NTNU | Norwegian University of Science and Technology

TPG4230 – Field development and operations

Spring Semester 2024

Information

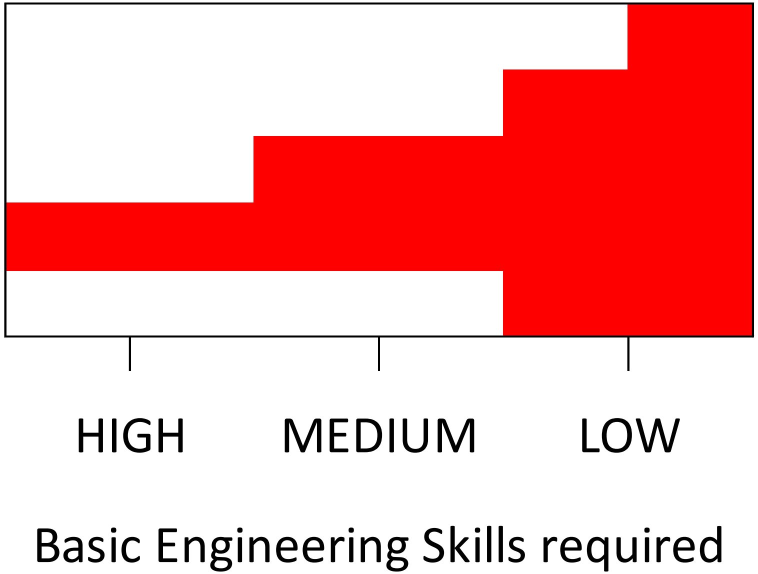
- Lecturer: Assoc. Prof. Milan Stanko (Production Tech) (milan.stanko@ntnu.no). Office 510.
- Teaching assistant: Ali Hamdan ali.hamdan@ntnu.no

- Lecture schedule
  - Thursdays, 08:15-10:00, P1 (theory and exercises)
  - Fridays, 10:15-11:00, P12 (session with TA)
  - Fridays, 12:15-14:00, P11 (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

- The course will focus on developing digital competences and will include some aspects on energy efficiency, emissions to air and sea, and skill transfer for the energy transition.

Examples

- Emissions to sea
- CO2 emissions to air
- Field development of CO2 storage fields
- CO2 injection networks

Course scope

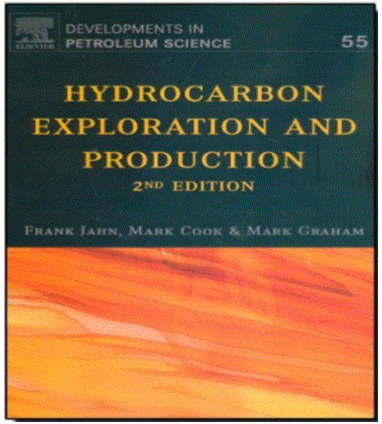
- Practical SI units only (bar, m3), not field units.
- Little focus on exploration and subsurface characterization (geology, geophysics, petrophysics, generation of reservoir realizations)

Information

- Lectures until 26 April (breaking for Easter)
- Consultation time: preferably after class. Try to make an email appointment.
- Reference group – **any volunteers?**
- **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, 2023
  - 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?

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Outline:
-(cont) Additional comments to course introductory information
-Class activity: oil content in discharged water

Useful links:

https://www.miljodirektoratet.no/ansvarsomrader/forurensning/petroleum/regulering-petroleum/

https://www.miljodirektoratet.no/regelverk/konvensjoner/oslo-paris-konvensjonen/

https://www.ospar.org/convention/text

Class activity: Maximum allowable concentration of oil in water for discharge to sea

Offshore oil and gas facilities worldwide must keep the hydrocarbon content of discharges to sea below acceptable levels set by authorities. In the North Sea, for instance, the required average concentration of hydrocarbons discharged in effluents, such as produced water, must be below 30 mg/l (monthly average concentration).

Work in groups to conduct the following activities and answer the following questions

1. Read and understand the definition of ppm https://en.wikipedia.org/wiki/Parts-per_notation
2. Who is setting the limit of 30 mg/l in the Norwegian Continental shelf? (tip: do an internet search).
3. What is the average concentration of oil in produced water in the Norwegian Continental Shelf? (tip: do an internet search)
4. How is this requirement monitored and enforced? What are the reporting requirements the companies must comply with and to whom must they report? What happens if this is not achieved in a month? (tip: do an internet search)
5. Assume that an oil platform has been discharging produced water (around 500 000 stb/d) with an oil concentration of 10 ppm for 15 days in a month. If the water processing train suddenly has an emulsification problem, that causes the concentration of oil in produced water to increase to 60 ppm, for how many days will the platform be able to produce before shutting down to comply with the 30 ppm-in-a-month requirement?
6. As a follow-up to question 5, how many barrels of oil are released in a month by the oil platform discharging produced water (around 500 000 stb/d) with an oil concentration of 10 ppm.
7. Set a person in your group to be the controller. Ask this person to close their eyes or leave the room while preparations. Using the colorant and the syringe provided, and tap water, prepare two containers, one with a 30 ppm solution of colorant in water, and one with water only. Ask the controller to open their eyes. See if they can identify which one is the one with the colorant.
8. Find out what is the lethal concentration of oil in water for fish (tip: do an internet search)
9. Using the colorant and the syringe provided, and tap water, prepare a container, with the concentration found in task 8. Discuss the differences with the one prepared in 7.

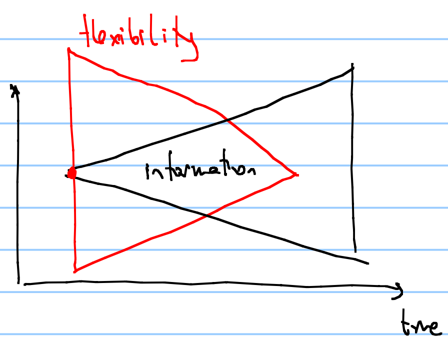
Notes for youtube video nr. 1

Field development and operations — offshore oil and gas production (from fields in Norway)

maximize economic value of HC exploitation 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 → DG0 (Decision gate) → field planning → field construction → operations → decommissioning abandonment

discovery

Eriksen process

(3-6) (5-40)

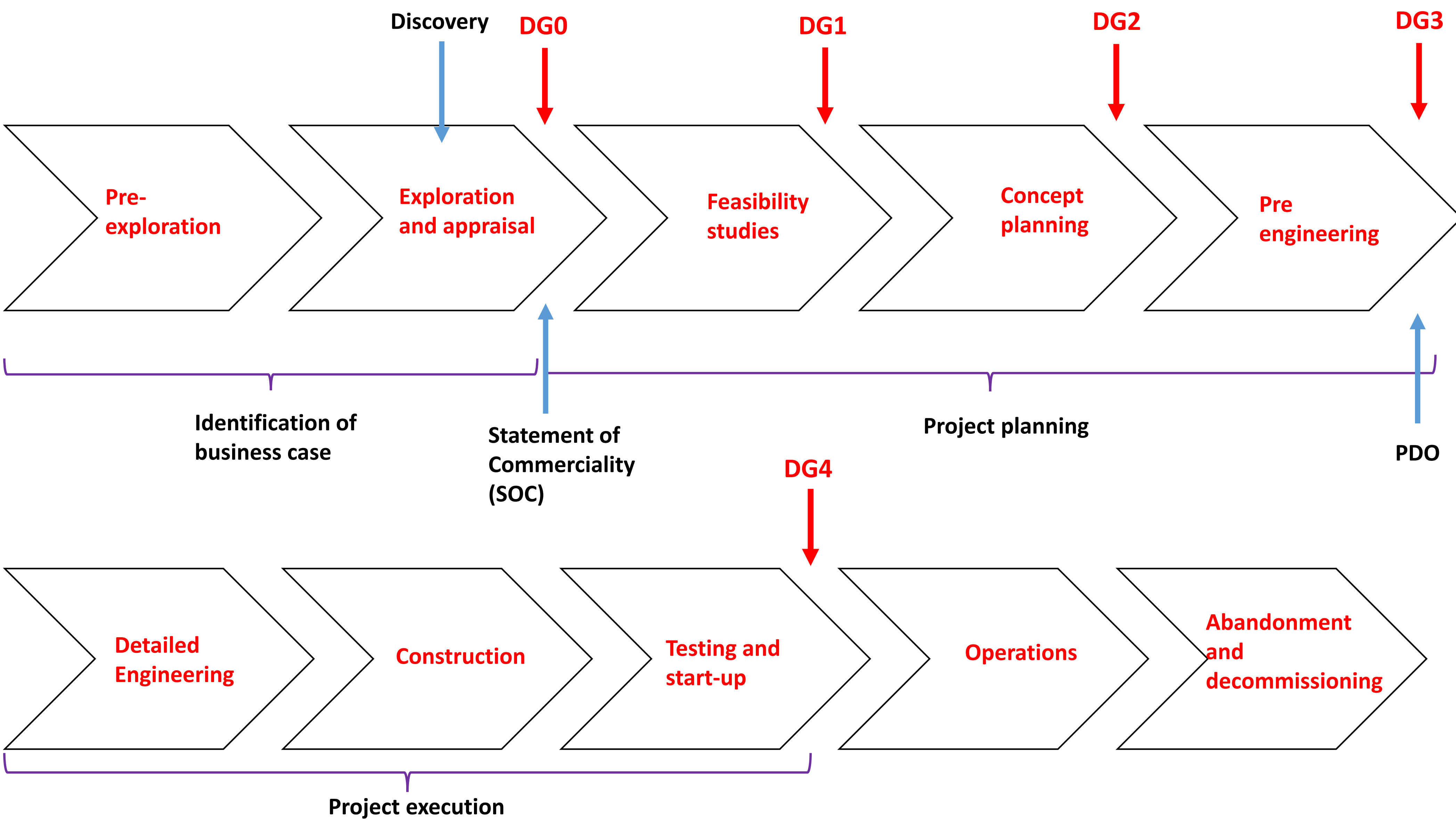
feasibility studies — DG1 (BoK) (Beslutning om Konkretisering) — concept planing — DG2 (BoV) → Beslutning om videreføring — preengineering — DG3 → BoG Beslutning om gjennomføring → issue PDO plan for development and operations

detailed engineering — construction — testing and startup — DG4

Notes for youtube video n. 2

THE FIELD DEVELOPMENT PROCESS

Prof. Milan Stanko (NTNU)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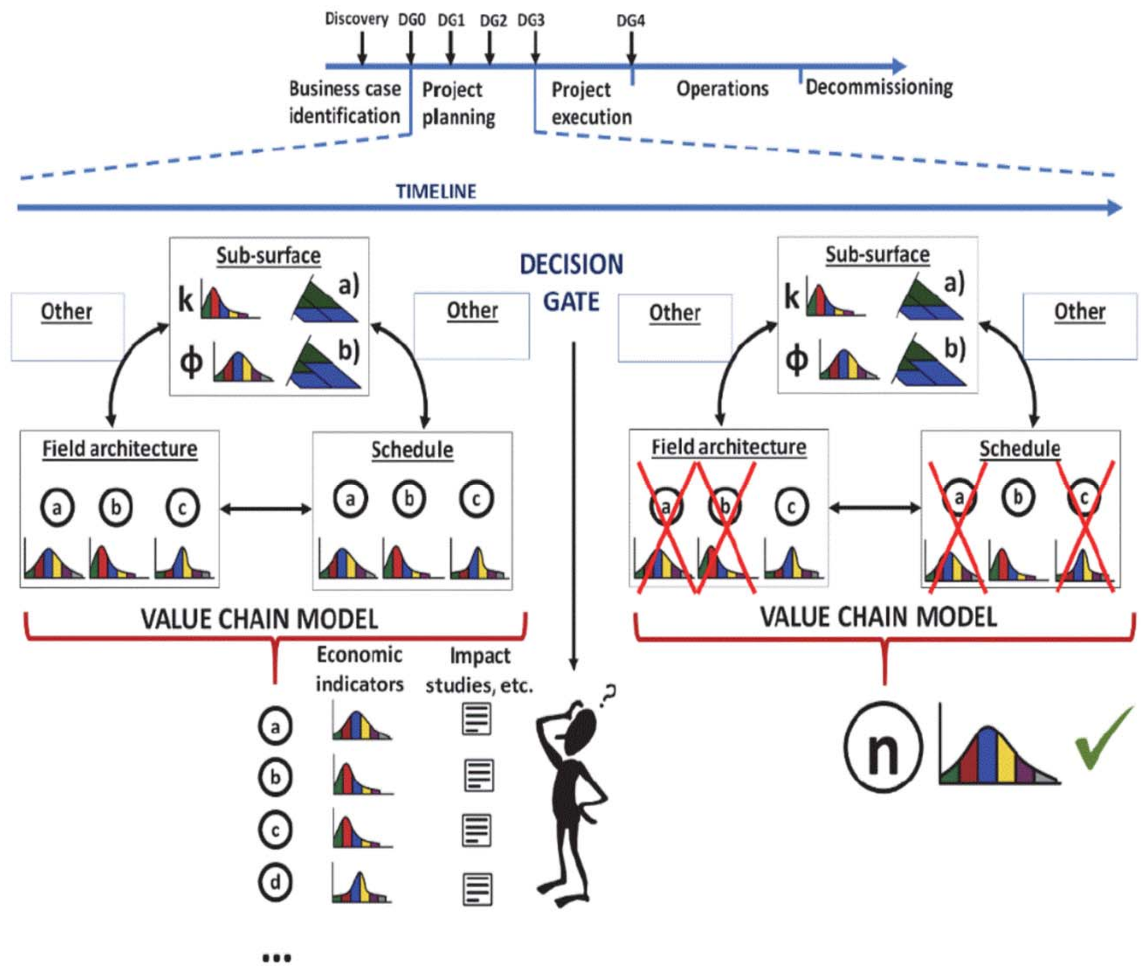
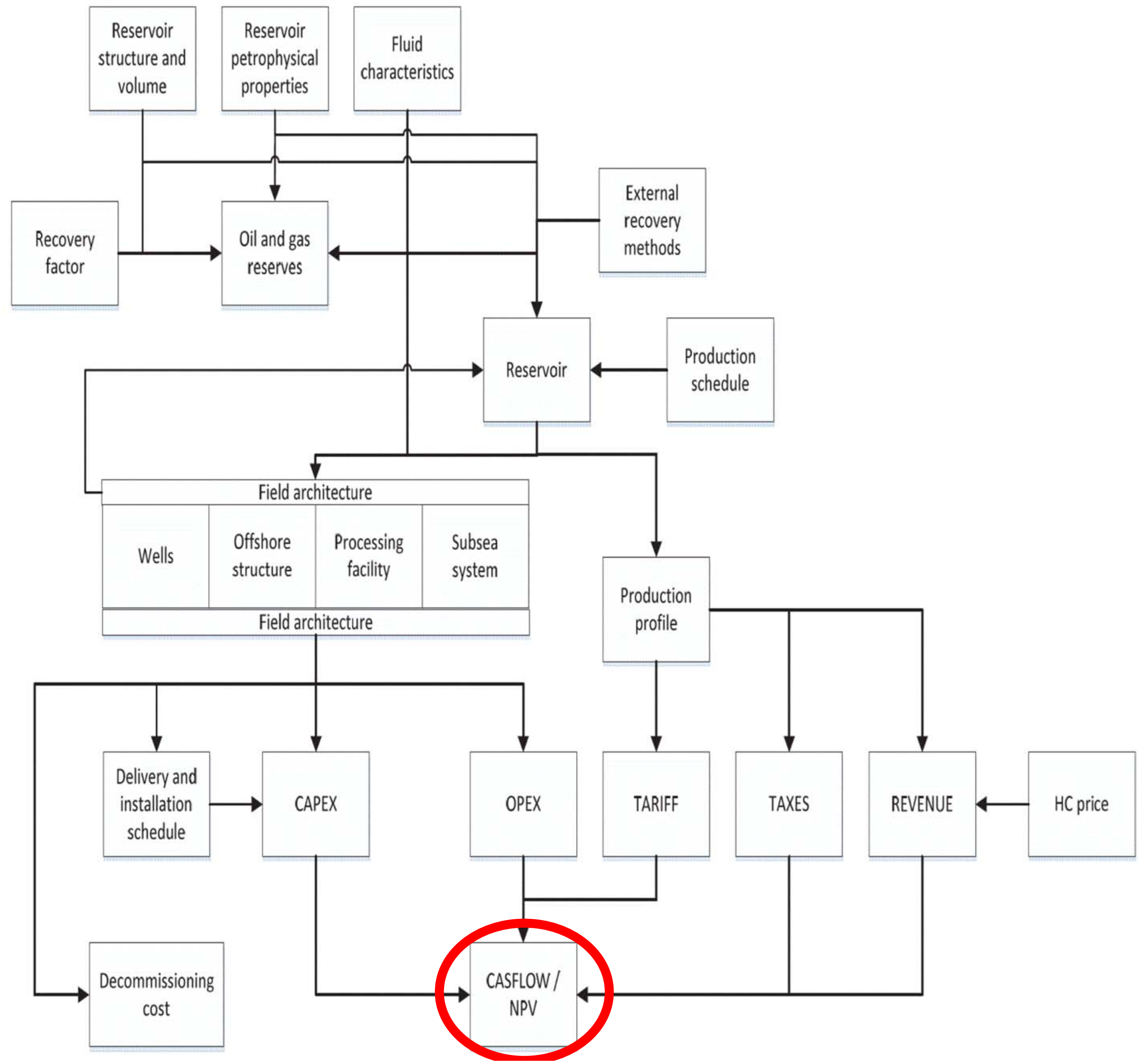
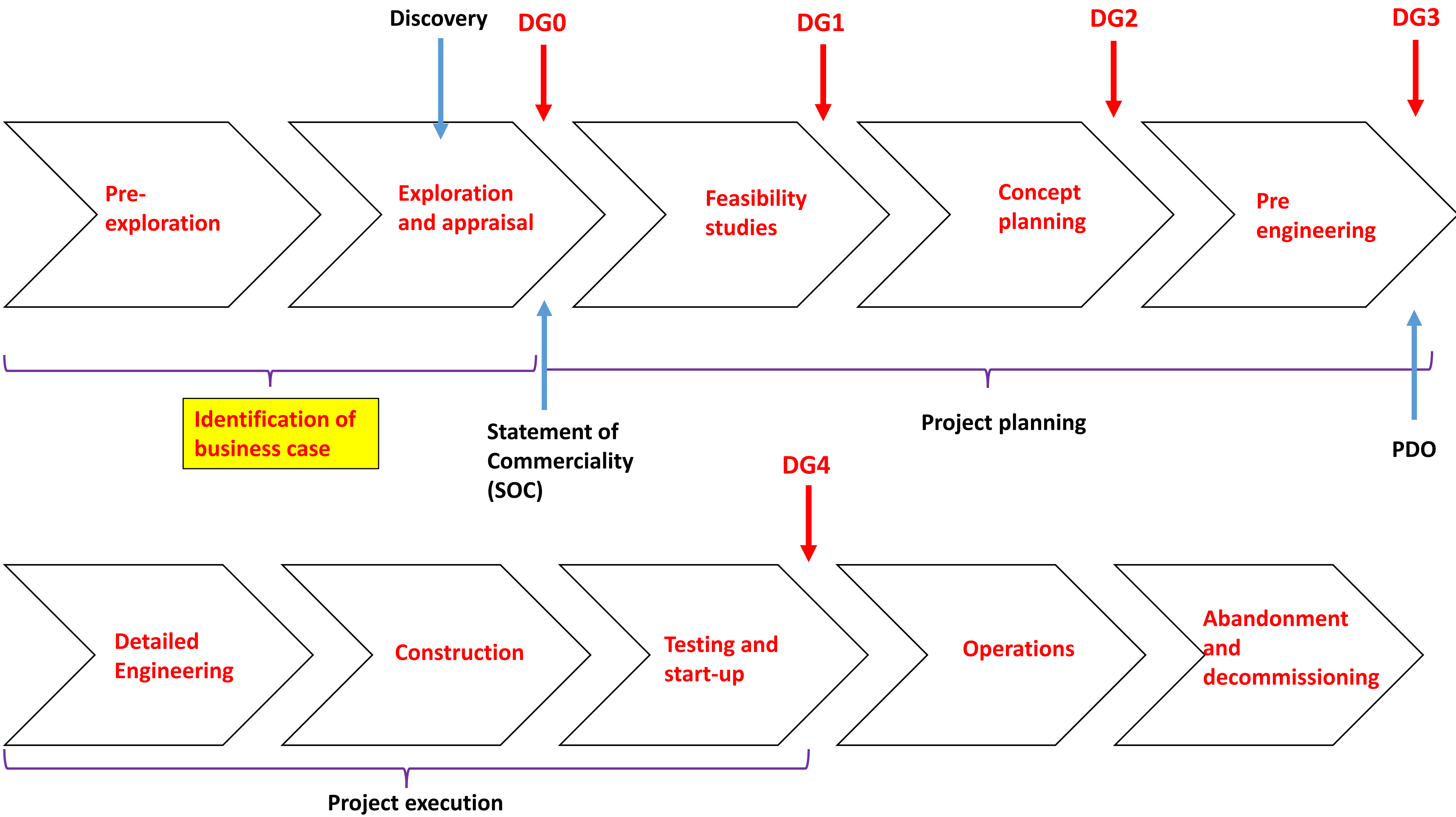
Project execution

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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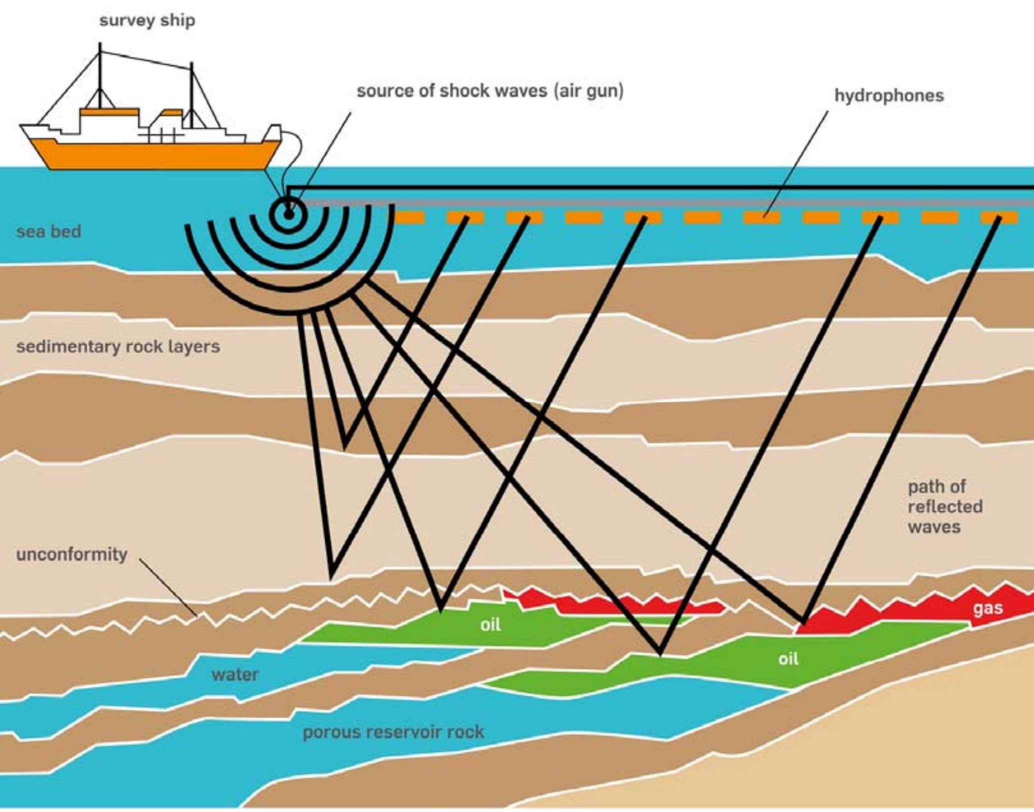
IDENTIFICATION OF BUSINESS CASE

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.

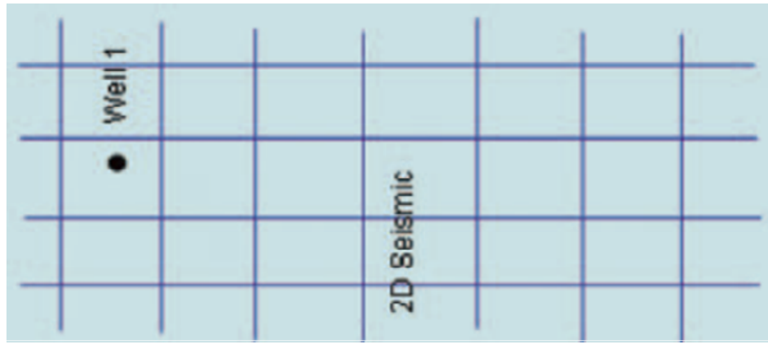
IDENTIFICATION OF BUSINESS CASE - TASKS

- 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.

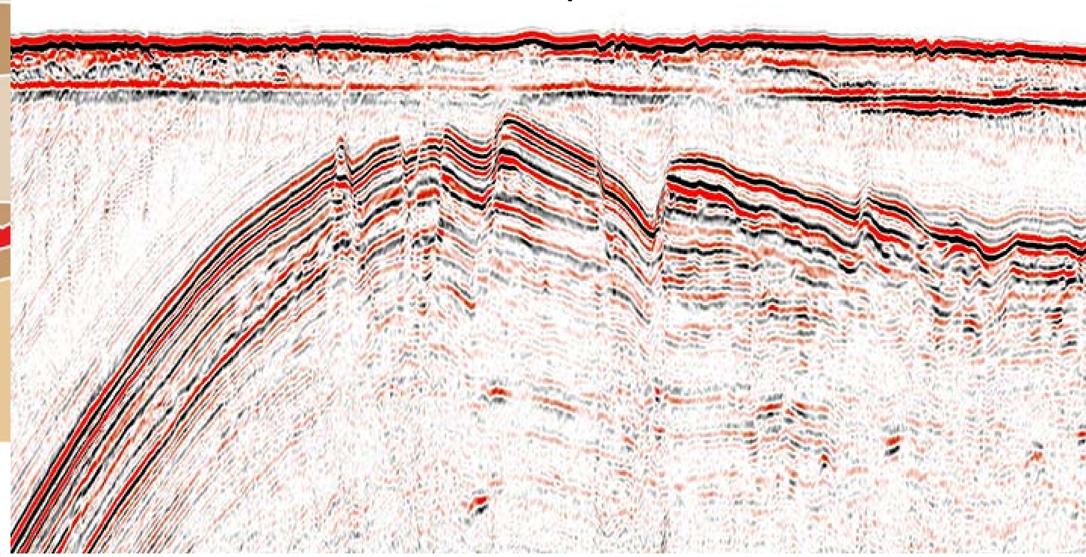
IDENTIFICATION OF BUSINESS CASE - TASKS



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

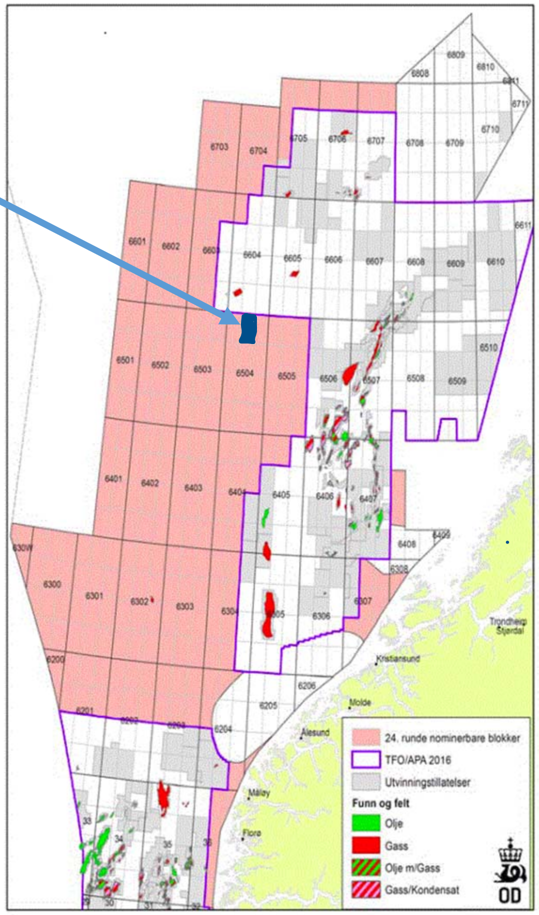


Seismic exploration



IDENTIFICATION OF BUSINESS CASE - TASKS

Ca 500 km^2



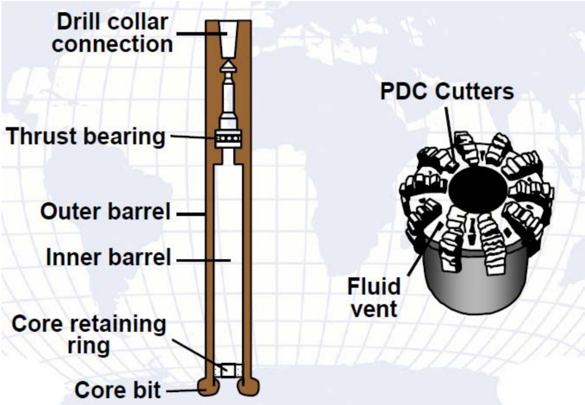
Ref: NPD

- 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.

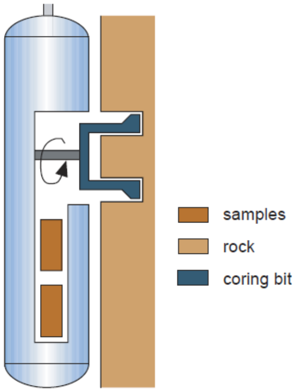
IDENTIFICATION OF BUSINESS CASE - TASKS

- 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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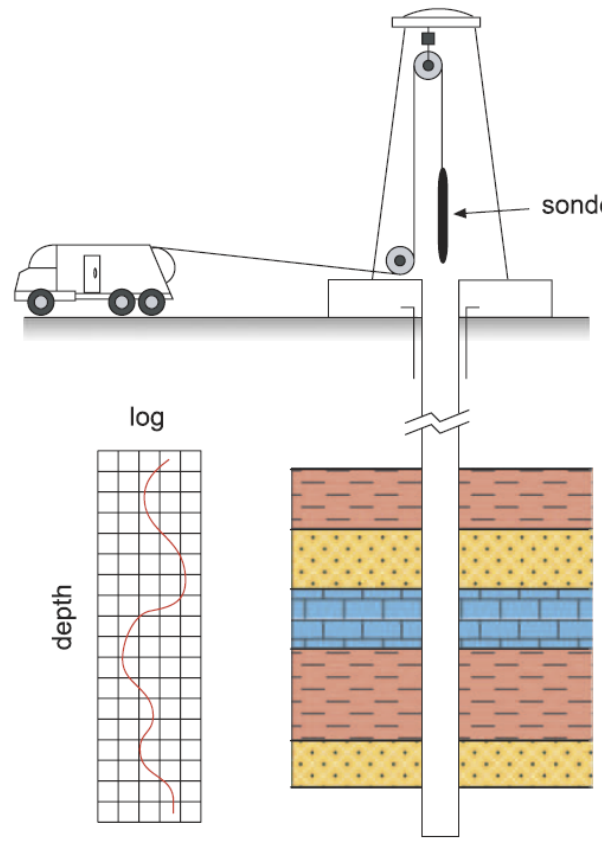

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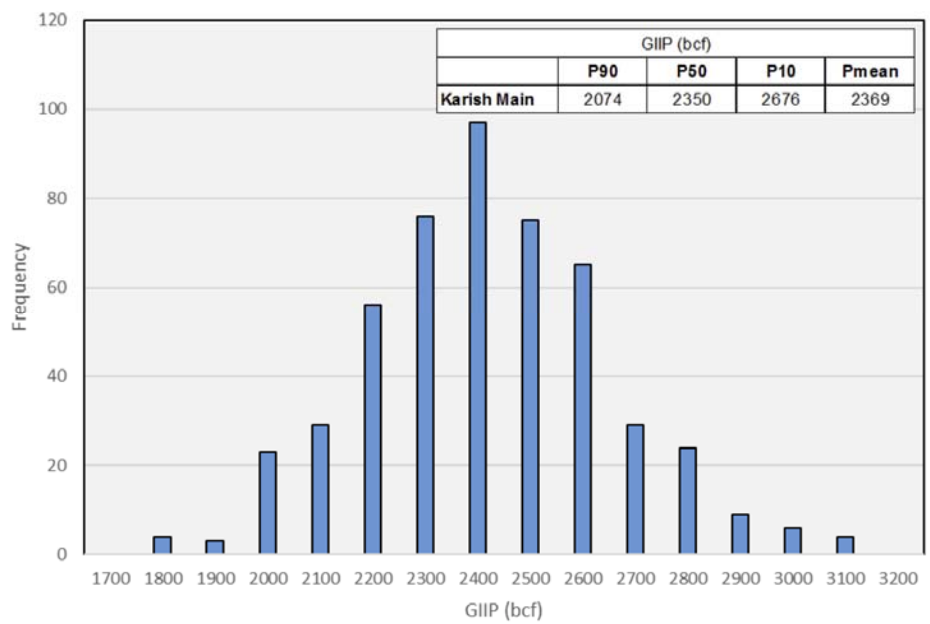
- Discovery!

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.



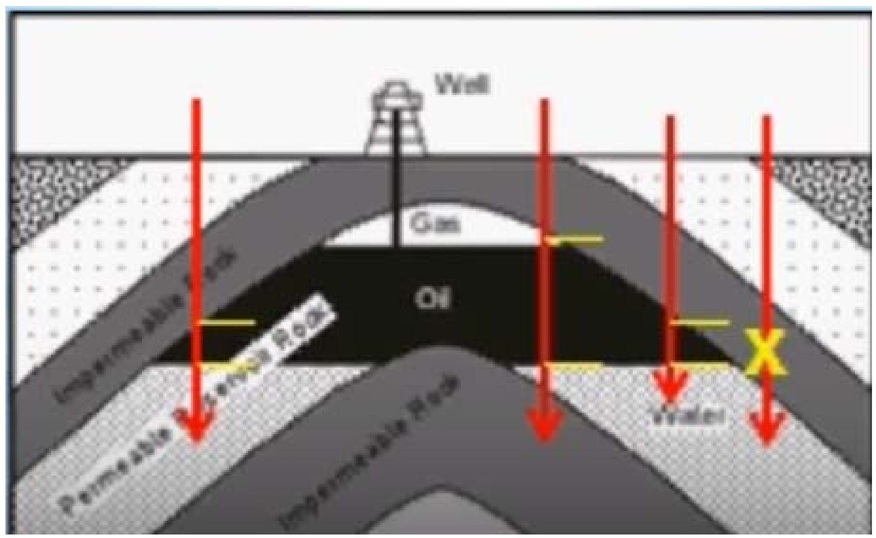
Ref: PDO Karish and Tanin. Energean

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

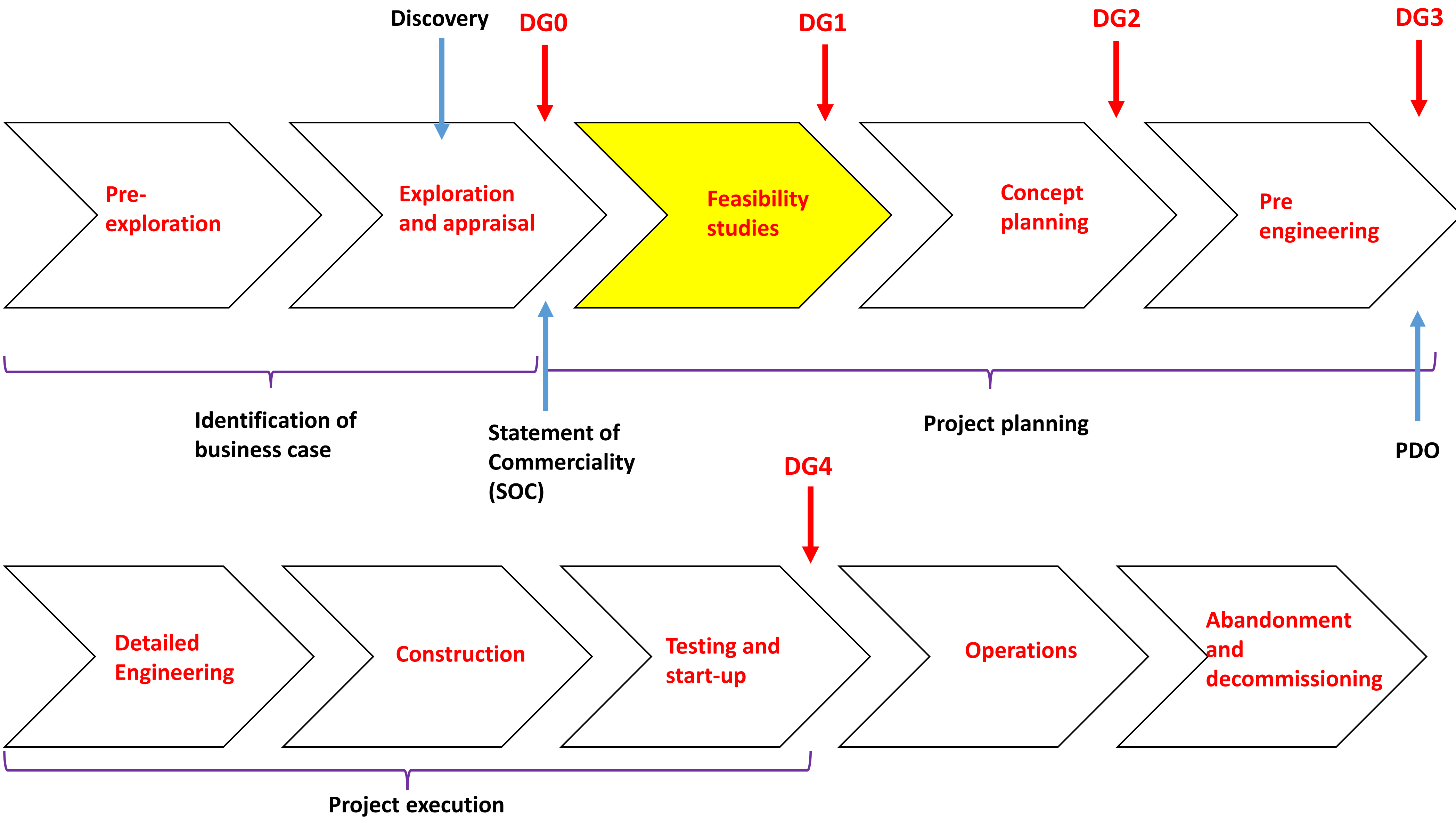


Ref: https://www.youtube.com/watch?v=-e9jjnsquGI

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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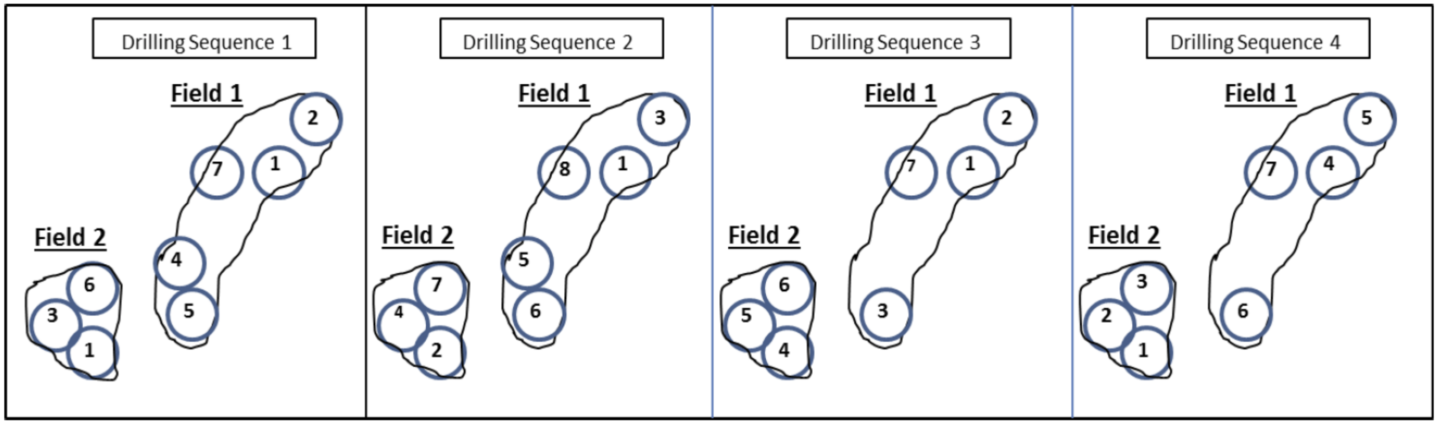
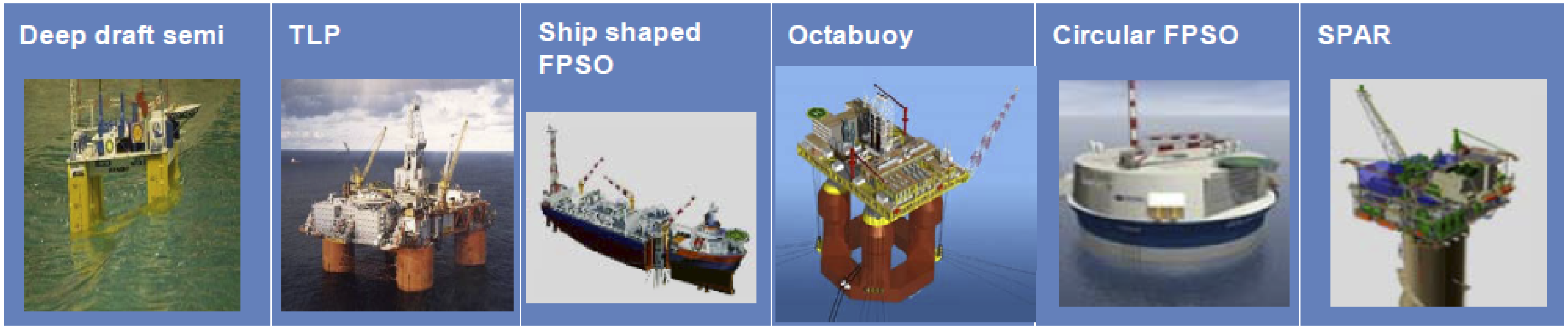
FEASIBILITY STUDIES - TASKS

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

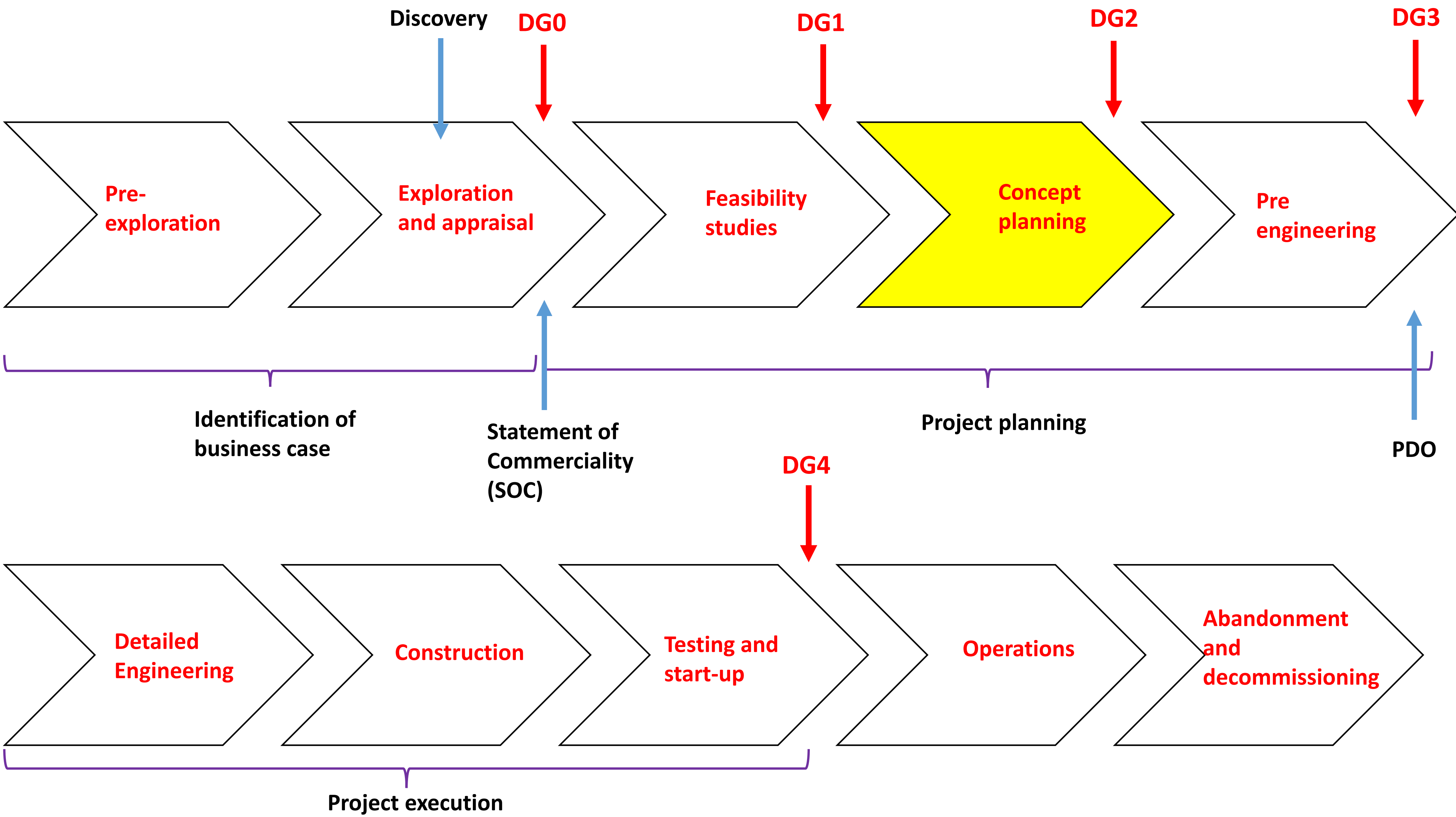




Ref: UTC 2017, Strategies, methods and tools for development of subsea fields, Skogvang and Løken.

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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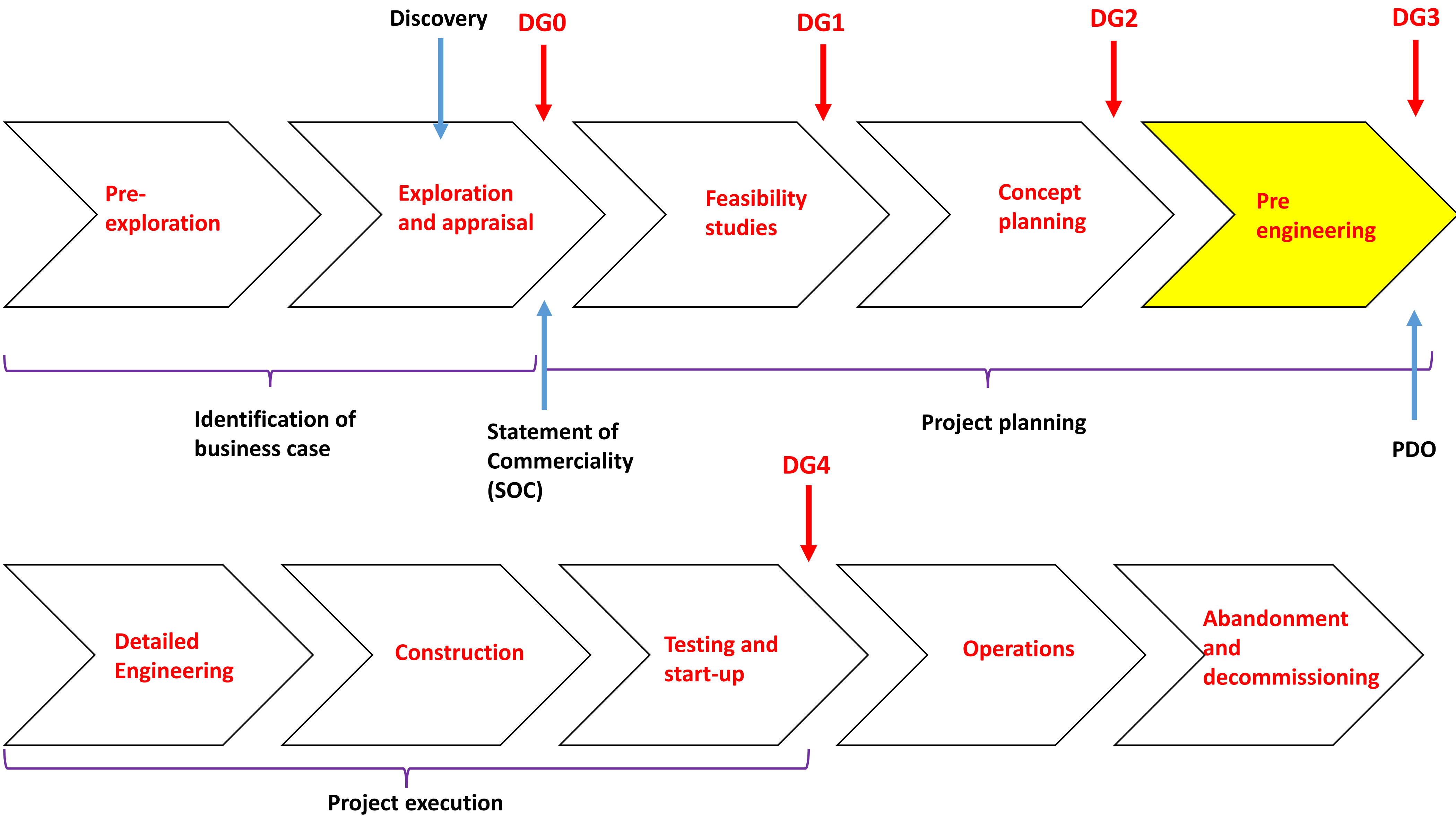
CONCEPT PLANNING - TASKS

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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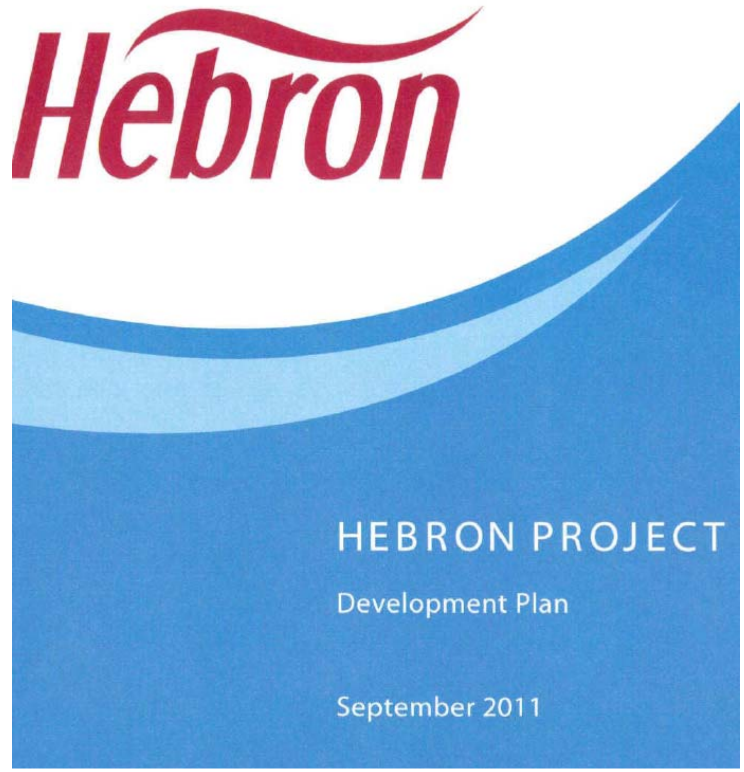
PRE-ENGINEERING - TASKS

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

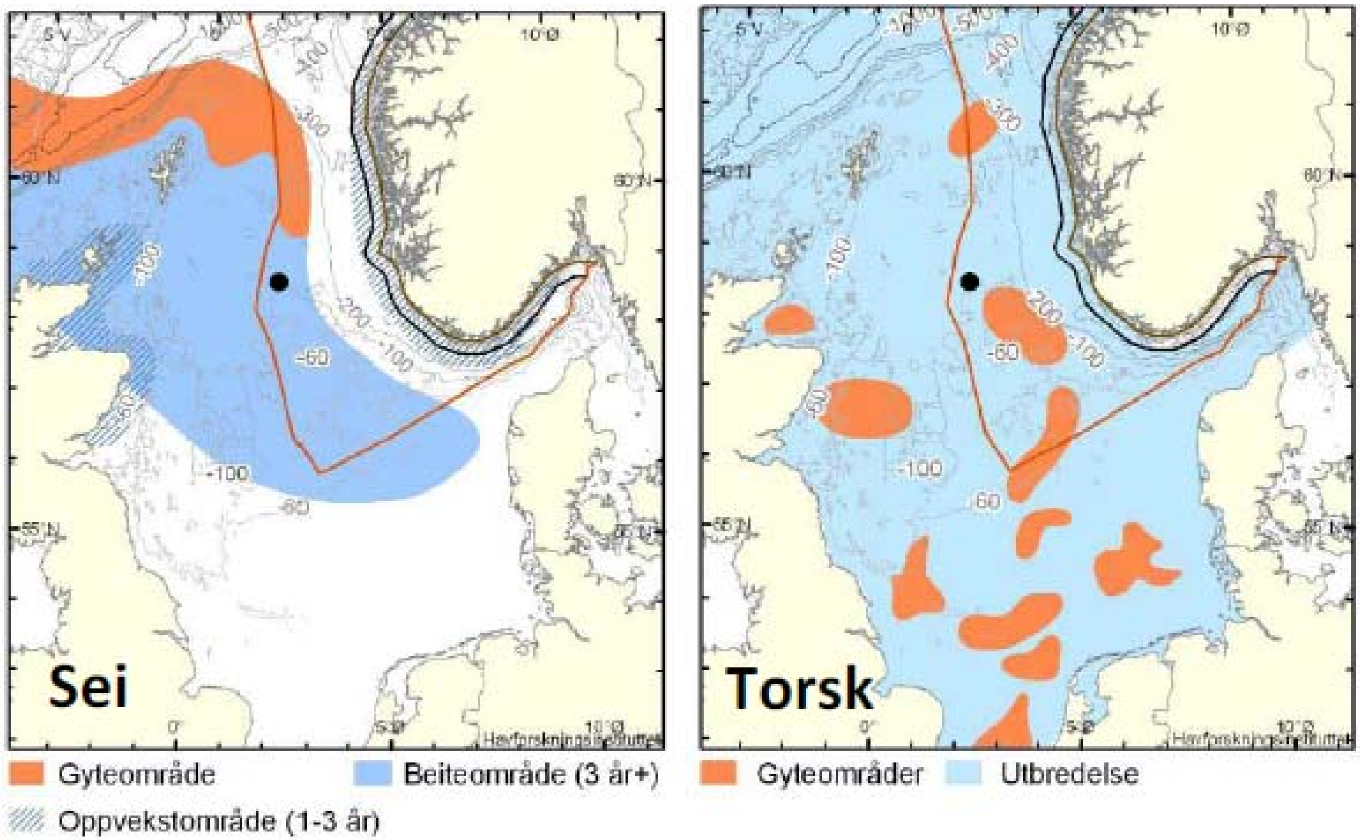
- Selection of the final technical solution. Decide and define all remaining critical technical alternatives.
- Execute Front End Engineering Design (FEED) Studies: determine technical requirements (arranged in packages) for the project based on the final solution chosen. Estimate cost of each package.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

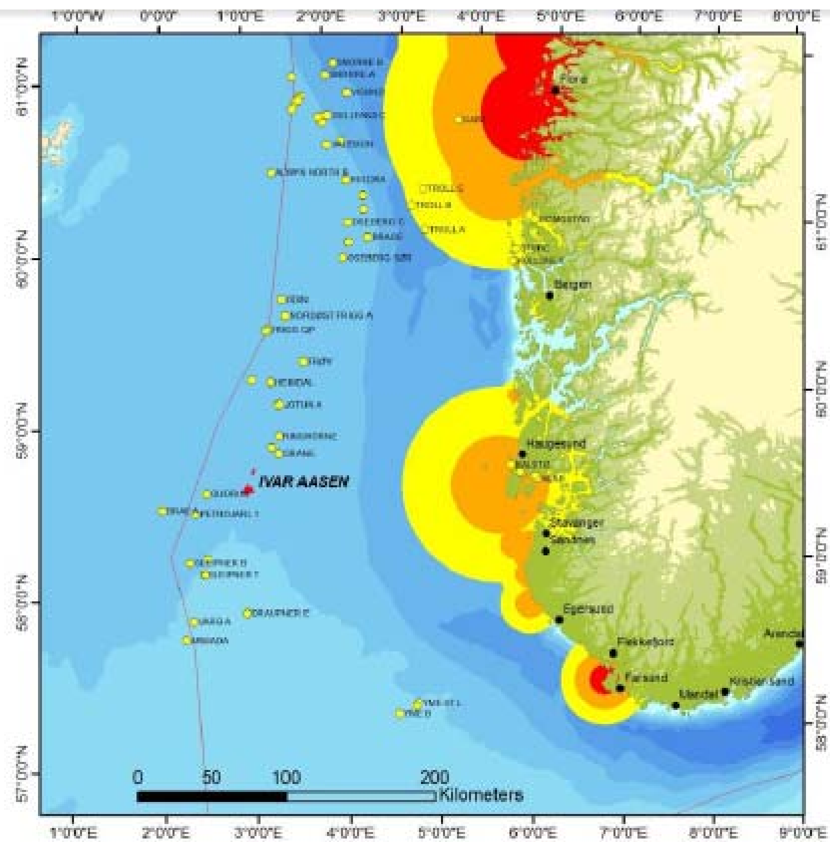


PRE-ENGINEERING - TASKS



Ref: PDO Ivar Aasen. Det Norske

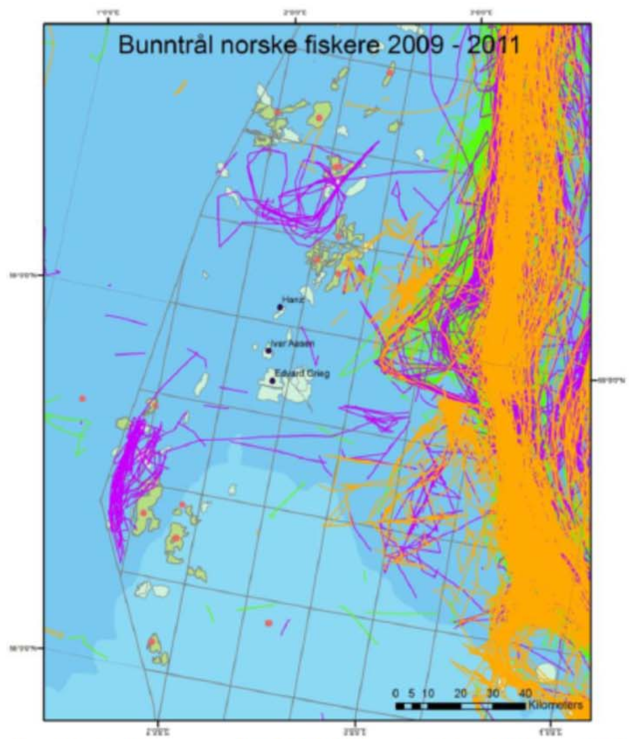
PRE-ENGINEERING - TASKS



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

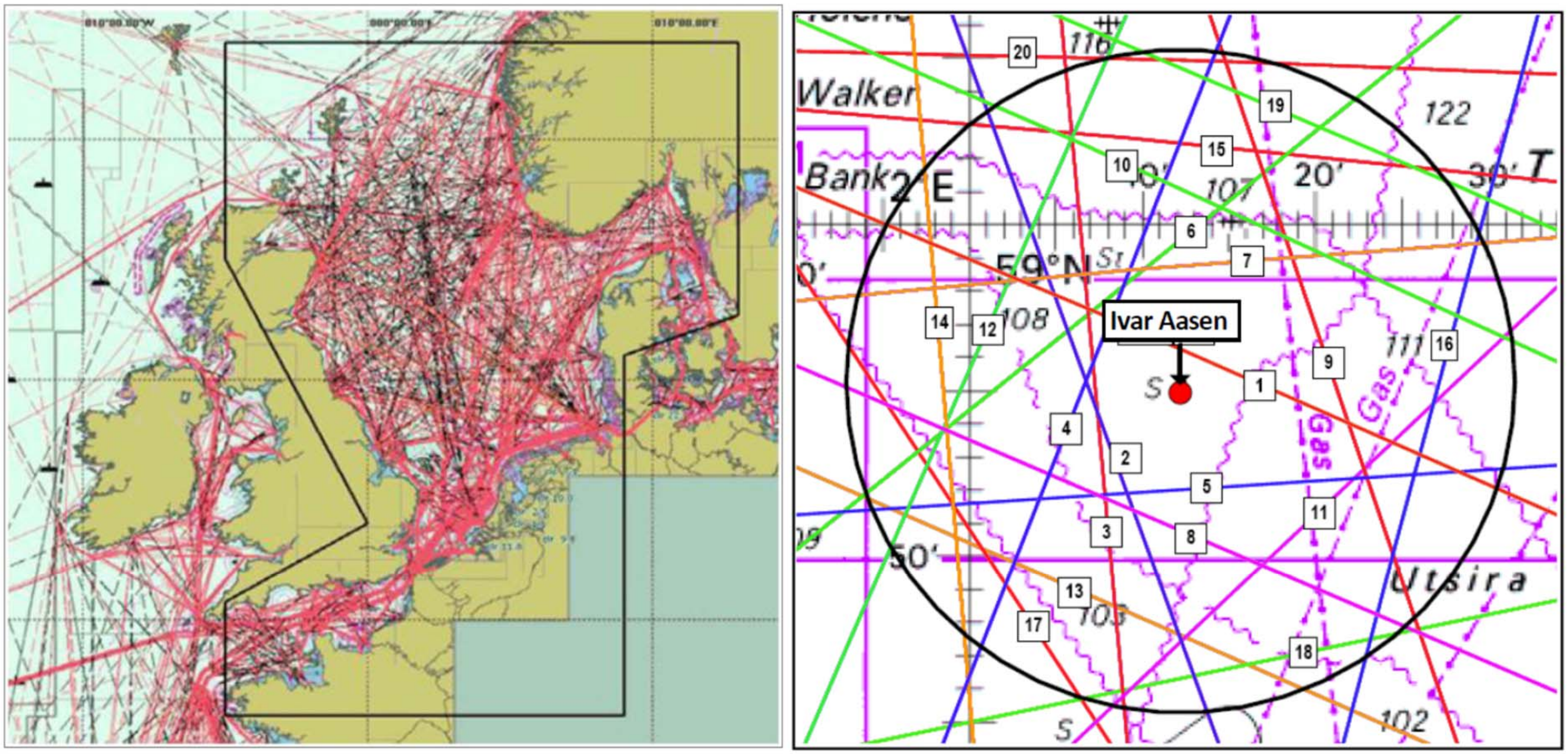
PRE-ENGINEERING - TASKS



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

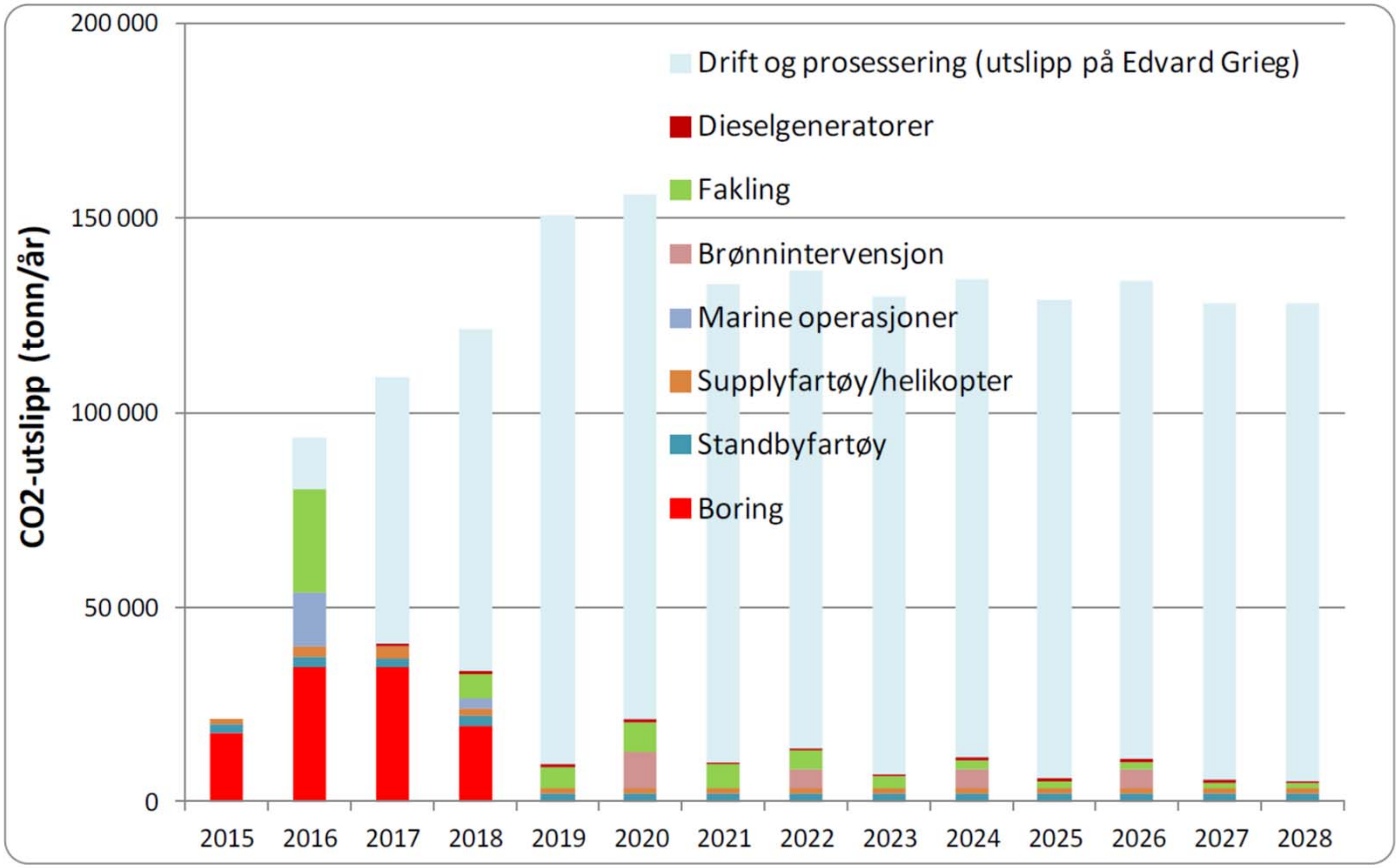
PRE-ENGINEERING - TASKS



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

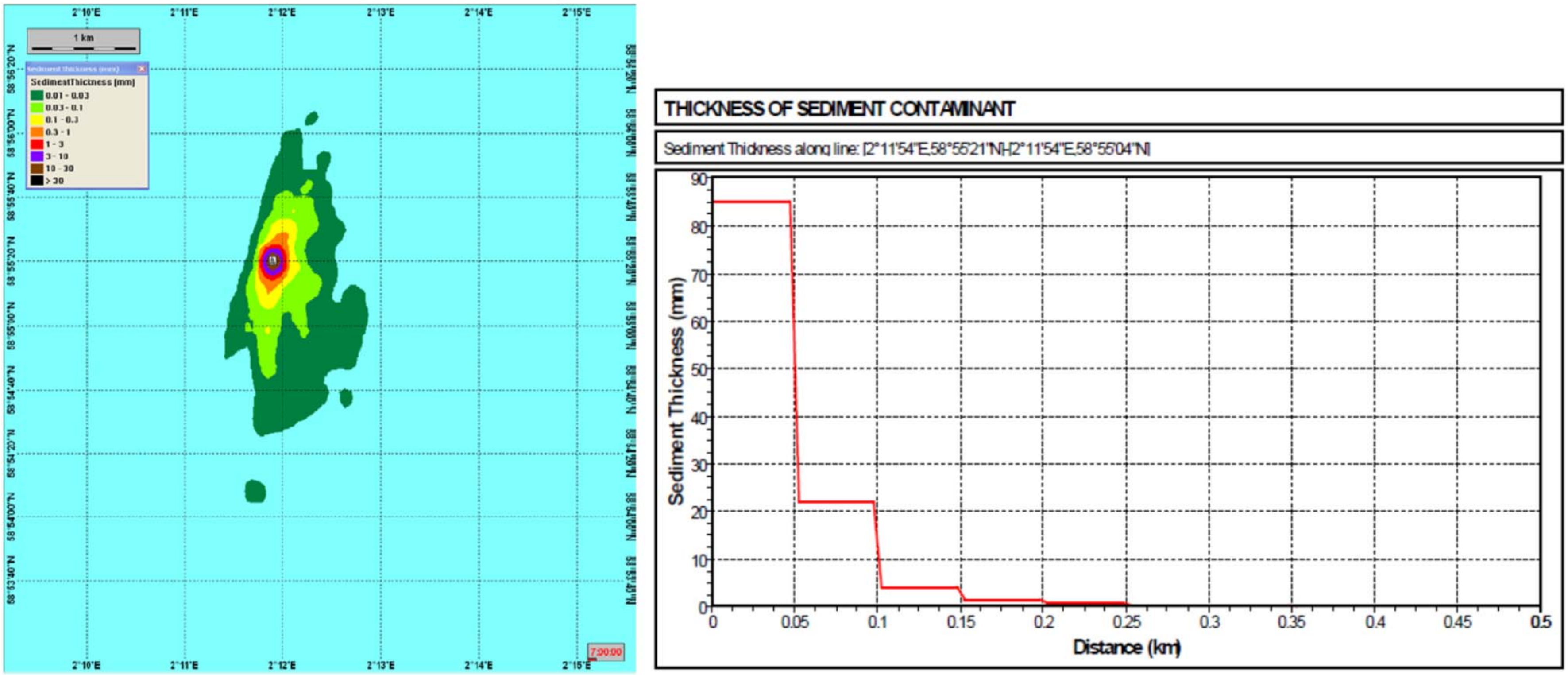
PRE-ENGINEERING - TASKS

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

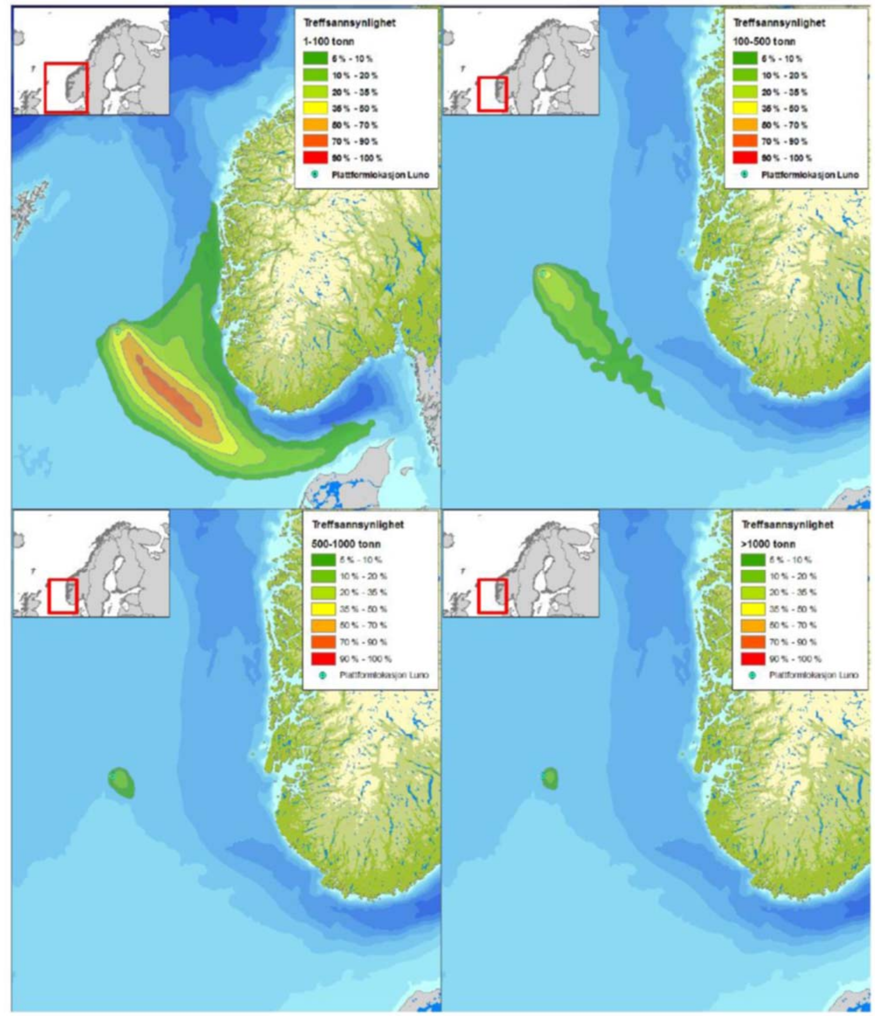
PRE-ENGINEERING - TASKS



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

Ref: PDO Ivar Aasen. Det Norske

PRE-ENGINEERING - TASKS

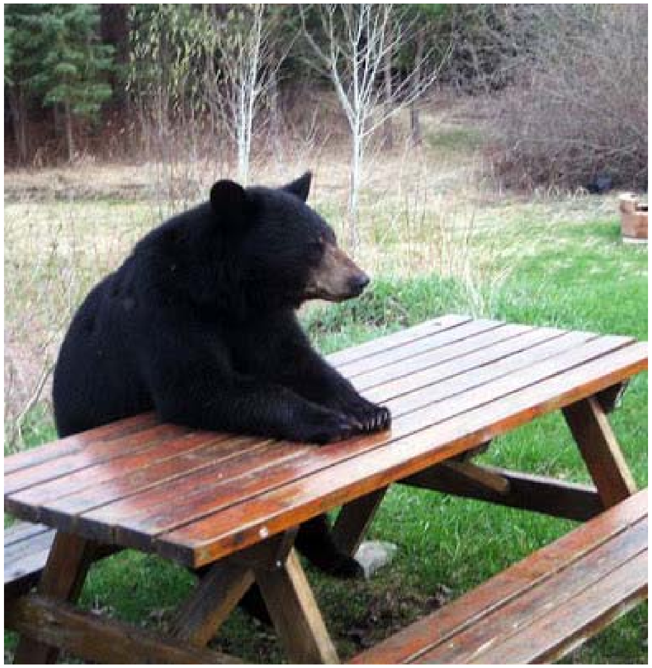


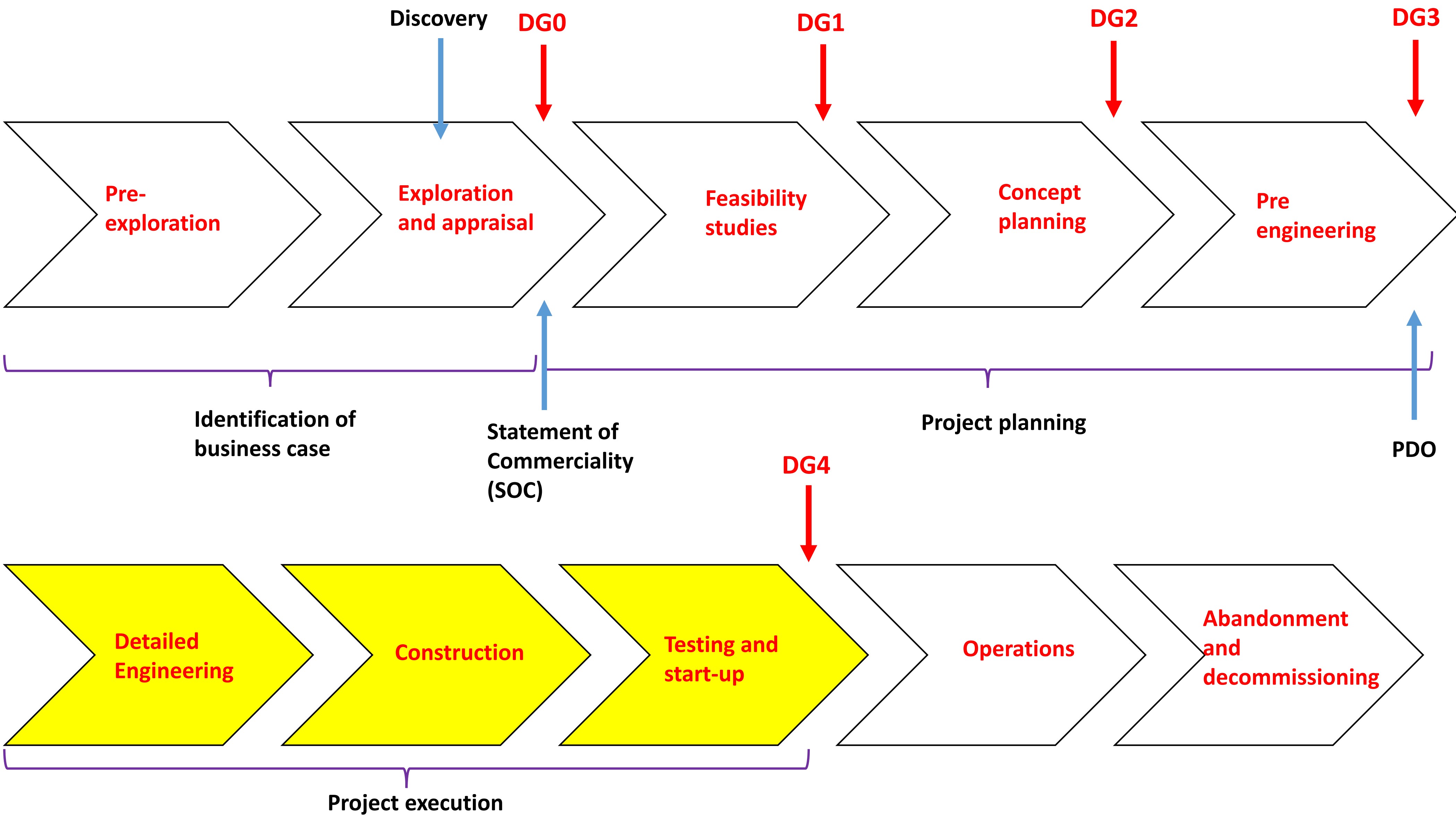
Figur 37. Sannsynligheten for treff av ulike mengdekategorier av olje i 10 × 10 km ruter gitt en sjøbunnsutblåsning fra Aasen/Grieg (helårsstatistikk). Influensområdet er basert på alle utslippsrater og varigheter og deres individuelle sannsynligheter. Merk at det markerte området ikke viser omfanget 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)

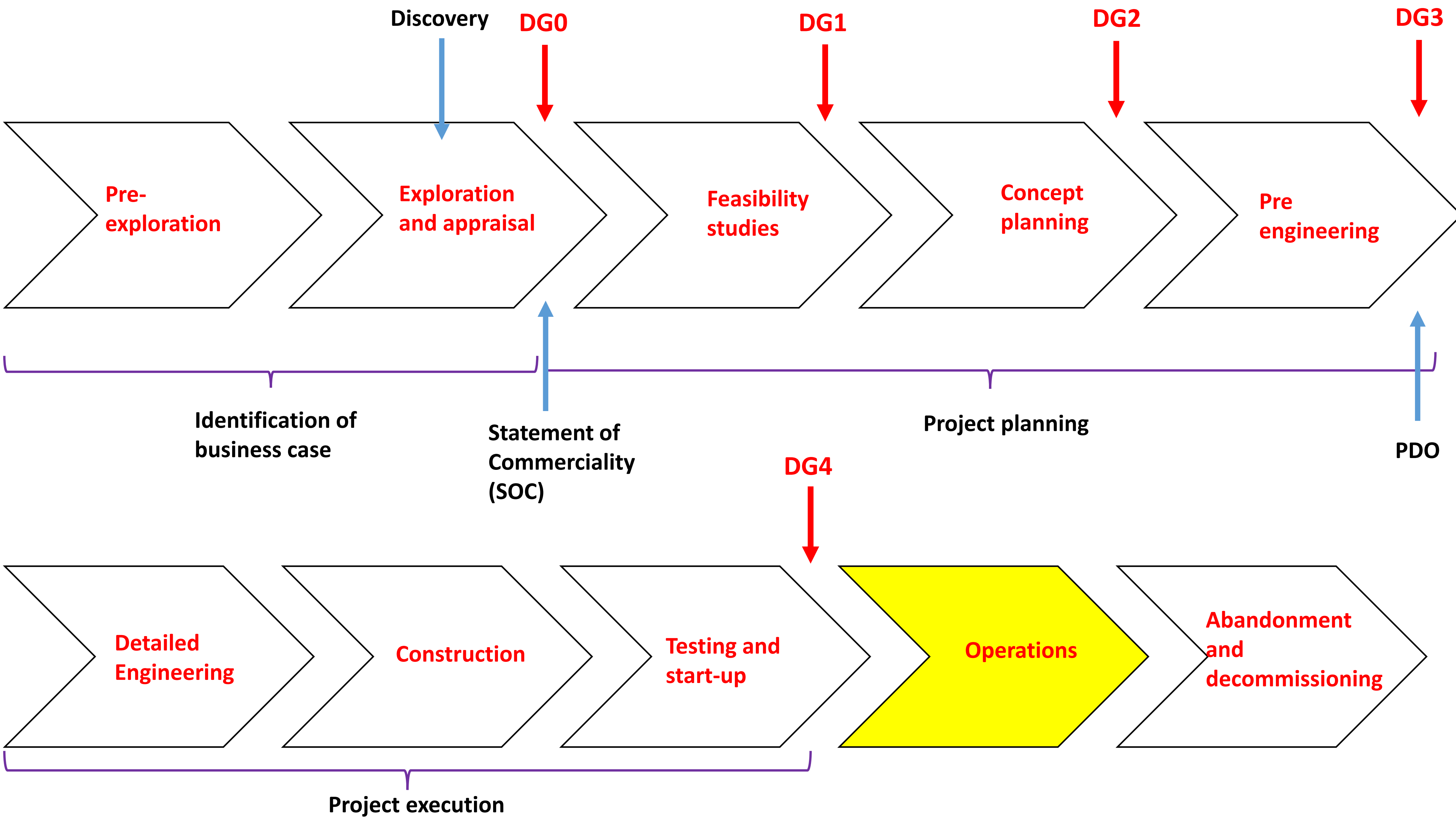
EPCM (Engineering, procurement, construction, and management contract) with one main contractor.

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


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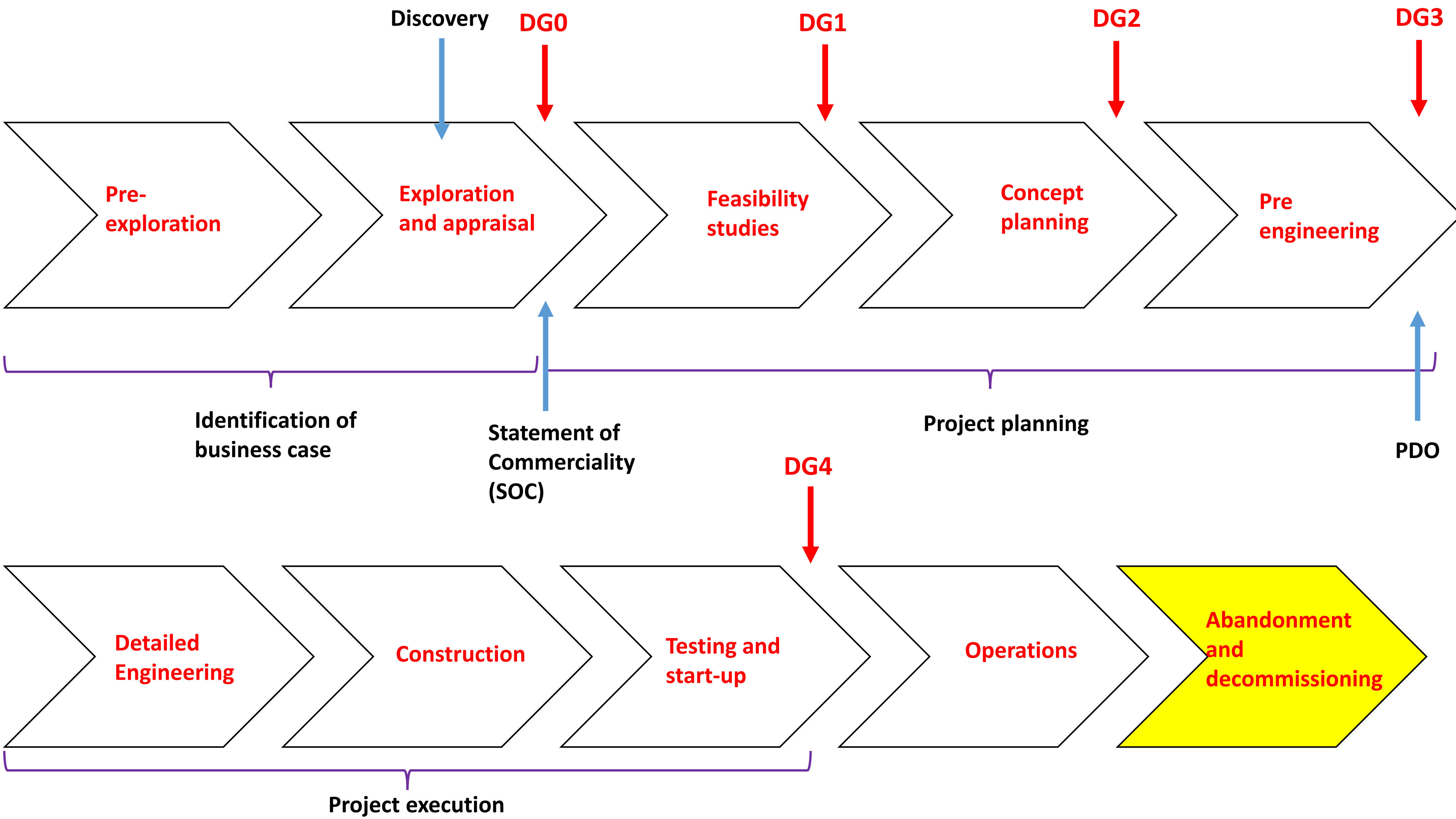
PDO
DG4
Detailed Engineering
Construction
Testing and start-up
Operations
Abandonment and decommissioning
Project execution

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.


Discovery
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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

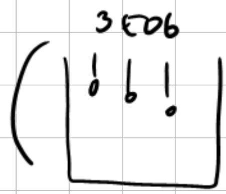
DECOMISSIONING AND ABANDONMENT

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

DECOMISSIONING AND ABANDONMENT

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

Class 20240119 - OUTLINE
- Members of reference group
- Clarification about ppm
- Field mechanical analog
- Bottlenecking
  - Interactive app
  - Heidrun Example



1 mt kg → ? 1E06 kg

1 kg / 1000000 kg

$$ppmw = \frac{m_a}{(m_t / 1E6)}$$ m_a → component, m_t → total

mt kg

I divide the denominator by 1E06 to find out how many million kg are in the amount

$$ppmw = \left(\frac{m_a}{m_t} \cdot 1E06\right)$$

ma and mt are in the same units

I can also use different units for ma and mt such that the 1E06 factor dissapears

$$m_a\,[kg]\,\frac{1E06\,(mg)}{(1\,kg)}$$

1000 g → 1 kg

1 000 000 mg → 1 kg

$$ppmw = \frac{m_a}{m_t} \quad m_a - [mg], \quad m_t - [kg]$$

$$ppmV = \frac{V_a}{V_t}$$

to convert from pure mass units to mixed mass-volume units, the density of the mixture is required

$$ppm = 30\,[mg/L] \quad \frac{[M]}{[V]}$$

$$[mg/L] = \frac{m_a}{(m_t / \rho_t)} \quad \rho_t - [\cancel{k}g/L]$$

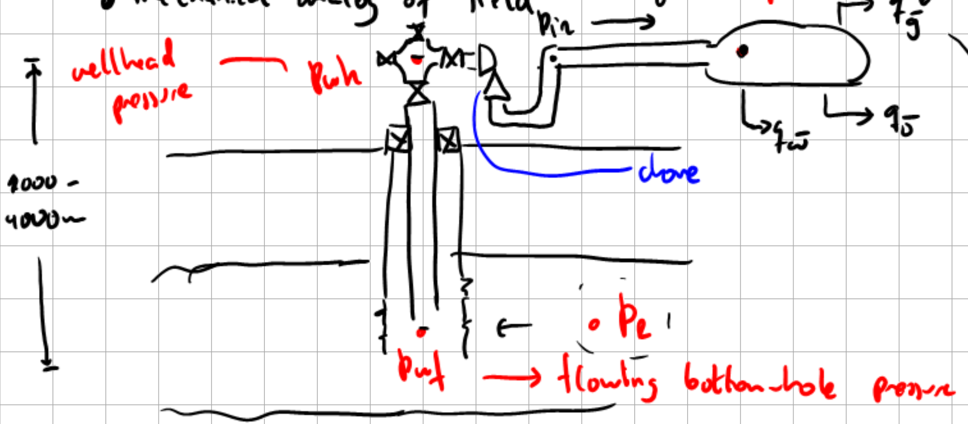
Often it is possible to neglect the mass of the component in the denominator and simply use the mass of the "rest"

$$30\ ppm \quad \frac{(m_a)}{m_a + m_{rest}} = \frac{m_{oil}}{m_{water}}\,1E06 \quad mg/L$$

$$\underbrace{m_t = m_a + m_{rest}} \approx m_{rest}$$

$$\frac{m_{oil}}{m_{wat}/\rho_w} \quad \rho_w - 1\,kg/L$$

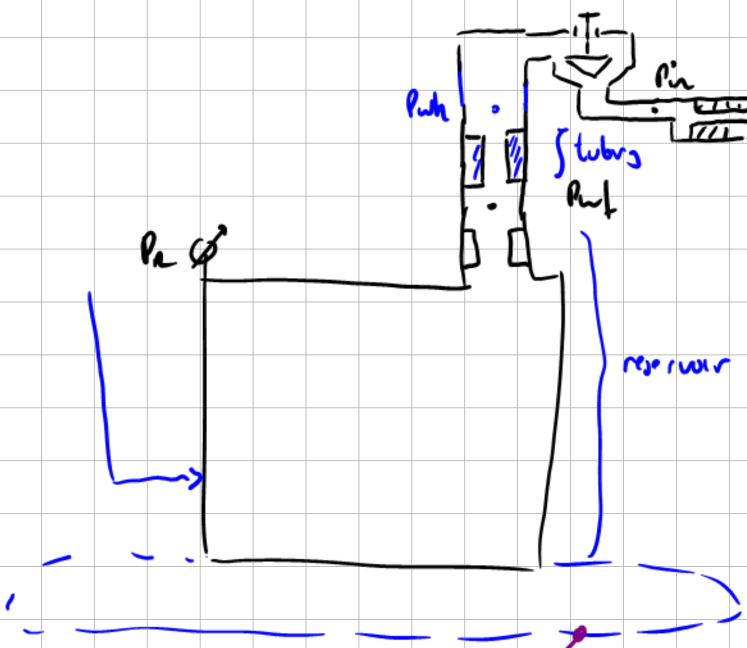
- mechanical analog of field



q_g ← S.C → $T_{sc} = 15.56\ °C$

$[Sm^3/d]$ $P_{sc} = 1.01325$ bara (1 atm)

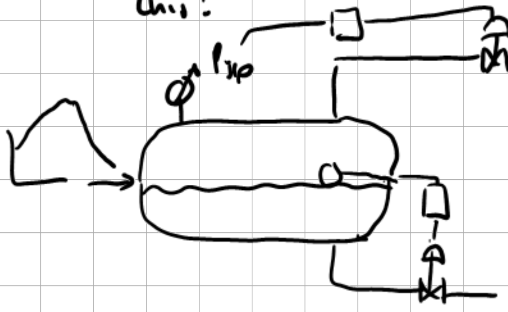
$$q_o = f \begin{cases} P_r \\ P_{sep} \\ \Delta p_{losses} \text{ along way} \\ (P_r \to P_{wf}) \text{ (drawdown)} \\ P_{wf} \to P_{wh} \text{ (tubing drop)} \end{cases}$$



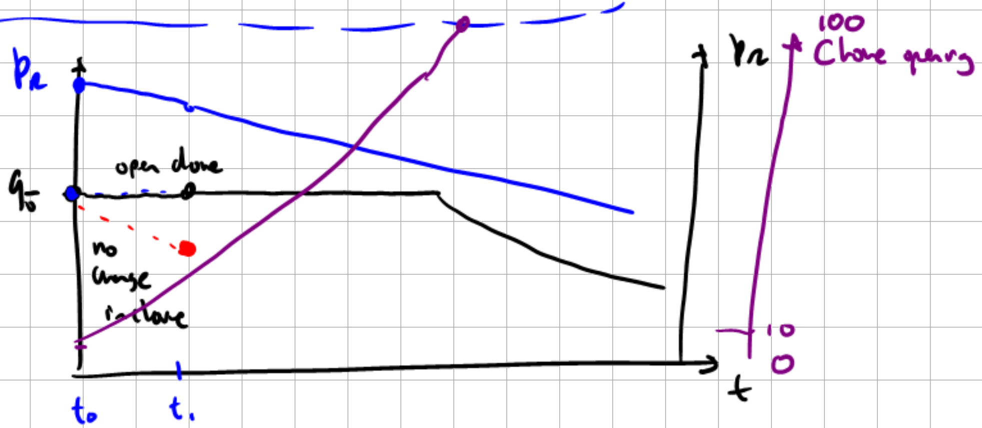
constant in time
how do I
achieve
this?

$P_{wh} \rightarrow P_{in}$ (choke Δp)

$P_{in} \rightarrow P_{sep}$ (pipeline drop)

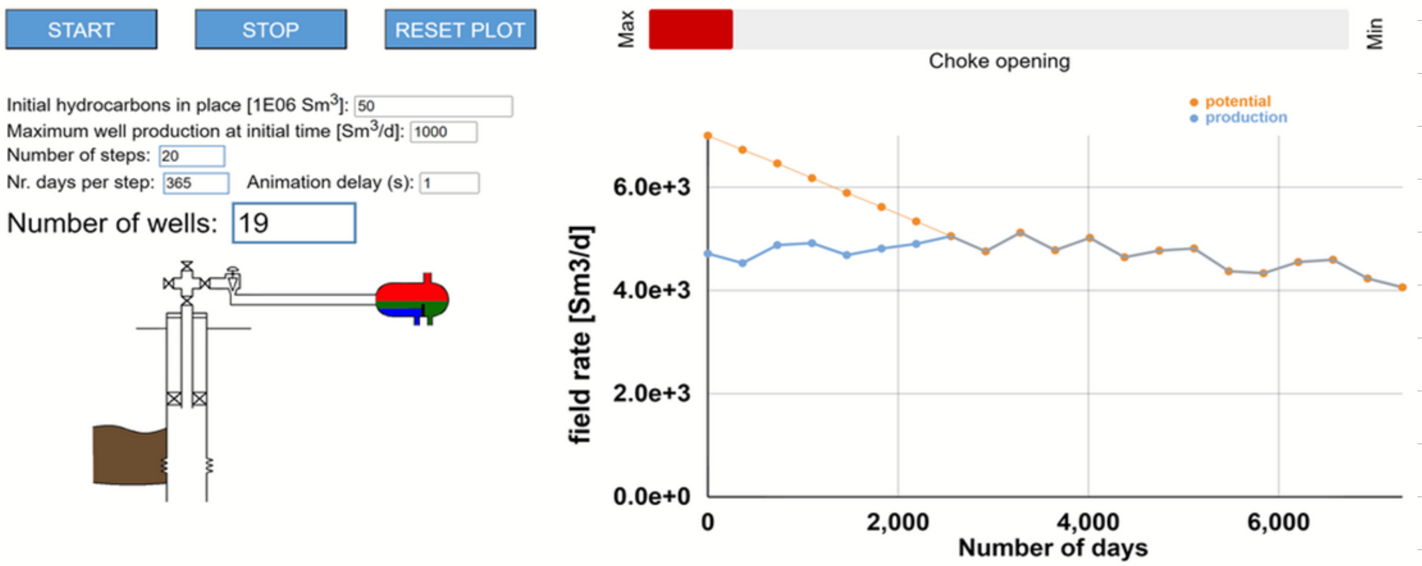


with control mechanism → liquid level
→ pressure



Demonstration using the field simulator

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

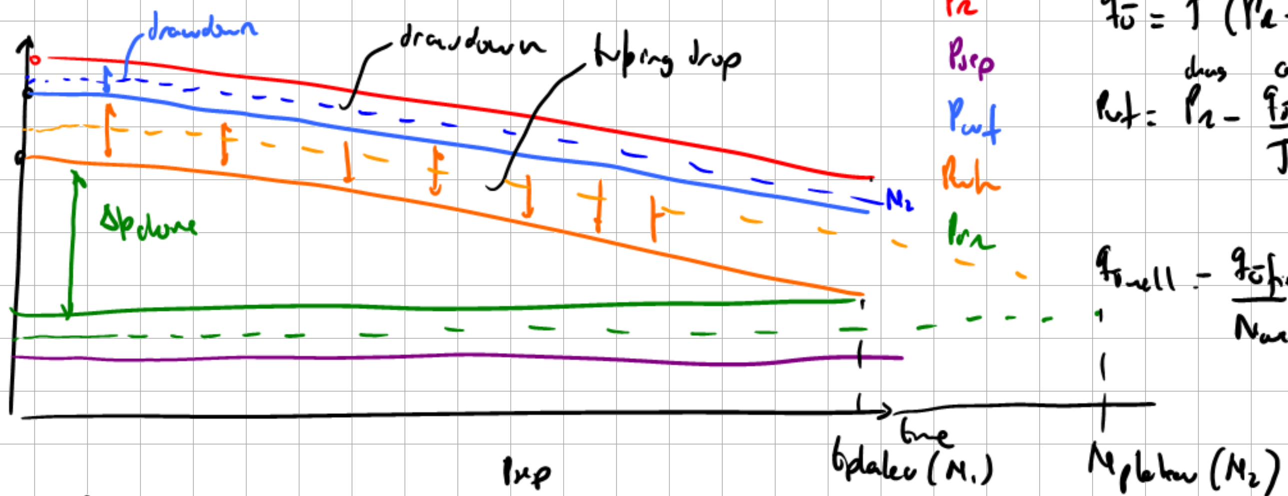


Main takeaways.

-Many things can be done to avoid rate dropping in time. Easiest and cheapest is to open the choke. Other solutions that are cumbersome, expensive and not practical for frequent adjustment are to avoid pR to drop (injection), reduce well drawdown (e.g. reservoir stimulation), reduce tubing drop (e.g. increase diameter), reduce pipeline drop (e.g. increase diameter)
-when reservoir pressure drops, Choke must be opened in time to keep constant rate
    -There will be a time at which the choke is fully open. at that time, we "lose" control of the field and decline starts.
-higher plateau gives shorter plateau, Lower plateau gives longer plateau
-Plateau can be prolonged by adding more wells (but is expensive)
-Isn't it better to always produce as much as possible?
    -In terms of just revenue, yes (money today as more value than money in the future). But: when considering cost, processing higher amounts will require more costly installations. A Net present value analysis is required, to evaluate expenses and income.

Why adding more wells prolongs plateau?

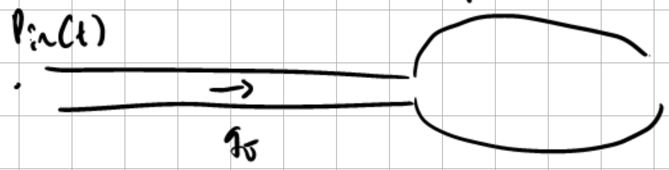
N_2^*, N_1^* number of wells } $q_{o\,field}$ = same



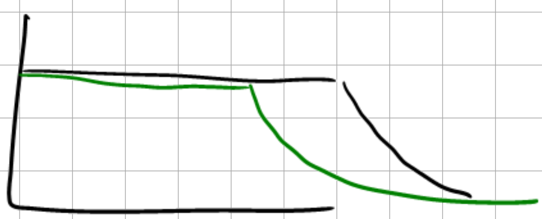
$$q_o = J\,(p_R - p_{wf})$$

$$p_{wf} = p_R - \frac{q_{o\,well}}{J_{well}}$$

$$q_{o\,well} = \frac{q_{o\,field}}{N_{well}}$$



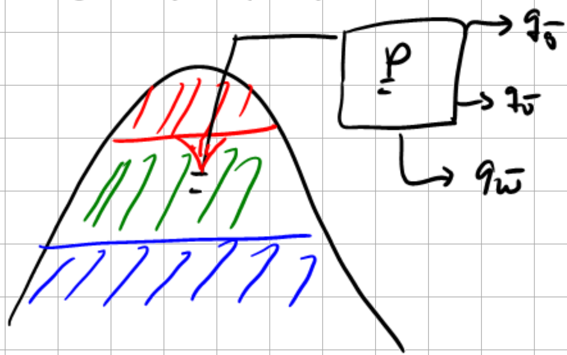
$$p_{in} = p_{sep} + \Delta p(q_{o\,well})$$

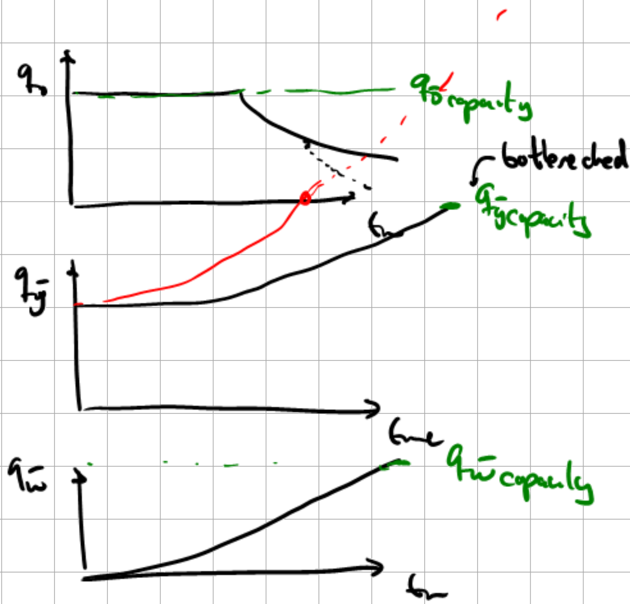


◦ Bottlenecking

-when we reached capacity of some process in the field --> that prevents from producing more oil and gas.

