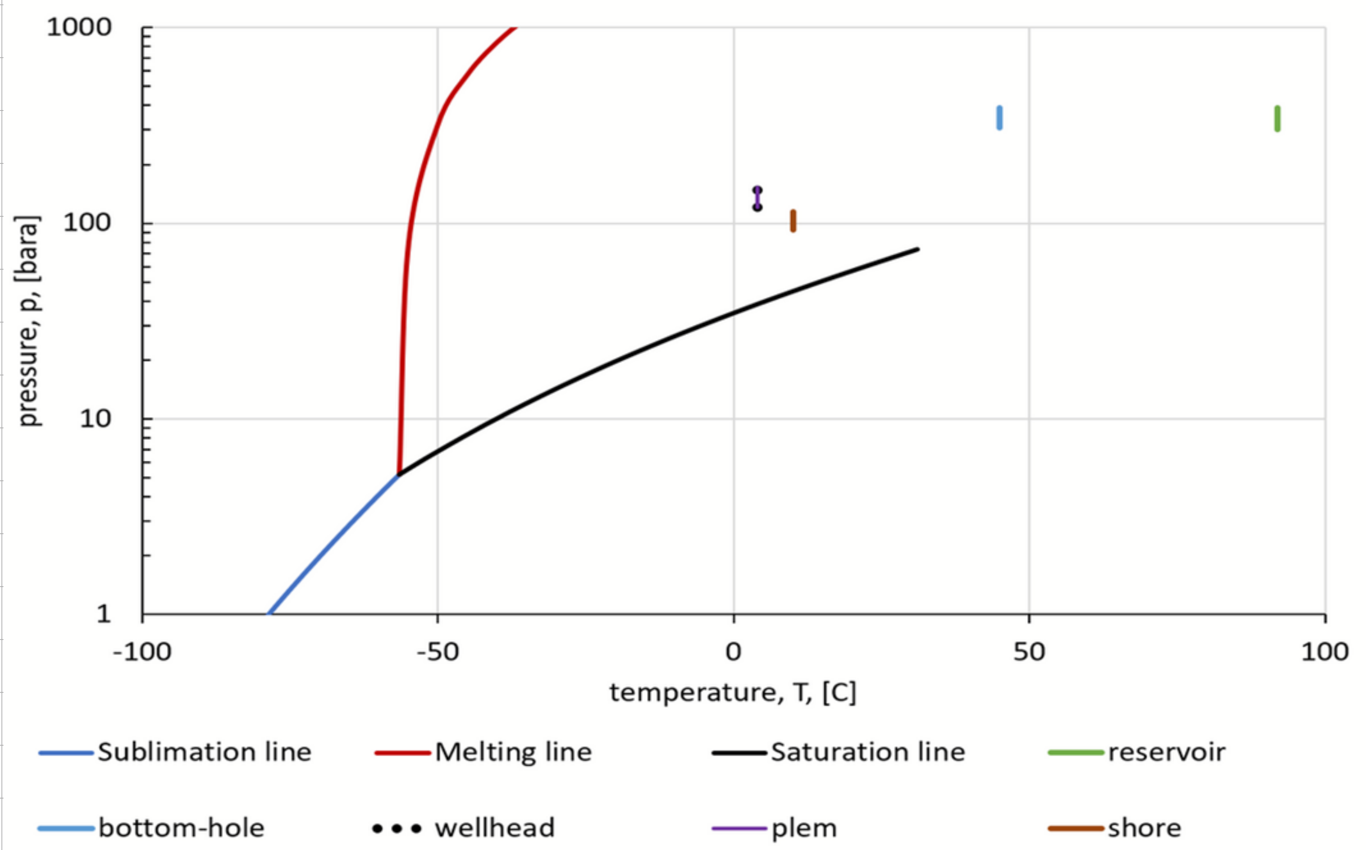
end of year	Nr injectors per template	Nr. Templates	Field rate	Cumulative inj	delta Cum inj	pR	TR	ZR	Well rate	pwf	Twf	pwh	Twh	DP choke	ptemp	Ttemp	template rate	pplem	Tplem	pshore
[-]	[-]		[t/d]	[t]	[t]	[bara]	[C]	[-]	[t/d]	[bara]	[C]	[bara]	[C]	[bara]	[bara]	[C]	[t/d]	[bara]	[C]	[bara]
0	3	3	18000	0	0	300.0	92	0.626	2000	308	45	120.6	4	0	120.6	4	6000	121.0	4	92.8
1	3	3	18000	6.48E+06	6.48E+06	305.1	92	0.631	2000	313	45	122.6	4	0	122.6	4	6000	123.0	4	94.2
2	3	3	18000	1.30E+07	6.48E+06	310.1	92	0.637	2000	318	45	124.5	4	0	124.5	4	6000	124.9	4	95.6
3	3	3	18000	1.94E+07	6.48E+06	315.1	92	0.642	2000	323	45	126.4	4	0	126.4	4	6000	126.8	4	97.0
4	3	3	18000	2.59E+07	6.48E+06	319.9	92	0.647	2000	328	45	128.3	4	0	128.3	4	6000	128.7	4	98.3
5	3	3	18000	3.24E+07	6.48E+06	324.8	92	0.653	2000	333	45	130.2	4	0	130.2	4	6000	130.6	4	99.7
6	3	3	18000	3.89E+07	6.48E+06	329.5	92	0.658	2000	338	45	132.1	4	0	132.1	4	6000	132.4	4	101.0
7	3	3	18000	4.54E+07	6.48E+06	334.2	92	0.663	2000	343	45	133.9	4	0	133.9	4	6000	134.2	4	102.3
8	3	3	18000	5.18E+07	6.48E+06	338.9	92	0.669	2000	347	45	135.7	4	0	135.7	4	6000	136.0	4	103.6
9	3	3	18000	5.83E+07	6.48E+06	343.5	92	0.674	2000	352	45	137.5	4	0	137.5	4	6000	137.8	4	104.9
10	3	3	18000	6.48E+07	6.48E+06	348.1	92	0.679	2000	356	45	139.3	4	0	139.3	4	6000	139.6	4	106.2
11	3	3	18000	7.13E+07	6.48E+06	352.6	92	0.685	2000	361	45	141.0	4	0	141.0	4	6000	141.3	4	107.5
12	3	3	18000	7.78E+07	6.48E+06	357.1	92	0.690	2000	365	45	142.8	4	0	142.8	4	6000	143.1	4	108.8
13	3	3	18000	8.42E+07	6.48E+06	361.6	92	0.695	2000	370	45	144.5	4	0	144.5	4	6000	144.8	4	110.0
14	3	3	18000	9.07E+07	6.48E+06	366.0	92	0.700	2000	374	45	146.2	4	0	146.2	4	6000	146.5	4	111.3
15	3	3	18000	9.72E+07	6.48E+06	370.4	92	0.705	2000	379	45	147.9	4	0	147.9	4	6000	148.2	4	112.5
16	3	3	18000	1.04E+08	6.48E+06	374.8	92	0.710	2000	383	45	149.6	4	0	149.6	4	6000	149.9	4	113.7
17	3	3	18000	1.10E+08	6.48E+06	379.1	92	0.716	2000	387	45	151.3	4	0	151.3	4	6000	151.6	4	114.9
18	3	3	18000	1.17E+08	6.48E+06	383.4	92	0.721	2000	392	45	153.0	4	0	153.0	4	6000	153.3	4	116.2
19	3	3	18000	1.23E+08	6.48E+06	387.7	92	0.726	2000	396	45	154.6	4	0	154.6	4	6000	154.9	4	117.4
20	3	3	18000	1.30E+08	6.48E+06	392.0	92	0.731	2000	400	45	156.3	4	0	156.3	4	6000	156.6	4	118.6
21	3	3	18000	1.36E+08	6.48E+06	396.2	92	0.736	2000	405	45	157.9	4	0	157.9	4	6000	158.2	4	119.8

When plateau ends? (when do I need to reduce the rate?):

-pshore required is higher than the maximum available. In this case the maximum available is 211 bara,so no problem there.
-pR (or pwf) is higher than maximum allowable (e.g. fracking pressure). in this case pwf max is 390 bara. We reach this constrain in year 18!!!! so, from year 18 the rate must be reduced --> use the solver and change the field rate until pwf <= 390 bara
-Usually there is a maximum amount of CO2 that can be injected. There is no information about this in this case.

The injection field rate drops dramatically to honor the constrain of powf <= 390 bara

end of year	Nr injectors per template	Nr. Templates	Field rate	Cumulative inj	delta Cum inj	pR	TR	ZR	Well rate	pwf
[-]	[-]		[t/d]	[t]	[t]	[bara]	[C]	[-]	[t/d]	[bara]
0	3	3	18000	0	0	300.0	92	0.626	2000	308
1	3	3	18000	6.48E+06	6.48E+06	305.1	92	0.631	2000	313
2	3	3	18000	1.30E+07	6.48E+06	310.1	92	0.637	2000	318
3	3	3	18000	1.94E+07	6.48E+06	315.1	92	0.642	2000	323
4	3	3	18000	2.59E+07	6.48E+06	319.9	92	0.647	2000	328
5	3	3	18000	3.24E+07	6.48E+06	324.8	92	0.653	2000	333
6	3	3	18000	3.89E+07	6.48E+06	329.5	92	0.658	2000	338
7	3	3	18000	4.54E+07	6.48E+06	334.2	92	0.663	2000	343
8	3	3	18000	5.18E+07	6.48E+06	338.9	92	0.669	2000	347
9	3	3	18000	5.83E+07	6.48E+06	343.5	92	0.674	2000	352
10	3	3	18000	6.48E+07	6.48E+06	348.1	92	0.679	2000	356
11	3	3	18000	7.13E+07	6.48E+06	352.6	92	0.685	2000	361
12	3	3	18000	7.78E+07	6.48E+06	357.1	92	0.690	2000	365
13	3	3	18000	8.42E+07	6.48E+06	361.6	92	0.695	2000	370
14	3	3	18000	9.07E+07	6.48E+06	366.0	92	0.700	2000	374
15	3	3	18000	9.72E+07	6.48E+06	370.4	92	0.705	2000	379
16	3	3	18000	1.04E+08	6.48E+06	374.8	92	0.710	2000	383
17	3	3	18000	1.10E+08	6.48E+06	379.1	92	0.716	2000	387
18	3	3	14874.6	1.16E+08	5.92E+06	383.1	92	0.720	1652.73	390
19	3	3	8547.44	1.20E+08	4.22E+06	386.0	92	0.724	949.716	390
20	3	3	4779.77	1.23E+08	2.40E+06	387.8	92	0.726	531.086	390
21	3	3	2650.14	1.24E+08	1.34E+06	388.8	92	0.727	294.461	390


1000
100
10
1
pressure, p, [bara]
-100
-50
0
50
100
temperature, T, [C]
Sublimation line
Melting line
Saturation line
reservoir
bottom-hole
wellhead
plem
shore

Class 20230224
Outline:

Group work: Solve the exercise given in the lecture of the 20230221 (CO_2 injection scheduling for the Snøhvit field)

1. Calculate duration of injection plateau considering the following constraints:
-pshoremax = 211 bara
-pwfmax=390 bara
-pump power max = 6 MW. assume suction pressure and Temperature 50 bara and 10 C. Estimate pump power with q_suction*DP/effic. Here DP is pshore-psuc. assume Effic = 0.7. q_suction = fieldmassFlow/den@suct

2. Calculate injection profile post plateau

3. Determine how your results change if pshoremax = 100 bara.

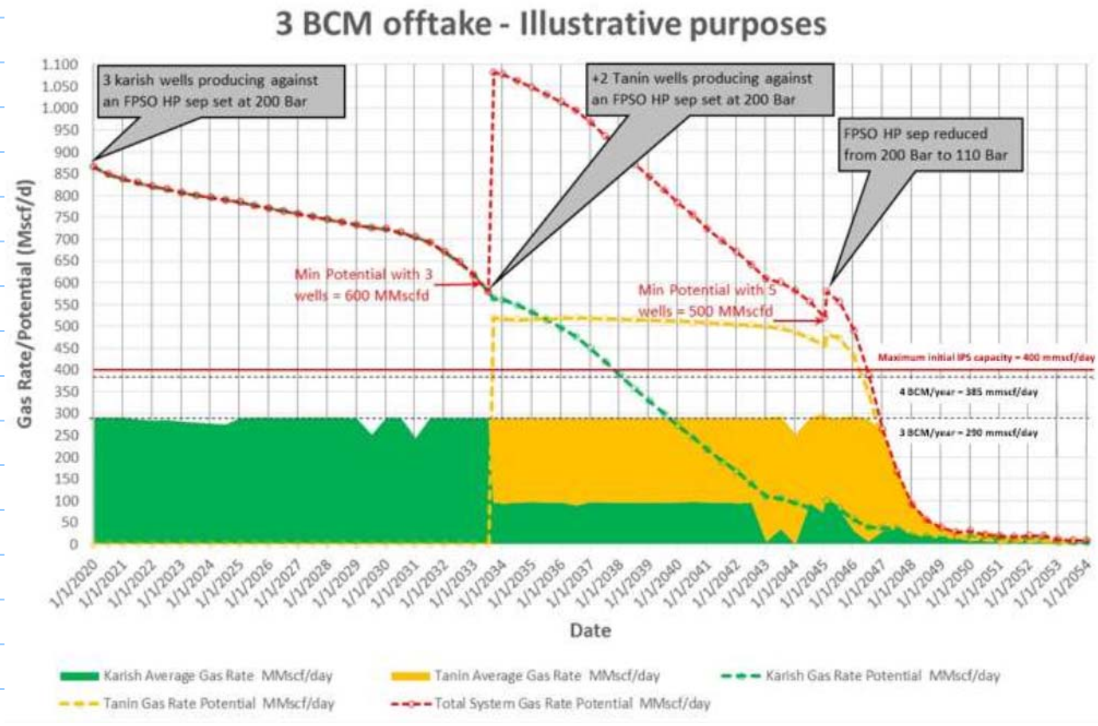
4. Will drilling more wells in each template help to prolong plateau?

Results:

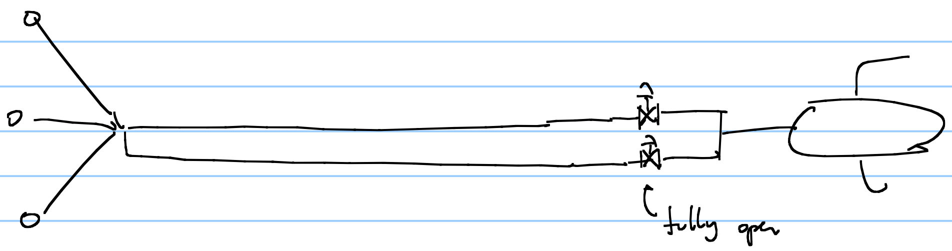
1. Observations:
-pshore max is not a problem, the pshore found is always below 211 bara.
-pwfmax is a problem. At year 18 we meet this constraint. We then must reduce the rate to make pwf equal to 390 bara. The rate drops sharply after plateau ends
-values of required pumping power on shore were between 1-2 MW, way below 6 MW. This is not a problem.

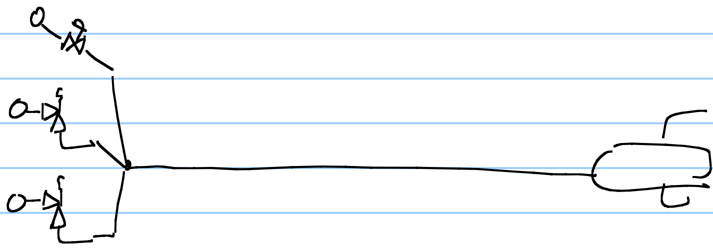
3. Results change dramatically if pshore max = 100 bara. The plateau duration is now around 6 years!!

4. Drilling more wells does not help much to prolong plateau (only a few months). The investment might be too high for the outcome.

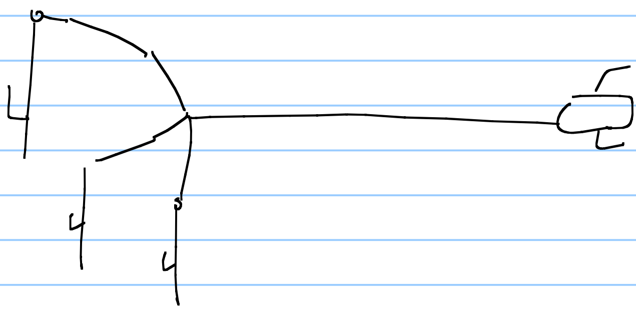


Production potential   maximum rate the production system can deliver at a given time





q_{pp} = fully open choke

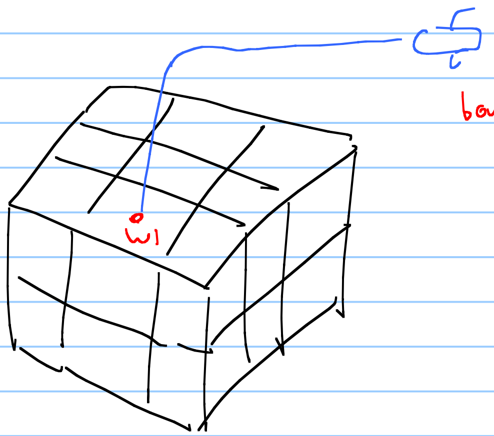


max q_o by changing $q_{g\,inj\,1}$

$q_{g\,inj\,2}$

$q_{g\,inj\,3}$

Production potential is also used in reservoir simulation

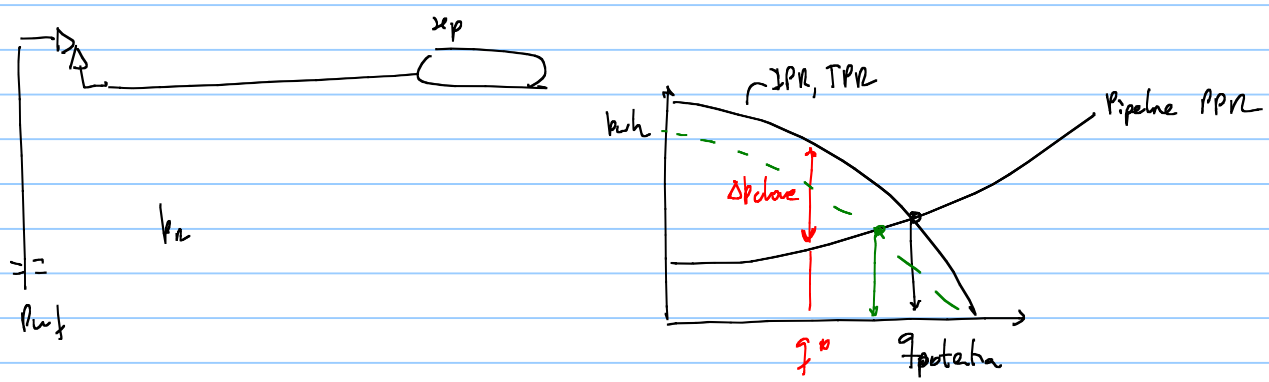


boundary conditions on well 1 → q_{target}

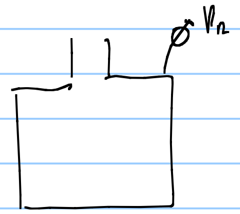
↳ $p_{wf\,min}$

in each time step

- tries $p_{wf\,min}$ → $q_{potential}$
- if $q_{potential} > q_{target}$
  - ↳ q_{target} can be produced; increase p_{wf} until $q_{well} = q_{target}$
- if $q_{pot} < q_{target}$
  - ↳ q_{target} cannot be produced; $p_{wf} = p_{wf\,min}$; $q_{well} = q_{potential}$



- Production potential is actually a function of p_R

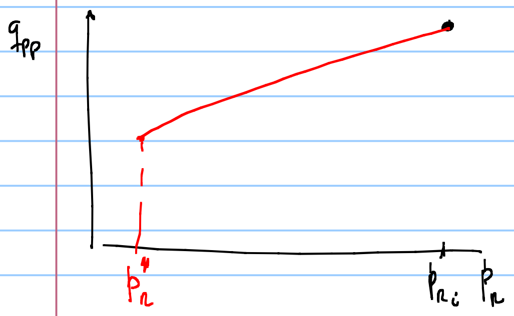


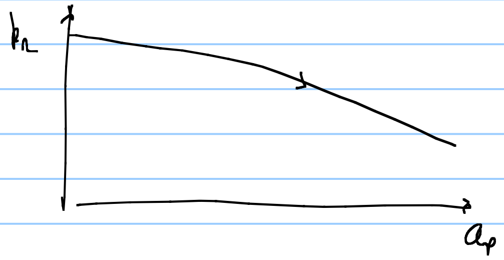
↳ and p_R is usually a function of Q_p → G_p (gas), N_p (oil)

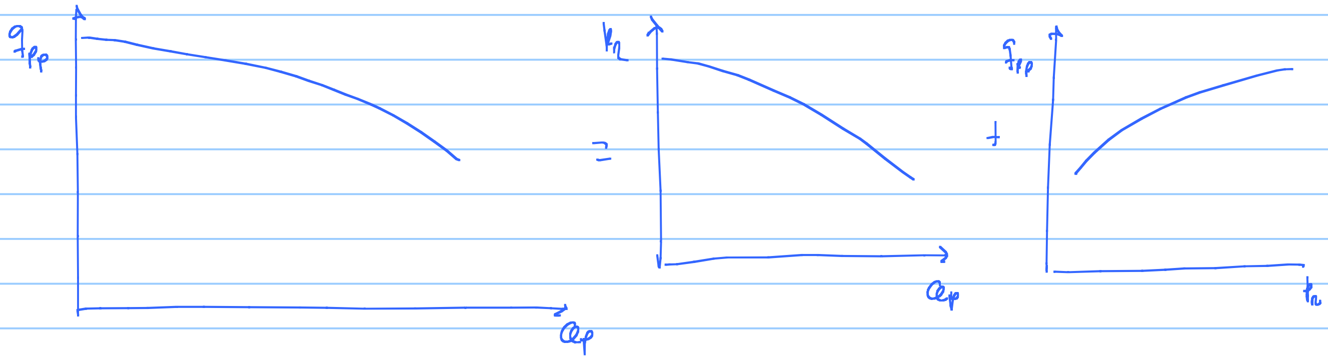
$$p_R = f(Q - Q_p)$$

$$p_R(t) = f(Q - Q_p(t))$$

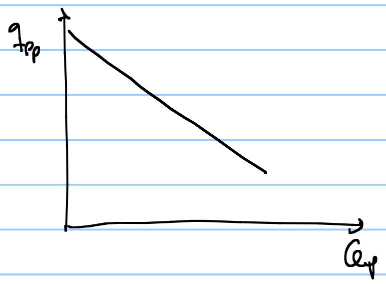
$$p_R = f(Q_p)$$



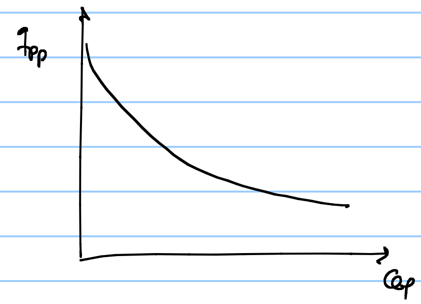




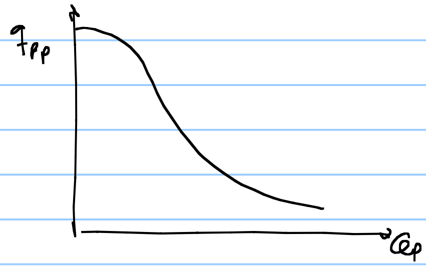
for dry gas and undersaturated oil



for saturated oil

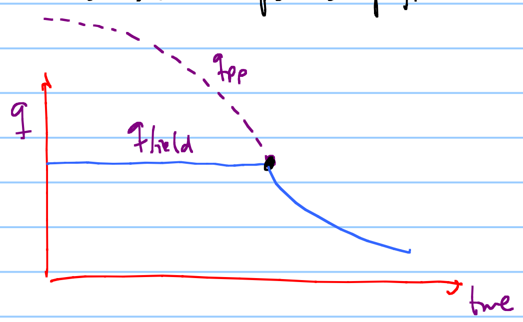


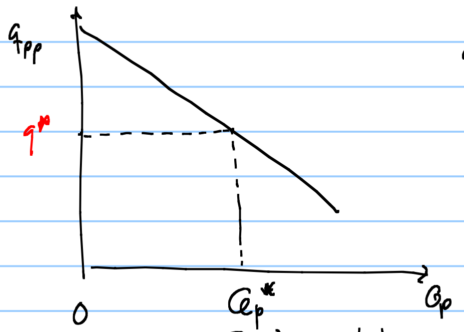
for oil water injection



Production potential curves can be used for

- determine plateau duration
- estimate production profile





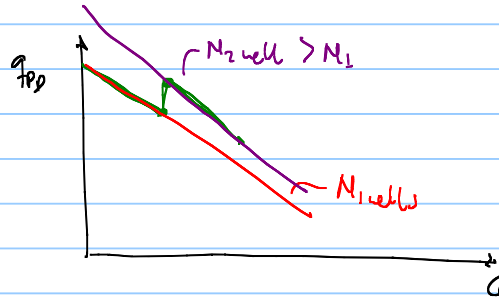
$q_{plateau} = q^*$

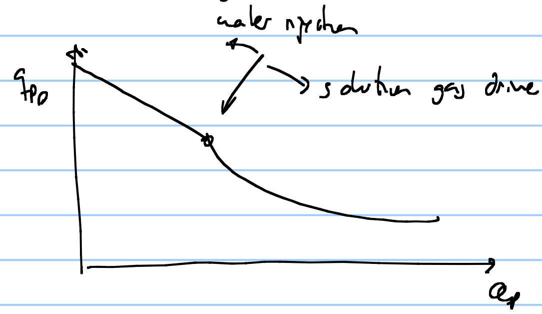
G_p^* — Cumulative production at which the end of plateau will occur

$0 \rightarrow Q_p^*$ has been produced at constant rate q^*

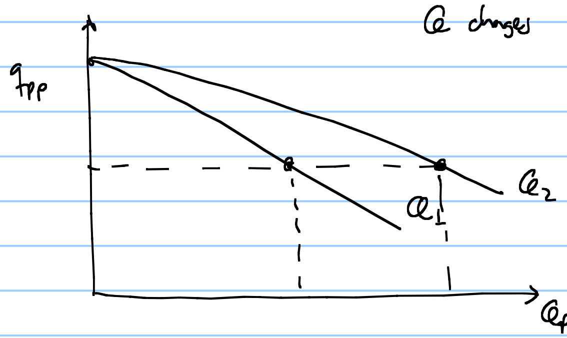
$$t_{plateau} = \frac{Q_p^* \, [Sm^3]}{q^* \, [Sm^3/d] \; t_{uptime}} \longrightarrow \frac{\text{nr. operational days}}{\text{year}}$$

Production potential curve is affected by changes to the production system





Q changes



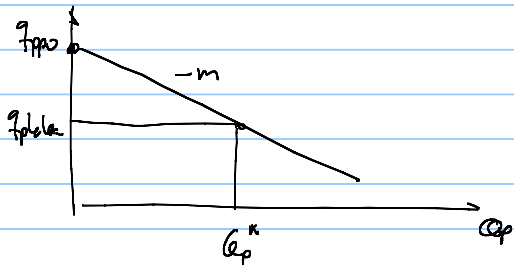
$p_R = f(R_f)$

$$R_{f_1} = \frac{Q_p}{Q_1} \qquad R_{f_2} = \frac{Q_p}{Q_2}$$

$R_{f_2} < R_{f_1}$

if curve q_{pp} is linear $q_{pp} = -m\, Q_p + q_{pp0}$

derive analytically $q_f(t)$ from q_{pp}



$$q_f(t) \begin{cases} q_{plateau} & \text{for } t \leq t_{plateau} = \left(\frac{q_{pp0}}{q_{plateau}} - 1\right)\frac{1}{m} \\ q_{field} = q_{pp} & \text{for } t > t_{plateau} \end{cases}$$

$$q_{plateau} = q_{pp} = -m\, Q_p^* + q_{pp0}$$

$$Q_p^* = \frac{q_{pp0} - q_{plateau}}{m}$$

$$t_{plateau} = \frac{Q_p^*}{q_{plateau}} = \left(\frac{q_{pp0}}{q_{plateau}} - 1\right)\frac{1}{m}$$

$$q_{pp} = -m\left(Q_p^* + \int_{t_{plateau}}^{t} q_{pp}\, dt\right) + q_{pp0}$$

$$q_{pp} = -m\,\frac{(\cancel{q_{pp0}} - q_{plateau})}{m} - m\int_{t_{plateau}}^{t} q_{pp}\, dt + \cancel{q_{pp0}}$$

$$q_{pp} = q_{plateau} - m\int_{t_{plateau}}^{t} q_{pp}\, dt \longrightarrow$$ a solution to this equation is

$$q_{pp} = q_{field} = q_{plateau} \cdot e^{-m(t - t_{plateau})}$$

$$q_f(t) \begin{cases} q_{plateau} & \text{if} \quad t \leq t_{plateau} = \left(\dfrac{q_{ppo}}{q_{plateau}} - 1 \right) \dfrac{1}{m} \\ q_{plateau}\, e^{-m(t - t_{plateau})} & \text{if} \quad t > plateau \end{cases}$$

$$= e^{\frac{1}{m}(t - t_{plateau})}$$

20230228 – Group work

<u>Group 1: Production scheduling calculations for the Snøhvit field</u>

This problem is a continuation of the Snøhvit production scheduling problem. Use the excel sheet provided.

1. Perform production scheduling calculations for the Snøhvit field for the following cases:

Case nr.	Number of wells per template	Number of templates	Field plateau rate [Sm3/d]	Initial gas in place [Sm3]
1	3	3	15 E6	270E+09
2	3	3	20 E6	270E+09
3	3	3	25 E6	270E+09
4	4	3	15 E6	270E+09
5	4	3	20 E6	270E+09
6	4	3	25 E6	270E+09
7	3	3	15 E6	350E+09
8	3	3	20 E6	350E+09
9	3	3	25 E6	350E+09

Comments:

- Perform your calculations until abandonment rate (6.7 E06)
- To calculate yearly gas production, use the trapezoidal rule.
- Find the exact time for end of plateau (using the solver)

2. Compare your results with the results of group 2.

Group 2: production scheduling calculations for the Snøhvit field using the production potential curve

This problem is a continuation of the Snøhvit production scheduling problem and using the theory covered in the production potential Youtube video. Use the excel sheet provided.

1. Perform production scheduling calculations for the Snøhvit field for the following case:

Number of wells per template	Number of templates	Field plateau rate [Sm3/d]	Initial gas in place [Sm3]
3	3	20 E6	270E+09

Guidelines:

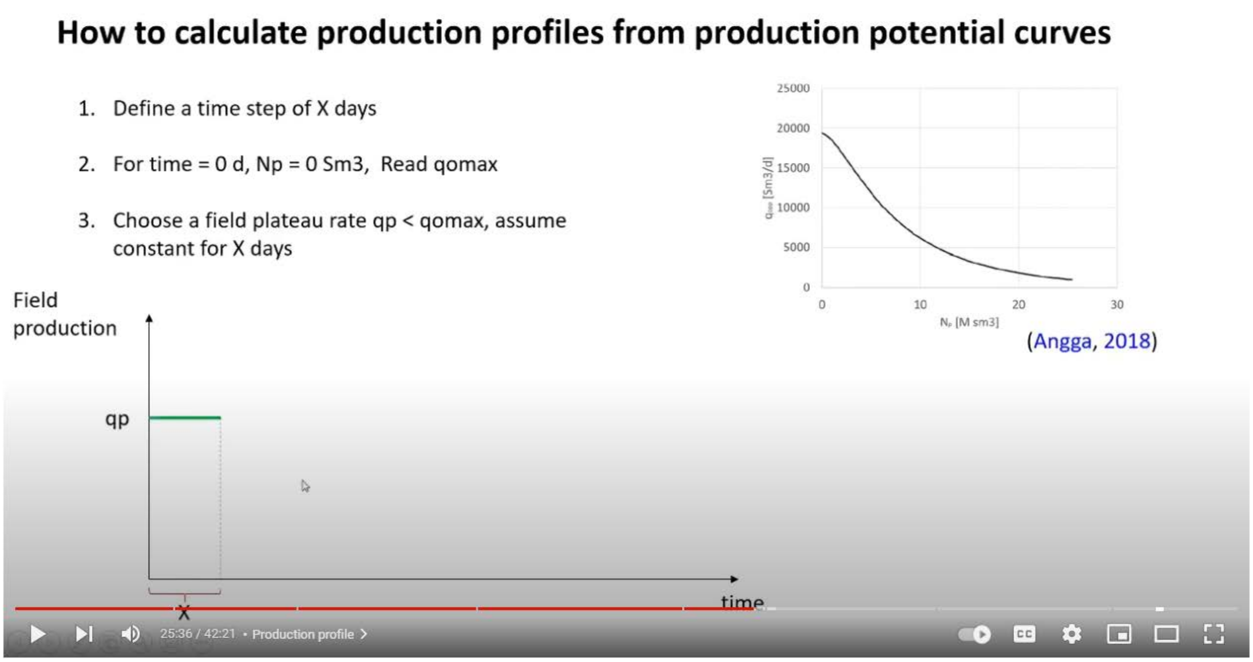
- Perform your calculations until an abandonment rate of 1 E06
- To calculate yearly gas production, use the trapezoidal rule.
- Find the exact time for end of plateau (using the solver)

2. Using the sheet created in task 1, calculate the production potential of the field (qpp) in every time. For this, you might find handy the blue button named "calculate field production potential…"
3. Copy columns qpp and Gp to another sheet (remember to paste as value). Find the "dimensionless production potential" curves by 1) diving the qpp column by qpp at Gp = 0 (gives qpp_dim) and 2) dividing the Gp column by G (gives recovery factor).
4. Using the curves of "dimensionless production potential", perform production scheduling calculations for the Snøhvit field for the following cases:

Case nr.	Number of wells per template	Number of templates	Field plateau rate [Sm3/d]	Initial gas in place [Sm3]
1	3	3	15 E6	270E+09
2	3	3	20 E6	270E+09
3	3	3	25 E6	270E+09
4	4	3	15 E6	270E+09
5	4	3	20 E6	270E+09
6	4	3	25 E6	270E+09
7	3	3	15 E6	350E+09
8	3	3	20 E6	350E+09
9	3	3	25 E6	350E+09

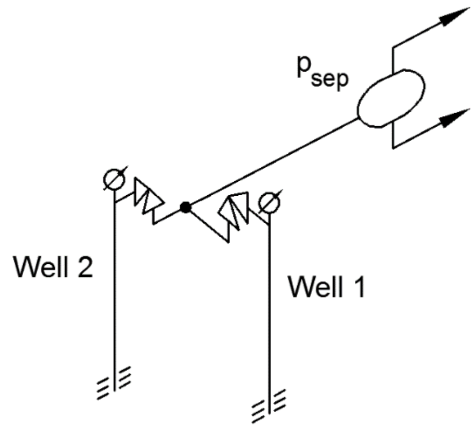
Guidelines:

- For each case, perform a flow equilibrium calculation at initial time with fully open choke to find out the value of qppo (use the number of wells specified)
- Multiply the values of dimensionless qpp (qpp_dim) by qppo, and the values of recovery factor by G.
- Use the resulting production potential curves, perform production scheduling calculations for the cases indicated above. Use the trapezoidal rule to estimate yearly cumulative production. The snapshot below shows the timestamp of the video where the procedure to calculate production profiles with production potential curves is explained. You need to use the 1D interpolation VBA function to find qpp at a given Gp.



5. Compare your results with the results of group 1.

<u>Group 3: Network solving in a CO2 injection network</u>



Using the Excel file provided, and using the learnings from the dry gas network videos, perform the following calculations

1. Sheet "no choke_field rate given": given a desired field injection rate, calculate flow rate injected per well with fully open chokes (natural flow).

Tips:

- Assume injection rate of well 1. The injection rate of well 2 can be calculated with this rate and the field injection rate.
- For each well, perform counter-current pressure drop calculations from reservoir to junction.
- Perform counter-current pressure drop calculations from junction to shore.
- Define an error function to ensure all junction pressures are equal (for example using the average of the pressure junctions)
- Use the solver to change the injection rate of well 1 until the error goes to zero.

2. Sheet "no choke_shore pressure given": given a shore pressure, calculate field injection rate and flow rate injected per well with fully open chokes (natural flow).

Tips:

- Assume injection rate of wells 1 and 2. The injection rate of the field can be calculating by adding these two.
- For each well, perform counter-current pressure drop calculations from reservoir to junction.
- Perform co-current calculations pressure drop calculations from shore to junction.
- Define an error function to ensure all junction pressures are equal (for example using the average of the pressure junctions)
- Use the solver to change the injection rate of wells 1 and 2 until the error goes to zero.

Discuss: should the results of cases 1 and 2 be identical?

