Note Title 09.01.2017

TPG 4230 Field Development and operations

Prof: Milan Stanko → Production engineering

tuesdays 8:15-11:00 thursdays 14:15-1600

mixed theory and exercise sessions
- → made by me in class
- → done by students with my support

bring laptop or team-up with a friend

60% written exam → date 15.05.2017 kl. 09:00
40% exercises / project → 5-6 sets

Consultation hours: after class

my office 230 2nd floor milan.stanko@ntnu.no

Main communication tool is Its learning. check it frequently use the "discussion tools"

Student assistants:

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- requirement for the exercises: deliver all but 1

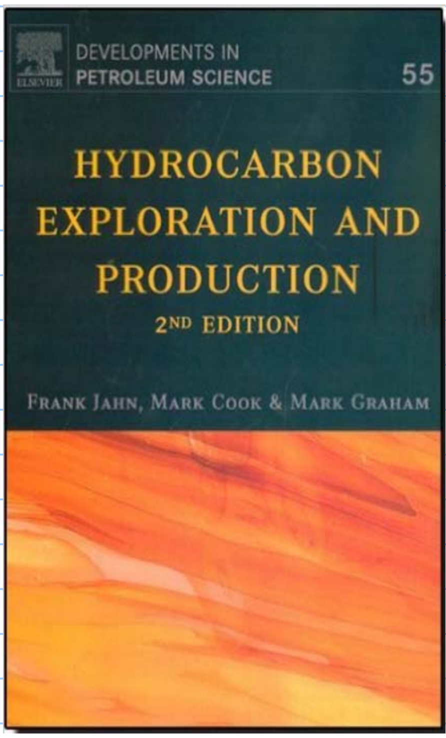
the compound exercise grade has to be 20/40

penalty for late delivery

Reference group:

http://www.ipt.ntnu.no/~stanko/index.html

Bibliography → support material.



this course is focused on offshore Norway production

Field development and operations

development:
- flexibility
- uncertainty
- sensitivity analysis
- scenarios
- optimization

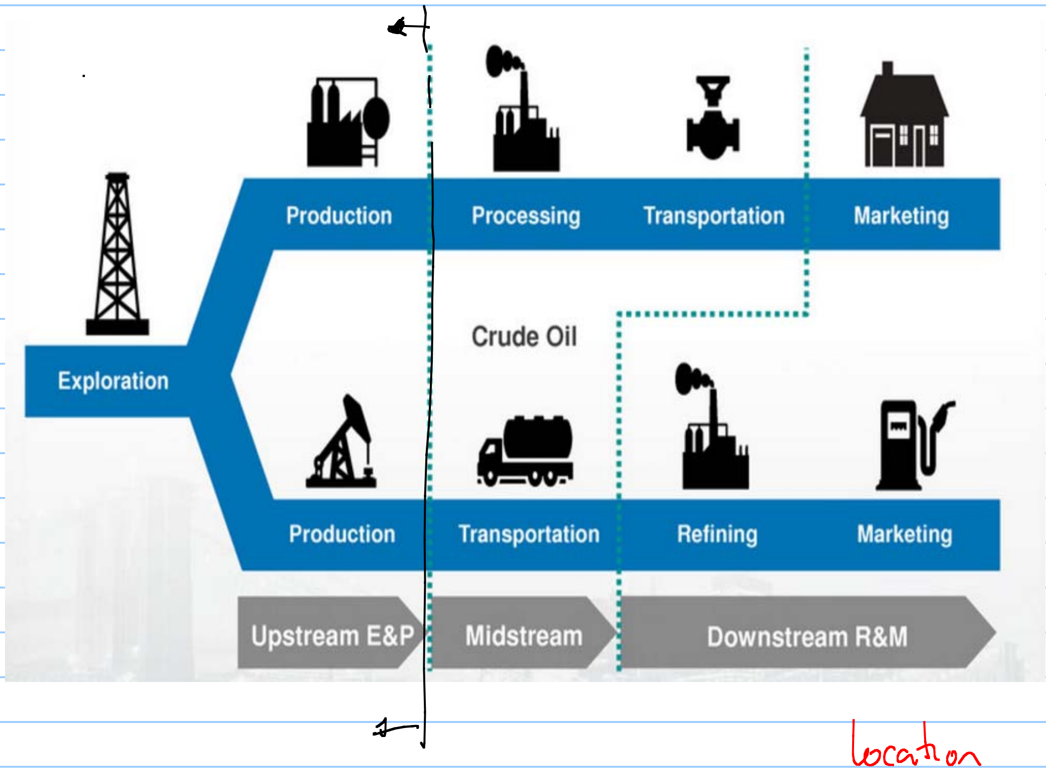
operations:
are tied to a physical system to cope with its deficiencies
- exploit its advantages
- {constrained}
- effectivization
- maintenance, trouble shooting

Topic	Level	Exercise	Engineering skills	Computational Tools
Life cycle of a hydrocarbon field	Appreciation	NO	-	-
Field development workflow -Probabilistic reserve estimation -Cost estimation and NPV calculations	Appreciation/ configuration/ design	YES	Gant chart, NPV calculations, Spider plot, decision trees, Monte Carlo simulation, basic probability	Excel VBA
Offshore (and some onshore) field architectures and layout of production systems -Production manifold -Pigging facilities	Configuration	YES	Engineering diagrams and drawings. Analysis	-
Dynamics of marine structures -Wave statistics	Configuration/ design	YES	Analysis. Modeling. Fast Fourier Transform for signal analysis.	Excel VBA
Reservoir depletion and field performance -Production potential -Production scheduling -Flow equilibrium in production systems, choking and boosting -Flow performance of surface and downhole production networks	Design	YES	Modeling. Programming. Problem solving	Excel VBA, Gap, Prosper (or Pipesim)
Flow assurance -Modeling of gas and condensate transport in pipeline and hydrate formation -Simplified modeling of oil and water emulsions	Appreciation, Design	YES	Modeling. Programming. Analysis. Problem solving.	Hysys, Excel VBA
ESP fundamentals, design and plan for the field life	Design	YES	Modeling. Problem solving.	Excel VBA
Early subsea boosting design	Design	YES	Modeling. Problem solving.	Excel VBA
Data management and allocation	Appreciation/ design	YES	Data analysis, filtering, QC, averaging, aggregating.	Excel VBA
Production optimization.	Design	YES	Analysis, modeling, critical thinking. Problem solving.	Excel VBA
Integrated asset modeling	Appreciation	NO	-	-
IAM				
Additional skills gained by home and class exercises			(Group work) Develop written and oral engineering communication skills.	

Material balance	TPG4145	whitson
Reservoir simulation fundamentals, flow tables	TPG4160	Kleppe
Well inflow	TPG4245	Asheim
Fluid phase behavior	TPG4145	
Black oil model	TPG4145	
Single and multi phase fluid flow in pipes	TPG4135	Larsen
(computation of pressure and temperature losses)	TPG4245	
Processing fundamentals, separation,	TPG4135	
Compression fundamentals	TPG4135	
Pumping fundamentals	TPG4135	

Introduction to subsea boosting	TPG4200	Sangesland
Introduction to subsea systems	TPG4200	
Risk analysis, decision making, uncertainty	TPG4151	Bratvold
Life cycle of an oil and gas field. Fundamentals	TPG4105	Stokka

where are we? P1 I



location

$\boxed{\text{E and P}}$ exploration and production

understanding the subsurface

optimization of the development
development phase
operation phase

commercialize the resource

when?

30 years

life cycle of an oil and gas field

$\boxed{\text{Pre-exploration}}$ → $\boxed{\text{exploration}}$ → $\boxed{\text{appraisal}}$ → $\boxed{\text{Project planning}}$ → $\boxed{\text{execution}}$ → $\boxed{\text{operations}}$

discovery

of commerciality

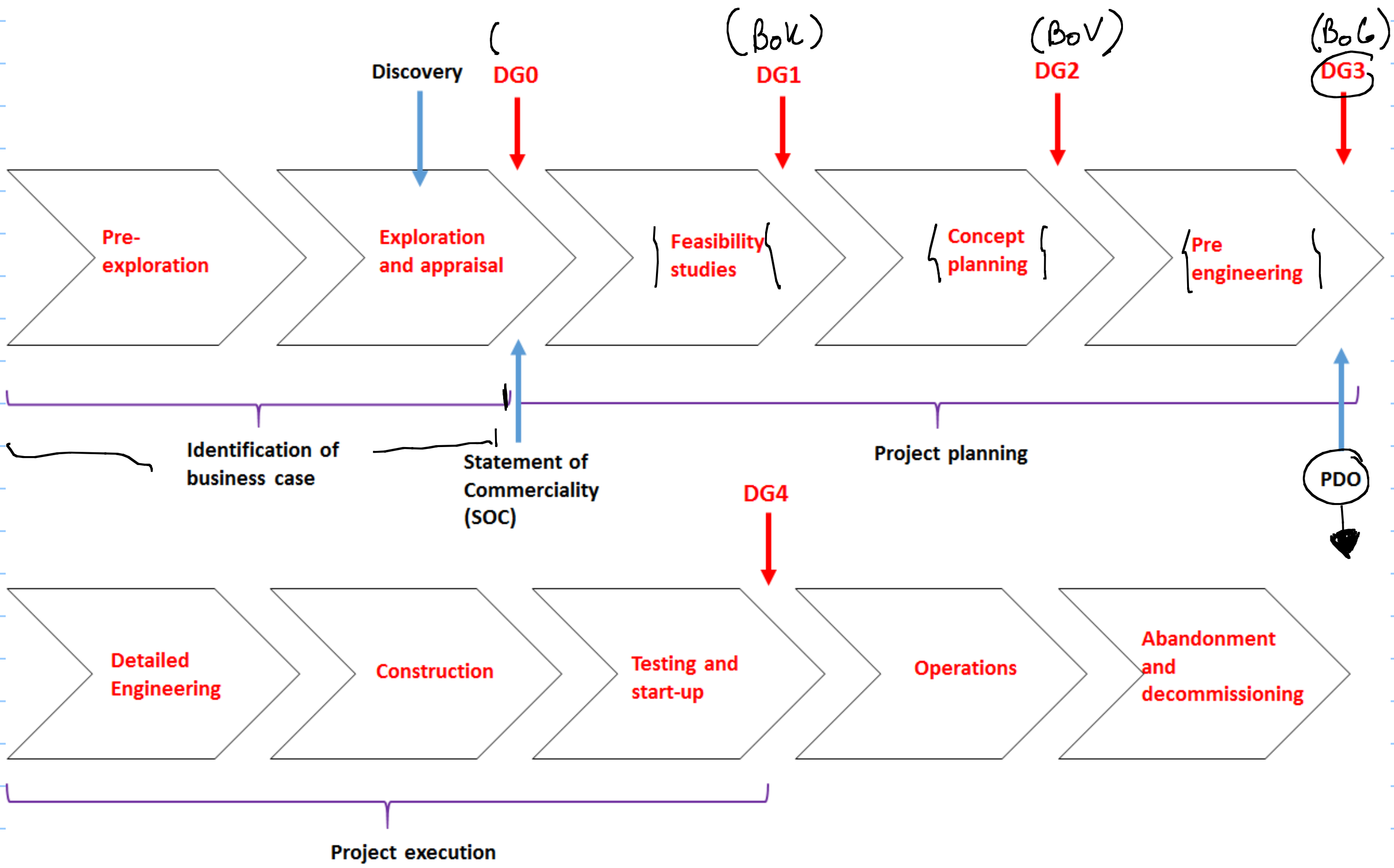
3-5 years

pre operations, pre-production

$\boxed{\text{abandonment and decommissioning}}$

BOK: Beslutning om konkretisering
BOV: Beslutning om videreføring
BOG: Beslutning om gjennomføring

DG - decision gate



- Identification of business case:

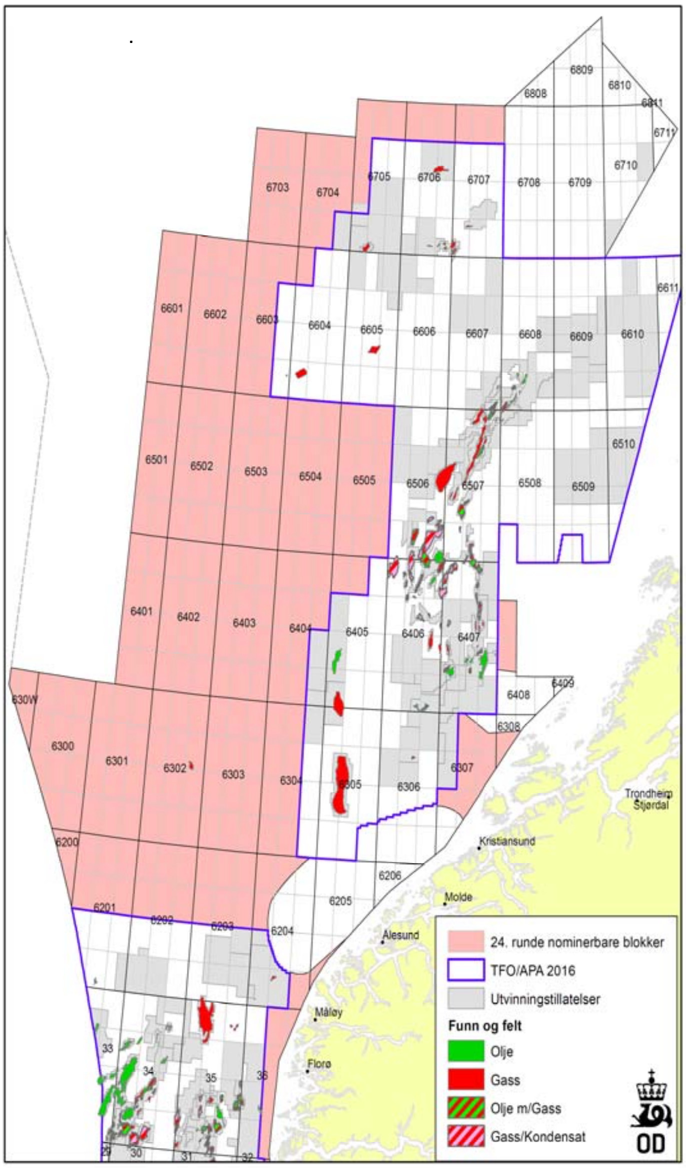
Demonstrate economic potential of the discovery and quantify and reduce uncertainty about recoverable reserves.

Steps: 1: pre exploration activities and scouting
→ collect information on areas of interest where there might be potential for hydrocarbon accumulation
- technical, political aspect, geographical, social, geological
environmental
chance of finding reserves and how big

2: Getting pre-exploration access → the exploration license
non-exclusive right to an area { seismic } in NCS
shallow wells
Sometimes this is done by specialized companies.

3: Identify a prospect

4: Applying for a exclusive production license. In NCS is max 10 years*. • licensing rounds (frontier areas)
• APA (Awards in predefined areas)



. 1st year

34000 NOK/km²

2nd

68 000 NOK/km²

3rd · 137 000 NOK/km²

• Exploration Perform geological studies, geophysical survey, seismic, exploration drilling.
- well cores
- wall cores
- cuttings
- fluid samples
- productivity test — DST Drill stem test
- logging

• Discovery!

- Assess the discovery further. Uncertainty, manage risk.
  - → Probabilistic reserve estimation. Identify and assess additional prospects and segments
  - Perform simplified economical evaluation
  - → Field appraisal to reduce uncertainty: more exploration wells and seismic. fault communication
    extent of reservoir
    aquifer
    WOC water oil contact
    GOC gas oil contact
    etc

- Reach DG0
  - Issue a SOC (statement of commerciality) and ROC

  continue to next phase

  - Do more appraisal.
  - Sell the discovery
  - Do nothing wait
  - Relinquish to the government

Project planning phase:

- feasibility studies find one or concepts (general) that are technically, commercially and organizationally viable
- objectives of the developments
- establish feasible development scenarios
- demonstrate techical and economical feasibility

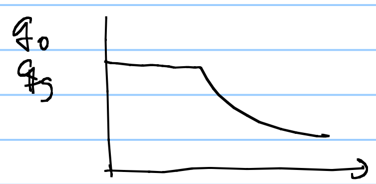
- Identify potential stoppers
- Identify the need for new technology
- Cost estimation including system.

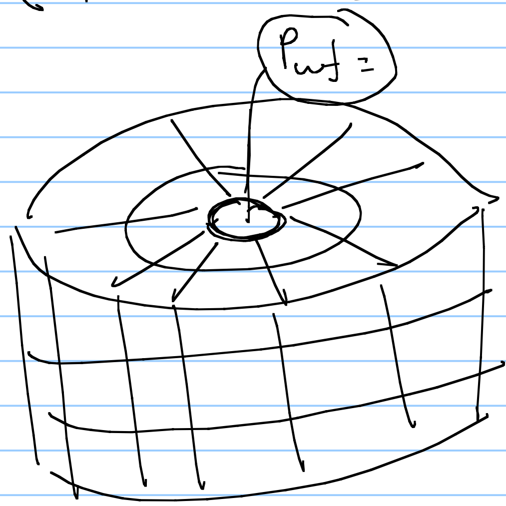
Concept planning

Identify alternative concepts, select a "viable" concept and document it preparing for DG2

- Define the commercial aspects: legislation, agreements, licensing, financing, marketing and supply, taxes
- Reservoir behavior (depletion strategy) → reservoir model
  - → static modeling
  - → dynamic modeling

  production profiles





- Reservoir simulator
- material balances + IPR equation
- Decline curve analysis

- Flow assurance { hydrates, wax, scale, slugging
- Drilling and well planing
- facilities
- Operation, start-up, operations, maintenance
- Concept selection

- Cost and manpower estimates

Pre engineering

mature, define document the selected concept.

- Selection of the final technical solution. Define all remaining technical alternatives
- execute FEED (front end engineering design)

techical requirements (arranged in packages) based on the final solution. Aker solutions

- plan and prepare the execution phase.
- prepare submission of PDO Plan for development and operations

Consequence and impact report.

PIO. Plan for installation and operation of facilities for transport and utilization of petroleum

for next class read page 9-17.

Field development process

FDP field development plan

PUD Plan for utbygging og drift

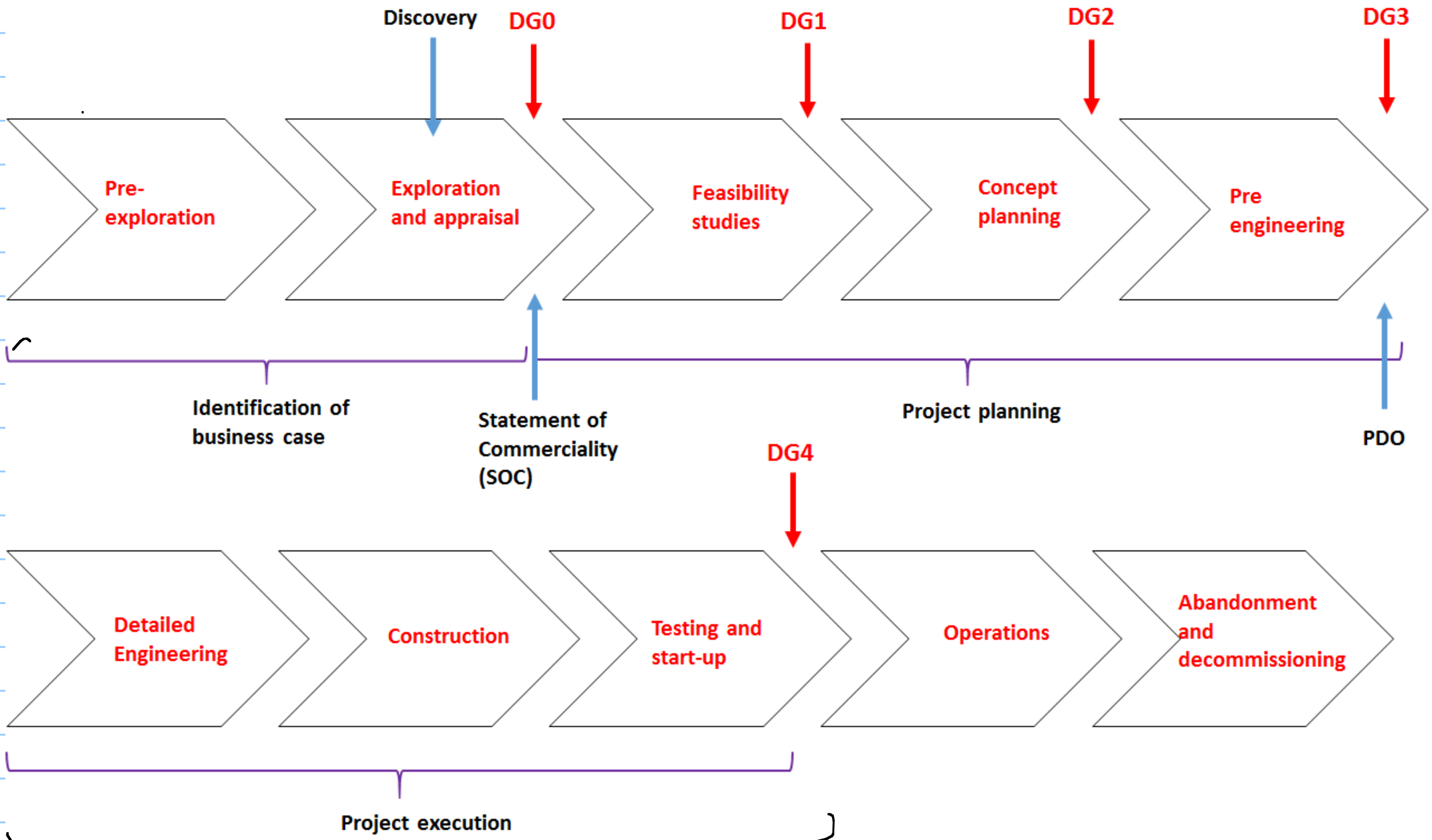
http://www.npd.no/Global/Engelsk/5-Rules-and-regulations/Guidelines/PDO-PIO-guidelines_2010.pdf

Read compendium from page 42-49

http://folk.uio.no/hanakrem/svalex/Misc/Visund_PDO_PUD.pdf example for Visund field

Impact assessment

Project execution phase

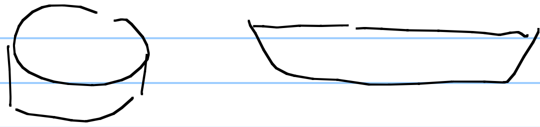


- Individual contract
  - several companies

Detailed engineering
Bids, contracts
Construction, fabrication
Installation
Commissioning

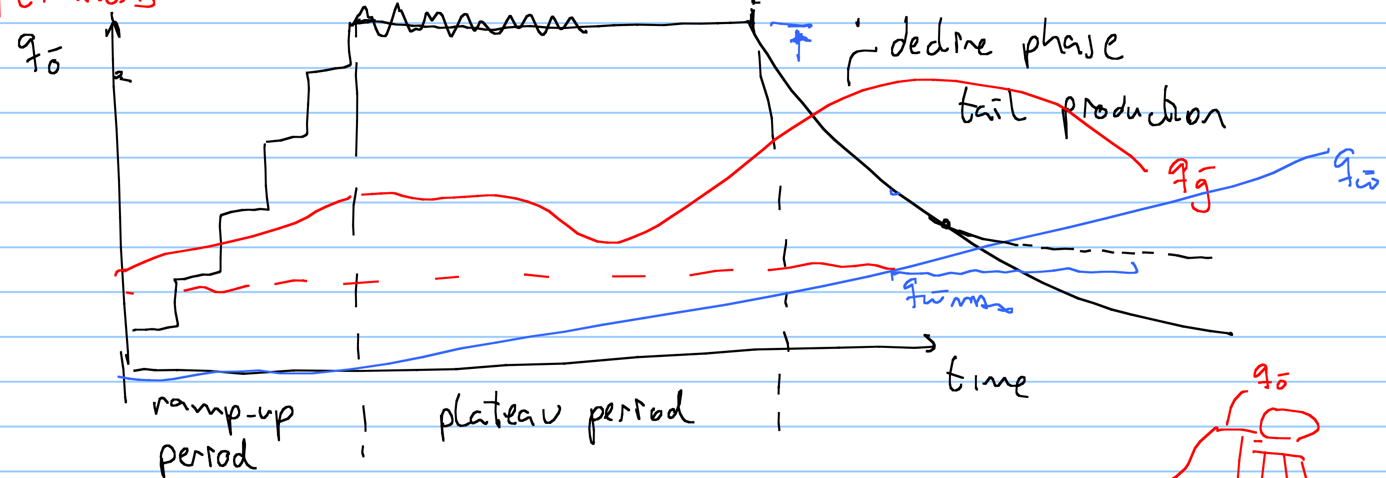
EPCM (Engineering, procurement, construction, management)

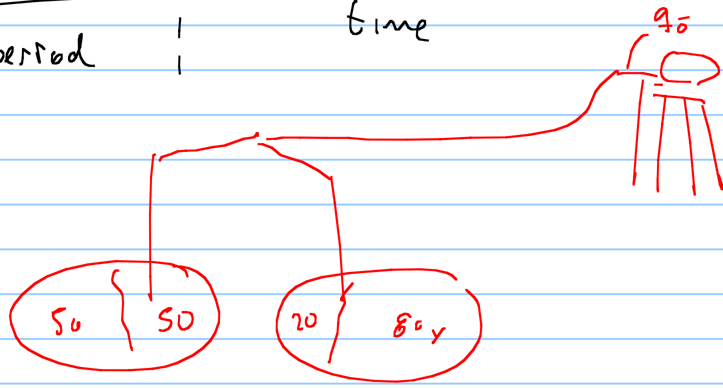
Single company.



- Constructing well
- Perform hand over to asset, operations
- prepare for start-up, operation and management

operations





- Maintenance
- Allocation. → metering
- trouble shooting
- Debottlenecking — facilities have q_g max, q_w max
  - dealing with associated products

- IOR improved oil recovery methods.
  - drilling more wells
  - Boosting
  - artificial lift
  - reperforate

- stop production

- Decommissioning phase.
  - Define a timeline and a plan
  - Coordinate with relevant environmental agencies
  - well plugging and abandonment (TPG4200)
  - Cut conductor
  - engineer "down and clean" flushing and clean tanks, processing equipment, piping
  - prepare the offshore structure for removal
  - plan and remove topside equipment
  - lifting operations and transport
  - remove or bury subsea pipelines
  - mark and register leftover installations on marine maps
  - monitoring
  - Recovery of material
    - steel
    - recycling of equipment
      - Gas turbines
      - separators
      - pump
      - processing

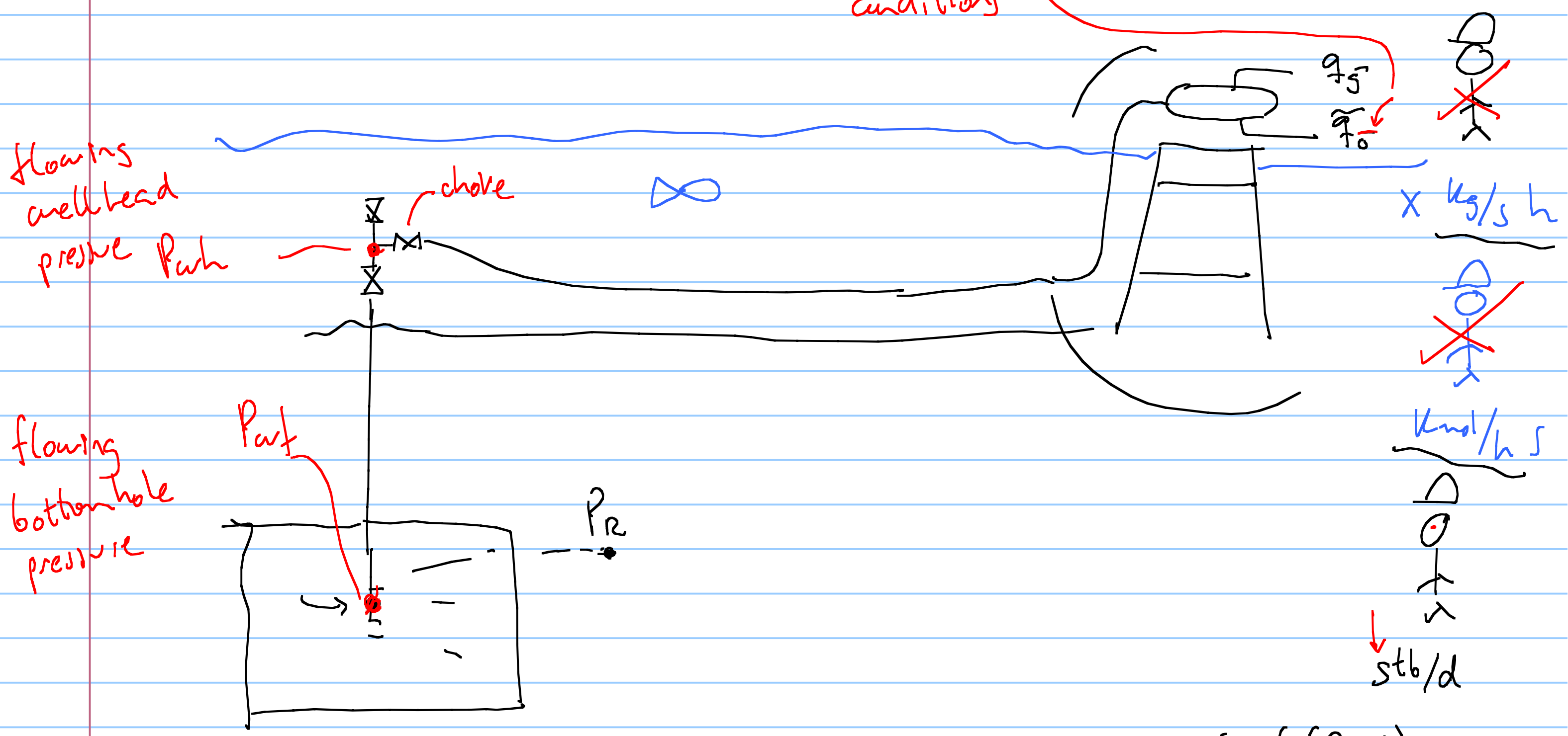
      $
  - disposal of residues

Decommissioning:
Overview of activities
https://www.youtube.com/watch?v=8Xm9VNZul9M
Transport of platform and scrap yard
https://www.youtube.com/watch?v=1GA3EIu81rw

Page 147-149 Compendium.

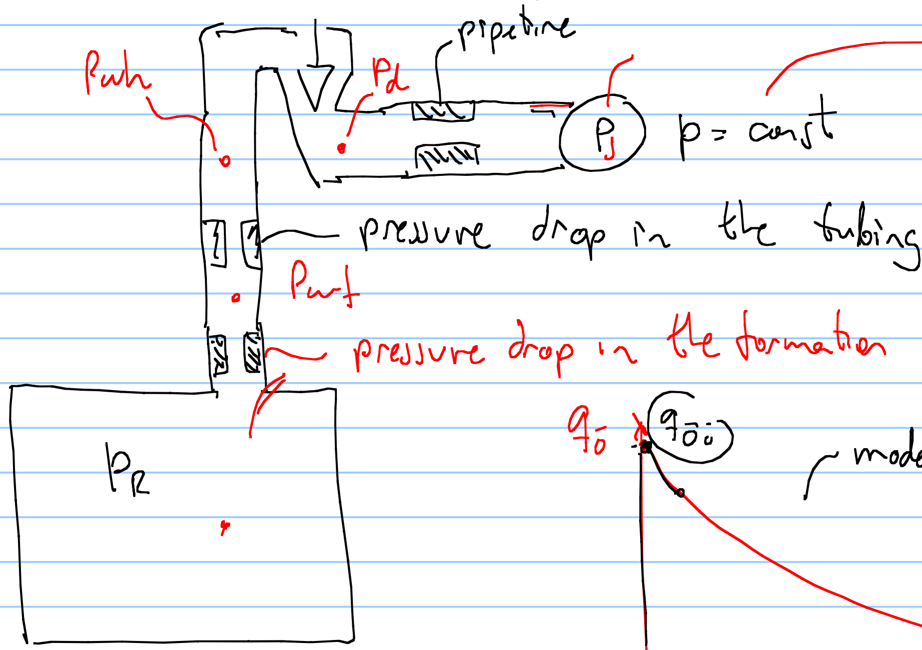
indicates standard conditions

q volumes

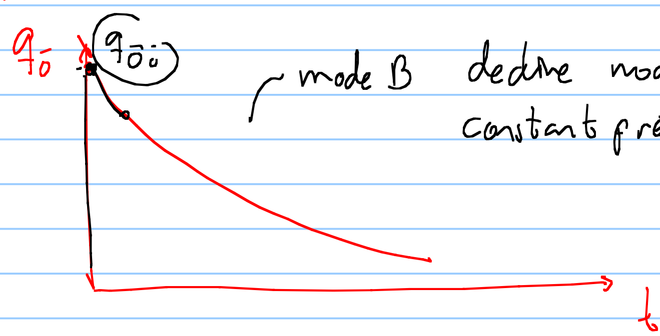


$v = f(P, T)$

mechanical analog of my production system



$$\Delta p = P_R - \underbrace{P_{sep}}_{\text{const}}$$

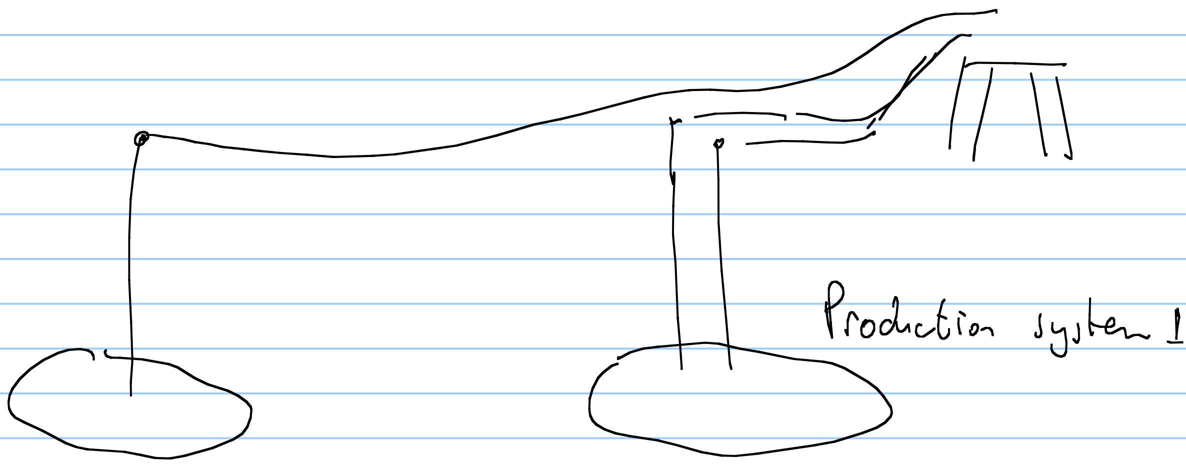


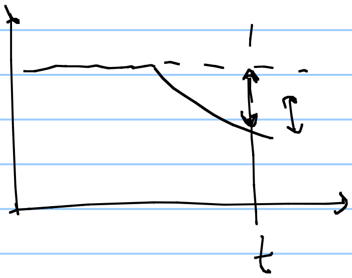
mode B decline mode
constant pressure

$$q = f(P_R - P_{sep})$$

Satellite field that are tied-back to existing processing facities

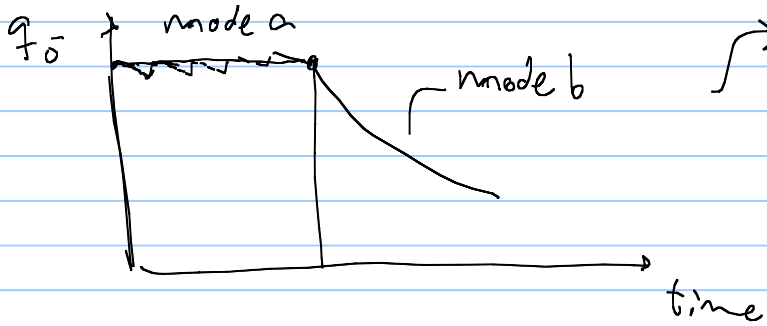
not used for standalone projects.





mode a   plateau mode

constant rate mode



new developments with standalone facilities

http://www.ipt.ntnu.no/~stanko/Field_Simulator.html

for fields operating in plateau mode:

a rule of thumb: drain 10% of the $\underbrace{\text{TRR}}_{\text{oil}}$ total recoverable reserves in a year

IOIP (N)

IGIP (G)

TRR = N . RF

G . RF

recovery factor

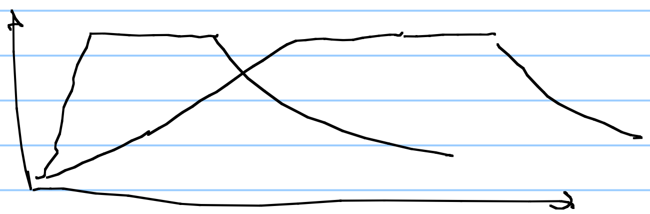
$$q_{plateau\ rate} = \frac{N \cdot RF \cdot 0.1}{365} = [stb/d]$$

for gas 0.03 - 0.05 per year

page 18 of the compendium

$\boxed{\text{Onshore}}$ on

- there are neighboring field of easy access to tie-in production



longer ramp-up than in offshore.

longer appraisal and overlapping with production

- test and verify reservoir communication and structure ~> use production data to improve reservoir models

- delay the planning of gas and water injection

$\boxed{\text{Offshore development}}$

- short ramp-up
- short appraisal
- Get production as soon as possible to get a healthy cashflow
- Don't acquire much production data to improve my reservoir model
- plan ahead for water and gas injection
- review planning and models "on the go"

Oil vs gas developments

- transportability
  - oil → shipped in tank — high energy density
  - gas → pipeline
    - LNG plant

price oil > price gas

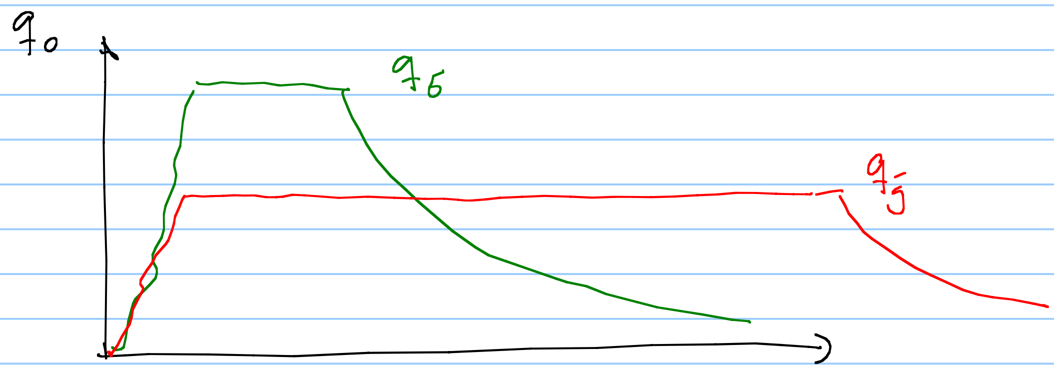
- Contract → time, amount, price USD/Sm^3/d, gas specs
  MM scf/d
  { heating value
  { N_2, CO_2, H_2S

You need to have a buyer, contract

if using LNG it is necessary to have an LNG infrastructure

sending LNG facility
Carrier LNG
receiving LNG facility

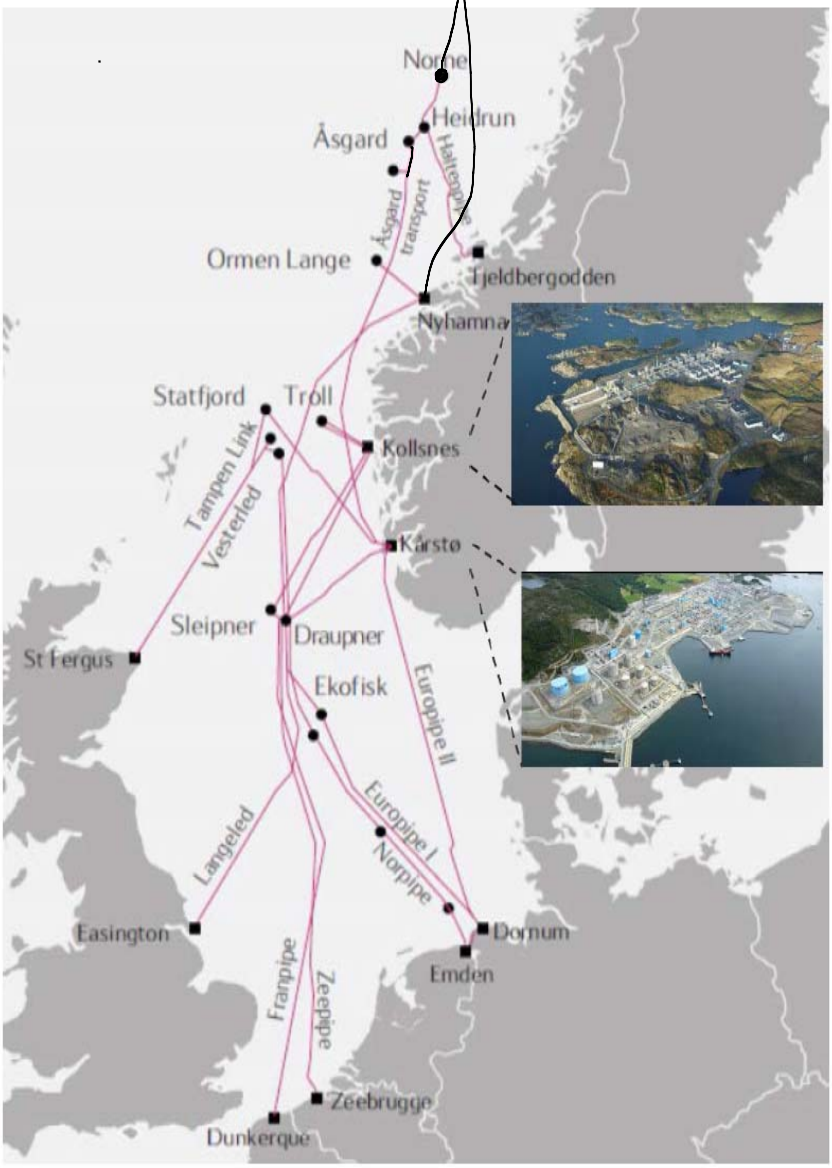
oil fiels have a plateau 2-5 years
gas fiels have a plateau 10-25 years → contract



• tentative date for first set of exercises : end of next week.