Processing facility «capacity» is reached





Processing facilities typically have design $q_{\bar{o}max}$, $q_{\bar{g}max}$, $q_{\bar{w}max}$

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

http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/Tools/Oilfield_bottlenecking_showcase_v1.exe

water cut WC

$$w_c = \frac{q_{\bar{w}}}{q_{\bar{L}}} = \frac{q_{\bar{w}}}{q_{\bar{o}} + q_{\bar{w}}} \quad [-]$$

$$\frac{q_{\bar{w}}}{q_{\bar{o}} + q_{\bar{w}}} \cdot (100) \quad [\%]$$

$q_{\bar{o}} = 1000$ Sm³/d

$w_c = 50\%$

$q_{\bar{w}} = 1000$ Sm³/d

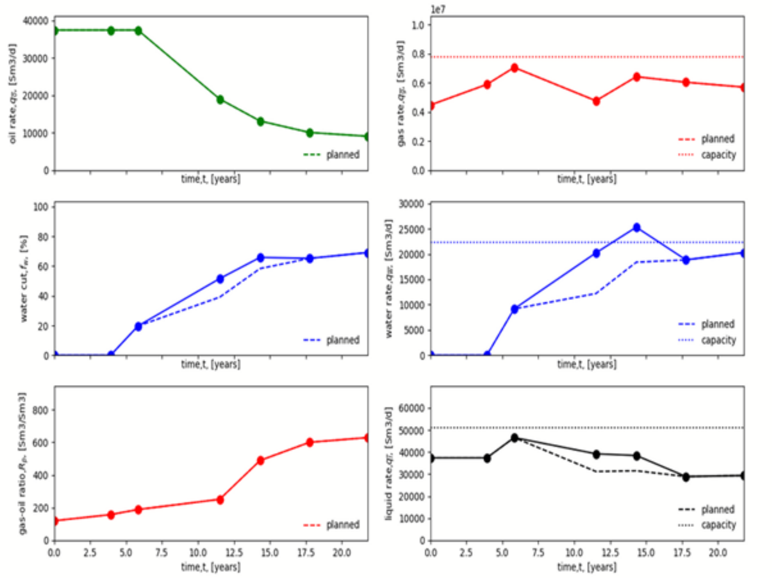
$q_{\bar{o}} = 1000$ Sm³/d

$w_c = 30\%$

$q_{\bar{w}} = ?$

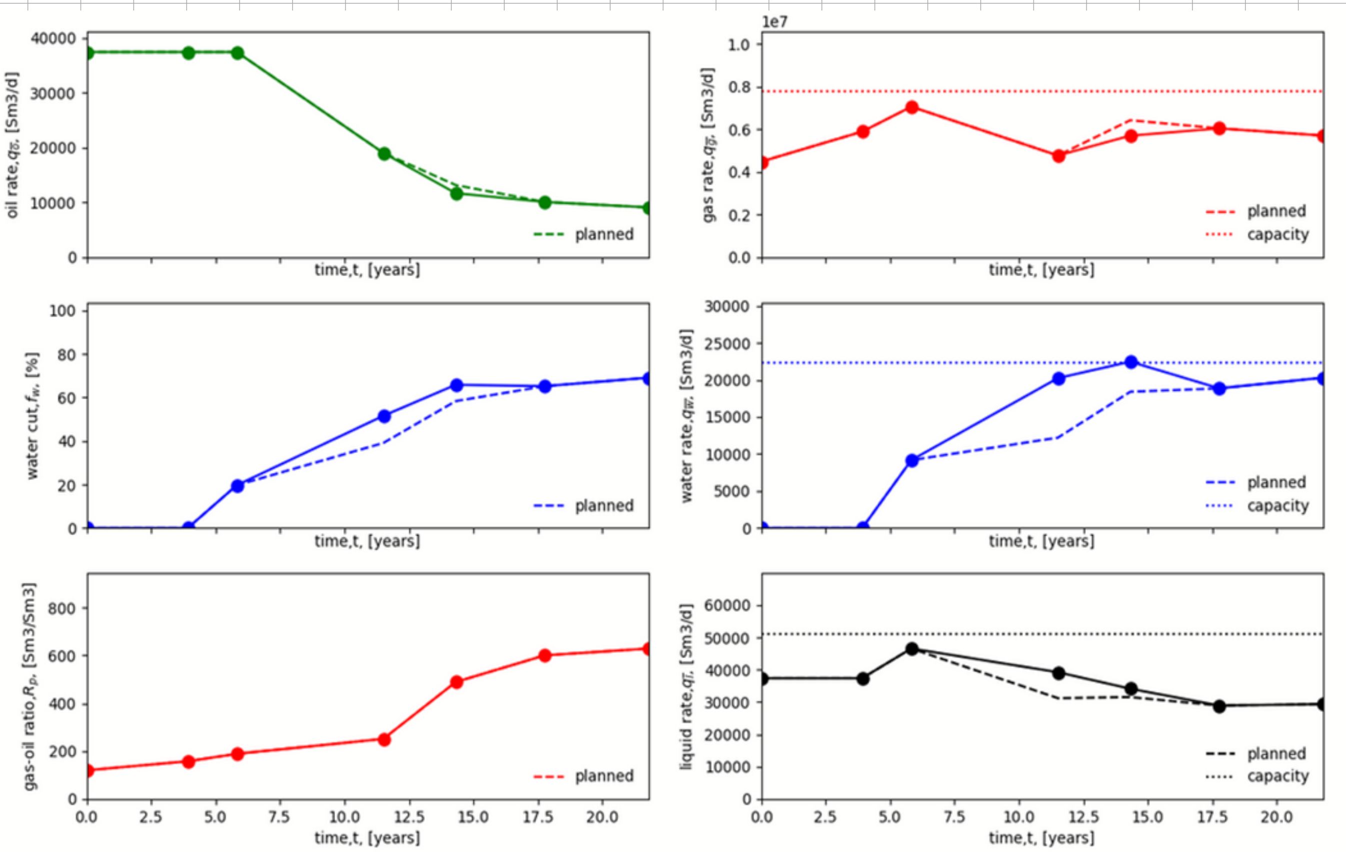
$$0.3 = \frac{q_{\bar{w}}}{1000 + q_{\bar{w}}}$$

$$GOR\,(R_p) = \frac{q_{\bar{g}}}{q_{\bar{o}}} \qquad q_{\bar{g}} = q_{\bar{o}} \cdot R_p$$



oil rate, $q_{\bar{o}}$, [Sm3/d]
time,t, [years]
planned
1e7
gas rate, $q_{\bar{g}}$, [Sm3/d]
planned
capacity
water cut, f_w, [%]
water rate, $q_{\bar{w}}$, [Sm3/d]
gas-oil ratio, R_p, [Sm3/Sm3]
liquid rate, $q_{\bar{l}}$, [Sm3/d]

*Adjusted



oil rate, $q_{\bar{o}}$, [Sm3/d]
time,t, [years]
planned
1e7
gas rate, $q_{\bar{g}}$, [Sm3/d]
planned
capacity
water cut, f_w, [%]
water rate, $q_{\bar{w}}$, [Sm3/d]
gas-oil ratio, R_p, [Sm3/Sm3]
liquid rate, $q_{\bar{l}}$, [Sm3/d]

Notes for Youtube video nr. 3

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

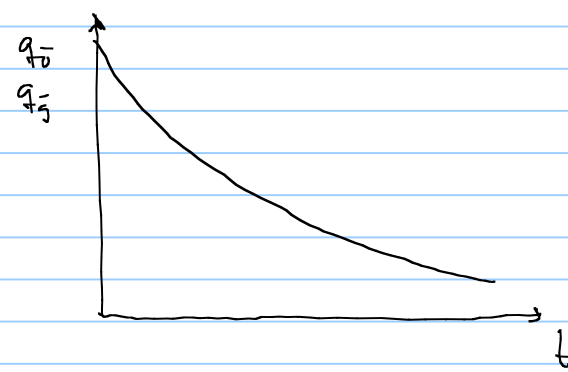
production scheduling : deciding / forecasting rates of oil | gas and associated products (oil: water; gas: water)

during the life of field

two ways to produce a field

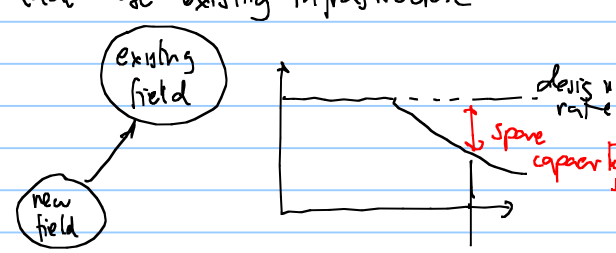
Production mode A "plateau production"

Production mode "B" "decline production"

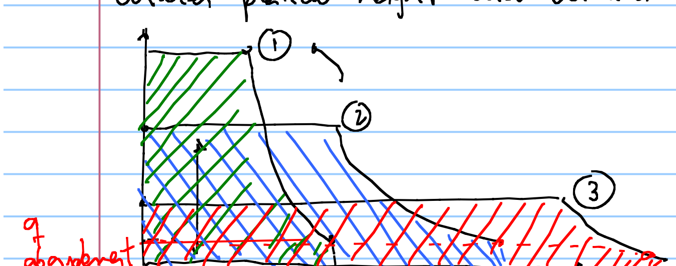


- typically used for gas fields with a contract
- Big-medium reservoir
- standalone development → requires its own facilities, offshore structure etc.

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



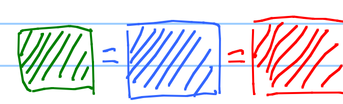
in mode "a" there is a relationship between plateau height and duration



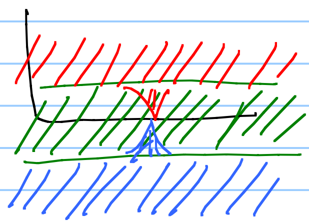
$$N_p = \int_0^t q(t)\,dt$$

↳ 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

cash flow = revenue − expenses

NPV ~> net present value

$$NPV = \sum_{i=1}^{N} \frac{CF_i}{(1+c)^i}$$

year

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

ΔQ_{p_i}: p_o^i production of oil/gas in year "i"

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

start production

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

$DF = \frac{1}{(1+c)^i}$

year	
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)

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

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

$N_{pu} = 72E06$ stb

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

[Sm^3/d]

[stb/d]

↳ 95% uptime (0.95 · 365)

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

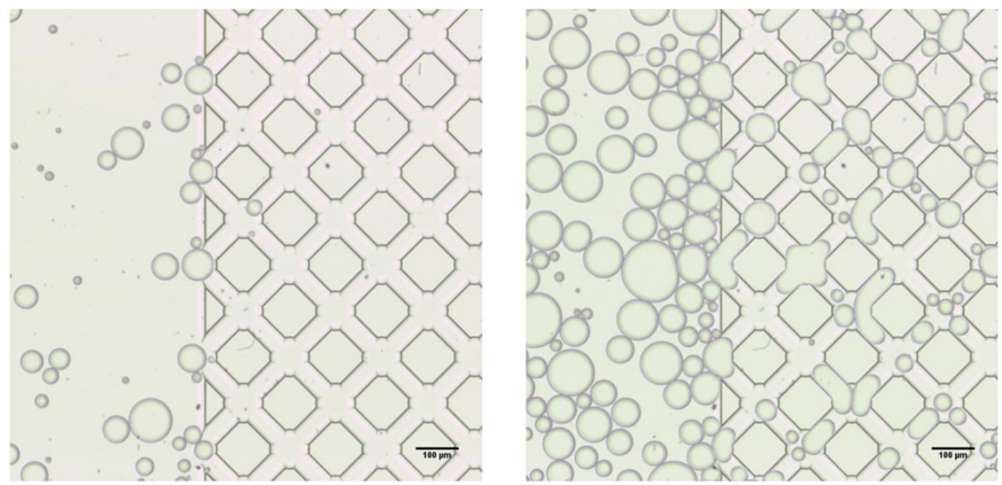
Q is either oil or gas
N is for oil
G is for gas

Class 20240125 - OUTLINE

-Additional comments about Bottlenecking
-quick go-through the previous video lectures' content
-Introduction to field processing

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 Sm^3/sd
Liquid production	28,000 Sm^3/sd
Water production	15,000 Sm^3/sd
Water injection	18,000 Sm^3/sd
Utsira water production	15,000 Sm^3/sd
Gas production initially (excl. fuel gas)	10 MSm^3/sd
Gas injection	10 MSm^3/sd
Export gas production	13 MSm^3/sd

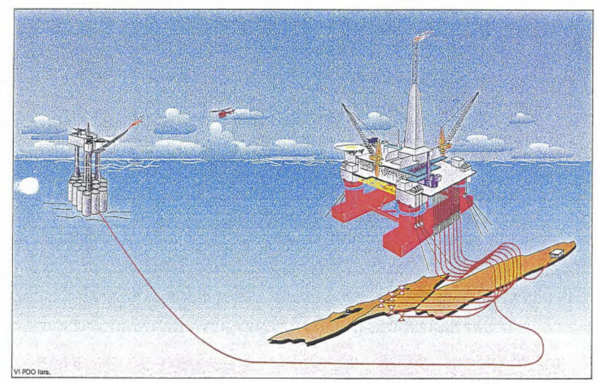
Table 1-2 Process Capacities

VISUND

Plan for Development and Operation

PL 120

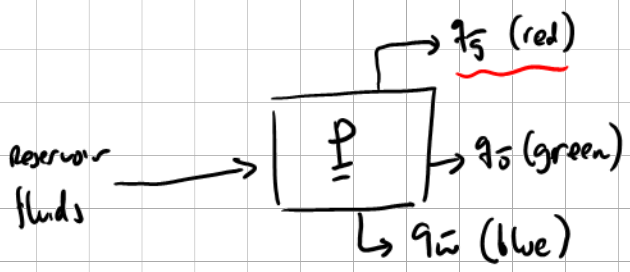
September 1995



Operator: HYDRO

Partners: STATOIL conoco saga elf

20240125



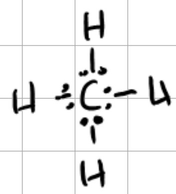
Non HC { CO_2, N_2, H_2S, H_2O } q_g

HC { C_1 (methane) } LNG, C_2, C_3, C_4 } LPG, iC_4, C_5, iC_5, C_6, …, C_{100}

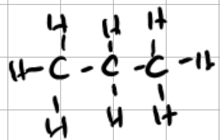
} NGL

q_o

SCN — single carbon number



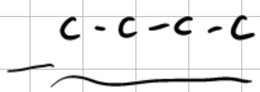
C_2H_6

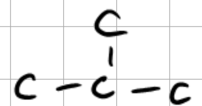


C_nH_{2n+2} Alkane

C_nH_{2n} Alkene

C_nH_{2n-2} Alkyne





isomers

LNG Liquified natural gas

LPG Liquified petroleum gas

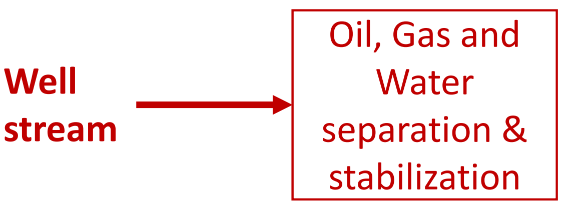
NGL .. Natural gas liquids

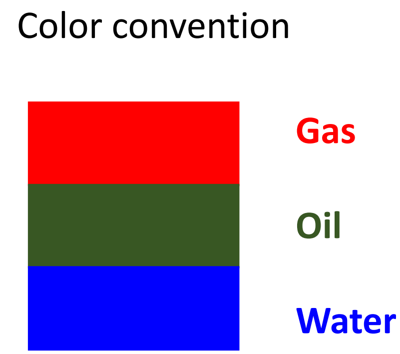
NTNU | Norwegian University of Science and Technology

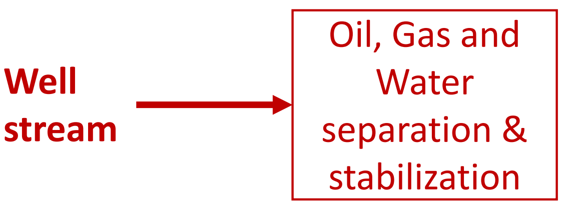
Introduction to oilfield processing

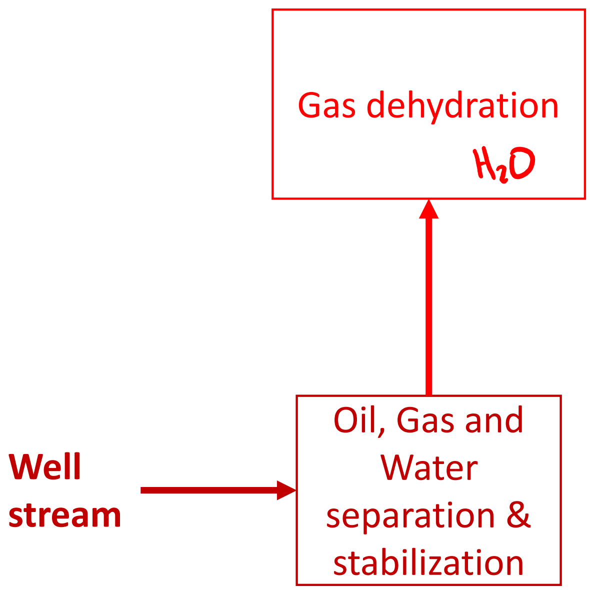
Assoc. Prof. Milan Stanko

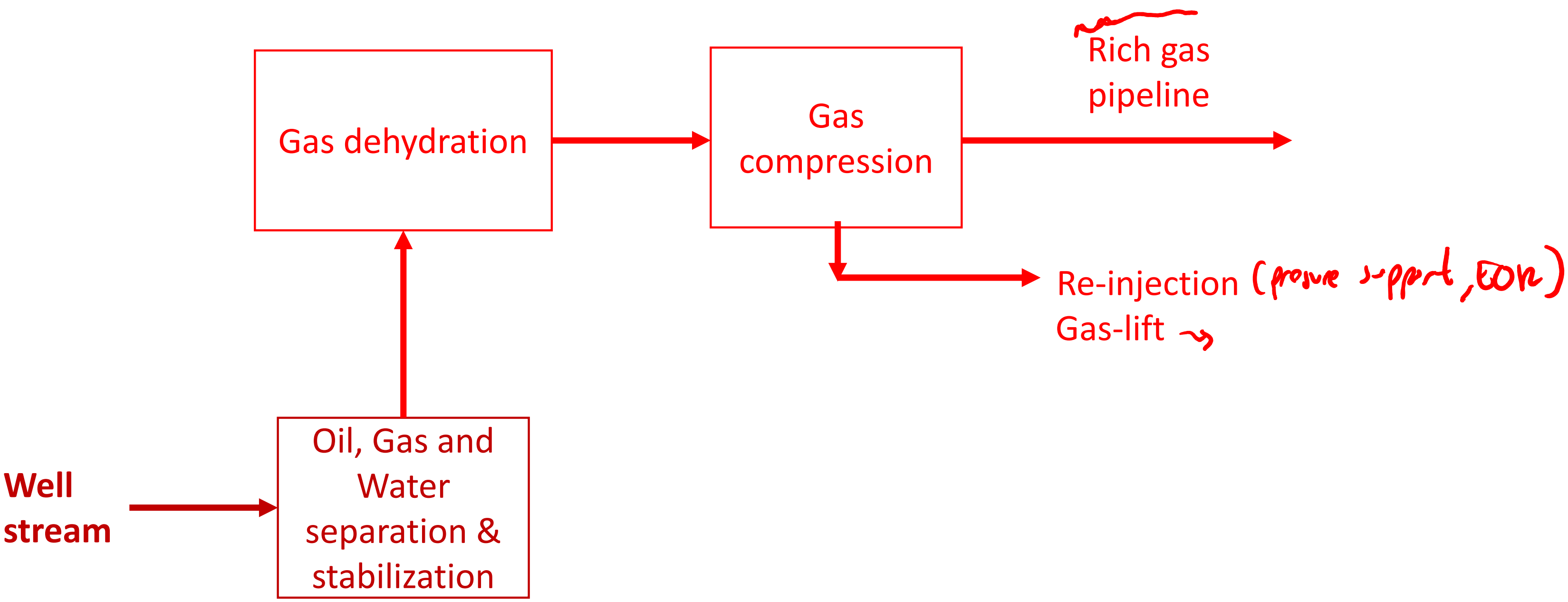
Well stream

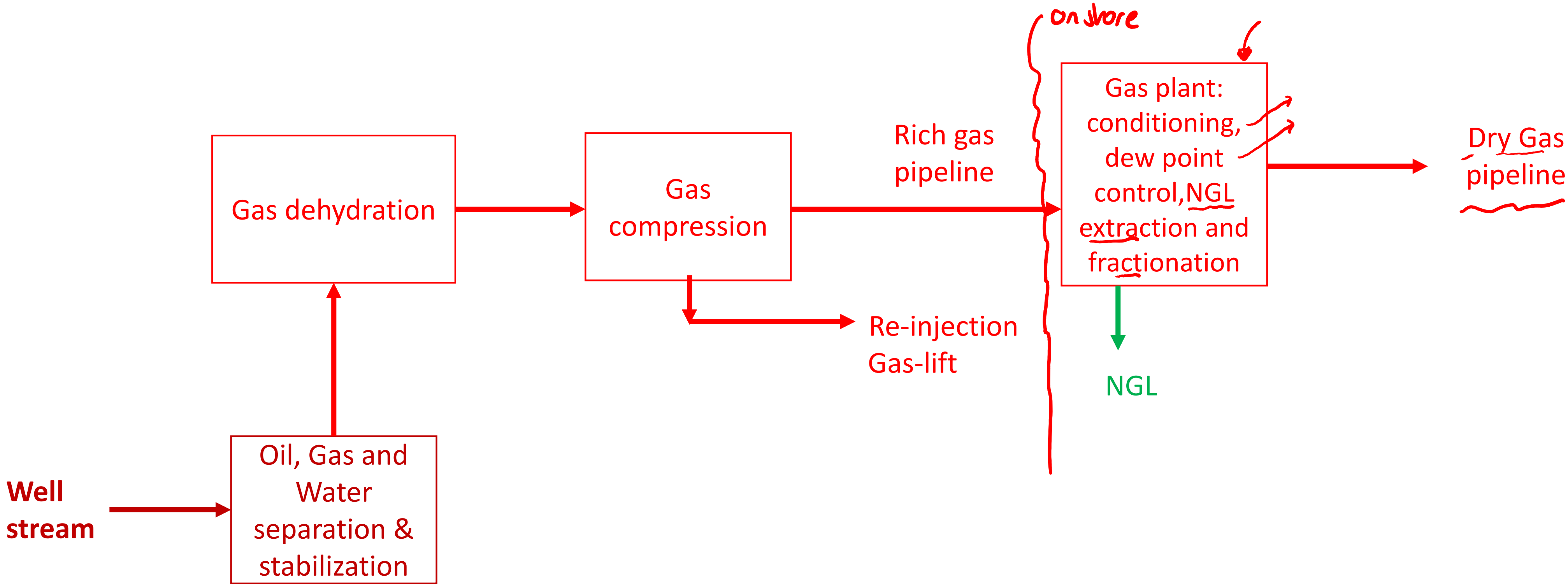

Well stream
Oil, Gas and Water separation & stabilization


Color convention
Gas
Oil
Water

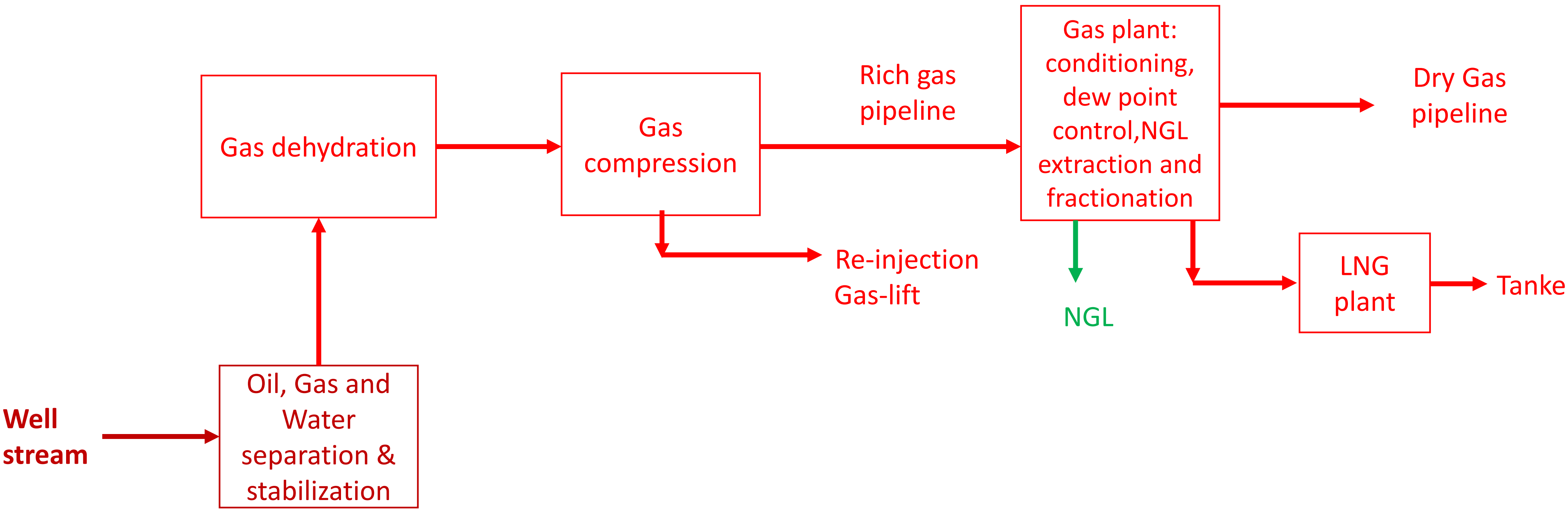

Well stream
Oil, Gas and Water separation & stabilization


Gas dehydration
H_2O
Oil, Gas and Water separation & stabilization
Well stream

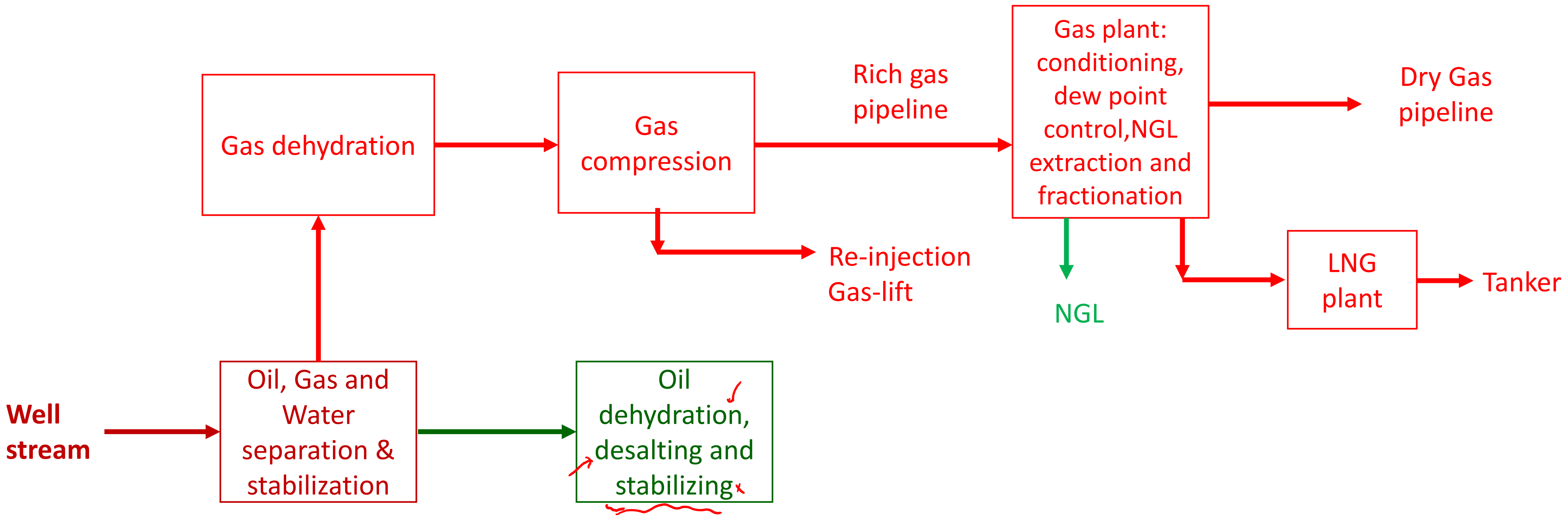

Rich gas
pipeline
Gas dehydration
Gas
compression
Re-injection (pressure support, EOR)
Gas-lift
Well
stream
Oil, Gas and
Water
separation &
stabilization

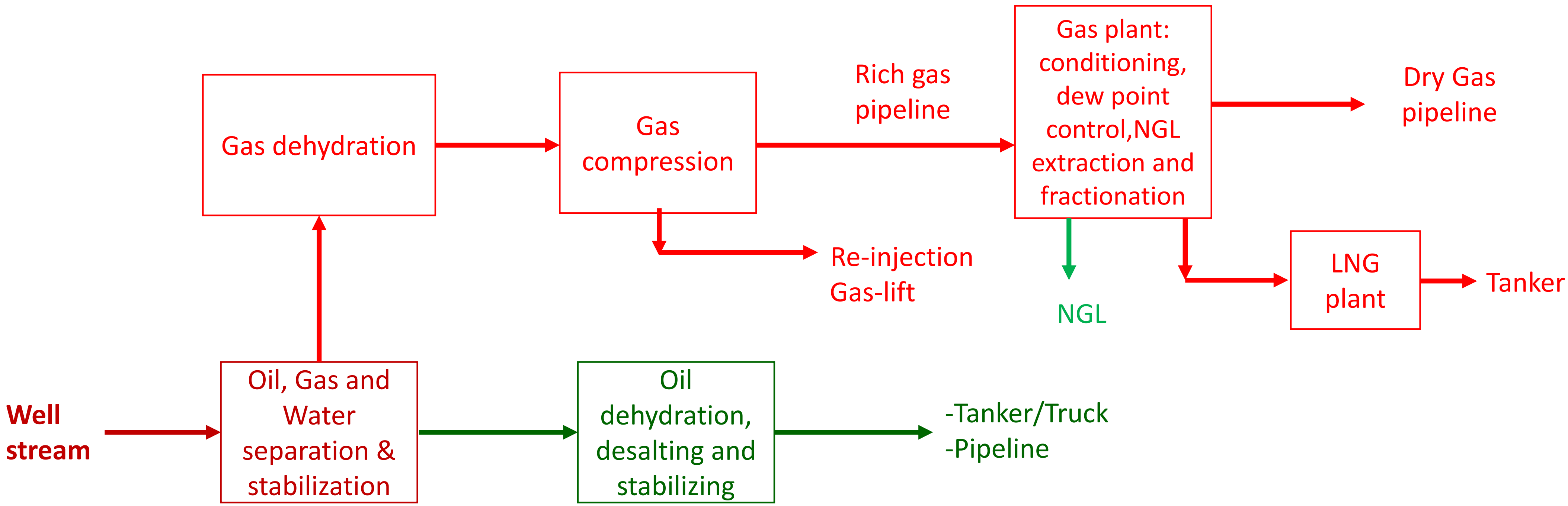


on shore
Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control, NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
Well stream
Oil, Gas and Water separation & stabilization

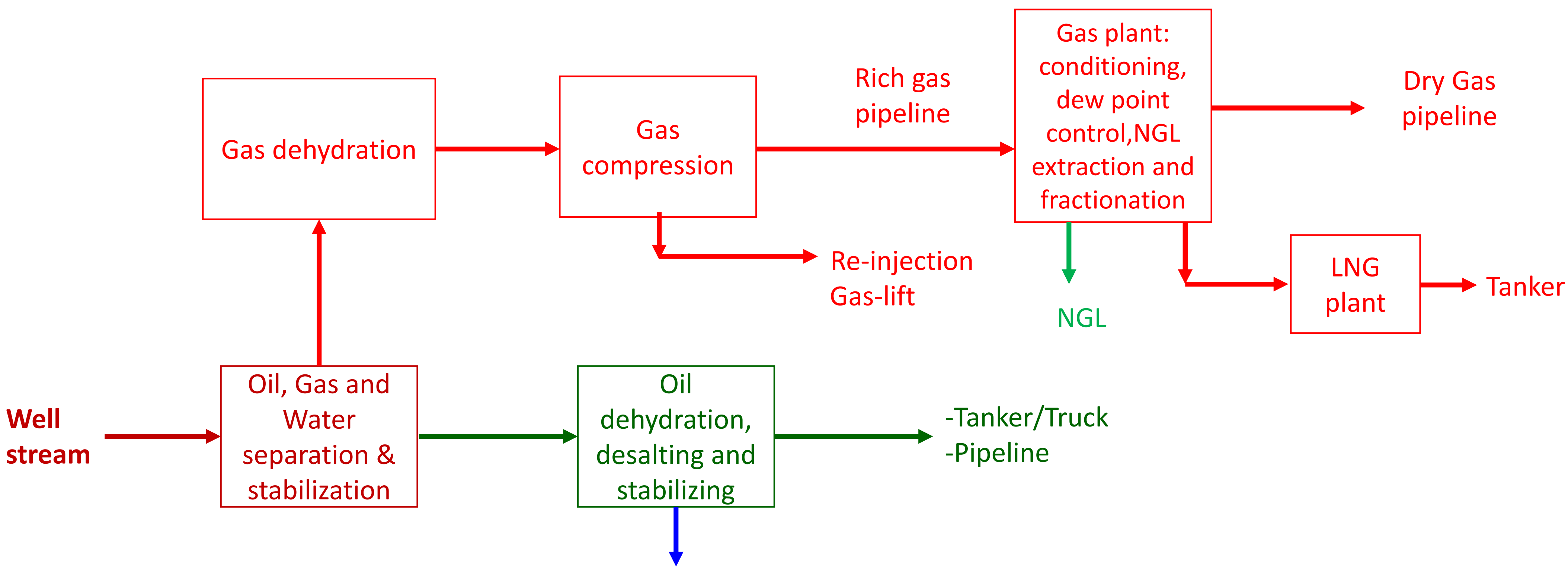


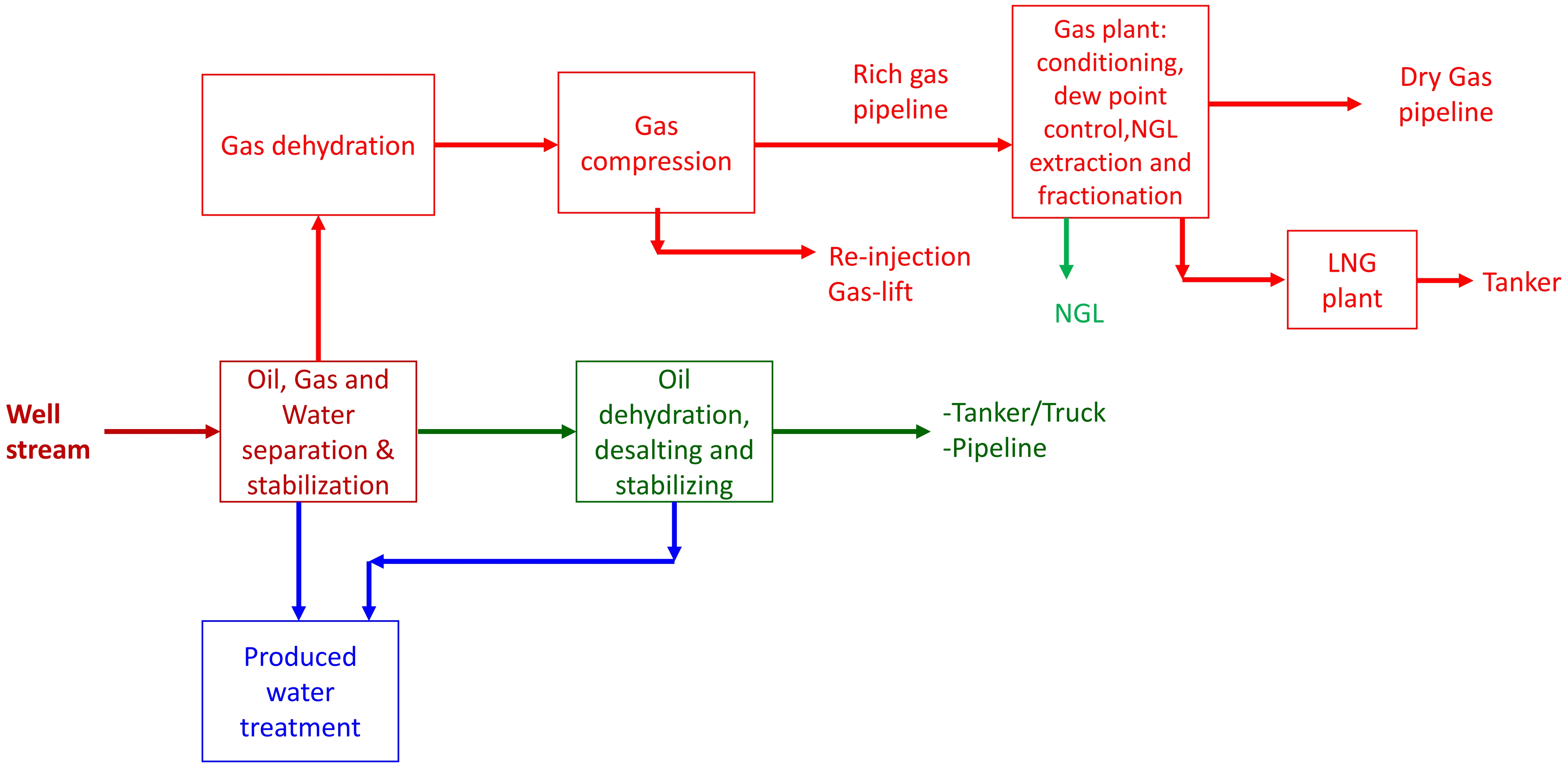
Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization

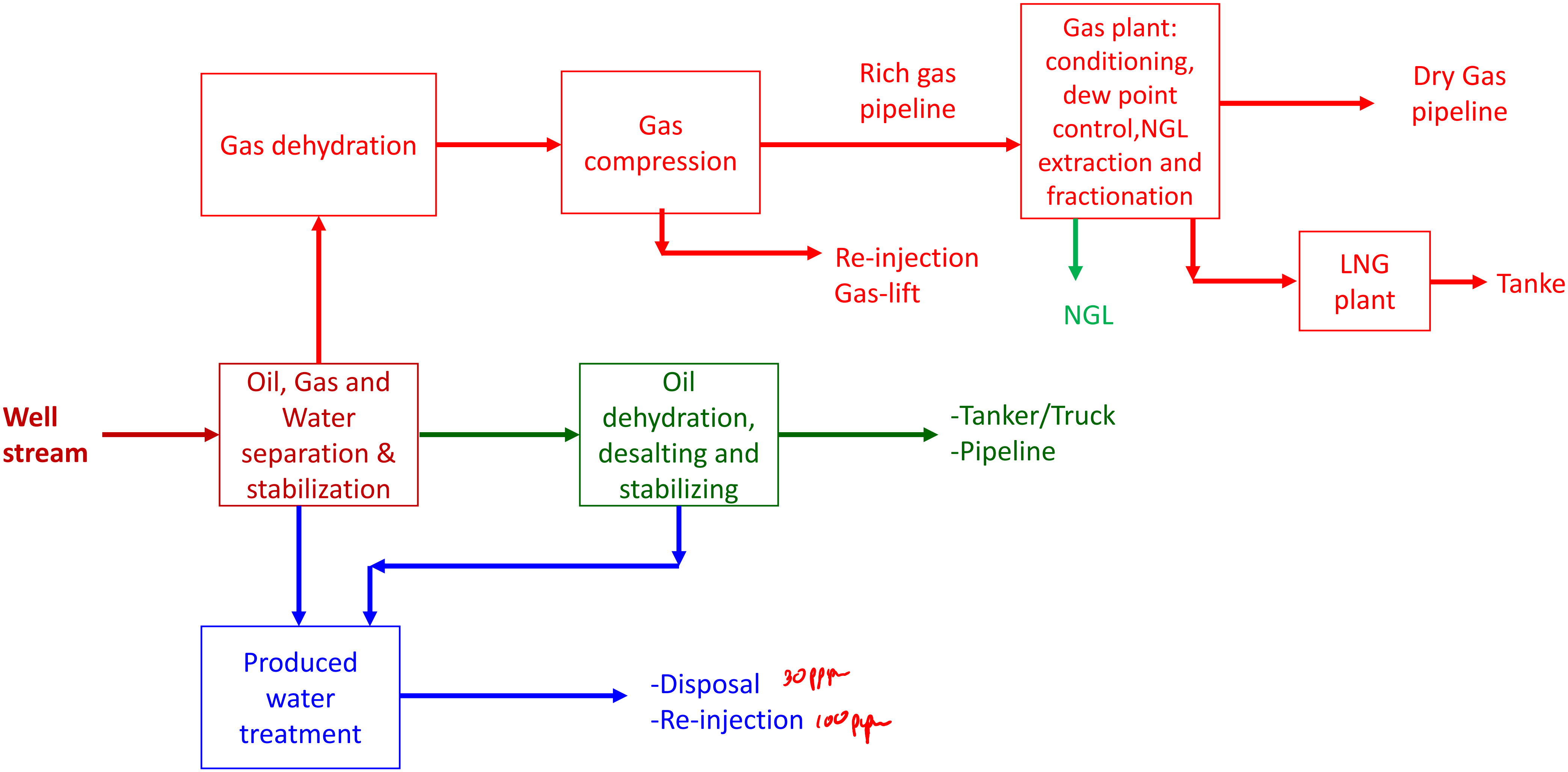

Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing

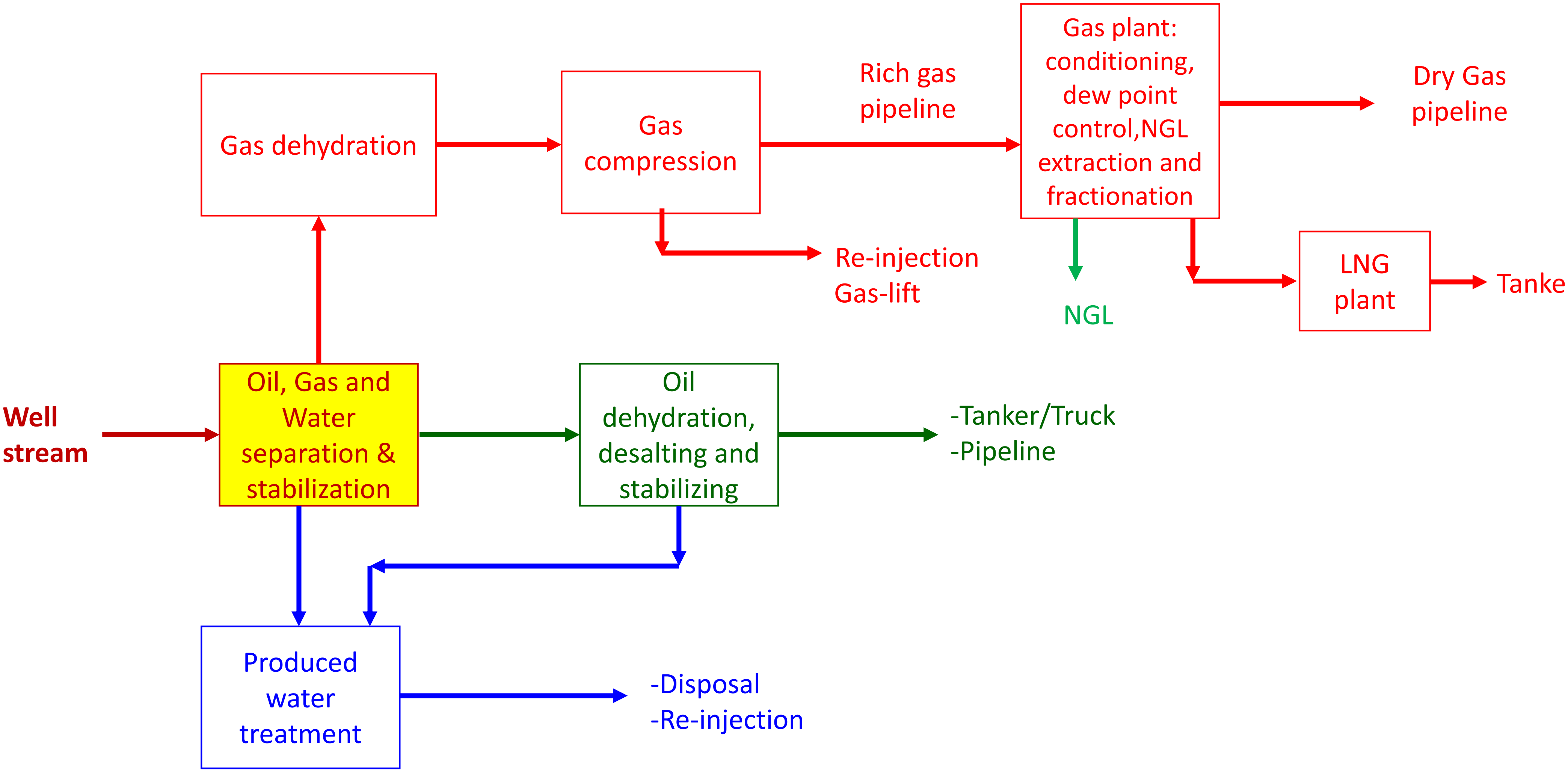


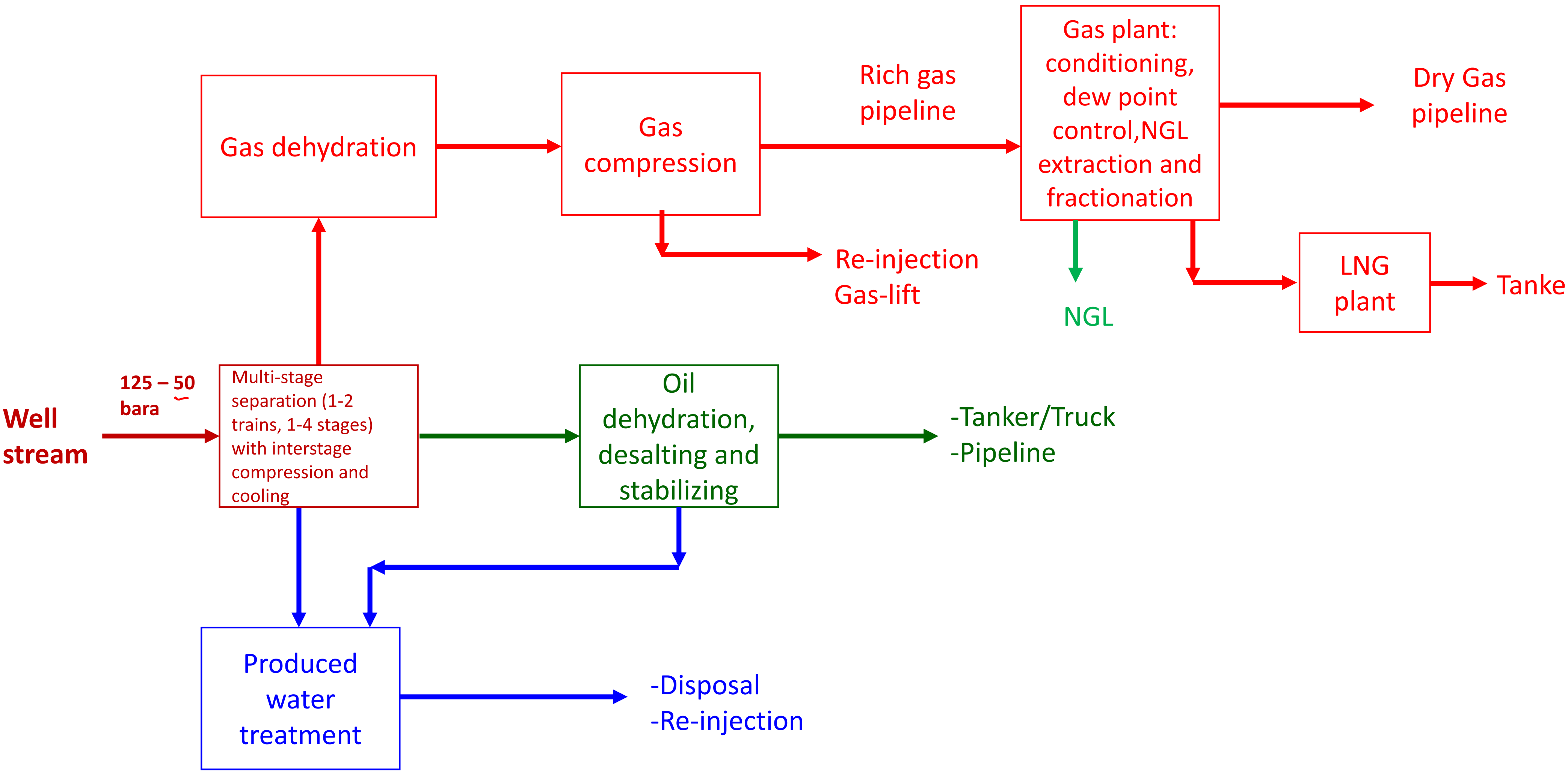
Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing
-Tanker/Truck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

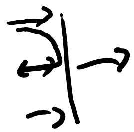

Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-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 30ppm
-Re-injection 100ppm

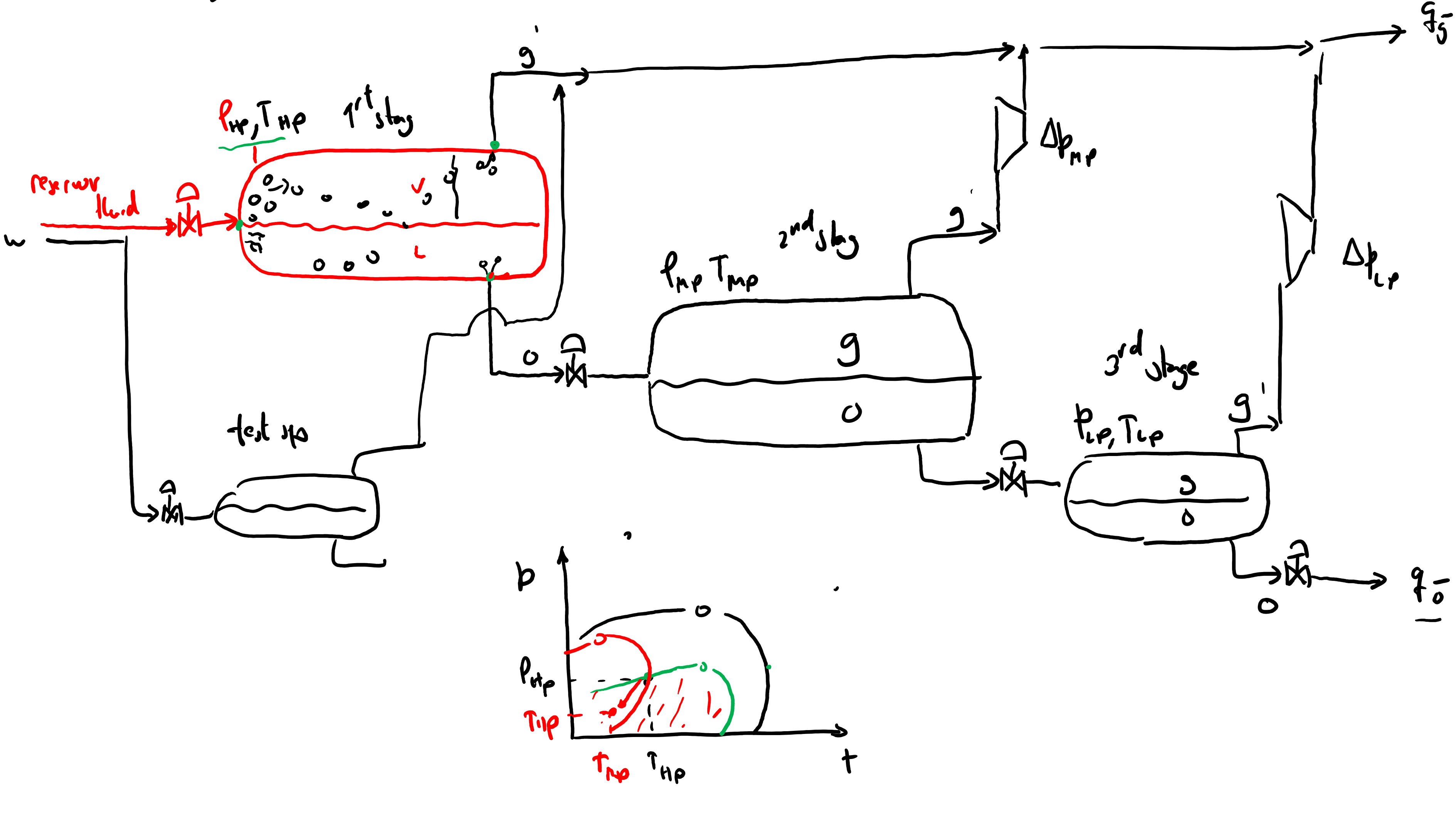

Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
Oil, Gas and Water separation & stabilization
Oil dehydration, desalting and stabilizing
-Tanker/Truck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

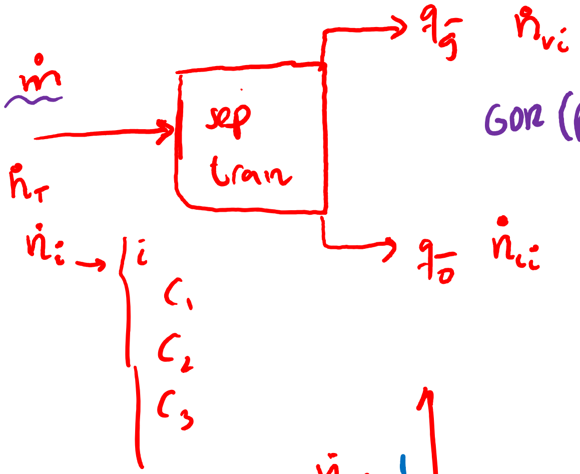


residence time



Class 20240126 - OUTLINE

-Missing reference group member
-Upcoming reference group meeting
-Exercise set 1 published –Deadline 11.02
-cont. multi-stage separation
-How do a horizontal and vertical separator look like?
-Class exercise, Hysys simulation

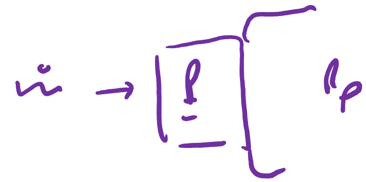


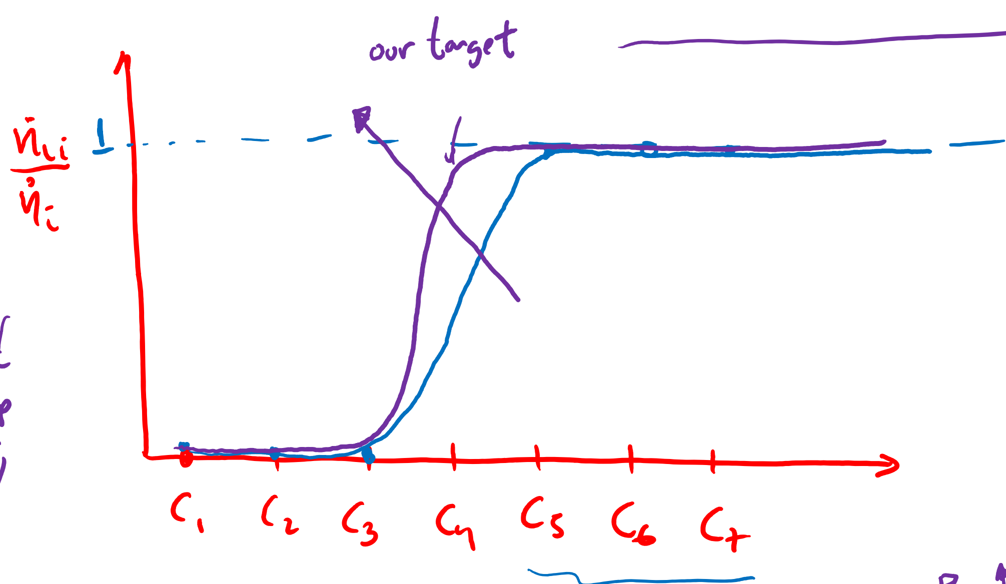
GOR $\left(R_p = \frac{q_g}{q_o}\right)$

$\dot{n}_i = \dot{n}_{vi} + \dot{n}_{Li}$

1 0.5 0.5

$\underline{\dfrac{\dot{n}_{Li}}{\dot{n}_i}}$



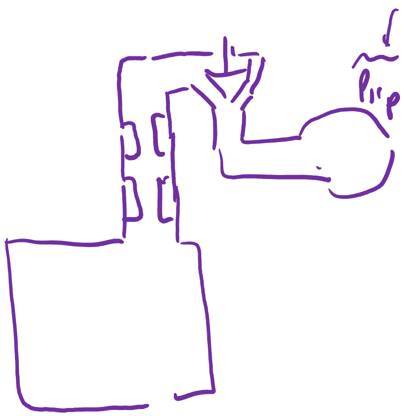


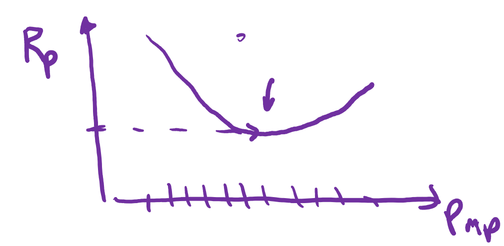
measured

1. more separator stages
2. P_{HP} high

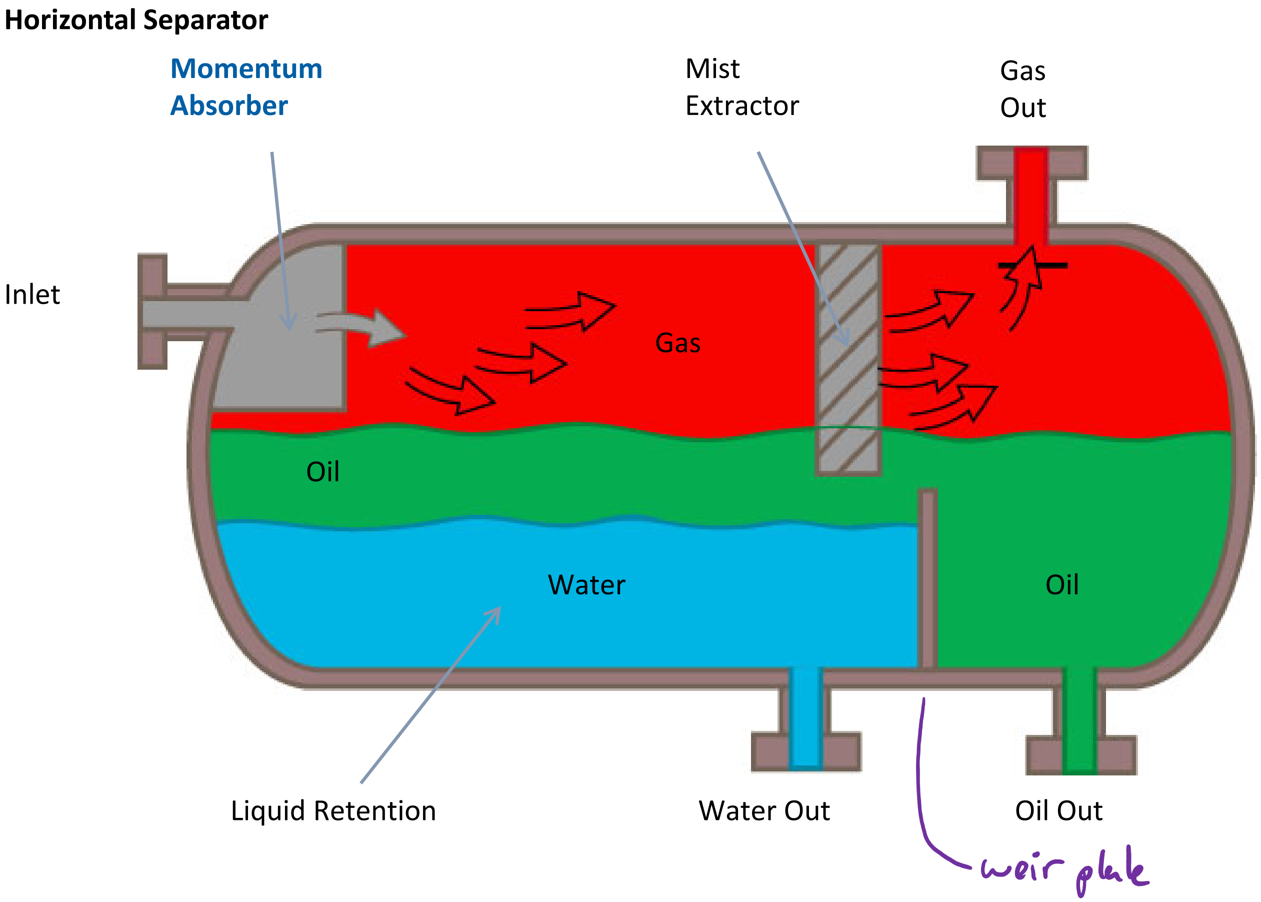
$\uparrow P_{HP} \downarrow \dot{m}$

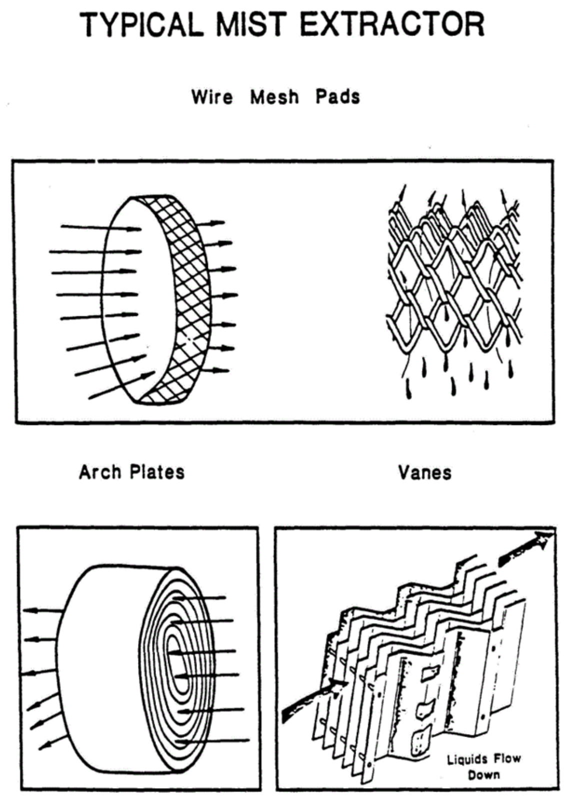
3. changing P_{MP}



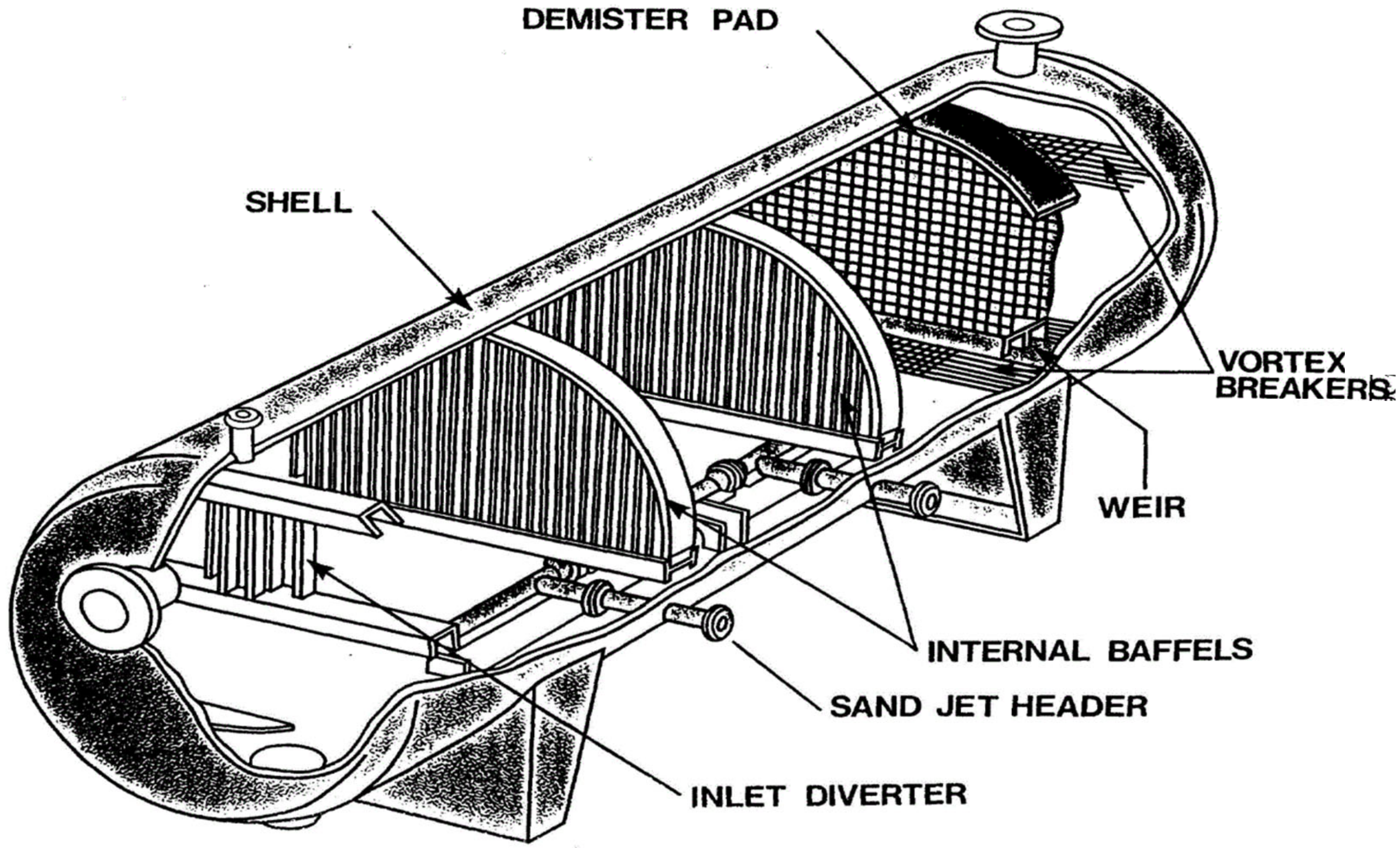


Horizontal separator



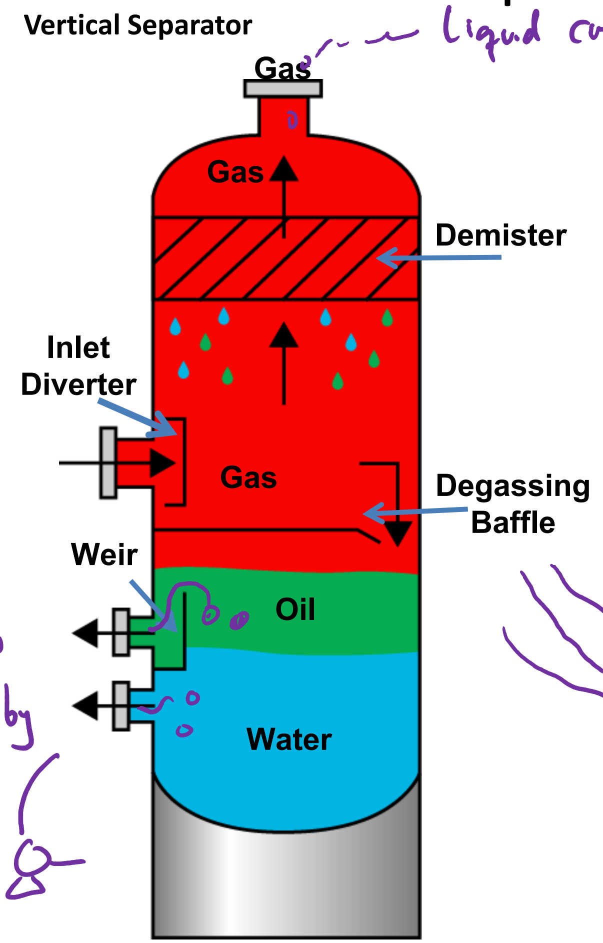


Horizontal separator

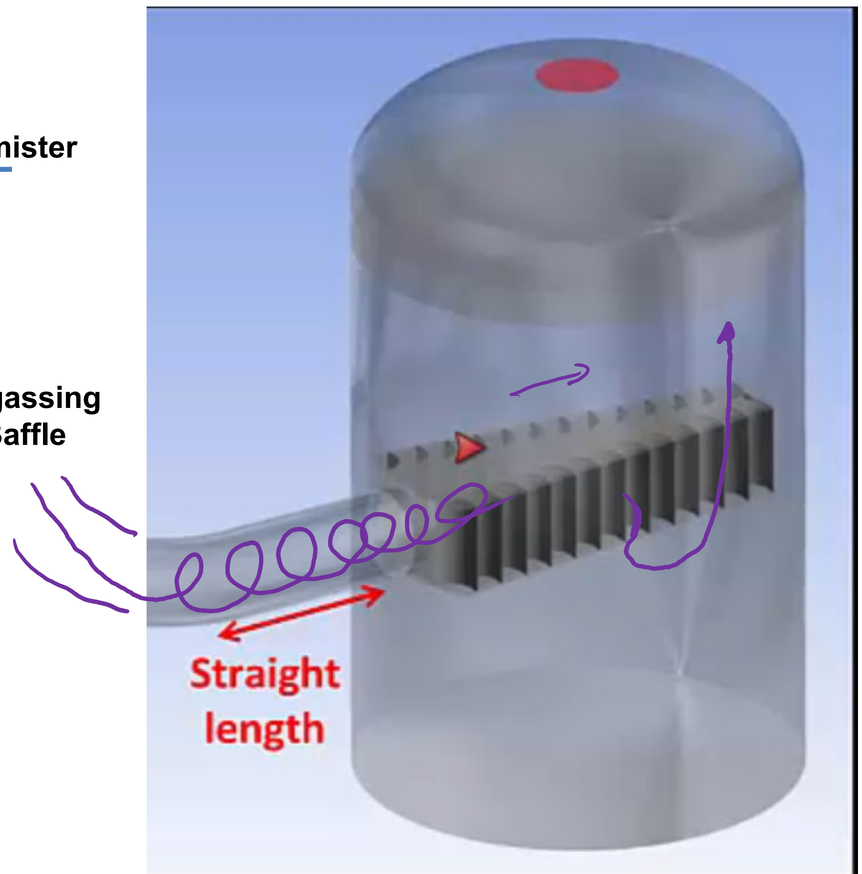


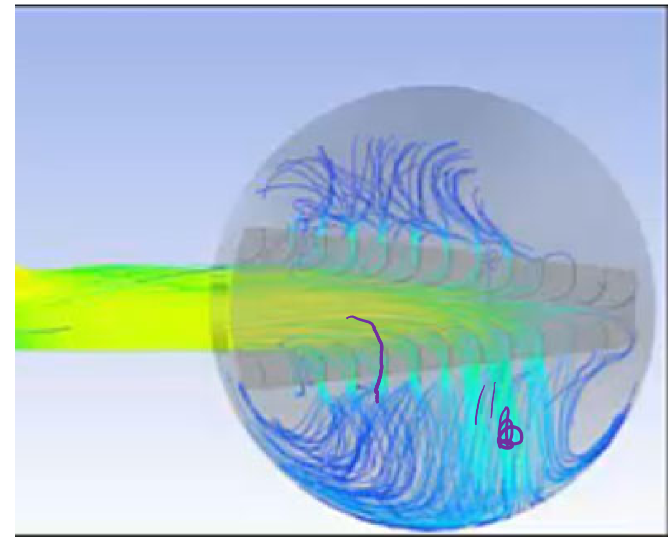
Vertical separator

liquid carry over →



gas
blowby





HYSYS Example

Problem 3[1]

$\dot{Q}_{\bar{o}}$

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

$q_{\bar{o}}$

$\dot{m} = \dot{Q} \cdot \rho$ (m³/s) kg/m³ [kg/s]

$\dot{m}$

$[V] \rightarrow [M]$

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

$q_{\bar{g}} = [Sm^3/d]$

API, $\gamma_{\bar{o}} = \frac{\rho_{\bar{o}}}{\rho_{\bar{w}}(1000)}$ $\quad q_{\bar{w}} = [Sm^3/d]$

$$\dot{m} = \underbrace{q_{\bar{o}} \cdot \rho_{\bar{o}}}_{\dot{m}_{\bar{o}}} + \underbrace{q_{\bar{g}} \cdot \rho_{\bar{g}}}_{\dot{m}_{\bar{g}}} + q_{\bar{w}} \cdot \rho_{\bar{w}}$$

$\rho_{\bar{w}}$: 1000 → 1200 kg/m³ (brine)

$q_{\bar{g}} = R_p \cdot q_{\bar{o}}$ $\quad \rho_{\bar{g}}$ $\quad \gamma_{\bar{g}} \rightarrow \rho_{\bar{g}}$

$\gamma_{\bar{g}} = \frac{MW_{\bar{g}}}{MW_{air}}$

$p_{sc} V = n R_u T_{sc}$

$n = \frac{m}{MW}$

$\frac{1}{\rho} = \frac{1}{MW} R_u$ (const)

Data

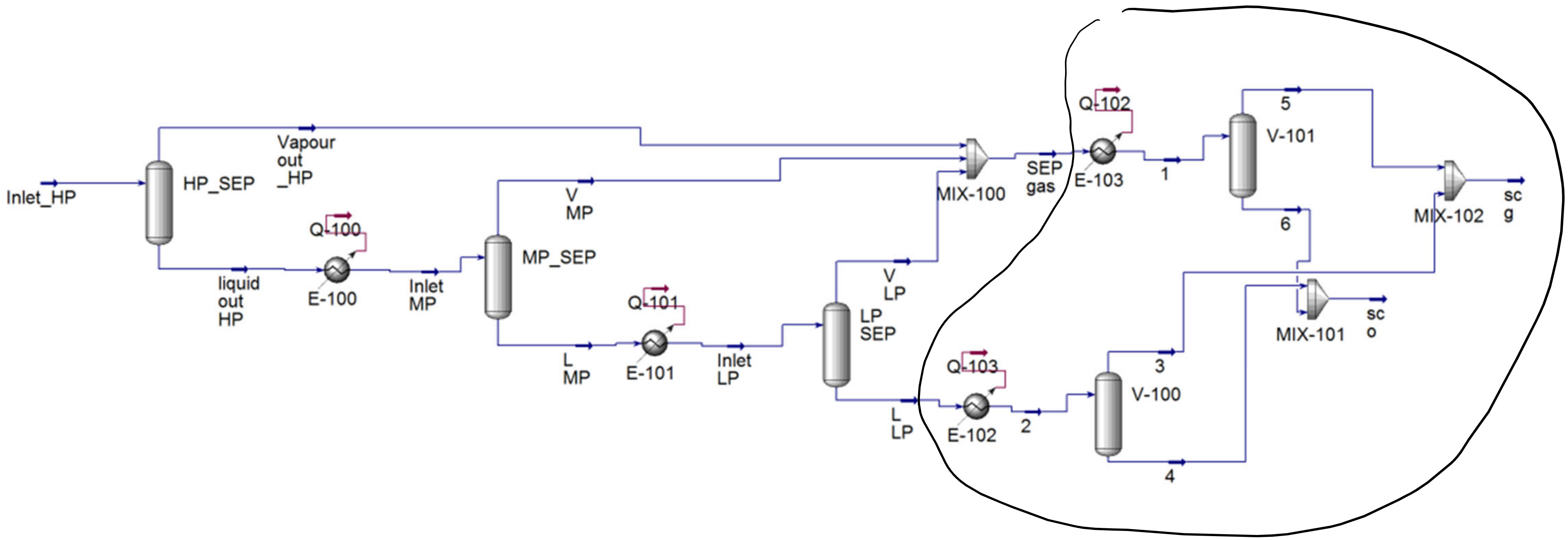
Component	Mole Fraction
Nitrogen	0.003672
CO2	0.001092
Methane	0.429256
Ethane	0.046897
Propane	0.029618
i-butane	0.014919
n-butane	0.009325
i-pentane	0.008446
n-pentane	0.005030
Hexanes	0.018433
Heptanes	0.041418
Octanes	0.049891
Nonanes	0.038403
Decanes	0.303600

Total mass flow: 27 000 kg/h

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



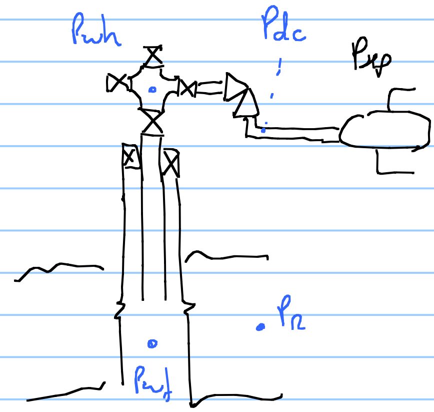
Taking to Standard conditions.
This is an imaginary process.

Youtube video: Intro to Excel VBA functions and sub

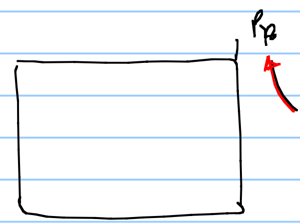
There were no notes for this video

Youtube video: modeling dry gas systems

Simplified dry gas production system



Reservoir model



Dry gas material balance

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

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

G: uncertain value

$\frac{G_p}{G}$: R_F recovery factor

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(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,

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

Equation approximation to Z chart

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

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

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

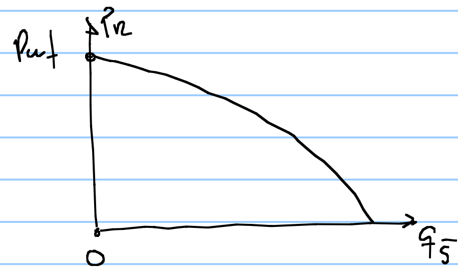
$$q_g = C_R\left(P_R^2 - P_{wf}^2\right)^n$$

← 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

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

tubing coefficient (friction losses)

elevation coefficient (hydrostatic losses)

$$q_g = 0 \qquad p_{wf} = p_{wh}\, e^{S/2}$$

Page 156, Appendix A of compendium

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

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

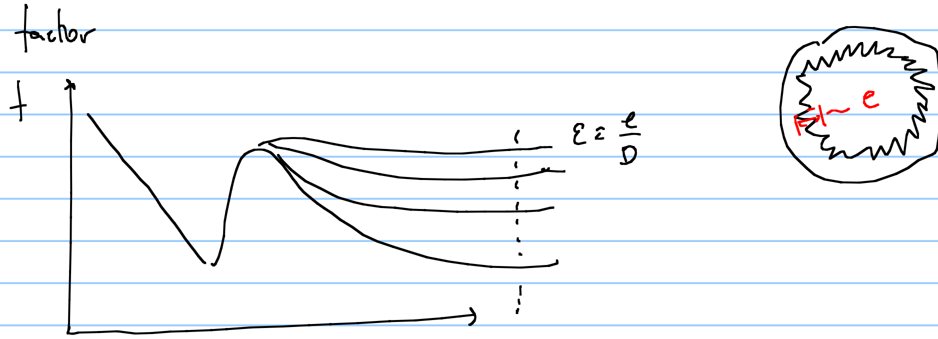
$$S = 2 \cdot L \cdot C_a = 2 \cdot \frac{M_g}{Z_{av} \cdot R \cdot T_{av}} \cdot L \cdot g \cdot \cos(\alpha)$$

Comments about tubing equation

to compute G_T $\quad T_{av} \rightarrow \dfrac{T_{wf} + T_{wh}}{2}$ An estimate of T_{wh} is needed

$Z_{av} \sim \dfrac{Z_{wf} + Z_{wh}}{2}$

f_M friction factor



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

$v = f(q_{local})$ 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 $e = f(D)$ due to manufacturing

Lore equation for dry gas: (page 166)

"opening" tuning factor

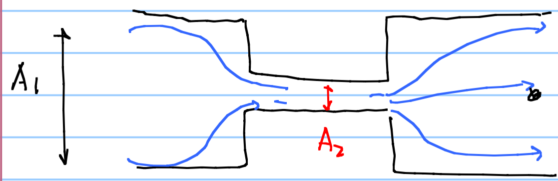
$\frac{R\bar{u}}{MW_g}$ $k = \frac{C_p}{C_v}$

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

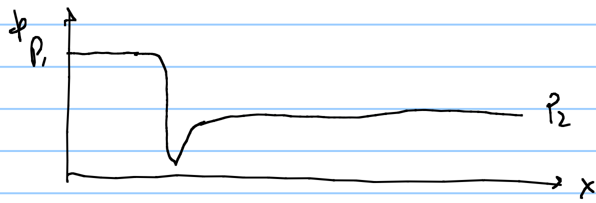
$P_{sc} = 1.01325$ bara

$T_{sc} = 15.56\,°C$

$y = \frac{P_2}{P_1}$ (downstream) (upstream)



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



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

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

in blue $\quad y_c \quad y_c$

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

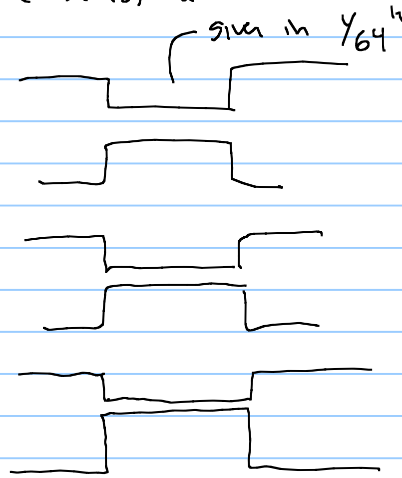
with P_1 = constan

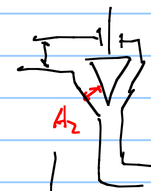
(flow is "choked", critical flow)

in onshore fields, bean choke are often used

offshore often adjustable chokes are used

needle choke





↳ adjustable throat area

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

horizontal flowline, the tubing equation simplifies to

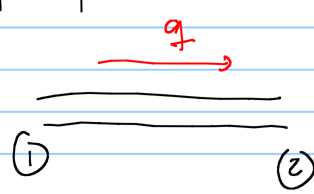
$$q_{\bar{s}} = C_{FL}\left(P_{dc}^2 - P_{sep}^2\right)^{0.5}$$

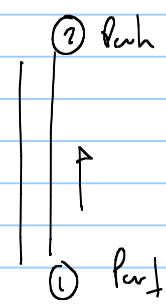
$S=0$ (L'Hopital)

VBA Visual basic for applications

for pipe equations in VBA ① is upstream

② is downstream





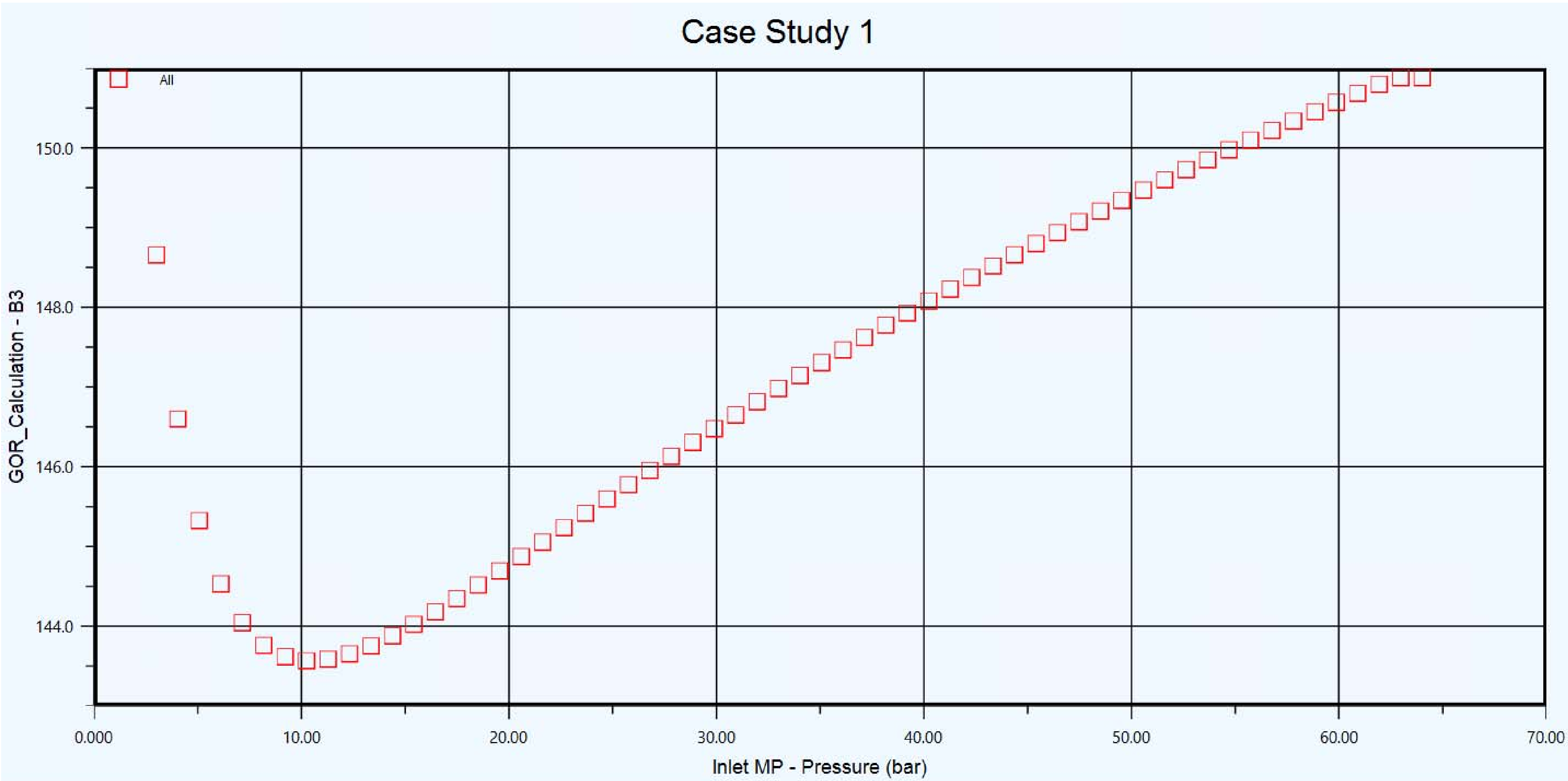
Class 20240201 - OUTLINE

-cont Class exercise (mandatory exercise 1), Hysys simulation
-How a real separation process looks like in reality
-Simple sizing of horizontal gas-oil separator

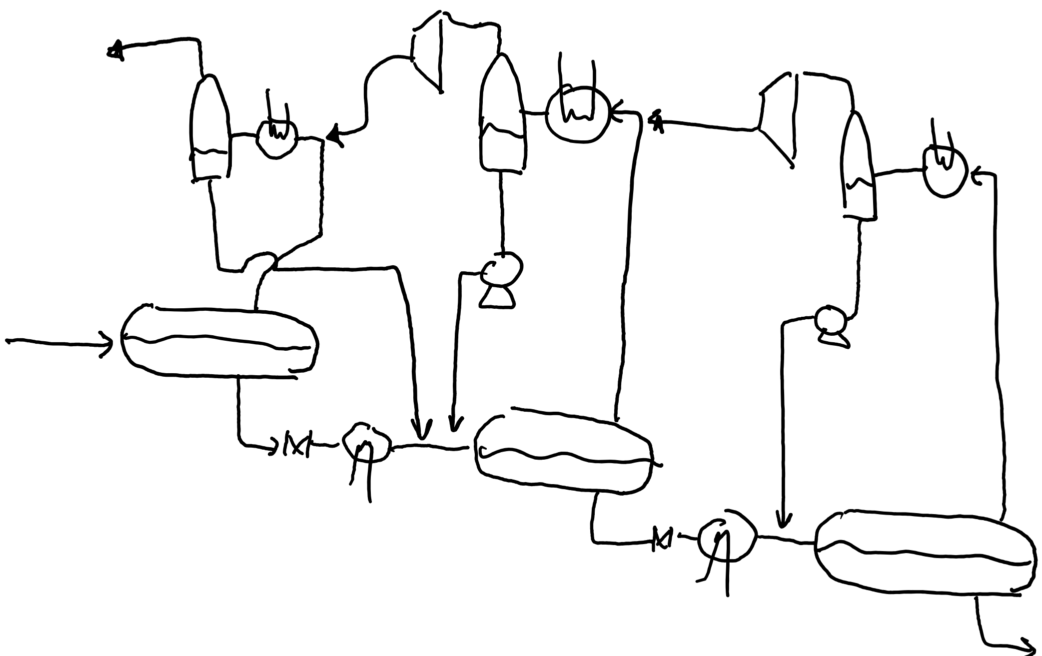
Tasks:

cont Class exercise (mandatory exercise 1), Hysys simulation

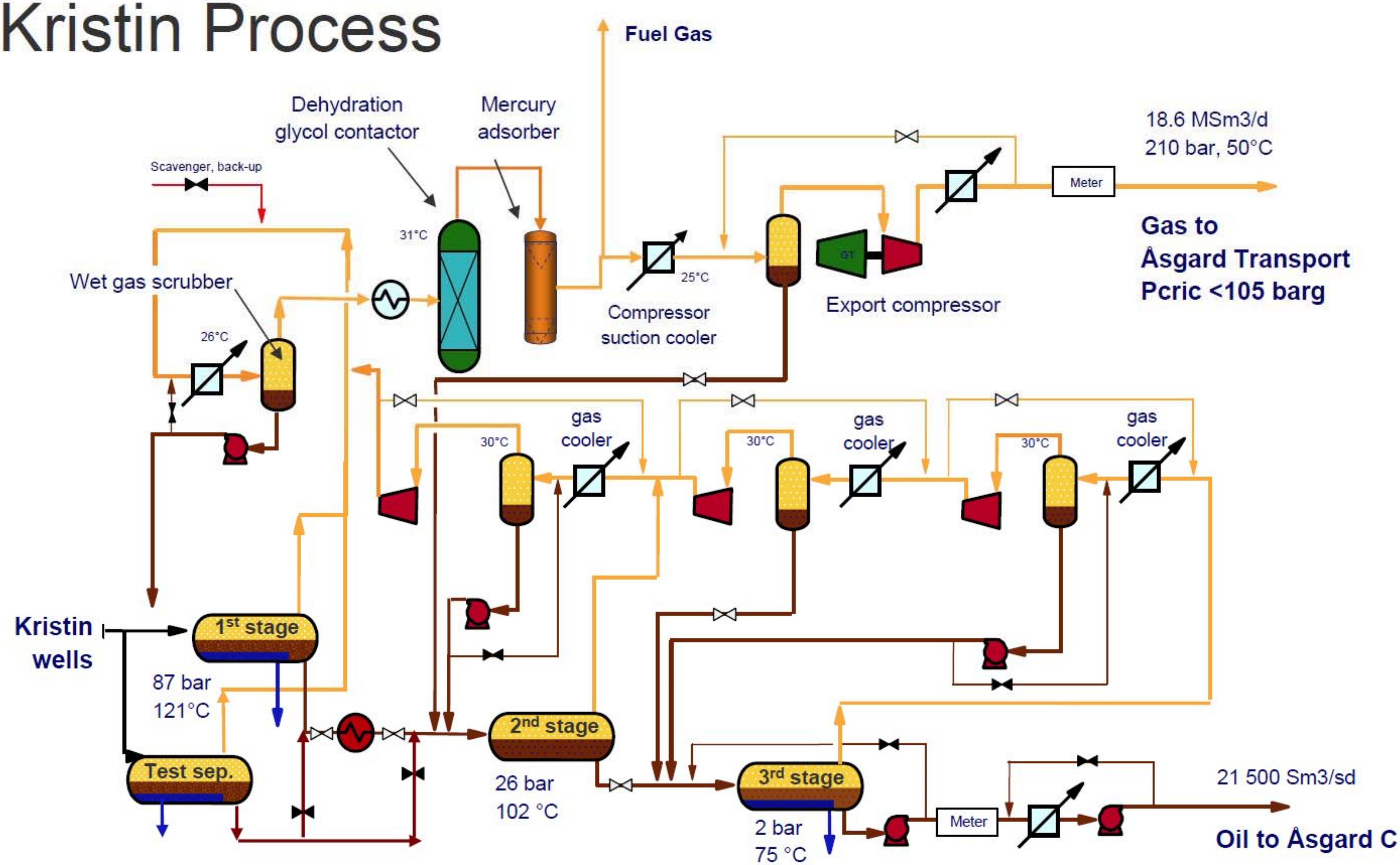
- Simulate the system in Hysys
- Perform a sensitivity study on the 2nd stage separation pressure to maximize oil production

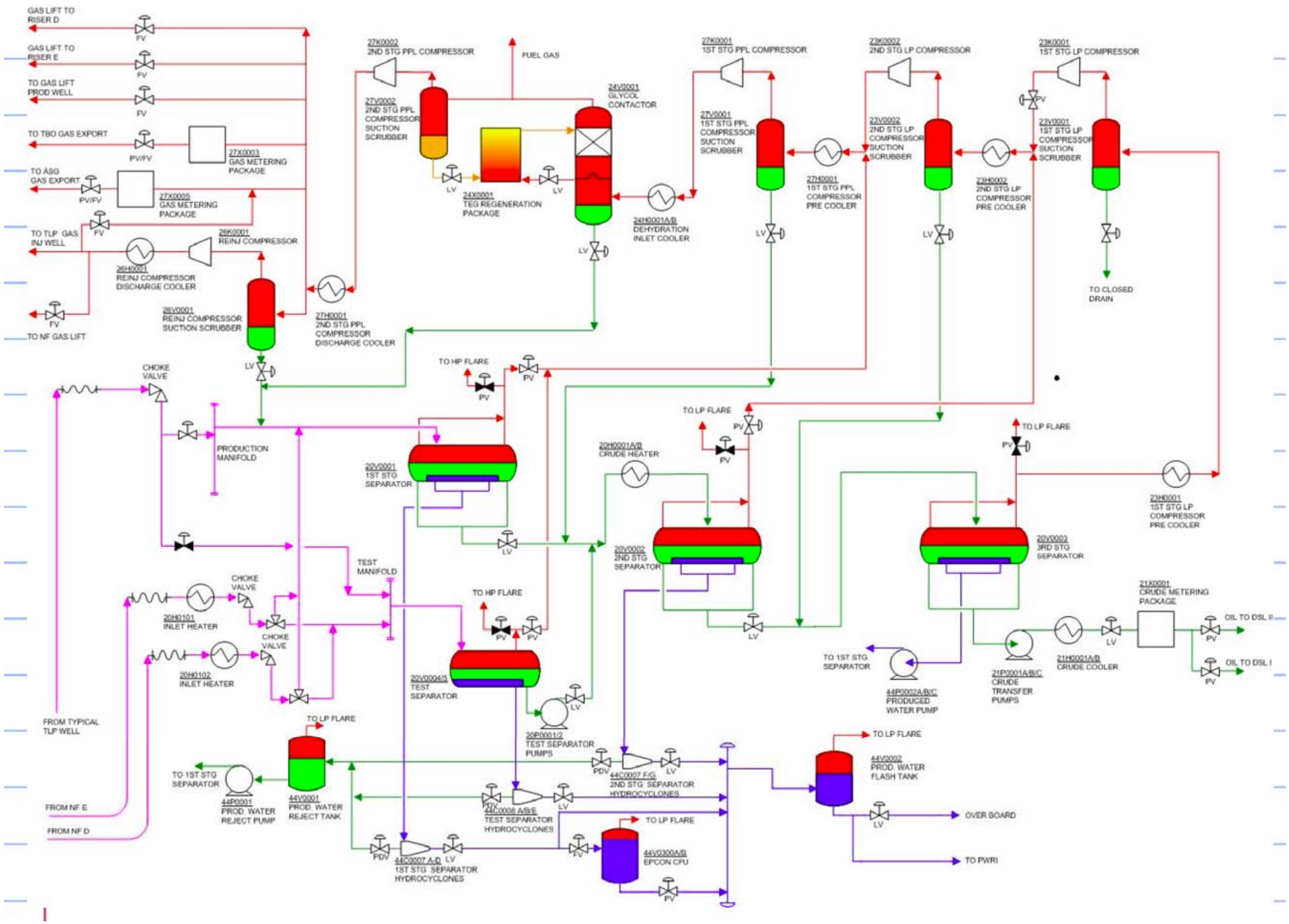

Case Study 1
All
GOR_Calculation - B3
150.0
148.0
146.0
144.0
0.000
10.00
20.00
30.00
40.00
50.00
60.00
70.00
Inlet MP - Pressure (bar)

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
44V0001 PROD. WATER REJECT TANK
44P0001 PROD. WATER REJECT PUMP
PDV
44C0007 F/G 2ND STG SEPARATOR HYDROCYCLONES
44C0008 A/B/E TEST SEPARATOR HYDROCYCLONES
44C0007 A-D 1ST STG SEPARATOR HYDROCYCLONES
44V0300A/B EPCON CFU
44V0002 PROD. WATER FLASH TANK
OVER BOARD
TO PWRI

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

Separation design theory

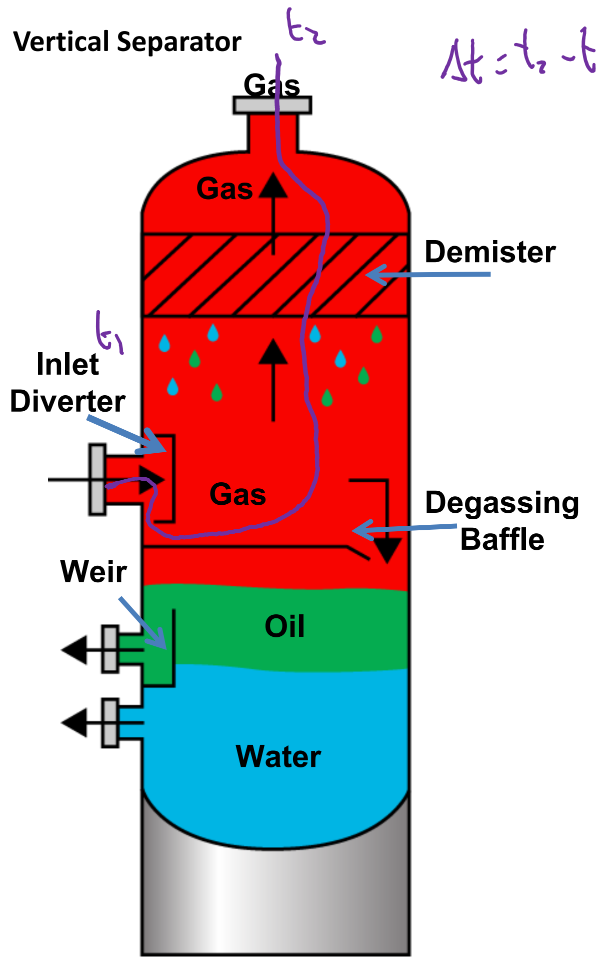
Find separator dimensions such as:

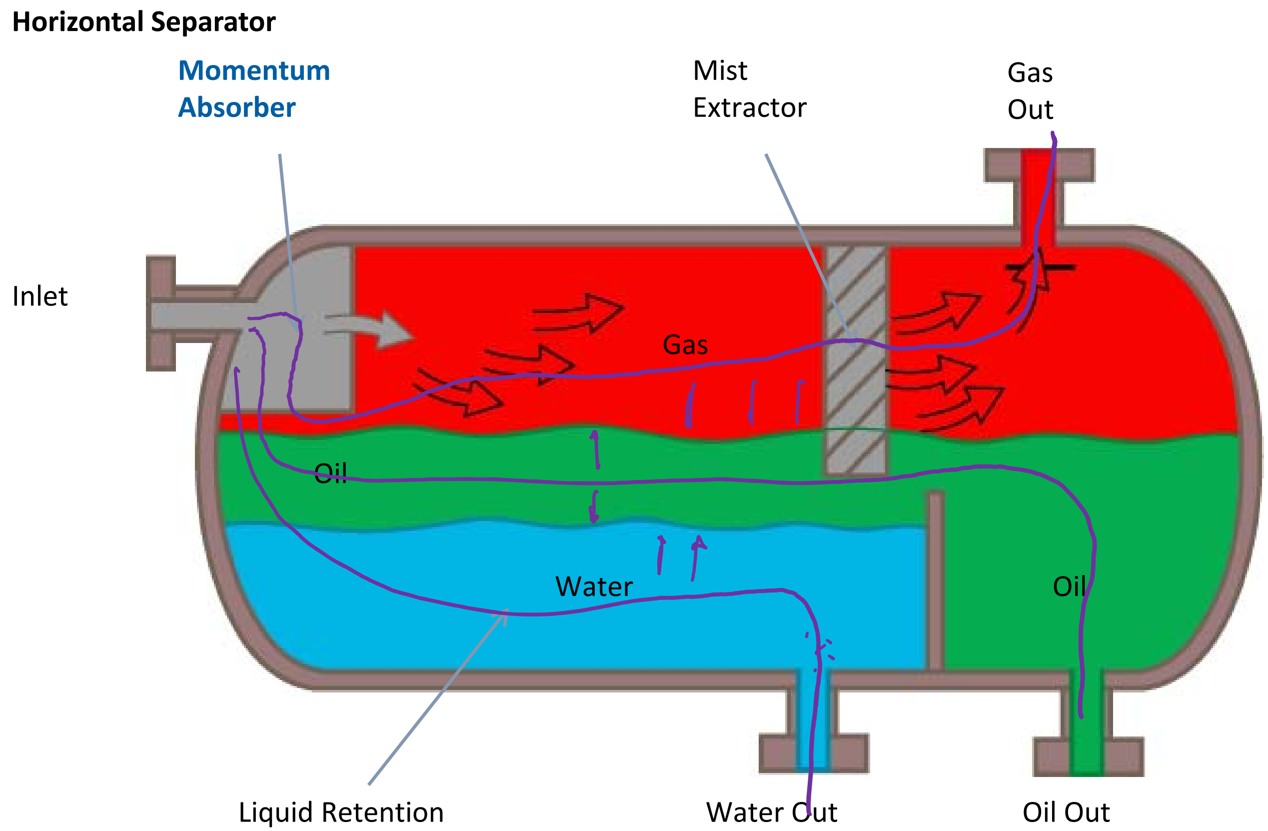
ID, L

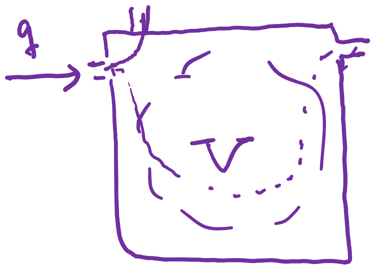
$\underbrace{\text{Residence time}} > \underbrace{\text{separation time}}$

Residence time

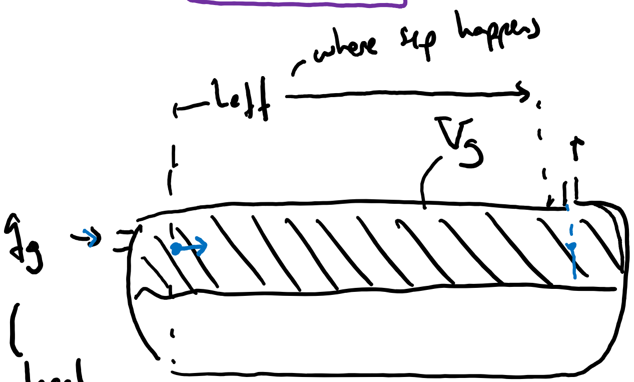
$\Delta t = t_2 - t_1$



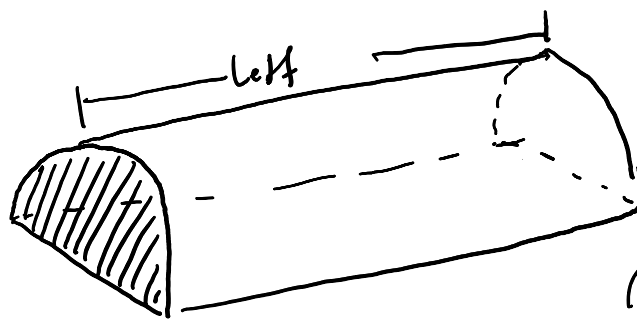




$t_{res} = \frac{V}{q}$ $\left[V\right]$ / $\left[\frac{V}{t}\right]$



at local
P, T



(internal diameter)

$V_g = L_{eff} \cdot \frac{\pi \cdot \phi^2}{4 \cdot 2}$

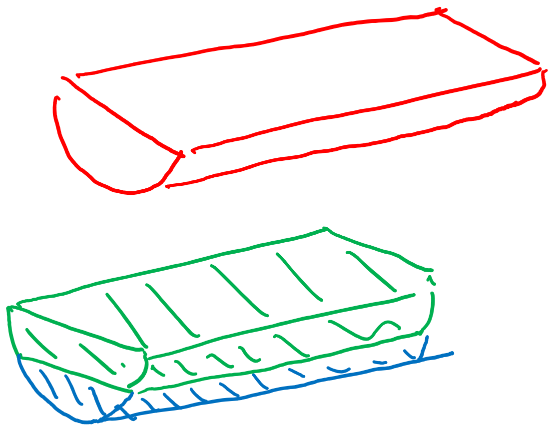
$t_{res,g} = \frac{V_g}{q_g} = L_{eff} \frac{\pi \phi^2}{8 \, q_g}$

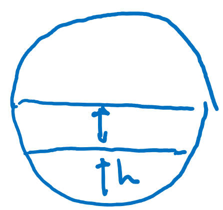
$v_g = \frac{q_g}{A} = \frac{q_g}{\frac{\pi \phi^2}{8}}$

$t_{res,g} = \frac{L_{eff}}{v_g} = \frac{L_{eff} \pi \phi^2}{q_g \, 8}$

30 s $\rightarrow$ 2,3 min

residace tme of oiL





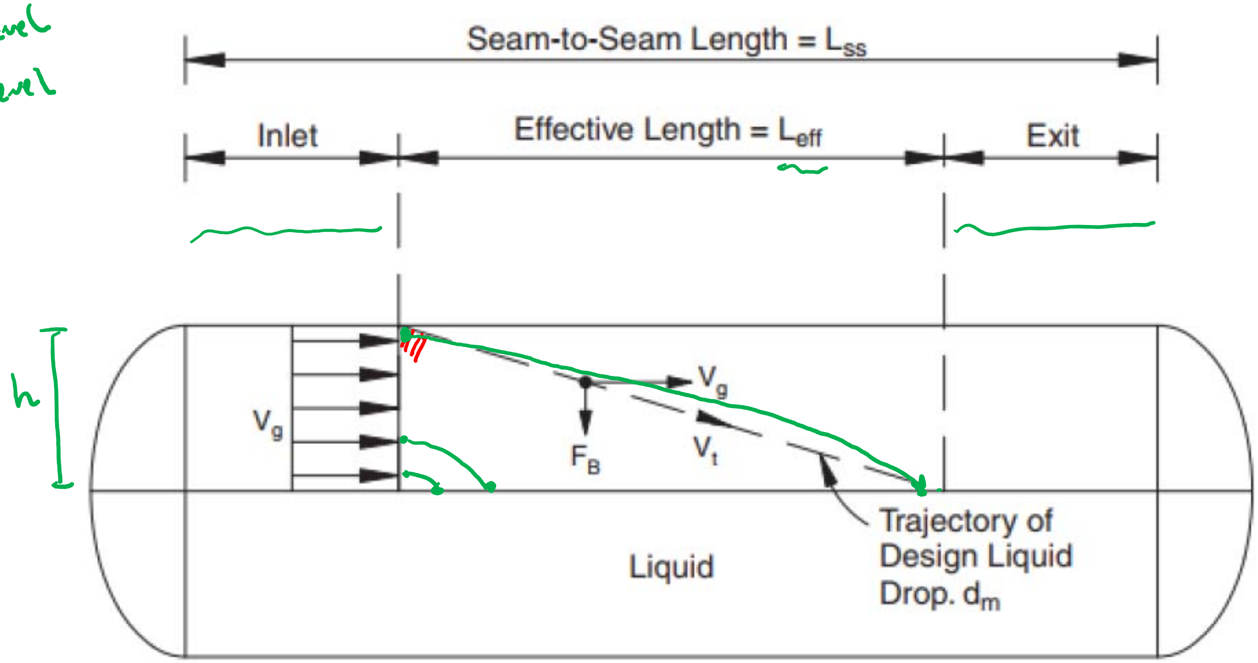
Separation time - gas

time that it takes for an oil droplet to travel from top to liquid level

t_{sep}

settling time $t_s = \frac{h}{v_s}$, $h = \frac{ID}{2}$

v_s settling velocity



Legend:

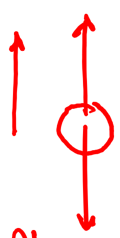
V_g = Average Gas Velocity = $\frac{Q}{A}$

V_t = Terminal or Setting Velocity Relative to Gas

F_B = Buoyant Force

Separation time = settling time

how to estimate v_s



F_{drag}

gas

$\rho_f V_d \cdot g$ (bouyancy)

$m \cdot g$ (weight))

v_s

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

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

$A_d = \frac{\pi d_d^2}{4}$

C_d: drag coefficient

$\Sigma F = 0$

assumed! (smallest possible, more conservative)

? ρ_{oil} ρ_{gas}

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

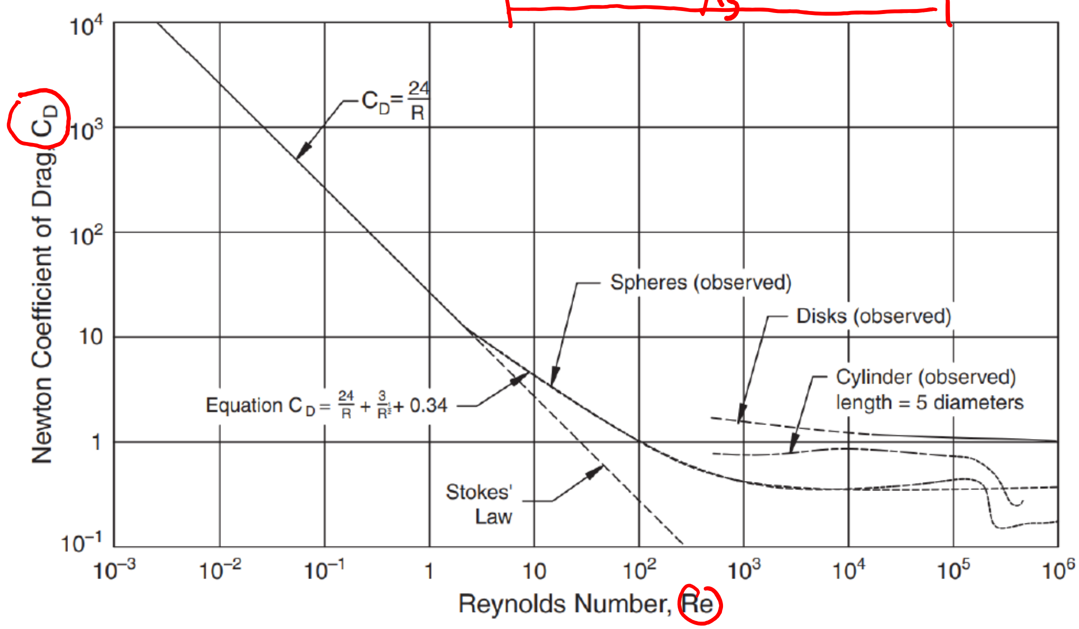
?