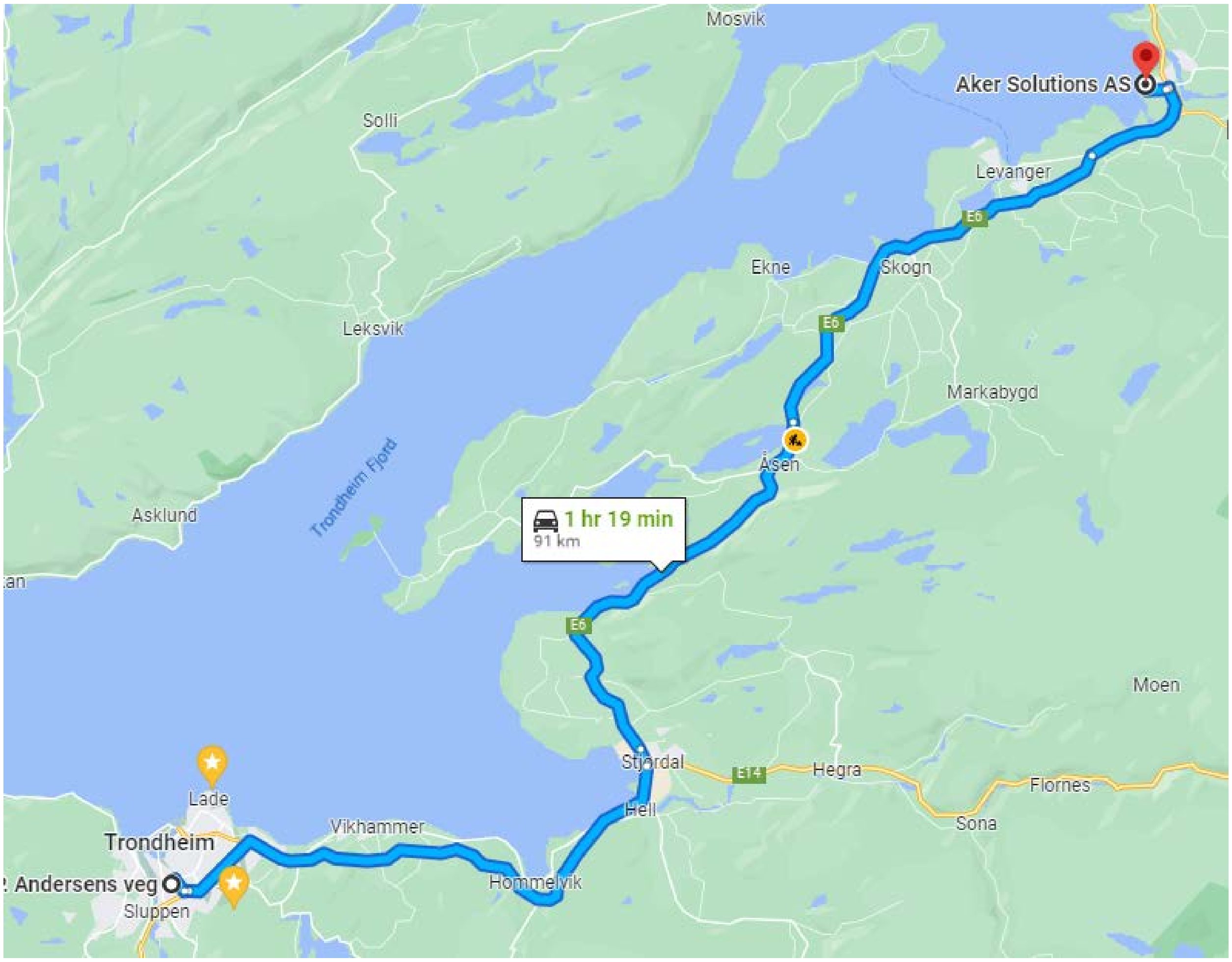
3. Sheet "choke_field well rate psh given": calculate choke pressure drop in each well to produce the well rates indicates and with the shore pressure provided.

Tips:

- For each well, perform counter-current pressure drop calculations from reservoir to wellhead.
- For the pipeline and for each well, perform co-current pressure drop calculations from shore to choke downstream.
- Calculate choke dp

Discuss: at which value of shore pressure will it become unfeasible to inject the desired rates?

20230303 – Visit to Aker Solutions Construction yard in Verdal



https://www.facebook.com/akersolutionsverdal/

How to deal and quantify uncertainty in field development

for example in our Snøhvit case

↳ G, N , $q_{\bar{g}} = C_R (P_R^2 - P_{wf}^2)^n$

\$

uptime 90 – 100%

$\left(\frac{\text{nr day producing in year}}{365} \right)$

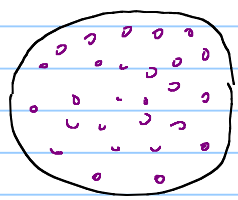
↳ cause additional OPEX

↳ cut in production → cut in Revenue

input variables used in engineering studies in FD are highly uncertain

$\Phi_{min} \leq \Phi \leq \Phi_{max}$ and affect the value of KPIs that are used to discriminate and select development alternatives.

Φ



number sample	Φ
–	–
–	–
–	–
–	–
–	–

→ discrete frequency analysis

create bins min Φ_1 (0.15)

0.175

Φ_2 (0.20)

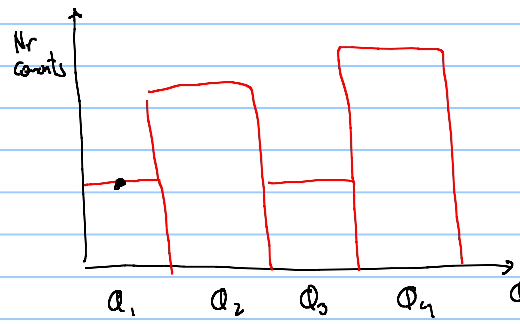
Φ_3 (0.25)

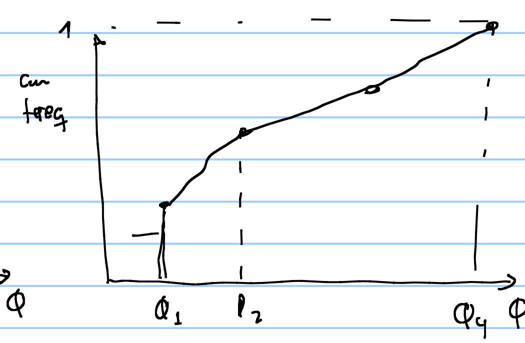
max Φ_4 (0.30)

if $\Phi_i = 0.18$

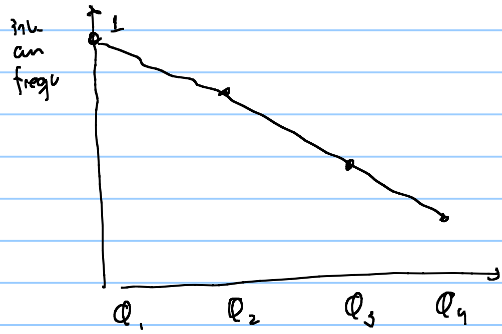
$\Phi_1 \leq \Phi_i \leq \Phi_2$

if $\Phi_i < \frac{(\Phi_2 - \Phi_1)}{2} + \Phi_1$ → counted as part of Φ_1

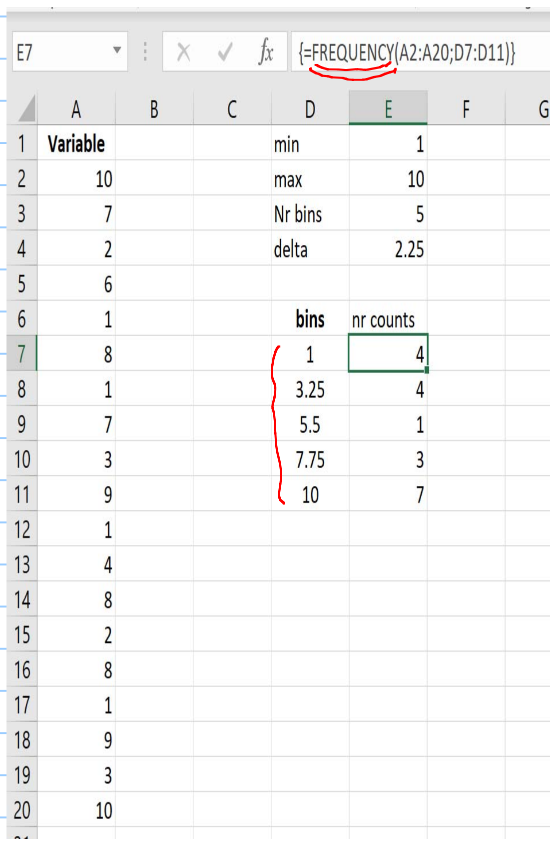




bin	Nr counts	rel. frequency	cum frequency	inv. cum frequency
Q_1	x	x/N	x/N	$(x+w+z+y)/N \rightarrow 1$
Q_2	y	y/N	$y/N + x/N$	$(w+z+y)/N$
Q_3	z	z/N	$y/N + x/N + z/N$	$(w+z)/N$
Q_4	w	w/N	$\frac{x+y+z+w}{N}$	w/N
	N			



how to do frequency analysis in excel:



E7 {=FREQUENCY(A2:A20;D7:D11)}

	A	B	C	D	E
1	Variable			min	1
2	10			max	10
3	7			Nr bins	5
4	2			delta	2.25
5	6				
6	1			bins	nr counts
7	8			1	4
8	1			3.25	4
9	7			5.5	1
10	3			7.75	3
11	9			10	7
12	1				
13	4				
14	8				
15	2				
16	8				
17	1				
18	9				
19	3				
20	10				

to create bins:

find max
find min
define Nr bins
calculate $\text{delta} = \frac{(\text{max} - \text{min})}{(\text{Nr bins} - 1)}$

compute each bin

$\text{bin}^i = \text{bin}^{i-1} + \text{delta}$

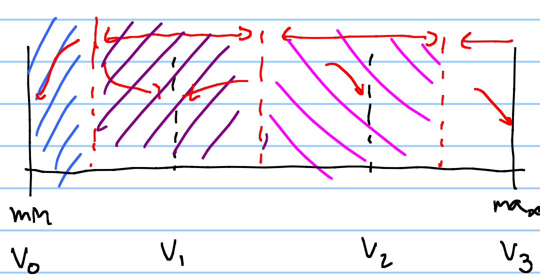
starting from $\text{bin}^0 = \text{min}$

to apply frequency function:

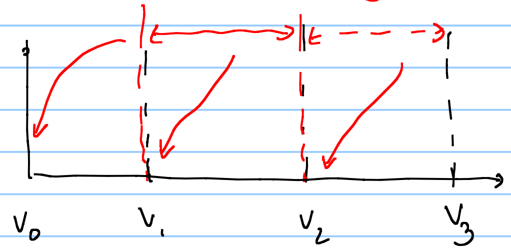
ctrl + shift + enter (in sequence and leave it pressed)

selecting bins must take into account

- nr data points



be careful how the frequency is accounted for



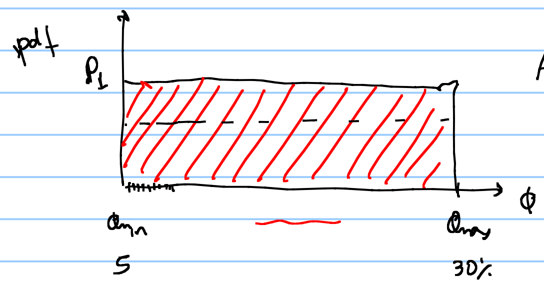
what happens if there are no measurements?

frequency ⤳ probability

rel frequency ⤳ pdf probability density function

cum frequency plot ⤳ cdf cumulative distribution function

poor boy, no data pdf ϕ continuous probability



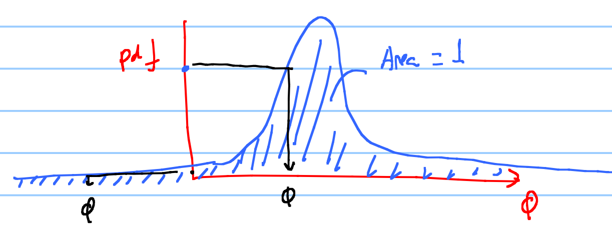
$$Area = (\phi_{max} - \phi_{min}) \cdot P_1 = 1$$

$$P_1 = \frac{1}{(\phi_{max} - \phi_{min})}$$

Continuous distributions are advantageous because:
-There is an analytical expression
-I need only few values to define the distribution
-There is no data to determine a discrete distribution

Warning: many continuous distributions go from $-\infty \to +\infty$

There are many parameters in FD that exhibit typical distributions:
-cost ---Normal
-Porosity --- Normal
-Initial oil/gas in place --- Log Normal



non-physical

so bounding is necessary

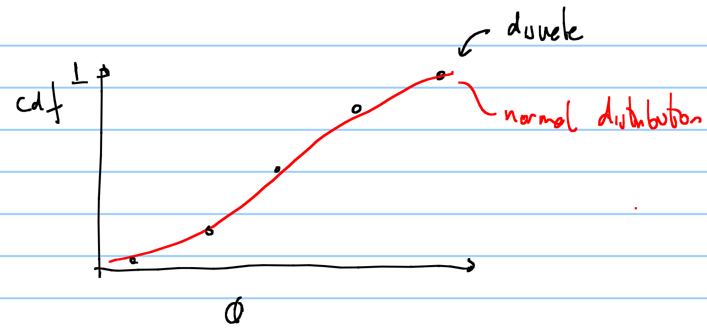
discrete distribution ⟶ continuous distribution

- calculate directly using population data

ϕ
ϕ_1
ϕ_2
⋮

μ → parameters of a normal distribution
σ

- tune parameters in the continuous distribution to represent the discrete distribution

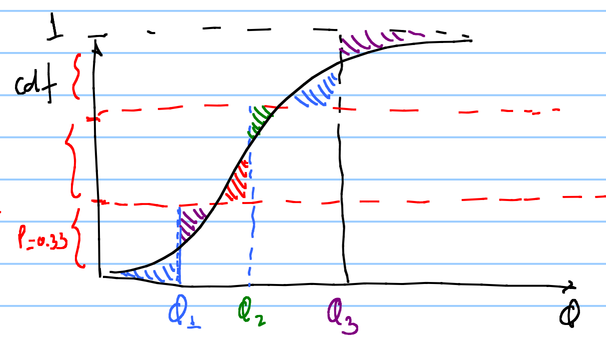


$$\frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}$$

change μ, σ until diff discrete and continuous is minimal

continuous distribution → discrete distribution

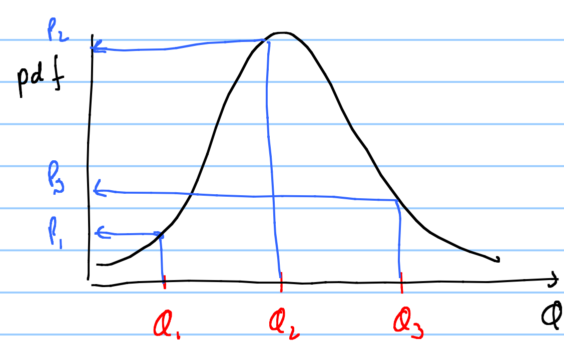
- Bracket mean
  - define nr. bins
  - define probability of bins



Φ	P
Q_1	0.33
Q_2	0.33
Q_3	0.33

find Q_1, such that [hatched area] = [hatched area]

- value discretization
- pick nr. bins in Q
- read probabilities from pdf



Φ	P
Q_1	P_1^*
Q_2	P_2^*
Q_3	P_3^*

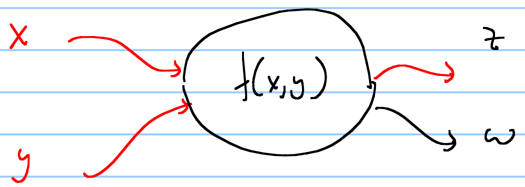
- Normalize probabilities using the sum

$$P_1^* = \frac{P_1}{P_1 + P_2 + P_3}$$

$$P_2^* = \frac{P_2}{P_1 + P_2 + P_3}$$

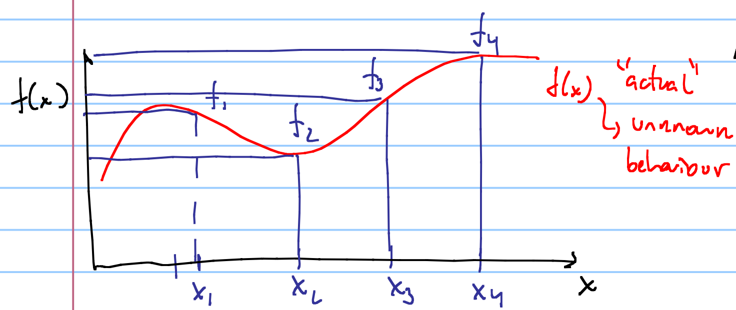
Notes to Youtube video 13

How to handle uncertain parameters in our FD calculations



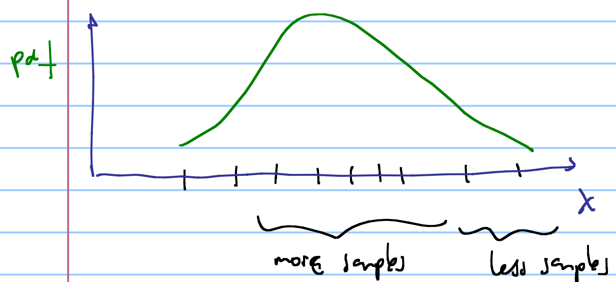
deterministic calculation: x and y have a unique known value

stochastic/probabilistic calculation: x and y exhibit a probabilistic distribution



Approach to deal with uncertainty:

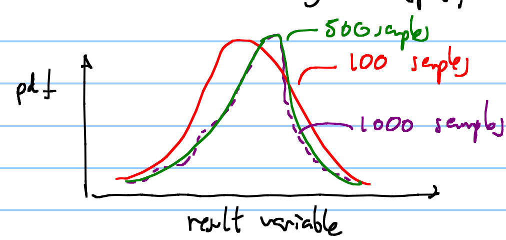
- create samples
- evaluate the function at samples
- calculate pdf and cdf of the results



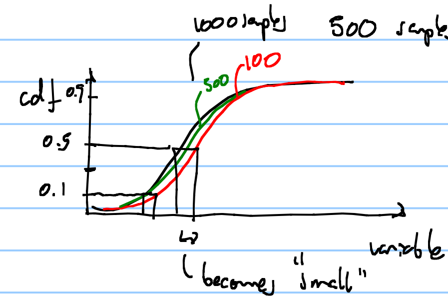
1: How many samples are needed?

2: How to generate the samples?

1: Increase the number of samples and see how the results change (pdf, cdf)



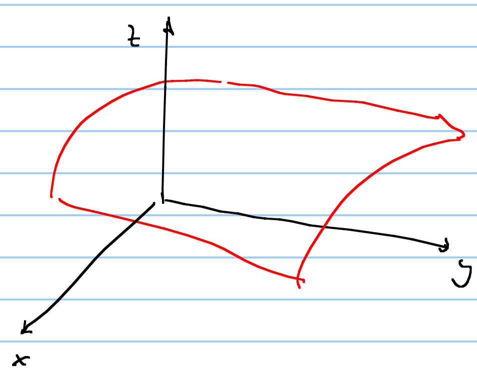
for this case, it seems 500 samples is enough

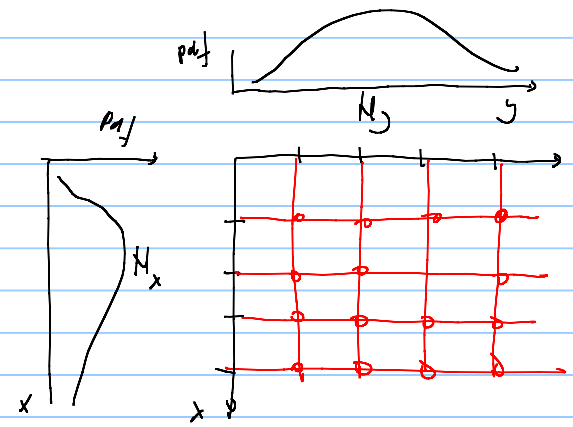


2: how to generate the samples

- Monte Carlo method
- Latin hypercube sampling

efficient sampling → less number of samples to achieve convergence brute-force sampling

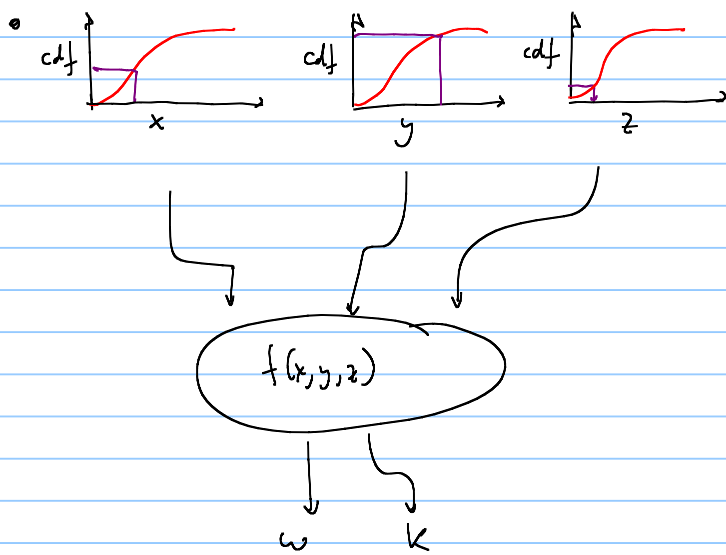




$N_{total} = N_x \cdot N_y$

It is impractical for large number of variables/samples

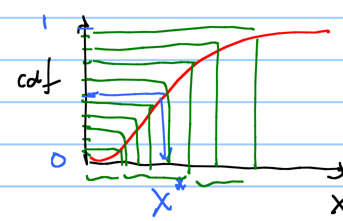
•



① For each variable

1.1 pick a random number between 0 - 1

1.2 enter cdf and read the value of the variable



② perform a simulation with the samples

③ repeat "many" times steps 1-2

④ perform a frequency analysis on the results → pdf cdf

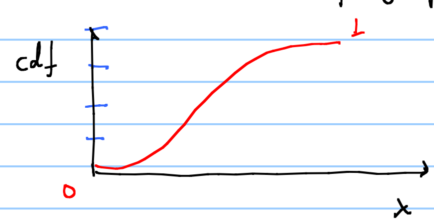
• Latin hypercube sampling (LHS)

① Define a number of samples "N"

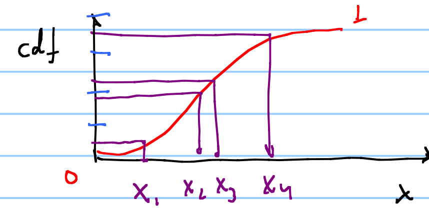
① For each variable

1.1. subdivide the cumulative probability in "N" intervals (equally-spaced)

N=4



1.2. Pick a random number in the interval find the corresponding value of the variable



$$\begin{Bmatrix} x_1 \\ x_2 \\ x_3 \\ x_4 \end{Bmatrix} \quad \begin{Bmatrix} y_1 \\ y_2 \\ y_3 \\ y_4 \end{Bmatrix} \quad \begin{Bmatrix} z_1 \\ z_2 \\ z_3 \\ z_4 \end{Bmatrix}$$

1.3. shuffle randomly the sample vector(s)

sim 1	x_3	y_1	z_3
sim 2	x_1	y_3	z_2
sim 3	x_4	y_4	z_1
sim 4	x_2	y_2	z_4

2) perform simulations for samples variables that are in the same row

3) perform a frequency analysis on the results
↳ cdf, pdf

Notes to Youtube video 14

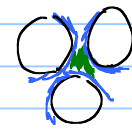
Reserve estimation : case undersaturated oil reservoir

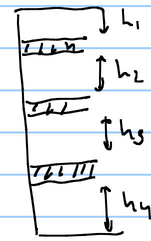
$$TRR = N_{pu} = \frac{V_R \cdot \phi \cdot N_{TG} \cdot S_o \cdot F_{RO}}{B_o}$$

TRR: total recoverable reserves

N_{pu}: ultimate cumulative production

F_{RO}: recovery factor





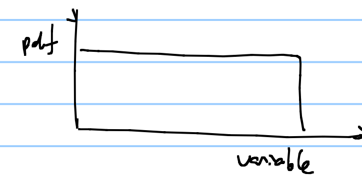
$$N_{TG} = \frac{h_1 + h_2 + h_3 + h_4}{h_{total}}$$

V_R ϕ N_{Tg} S_o F_{RO} B_o

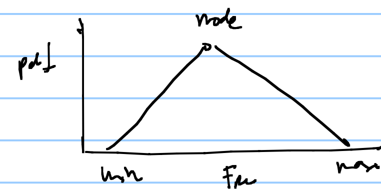
$$N_{pu} = \frac{V_R \cdot \phi \cdot N_{Tg} \cdot S_o \cdot F_{RO}}{B_o}$$

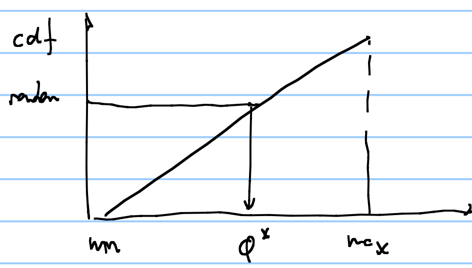
N_{pu}

$V_R, \phi, N_{Tg}, S_o, B_o$ have a uniform pdf



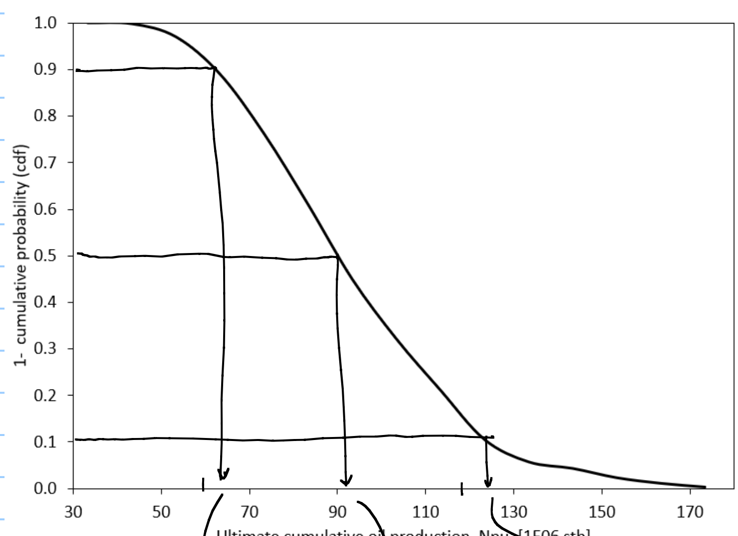
F_{RO}





expectation curve

- Conservative estimate (90%) P90
- Average estimate (50%) P50
- optimistic estimate (10%) P10



65 E06 stb

~90 E06 stb

~125 E06 stb

20230307

Useful links:

- General information about python: https://en.wikipedia.org/wiki/Python_(programming_language)
- Creator of python: https://en.wikipedia.org/wiki/Guido_van_Rossum
- Origin of the name: https://en.wikipedia.org/wiki/Monty_Python
- To install python, Jupyter Notebook, libraries, etc. on your computer: https://www.anaconda.com/
- Online jupyter notebook by Google (no need to install): https://colab.research.google.com/
- Desktop editors for python: https://www.jetbrains.com/pycharm/ , https://code.visualstudio.com/ , spyder (included in Anaconda) https://www.spyder-ide.org/
- Information about code version control and backup: https://www.w3schools.com/git/git_intro.asp?remote=github , https://github.com/
- Course that Milan took on python: https://www.coursera.org/specializations/python#courses , https://www.dr-chuck.com/ , https://www.py4e.com/lessons
- numpy documentation: https://numpy.org/doc/stable/index.html

```
Probalistic_estimation_of_reserves_MCS

#importing needed libraries
import numpy as np #for math operations
import matplotlib.pyplot as plt #library for plotting
import pandas as pd #for creating and displaying a table

#declaring necessary functions
def Npu(por,RV,NTG,So,Bo,Fr):
  #returns ultimate cumulative oil production in [stb, Sm3]
  #input:
  #por, porosity in [-]
  #RV, rock volume, in [bbl, m3]
  #NTG, net to gross ratio, [-]
  #So, oil saturation, [-]
  #Bo, oil formation volume factor [bbl/stb, m3/Sm3]
  #Fr, ultimate recovery factor in [-]
  TRR=por*RV*NTG*So*Fr/Bo
  return TRR

#defining input
#porosity
por_min=0.18
por_max=0.3
#rock volume [1E06 bbl]
RV_min=5000
RV_max=6250
#Net to gross [-]
NTG_min=0.3
NTG_max=0.5
#oil saturation [-]
So_min=0.8
So_max=0.9
#Oil formation volume factor [bbl/stb]
Bo_min=1.35
Bo_max=1.6
#recovery factor, Fr, [-]
Fr_min=0.18
Fr_max=0.35
Fr_mode=0.25


#creating random samples
n=1000  #number of samples
por_v=np.random.uniform(por_min,por_max,n)
```

```python
RV_v=np.random.uniform(RV_min,RV_max,n)
NTG_v=np.random.uniform(NTG_min,NTG_max,n)
So_v=np.random.uniform(So_min,So_max,n)
Bo_v=np.random.uniform(Bo_min,Bo_max,n)
Fr_v=np.random.triangular(Fr_min,Fr_mode,Fr_max,n)

#MC simulation
Npu_v=Npu(por_v,RV_v,NTG_v,So_v,Bo_v,Fr_v)


#frequency analysis on the results
nr_bins=15
bins=np.linspace(Npu_v.min(),Npu_v.max(),nr_bins)
counts=np.histogram(Npu_v,bins)[0]
pdf=counts/n
bins_for_pdf_plotting=0.5*(bins[0:-1]+bins[1:])
#plot pdf
plt.xlabel('ultimate cumulative oil production, Npu, [1E06 stb]')
plt.ylabel('frequency')
plt.plot(bins_for_pdf_plotting,pdf,label='pdf')
plt.legend()
plt.show()


#plot cdf
cdf=np.cumsum(pdf)
bins_for_cdf_plotting=bins[1:]
plt.xlabel('ultimate cumulative oil production, Npu, [1E06 stb]')
plt.ylabel('cumulative probability distribution, cdf')
plt.plot(bins_for_cdf_plotting,cdf,label='cdf')
plt.legend()
plt.show()


#create a summary table

Npu_mode= bins_for_pdf_plotting[np.argmax(pdf)]

P90= np.percentile(Npu_v,10)

P10= np.percentile(Npu_v,90)

P50= np.percentile(Npu_v,50)

Npu_max= Npu_v.max()

Npu_min= Npu_v.min()

Npu_mean= Npu_v.mean()
```

```
summary_table=pd.DataFrame({
    "Variable":['Mean [1E06 stb]','Mode [1E06 stb]','Minimum [1E06 stb]','
Maximum [1E06 stb]','P90 [1E06 stb]','P50 [1E06 stb','P10 [1E06 stb]'],
    "Value":[Npu_mean,Npu_mode, Npu_min,Npu_max,P90,P50,P10]
})
summary_table

#exporting results
output=np.vstack((pdf_bins,pdf))
np.savetxt('data.txt',output.T)


#how to make a function run element-wise for all members of an array
def test_function(a):
  if a>0:
    result=0
  else:
    result=1
  return result
a=np.linspace(-6,6,10)
V_test_function=np.vectorize(test_function)
V_test_function(a)
```

20230309 Outline

-Probability/decision trees

Decision/Probability Trees:

- Is a visual tool often used for decision support. It consists of a tree-like model of decisions/events and their possible consequences, including chance event outcomes, resource costs, and utility.

It is often used instead of Monte Carlo simulation usually when there are discrete variables, that are challenging to express mathematically with a probability distribution (e.g. choices of offshore structure, choices regarding appraisal, etc).

A decision tree consists of three types of nodes:

Decision nodes – typically represented by squares
Chance nodes – typically represented by circles
End nodes – typically represented by triangle

- To calculate probability outcomes, multiply the probability values of the connected branches.
- To calculate the probability of multiple outcomes, add the probabilities together. The probability of all possible outcomes should always equal one. If you get any other value, go back and check for mistakes.

Sources:
https://www.mashupmath.com/blog/probability-tree-diagrams
https://en.wikipedia.org/wiki/Decision_tree.

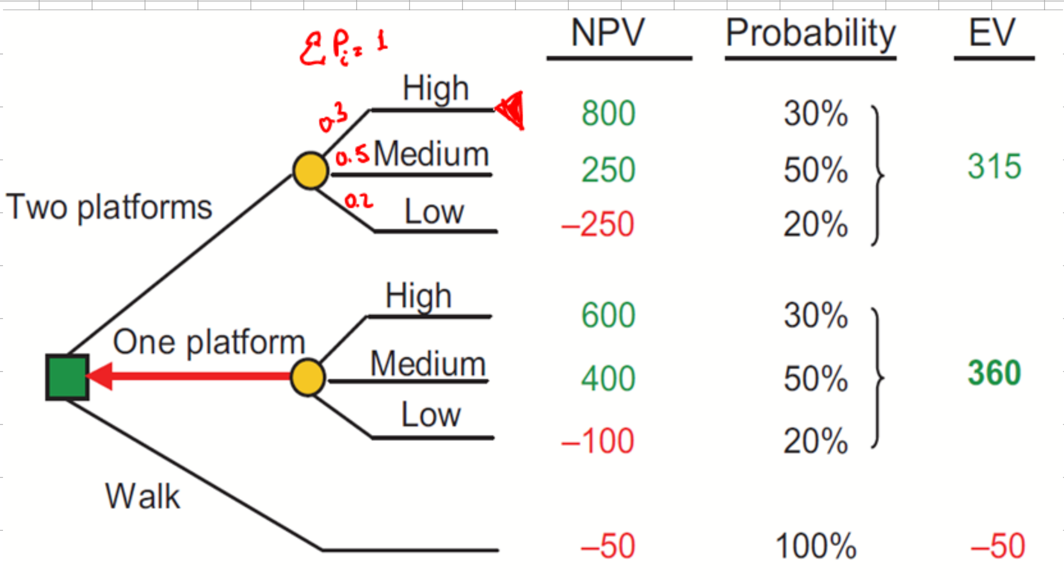
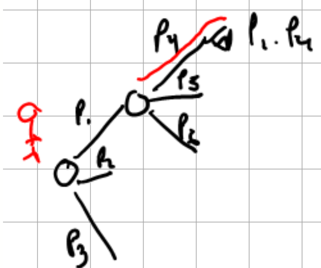
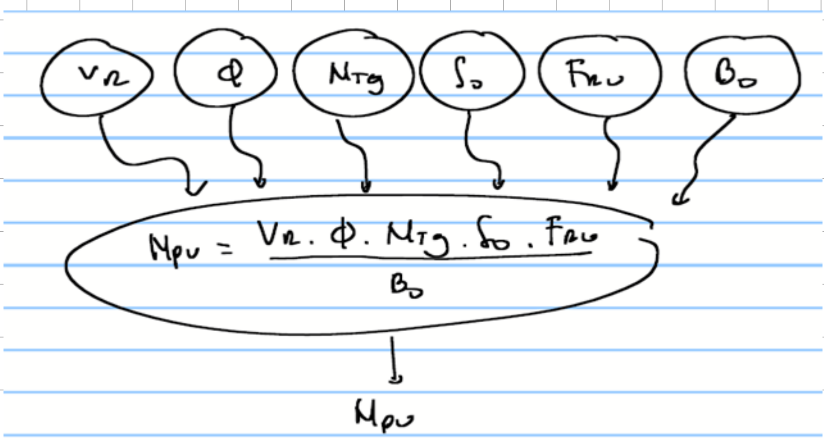
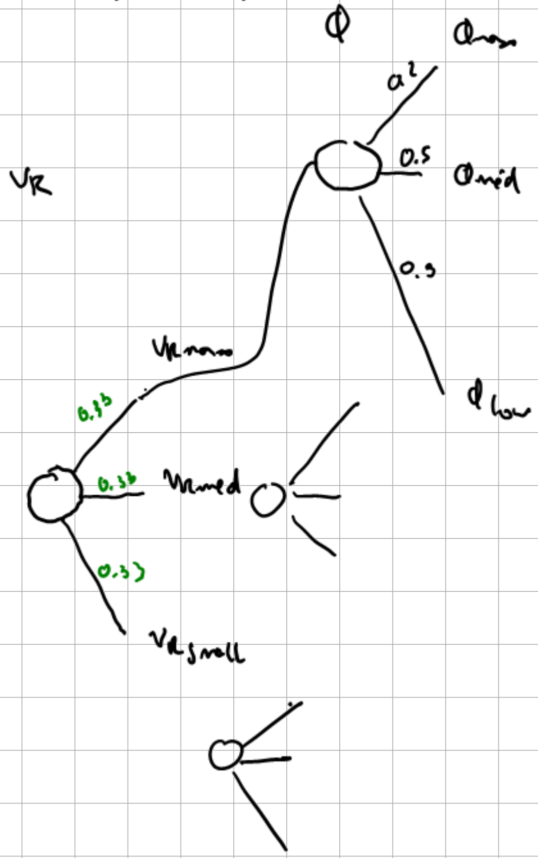


Fig. 5.11—Decision tree with probabilities and payoffs (in USD millions).



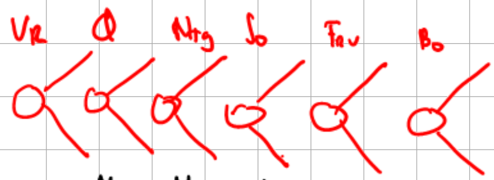
Can we solve the reserve estimation problem with a probability tree? if yes, how to obtain a pdf of Npu with it?