• things that were missing from last class:

for gas developments using a gas distribution network a tariff must be paid (in Norway is Gassco)

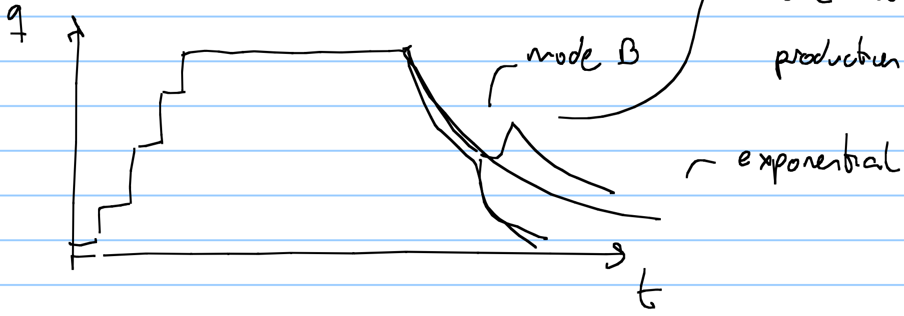


in gas contracts one usually has a: • DCQ (daily contract quantity)

• Swing factor (multiplier to DCQ) 1.2, 1.3

• penalty clause: how much the producer has to pay if doesn't deliver DCQ.

about the production profile



changes in the decline are due to changes in the production system: wellbore collapse
scale in tubing, liquid loading
wax accumulation

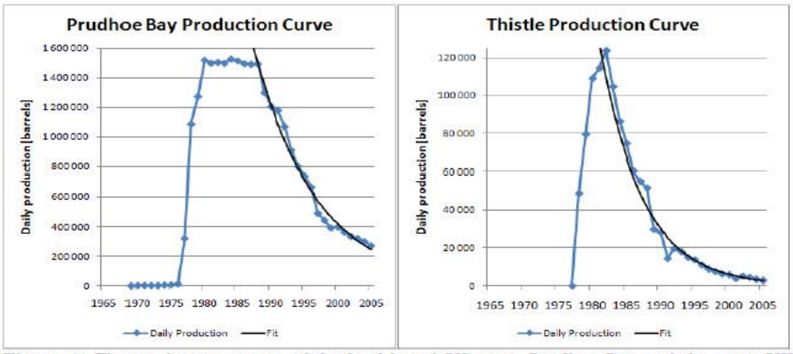
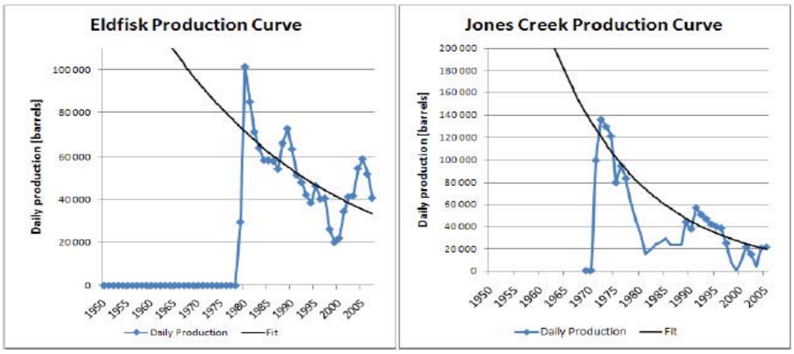
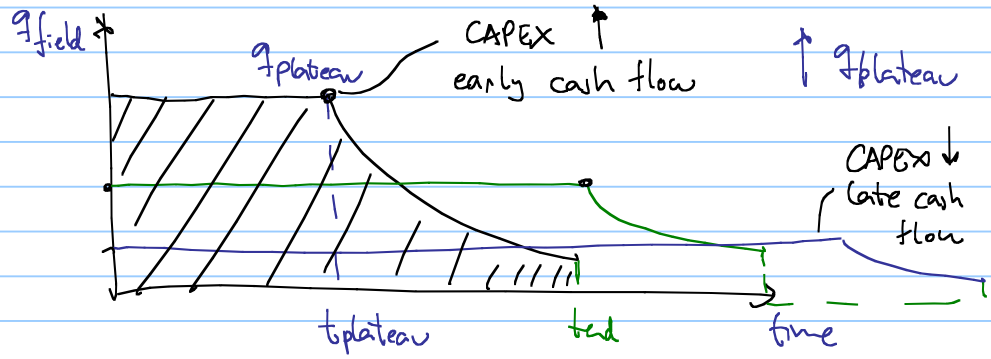


Figure 4: *The production curves of the land-based US giant Prudhoe Bay and the giant UK Thistle offshore field. The approximately exponential average decline rate is clearly seen in these two well-behaved fields.*



https://grandemotte.wordpress.com/oil-and-gas-5-production-decline-rates/

- there is a very close relationship between plateau length and plateau height



↑ $q_{plateau}$ ↓ $t_{plateau}$

$$N_{pu} = \int_0^{t_{end}} q_{field}(t)\, dt$$

ultimate cumulative production

how do I decide a proper plateau length? { economical analysis, max NPV for a fixed production system.

- height is dictated by physics (engineering) / economics

If q is higher:
- produce excessive sand
- erosion
- damage
-

- length is dictated by physics

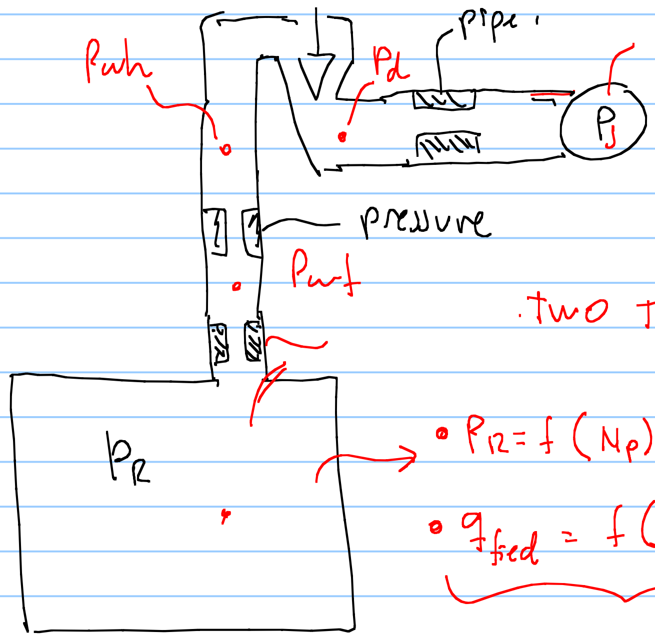
Production is the ONLY SOURCE OF REVENUE IN THE FIELD!

- how to compute production profiles?

N_p oil

G_p gas

Q_p ~ generic

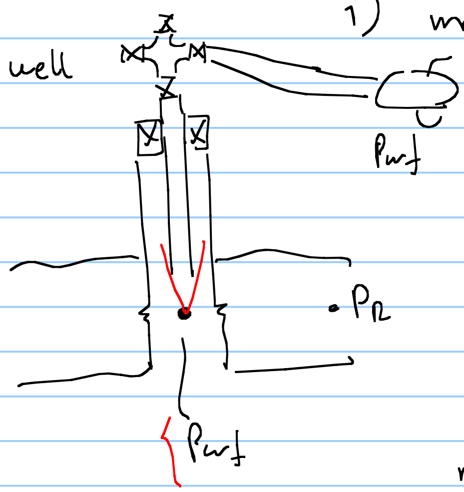


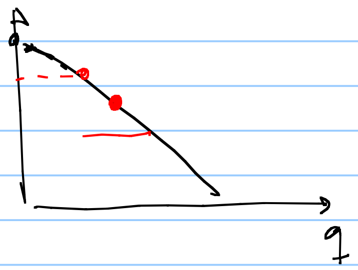
TWO THINGS ARE REQUIRED

- $P_R = f(N_p)$ → static reservoir equation { material balance
- $\underbrace{q_{fluid} = f(P_R, P_s, \text{restrictions})}$ → dynamic model

1) material balance + IPR equation

IPR: Inflow performance relationship → how much production will I get from the reservoir if I exert certain Pwf





neglects all the system downstream the well bottomhole

? ? It is important to use a Pwf that is realistic and that allows the fluid to flow from bottomhole to separator (required Pwf)

- a too high P_{wf} will give less production and be too pessimistic
- a too low P_{wf} will give more production and be too optimistic.

required P_{wf} usually changes with time ! . $f(q_{well})$!

2) Reservoir simulator (mass conservation, momentum conservation } !

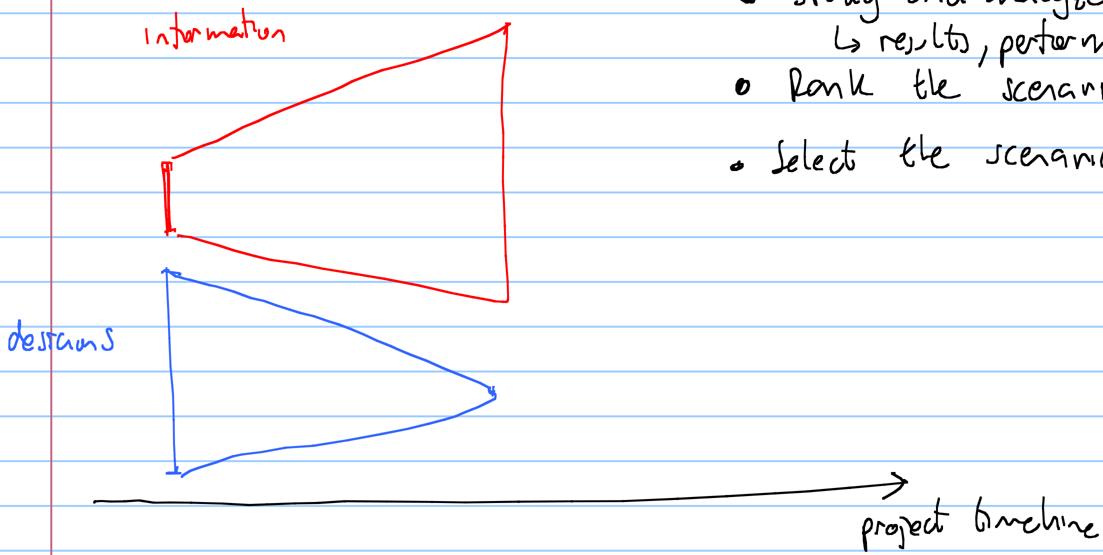
areal distribution of parameters.

↑ big uncertainty in the input → ↑ big uncertainty in the output

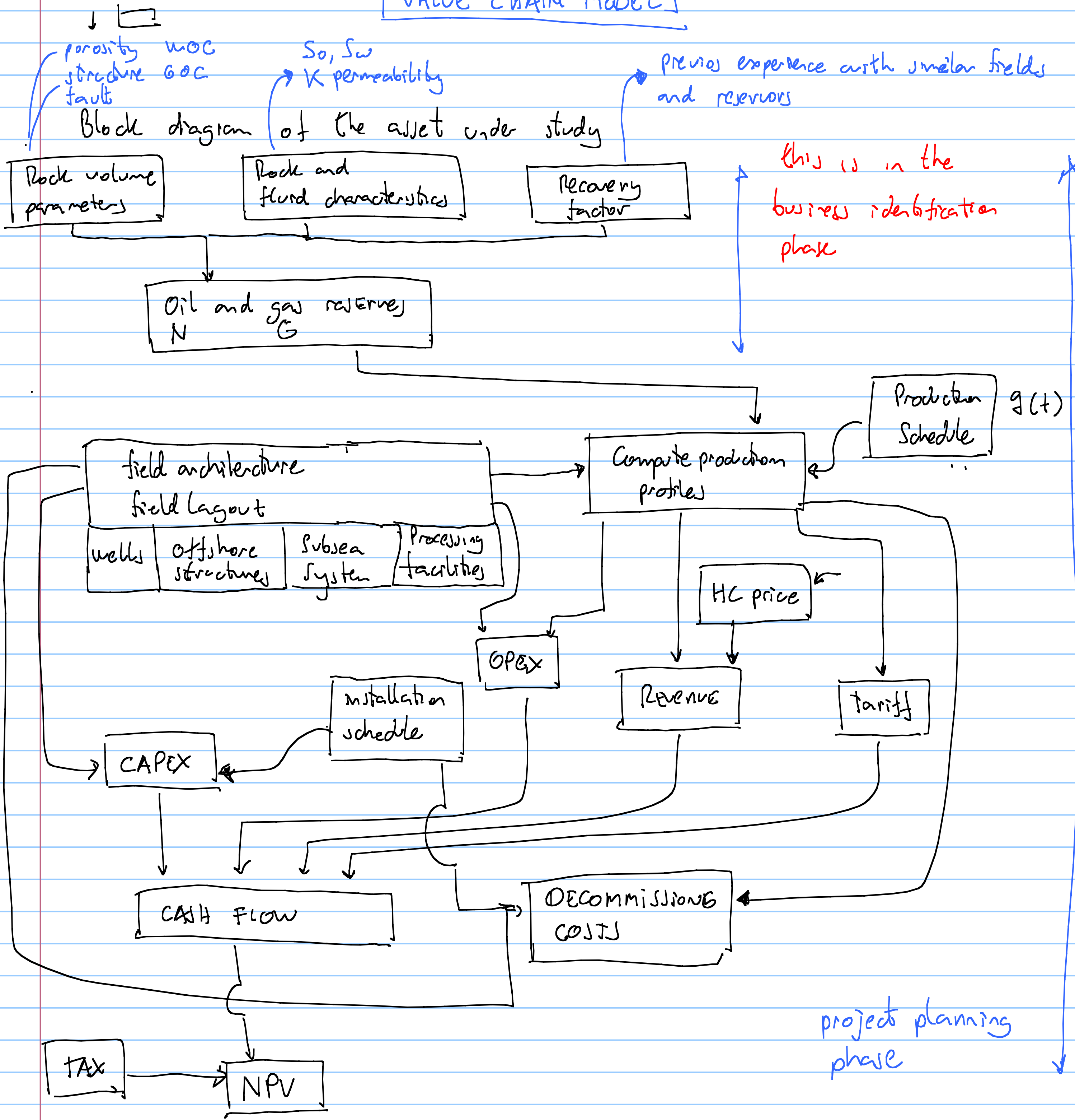
—— // ——

Uncertainty quantification and management in the field planning process

the main tasks of field planning:
- Identify field development scenarios
- Perform a pre-design of each scenario
- study and analyze each scenario
  ↳ results, performance
- Rank the scenarios using a criteria
- Select the scenario (Best case)



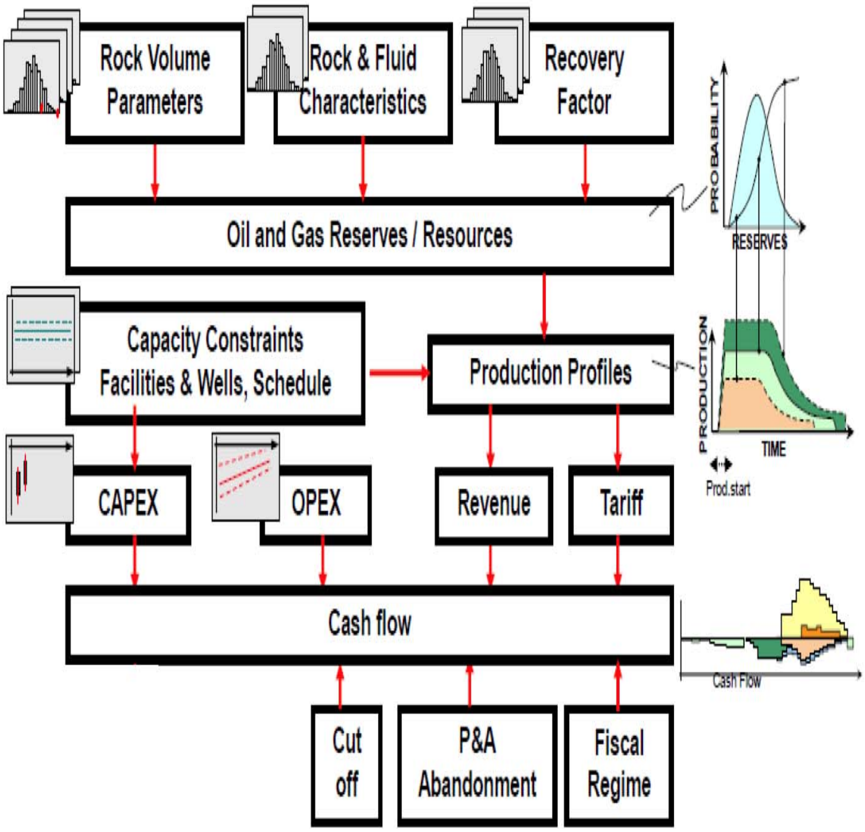
VALUE CHAIN MODEL



- there is a team of experts working constantly in every box.

interdisciplinary : geologist
geophysicists
reservoir engineer
offshore engineer
(accountant, economist
drilling engineer

\+ non technical-petroleum disciplines
HSE
political advisor


Rock Volume Parameters
Rock & Fluid Characteristics
Recovery Factor
Oil and Gas Reserves / Resources
PROBABILITY
RESERVES
Capacity Constraints Facilities & Wells, Schedule
Production Profiles
PRODUCTION
TIME
Prod.start
CAPEX
OPEX
Revenue
Tariff
Cash flow
Cash Flow
Cut off
P&A Abandonment
Fiscal Regime

Evaluation criteria

① **Economical**
- Cost
- Revenue
- Cash flow investment
- NPV

Schedule
- time line
- resources
- project management

Risk

this is not a deterministic process

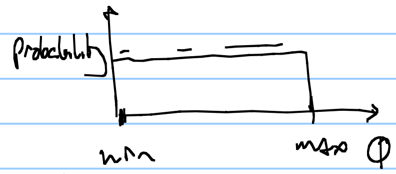
single value → single value

INPUT → f(x) → output

probabilistic: there is a probabilistic distribution for each input

range of values for the input

Φ min base low



Probability: chance of ocurrance of an event

Deterministic: discrete outputs (calculated based on min, mean, max)

cannot guarantee that mean case is the base case

It is very unlikely that the maximum or minimum will occur simultaneously for all variables

NPV_{min}, NP_{max}, NPV_{base}

Probabilistic • full range of possible outcomes

there are several tools to evaluate a project:
- Probability plots
- time plots
- Decision trees
- tornado plots (spider plots)
- summary tables advantages disadvantages
- Qualitative ranking assign grade to a quality

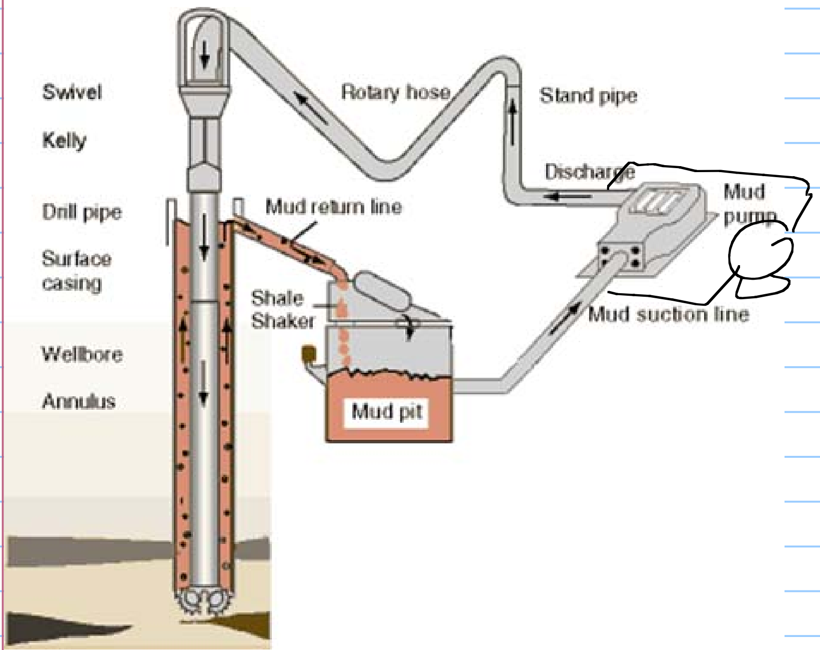
Probability → reserve estimation → probability distribution
MONTE CARLO

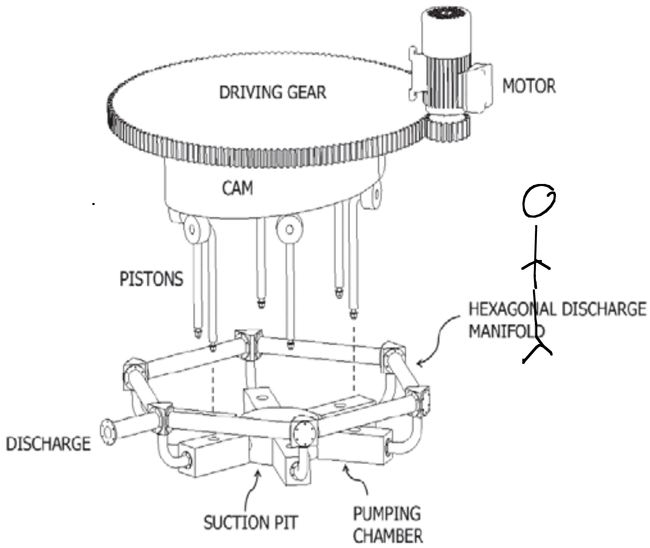
start with an example in excel.

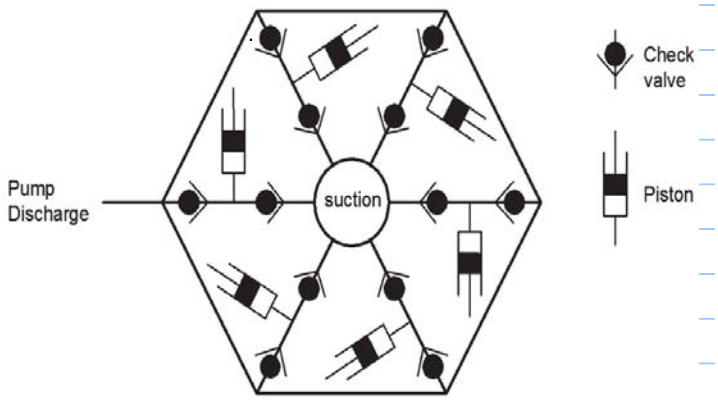
tripeso

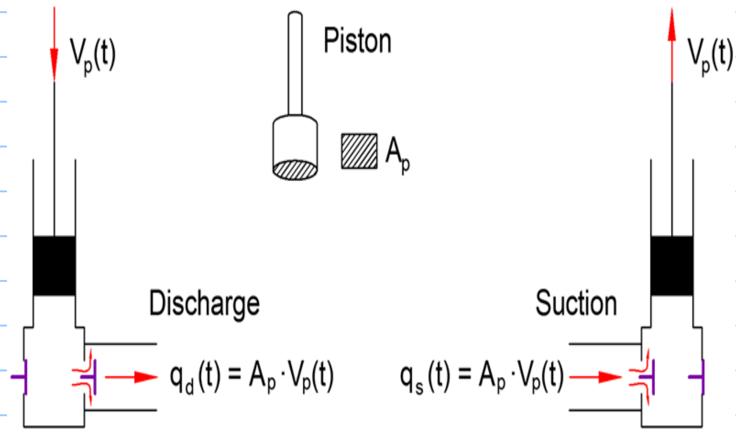
Oseberg Øst

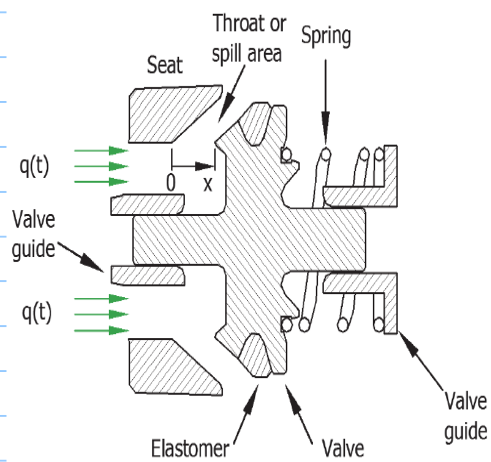
200 rpm

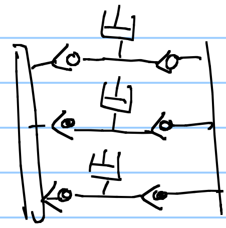








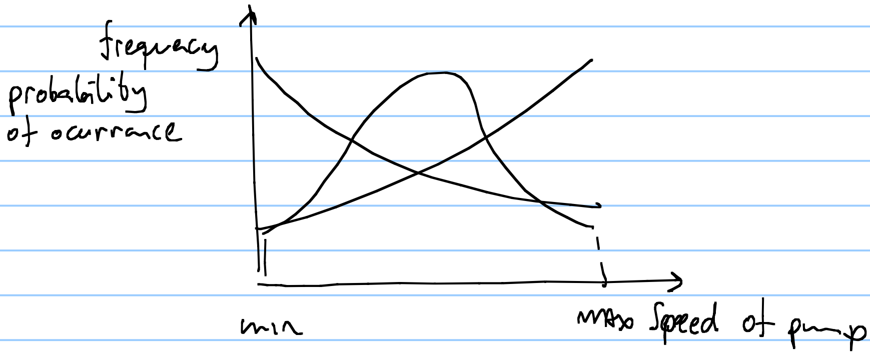




120 rpm

high pump ~~speed~~ speed ⇝ high valve failure ?

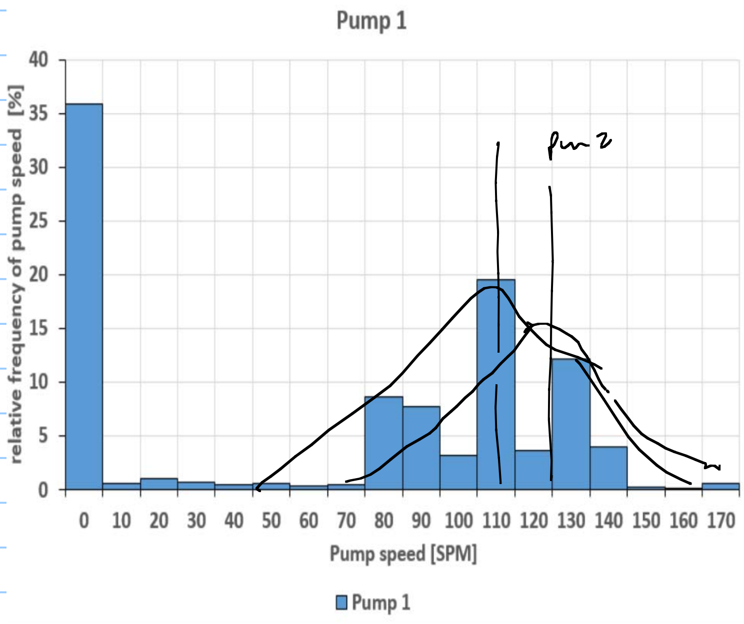
mud logging data every 10 s, for

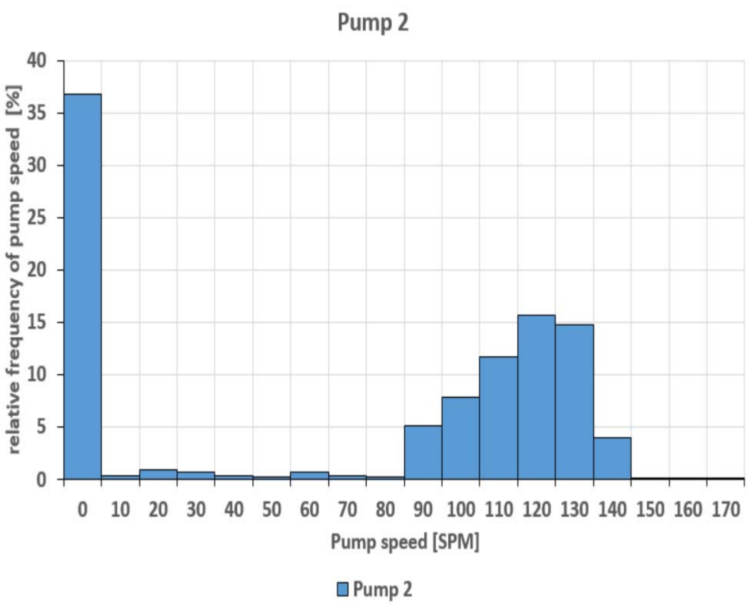


tricks in Excels

0 -5
<5
10 5.1 ≤
14.999
20
30

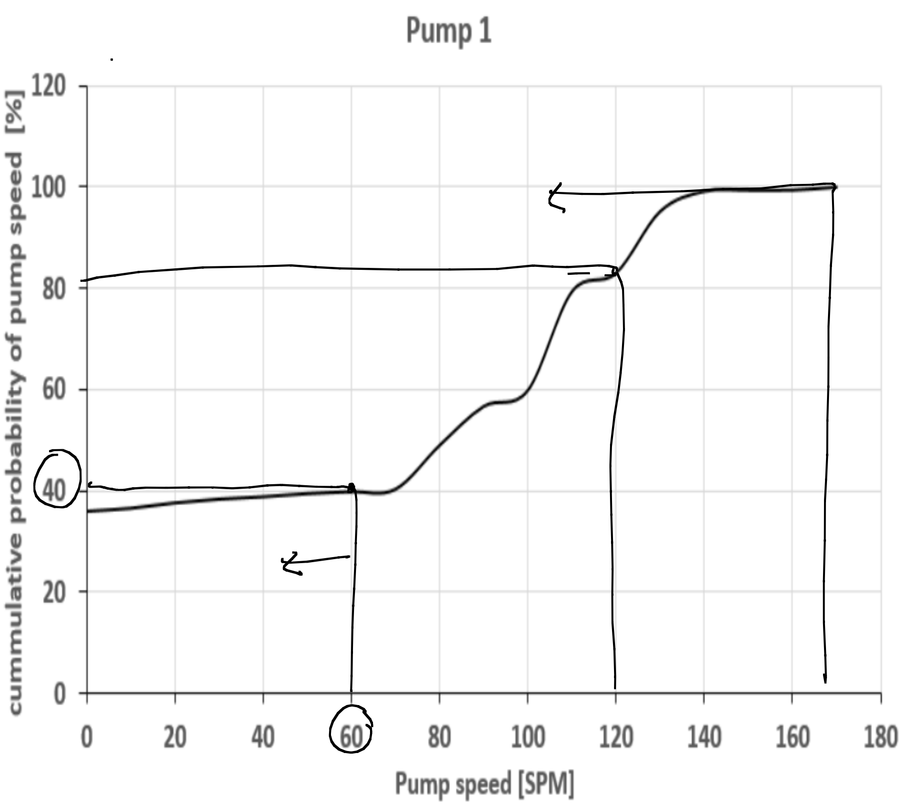
- to send the selection all the way to the end press sequentially ctrl + shift + down
- to apply a matricial function (takes vector and returns vector) instead of pressing "enter" press ctrl + shift + enter sequentially



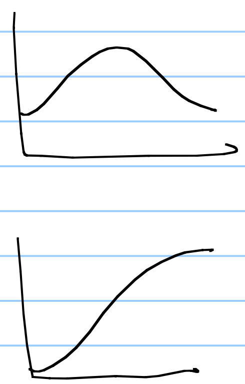


relative frequency plot. probability density function pdf

cummulative probability:

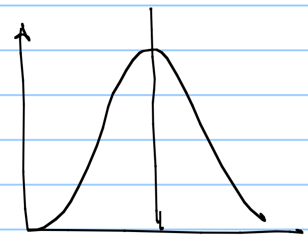


pdf



We have worked so far with a discrete distribution. It is possible to use continuous dist. using analytical equation x variable of interest

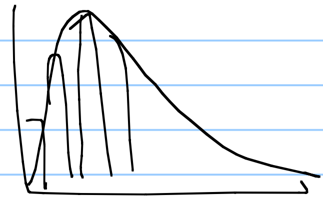
pdf $$f_\zeta(\zeta) = \frac{1}{\sigma_\zeta\sqrt{2\pi}} exp\left[-\left(\frac{\zeta}{\sigma_\zeta\sqrt{2}}\right)^2\right]$$ Gaussian



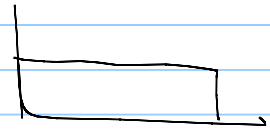
x variable of interest

$$f_H(H) = \frac{H}{4\sigma_\zeta^{\;2}} exp\left[-\left(\frac{H}{\sigma_\zeta\sqrt{8}}\right)^2\right]$$ Raleigh distribution

standard deviation



it is possible with discrete data to tune to a analytical probability expression



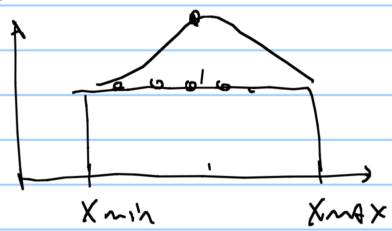
- Reference group:
  - Wilfred, Erca
  - Kjørslevik, Erik Kristoffer Carlsen
  - Mkinga, Oras Joseph

- Uncertainty quantification and management.

for each variable in my field development process it is necessary to determine a probability distribution