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

Separation time = settling time

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

ρ_g μ_g



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

case ① oil droplet in gas

$\mu_g \downarrow$

$Re_d \uparrow$

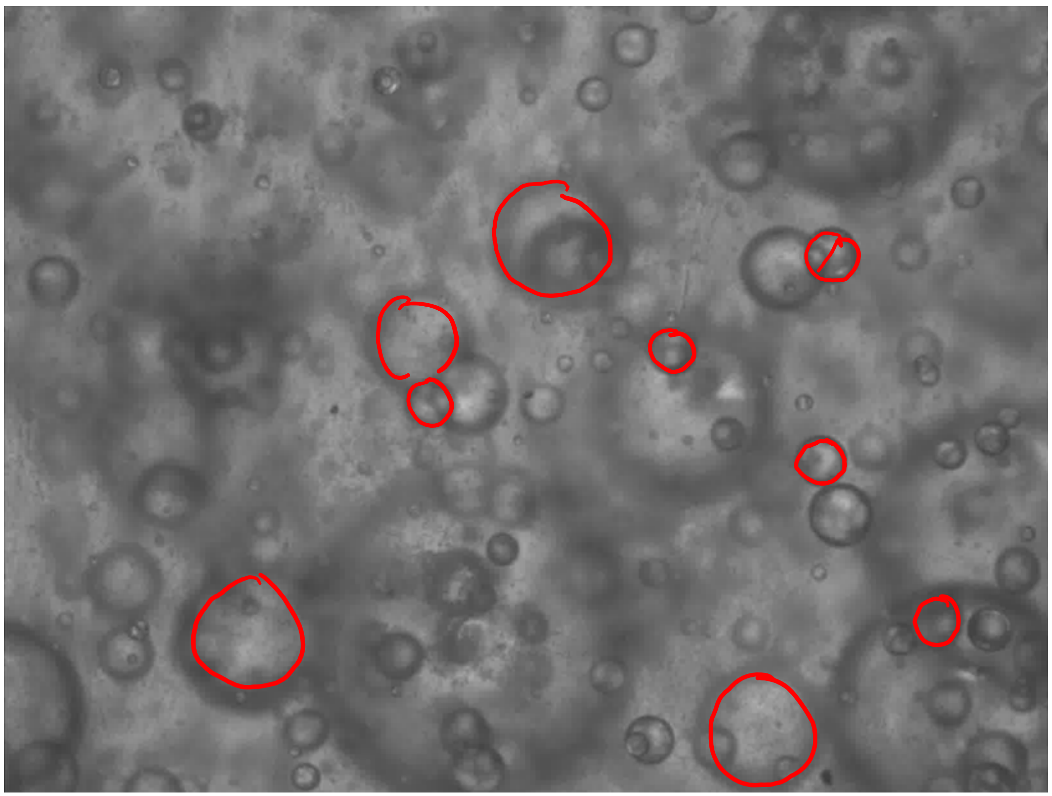
oil in water

casee ② water droplet in oil

$\mu_o \uparrow$

$Re \downarrow$

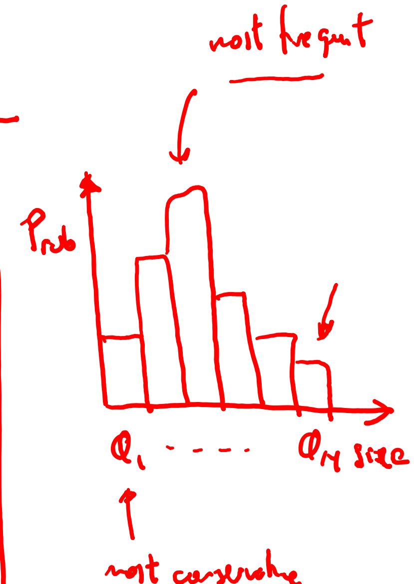
Separation time – droplet size distribution



10 - 100 μm (1E-6 m)

d = 1E01-1E02 um

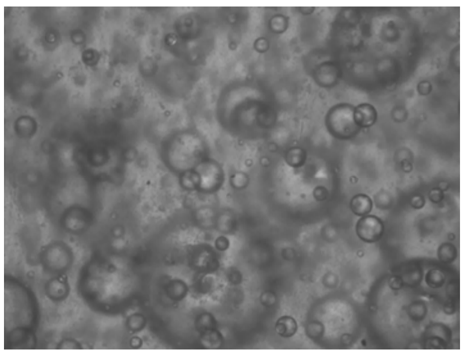
d	Count		Probability
min Φ_1	n_1		n_1/N
Φ_2	n_2	4	n_2/N
Φ_3	n_3	3	⋮
Φ_4	n_4		
⋮	⋮		
max Φ_N	n_N		n_N/N



Separation time – droplet size distribution

d = 1E01-1E02 um

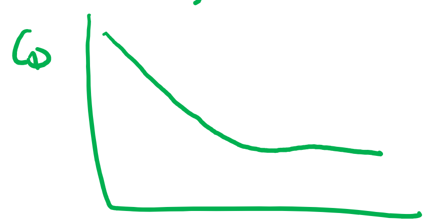
(volume based)



d	cnt	volume	volume rel frequency
d_1	n_1	$n_1 \cdot \frac{4\pi}{3}\left(\frac{d_1}{8}\right)^3 = V_1$	$V_1/V_{oil\,total}$
d_2	n_2	$n_2 \cdot \frac{4\pi}{3}\left(\frac{d_2^3}{8}\right) = V_2$	$V_2/V_{oil\,total}$
⋮	⋮	⋮	
d_N	n_N	$= V_N$	$V_N/N_{oil\,total}$

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

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



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

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

not

yes

solution

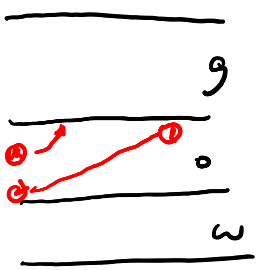
The same equation can be used for
-Bubles of gas in liquid
-droplets of liquid in liquid
BUT if the droplet/bubble is going up, the order of the density difference must be changed.

Oil separation time

API

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

$t_{res} \geq t_{sep,oil} = t_{retention\ time}$



$[\ L/v_o = t_{sep}$ too optimistic

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

Separation time = settling time

for droplet of oil in gas :

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

$$\frac{L_{eff}\,\phi_{sep}^2\,\pi}{4 \cdot q_{sep}} \geq \frac{\phi_{sep}/2}{v_s}$$ assuming liquid level is at half separator

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

Class 20240202 - OUTLINE

-Simple sizing of horizontal gas-oil separator – Exercise
-Other topside processing equipment

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

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

$q_{gas} = 48.54\ m^3/h$

$L_{eff} \cdot \phi_{sep} \geq 4 \cdot \left(\frac{48.54}{3600}\right) \frac{1}{0.16 \cdot 3.1415}$

$\phi_d = 150E{-6}\ m$

$\rho_o = 631.7\ kg/m^3$

$\rho_g = 46.81\ kg/m^3$

$\mu_g = 1.44E{-2}\ cP$

V_s

$L_{eff} \cdot \phi_{sep} \geq 0.11\ m^2$

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

$Re = \frac{\rho_g\, \phi_d\, v_s}{\mu_g}$

$v_s = 0.16\ m/s$

Convention: red is input, blue is calculated

Simple Calculation example

slenderness ratio condition

$$3 \leq \frac{l_{ss}}{\phi_{sep}} \leq 4$$

$l_{ss} = l_{eff} + \phi$ not always true !

$$3 \leq \frac{l_{eff}}{\phi_{sep}} + 1 \leq 4$$

$$2 \leq \frac{l_{eff}}{\phi_{sep}} \leq 3$$

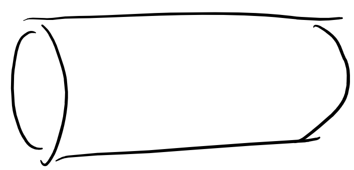
$$\boxed{2\,\phi_{sep} \leq l_{eff} \leq 3\,\phi_{sep}}$$

Simple Calculation example

Oil separation time

$t_{res_o} \geq t_{sep_{oil}}$ → separation of gas bubbles from oil to gas

$$\frac{\dfrac{l_{eff} \cdot \phi_{sep}^2 \cdot \pi}{8}}{q_o} \geq t_{sep_{oil}}$$



→ from table API 12 J

from Hysys 39.18 m³/h → 0.0108 m³/s

$$\text{API gravity} = \frac{141.5}{\text{SG}} - 131.5$$

$$API = \frac{141.5}{\frac{631.2}{1000}} - 131.5 = 92$$

$$API > 30$$

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

$\rightarrow 60s$

$$\frac{L_{eff}\, \phi_{sep}^2\, \pi}{8\, q_o} \geq 60s$$

$$L_{eff}.\phi_{sep}^2 \geq 1.65$$

$$L_{eff}\, \phi_{sep}^2 \geq \frac{60}{\pi} \times 8\, q_o \;(m^3/s) = \frac{60 \cdot 8}{\pi} \cdot 0.0108 = 1.65\ m^3 \rightarrow$$

$l_{eff} \cdot \phi_{sep} \geq 0.11\ m^2$ (1) separation of oil from gas

$$\boxed{2\phi_{sep} \leq l_{eff} \leq 3\phi_{sep}}$$ (2) slenderness ratio

separation of gas from oil

$l_{eff} \cdot \phi_{sep}^2 \geq 1.65\ m^3$ (3)

decide l_{eff}, ϕ_{sep}, as small as possible

$\downarrow$ cost $\downarrow$ trasport

Attempt 1

$\phi_{sep} = 0.5\ m$

$L_{eff} = 1.5\ m$

$0.5 \cdot 1.5 = 0.75 \geq 0.11$ ① ✓

$(L_{eff}/\phi_s) = 3 \leq 3$ ② ✓

$1.5 \cdot (0.5)^2 \geq 1.65$ ③

$0.375 \geq 1.65$ ✗ doesn't work

Attempt 2

$\left.\begin{array}{l}\phi_{sep} = 0.9\ m \\ L_{eff} = 2.1\ m\end{array}\right\}$

① $0.9 \cdot 2.1 = 1.89 \geq 0.11$ ✓

② $\dfrac{L_{eff}}{\phi_{sep}} = 2.33$ $\quad 2 \leq 2.33 \leq 3$ ✓

③ $L_{eff} \cdot \phi_{sep}^2 = 1.7 \geq 1.65$ ✓ limiting constraint !

Problem 1 (20 points)

You are part of the field development team for a recently discovered reservoir. You are considering to re-use equipment from an existing platform that will be dismantled soon.

Consider a horizontal gas oil separator with an effective length of 5 m and an inner diameter of 1.7 m. consider the required residence time for gas is 20 s, and the required retention time for oil is of 60 s. During normal operating conditions, half of the separator is filled with liquid.

Task 1 (5 points). Calculate what are the maximum volumetric rates of oil and gas (at local pressure and temperature, q_o and q_g), in m^3/d, than can flow through the separator.

Task 2 (5 points). From the values calculated in task 1, compute the maximum allowed standard conditions rates of oil and gas (in Sm^3/d). Use the following expressions:

$$q_{\bar{g}} = \frac{q_g}{B_g} + \frac{R_s}{B_o} q_o$$

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

Use the following values for the black oil properties:

B_g = 0.01 [m^3/Sm^3]

R_s = 50 [Sm^3/Sm^3]

B_o = 1.2 [m^3/Sm^3]

Task 3 (5 points). Consider that a field starts producing in plateau mode with a producing gas-oil ratio (GOR or R_p) equal to 150 Sm^3/Sm^3. What is the maximum oil production (in standard conditions, in Sm^3/d) that can be processed by the horizontal separator.

Task 4 (5 points). The value of producing gas-oil ratio used in Task 3 was calculated using a reservoir model assuming that vertical permeability is low and there is no coning from the gas cap. There is high uncertainty in this assumption. If a higher value of vertical permeability is used, the producing gas-oil ratio reaches 400 Sm^3/Sm^3 during the plateau period. For this situation, estimate what is the maximum oil production (in standard conditions, in Sm^3/d) that can be processed by the horizontal separator.

Additional information:

- You can use the Excel sheet provided to perform your calculations.
- Add text explaining your procedure

metry, calculate max oil and gas

http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/Old_Exams/2023/TPG4230_2023_Exam_solution.pdf

$\Phi_{sep} = 1.7$ m $\quad t_{resg} = 20s$

$L_{eff} = 5$ m $\quad t_{reso} = 60s$

$\{ \Phi_{sep}/2$

Task 1 (5 points). Calculate what are the maximum volumetric rates of oil and gas (at local pressure and temperature, q_o and q_g), in m³/d, than can flow through the separator.

$$t_{resg} = \frac{V_g}{q_g ?} \rightarrow \frac{L_{eff} \cdot \phi_{sep}^2 \cdot \pi}{8}$$

1.7   5/2

205

$$t_{resg} \geq t_{sepg}$$

$$t_{resg} = t_{sepg}$$

$$q_{g\,max} = \frac{L_{eff} \cdot \phi_{sep}^2\, \pi}{8\ t_{resg}} = 0.283\ m^3/s = \underline{24501}\ m^3/d \sim \; 5\ m^3/d$$

at local P, T   1st stage sep

$$t_{reso} = \frac{V_o}{q_o} \rightarrow \frac{L_{eff} \cdot \phi_{sep}^2 \cdot \pi}{8}$$

605

$$q_{o\,max} = 1167\ m^3/d \rightarrow 5\ m^3/d$$

$$q_{o}@P,T \xrightarrow{\text{Bo prop}} q_{\bar{o}}@P_{sc},T_{sc}$$

Task 2 (5 points). From the values calculated in task 1, compute the maximum allowed standard conditions rates of oil and gas (in Sm³/d). Use the following expressions:

$$q_{\bar{g}} = \frac{q_g}{B_g} + \frac{R_s}{B_o} q_o$$

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

Use the following values for the black oil properties:

B_g = 0.01 [m³/Sm³]

R_s = 50 [Sm³/Sm³]

B_o = 1.2 [m³/Sm³]

$$q_{\bar{g}} = \frac{\overset{24501}{q_g}}{\underset{0.01}{B_g}} + \frac{\overset{50}{R_s}}{\underset{1.2}{B_o}} \overset{8167}{q_o} = 2790391 \ Sm^3/d$$

$$q_{\bar{o}} = \frac{\overset{8167}{q_o}}{\underset{1.2}{B_o}} = 6805 \ Sm^3/d$$

To refresh about Boproperties check chapter 4 of the compendium (ca 100 ish page)

Task 3 (5 points). Consider that a field starts producing in plateau mode with a producing gas-oil ratio (GOR or R_p) equal to 150 Sm^3/Sm^3. What is the maximum oil production (in standard conditions, in Sm^3/d) that can be processed by the horizontal separator.

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

$q_{\bar{g}} = ?$

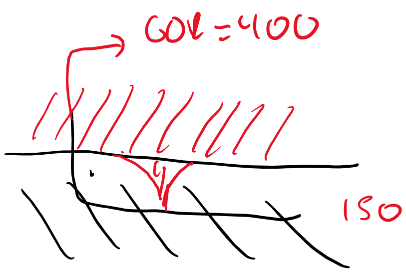
① the field operates at maximum oil rate (6805 Sm^3/d)

$q_{\bar{g}\,plateau} = 150 \cdot 6805 = 1.020\,750\ E06\ Sm^3/d < 2.8E6\ Sm^3/d$

② the field operates at maximum gas rate (2.8E6 Sm^3/d)

$q_{\bar{o}\,plateau} = \frac{2.8E6}{150} = 18666\ Sm^3/d$

Task 4 (5 points). The value of producing gas-oil ratio used in Task 3 was calculated using a reservoir model assuming that vertical permeability is low and there is no coning from the gas cap. There is high uncertainty in this assumption. If a higher value of vertical permeability is used, the producing gas-oil ratio reaches 400 Sm^3/Sm^3 during the plateau period. For this situation, estimate what is the maximum oil production (in standard conditions, in Sm^3/d) that can be processed by the horizontal separator.



1 Case 1

$q_{o\,plateau} = 6805\ Sm^3/d$ (at capacity)

$q_{g\,plateau} = 400 \cdot 6805 = 2722000\ Sm^3/d < 2.8E6$

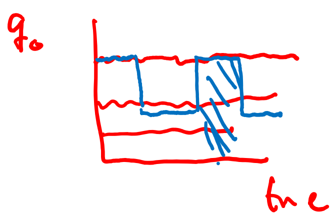
2 Case 2

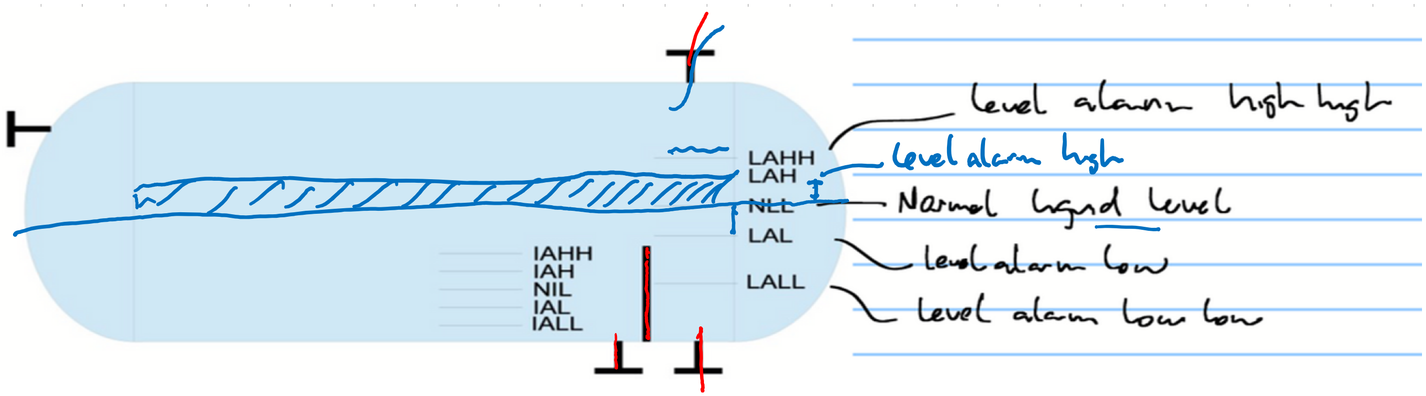
$q_{g\,plateau} = 2.8E6\ Sm^3/d$ (at capacity)

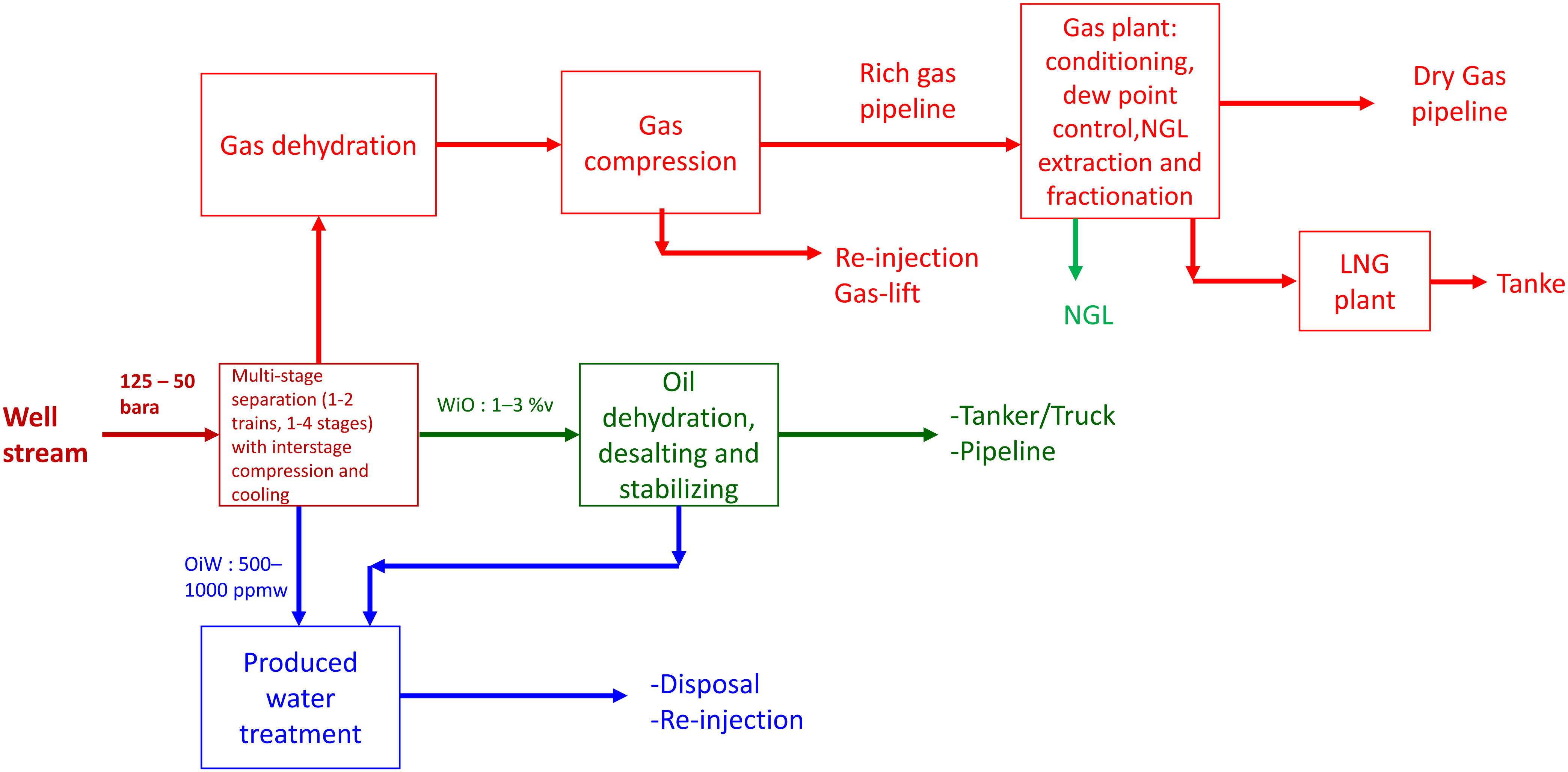
$$q_{o\,plateau} = \frac{2.8E6}{400} = 7000\ Sm^3/d$$

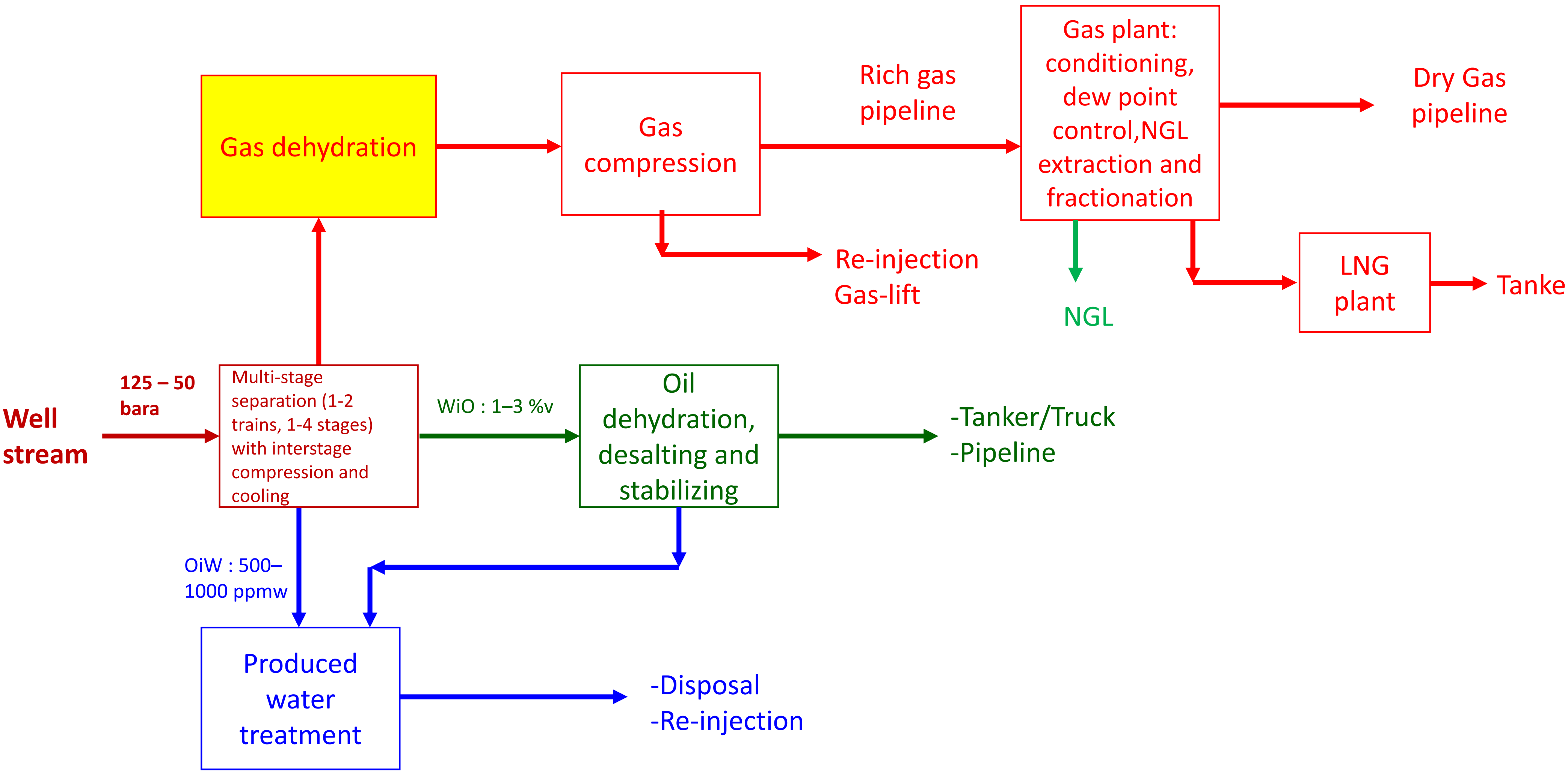
Other design considerations

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






Gas dehydration
Gas compression
Rich gas pipeline
Gas plant: conditioning, dew point control,NGL extraction and fractionation
Dry Gas pipeline
Re-injection
Gas-lift
NGL
LNG plant
Tanker
Well stream
125 – 50 bara
Multi-stage separation (1-2 trains, 1-4 stages) with interstage compression and cooling
WiO : 1–3 %v
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection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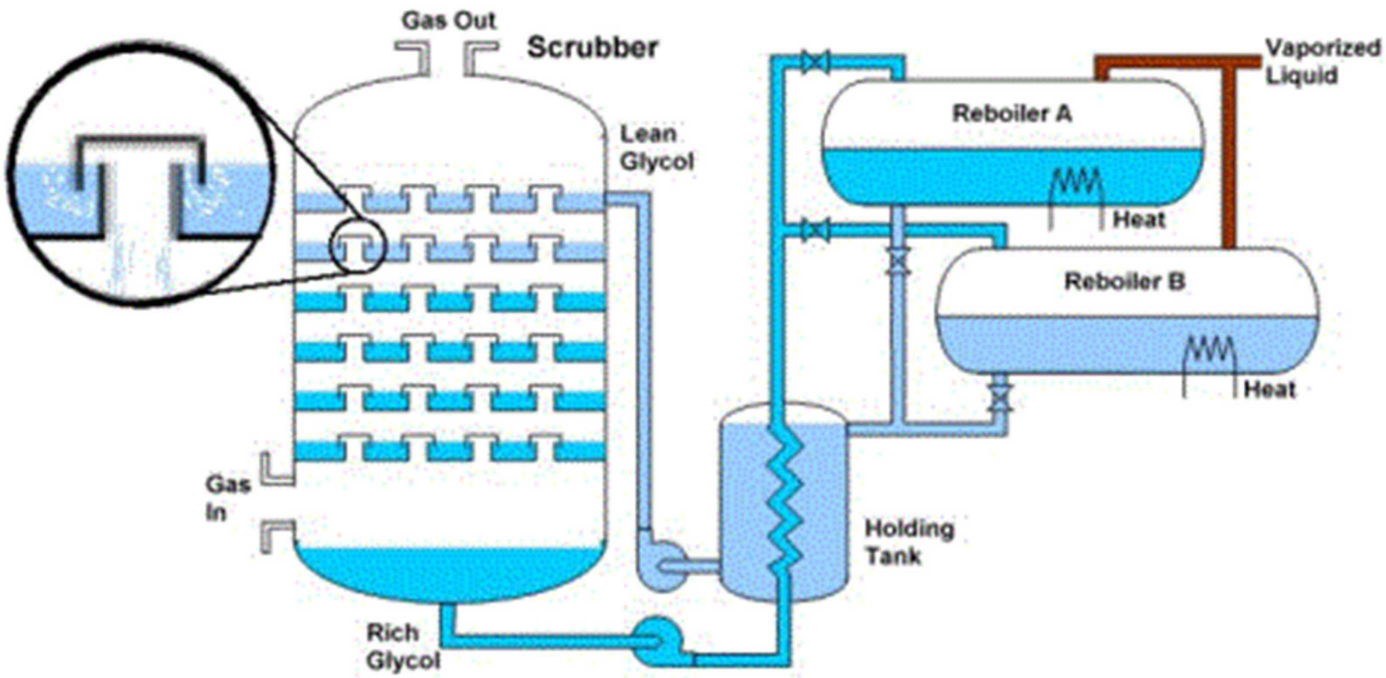
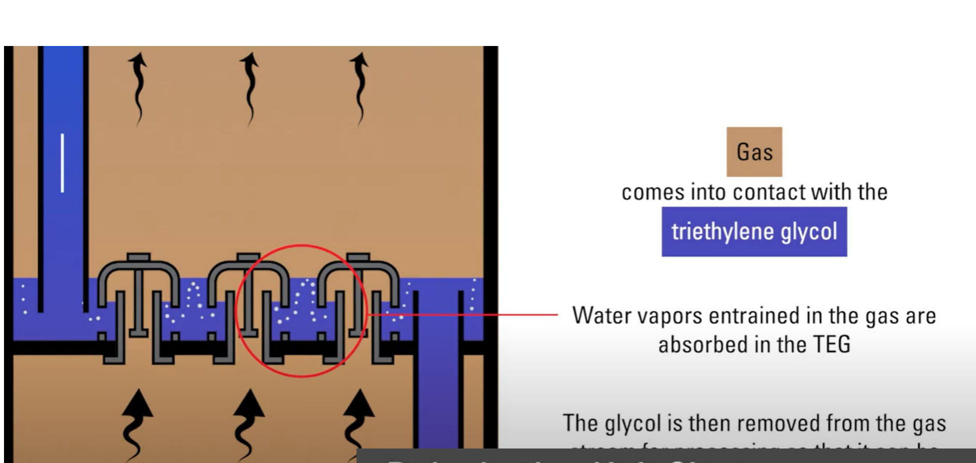
-Tanker/Truck
-Pipeline
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection

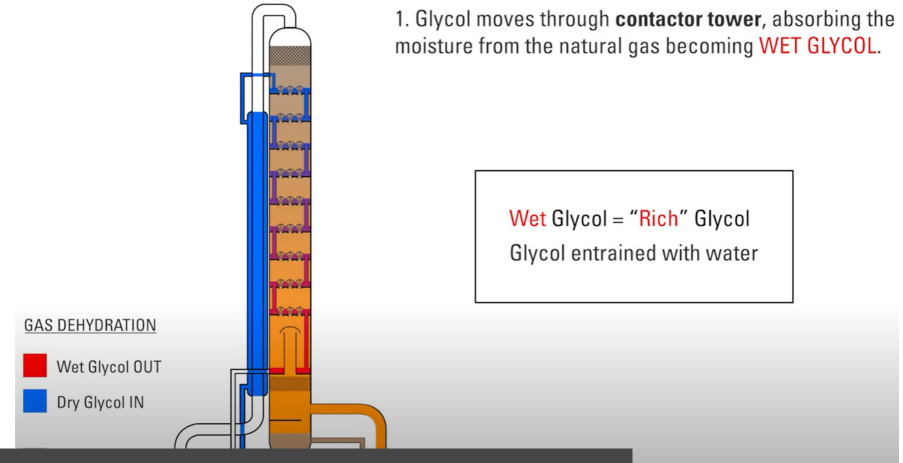
TEG dehydration

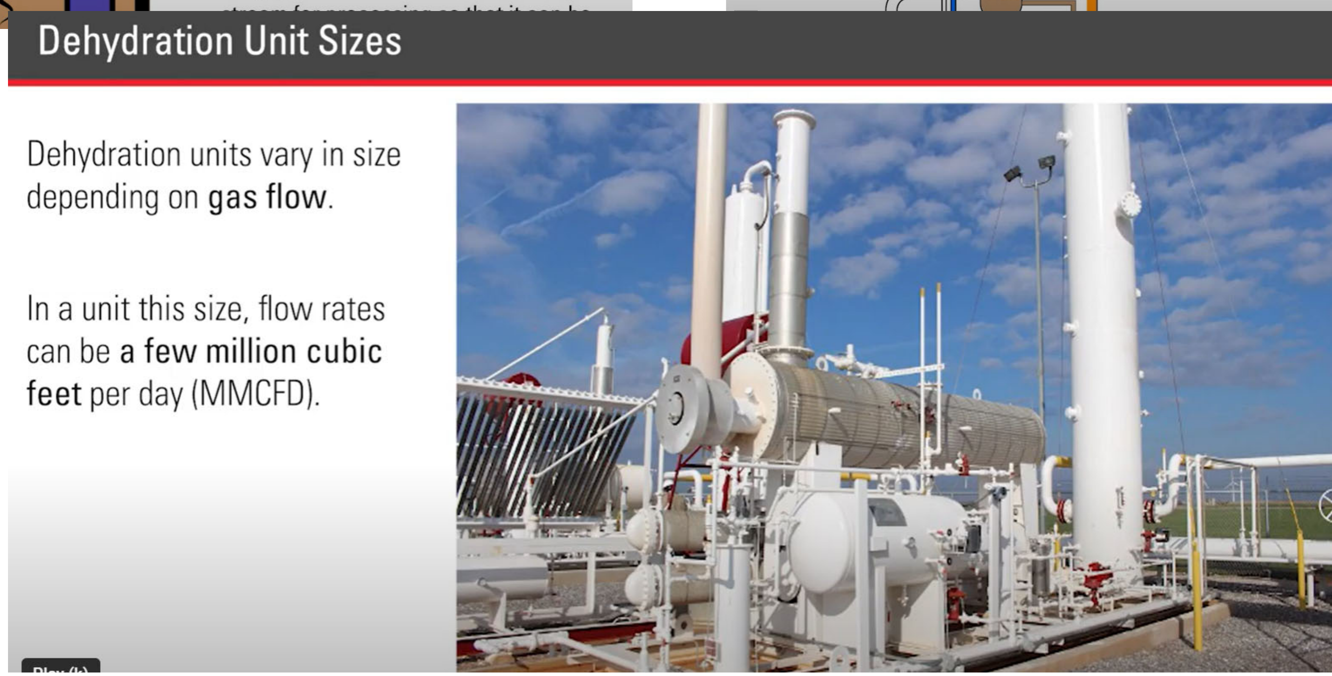


Youtube links for TEG dehydration

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

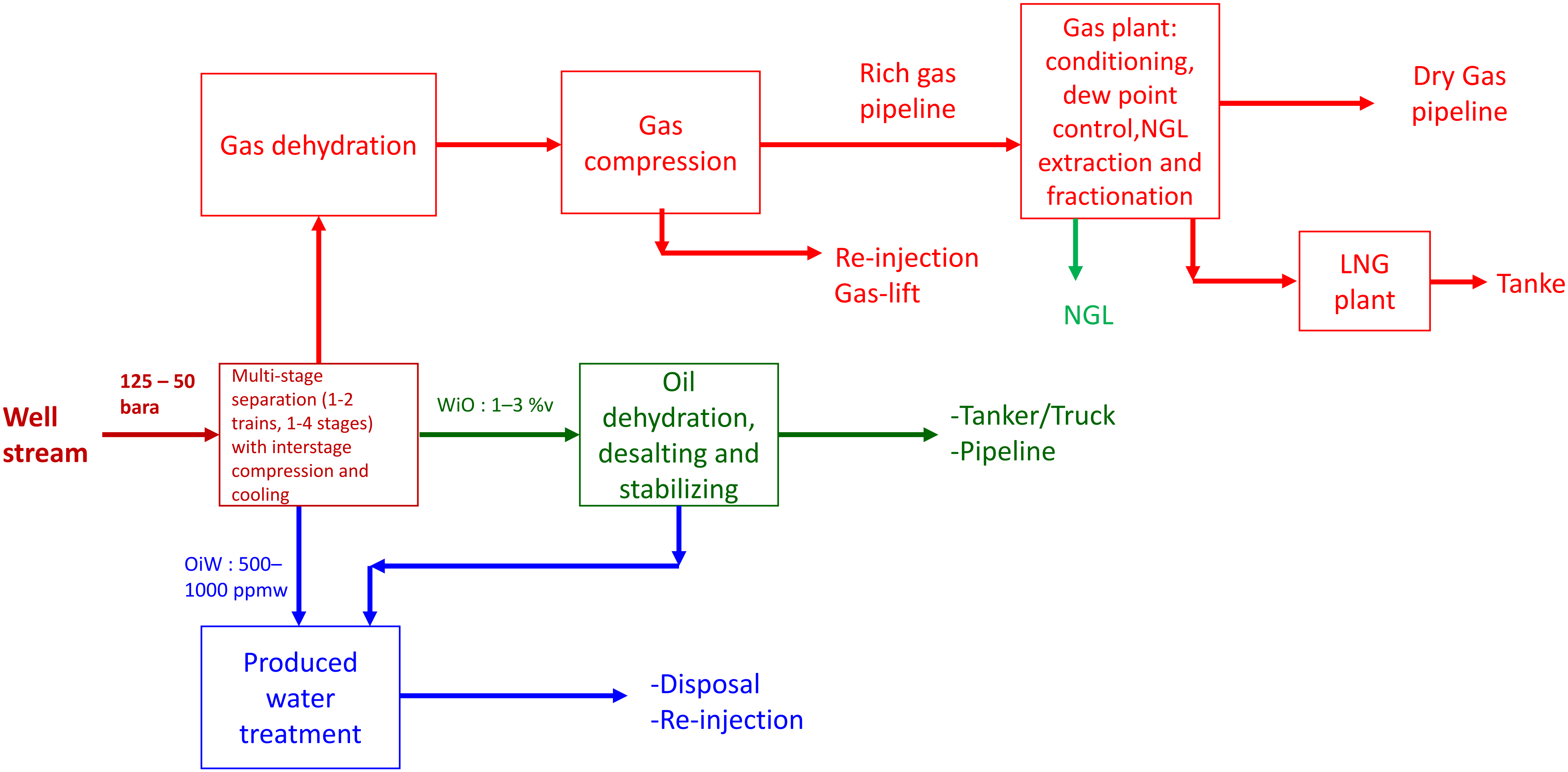

Gas
comes into contact with the
triethylene glycol
Water vapors entrained in the gas are absorbed in the TEG
The glycol is then removed from the gas

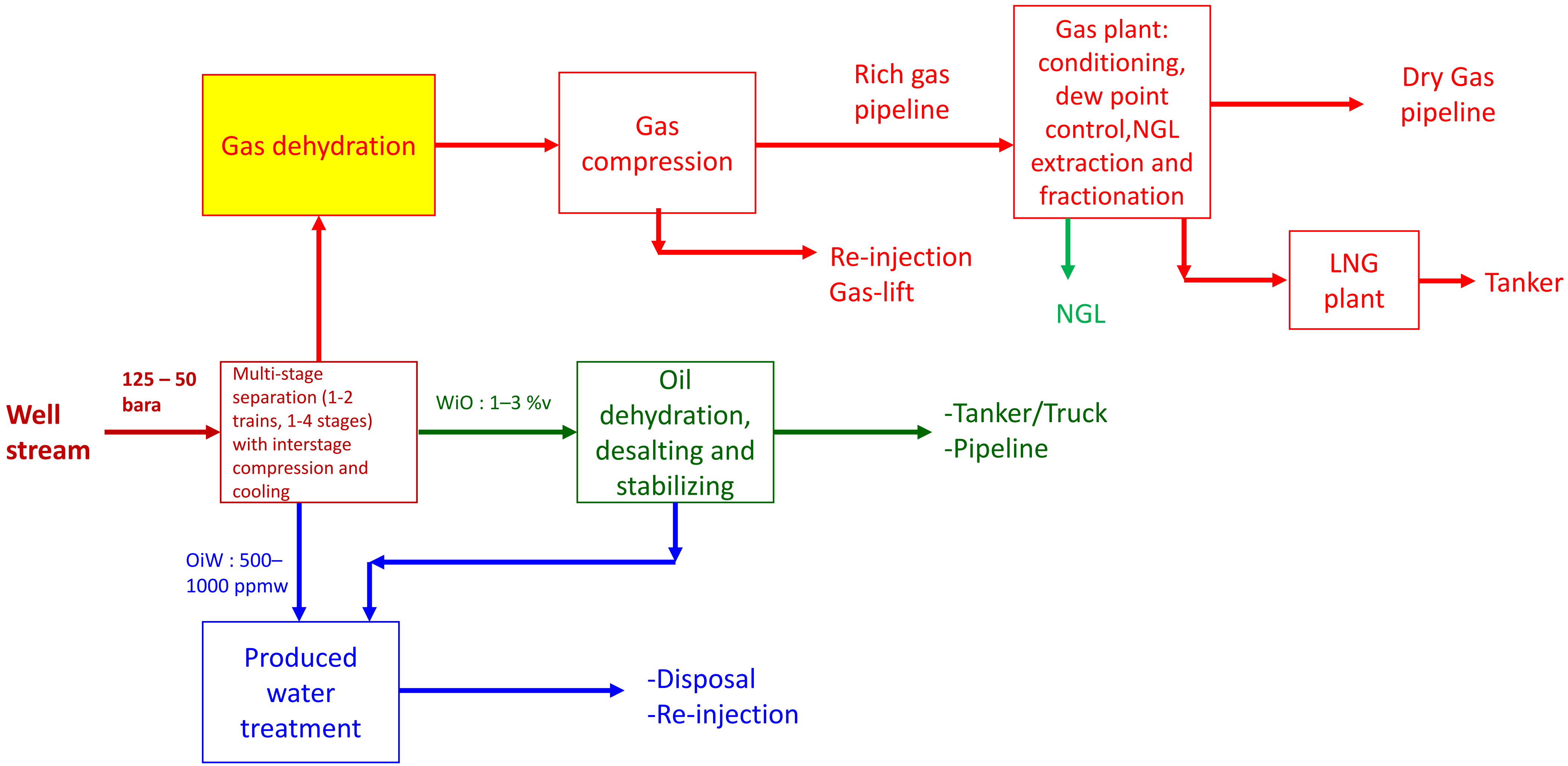

1. Glycol moves through contactor tower, absorbing the moisture from the natural gas becoming WET GLYCOL.
Wet Glycol = “Rich” Glycol
Glycol entrained with water
GAS DEHYDRATION
Wet Glycol OUT
Dry Glycol IN


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).

Class 20240208 - OUTLINE

-Other topside processing equipment
-Intro – Production scheduling for the Snowhite field


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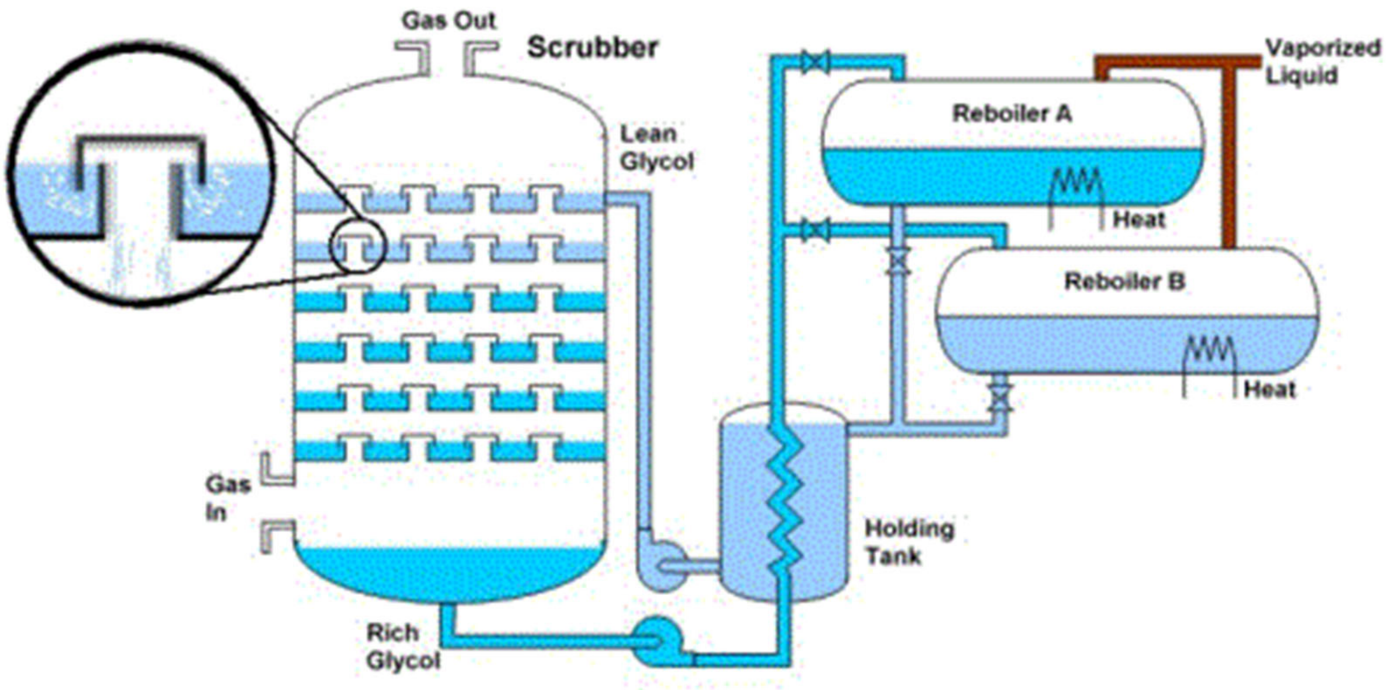
TEG dehydration



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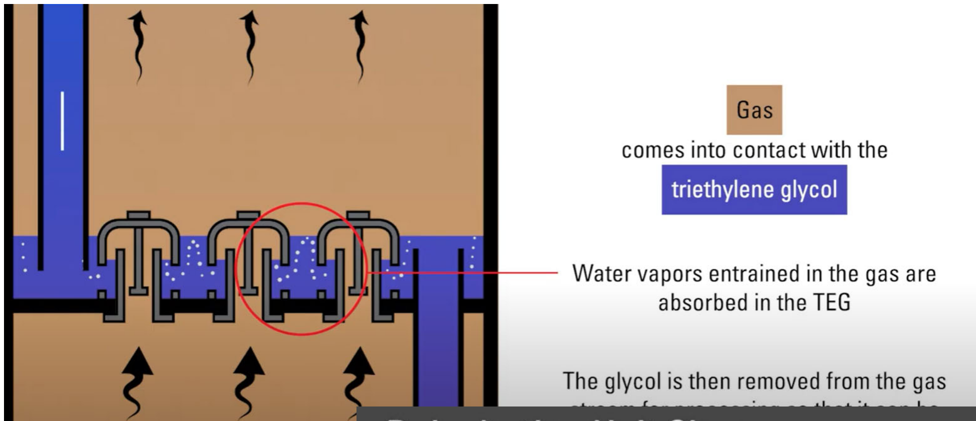
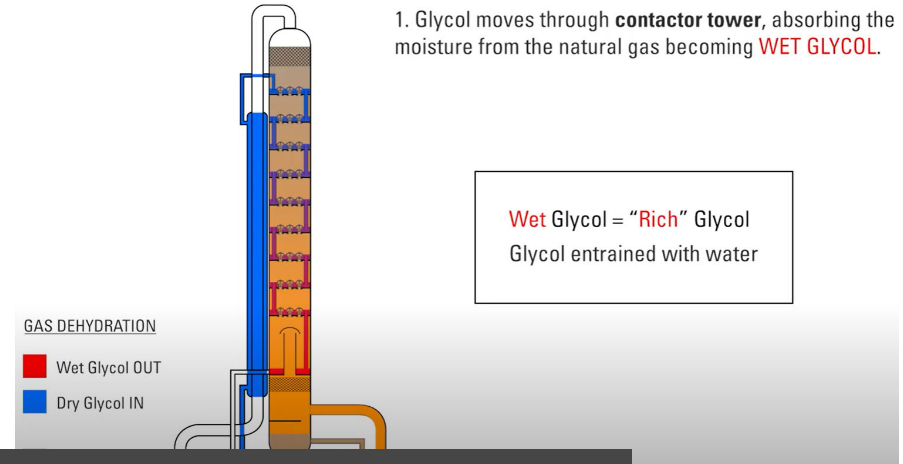
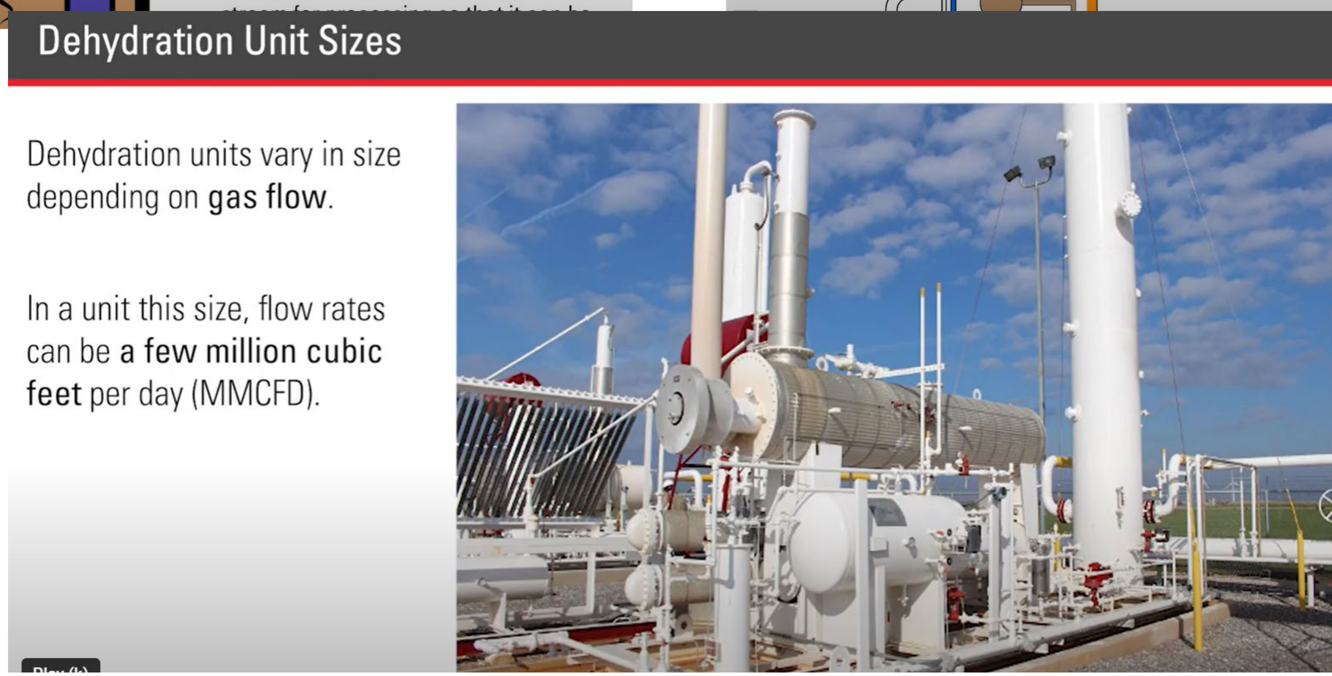
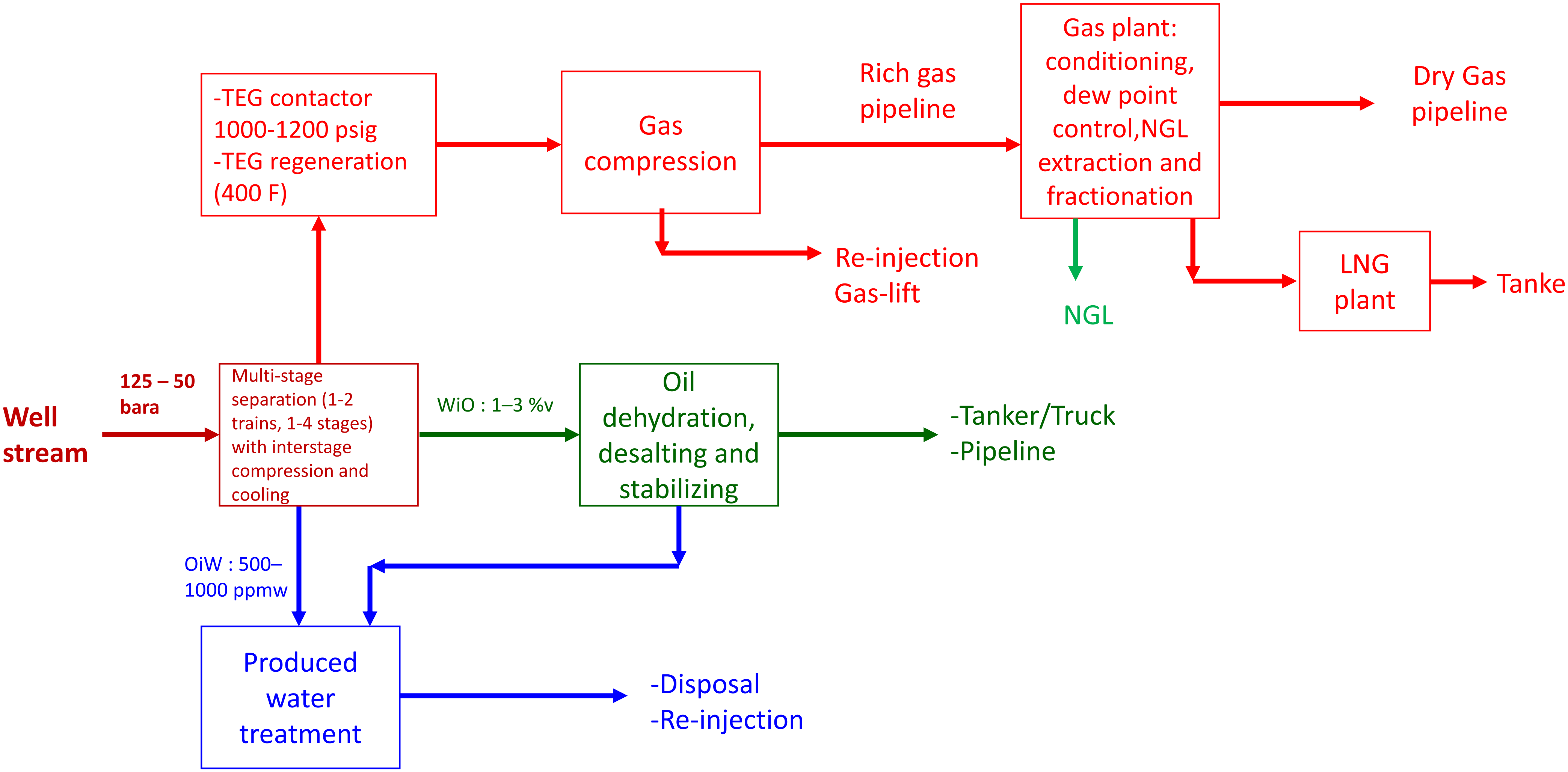
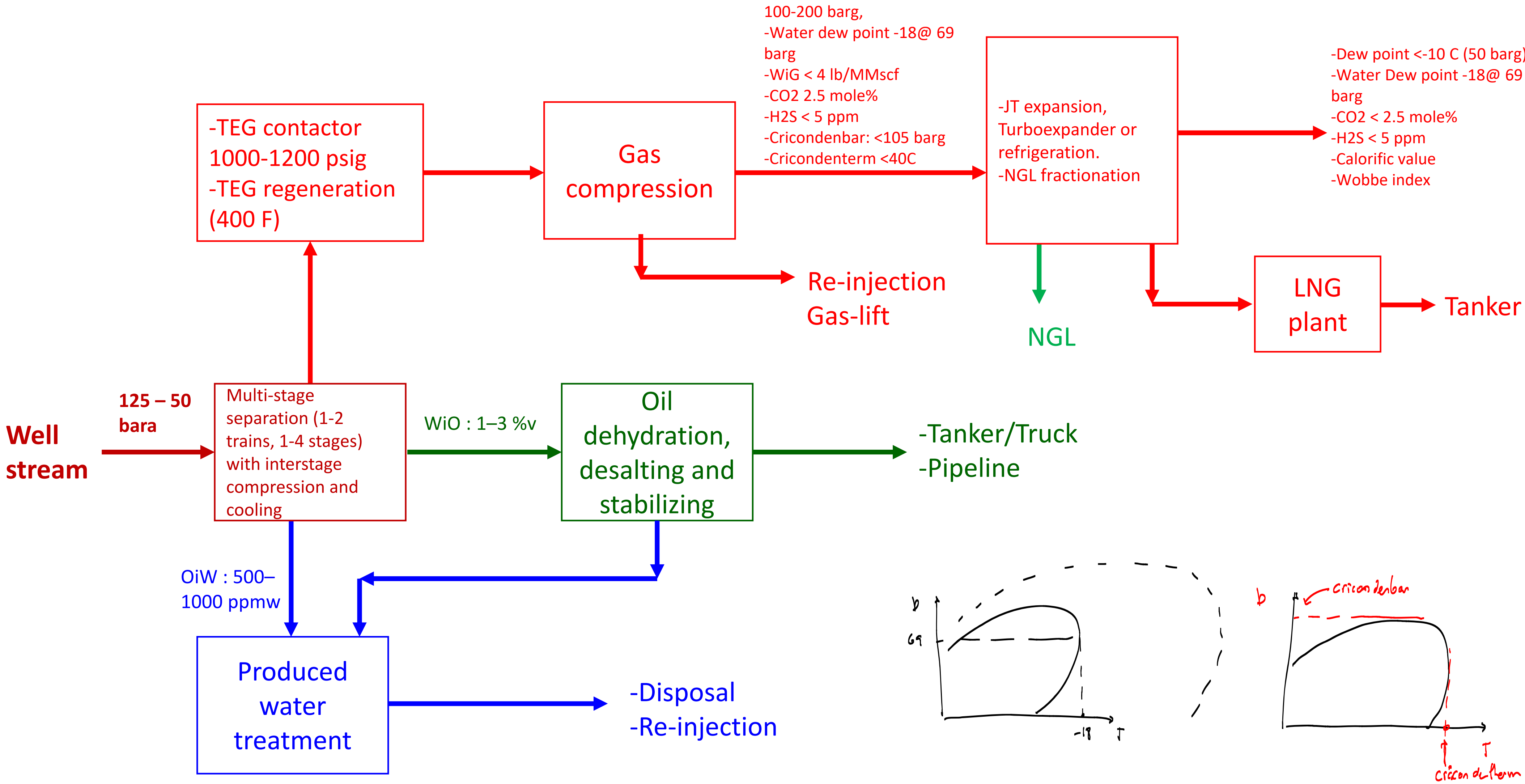

Gas
comes into contact with the
triethylene glycol
Water vapors entrained in the gas are absorbed in the TEG
The glycol is then removed from the gas

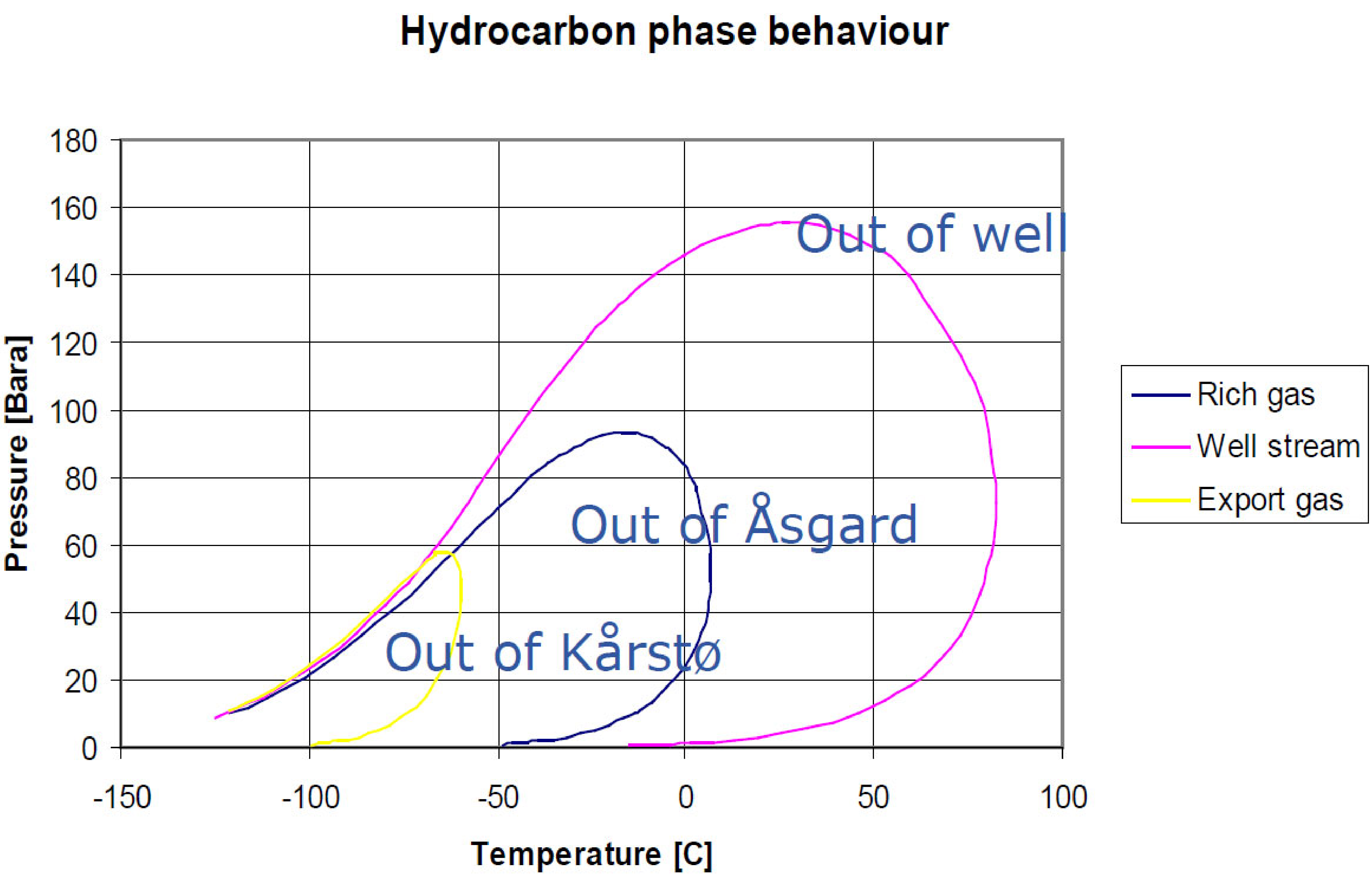

1. Glycol moves through **contactor tower**, absorbing the moisture from the natural gas becoming WET GLYCOL.
Wet Glycol = “Rich” Glycol
Glycol entrained with water
GAS DEHYDRATION
Wet Glycol OUT
Dry Glycol IN

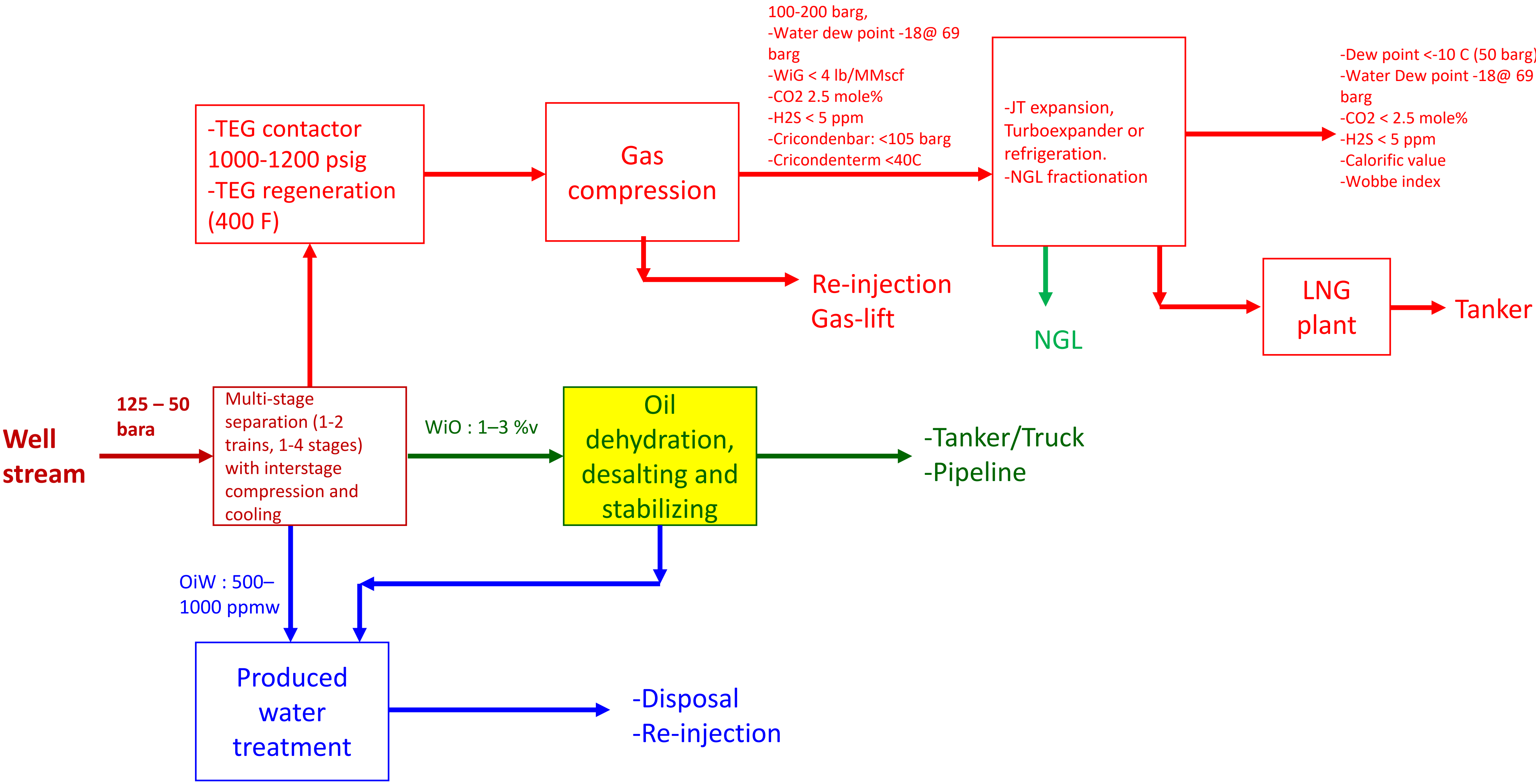

Dehydration Unit Sizes
Dehydration units vary in size depending on **gas flow**.
In a unit this size, flow rates can be **a few million cubic feet** per day (MMCFD).


-TEG contactor
1000-1200 psig
-TEG regeneration
(400 F)
Gas
compression
Rich gas
pipeline
Gas plant:
conditioning,
dew point
control,NGL
extraction and
fractionation
Dry Gas
pipeline
Re-injection
Gas-lift
NGL
LNG
plant
Tanker
Well
stream
125 – 50
bara
Multi-stage
separation (1-2
trains, 1-4 stages)
with interstage
compression and
cooling
WiO : 1–3 %v
Oil
dehydration,
desalting and
stabilizing
-Tanker/Truck
-Pipeline
OiW : 500–
1000 ppmw
Produced
water
treatment
-Disposal
-Re-injection



Well stream
125 – 50 bara
Multi-stage separation (1-2 trains, 1-4 stages) with interstage compression and cooling
-TEG contactor 1000-1200 psig
-TEG regeneration (400 F)
Gas compression
Re-injection
Gas-lift
100-200 barg,
-Water dew point -18@ 69 barg
-WiG < 4 lb/MMscf
-CO2 2.5 mole%
-H2S < 5 ppm
-Cricondenbar: <105 barg
-Cricondenterm <40C
-JT expansion, Turboexpander or refrigeration.
-NGL fractionation
NGL
-Dew point <-10 C (50 barg)
-Water Dew point -18@ 69 barg
-CO2 < 2.5 mole%
-H2S < 5 ppm
-Calorific value
-Wobbe index
LNG plant
Tanker
WiO : 1–3 %v
Oil dehydration, desalting and stabilizing
-Tanker/Truck
-Pipeline
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection
69
-18
T
T


Hydrocarbon phase behaviour
Pressure [Bara]
180
160
140
120
100
80
60
40
20
0
-150
-100
-50
0
50
100
Temperature [C]
Out of well
Out of Åsgard
Out of Kårstø
Rich gas
Well stream
Export gas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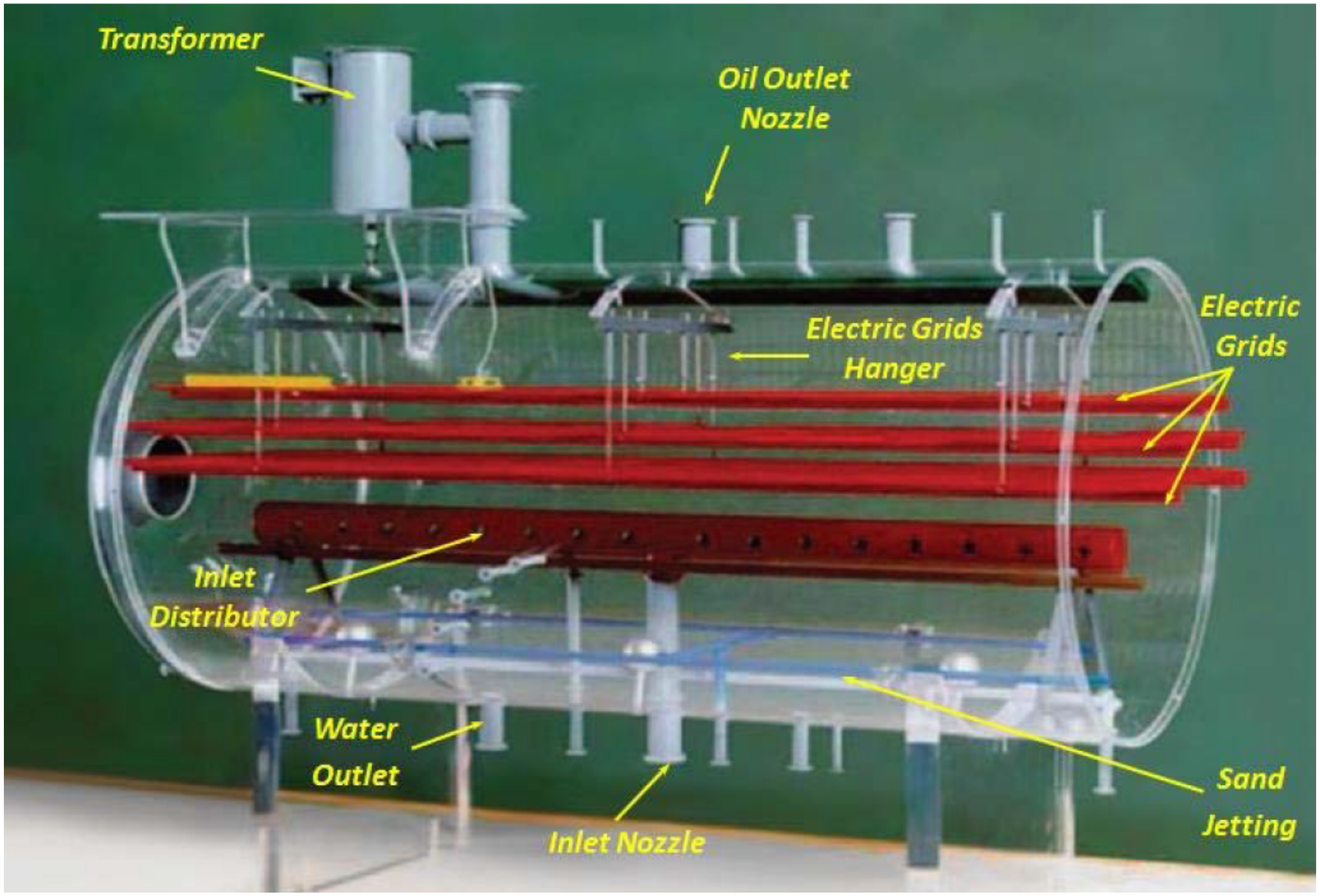
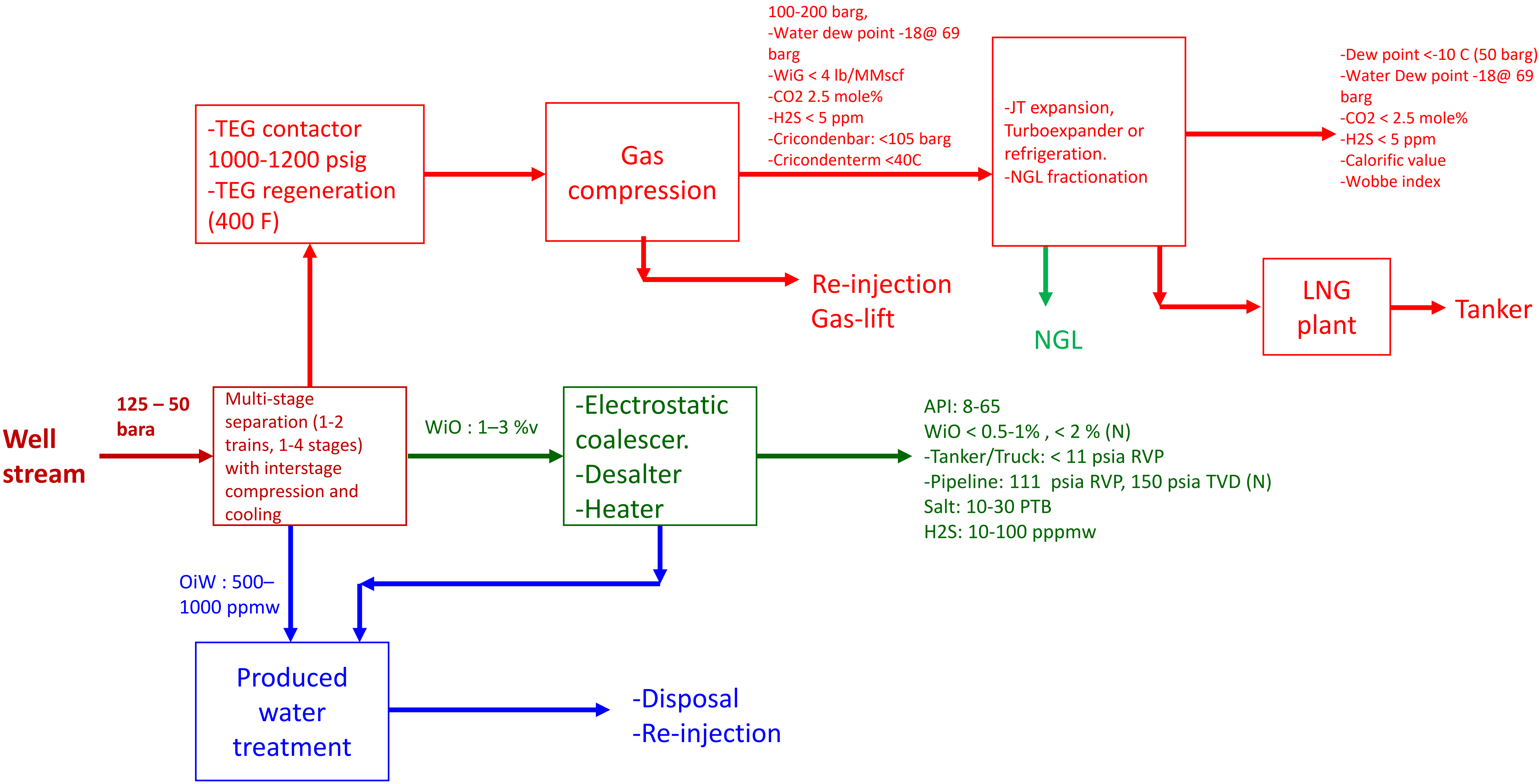
-Tanker/Truck
-Pipeline
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection

Electrostatic coalescer





-TEG contactor
1000-1200 psig
-TEG regeneration
(400 F)
Gas compression
100-200 barg,
-Water dew point -18@ 69 barg
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-Wobbe index
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NGL
LNG plant
Tanker
Well stream
125 – 50 bara
Multi-stage separation (1-2 trains, 1-4 stages) with interstage compression and cooling
WiO : 1–3 %v
-Electrostatic coalescer.
-Desalter
-Heater
API: 8-65
WiO < 0.5-1% , < 2 % (N)
-Tanker/Truck: < 11 psia RVP
-Pipeline: 111 psia RVP, 150 psia TVD (N)
Salt: 10-30 PTB
H2S: 10-100 pppmw
OiW : 500–1000 ppmw
Produced water treatment
-Disposal
-Re-injection

API: 8-65

WiO < 0.5-1% , < 2 % (N)

-Tanker/Truck: < 11 psia RVP

-Pipeline: 111 psia RVP, 150 psia TVD (N)

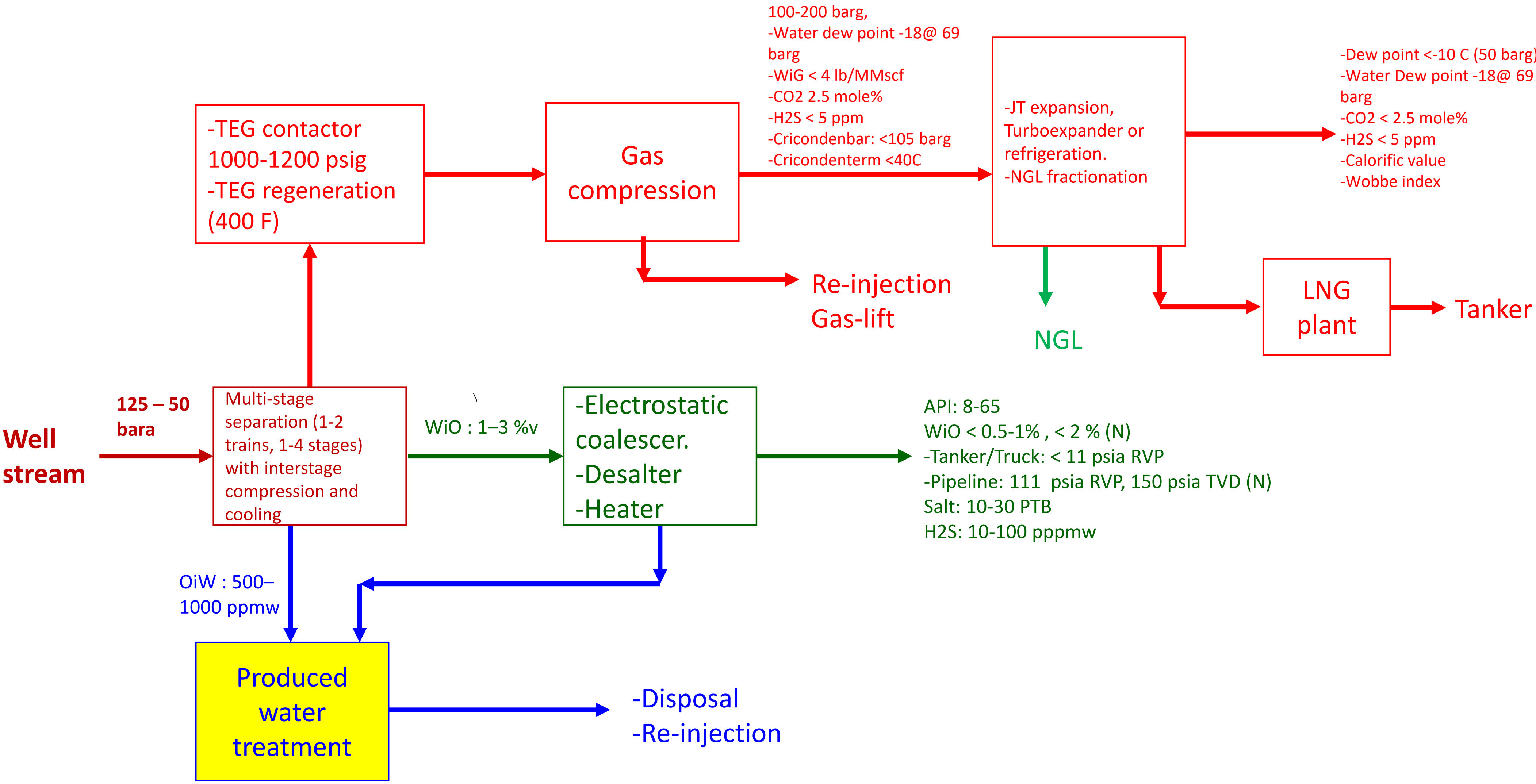
Salt: 10-30 PTB

H2S: 10-100 pppmw

~~Main~~ Reid vapor pressure

True vapor pressure

pounds per thousand barrels



-TEG contactor 1000-1200 psig
-TEG regeneration (400 F)
Gas compression
100-200 barg,
-Water dew point -18@ 69 barg
-WiG < 4 lb/MMscf
-CO2 2.5 mole%
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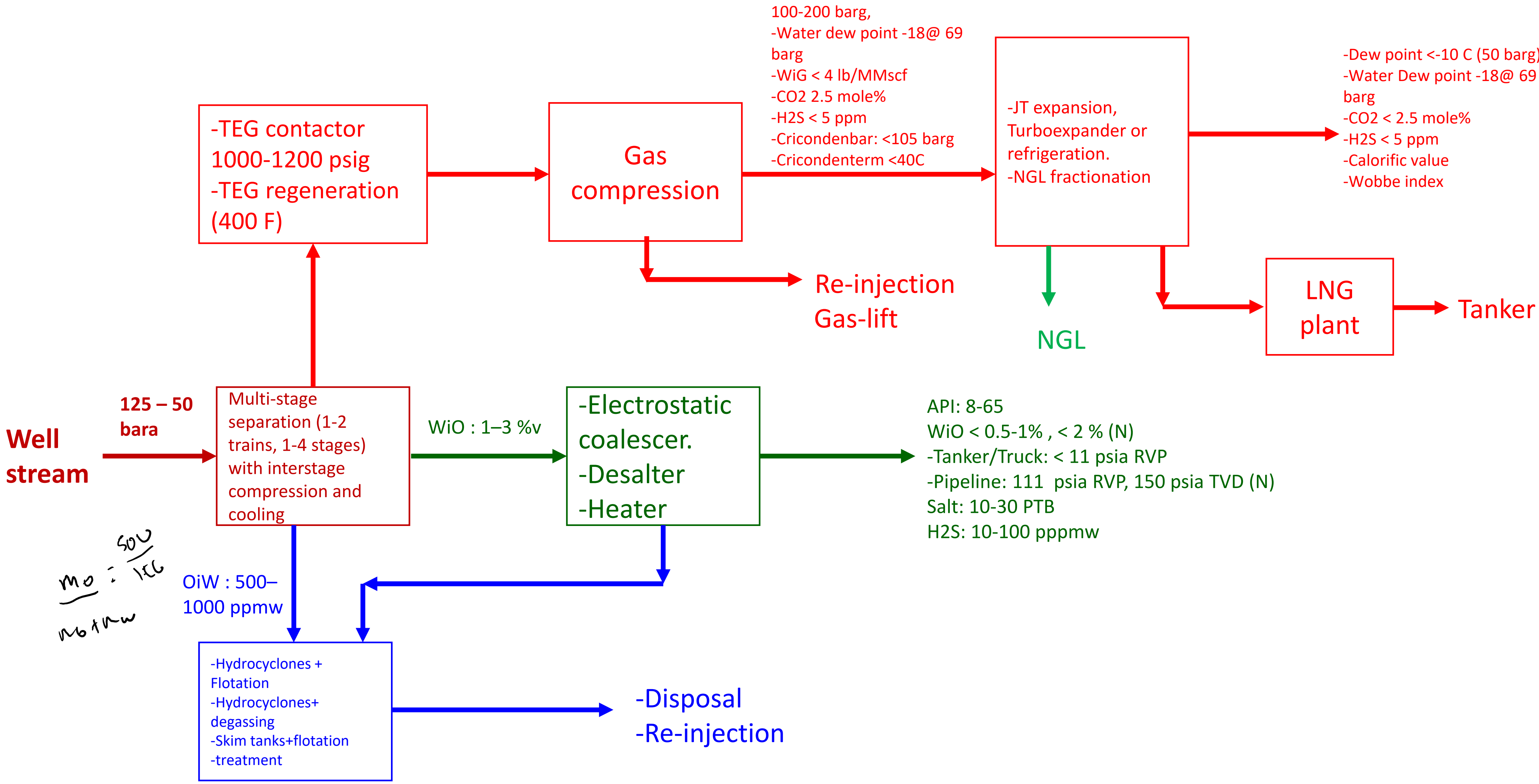
Produced water treatment
-Disposal
-Re-injection



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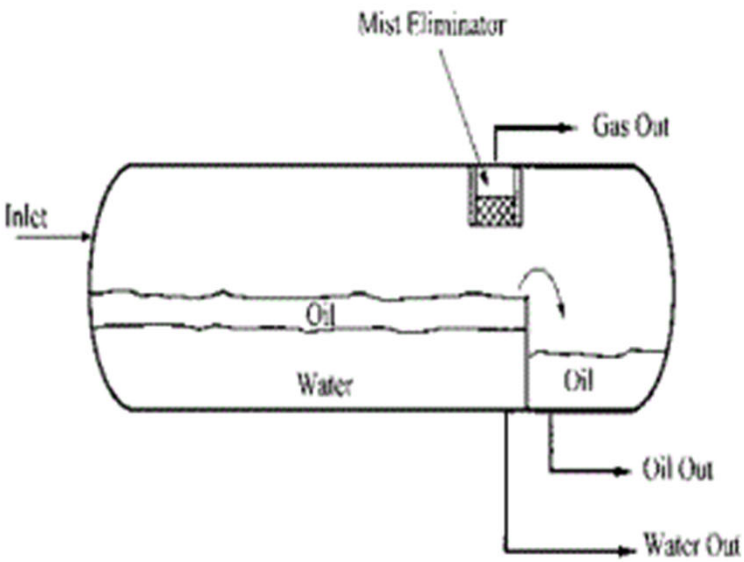
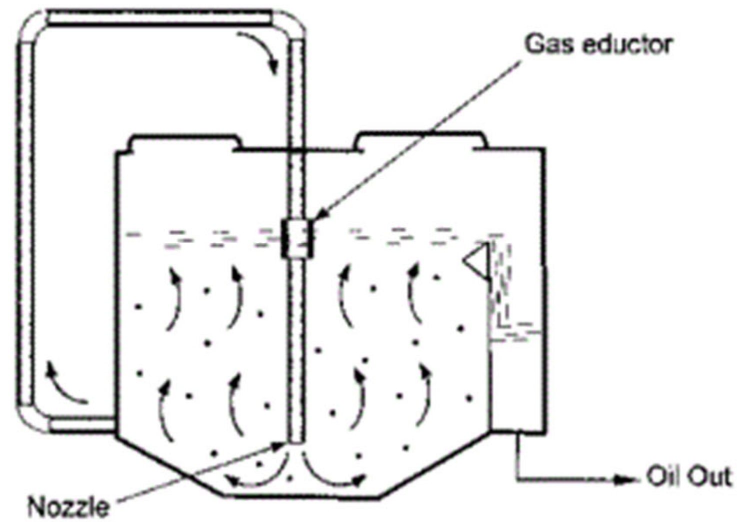
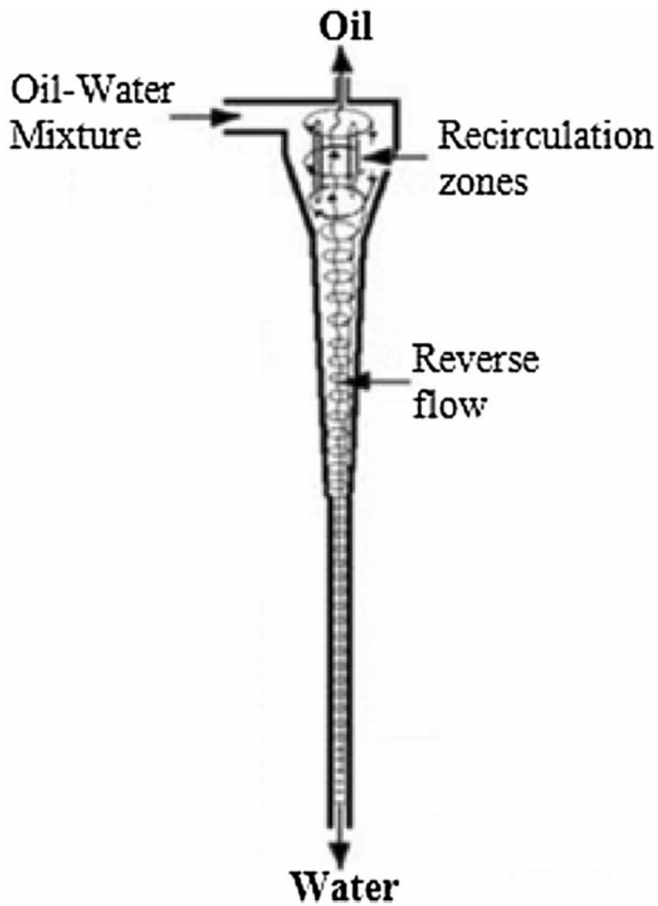
-Wobbe index
LNG plant
Tanker
WiO : 1–3 %v
-Electrostatic coalescer.
-Desalter
-Heater
API: 8-65
WiO < 0.5-1% , < 2 % (N)
-Tanker/Truck: < 11 psia RVP
-Pipeline: 111 psia RVP, 150 psia TVD (N)
Salt: 10-30 PTB
H2S: 10-100 pppmw
OiW : 500–1000 ppmw
-Hydrocyclones + Flotation
-Hydrocyclones+ degassing
-Skim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

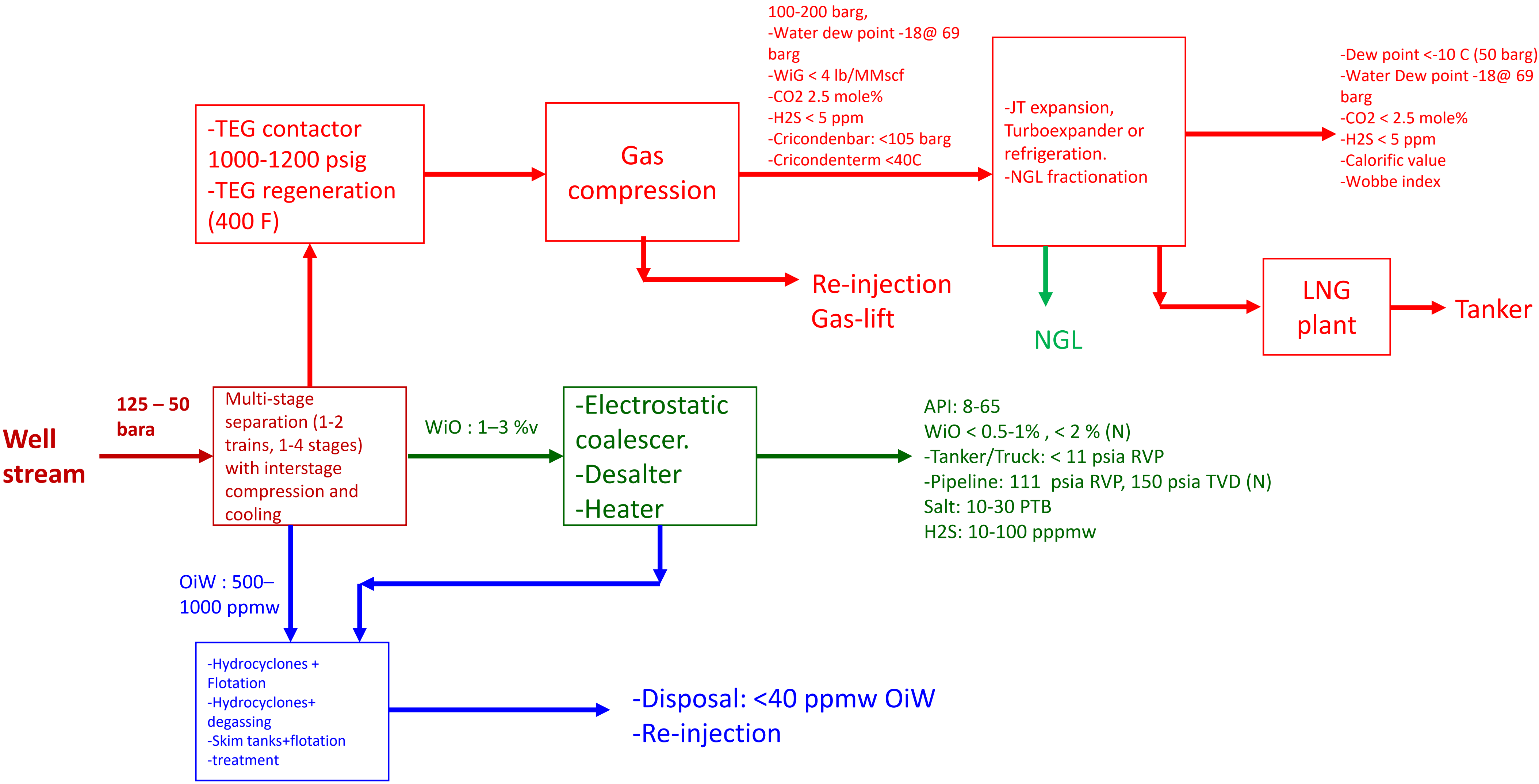
Skim tank + flotation unit





Hydrocyclone

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1000-1200 psig
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Re-injection
Gas-lift
NGL
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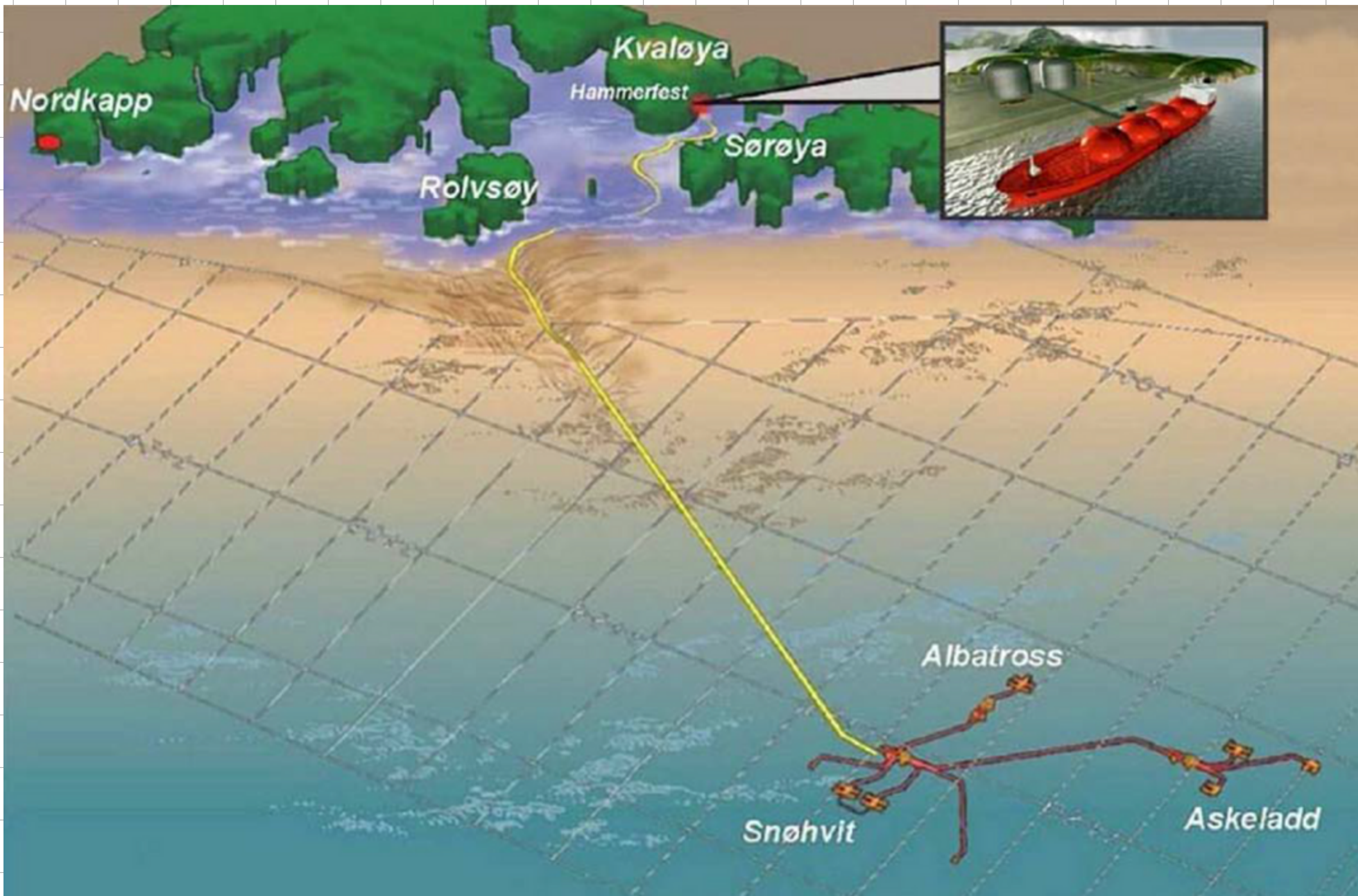
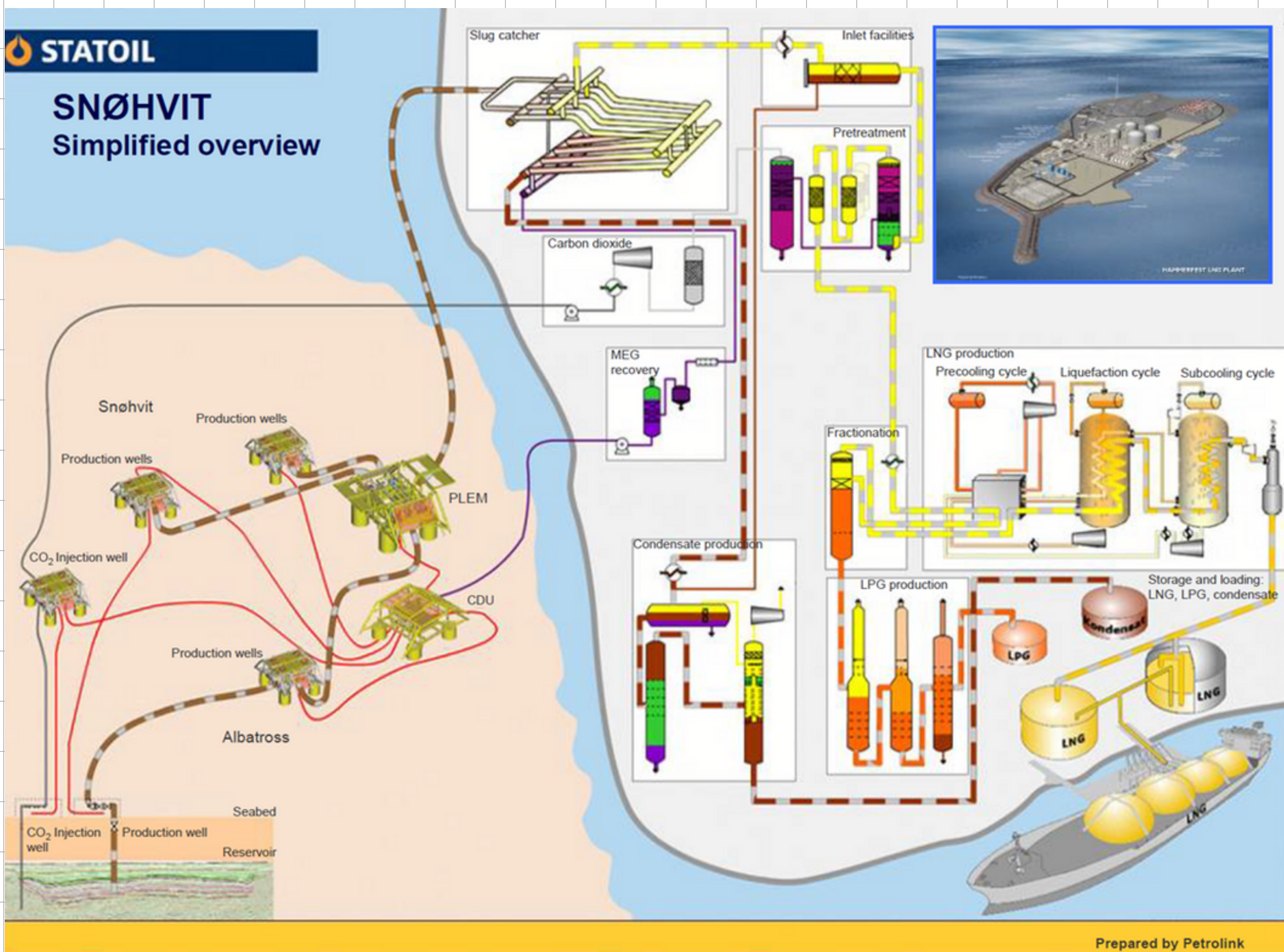
Salt: 10-30 PTB
H2S: 10-100 pppmw
OiW : 500–1000 ppmw
-Hydrocyclones + Flotation
-Hydrocyclones+ degassing
-Skim tanks+flotation
-treatment
-Disposal: <40 ppmw OiW
-Re-injection

Other links

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

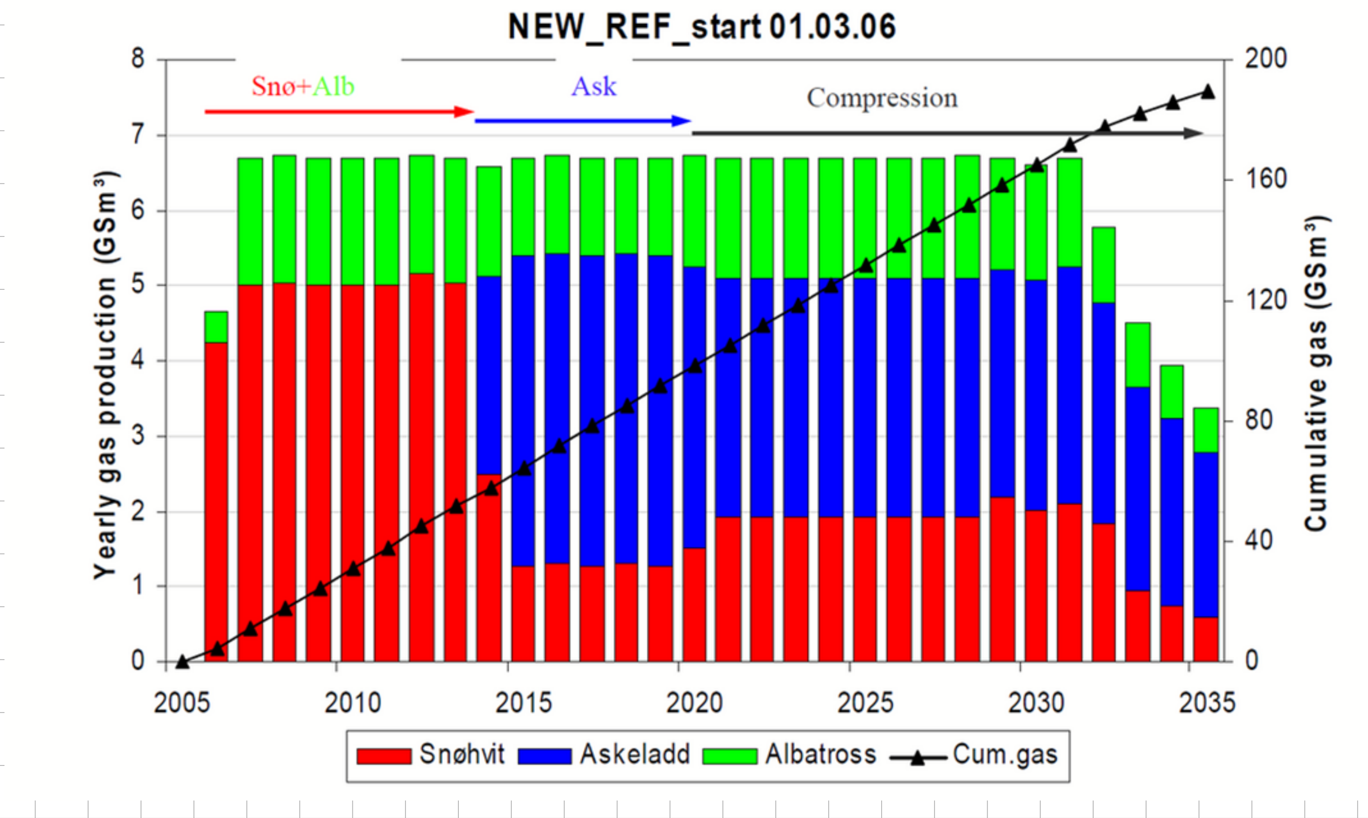
Walkthrough an oil and gas platform in the UK . https://www.youtube.com/watch?v=UrWTMCgHr6s


Nordkapp
Kvaløya
Hammerfest
Sørøya
Rolvsøy
Albatross
Snøhvit
Askeladd

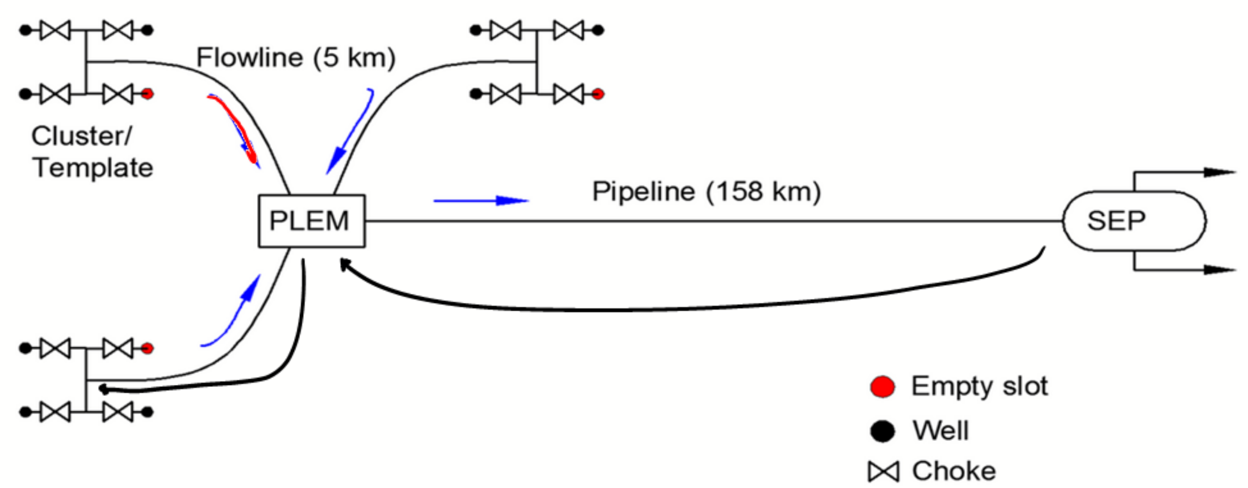

STATOIL
SNØHVIT
Simplified overview
Slug catcher
Inlet facilities
Pretreatment
Carbon dioxide
MEG recovery
LNG production
Precooling cycle
Liquefaction cycle
Subcooling cycle
Fractionation
Condensate production
LPG production
Storage and loading: LNG, LPG, condensate
LPG
LNG
Snøhvit
Production wells
Production wells
PLEM
CO_2 Injection well
CDU
Production wells
Albatross
Seabed
CO_2 Injection well
Production well
Reservoir
Prepared by Petrolink

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

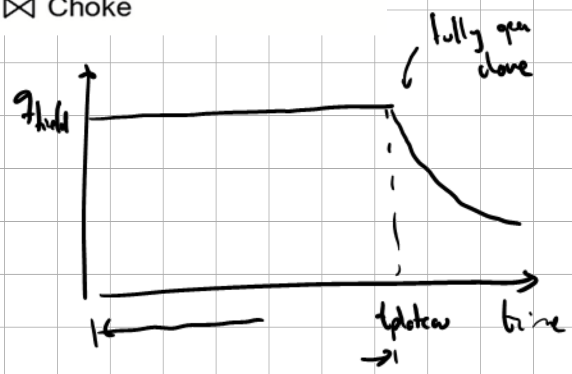
Production profile (20,8mill. Sm³/sd – 6,7 GSm³/år)

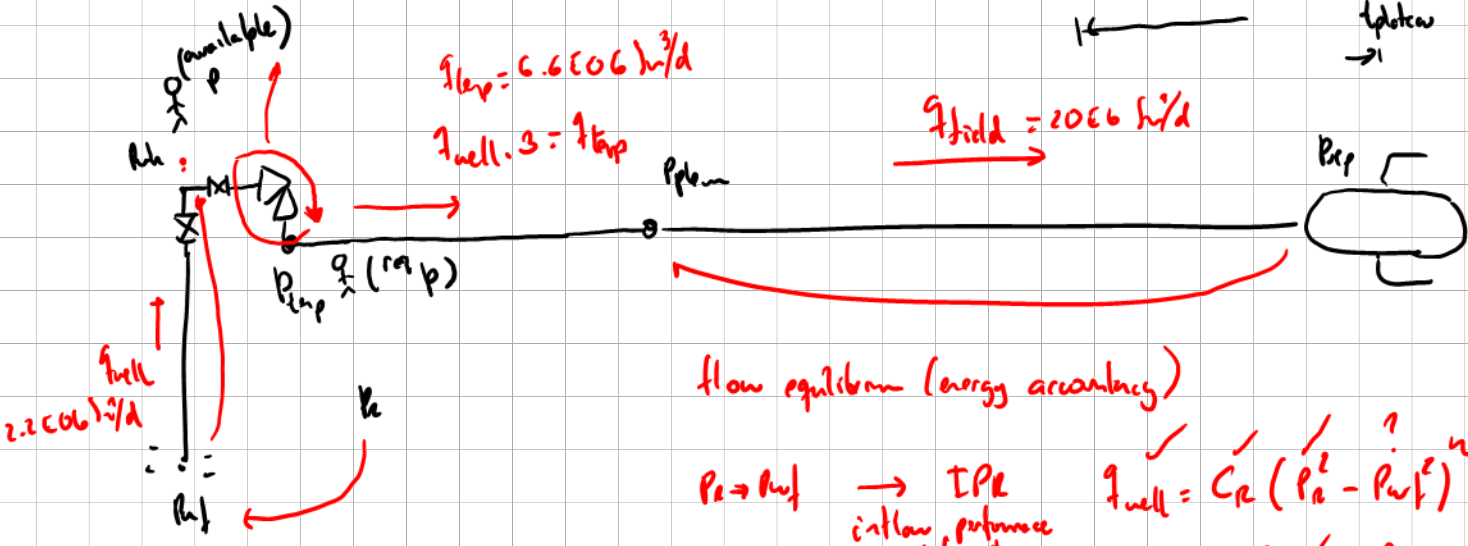


Goal: perform production scheduling calculations for the Snøhvit field, i.e. 1) determine plateau duration, 2) determine post-plateau production



$q_{field} = 20E06$ Sm³/d $t_{plateau}$





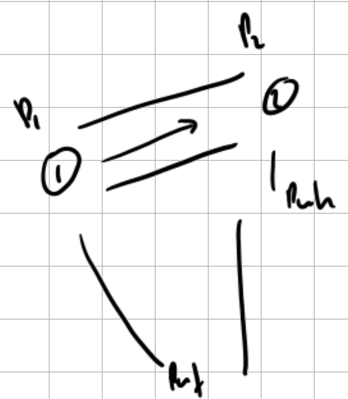
flow equilibrium (energy accounting)

$p_R \to p_{wf}$ → IPR inflow performance relationship $q_{well} = C_R\left(p_R^2 - p_{wf}^2\right)^n$

$p_{wf} \to p_{wh}$ → TPR tubing performance relationship $q_{well} = C_T\left(\frac{p_{wf}^2}{e^S} - p_{wh}^2\right)^{0.5}$

counter-current

$p_{sep} \to p_{plem}$ → pipeline performance relationship $q_{field} = C_P\left(p_{plem}^2 - p_{sep}^2\right)^{0.5}$



$p_{plem} \to p_{temp}$ → flowline performance relationship $q_{temp} = C_{FL}\left(p_{temp}^2 - p_{plem}^2\right)^{0.5}$

when $\Delta p_{choke} = 0$ $p_{wh} = p_t$

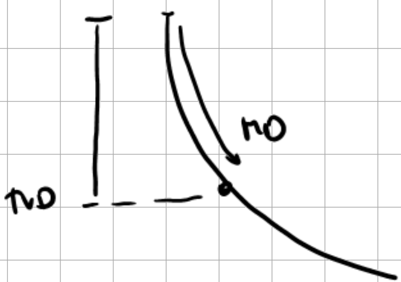
$\Delta p_{choke} = p_{wh} - p_t$ >0 there is enough energy to deliver the rate

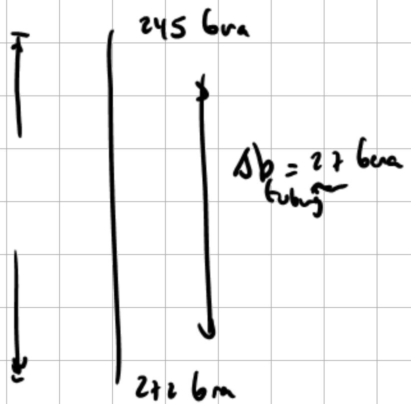
<0 there is not enough energy to deliver

IPR TPR FPR PPR $p_{wh}-p_t$ checkin 20

time	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	70E6					P_{Ri}	2.2E06									
1																

p_R	q_{well}	p_{wf}	p_{wh}
[bara]	[Sm^3/d]	[bara]	[bara]
276	2.2E+6	271.9	245.5





$$\Delta p_{Hydrostatic} = \frac{\rho_{fluid} \cdot g \cdot h}{1E5}$$

300 kg/m3, 9.81, 2100 MD measured depth

vertical well MD = TVD true vertical depth

$$\Delta p_{hydrostatic} = \frac{300 \cdot 9.81 \cdot 2100}{1E5}$$

$$\Delta p_{Hydro} = 63 \text{ bar}$$

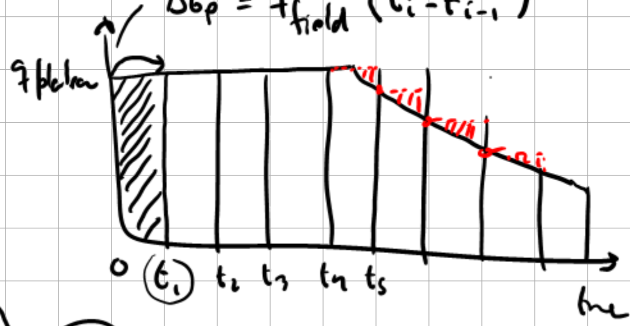
It is similar order of magnitude but a bit higher

20240209

Outline:
-(cont) Snowhite production scheduling exercise
Additional information:
-Outcome of ref group meeting nr 1
-Mandatory exercise nr. 2 published

rectangular approximation

$$\Delta G_p^{i} = q_{field}^{i-1} \left(t_i - t_{i-1}\right)$$



$$G_p = \int_0^{t^*} q_{field}\, dt$$

$$G_p(t^*) = q_{plateau} \cdot \left(t^* - 0\right)$$

trapezoidal approximation

$$\Delta G_p^{i} = \frac{\left(q_{field}^{i-1} + q_{field}^{i}\right)\left(t^{i} - t^{i-1}\right)}{2}$$

Excel value error for Pwh

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

$$P_{wh} = \sqrt{\frac{P_{wf}^2}{e^S} - \left(\frac{q_{well}}{C_r}\right)^2}$$

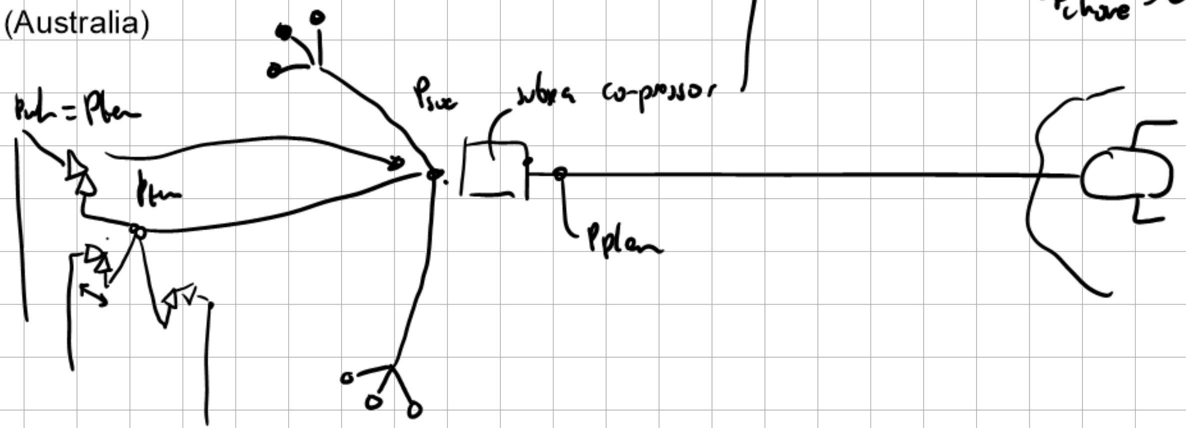
Check the video recording for the step-by-step solution!