VRmax Qmax Ntgmax Somax Fevmax Bomax → Npv

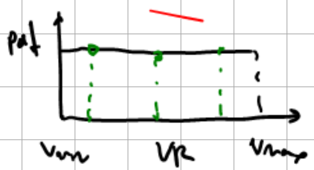
VRmax Qmax Ntgmax Somax Fevmax Bomid

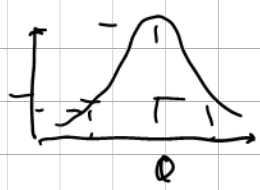


$N_{cases} = N_{VR} \times N_Q \times N_{NTG} \times N_{So} \cdot N_{Fev} \times N_{Bo}$

if N is same for all variables

$N_{cases} = N^{\text{nr variables}}$





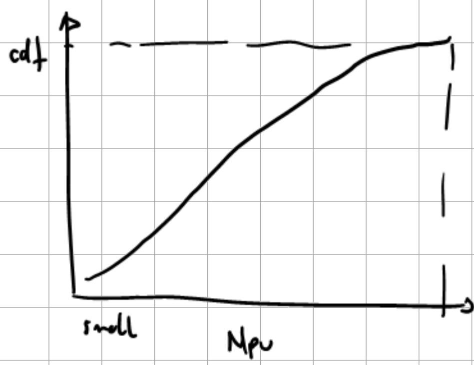
case nr	Npv	P
1	□.	
⋮	□	
	□	
	□	
	□	
Nr cases		

?. cdf

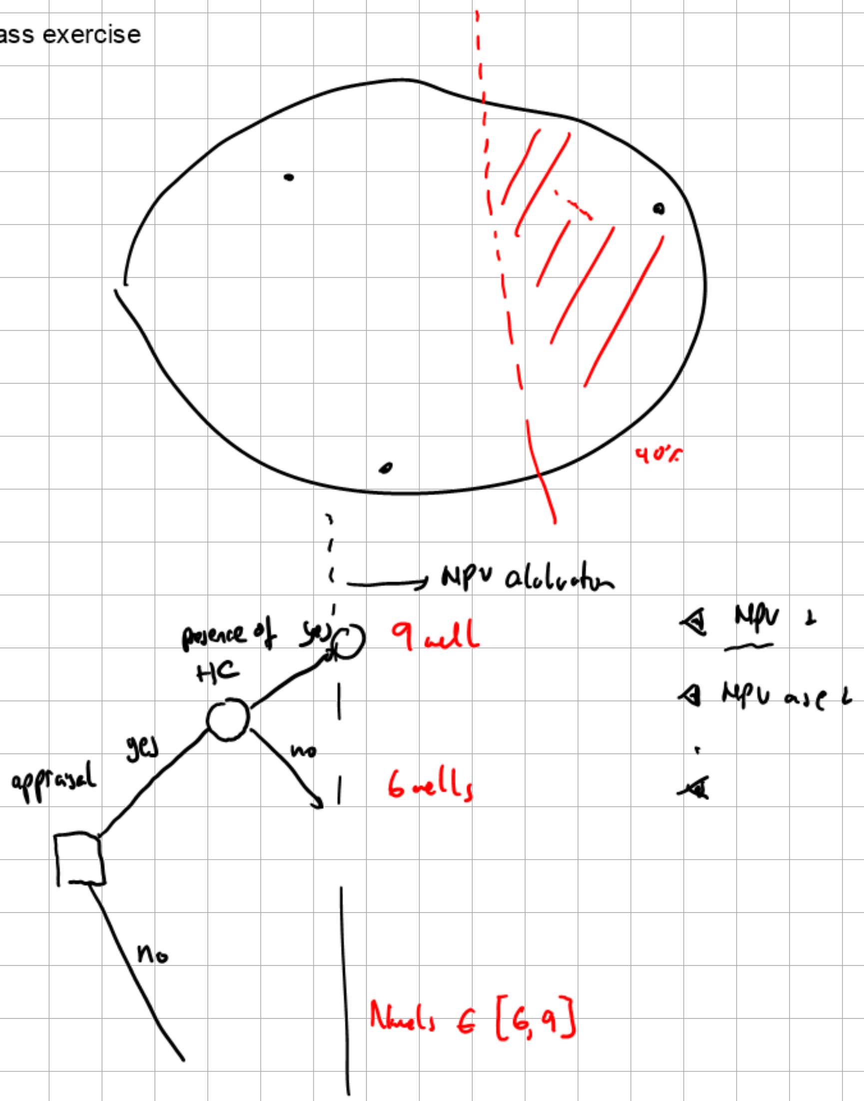
1. sort by Npv size

2. calculate cum probability

	Npv	P	cdf
small	□	1%	□
		□	□+□
↓			
big			1



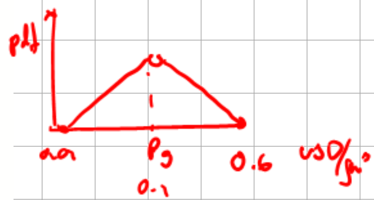
Class exercise

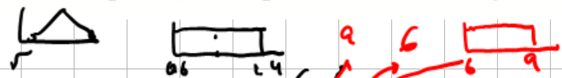


$$NPV = 0.3 \cdot P_g \cdot G_{pu} - DRILLEX - CAPEX$$

Where:

- P_g is the price per Sm3 of gas [USD/Sm3]. Assume it exhibits a triangular probability distribution with min = 0.01 USD/Sm3, max = 0.6 USD/Sm3 and mode = 0.1 USD/Sm3
- $CAPEX$ represents cost of subsea, onshore facilities and pipeline [in million USD]. It will be assumed that it is equal to 3000 E06 USD.
- $DRILLEX$ represents costs of wells. If N_w wells are needed, then $DRILLEX = 100\ E06\ USD \cdot N_w$. For the base case, 9 producer wells are needed. However, if the appraisal well is dry, then only 6 wells will be needed.
- There is usually high uncertainty associated to CAPEX and DRILLEX (usually ±40% during the business identification phase). To capture this uncertainty, it is





$$NPV = 0.3\ P_g\ G_{pu} - F\ (N_w \cdot 100E06 - 3000E06)$$

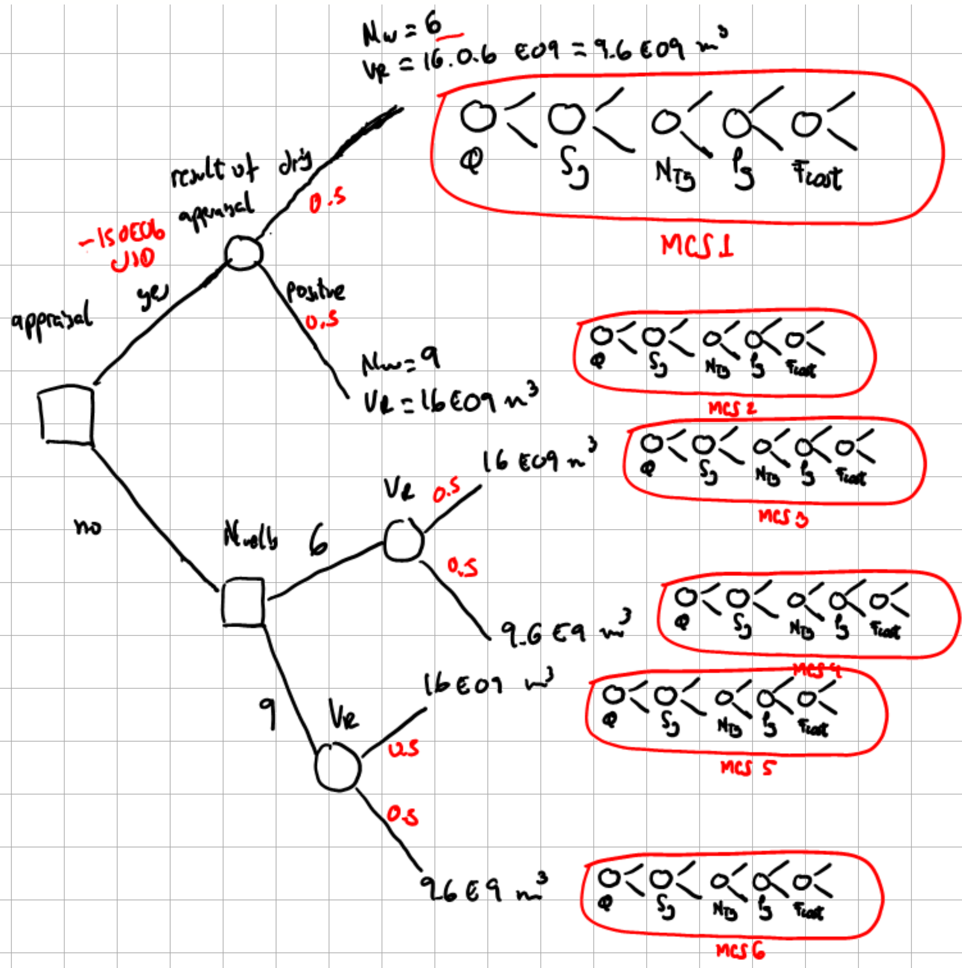
The ultimate cumulative gas production is $G_{pu} = G \cdot F_R$, where:

- F_R is the ultimate recovery factor [-]. Assume this value can vary uniformly between 0.8-0.9.
- G is the initial gas in place [Sm³], estimated by the expression:

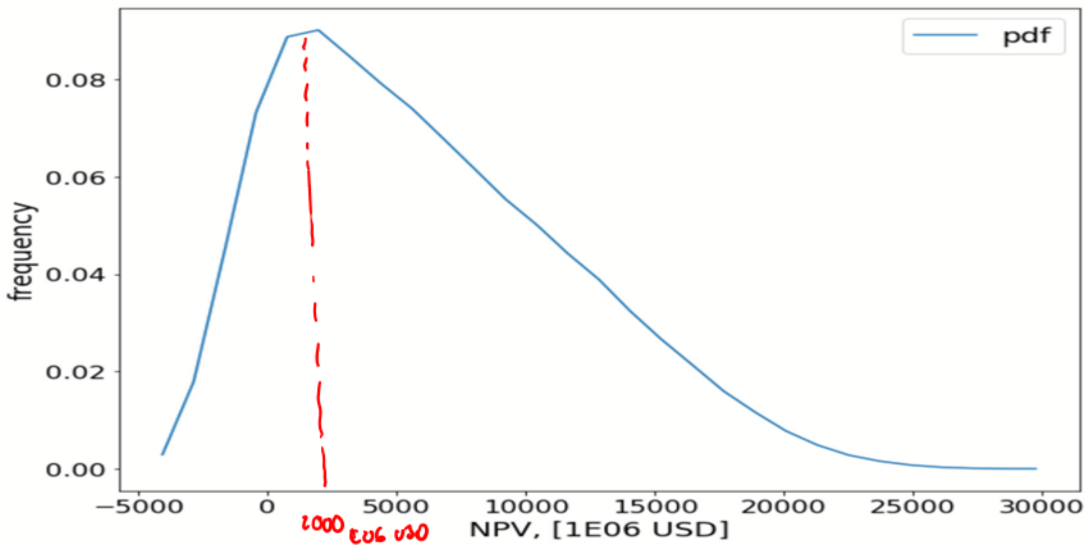
$$G = \frac{\dot{V}_R \cdot \phi \cdot S_g \cdot N_{tg}}{B_g}$$

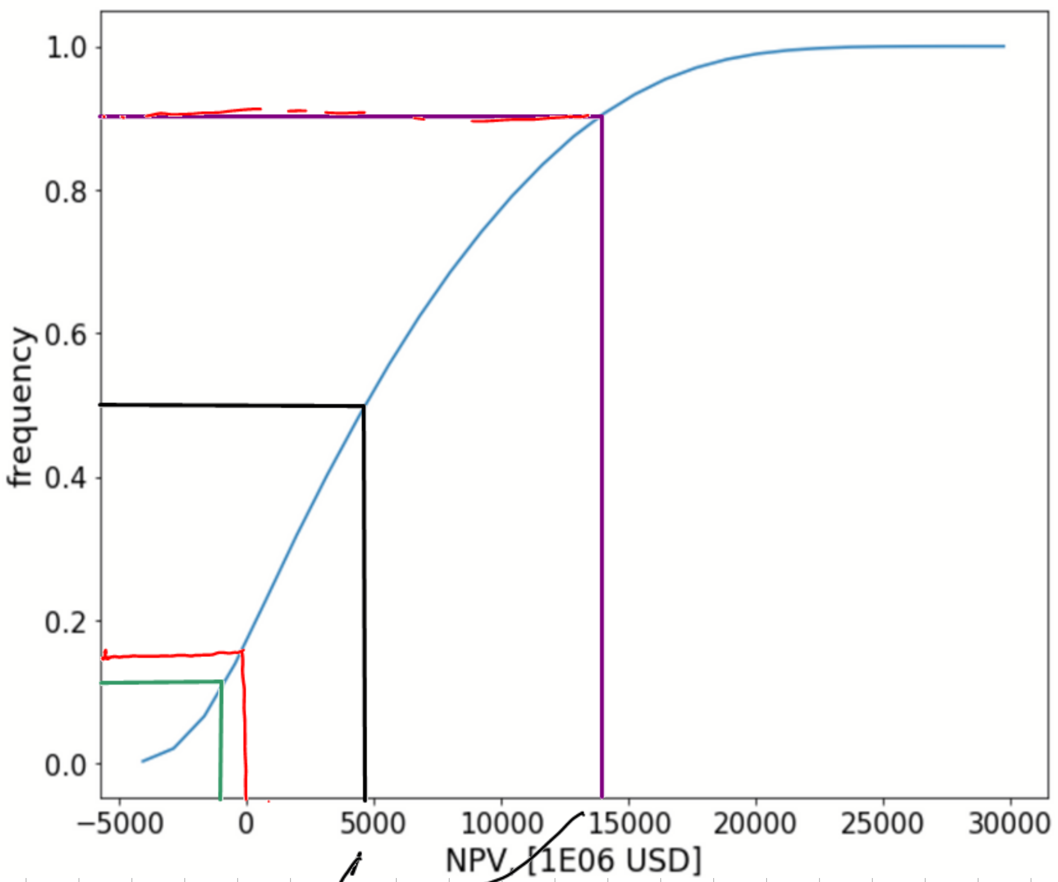
Where:

- V_R Rock volume [Sm3], 16 E09 Sm3 $\rightarrow 16 \rightarrow 16 \cdot 0.6$
- ϕ porosity [-], uniformly distributed between 0.23-0.29
- S_g gas saturation [-], uniformly distributed between 0.8-0.9
- N_{tg} Net to gross [-], uniformly distributed between 0.3-0.4
- B_g gas formation volume factor [m3/Sm3], having a value equal to 4.5 E-3



MCS 1:



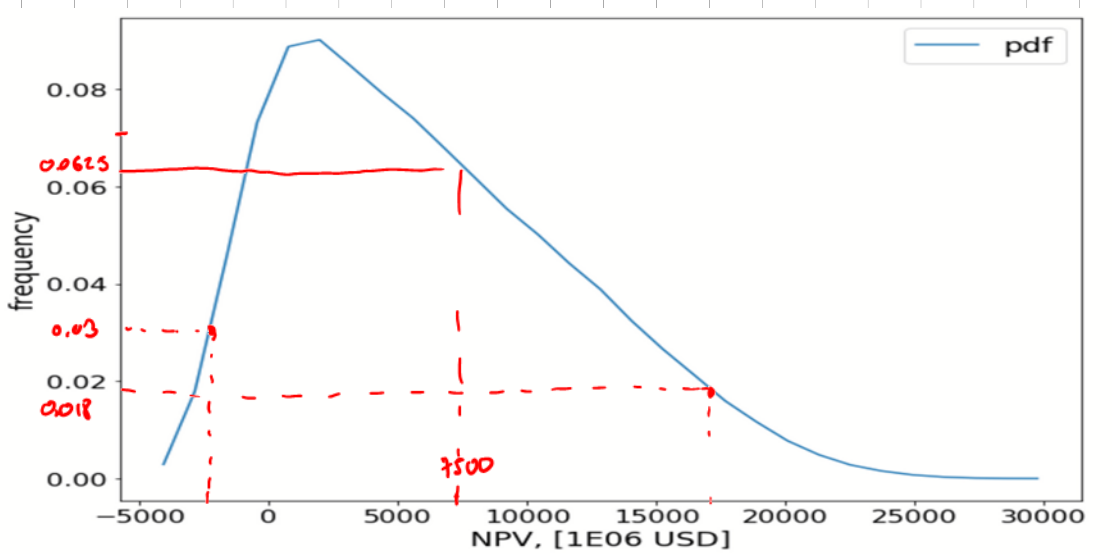


P10 = 14E09 USD

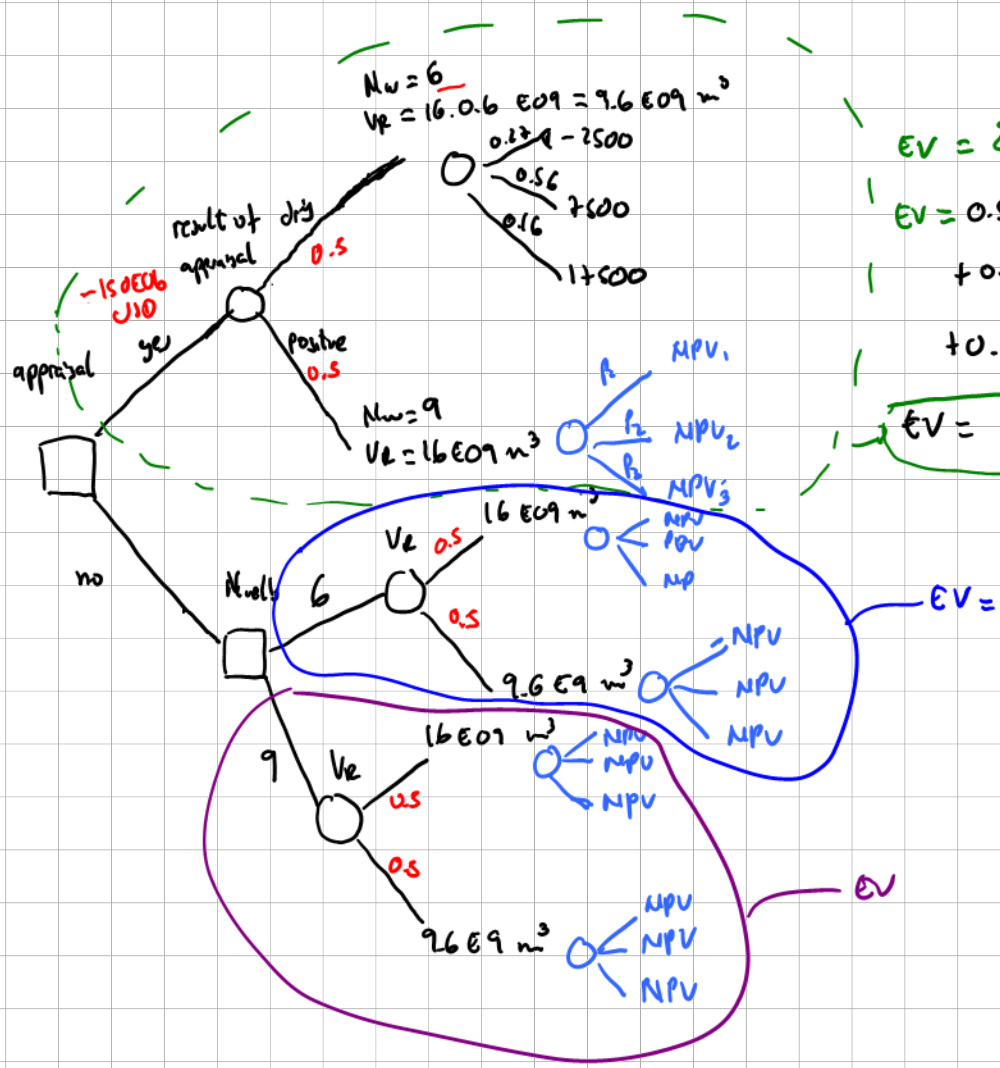
P50 = 5E09 USD

P90 = -1E09 USD

discretizing this distribution:



NPV [E06]	P
-2500	$0.03/(0.03+0.018+0.0625) \cong 0.27$
7500	$0.0625/(0.03+0.018+0.0625) = 0.56$
17500	$0.018/(0.03+0.018+0.0625) = 0.16$



$$EV = \sum P_i \, NPV_i$$

$$EV = 0.5 \cdot 0.27 \cdot (-2500) + 0.5 \cdot 0.56 \cdot 7500 + 0.5 \cdot 0.16 (17500) + 0.5 \cdot P_1 \, NPV_1 + 0.5 \, P_2 \, NPV_2 + 0.5 \cdot P_3 \, NPV_3$$

$$\boxed{EV = \quad \times \quad [1E06] \text{ USD}}$$

The offshore Alta-Gohta field consists of two separate reservoirs (Alta and Gohta). Each reservoir will be produced independently via a separate pipeline to a common FPSO. The field (and reservoirs) will be produced in plateau mode. The oil production potential of each reservoir can be estimated with following expression: qpp = Nw * qppow * (1 - 2.5 * (Np/N)). Nw is the number of producers in the reservoir, qppow is the maximum rate of oil produced by one well at initial time, Np is cumulative oil production from the reservoir and N is initial oil in place in the reservoir. This expression assumes all wells in a reservoir are identical. Data is provided in the Excel sheet .

1. If Alta is produced with a plateau rate of 12 000 Sm3/d and using 6 producers, determine the plateau duration (in days). Write the numbers without the digits after the decimal point and without rounding.

Plateau duration (days)

2. If Alta is produced with a plateau rate of 12 000 Sm3/d and using 6 producers, determine the plateau duration if it turns out the reservoir is 20% smaller than originally estimated (but same initial reservoir pressure). Write the numbers without the digits after the decimal point and without rounding.

Plateau duration (days)

3. If Alta is produced with a plateau rate of 12 000 Sm3/d, determine the plateau duration when 4 wells are used instead of 6 in Alta. Write the numbers without the digits after the decimal point and without rounding.

Plateau duration (days)

4. Assume that Alta is produced in plateau mode with 12 000 Sm3/d and then enters in decline (producing at production potential). 6 wells are used. The economical rate (where operational expenses are equal to revenue from hydrocarbon sales) of Alta is 400 Sm3/d. Estimate the ultimate recovery factor that will be achieved from the field. Input the number in fraction with only two digits after the decimal point, no rounding.

Ultimate recovery factor:

5. As a follow-up to question 4, a colleague has suggested to drill 2 more wells to prolong plateau duration. He argues that this will also bring an increase in ultimate recovery factor. Estimate the ultimate recovery factor that will be achieved from the field when production is ceased (400 Sm3/d) and using 8 wells. Input the number in fraction with only two digits after the decimal point, no rounding.

Ultimate recovery factor:

6. If there are 6 producers in Alta, find the plateau rate such that each the plateau duration is 1000 days. Write the number in Sm3/d without the digits after the decimal point and without rounding.

Plateau rate of Alta (Sm3/d)

7. If it is desired that the field will produce a plateau rate of 12 000 Sm3/d. 6 producers are used in Alta and 3 in Gohta. Find the plateau rates from reservoirs Alta and Gohta such that the plateau duration is maximum. Write the numbers without the digits after the decimal point and without rounding.

Plateau rate of Alta (Sm3/d)
Plateau rate of Gohta (Sm3/d)
Plateau duration (in days)

8. Well tests indicate Alta has an API of 30 and Gohta of 35. The crude export department has indicated that API of the field must be of 32. The API of the field can be calculated with a weighted average of the APIs of Alta and Gohta using the production rates. If the field is to be produced with a plateau rate of 12 000 Sm3/d and using 6 producers in Alta and 3 in Gohta, determine the plateau duration, if the field API constraint is enforced.

Plateau duration (in days)

Once ready submit here your results:

Submit

Submission message

Your result will appear here!

Notes for Youtube video offshore structures 1

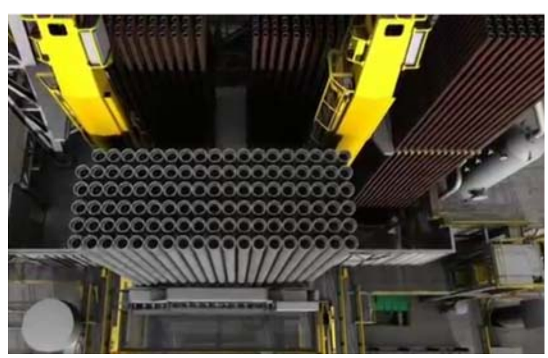
Offshore structures for oil and gas production

Prof. Milan Stanko (NTNU)

1

Components

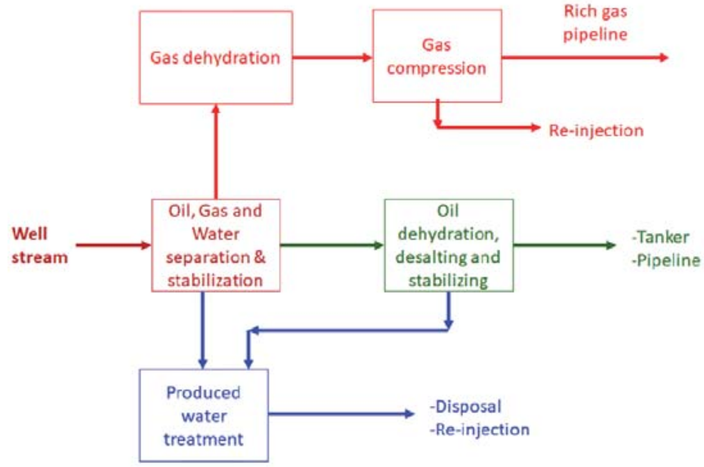
- Facilities for drilling and full intervention. This includes drilling tower, BOP, drilling floor, mud package, cementing pumps, storage deck for drill pipes and tubulars, drilling risers.



2

Components

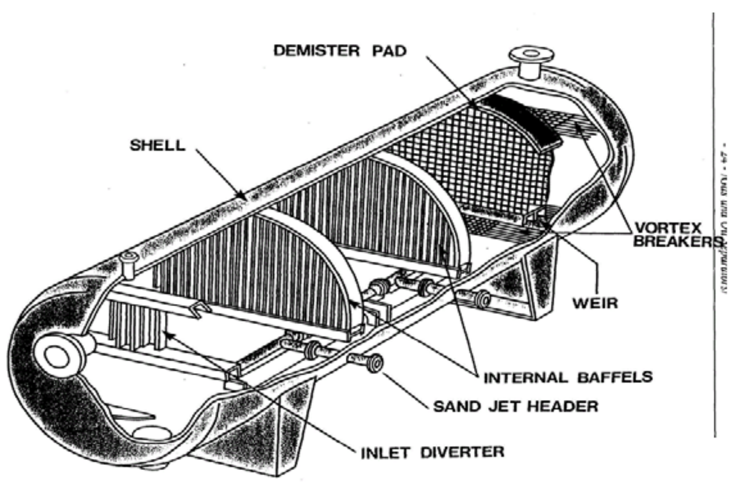
- Facilities for light well intervention.
- Processing facilities: separator trains for primary oil, gas and water separation, gas processing train, water processing train.
- Gas injection system
- Gas compression units for pipeline transport
- Water injection system



3

Components

- Facilities for light well intervention.
- Processing facilities: separator trains for primary oil, gas and water separation, gas processing train, water processing train.
- Gas injection system
- Gas compression units for pipeline transport
- Water injection system



4

Components

- Living quarters
- Helideck.
- Power generation.
- Flare system.
- Utilities (hydraulic power fluid, compressed air, drinking water unit, air condition system, ventilation and heating system)

5

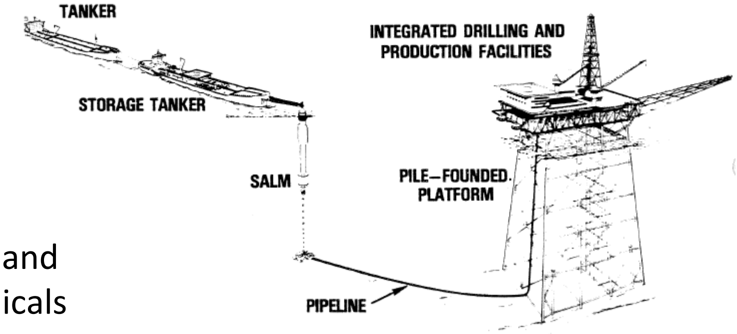
Components

- Bay for wellheads and X-mas trees
- Production manifolds
- Oil storage
- Facilities for oil offloading
- Control system
- Monitoring system
- System for storage, injection and recovery of production chemicals (wax, scale, hydrate or corrosion inhibitors)
- Repair workshop

6

Components

- Bay for wellheads and X-mas trees
- Production manifolds
- Oil storage
- Facilities for oil offloading
- Control system
- Monitoring system
- System for storage, injection and recovery of production chemicals (wax, scale, hydrate or corrosion inhibitors)
- Repair workshop



7

Components

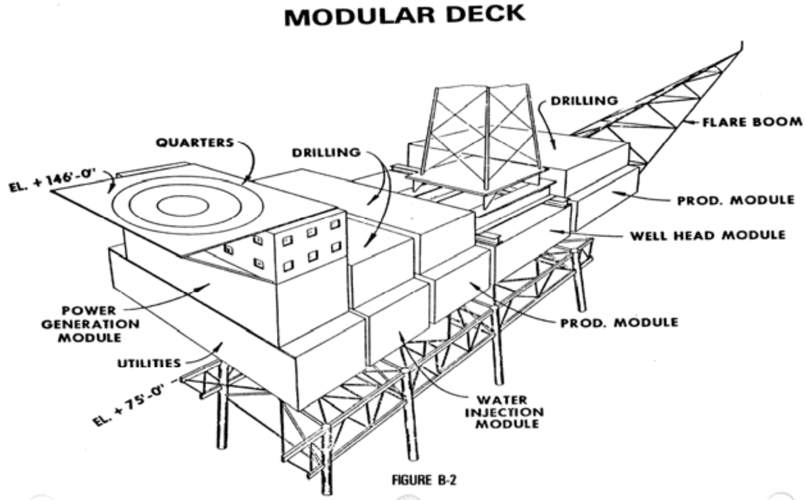


FIGURE B-2

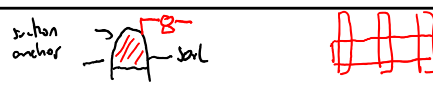
8

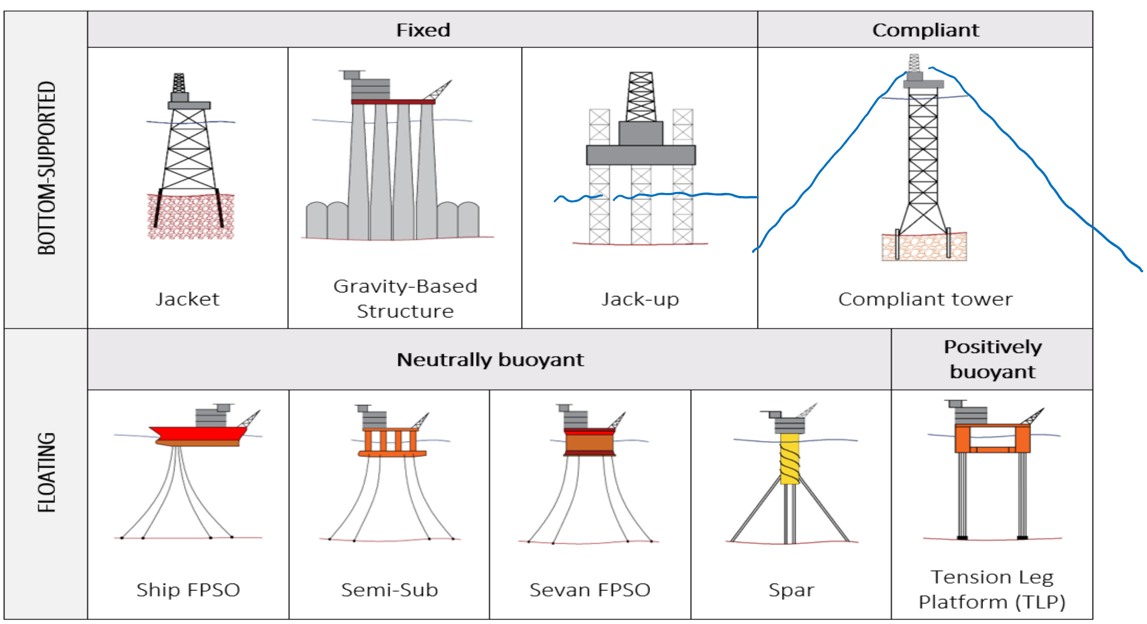
Components – can be spread

https://www.akerbp.com/produksjon/valhall/

9

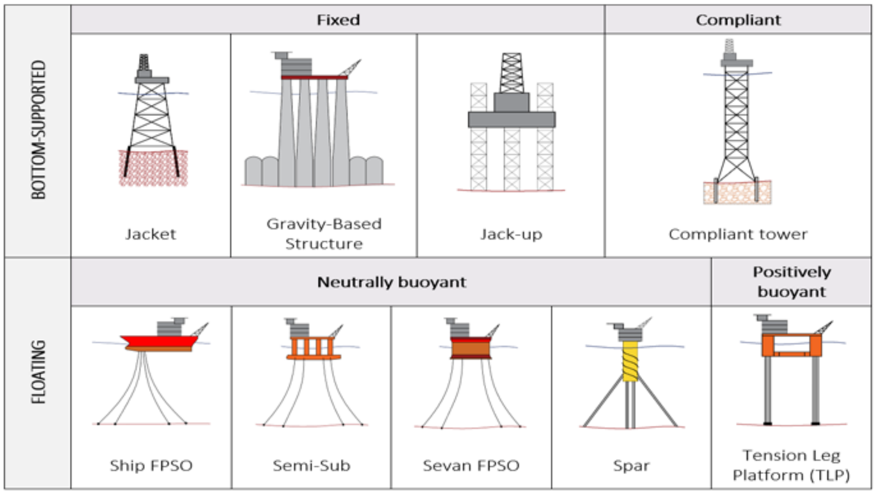
Types





10

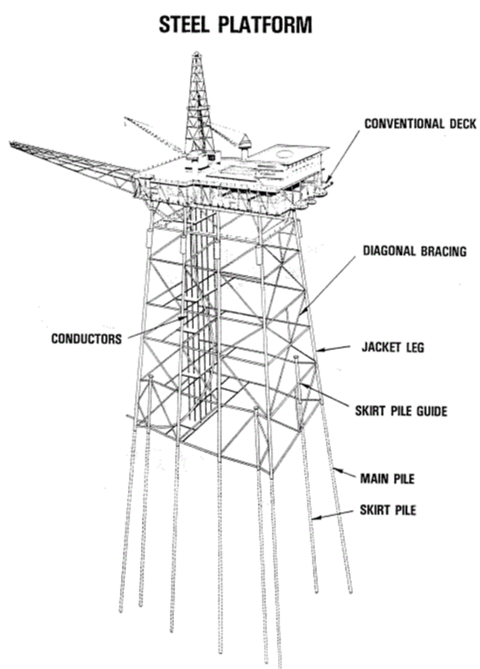
Types



- Have significant movement
- Are usually moored
- Buoyancy is controlled actively with ballast

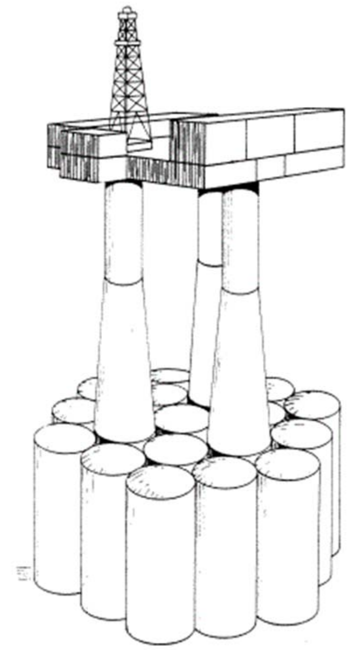
11

Jacket



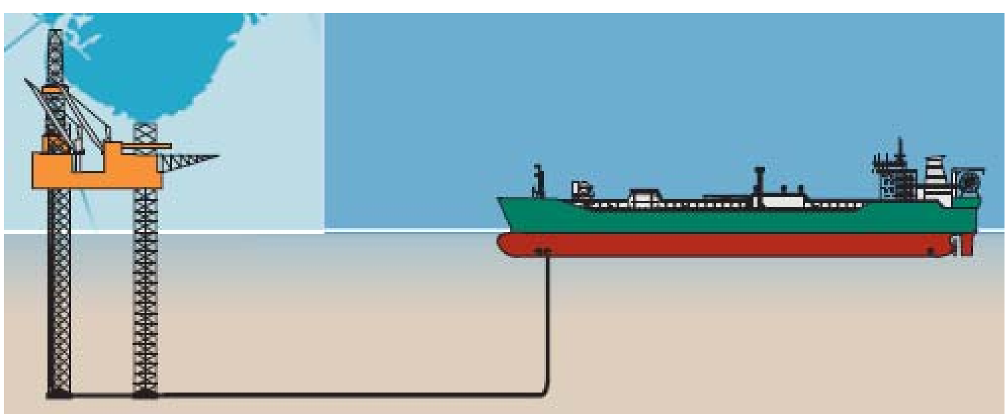
12

GBS



13

JACKUP



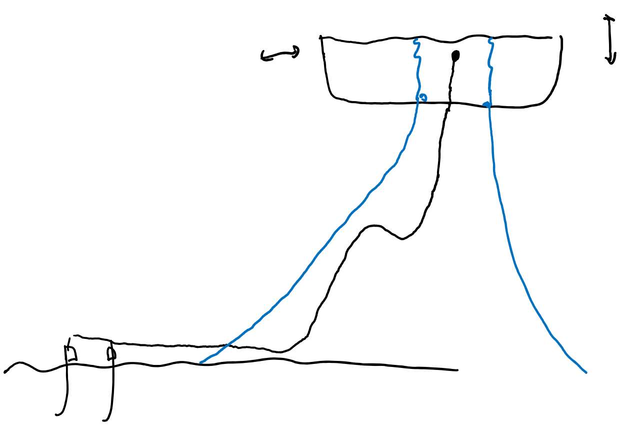
Taken from Volve PDO

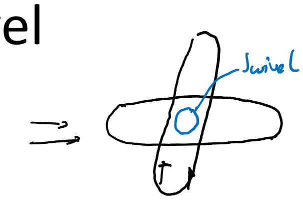
14

FPSO

15

FPSO - Comment about swivel





the Swivel allows to adjust the orientation of the FPSO to wind, waves and current

16

FPSO - Swivel

https://www.youtube.com/watch?v=70XwYmmZFWs

17

FPSO - Swivel

https://www.youtube.com/watch?v=cCiUggjUhY0

https://www.youtube.com/watch?v=Sfjay0Rt3hU

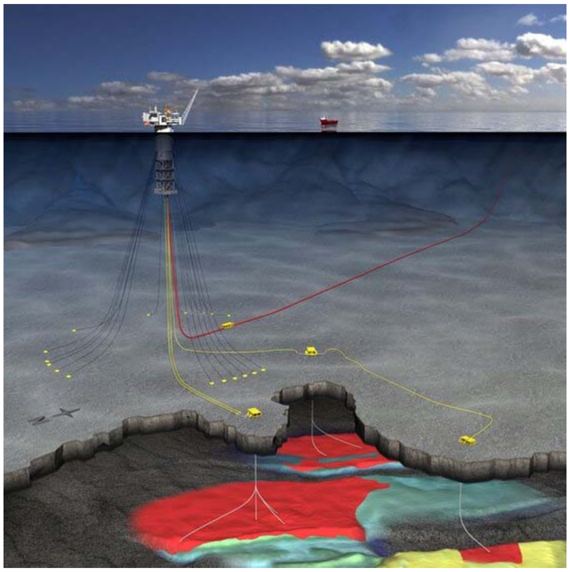
18

FPSO - Swivel

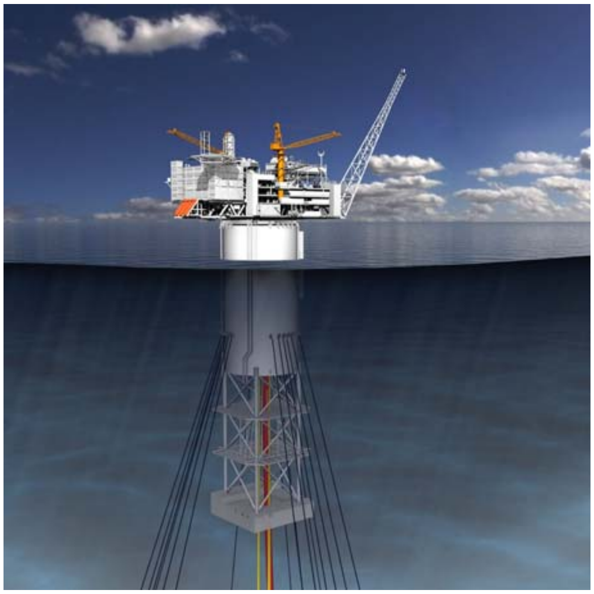
https://www.youtube.com/watch?v=HbJh1ar0u1s

19

SPAR



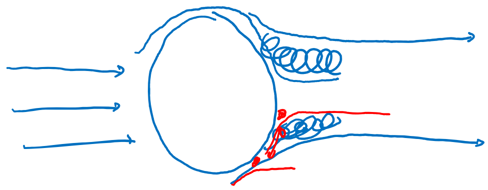
https://www.tu.no/artikler/industri-kvaerner-sikrer-enda-et-aasta-hansteen-oppdrag/225940



https://www.tu.no/artikler/industri-kvaerner-sikrer-enda-et-aasta-hansteen-oppdrag/225940

20

Vortex shedding



21

SPAR – Vortex induced vibrations

https://www.youtube.com/watch?v=_Hbbkd2d3H8&feature=youtu.be

22

SPAR – Vortex induced vibrations

Summary of project.