ϕ

P_{Ri}



Probabilistic estimation of total recoverable reserves

oil G TRR G_{pu} ultimate cumulative gas production

gas N N_{pu} ultimate cumulative oil production

recovery factor

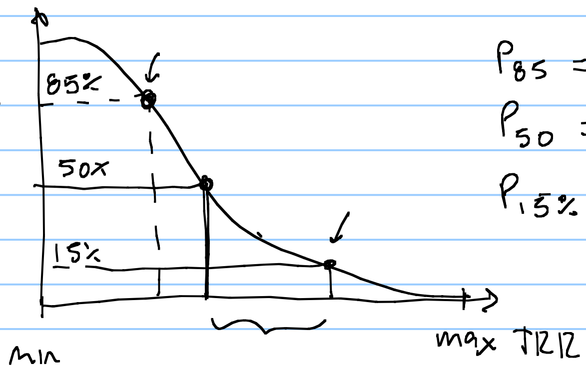
$$RF,\ F_{RU} = \frac{N_{pu}}{N} \begin{cases} 20\% \\ 50\% \end{cases}$$

$$= \frac{G_{pu}}{G} \begin{cases} 30\% \\ 70\text{-}80\% \end{cases}$$

$$N_{pu} = \int_0^{t_{end}} q_o(t)\,dt$$

Desired output

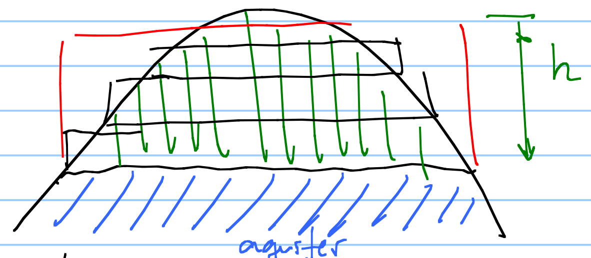
cumulative distribution probability TRR

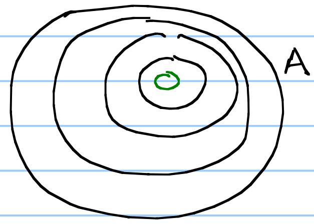


P_{85} = proven

P_{50} = proven + probable

$P_{15\%}$ = proven + probable + possibe oil reservoir

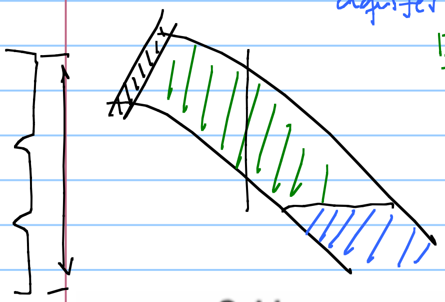




~ view from top

$V_{PR} = h \cdot A$

$V_{PR} = \sum_{i=1}^{N_{layers}} h_i \cdot A_i$



Rock bulk volume

pore volume, adimensional, adimensional

$\phi = \dfrac{\text{Pore volume}}{\text{total volume}}$

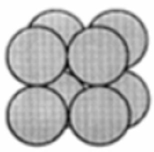
$$TRR = N_{pu} = \frac{\overbrace{\underbrace{V_{PR} \cdot \phi}_{\text{pore volume}} \cdot (1-S_w)}^{} \left(\frac{N}{G}\right)}{B_o} \cdot Fr_u \qquad Sm^3,\ stb$$

N

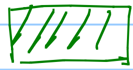
p, T

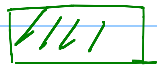
T_{sc} (15.56°C) p_{sc} (1.01325 bara)

Cubic:



$$\text{Porosity} = \frac{\text{Pore volume}}{\text{Bulk volume}} =$$



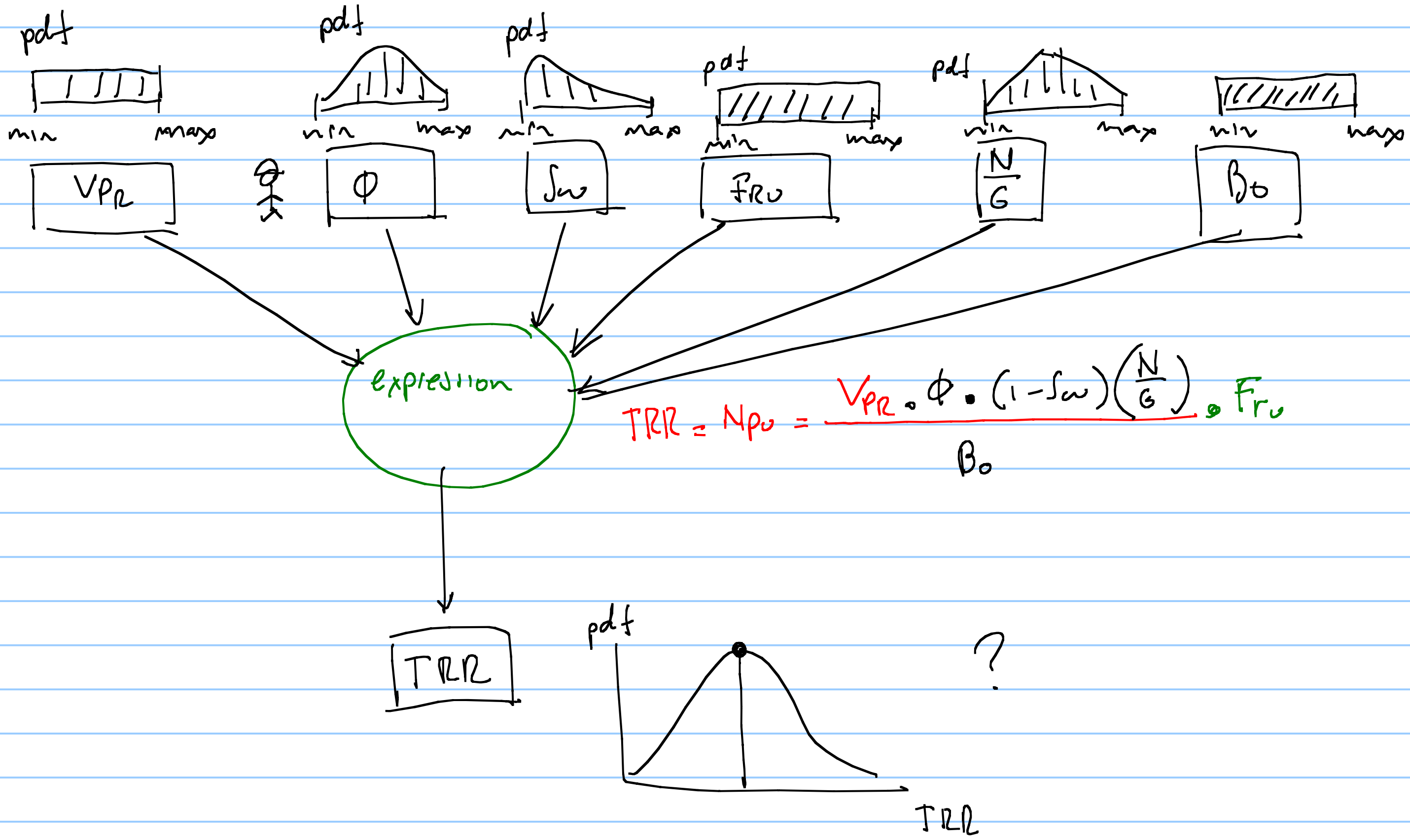


$$B_o = \frac{V_o(p,T)}{V_{sc}}$$

Uncertainties in IOIP Estimation

Factor	Typical source of estimate	Approximate range of expected accuracy (%)
Area	drill holes	± 10–20
	geophysical data	± 10–20
	regional geology	± 50–80
	cores	± 5–10
Pay thickness	logs	± 10–20
	drilling time records and samples	± 20–40
	regional geology	± 40–60
Porosity	cores	± 5–10
	logs	± 10–20
	production data	± 10–20
	drill cuttings	± 20–40
	correlations	± 30–50
Interstitial water saturation	capillary pressure data	± 5–15
	oil base cores	± 5–15
	saturation logs	± 10–25
	routine cores with adjustments	± 25–50
	correlations	± 25–60
Formation volume factor	pressure volume temperature analysis of fluid samples	± 5–10
	correlation	± 10–30

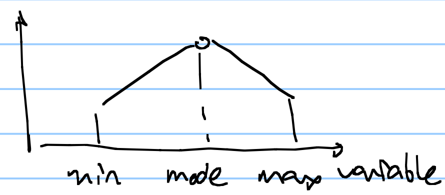
- **Recovery factor, F_R depends on:**
  - Permeability and Permeability distribution
  - Relative permeability characteristics
  - Drive mechanism
  - Pressure support, displacement and sweep efficiency
  - Reservoir architecture-continuity, shape, layering, fault blocks
  - Reservoir anisotropy
  - Reservoir fluid properties
  - Well placement. Number of wells
  - Artificial lift
  - Minimum economical field rate



$$TRR = N_{po} = \frac{V_{PR} \cdot \phi \cdot (1-S_w)\left(\frac{N}{G}\right)}{B_o} \cdot F_{Ro}$$

?

for the input variables engineers usually use a uniform (rectangle) distribution or a triangle distribution



- to obtain the probability distribution of TRR engineers often use the Monte-Carlo method

↳ Stanisław Ulam, Von-Neuman, Los Alamos 1940 } Monte-Carlo

(1) • Define a domain of possible values for each input variable { propose, find a probability distribution

(2) • Generate a random input for each variable using its pdf

(3) • Perform a deterministic calculation using { equation / simulator / routine } depending on the model available
Compute the value(s) of interest.

(4) • Repeat step 2. for "many" time. for our case 8000 iterations

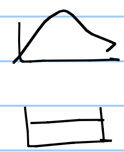
achieved required number of iterations

Aggregate all results TRR(s) and perform, compute its pdf, cd

the applicability of Monte-Carlo method depends on how long it's takes for step 3 to complete

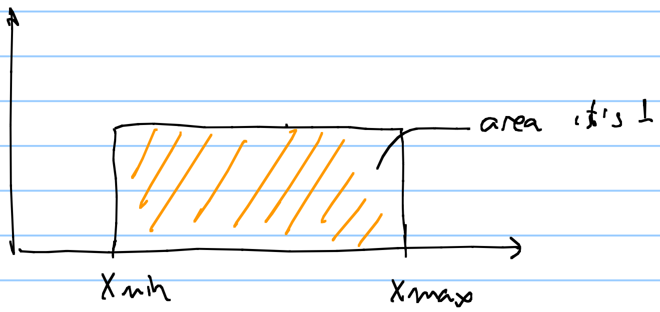
.			Net to Gros	Oil Saturation	Formation Volume Factor	Ultimate Recovery Factor
	Rock volume	Porosity	N/G	So=(1-Sw)	Bo	Fr
	bbl	fraction	fraction	fraction	Res bbl/STB	fraction
Min	2000000000	0.18	0.3	0.8	1.35	0.42
Max	2500000000	0.3	0.5	0.9	1.6	0.65

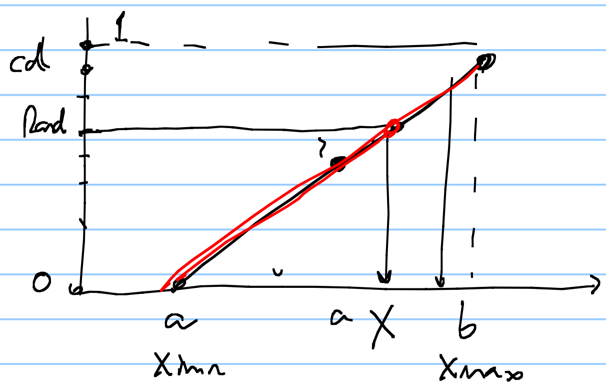
~ pseudo Goliat



uniform distribution

$f(x) =$





$$\frac{1-0}{X_{max}-X_{min}} = \frac{Rand - 0}{(X)-X_{min}}$$

use excel Rand( ) Rnd( )

$$X = X_{min} + (X_{max} - X_{min})\,Rand$$

	Rock volume	Porosity	Net to Gros N/G	Oil Saturation So=(1-Sw)	Formation Volume Factor Bo	Ultimate Recovery Factor Fr
	bbl	fraction	fraction	fraction	Res bbl/STB	fraction
Min	2000000000	0.18	0.3	0.8	1.35	0.42
Max	2500000000	0.3	0.5	0.9	1.6	0.65

$$V_{PR} = V_{PR\,min} + Rand_{V_{PR}} (V_{PR\,max} - V_{PR\,min})$$

use formula $TRR = \frac{\Phi \cdot V_{PR} (S_o) Fr (N/G)}{B_o}$

	V_{PR} [bbl]	(Φ [-])	N/G [-]	S_o [-]	B_o [bbl/Stb]	Fr_o [-]	TRR
1	0						0
2							
3							
⋮							
3000							

compute pdf cd for this column

- Usually Monte Carlo is non practical for heavy models (Reservoir Simulator).

thus another method calle Latin hypercube Sampling is used.

Continuation of the discussion from last class: Probabilistic estimation of reserves

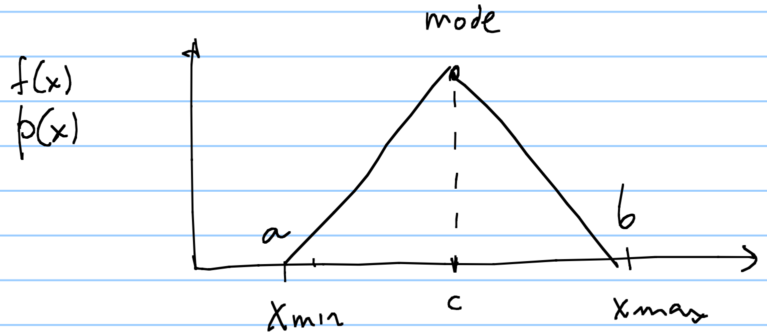
max — P90 the quantity for wich there is a 90% probability that the quantities actually recovered will equal or exceed the estimate.

median — P50 the quantity for wich there is a 50% probability that the quantities actually recovered will equal or exceed the estimate.

min — P10 the quantity for wich there is a 10% probability that the quantities actually recovered will equal or exceed the estimate.

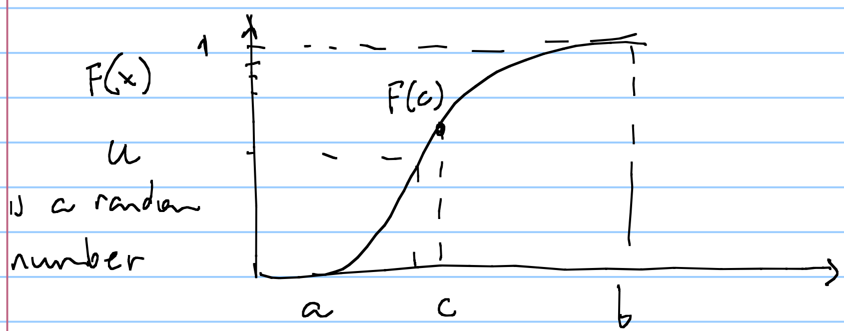
typically triangular or uniform probability distributions are used during early stages of the planning phase.

triangle distribution



$0 \le u \le 1$

funtion (u, a, b, c)



for $0 < u < F(c)$

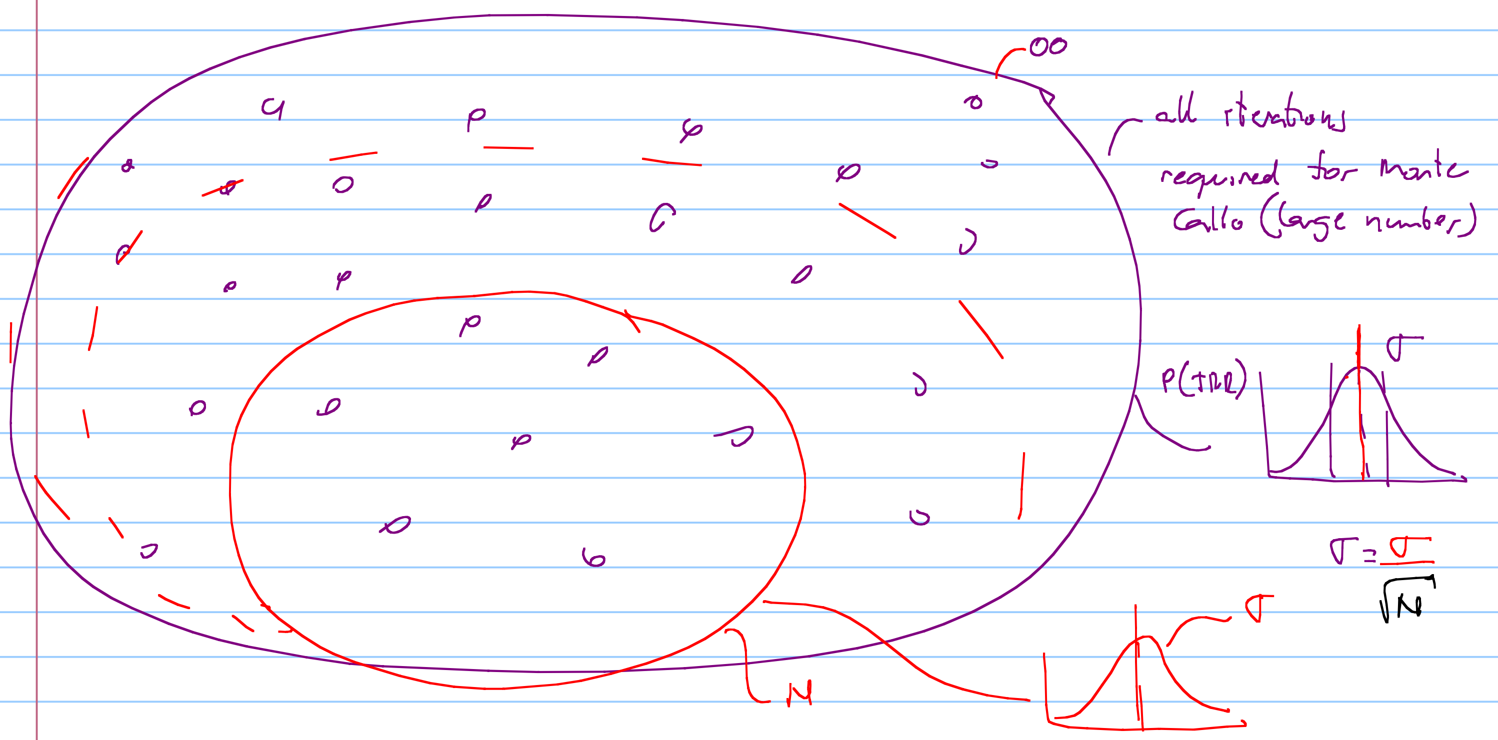
$$x = a + \sqrt{u(b-a)(c-a)}$$

for $1 > u > F(c)$

$$x = b - \sqrt{(1-u)(b-a)(b-c)}$$

$$F(c) = \frac{(c-a)}{(b-a)}$$

How many iterations are required in Monte-Carlo?

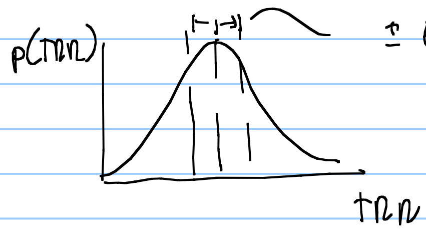


Estimating confidence interval. Estimating number of samples

number of iterations

$$N = \left(\frac{z \cdot \sigma}{\epsilon} \right)^2$$

ϵ is the desired error of the most probable value



$\pm\ \epsilon$ number with the units

$\pm$ X number of stb, Sm^3

confidence level associated with the error range

95%, 98%, 99%

function in excel

$$z = \text{NORM.S.INV}(\underbrace{\text{confidence range in fraction}}_{\substack{0.95 \\ 0.98 \\ 0.998}})$$

σ standard deviation of the population.

so it is necessary to assume an initial number of iterations and calculate N.

$z = 3$

$$N = \left(\frac{3\ \sigma}{\epsilon} \right)^2$$

% of the average. 2% Average $\pm$ 2% (average)

Some engineers don't estimate beforehand the required number of iterations, just run increasing the number of iterations until the results don't change much

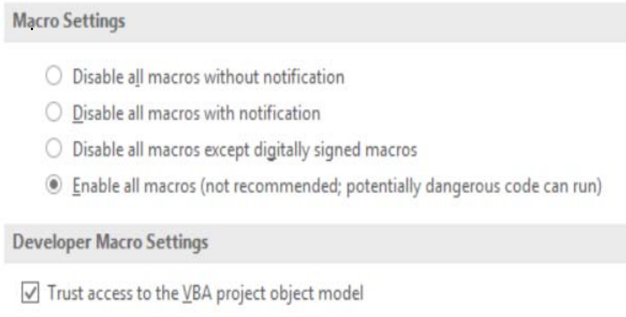
pdf
cdf 1%
0.5%
3%

Excel practices in petroleum engineering

- initial setup:

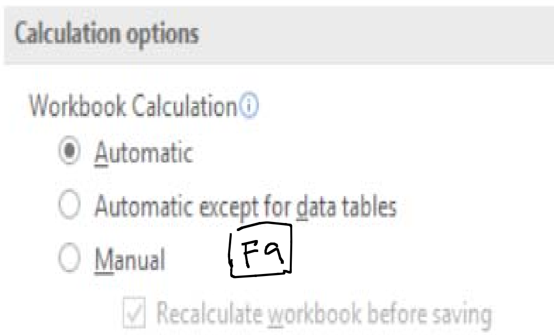
- Reduce macro security: to be able to run macros

options → trust center → macro setting



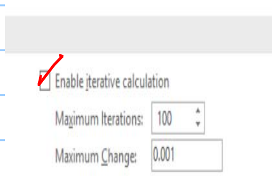
- Automatic cell calculation

options → formula



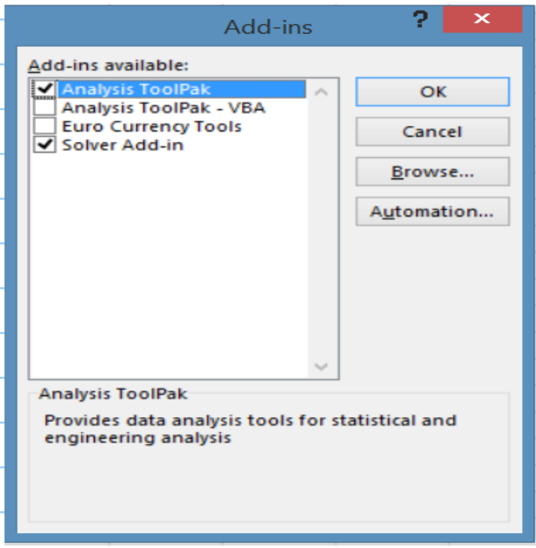
- activate circular references.

general - formula



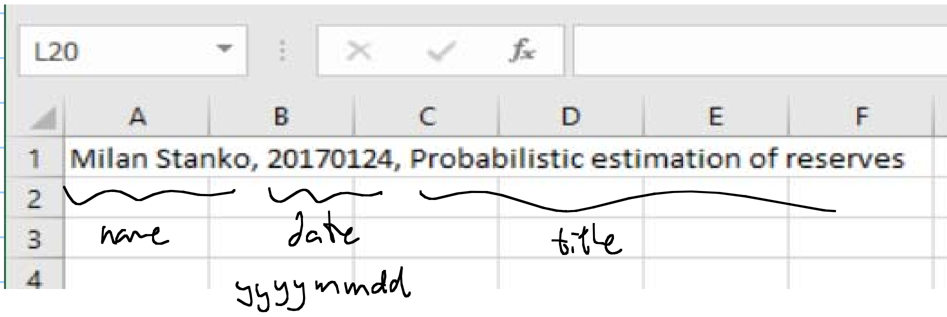
- Enable solver add-in and analysis toolpack

  options → add-in → "go" (bottom window)



- Etiquette:

  - IO sheet



- Color convention for cell info

  Red for user input

  blue for calculated cells, in long columns we use black

- figures should be in a separate sheet

- for each column: variable name, variable symbol, units in brackets

  porosity, ϕ

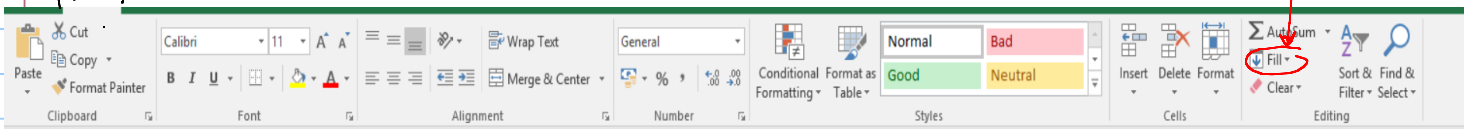
  [-]

  fraction.

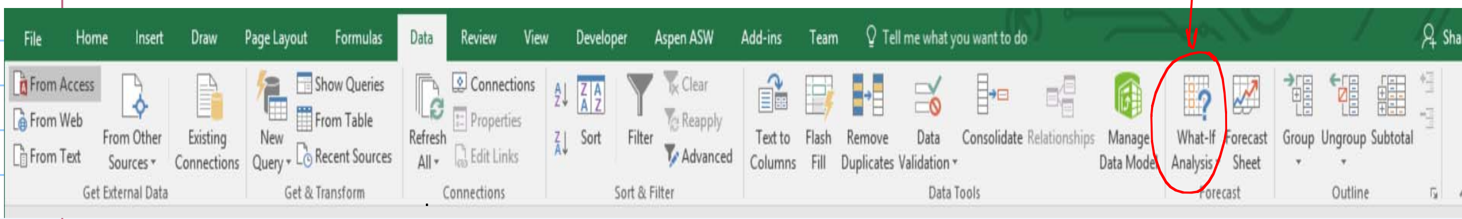
- Use common sense imagine that another person will use your excel sheet

- built functions and utilities → apply on a cell (group of cells) → use the upper menu
  - fill → apply values to many cell (rows / columns)

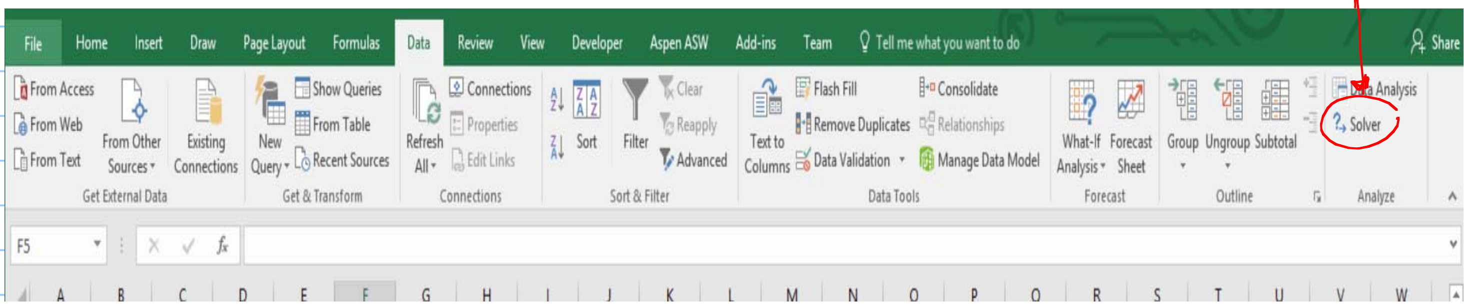
HOME



- Goal seek (solver but simplified)

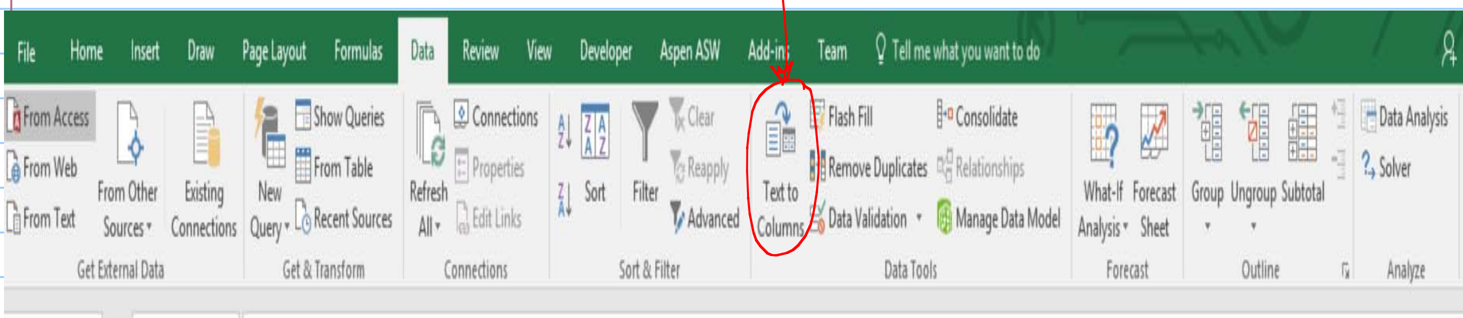


- Solver



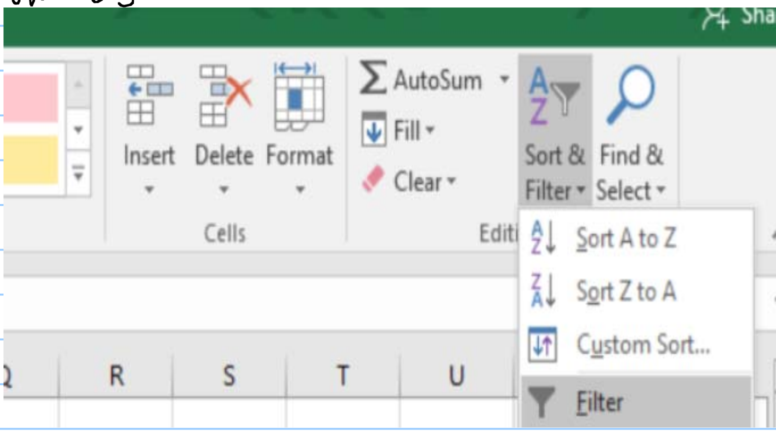
- making frequency table (frequency function) matricial function
  apply function with ctrl + shift + enter.

- Paste text in excel



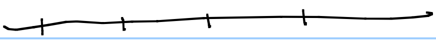
- Sorting, filtering cells

[Home]



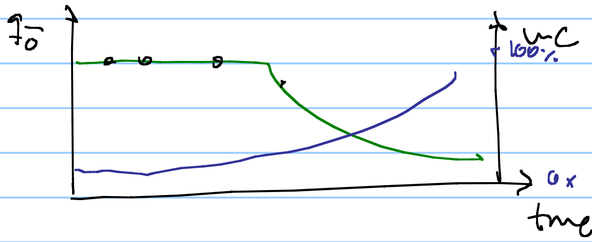
- Plotting

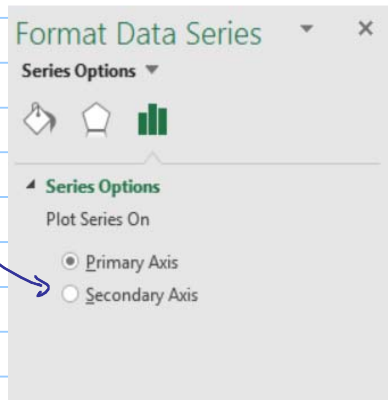
  - in its own sheet
  - Appearance: font size (14-18), bold. Add line data point. point size should be visible (4-6). White background. outside tick marks on the axis, vertical grid. change color or vertical and horizontal axis to black. Adjust data range (min max)



optional to plot another variable that has significantly different values

secondary vertical axis.



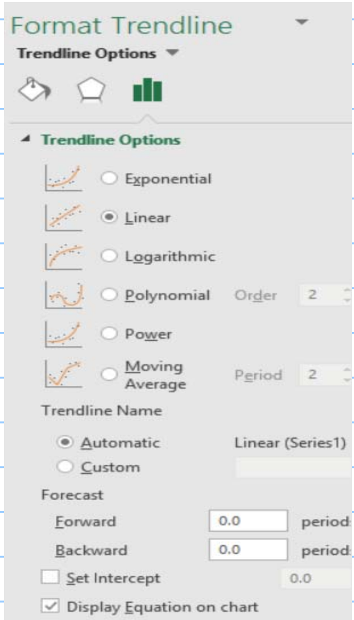


select series right click → properties data series

use log scale when required

- types of plots ~ scatter with lines
  ↳ bar (no gap between the bars)

- trendline



- Programming in Excel
  - Accesing VBA enviroment - $\boxed{\text{alt}} + \boxed{\text{F11}}$
  - UDF → user defined function, Remember to comment → purpose
    → input, units
    → clarify an action if necessary
    L apostrophe before
    ' _ _ __

- Key shorcuts

  ctrl + shift + enter apply matricial functions

  ctrl + shift + down | up | righ | left bings to the end of the column, row

CLASS EXERCISE

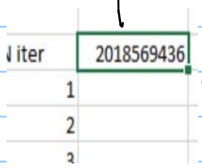
- in Windows there are two options to save the file :
  1997-2003 ekcel file .xls { save both the sheet and the macro

if you want to use the latest format then
→ .xslx → only sheets
.xslm → sheets + macro

freezes in column

freezes in row

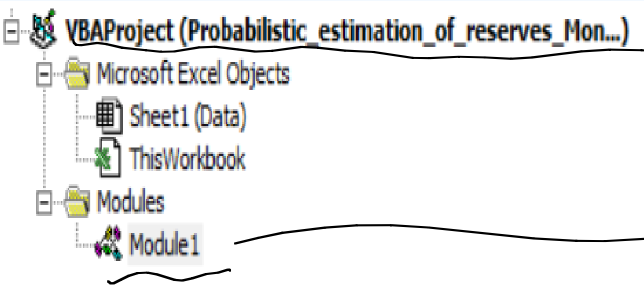
X_uniform(B5 , B6)



two extra tricks ~> fill: to fill Nr iter column from 1-1000 and double click on the right bottom corner to apply automatically until the end

Observations / sources of error:

- Some computers use ; for separator in function arguments
  f(a, b, c) or f(a; b; c) be careful!
- in computers with norwegian language rand() is tilfeldig()
- Once you create the UDF, save it!
- module 1 should be located in the excel sheet where you are working



your excel file

this is where your macro should be!

random has a volatile behavior any change a new number will be generated

if after some iterations the value doesn't change. I recommend to put Rand inside VBA function

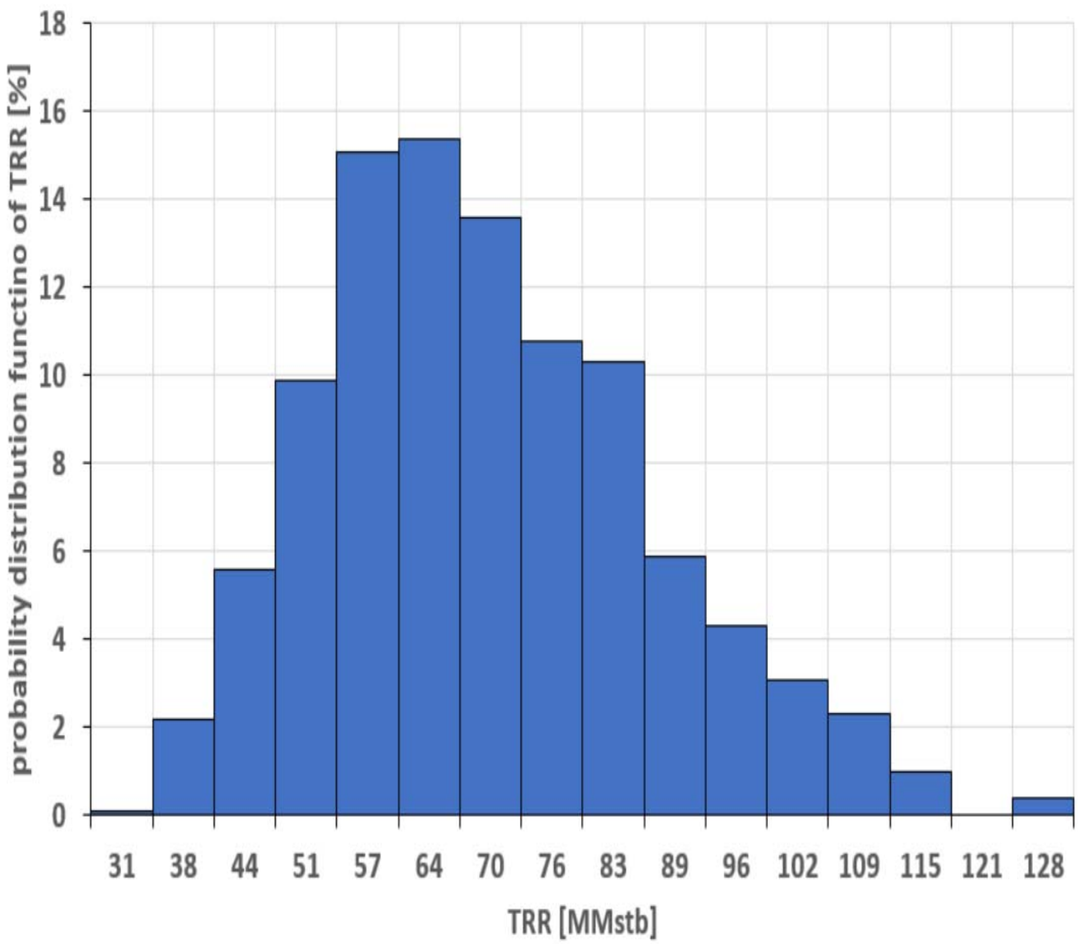
```
Function X_uniform(a, b)
'value of the variable X for a uniform probability distribution
'a is the minimum value of X
'b is the maximum value of X
Application.volatile(true)
U=Rnd()
X_uniform = a + (b - a) * U
End Function
```

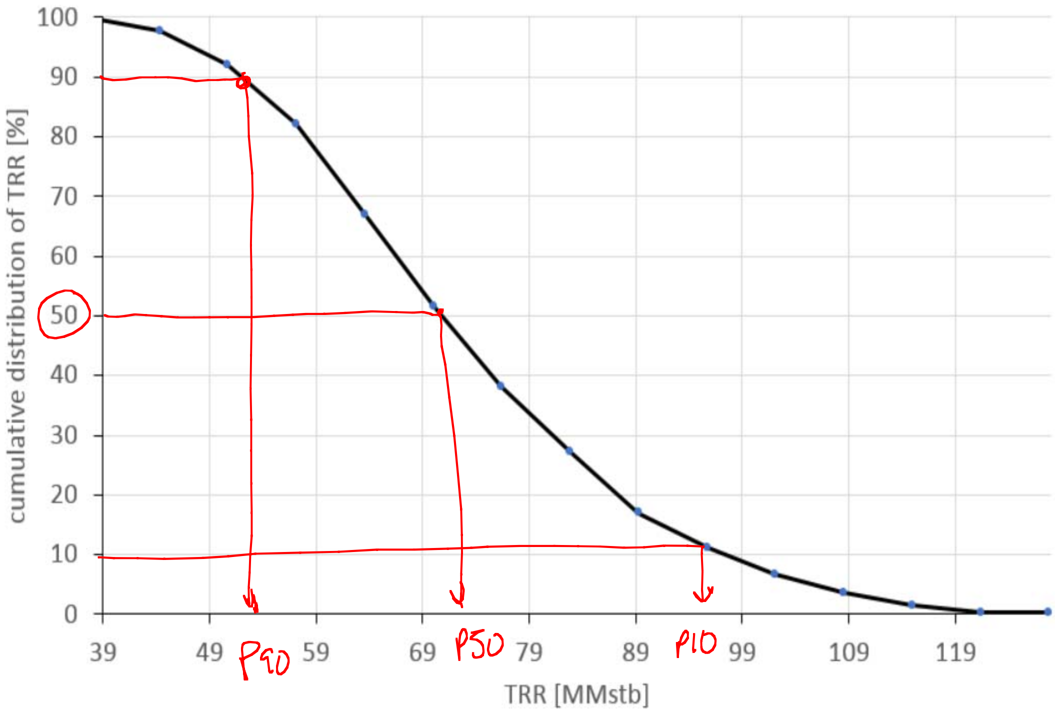
	TRR	count	relative freq		cumulative freq
	[MMstb]		%		[%]}
	31	1	0.1		100
	38	22	2.2		99.9
	44	56	5.6		97.7
y_1	51	99	9.9	x_1	92.1
y_2	57	151	15.1	x_2	82.2
	64	154	15.4		67.1
	70	136	13.6		51.7
	76	108	10.8		38.1