Check the video recording for the step-by-step solution!

Boosting available energy < required energy provides energy to the fluid to bridge the gap!

-Ormen lange (Shell)
-Aasgard
-Gullfaks
-Janz (Australia)

at end of natural plateau and forward $\Delta p_{choke} = 0$



$$q_{temp} = C_{fl}\left(P_{te}^{2} - P_{suc}^{2}\right)^{0.5}$$

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

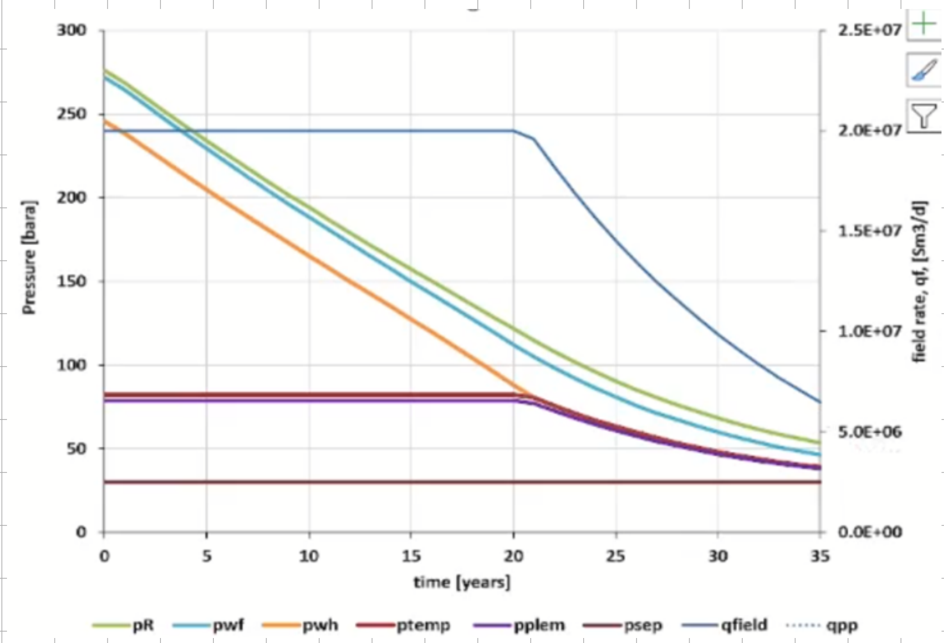
- Installing a compressor at the PLEM. Consider the minimum allowable suction pressure is 15 bara and maximum two compressors of 11 MW each.

When considering boosting equipment, there are a few factors to take into account:
-Minimum allowed suction pressure (compressors, pump-cavitation, gas liberation which is bad for pump performance)
-Required boosting power
  -Liquid pumps 0.5-5 MW Max)
  -Compressor (11 MW max)
  -Multiphase pmp (0.5-5 MW max)

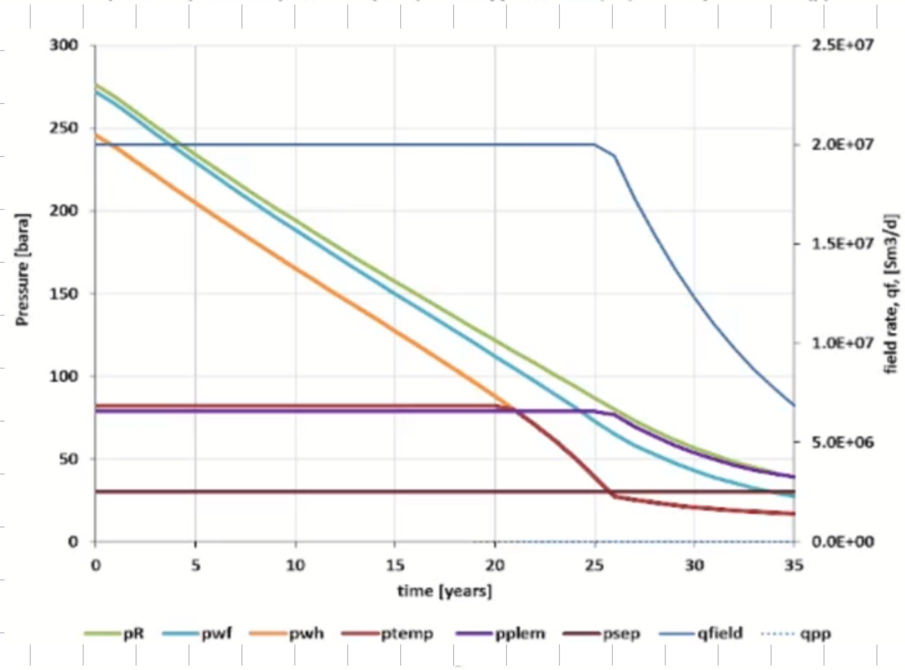
1 car --> 80 hp --> 80*700 W = 56 000 W --> 56 kW
1MW = 1000 kW/56 kW --> 19 cars

house compsuption per year (Robin) --> 15 000 kWh (15 MWh) --> power = energy/time --> 15 MWh/(24*365) = 1.7 kW --> 588 houses

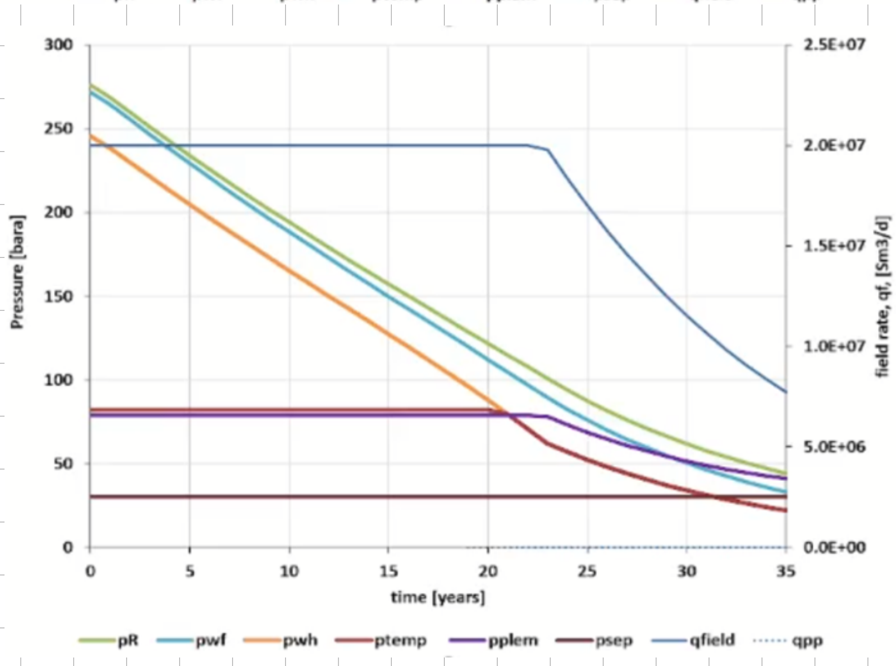
Results:



No compressor



Compressor, minimum suction pressure = 15 bara



Compressor:
-minimum suction pressure = 15 bara
-Maximum total power = 22 MW

Missing data:
Polytropic efficiency of compressor: 0.7
Inlet temperature 67 C

20240215

Outline:
-Boosting
-Economic indicators of petroleum projects

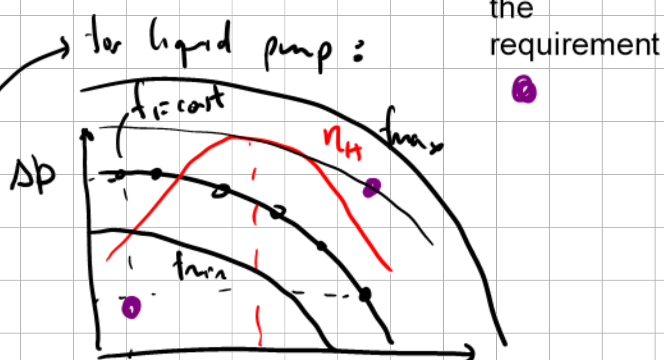
for liquid pumps $\overbrace{P_H}^{max} = \frac{Q \, \Delta P}{\eta_H}$

volumetric rate at inlet

hydraulic power

When evaluating boosting equipment, some things to take into account are:
-Minimum suction pressure
-Maximum Available power
-Maximum allowed outlet temperature (compressors)
-Operational map (envelope)

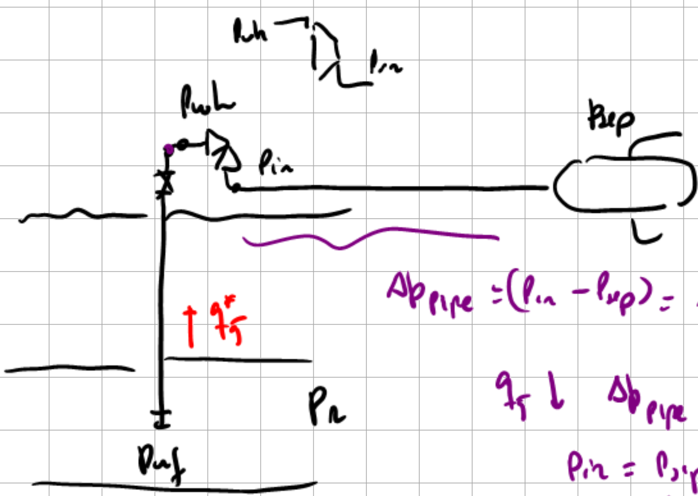
The pump is too small for the requirement

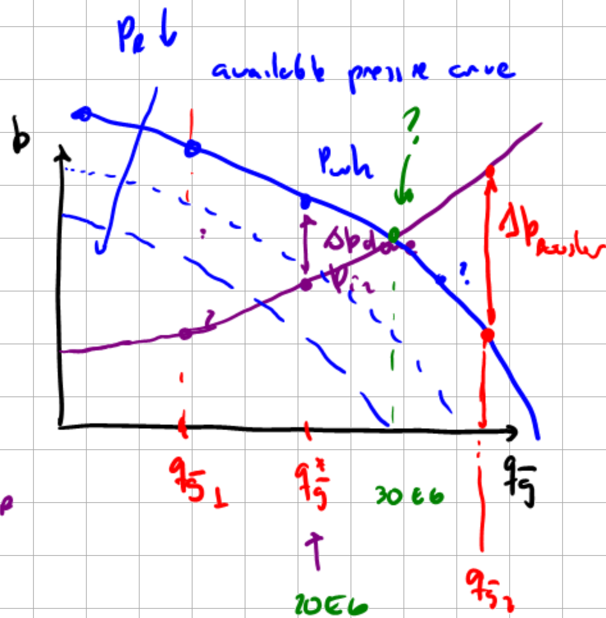


The pump is too large for the requirement

Q ← local at inlet

flow equilibrium (accountancy of available and required energy in the system)





$\Delta p_{pipe} = (P_{in} - P_{sep}) = f(q_g)$

$q_g \downarrow \quad \Delta p_{pipe} \downarrow$

$P_{in} = P_{sep} + \Delta p_{pipe}$

$P_{in} \downarrow$

$\Delta p_{res} = (P_R - P_{wf}) = f(q_g)$

$q_g \downarrow \quad \Delta p_{res} \downarrow$

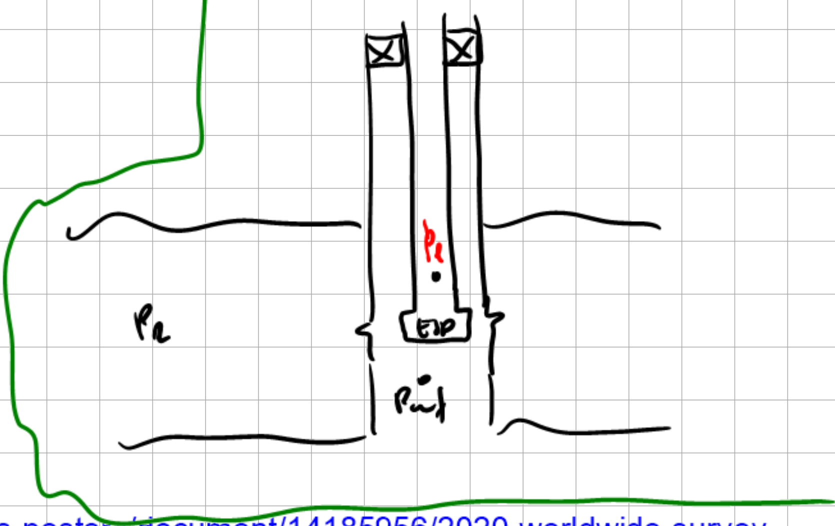
$\Delta p_{tubing} = (P_{wf} - P_{wh}) = f(q_g) \quad (\Delta p_{friction})$

$q_g \downarrow \quad \Delta p_t \downarrow$

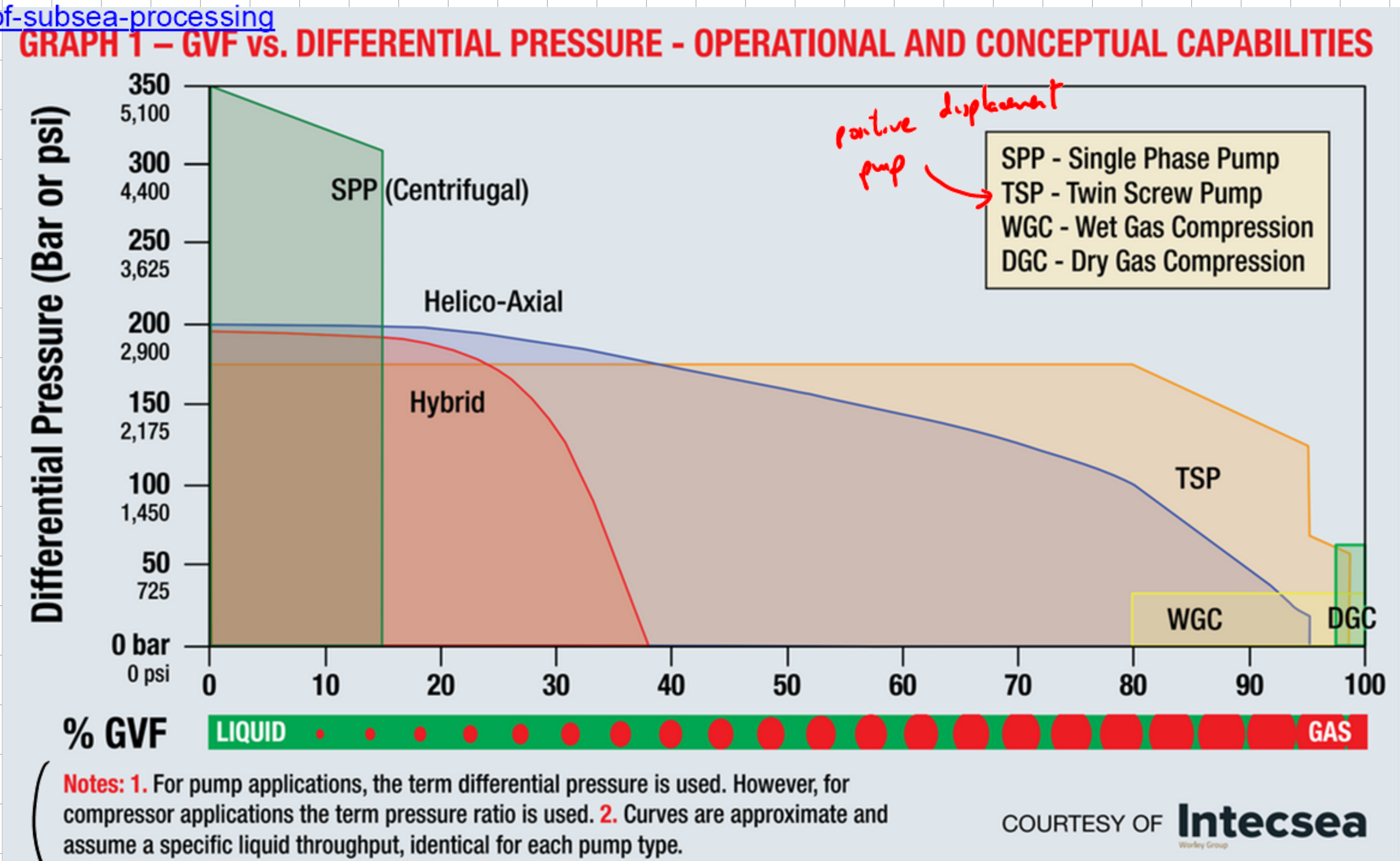
$P_{wh} = P_R - \Delta p_R - \Delta p_t$

types of boosters for subsea applications
for groups of wells
"subsea boosting"

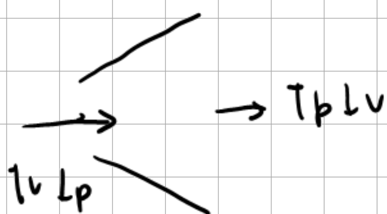
Artificial lift
in well (ESP electric submersible pump)



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



gas volume fraction at inlet $GVF = \frac{Q_g}{Q_g + Q_L} \times 100$

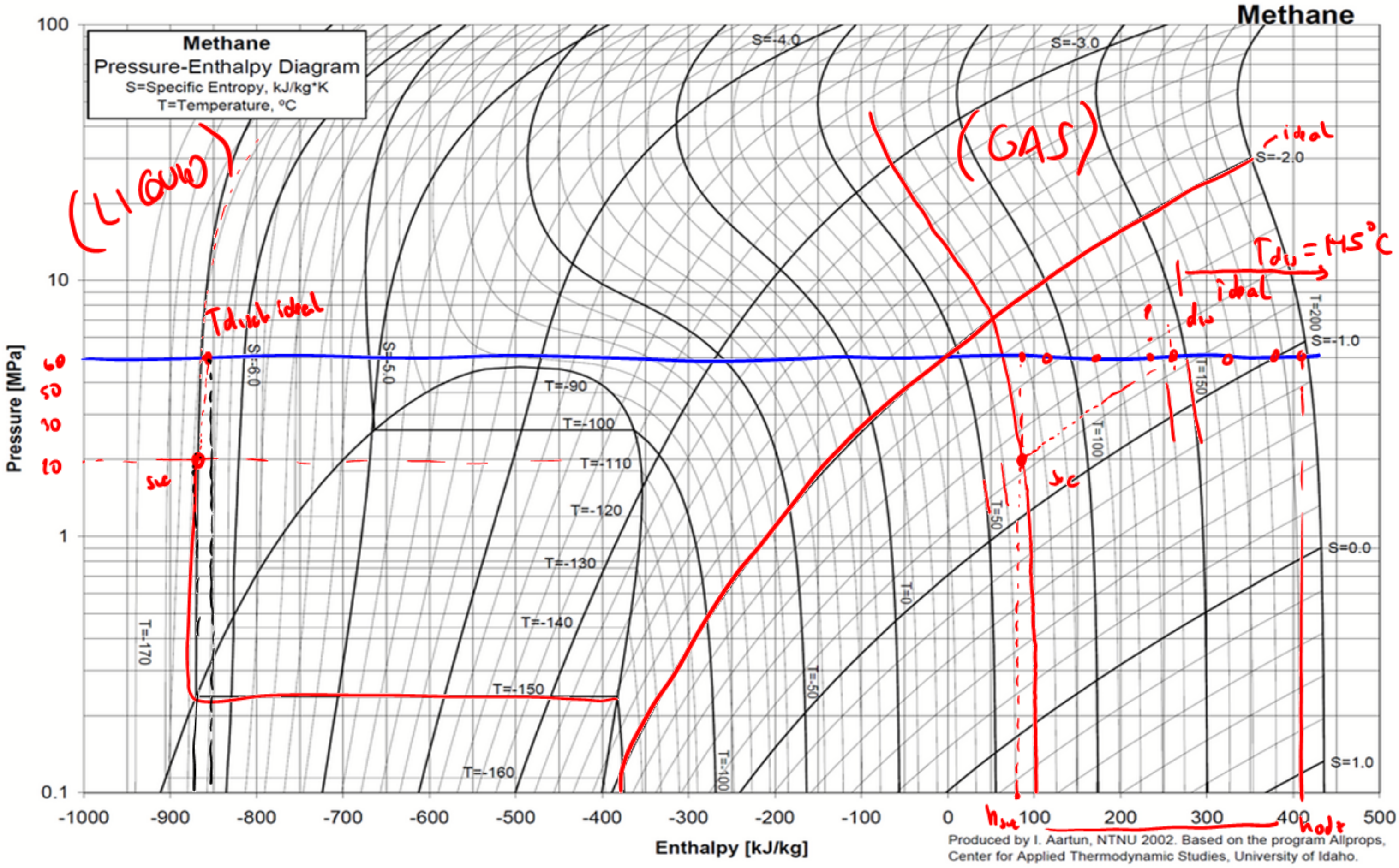


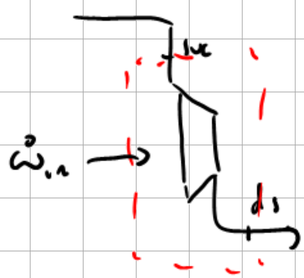
helico-axial pump arrangement

Video of a twin screw pump operating

https://www.youtube.com/watch?v=fcpTchOS81g

A short comment about boosters and temperature change:





$$\dot{w}_{comp} = \dot{m}\left(h_{dis} - h_{suc}\right)$$

$$h_{dis} = \left(h_{suc} + \frac{\dot{w}_{com}}{\dot{m}}\right)$$

Key performance indicators

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

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

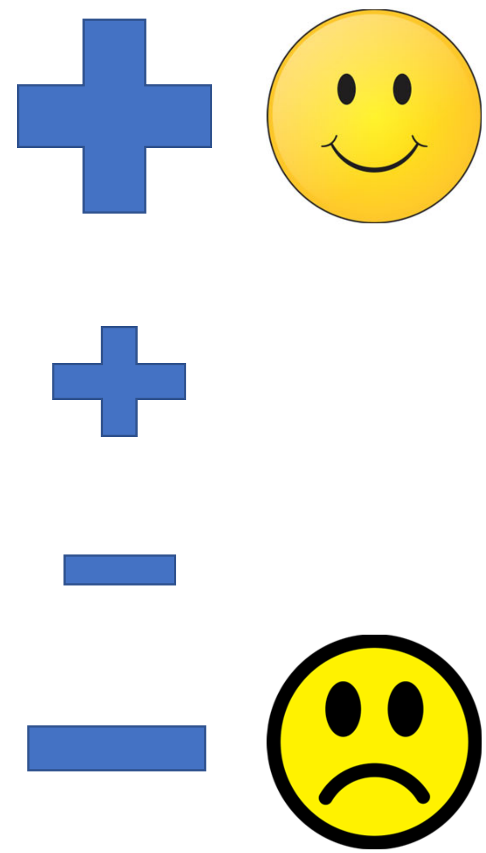
discount rate

Discounted cash flow (DCF) method

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

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

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

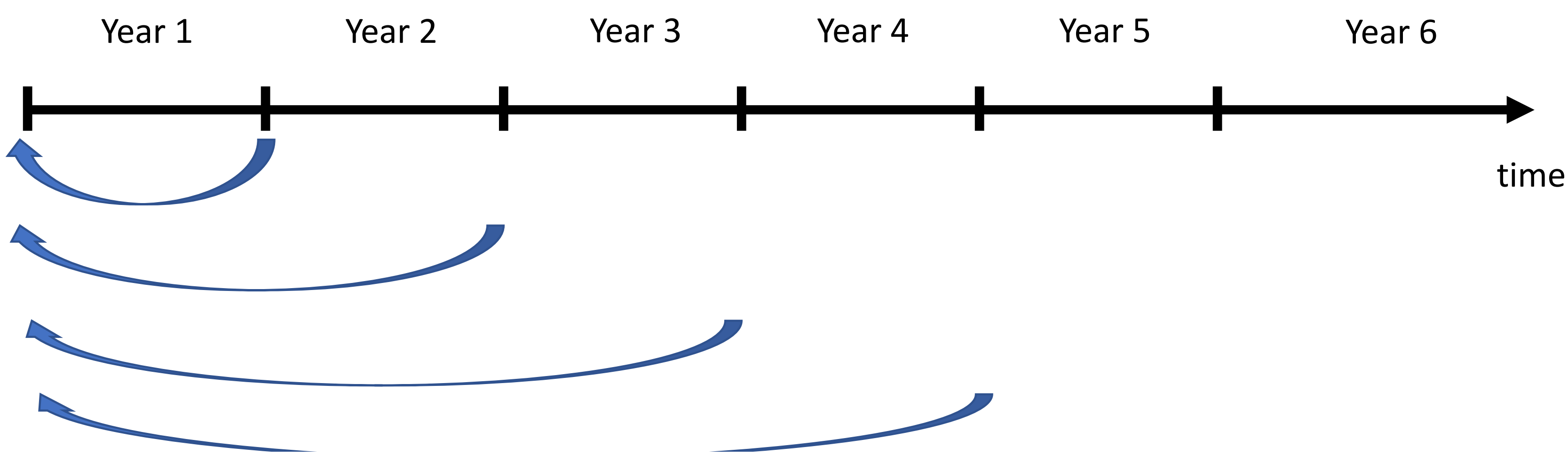
$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t - Expenses_t}{(1+i)^t}$$

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

Net present value

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

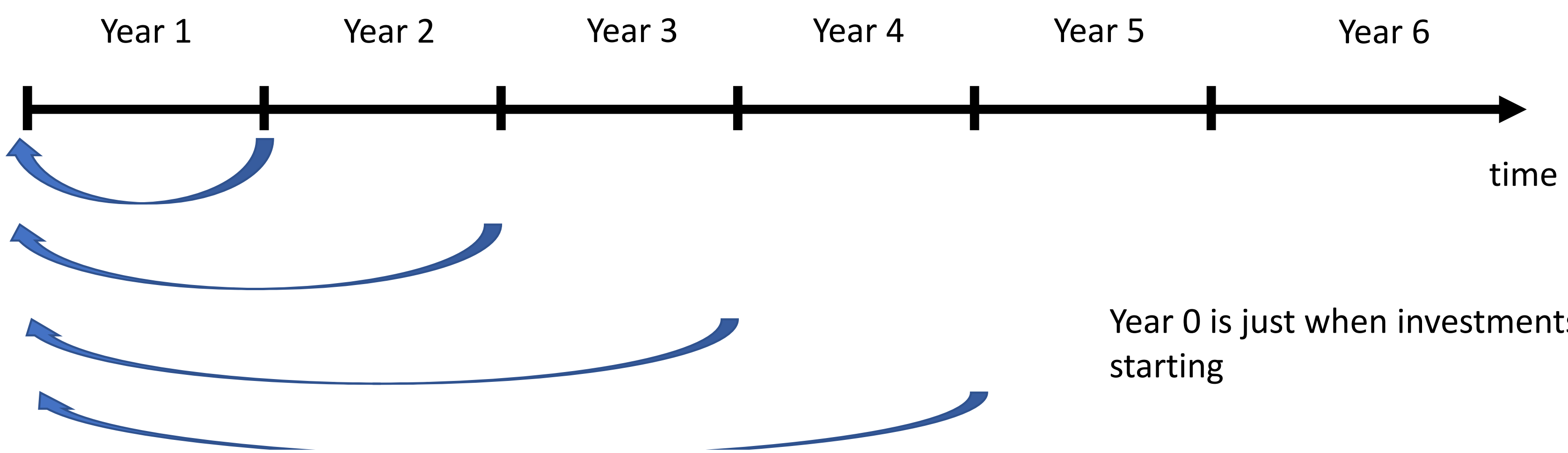
To convert currency in year «t» to year 0 (reference year)



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

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

$$Expenses_t = \underbrace{DRILLEX_t}_{\text{Drilling expenditures}} + CAPEX_t + Depreciation_t + OPEX_t + TAX_t + ABEX_t$$

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

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

often neglected

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

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 drilling (DST, logging, pressure tests, sampling)
- X-mas tree
- Drilling tools
- Salaries, insurance

Net present value

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

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

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

- 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

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

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

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

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 25,000ft Length		$11,606,659
Risers		
Riser Prod. 8.625-in. × 0.906-in. × 65 SCR, 2 × 7500 ft		$6,987,752
Flowlines		
Flowline Dual 10-in. SMLS API 5L X-65, flowline, 52,026 ft		$4,743,849
	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
- 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)

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

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

$$\left.\begin{array}{l} DRILLEX_t \\ \\ CAPEX_t \\ \\ OPEX_t \end{array}\right\}$$

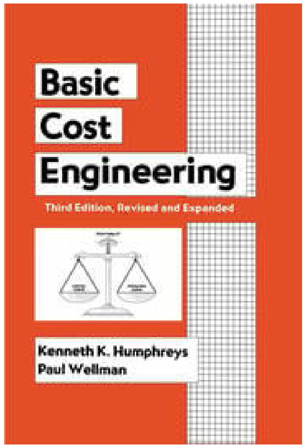
Function of number of wells, maximum production rates of oil, gas and water, development concept, type of fluids etc.

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

Class outline 20240216

-(cont). Economic indicators for oil and gas projects

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

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

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

$262800 \ \cancel{MWh} \ (30\,MW)$

$\frac{1 \ \cancel{MWh}}{257 \ Sm^3 \ Gas}$

- CO_2 tax (in 2022 NOK 1.65 NOK/Sm3 gas)

Example:

- Considering gas turbine efficiency 1 MWh/257 Sm3 gas (TPG4245 – 2022).
- 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!!

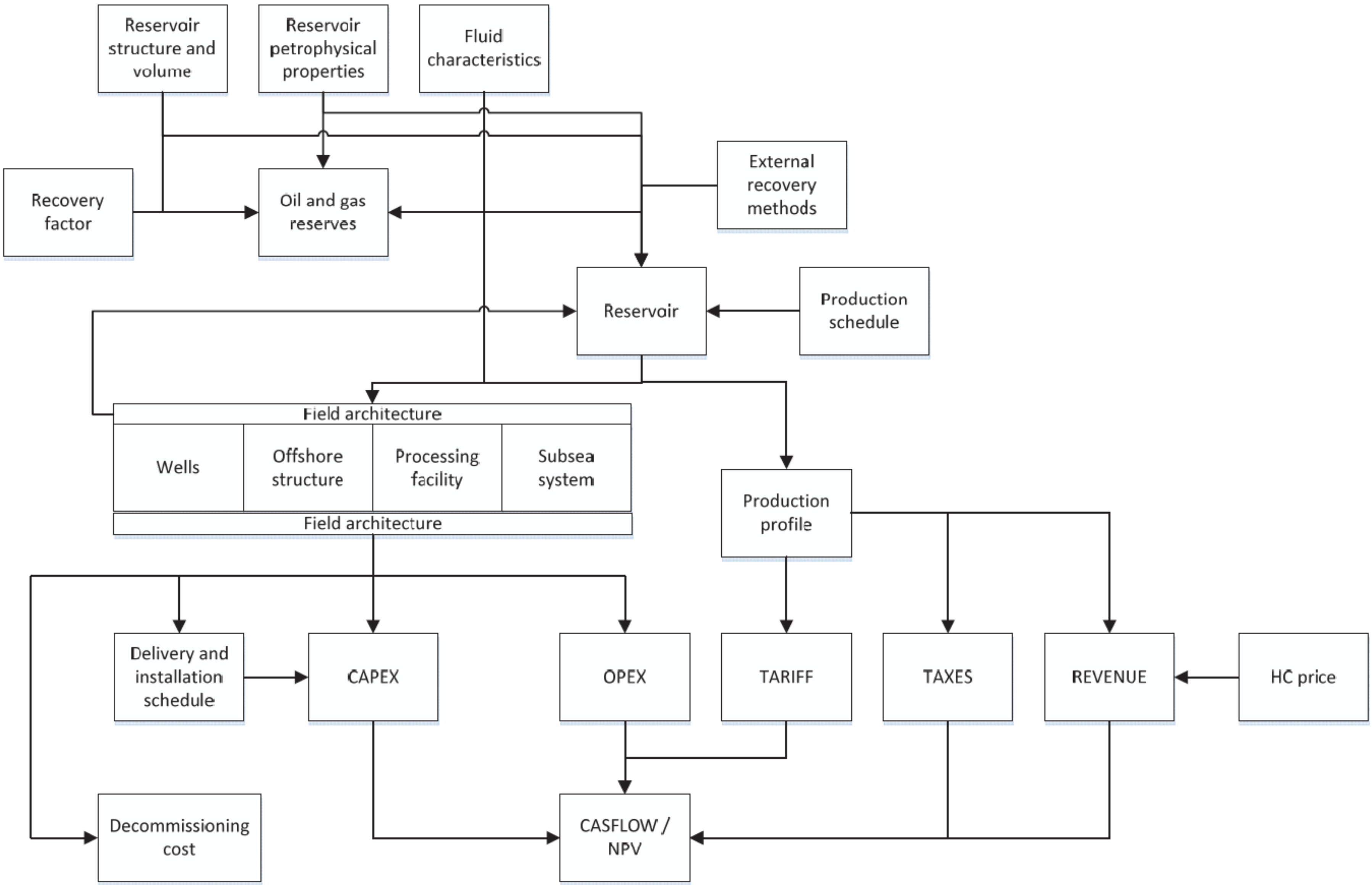
Net present value calculation- Who does what:

- 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→

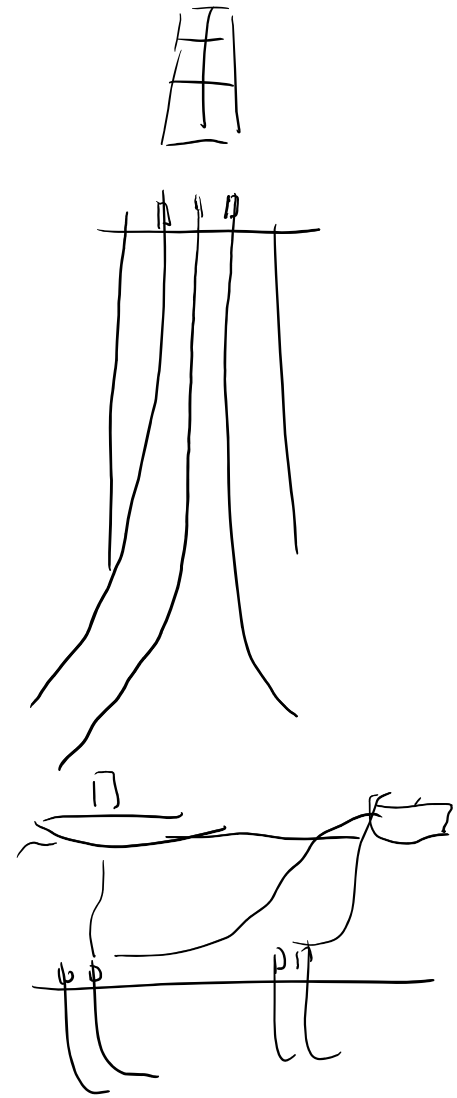
bigger offshore structure

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

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

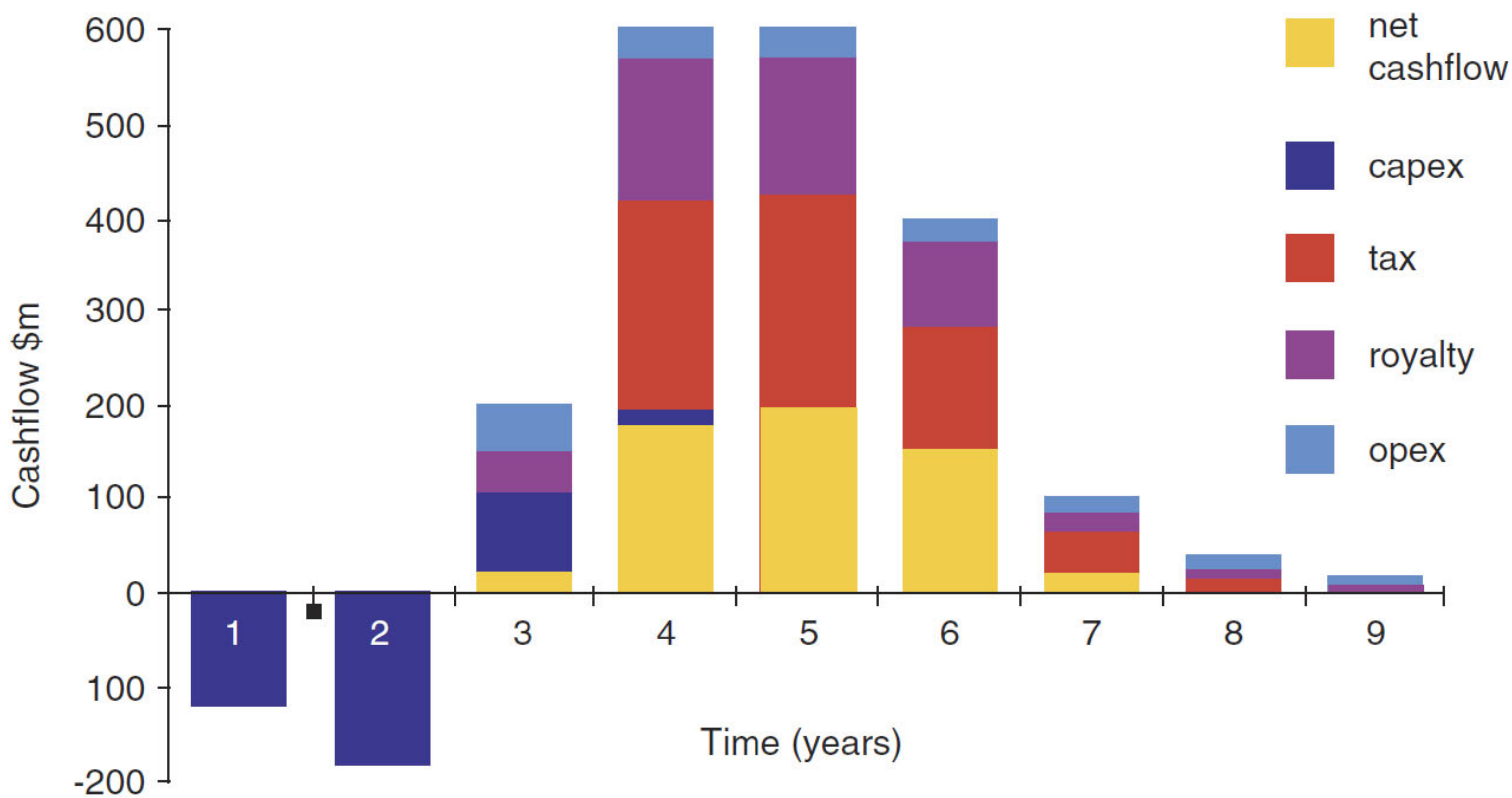
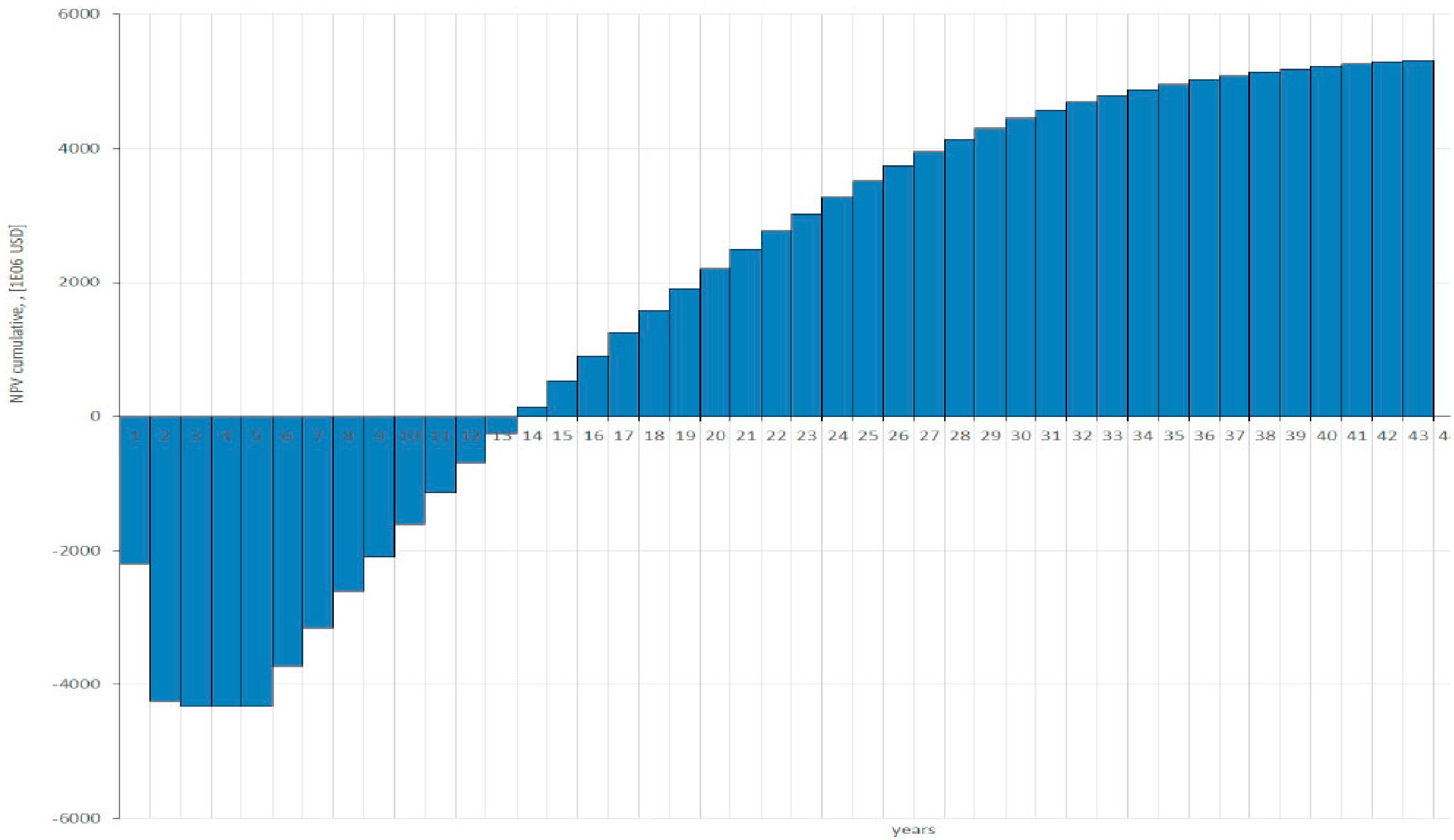


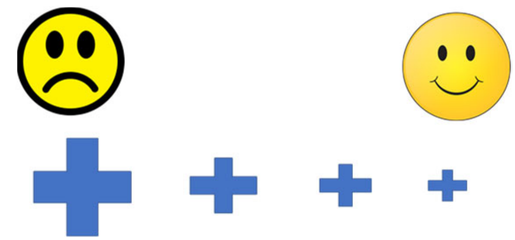
Figure 14.5 Components of a project cashflow.

NPV versus time



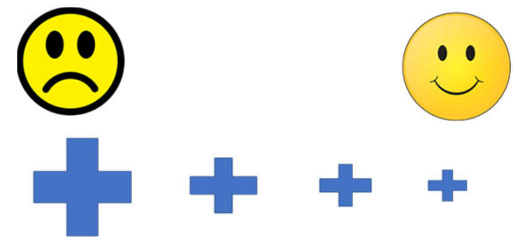
Other KPIs used

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

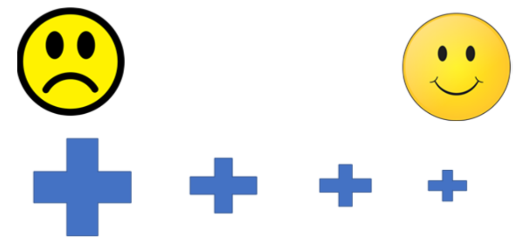


Other KPIs used

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

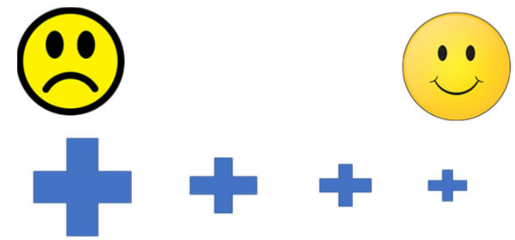


- NPV break-even→ time when NPV = 0

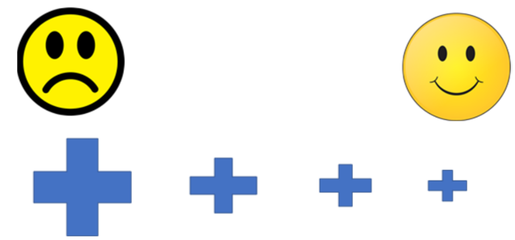


Other KPIs used

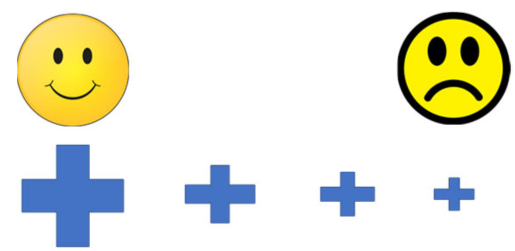
- Break-even price → oil price that give NPV = 0



- NPV break-even→ time when NPV = 0

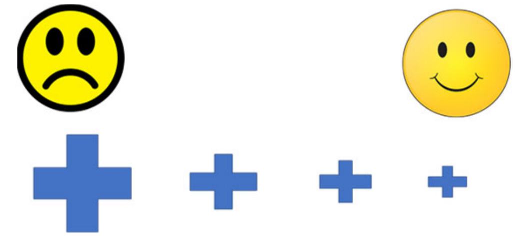


- Internal rate of return (IRR) → discount rate for which NPV = 0

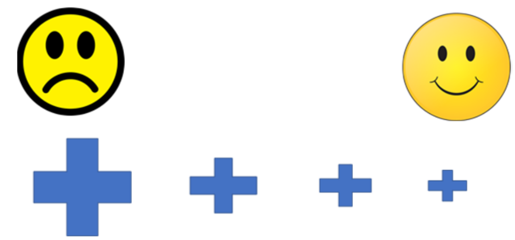


Other KPIs used

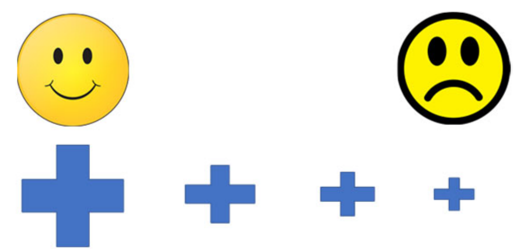
- Break-even price → oil price that give NPV = 0



- NPV break-even→ time when NPV = 0



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



- OTHERS…

Standards

INTERNATIONAL STANDARD

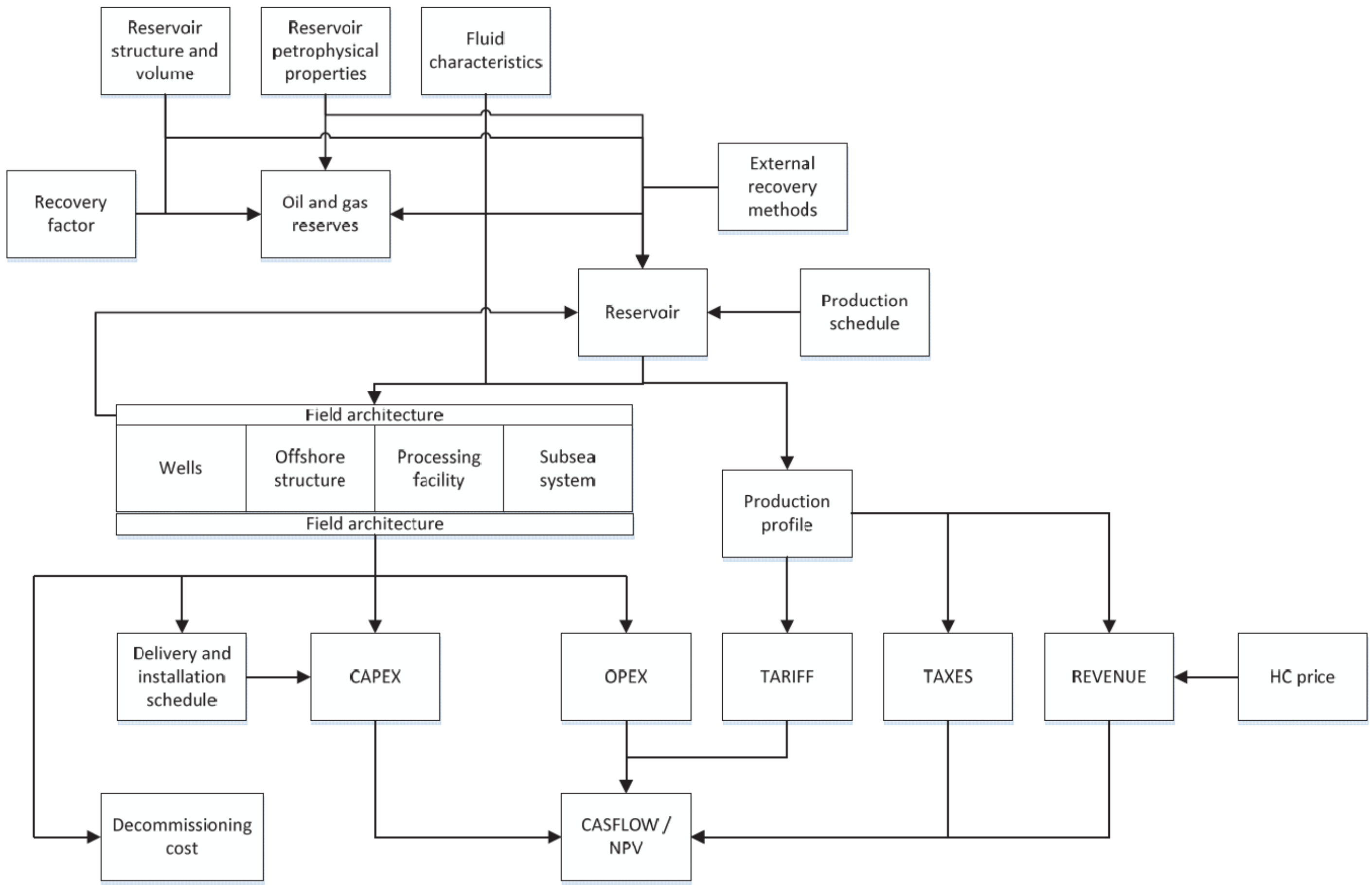
ISO 15663

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

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**

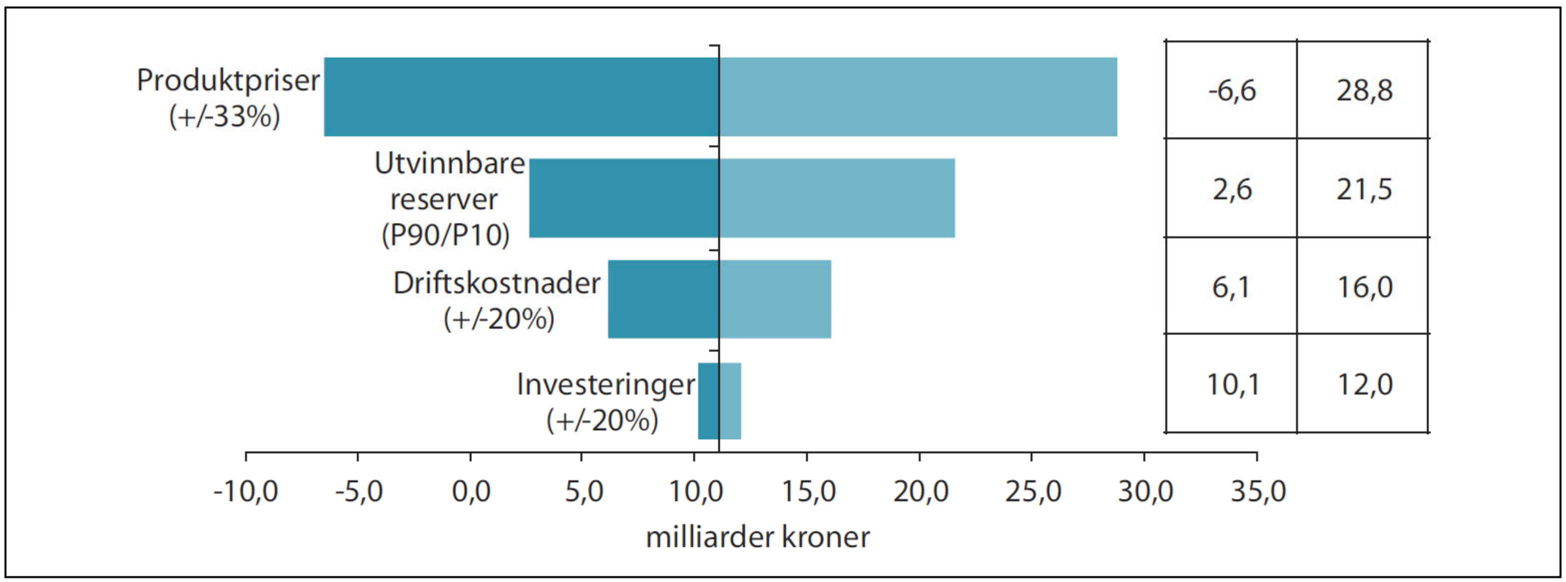
Source: ISO 15663:2021 course, 9 June 2021

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

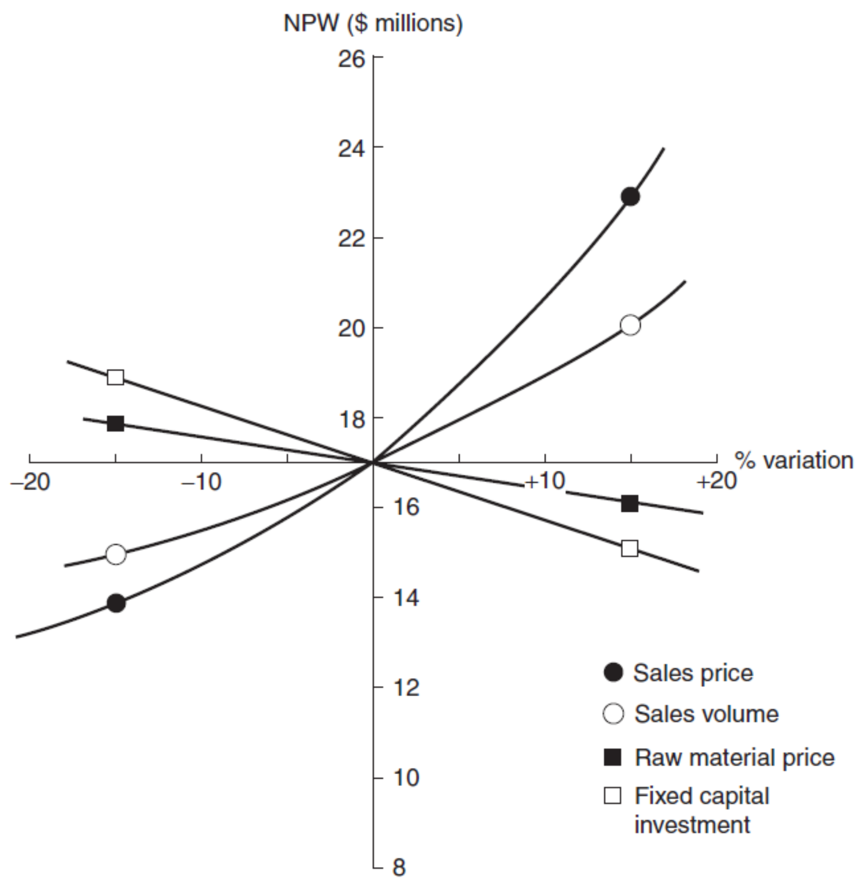


FIG. 9-14 Strauss plot.

Sensitivity analysis - defficiencies

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

Field development goal

Find field design to maximize NPV

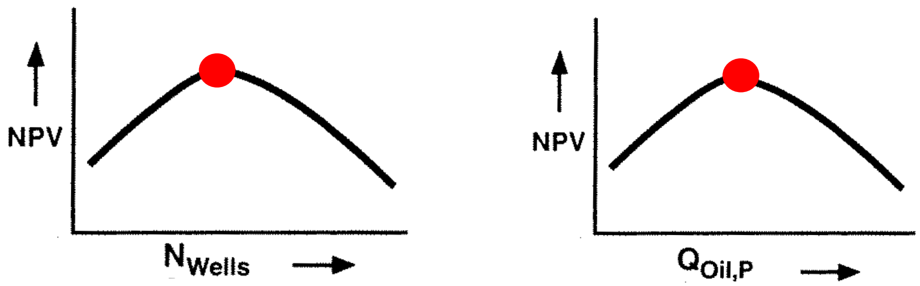
Field development goal

Find field design to maximize NPV

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

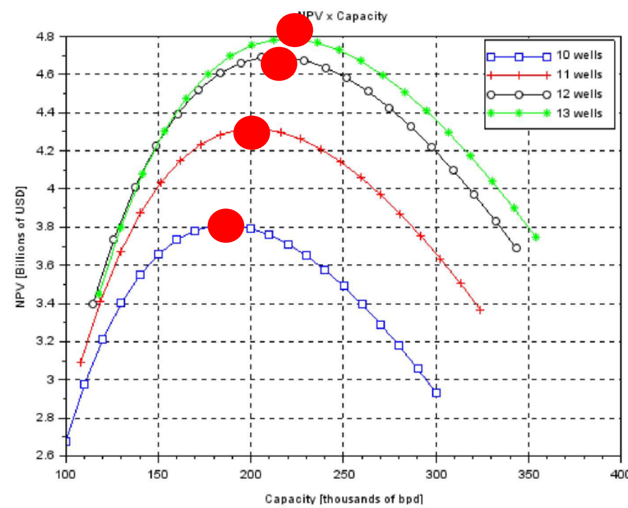
Action	Advantages	Disadvantages
Higher HC rates during early times	Gives higher revenue	Gives higher cost (CAPEX, OPEX)
Drill more wells	Allows for higher rates, extends field life	Gives higher cost (DRILLEX, CAPEX, OPEX)

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

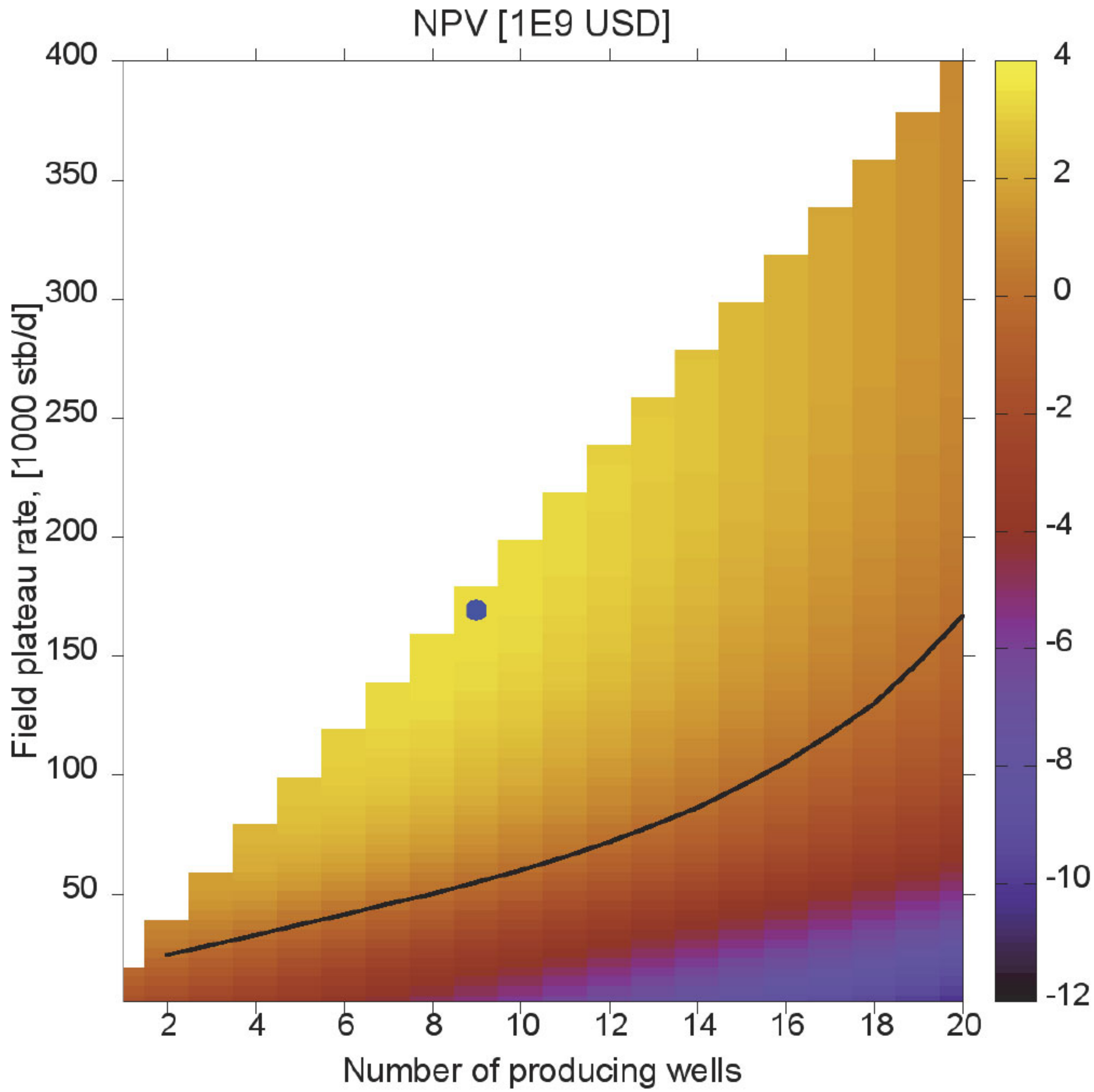


OTC-28898-MS

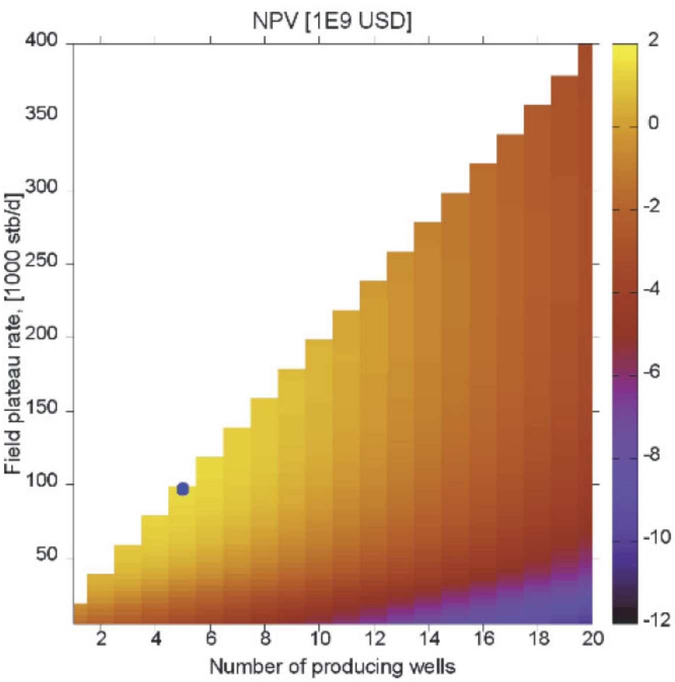
A Cost Reduction Methodology for Offshore Projects

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

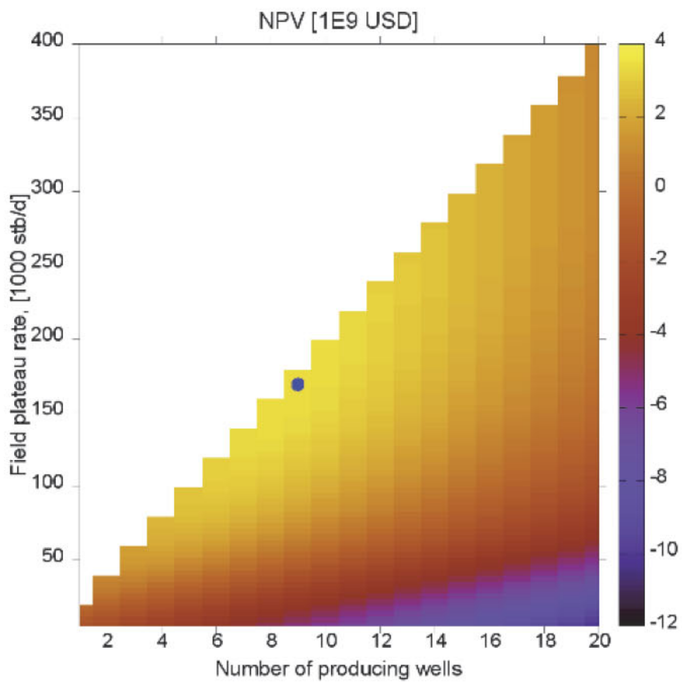
Example from Milan's Compendium section 5.2.3.



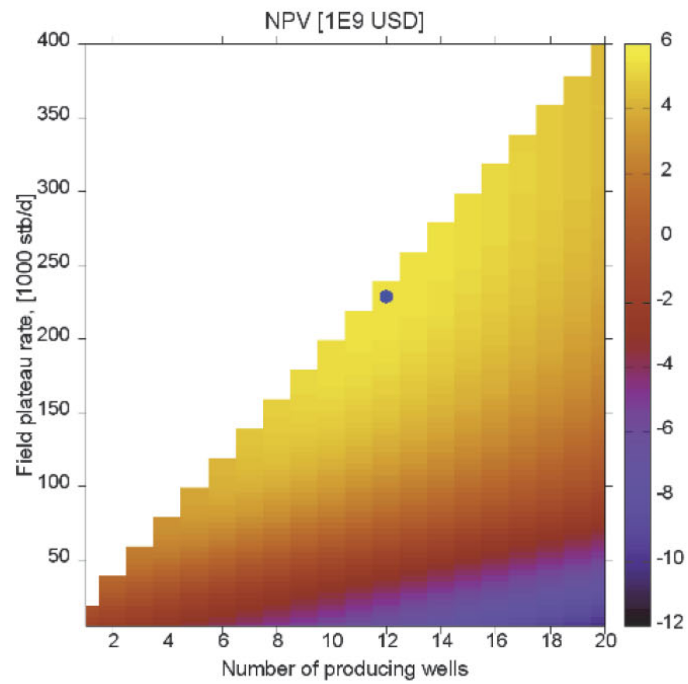
Effect of uncertainties



a) N= 0.6·base

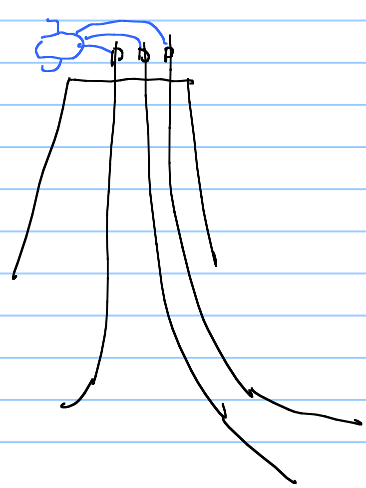


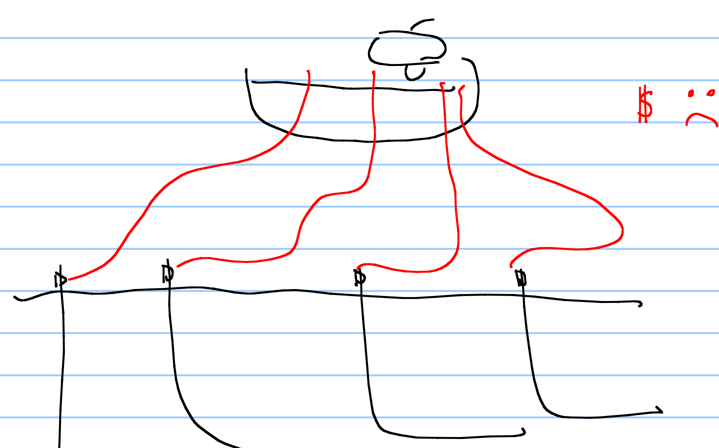
b) N= base

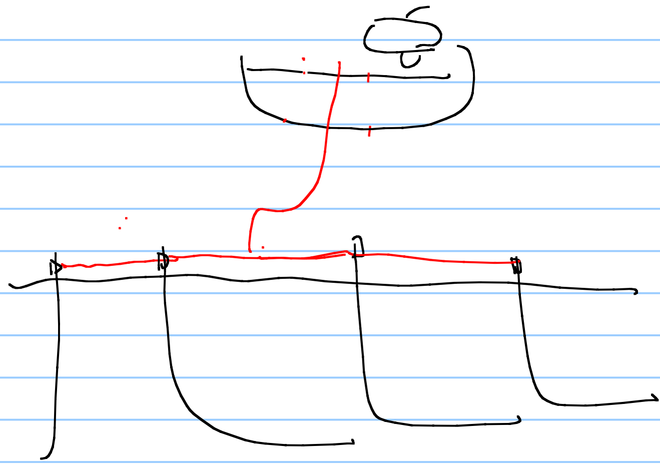


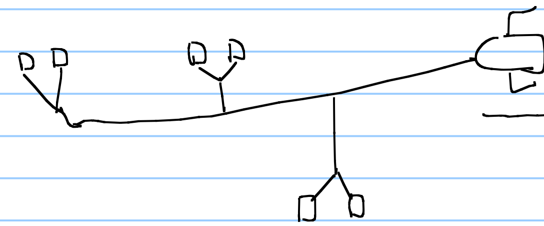
c) N= 1.4·base

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

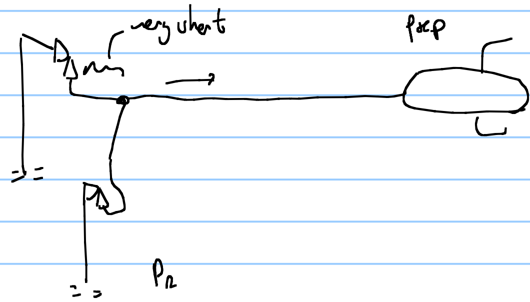








Example: 2 Dry gas wells

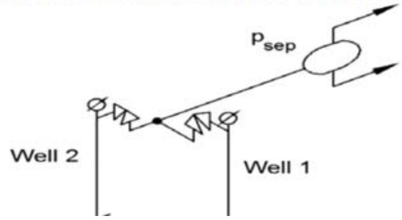


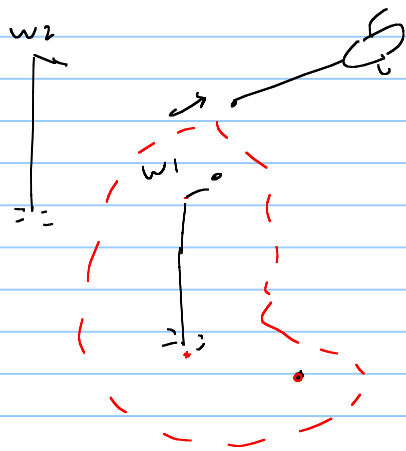
open choke $\Delta p_{c_1} = 0$ $\Delta p_{c_2} = 0$

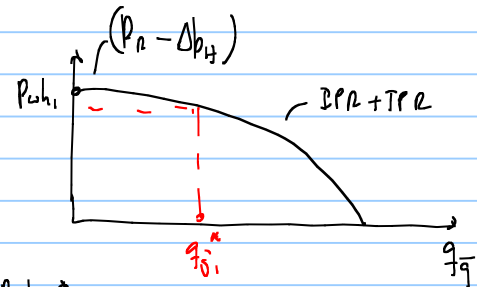
	Equations	Nr equations	Nr unknowns
IPR	$q_{j_1} = C_{R_1}\left(p_{R_1}^2 - p_{wf_1}^2\right)^{n_1}$ $q_{j_2} = C_{R_2}\left(p_{R_2}^2 - p_{wf_2}^2\right)^{n_2}$	2	4
TPR	$q_{j_1} = C_{T_1}\left(\frac{p_{wf_1}^2}{e^{s_1}} - p_{wh_1}^2\right)^{0.5}$ $q_{j_2} = C_{T_2}\left(\frac{p_{wf_2}^2}{e^{s_2}} - p_{wh_2}^2\right)^{0.5}$	2 ⌊4	2 ⌊6
PPR	$q_{j_1} + q_{j_2} = C_{PL}\left(p_j^2 - p_{sep}^2\right)^{0.5}$	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

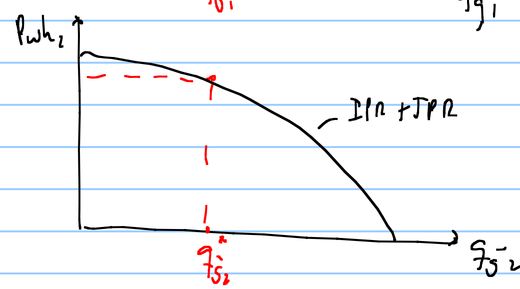
PROBLEM 4 (18 POINTS). Network solving. (2017) exam

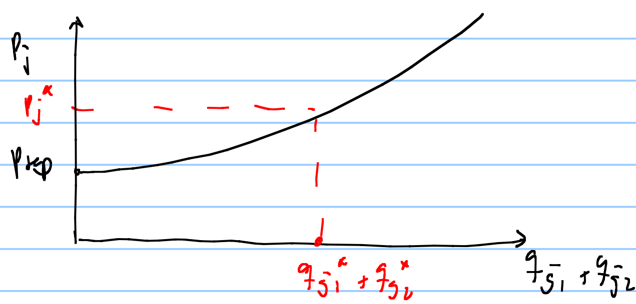
Consider the gas field with two wells, a manifold a pipeline and a separator shown in the figure below. The wellhead of the wells are very close to the junction so it can be safely assumed that the wellhead pressure and junction pressure are equal when the choke is open.











approach nr. 1

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

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

3: Verify $P_{wh_1}^* = P_{wh_2}^* = P_j^*$ — not → back to 1

↓ 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 → back to 1

↓ yes

solution

1st iteration $p_j = 50$ bara

$q_{g_1}^* = 1.2\text{E}06\ Sm^3/d$

$q_{g_2}^* = 1.57\text{E}06\ Sm^3/d$ + $2.77\text{E}6\ Sm^3/d$ $\varepsilon = 0.97\ 1\text{E}06\ Sm^3/d$

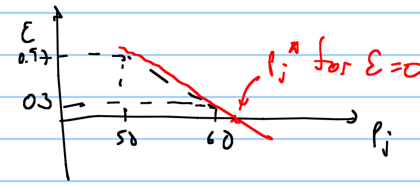
$q_{pipeline}^* = 1.8\text{E}06\ Sm^3/d$ $1.8\text{E}06\ Sm^3/d$

2nd $p_j = 60$ bara

$q_{pipeline}^* = 2.3\text{E}06\ Sm^3/d$ $2.3\text{E}06\ Sm^3/d$ $\varepsilon = 0.3\ 1\text{E}06\ Sm^3/d$

$q_{g_2}^* = 1.45\text{E}06\ Sm^3/d$ + $2.60\text{E}06\ Sm^3/d$

$q_{g_1}^* = 1.15\text{E}06\ Sm^3/d$



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

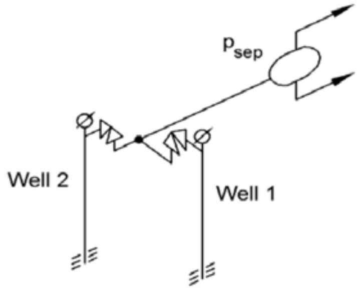
$p_j^* = \sim$

Youtube video: Solving dry gas networks in Excel

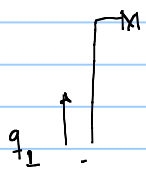
Exercise: using data from Problem 4 of the Exam 2017:

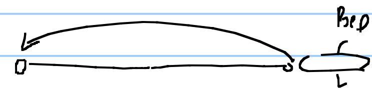
PROBLEM 4 (18 POINTS). Network solving.

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.



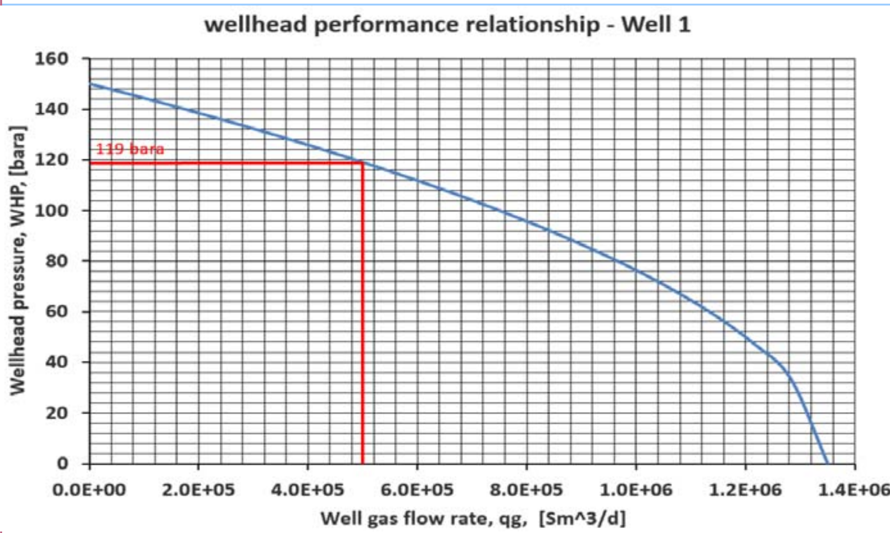
Will it be possible to produce 0.5 E06 Sm3/d from each well? if so, what is the choke deltap required in each well?