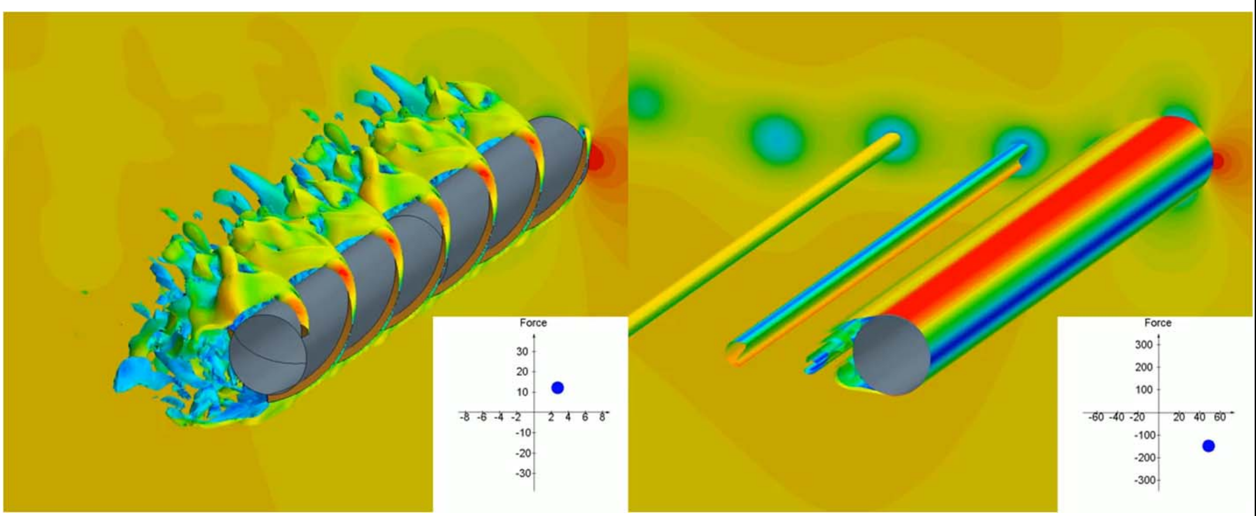
A*max = Ymax/D

"Fixed" means the cylinder is not allowed to oscillate. "VIV" means it is based on vortex shedding.

https://www.youtube.com/watch?v=24tBX_UD3fM

23

SPAR – Effect of helical strakes



https://www.youtube.com/watch?v=W-zXwPT2r14

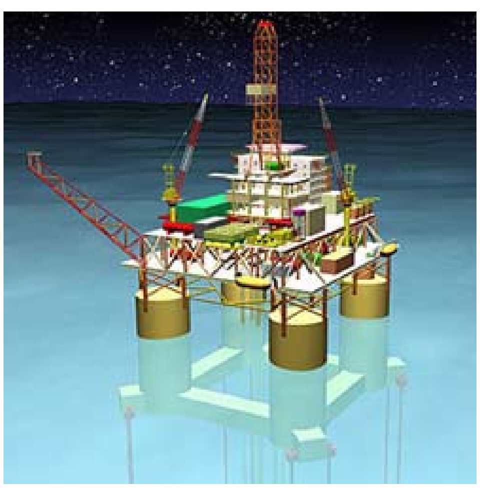
24

SEVAN FPSO

https://www.upstreamonline.com/epaper/sevan-fpso-selected-for-bream/1-1-1160389

25

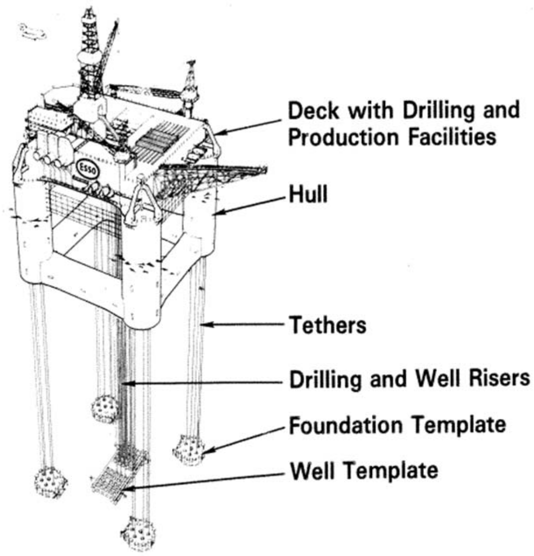
Tension leg platform



https://www.rigzone.com/training/insight.asp?insight_id=305&c_id=

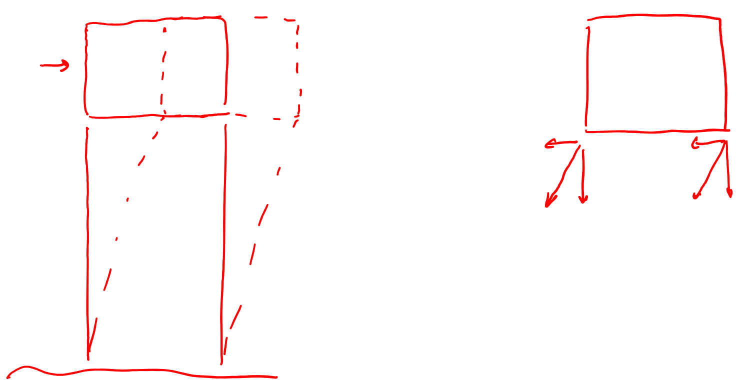
26

Tension leg platform



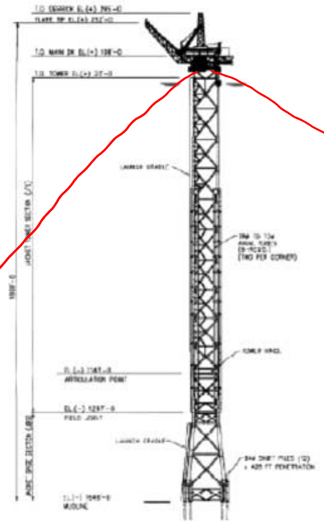
27

Comment about Tension leg platform



28

Compliant tower



https://www.sciencedirect.com/science/article/pii/S0951833914000148

29

Semi-Sub

https://www.oedigital.com/news/453987-jack-st-malo-flows-for-chevron

https://www.bairdmaritime.com/work-boat-world/offshore-world/offshore-extraction-and-processing/offshore-drilling/awilco-orders-second-semi-submersible-drilling-rig-from-keppel-fels/

30

Some selection criteria for offshore structures

- Water depth
- Type of X-mas tree
  - Well intervention needs
    - Tubing replacement
    - Completion modifications
    - Artificial lift (ESP)
  - Infill drilling needs
  - Reservoir spread and structure
- Need for oil/condensate storage
- Marine loads Oceanographic environment
  - Wind, waves, current

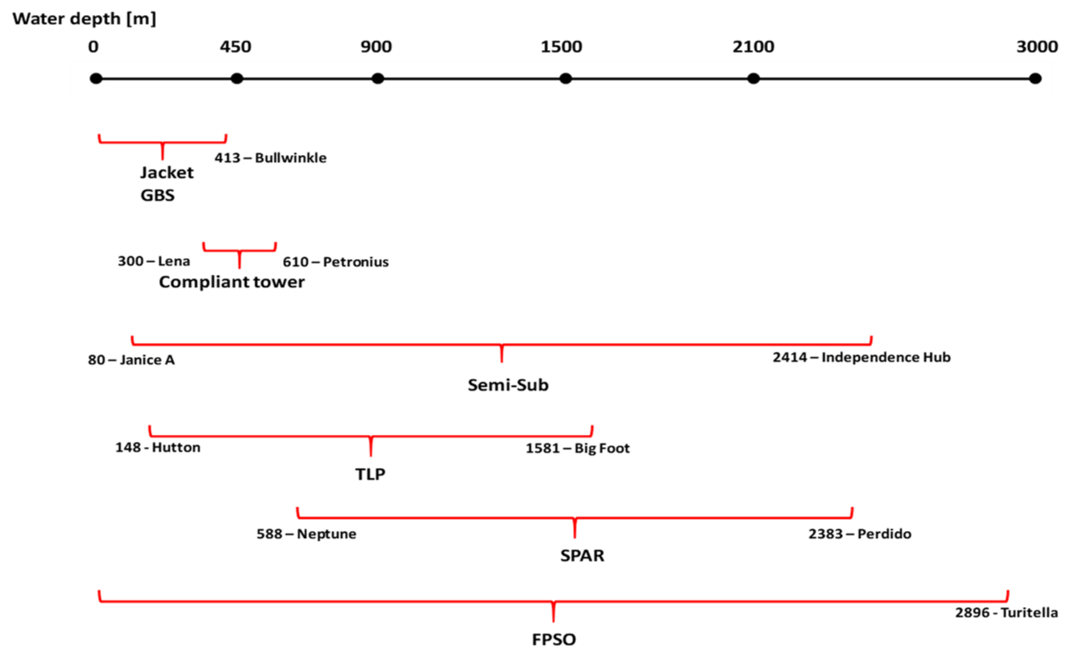
31

Some selection criteria for offshore structures

- **Water depth**
- Type of X-mas tree
  - Well intervention needs
    - Tubing replacement
    - Completion modifications
    - Artificial lift (ESP)
  - Infill drilling needs
  - Reservoir spread and structure
- Need for oil/condensate storage
- Marine loads Oceanographic environment
  - Wind, waves, current

32

Water depth



33

Some selection criteria for offshore structures

- Water depth
- **Type of X-mas tree**
  - Well intervention needs
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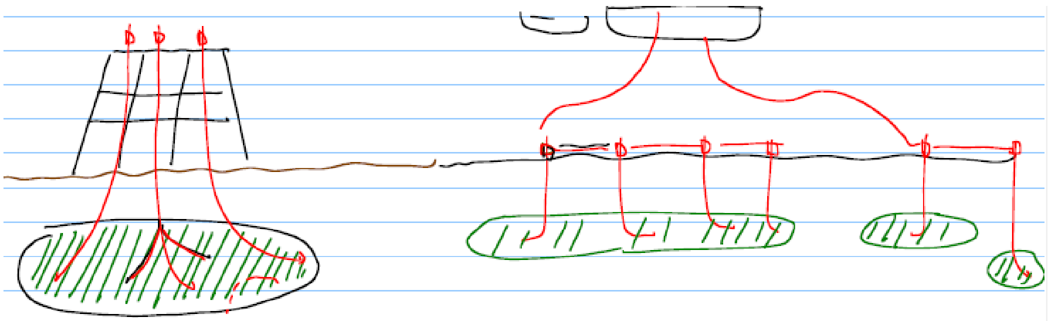
    - Completion modifications
    - Artificial lift (ESP)
  - Infill drilling needs
  - Reservoir spread and structure
- Need for oil/condensate storage
- Marine loads – Oceanographic environment
  - Wind, waves, current

34

Reservoir spread and structure

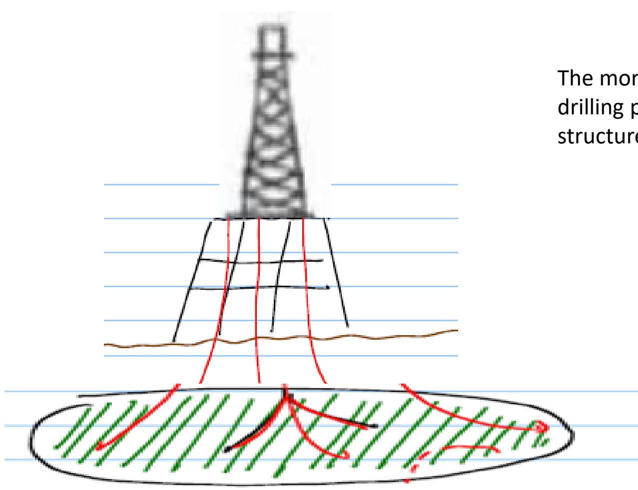


- Long deviated wells ($$$)
- Wells are drilled from one location, no need to spend mobilization time ($$)
- Production startup must be delayed until all wells are drilled

- Shorter, vertical wells ($)
- The drilling rig must be mobilized often which costs money ($$$)
- Production can start in ramp up mode (if topside is in place)

35

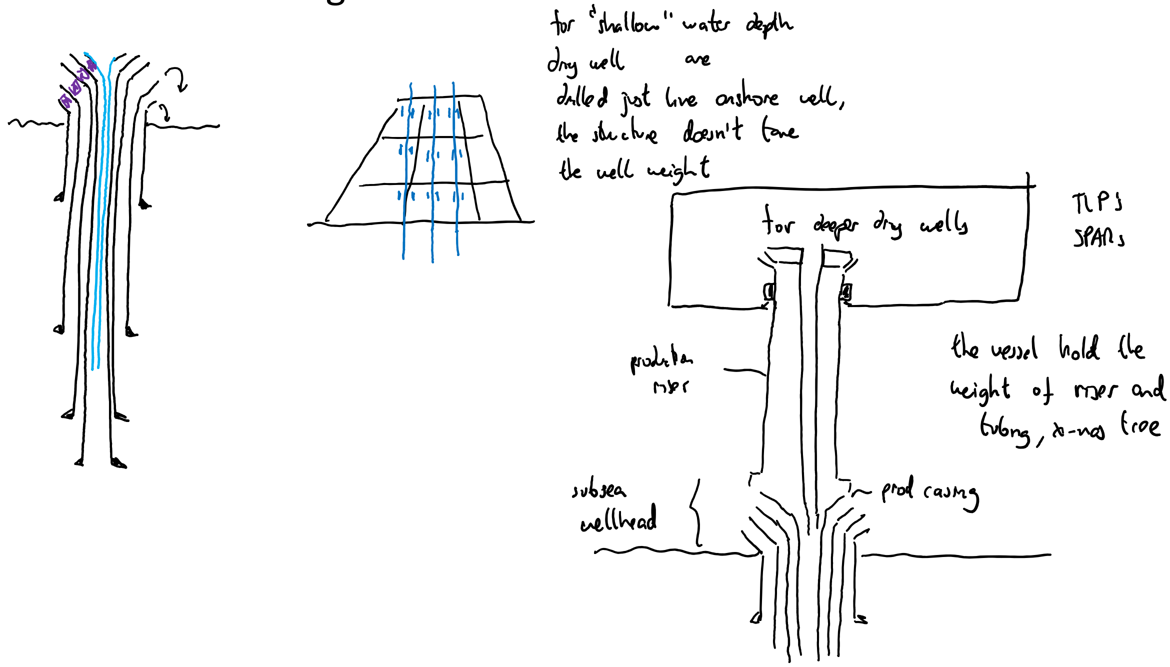
Reservoir spread and structure



The more spread - requires a bigger and more costly drilling package – more weight on the structure, bigger structure ($$$)

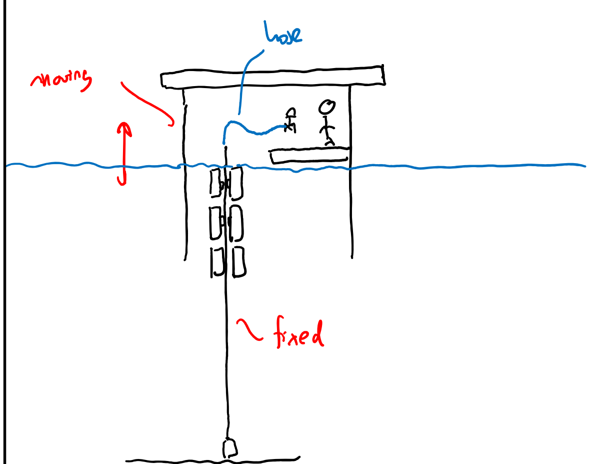
36

Transfer of well weight to soil and to offshore structure



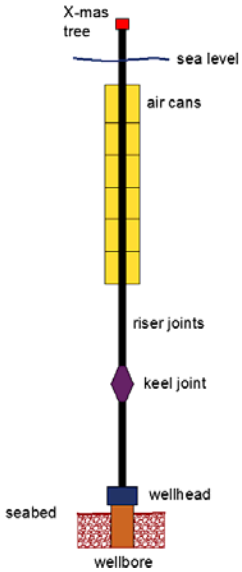
37

Transfer of well weight to soil and to offshore structure



38

Support system for dry X-mas trees – deep water



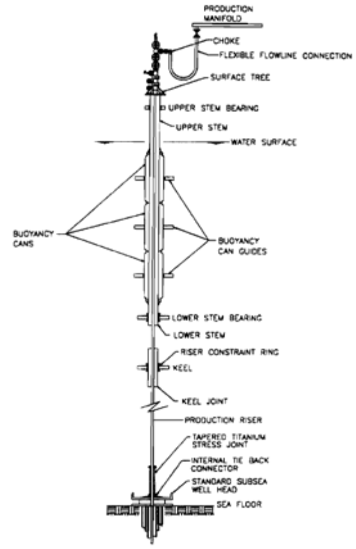


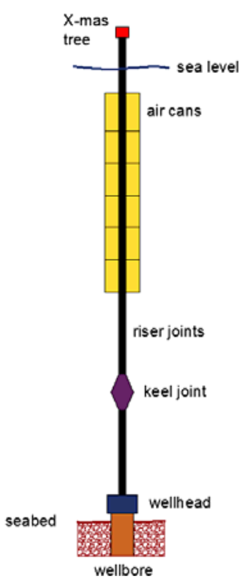
Figure 6 - Well System

OTC 8382

Neptune Project: Spar History and Design Considerations
R.S. Glanville, J.E. Halkyard, R.L. Davies, A. Steen, F. Frimm, Deep Oil Technology, Inc.

39

Support system for dry X-mas trees – deep water



Real State on offshore structure is critical, not more slots than what is needed!

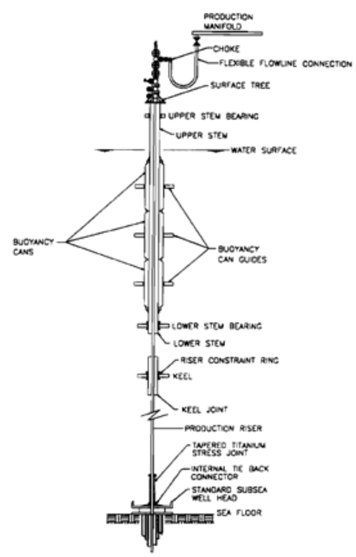


Figure 6 - Well System

OTC 8382

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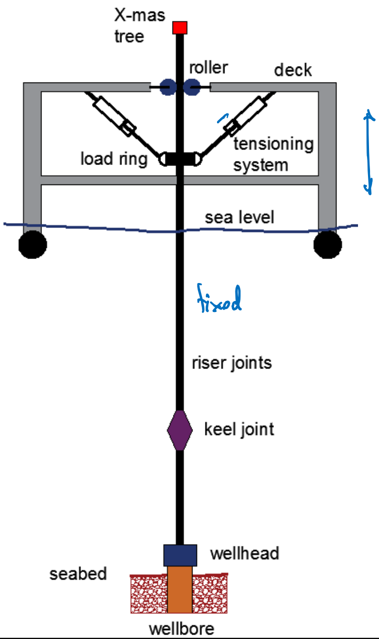
40

Support system for dry X-mas trees – deep water



41

Some selection criteria for offshore structures

- Water depth
- **Type of X-mas tree**
  - Well intervention needs
    - Tubing replacement
    - Completion modifications
    - Artificial lift (ESP)
  - Infill drilling needs
  - Reservoir spread and structure
- Need for oil/condensate storage
- Marine loads – Oceanographic environment
  - Wind, waves, current

Only floating structures SPAR, TLPs and Semi-subs have "small" movement ranges suitable for dry X-mas trees

42

Possibility for jackets without drilling package

https://www.youtube.com/watch?v=-vJmAvqn6dU

43

Possibility for jackets without drilling package

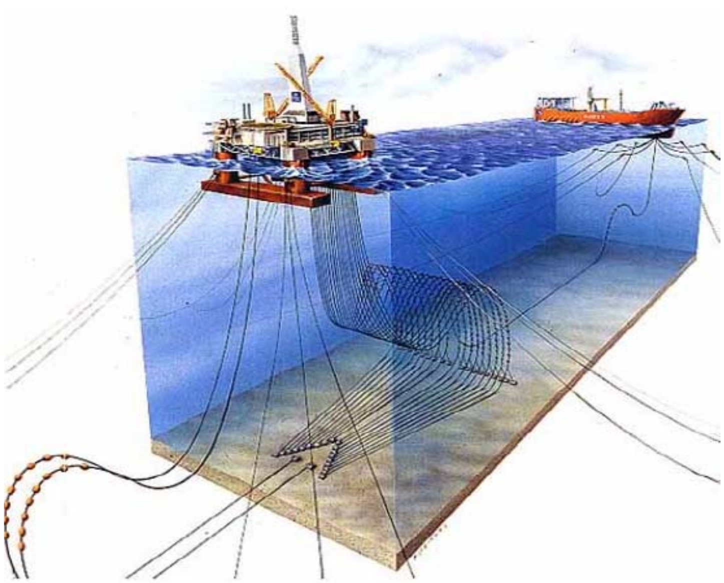
44

Possibility for jackets without drilling package

https://www.offshoreenergytoday.com/offshore-safety-watchdog-to-investigate-maersk-invincible-incident/

45

Njord: subsea wells with well intervention possibility



46

Layout of subsea systems – template wells

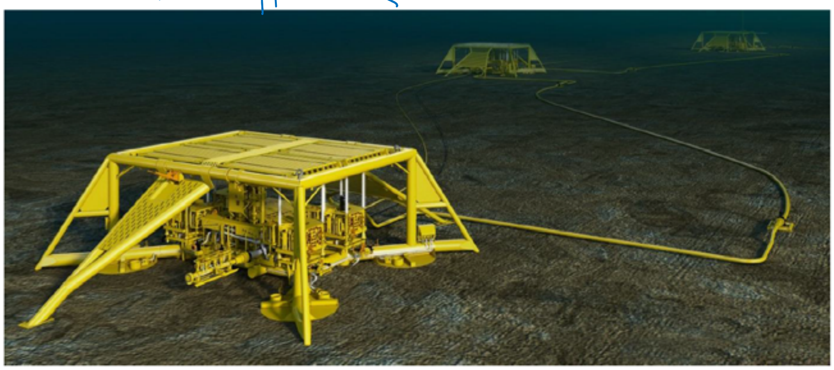
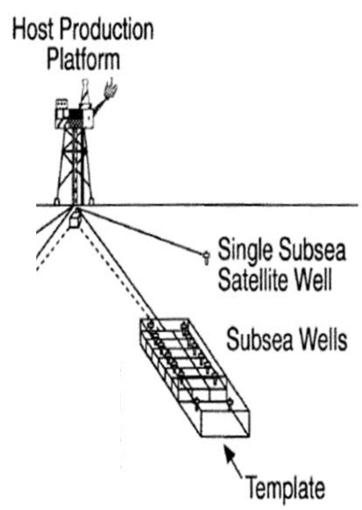


Figure 3.3 Typical NCS tie-back solution (Image: Statoil ASA)

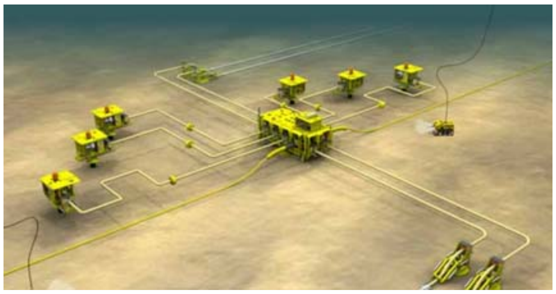
47

Layout of subsea systems – template wells



48

Satellite wells



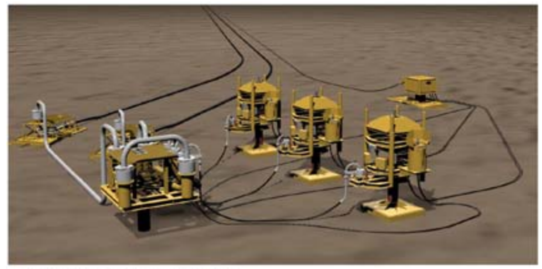
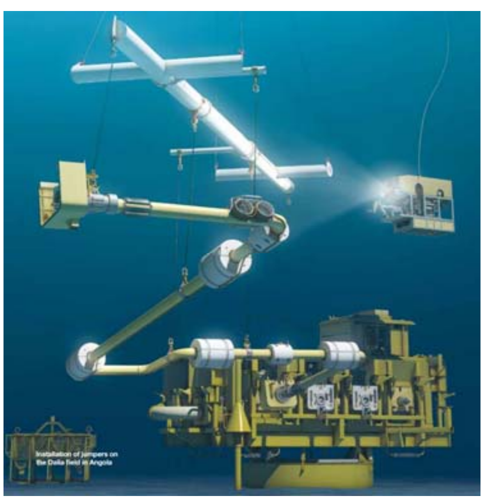


Figure 3.4 Typical GOM subsea tie-back

49

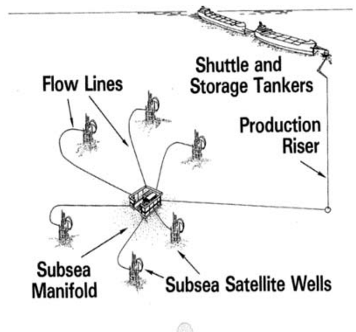
Jumpers for satellite wells (if close)



50

Template wells vs satellite wells – similar dilemma to dry versus wet X-mas tree

Figure 3.3 Typical NCS tie-back solution (Image: Statoil ASA)



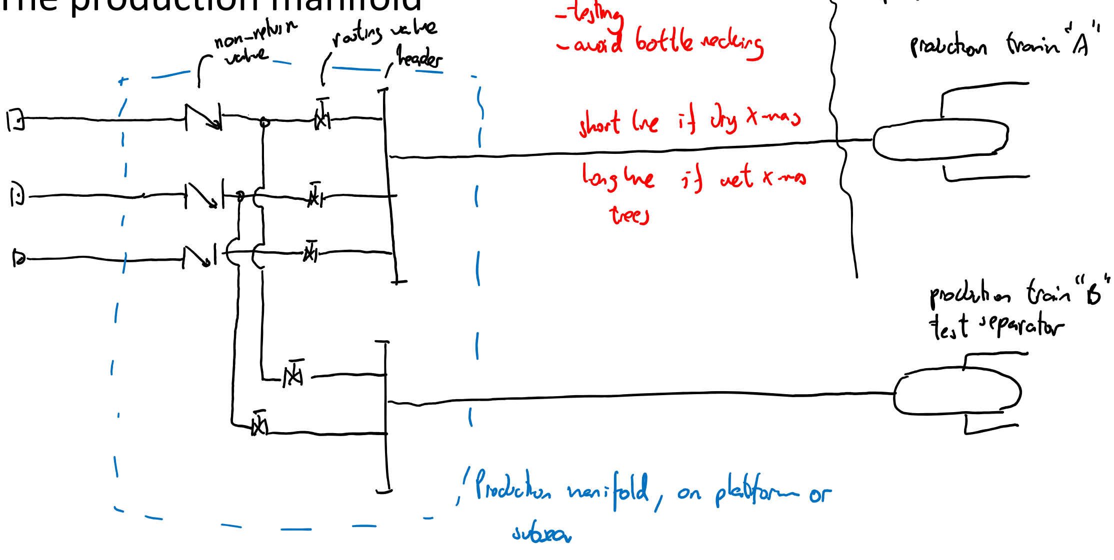
- Long deviated wells
- Wells are drilled from one location, no need to spend rig mobilization time
- Less subsea equipment

- Shorter, vertical wells
- The drilling rig must be mobilized often which costs money
- More flowlines, pipelines. Manifolds are required

51

The production manifold

- Commingle production
- redirect production
  - testing
  - avoid bottlenecking

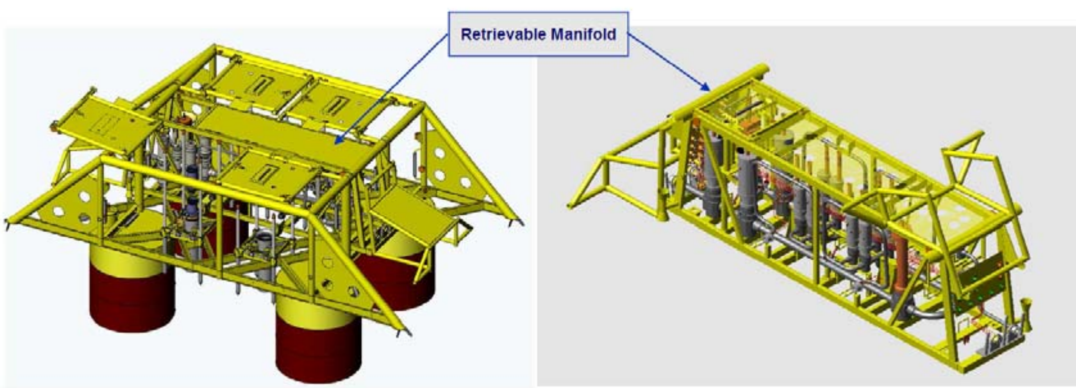


52

The production manifold

53

4 well template – the production manifold



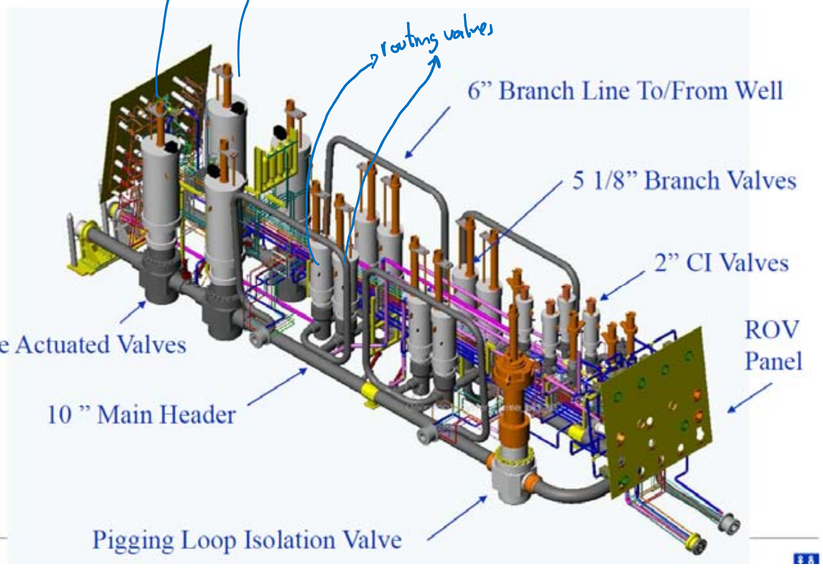
54

The manifold

integrity

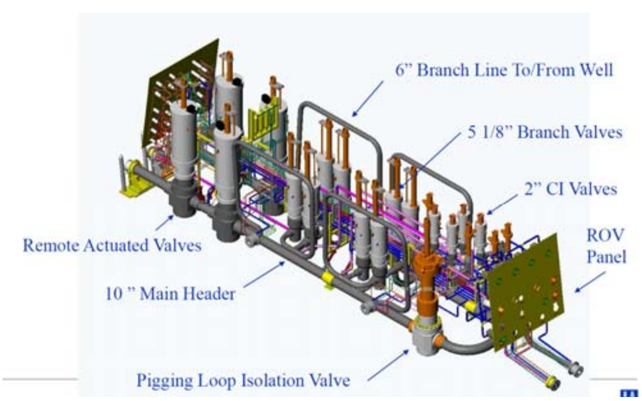
HIPPS (high pressure protection system)

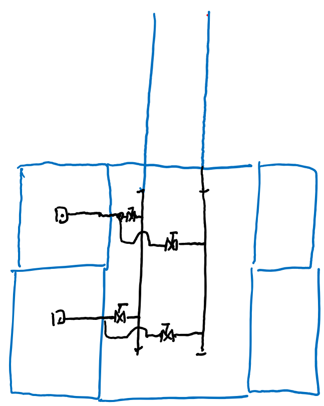
routing valves



55

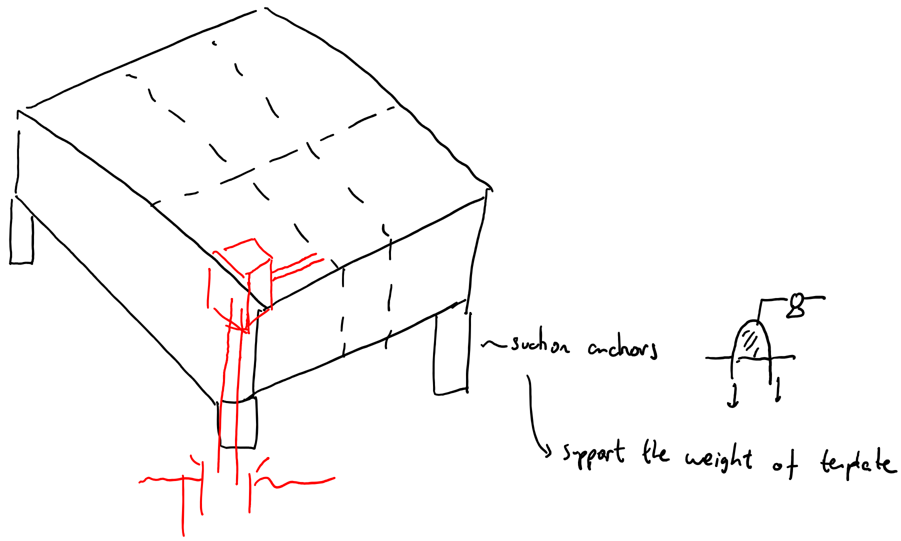
The manifold – reality vs sketch





56

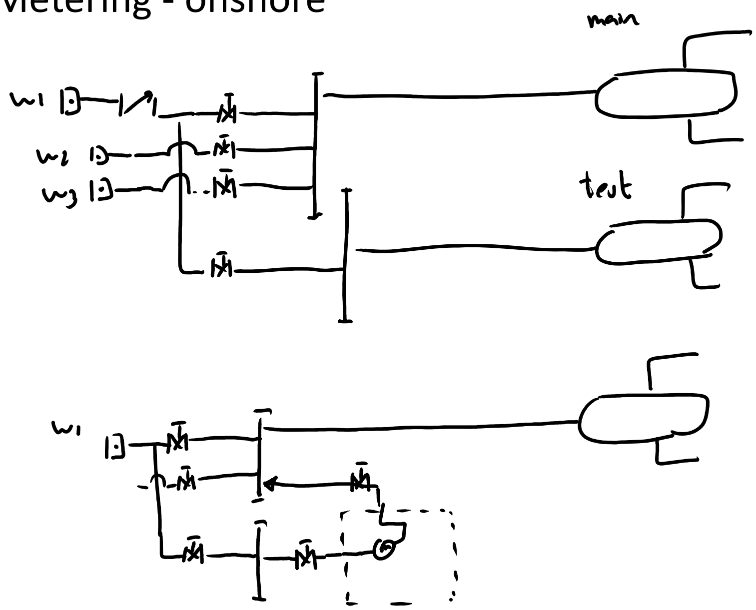
4 well template – weight transfer



57

notes for Youtube video offshore structures 2

Metering - onshore



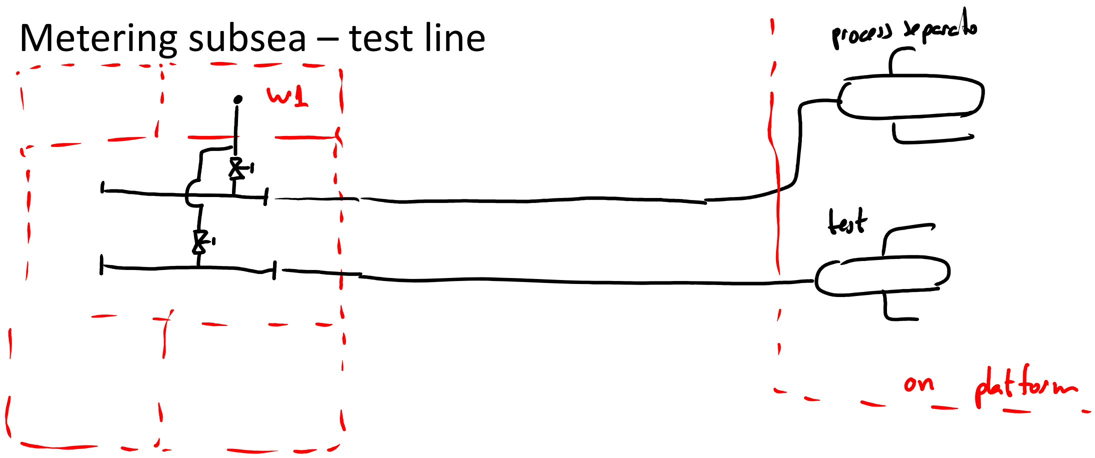
instead of separating, a multiphase meter can also be used, instead of a test separator

55

Metering onshore – test separator

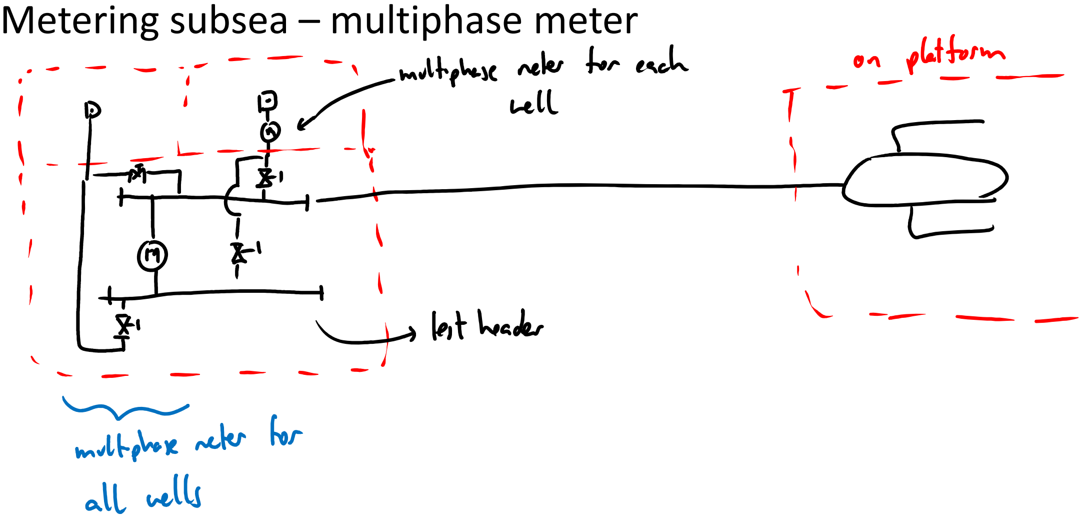
56

Metering subsea – test line

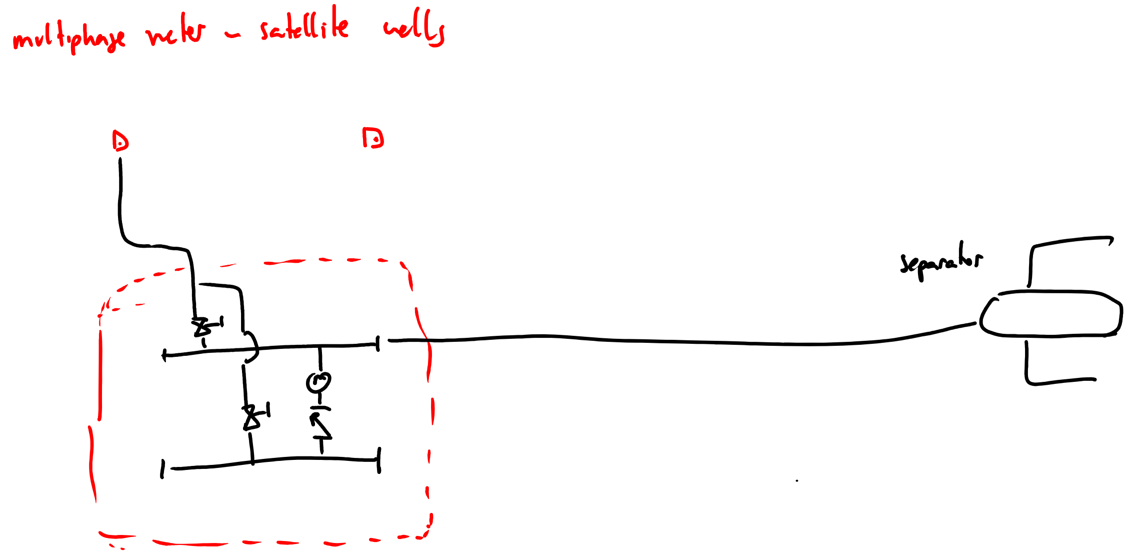


57

Metering subsea – multiphase meter



58



59

Metering requirements affect field layout - Brazil

RESOLUÇÃO CONJUNTA ANP/INMETRO Nº 1, DE 10.6.2013 - DOU 12.6.2013 – RETIFICADA DOU 17.6.2013

7.2.7. Testes de poços

7.2.7.1. Nos casos em que os resultados dos testes de poços sejam utilizados somente para apropriação da produção aos poços, cada poço em produção deve ser testado com um intervalo entre testes sucessivos não superior a noventa dias, ou sempre que houver mudanças nas condições usuais de operação ou quando forem detectadas variações na produção.