P90

$\sim 90\%$ $x_3 \rightarrow y_3$

$$\frac{y_2 - y_1}{x_2 - x_1} = \frac{y_2 - y_3}{x_2 - x_3}$$





$$N = \left(\frac{z \cdot \sigma}{E}\right)^2$$

sigma	[MMstb]	17
average	[MMstb]	66
E (2% of average)	[MMstb]	1
Z factor (for 98% confidence)		2
Required N		693

stddev (Popul)

Average (Col)

3 ~ 99.97

2% of the average

$$\frac{2\% \cdot \text{Averag}}{100} = E$$

for more detailed economical calculations → Petroleum Economics Trygve Strøm (TPG5110)

TRR [MMstb]	count	relative freq %
31	1	0.1
38	22	2.2
44	56	5.6
51	99	9.9
57	151	15.1
64	154	15.4
70	136	13.6
76	108	10.8
83	103	10.3
89	59	5.9
96	43	4.3
102	31	3.1
109	23	2.3
115	10	1
121	0	0
128	4	0.4

if I sum from bottom up

probability that my TRR is equal or lower than 51

probability that my TRR is equal or higher than

Cash flow and economic indicators of the project (Field development project)

Equity: share holders — consultation with share holders is done during the decision gates

Loans: banks, individuals, trusts

pay back loans

dividends to share holders

(+) (+)

NTNU oil inc. (AS)
Project TPG4230 field

// NET CASH FLOW ////

(−) CAPEX Capital expenditures
engineering studies
facilities
offshore structure
subsea components
pipeline
installation

(+) Revenue:
Sales of HC: oil, gas, LNG (liquified natural gas), NGL (Natural gas liquid), LPG (liquified petroleum gas)
(C3 C5)
• Condensate

(−) DRILLEX
• rig daily fee
• well completion
• well construction
• well services

economical indicators
NPV
IRR

(−) OPEX
Salaries
maintenance
Consultants
energy consumption
renting cost
chemicals
processing
stimulation
insurance
tariff

(−) TAX and Royalties — government authorities

Cash flow with time

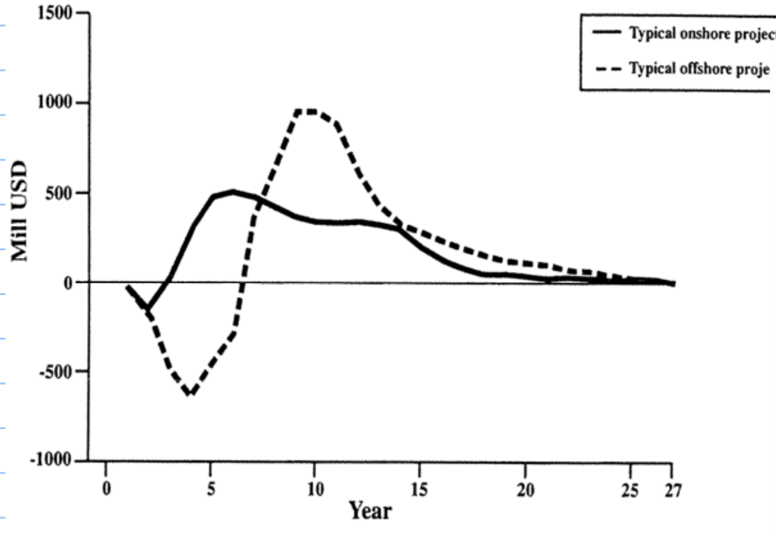
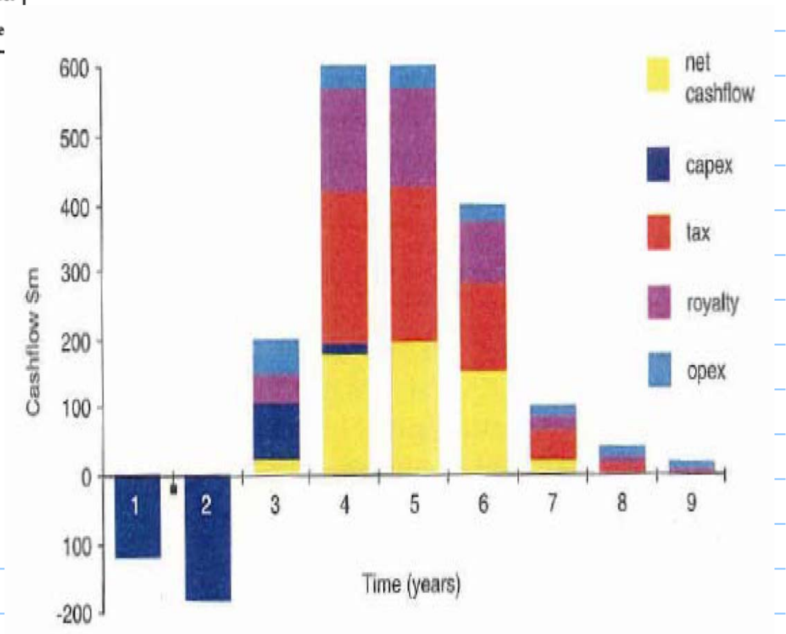


Fig. 9. Typical before tax cash flow profiles for offshore and onshore projects.



060

Cash flow is calculated on a yearly basis.

Year	CAPEX	OPEX	DRILLEX	TAX AND ROYALTIES	EXPENSES	Revenues	Cash flow	PV of cashflow
0	–	0	–	0	–	0	–	
1	–	0	–	0	–	0	–	
2	0	–	0	–	–	+	+	
3	0	–	0	–	–	+	+	

$\{\Sigma(\quad)$ NPV

Present value: the current worth of a future sum of money

$$V_P = V_F \frac{1}{(1+i)^n}$$

present value, future value

n is the year were the future value is spent or gained

i interest, discount rate ~ 8

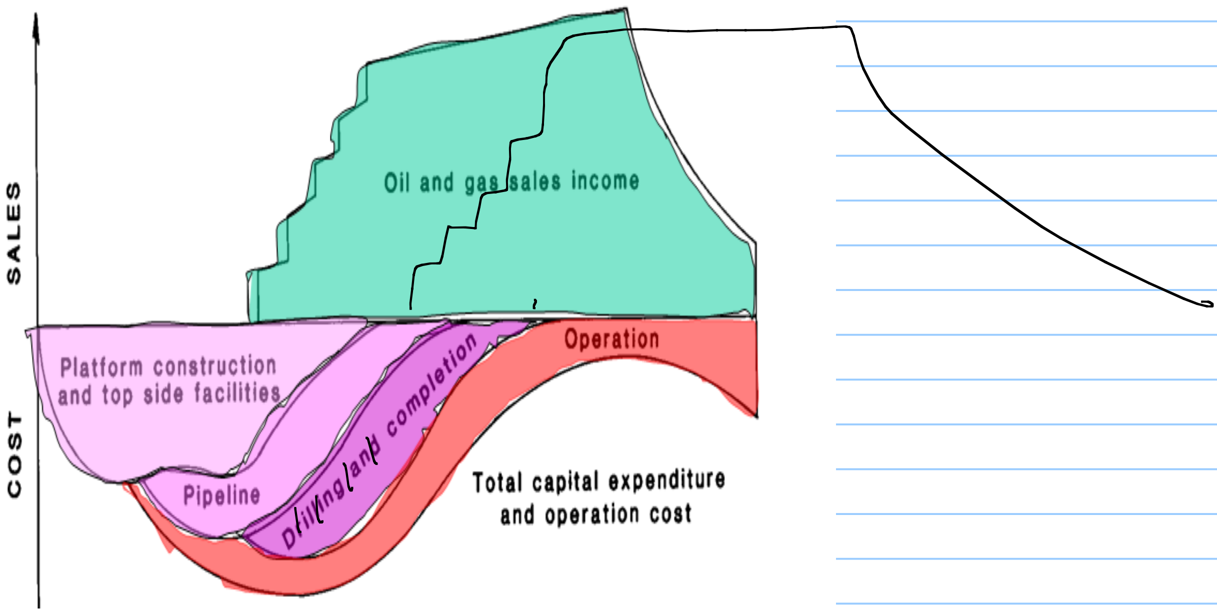
$(1+i)$ compound factor

$\left(\frac{1}{1+i}\right)$ ~ discount factor

Net present value — main economical indicator of the project!

has to be (+)

Revenue and Cost Profiles



The Ultimate driver in E&P operations

total number of years

+ gas prod(i) + gas price(i)

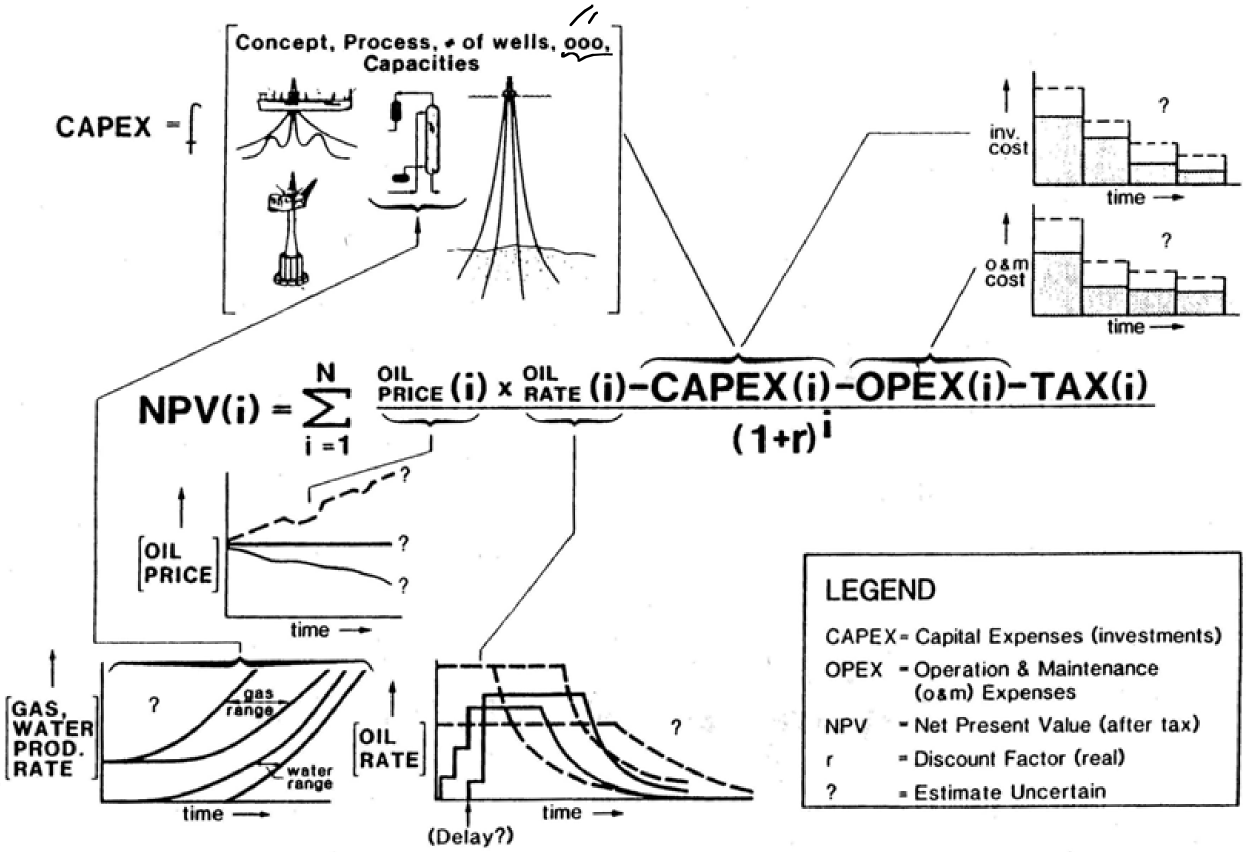
neglected in this course

$$\mathrm{NPV} = \sum_{i=0}^{N} \frac{\text{OIL PRICE}(i) \times \text{OIL PROD}(i) - \text{CAPEX}(i) - \text{OPEX}(i) - \text{TAX}(i)}{(1+r)^{i}}$$

year

interest, discount rate

What can we control?



to get accurate estimates of cost values (and production rates) we need the input from the following specialists:

petroleum engineer : Reserves, location and Nr wells, production schedling, fluids

drilling engineer : Drilling and completion costs (DRILLEX)

facilities engineer (processing) : production processing facilities, equipment required, transportation — size, cost

Operations and maintenance : maintenance costs, manpower requirements

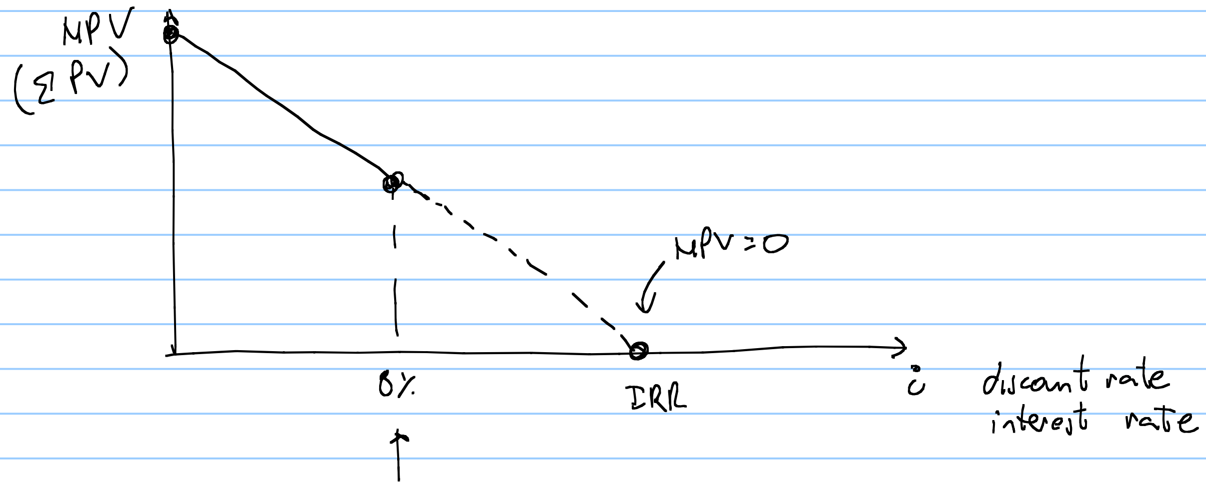
Offshore engineer : offshore structure, layout of the system

Project manager.

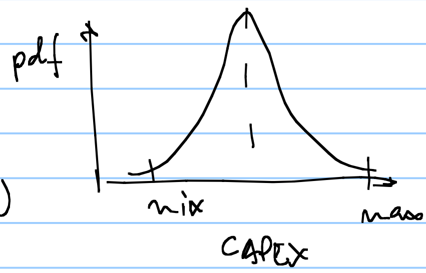
Human resources; Fiscal system expert (tax, royalties), corporate planner

Another indicator of economical health of the project. IRR

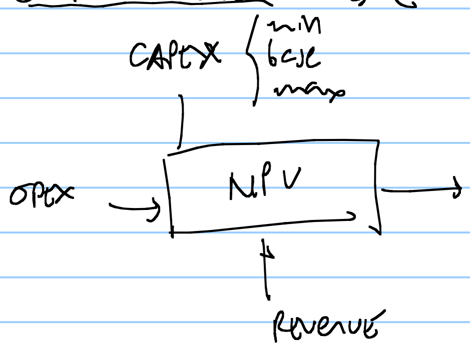
internal rate of return: the interest rate that makes the project NPV = 0



how do we quantify the effect of uncertainty in the NPV,



Sensitivity studies using the principle of "Ceteris Paribus" ~ (all others same)



tornado charts
spider plots

① Define a base case scenario base value for { oil price, CAPEX, opex, etc

② Define a range for each variable. E.g. oil price { min base MAX }

③ Calculate value of interest (economic indicator NPV) changing (one at a time) the variables (while keeping all other variables at their base value)

min price ⟶ calculate NPV

base oil price ⟶ NPV

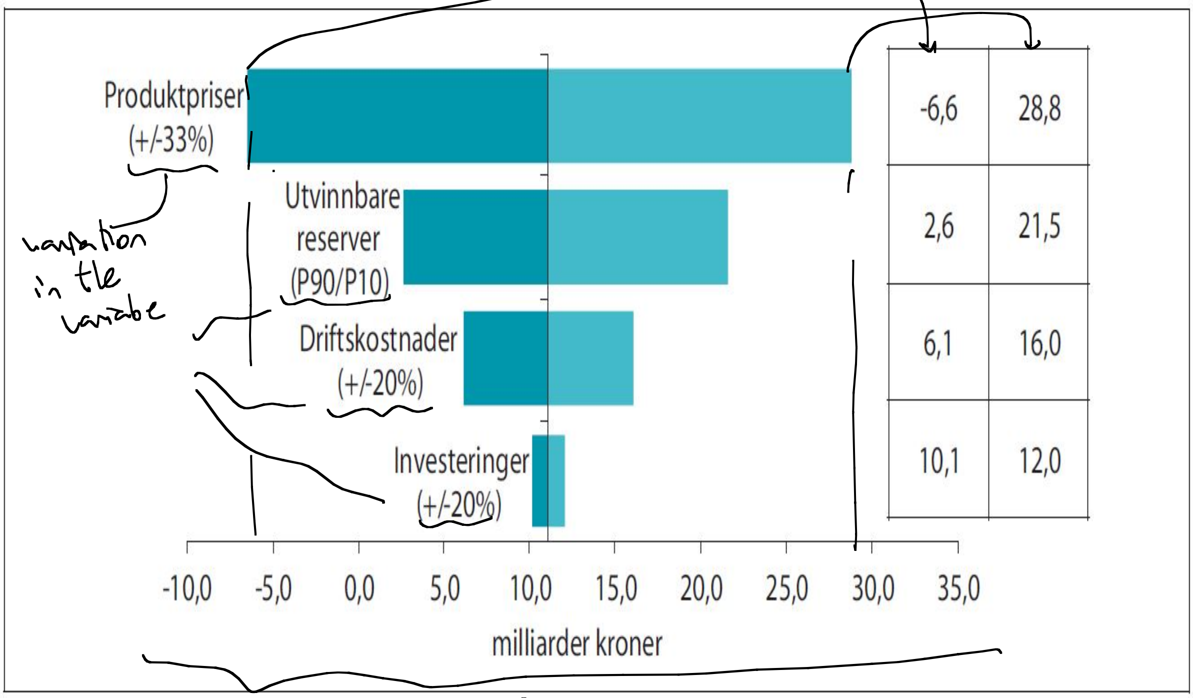
max oil price ⟶ NPV

variable	X_{min}	X_{base}	X_{max}	NPV_{min}	NPV_{base}	NPV_{max}
CAPEX					S	
OMLEX					A	
oil price					M	
OPEX					E	
i ? 20%						

apply normalization

	$X_{normalized\ min}$	normalized X_{base}	normalize X_{max}	% NPV normalize
CAPEX	$\frac{X_{min}-X_{base}}{X_{base}}\cdot 100$	0 %	$\frac{X_{max}-X_{base}}{X_{base}}\cdot 100$	$\frac{NPV_{min}-NPV_{base}}{NPV_{base}}\cdot 100$
OMLEX	"	0%	"	
oil price	"	0%	"	

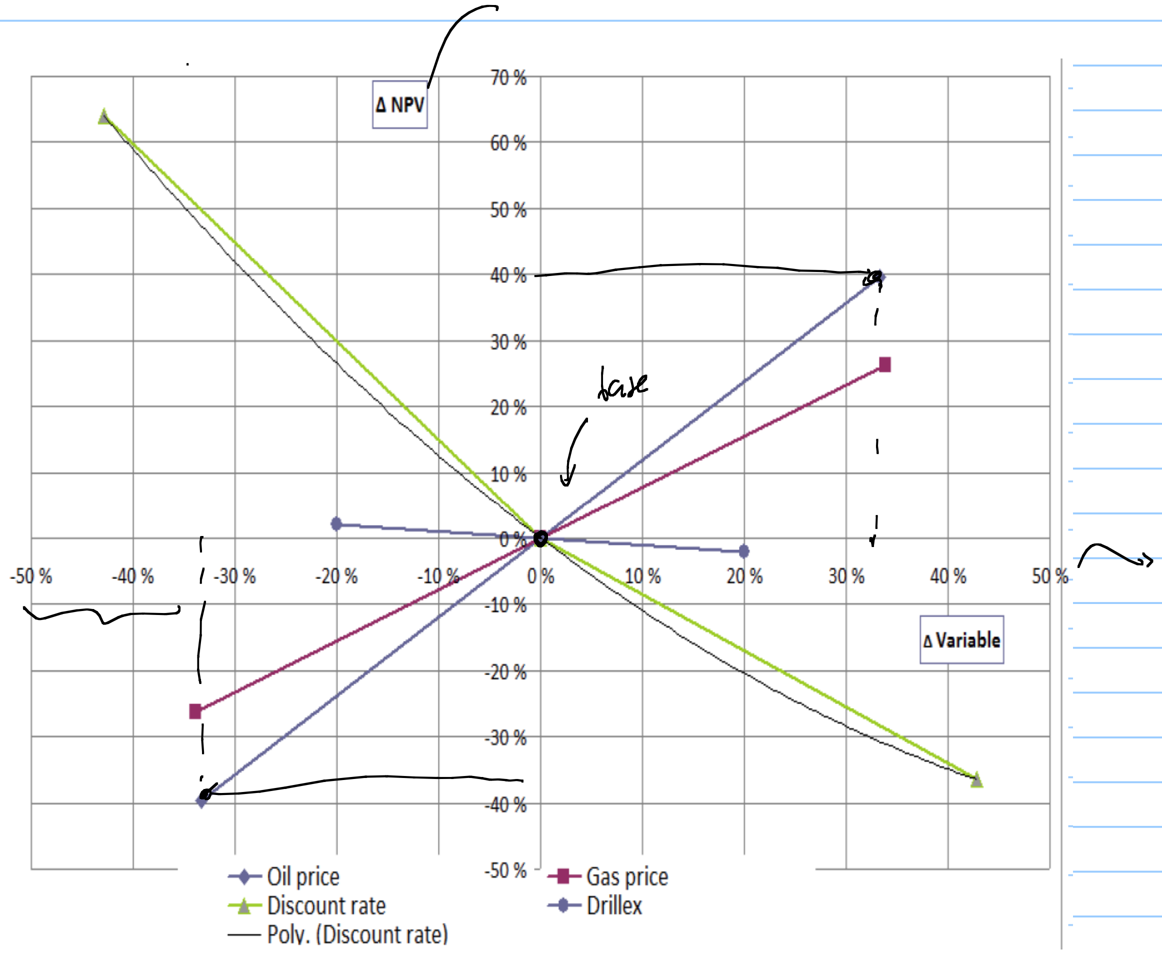
tornado chart

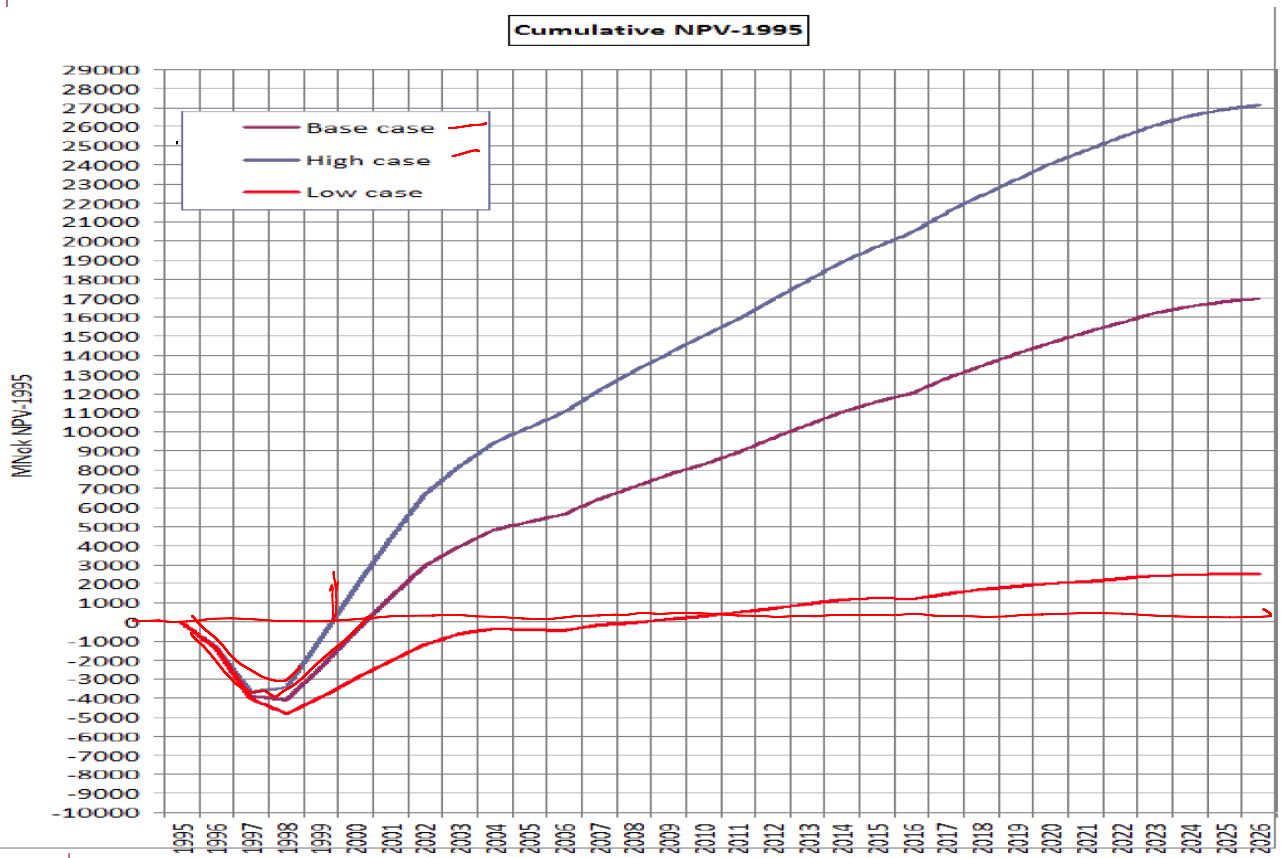


variation in the variable

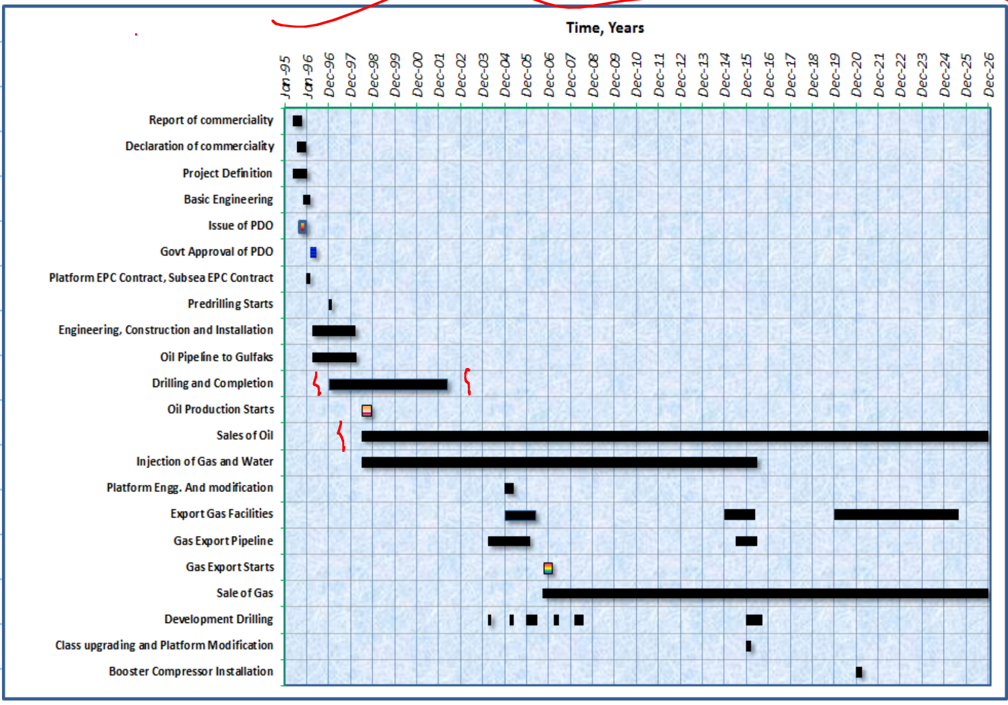
variation in NPV

Spider plot


Δ NPV
70 %
60 %
50 %
40 %
30 %
20 %
10 %
0 %
-10 %
-20 %
-30 %
-40 %
-50 %
-50 %
-40 %
-30 %
-20 %
-10 %
0 %
10 %
20 %
30 %
40 %
50 %
Δ Variable
base
Oil price
Discount rate
Poly. (Discount rate)
Gas price
Drillex


Cumulative NPV-1995
MNok NPV-1995
Base case
High case
Low case

Gantt diagrams Special chart diagram used in project management that shows
timeline
when and the duration of important events in the design and construction of the field



Henry Gantt (1861-1919), a mechanical engineer, management consultant, and industrial advisor developed Gantt charts in the 1910's. Not as commonplace as they are today, Gantt charts were innovative and new during the 1920's, where Gant charts were used on large construction projects like the Hoover Dam started in 1931 and the Eisenhower National Defense Interstate Highway System started in 1956.

Henry Gantt

Every time we, in our project management careers, go through the rigmarole of our projects, trying to meet and beat our own-set goals, a silent word of gratitude goes to the heavens for Henry Gantt for conceiving this intuitive diagram for charting project timelines, for the Gannt Diagram allows us to excel in this chosen career.

https://www.smartsheet.com/blog/gantt-chart-excel useful for exercise.

How to deal with uncertainty in decisions or with integer variables

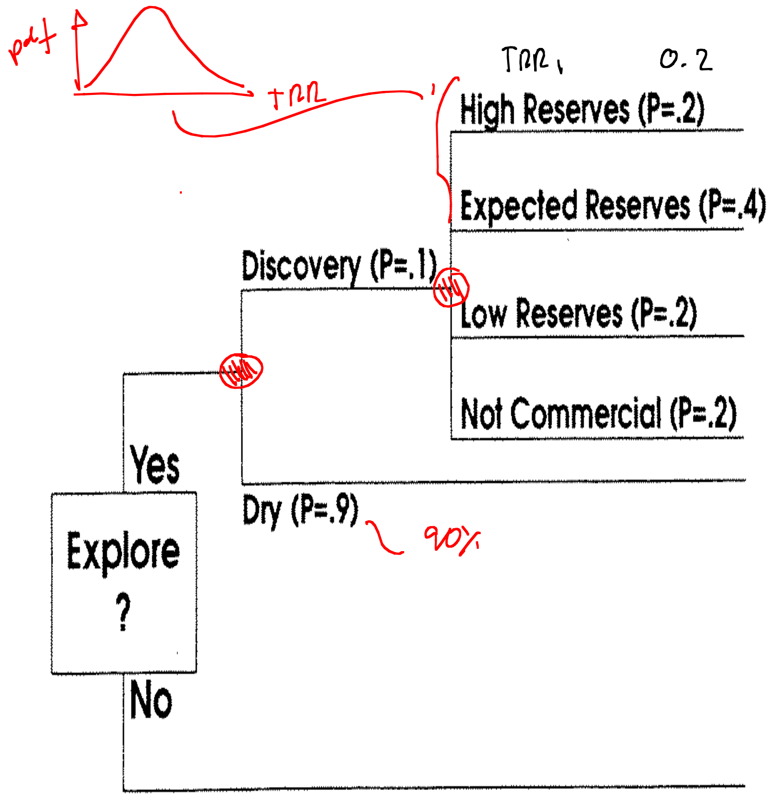
- decisions
- development options
  - platform
  - subsea to beach
  - FPSO

Decision trees allow to deal with integer variables (not continuous)

▢ ~ decision nodes

◯ ~ chance nodes

◁ ~ end node



multiplication of all probabilities (chance nodes) of that particular branch

i	$Prob_i$	NPV_i	$Prob_i \times NPV_i$
1	0.02	A	(.02) A
2	0.04	B	(.04) B
3	0.02	C	0.02 C
4	0.02	D	(.02) D
5	0.90	E	(.90) E
6	1.00	0	0

$\sum P(i) NPV(i)$

EMV

NPV

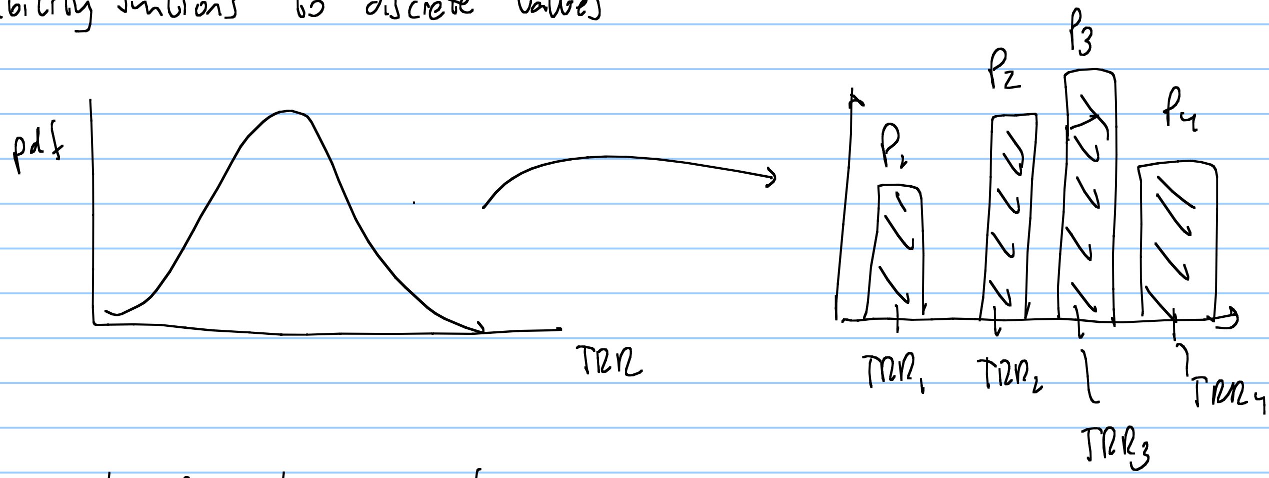
A > B > C > D

E negative

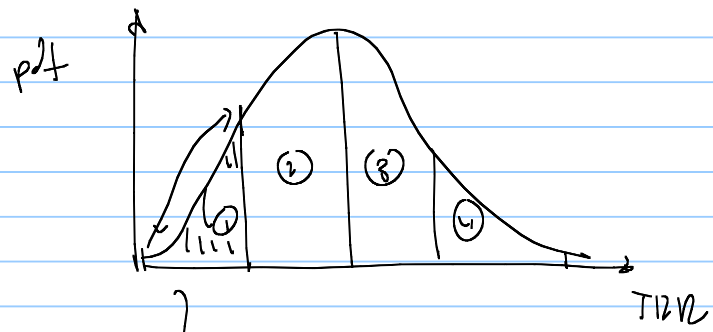
(+)

- Weighted AVG. NPV ('Yes-Branch') $= \sum_{i=1}^{5} (Prob_i) \times NPV_i) = G$
- NPV ('No-Branch') =0
- IF G>O, Explore !
- A-E; Shows the spread in NPV-Outcome for this venture

in decision trees we sometimes have to convert continuous probability funtions to discrete values

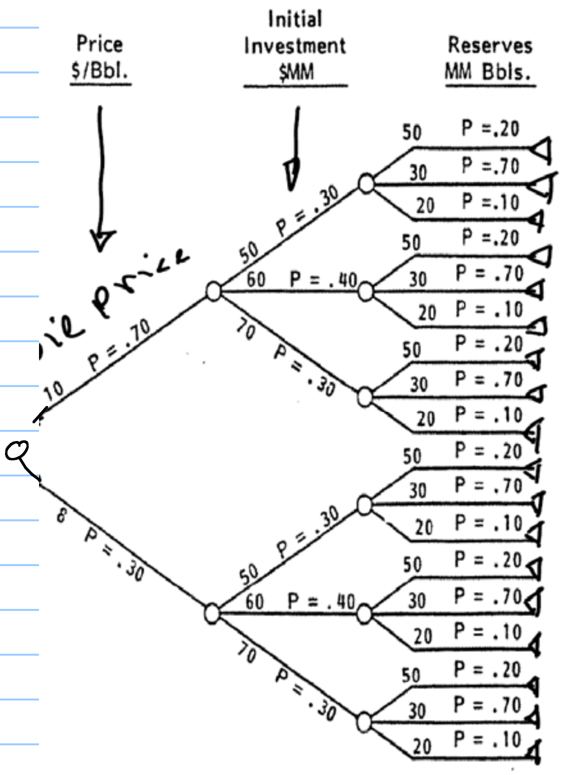


one way to do it is the following:
divide the pdf in sections



area under the curve provides the probability of the section

for the value TRR1 calculate the most probable value in the section (mode of each section)



Case	Prob.	NPV	NPV x Prob.
1	.042	60	2.52
2	.147	15	2.21
3	.021	-10	-0.21
4	.056	53	2.97
5	.196	8	1.57
6	.028	-17	-0.48
7	.042	46	1.93
8	.147	1	0.15
9	.021	-24	-0.50
10	.018	35	0.63
11	.063	0	0.00
12	.009	-20	-0.18
13	.024	28	0.67
14	.084	-7	-0.59
15	.012	-27	-0.32
16	.018	21	-0.38
17	.063	-14	-0.88
18	.009	-35	-0.32
		Weighted Avg. NPV	9.55

MEV mean expected value

Petroleum fiscal systems (brief)

- in almost every country in the world the owner of the mineral rights is the government (except in the USA).
  - ↳ the individuals pay a tax to state.