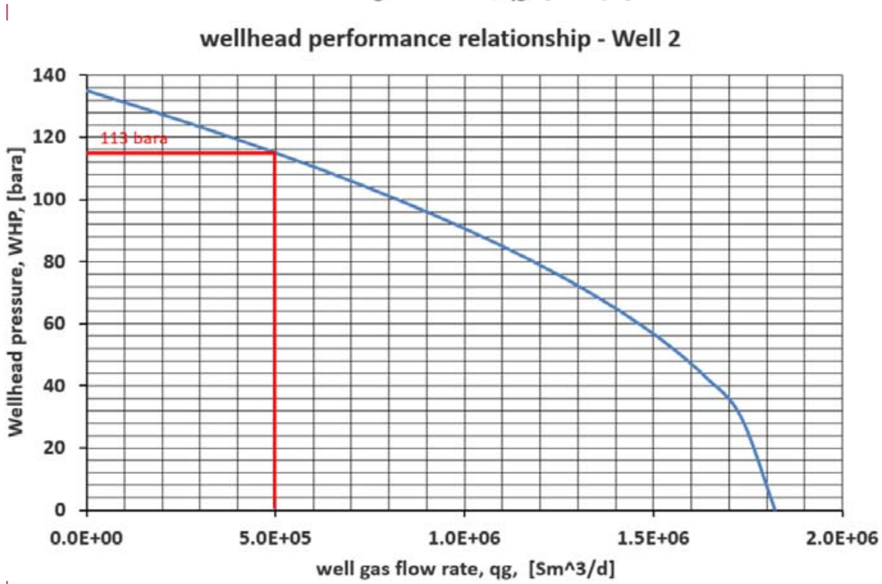


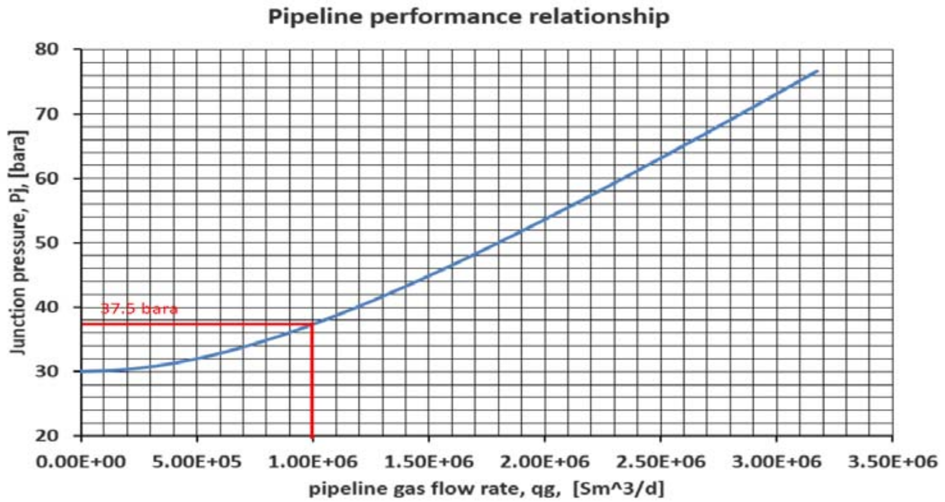


verify $\Delta p > 0$ then q_1 is feasible

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



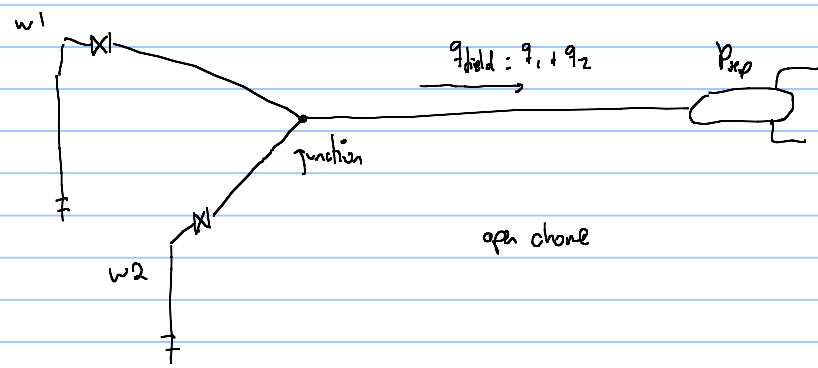




Deltap_choke1 = 119 - 37.5 = 81.5 bara
Deltap_choke2= 113-37.5 = 75.5 bara

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 $\bar{q}_1$, $\bar{q}_2$

OR: P_{wf_1}, P_{wf_2} ← $P_{wf} < P_R$

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

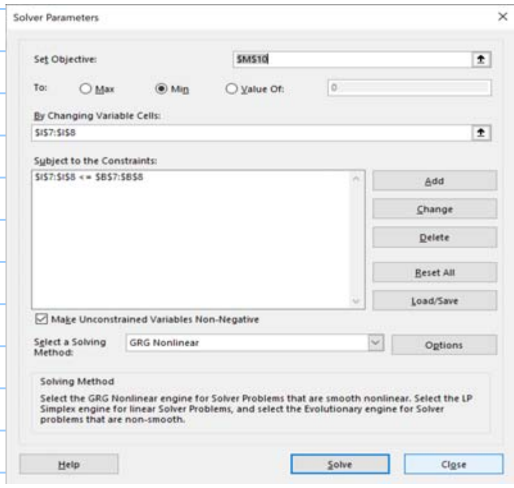
$$q = C_R \left(P_R^2 - P_{wf}^2\right)^n$$

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

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

↓

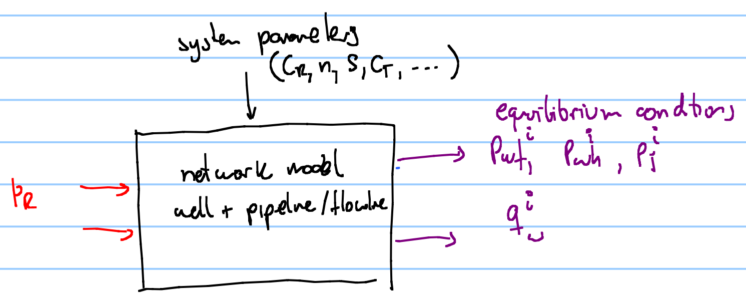
Add in

↓

"go"

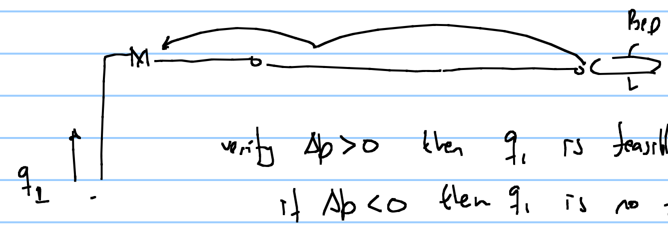
↓

tick on "solver" or "problem solver"



solving the network
with choke

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

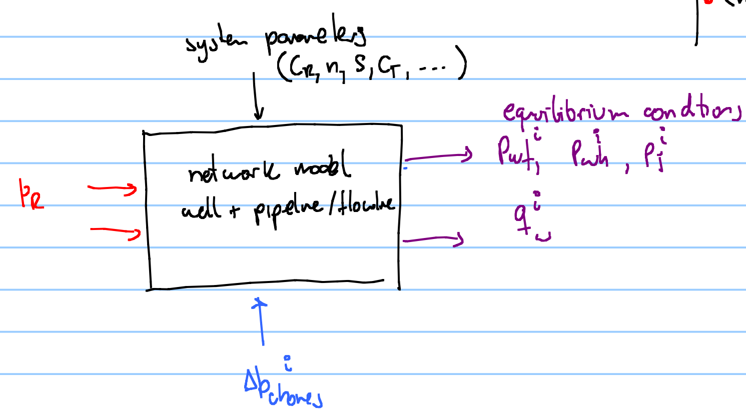


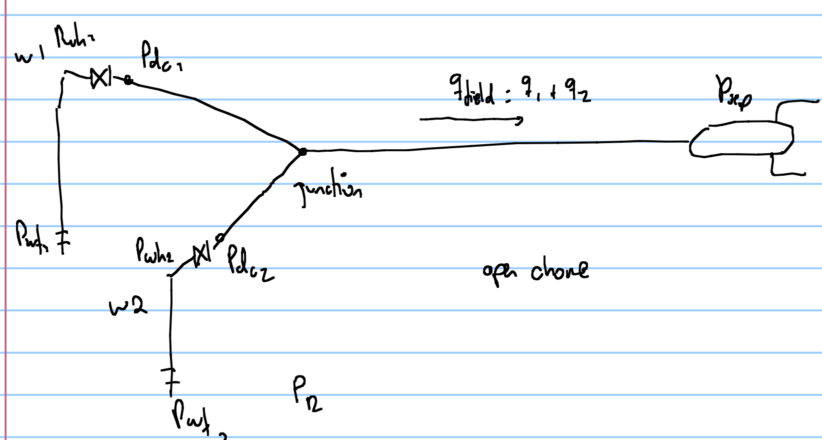
verify $\Delta p > 0$ then q_1 is feasible
if $\Delta p < 0$ then q_1 is no feasible

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

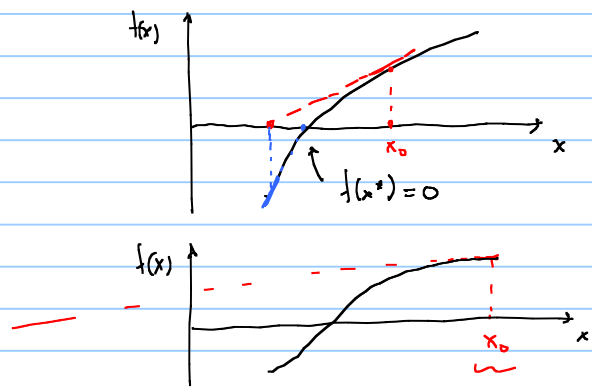
- option 2 : include the choke "model" → 2 options
  - Δp_{choke}. ← this option will be discussed next
  - choke opening $\Delta p_{choke} = f(q_g, \text{Opening}, P_1)$





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



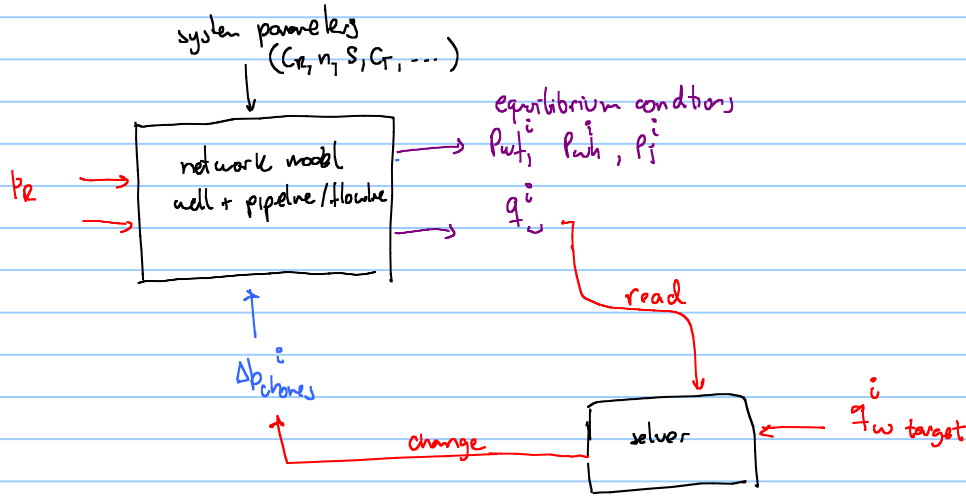
--- step 1

--- step 2

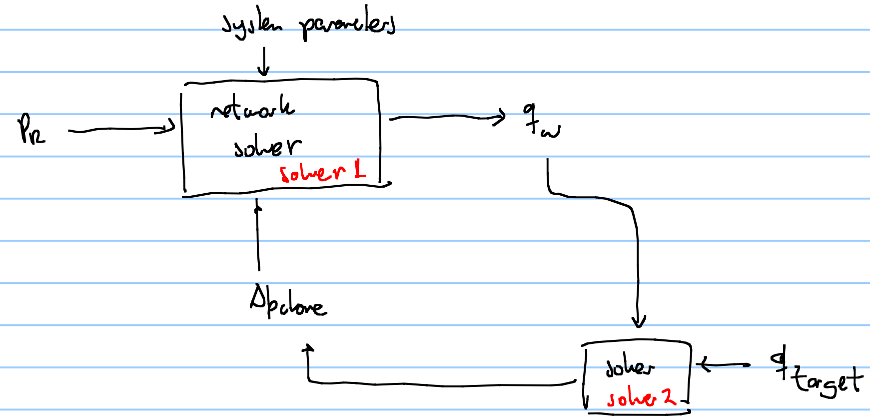
for derivative based solver it is necessary to give a good initial seed

	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

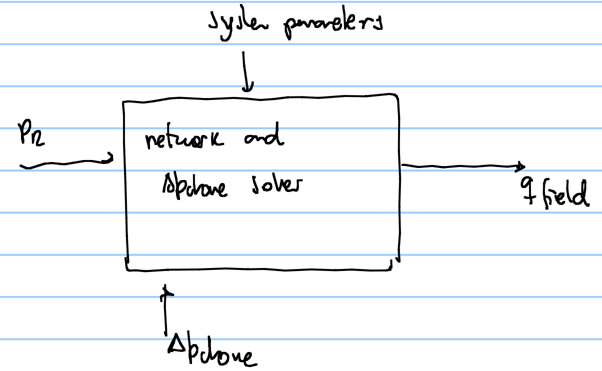
- How to use this model to find Δp_{chokes} such that $q_1 = 80000$ Sm³/d, $q_2 = 40000$ Sm³/d



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



"Merging the two solvers"



objective variable:

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

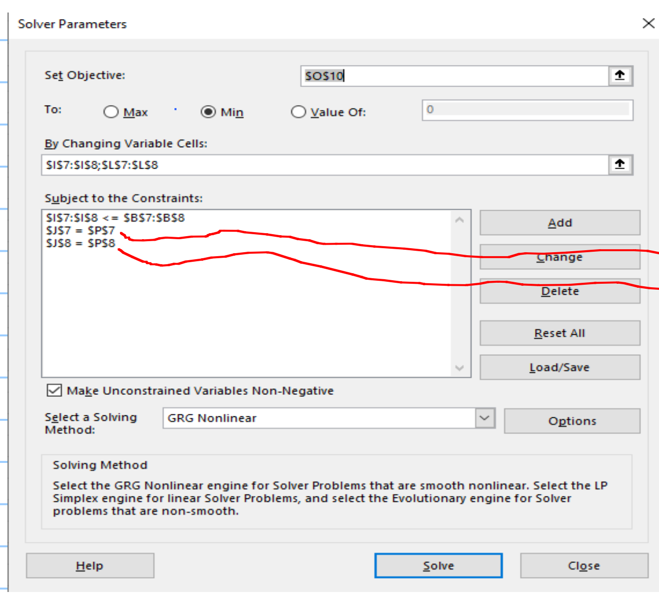
variables

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	

20240222

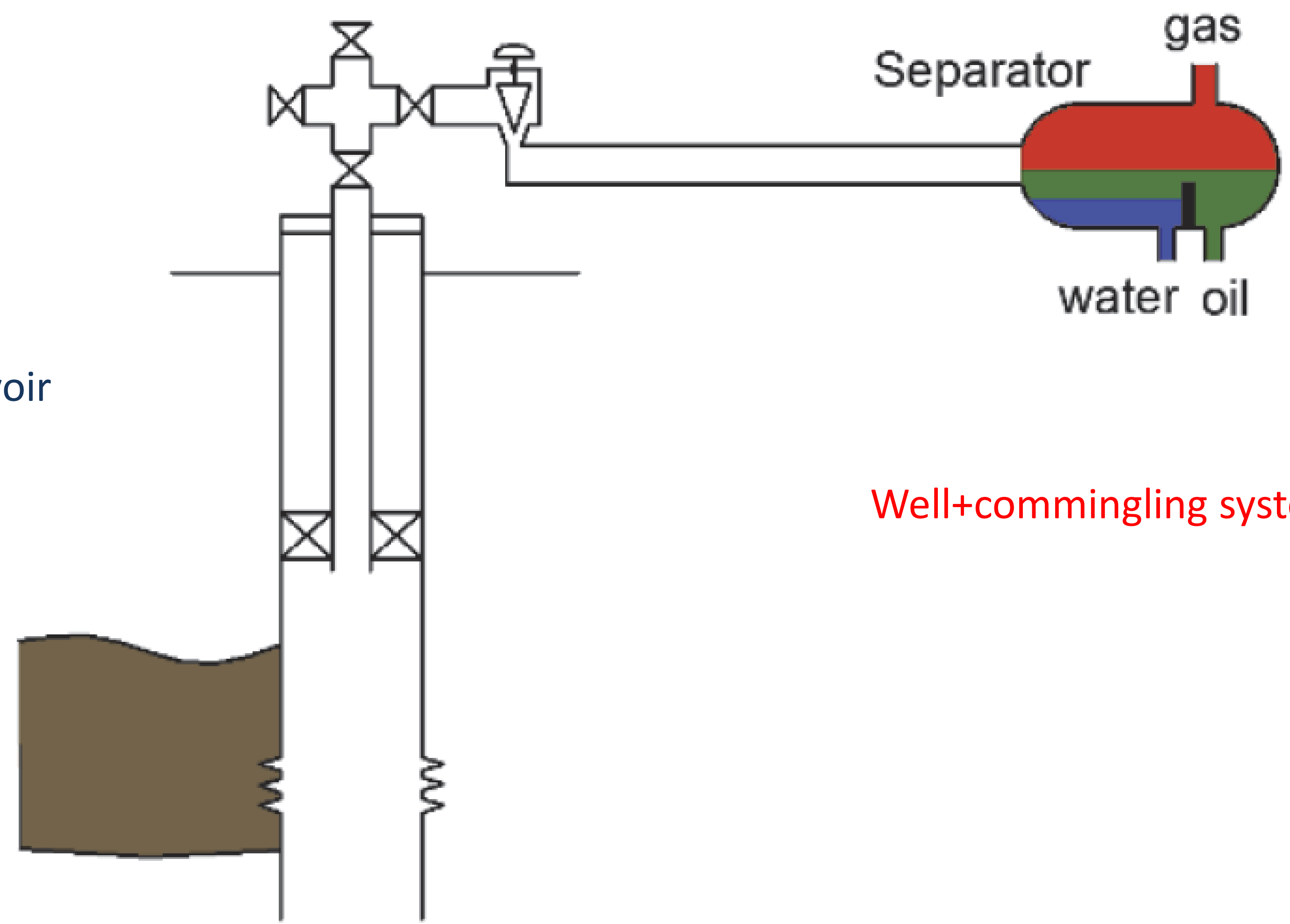
Outline:

-re-cap network solving
-approaches to generate production profiles

NTNU – Trondheim
Norwegian University of
Science and Technology

Approaches to generate production profiles

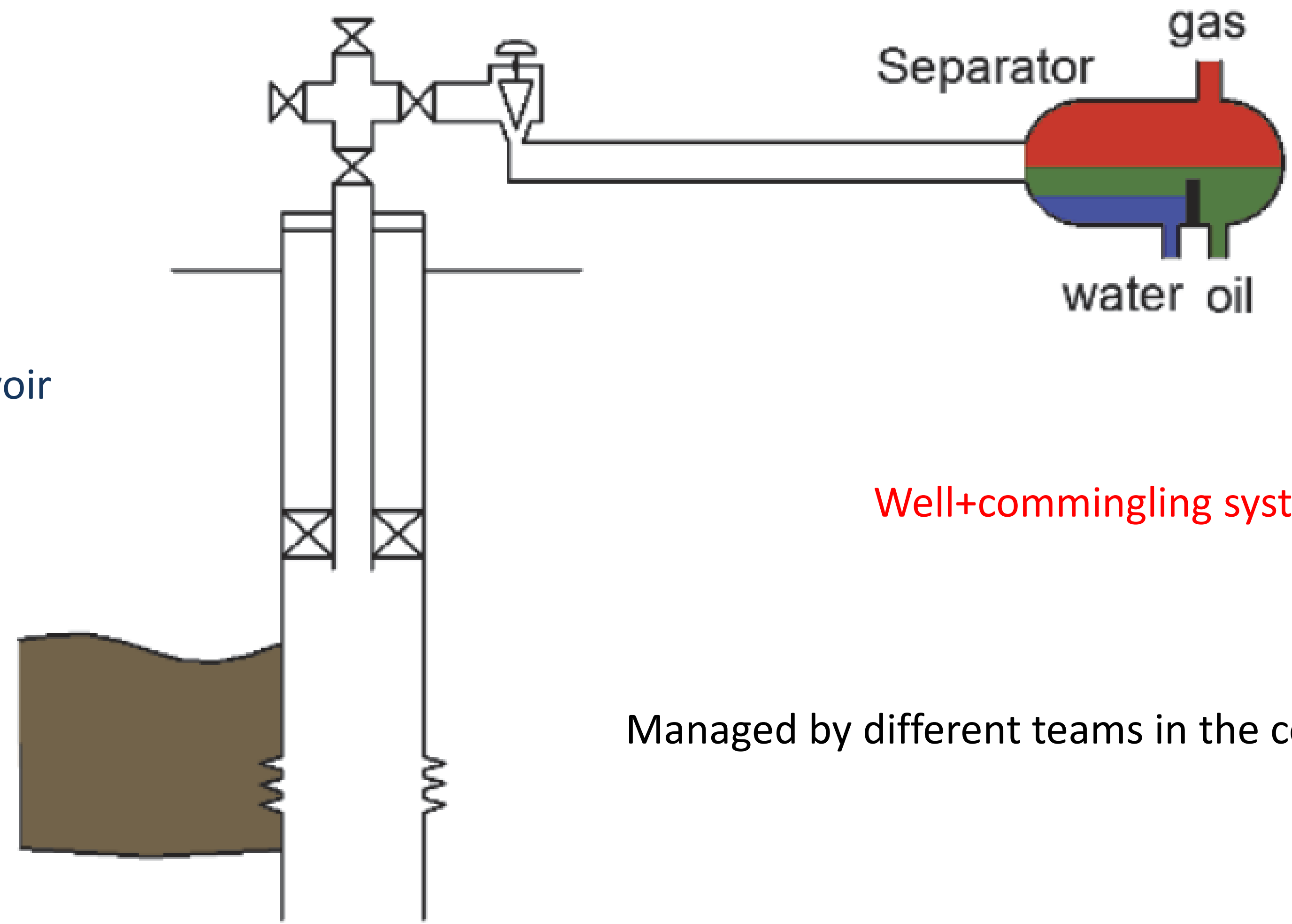
Virtual field



Reservoir

Well+commingling system

Virtual field

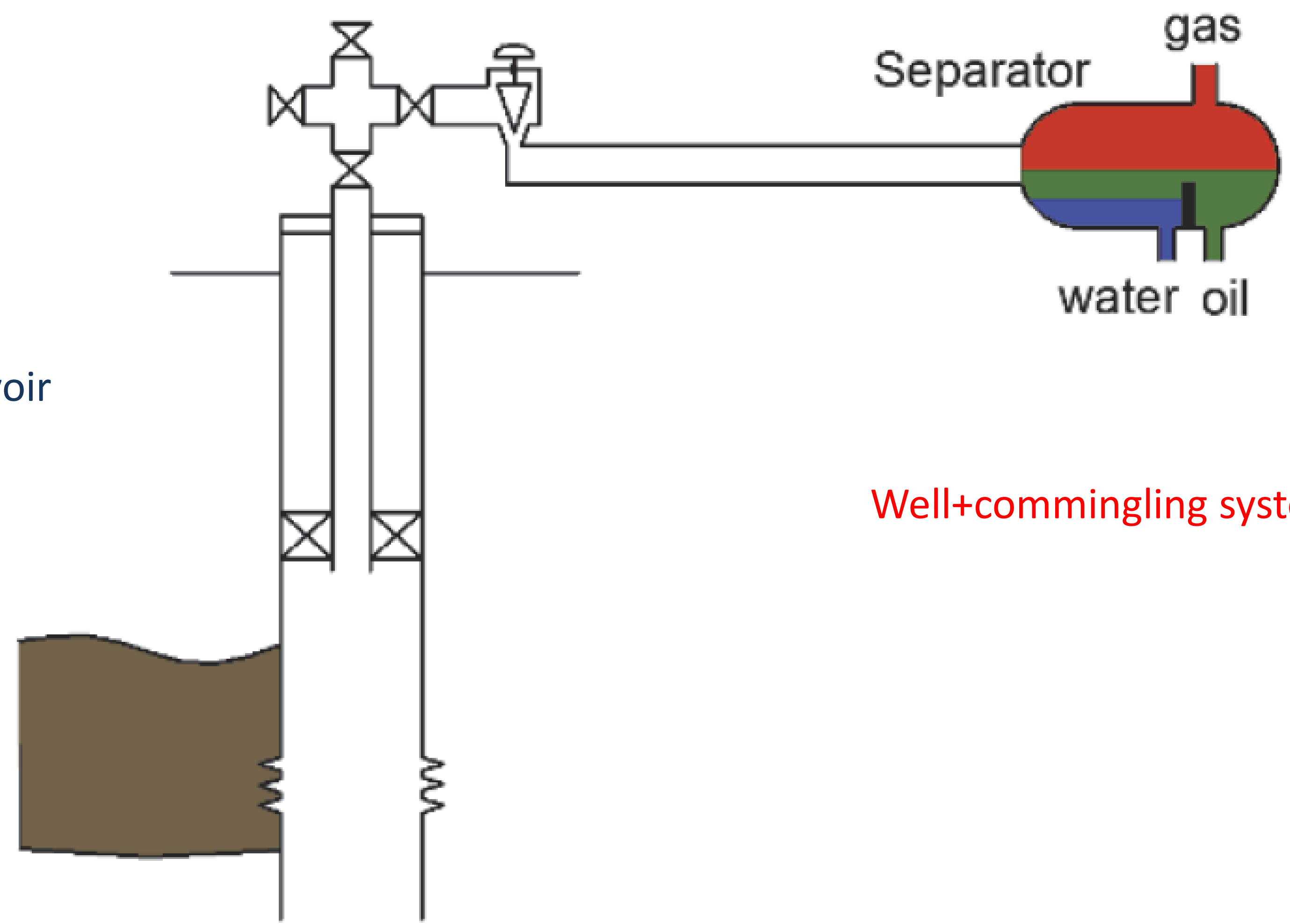


Reservoir

Well+commingling system

Managed by different teams in the company

Virtual field



Reservoir

Well+commingling system

Alternatives to generate production profiles

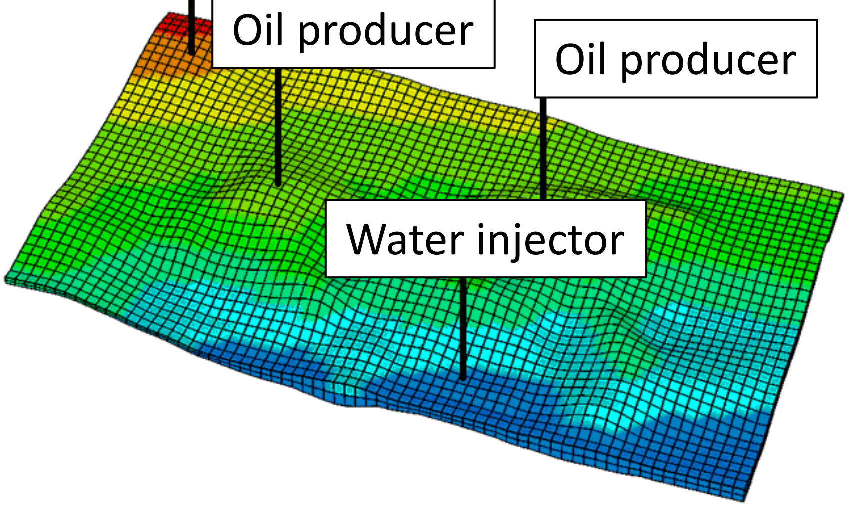
-Reservoir only
-Reservoir + network (coupled)

Reservoir model

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

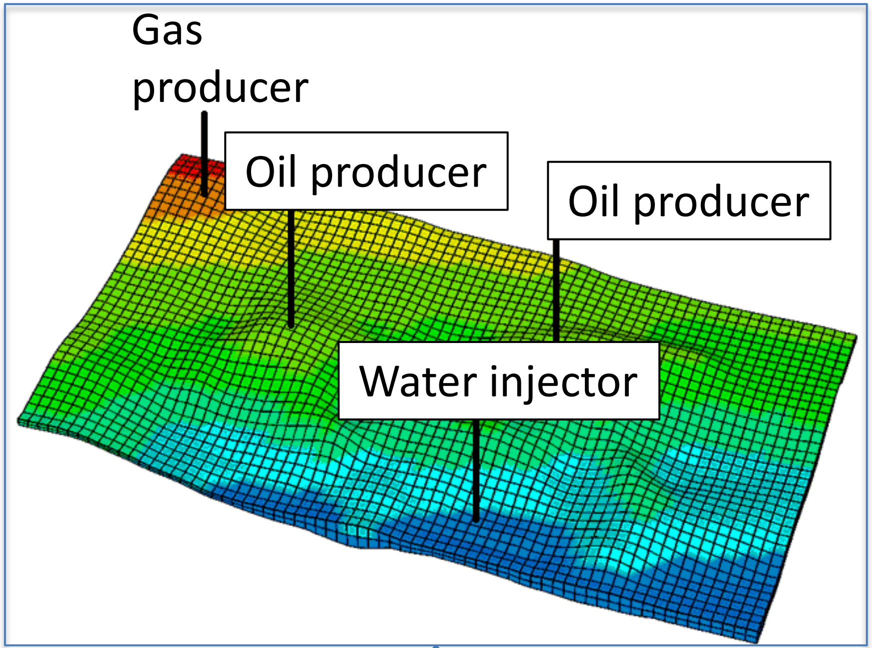


- 3D computer representation of a petroleum reservoir
- Computes the **variation** of the pressures, saturations and other properties **with time** when fluids are retrieved from or injected into the domain
- Captures the flow in porous media in the reservoir, thermal effects, thermodynamic flashing

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

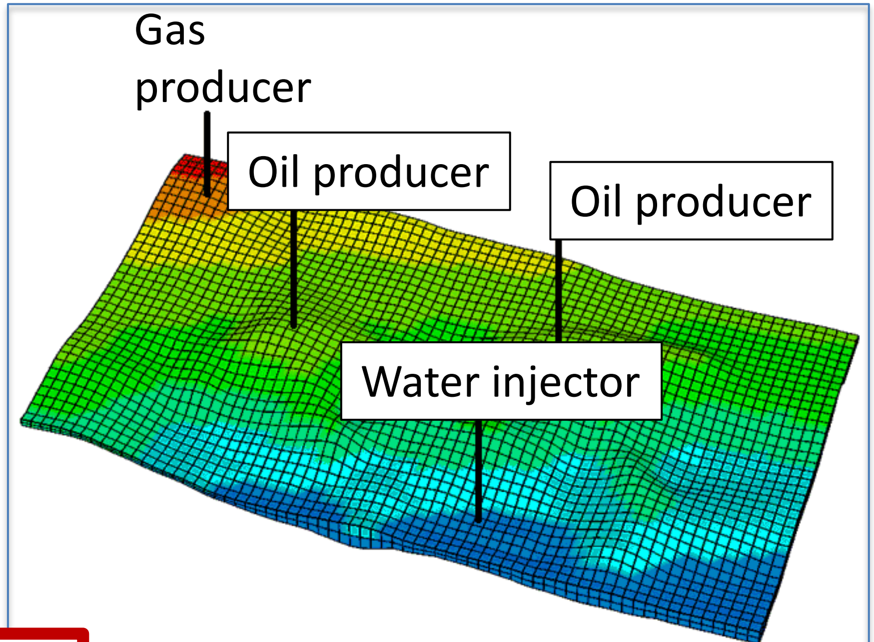
- Reservoir / system properties (Porosity, saturations, permeability, EOS, fluid composition, reservoir temperature, initial reservoir pressure)
- Well locations
- **Well status (t)**

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!!

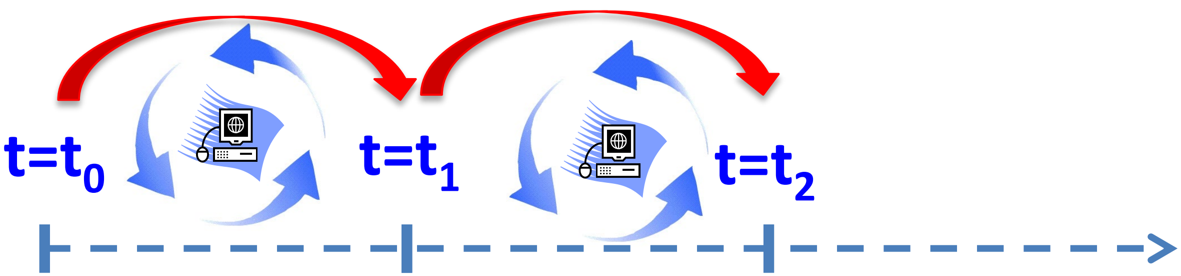
INPUT

- 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

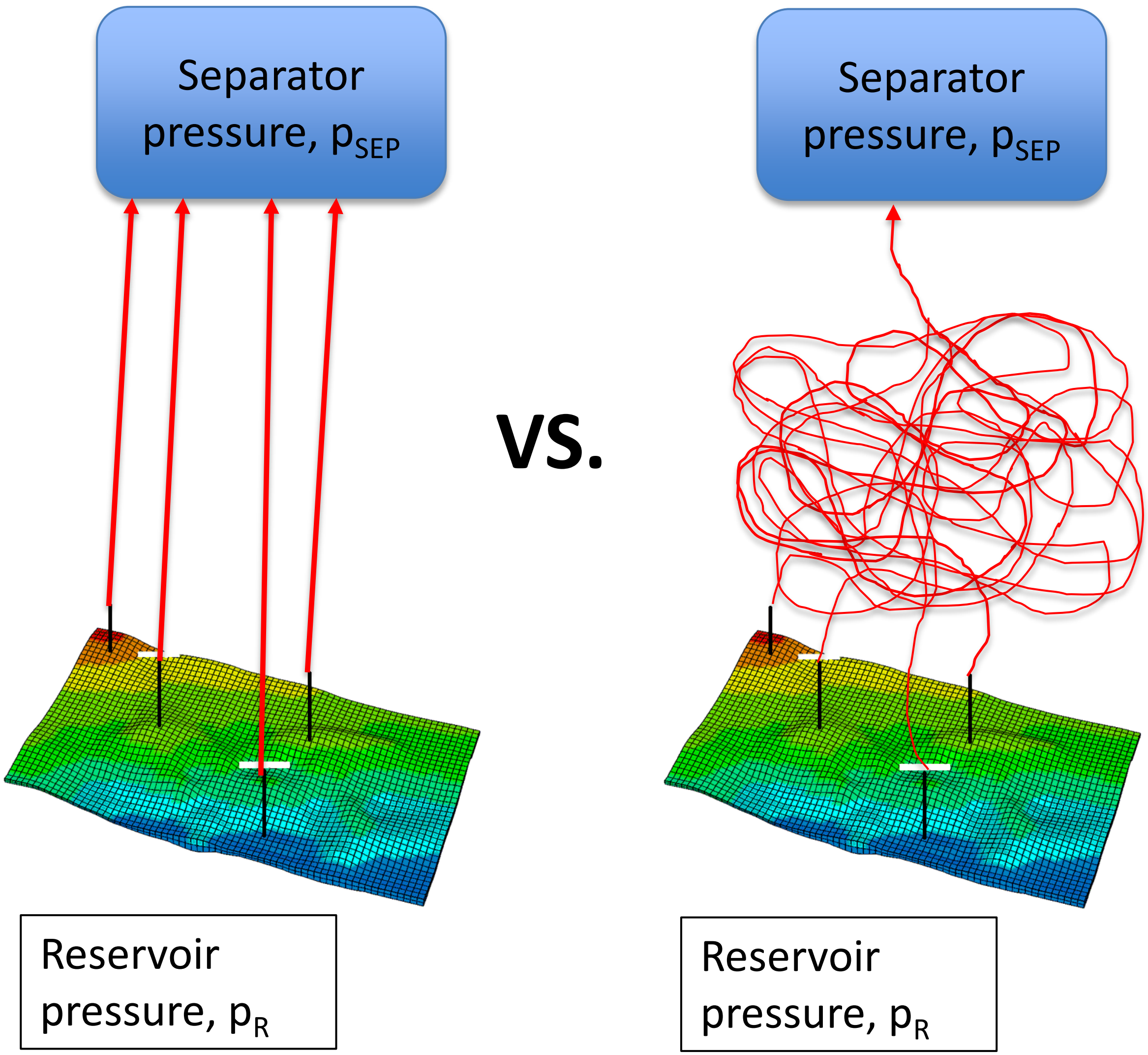


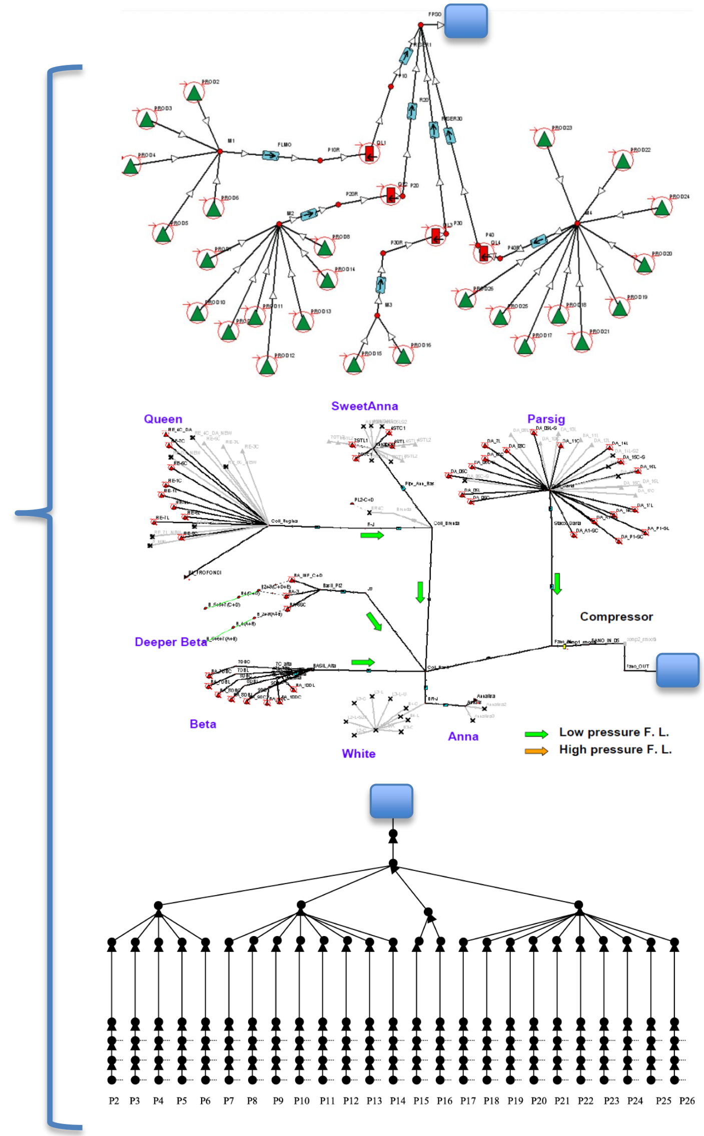
Progression in time

Input file - Example

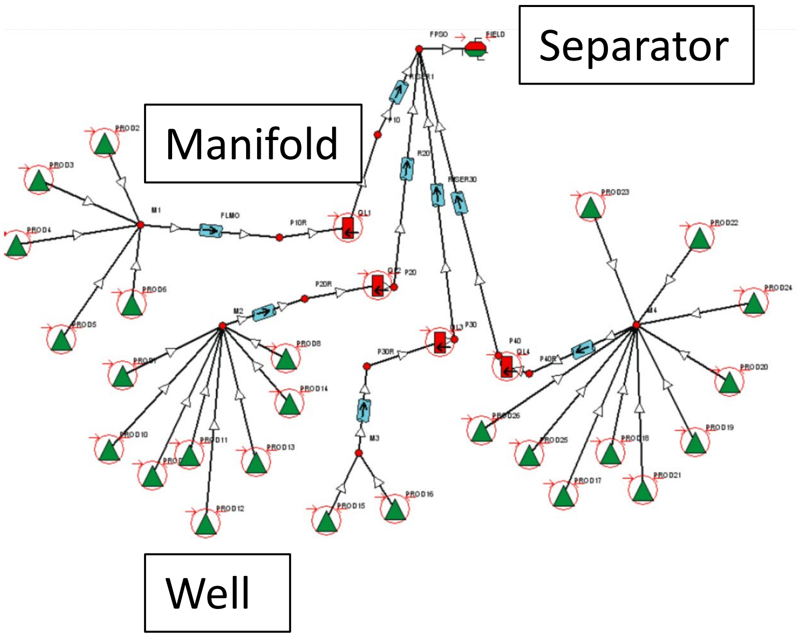
Network model

Network model characteristics





Network model

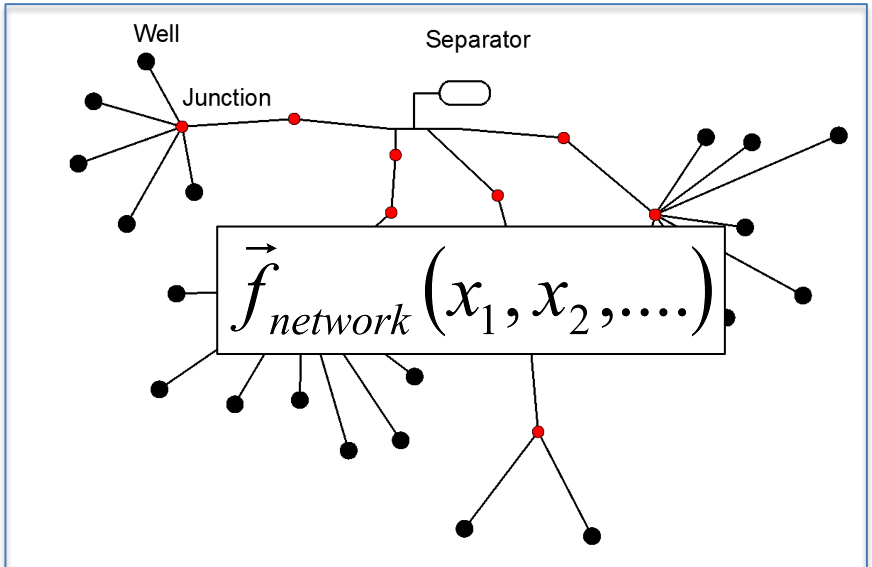


- Steady state (for a given condition in time), 1D Computer representation of a petroleum production network (wells, pipelines, equipment)
- Computes the pressure and temperature profiles in each flowline, the flow rate of each well, the conditions upstream and downstream of equipment
- Captures the 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

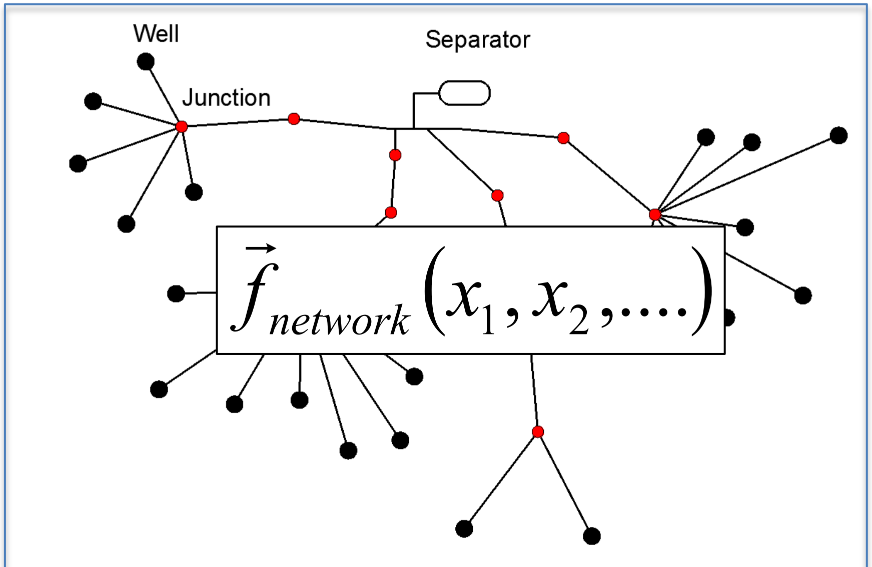
- System Properties (pipe dimensions, layout, fluid composition, EOS, separator pressure, ambient temperature)
- **Adjustable variables:** choke opening, well routing, Inflow control valves, gas lift injection rate, diluent injection rate, pump frequency, compressor.

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

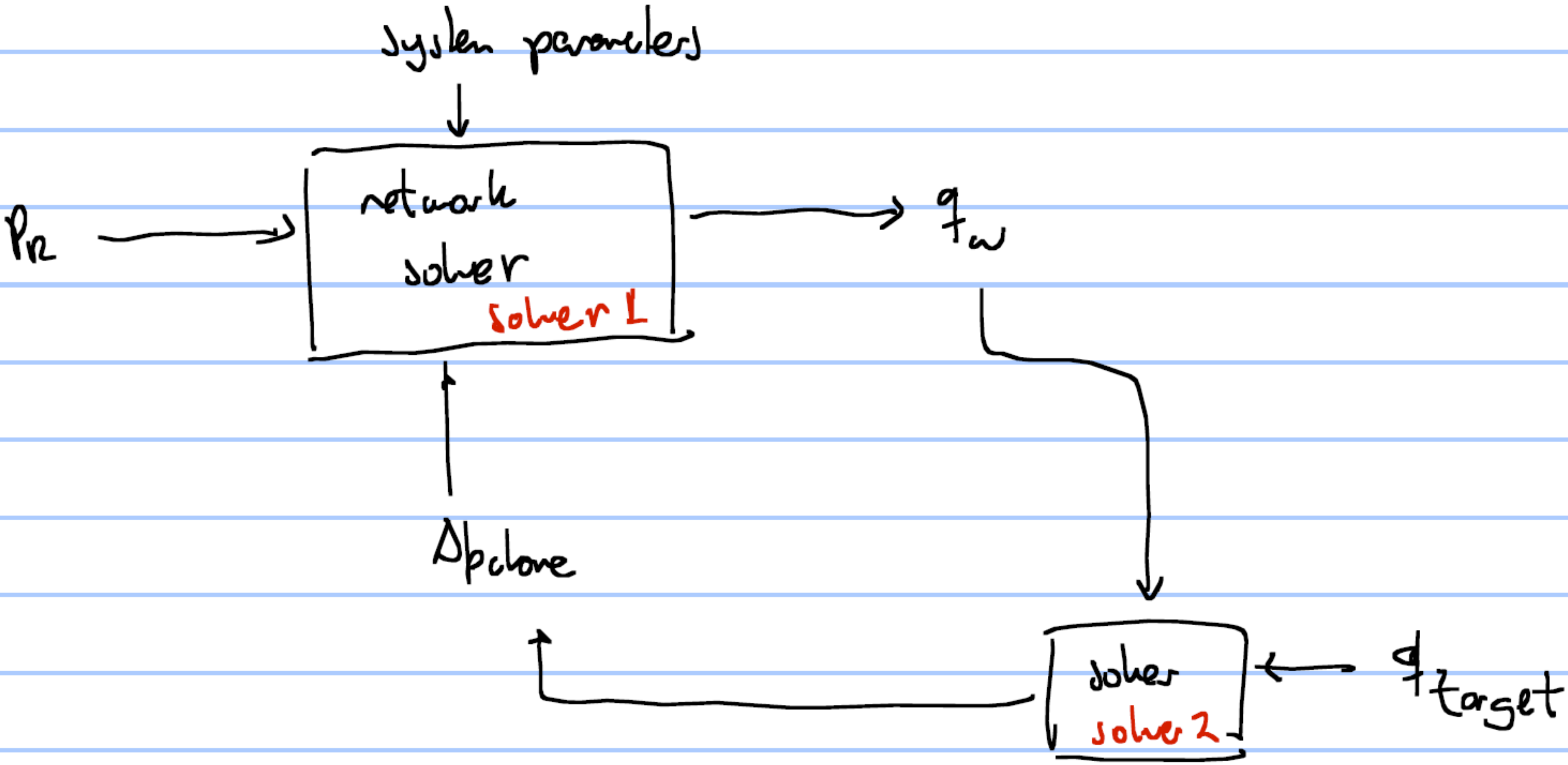
- **Well flow rates**
- Pressure and temperature along the system

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.

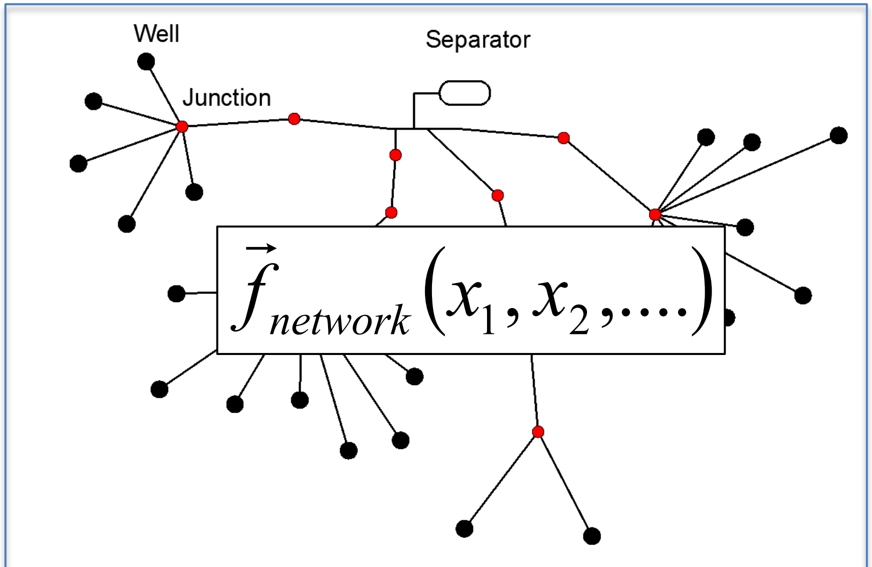
Network model – v1 variation (requires an "optimizer")



Network model – v2

Boundary conditions for injectors or producers:
Desired well rates

INPUT



OUTPUT

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

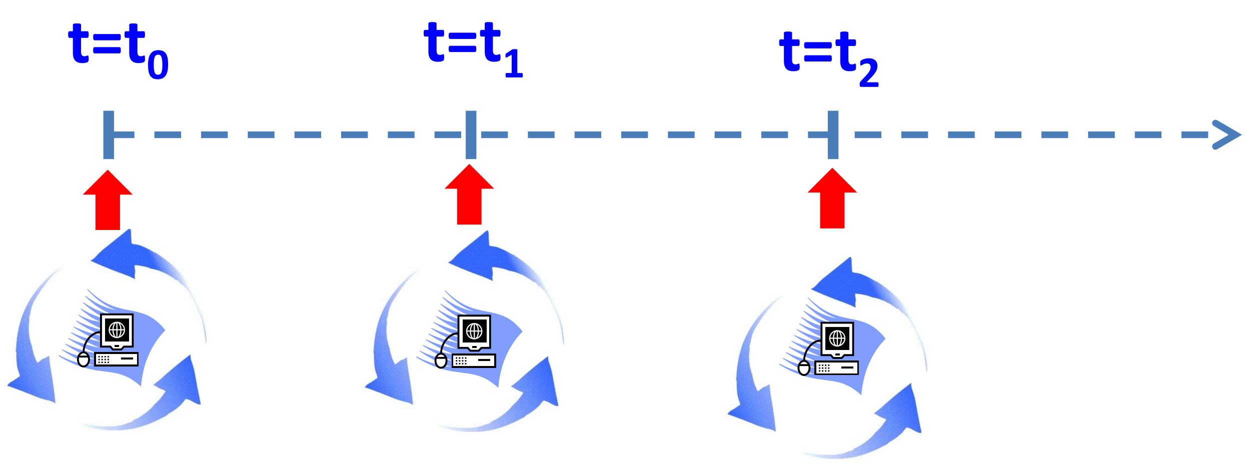
INPUT

- 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

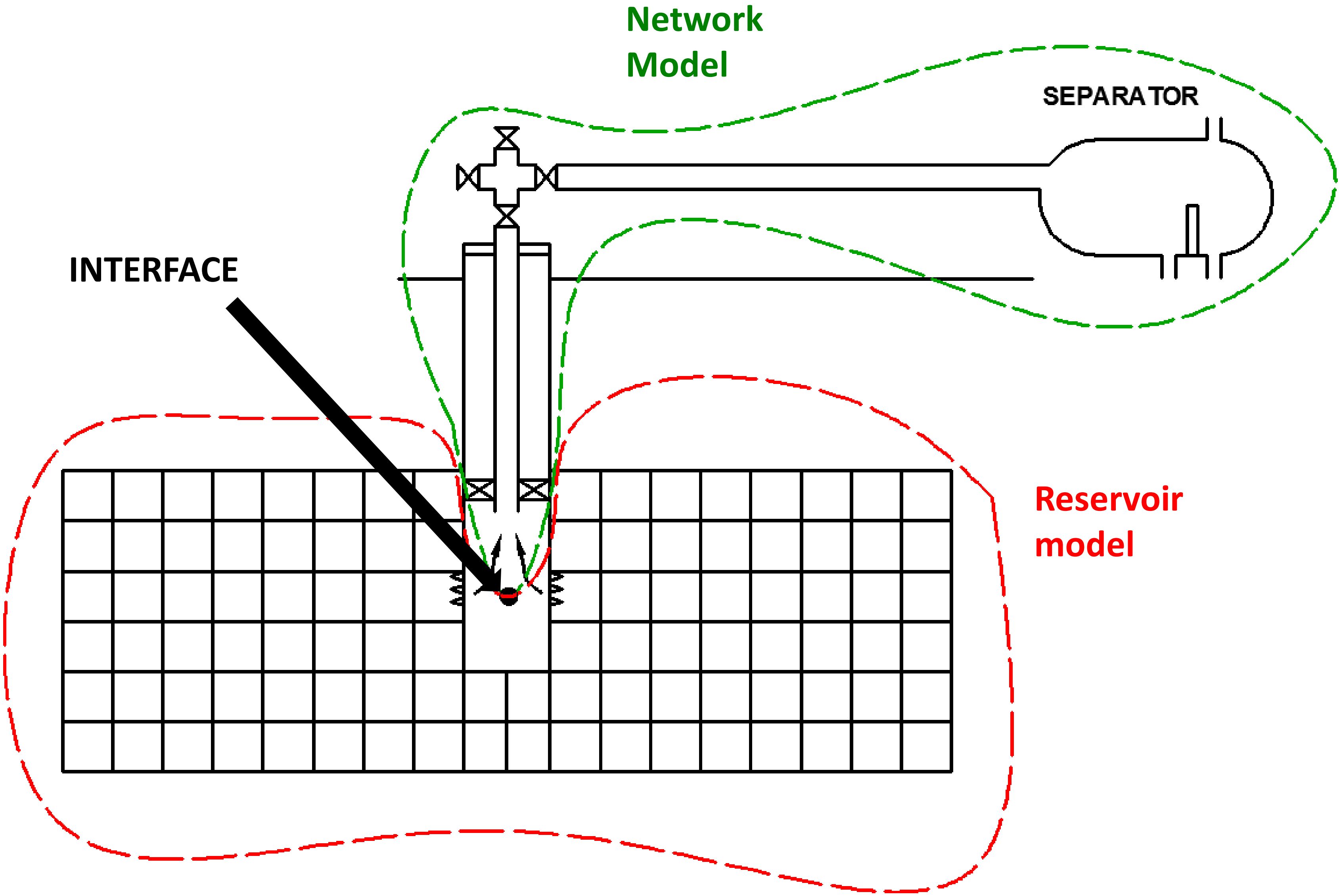
Coupling:

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

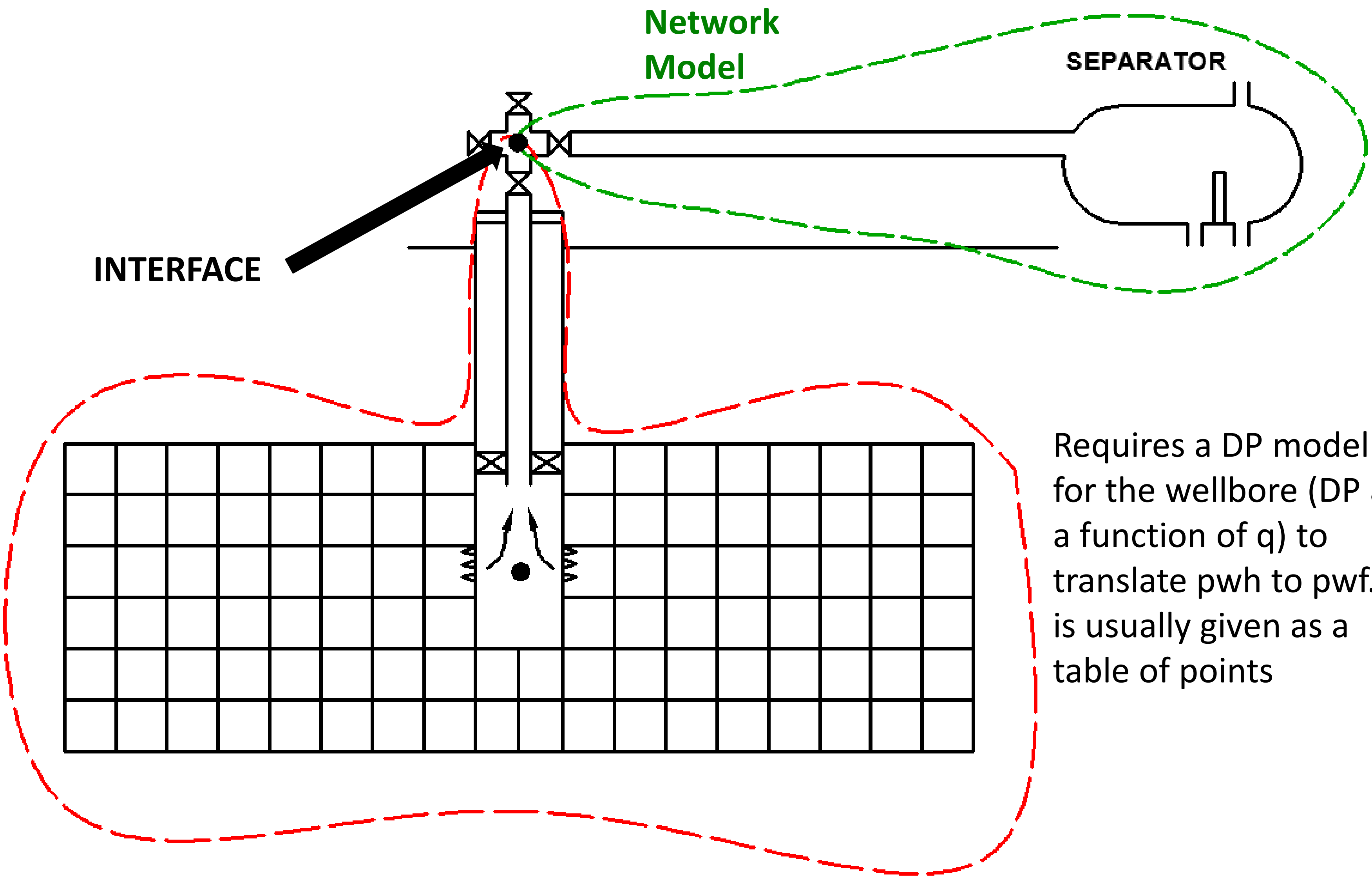
Or, equivalently:

- 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



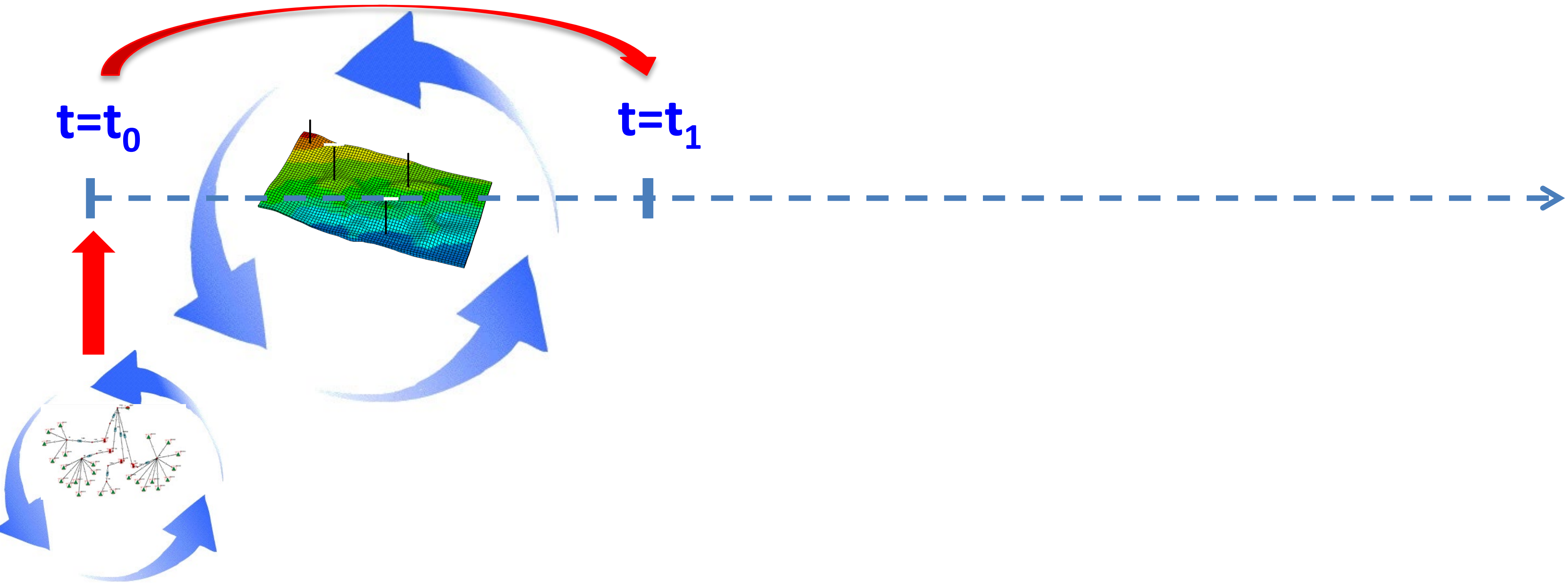
Requires a DP model for the wellbore (DP as a function of q) to translate pwh to pwf. It is usually given as a table of points

Integration strategies

- **Explicit**

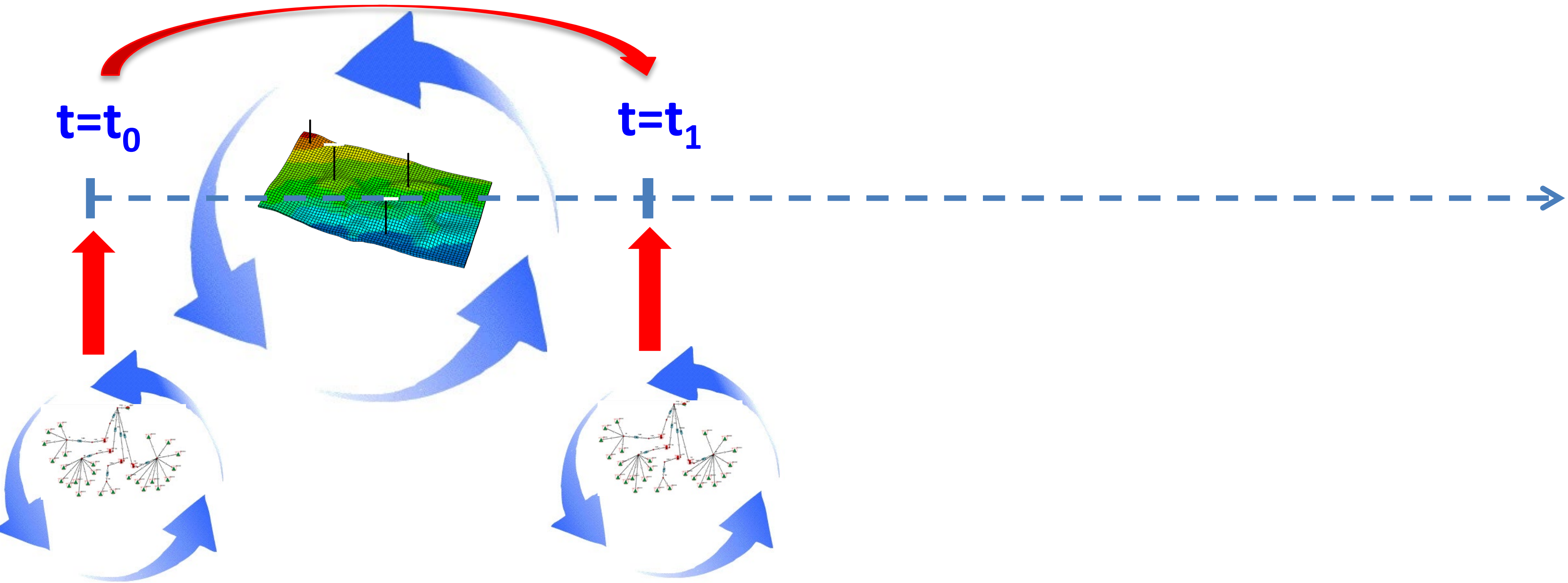
Integration strategies

- **Explicit**



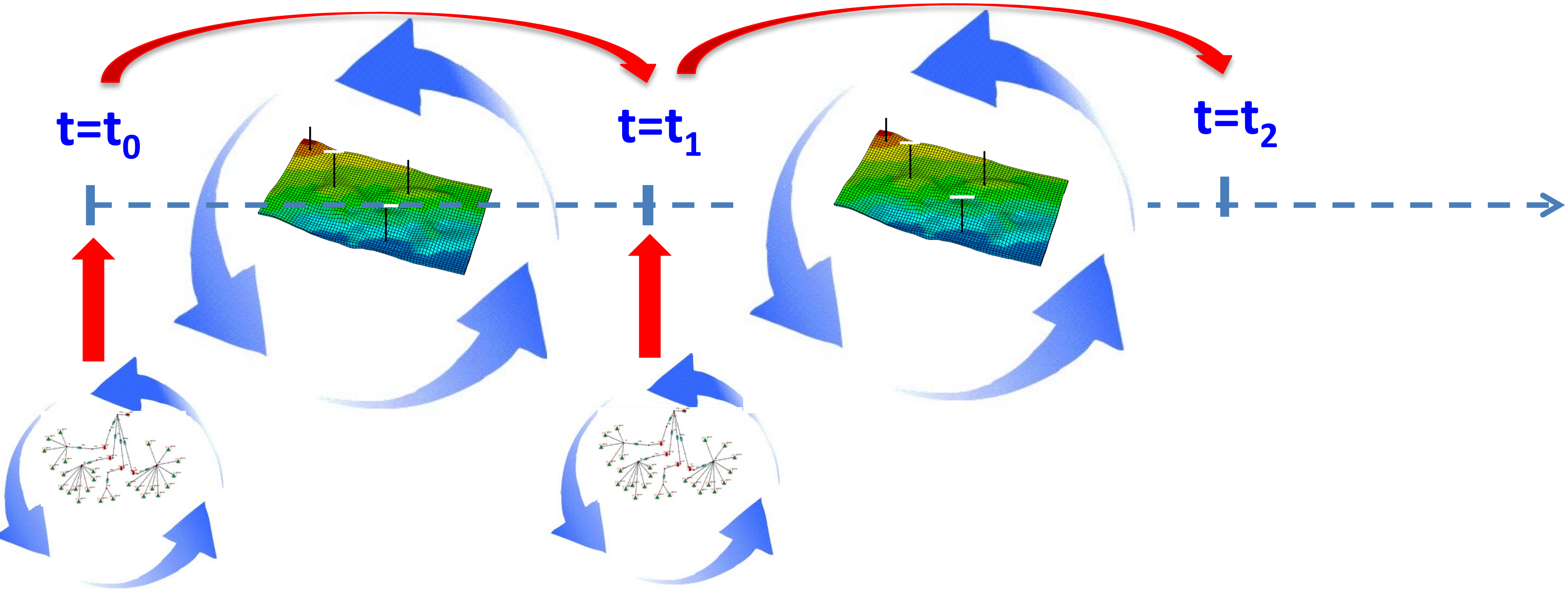
Integration strategies

- **Explicit**



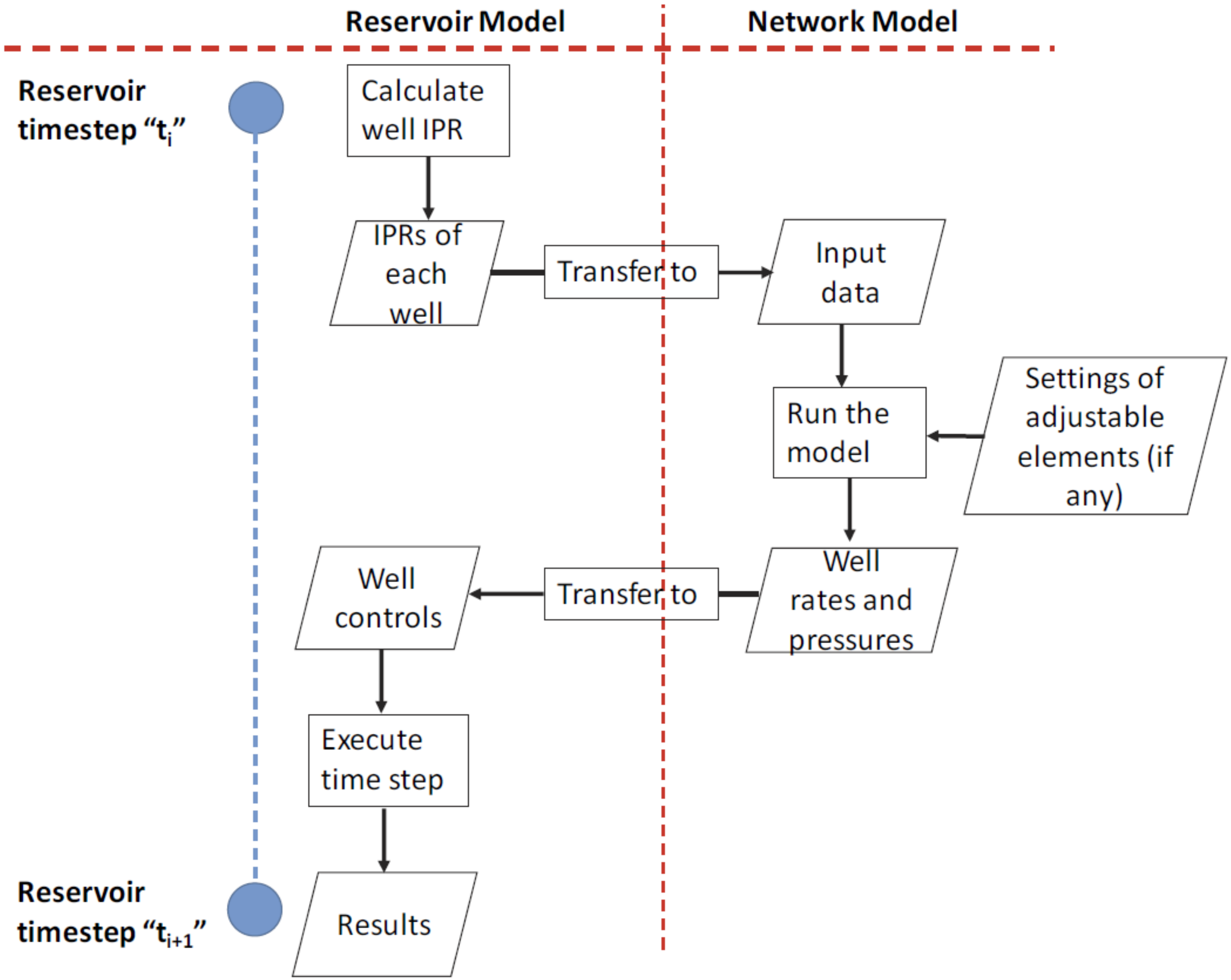
Integration strategies

- **Explicit**

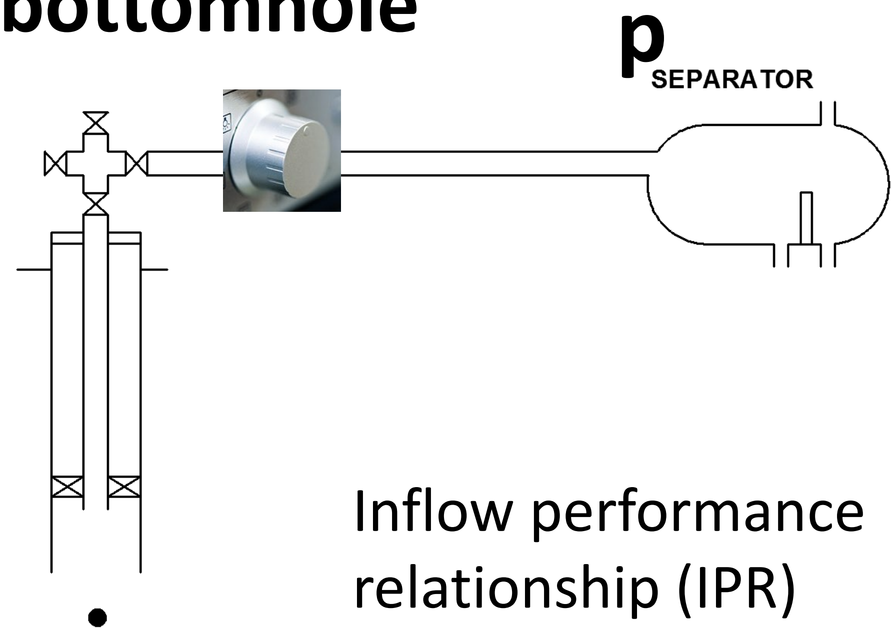


Integration strategies

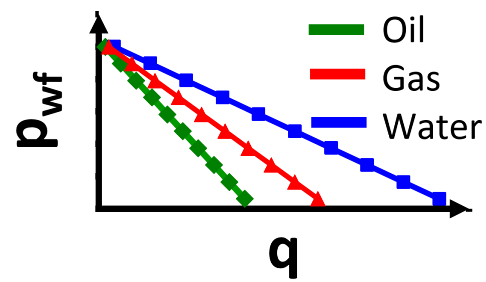
- **Explicit**

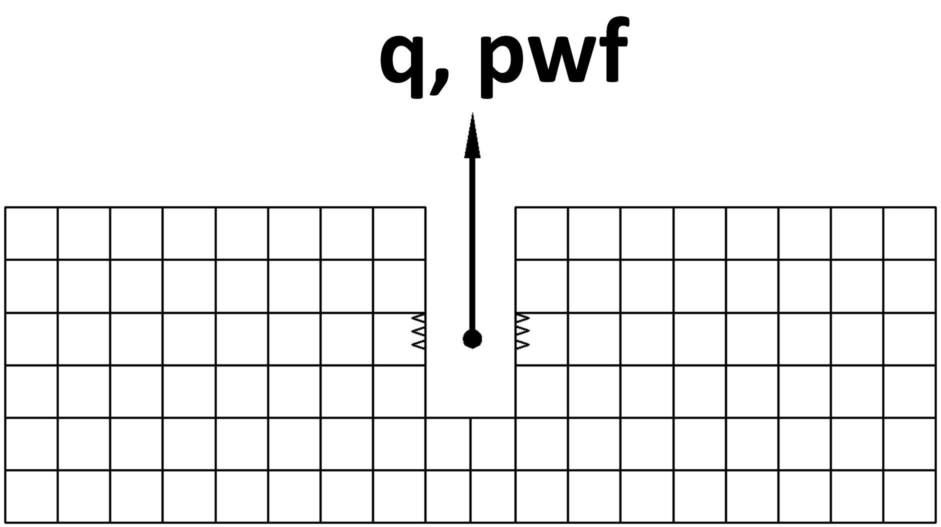


Model's Interface: well's bottomhole



Inflow performance relationship (IPR)



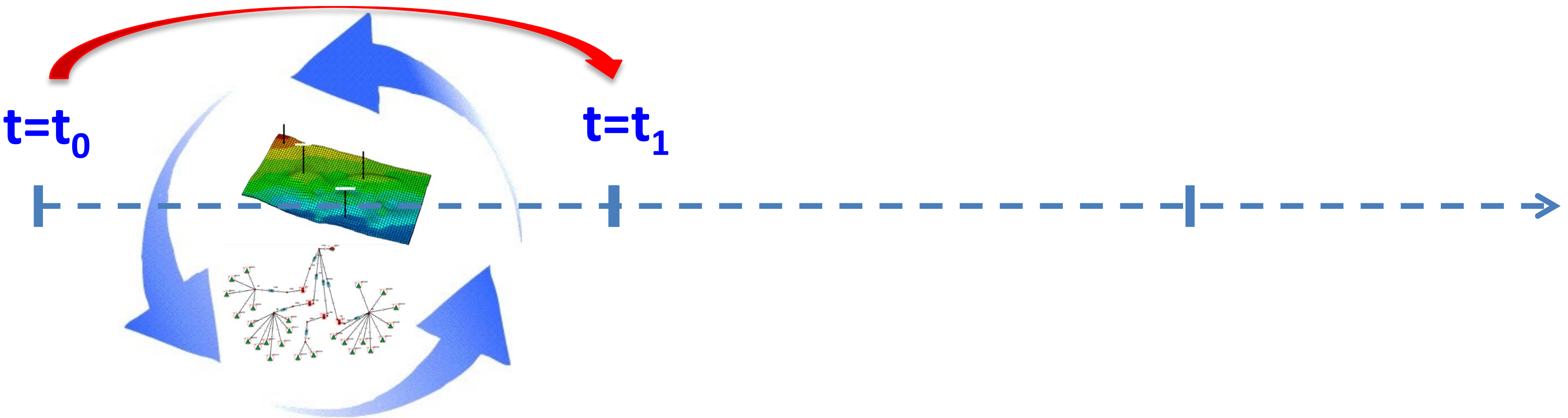


Explicit integration strategy

- 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

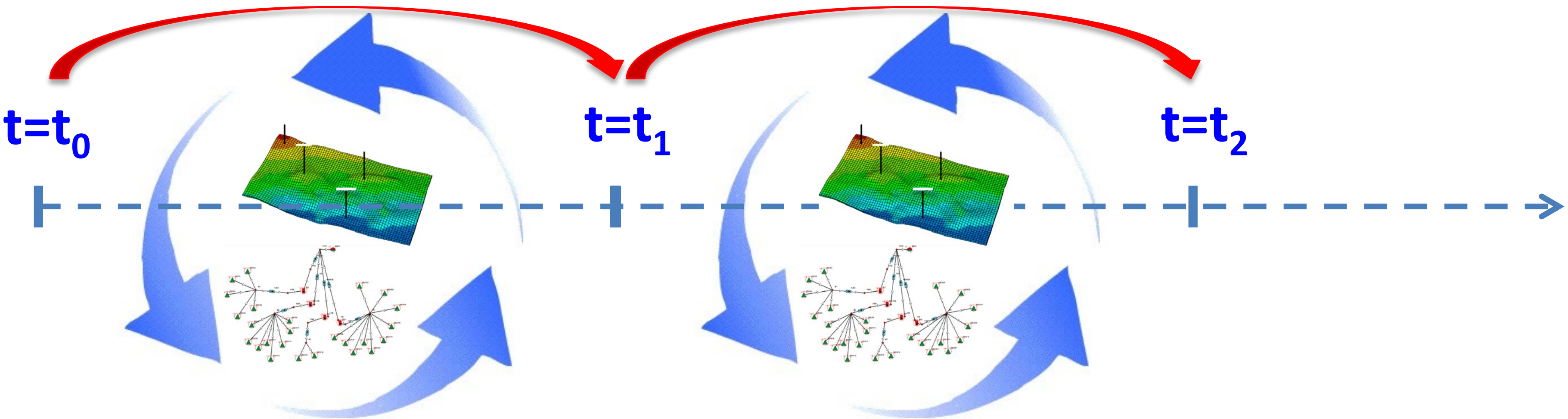
Integration strategies

- **Implicit**



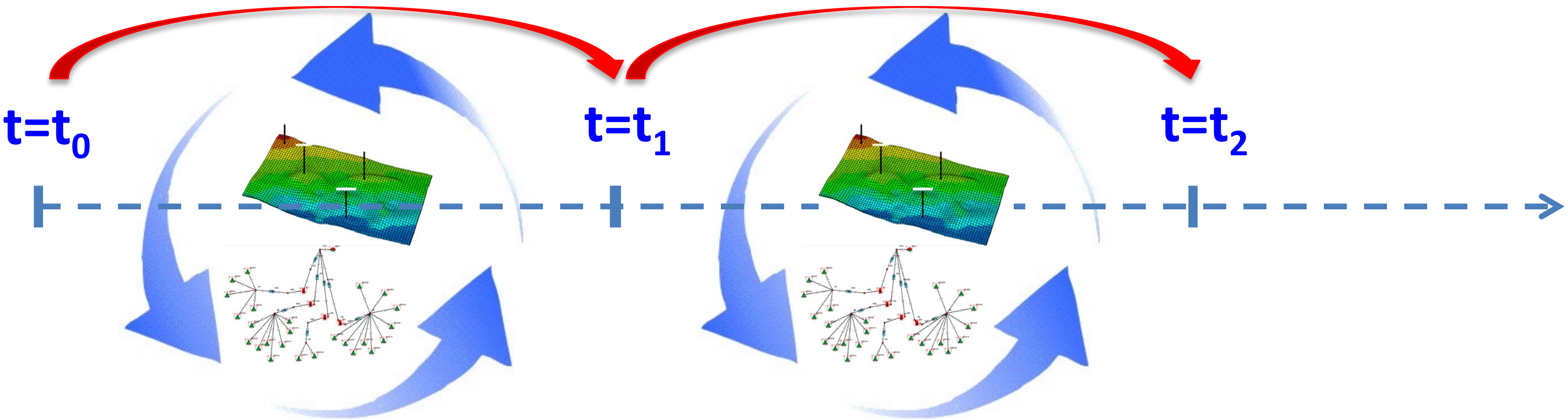
Integration strategies

- **Implicit**



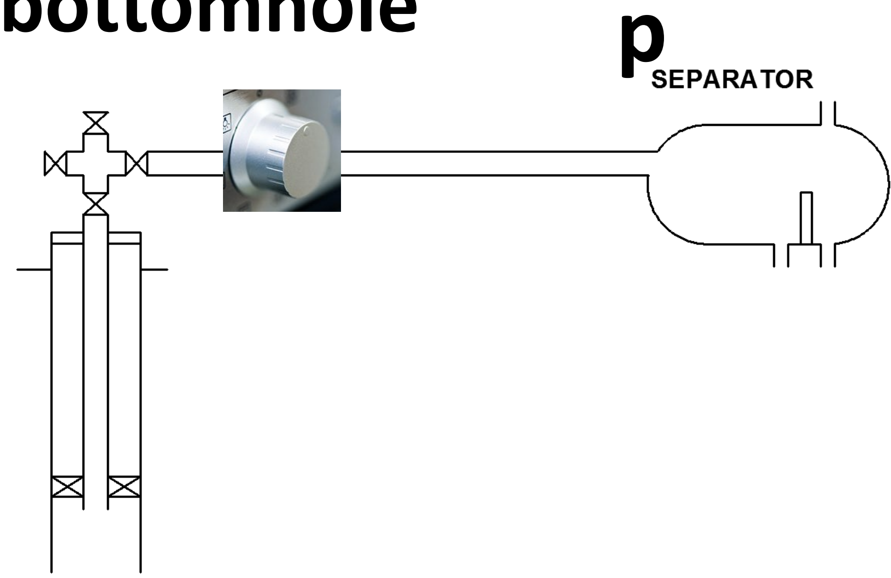
Integration strategies

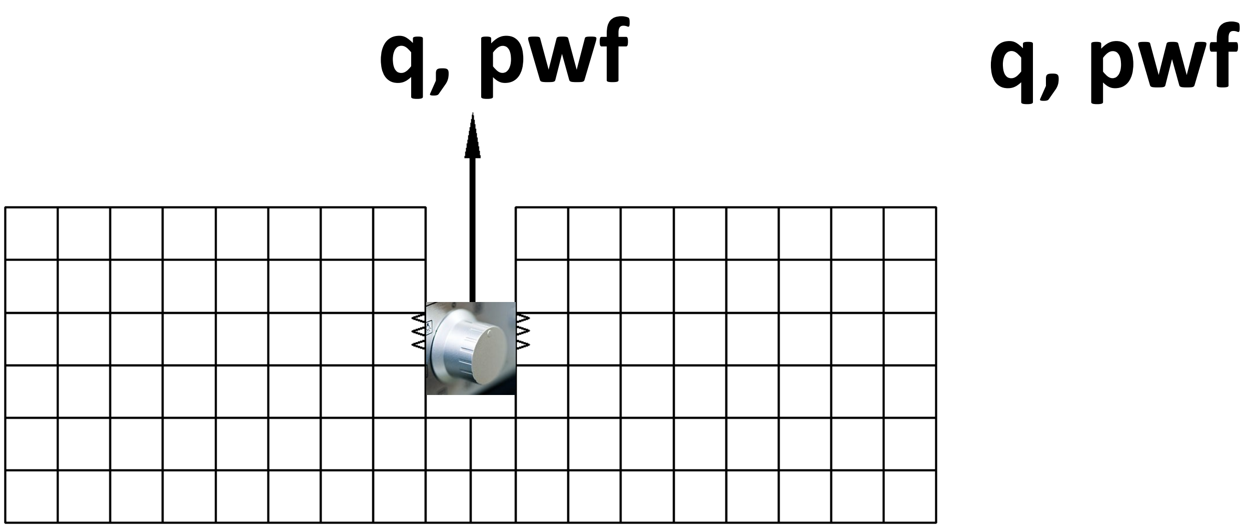
- **Implicit**



Here an IPR might not be needed

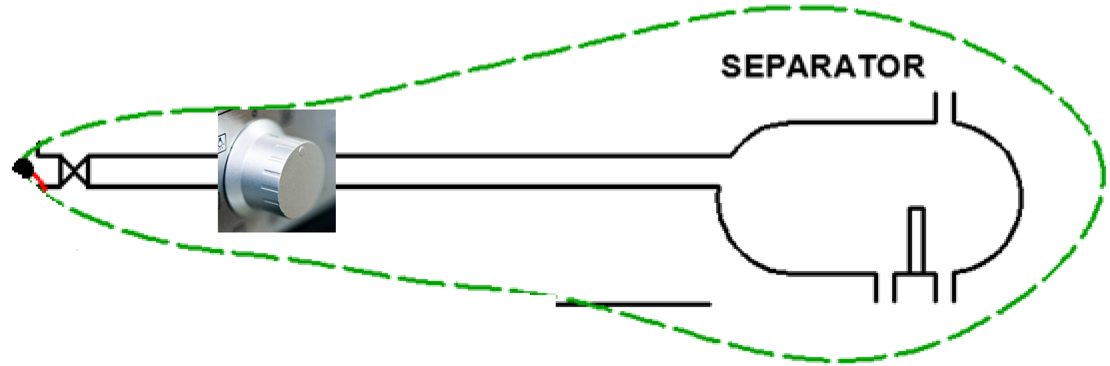
Model's Interface: well's bottomhole



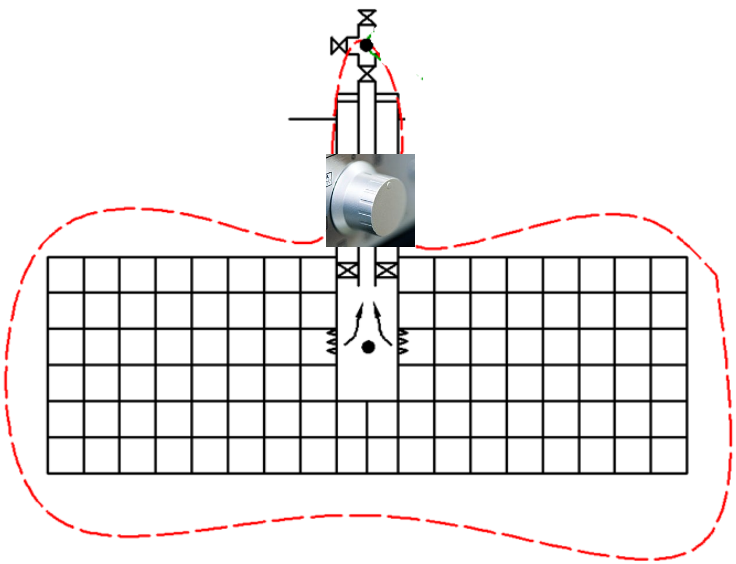


Model’s Interface: wellhead

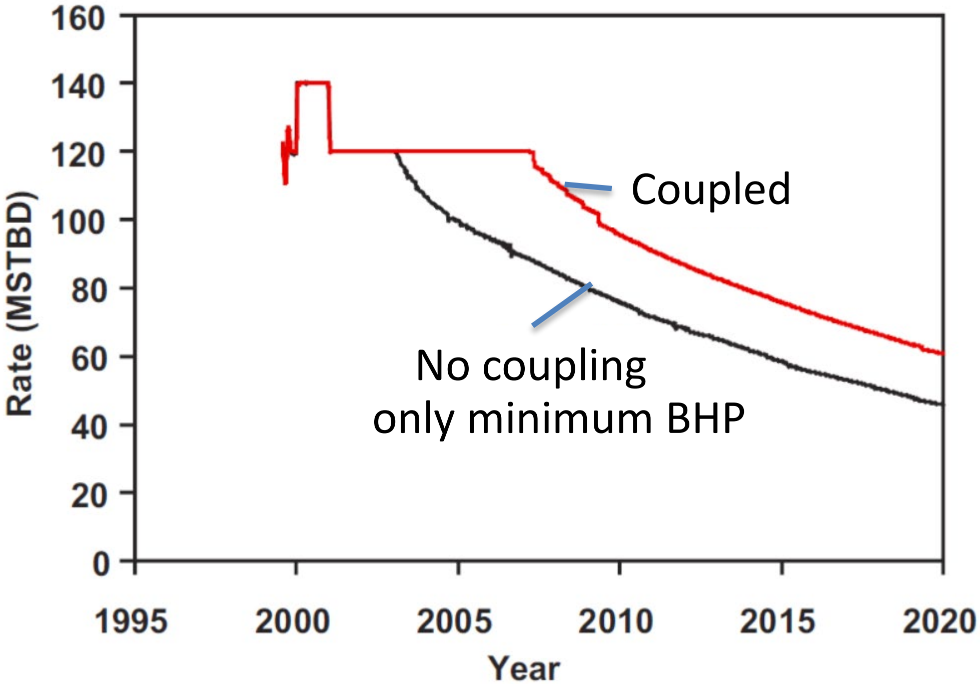
q



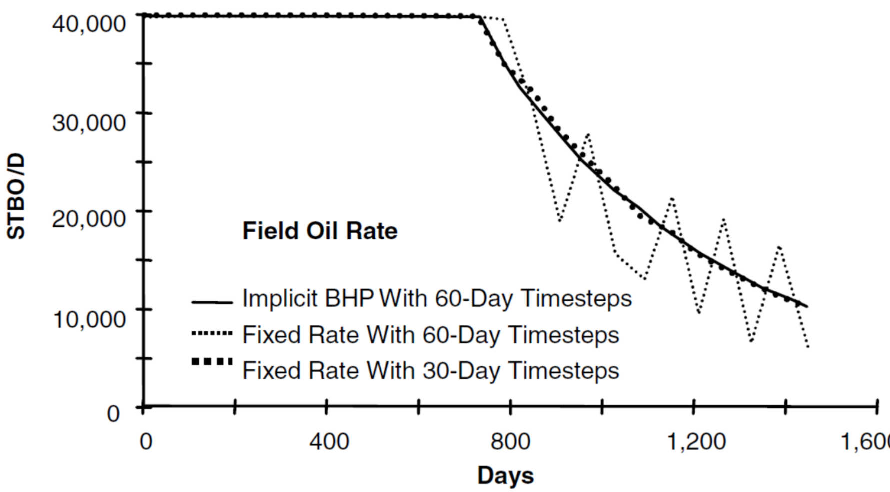
q, pwh



Examples from the literature



From Al-Shaalan, 2002



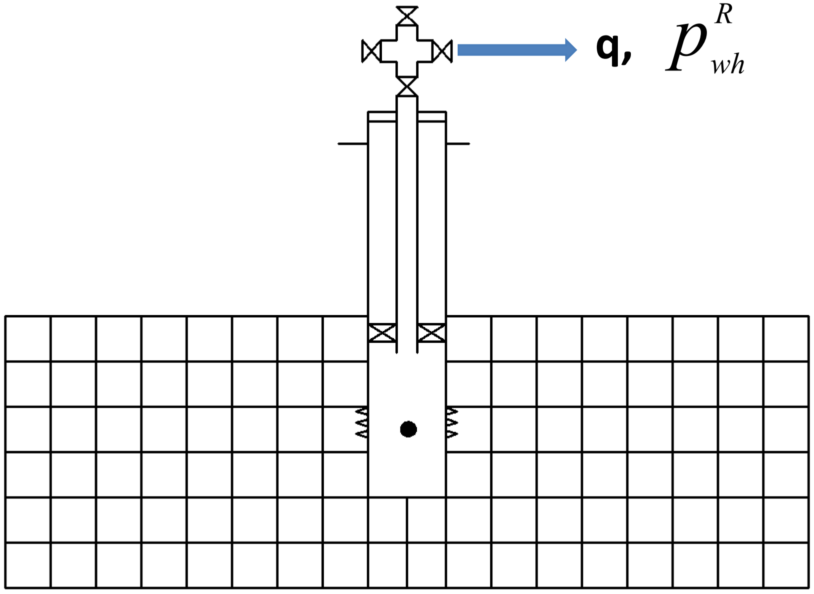
Solution instability from SPE 71120

Implicit integration strategy

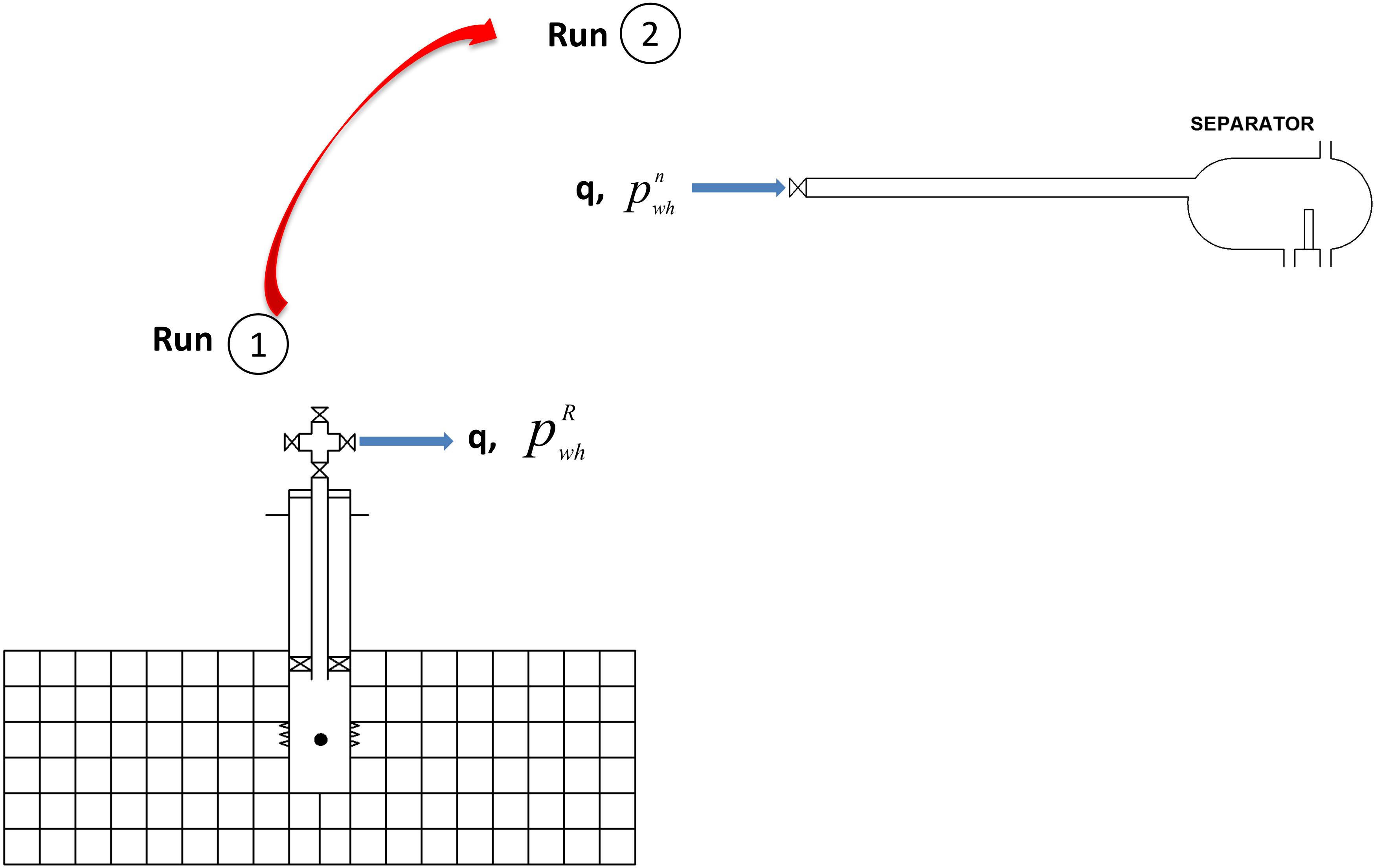
- Difficult to integrate software from different providers (for efficient solving, the source code should be integrated)
- IPR generation is not required
- More numerically stable, bigger time-steps can be used

Coupling strategy for choked wells

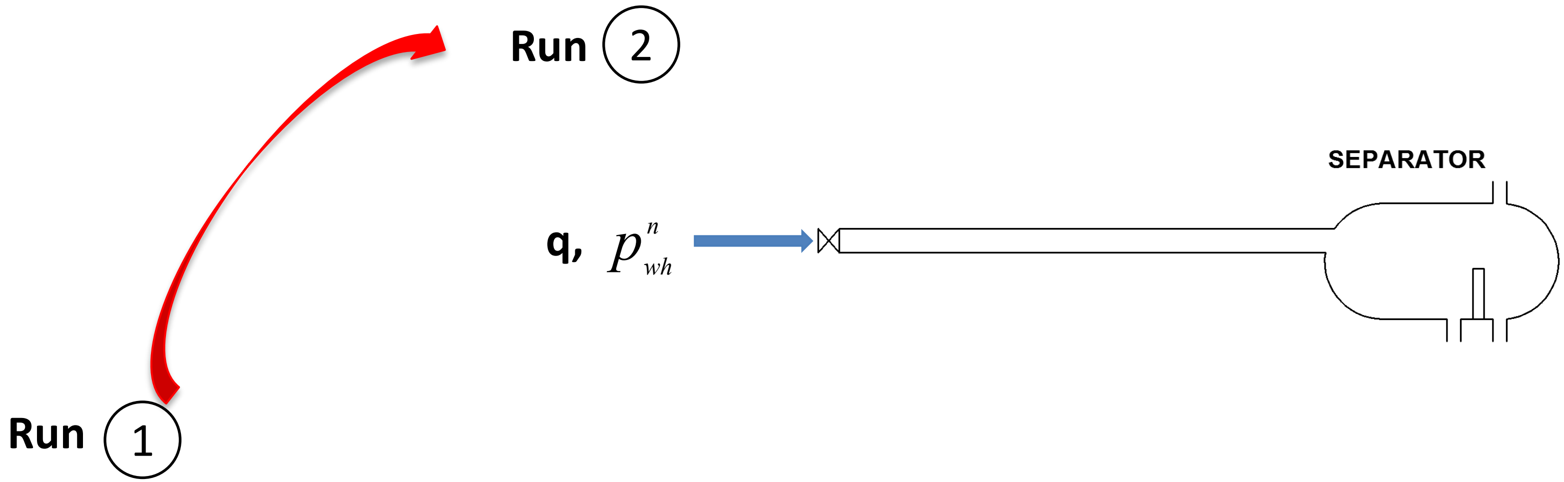
Run 1

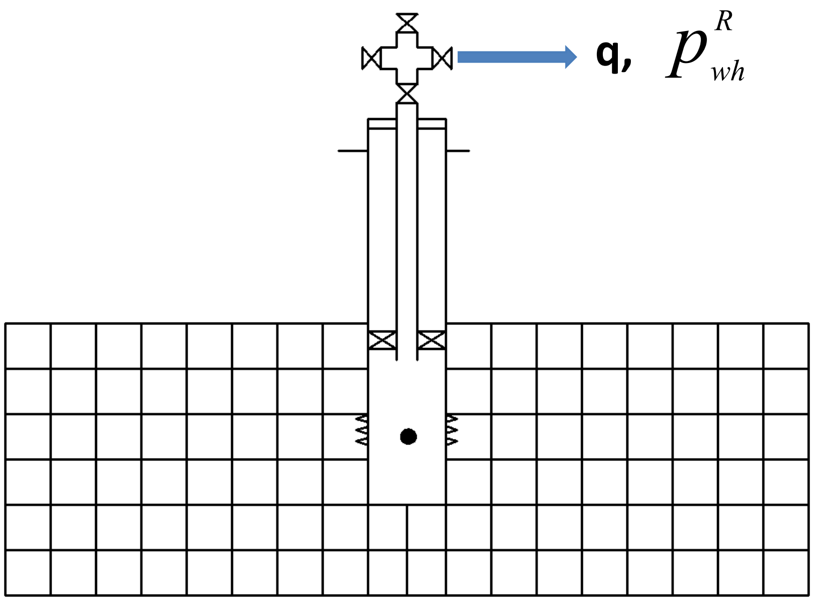


Coupling strategy for choked wells



Coupling strategy for choked wells





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

- Well is choked, proceed to next reservoir time step

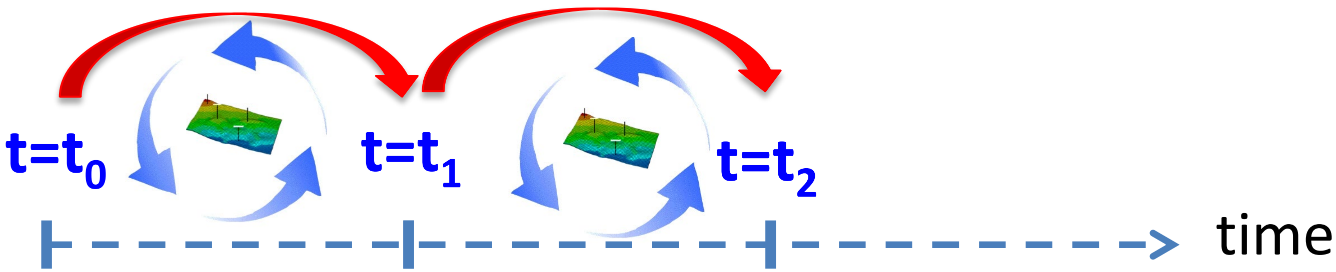
Integration strategies

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

Integration strategies

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

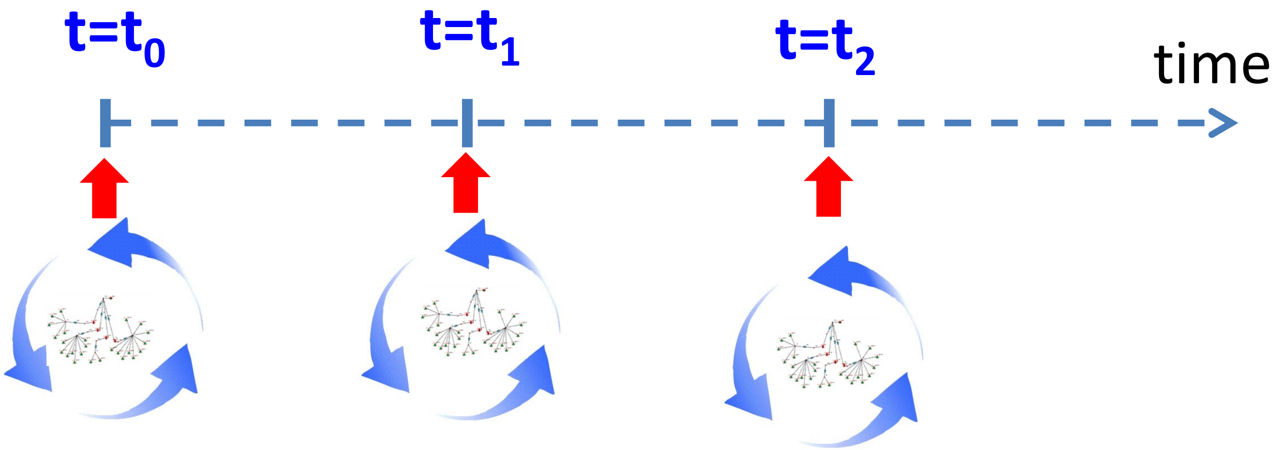
1. Assume p_{wfmin}
2. Run reservoir simulation



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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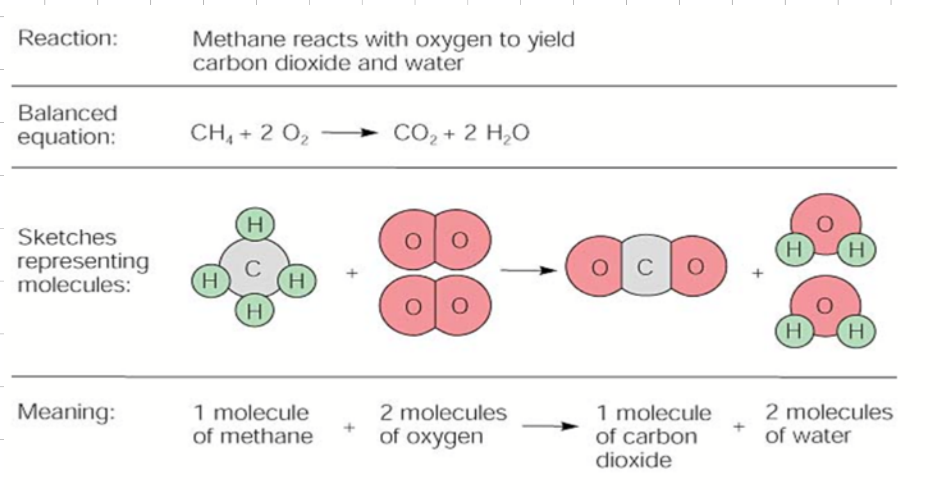
20240223-CO2 emissions and CO2 value chain

Source of CO2 emissions



Beware!:
-Not all the fuel that is burned is methane, so the reaction could look slightly different
- natural gas has other heavier components
- liquid fuel
- there are other components that might not react (inert) like N2 (but take some energy to heat up), or some compounds are generated that are undesired.

https://web.fscj.edu/Milczanowski/psc/lect/Ch11/slide3.htm

1 mol of methane (16 gr) gives 1 mol of CO2 (44 gr). There is a ratio of 44/16=2.75

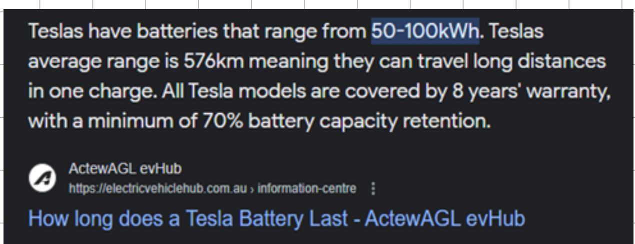
1 kg CH4 combusted -->2.75 kg CO2 generated

Purpose of combustion: For power/electricity generation or heating

Energy in an oil barrel:

*1,700 kilowatt-hours (kWh) of energy.

10 691 kWh/Sm3


Teslas have batteries that range from 50-100kWh. Teslas average range is 576km meaning they can travel long distances in one charge. All Tesla models are covered by 8 years' warranty, with a minimum of 70% battery capacity retention.

ActewAGL evHub
https://electricvehiclehub.com.au › information-centre
How long does a Tesla Battery Last - ActewAGL evHub

Energy in natural gas:

Calorific value of natural gas:
42-55 MJ/kg**

34-52 MJ/Sm3

1 MJ --> 0.2777 kWh

9.44-14.44 kWh/Sm3

1000 Sm3 gas-> 1 Sm3 o.e.***

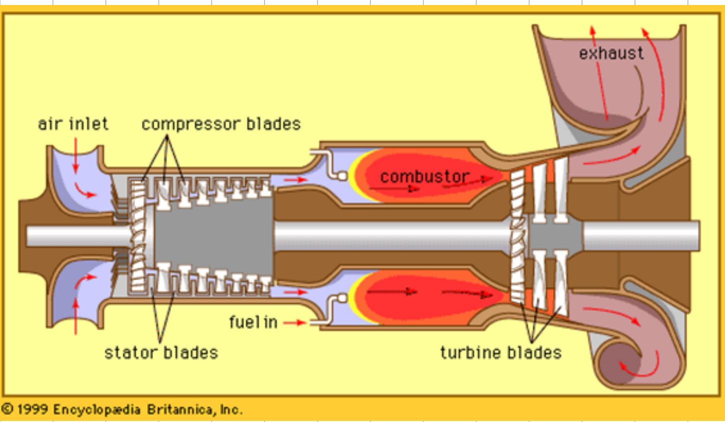
9444-14440 kWh/Sm3 o.e.

*https://www.investopedia.com/terms/b/barrelofoilequivalent.asp

**https://group.met.com/en/media/energy-insight/calorific-value-of-natural-gas

***https://www.sodir.no/en/about-us/use-of-content/conversion-table/

If using a gas turbine to generate power:



https://en.wikipedia.org/wiki/Gas_turbine

GT for offshore applications have efficiencies 40-50%. Using an approximation:

$$\eta_{GT} = \frac{\dot{W}_{out}}{\dot{Q}_{in}} \qquad \dot{Q}_{in} = \dot{m}_g \cdot Cv$$

calorific value

*https://www.havtil.no/contentassets/3391c6686b2b4265abe8585294151335/2020_1862_rapport-equinor-hammerfest-lng-gransking.pdf

If output power is e.g. 45 MW (1 GT at Melkøya*, out of 5)

kW . h

$P \cdot t$

$$\dot{m}_g = \left(\frac{\dot{W}_{out}}{\eta_{GT}}\right)\frac{1}{Cv}$$

0.4 → 0.5 9.44 14.44

This gives, in a year:

45000 . 24 . 365

-Energy: 3.94 E8 kWh
-Gas burned: 54.6E6 - 104 E6 Sm3 --> 38 E06 - 73 E06 kg (assuming , GT effic: 0.4-0.5, deng_sc=0.7 kg/m3)
-CO2 emissions: 105 E06 - 201 E06 kg --> 105-201 E03 t (assuming 2.75 kg CO2/1 kg gas)

1 tonne t = 1000 kg

Melkøya past 2030. Moreover, electrification of the plant is one of the most extensive climate measures in Norway, reducing CO_2 emissions by 850,000 tonnes per year.

**https://www.equinor.com/magazine/future-of-melkoya-lng-plant

Numbers to remember! (Gas turbine)

1 Sm3 of gas --> 1.95 kg CO2 --> 4.7-7.2 kWh

1 MWh --> 139-213 Sm3-->0.27- 0.5 t CO2 (similar to ***)

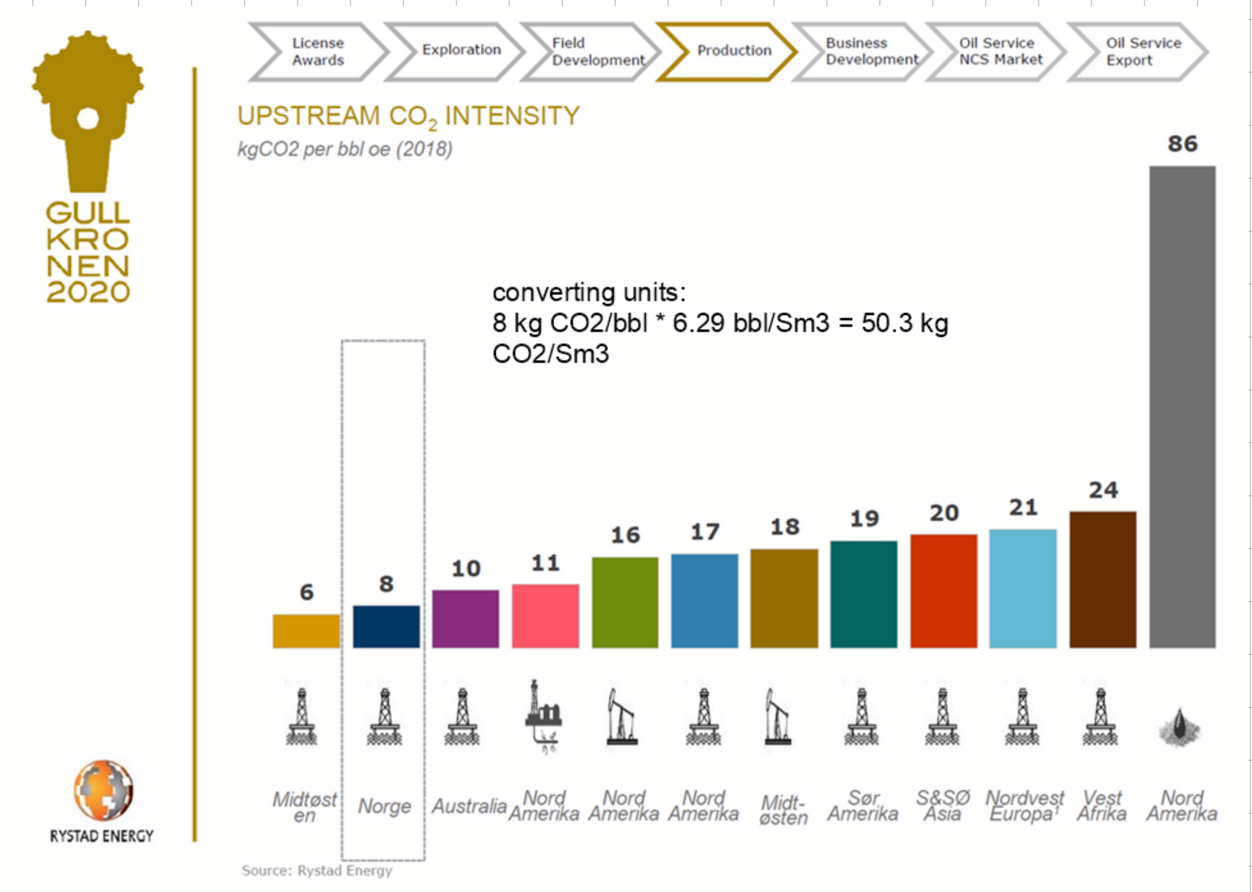
***https://www.rte-france.com/en/eco2mix/co2-emissions

- **Scope 1 emissions**— This one covers the Green House Gas (GHG) emissions that a company makes directly — for example while running its boilers and vehicles.
- **Scope 2 emissions** — These are the emissions it makes indirectly – like when the electricity or energy it buys for heating and cooling buildings, is being produced on its behalf.
- **Scope 3 emissions** — Now here's where it gets tricky. In this category go all the emissions associated, not with the company itself, but that the organisation is indirectly responsible for, up and down its value chain. For example, from buying products from its suppliers, and from its products when customers use them. Emissions-wise, Scope 3 is nearly always the big one.

https://www2.deloitte.com/uk/en/focus/climate-change/zero-in-on-scope-1-2-and-3-emissions.html

Scope 1 CO_2 emissions in the oil and gas industry:

-Gas turbines used for electricity generation, shaft power, and from heaters. (MOST SIGNIFICANT)
-Transport of personnel and goods to and from the platform
-Drilling, completion and intervention
-Tanker transport of oil to refineries
-Gas transport to customer (LNG or pipeline)



converting units:
8 kg CO2/bbl * 6.29 bbl/Sm3 = 50.3 kg CO2/Sm3

Usually to estimate CO_2 emissions it is necessary to :

Calculate energy requirements --> calculate gas to burn --> calculate CO_2 emissions

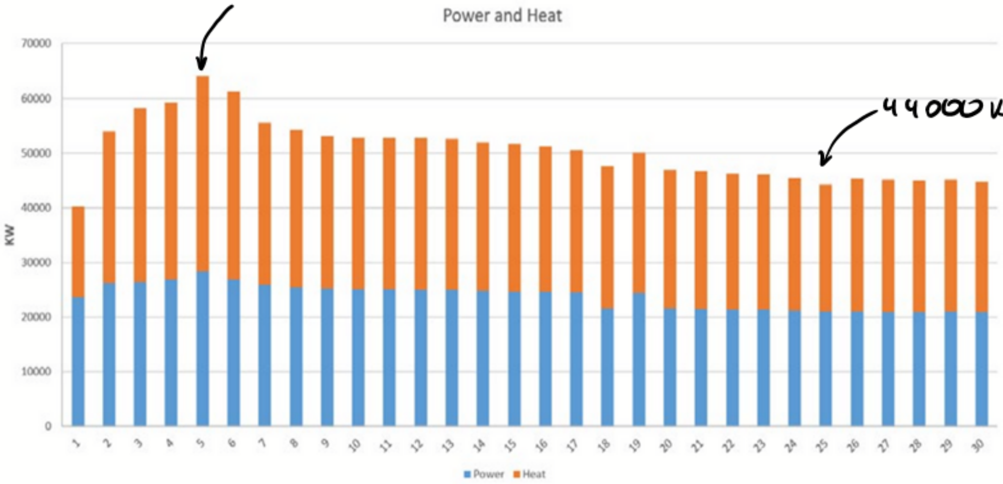
An example:

https://www.equinor.com/content/dam/statoil/documents/impact-assessment/wisting/equinor-wisting-forslag-til-ku-program-05-01-21.pdf

Kilder til utslipp

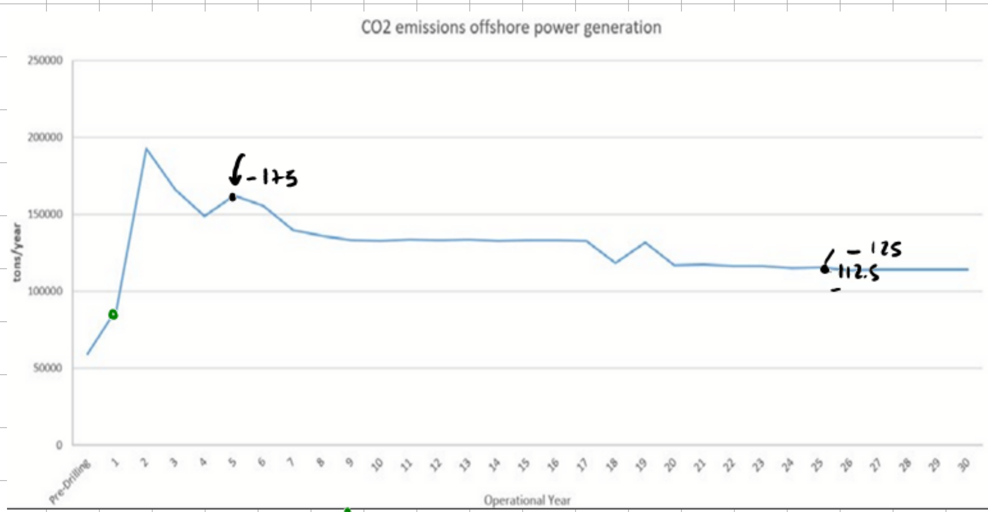
Kilder til utslipp til luft i driftsfasen inkluderer normalt utslipp fra kraftgenerering på produksjonsenheten (turbiner), borerigg og fartøy (diesel), omlasting av råolje, lasteskip og helikopter. Ved import av kraft fra land vil det ikke være behov for gassturbiner på produksjonsinnretningen. Varmebehovet vil da dekkes gjennom elektriske kjeler.