7.2.7.2. Quando os resultados dos testes de poços forem utilizados para apropriação da produção a um campo, em casos de medição fiscal compartilhada, cada poço em produção deve ser testado em intervalos não superiores a quarenta e dois dias, ou sempre que houver mudanças nas condições usuais de operação ou quando forem detectadas variações na produção.

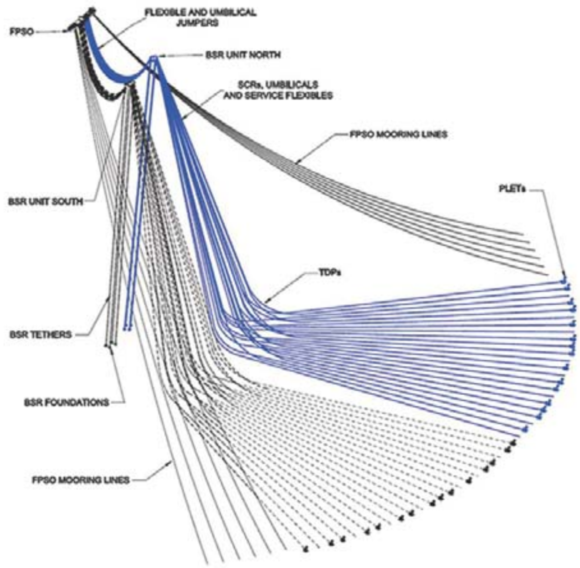
7.2.7.4. Devem ser utilizados separadores de testes ou tanques de testes nos testes de poços. Outros métodos de testes, utilizando novas tecnologias, devem ser previamente aprovados pela ANP.

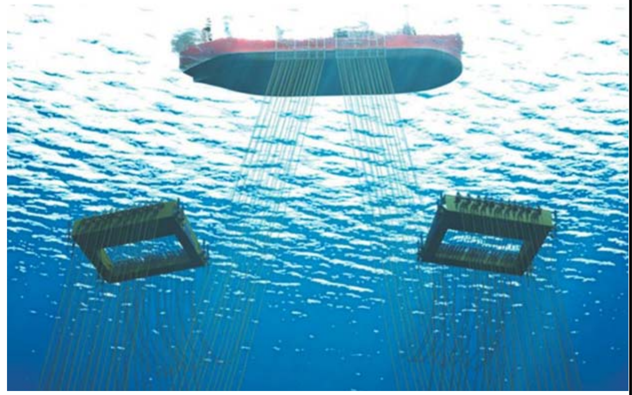
http://www.anp.gov.br/wwwanp/?dw=66648

60

Metering requirements - Brazil

$$$





https://www.marinetechnologynews.com/news/reviewing-sapinho-system-564661

61

Metering requirements - Norway

http://www.npd.no/Global/Engelsk/5-Rules-and-regulations/NPD-regulations/Maaleforskriften_e.pdf

REGULATIONS RELATING TO MEASUREMENT OF PETROLEUM FOR FISCAL PURPOSES AND FOR CALCULATION OF CO_2-TAX (THE MEASUREMENT REGULATIONS)

Multiphase measurement

Multiphase measurement may be used if traditional single phase measurement of hydrocarbons is not possible for financial reasons. The multiphase meter can then be used as a fiscal meter.

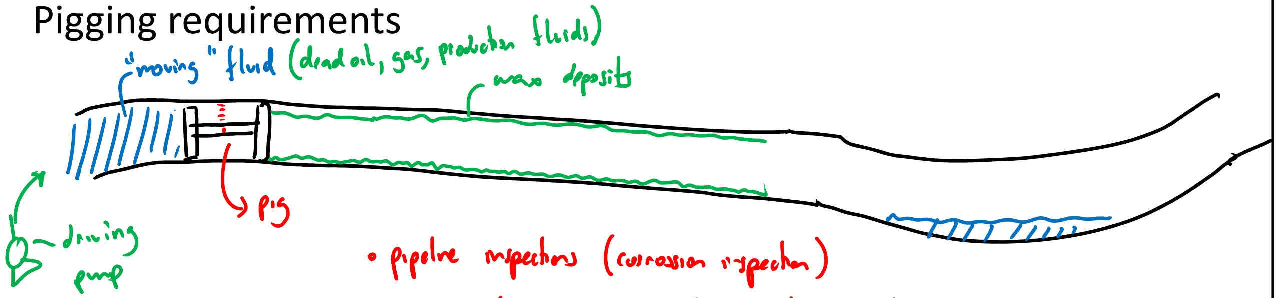
The following elements shall be satisfactorily documented to allow use of a concept based on multiphase measurement, cf. Chapter VII and Section 18:

- The operator shall present a concept to the Norwegian Petroleum Directorate for comments and formal processing well before submitting the Plan for Development and Operation (PDO). An estimate of the expected measurement uncertainty shall be presented, combined with financial figures for the risk of loss between production licenses (cf. NORSOK I-105), Annex C).
- The main principles of the operations and maintenance philosophy shall be described.
- Possibility to calibrate meters against test separator or other reference.
- Redundancy in sensors and robustness in the design of the measurement concept.
- Relevant PVT (equation of state) model and representative sampling opportunity to be able to perform a sound PVT calculation.
- Design of inlet pipes to ensure similar conditions if multiple meters are used in parallel.
- Flexibility in the system for handling varying GVF (gas volume fraction).
- The planned method for condition monitoring and/or planned calibration interval shall be described.
- The planned method and interval for sampling and updating PVT data shall be described.

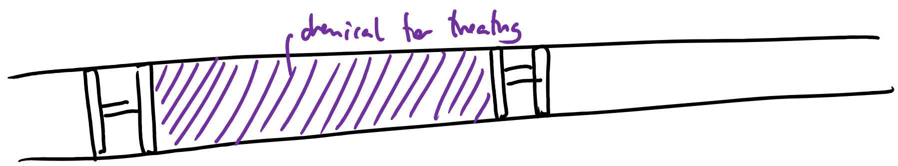
When the multiphase meters are part of the fiscal measurement system, they shall be treated as other fiscal measurement equipment and the administrative requirements which apply pursuant to these Regulations shall therefore be fulfilled.

62

Pigging requirements



- pipeline inspections (corrosion inspection)
- remove liquid accumulated in low points
- chemical treatment
- wax scraping



63

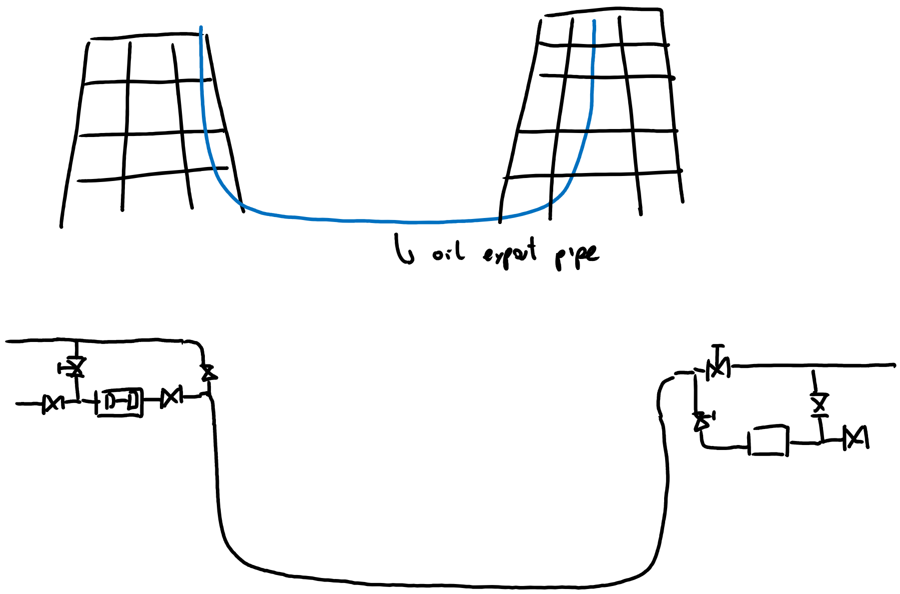
Pigs

Various pig types

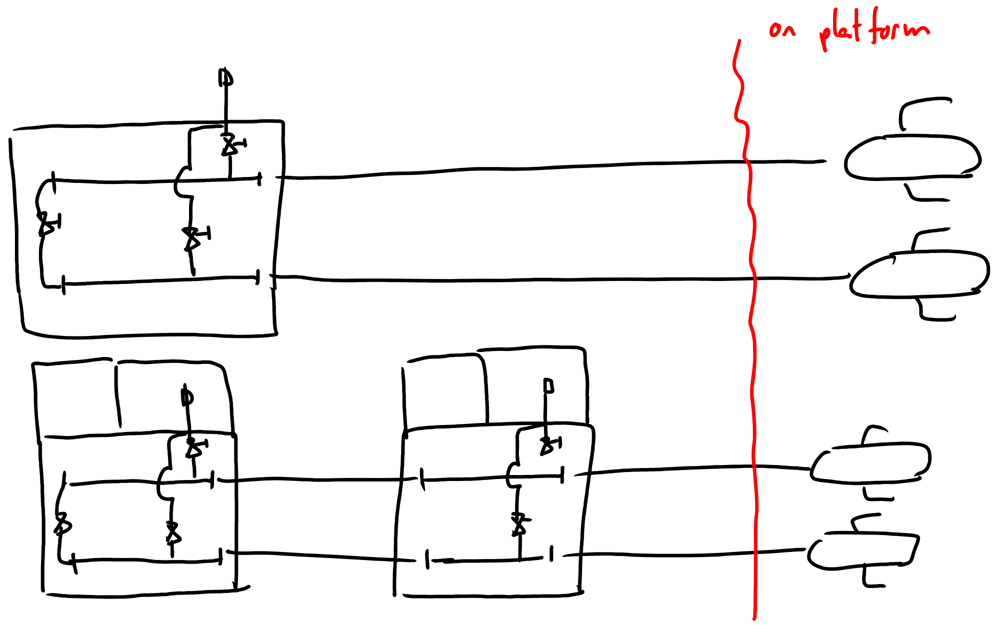
Wax plug-North Sea line pigging

64

Pigging loop and subsea pig launcher

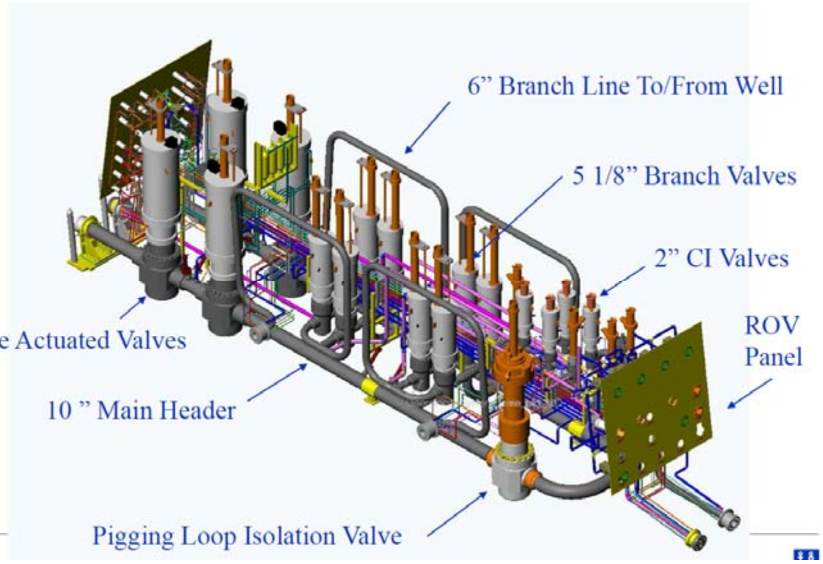


65



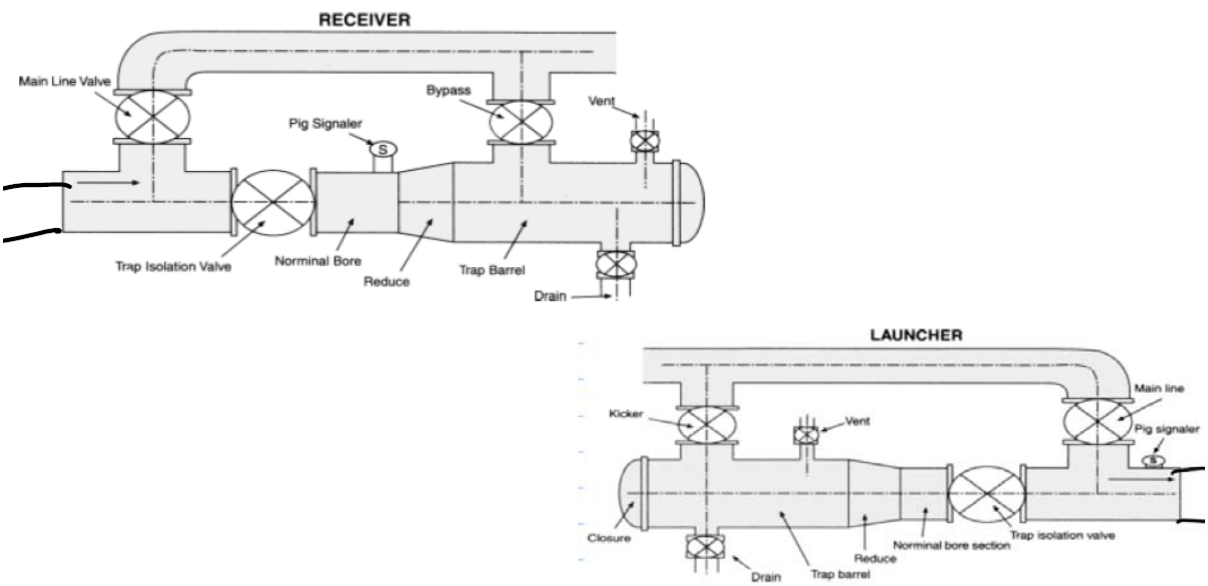
66

The pigging valve



67

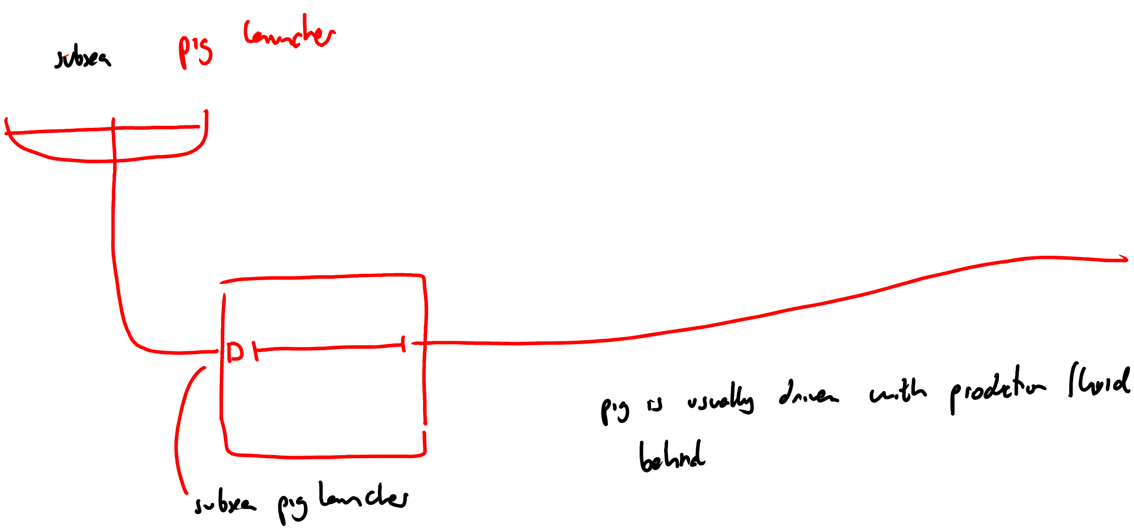
Pig launcher and receiver



68

Pigging - video

69



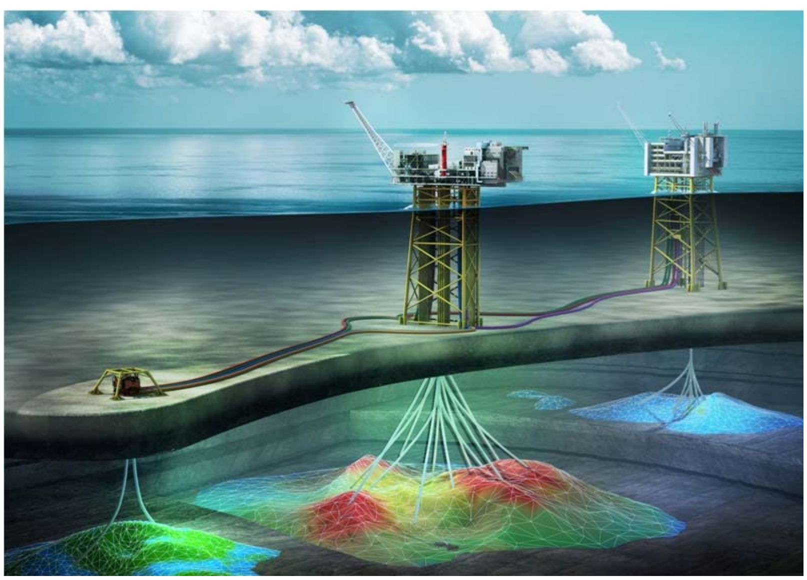
70

Summary table

	Dry X-mas trees	Wet X-mas trees
Deep water (1700 m+)		X
Reservoir is "spread" or multiple reservoirs		X
Frequent well intervention	X	
Flow assurance concerns	X	
Plans for infill drilling (and coping with reservoir uncertainty)*	X	X
Progressive production startup		X
	Jacket, GBS, SPAR, TLP	ALL

71

Combinations can be used



https://www.akerbp.com/en/our-assets/production/ivar-aasen/the-development-solution/

72

Some selection criteria for offshore structures

- Water depth
- Type of X-mas tree
    - Well intervention needs
        - Tubing replacement
        - Completion modifications
        - Artificial lift (ESP)
    - Infill drilling needs
    - Reservoir spread and structure
- **Need for oil/condensate storage**
- Marine loads – Oceanographic environment
    - Wind, waves, current

73

Need for liquid storage

No or limited storage	Steel Jackets, Semi-subs, TLPs, Spars[20]
Medium - Large storage (up to 2.5000.000 STB)	FPSOs, GBS

74

Other selection criteria for offshore structures

- Previous experience
- Riser issues
- Topside upgrade flexibility
- Manufacturing workshop availability
- Maturity of technology
- Maintenance and OPEX

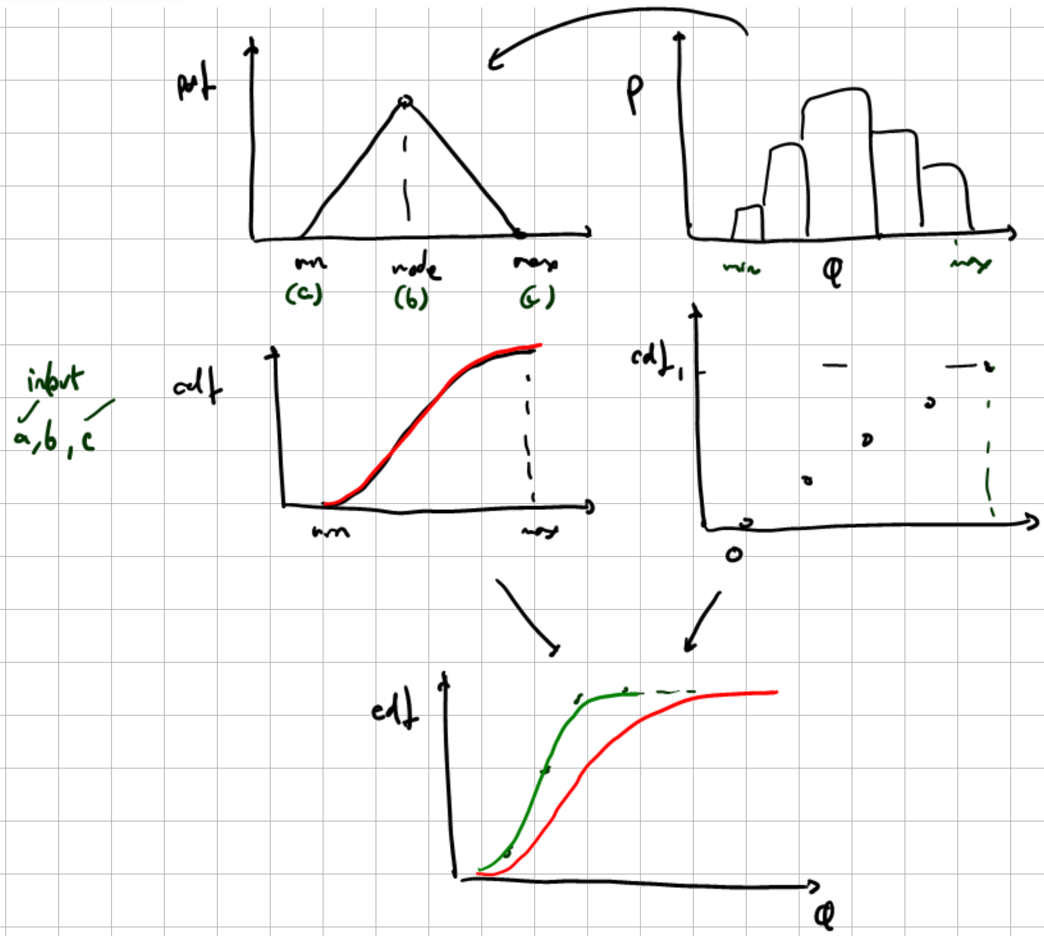
75

20230321:
Outline
-Quick overview of material covered last week in YT videos
-Clarify doubts about quiz 11
-Discuss quiz 12

http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/2022/Quizzes/Quiz11.html

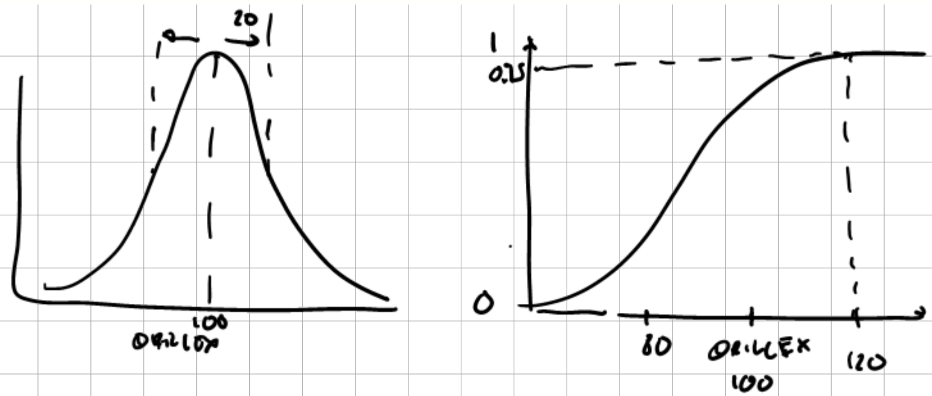
1. The triangular distribution is an analytical continuous probability distribution that uses three input values, min, maximum and mode. Using the procedure explained in the video lecture, tune the mode of this distribution to match the discrete cumulative distribution function of porosity provided. Use the Excel sheet provided. Write the value of the mode found in fraction, with two digits after the decimal point and without rounding. TIP: use the UDF VBA functions provided, “triang_pdf” and “triang_cdf”.

Answer:



2. Assume that the DRILLEX of a well exhibits a continuous normal distribution with mean = 100 and sigma = 20 (values are given in 1E06 USD). Using the cdf, determine what is the probability that the cost will be equal to 120 1E06 USD or higher. TIP: use the built-in Excel function: “NORM-DIST”. Write the value in fraction, with two digits after the decimal point and without rounding.

Answer:

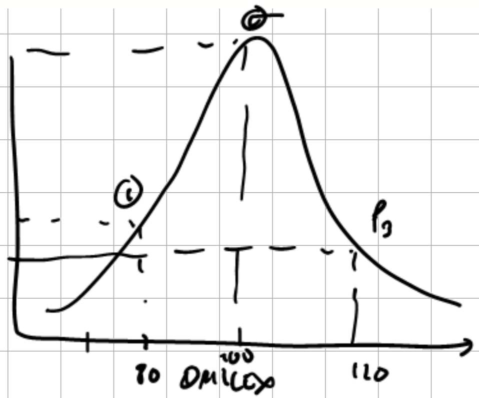


4. Using the method of value discretization, discretize the well DRILLEX distribution provided in question 2 using three values (bins) of 80, 100 and 120. What are the associated probabilities to each value? Write the values in fraction, with two digits after the decimal point and without rounding. TIP: use the built-in function in VBA: "NORM.DIST".

Prob for 80:

Prob for 100:

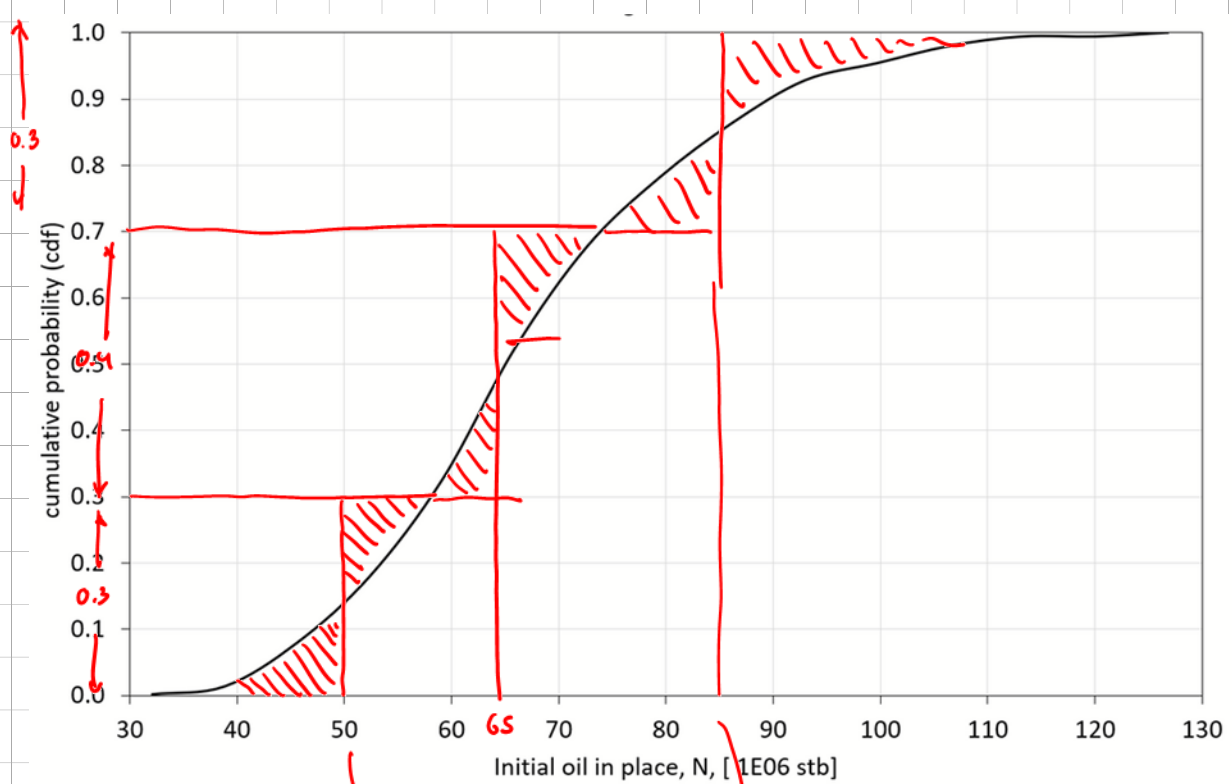
Prob for 120:



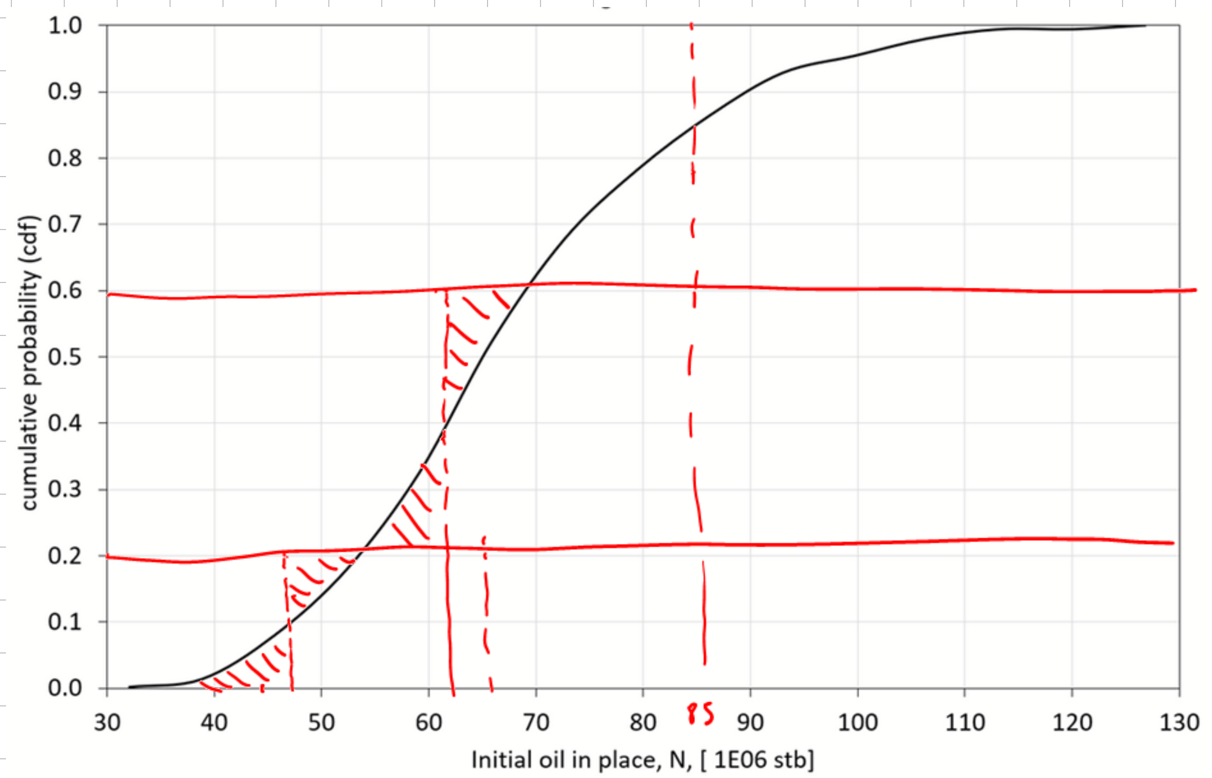
DRILLEX	P
80	$P_1/(P_1+P_2+P_3)$
100	
120	

6. Using the method of bracket mean (and estimating with the naked eye), discretize the continuous distribution of initial oil in place provided in the Excel sheet using three values. The small value should have a probability of 0.3, the medium value with a probability of 0.4 and the highest value with a probability of 0.3. Select the option that makes most sense:

- 50, 65 and 80 1E06 stb
- 40, 65 and 90 1E06 stb
- 50, 65 and 85 1E06 stb



N	P
N_1	0.3
N_2	0.4
N_3	0.3

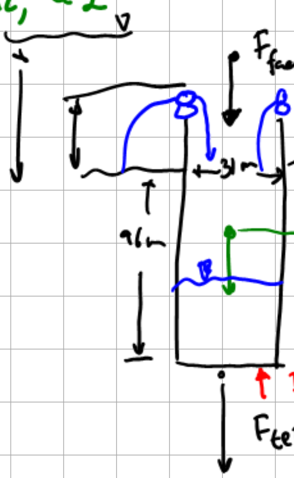


N	P
47	0.2
62	0.4
85	0.4

http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/2022/Quizzes/Quiz12.html

Quiz 12, Q2

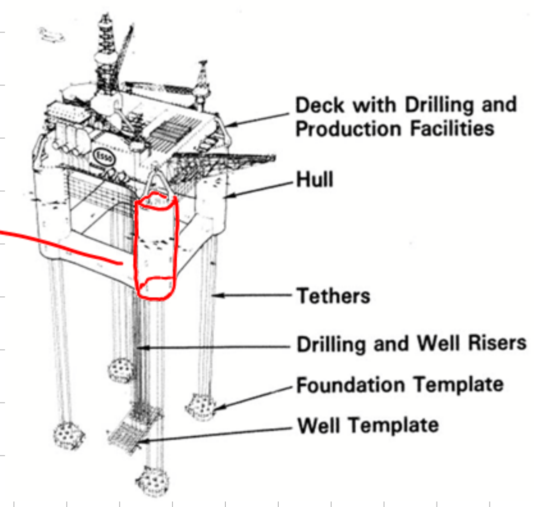
$F_{facility} = 235027\text{E}03\ kg \cdot g / 4$



$F_{ballast} = V_{water} \cdot \rho_{water} \cdot g$

$F_{buoyancy} = V_{displaced} \cdot \rho_{seawater} \cdot g$

$F_{tether} = 292338\ kN/4$



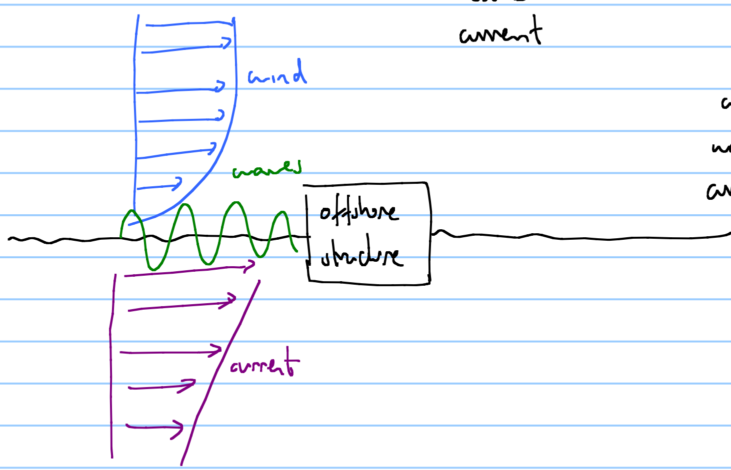
$\Sigma F = 0 \rightarrow V_{water}$

Note Title

Notes for Youtube video Marine loads and offshore structures for hydrocarbon production

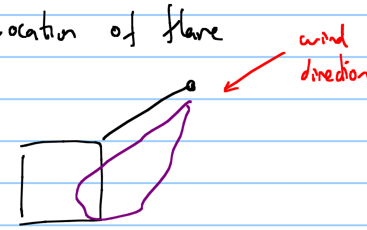
Offshore structures for oil and gas production

- effect of oceanographic environment: wind
  waves
  current

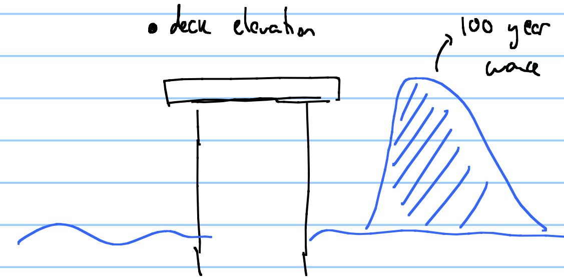


wind, waves, current must be taken into account when designing the offshore structure

- Location of flare



- deck elevation

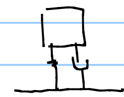


- design wave, for a range of periods
  ↳ most likely in the area
- storm (100 year storm)
- long term variations ⤳ fatigue

forces and marine loads on structure (t) → structure (mechanical system) → movement (t)
stress (t) → maximum stress
fatigue design

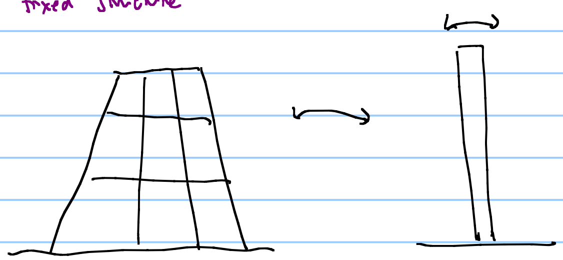
- magnitude
- frequency
- direction

each structure, depending on it characteristics (mass, flexibility, dampening)

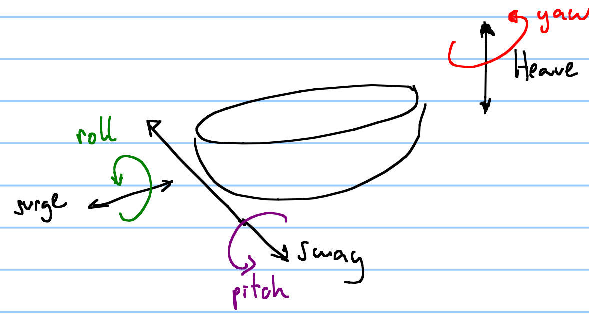


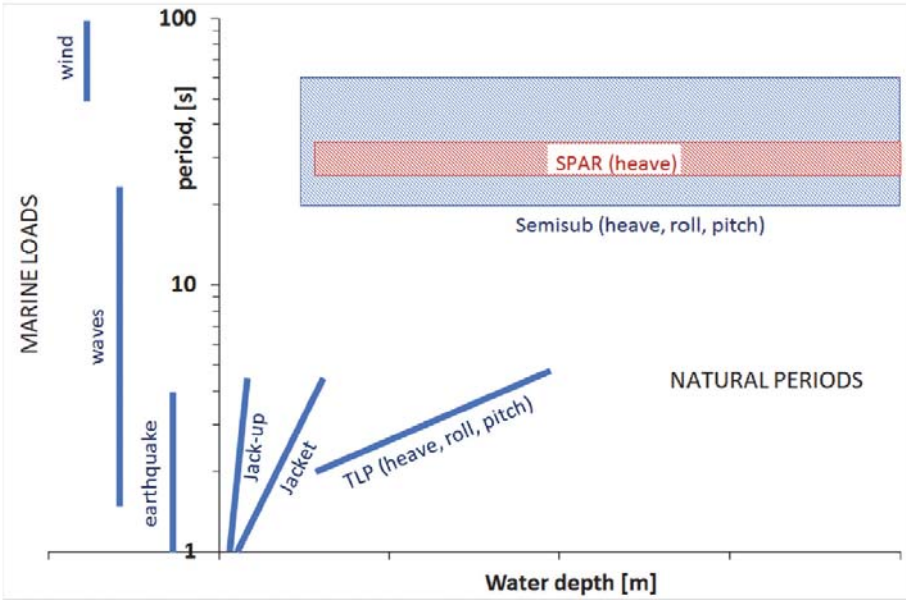
will have a natural frequency that if excited at this frequency might exhibit maximum movement and stress.