Royalty system / Concessionary system

- License to operate for a fixed period of time (NORWAY – 30 years)
- UK, France, Norway, Russia, Australia, New Zealand, South Africa, Colombia, Argentina

- Company pay royalty on the gross production and a tax on profit

Total oil and gas revenues

↓ (–) → royalties (%)

Net revenue

↓
(–) OPEX
(–) Depreciation, Amortization,
(–) interest on financing
(–) bonus?
} deductions

TAXABLE INCOME

↓ (–) TAX (might be split in state and country)

NET INCOME (AFTER TAX)

Contractual systems

service contracts

- the company gets their share in money

PSC – production sharing contracts

- the company get share in production

- Company receives a share of {production / revenue}
- government receives share in oil/gas
- Government has decision power on the management of example

Examples: Malaysia, India, Nigeria, Angola, Trinidad, Algeria, Egypt, Yemen, Syria (?), Mongolia, China.

TOTAL REVENUE

↓ (–) → (%) Royalty

NET REVENUE

↓ (–) → deductibles, cost recovery, investment credits

Profit production

→ company 1 (%) → **Contractor oil** → (–) tax → **Net cash flow**
→ company 2 (%)
→ share 3 (%) government

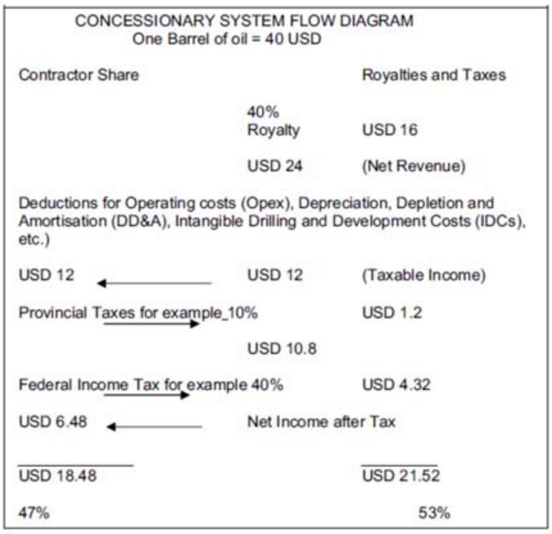


Figure 1.4 Example concessionary system flow diagram

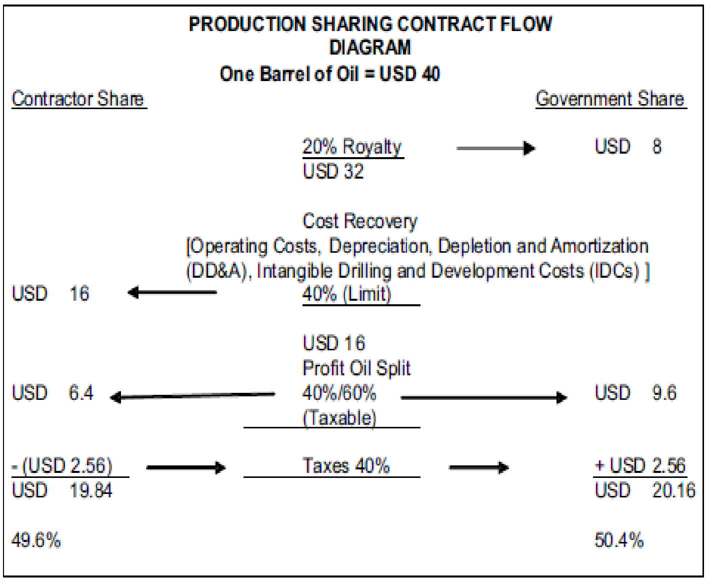
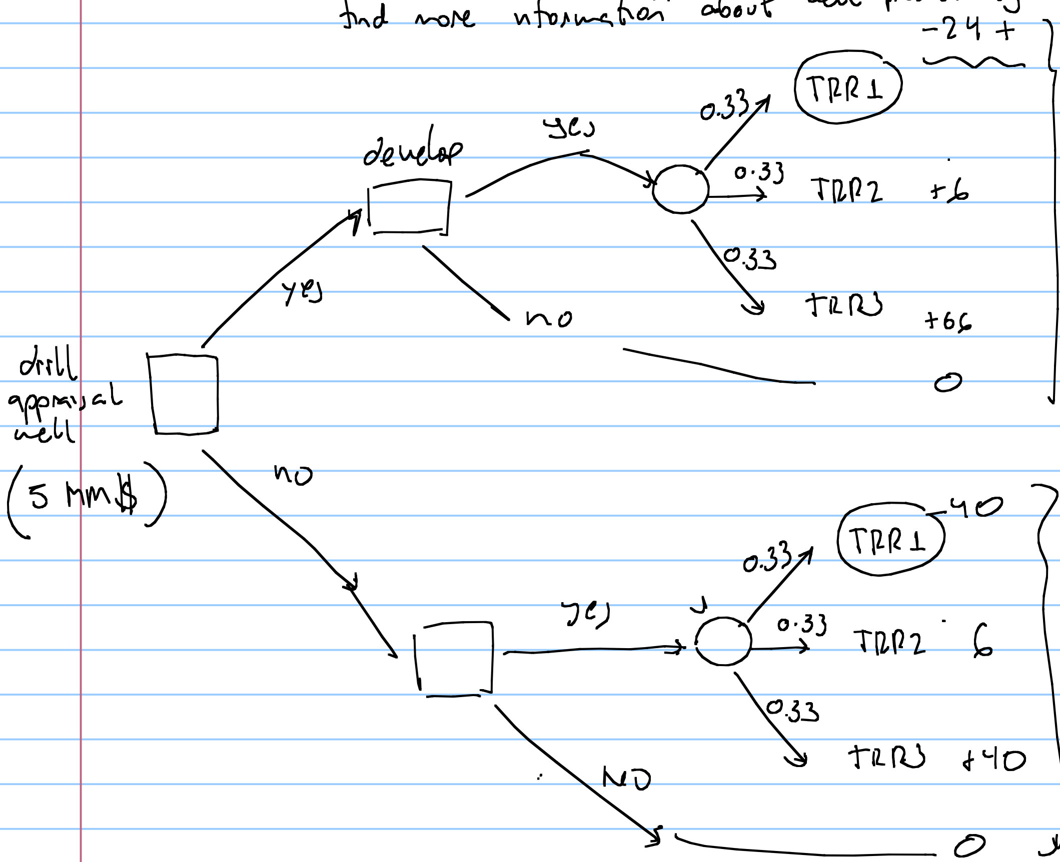


Figure 1.9 Example production sharing contract flow diagram

Decision trees can be used to determine the value of new information given by a specific activity. Determining the value of information.

An example: drilling an appraisal well to find more information about well productivity



better approximation of NPV because I have a better idea how much the formation can produce (K)

EMV 24 MM$

↳ this affects the number of wells required and (or) the size of the processing facilities

EMV

EMV = 2 MM$

Value of appraisal information = EMV with appraisal − EMV without appraisal = 22 MM$

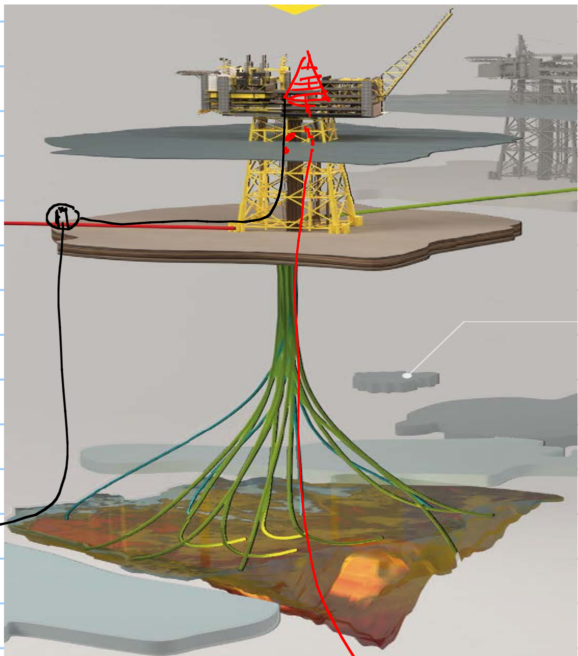
Layout of hydrocarbon production systems: (focusing offshore Norway)

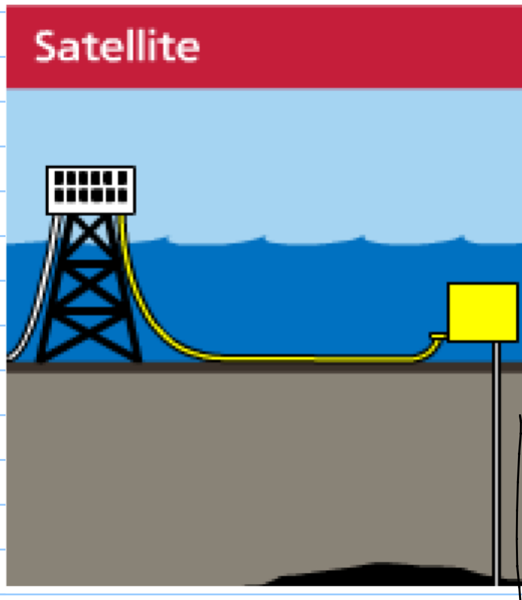
dry christmas trees (platform wells) + (subsea wells)

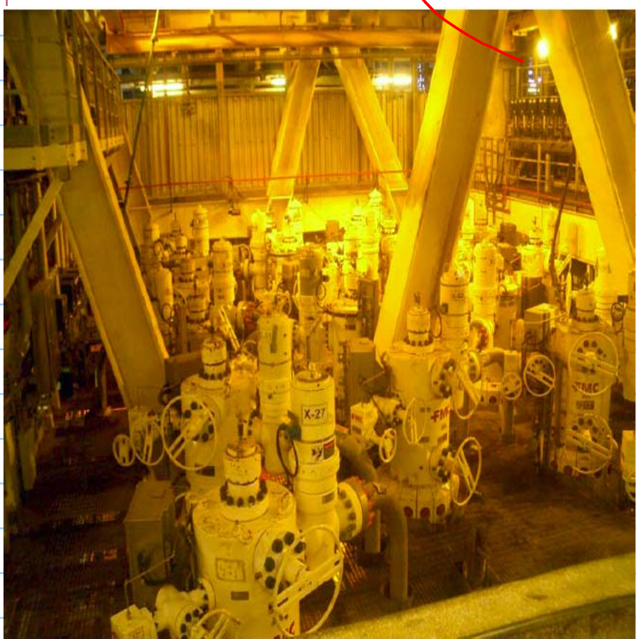
- wells are drilled similar to onshore
- wells . are deviated (highly deviated)
- careful for intersecting well paths

wet christmas trees (subsea wells)

- Drilling is done with a drilling vessel (ship, semi-sub)
- well are not so deviated if they are not gouped in clusters.

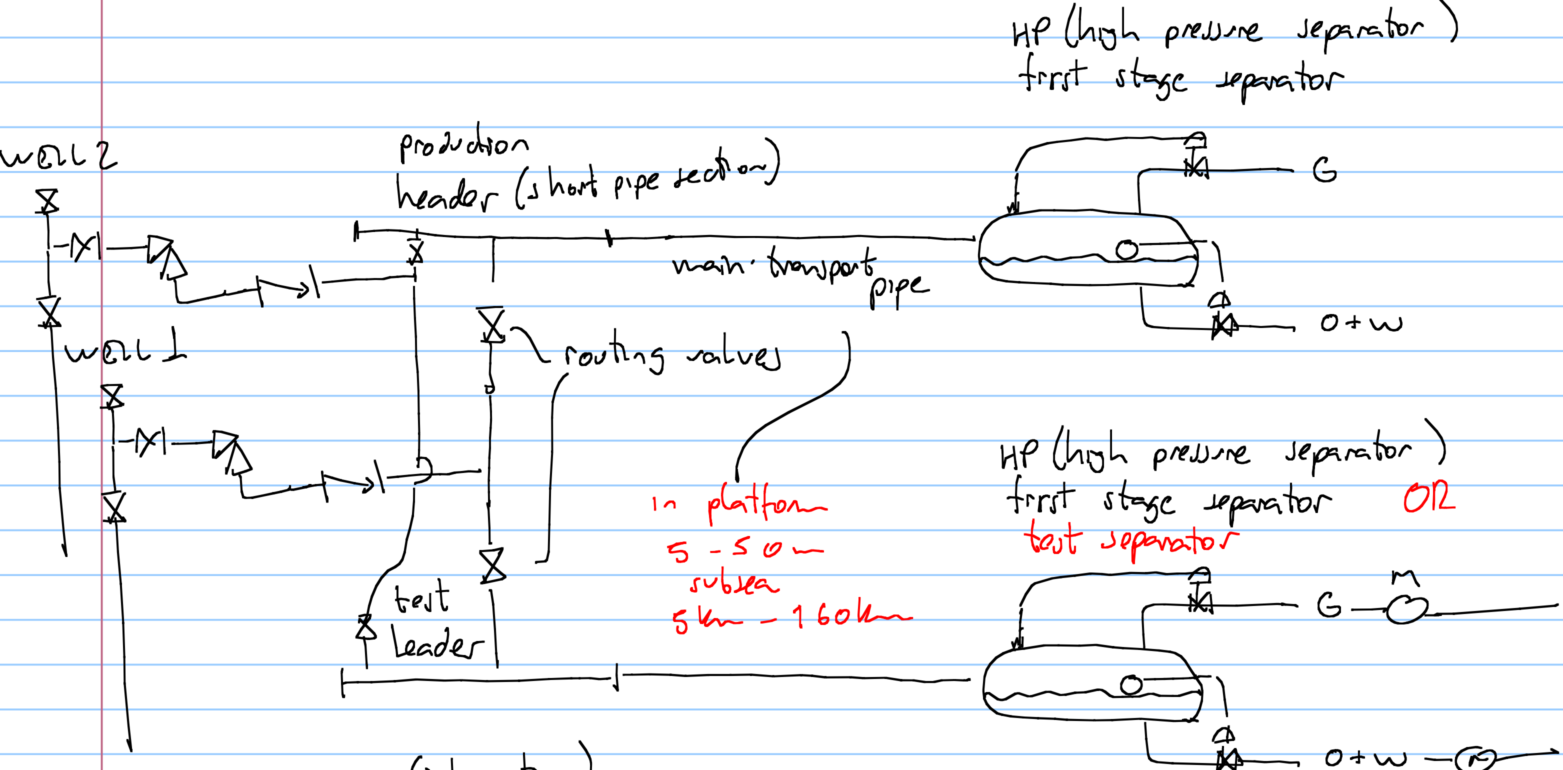


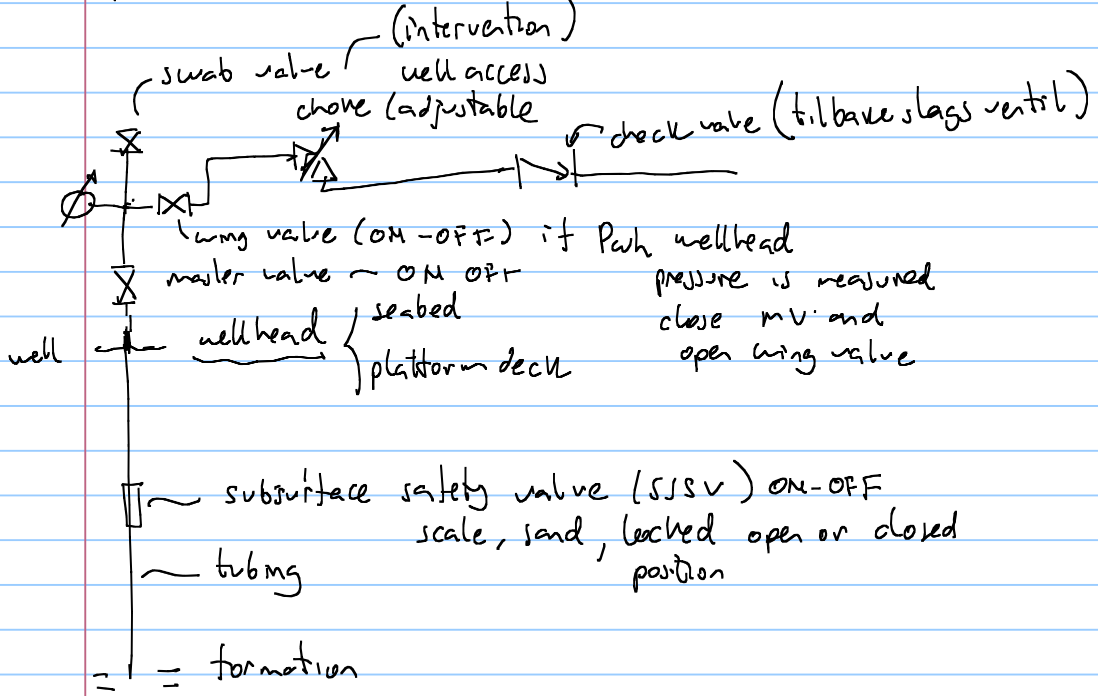




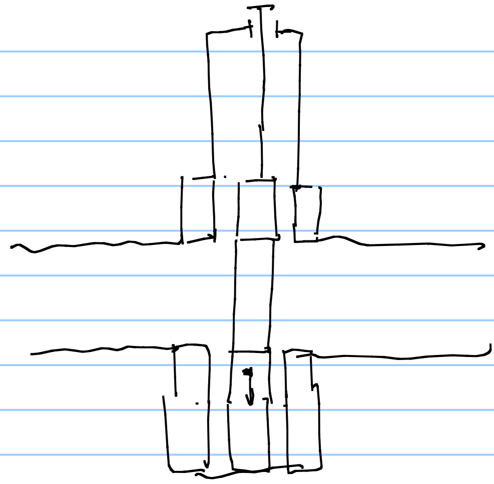
well bay

- Production manifold:
  - Comingle (merge production from different sources)
  - Test the well
    - determine production shares (allocation)
    - estimate the productivity of the well (IPR) inflow performance relationship.
    - to generate data to tune reservoir models (history matching) and improve predictions
    - to sample the fluids → to determine fluid behavior
  - to route the well production to a particular separator

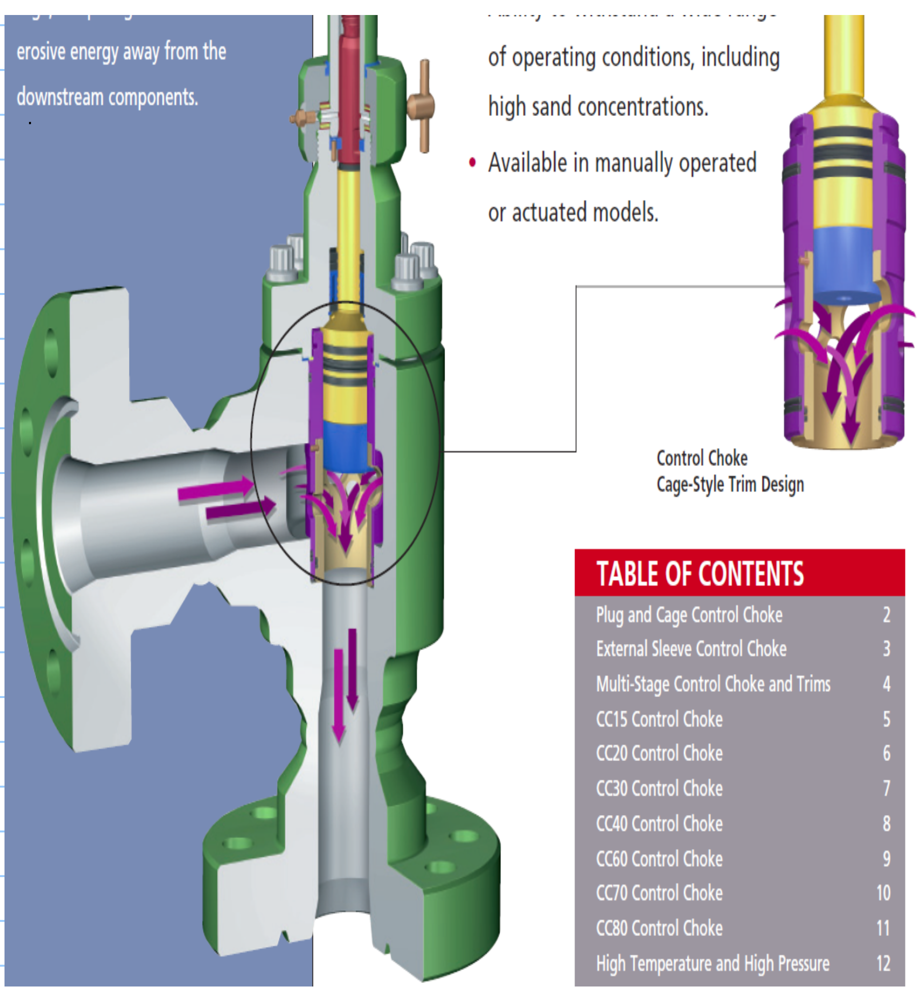




master valve
wing valve
routing valve } they are usually gate valves



choke ~> is a control valve, adjustable valve
needle choke
cage choke


erosive energy away from the downstream components.

of operating conditions, including high sand concentrations.

• Available in manually operated or actuated models.

Control Choke
Cage-Style Trim Design

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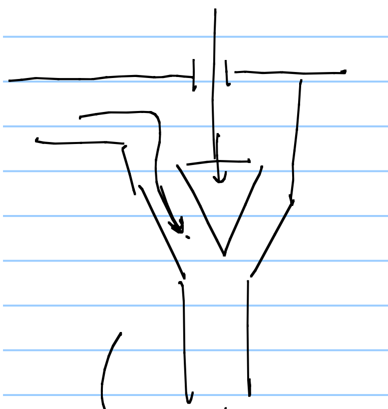
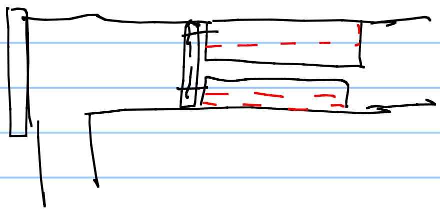
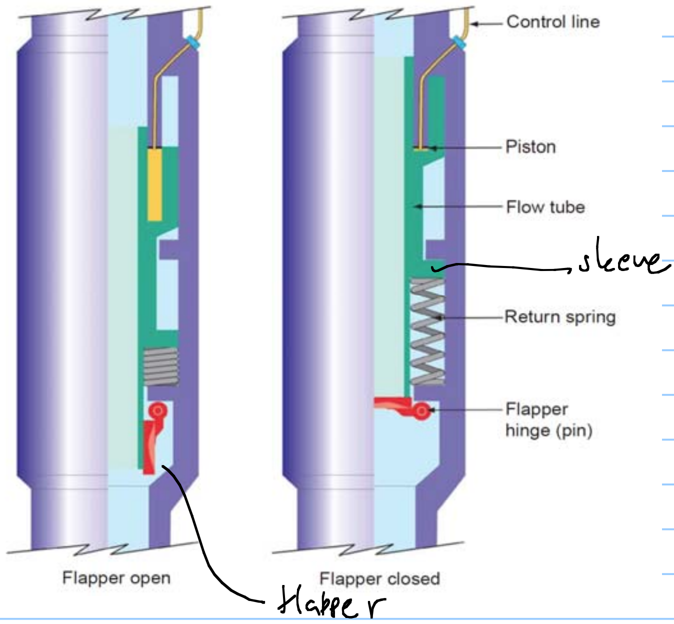
needle choke



prone to erosion due to high v

in onshore fields bean choke is often used to control the production. are not adjustable!
cartridge that is replaced with time.





subsurface safety valve □ always energized with a hydraulic line ~100 m ~ below the X-mas tree.

Gulf war (1990's)
Kuwait bombed.

Production manifold for platform wells or onshore wells

africa (lybia)

routing valves

test header

main production header

Colombia

Very big difference between dry X-mas trees vs. subsea wells

(tree is cheaper.

Onshore tree Offshore tree Subsea tree

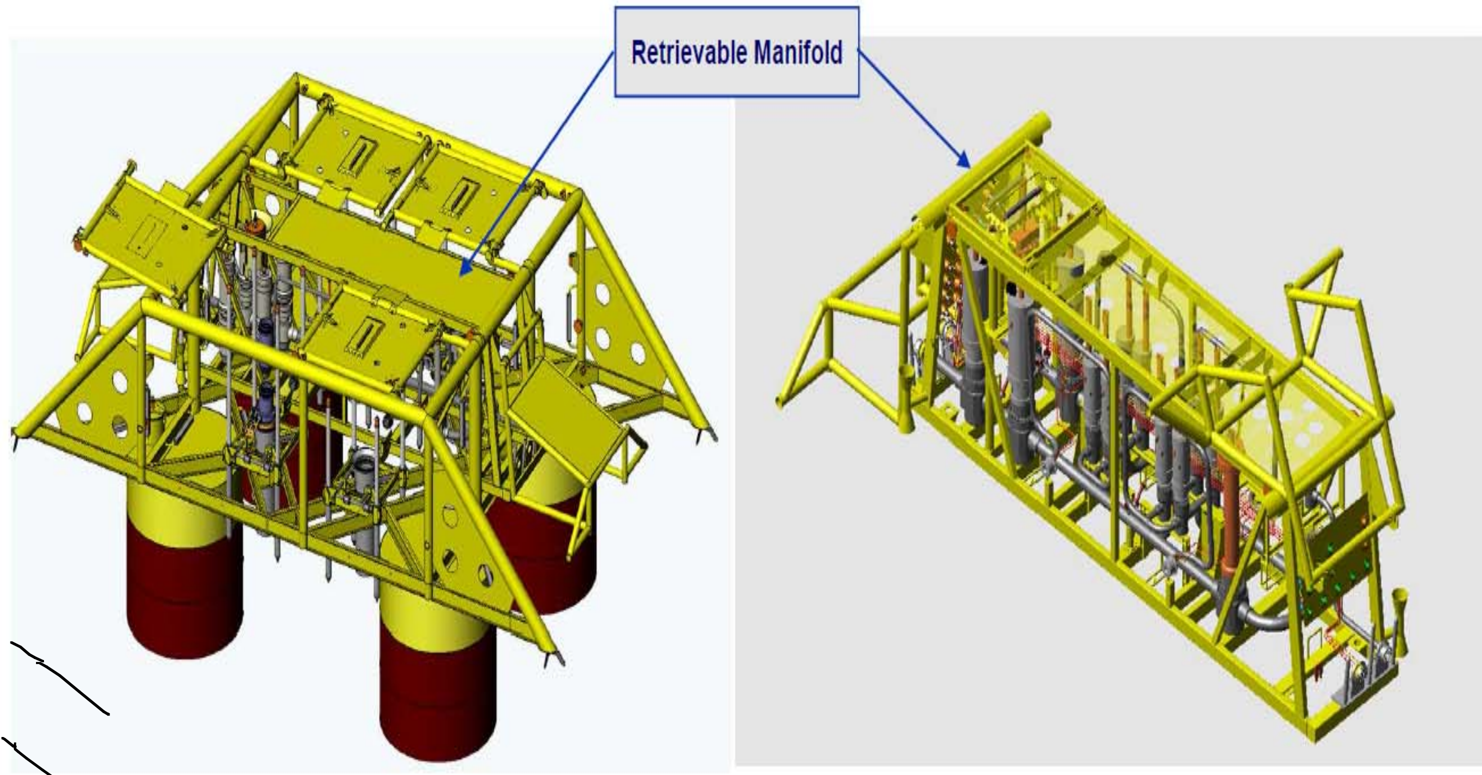
ROV to operate

alignment,
remote operation
protection
pressure resistance.

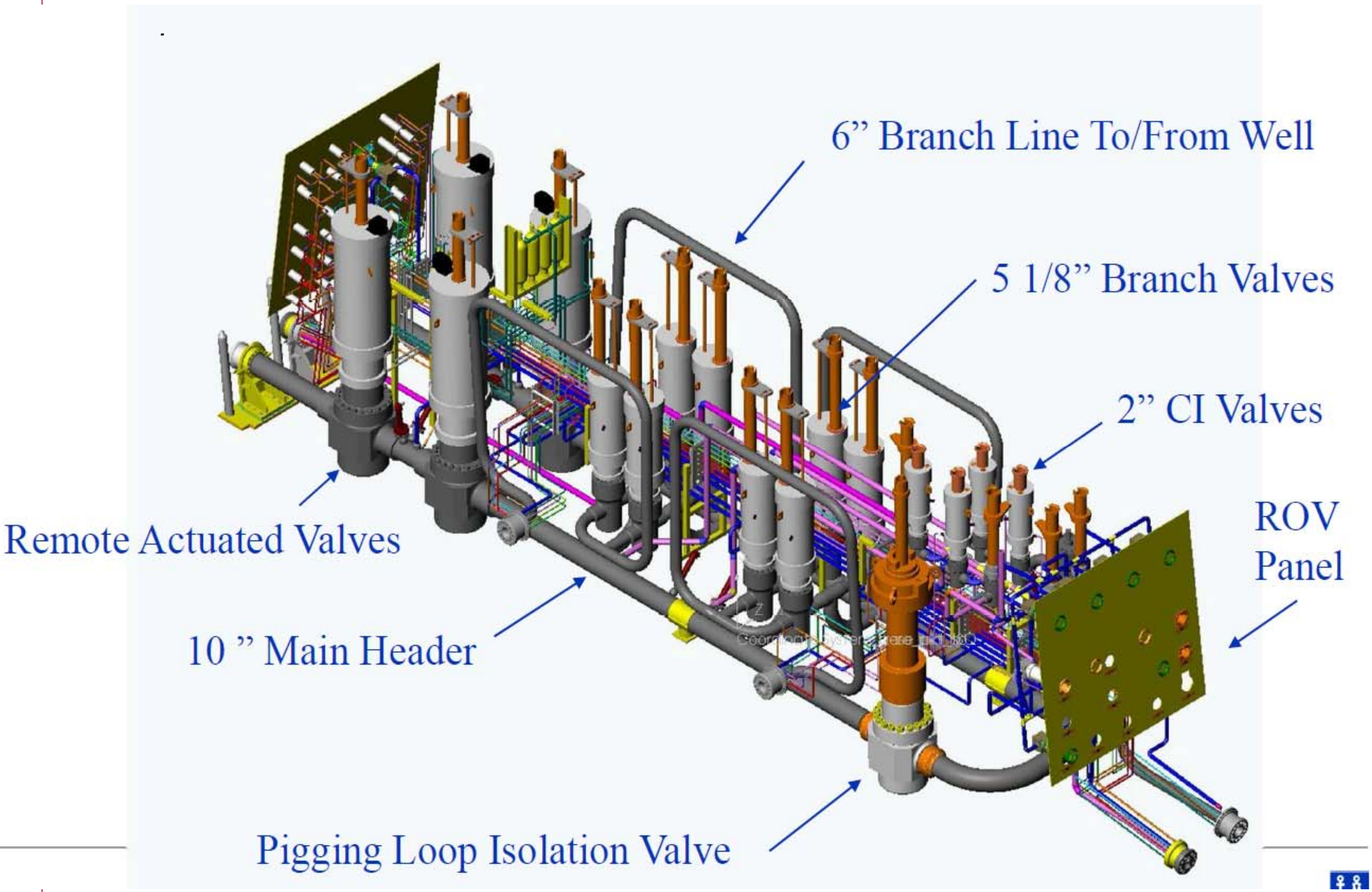
platform ewells are very deviated
subsea wells are less deviated (usually)

focusing on subsea systems.

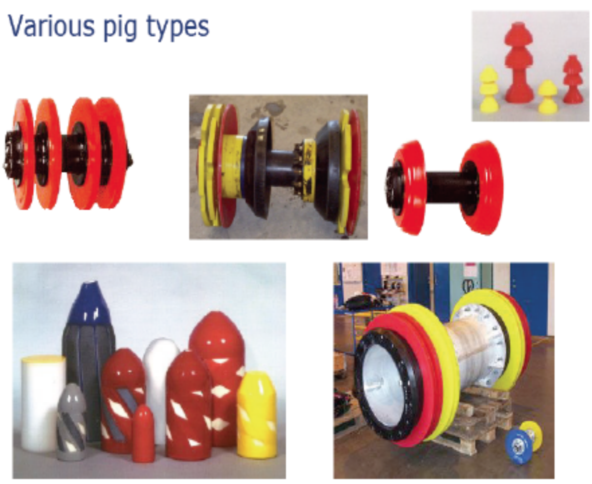
- the production manifold has another function: allow for pigging.