64 MW → In year $64000 \cdot 365 \cdot 24 = 560\,E06$ KWh $= 560\,E03$ MWh



$44000\,\text{KW} \cdot 365 \cdot 24 = 433\,E06$ kWh

433 E03 MWh

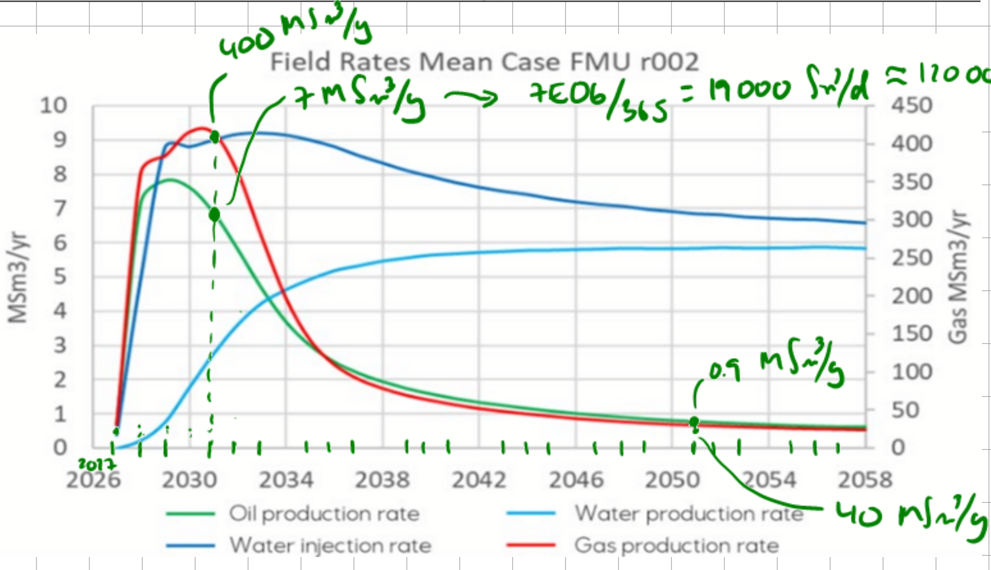


162.5 E03 t CO_2/yer

112.5 E03 t CO_2/year

t CO_2/MWh $\quad \dfrac{162.5\,E03}{560\,E03} = 0.29$

$\dfrac{112.5}{433} = 0.25$



kg CO_2/Sm³ o.e

for year 5: $\dfrac{162.5\,E06 \text{ kg } CO_2}{7E06 + \dfrac{400\,E06}{1000}}$

$= 22$ kg CO_2/Sm³ o.e.

for year 25 $= \dfrac{112.5}{0.9 + \dfrac{40}{1000}} = 119 \dfrac{\text{kg } CO_2}{\text{Sm}^3\text{oe}}$

- What is the average energy required to produce a barrel (or Sm3) of oil

kWh/Sm^3 o.e

for year 5: $\frac{560 \cancel{E06} \text{ kWh}}{7\cancel{E06} + \frac{400\cancel{E06}}{1000}} = 75.6$ kWh/Sm^3 o.e.

for year 25 $= \frac{433}{0.9 + \frac{40}{1000}} = 460$ kWh/Sm^3 o.e

Energy contained in the HC / required to produce ?

10 691 kWh/Sm3

141 times

23 times

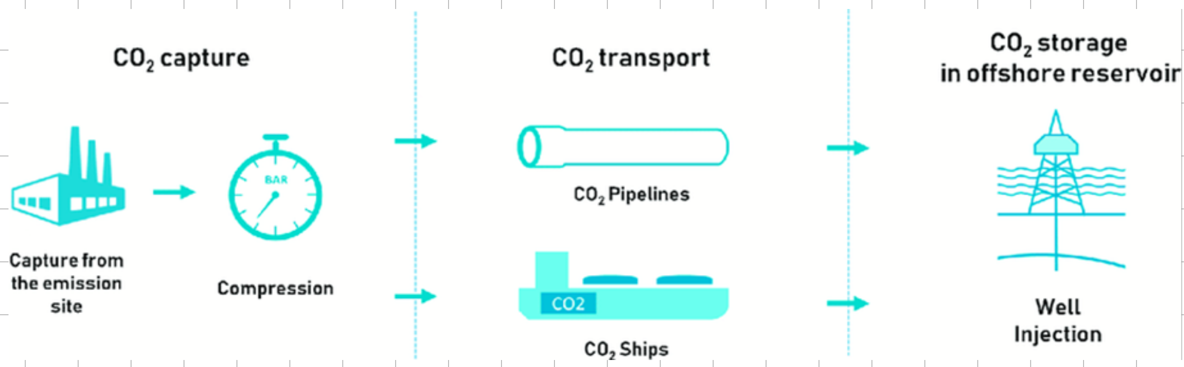
Scope 3 emissions:
-emissions of oil and gas sold to the market (e.g. gas sold for electricity generation)

CO2 emitted to produce compared to CO2 emitted by burning the gas?

22-119 kg CO_2/Sm^3 oe emitted during production

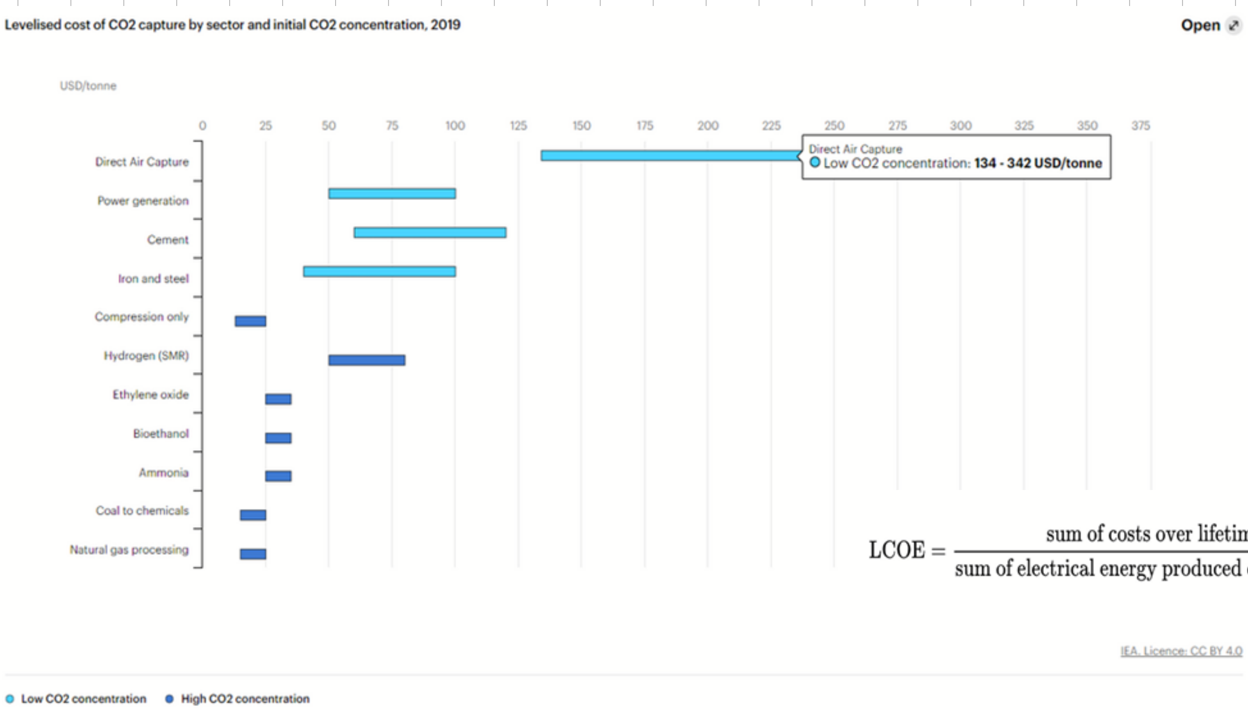
$$\frac{1.95 \text{ kg } CO_2}{\frac{1 \, Sm^3 \text{ gas}}{1000 \, Sm^3 \text{ gas}} \, \underline{1 \, Sm^3 \text{ o.e}}} = 1950 \text{ kg } CO_2/Sm^3 \text{ o.e.}$$

CO2 value chain - Capture and storage



https://www.researchgate.net/publication/338819648_Effects_of_CO2_on_polymeric_materials_in_the_CO2_transport_chain_A_review

https://www.equinor.com/magazine/climate-solution-for-european-industry



$$\mathrm{LCOE} = \frac{\text{sum of costs over lifetime}}{\text{sum of electrical energy produced over lifetime}} = \frac{\sum_{t=1}^{n} \frac{I_t+M_t+F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

"the cost of onshore pipeline transport is in the range of USD 2-14/t CO2,"

https://www.iea.org/commentaries/is-carbon-capture-too-expensive

", more than half of onshore storage capacity is estimated to be available below USD 10/t CO2"

In 2023, the tax rates are respectively NOK 761 .... per tonne of CO2

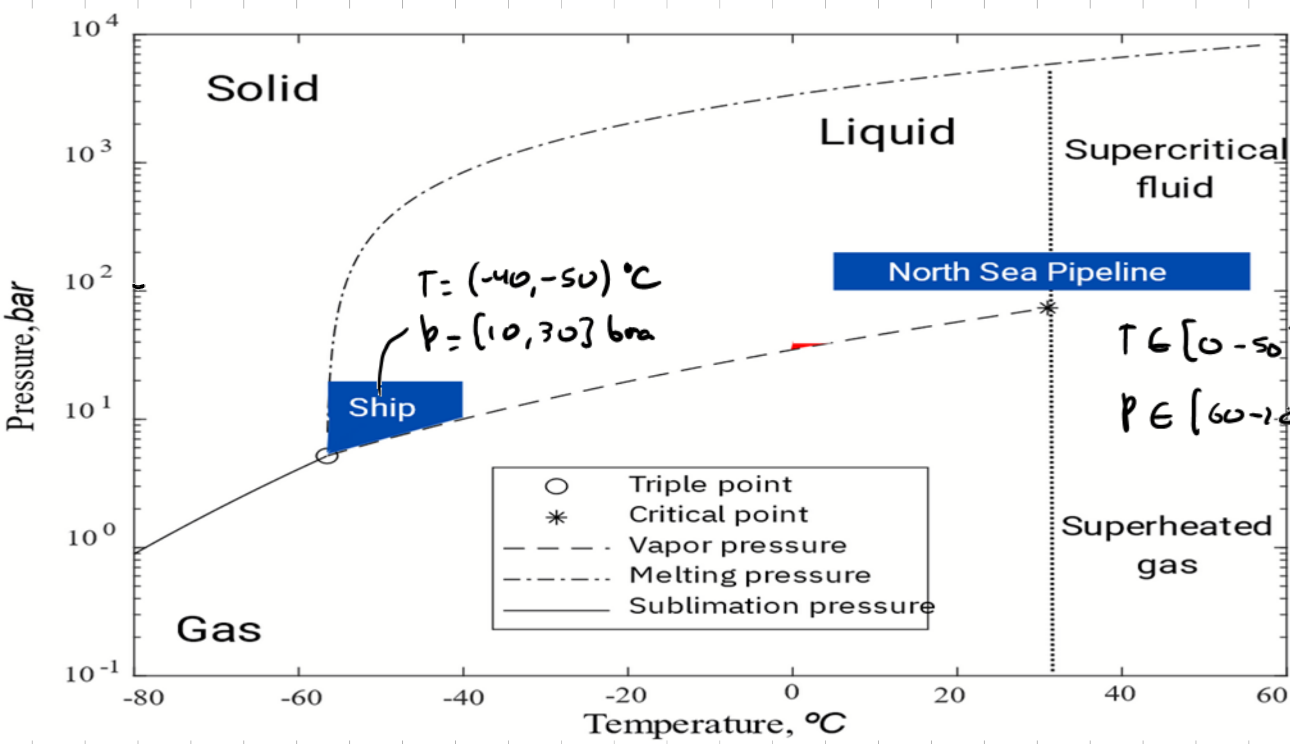
https://energifaktanorge.no/en/et-baerekraftig-og-sikkert-energisystem/avgifter-og-kvoteplikt

$\frac{761 \text{ NOK}}{t CO_2} \simeq 76.1 \text{ USD}/t CO_2$

Capture + transp + stor

50-100 + 2-14 + 10 = 62-124

P-T conditions of CO2 in pipeline transportation and injection using subsea wells



$T = (-40, -50)$ °C

$p = [10, 30]$ bara

$T \in [0 - 50]$ °C

$P \in [60 - 100]$ bara

$T_{seabed} = (5-10)$ °C

$\rho_w = 1000 \ kg/m^3$

	T [C]					
p [bara] / DENSITY [kg/m3]	0	10	20	30	40	50
50	940	587	144	125	114	105
60	948	882	567	175	150	136
70	955	893	808	487	201	173
80	962	903	827	692	287	221
90	968	912	843	743	482	288
100	974	920	856	771	620	387
110	980	928	868	792	682	499
120	985	935	878	809	717	582
130	990	942	887	823	743	635
140	995	948	896	836	763	672
150	1000	954	904	847	780	699
160	1004	960	911	857	795	722
170	1008	965	918	866	808	741
180	1012	970	925	875	819	757
190	1017	975	931	883	830	771
200	1021	980	937	891	840	784

	T [C]					
p [bara] / Viscosity [Pa s]	0	10	20	30	40	50
50	1.04E-04	5.92E-05	1.66E-05	1.67E-05	1.70E-05	1.74E-05
60	1.07E-04	8.83E-05	5.11E-05	1.79E-05	1.78E-05	1.80E-05
70	1.09E-04	9.10E-05	7.29E-05	3.80E-05	1.92E-05	1.89E-05
80	1.11E-04	9.36E-05	7.66E-05	5.52E-05	2.25E-05	2.04E-05
90	1.13E-04	9.59E-05	7.97E-05	6.22E-05	3.49E-05	2.30E-05
100	1.15E-04	9.82E-05	8.25E-05	6.66E-05	4.70E-05	2.82E-05
110	1.17E-04	1.00E-04	8.50E-05	7.02E-05	5.41E-05	3.60E-05
120	1.19E-04	1.02E-04	8.74E-05	7.32E-05	5.88E-05	4.33E-05
130	1.21E-04	1.04E-04	8.96E-05	7.59E-05	6.25E-05	4.88E-05
140	1.22E-04	1.06E-04	9.17E-05	7.84E-05	6.57E-05	5.32E-05
150	1.24E-04	1.08E-04	9.37E-05	8.07E-05	6.84E-05	5.67E-05
160	1.26E-04	1.10E-04	9.56E-05	8.28E-05	7.10E-05	5.98E-05
170	1.27E-04	1.11E-04	9.74E-05	8.48E-05	7.33E-05	6.26E-05
180	1.29E-04	1.13E-04	9.92E-05	8.67E-05	7.54E-05	6.50E-05
190	1.31E-04	1.15E-04	1.01E-04	8.86E-05	7.75E-05	6.73E-05
200	1.32E-04	1.16E-04	1.03E-04	9.03E-05	7.94E-05	6.95E-05

$\mu_w = 1E-3 \ Pa \cdot s$

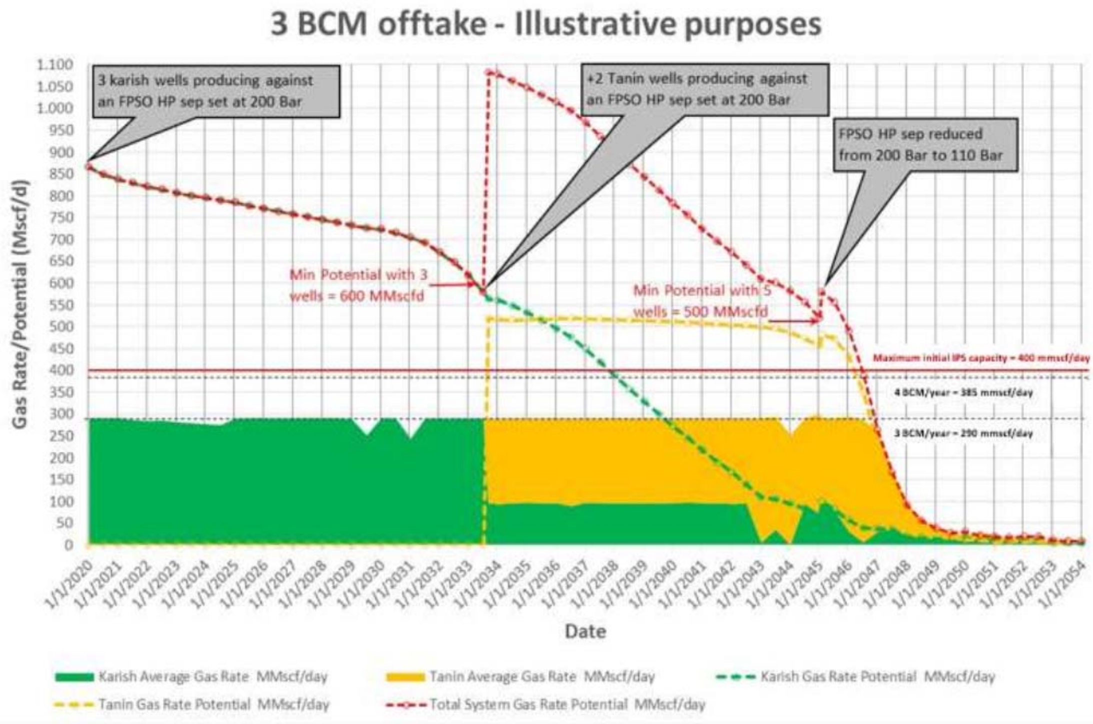
E-4 $\rightarrow \mu_g$

E-5

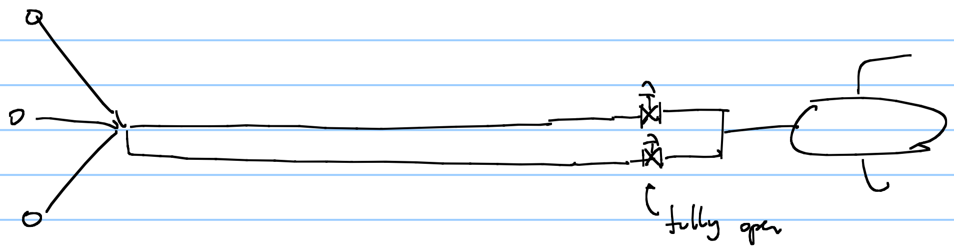
CO_2 in subsea injection systems has density as a liquid but viscosity as a gas

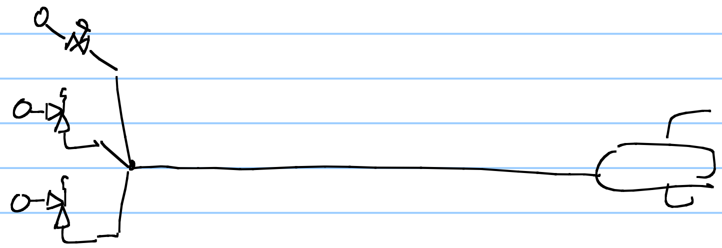
$$\Delta p = \underbrace{\Delta p_H}_{\uparrow \rho \uparrow} + \Delta p_f$$

$f(\mu) \downarrow \ \mu \downarrow$

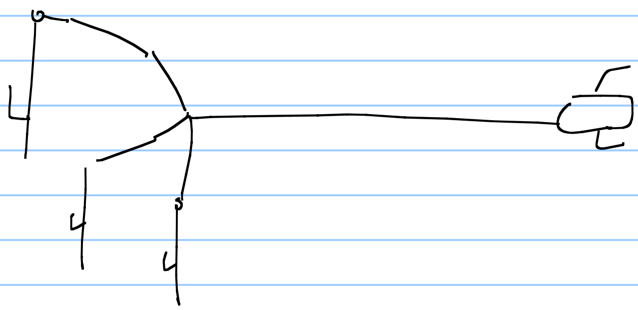


Production potential maximum rate the production system can deliver at a given time



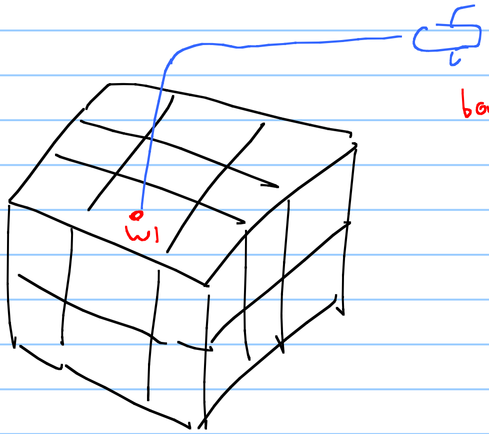


q_{pp} = fully open choke



max q_g by changing $q_{g\,inj\,1}$, $q_{g\,inj\,2}$, $q_{g\,inj\,3}$

Production potential is also used in reservoir simulation

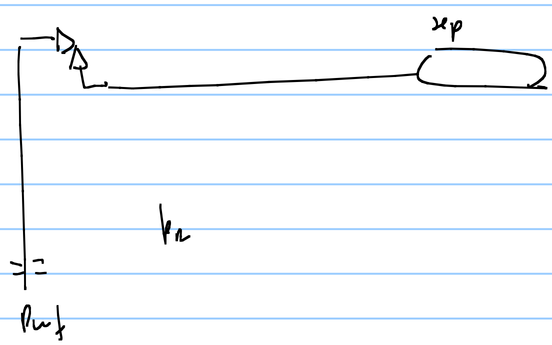


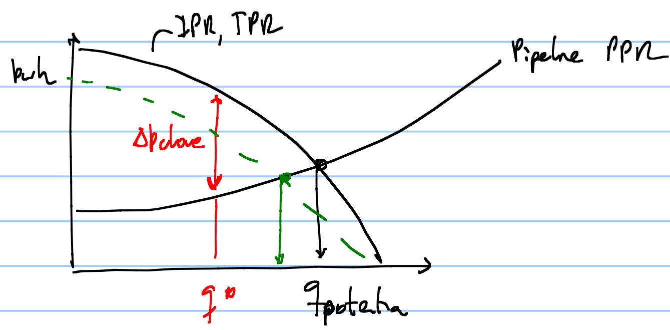
boundary conditions on well ! → q_{target}

↳ $p_{wf\,min}$

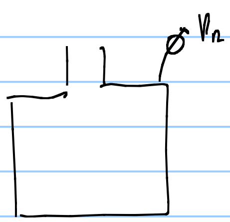
in each time step

- 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 $q_{pot} \leq q_{target}$
  - ↳ q_{target} cannot be produced; $p_{wf} = p_{wf\,min}$; $q_{well} = q_{potential}$





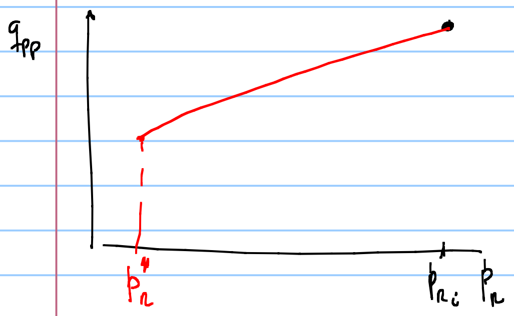
- Production potential is actually a function of p_R
  - ↳ and p_R is usually a function of Q_p → G_p (gas), N_p (oil)

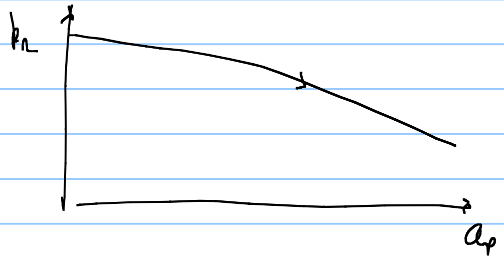


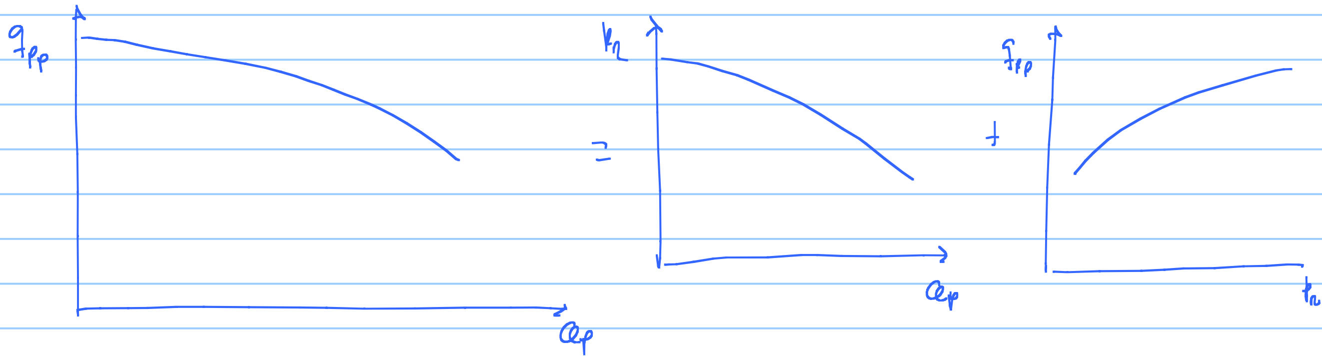
$$p_R = f(Q - Q_p)$$

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

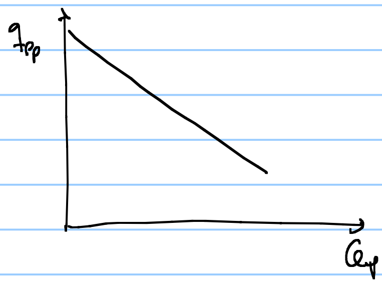
$$p_R = f(Q_p)$$



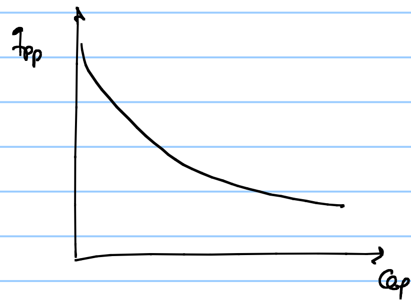




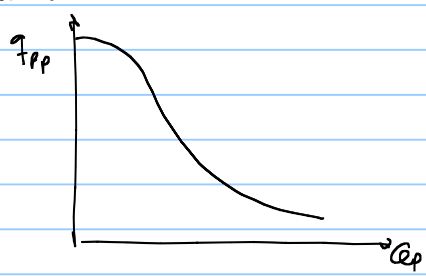
for dry gas and undersaturated oil



for saturated oil

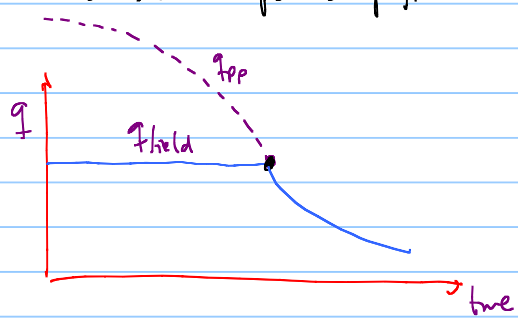


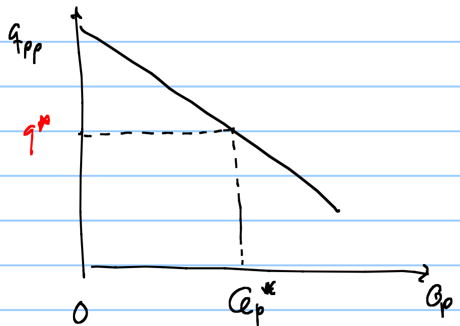
for oil water injection



Production potential curves can be used for

- determine plateau duration
- estimate production profile





$q_{plateau} = q^*$

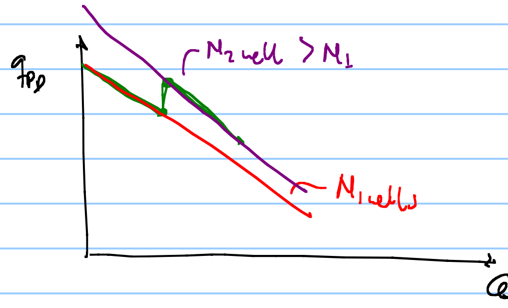
Q_p^* ~ cumulative production at which the end of plateau will occur

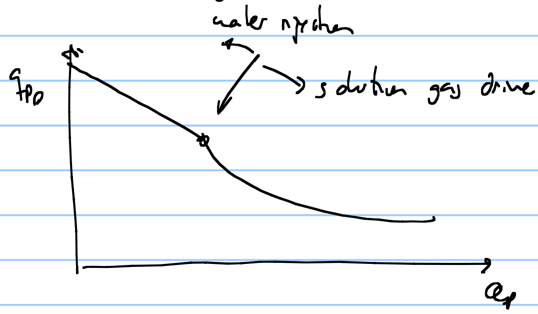
$0 \rightarrow Q_p^*$ has been produced at constant rate q^*

$$t_{plateau} = \frac{Q_p^* \ [Sm^3]}{q^* \ [Sm^3/d] \ \text{uptime}}$$

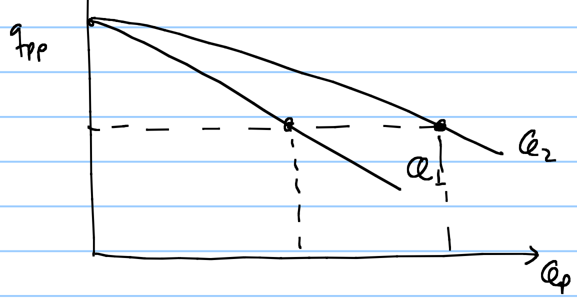
$\text{uptime} \longrightarrow \dfrac{\text{nr. operational days}}{\text{year}}$

Production potential curve is affected by changes to the production system





Q changes



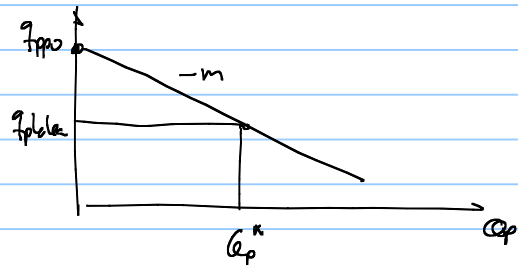
$p_R = f(R_f)$

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

$R_{f_2} < R_{f_1}$

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

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



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

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

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

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

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

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

$$q_{pp} = q_{plateau} - m\int_{t_{plateau}}^{t} q_{pp}\,dt$$

$\longrightarrow$ a solution to this equation is

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

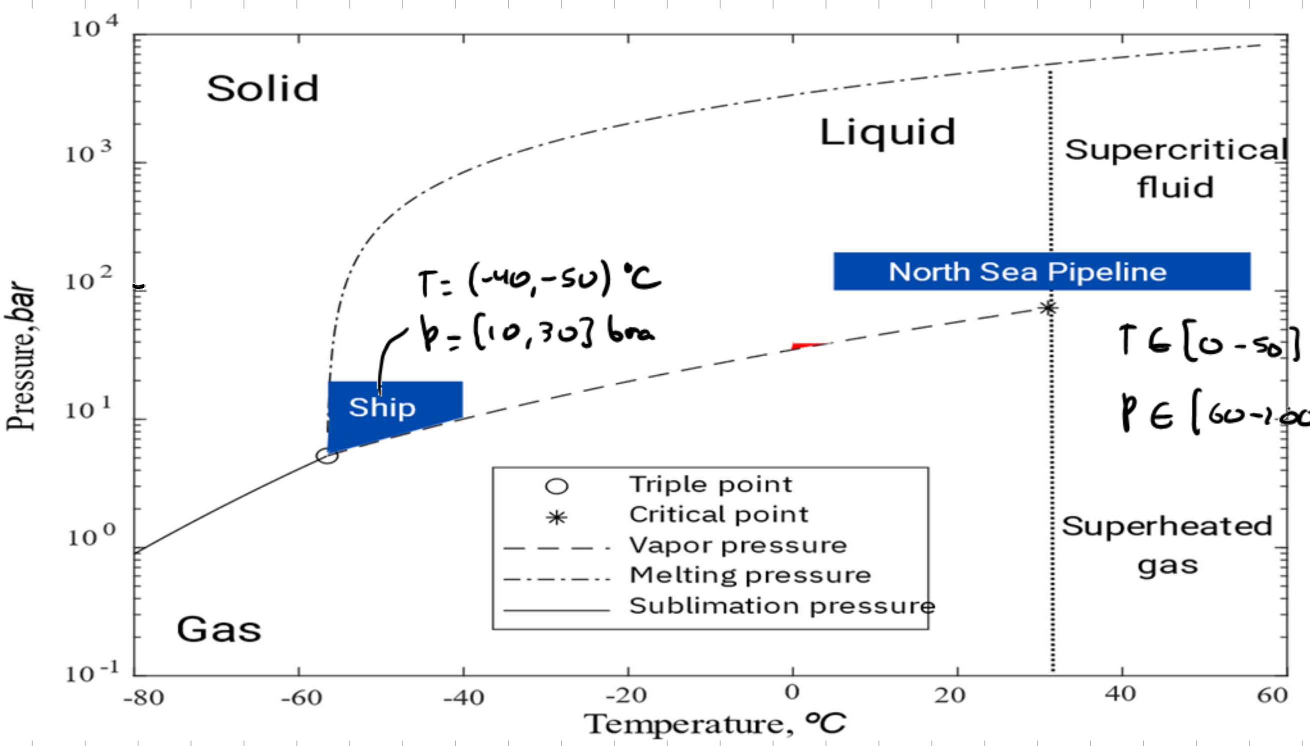
$$q_f(t) \begin{cases} q_{plateau} & \text{if} \quad t \le t_{plateau} = \left(\dfrac{q_{ppo}}{q_{plateau}} - 1 \right) \dfrac{1}{m} \\ q_{plateau}\, e^{-m(t - t_{plateau})} & \text{if} \quad t > plateau \end{cases}$$

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

20240229

OUTLINE:
-CO2 P-T conditions in subsea injection systems
-Injection scheduling for a subsea field (ala Snøhvit)

P-T conditions of CO2 in pipeline transportation and injection using subsea wells



$T \in [0-50]$ °C
$P \in [60-100]$ bara

wh
2500 m 1000 kg/m³ $\rho_w = 1000$ kg/m³
$\Delta p_H = \frac{\rho \cdot h \cdot g}{1E5} = \frac{25E6}{1E5} \approx 250$ bar
$T_{seabed} = (5-10)$ °C

	DENSITY [kg/m3]	T [C] 0	10	20	30	40	50
p [bara]	50	940	587	144	125	114	105
	60	948	882	567	175	150	136
	70	955	893	808	487	201	173
	80	962	903	827	692	287	221
	90	968	912	843	743	482	288
	100	974	920	856	771	620	387
	110	980	928	868	792	682	499
	120	985	935	878	809	717	582
	130	990	942	887	823	743	635
	140	995	948	896	836	763	672
	150	1000	954	904	847	780	699
	160	1004	960	911	857	795	722
	170	1008	965	918	866	808	741
	180	1012	970	925	875	819	757
	190	1017	975	931	883	830	771
	200	1021	980	937	891	840	784

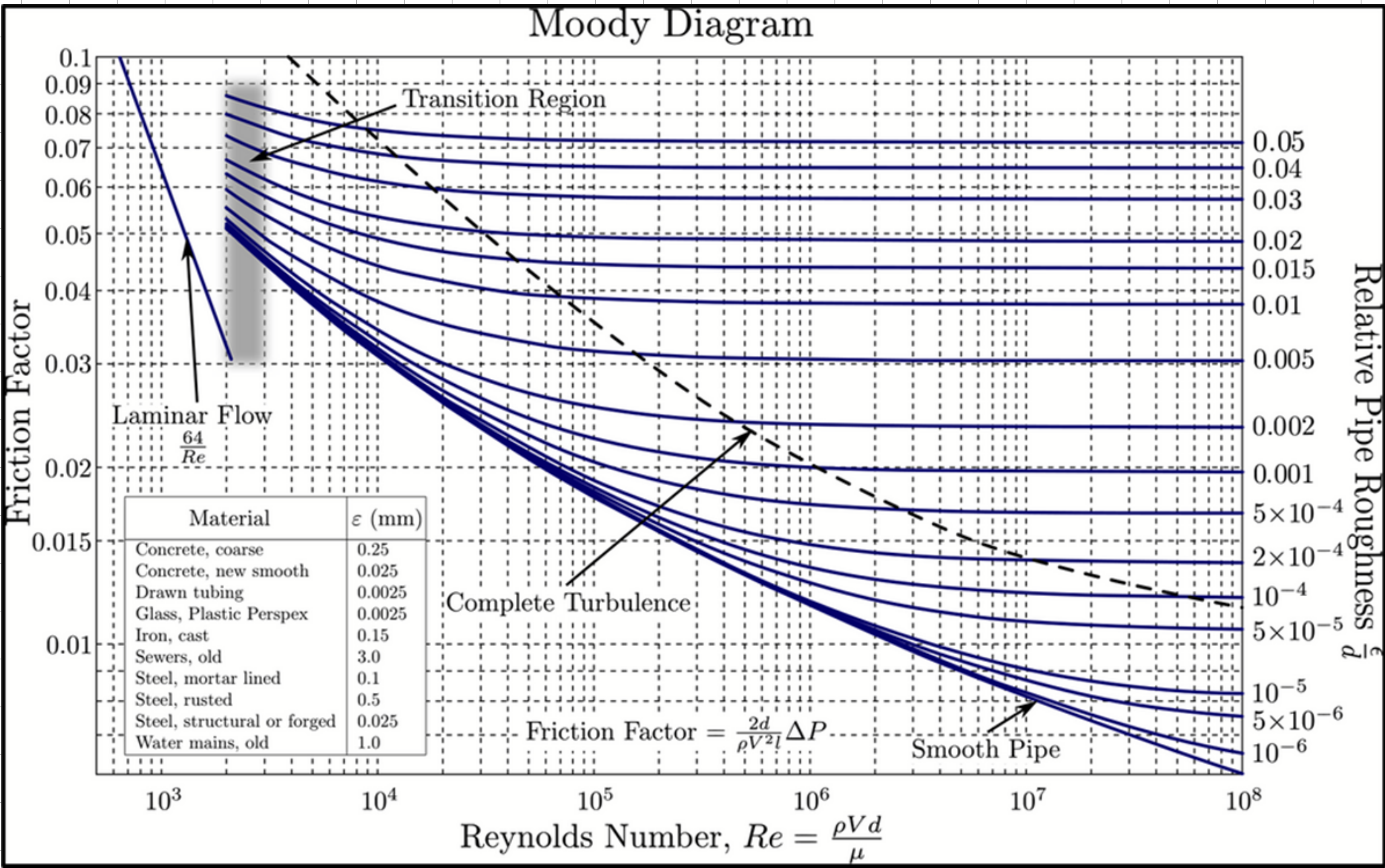
	Viscosity [Pa s]	T [C] 0	10	20	30	40	50
p [bara]	50	1.04E-04	5.92E-05	1.66E-05	1.67E-05	1.70E-05	1.74E-05
	60	1.07E-04	8.83E-05	5.11E-05	1.79E-05	1.78E-05	1.80E-05
	70	1.09E-04	9.10E-05	7.29E-05	3.80E-05	1.92E-05	1.89E-05
	80	1.11E-04	9.36E-05	7.66E-05	5.52E-05	2.25E-05	2.04E-05
	90	1.13E-04	9.59E-05	7.97E-05	6.22E-05	3.49E-05	2.30E-05
	100	1.15E-04	9.82E-05	8.25E-05	6.66E-05	4.70E-05	2.82E-05
	110	1.17E-04	1.00E-04	8.50E-05	7.02E-05	5.41E-05	3.60E-05
	120	1.19E-04	1.02E-04	8.74E-05	7.32E-05	5.88E-05	4.33E-05
	130	1.21E-04	1.04E-04	8.96E-05	7.59E-05	6.25E-05	4.88E-05
	140	1.22E-04	1.06E-04	9.17E-05	7.84E-05	6.57E-05	5.32E-05
	150	1.24E-04	1.08E-04	9.37E-05	8.07E-05	6.84E-05	5.67E-05
	160	1.26E-04	1.10E-04	9.56E-05	8.28E-05	7.10E-05	5.98E-05
	170	1.27E-04	1.11E-04	9.74E-05	8.48E-05	7.33E-05	6.26E-05
	180	1.29E-04	1.13E-04	9.92E-05	8.67E-05	7.54E-05	6.50E-05
	190	1.31E-04	1.15E-04	1.01E-04	8.86E-05	7.75E-05	6.73E-05
	200	1.32E-04	1.16E-04	1.03E-04	9.03E-05	7.94E-05	6.95E-05

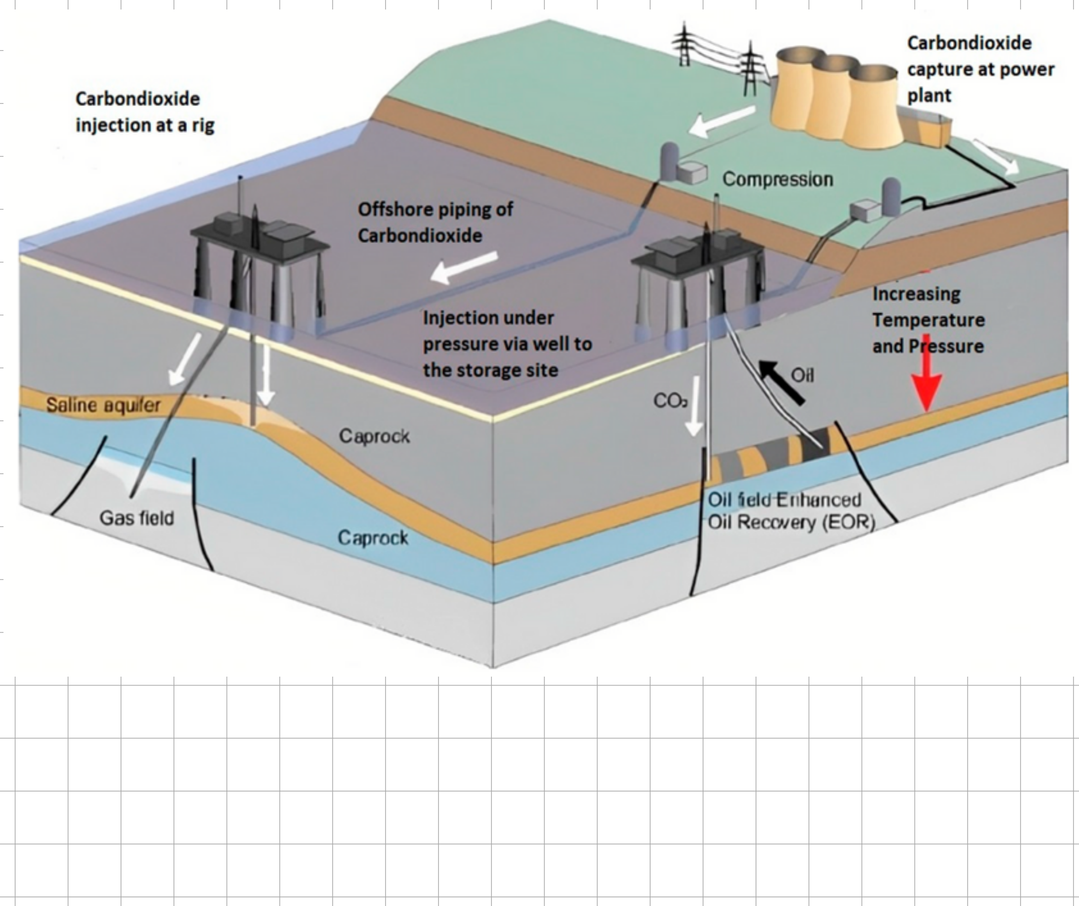
$\mu_w = 1E-3$ Pa·s

E-4 → μ_g
E-5

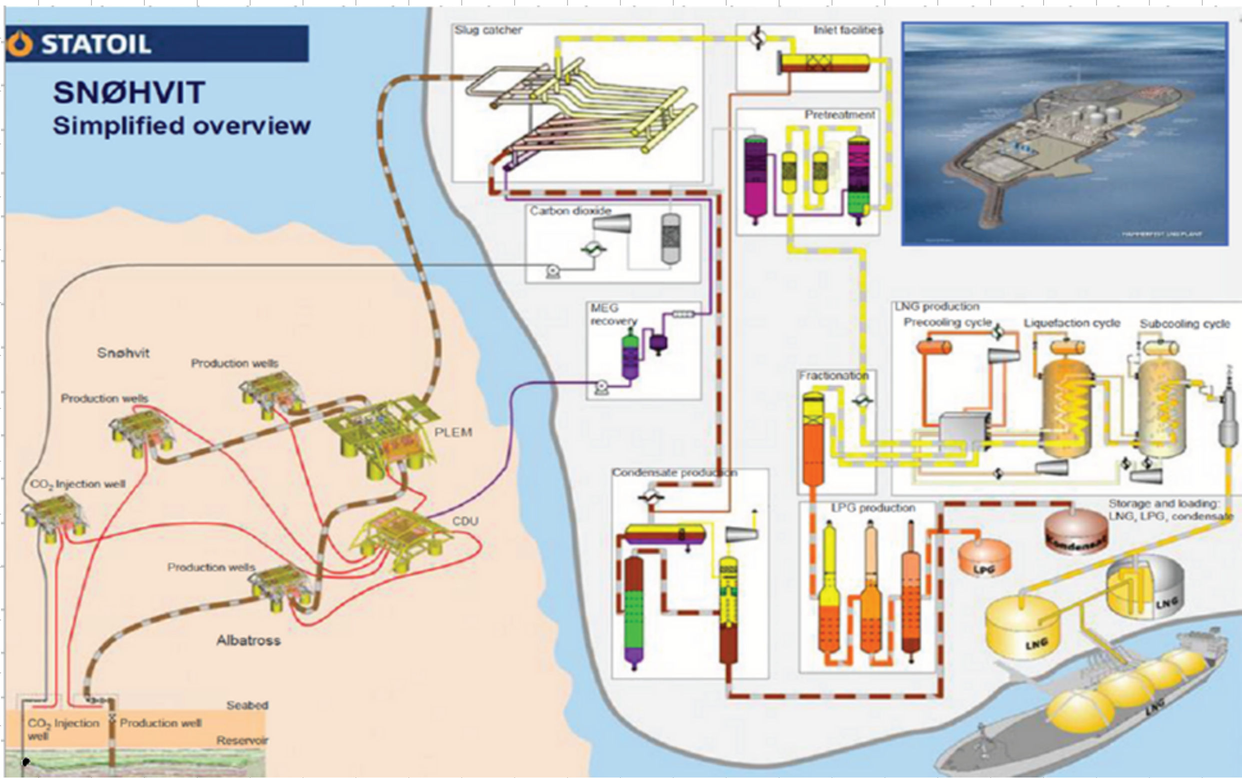
CO_2 in subsea injection systems has density as a liquid but viscosity as a gas

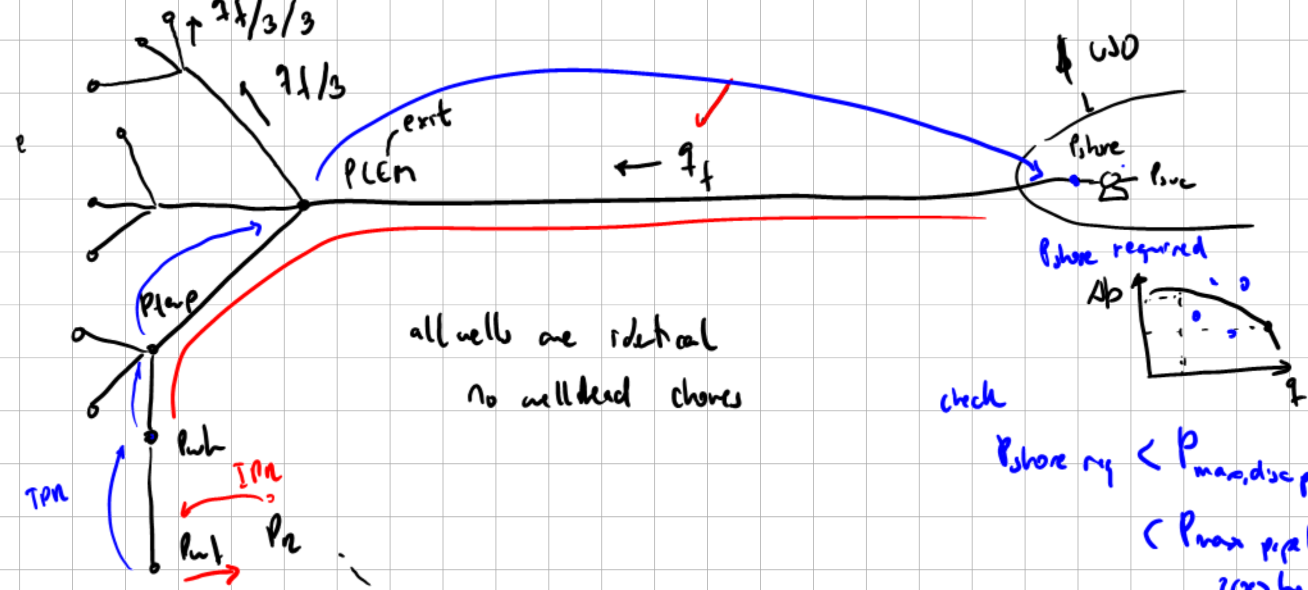
$\Delta p = \underbrace{\Delta p_H}_{\uparrow \rho \uparrow} + \Delta p_f$
$\downarrow f(\mu) \downarrow \quad \mu \downarrow$

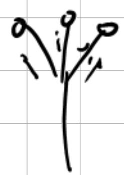




https://www.mdpi.com/2071-1050/15/8/6599







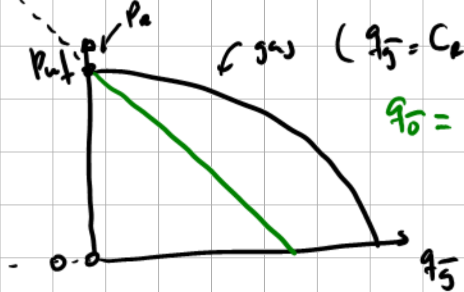
all wells are identical

no wellhead chokes

check

$P_{shore\ req} < P_{max,disc\ pump}$

$< P_{max\ pipeline}$ 200 bara



IPR for Liquid ($q_g = C_R (P_R^2 - P_{wf}^2)^n$)

(inflow performance relationship

$q_o = J (P_R - P_{wf})$ ← CO_2

productivity index

injection performance relationship

$\dot{m}_{CO_2}$

Pmax (to avoid fracturing the reservoir)

$q_{CO_2} = J (P_{wf} - P_R)$

[Sm^3/d] $Sm^3/d/bar$ bar

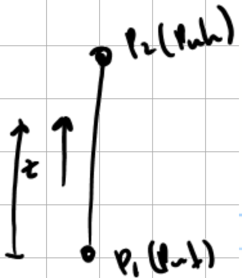
t/d mass units

$J \left[Sm^3/d/bara \right] \rightarrow \left[t/d/bar \right]$

$Sm^3 \rightarrow kg$

$J \cdot \rho_{CO_2} = J_{mass}$

↳ 1.8 kg/m³



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

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

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

angle with respect to :

$\cos(180°) = -1$

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

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

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

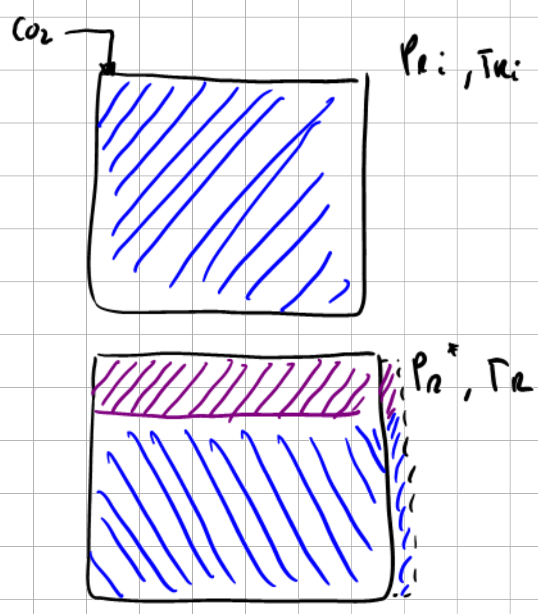
$$\frac{n_{inj} \cdot R \cdot Z_R \cdot T_R}{c_e \cdot V_{T,i} \cdot p_R} = (p_R - p_{Ri})$$

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

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

The physical solution is the positive, then

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



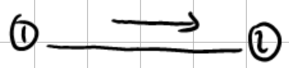
20240301

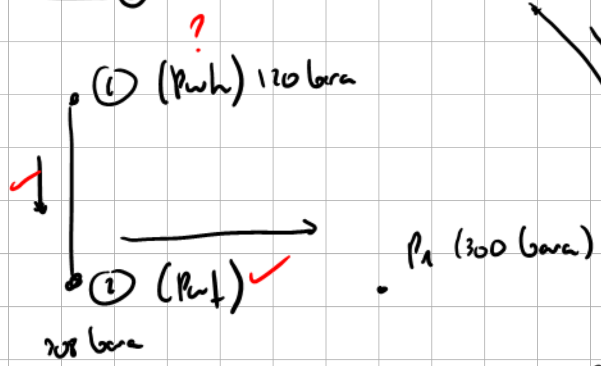
OUTLINE
-Ala Snohvit CO2 injection scheduling (cont)
-Intro to Class exercise: CO2 injection network

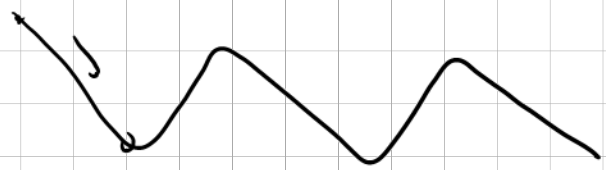
Equinor a CO_2 injection well $q_{CO_2,well} = 1.5E06\ t/y$

in our exercise $q_{field,CO_2} = 18000\ t/d \xrightarrow{\cdot 365} 6.57E6\ t/y$

$$q_{well,CO_2} = \frac{q_{field,CO_2}}{9} = 0.7E06\ t/y$$







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

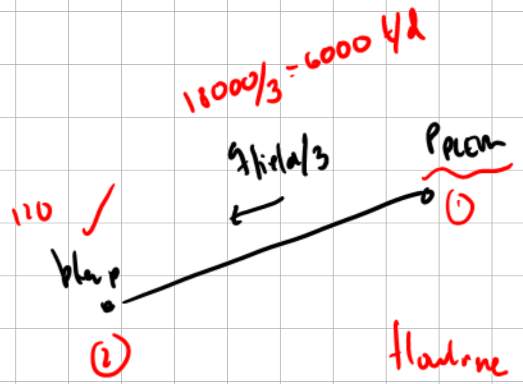
$\rho_{\bar{CO_2}} \cdot g \cdot h$; $h \sim 2400$, $g \sim 10$, $\rho \sim 900$

~ 216 bara $- \Delta p_f$

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

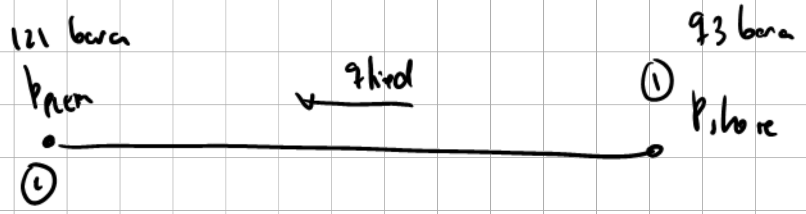
$$120 = 308 + 216 +$$

$$\Delta p_f = 28 \text{ bara}$$



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

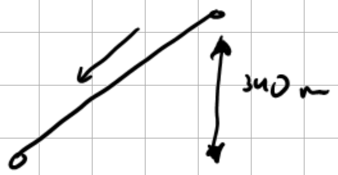
VBA func line P1

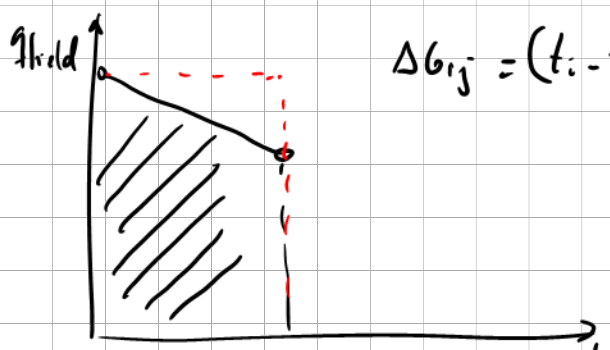


UBA function inclined pipe

$$q = C \cdot \left(\frac{p_1^2}{e^s} - p_2^2 \right)^{0.5}$$

?



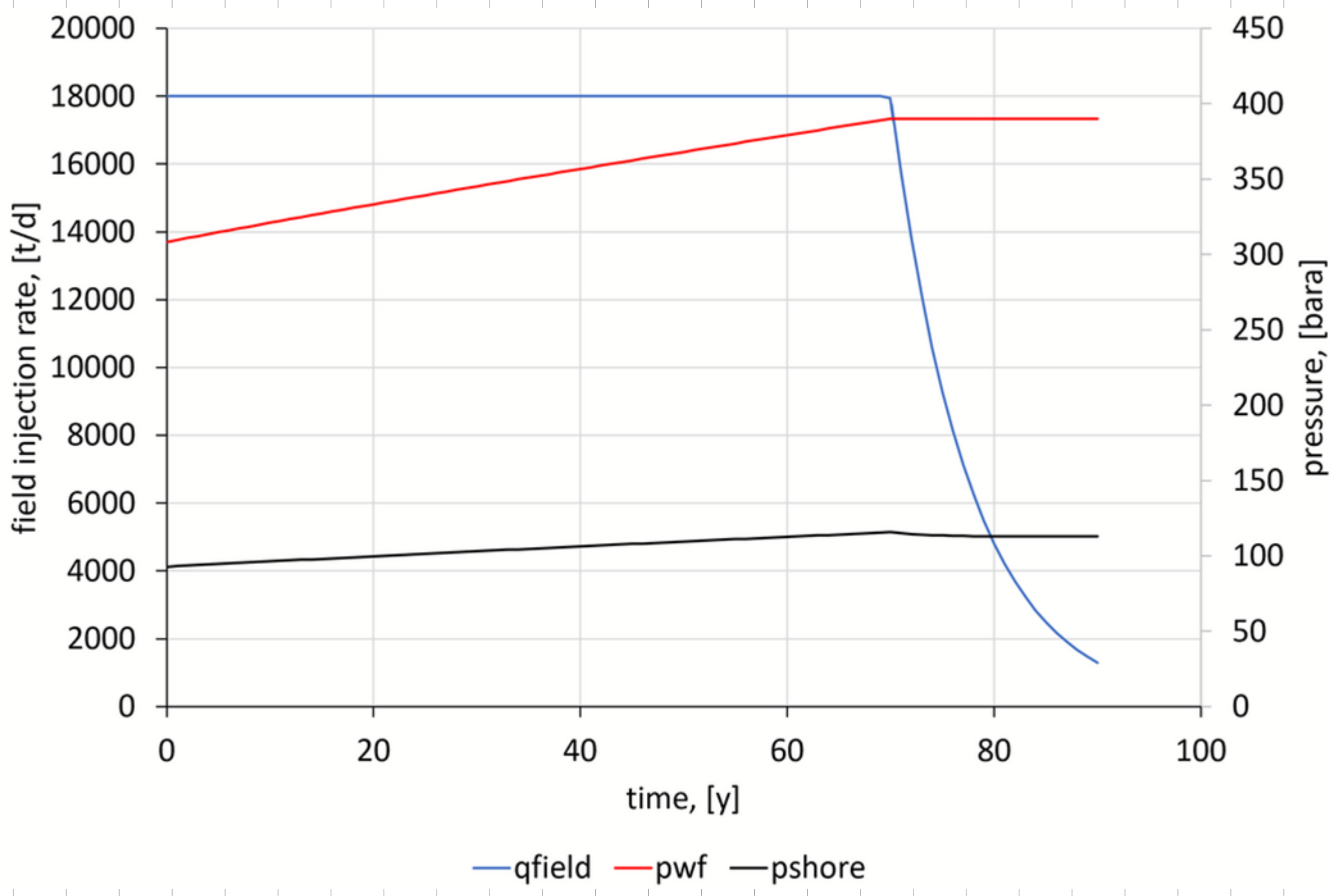


$$\Delta G_{i,j} = (t_i - t_{i-1})\, q_{field_{i-1}} \cdot {}^{n\,days}/_{year}$$

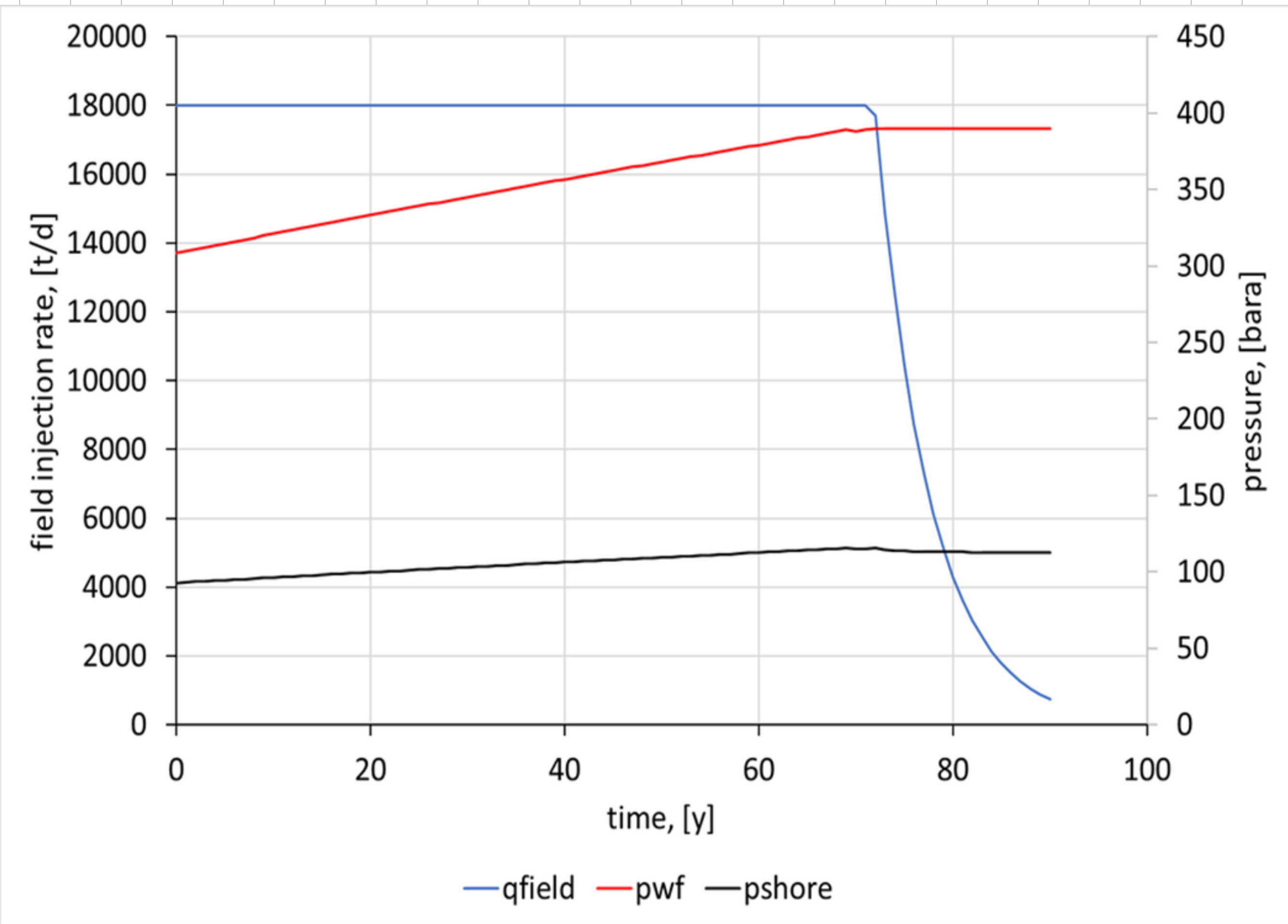
$$\Delta G_{i,j} = \frac{(q_{field_i} + q_{field_{i-1}})}{2} \cdot (t_i - t_{i-1}) \cdot {}^{n\,days}/_{year}$$

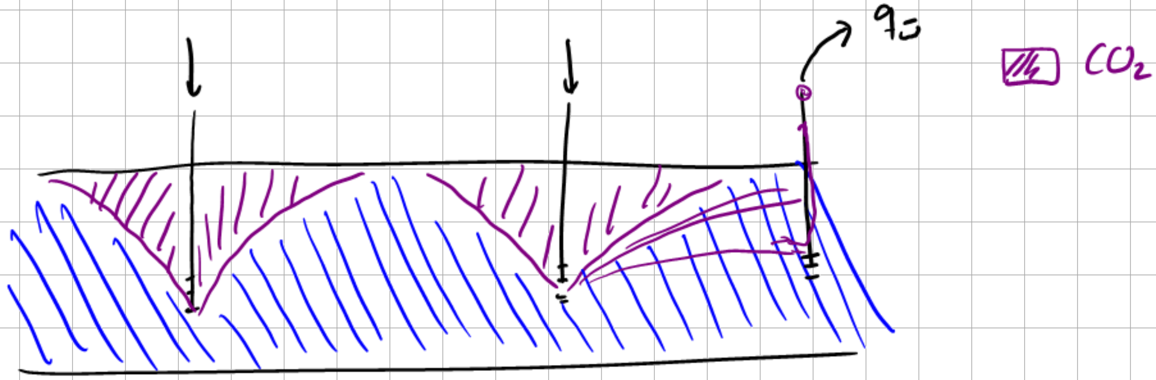
$^{t}/_{d}$ year $^{d}/_{y}$

qfield = 18000 t/d, 9 wells



12 wells, 2 year plateau extension

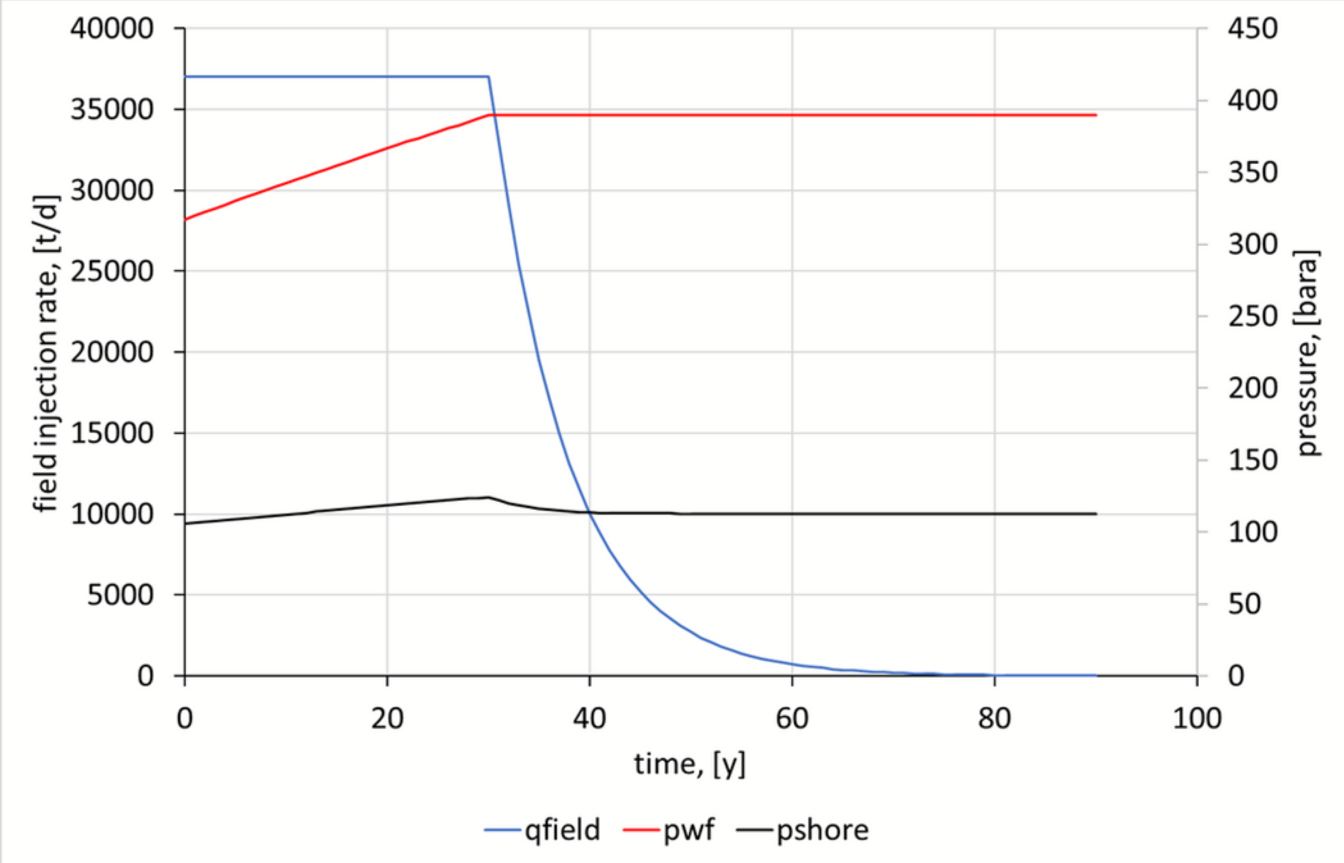




drilling water producers to maintain reseroir pressure limited.

Using Equinor data $q_{field} = 1.5\ E6\ t/y \cdot 9 = 13.5\ E06\ t/y \rightarrow$

$\sim 37\,000\ t/d$



$$NPV_{calc} = \sum_{i=0}^{N} \frac{CF_i}{(1+d)^i}$$

$CF_i = \underbrace{revenue_i} - expenses_i$

ΔG_{inj}: Price of disposal of CO2

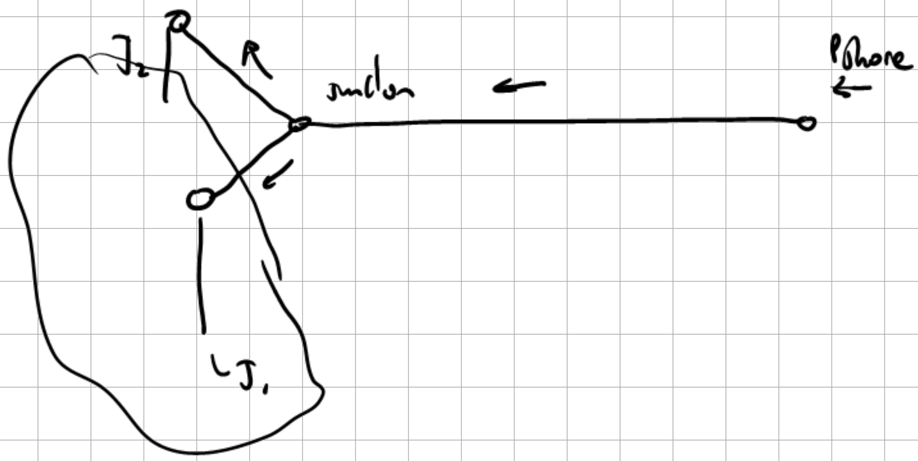
$\frac{USD}{t}$ $\frac{NOK}{t}$

", more than half of onshore storage capacity is estimated to be available below USD 10/t CO2"

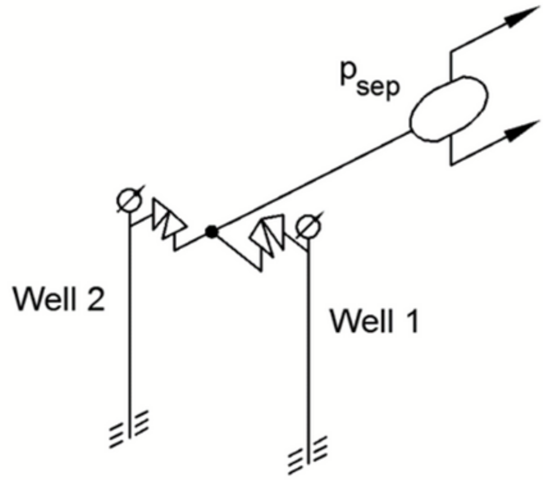
$\underbrace{10}\ USD/t \cdot 13\,E06\ t = \underbrace{130\,E06}\ USD/y$

$expenses_i = \underbrace{DRILLEX_i}_{\text{Well cost each well}} + \underbrace{Subsea_i}_{\text{flowlines, PLEM, template}} + \underbrace{OPEX_i}_{\text{maintenance, power requirement}}$

Network solving for CO_2 injection system



Network solving in a CO2 injection network



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).
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).
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.

How to deal and quantify uncertainty in field development

for example in our Snøhvit case

↳ G, N , $q_g = C_R (P_R^2 - P_{wf}^2)^n$

$

uptime 90 – 100%

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

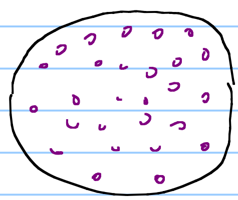
↳ cause additional OPEX

↳ cut in production → cut in Revenue

Input variables used in engineering studies in FD are highly uncertain

$\Phi_{min} \le \Phi \le \Phi_{max}$ 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)

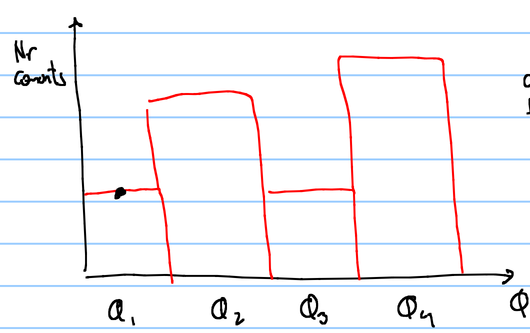
Φ_3 (0.25)

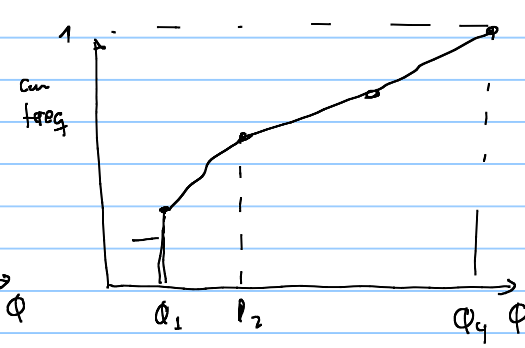
max Φ_4 (0.30)

if $\Phi_i = 0.18$

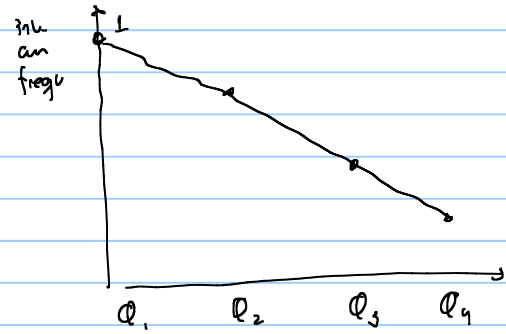
$\Phi_1 \le \Phi_i \le \Phi_2$

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 → 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	(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	F	G
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

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

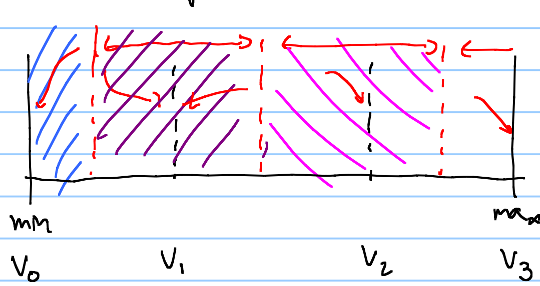
starting from $\text{bin}^0 = \text{min}$

to apply frequency function:

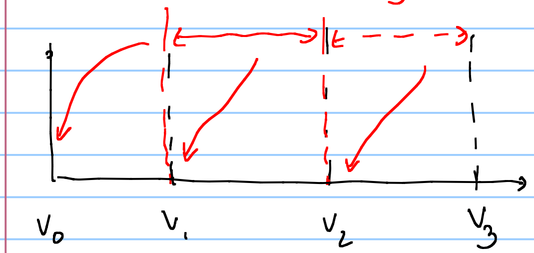
ctrl + shift + enter (in sequence and leave it pressed)

selecting bins must take into account

- nr data points



be careful how the frequency is accounted for



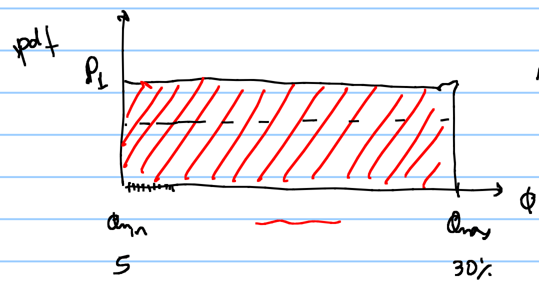
what happens if there are no measurements?

frequency ⤳ probability

rel frequency ⤳ pdf probability density function

cum frequency blol ⤳ cdf cumulative distribution function

poor boy, no data pdf ϕ continuous probability



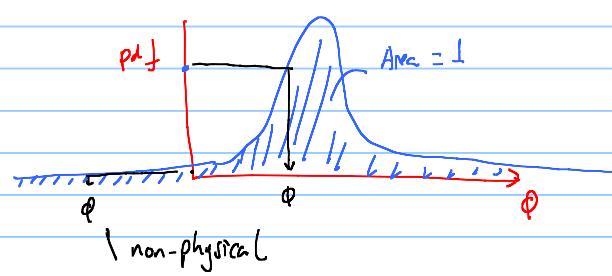
$$Area = (\phi_{max} - \phi_{min}) \cdot P_1 = 1$$

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

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



so bounding is necessary

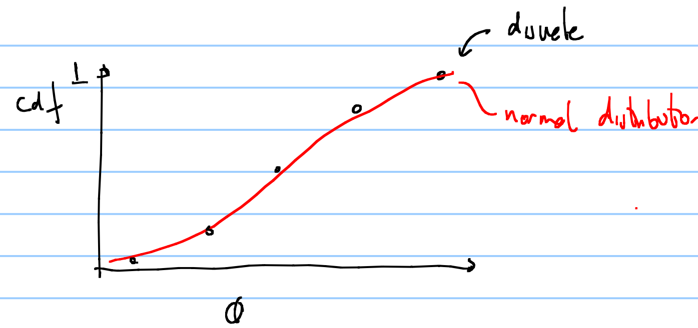
discrete distribution ⟶ continuous distribution

ϕ
ϕ_1
ϕ_2
⋮

$\left.\right\}$ μ, σ → parameters of a normal distribution

- calculate directly using population data

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

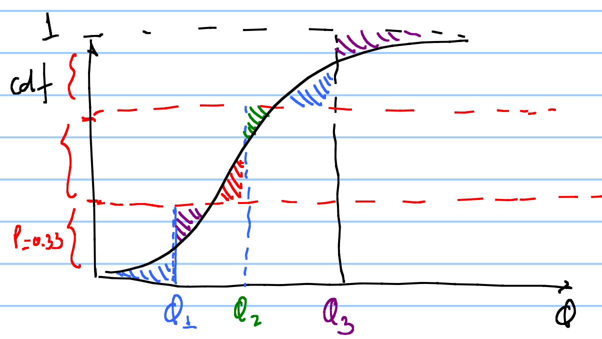


$$\frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{1}{2}\left(\frac{x-\mu}{\sigma}\right)^2}$$

change μ, σ until diff discrete and continuous is minimal

continuous distribution → discrete distribution

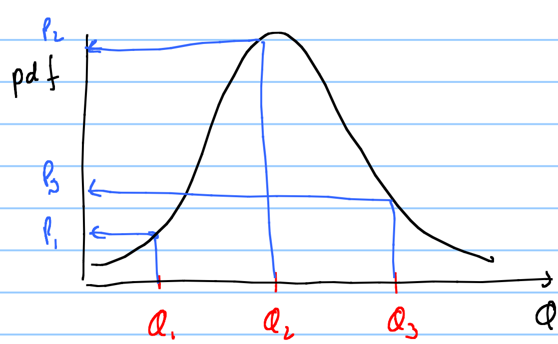
- Bracket mean
  - define nr bins
  - define probability of bins



Q	P
Q_1	0.33
Q_2	0.33
Q_3	0.33

find Q_1, such that [purple area] = [blue area]

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



Q	P
Q_1	P_1^*
Q_2	P_2^*
Q_3	P_3^*

- Normalize probabilities using the sum

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

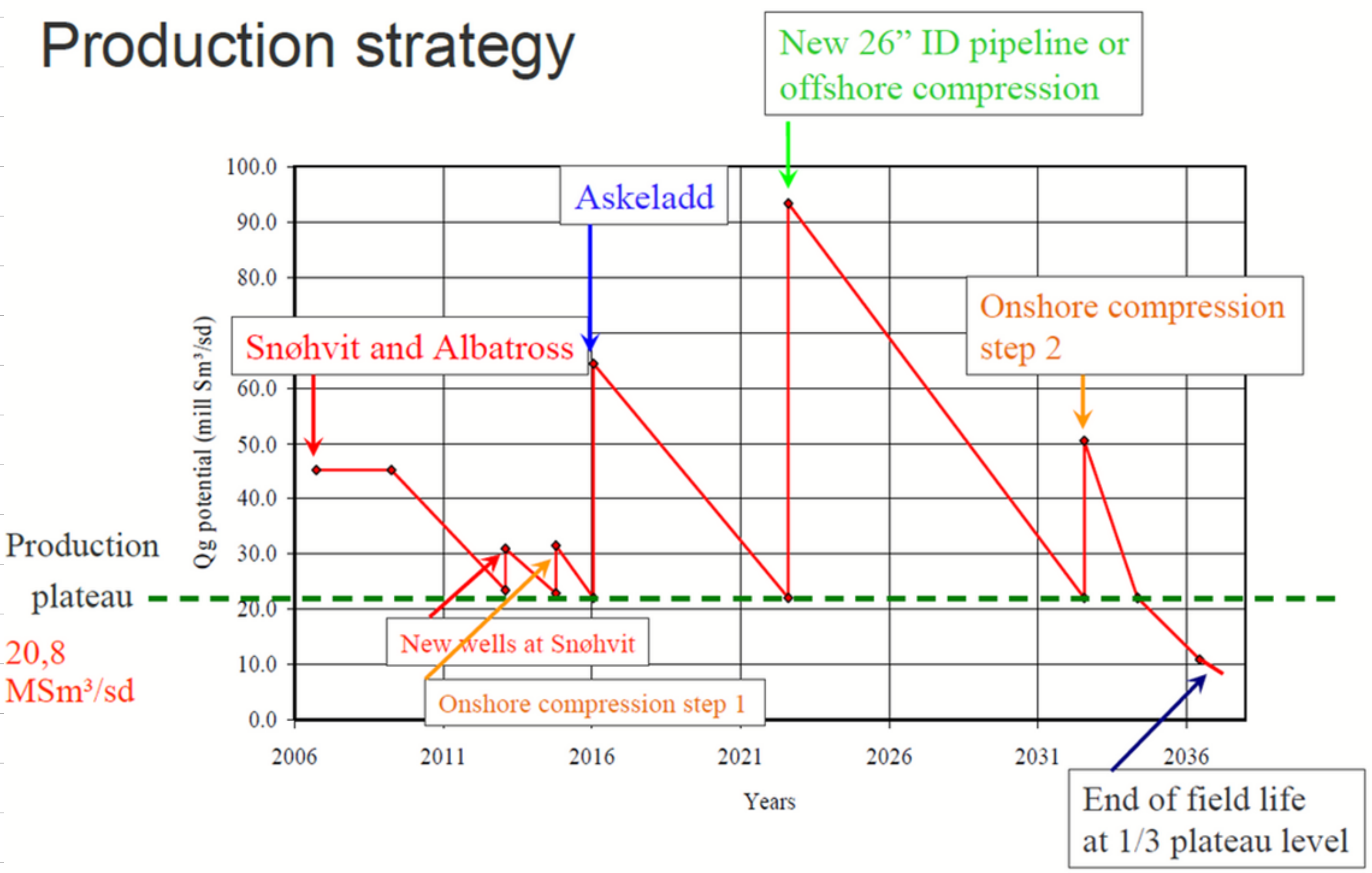
$$P_2^* = \frac{P_2}{P_1 + P_2 + P_3}$$

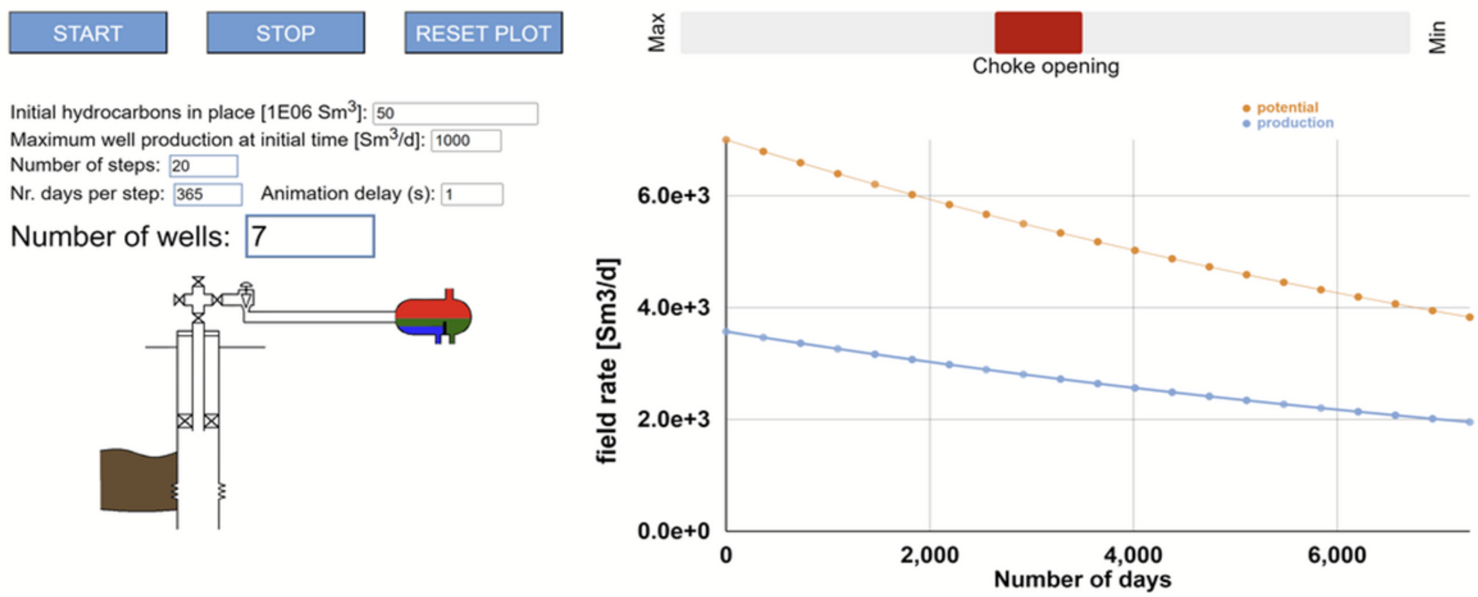
20240314

Outline:
-Recap on video lecture: production potential
-Production potential exercise

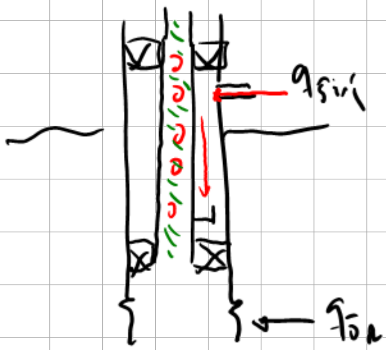
Information:
-2nd meeting of reference group today after class
-Changing the deadline of mandatory exercise set 3 for next week (Thursday)?

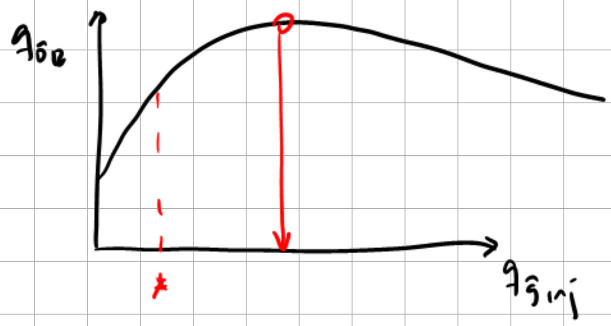
Production strategy





I could be operating below potential and still be in decline (mode B), for example:
-To limit the maximum well rate to avoid erosion, wellbore stability issues, sand production
-We might not now that we are not at potential (it is trivial for wells with chokes, but for e.g. gas lift, we need to find the maximum mathematically)





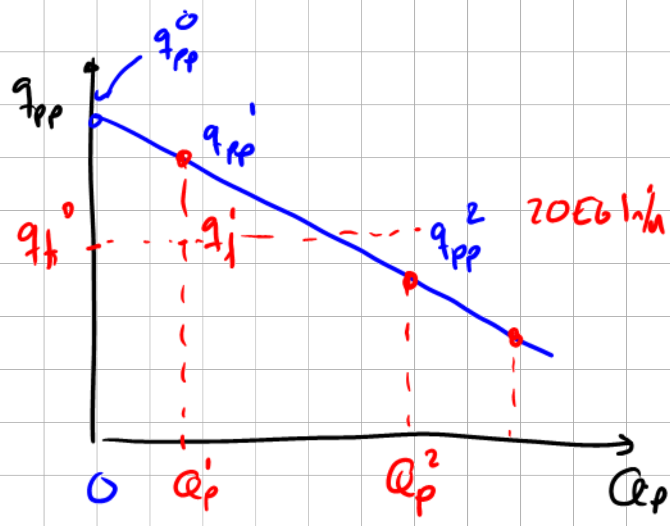
- if there are no changes to the system in time

Q_p ~ { N_p (oil cumulative production) / G_p (gas cumulative production) }

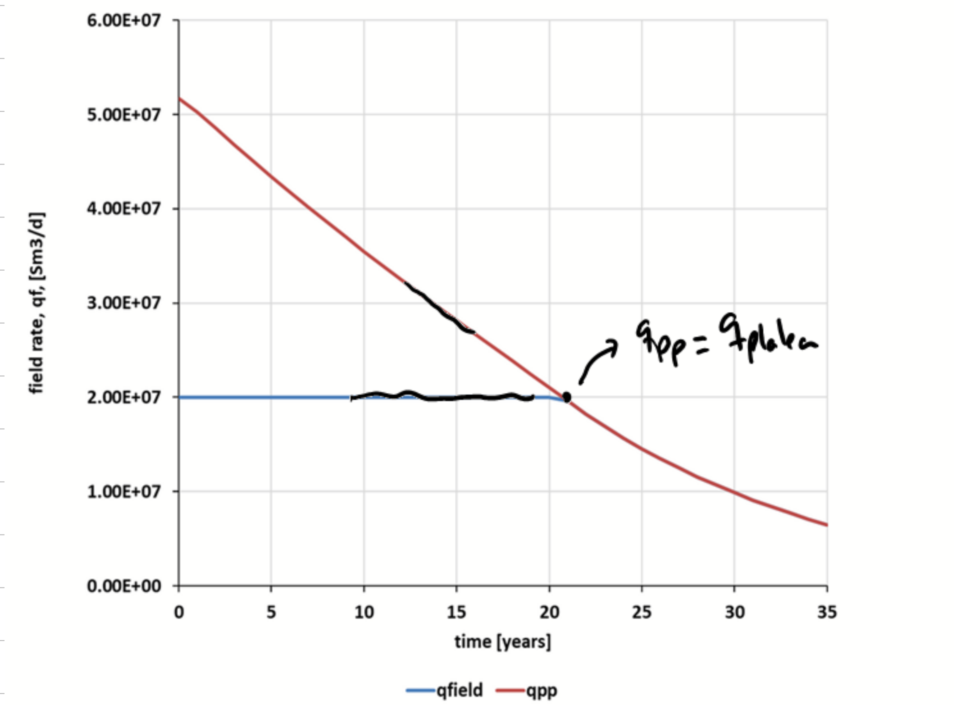
ultimate cumulative production (total recoverable reserves, TRR)

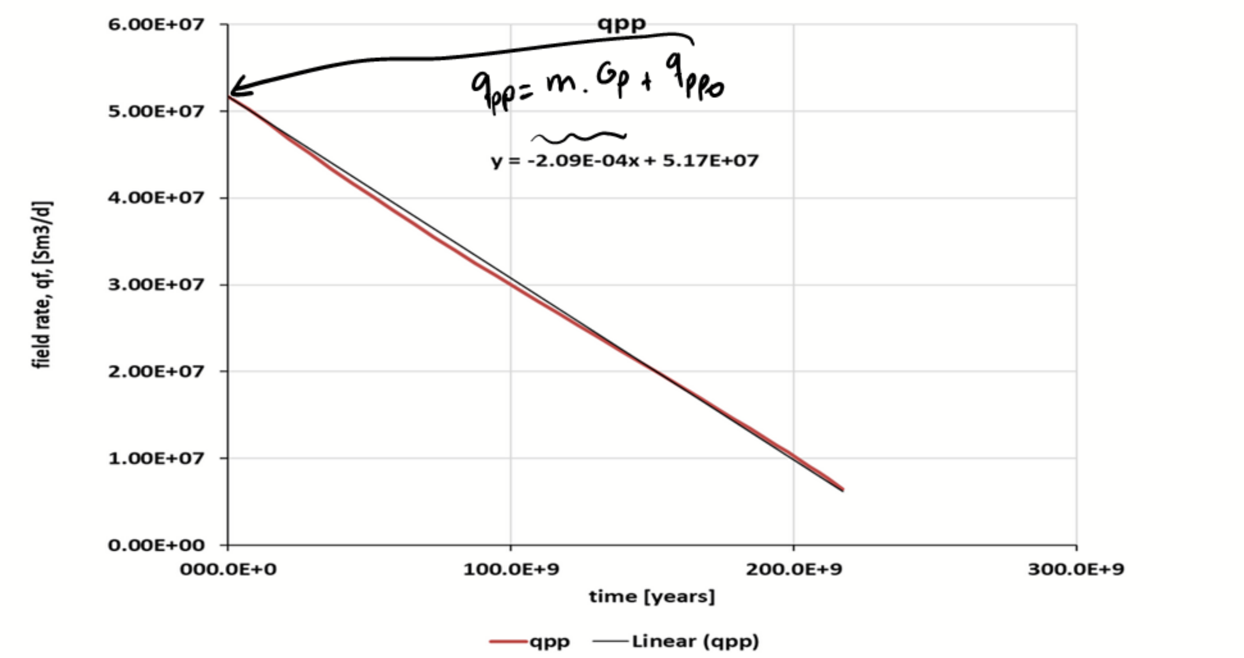
Production potential curves can be used to calculate production profiles!

time	q_{field}	q_{pp}	Q_p
0	q_f^0	q_{pp}^0	0
1	q_f^1	q_{pp}^1	$\square + q_f^0 (1-0) \cdot N_{days/yr} = Q_p^1$
2	q_{pp}^2	q_{pp}^2	$\square + q_f^1 (2-1) N_{days} = Q_p^2$
	q_{pp}^3	q_{pp}^3	



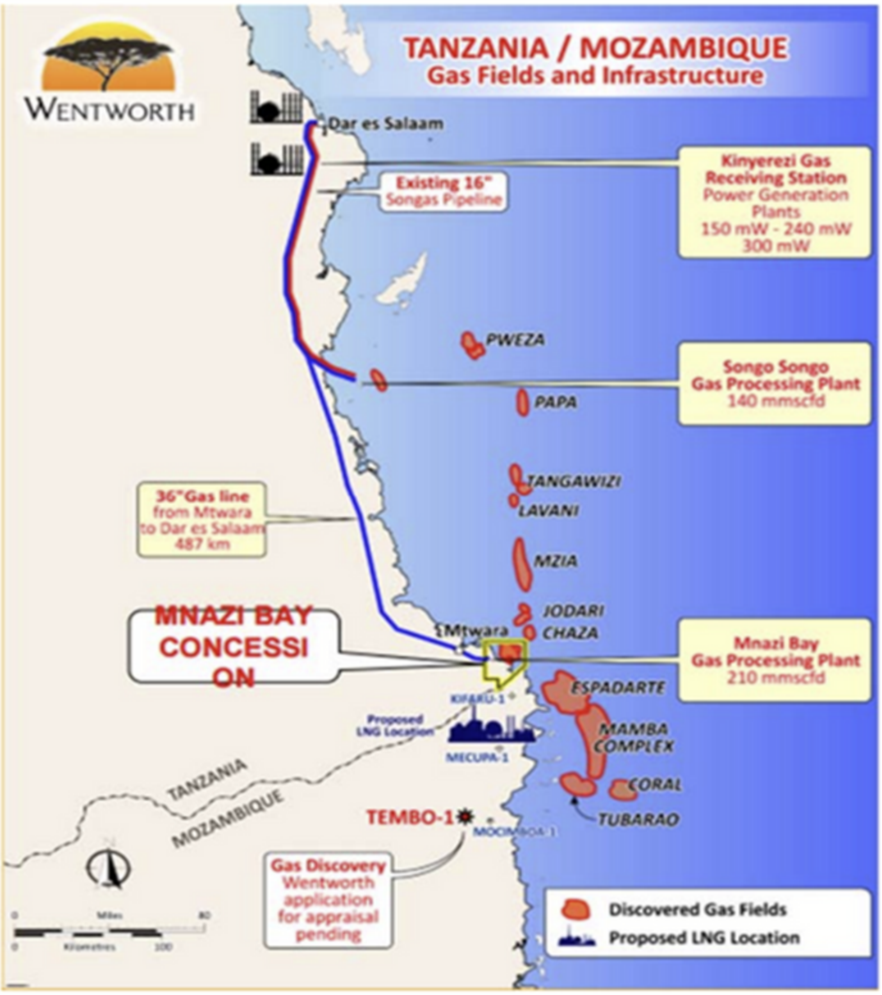
For the Snowhite field:





PROBLEM 1. (25 POINTS)

The Mnazi Bay is a gas field located in the south-eastern shores of Tanzania. The field will be produced with standalone vertical wells to a gas processing center (dehydration and refrigeration). The gas will be sent further via pipeline to feed the main power plant in Dar es Salaam, a local power plant in Mtwara/Lind and a Urea and Cement plant.



1. Estimate the minimum number of wells required to produce in plateau for 10 years with a field rate of 2.5 E6 Sm³/d. Determine the exact plateau duration (in days).
2. Using the results from question 1, and assuming that the minimum economic rate (field abandonment rate) is 0.2 E06 Sm3/d, what is the ultimate recovery factor expected from the field?
3. The values of $q_{ppo,well}$ and G are highly uncertain. Experts have estimated that they may vary within the ranges described below.

	min	max
$q_{ppo,well}$ [1E06 Sm³/d]	2	3
G [1E09 Sm³]	11	18

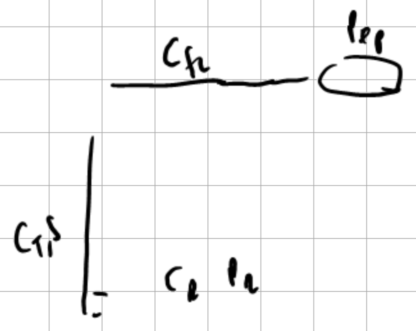
Considering these uncertainties, and using a conservative approach, determine the number of wells needed to ensure the field delivers a reservoir plateau rate of 2.5 E6 Sm3/d for at least 10 years.

$t_{plateau} > 10$ years

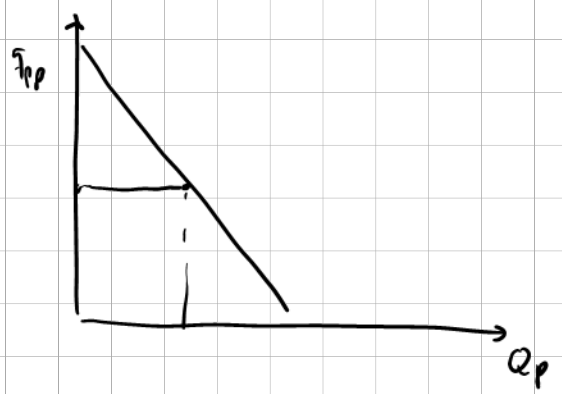
$q_{field} = 2.5E06\ Sm^3/d$

$t_{plateau} = ?$

option 1



option 2



$$q_{pp} = \underbrace{q_{pp0,w} \cdot N_w}_{q_{pp0t}} \left(1 - 1.14 \frac{G_p}{G}\right)$$

$q_{pp0,w} = 2.5E06$ Sm³/d

$G = 12E09$ Sm³

days/year = 355

at plateau end

$$G_p^* \geq 10 \cdot \underbrace{q_{plateau}}_{2.5E06} \cdot 355 = 8.875E9 \text{ Sm}^3$$

at plateau end (G_p^*) $\quad q_{pp} = q_{plateau}$

$$q_{plateau} = q_{pp0,w} \cdot N_w \cdot \left(1 - 1.14 \cdot \frac{G_p^*}{G}\right)$$

$$\frac{\frac{2.5E06}{2.5E06}}{1 - 1.14\left(\frac{8.875}{12}\right)} = N_w$$

$1.14 \cdot 0.7395$

$$\frac{1}{0.1569} = N_w$$

$6.37 = N_w$

$$\boxed{N_w = 7}$$

$$\overset{2.5E06}{q_{pp}} = \overset{2.5E06}{q_{pp0,w}} \cdot \overset{7}{N_w} \left(1 - 1.14 \cdot \frac{G_p^*}{\underbrace{G}_{12E09}}\right)$$

end of plateau occurs at $G_p^* = \left(1-\frac{q_{pp}}{q_{ppo,w}\cdot N_w}\right)\frac{1}{1.14}\cdot G$

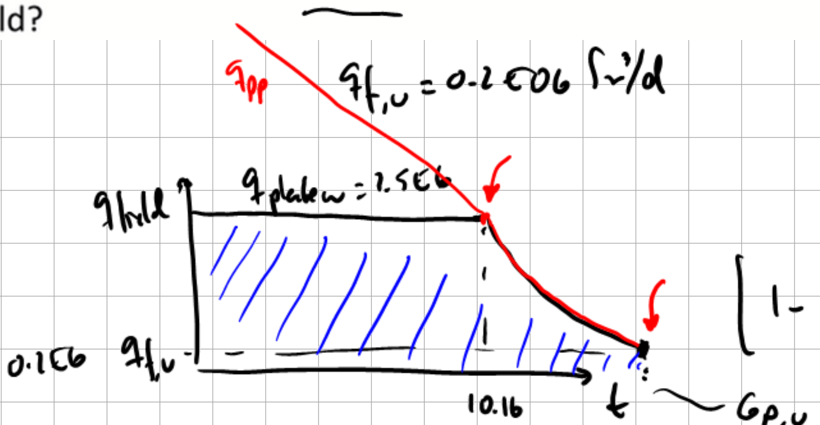
$$G_p^* = \left(1-\frac{1}{7}\right)\frac{1}{1.14}\cdot 12\,E9$$

$$G_p^* = \left(\frac{6}{7}\cdot\frac{12}{1.14}\right) = 9.02\,E9\ Sm^3$$

$$G_p^* = t_{plateau}\cdot q_{plateau}\cdot Ndays/year$$

$$\frac{9.02\,E9}{2.5E06\cdot 355} = t_{plateau} \rightarrow t_{plateau} = 10.16\ y$$

2. Using the results from question 1, and assuming that the minimum economic rate (field abandonment rate) is 0.2 E06 Sm3/d, what is the ultimate recovery factor expected from the field?



$$q_{pp,u} = q_{f,u} = q_{ppo,w}\cdot N_w\left(1-1.14\frac{G_{p,u}}{G}\right)$$

$R_{f,u}$

$$\left[1-\frac{0.2\,E6}{2.5E6\cdot 7}\right]\frac{1}{1.14} = \frac{G_{p,u}}{G}$$

$$\frac{(0.9885)}{1.14} = \frac{G_{p,u}}{G}$$

$$R_{f,u} = 0.867$$

3. The values of $q_{ppo,well}$ and G are highly uncertain. Experts have estimated that they may vary within the ranges described below.