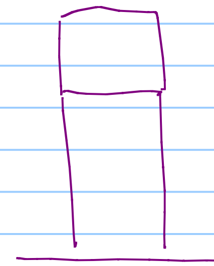
fixed structure

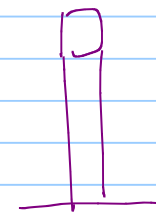


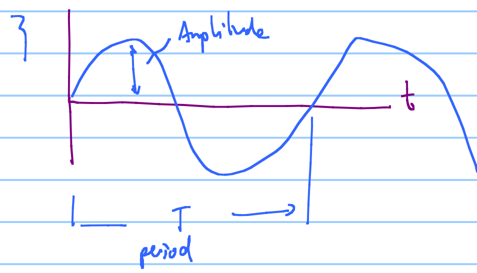
floating structure







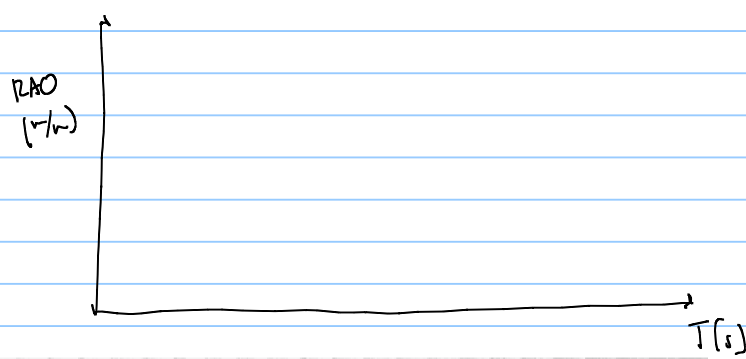




$$\text{Response amplitude operator (RAO)} = \frac{\text{amplitude of response}}{\text{amplitude of excitation}} = \frac{\text{Heave [m]}}{\text{wave amplitude [m]}}$$

$$f = \frac{1}{T} \quad \frac{\text{cycle}}{\text{s}}$$

RAO = 2



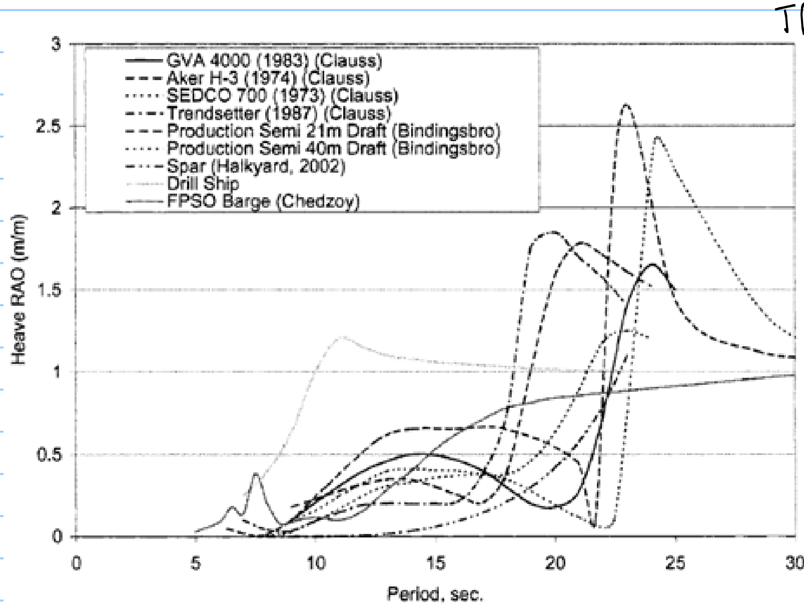
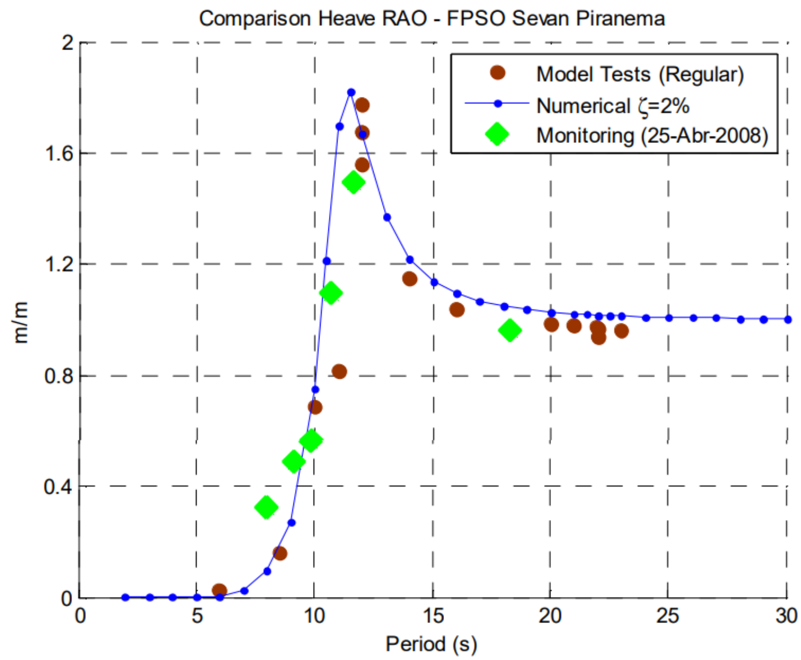


Figure 7.3 Example heave RAOs of various floaters



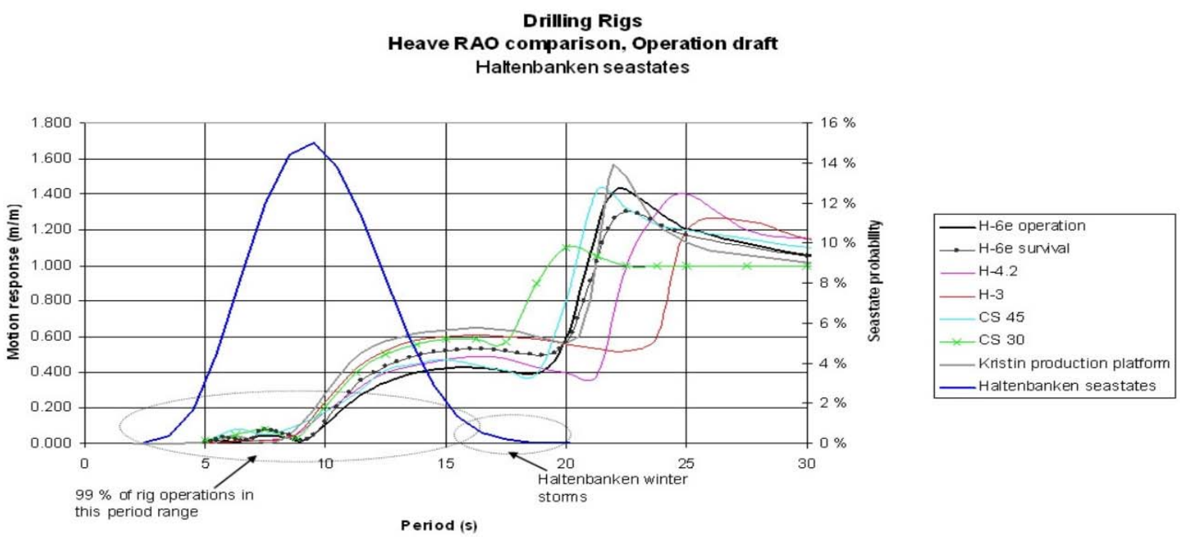


Figure 16.2: *RAO published on the AKER Drilling website.*

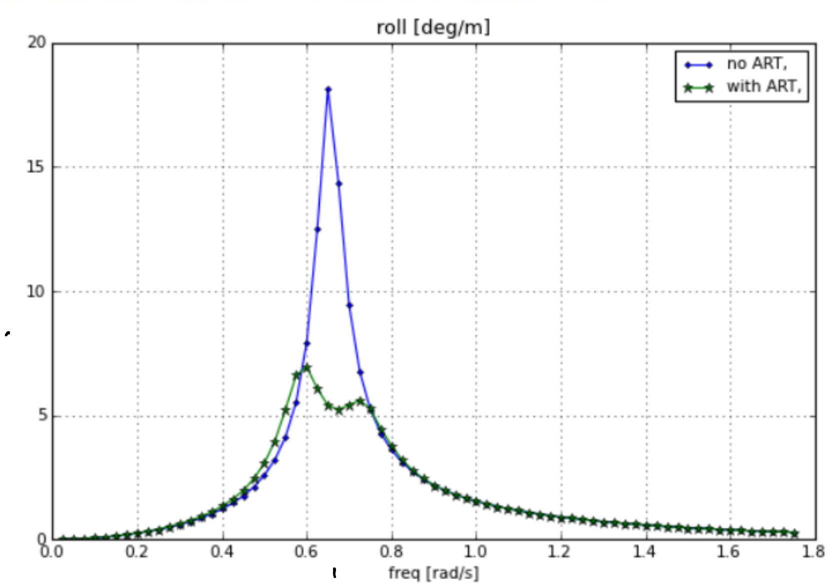
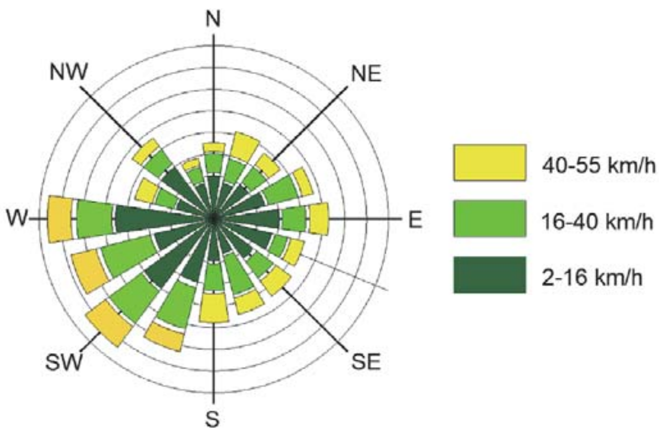


Figure 1: Typical RAO of roll of a ship with and without ART.

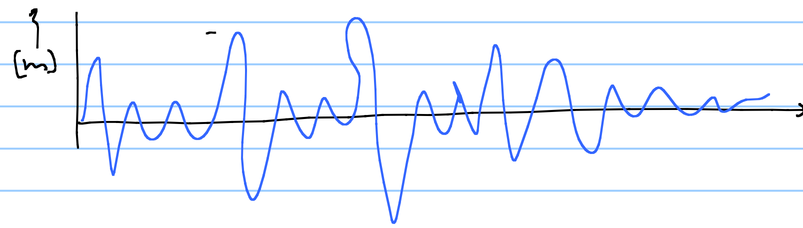
Wind



wind rose

wind and current are typically assumed constant and using the maximum value. (wind direction also must be taken into account)

Waves

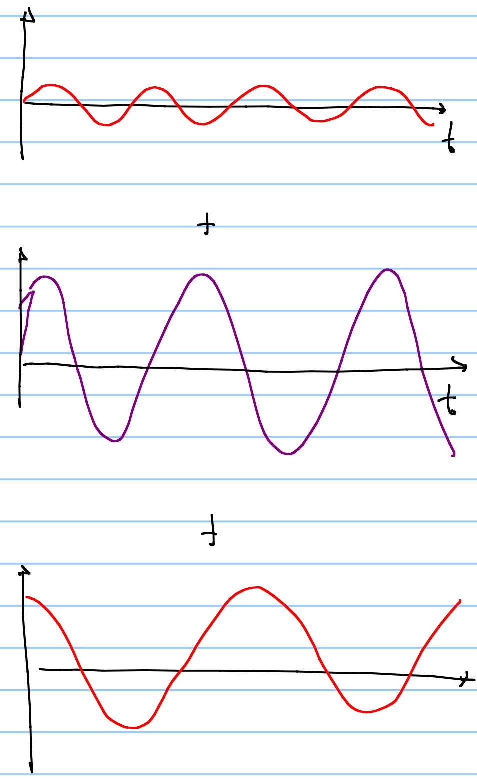


Fourier

$$f(t) = \sum_{i=1}^{N} \underbrace{A_i}_{\text{amplitude (m)}} \sin(\omega_i t + \underbrace{\phi_i}_{\text{phase shift}})$$

angular frequency $\omega_i = 2\pi f_i$

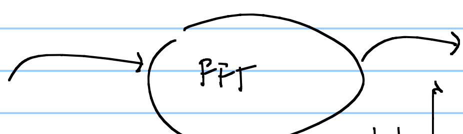
$\omega_i = \frac{rad}{s}$ $\left[\frac{\cancel{cycle}}{s}\right]\left[\frac{2\pi \ rad}{1 \ \cancel{cycle}}\right]$



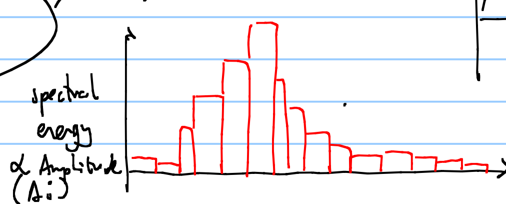
Discrete Fourier transform

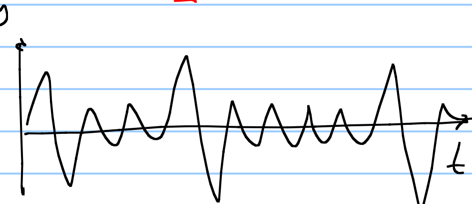
FFT Fast fourier transform

t	value
□	□
□	□
□	□
□	□

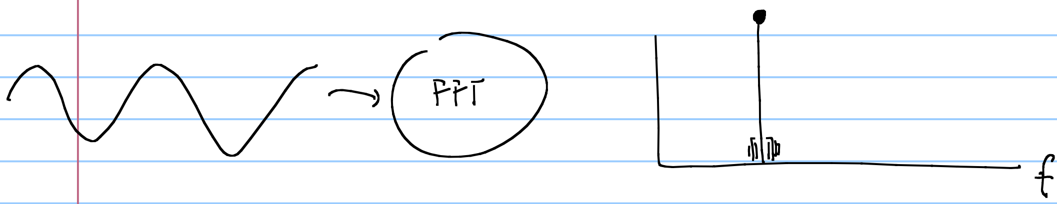


spectral peak period
dominant frequency





sometimes analytical equations are used
Pierson Moskowitz, JONSWAP



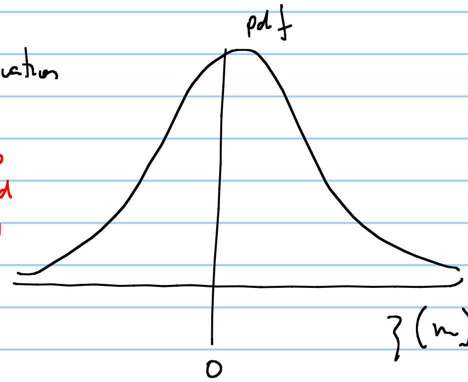
to deal with the variability of waves in time, we apply FFT on the signal and report spectral peak period

the spectral peak period does not change significantly in 3 hours

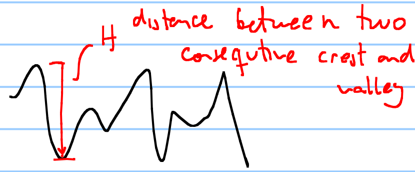
sea state

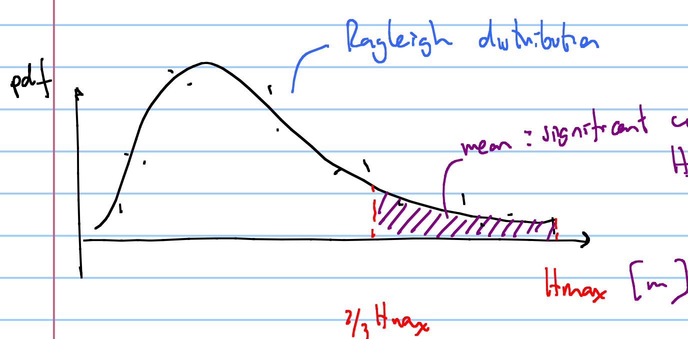
what to do with amplitudes?

statistics on wave elevation



wave height



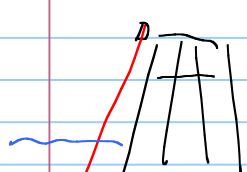


to characterize a sea state (3 hrs) Hs and Tp are used

wave Data must be gathered for at least 2 years to obtain a representative sample of wave conditions in the area

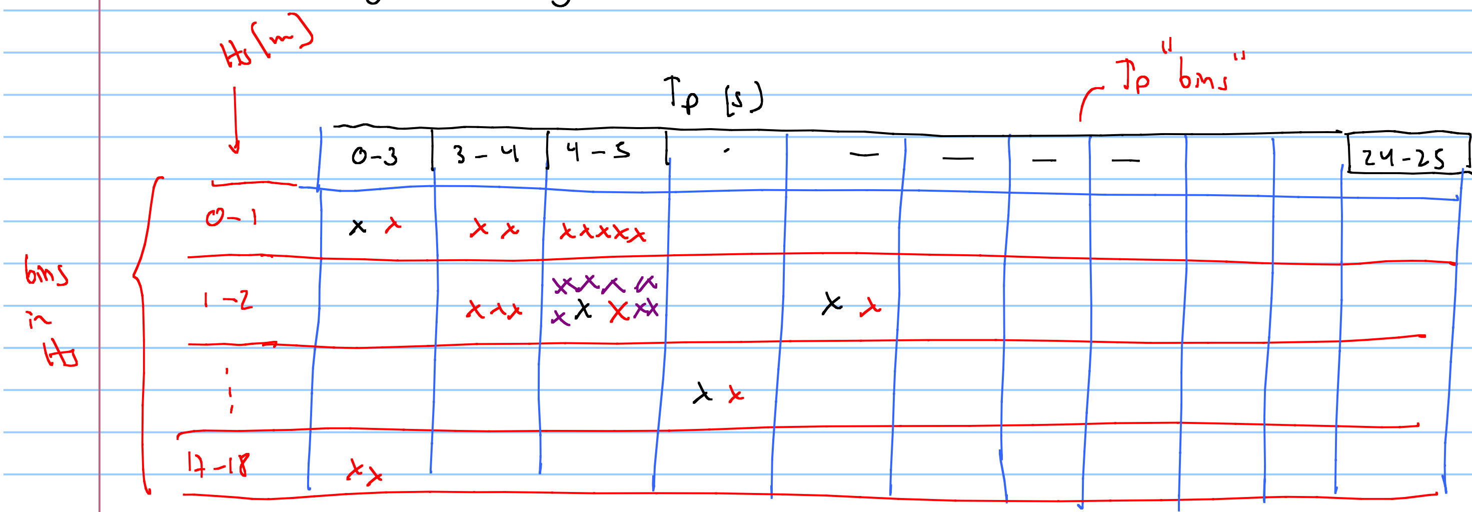
How many sea states are in 2 years

$$2 \text{ years} \cdot \frac{365 \text{ day}}{\text{year}} \cdot \frac{24 \text{ hrs}}{1 \text{ day}} \cdot \frac{1 \text{ sea state}}{3 \text{ hr}} = 5840$$



with all measured data, compute Tp, Hs for all

Scatter diagram of long term wave statistics



classify each data point i have in each box

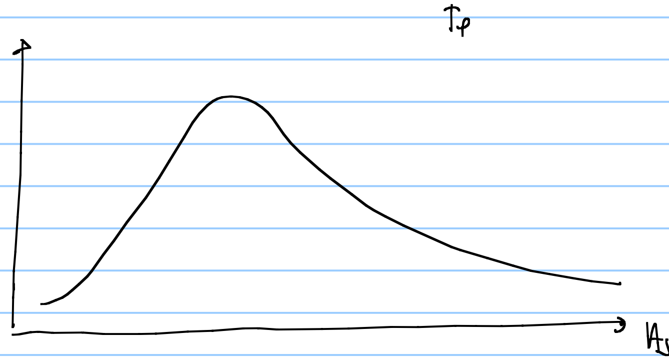
	Spectral Peak period (T_p) [s]																								
Hs [m]	0-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24	24-25	Sum
0-1	15	290	1367	2876	3716	3527	2734	1849	1138	656	362	192	101	52	26	13	7	3	2	1	0	0	0	18927
1-2	1	81	1153	5308	12083	17323	18143	15262	10980	7053	4169	2316	1229	631	315	155	75	36	17	8	4	5	1	96348
~~2-3~~	~~0~~	~~2~~	~~94~~	~~1050~~	~~4532~~	~~10304~~	~~15020~~	~~15953~~	~~13457~~	~~9752~~	~~5991~~	~~3403~~	~~1795~~	~~894~~	~~426~~	~~197~~	~~88~~	~~39~~	~~17~~	~~7~~	~~3~~	~~1~~	~~1~~	~~83026~~
3-4	0	0	2	72	686	2782	6171	8847	9189	7493	5082	2991	1577	762	345	148	61	24	9	4	1	0	0	46246
4-5	0	0	0	2	51	433	1645	3495	4807	4750	3638	2286	1229	584	251	100	37	13	5	1	0	0	0	23327
5-6	0	0	0	0	2	39	294	1037	2069	2664	2440	1709	968	463	193	72	25	8	2	1	0	0	0	11986
6-7	0	0	0	0	0	2	32	215	692	1264	1485	1228	767	382	159	57	18	5	1	0	0	0	0	6307
7-8	0	0	0	0	0	0	2	27	157	447	730	762	555	302	130	46	14	4	1	0	0	0	0	3177
8-9	0	0	0	0	0	0	0	2	23	112	276	392	355	223	104	38	11	3	1	0	0	0	0	1540
9-10	0	0	0	0	0	0	0	0	2	19	77	160	192	148	79	31	9	2	0	0	0	0	0	719
10-11	0	0	0	0	0	0	0	0	0	2	16	50	85	85	55	24	8	2	0	0	0	0	0	327
11-12	0	0	0	0	0	0	0	0	0	0	2	12	29	40	33	18	7	2	0	0	0	0	0	143
12-13	0	0	0	0	0	0	0	0	0	0	0	2	8	15	17	12	5	2	0	0	0	0	0	61
13-14	0	0	0	0	0	0	0	0	0	0	0	0	2	5	7	6	4	1	0	0	0	0	0	25
14-15	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	2	1	0	0	0	0	0	9
15-16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	4
16-17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17-18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sum	16	373	2616	9308	21070	34410	44041	46687	42514	34212	24268	15503	8892	4587	2143	921	372	146	55	22	8	6	2	292172

FIGURE 6-18. SCATTER DIAGRAM OF LONG TERM WAVE STATISTICS

$$\frac{292172}{2920\left(\frac{\text{states}}{1\,\text{year}}\right)} \simeq 100 \text{ years}$$

for a fixed wave Hs

for a fixed Tp

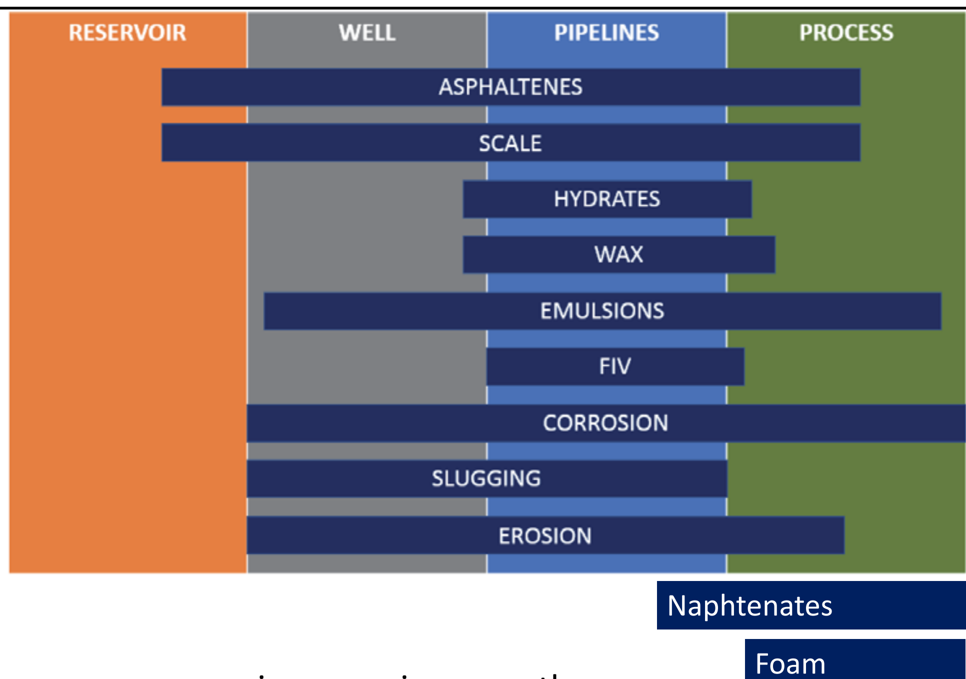


Flow assurance considerations in hydrocarbon field development and planning

Prof. Milan Stanko (NTNU)

1

Issues

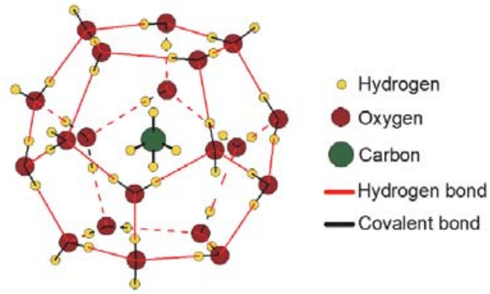


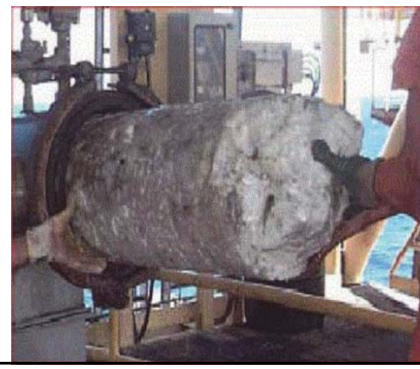
- microorganism growth

2

Hydrates

https://www.youtube.com/watch?v=Oz4NLXfdqpA

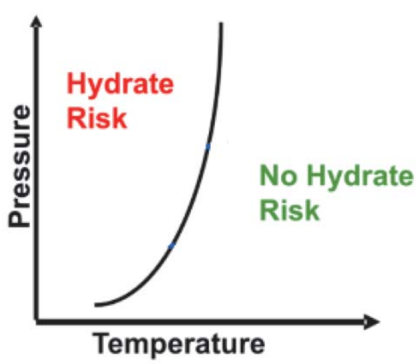




3

Hydrates - conditions

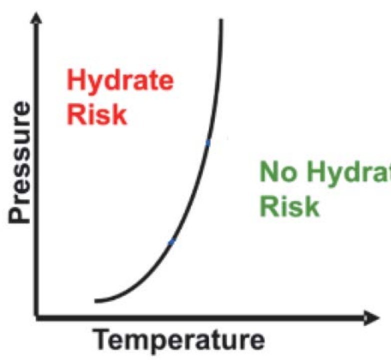
- Free water (in liquid phase)
- Small hydrocarbon molecules
- Particular range of pressure and temperature.

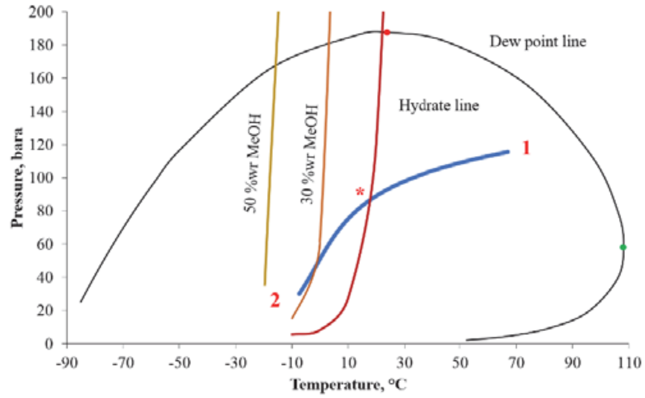


4

Hydrates - conditions

- Free water (in liquid phase)
- Small hydrocarbon molecules
- Particular range of pressure and temperature.

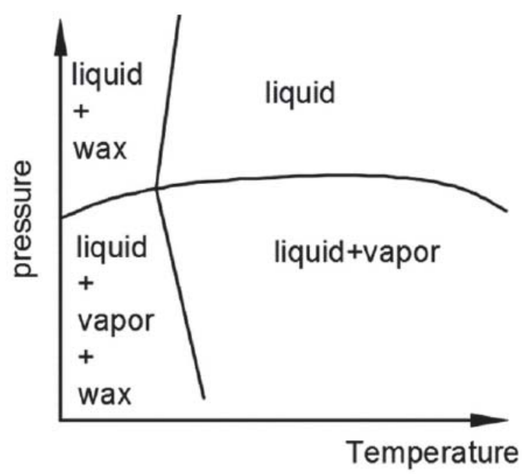




5

Wax

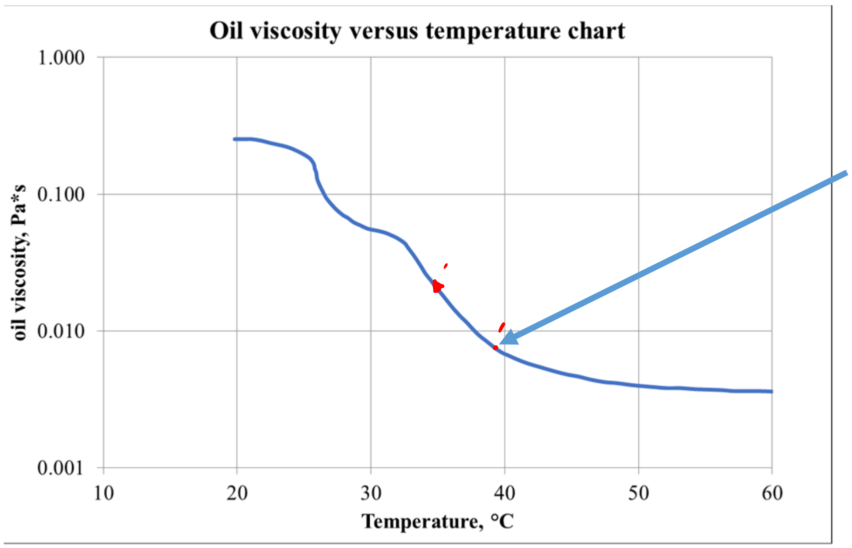
TAKEN FROM EQUINOR



Paraffins (C18 - C36)

6

Wax

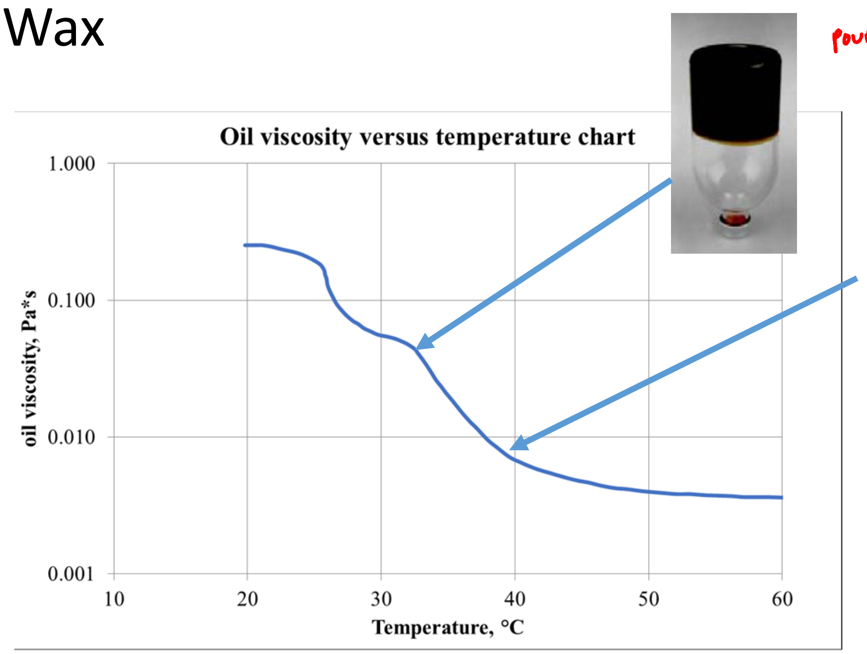


cloud point
WAT (wax apperance temperature)

7

Wax

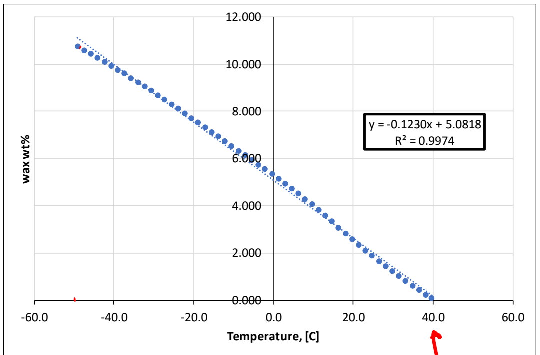
pour point



8

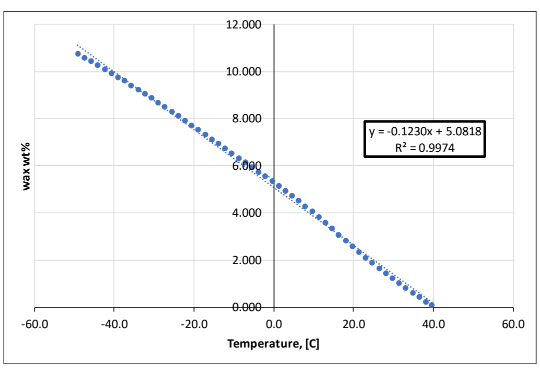
Wax

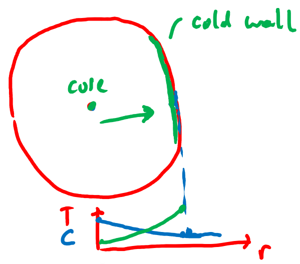
$$\frac{\text{weight of wax particles}}{\text{total weight}} \times 100$$

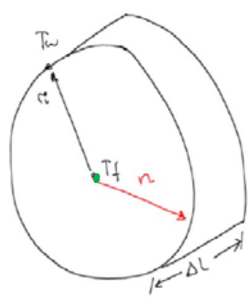


9

Wax





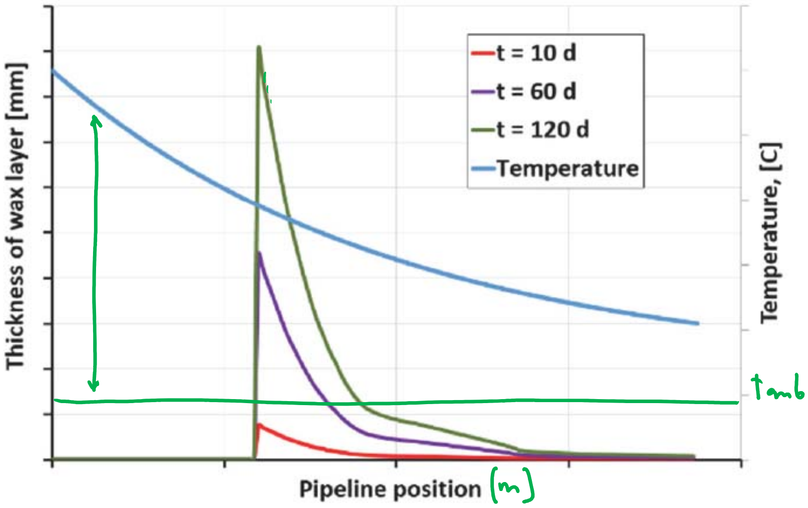


r_i: internal pipe diameter
T_f: fluid temperature
T_w: wall Temperature
n: mass flux of wax from fluid to wall [Kg/s.m²]
$dA = 2 \pi r_i \, dL$
total mass flow of wax (m_w) deposited in a section
$m_w = n \cdot dA$

$$n = \rho_{wax} \cdot \frac{B}{\mu_o} \cdot \frac{dC}{dT} \cdot \frac{dT}{dr}$$

10

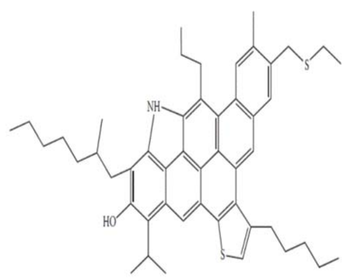
Wax

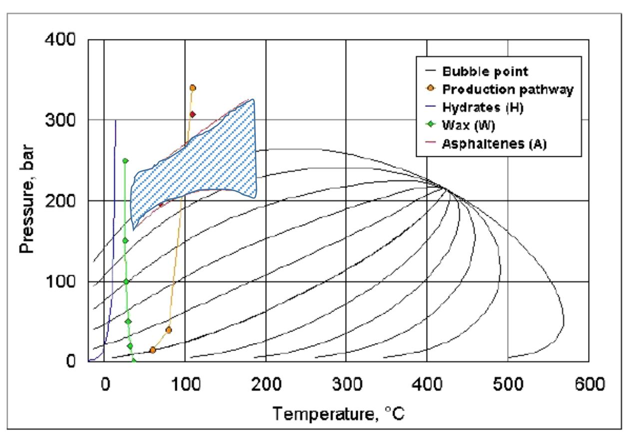


11

Asphaltenes

TAKEN FROM EQUINOR (KALLEVIK)