4-well Template



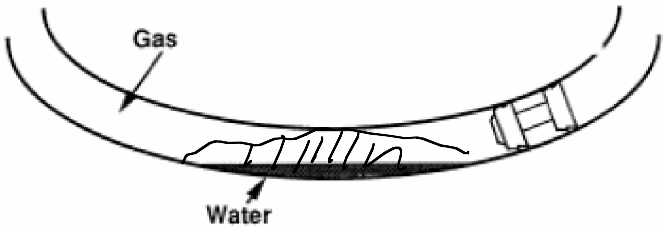
Pigging: Send a "pig" through the pipe to execute different tasks



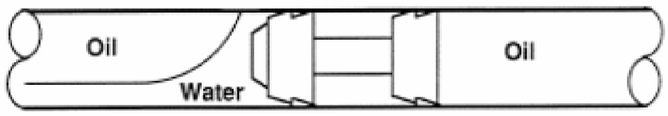
wax: at a particular P and T heavy hydrocarbon chains precipitate out of the liquid and form waxes

Pig animation: https://www.youtube.com/watch?v=CDHtL-J1Xxo

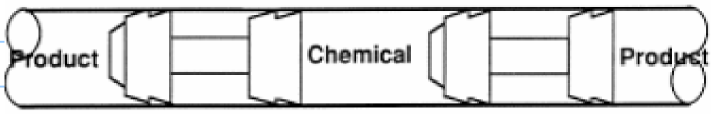
Removing water in a gas flow system



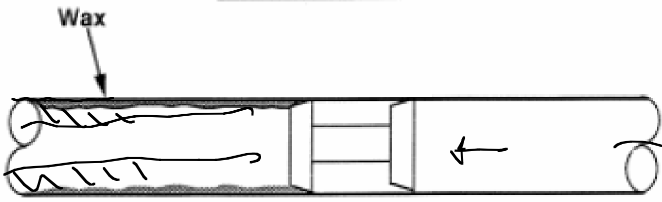
Removing water in a oil system



Treating by chemicals



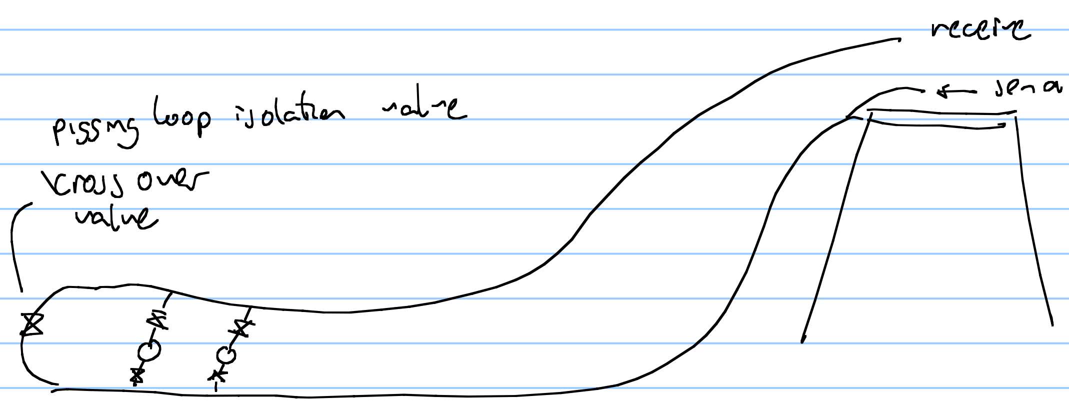
Removal of Wax



high pressure fluid

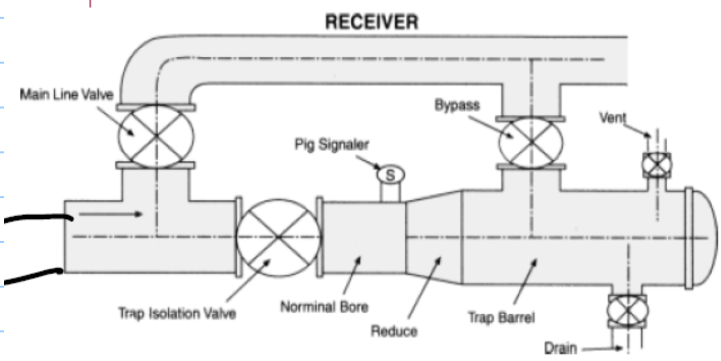
↓↓ hig pressure drop
~ reduced production

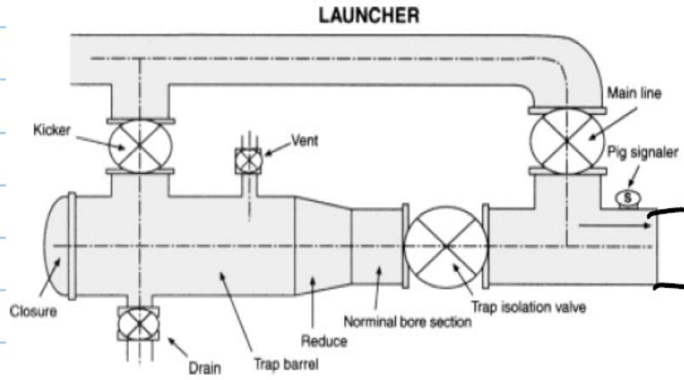
In systems with oil prone to generate wax pigging is done regularly



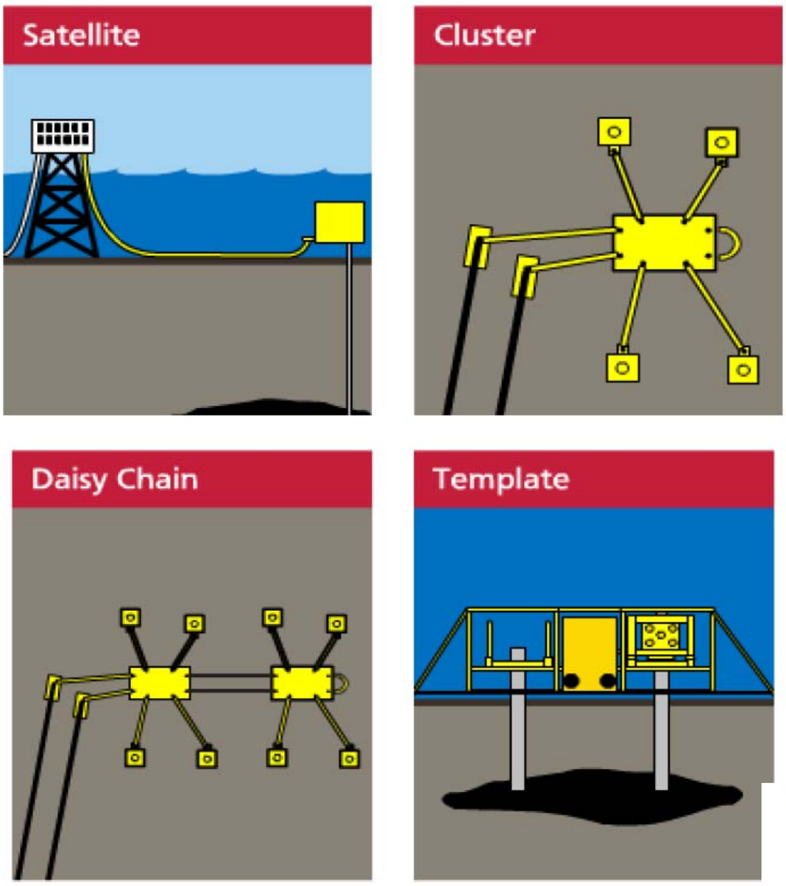
Pig receiver

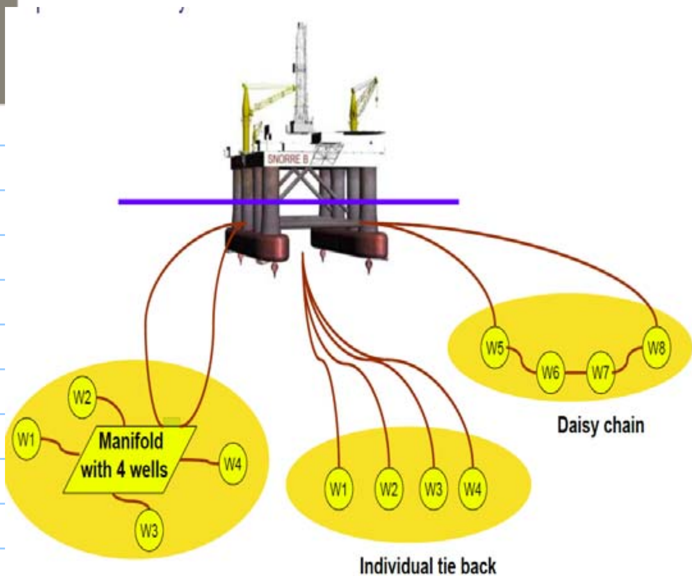
pig launcher





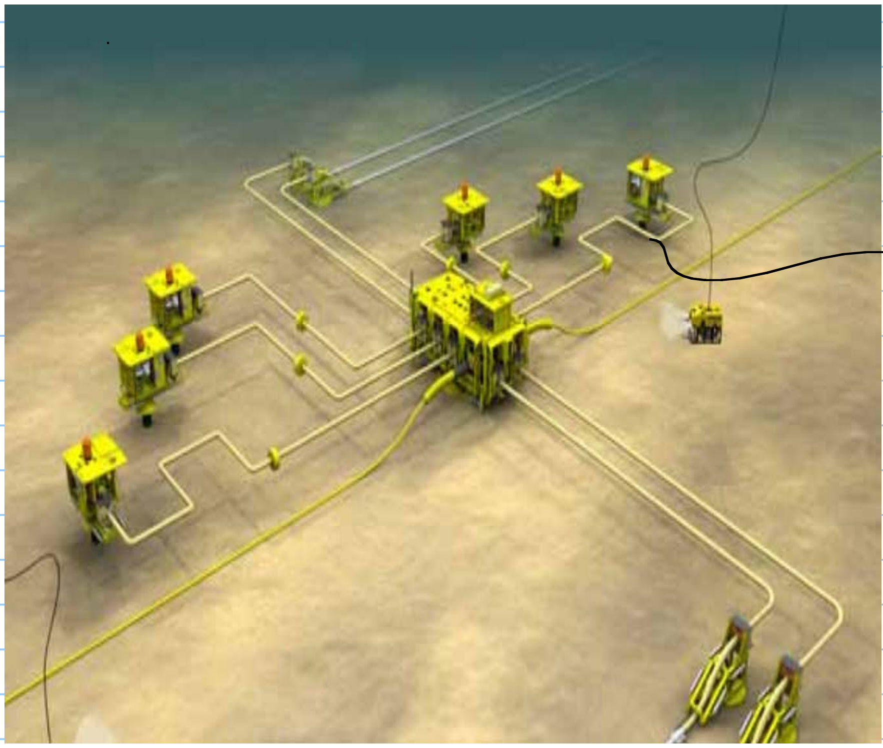
Some other subsea field architectures:



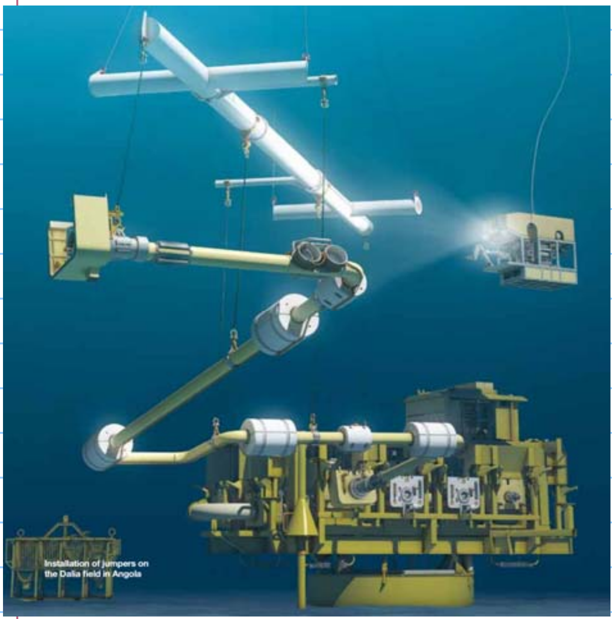


template , well + manifold
- manifold
- subsea separation
- subsea boosting.

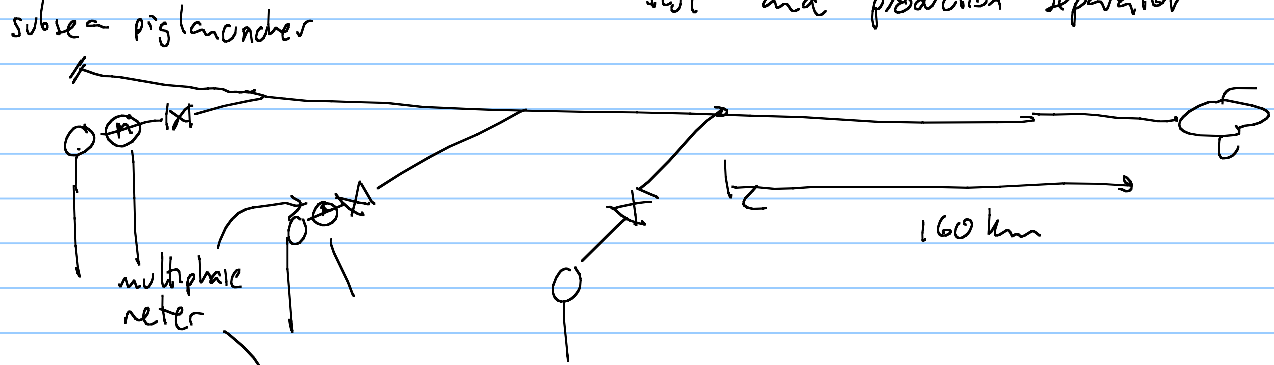
wells and manifold are not in the same template



conection between templates well and manifold is called jumper
rigid piece of pipe



how do we test subsea systems or onshore systems where i dont have two separate lines that go to test and production separator



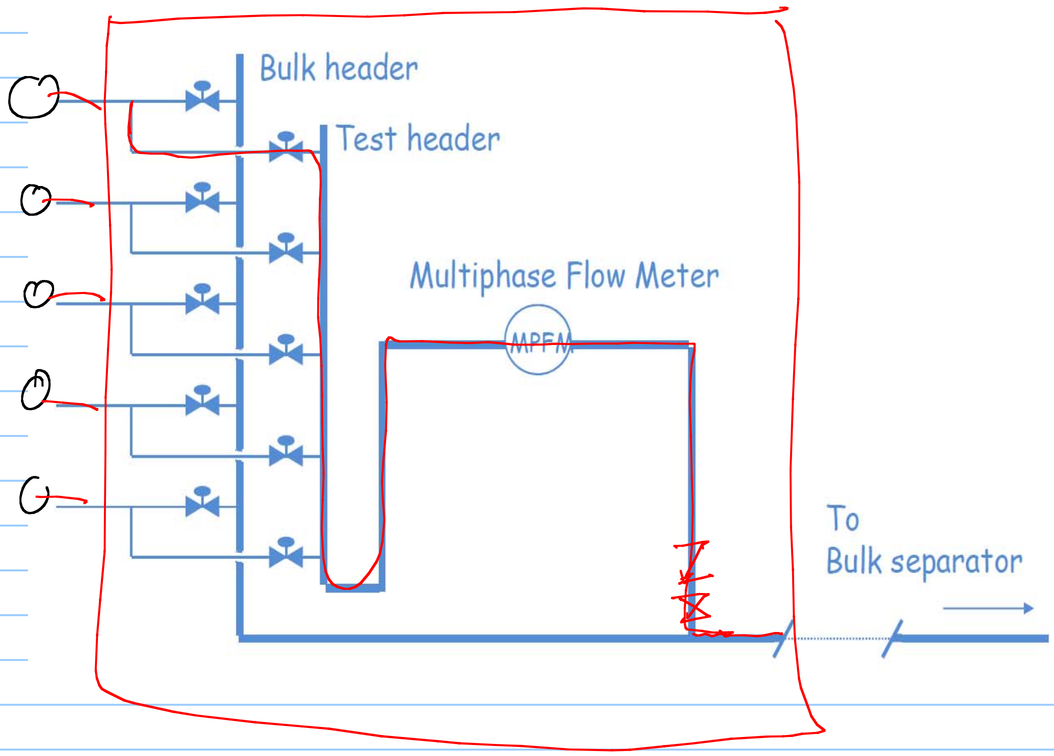
Snøhvit Snowhite

measuring oil, gas, water rates while flowing simultaneously

- place multiphase meters on each well
- place a subsea pig launcher
- Use a $\underbrace{\text{multiphase meter}}_{\$\$\$}$ for a group of wells.

Use a manifold to route the well production through the mpm

multiphase meter

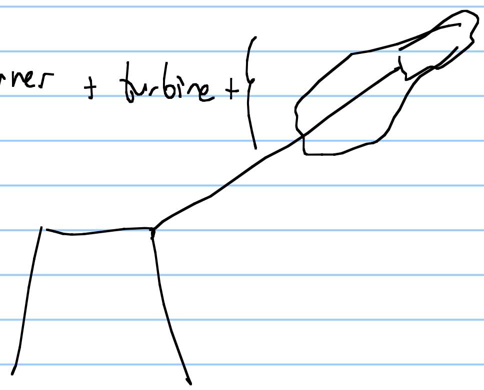


In onshore systems a portable test separator (see below) is often used in this arrangement instead of the multiphase meter.

Offshore structures for oil and gas production

not discussed here
- drilling vessels, ships
- vessel to lay equipment pipes,
- tankers
- supply vessels

- Drilling package: facilities for well drilling and intervention. drilling tower, BOP, mud pumping and processing system, cementing system
  mud package
  storage deck for tubulars, drilling risers
- facilities for light well intervention. {wireline, coiled tubing}
- Processing facilities
  - gas processing train
  - oil separation train
  - water processing train (polishing unit)
- gas injection system { compressor trains
- gass compression system for pipeline transport
- gas lift system { compressor trains, pipes, valves }
- water injection system { seawater treatment, pumping
- Living quarters
- Helideck or access points
- Power generation { gas turbines { compressor + burner + turbine + }
- flare system: burn gas when needed



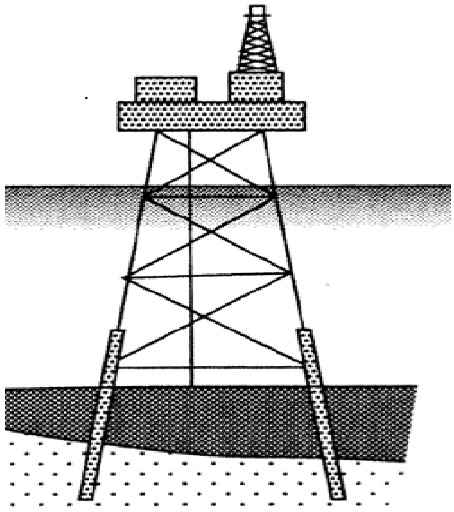
- Utilities: hydraulic power fluid, compressed air
  seals of rotating machinery
  drinking water, air condition
  ventilation and heating system
- well bay
- production manifolds
- metering
- oil storage
- facilities for oil offloading
- Control system
- monitoring system
- System to recover production chemicals (corrosion, scale, wax, demulsifier, hydrate)
- Repair workshop

Classification of offshore structures

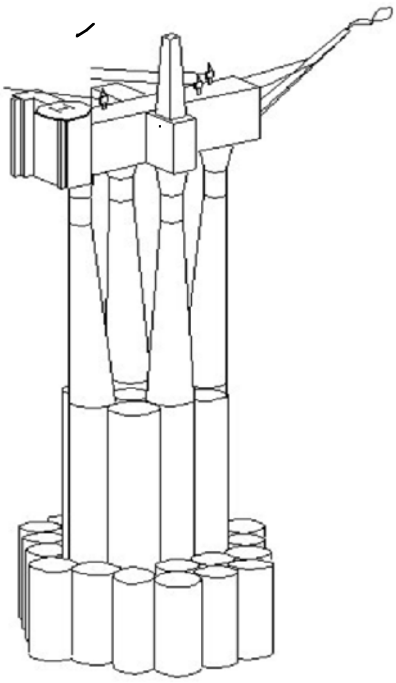
	Fixed		Compliant
Bottom supported	Jacket	Gravity Based structures	Compliant tower

most of the loads are transferred to seabed, soil

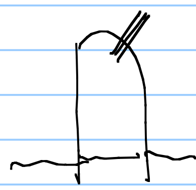
Jacket



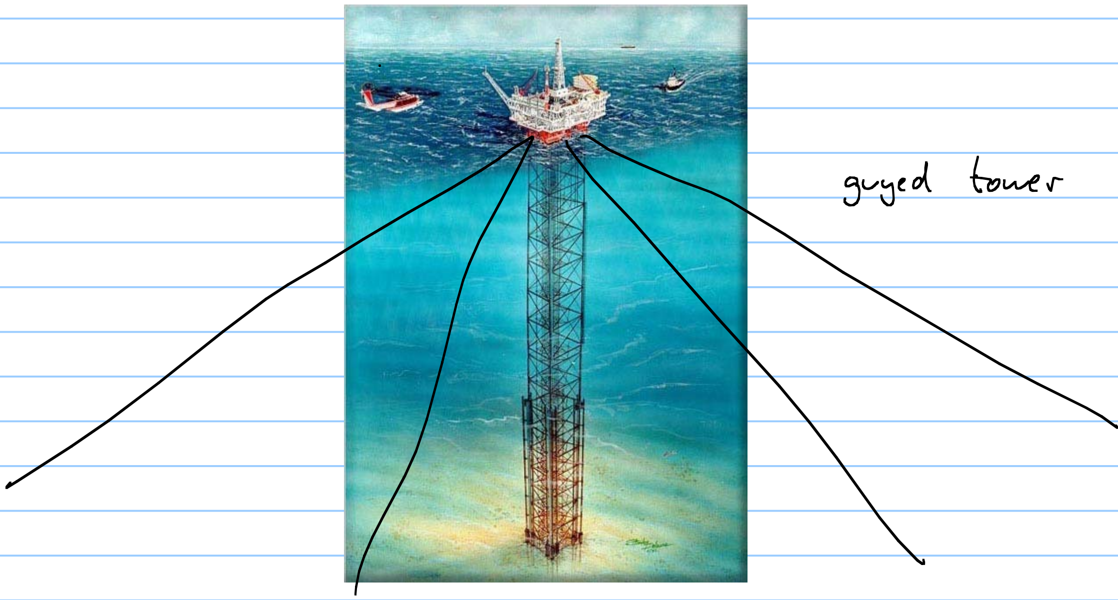
Gravity based structures



suction anchor



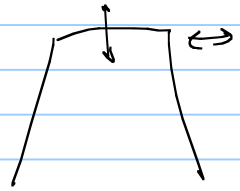
Compliant tower



Fixed | Compliant

Bottom supported — Jacket — Gravity Based structures — Compliant tower

most of the loads are transferred to seabed, soil



have reduced movement in the vertical and horizontal direction

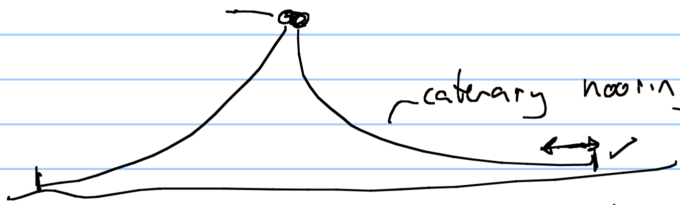
Floating Production Storage Offloading

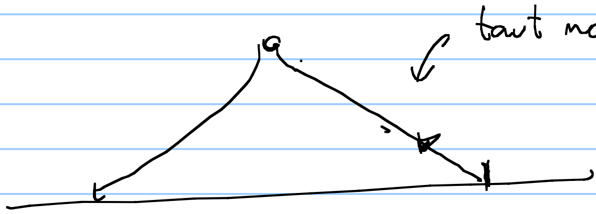
floating structures

Naturally bouyant: FPSO, Sevan FPSO, Semi-Sub, SPAR

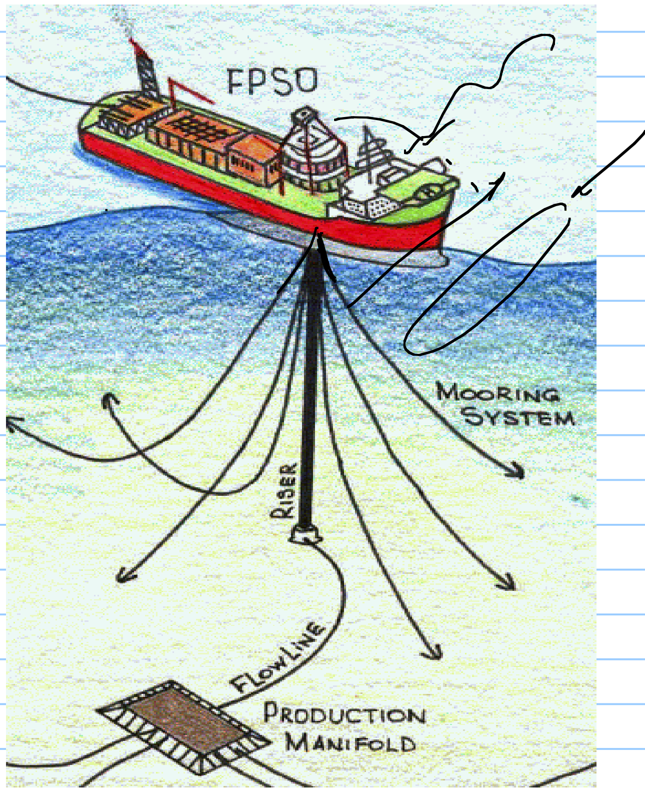
positively bouyant: TLP tension leg platform

keept afloat above the sea level by bouyancy.
have movement in the vertical and horizontal direction.
ballast tanks allow to control bouyancy
the are typically moored with steel chains or pre tensioned composite lines

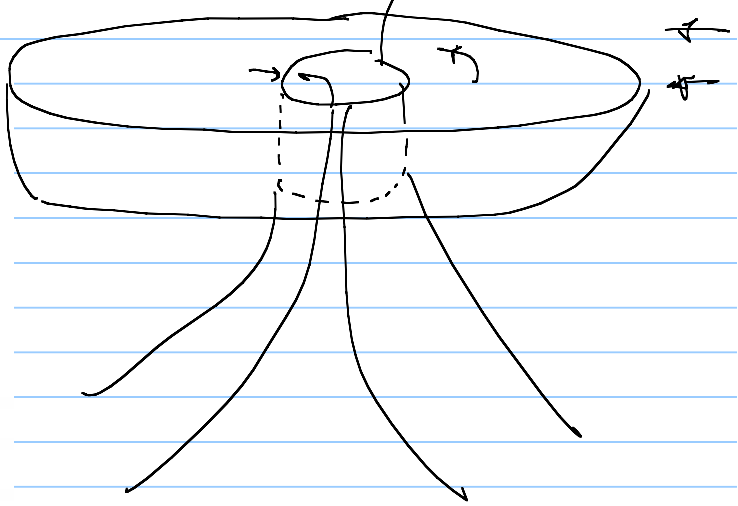




FPSO-ship

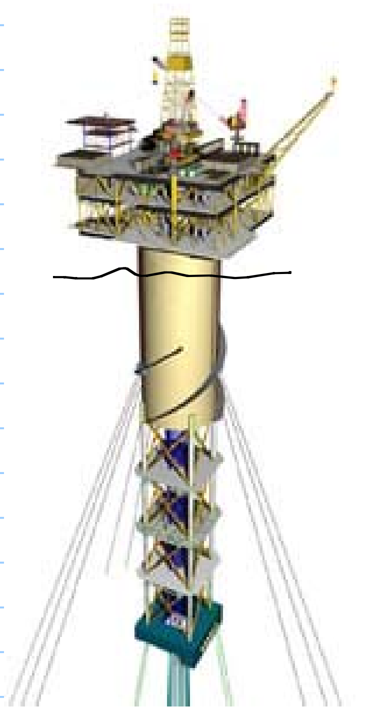


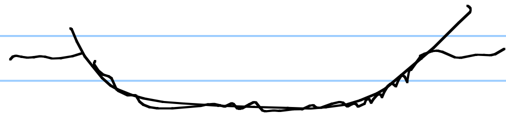
Sevan type FPSO

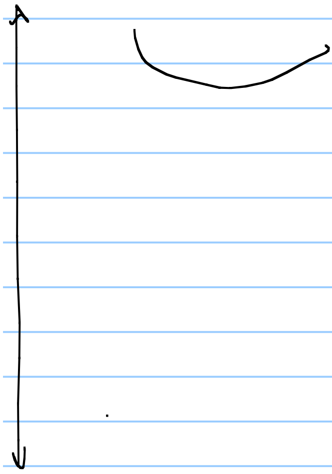


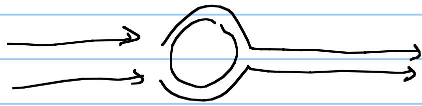
Semi - submersible

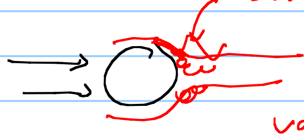
spar → deep hull structures







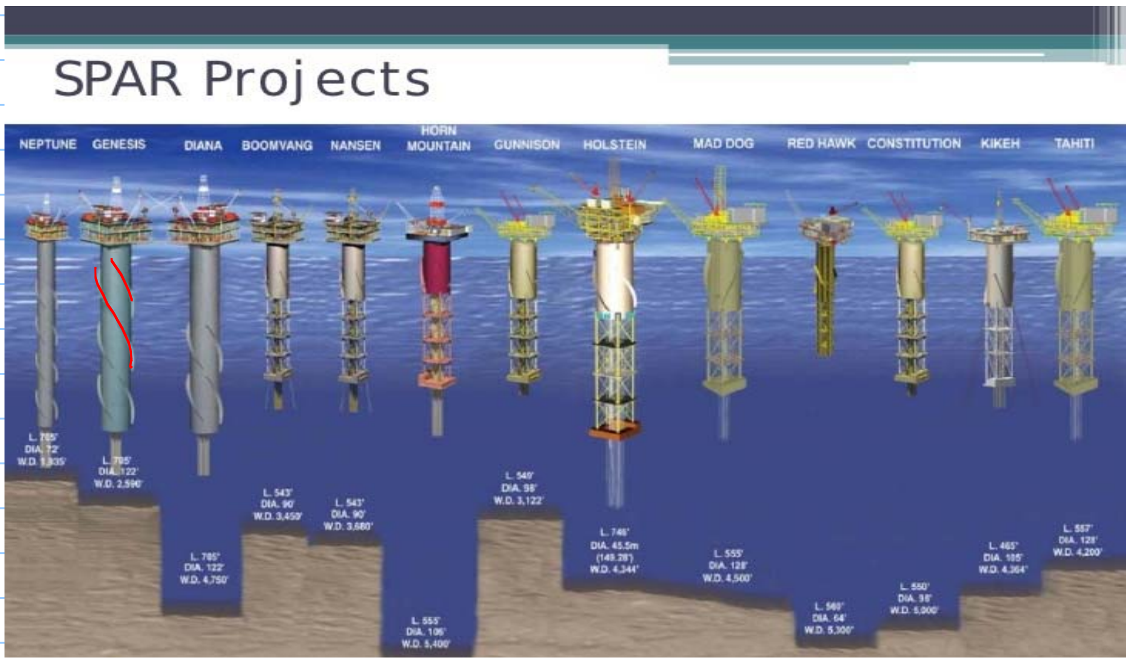


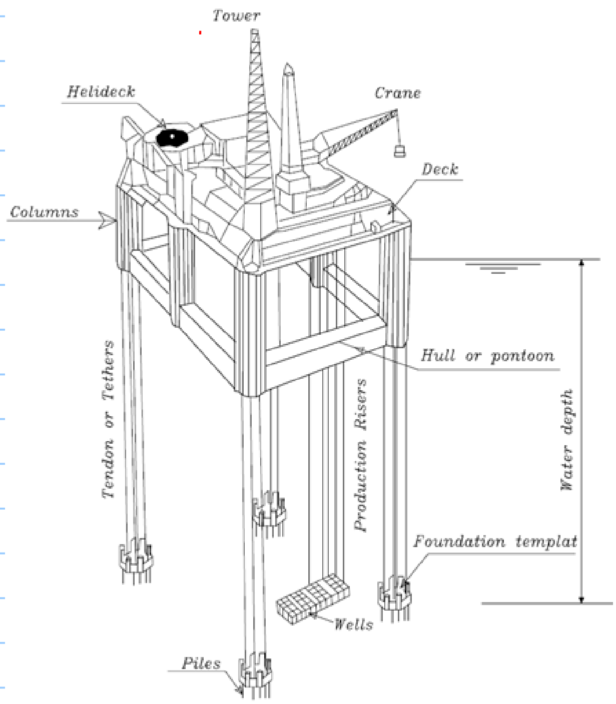


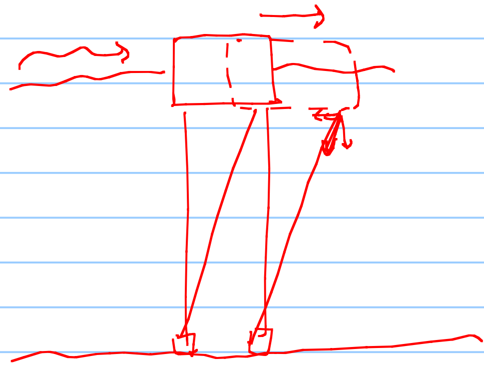
dettachment point

wake

vortex shedding induces big vibrations in the structure that is why we have the spirals





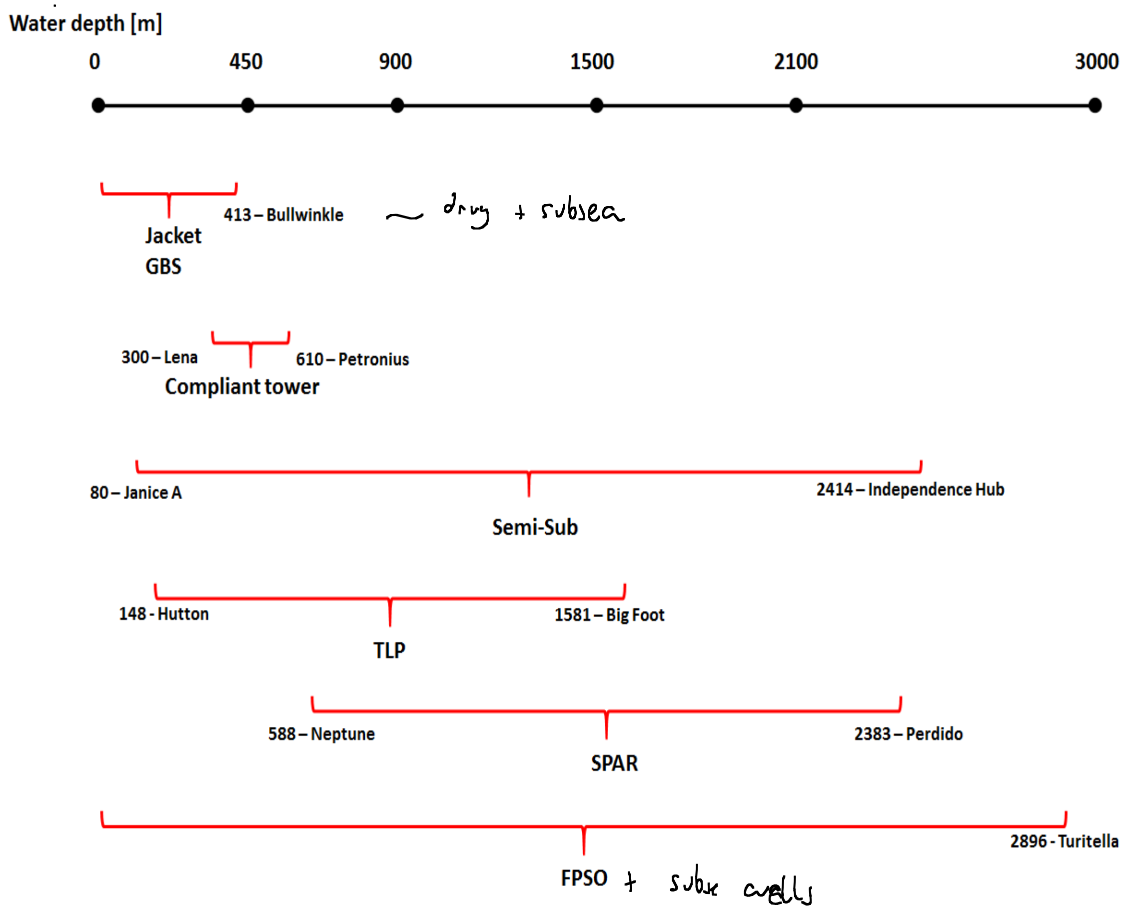


Heidrun

How do we chose offshore structures?

- water depth
- reservoir structure and extent
- Ocean conditions → Loads
  - wind
  - waves
  - current
- soil characteristics
- well artificial lift
- dry vs. subsea wells
- storage
- future development plans
- delivery time availability
- experience of the company.

Water depth:



- Dry vs. subsea wells

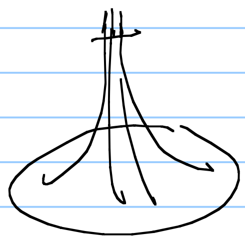
X-mas { is on the offshore structure
{ is in the seabead

Dry well ~> max depth is 1700 m

I choose dry X-mas trees if:

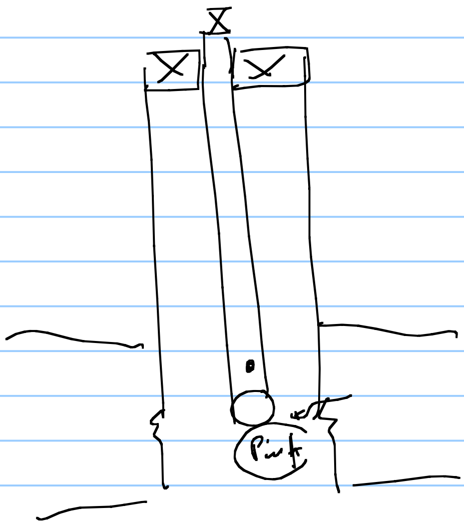
- frequent well intervention is required

① reservoir structure



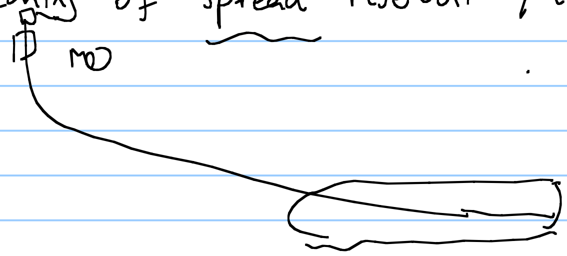
compact, not spread

- if well have ESPs electric submersible pump lifetime 1-2 years need to access the well bore often



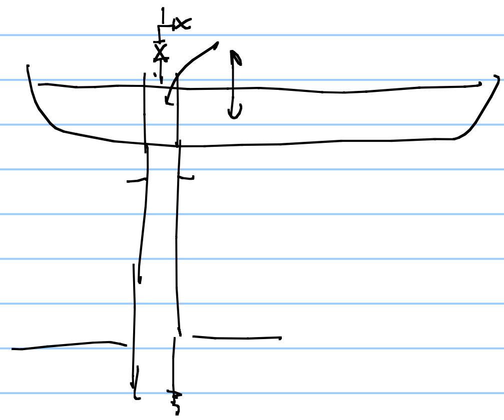
in contrast subsea wells have an average intervention time of 5 years.

what is the meaning of spread reservoir / localized { depends on the drilling package

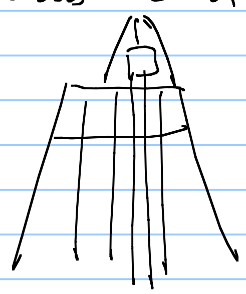


the only structures that have low movement, that allow to have dry wellhead is { bottom-supported structures { jacket, GBS, tower

TLP
SPAR { ± 3 m



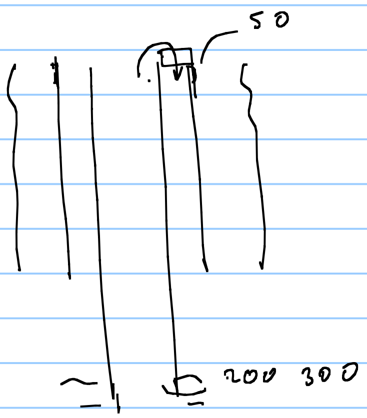
jackets an GBS wells are drilled just like onshore

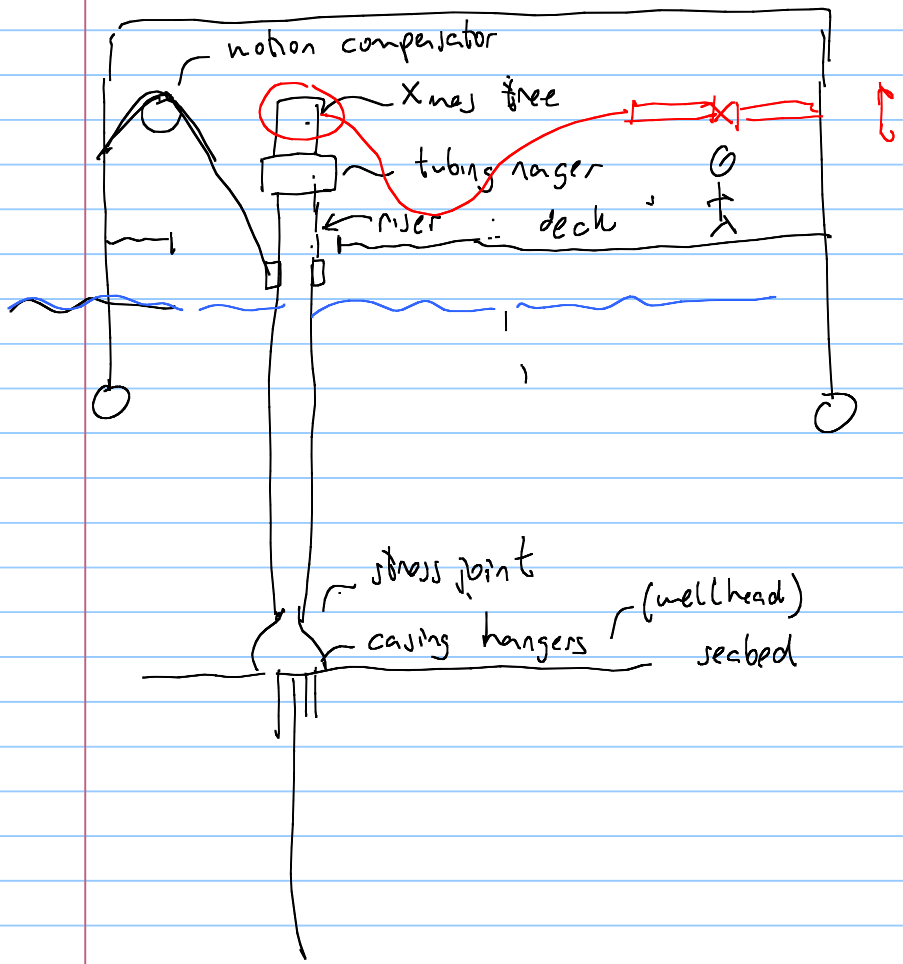


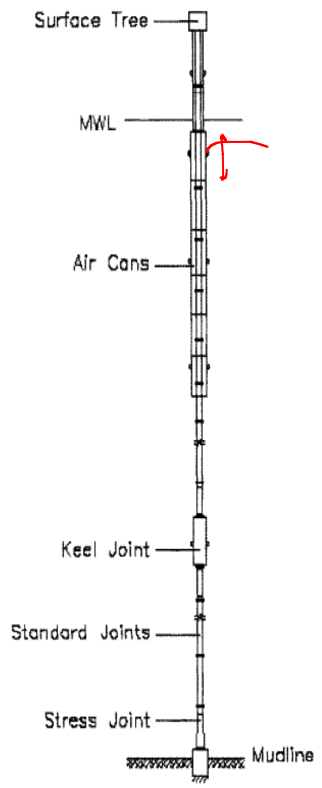
for TLP, SPARs and compliant towers the movement is significant