2 ~ 2.5

$q_{ppo,t} = q_{pp,w}\cdot N_w$

	min	max
$q_{ppo,well}$ [1E06 Sm³/d]	2	3
G [1E09 Sm³]	11	18

2.5

2

Considering these uncertainties, and using a conservative approach, determine the number of wells needed to ensure the field delivers a reservoir plateau rate of 2.5 E6 Sm3/d for at least 10 years.

repeat question 1 with $G = 11\,E09$, $q_{ppo,w} = 2$

888.5E9

$$q_{plateu} = q_{IPo,w} \cdot N_w \cdot \left(1 - 1.14 \cdot \frac{G_p^*}{G}\right)$$

2.5E6 2 (~11E9

{20% productio..

2.5 → 2

{10% in

12 → 11

$$N_w = \frac{1.25}{0.08} = 15.6 \simeq 16$$

7 → 16 2×

4. Using the results from Task 1, compute the NPV of the project. Consider **only** the revenue from gas sales in the 10-year plateau period and the DRILLEX.

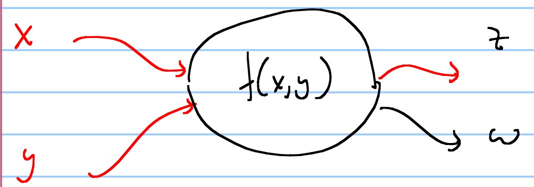
Task 4 (5 POINTS):

$$NPV = -CAPEX - DRILLEX + NPV_{rev}$$

Gas price	[USD/Sm3]	0.11
discount rate	[-]	0.08
DRILLEX per well	[USD/well]	5.00E+06
DRILLEX TOTAL	[USD]	3.50E+07
	NPV [USD]	4.46E+08
end of year	yearly cum prod	DCF (revenue)
	[Sm3]	[USD]
5	8.88E+08	6.64E+07
6	8.88E+08	6.15E+07
7	8.88E+08	5.70E+07
8	8.88E+08	5.27E+07
9	8.88E+08	4.88E+07
10	8.88E+08	4.52E+07
11	8.88E+08	4.19E+07
12	8.88E+08	3.88E+07
13	8.88E+08	3.59E+07
14	8.88E+08	3.32E+07

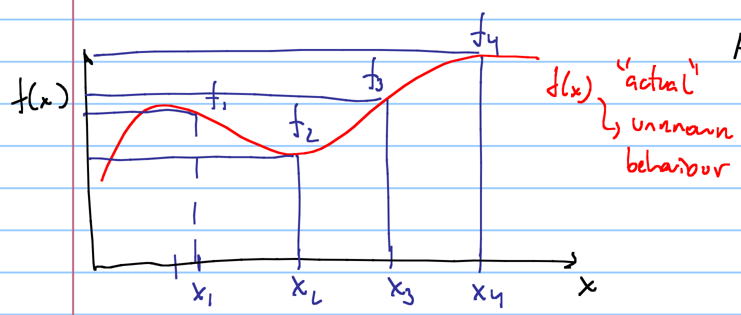
Notes to Youtube video 13

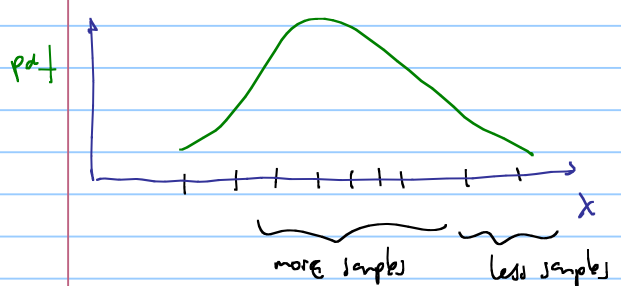
How to handle uncertain parameters in our FD calculations



deterministic calculation: x and y have a unique known value

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





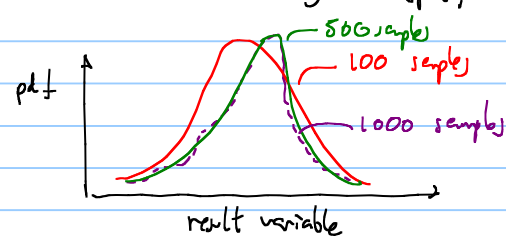
Approach to deal with uncertainty:

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

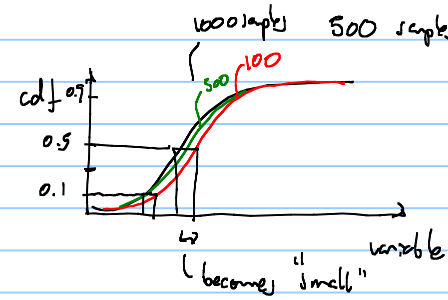
1: How many samples are needed?

2: How to generate the samples?

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



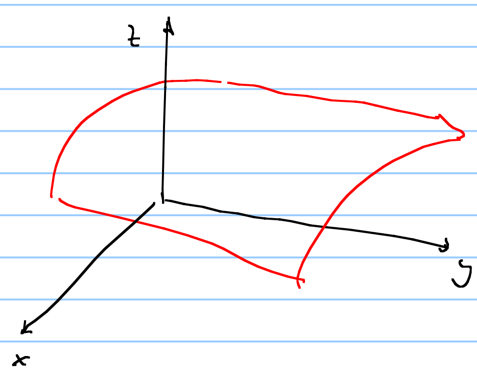
for this case, it seems 500 samples is enough

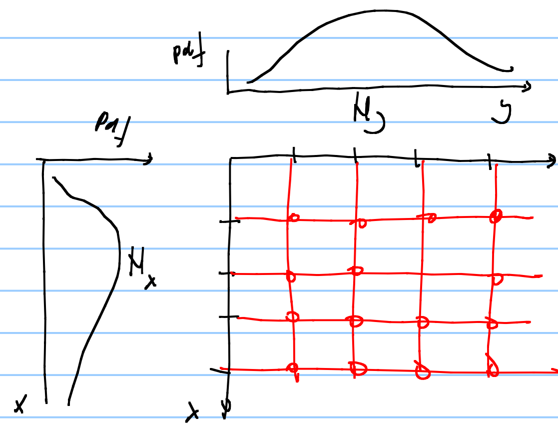


2: how to generate the samples

- Monte Carlo method
- Latin hypercube sampling

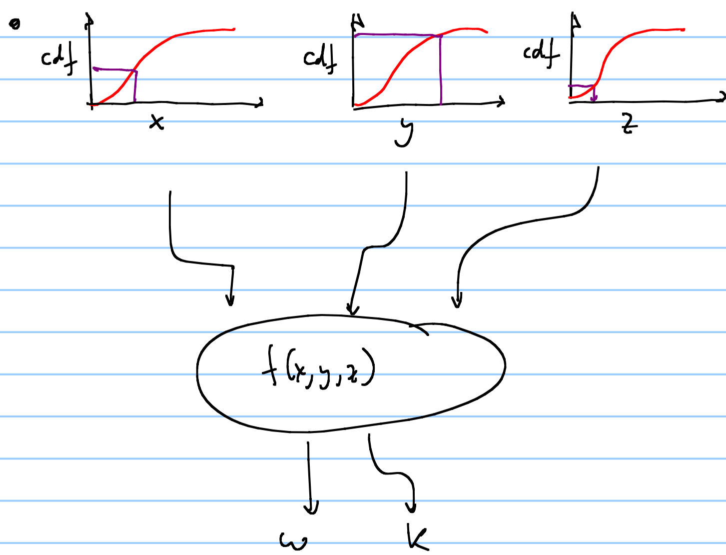
} efficient sampling → less number of samples to achieve convergence brute-force sampling





$N_{total} = N_x \cdot N_y$

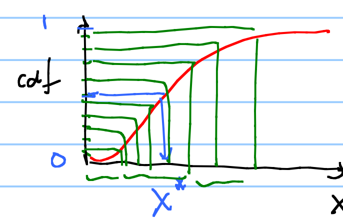
it is impractical for large number of variables/samples



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

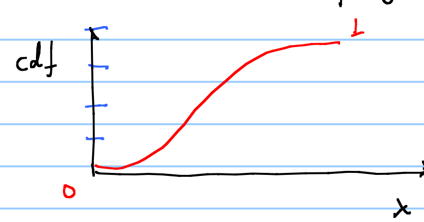
• Latin hypercube sampling (LHS)

① Define a number of samples "N"

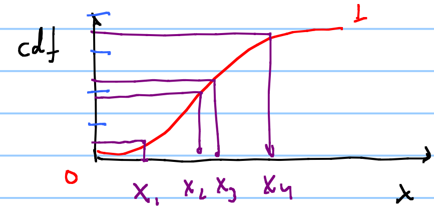
① For each variable

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)

$$\begin{array}{l} \text{sim 1} \\ \text{sim 2} \\ \text{sim 3} \\ \text{sim 4} \end{array} \begin{Bmatrix} x_3 \\ x_1 \\ x_4 \\ x_2 \end{Bmatrix} \quad \begin{Bmatrix} y_1 \\ y_3 \\ y_4 \\ y_2 \end{Bmatrix} \quad \begin{Bmatrix} z_3 \\ z_2 \\ z_1 \\ z_4 \end{Bmatrix}$$

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

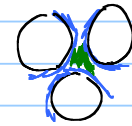
Reserve estimation : case undersaturated oil reservoir

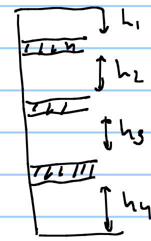
$$TRR = N_{pu} = \frac{V_R \cdot \phi \cdot N_{TG} \cdot S_o \cdot F_{RU}}{B_o}$$

TRR: total recoverable reserves

N_{pu}: ultimate cumulative production

F_{RU}: recovery factor





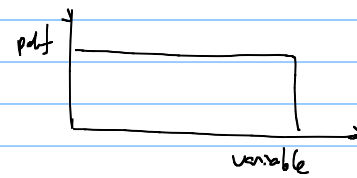
$$N_{TG} = \frac{h_1 + h_2 + h_3 + h_4}{h_{total}}$$

V_R ϕ N_{TG} S_o F_{RU} B_o

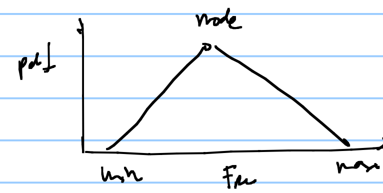
$$N_{pu} = \frac{V_R \cdot \phi \cdot N_{TG} \cdot S_o \cdot F_{RU}}{B_o}$$

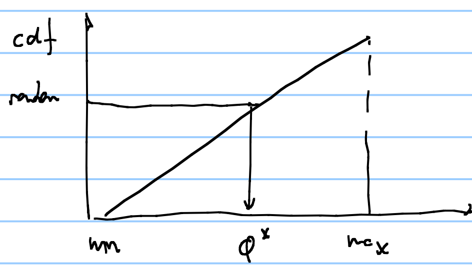
N_{pu}

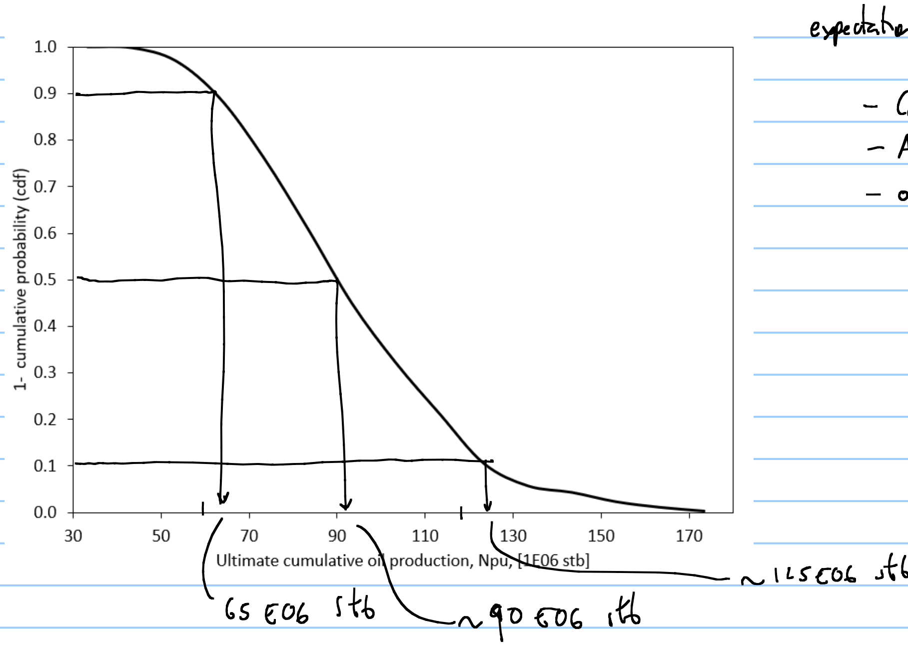
$V_R, \phi, N_{TG}, S_o, B_o$ have a uniform pdf



F_{RU}







expectation curve

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

20240321

OUTLINE:
-Recap
-Probability trees mini-theory
-Probability trees exercise
    -Including TRR MC simulation using Python

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 triangles

-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

expected value
"roll back the tree"

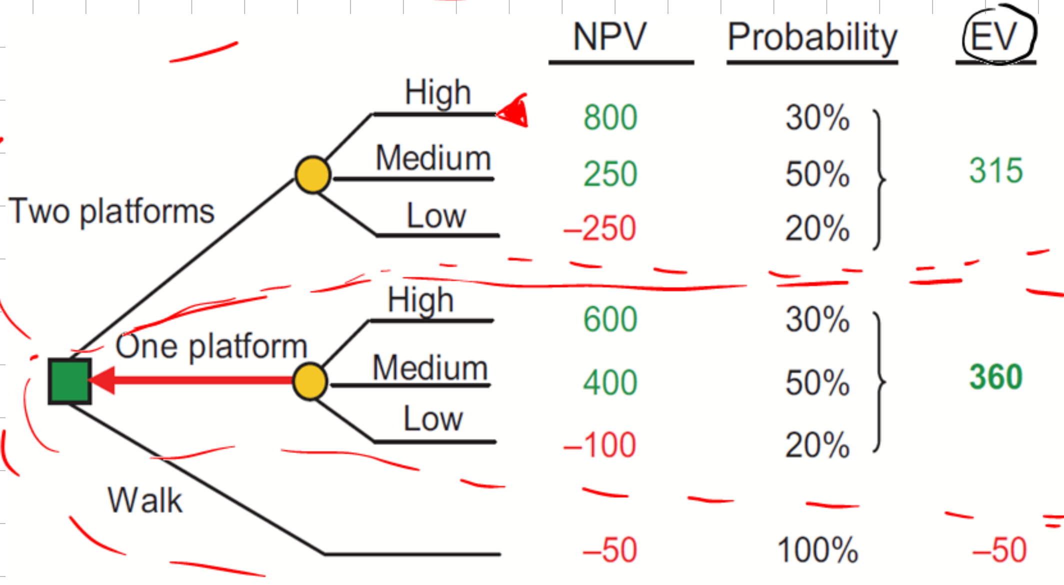
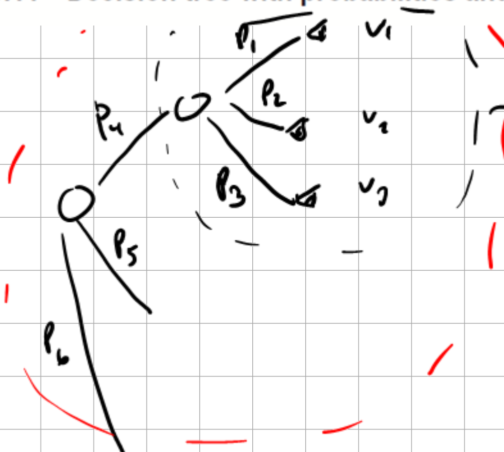


Fig. 5.11—Decision tree with probabilities and payoffs (in USD millions).



$EV = \Sigma(P_i V_i)$

An oil reservoir has been discovered in the Barents Sea, 310 km from Hammerfest. Seismic data and a few exploration wells have been drilled that provide enough information to perform an initial reserve estimation and economic valuation.

The company is currently in the business identification phase (leading to DG0) and is currently considering the following options:

- Go forward with the development
- Drill an appraisal well to find more information about the reservoir
- Relinquish to the government

To help the company to take the decision, you are considering employing a probability tree together with Monte Carlo simulations.

The cost of the appraisal well campaign is 100 million USD. The campaign could have two outcomes:

a. If the appraisal wells give a positive indication of hydrocarbons, It will confirm the upper value and lower values of the rock volume. If this is the case, 9 wells will be used, and 3 of those will be subsea, which require a heavier capital investment in facilities (1500 million USD).
b. If the appraisal wells give a negative indication of hydrocarbons, the maximum and minimum rock volumes must be reduced by 40%. If this is the case, only 6 wells can be used, and the capital investment in facilities is less (900 million USD).

Additional information

For estimating the economic value of the project, you must use the following simplified expression (in million USD)

$$NPV = P_o \cdot F_D \cdot N_{pu} - DRILLEX - CAPEX$$

Where:

- P_o is the price per barrel of oil [USD/bbl]. Use 60.
- $CAPEX$ is the cost of facilities, in million USD.
- $DRILLEX$ is the cost of drilling, equal to $N_w \cdot 50$ million USD, where N_w is number of wells.

- F_D is a discounting factor [-], representing that reserves are recovered and discounted gradually within a period of time, instead of at time zero. This value will depend on the production profile, but for your analysis, assume it is equal to 0.4.
- N_{pu} is the ultimate cumulative oil production [in Million stb] (or total recoverable reserves). Only oil is recovered from this field (due to lack of gas transport infrastructure).

The ultimate cumulative oil production is $N_{pu} = N \cdot F_R$, where

- F_R is the ultimate recovery factor [-].
- N is the initial oil in place [stb] , estimated by the expression

$$N = \frac{V_R \cdot \phi \cdot S_o \cdot N_{tg}}{B_o}$$

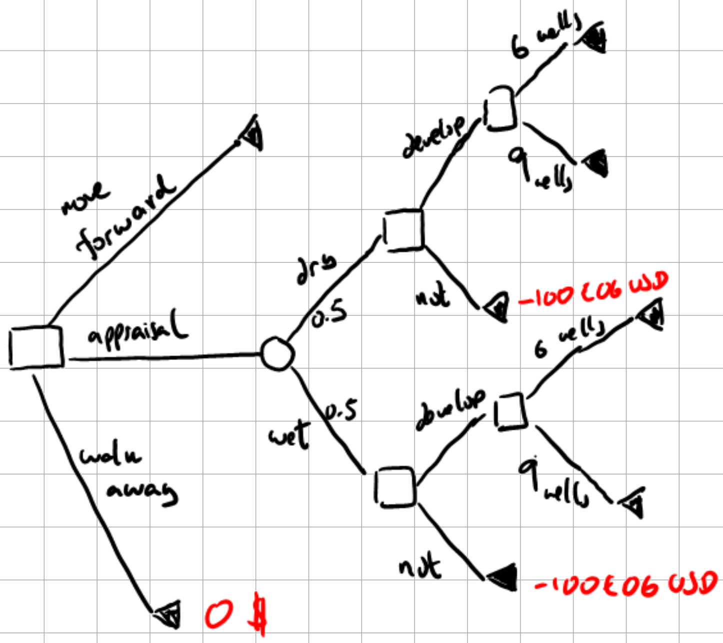
Where:

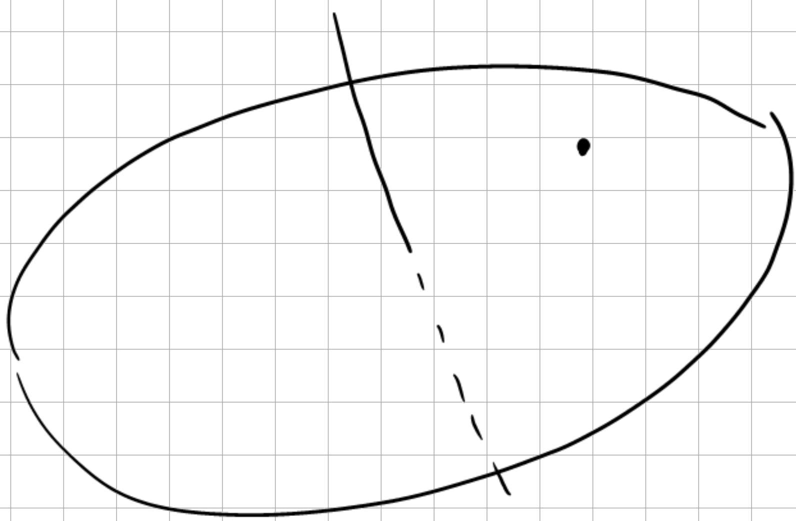
- V_R Rock volume [bbl]
- ϕ porosity [-]
- S_o oil saturation [-]
- N_{tg} Net to gross [-]
- B_o Oil formation volume factor [bbl/stb]

Values for the parameters and their probability distributions are provided in the table below:

			Net to Gros	Oil Saturation	Formation Volume Factor	Ultimate Recovery Factor
	Rock volume	**Porosity**	**N/G**	**So=(1-Sw)**	**Bo**	**Fr**
	bbl	fraction	fraction	fraction	Res bbl/STB	fraction
Min	5.00E+09	0.18	0.3	0.8	1.35	0.18
Max	6.25E+09	0.3	0.5	0.9	1.6	0.35
Mode						0.25

Class exercise

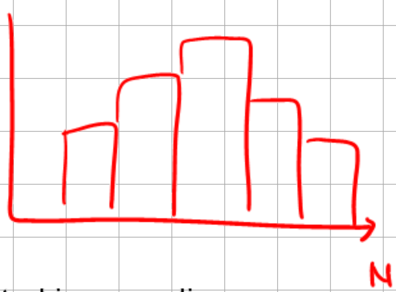




Calculate economic value using this equation:

$$NPV = \overset{60}{P_o} \cdot \overset{0.4}{F_D} \cdot N_{pu} - \overset{N_w \cdot 50,\ N_w = 6 \text{ or } 9}{DRILLEX} - \overset{\text{if } N_w=9,\ 1500\ E06\ USD;\ \text{if } N_w=6,\ 900\ E06\ USD}{CAPEX}$$

$$N_{pu} = \frac{V_R \cdot \phi \cdot S_o \cdot F_{RU} \cdot N_{tg}}{B_o}$$

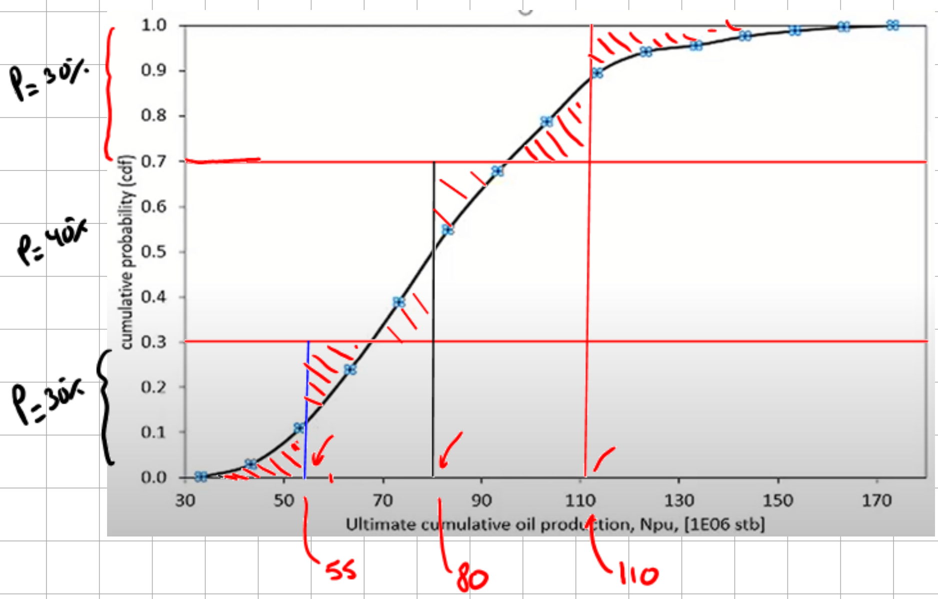


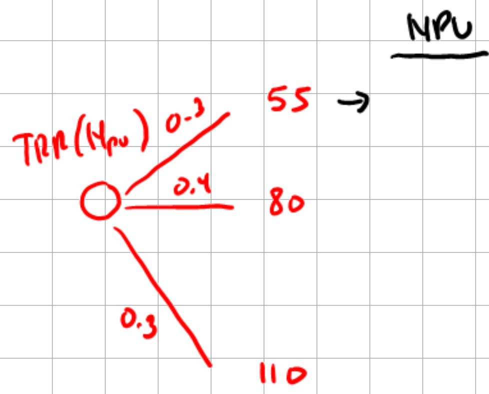
Calculated in an earlier Youtube video

https://youtu.be/eeljCw5h8-s?feature=shared&t=1389

Discretize the probsability distribution of TRR (Npu)

Bracket mean





P	Npu (positive appraisal)	NPV (6 wells)	NPV (9 wells)
0.3	55	120	-630
0.4	80	720	-30
0.3	110	1440	690

$$NPV(6\ wells) = 60 \cdot 55 \cdot 0.4 - 6 \cdot 50 - 900 =$$

$$1320 - 300 - 900 = 120$$

$$NPV(9\ wells) = 60 \cdot 55 \cdot 0.4 - 9 \cdot 50 - 1500 = -630$$

If the appraisal well is dry:

			Net to Gros	Oil Saturation	Formation Volume Factor	Ultimate Recovery Factor
	Rock volume	Porosity	N/G	So=(1-Sw)	Bo	Fr
	bbl	fraction	fraction	fraction	Res bbl/STB	fraction
Min	5.00E+09	0.18	0.3	0.8	1.35	0.18
Max	6.25E+09	0.3	0.5	0.9	1.6	0.35
Mode						0.25

→ 3E9

→ 3.75 E9

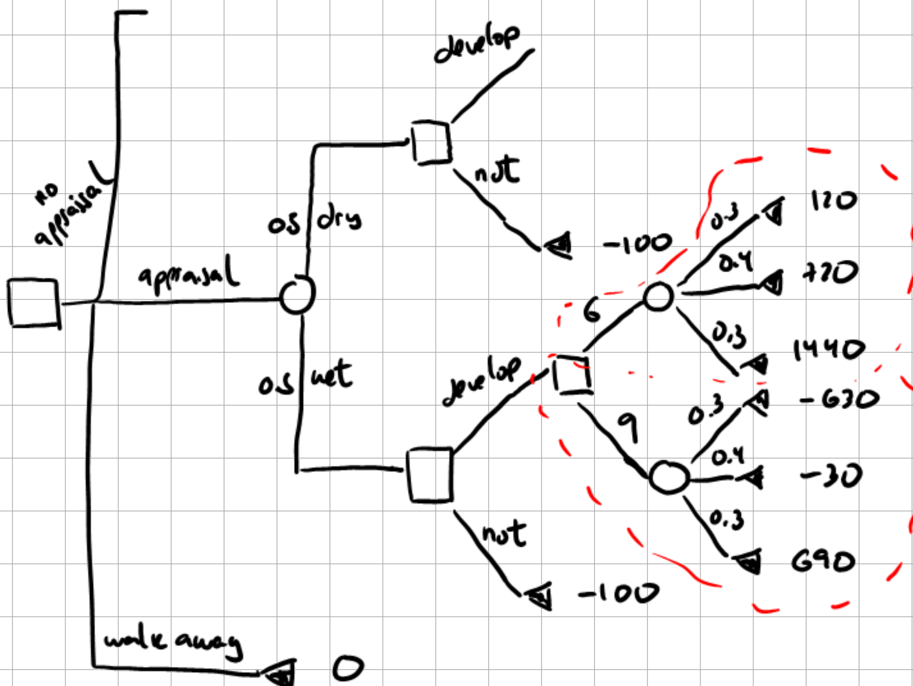
so in principle, I would need to repeat the MC simulation

$$N_{pu} = \frac{V_R \cdot \phi \cdot N_{tg} \cdot S_o \cdot F_{RU}}{B_o}$$

$$V_{R\,New} = V_{R\,OLD} \cdot 0.6$$

So, as an approximation, I assume I will obtain the same distribution in the new MC, but scaled by 0.6!

p	NPV (dry appraisal)	NPV (6 wells)	NPV (9 wells)
0.3	55 · 0.6 = 33	−408	−1158
0.4	80 · 0.6 = 48	−48	−798
0.3	110 · 0.6 = 66	384	−366

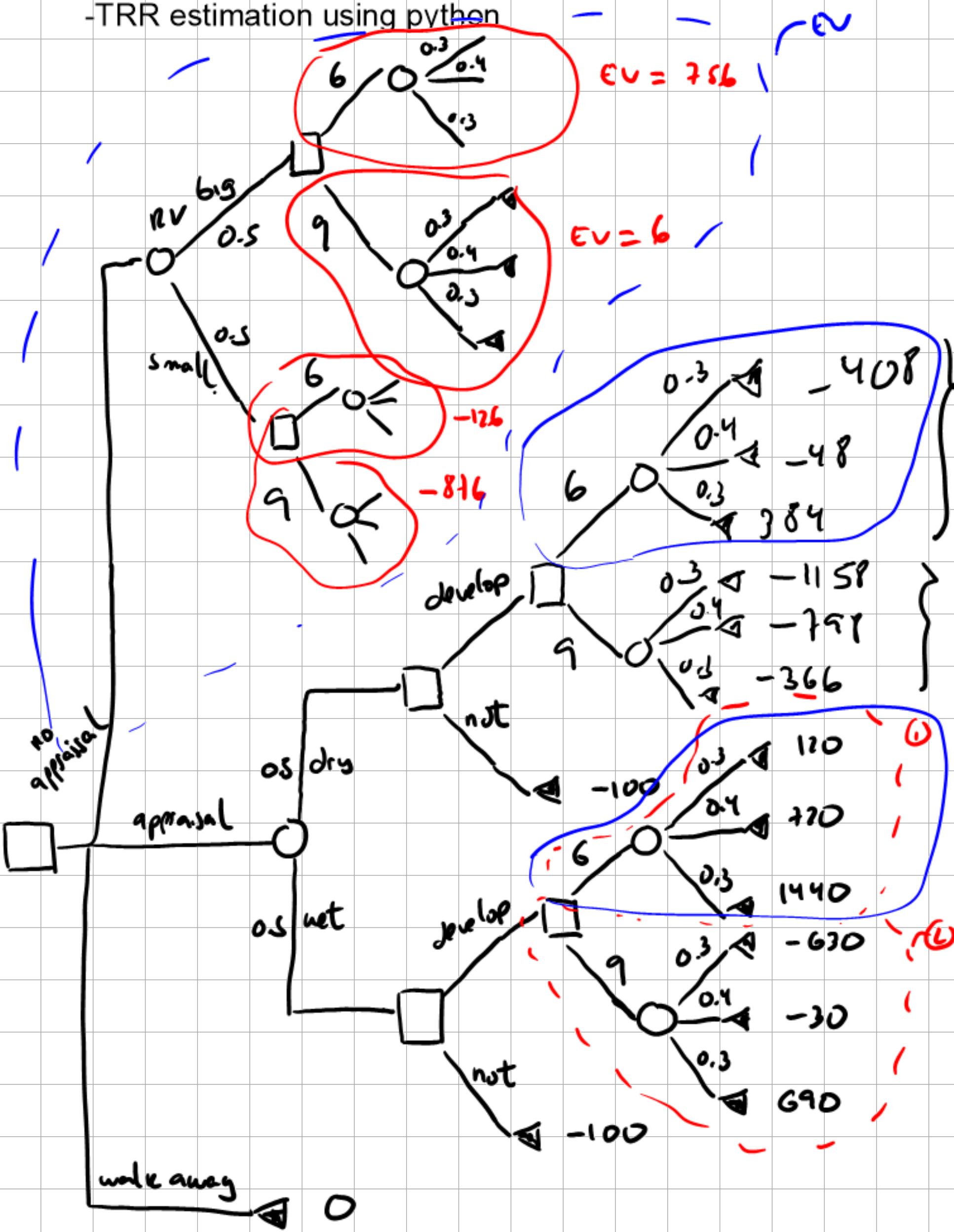


① $EV^{①} = 0.3 \cdot 120 + 0.4 \cdot 720 + 0.3 \cdot 1440$
$= 756$

② $EV^{②} = 0.3 \cdot (-630) + 0.4(-30) + 0.3 (690) = 6$

20240322

Outline
-Cont of exercise on probability trees
-TRR estimation using python



$EV = \Sigma(P_i \cdot NPV_i)$

$0.3(-408) + 0.4(-48) + 0.3(384)$

$EV = -26 - 100 = -126$

$EV = 0.3(-1158) + 0.4(-798) + 0.3(-366)$

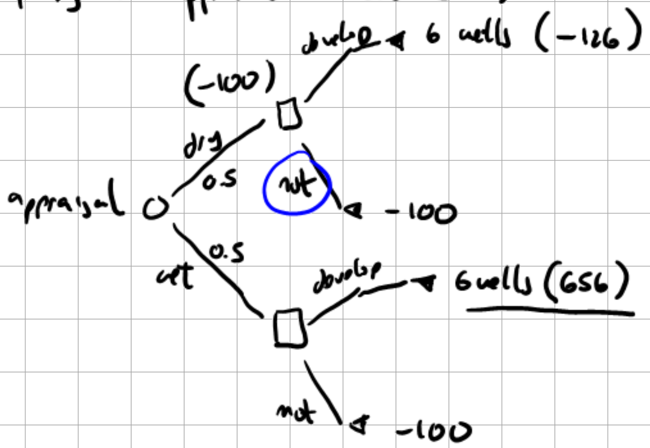
$EV = -776 - 100 = -876$

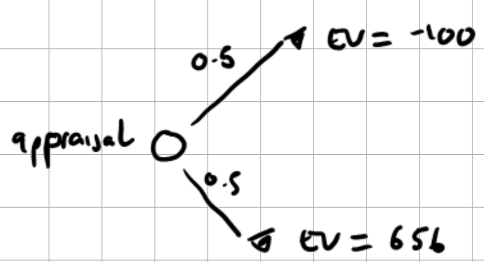
① $EV^{①} = 0.3 \cdot 120 + 0.4 \cdot 720 + 0.3 \cdot 1440$

$= 756 - 100 = 656$

② $EV^{②} = 0.3 \cdot -630 + 0.4(-30) + 0.3(690) = 6 - 100 = -94$

simplify the appraisal Branch (EV)

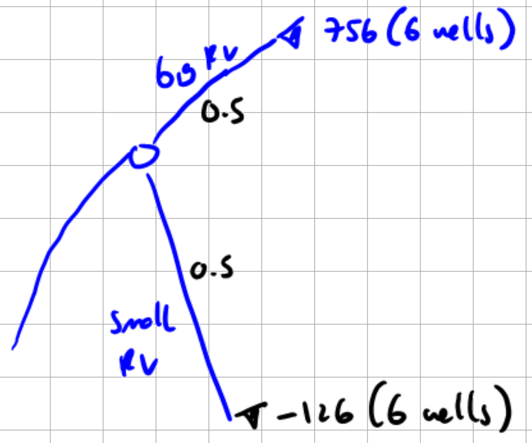




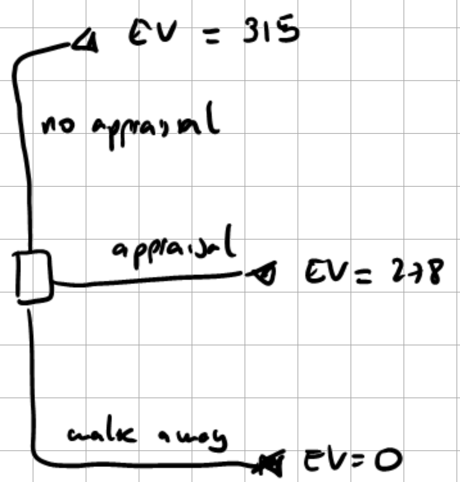
appraisal $EV = 0.5 \cdot (-100) + 0.5(656)$

$EV = 278$

Simplify the "no appraisal" branch



$$EV = 756 \cdot 0.5 + (-126) \cdot 0.5 = 315$$

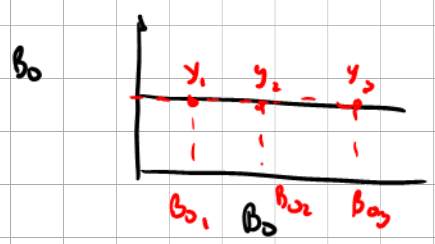


it seems the best solution is

- no appraisal
- 6 wells

How would you solve the MC TRR problem using probability trees?

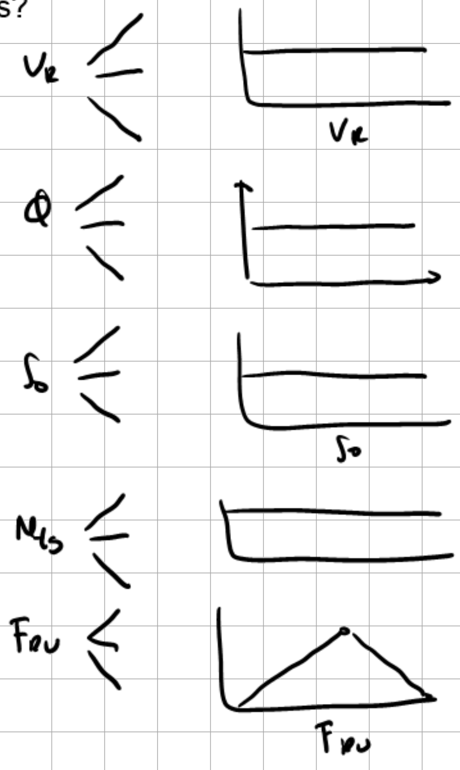
$$N_{pu}(TRR) = \frac{V_R \cdot \Phi \cdot S_o \cdot N_{tg} \cdot F_{pu}}{B_o}$$



$$P_1 = \frac{y_1}{y_1 + y_2 + y_3}$$

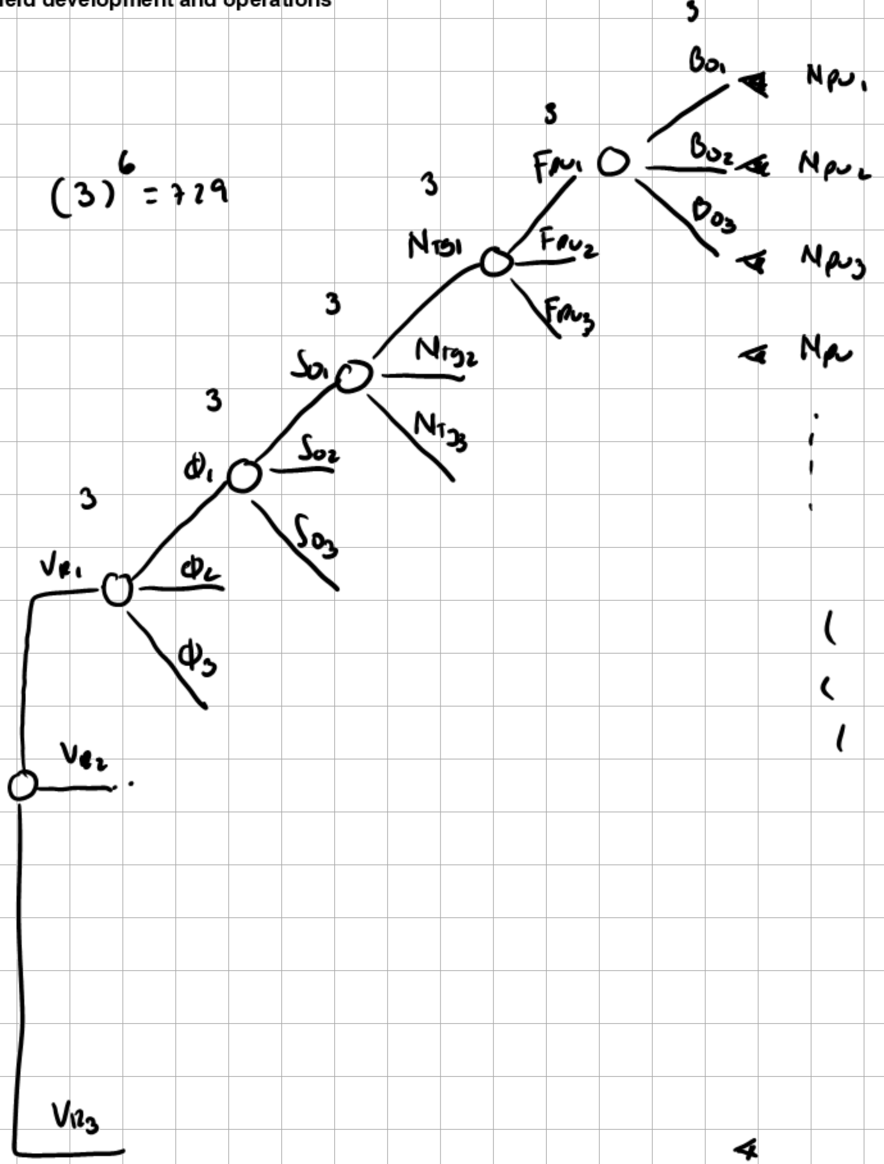
B_o

$$P_2 = \frac{y_2}{y_1 + y_2 + y_3}$$



$(3)^6 = 729$

$$P \overset{?}{=} P_{VR_1} \cdot P_{\Phi_1} \cdot P_{So_1} \cdot P_{NtG_1} \cdot P_{FRU_1} \cdot P_{Bo_1}$$

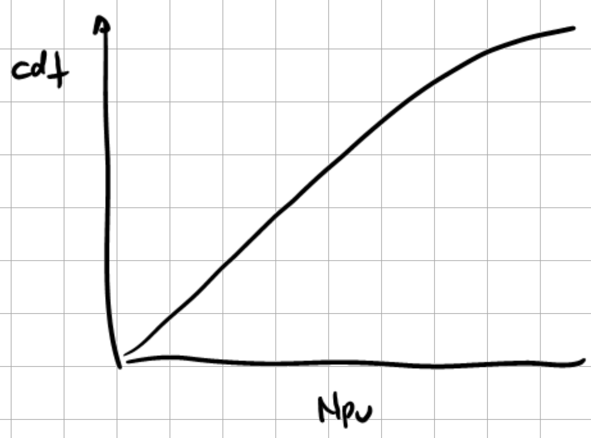


Result

Npu	P
Npu_1	P_1
Npu_2	P_2
⋮	⋮
729	

Sort from small to big

?



Npu	P	CP
Npu_7	P_7	P_7
Npu_{100}	P_{100}	$P_7 + P_{100}$
⋮		$P_7 + P_{100} + \dots$

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

Using python to perform MC simulation of the TRR

```
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)
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()
```

```
P90= np.percentile(Npu_v,10)
P10= np.percentile(Npu_v,90)
P50= np.percentile(Npu_v,50)
```

Notes for Youtube video offshore structures 1

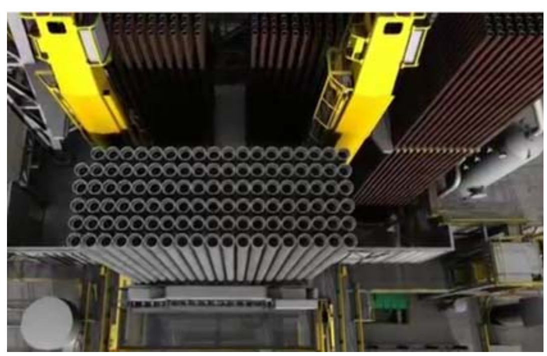
Offshore structures for oil and gas production

Prof. Milan Stanko (NTNU)

1

Components

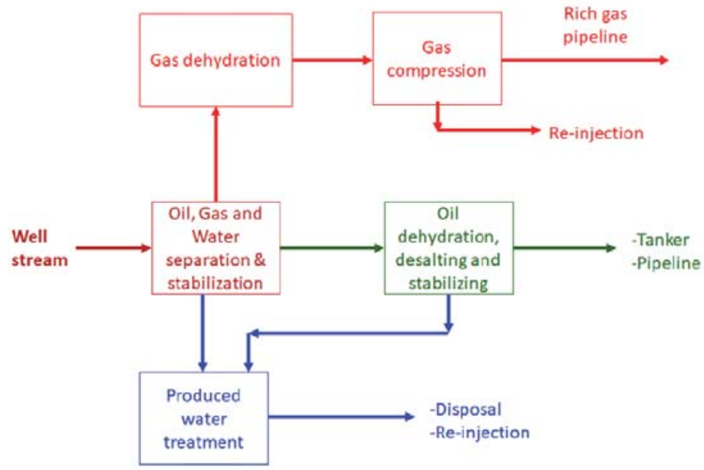
- Facilities for drilling and full intervention. This includes drilling tower, BOP, drilling floor, mud package, cementing pumps, storage deck for drill pipes and tubulars, drilling risers.



2

Components

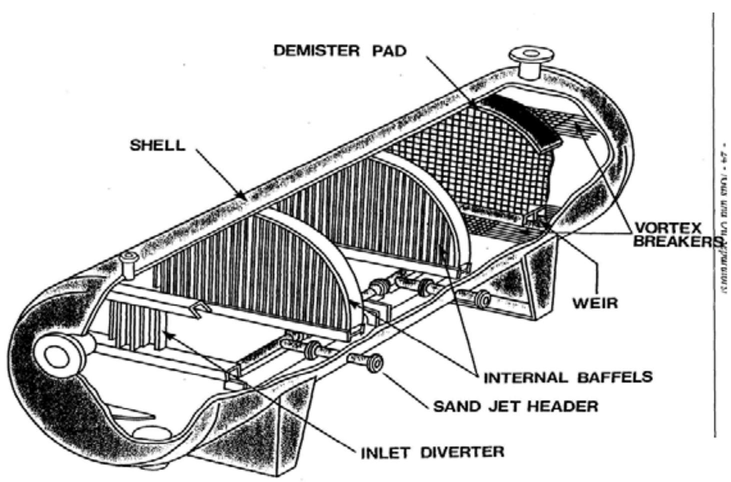
- Facilities for light well intervention.
- Processing facilities: separator trains for primary oil, gas and water separation, gas processing train, water processing train.
- Gas injection system
- Gas compression units for pipeline transport
- Water injection system



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

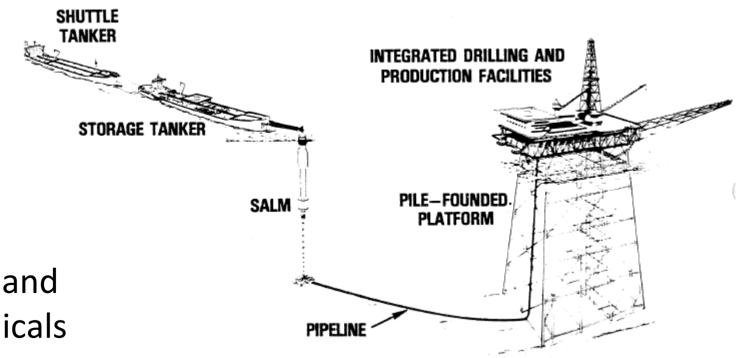
Components

- 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

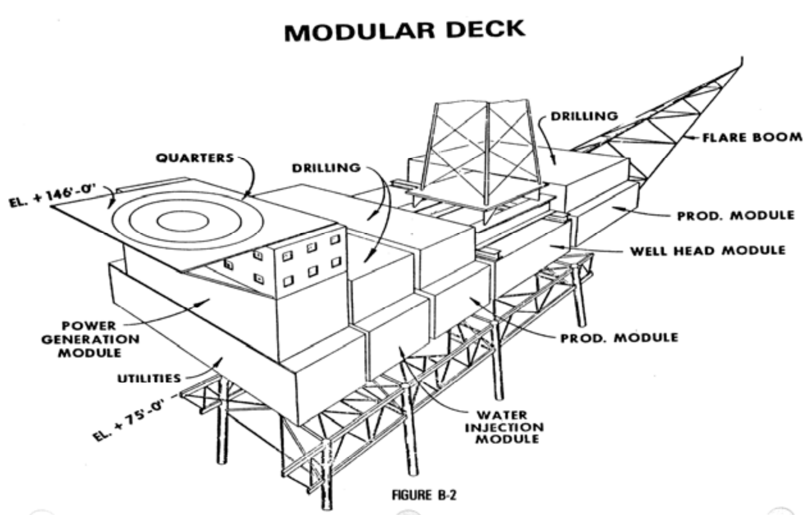


FIGURE B-2

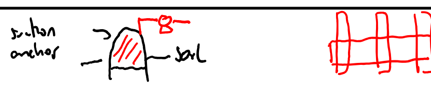
8

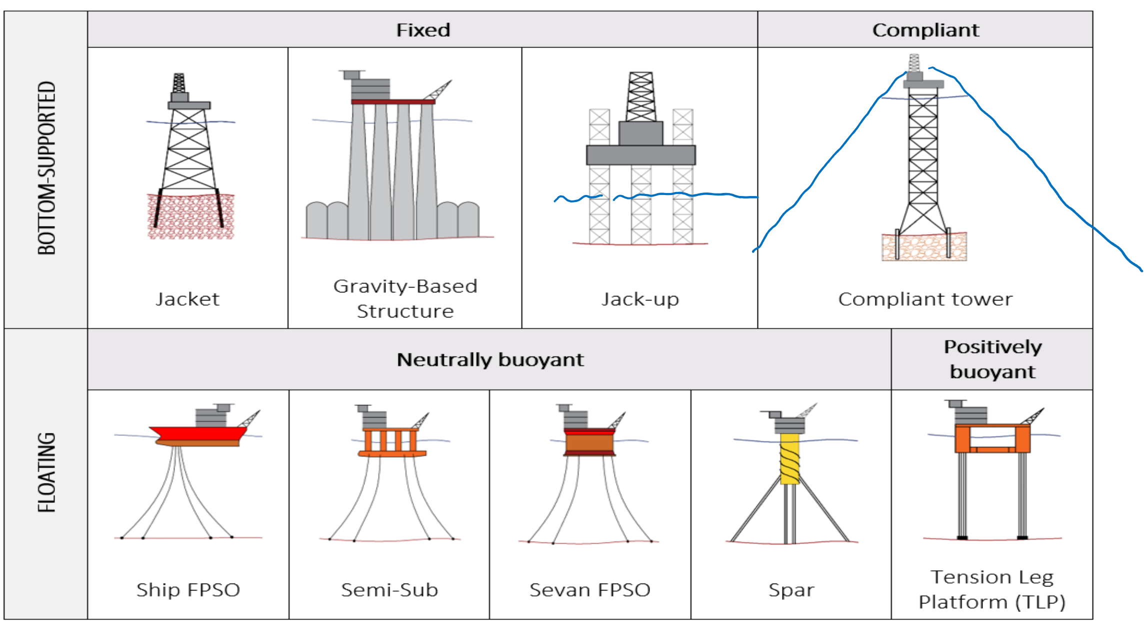
Components – can be spread

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

9

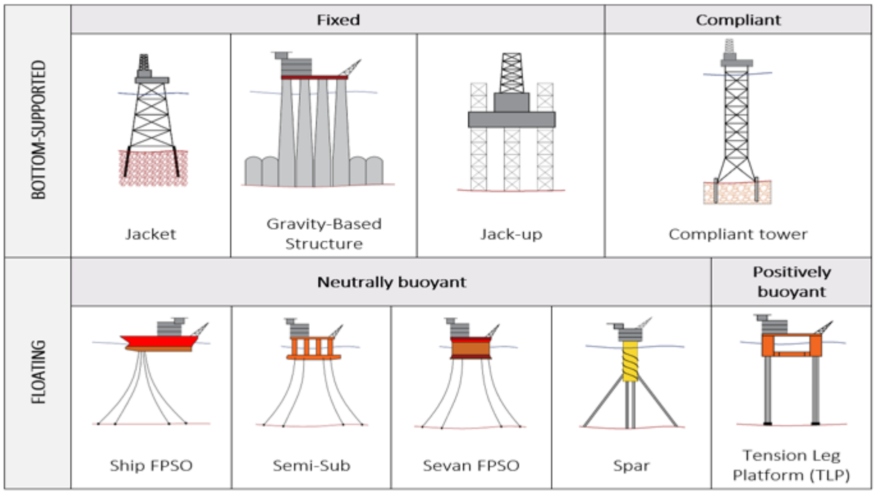
Types





10

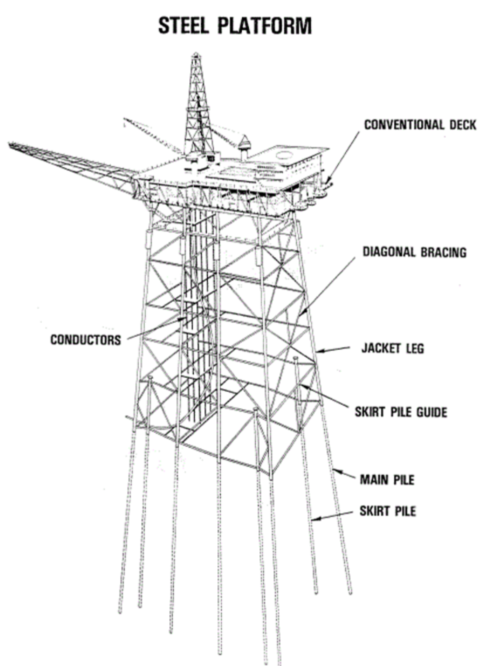
Types



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

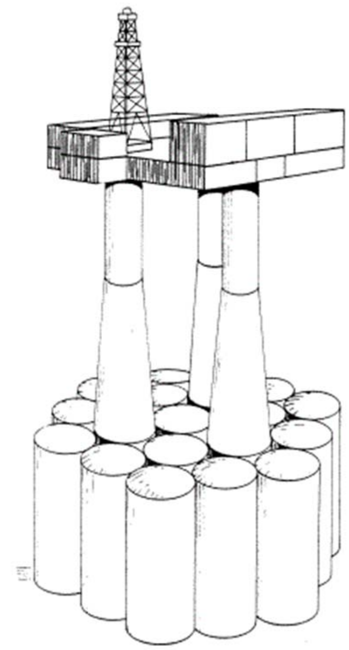
11

Jacket



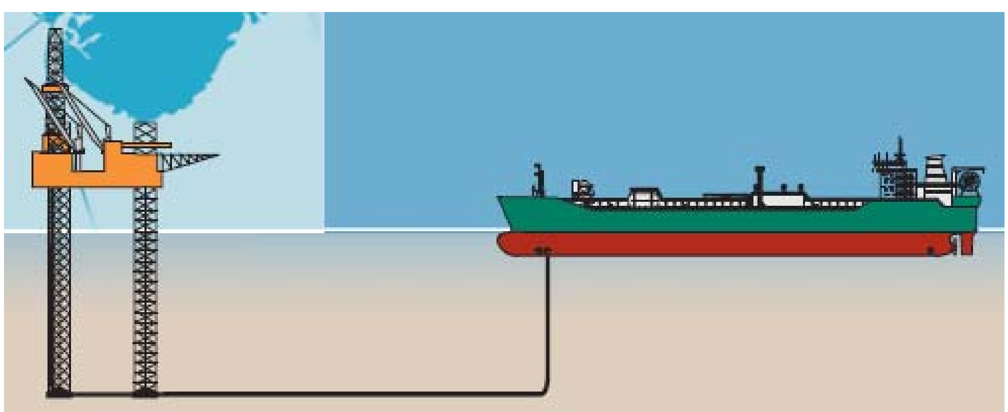
12

GBS



13

JACKUP



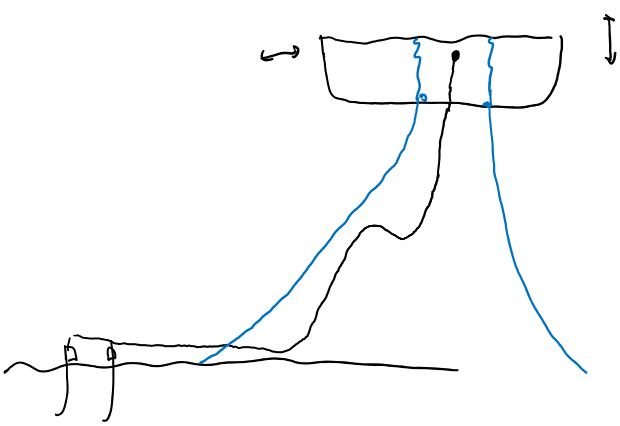
Taken from Volve PDO

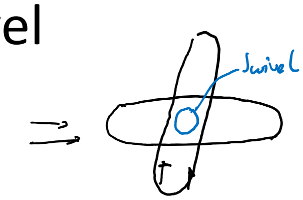
14

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

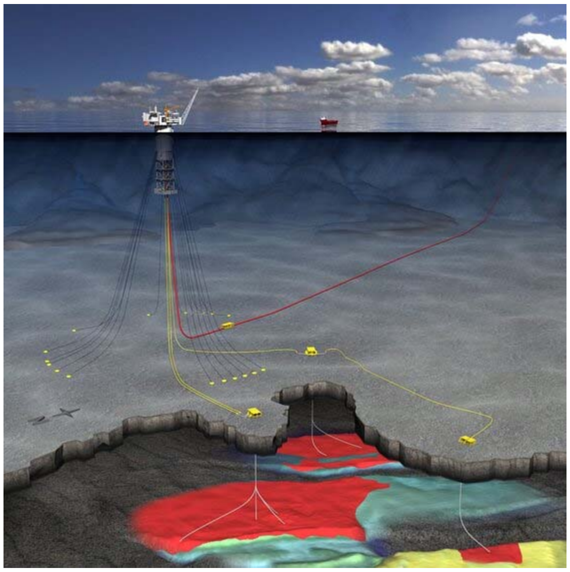
18

FPSO - Swivel

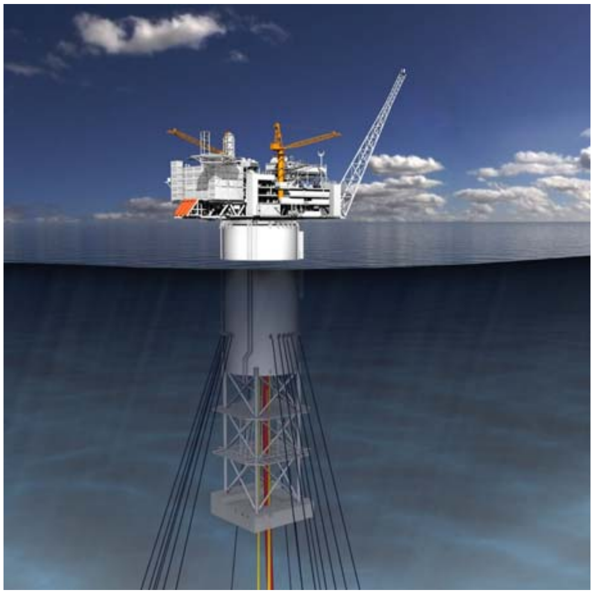
https://www.youtube.com/watch?v=HbJh1ar0u1s

19

SPAR



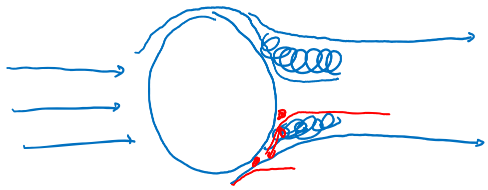
https://www.tu.no/artikler/industri-kvaerner-sikrer-enda-et-aasta-hansteen-oppdrag/225940



https://www.tu.no/artikler/industri-kvaerner-sikrer-enda-et-aasta-hansteen-oppdrag/225940

20

Vortex shedding



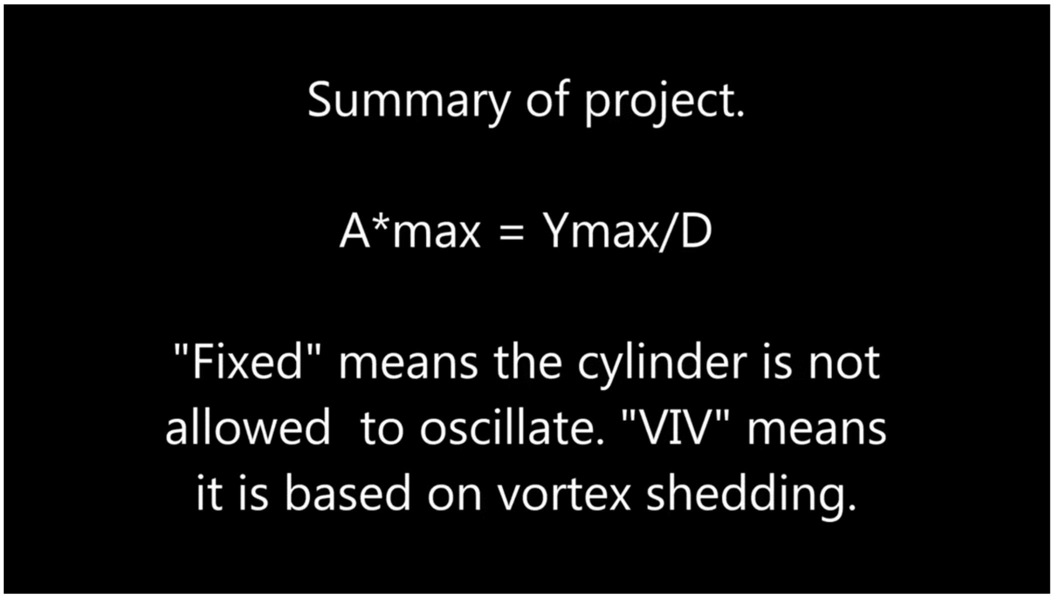
21

SPAR – Vortex induced vibrations

https://www.youtube.com/watch?v=_Hbbkd2d3H8&feature=youtu.be

22

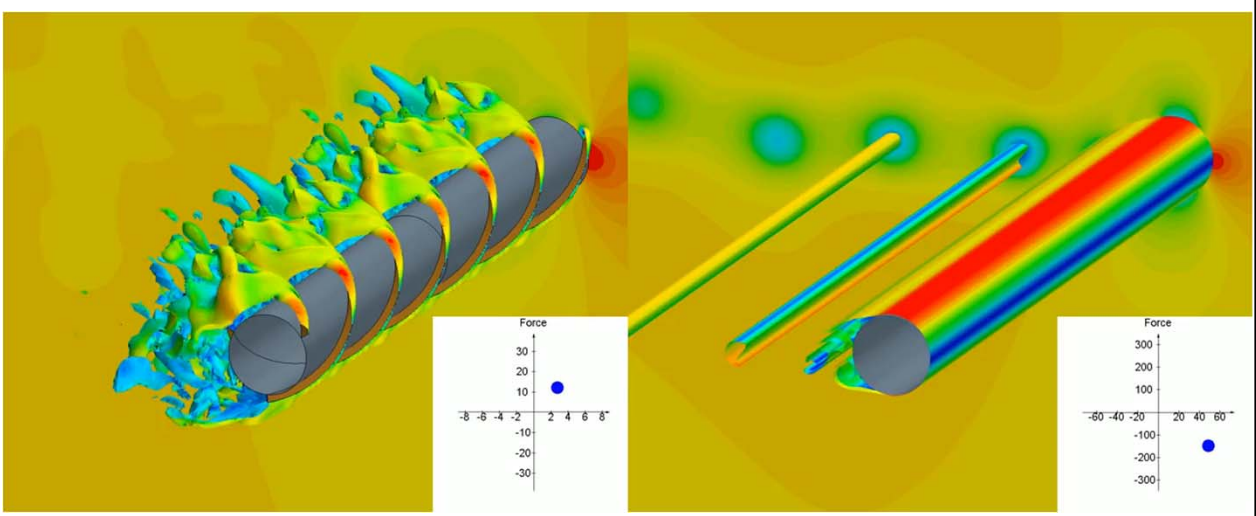
SPAR – Vortex induced vibrations



https://www.youtube.com/watch?v=24tBX_UD3fM

23

SPAR – Effect of helical strakes



https://www.youtube.com/watch?v=W-zXwPT2r14

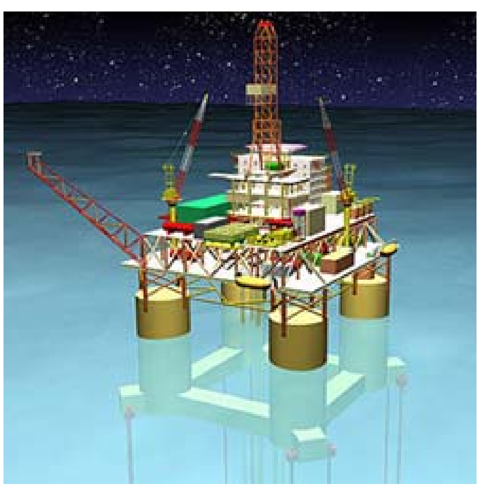
24

SEVAN FPSO

https://www.upstreamonline.com/epaper/sevan-fpso-selected-for-bream/1-1-1160389

25

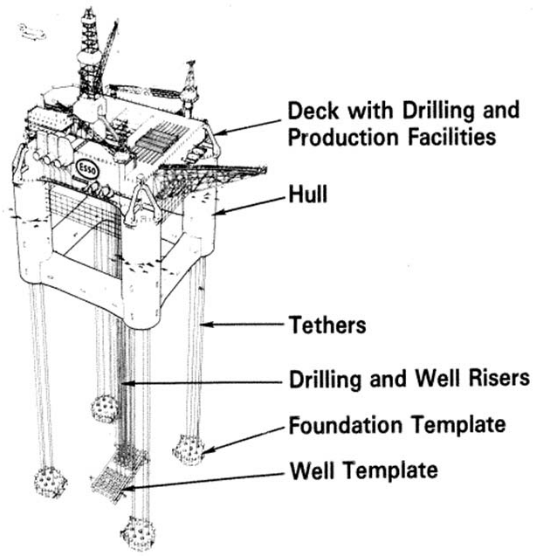
Tension leg platform



https://www.rigzone.com/training/insight.asp?insight_id=305&c_id=

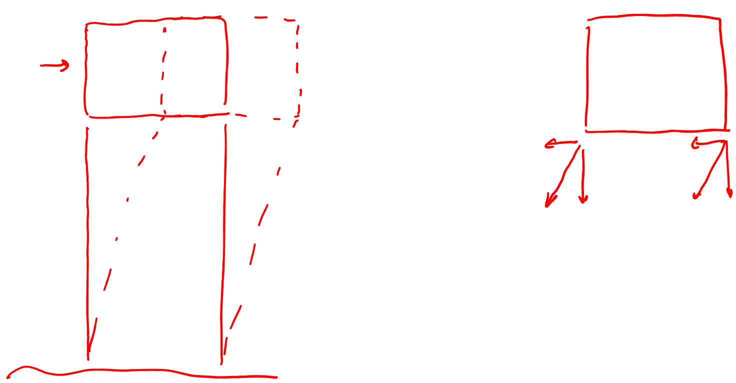
26

Tension leg platform



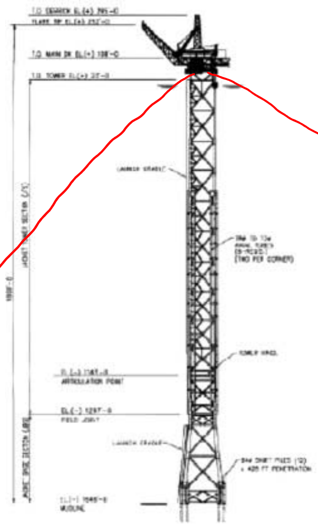
27

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

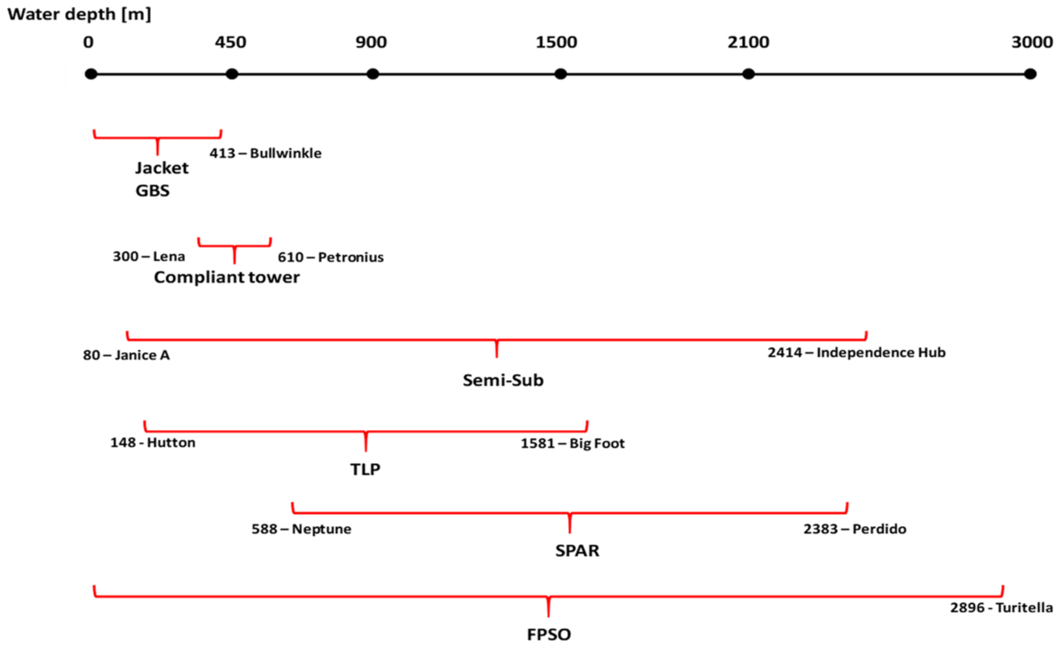
31

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



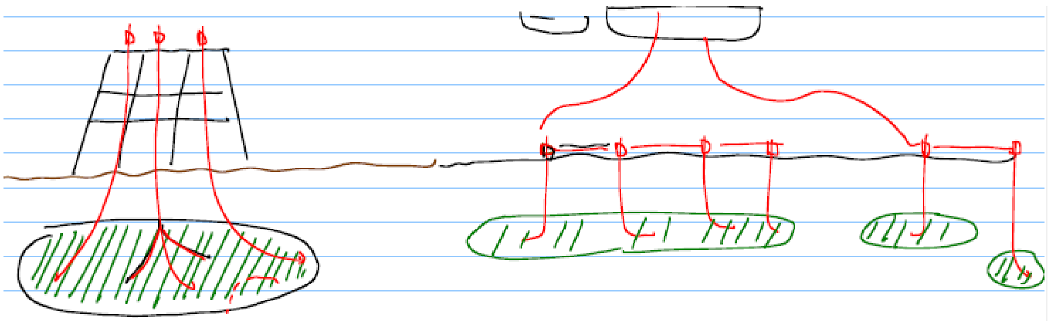
33

Some selection criteria for offshore structures

- Water depth
- **Type of X-mas tree**
  - Well intervention needs
    - 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

34

Reservoir spread and structure

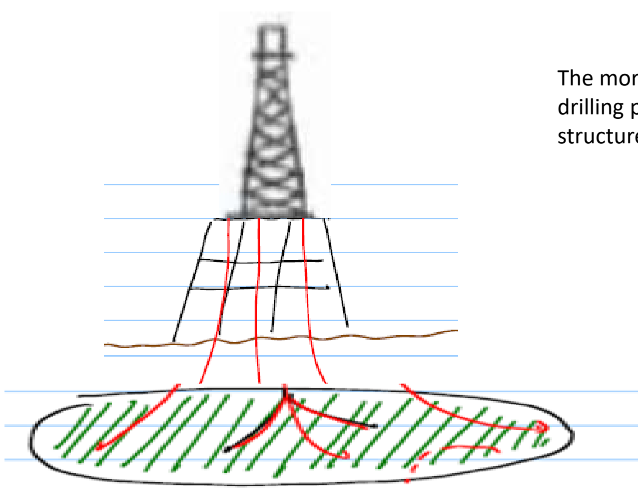


- Long deviated wells ($$$)
- Wells are drilled from one location, no need to spend mobilization time ($$)
- Production startup must be delayed until all wells are drilled

- 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

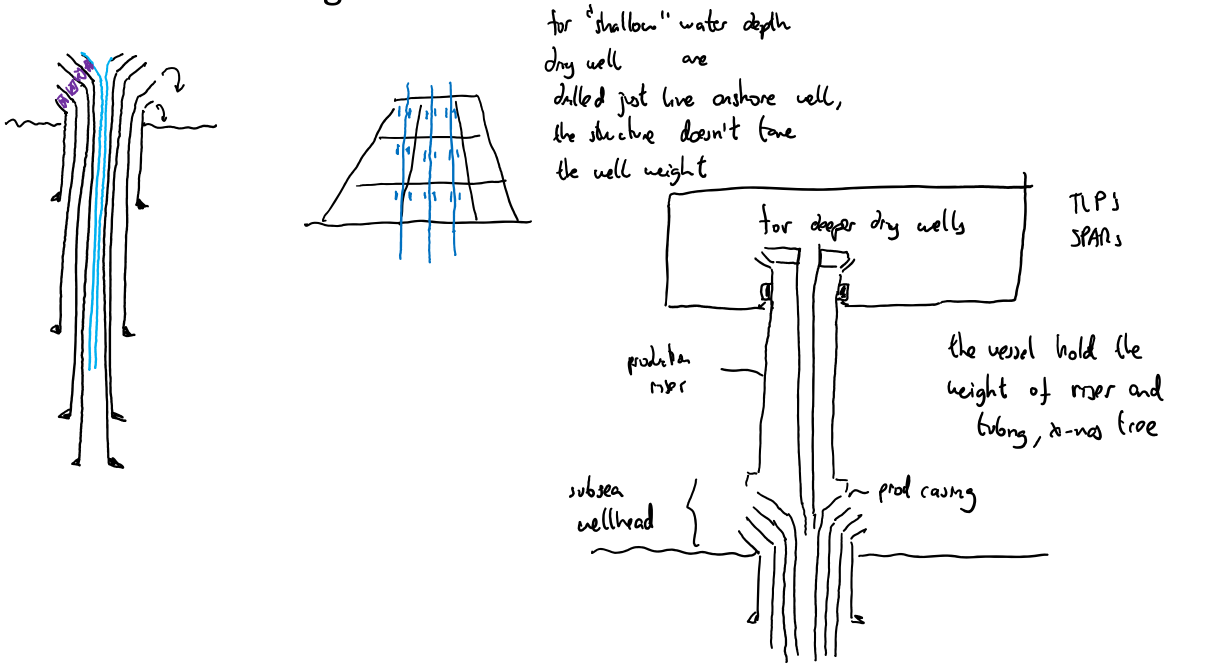
Reservoir spread and structure



The more spread - requires a bigger and more costly drilling package – more weight on the structure, bigger structure ($$$)

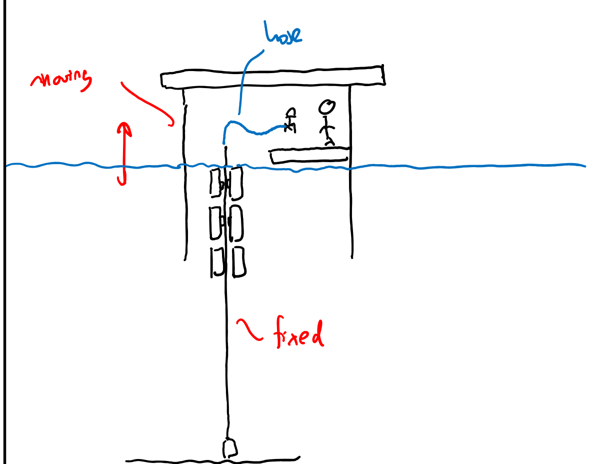
36

Transfer of well weight to soil and to offshore structure



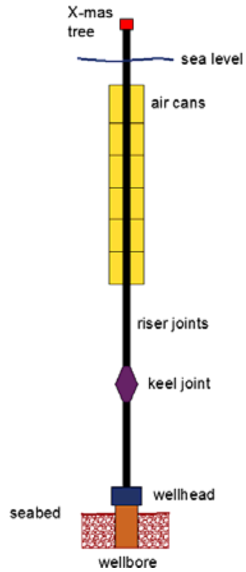
37

Transfer of well weight to soil and to offshore structure



38

Support system for dry X-mas trees – deep water



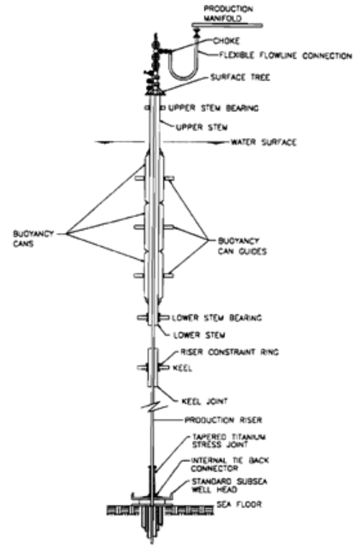


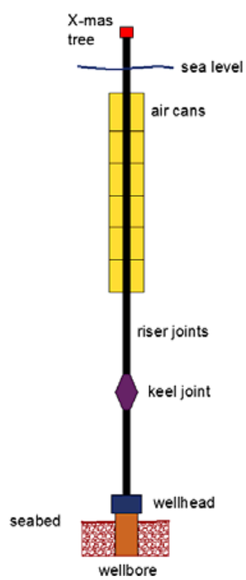
Figure 6 - Well System

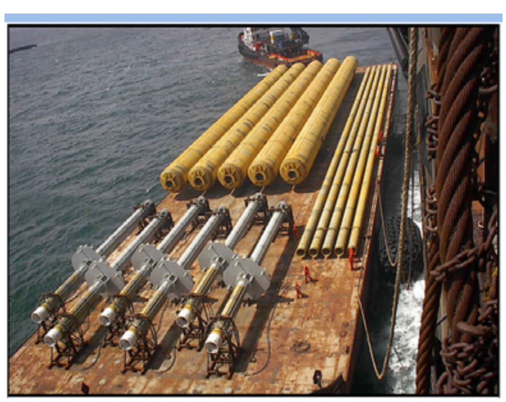
OTC 8382

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!

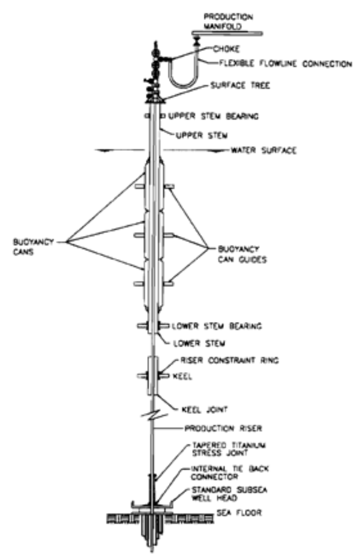


Figure 6 - Well System

OTC 8382

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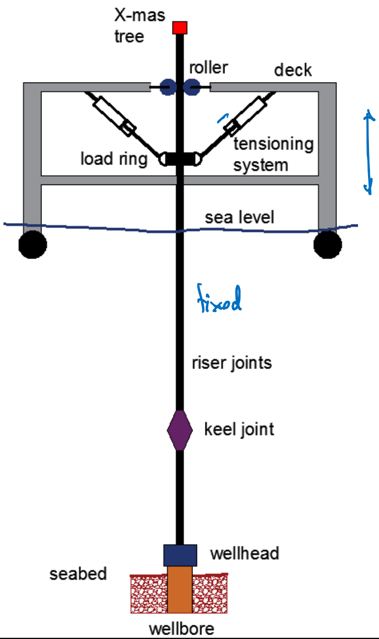
40

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

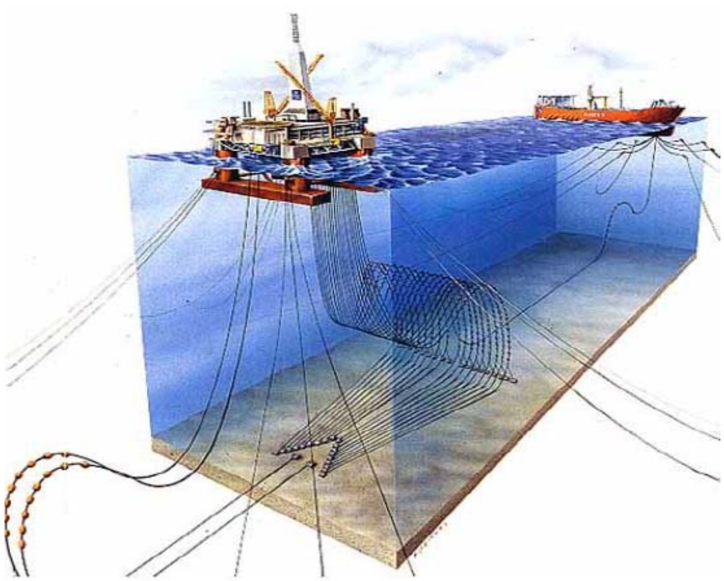
44

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

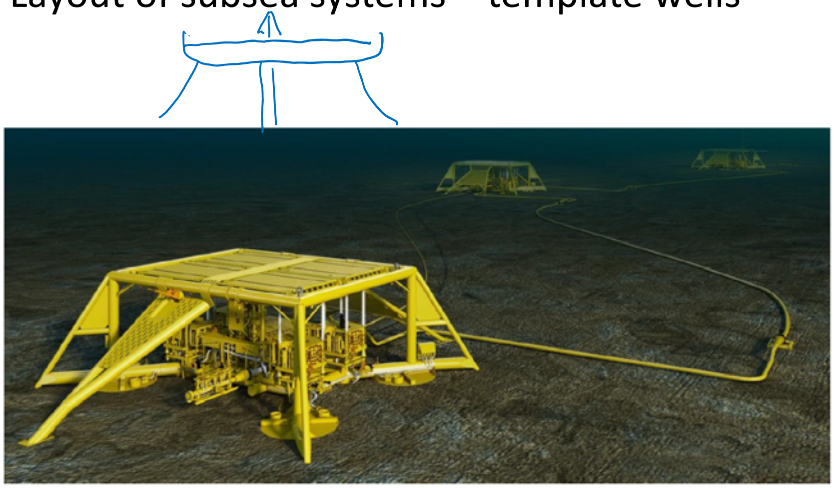
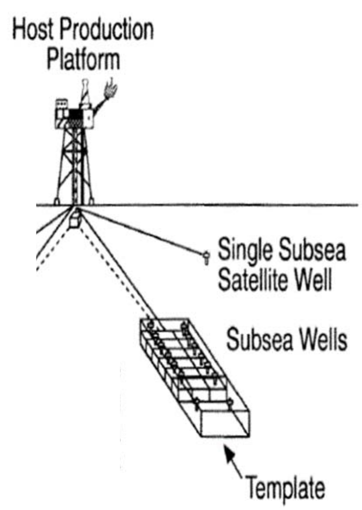


Figure 3.3 Typical NCS tie-back solution (Image: Statoil ASA)

47

Layout of subsea systems – template wells



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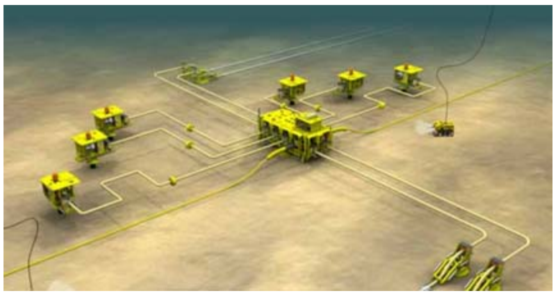
Satellite wells



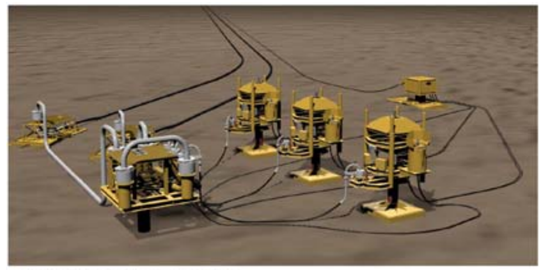
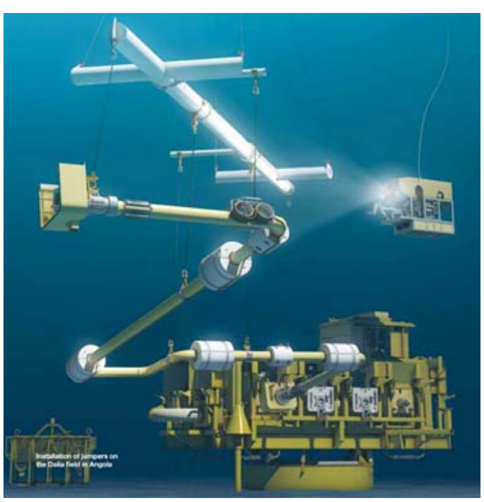
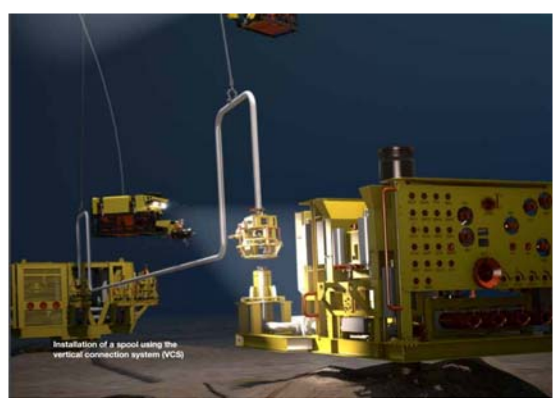


Figure 3.4 Typical GOM subsea tie-back

49

Jumpers for satellite wells (if close)

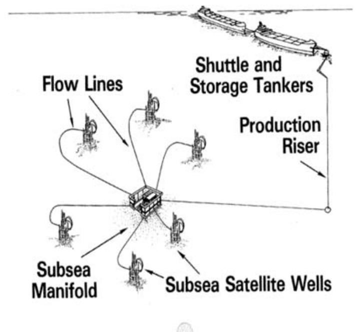




50

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

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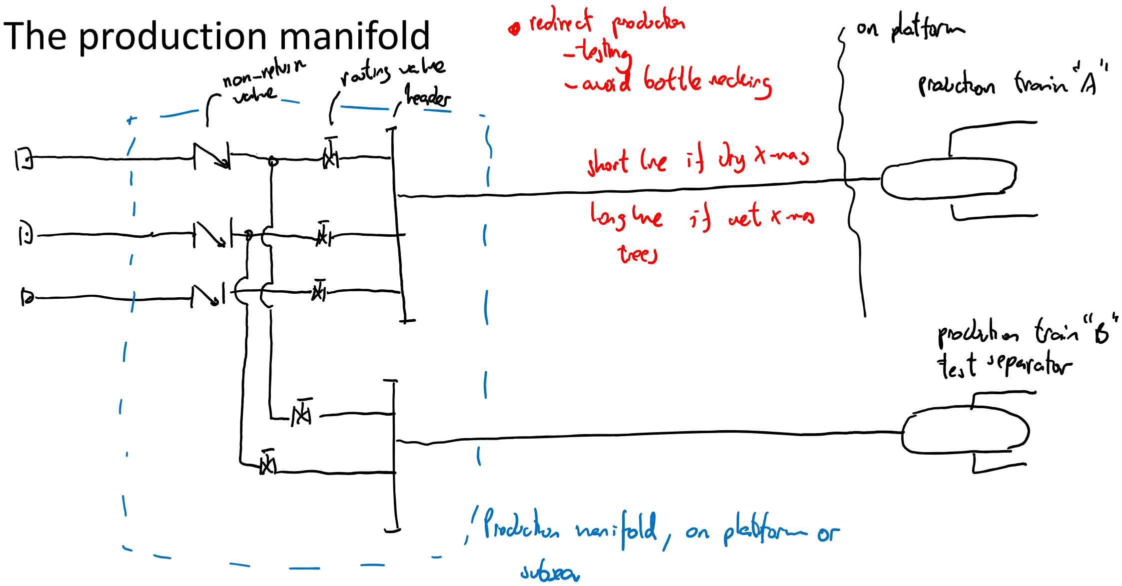
The production manifold

- Commingle production
- redirect production
  - testing
  - avoid bottlenecking

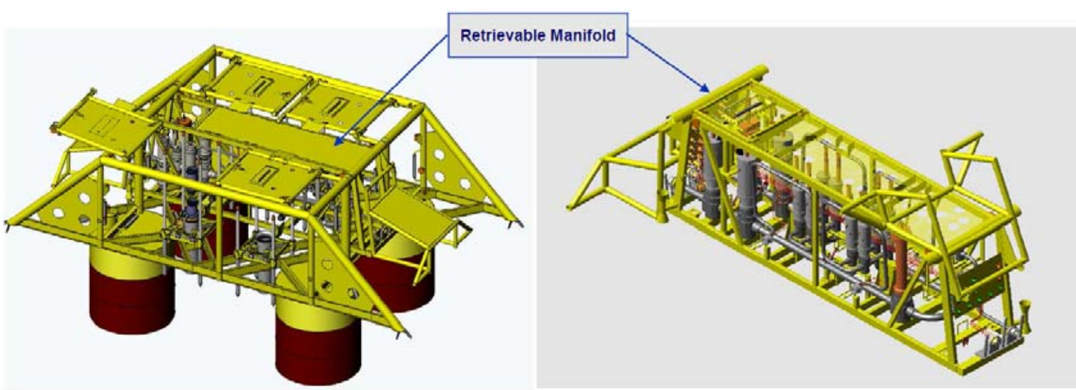


52

The production manifold

53

4 well template – the production manifold

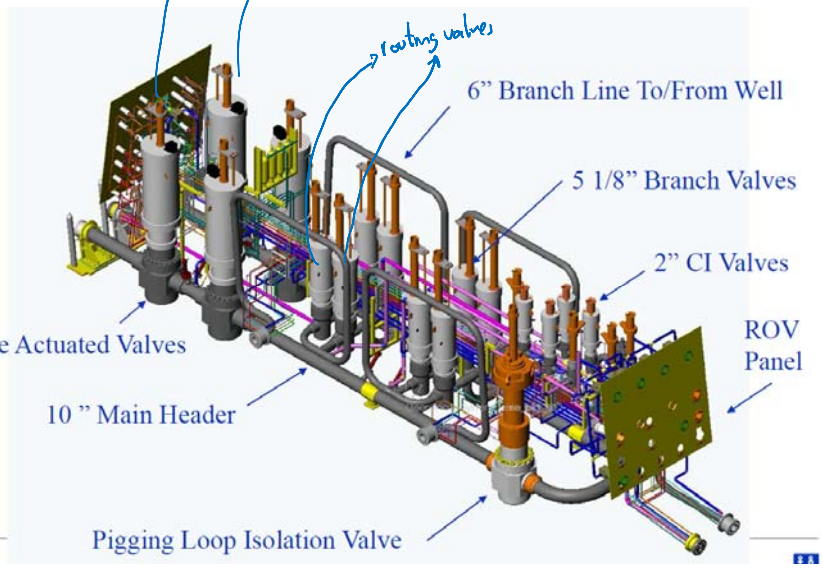


54

The manifold

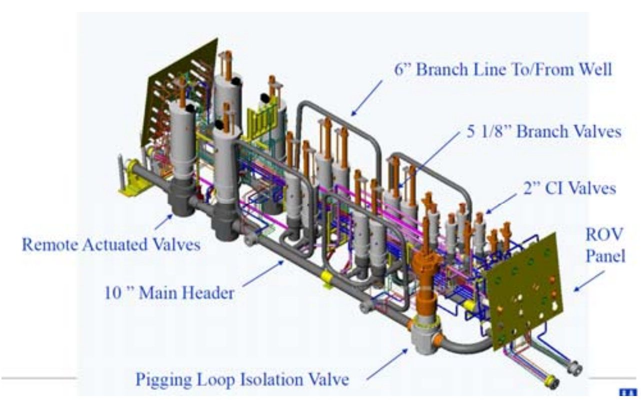
HIPPS (high pressure protection system) integrity

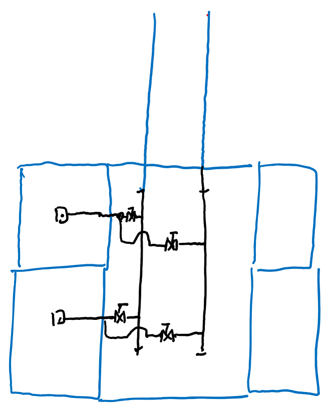
routing valves



55

The manifold – reality vs sketch





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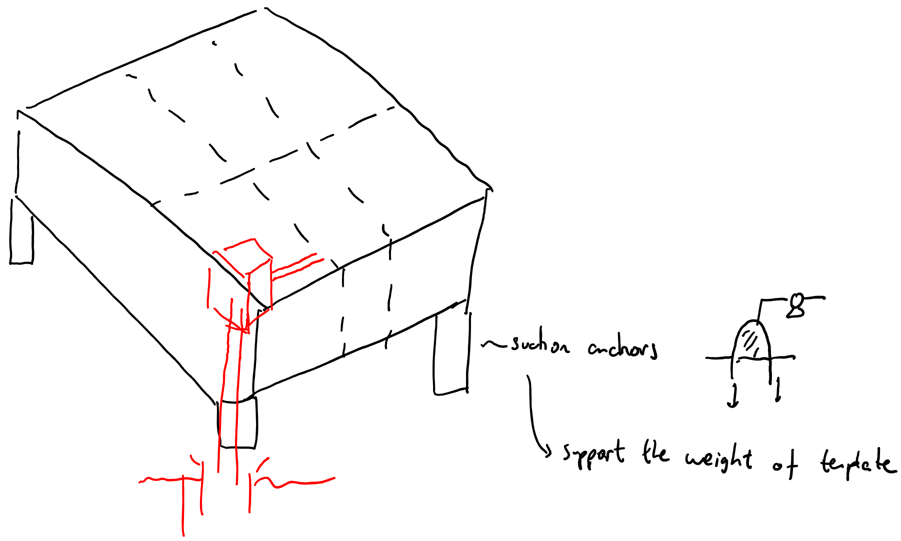
4 well template – weight transfer



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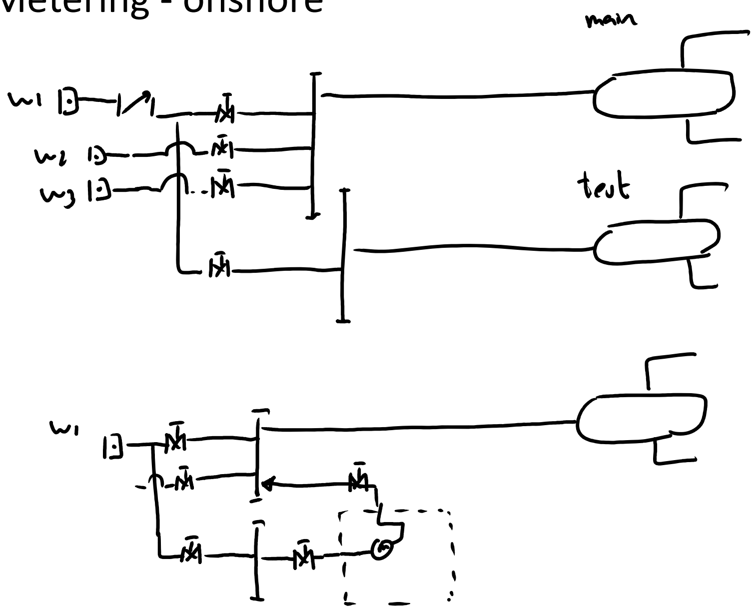
notes for Youtube video offshore structures 2

Metering - onshore



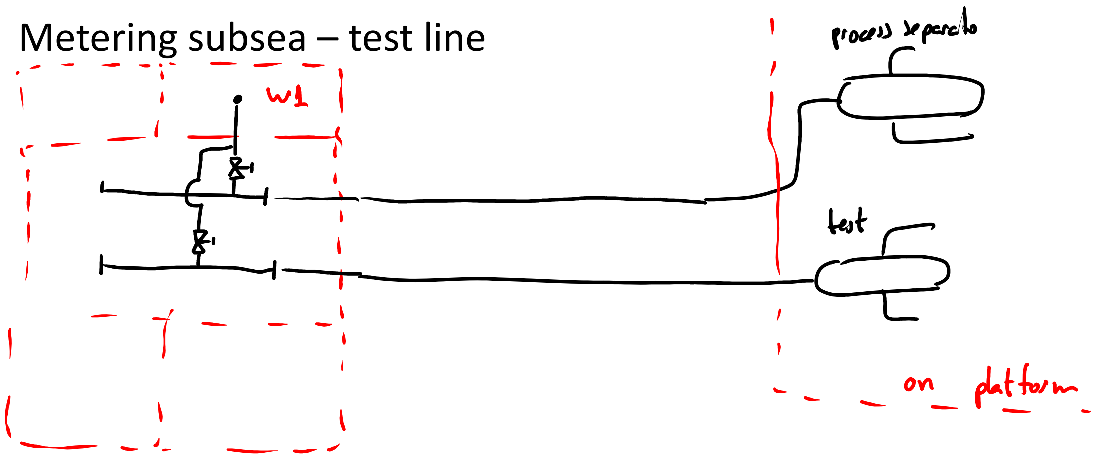
instead of separating, a multiphase meter can also be used, instead of a test separator

55

Metering onshore – test separator

56

Metering subsea – test line



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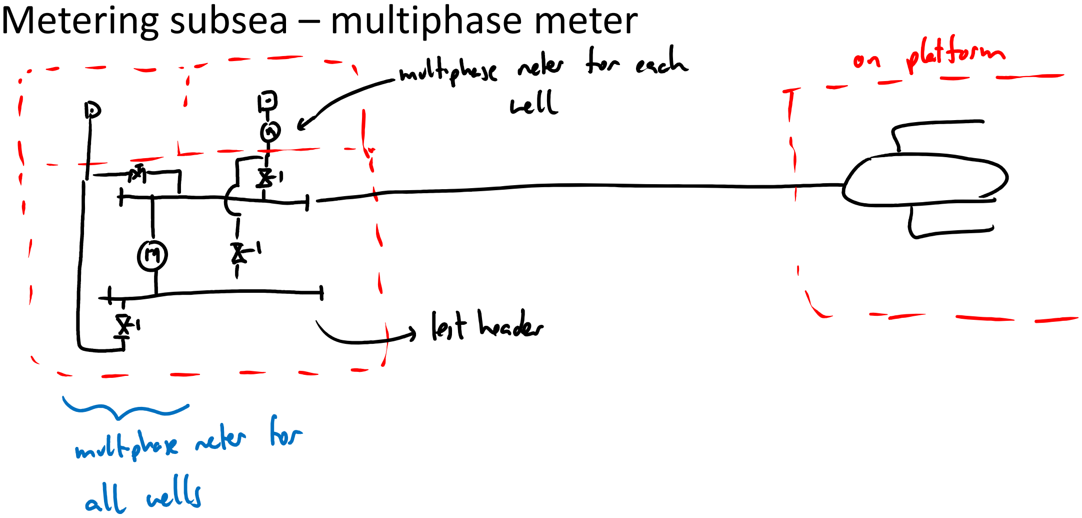
Metering subsea – multiphase meter



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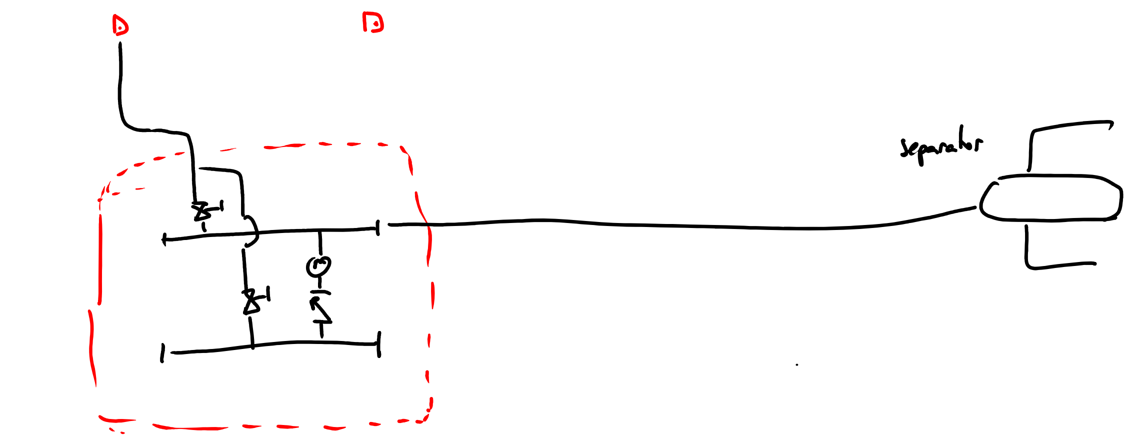
multiphase meter - satellite wells



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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.

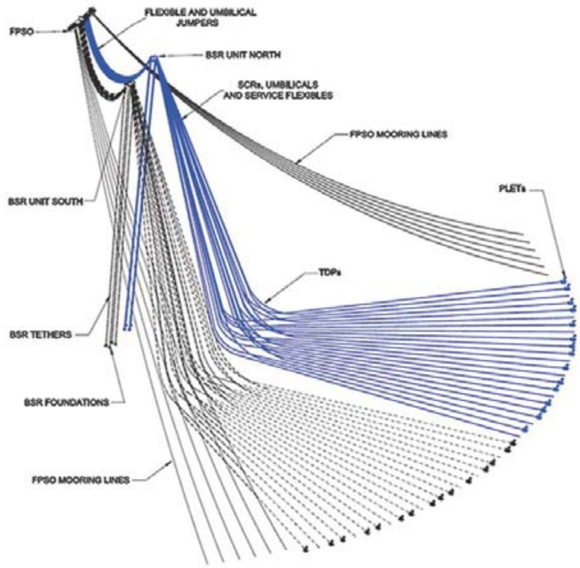
7.2.7.4. Devem ser utilizados separadores de testes ou tanques de testes nos testes de poços. Outros métodos de testes, utilizando novas tecnologias, devem ser previamente aprovados pela ANP.

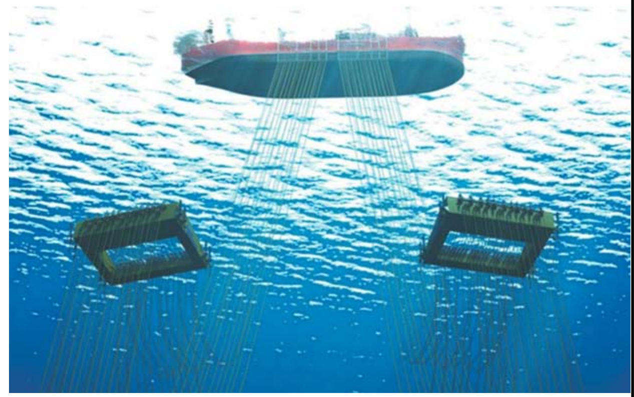
http://www.anp.gov.br/wwwanp/?dw=66648

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.