12

Scale

Ion	Formasjonsvann [mg/l]
Na	14 800
K	520
Mg	13
Ca	378
Ba	410
Sr	228
Fe	58
Cl	23 600
SO4	0

+

Ion	Seawater [mg/l]
Na	10 680
K	396
Mg	1 279
Ca	409
Ba	8
Sr	0
Fe	0
Cl	19 220
SO4	2 689

$$Ba^{2+} + SO_4^{2-} = BaSO_4(s)$$

$$Ca^{2+} + CO_3^{2-} = CaCO_3(s)$$

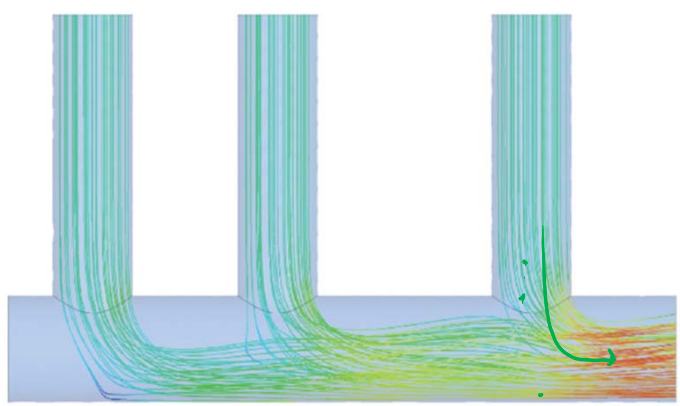
$p\downarrow$
$T\uparrow$

$BaSO_4$ $CaCO_3$ NaCl

TAKEN FROM EQUINOR (SANDENGEN)

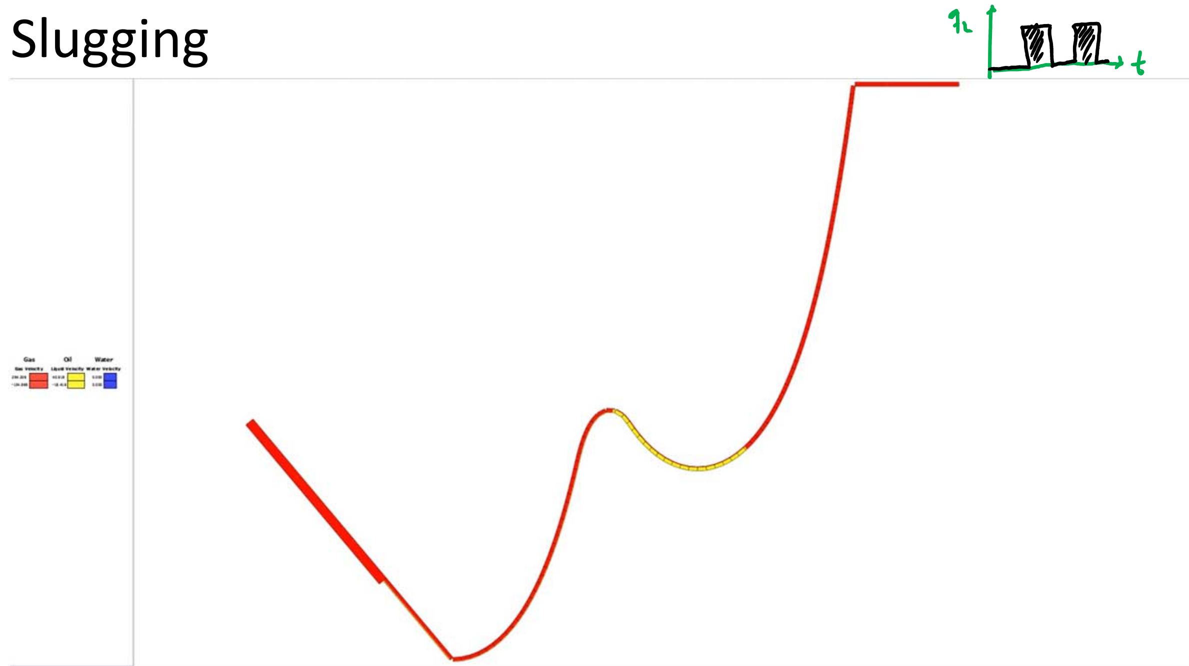
13

Erosion



14

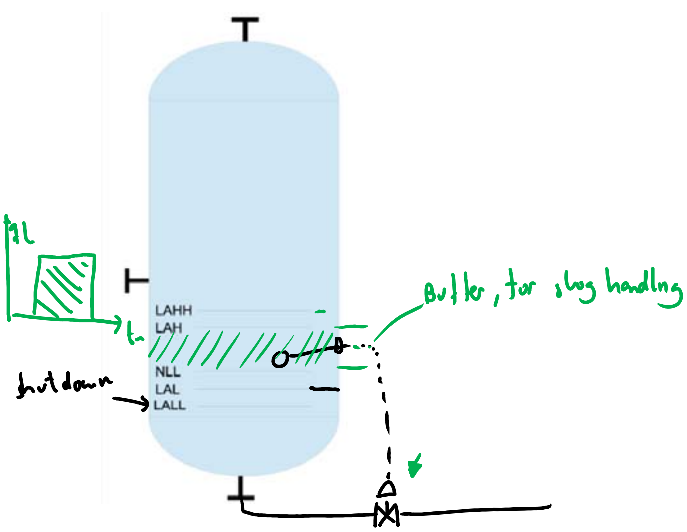
Slugging



https://www.youtube.com/watch?v=j59QLHsTs_c

15

Slugging – impact on separator operation

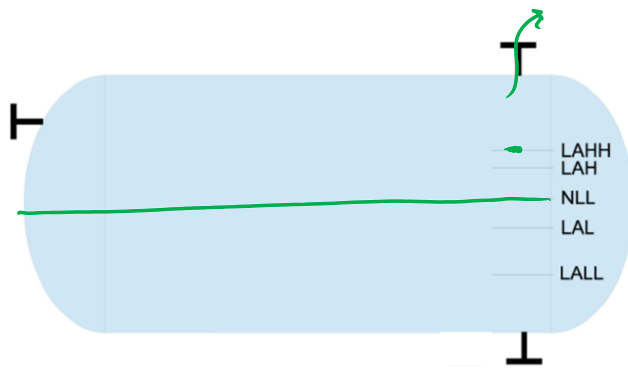


LAL: Level alarm low
LAH: Level alarm high
LALL: Level alarm low low
LAHH: Level alarm high high

https://pubs.spe.org/en/ogf/ogf-article-detail/?art=1028

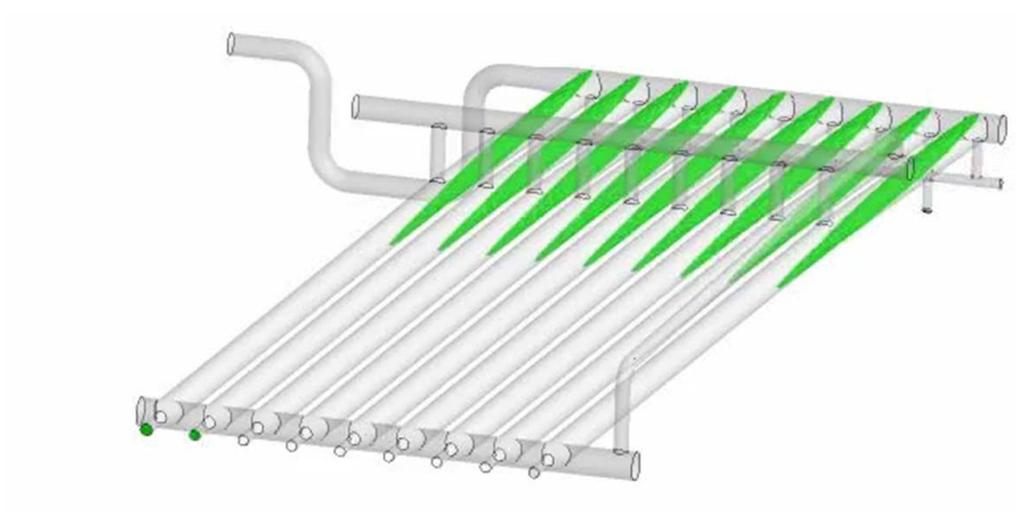
16

Slugging – impact on separator operation



17

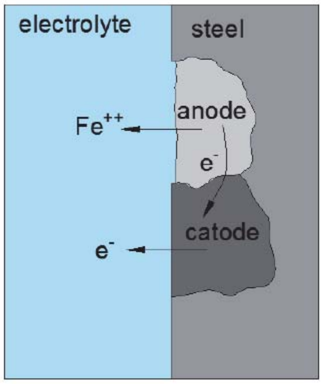
Slugging – slugcatcher handling slugs

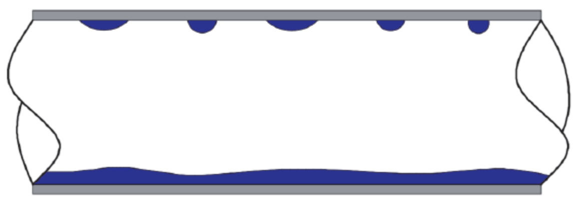


https://www.youtube.com/watch?v=LKLW5284adI

18

Corrosion



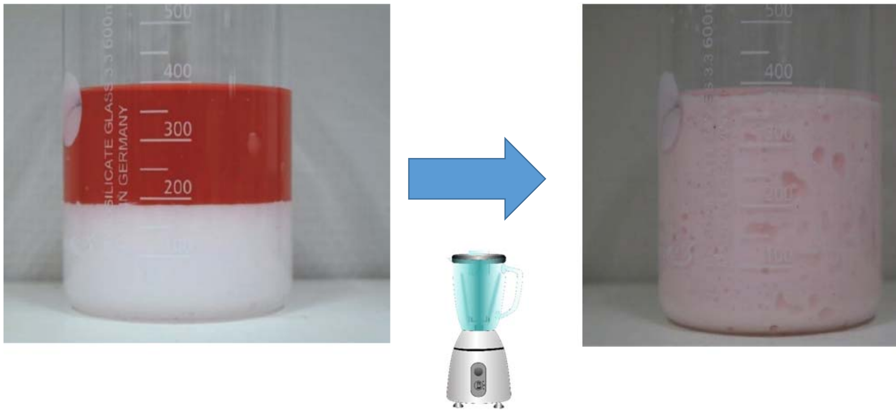


19

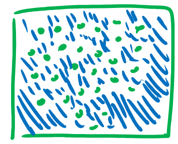
Oil-water emulsions

20

Oil-water emulsions

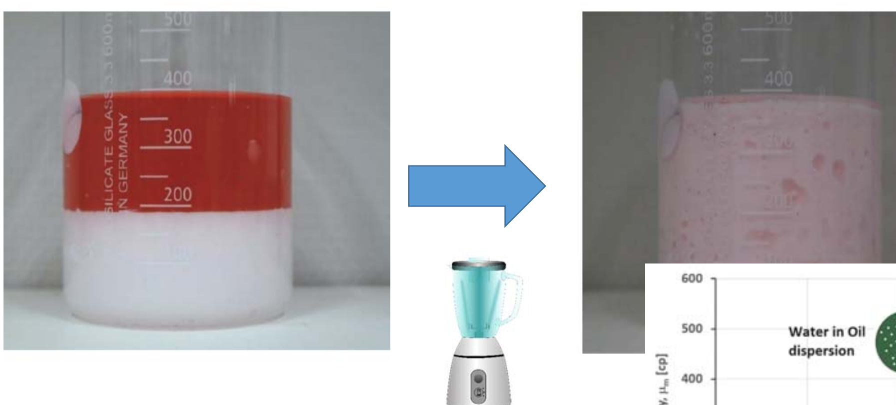


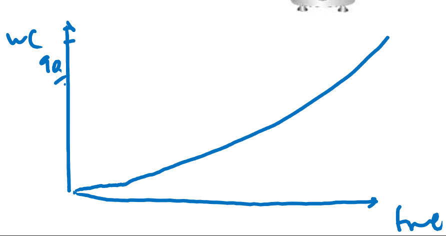
fine and stable dispersion

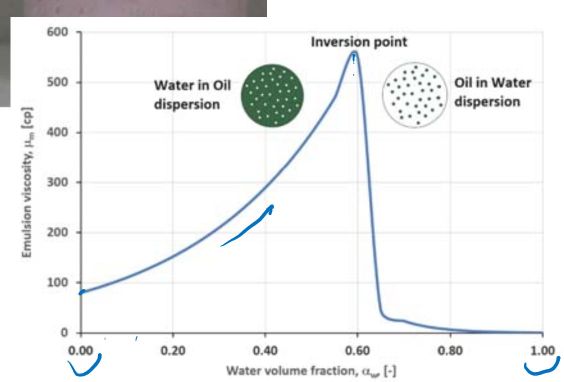


21

Oil-water emulsions

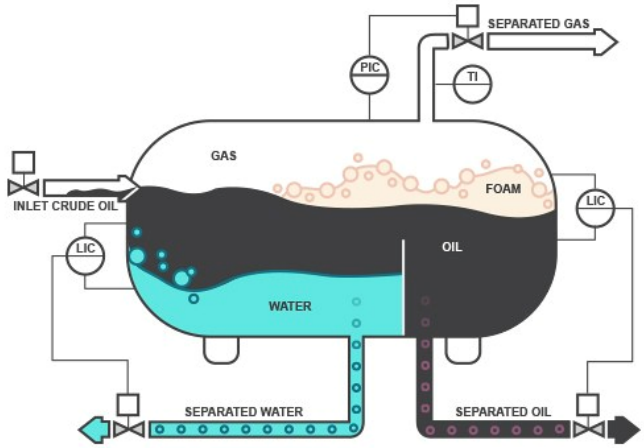




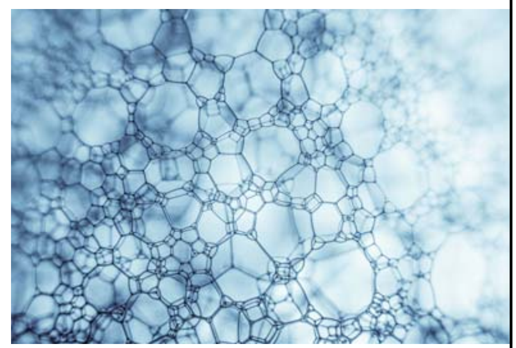


22

Foam



https://www.arab-oil-naturalgas.com/foam-in-oil-gas-separators/



https://www.crodaoilandgas.com/en-gb/discovery-zone/functions/foamers

23

Flow assurance issue	Causes	Potential Consequences	Prevention/solution	Tools available for analysis
Hydrates	• Small gas HC molecules • Free water • Begin to form at a given p and T (low T, high P) given by thermodynamic equilibrium of the hydrate phase.	• Blockage of flowlines and pipelines	Reduce the hydrate formation region: •Continuous or on-demand injection of chemical inhibitor (MEG or MEOH) Stay out of hydrate formation region: •Improve thermal insulation •Electric heating Others: •Cold flow* •Water removal and gas dehydration*	To determine Hydrate formation conditions: •Laboratory tests •Empirical correlations •Thermodynamic simulators (e.g. Hysys, PVTsim, Unisim) To determine p and T along the pipe: •Multiphase simulator (Olga, LedaFlow). •Computational fluid dynamics (CFD)
Wax	• Composition of the crude oil • Begins to form at given p and T due to changes in solubility • Cold wall	In wells, flowlines and pipelines: •Increase pressure drop (pipe roughness) •Reduction of cross section area •Pipe blockage •Changes fluid rheology •Gelling (problem for startup)	• Pigging • Thermal insulation • Electric heating • Chemical inhibitors • Chemical dissolvers • Pipe coating • Cold flow*	• Laboratory tests • Transient multiphase simulators (e.g. Olga, LedaFlow) • Computational fluid dynamics (CFD)
Slugging	• Dynamics of multiphase flow of liquid and gas • Reduction of rate • Liquid accumulation on low points	• Fluctuating liquid and gas input to processing facilities In flowlines and pipelines: • Vibration • Added pressure drop • Fatigue	• Change separator size • Pipeline dimensioning • Maintain flow above minimum flow rate • Gas lift in riser base • Choking topside • Pipeline re-routing • Subsea separation*	• Transient multiphase simulator (OLGA, LEDA) • Structural analysis (usually with FEA, e.g. Ansys) • Laboratory experiments
Scaling	• Changes in solubility (e.g. changes in P and T conditions, changes in pH, mixture of incompatible water, CO2 injection).. • Irregularities on surface	In wells, pipelines and flowlines: •Reduction of cross section area •Pipe blockage •Malfunctioning of valves and equipment	• Continuous injection of chemical inhibitors • Dilution by adding more water • Chemical dissolvers • Mechanical removal • Coating	• Laboratory tests • Simulation tools

24

Flow assurance issue	Causes	Potential Consequences	Prevention/solution	Tools available for analysis
Erosion	• Sand production • High flow velocities • Liquid droplets in the gas • Gas droplets in the liquid	In wells, pipelines and flowlines: •Structural damage •Vibration •Leaks •Corrosion	• Change geometry • Replacement and maintenance of components • Reduce flow rate (reduce formation drawdown) • Sand separation* • Coatings	• Standards (DNV-RP-0501) • Computational fluid dynamics • Laboratory testing
Corrosion	• Water • O_2 • CO_2 • H_2S	• Leaks • Integrity	• Coatings • Material selection • Surface passivation	• Laboratory testing
Emulsions	• Emulsification agents in the crude • Mixing, shear when flowing through valves, chokes, etc	• Added pressure drop • Increased separation time	• Injection of demulsifiers • Heating	• Laboratory tests • Multiphase models
Asphaltenes	• Crude with asphaltenes • Pressure reduction • Addup of light hydrocarbon components	• Blockage of formation, well, flowline and pipeline • Loss of equipment functionality • Emulsification and foamification	• Mechanical removal • Chemical injection	• Laboratory tests • Some simulation tools

25

Measures and consequences

- **Chemical injection**
- System design, e.g.
  - o pipe and component insulation
  - o heat tracing
  - o dead legs
  - o pipeline routing
- Well intervention needs
- Water injection strategy
- Define procedures when shutting down and starting up
- Ensure proper distribution of chemicals

26

Example of chemical injection program

Tabell 5-2. Foreløpig oversikt over kjemikalietyper

Type kjemikalie	Konsentrasjon (ppm vol.)	Tilsettes i	Frekvens
Avleiringshemmer A	50	Produsert vann	Kontinuerlig
Avleiringshemmer B	20-50	Sjøvann	Kontinuerlig
Korrosjonshemmer	50	Produsert vann	Kontinuerlig
Emulsjonsbryter	50	Total væske 1)	Kontinuerlig ved behov
Skumdemper	5	Total væske	Periodisk
Flokkulant	10	Produsert vann	Kontinuerlig
Vokshemmer	150	Total væske 1)	Periodisk
Biocid	80	Total væske 1)	Kontinuerlig
Oksygenfjerner	5	Sjøvann	Kontinuerlig
H2S fjerner	150	Produsert vann	Kontinuerlig ved behov
MEG	Batch	Brønnstrøm	Ved behov

1) Olje og produsert vann.

27

Release and disposal of chemicals

Tabell 7-1 Klassifisering av kjemikalier i henhold til OSPAR

	Svart kategori: Stoffer som er lite nedbrytbare og samtidig viser høyt potensial for bioakkumulering og/eller er svært akutt giftige. I utgangspunktet er det ikke er lov å slippe ut kjemikalier i svart kategori. Tillatelse til bruk og utslipp til spesifikke kjemikalier gis dersom det er nødvendig av sikkerhetsmessige og tekniske grunner.
	Rød kategori: Stoffer som brytes sakte ned i det marine miljøet, og viser potensiale for bioakkumulering og/eller er akutt giftige. Kjemikalier i rød kategori kan være miljøfarlige og skal derfor prioriteres for utskifting med mindre miljøfarlige alternativer. Tillatelse til bruk og utslipp gis kun av sikkerhetsmessige og tekniske hensyn.
	Gul kategori: Kjemikalier i gul kategori omfatter stoffer som ut ifra iboende egenskaper ikke defineres i svart eller rød kategori og som ikke er oppført på PLONOR-listen (se under). Ren gul kategori er uorganiske kjemikalier med lav giftighet eller kjemikalier som brytes ned >60% innen 28 dager. Gul-Y1 er 20-60% nedbrutt og forventes å brytes ned fullstendig over tid. Gul-Y2 er moderat nedbrytbare til ikke giftige og ikke-nedbrytbare komponenter. Y2 skal forsøkes substituert på lik linje med røde kjemikalier.
	Grønn kategori: Stoffer som er oppført på OSPAR-konvensjonens PLONOR-liste (Substances used and discharged offshore which are considered to Pose Little Or No Risk to the Environment). Disse kjemikaliene vurderes å ha ingen eller svært liten negativ miljøeffekt. Kjemikalier i grønn kategori omfatter også vann som inngår i kjemikaliene.

From Ivar Aasen PDO, Del 2

28

Release and disposal of chemicals

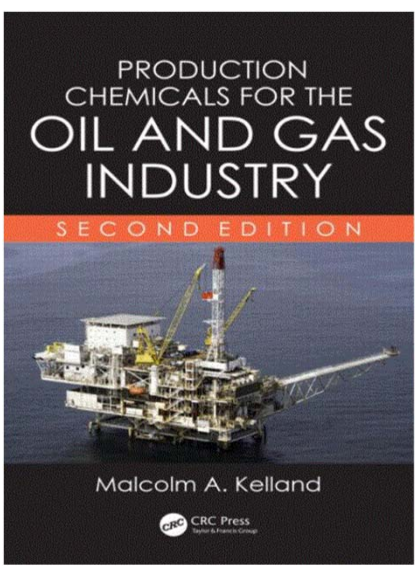
Tabell 7-4 Miljømessige egenskaper til produksjonskjemikalier som vil følge produsert vann fra Johan Castberg-feltet

Type kjemikal	Vannfase/oljefase	Klassifisering
Avleiringshemmer	Vannløselig. Følger produsert vann.	Det er antatt at gult kjemikalie (i klassen Y2) kan velges. Kjemikaliet er moderat bionedbrytbart til ikke bionedbrytbart Det er ikke giftig og vil ikke bioakkumuleres i næringskjeden.
Emulsjonsbryter	Oljeløselig. Følger hovedsakelig oljefasen (95%). 5% følger produsert vann.	Alle disse kjemikaliene er klassifisert som røde, pga det ikke er bionedbrytbart. De er ikke giftige og vil ikke bioakkumulers i næringskjeden.
Vokshemmer	Oljeløselig. Følger oljefasen.	
Skumdemper	Oljeløselig. Følger i all hovedsak oljefasen, lave konsentrasjoner i produsert vann.	
Flokkulant	Vannløselig, men binder seg til oljedråper. Følger hovedsakelig oljefasen (80%). 20% er antatt å følge produsert vann.	
Biocid/Glutaraldehyd	Vannløselig. Følger injeksjonsvannet eller produsert vann.	Kjemikalie er klassifisert som gult pga giftighet. Det er ikke nedbrytbart og vil ikke bioakkumuleres i næringskjeden.

From Johan Castberg PDO, Del 2

29

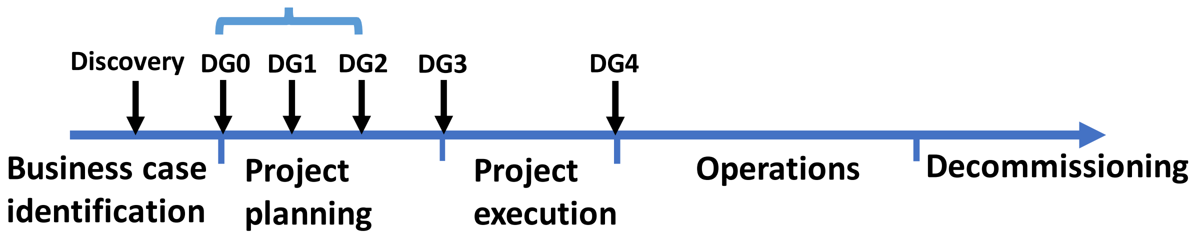
More about production chemicals



30

Flow assurance evaluation during field planning

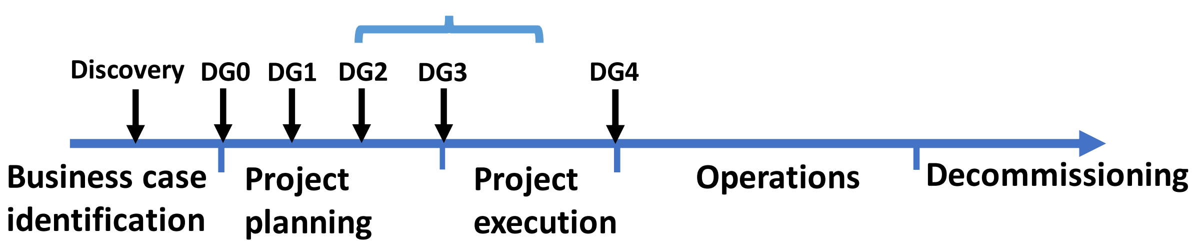
- Detect potential showstoppers and communicate technical constraints and repercussions to field planner
- Laboratory tests



31

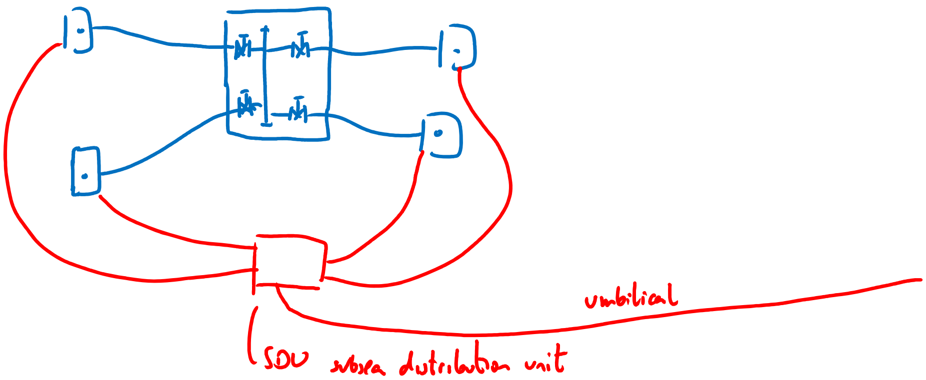
Flow assurance evaluation during field planning

Refine the flow assurance strategy
-More laboratory tests
-Management plan
-prediction of p and T
-Study of startup and shutdown
-System design and verification
-FIV



32

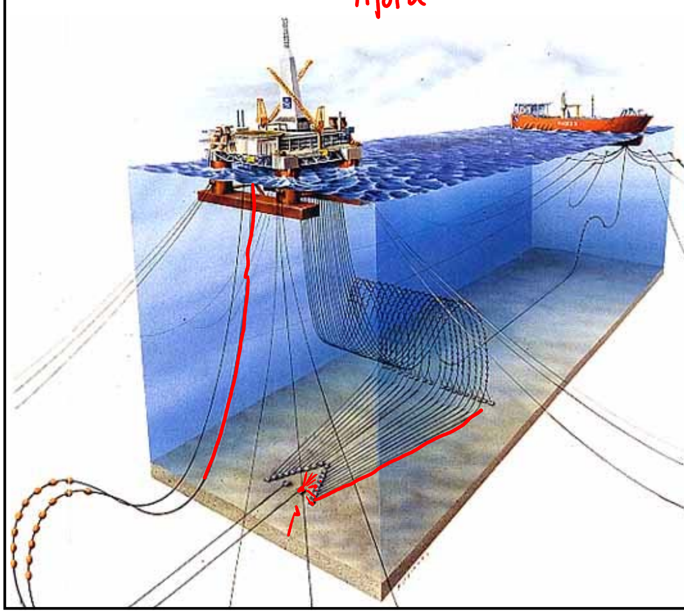
Injection of production chemicals subsea



33

Injection of production chemicals

Njord



34

Umbilicals, injection of production chemicals

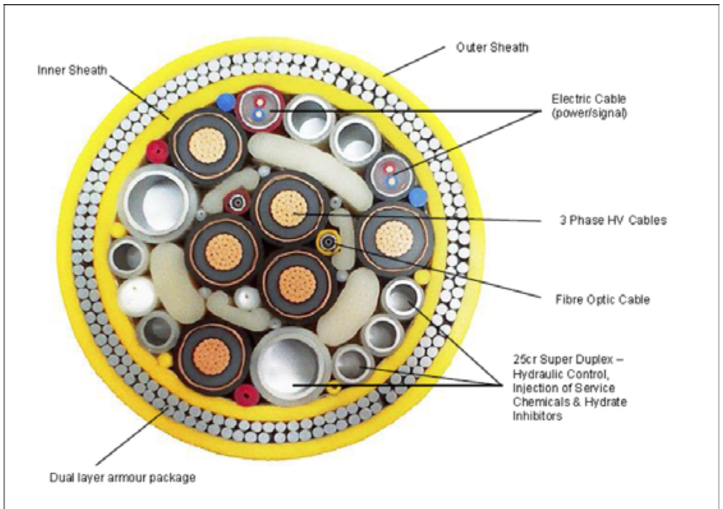
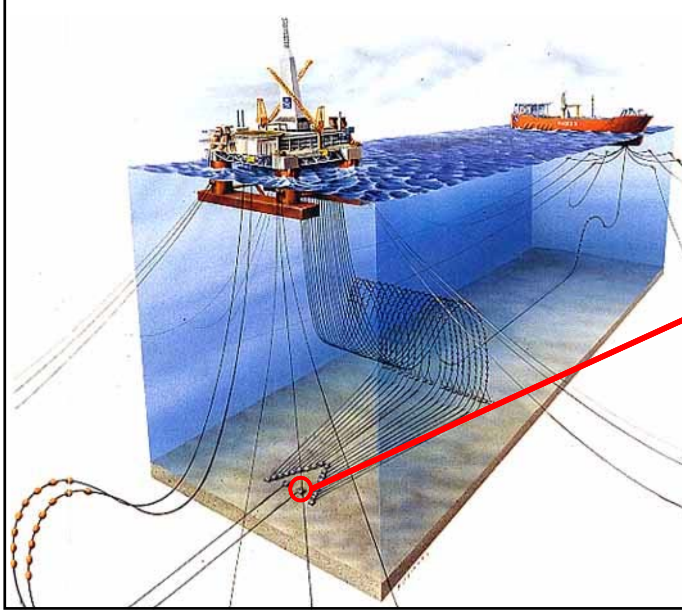


Figure 3 – Umbilical Cross Section Example

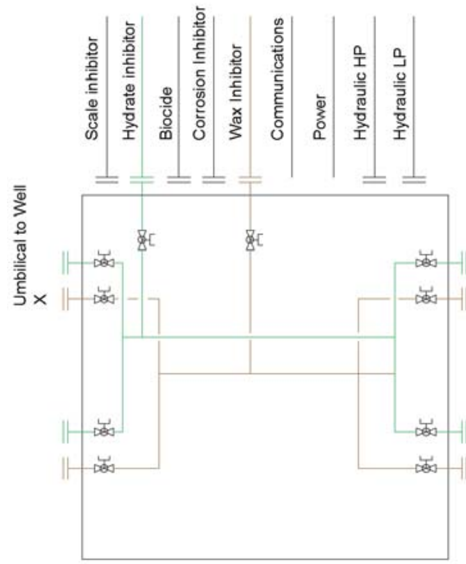
35

Umbilicals, injection of production chemicals

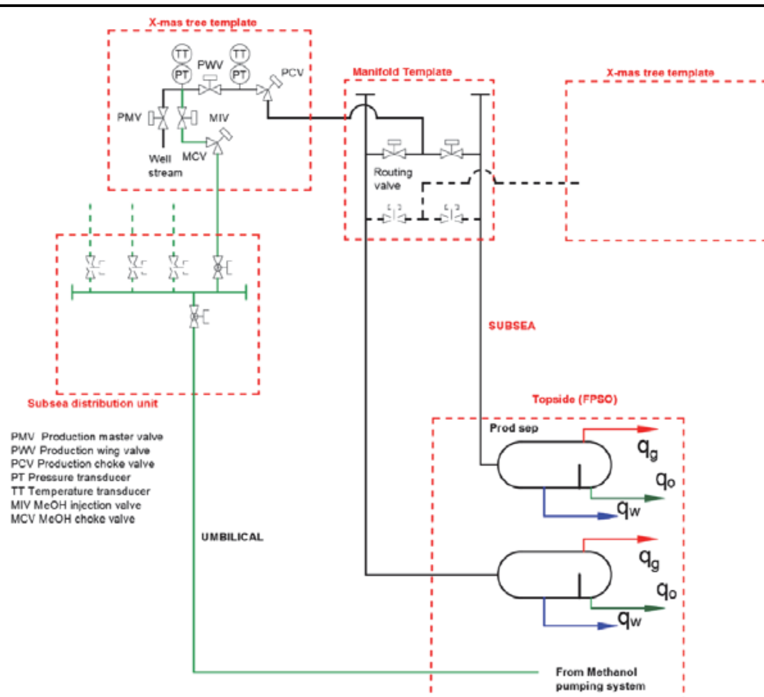


36

Release and disposal of chemicals

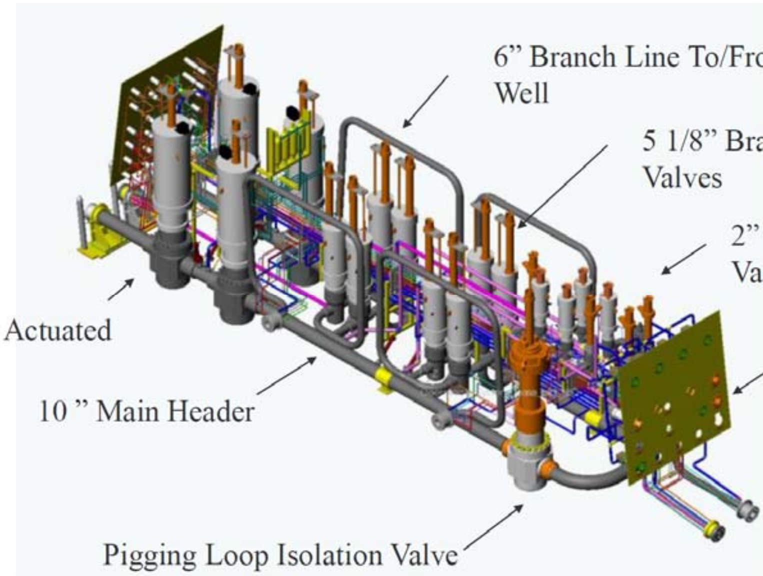


37



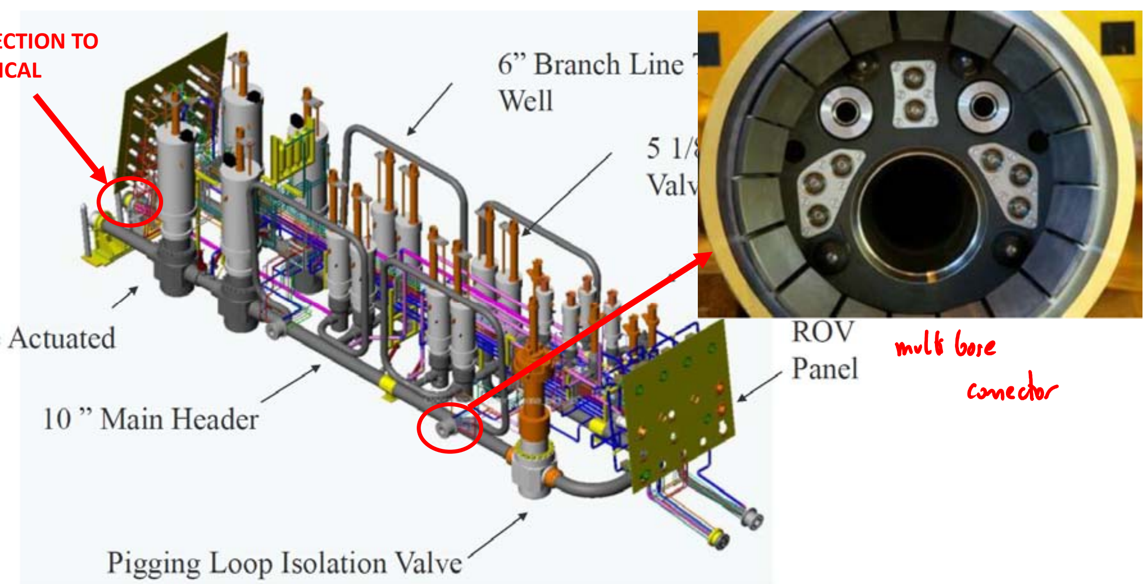
38

Injection of production chemicals – template wells



39

Injection of production chemicals – template wells



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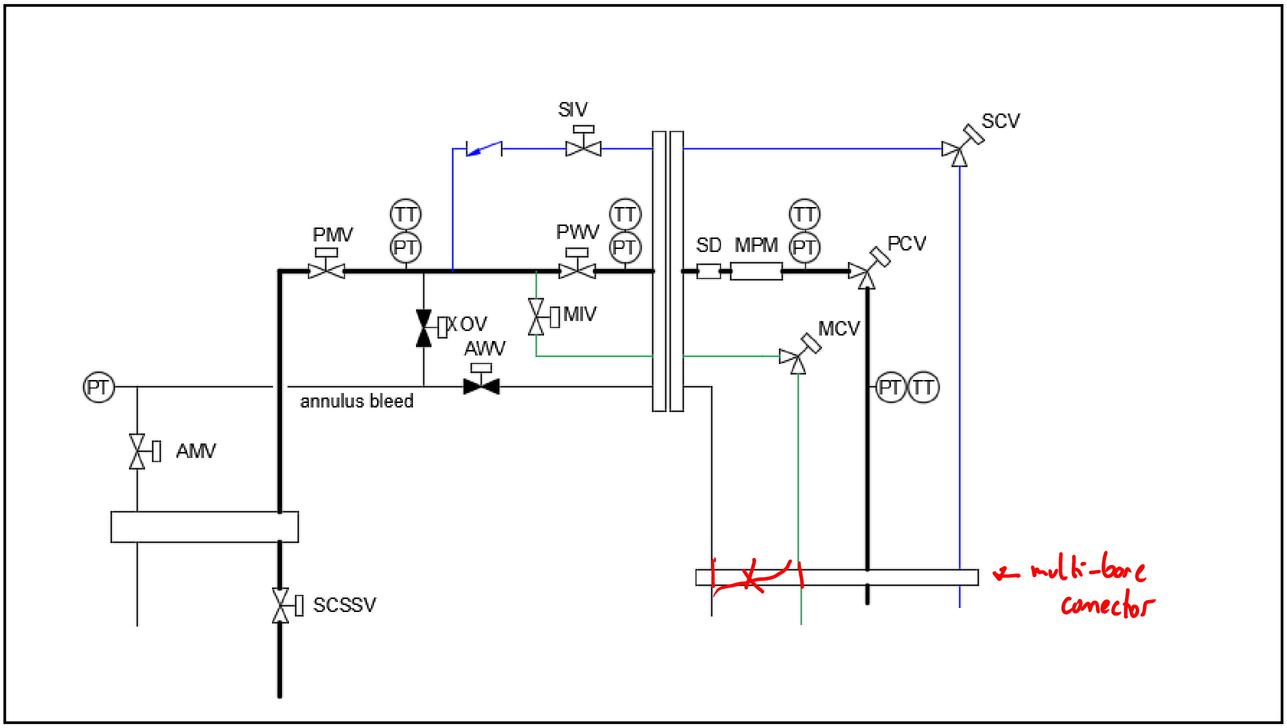
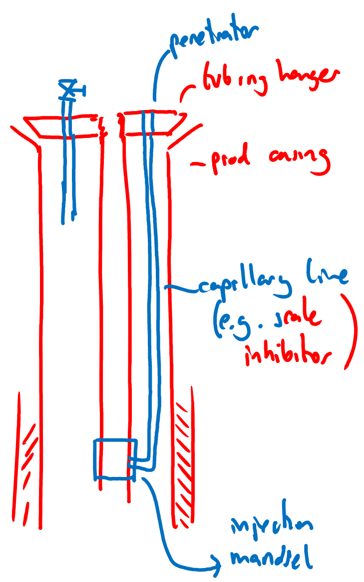