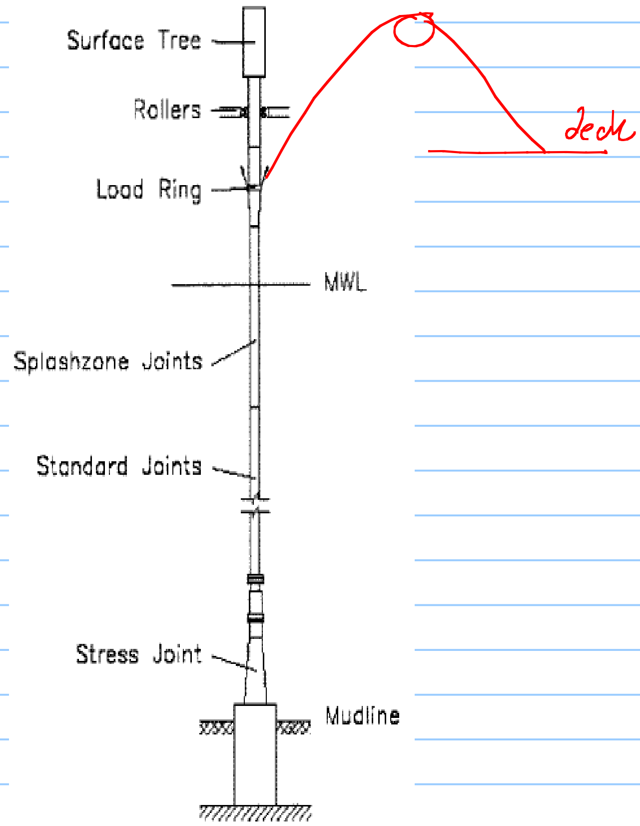
have a wellhead in the seabed:

- support casing
- transfer load of X-mas tree to conductor (soil)
- seal between annular spaces in the casing



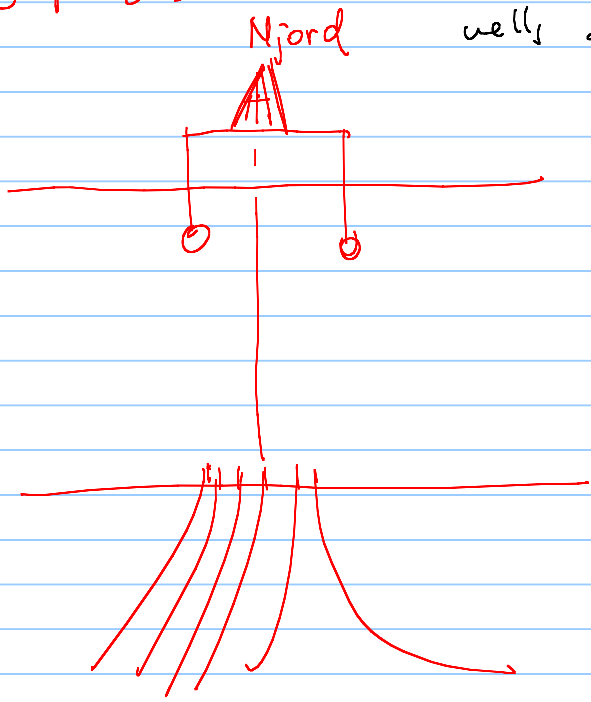

motion compensator
Xmas tree
tubing hanger
riser
deck
stress joint
casing hangers
(wellhead)
seabed


Surface Tree
MWL
Air Cans
Keel Joint
Standard Joints
Stress Joint
Mudline


Surface Tree
Rollers
Load Ring
MWL
Splashzone Joints
Standard Joints
Stress Joint
Mudline
deck

if dry wells are used usually the offshore structure has a drilling package

(when wells are subsea sometime (not often) the offshore structure has a drilling package)



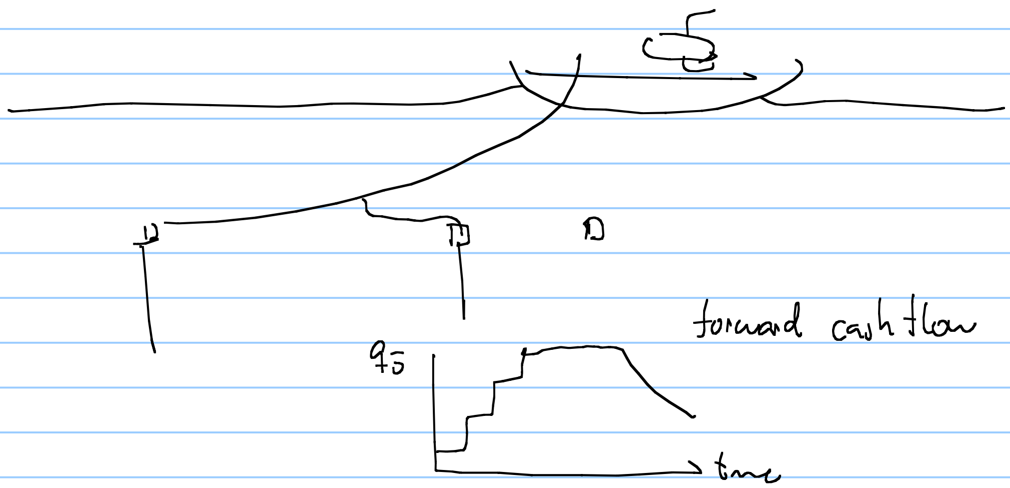
wells are exactly below the offshore structure

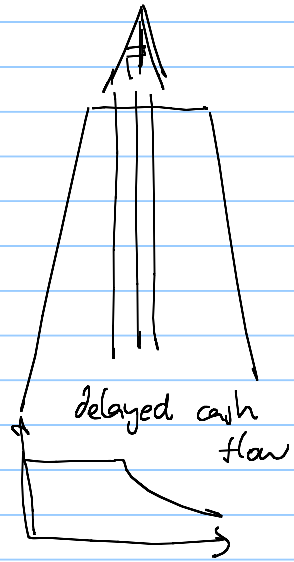
- Dry well structures have limited numbers of well slots available

  not suitable for infill drilling (maintain the production rates)

- Systems with subsea wells: have to perform flow assurance

- in systems with subsea wells production can start gradually as soon as the offshore structure is in place

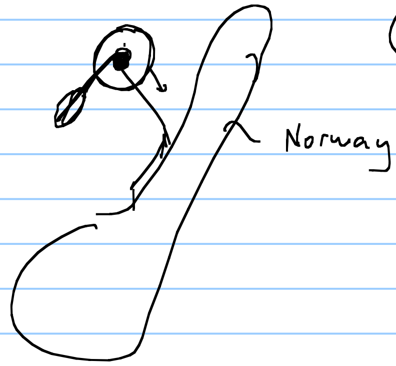




- storage of oil : only structures that allow storage are:

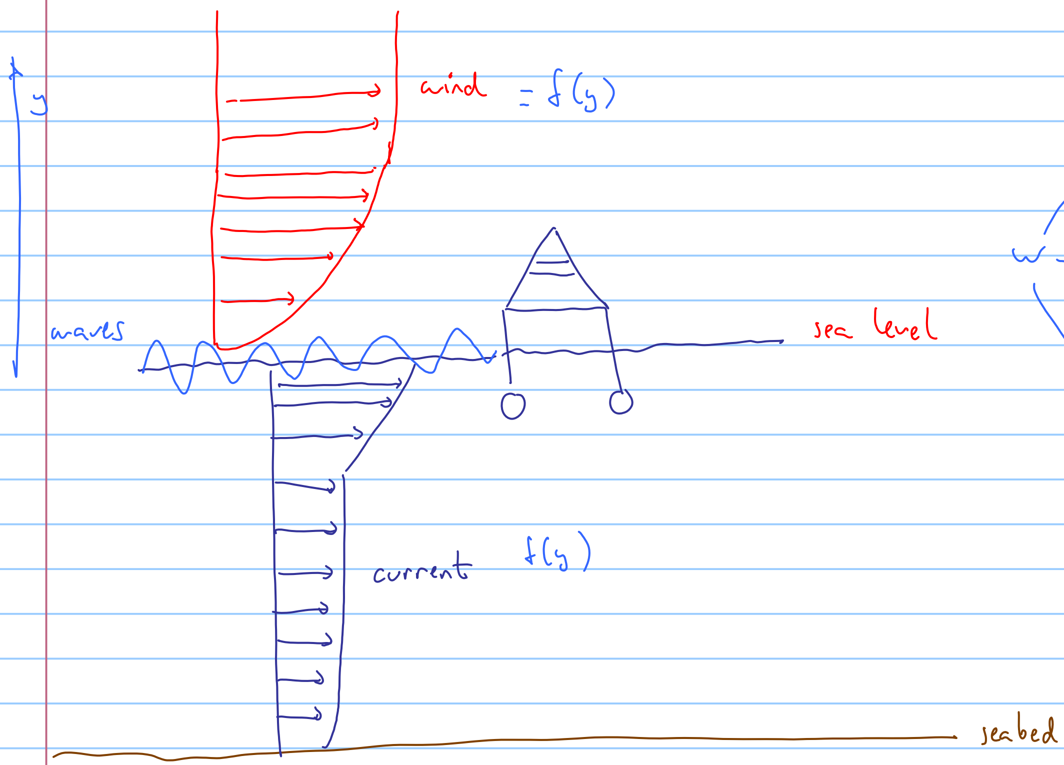
  - FPSO ~ 2.5 MMbbls
  - GBS ~ 300.000 bbls

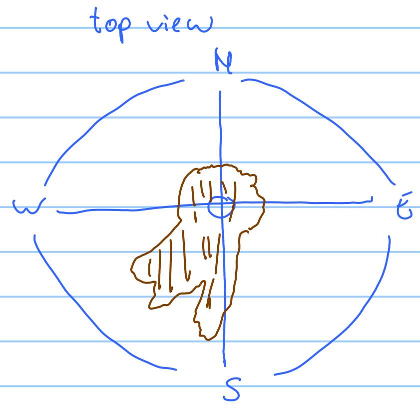
SPAR Aasta Hansteen it's the only spar with storage capacity (up to date) 150.000 bbls



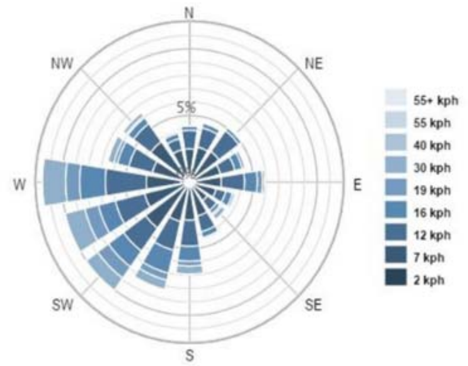
- Marine loads on offshore structure { next class

Marine loads in offshore structures





marine loads usually have a preferential direction



- for practical purposes:
  - wind is considered with a uniform constant value (exception some floating structures)

    values vary with minutes

  - current: the spatial variation is considered. Considered constant with time

    {a high value is usually used (100 years current)

    values usually change within hours

- waves:

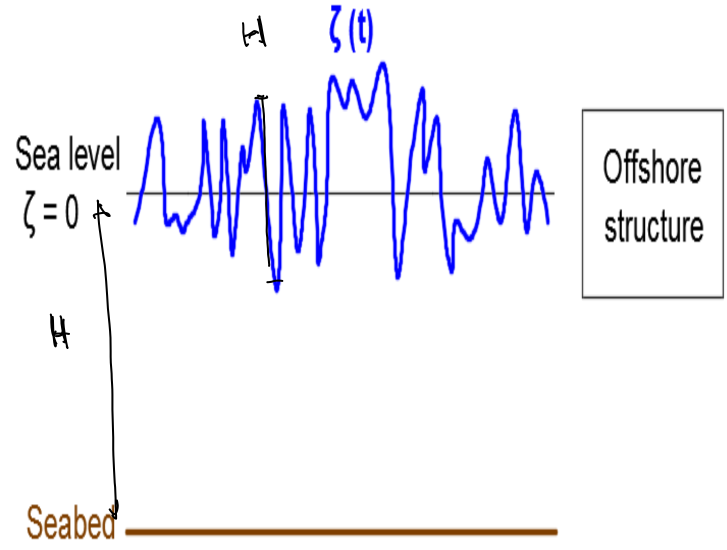
height difference between two consequtive waves
periodicity

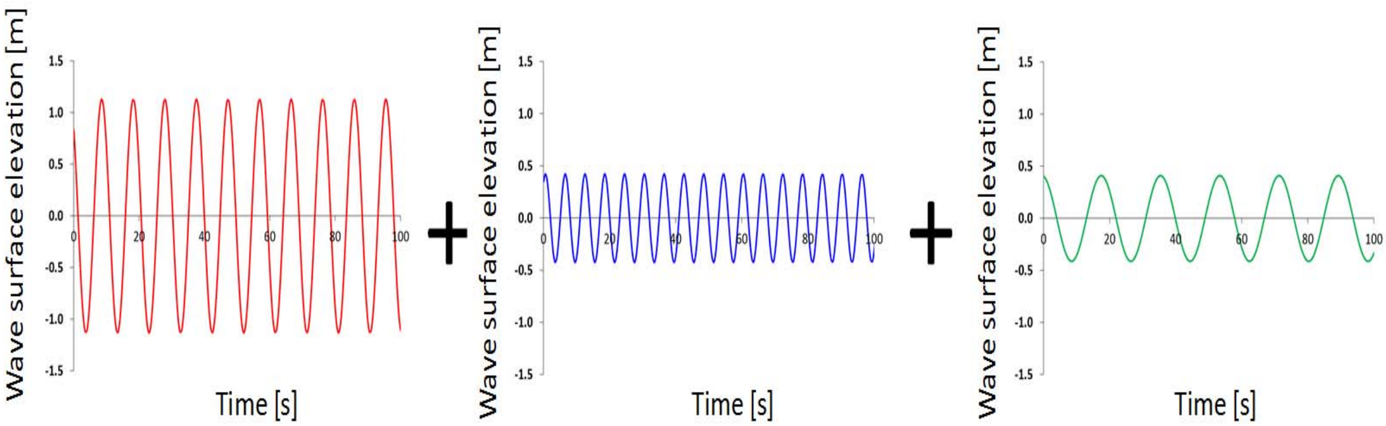
- waves

wave elevation

ζ

fourier theorem





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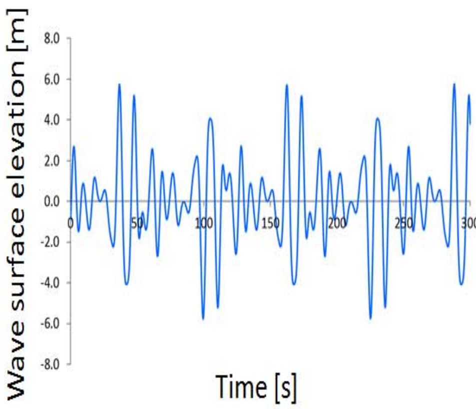
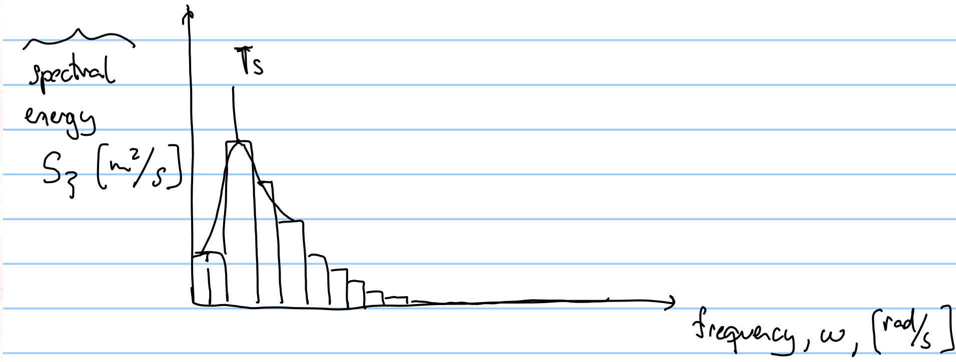


$$\zeta(t) = \sum_{i=1}^{N} \zeta_{ai} \sin(\omega_i t + \varepsilon_i)$$

measurements of wave statistics buoys attached to merchant ships
measurement ships
existing offshore structures.

FFT fast fourier transform



wave energy spectrum

To convert from energy to elevation:

$$\varsigma_i = \sqrt{2 \cdot S_{\varsigma i} \cdot \Delta\omega_i}$$

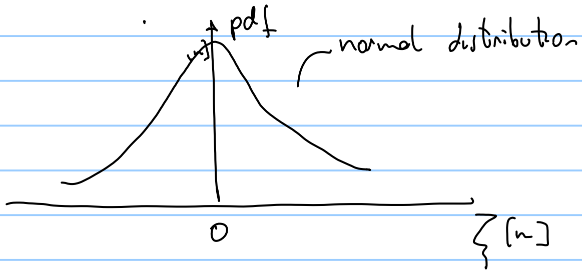
Some formulas that are typically used for spectrum

Pierson moskowitz (P-M)

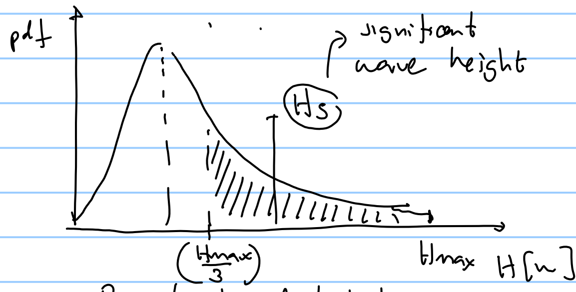
JONSWAP

for shorts periods of time (sea state) → 3hrs : there is a significant period mean period which is dominant and is usually considered constant.

the wave elevation



the wave height



Rayleigh distribution

Ts, Hs characterize a sea state

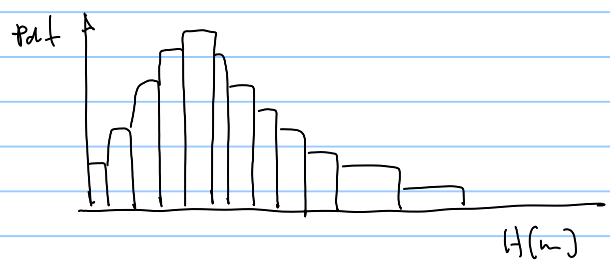
Scatter diagram of long term wave statistics Aasta Hansteen for 15 years

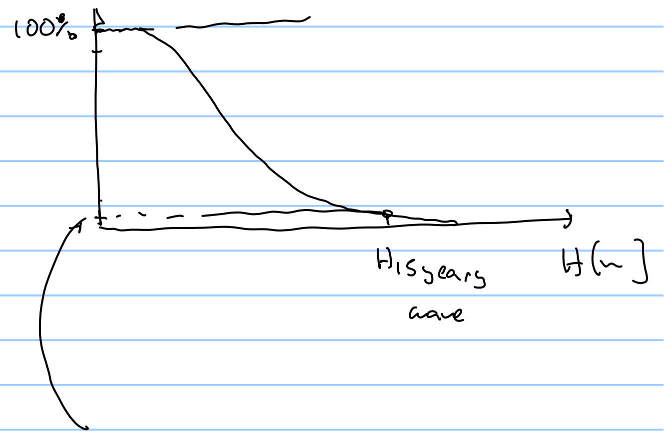
Hs [m]	Spectral Peak period (T_p) [s]																						
	0-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24	24-25	Sum
0-1	15	290	1367	2876	3716	3527	2734	1849	1138	656	362	192	101	52	26	13	7	3	2	1	0	0	0	18927
1-2	1	81	1153	5308	12083	17323	18143	15262	10980	7053	4169	2316	1229	631	315	155	75	36	17	8	4	5	1	96348
2-3	0	2	94	1050	4532	10304	15020	15953	13457	9752	5991	3403	1795	894	426	197	88	39	17	7	3	1	1	83026
3-4	0	0	2	72	686	2782	6171	8847	9189	7493	5082	2991	1577	762	345	148	61	24	9	4	1	0	0	46246
4-5	0	0	0	2	51	433	1645	3495	4807	4750	3638	2286	1229	584	251	100	37	13	5	1	0	0	0	23327
5-6	0	0	0	0	2	39	294	1037	2069	2664	2440	1709	968	463	193	72	25	8	2	1	0	0	0	11986
6-7	0	0	0	0	0	2	32	215	692	1264	1485	1228	767	382	159	57	18	5	1	0	0	0	0	6307
7-8	0	0	0	0	0	0	2	27	157	447	730	762	555	302	130	46	14	4	1	0	0	0	0	3177
8-9	0	0	0	0	0	0	0	2	23	112	276	392	355	223	104	38	11	3	1	0	0	0	0	1540
9-10	0	0	0	0	0	0	0	0	2	19	77	160	192	148	79	31	9	2	0	0	0	0	0	719
10-11	0	0	0	0	0	0	0	0	0	2	16	50	85	85	55	24	8	2	0	0	0	0	0	327
11-12	0	0	0	0	0	0	0	0	0	0	2	12	29	40	33	18	7	2	0	0	0	0	0	143
12-13	0	0	0	0	0	0	0	0	0	0	0	2	8	15	17	12	5	2	0	0	0	0	0	61
13-14	0	0	0	0	0	0	0	0	0	0	0	0	2	5	7	6	4	1	0	0	0	0	0	25
14-15	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	2	1	0	0	0	0	0	9
15-16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	4
16-17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17-18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sum	16	373	2616	9308	21070	34410	44041	46687	42514	34212	24268	15503	8892	4587	2143	921	372	146	55	22	8	6	2	292172

Design is usually made using values for longer periods. thus an extrapolation is required.

Looking at Tp ~ spectral peak period

Tp,





$H_{s\,[15\,year]} =$

15 years ~> 292000 states of (3h)

it has an associated probability of $\left(\frac{1}{292000} = 7.6E-6\right)$

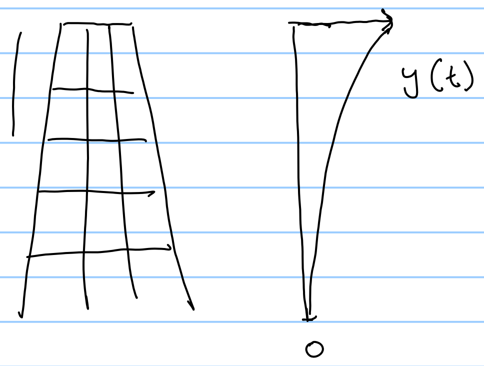
we assume that significant wave heights in different time periods follow a logarithmic equation

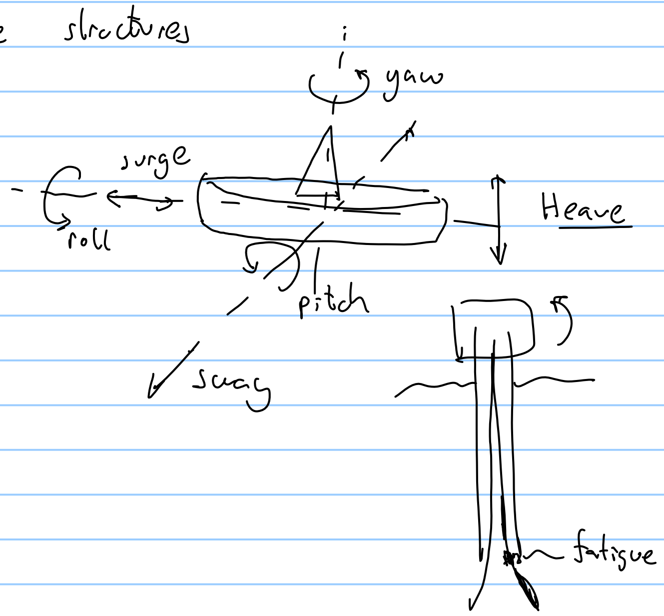
$$\log(P(H)) = \frac{1}{a} H$$

$$\log(7.6E-6) = \frac{1}{a} H_{15}$$

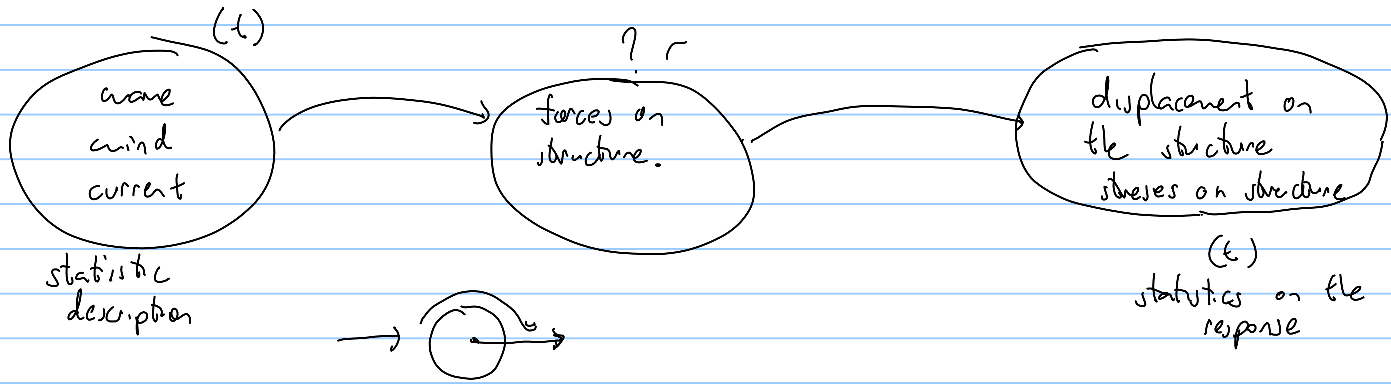
- Calculation of displacements of offshore structures

bottom supported structures





- $H_{s(100\ years)}$ is used to desig deck height



three types of analysis are usually made

- Design wave $H_{s,100}$ → with a range of periods. NORSOK N-003 suggests using

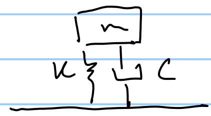
$$\sqrt{6.5\ H_{s,100}} \leq T \leq \sqrt{11 \cdot H_{s,100}}$$

$$\boxed{H_{s,100} = 1.9 \cdot H_s}$$

- short term design H_s, T_s → usually to calculate maximum loads and stresses on components. storm

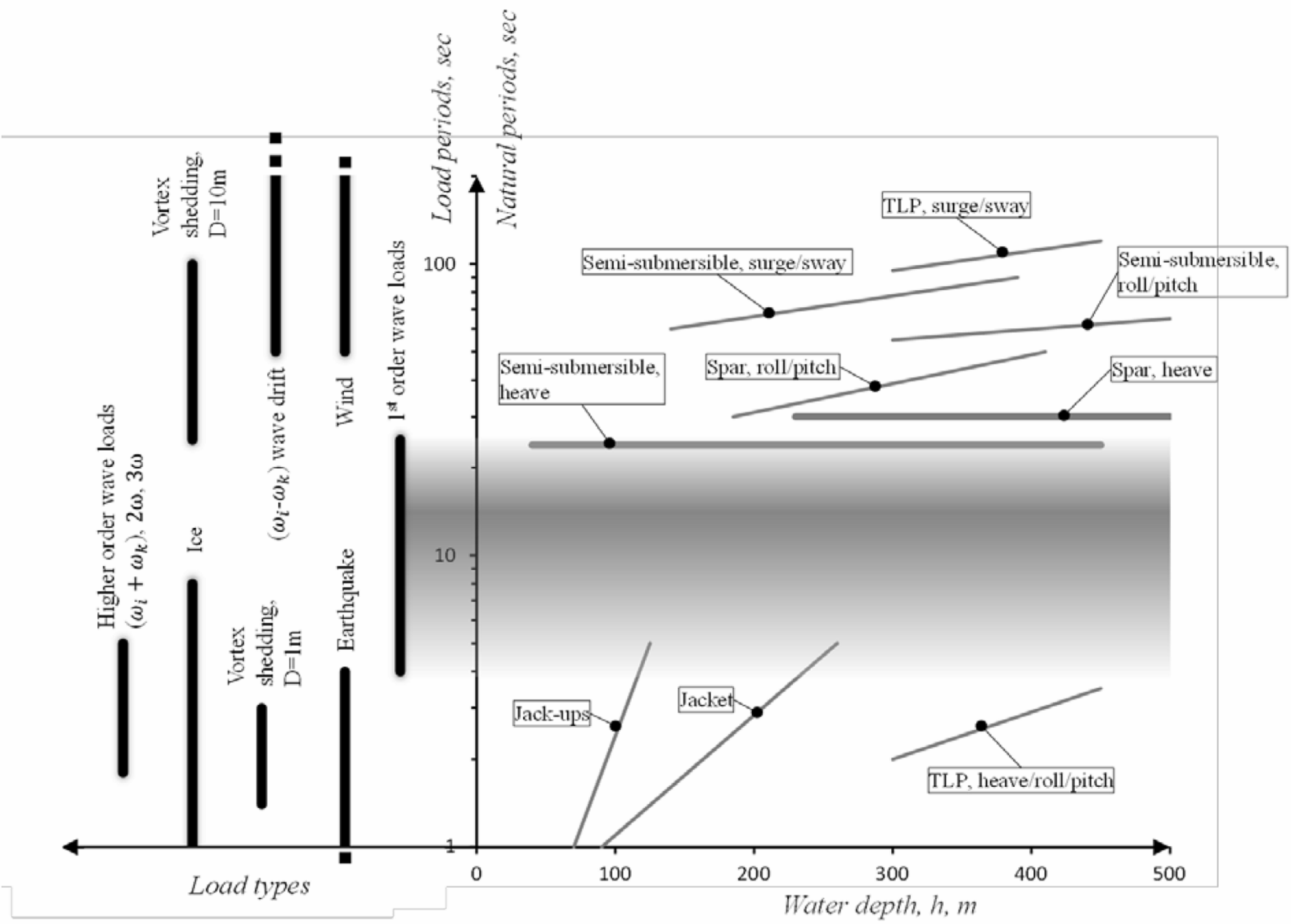
- long term desingn : varying H_s, T_s, is usually used to calculate fatigue.

Each offshore structure has a natural frequency
- flexibility of structure
- weight of structure
- damping of structure

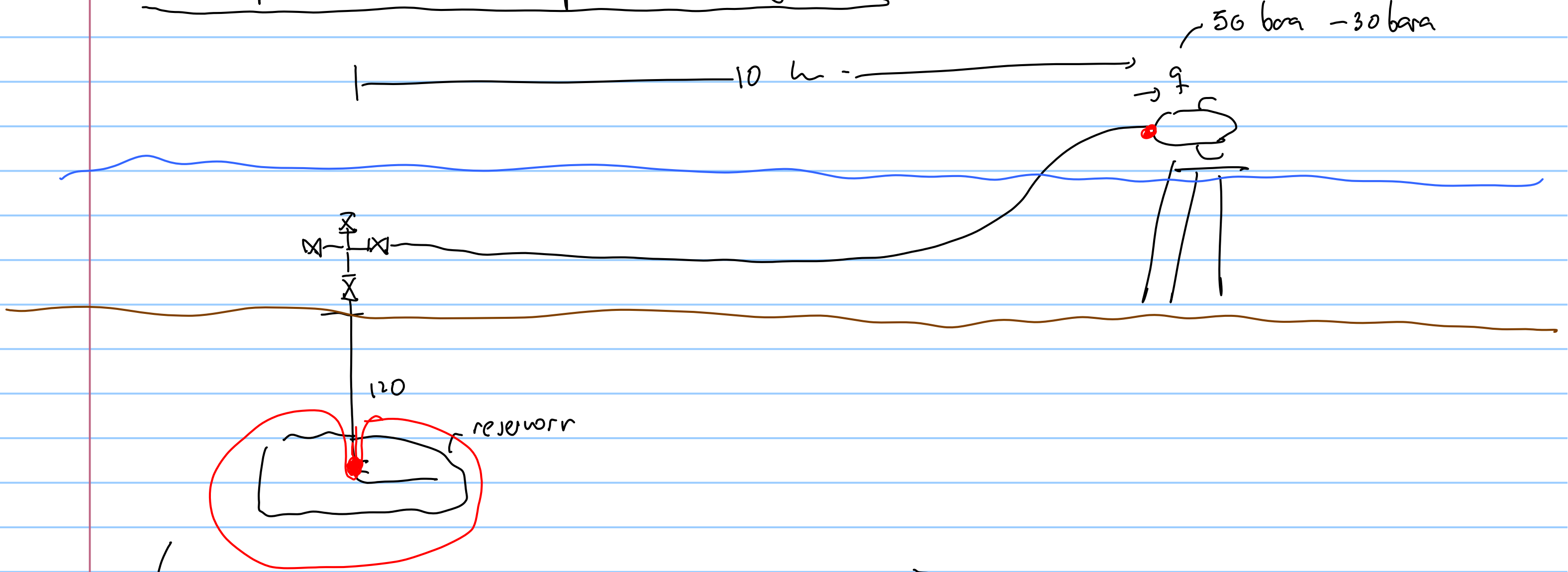


Resonance excite the structure with natural frequency and amplitudes will be big

→ stresses and loads are usually big

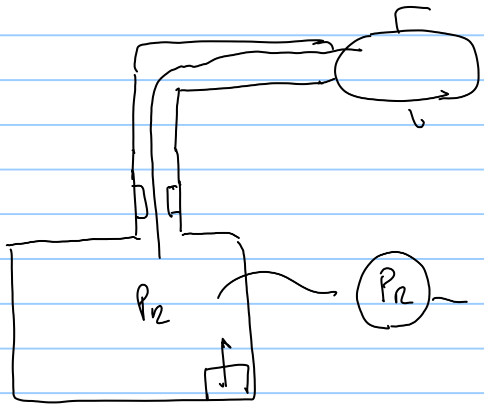


Flow performance of production system.



$q_{field}(t) = ?$ → Revenue → NPV

to compute the performance of production system we use numerical models

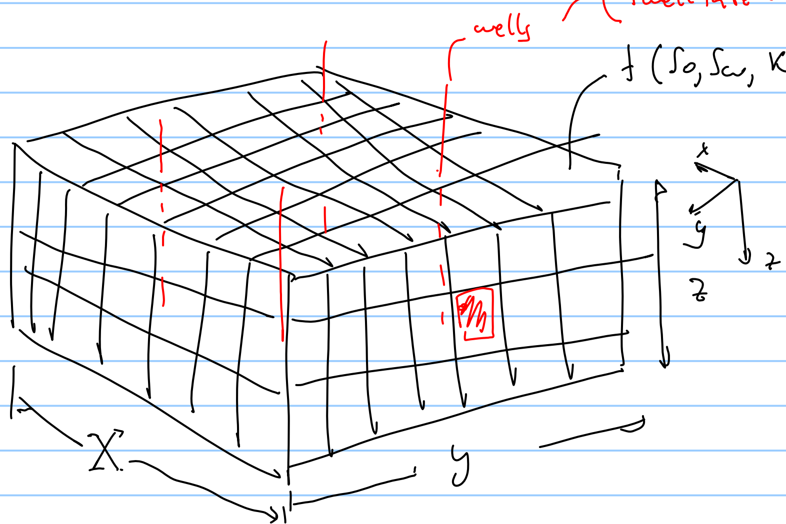


$q \propto P_R - P_{sep}$ ~ (rate effect)

P_R ~ with production (time effect)

In early phases of field development reservoir simulator is often used and the surface production system is ignored

(q_{well} rate (target), $P_{wf\,min}$)



$f(S_o, S_w, k_y, k_x, k_z, \phi, P_c)$

P_{Ri} initial reservoir pressure

fluid properties

$\mu = f(P,T)$

$\rho = f(P,T)$

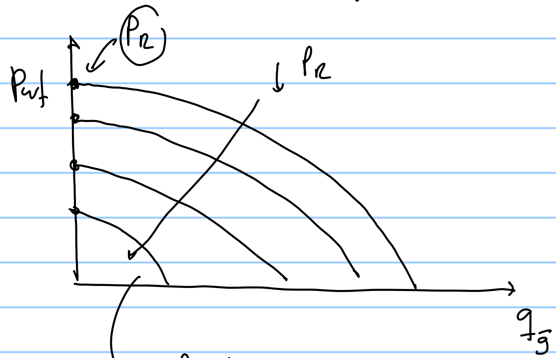
$q = \frac{k}{\mu}\frac{\partial P}{\partial r}$

Result of reservoir simulator is $P_{wf}^i(t)$

$q_w^i(t)$

Snøhvit. dry gas example. Proxy → surrogate of a reservoir model

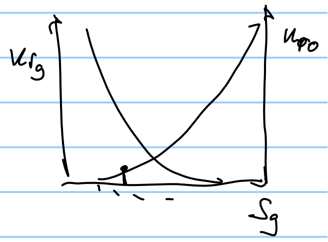
- material balance →
- productivity of well IPR
  inflow performance relationship



Backpressure equation

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

C_R ← K, μ, S



material balance

$$\frac{P_R}{Z_R} = \frac{P_i}{Z_i}\left(1 - \frac{G_p}{G}\right) \qquad G_p = \int_0^t q_g\,dt$$

$\frac{G_p}{G}$ → R_F

G → initial gas in place

P_i → intial reservoir pressure

Z_i → initial deviation factor

Z_R → deviation factor @ current P_R

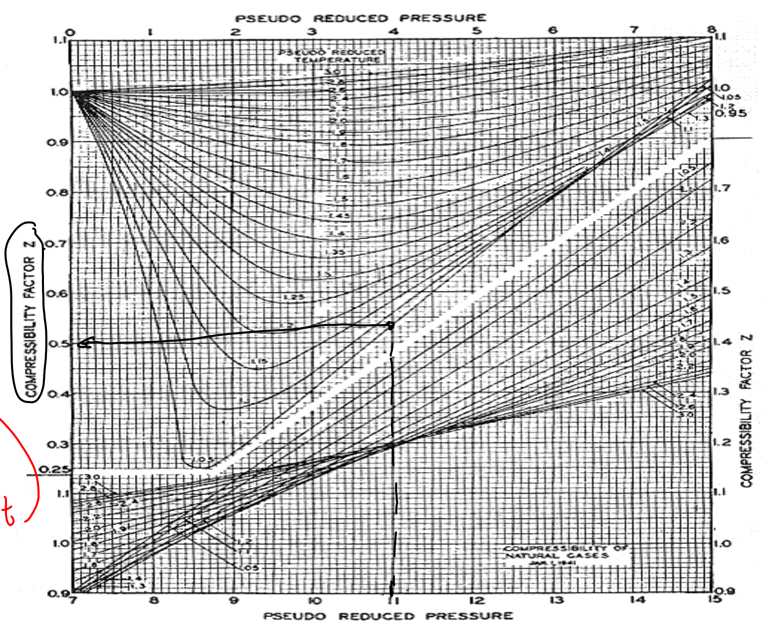
https://www.youtube.com/watch?v=ssmJrENliwg&list=PLgktb39S1tGcix-up7-23QyYhNeUuhMX0&index=1

provide $P_i, Z_i, \overbrace{G_p, G}^{R_F}$

$$Z = f\left(\frac{P}{P_c}, \frac{T}{T_c}\right)?$$

$$P_c, T_c = f(\gamma_g)$$

implicit equation
- assume P_R, calculate Z
- calculate P_R from MB
- check if $P_{Rcalc} = P_{Rassum}$. if not



http://folk.ntnu.no/stanko/Courses/TPG4230/2017/Class_files/20170214/

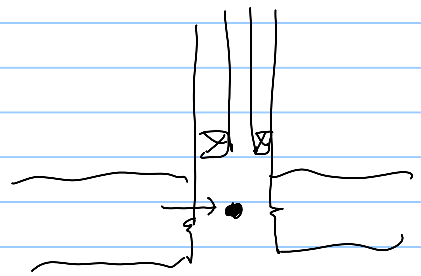
Anual offtake for gas $\underbrace{(2\text{-}3\%)(G)}$

20E6 Sm³/d ~

Atila East gas Field (Base Case Data)									
G=IGIP	270E+09	Sm3							
T_R	92	oC							
Pi, initial Res pressure	276	bara							
C, inflow Back pressure coefficient	1000	Sm3/bar^2n							
n, backpressure, exponent	1								
Gas molecular weight (Methane)	16	kg/kmole							
Gas specific gravity	0.55	Gas specific gravity							
Number of wells	4								
pwfmin	120	[bara]							
qfield_target	2.00E+07	[Sm^3/d]							
	time	qwell_pot	qfield_pot	qfield	ΔGp	Gp	Z	RF	PR
	[years]	[Sm^3/d]	[Sm^3/d]	[Sm^3/d]	[Sm^3]	[Sm^3]	[-]	[-]	[bara]
	0				0.00E+00		0.9672446		276
	1								
	2								
	3								
	4								
	5								
	6								
	7								
	8								
	9								
	10								

the end of the year

Calculating well potential by applying the provided $p_{wf\,min}$ in the sand phase



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

$q_{g\,pot}$ = maximum rate that the well can produce

$q_{g\,pot} > q_{g\,target}$ the target rate provided is feasible ☺ !!