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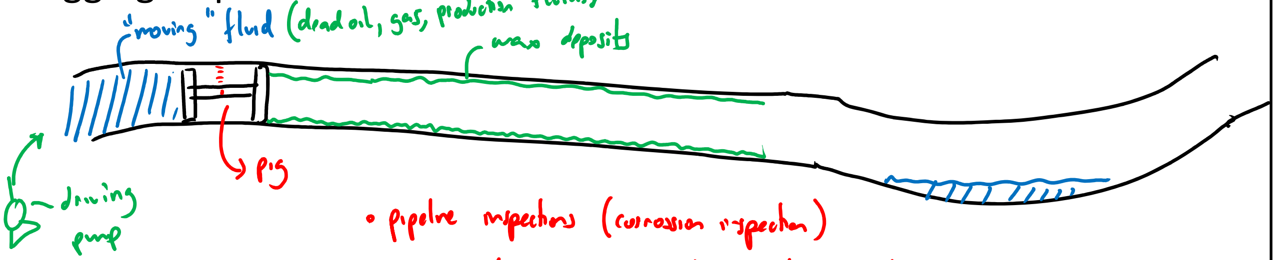
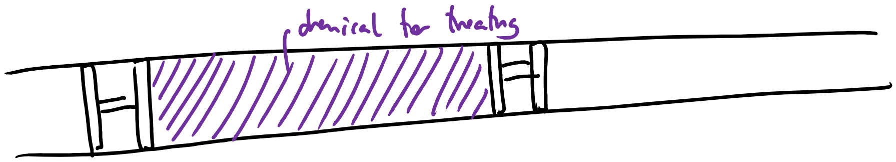
Pigging requirements



- pipeline inspections (corrosion inspection)
- remove liquid accumulated in low points
- chemical treatment
- wax scraping



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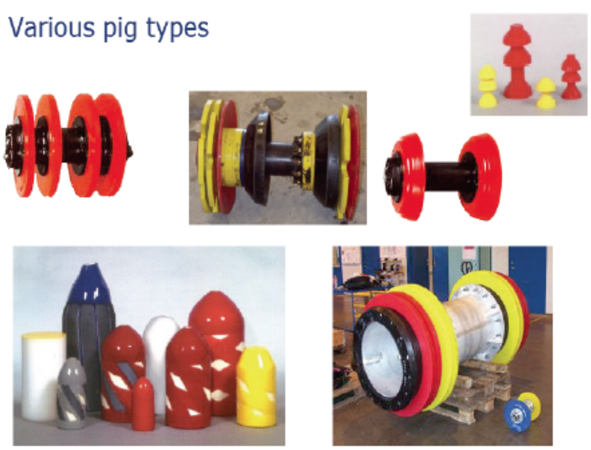
Pigs

Various pig types



Wax plug-North Sea line pigging

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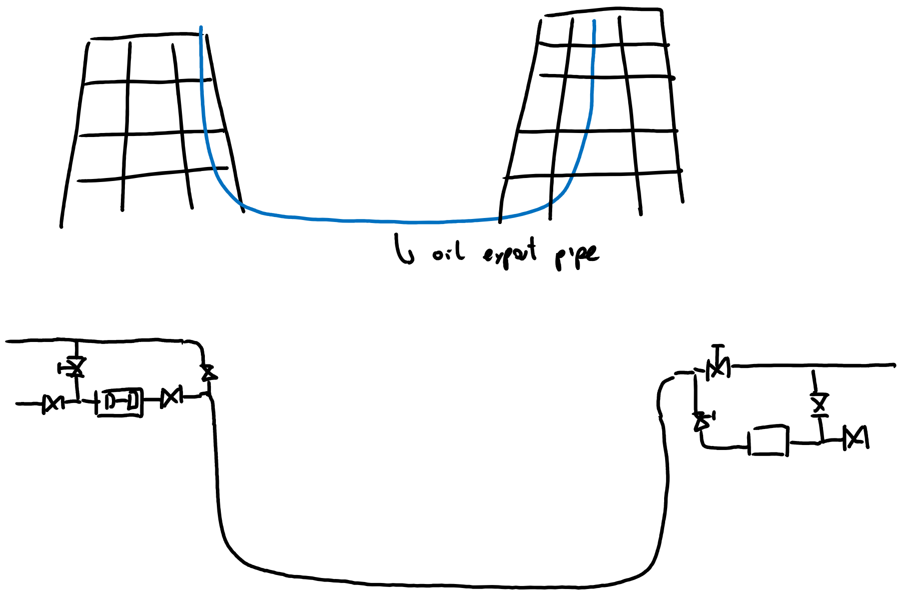
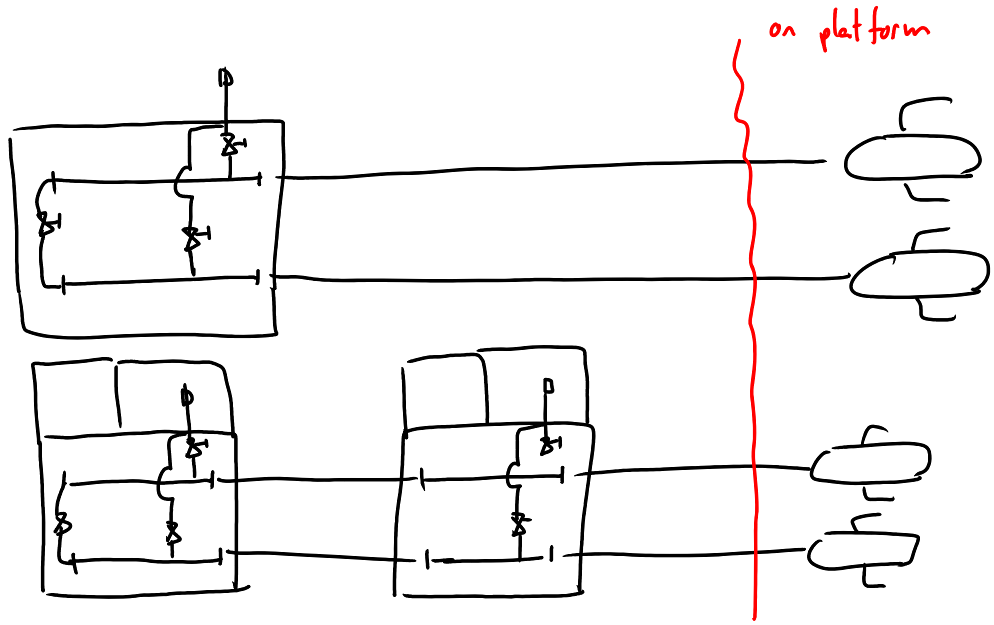
Pigging loop and subsea pig launcher

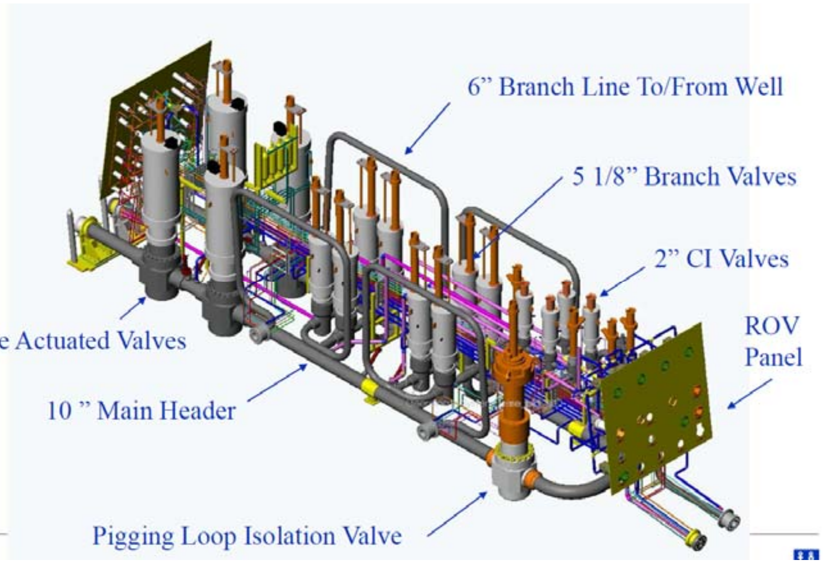


65



66

The pigging valve



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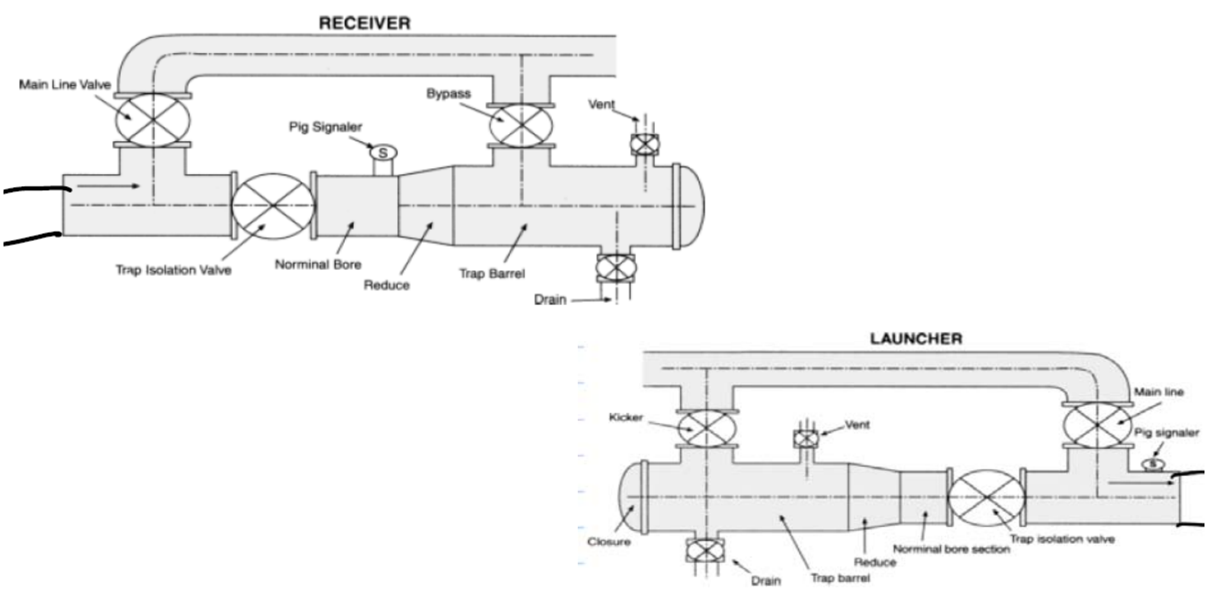
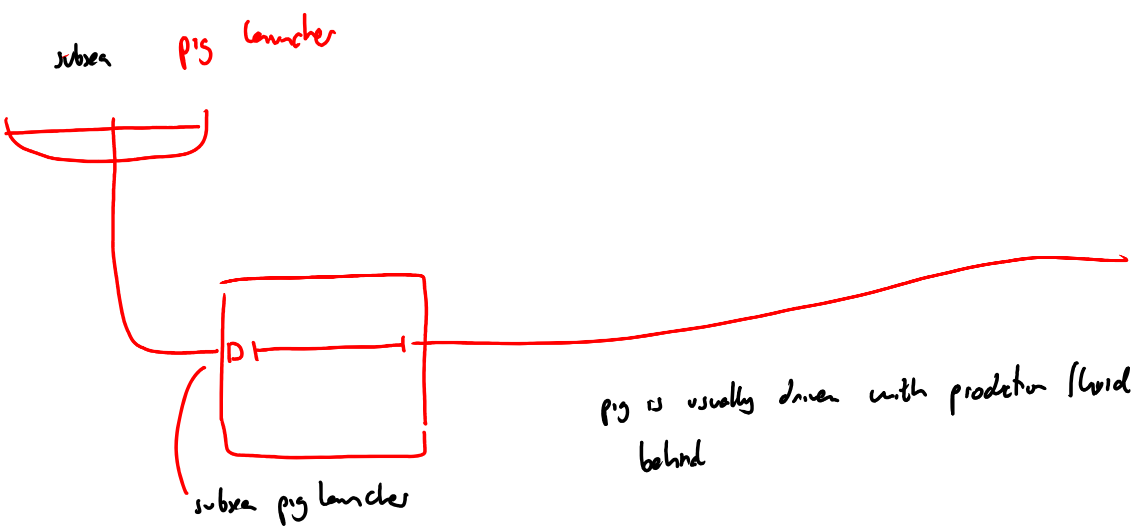
Pig launcher and receiver



68

Pigging - video

69



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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

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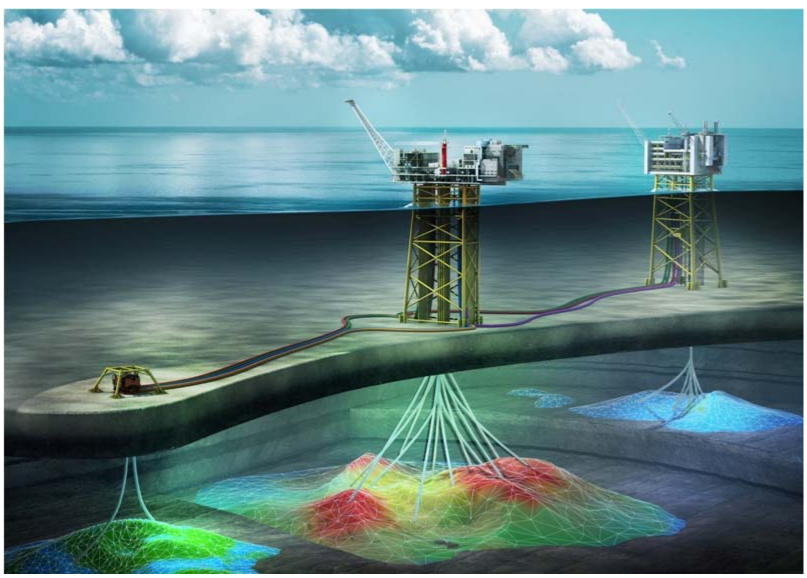
Combinations can be used



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

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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

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Other selection criteria for offshore structures

- Previous experience
- Riser issues
- Topside upgrade flexibility
- Manufacturing workshop availability
- Maturity of technology
- Maintenance and OPEX

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Class 20240411

Outline:

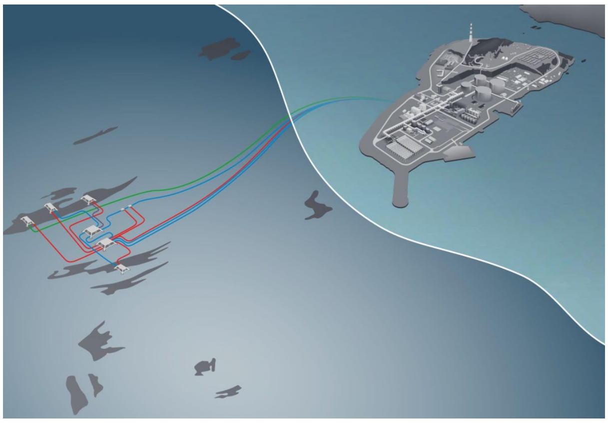
Recap of content covered in previous weeks:

- How to quantify the effect of uncertainty in field development
- Offshore structures

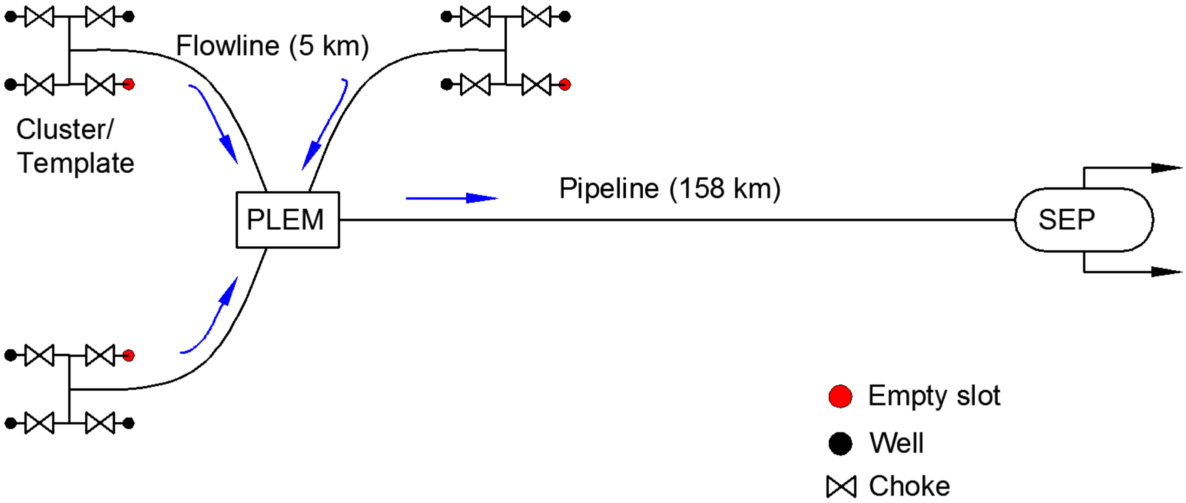
Review of exam questions (2023) related to offshore structures

Flow assurance analysis of the Snøhvit pipeline using Hysys

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.



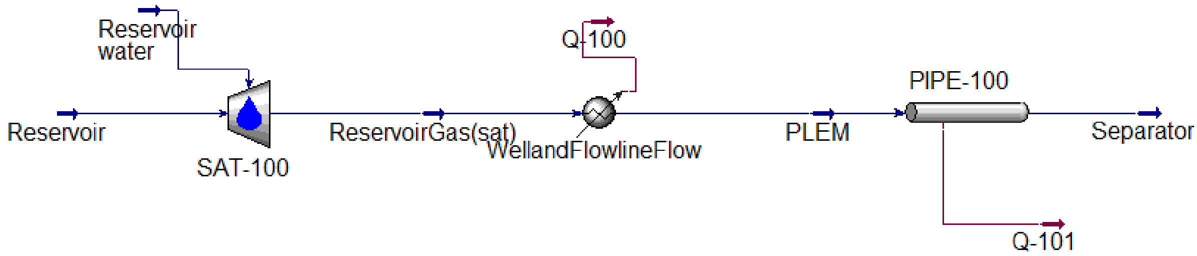
You are asked to perform a steady-state, 1D simulation using the simulator Hysys to compute pressure and temperature drop along the main transportation pipeline from the PLEM to the slug catcher. The main goal is to assess hydrate formation. You have to perform your calculations for the plateau phase.

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.

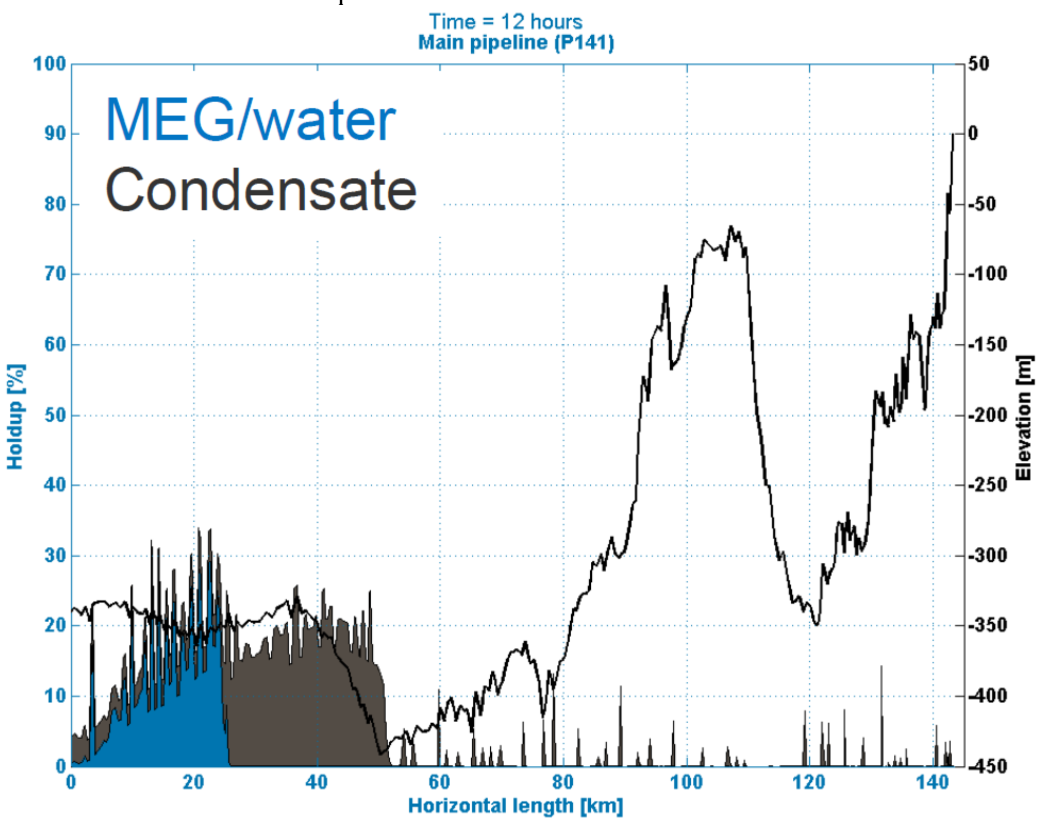


Pressure and temperature are specified in the streams “Reservoir water”, “Reservoir” and “PLEM”. Composition is specified in Streams “Reservoir water” and “Reservoir”. Mass rate is specified in stream “Reservoir”. The mass rate can be estimated by multiplying the standard conditions gas rate of the field 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 ºC). 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

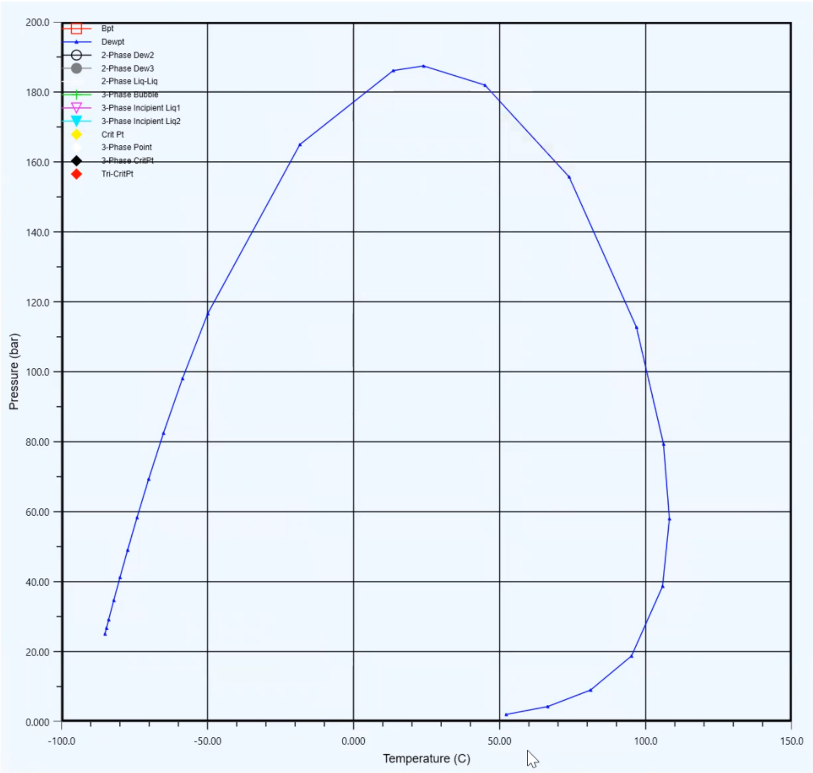
Pipe diameter information:

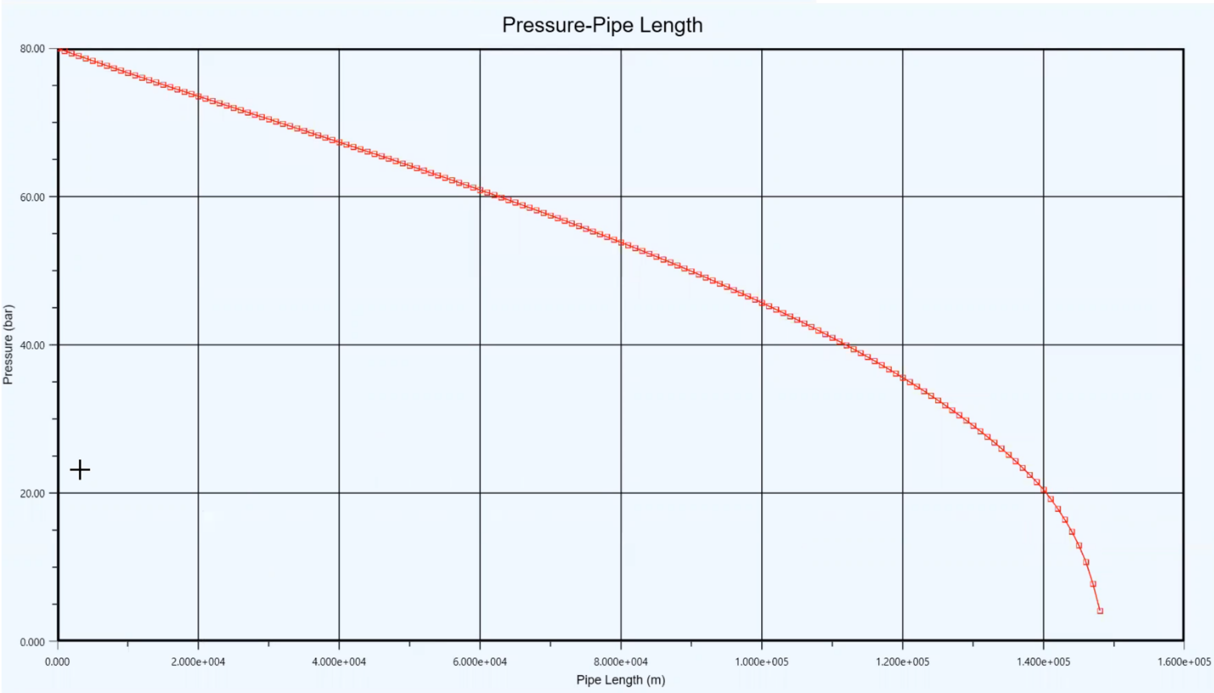
Inner diameter of the steel pipe ID, [mm]	**678.2**
Outer diameter of the steel pipe OD [mm]	**711.2**

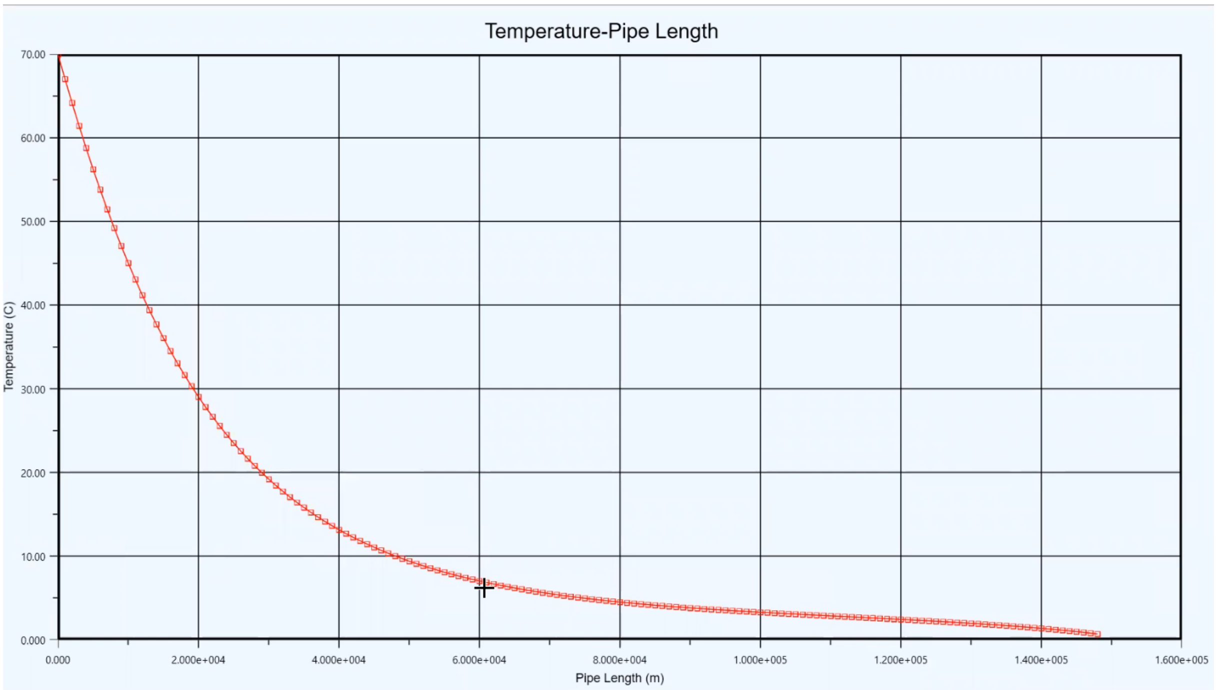
Some help with Hysys:

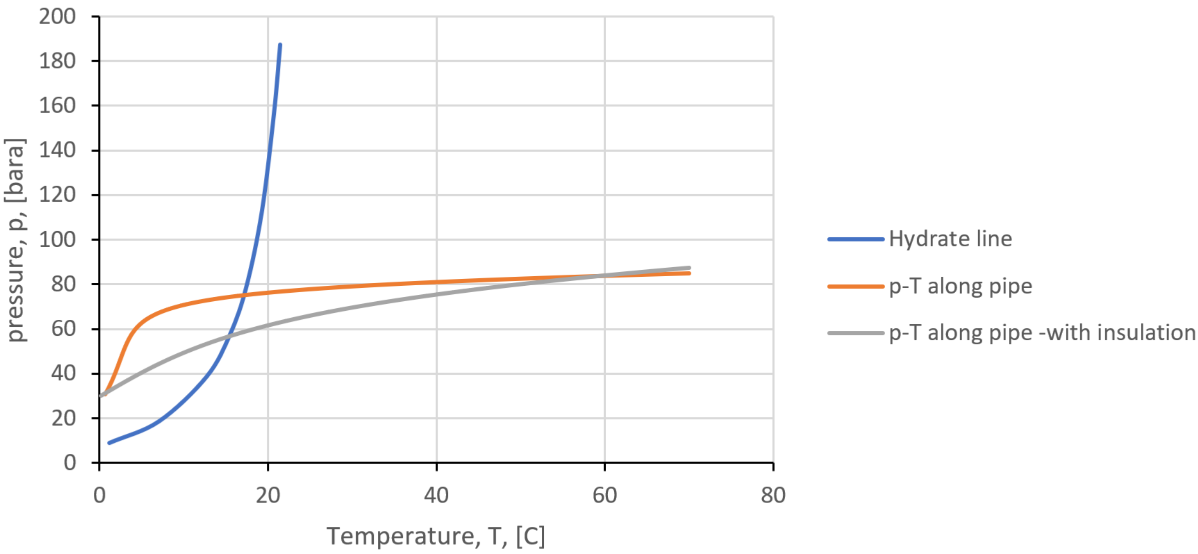
You can run Hysys remotely from your computer using
https://farm.ntnu.no
Alternatively, Hysys is installed in some computers in the computer lab on the 3rd floor.

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)

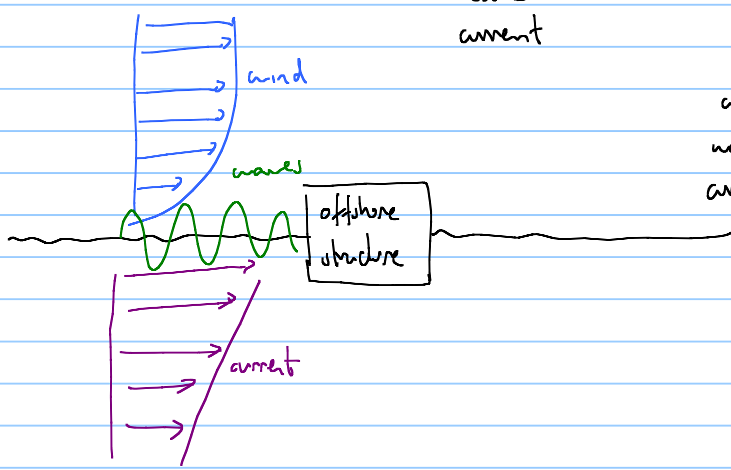

pressure, p, [bara]
200
180
160
140
120
100
80
60
40
20
0
0
20
40
60
80
Temperature, T, [C]
Hydrate line
p-T along pipe
p-T along pipe -with insulation

Note Title

Notes for Youtube video Marine loads and offshore structures for hydrocarbon production

Offshore structures for oil and gas production

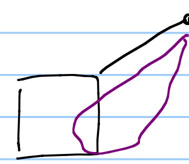
- effect of oceanographic environment : wind
  waves
  current



wind, waves, current must be taken into account when designing the offshore structure

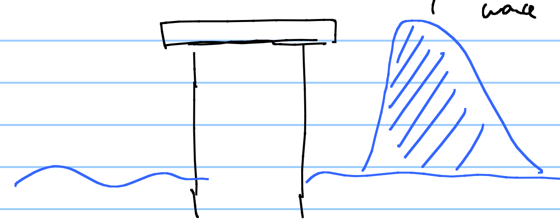
- Location of flare

wind direction



- deck elevation

100 year wave

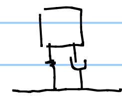


- design wave, for a range of periods
  ↳ most likely in the area
- storm (100 year storm)
- long term variations ⤳ fatigue

forces and marine loads on structure (t) → structure (mechanical system) → movement (t)
stress (t) → maximum stress
fatigue design

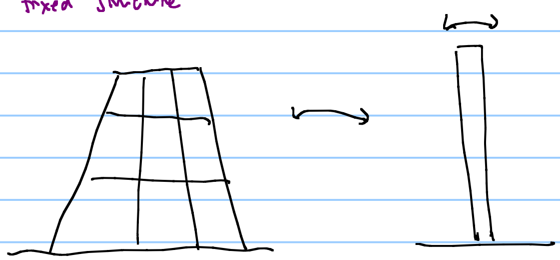
- magnitude
- frequency
- direction

each structure, depending on it characteristics (mass, flexibility, dampening)

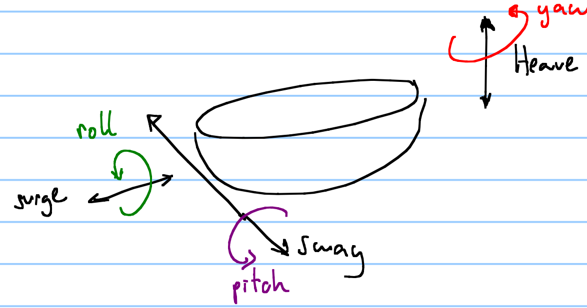


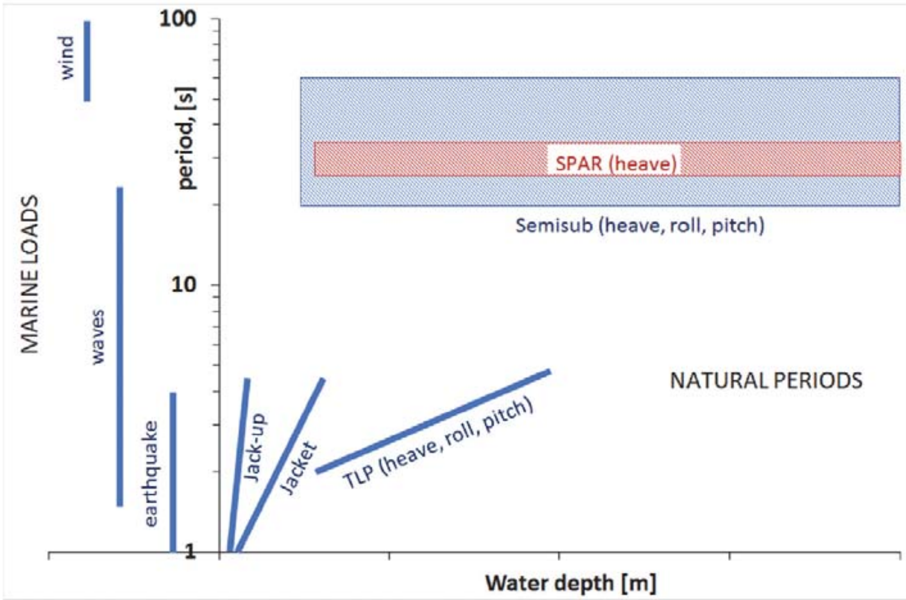
will have a natural frequency that if excited at this frequency might exhibit maximum movement and stress.

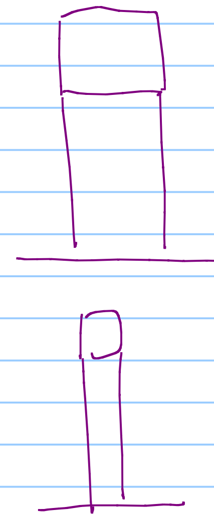
fixed structure

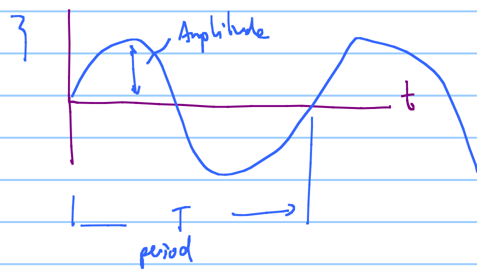


floating structure





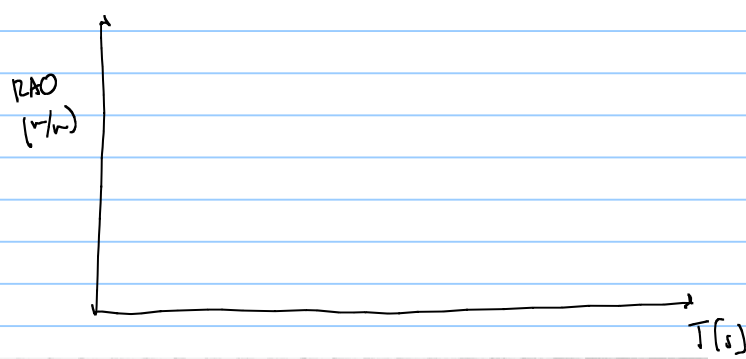




Response amplitude operator (RAO) $= \dfrac{\text{amplitude of response}}{\text{amplitude of excitation}} = \dfrac{\text{Heave [m]}}{\text{wave amplitude [m]}}$

$f = \dfrac{1}{T}$ $\dfrac{\text{cycle}}{\text{s}}$

RAO = 2



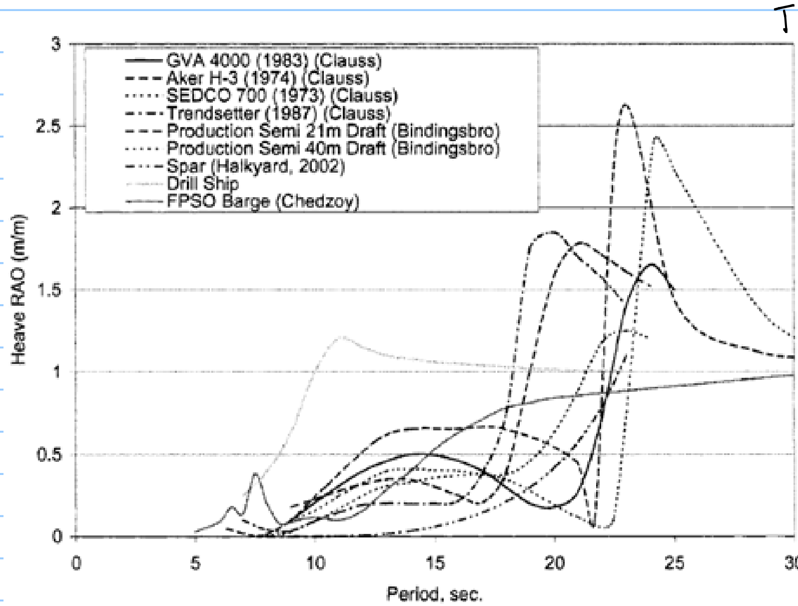
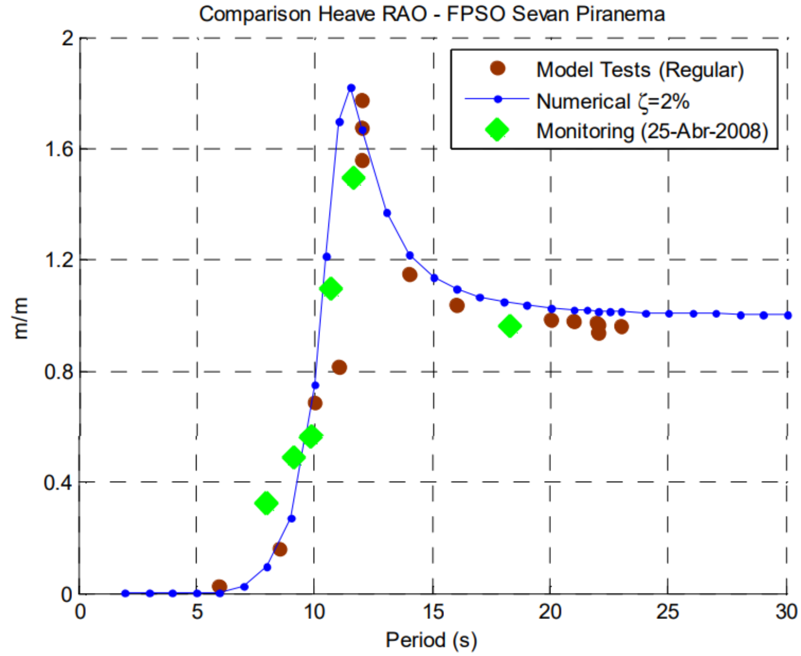


Figure 7.3 Example heave RAOs of various floaters



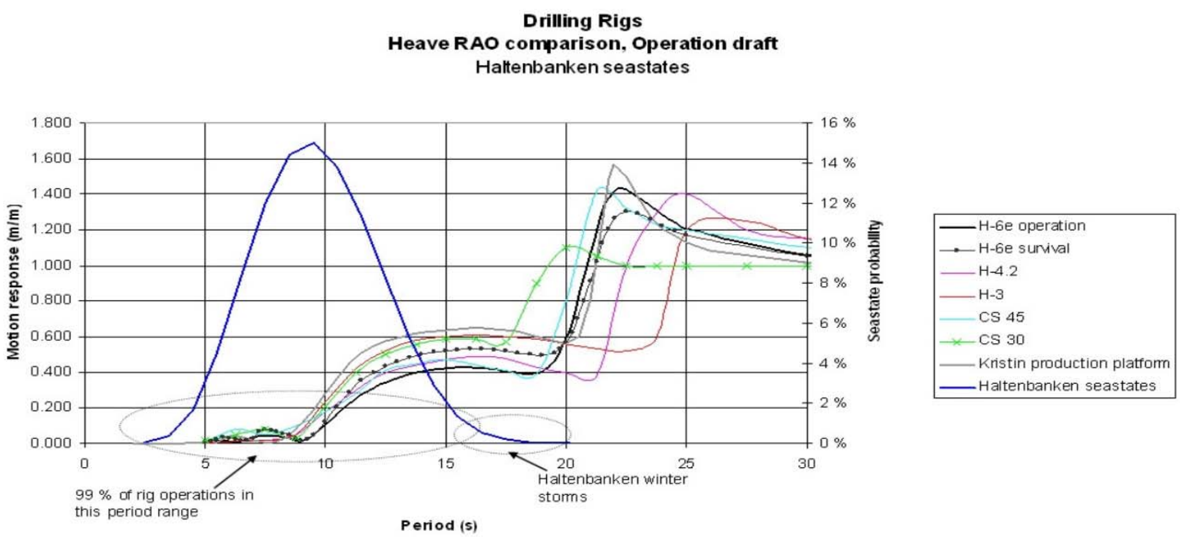


Figure 16.2: *RAO published on the AKER Drilling website.*

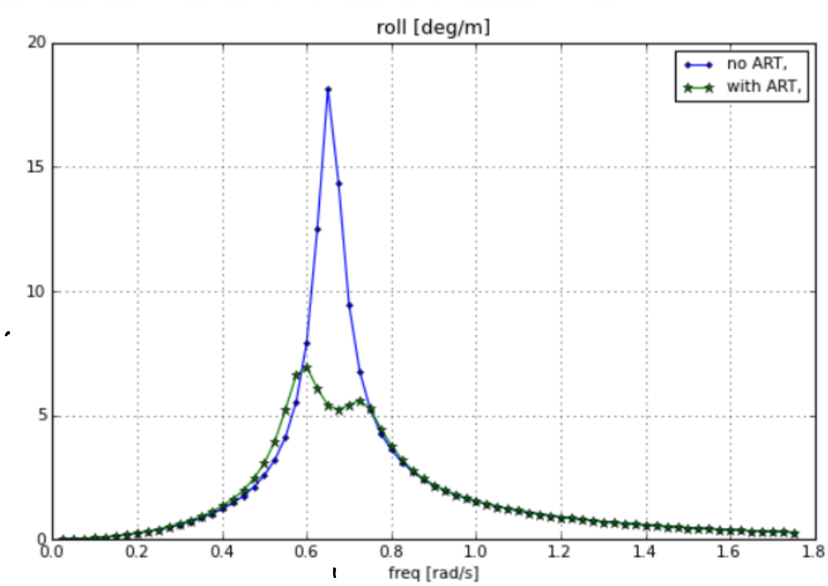
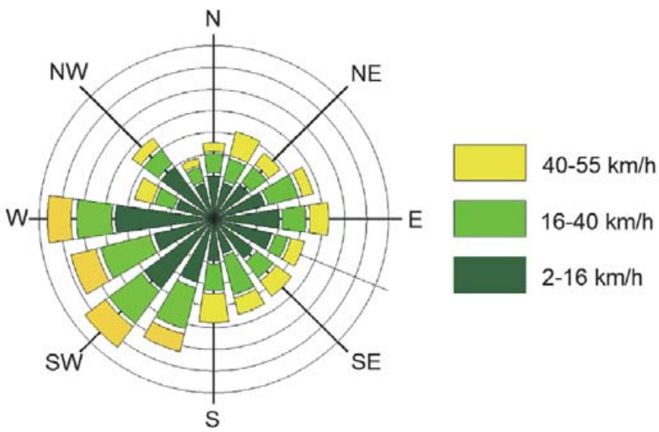


Figure 1: Typical RAO of roll of a ship with and without ART.

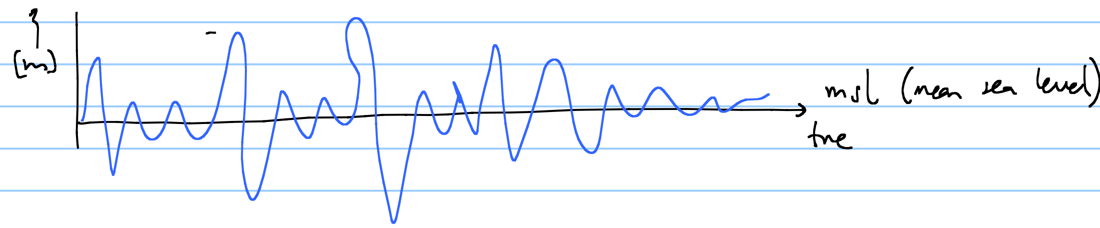
Wind



wind rose

wind and current are typically assumed constant and using the maximum value. (wind direction also must be taken into account)

Waves



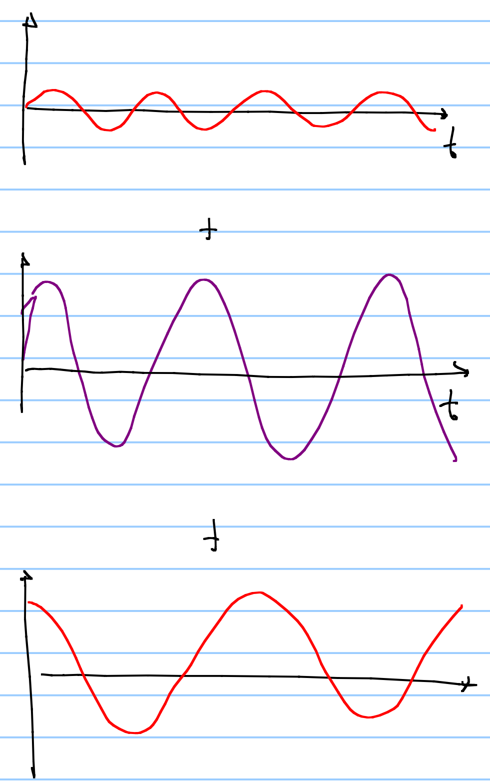
Fourier

phase shift

$$f(t) = \sum_{i=1}^{N} \underbrace{A_i}_{\text{amplitude (m)}} \sin(\omega_i t + \phi_i)$$

angular frequency $\omega_i = 2\pi f_i$

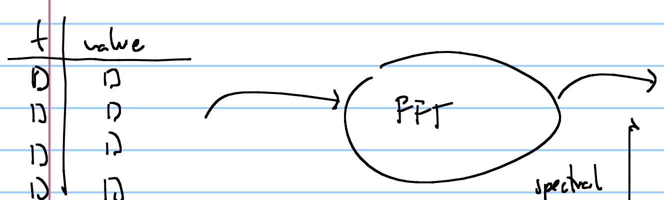
$\omega_i = \frac{rad}{s}$ $\left[\frac{\cancel{cycle}}{s}\right]\left[\frac{2\pi \text{ rad}}{1 \cancel{cycle}}\right]$

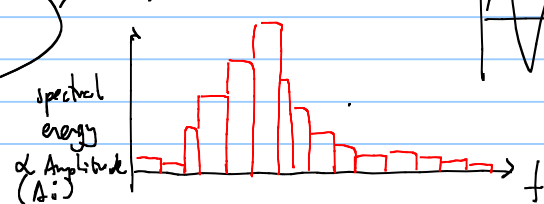


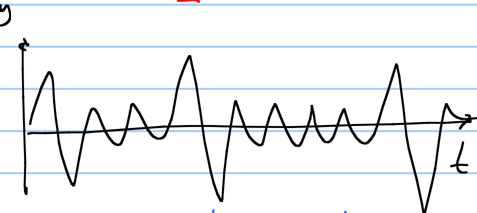
Discrete Fourier transform

FFT Fast fourier transform

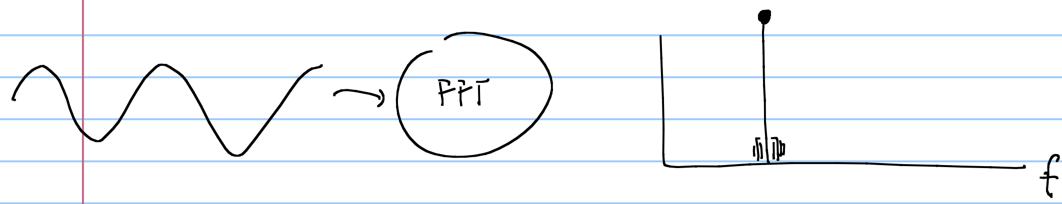
spectral peak period
dominant frequency







→ sometimes analytical equations are used
Pierson Moskowitz, JONSWAP



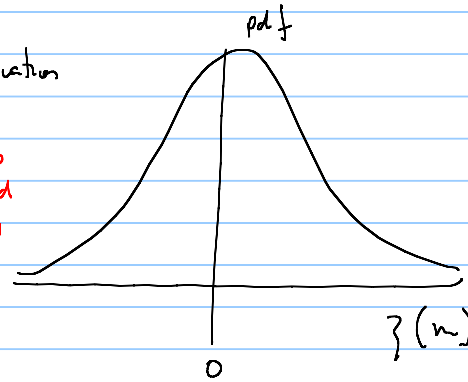
to deal with the variability of waves in time, we apply FFT on the signal and report spectral peak period

the spectral peak period does not change significantly in 3 hours

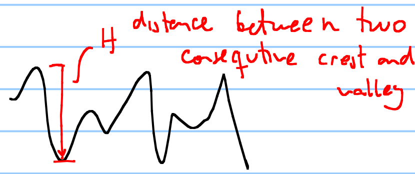
sea state

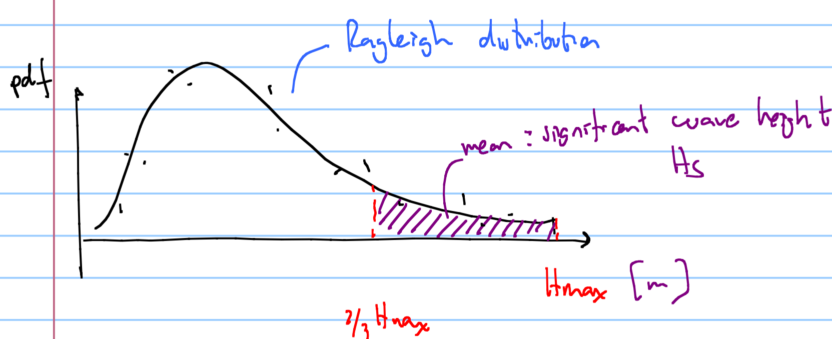
what to do with amplitudes?

statistics on wave elevation



wave height



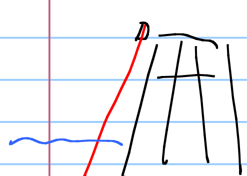


to characterize a sea state (3 hrs) H_s and T_p are used

wave Data must be gathered for at least 2 years to obtain a representative sample of wave conditions in the area

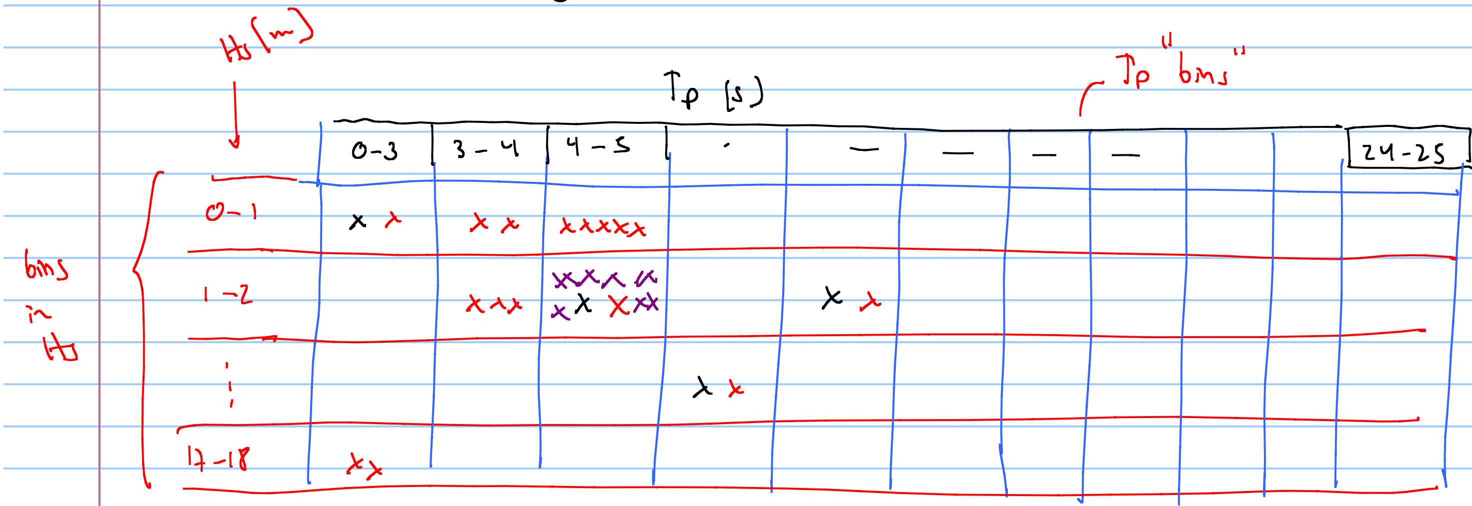
How many sea states are in 2 years

$$2\ \text{years} \cdot \frac{365\ \text{day}}{\text{year}} \cdot \frac{24\ \text{hrs}}{1\ \text{day}} \cdot \frac{1\ \text{sea state}}{3\ \text{hr}} = 5840$$



with all measured data, compute T_p, H_s for all

Scatter diagram of long term wave statistics



classify each data point i have in each box

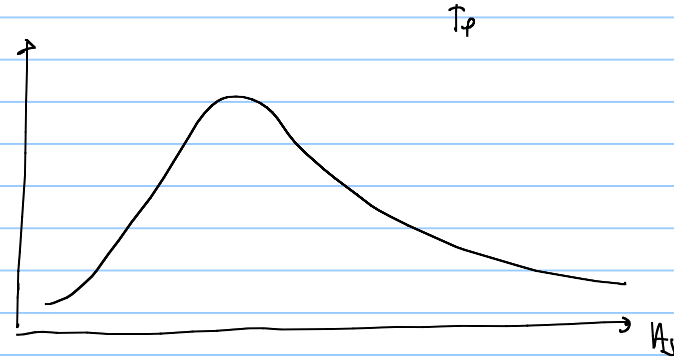
Hs [m]	Spectral Peak period (T_p) [s]																							Sum
	0-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24	24-25	
0-1	15	290	1367	2876	3716	3527	2734	1849	1138	656	362	192	101	52	26	13	7	3	2	1	0	0	0	18927
1-2	1	81	1153	5308	12083	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	9139	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

$$\frac{292172}{2420\left(\frac{\text{states}}{1\text{ year}}\right)} \approx 120 \text{ years}$$

for a fixed wave Hs

for a fixed Tp



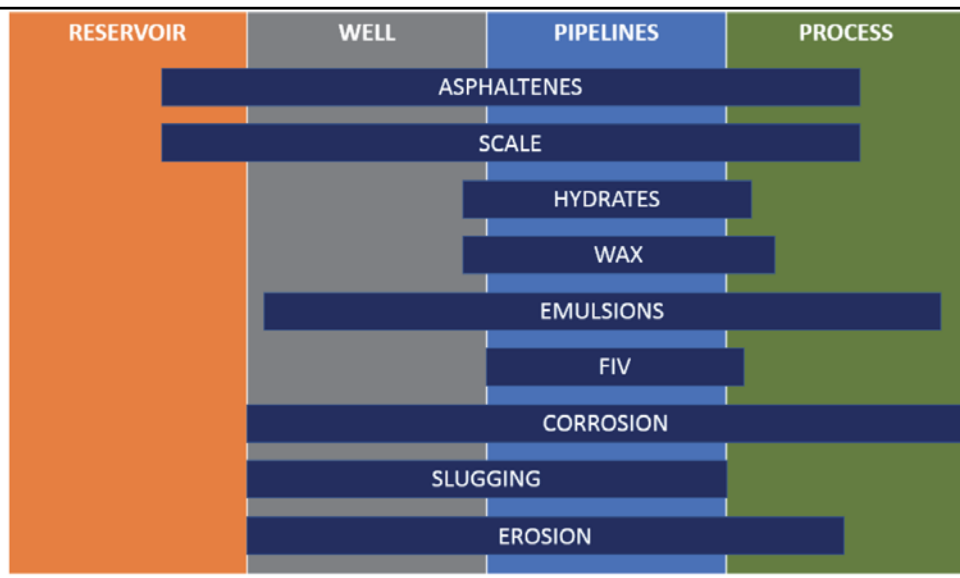
Notes for Youtube video Flow assurance considerations in Field development

Flow assurance considerations in hydrocarbon field development and planning

Prof. Milan Stanko (NTNU)

1

Issues



Naphtenates

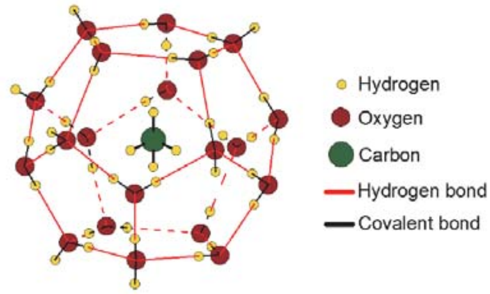
Foam

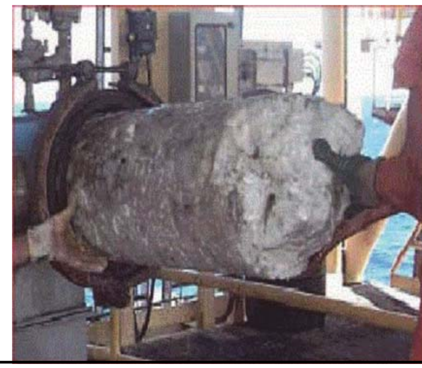
- microorganism growth

2

Hydrates

https://www.youtube.com/watch?v=Oz4NLXfdqpA

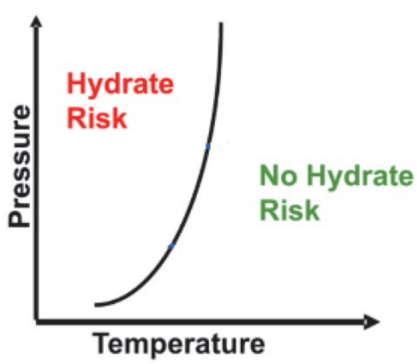




3

Hydrates - conditions

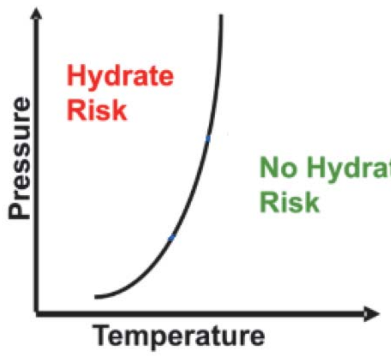
- Free water (in liquid phase)
- Small hydrocarbon molecules
- Particular range of pressure and temperature.

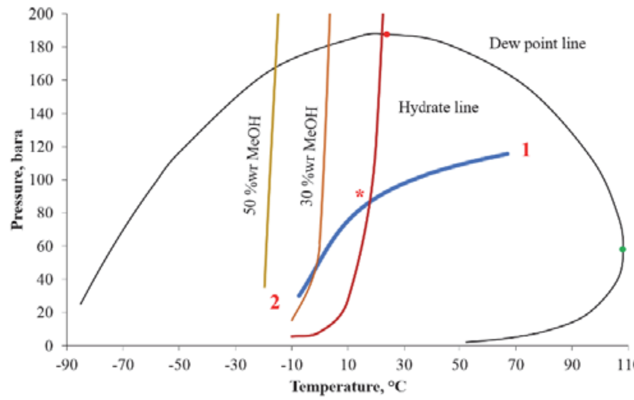


4

Hydrates - conditions

- Free water (in liquid phase)
- Small hydrocarbon molecules
- Particular range of pressure and temperature.

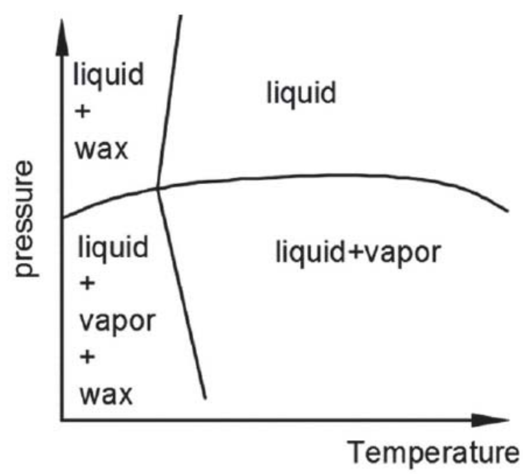




5

Wax

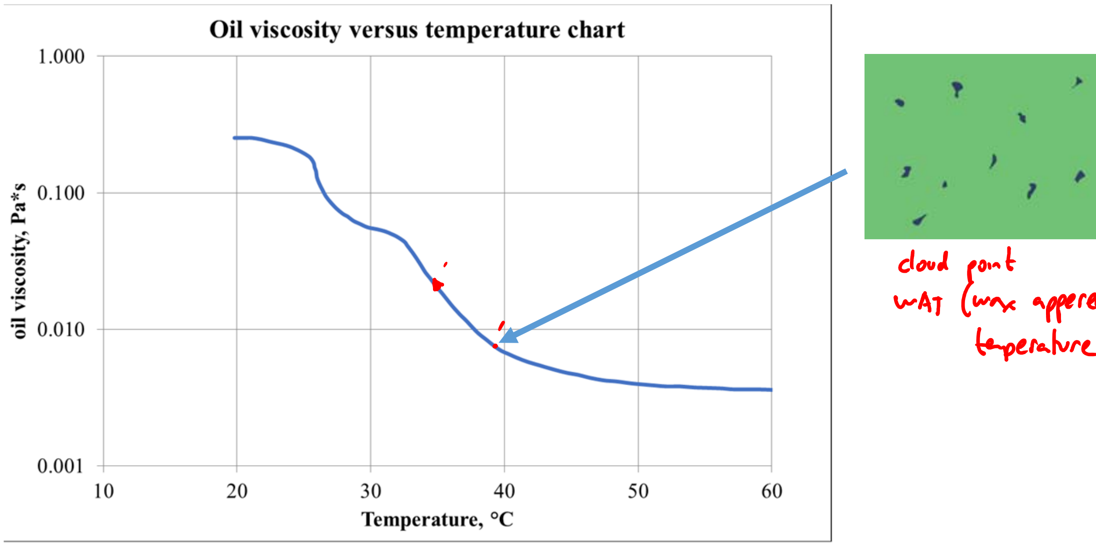
TAKEN FROM EQUINOR



Paraffins (C18 - C36)

6

Wax

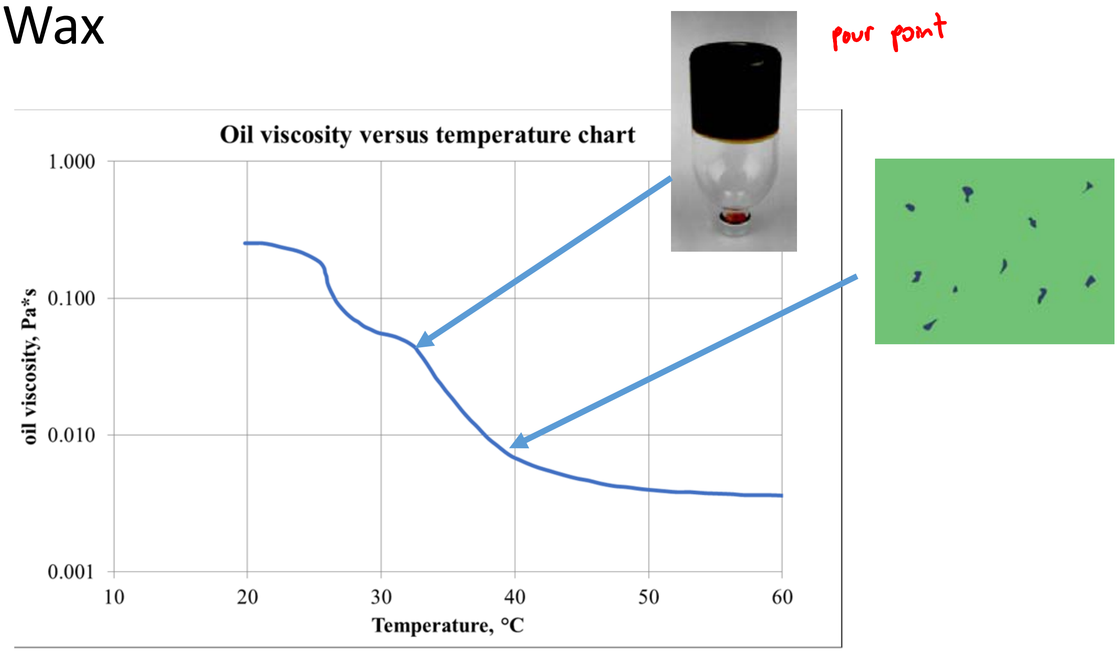


cloud point
WAT (wax appereance temperature)

7

Wax

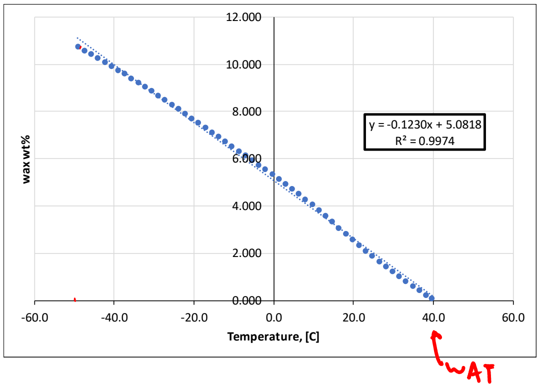
pour point



8

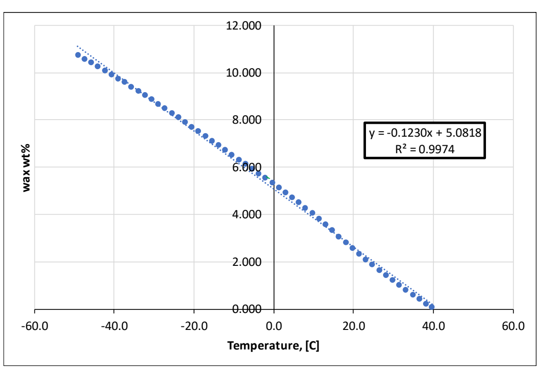
Wax

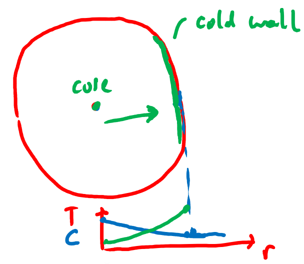
$\frac{\text{weight of wax particles}}{\text{total weight}} \times 100$

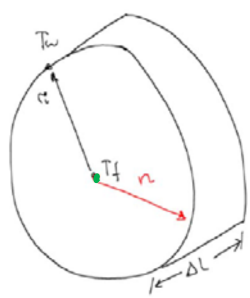


9

Wax





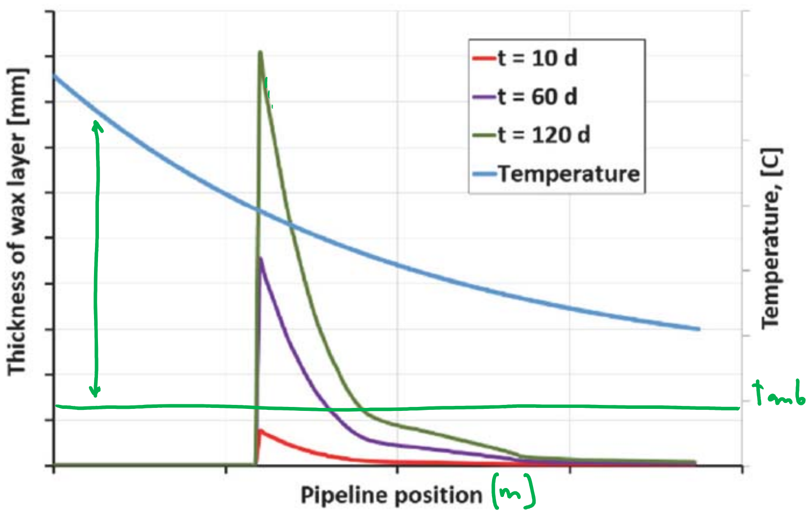


r_i: internal pipe diameter
T_f: fluid temperature
T_w: wall Temperature
n: mass flux of wax from fluid to wall [$Kg/s.m^2$]
$dA = 2\pi r_i \, dL$
total mass flow of wax (m_w) deposited in a section
$m_w = n \cdot dA$

$$n = \rho_{wax} \cdot \frac{B}{\mu_o} \cdot \frac{dC}{dT} \cdot \frac{dT}{dr}$$

10

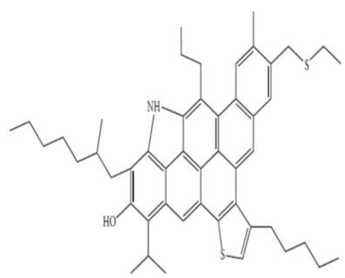
Wax

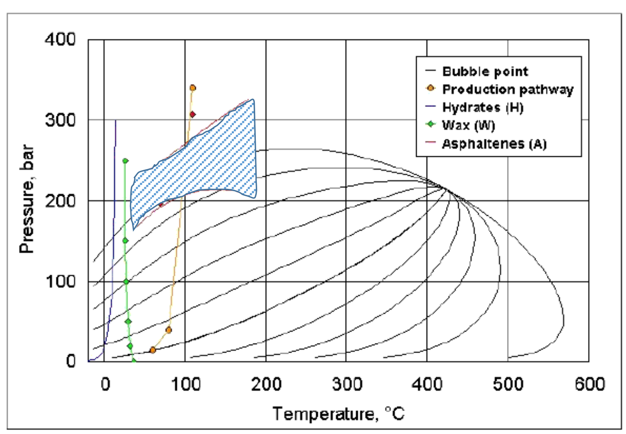


11

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

$$Ba^{2+} + SO_4^{2-} = BaSO_4(s)$$

$$Ca^{2+} + CO_3^{2-} = CaCO_3(s)$$

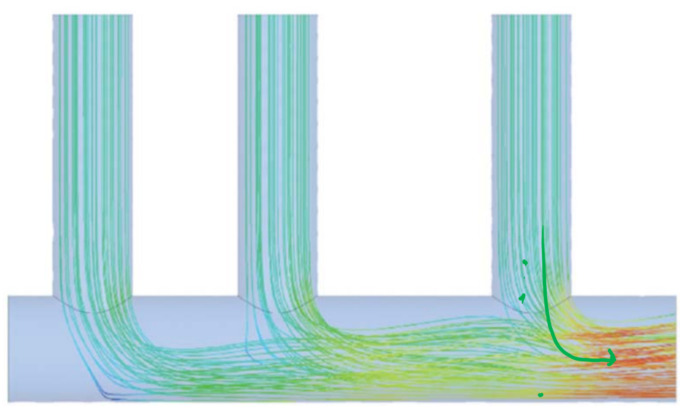
$p\downarrow$
$T\uparrow$ $\rightarrow$

$BaSO_4$ $CaCO_3$ NaCl

TAKEN FROM EQUINOR (SANDENGEN)

13

Erosion



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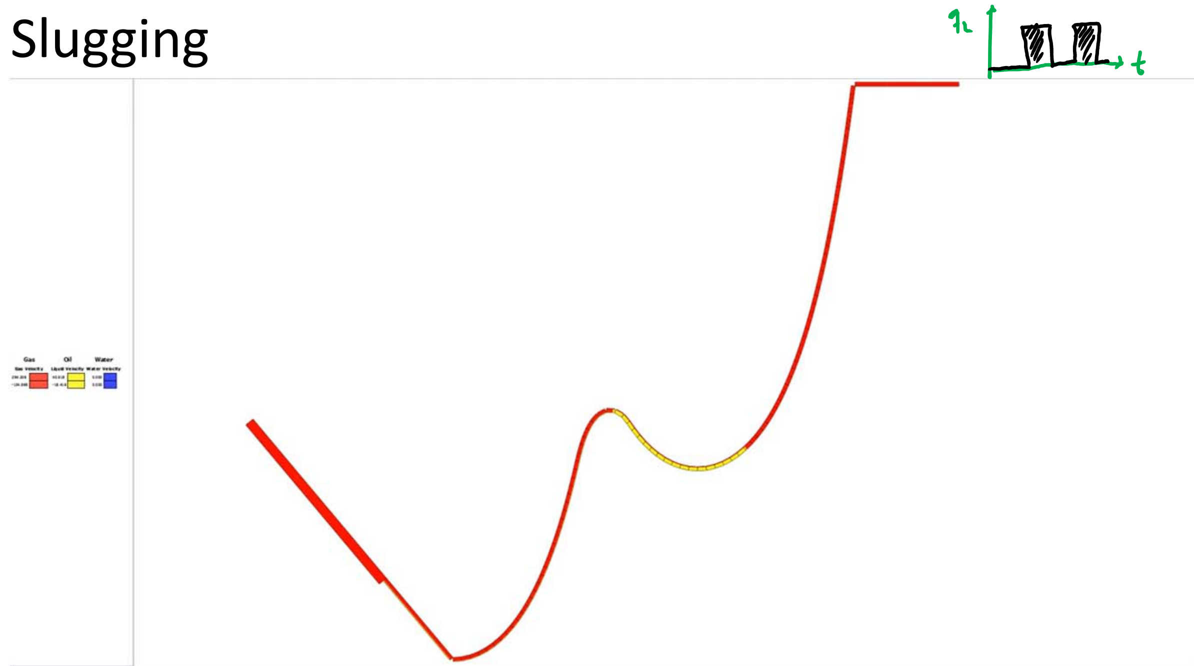
Slugging



https://www.youtube.com/watch?v=j59QLHsTs_c

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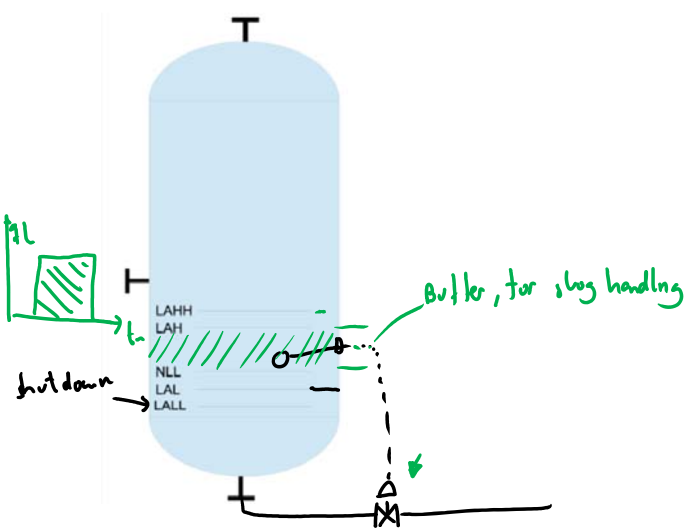
Slugging – impact on separator operation

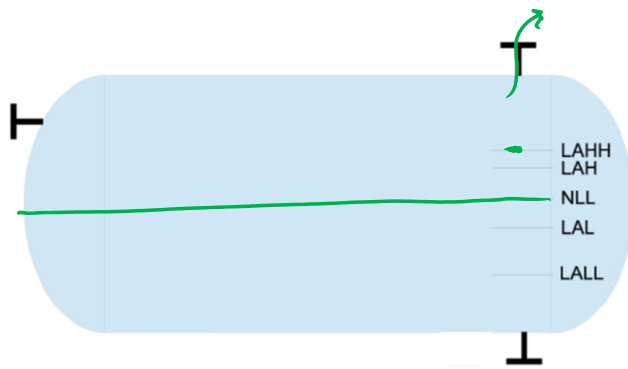


LAL: Level alarm low
LAH: Level alarm high
LALL: Level alarm low low
LAHH: Level alarm high high

https://pubs.spe.org/en/ogf/ogf-article-detail/?art=1028

16

Slugging – impact on separator operation



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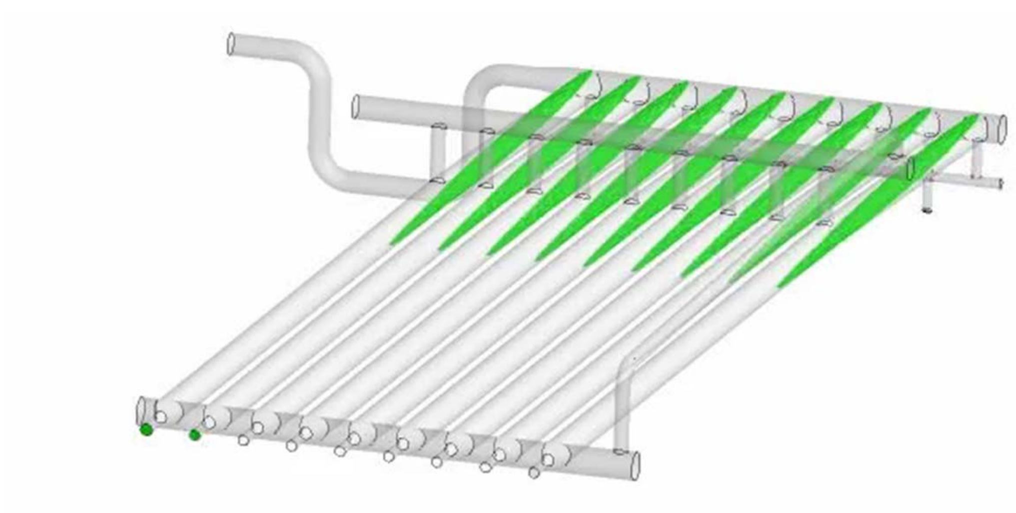
Slugging – slugcatcher handling slugs



https://www.youtube.com/watch?v=LKLW5284adI

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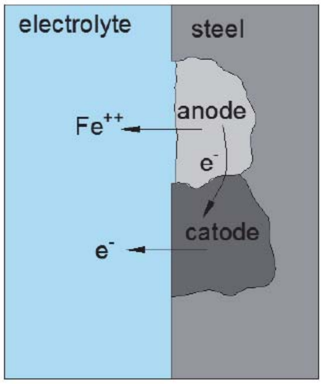
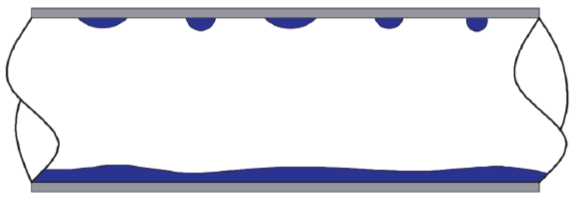
Corrosion





TOP of line corrosion

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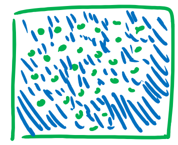
Oil-water emulsions

20

Oil-water emulsions

fine and stable dispersion



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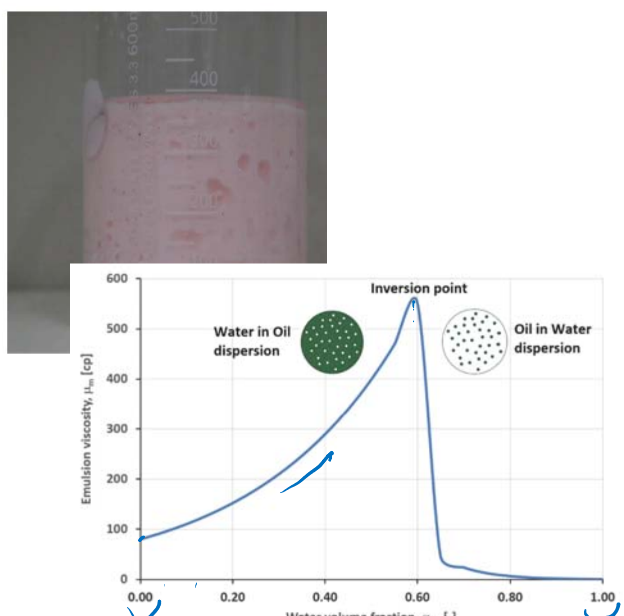
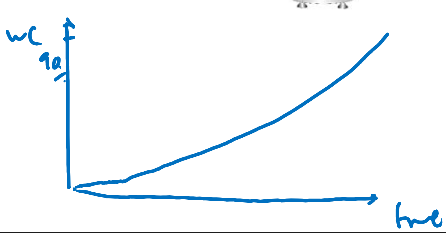
Oil-water emulsions





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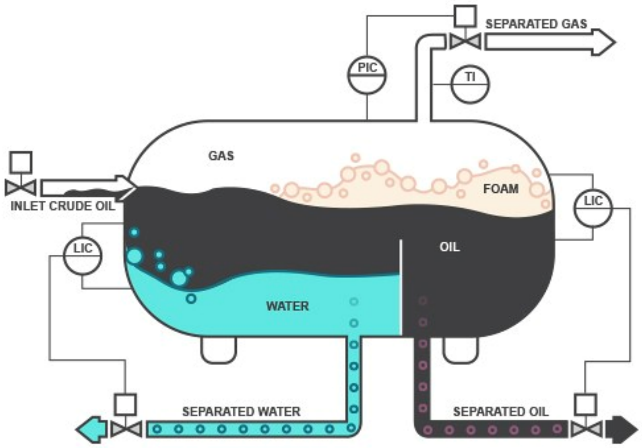
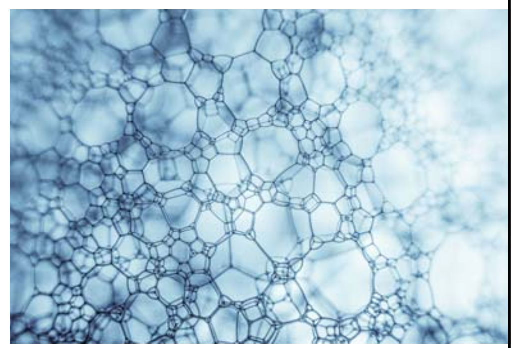
Foam



https://www.arab-oil-naturalgas.com/foam-in-oil-gas-separators/



https://www.crodaoilandgas.com/en-gb/discovery-zone/functions/foamers

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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

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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

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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

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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.

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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 miljoeffekt. Kjemikalier i grønn kategori omfatter også vann som inngår i kjemikaliene.

From Ivar Aasen PDO, Del 2

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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

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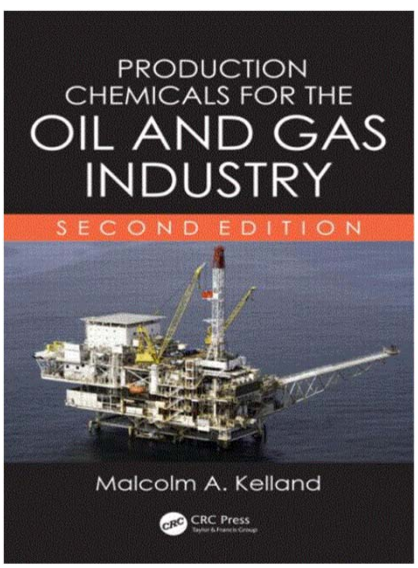
More about production chemicals



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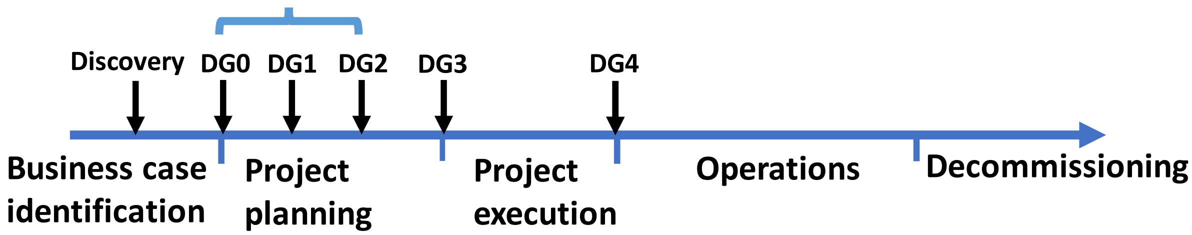
Flow assurance evaluation during field planning

- Detect potential showstoppers and communicate technical constraints and repercussions to field planner
- Laboratory tests



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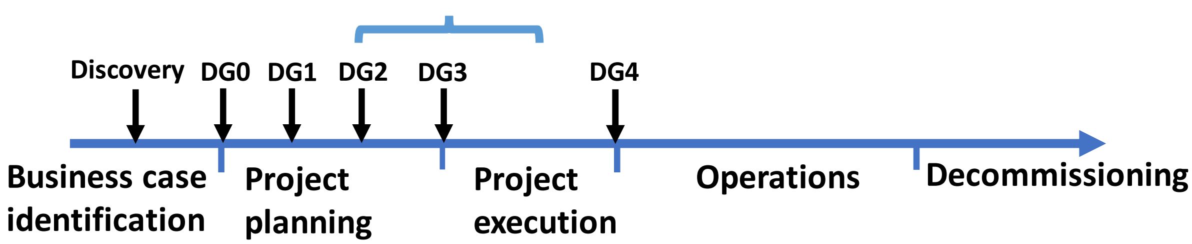
Flow assurance evaluation during field planning

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



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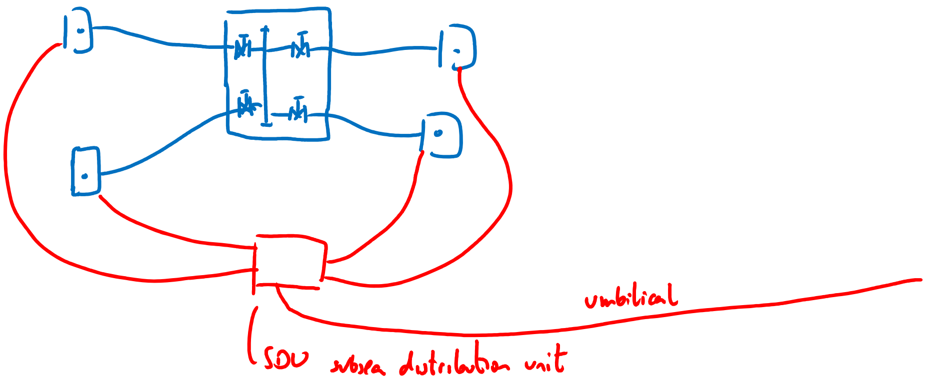
Injection of production chemicals subsea



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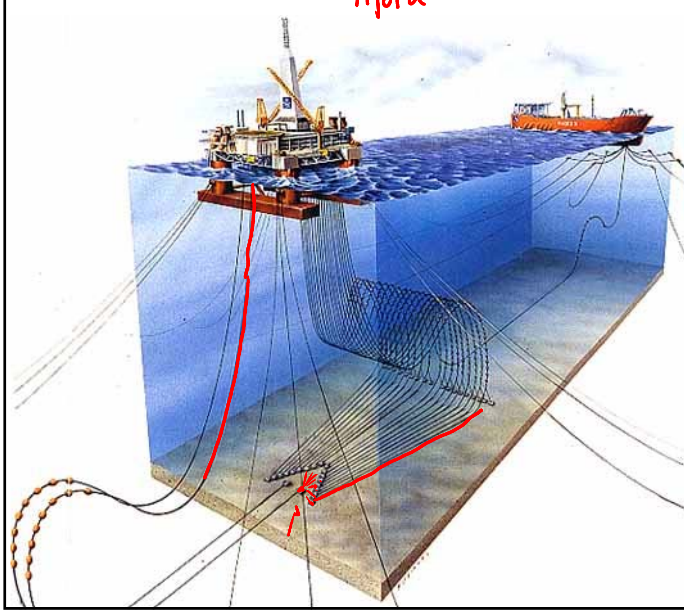
Injection of production chemicals

Njord



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Umbilicals, injection of production chemicals

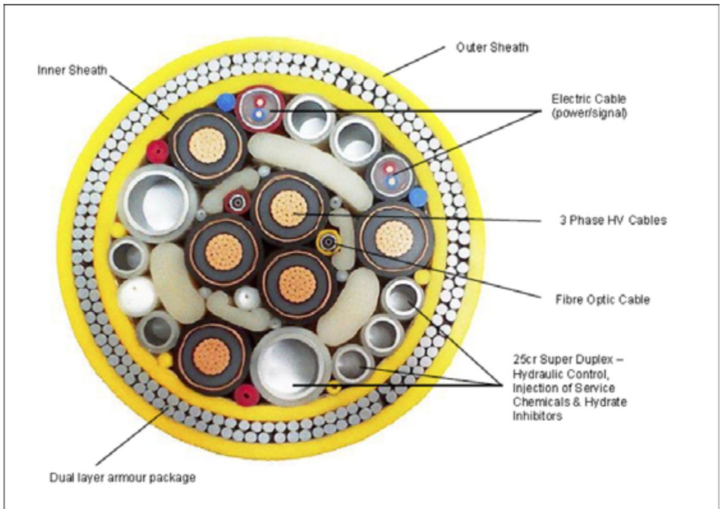

Figure 3 – Umbilical Cross Section Example

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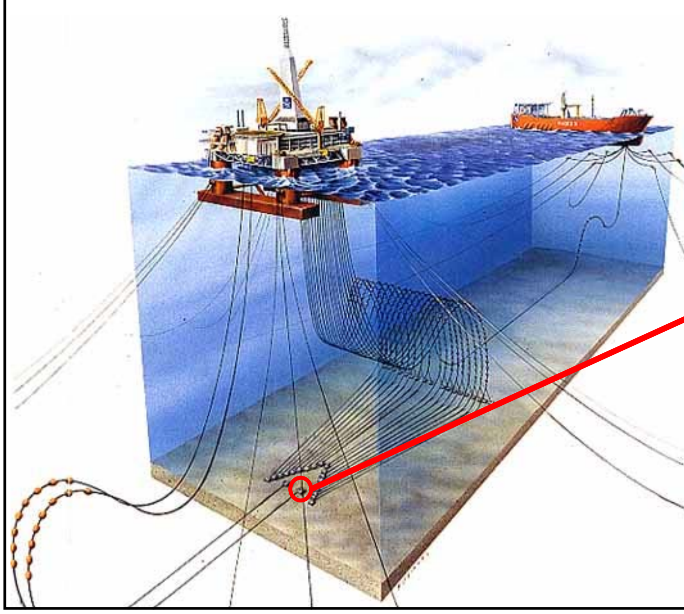
Umbilicals, injection of production chemicals



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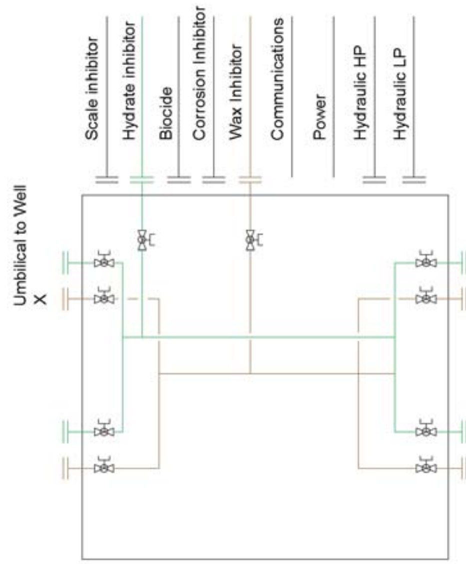
Release and disposal of chemicals



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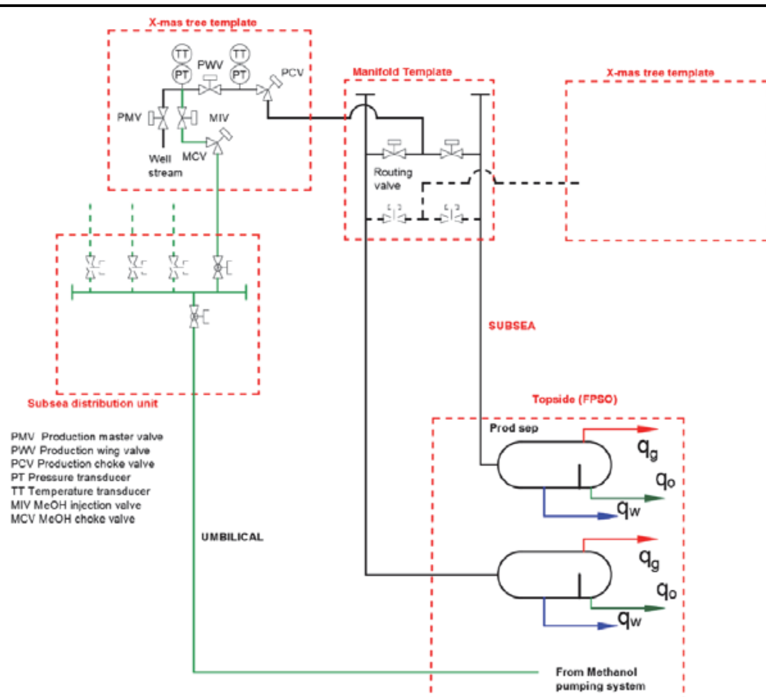

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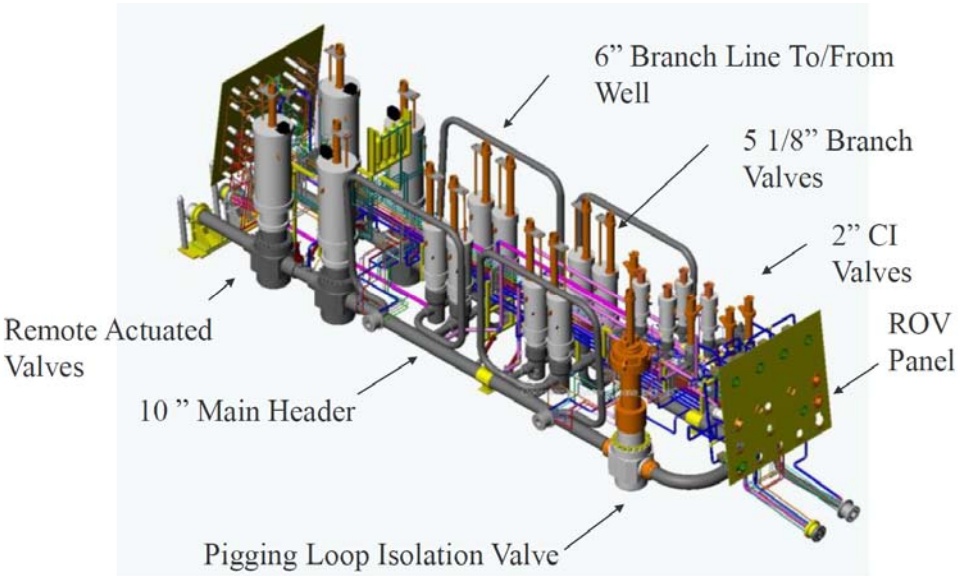
Injection of production chemicals – template wells



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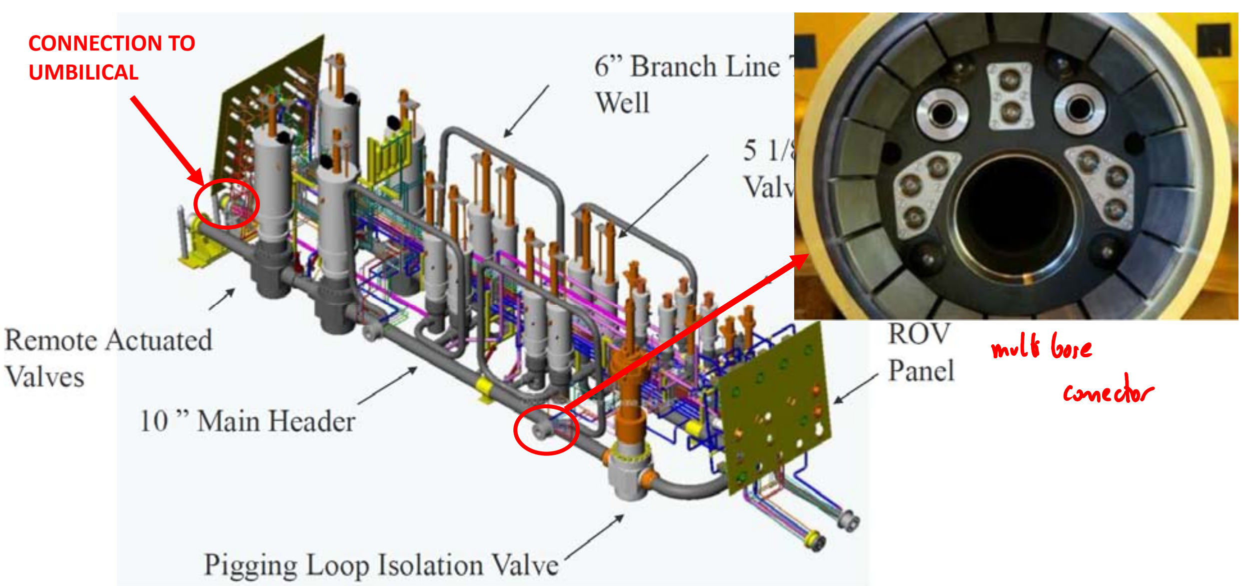
Injection of production chemicals – template wells



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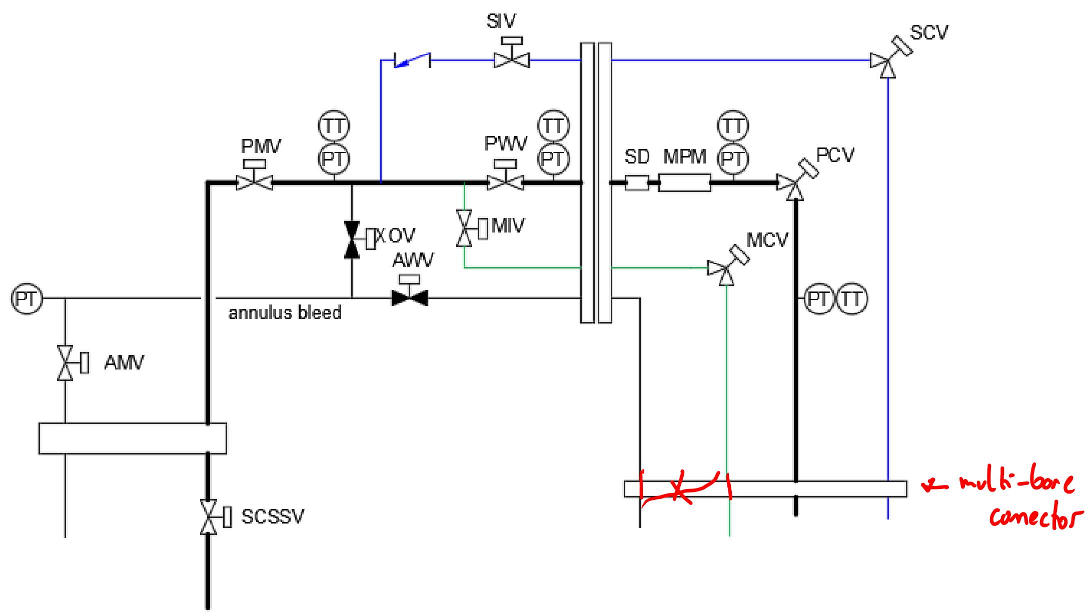

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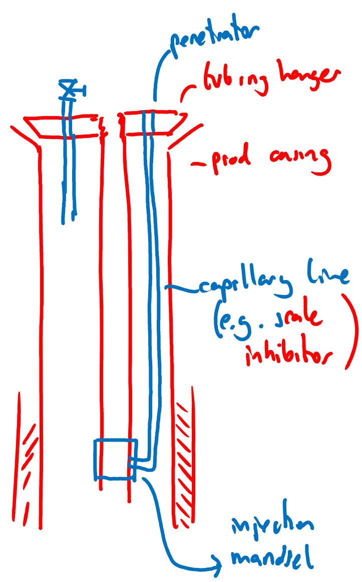
Injection of production chemicals in well



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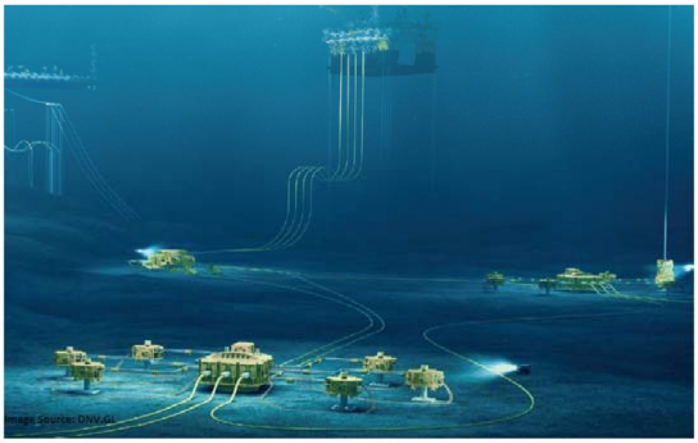
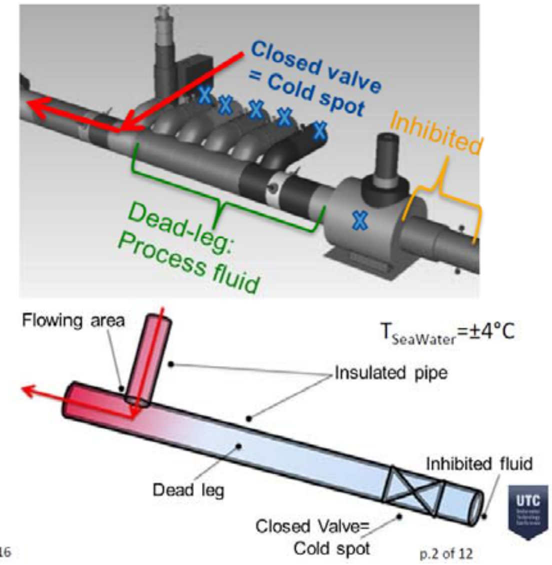
Subsea manifold and dead-leg geometry

- Dead-legs are inherently present





UTC Bergen - 16th June 2016

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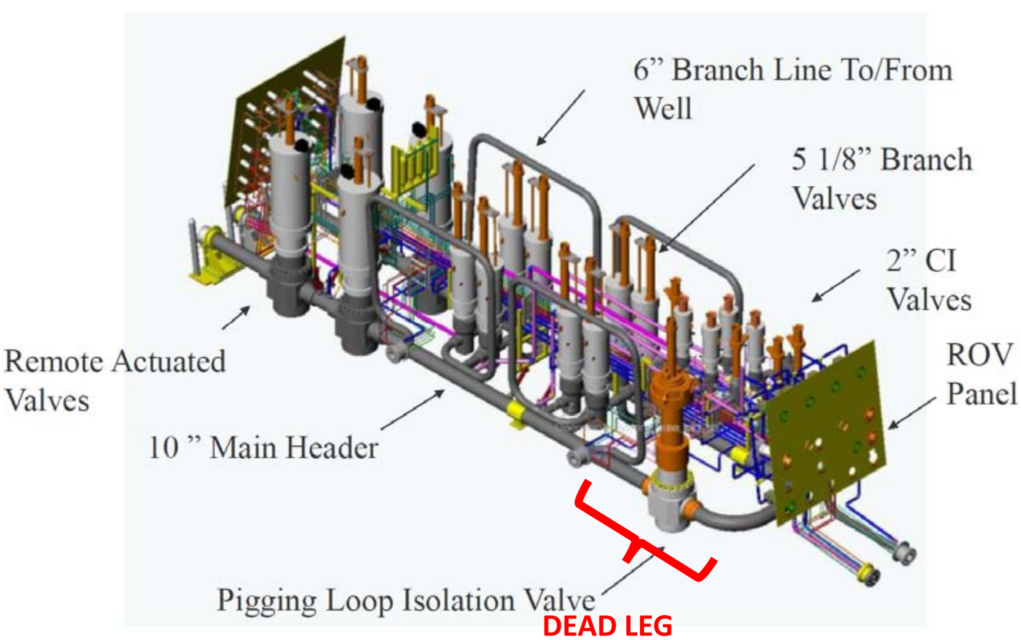

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Tools for analysis

- 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)

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Home exercises Class exercises/Class group work Quizzes

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
  - Familiarization with SODIR website
- Excel VBA, functions, and routines.
- Topside processing
  - Overview
  - O-G-W Separation and stabilization (Exercise with Hysys)
  - Separation capacity
    - Droplet settling theory
    - Droplet size distribution
  - Horizontal separator design
  - Oil content in disposed water
- 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
  - Dry gas networks.
  - CO_2 accountancy
    - CO_2 emissions and CO_2 value chain
    - Injection scheduling for the Snøhvit field
  - Production potential
- Value chain model, cost estimation and NPV calculations
- Dealing with uncertain parameters in FD
  - Probabilistic reserve estimation
    - Monte Carlo
  - Decision and probability tree analysis
- Introduction to Python, Jupyter Notebook
- Offshore structures
  - Overview
  - Layout of production systems
  - Marine loads on offshore structures
- Flow assurance considerations
  - General overview
  - Inhibitor subsea system. Disposal.

Home exercises Class exercises/Class group work Quizzes

- Simulation of pipeline using commercial software (Hysys)

Lecture material :

- Live lectures
- Youtube videos
- Reading material

Home exercises Class exercises/Class group work Quizzes

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: 6th June, 2024, 15:00-19:00. SL311 brun sone

-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.
- 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).

-After the exam is ready, Milan will publish information about number and type of questions on Inspera (1-2 weeks before the exam date).

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, **I believe you will need to use the tablet provided on the table.**

-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