41

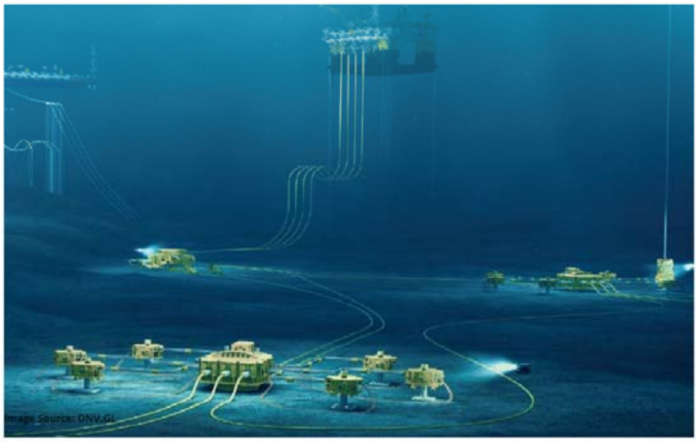
Injection of production chemicals in well

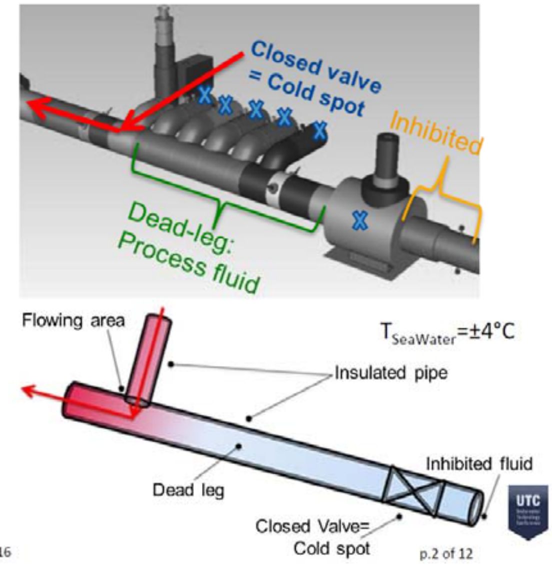


42

Subsea manifold and dead-leg geometry

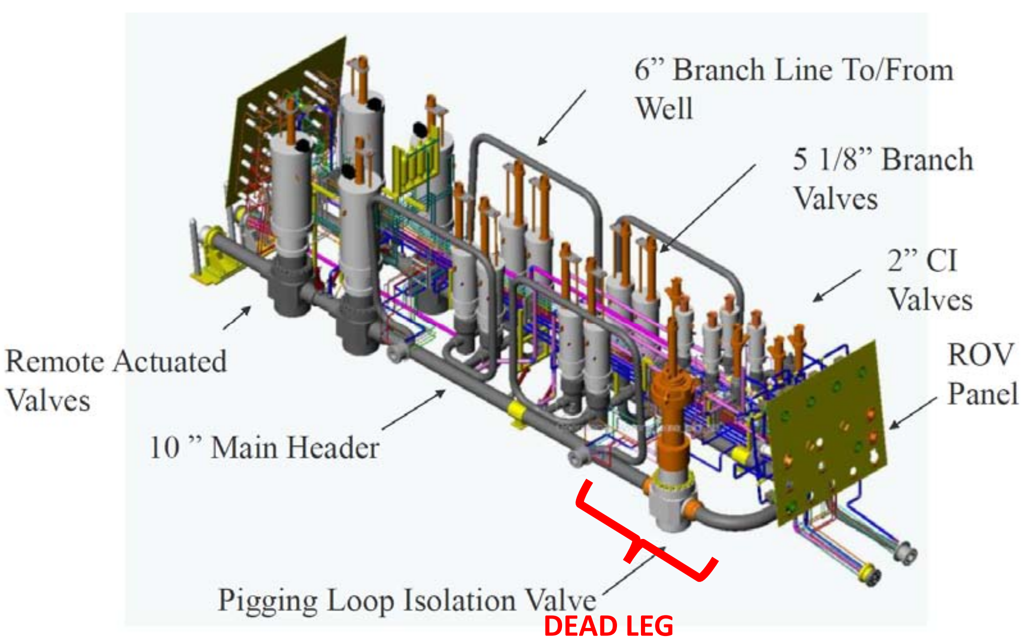
- Dead-legs are inherently present





UTC Bergen - 16th June 2016 p.2 of 12

43



44

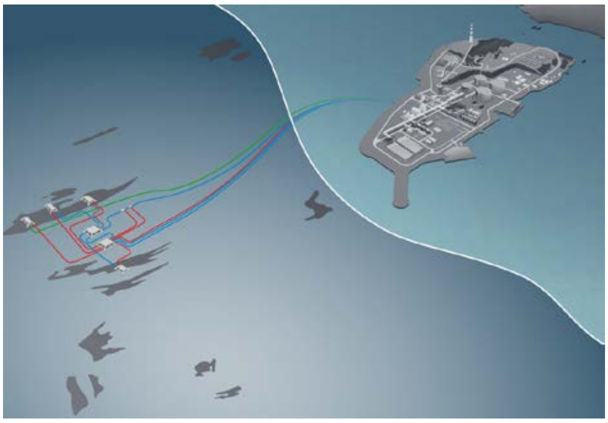
Tools for analysis

- Laboratory tests of fluids (oil, gas, water)
- Steady state flow simulators (Hysys, Gap, Pipesim, Olga, Leda, FlowManager)
- Transient flow simulators (Olga, LedaFlow, FlowManager, Hysys)
- Thermodynamic or PVT simulators (PVTsim, Hysys)
- Standards (DNV, API)
- CFD simulation for 3D flow analysis of pressure and temperature (Comsol, Ansys)
- Finite element analysis for structural analysis and heat transfer in solids (Abacus, Ansys)

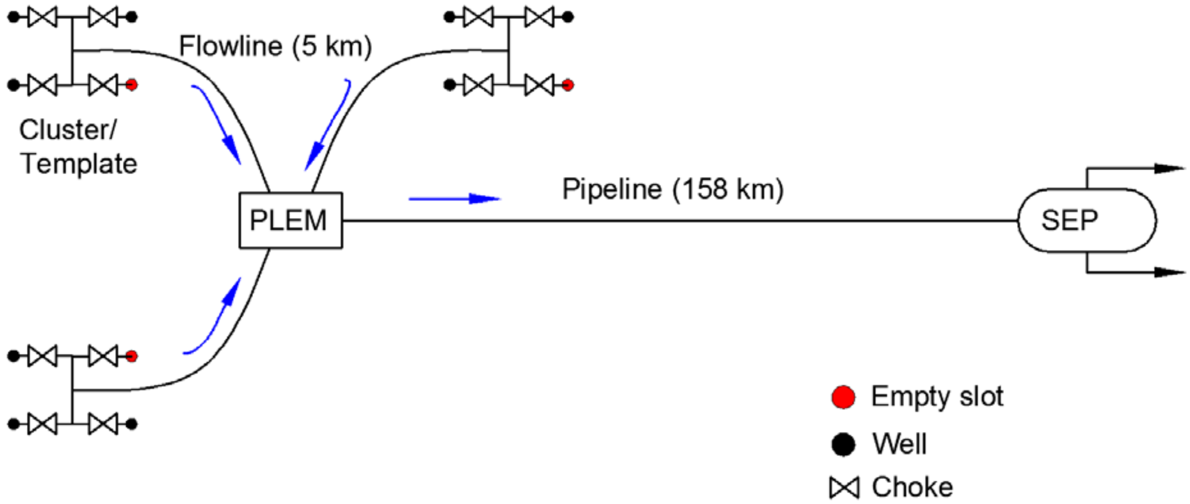
45

<u>Flow assurance analysis of the Snøhvit pipeline using Hysys</u>

Snøhvit is an offshore gas field located in the Barents Sea 158 km from Hammerfest currently under development. The field will be developed with the “subsea to beach” concept. The gas production will be taken by an LNG plant and transported further in LNG carrier to customers in US and Spain. The plateau rate of the field has been set to 20 E6 Sm^3/d and Equinor plans to maintain it until year 2032.



According to the base case Scenario (BCS) selected for the study, the field is completed subsea with three subsea templates, each with 3 wells.



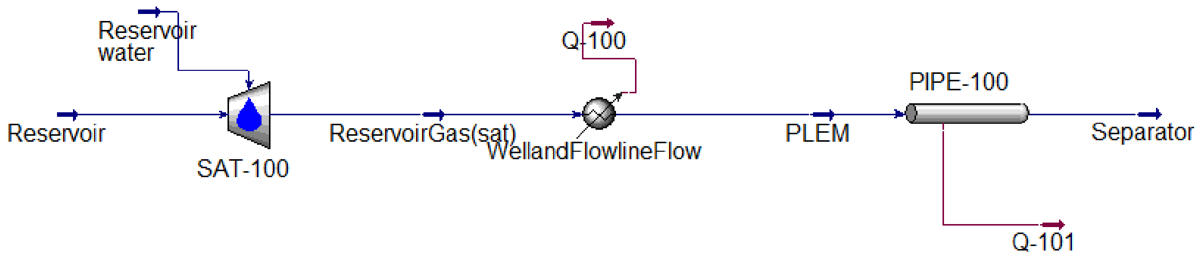
You are asked to perform a steady-state, 1D simulation using the simulator Hysys to compute pressure and temperature drop along the main transportation pipeline from the PLEM to the slug catcher. The main goal is to assess hydrate formation. You have to perform your calculations for the plateau phase.

Tasks:

- Tabulate and plot pressure, temperature and liquid holdup along the pipeline. Compute the total amount of liquid in the pipeline (this can be calculated by integrating the holdup along the pipeline).
- Plot the phase envelope (p-T diagram) of the gas mixture illustrating the saturation lines (bubble and dew point lines) and the quality lines inside the two-phase region (0.01, 0.02, 0.03, 0.04, 0.05, 0.1, 0.2). Plot also the hydrate line provided. Indicate in your plot the following:
  - Cricondenbar and Cricondentherm points
  - Plot the p-T along the pipeline on top of the p-T diagram. Detect if there is any condensate retrograde behavior. In this context condensate retrograde behavior is when the liquid stops condensing in the pipeline and it starts evaporating (the quality, mliquid/mtotal, starts to diminish)
  - Will hydrates form in the pipeline?

Solving suggestions

- Suggested layout in Hysys is shown below. First saturator representing saturation with water at reservoir conditions (276 bara and 92 C), then heat exchanger, to bring pressure and temperature of the stream from reservoir conditions to plem conditions. Then pipeline to model pressure and temperature drop in the pipeline.

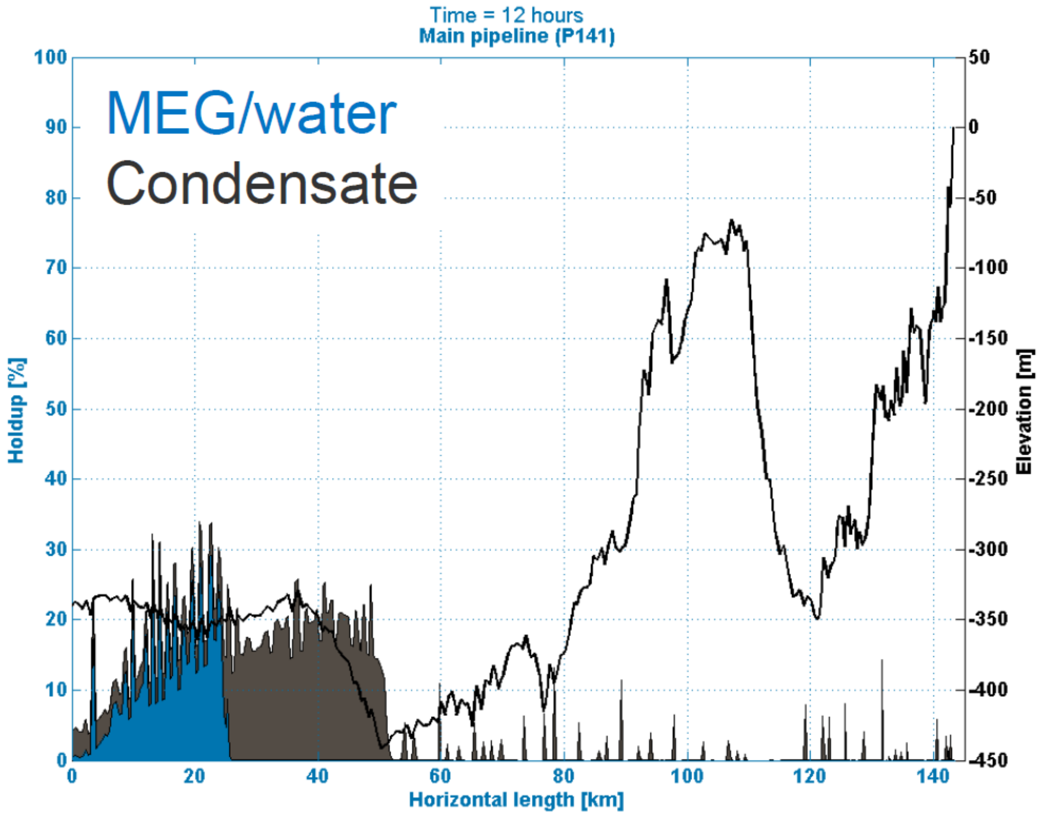


Pressure and temperature are specified in the streams “Reservoir water”, “Reservoir” and “PLEM”. Composition is specified in Streams “Reservoir water” and “Reservoir”. Mass rate is specified in stream “Reservoir”. The mass rate can be estimated by multiplying the standard conditions gas rate of the field times the density of the gas at standard conditions (20 E06 Sm3/d * 0.67 kg/m3)

- Remember that Hysys performs its calculations co-current. This means that you provide a plem pressure and temperature, and a molar rate at the inlet of the pipeline, then Hysys calculates the separator pressure. However, separator pressure has to be 30 bara. Therefore, it is necessary to use an ADJUST to iterate on plem pressure to get 30 bara at the separator.
- Get the points for the elevation profile of the pipeline using the webplot digitizer https://automeris.io/WebPlotDigitizer/
- Water should be included in your calculations. Assume the well stream is saturated with water at reservoir pressure and temperature (92 ^{o}C). For this use the water saturator unit available in hysys.
- There might be a mismatch between the pressure drop calculations in Hysys and the ones performed previously with Excel. Hysys considers the effect of liquid on the pipe and the variation of density and viscosity of the fluids.
- Use increments of 1 km for your calculations.
- The hydrate equilibrium line can be found in the “envelope” attachment to a stream in Hysys.

Available information

- Pipeline profile. Use the program webplotdigitizer (https://automeris.io/WebPlotDigitizer/) to "steal" the poins from the chart below. Use at least 10 points.



Pout (Slug catcher pressure)	**[bara]**	30
Tseabed	**[C]**	6

Component	Mole %
Nitrogen	2.525
Carbondioxide	5.262
Methane	81.006
Ethane	5.027
Propane	2.534
i-Butane	0.4
n-Butane	0.83
i-Pentane	0.281
n-Pentane	0.308
Hexanes	0.352
Heptanes	0.469
Octanes	0.407
Nonanes	0.203
Decanes+	0.397

Density of Decane+: 814 kg/m^3
MW of Decane+: 172 kg/kmol

The overall heat transfer coefficient of the pipeline assuming that the pipe is "naked" is: 10 W/m2 K

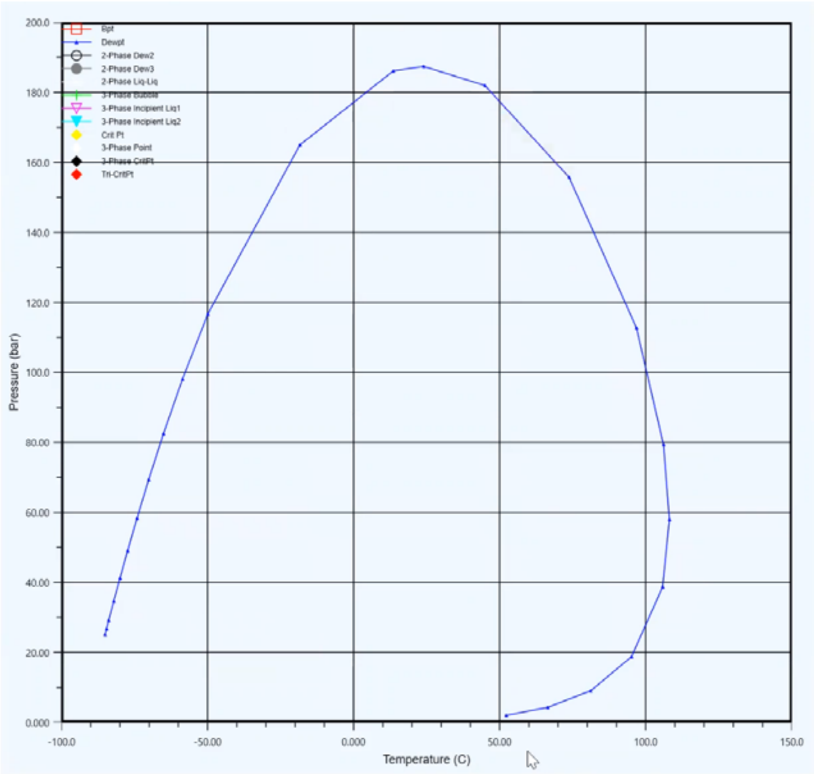
Pipe diameter information:

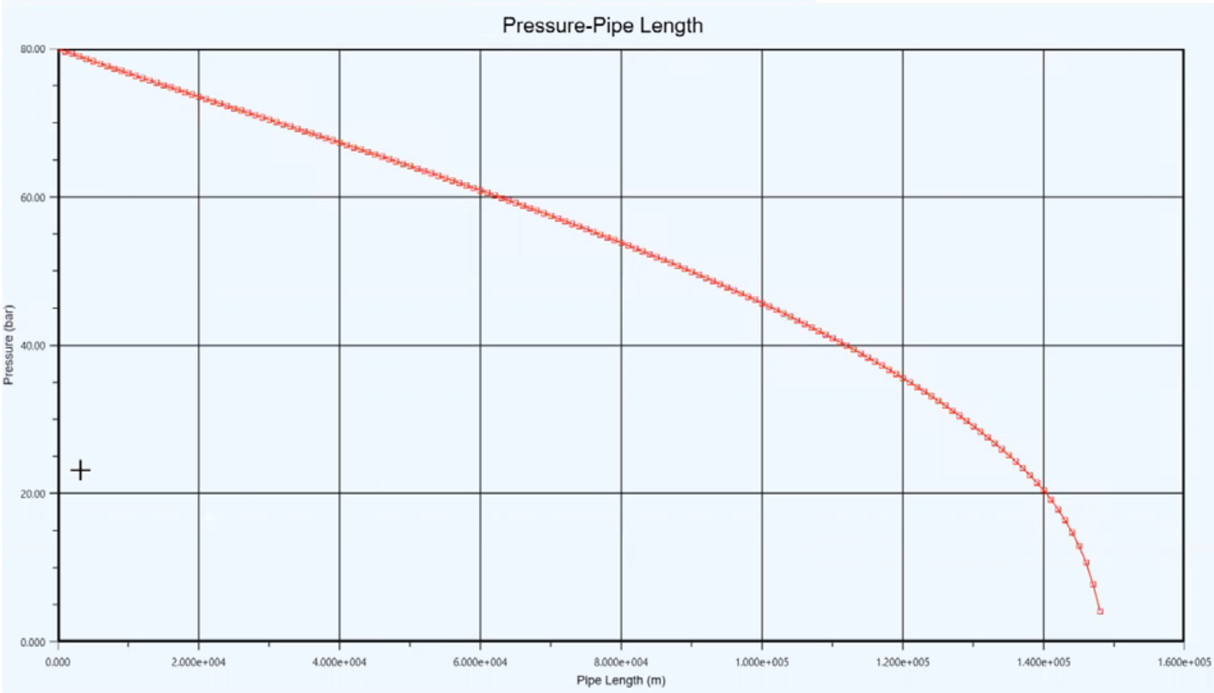
Inner diameter of the steel pipe ID, [mm]	**678.2**
Outer diameter of the steel pipe OD [mm]	**711.2**

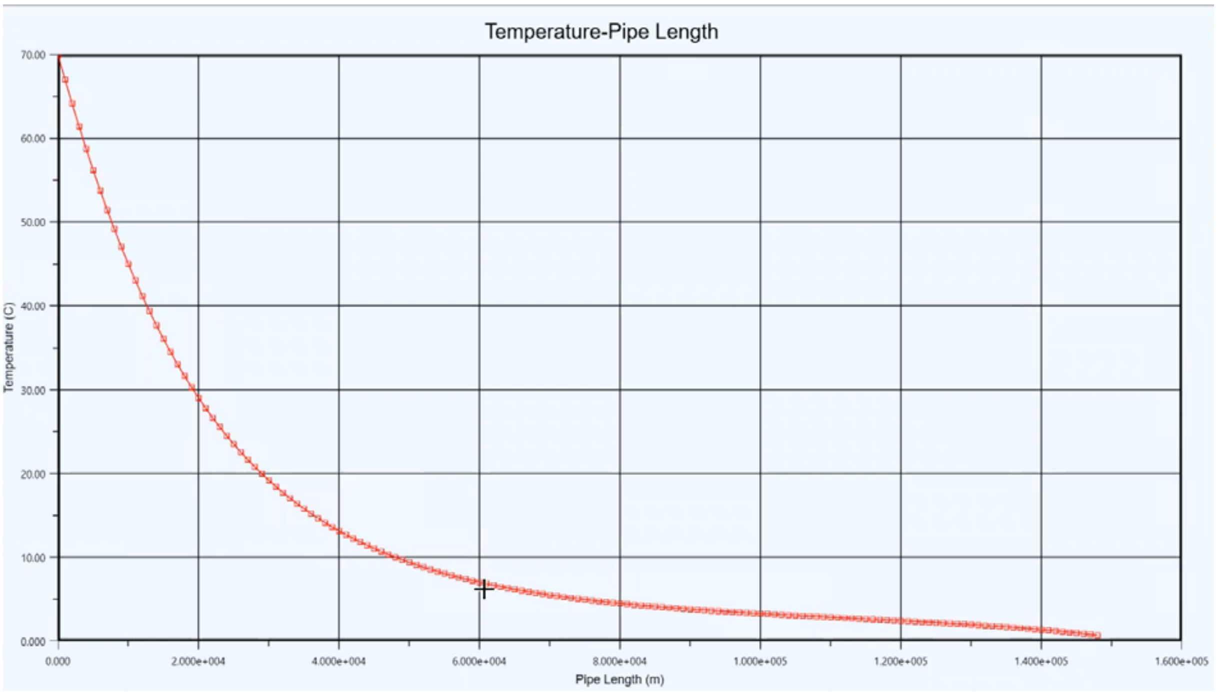
Some help with Hysys:

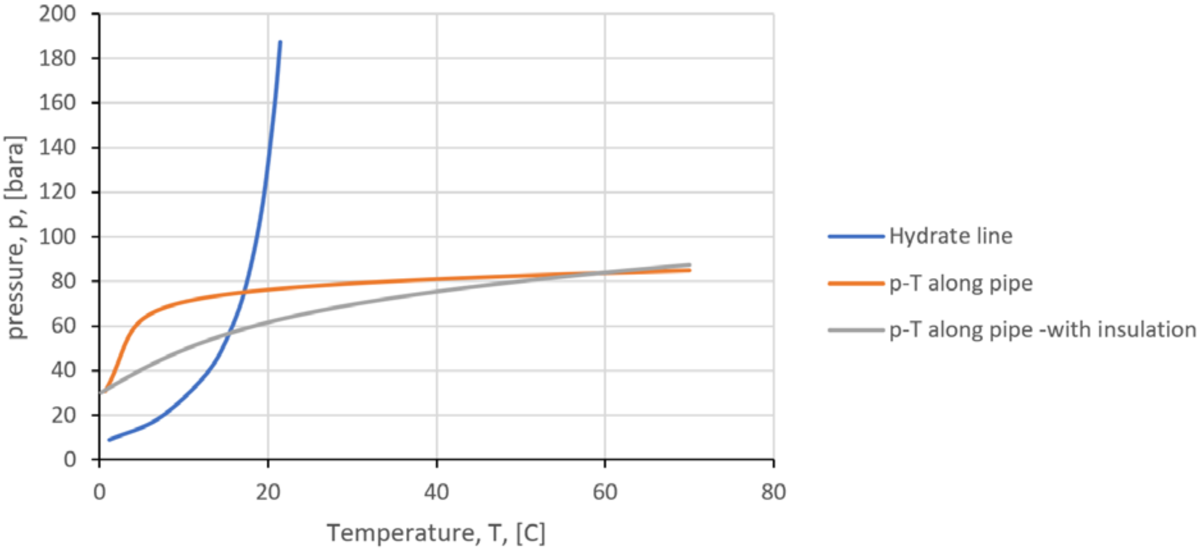
You can run Hysys remotely from your computer using
https://farm.ntnu.no
Alternatively, Hysys is installed in some computers in the computer lab on the 3rd floor.

Solution (worked out in class):



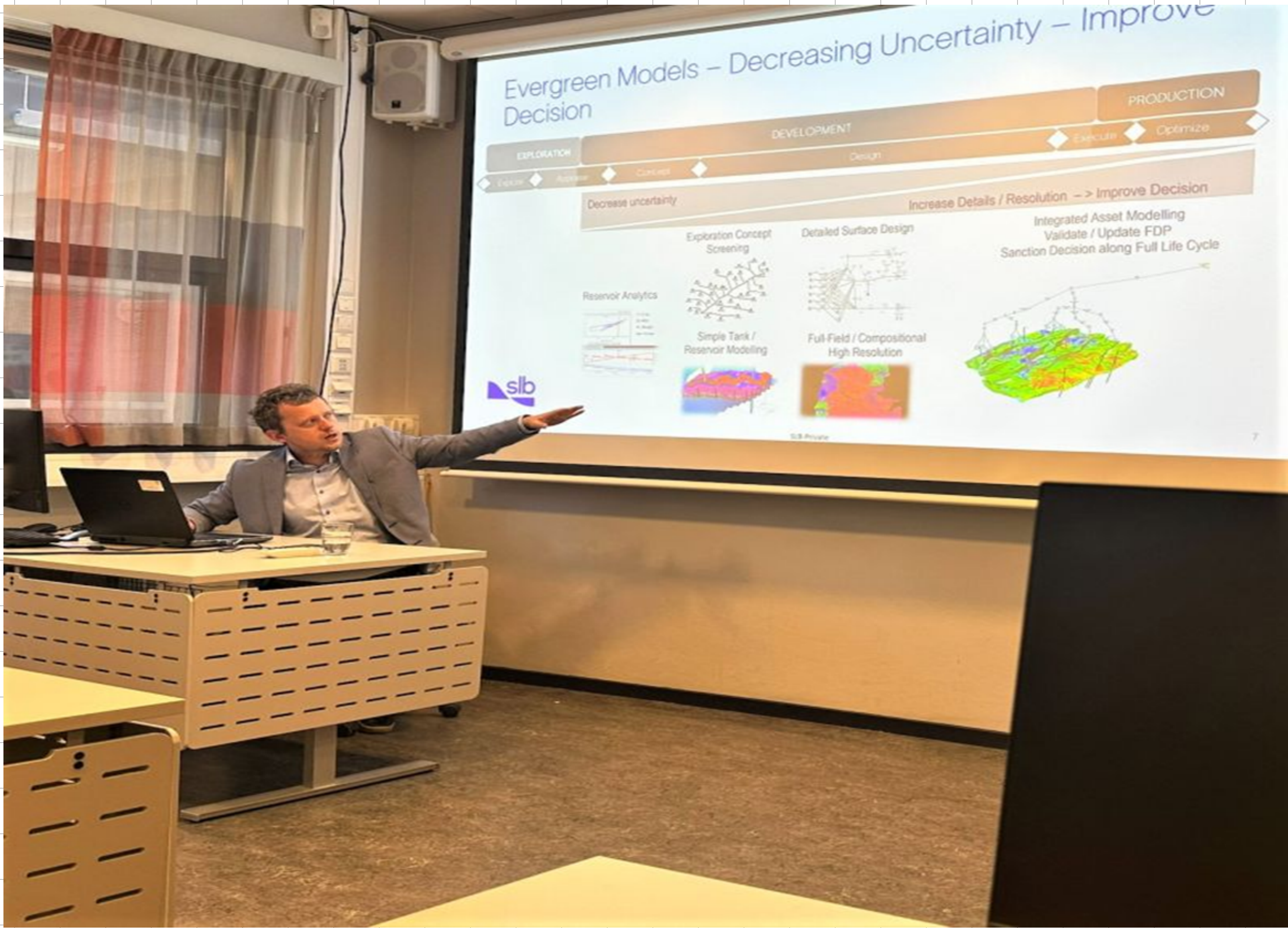



Temperature-Pipe Length
Temperature (C)
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.000
0.000
2.000e+004
4.000e+004
6.000e+004
8.000e+004
1.000e+005
1.200e+005
1.400e+005
1.600e+005
Pipe Length (m)


pressure, p, [bara]
200
180
160
140
120
100
80
60
40
20
0
0
20
40
60
80
Temperature, T, [C]
Hydrate line
p-T along pipe
p-T along pipe -with insulation

-Lecture of the 14.04: software tutorial about integrating reservoir (Reveal) and network (GAP) model using Resolve. This tutorial is the worked example 2.1.1. given in the manual of Resolve, under the “Examples Guide” section.

20230418- presentation by Ruslan Baiguzov from SLB Oslo with regards to PIPESIM and it's last capabilities to model well network system and doing economic analysis of different field development plan using IAM package.



<u>Problem 1:</u>

This problem is based on the software tutorial provided on the lecture of the 14.04, on integrating reservoir (Reveal) and network (GAP) model using Resolve. This tutorial is the worked example 2.1.1. given in the manual of Resolve, under the "Examples Guide" section.

You can work in groups of up to 3 people. When delivering in blackboard, you need to join a group first (even if delivering alone). Please be aware there are only 10 licenses available of Resolve/Reveal/GAP, so please share. You can use the PCs in computer room P2 during regular lecture hours.

Your main tasks are as follow:

Task 1. Do the tutorial by yourself. For that you can use the video recording of the lecture.
Task 2. Provide a plot of field plateau duration versus field plateau rate. The plot should contain at least 4 points. Be aware you might need to adjust the total simulation time for long plateau durations.
Task 3. Plot the IPR (pwf versus oil rate) of well 1 for several times (at least 5)
Task 4. Make a video animation of the IPR of well 1 in time.

Deliverables:

- All simulation files.
- A short summary document with the answers.
- The video/animation file

PENSUM:

- Field development workflow.
    - Lifecycle of a hydrocarbon field
    - Overview – The field development process
    - Production modes
    - Discounting
    - Relationship between plateau height and length
    - Rule of thumb between plateau height and TRR
    - Bottlenecking and processing capacity (separation capacity)
    - Onshore vs offshore
    - Oil vs gas
    - Video recording of presentation about Aasta Hansteen development
- Excel VBA, functions, and routines.
- Topside processing
    - Overview
    - O-G-W Separation and stabilization
    - Separation capacity
    - Horizontal separator design
- Field production performance
    - Estimation of production profiles
    - Dry gas production system: material balance, IPR, TPR, FPR, choke, flow equilibrium.
    - Production scheduling
    - Measures to prolong the plateau.
    - Boosting
    - Approaches to generate production profiles, coupling reservoir and wellbore models
        - Coupling reservoir and production simulator in commercial software (Resolve, Reveal, GAP,PROSPER)
    - Dry gas networks.
    - CO_2 injection scheduling
    - Production potential
    - Presentation by Ruslan Baiguzov from SLB Oslo: PIPESIM, IAM.
- Value chain model, cost estimation and NPV calculations
- Introduction to Python, Jupyter Notebook
- Dealing with uncertain parameters in FD
    - Probabilistic reserve estimation
        - Monte Carlo
    - Decision and probability tree analysis
- Offshore structures
    - Overview
    - Layout of production systems
    - Marine loads on offshore structures
    - Visit to AkerSolutions Verdal
- Flow assurance considerations
    - General overview
    - Inhibitor subsea system. Disposal.
    - Simulation of pipeline using commercial software (Hysys)

Home exercises
Class exercises/Class group work
Quizzes

Lecture material :

- Live lectures
- Youtube videos
- Reading material

Upcoming deadlines

- Date to be decided. Last meeting of reference group
- 02.05. Deadline for exercise set 4.
- 09.05. (Latest) Milan sends approval of mandatory exercises (approval to take the exam)
- 23.05. Exam

Q&A before the exam

If you have questions from now until the date of the exam, I suggest the following alternatives:

- Use the Blackboard forum
- Send an email to the TA or to me
- We can arrange general Q&A sessions for several people with the TA or me, or both, if this is necessary. Please, send an email to the TA or to me to make this request.

Final exam

-Date: 23 May, 2023, 15:00-19:00. Sal SL310 hvit sone (40)

-The exam accounts for 100/100 points, and it will be conducted in Inspera. The exam questions will add up to 100 points that will then be converted to grade letter.

-You can see examples of previous exams in the side menu of Blackboard, under the point "Previous exams"

-The exam covers all the materials provided during the course, but emphasis is made on the material covered in the class exercises/group work, home exercises, quizzes, and lectures.

The following items will NOT be covered in the exam:

- Python, HYSYS, RESOLVE/GAP/PROSPER/REVEAL, PIPESIM for the exam.
- The guest presentation by SLB.
- The field trip to AkerSolutions in Verdal.
- The presentation on Aasta Hansteen

-The value of each exam task will be provided in Inspera.

-The exam will be applied in Inspera, using an NTNU computer and in a NTNU examination room. No aids are permitted. A specific basic calculator is allowed (although it is not necessary). In the examination computer you will have access to the internet browser to see the Inspera test, the Windows Explorer, and some basic Windows programs such as Microsoft Office (Word, Excel, PowerPoint).

-Milan will pass by at approximately 1 hour after the examination has started. The total duration of the exam is 4 hrs. If you need to reach Milan before or after that, contact the invigilators to call me.

-If you need to deliver several files as part of your answer, use a compressed (for example zip) file.

-The exam hasn't been prepared yet, but it could be a combination of long answer questions, value-fill questions in Inspera, and questions using Excel (where the problem must be solved in Excel and the Excel file is delivered).

A long exam question may be structured in the following way:

- Question text (indicating the number of points that the problem is worth)
- Data
- Link to download an Excel file (if any). The Excel file contains, in most cases, the problem's data, a suggested structure layout to solve the problem and some useful VBA functions.
- A long answer field, to provide a brief explanation about how you solved the problem
- A link to upload the Excel file containing your solution (if any)
- A link to upload additional files, e.g. images, sketches, word document, pdf, etc. (if any).

-When solving the exam, make sure that you make clear the procedure used to solve it, either by adding text to the Excel file, or by filling the text box.

-During the exam, when working with Excel, remember to save often.

-When you first download and open the Excel file, make sure to enable macros and make it a trusted document, otherwise you will have issues using the VBA functions. You can also save it with a different name so the computer recognizes it as its own.

-If you want to provide hand-written notes, at the bottom of the question you will find a seven-digit code. Fill in this code in the top left corner of the sheets you wish to submit. We recommend that you do this during the exam.

-Other relevant information:

- https://innsida.ntnu.no/wiki/-/wiki/English/Pack+and+unpack+zip+files

Evaluation

-In most questions, you will be graded based on both procedure and results. You could have made an error in a calculation, but if the procedure is correct, you will still get points.
-The course will be evaluated using percentage points, later converted to letters. The following limits will be used: https://innsida.ntnu.no/wiki/-/wiki/English/Grading+scale+using+percentage+points