$q_{g\,pot} < q_{g\,target}$ i canot produce the target rate provided !! ☹

Predicting production profile of Snohvit field - Reservoir simulator proxy - Milan Stanko, 20170214

Snohvit gas Field

G=IGIP	270E+09	Sm3
T_R	92	oC
Pi, initial Res pressure	276	bara
C, inflow Back pressure coefficient	1000	Sm3/bar^2n
n, backpressure, exponent	1	
Gas molecular weight (Methane)	16	kg/kmole
Gas specific gravity	0.55	Gas specific gravity
Number of wells	4	
pwfmin	120	**[bara]**
qfield_target	2.00E+07	**[Sm^3/d]**

time [years]	qwell_pot [Sm^3/d]	qfield_pot [Sm^3/d]	qfield [Sm^3/d]	pwf [bara]	ΔGp [Sm^3]	Gp [Sm^3]	Z [-]	RF [-]	PR [bara]
0	61776000	2.47E+08	2.00E+07	267	0.00E+00	0.00E+00	0.9672446	000.0E+0	276
1	58113872.7	2.32E+08	2.00E+07	260	6.57E+09	6.57E+09	0.9672446	24.3E-3	269
2	53941551.6	2.16E+08	2.00E+07	252	6.57E+09	1.31E+10	0.9630236	48.7E-3	261
3	49857914.9	1.99E+08	2.00E+07	243	6.57E+09	1.97E+10	0.9583206	73.0E-3	253
4	45961532.4	1.84E+08	2.00E+07	235	6.57E+09	2.63E+10	0.9538497	97.3E-3	246
5	42258575.5	1.69E+08	2.00E+07	227	6.57E+09	3.29E+10	0.9497312	121.7E-3	238
6	38740056.4	1.55E+08	2.00E+07	219	6.57E+09	3.94E+10	0.9459766	146.0E-3	231
7	35395346.7	1.42E+08	2.00E+07	212	6.57E+09	4.60E+10	0.9425795	170.3E-3	223
8	32214305.9	1.29E+08	2.00E+07	204	6.57E+09	5.26E+10	0.9395311	194.7E-3	216
9	29187545.5	1.17E+08	2.00E+07	196	6.57E+09	5.91E+10	0.9368227	219.0E-3	209
10	26306418.5	1.05E+08	2.00E+07	189	6.57E+09	6.57E+10	0.9344457	243.3E-3	202
11	23562975	9.43E+07	2.00E+07	182	6.57E+09	7.23E+10	0.932392	267.7E-3	195
12	20949917.2	8.38E+07	2.00E+07	174	6.57E+09	7.88E+10	0.9306539	292.0E-3	188
13	18460558.4	7.38E+07	2.00E+07	167	6.57E+09	8.54E+10	0.9292238	316.3E-3	181
14	16088783.8	6.44E+07	2.00E+07	160	6.57E+09	9.20E+10	0.9280946	340.7E-3	175
15	13829016.2	5.53E+07	2.00E+07	152	6.57E+09	9.86E+10	0.9272597	365.0E-3	168
16	11676183.7	4.67E+07	2.00E+07	145	6.57E+09	1.05E+11	0.9267125	389.3E-3	161
17	9625689.72	3.85E+07	2.00E+07	138	6.57E+09	1.12E+11	0.926447	413.7E-3	155
18	7673386.72	3.07E+07	2.00E+07	131	6.57E+09	1.18E+11	0.9264573	438.0E-3	149
19	5815551.3	2.33E+07	2.00E+07	123	6.57E+09	1.25E+11	0.9267379	462.3E-3	142
20	4048861.89	1.62E+07	1.62E+07	120	6.57E+09	1.31E+11	0.9272836	486.7E-3	136
21	2689377.84	1.08E+07	1.08E+07	120	5.32E+09	1.37E+11	0.9280894	506.4E-3	131
22	1824335.63	7.30E+06	7.30E+06	120	3.53E+09	1.40E+11	0.928925	519.5E-3	127
23	1251902.59	5.01E+06	5.01E+06	120	2.40E+09	1.43E+11	0.9295651	528.3E-3	125
24	865700.421	3.46E+06	3.46E+06	120	1.65E+09	1.44E+11	0.9300388	534.4E-3	124
25	601733.801	2.41E+06	2.41E+06	120	1.14E+09	1.45E+11	0.9303821	538.6E-3	122

In this time, potential rate is smaller than the target rate. The mode changes to constant bottomhole pressure

MIN =IF(D16>=B12,B12,D16)

	A	B	C	D	E	F	G	H	I	J	K
1	Predicting production profile of Snohvit field - Reservoir simulator proxy - Milan Stanko, 20170214										
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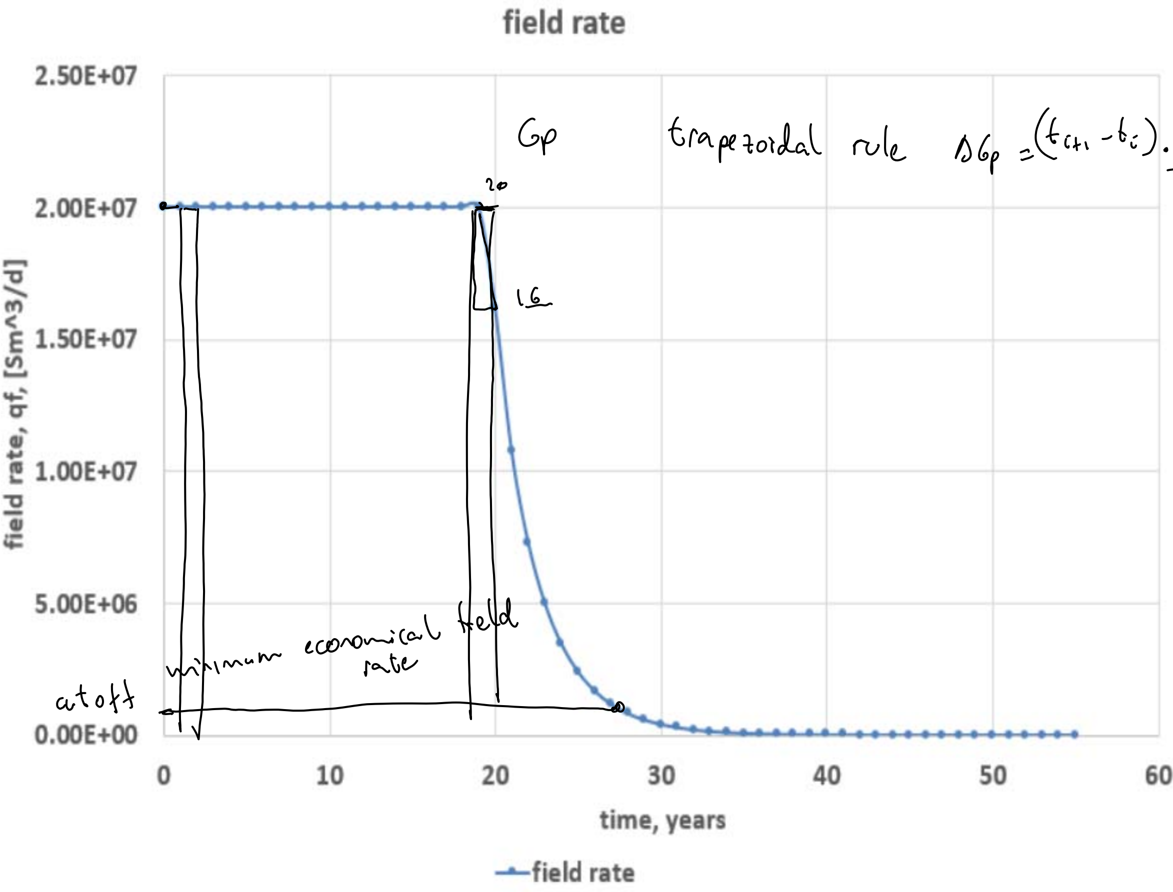
8	Gas molecular weight (Methane)	16	kg/kmole								
9	Gas specific gravity	0.55	Gas specific gravity								
10	Number of wells	4									
11	**pwfmin**	120	**[bara]**								
12	**qfield_target**	2.00E+07	**[Sm^3/d]**								
13											
14		time	qwell_pot	qfield_pot	qfield	pwf	ΔGp	Gp	Z	RF	PR
15		[years]	[Sm^3/d]	[Sm^3/d]	[Sm^3/d]	[bara]	[Sm^3]	[Sm^3]	[-]	[-]	[bara]
16		0	61776000	2.47E+08	=IF(D16>=$	267	0.00E+00	0.00E+00	0.9672446	000.0E+0	276
17		1	58113872.7	2.32E+08	2.00E+07	260	6.57E+09	6.57E+09	0.9672446	24.3E-3	269
18		2	53941551.6	2.16E+08	2.00E+07	252	6.57E+09	1.31E+10	0.9630236	48.7E-3	261
19		3	49857914.9	1.99E+08	2.00E+07	243	6.57E+09	1.97E+10	0.9583206	73.0E-3	253
20		4	45961532.4	1.84E+08	2.00E+07	235	6.57E+09	2.63E+10	0.9538497	97.3E-3	246



$$\Delta G_p = (t_{i+1} - t_i) \cdot \frac{(q_{i+1} + q_i)}{2}$$

Note Title 12.01.2017

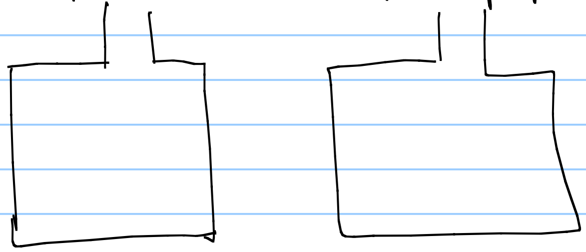
How do we predict reservoir performance

RF
q_o, q_g, q_w vs time
P_{wf} flowing bottomhole pressures
for each well

- material balance

tank approach with uniform properties

P
T
S_o, S_w, S_g
K
ϕ



n_{g_i} $n_{g_{i+1}}$

$$n_{g_{i+1}} - n_{g_i} = \Delta n$$

FDM

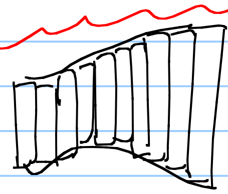
$\vdash \Delta x \rightarrow$

P_i P_{i+1}

$$\frac{\partial p}{\partial x} = \frac{P_{i+1} - P_i}{\Delta x}$$

- Reservoir simulator

domain reservoir $\xrightarrow{\text{discretize}}$ Grid



Set of differential equations
- flow in porous media
- fluid behavior

Finite difference method FDM
numerical approximation →

Set of algebraic equations → applied

System of algebraic equations

initial conditions
P, S_o,

boundary conditions →

customized set of algebraic equations

$$[A] \cdot \{\vec{X}\} = \vec{B}$$

→ iterative scheme for solving it in time

results

q, P, S_o, S_w, S_o

Advantages : - more realistic, can capture the heterogeneities of the field
(-) take longer computation time
(-) Requires large input ~ in early phase we need to extrapolate or assume

water:

$$\nabla \circ [\frac{[k]k_{rw}}{\mu_w B_w}(\nabla p_w - \gamma_w \nabla d)] + Q_w = \frac{\partial}{\partial t}(\phi \frac{S_w}{B_w})$$

oil:

$$\nabla \circ [\frac{[k]k_{ro}}{\mu_o B_o}(\nabla p_o - \gamma_o \nabla d)] + Q_o = \frac{\partial}{\partial t}(\phi \frac{S_o}{B_o})$$

gas :

$$\nabla \circ [\frac{[k]k_{rg}}{\mu_g B_g}(\nabla p_g - \gamma_g \nabla d)] + \nabla \circ [\frac{[k]k_{ro}}{\mu_o B_o} R_s(\nabla p_o - \gamma_o \nabla d)] + Q_g$$

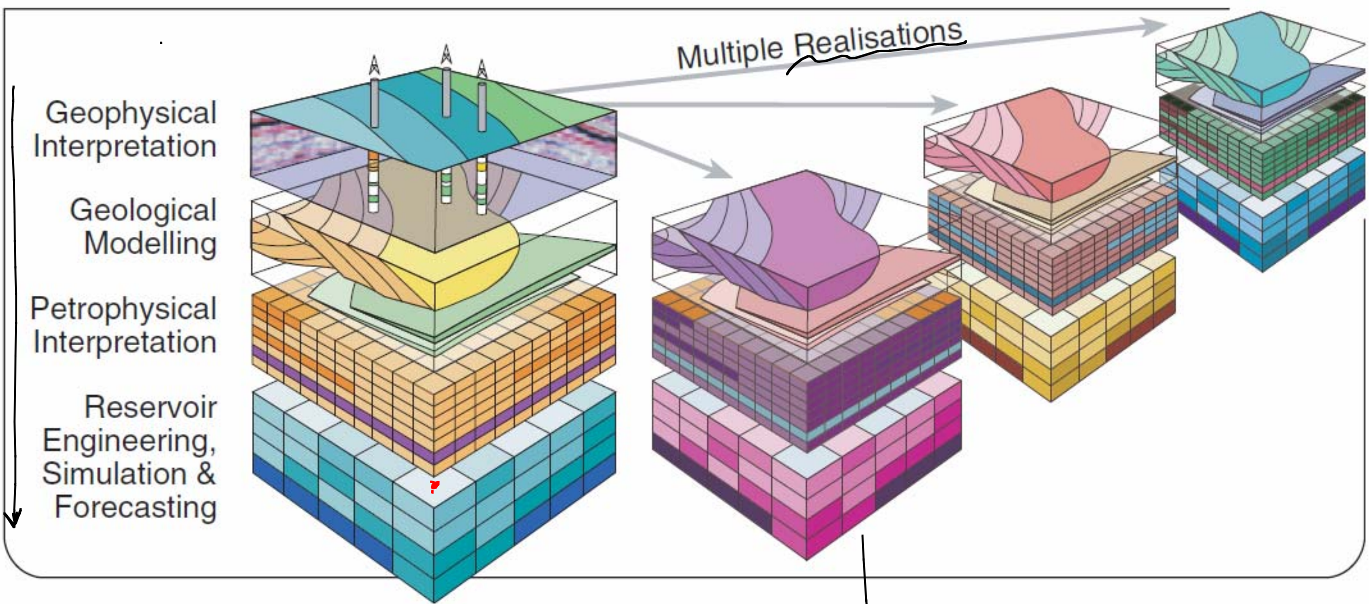
$$= \frac{\partial}{\partial t}(\phi \frac{S_g}{B_g} + \phi \frac{S_o R_s}{B_o})$$

water:

$$\Delta_y T_{wy} \Delta_y \Psi_w = (\frac{k_y k_{rw}}{\mu_w B_w \Delta y})_{j+1/2} \Delta x_i \Delta z_k (\Psi_{w,j+1} - \Psi_{w,j})$$
$$-(\frac{k_y k_{rw}}{\mu_w B_w \Delta y})_{j-1/2} \Delta x_i \Delta z_k (\Psi_{w,j} - \Psi_{w,j-1})$$

- there is a high uncertainty in the subsurface

workflow to create res model.



TRR $q_o(t)$
RF

- there are 3 ways to address uncertainty in the creation of the subsurface model

  - Define a base case ~ the most likely realization
    run sensitivity analysis on that case.

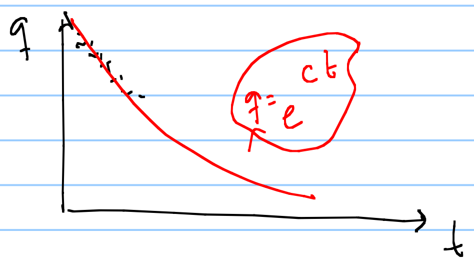
- define a limited number of cases (4-5) - assign a probability to each case. ask expert $$

  ↳ run sensitivity analysis on each one of the realizations

- built a stochastic model and compute the most likely outcome using Monte-Carlo, latin Hypercube sampling.

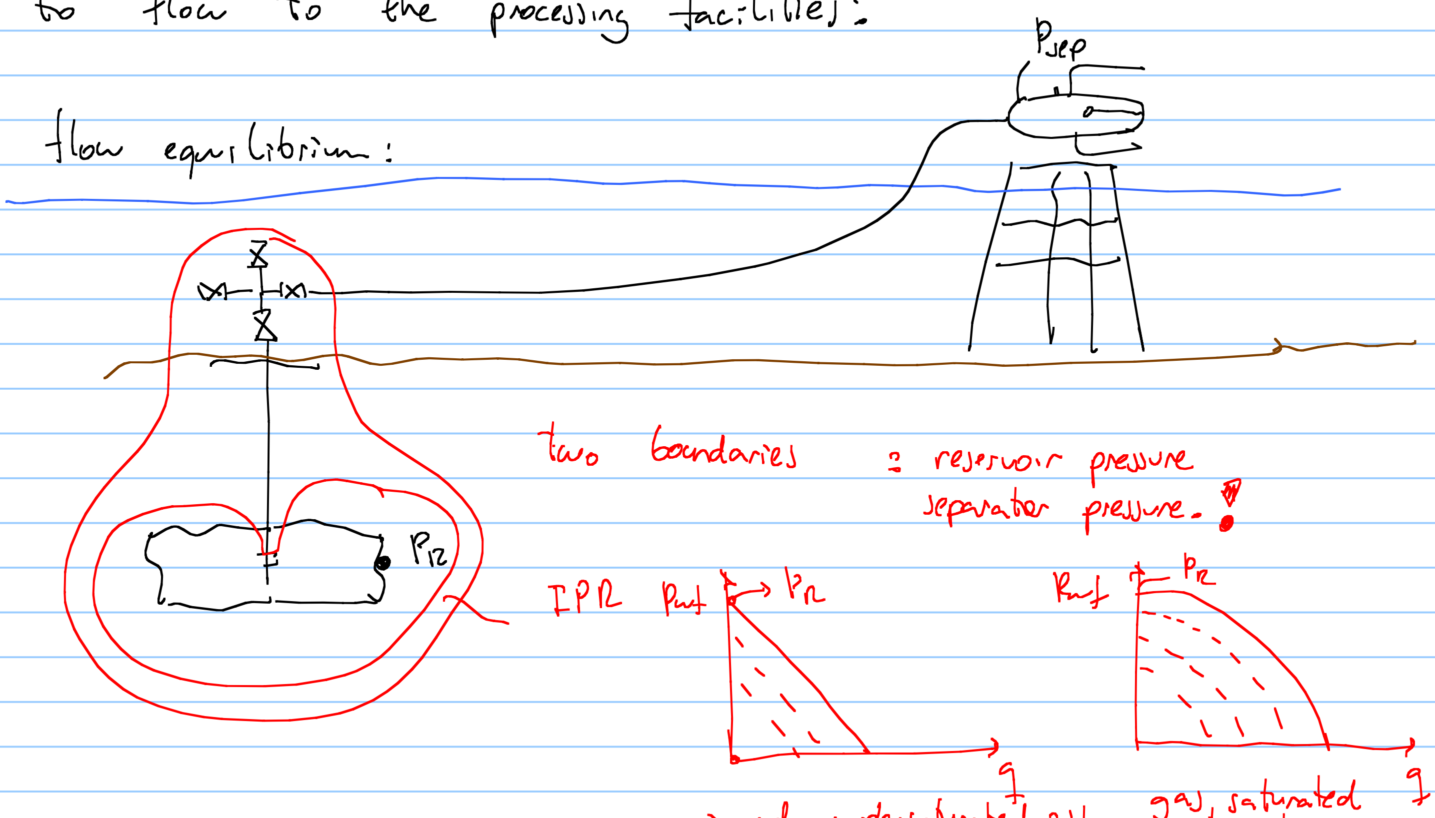
  ↳ very computationally expensive process due to the high number of cells and variables per cell.

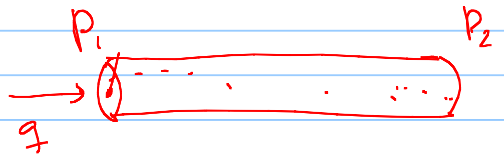
- decline curve analysys (DCA) { material balance equation + IPR equation + empirical information



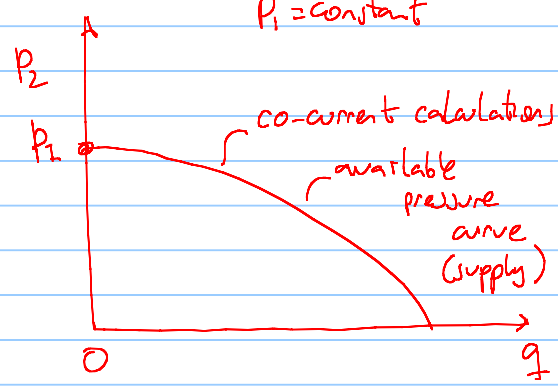
How to capture properly the pressure required at the bottom hole to flow to the processing facilities?

flow equilibrium:



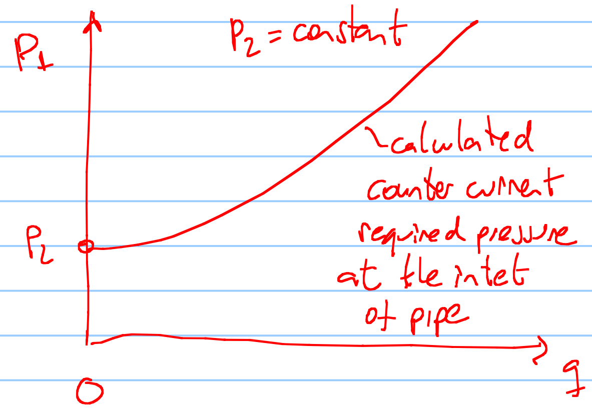


$$\Delta p = \underbrace{\Delta p\big|_{friction}}_{f(q)} + \cancel{\Delta p\big|_{gravity}}^{\,0}$$



① Available pressure at the exit of the pipe

provide $p_1, q \rightsquigarrow$ calculate p_2



② Required pressure at the inlet of the pipe

provide $p_2, q \rightsquigarrow$ calculate p_1

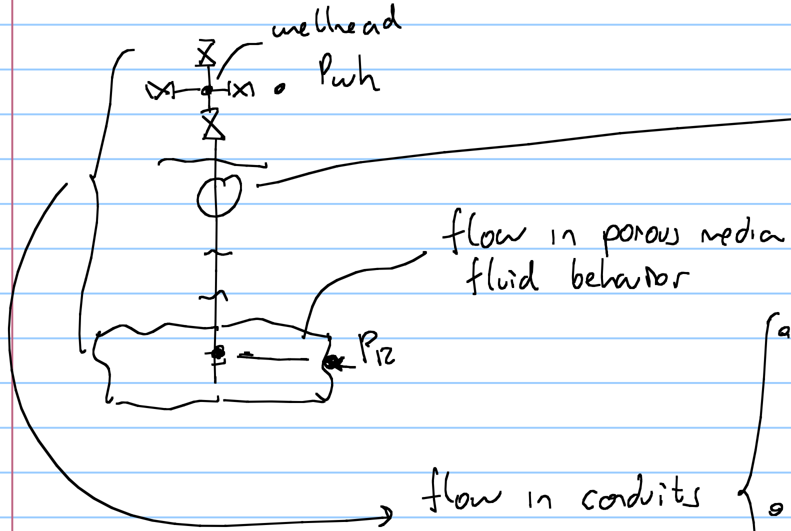
$$p_1 - p_2 = \Delta p$$

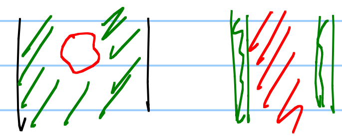
$$p_1 = p_2 + \Delta p$$

③ Calculate rate

provide $p_1, p_2 \rightsquigarrow$ calculate q

I can use available and required pressure curves to characterize complex parts of the production system

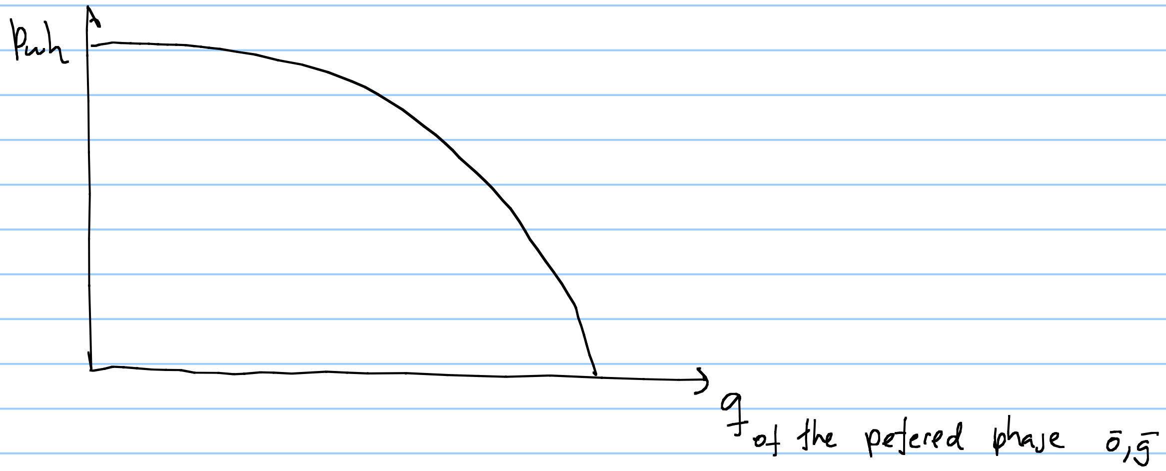




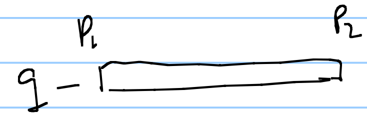
- pressure drop model $\begin{cases} \text{single} \\ \text{multiphase} \end{cases}$

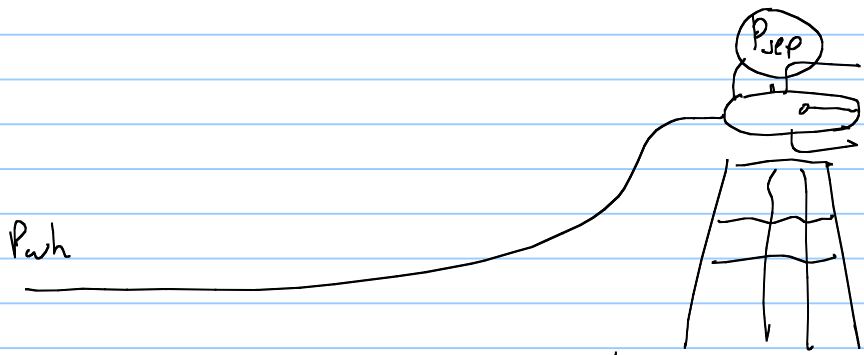
  $\Delta p = \Delta p\big|_{friction} + \Delta p\big|_{gravity}$

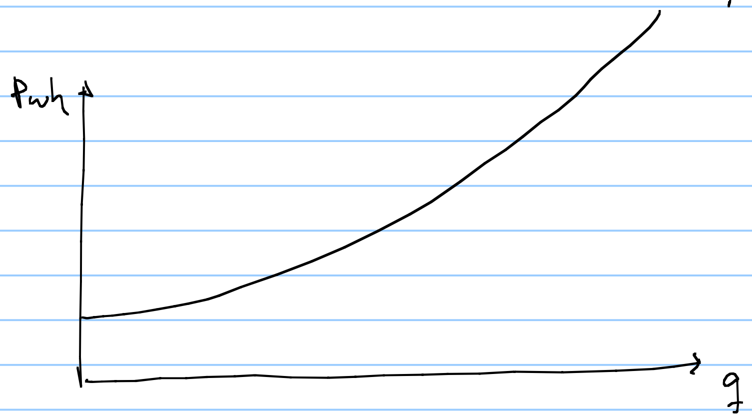
- temperature drop model
- fluid model ~ fluid properties change with pressure and temperature



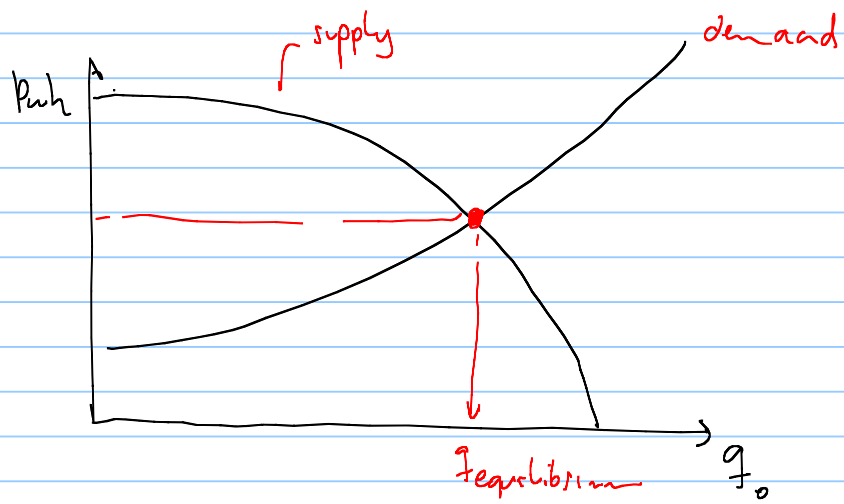
looking at the rest of the system







the only feasible operating rate is the intersection of both curves



one example with dry gas

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

tubing =

remember pressure drop depends on the velocity. $\frac{q_{local}}{A}$

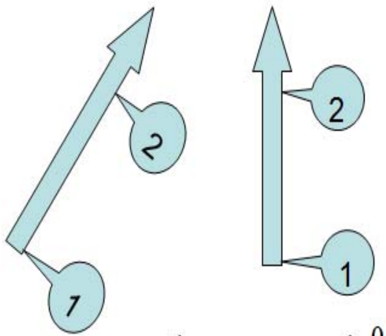
but we need equations in term of surface rates. so we need a conversion factor between local rate and surface rates B_g

Tubing flow Equation-Dry gas

$$\boxed{q_{sc} = \left(\frac{\pi}{4}\right)\left(\frac{R}{M_{air}}\right)^{0.5}\left(\frac{T_{SC}}{P_{SC}}\right)\left[\frac{D^5}{\gamma_g f_M Z_{av} T_{av} L}\right]^{0.5}\left(\frac{se^S}{e^S - 1}\right)^{0.5}\left(\frac{p_1^2}{e^S} - p_2^2\right)^{0.5}}$$

$$\boxed{\frac{s}{2} = \frac{M_g g}{Z_{av} R T_{av}} H = \frac{(28.97)\gamma_g g}{Z_{av} R T_{av}} H}$$

$$\boxed{q_{gsc} = C_T\left(\frac{p_1^2}{e^s} - p_2^2\right)^{0.5}}$$



$$p_{inlet} = p_1 = e^{s/2}\left(p_2^2 + \frac{q_g^2}{C_T^2}\right)^{0.5} \qquad p_{wh} = p_2 = \left(\frac{p_1^2}{e^s} - \frac{q_g^2}{C_T^2}\right)^{0.5}$$

tubing equation $q_{\bar{g}} = C_T\left(\frac{p_1^2}{e^s} - p_2^2\right)^{0.5}$

for dry gas, horizontal line

$$q_{\bar{g}} = C_{FL}\left(P_1^2 - P_2^2\right)^{0.5}$$

let's find mathematically the equilibrium rate

Known
blue

$q_{\bar{g}}^{?} = C^{✓}\left(P_R^{2\,✓} - P_{wf}^{2\,?}\right)^{n\,✓}$

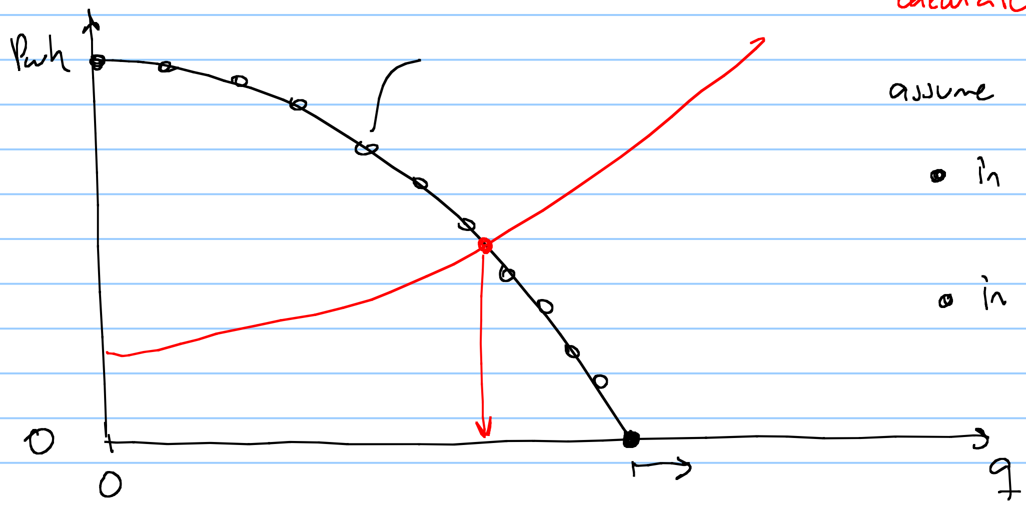
1 eq, 2 unknowns.

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

2equ, 3 unknowns

$q_{\bar{g}}^{?} = C_{FL}^{✓}\left(P_{wh}^{2\,?} - P_{sep}^{2\,✓}\right)^{0.5}$

3eq. 3unknowns



calculate available pressure curve

assume $q_{\bar{g}}$ in the range $(0 \rightarrow q_{\bar{g}}^*)$

- in IPR eq. calculate P_{wf}
- in tubing equation calculate P_{wh}

repeat for other rates

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

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

calculate the required pressure curve

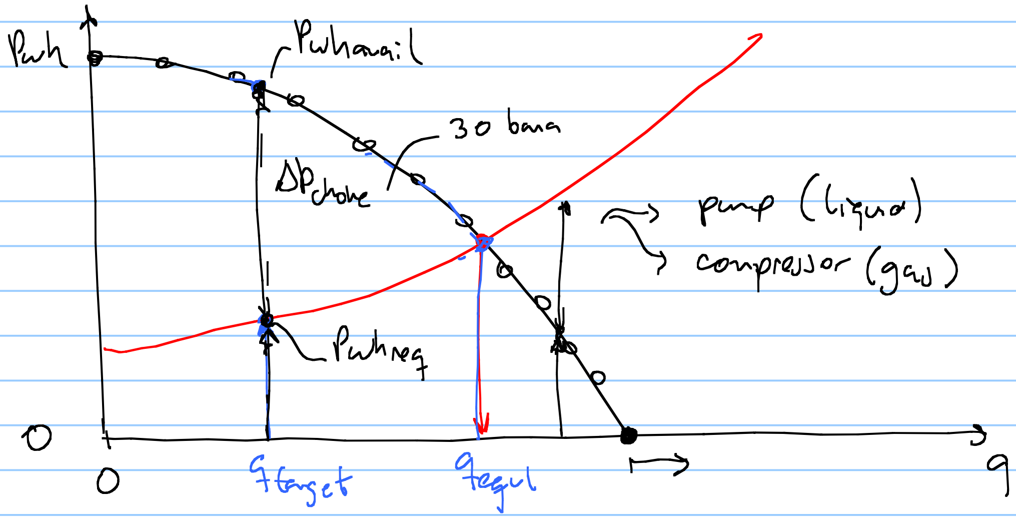
assume $q_{\bar{g}}$ $(0 \rightarrow q_{\bar{g}}^*)$

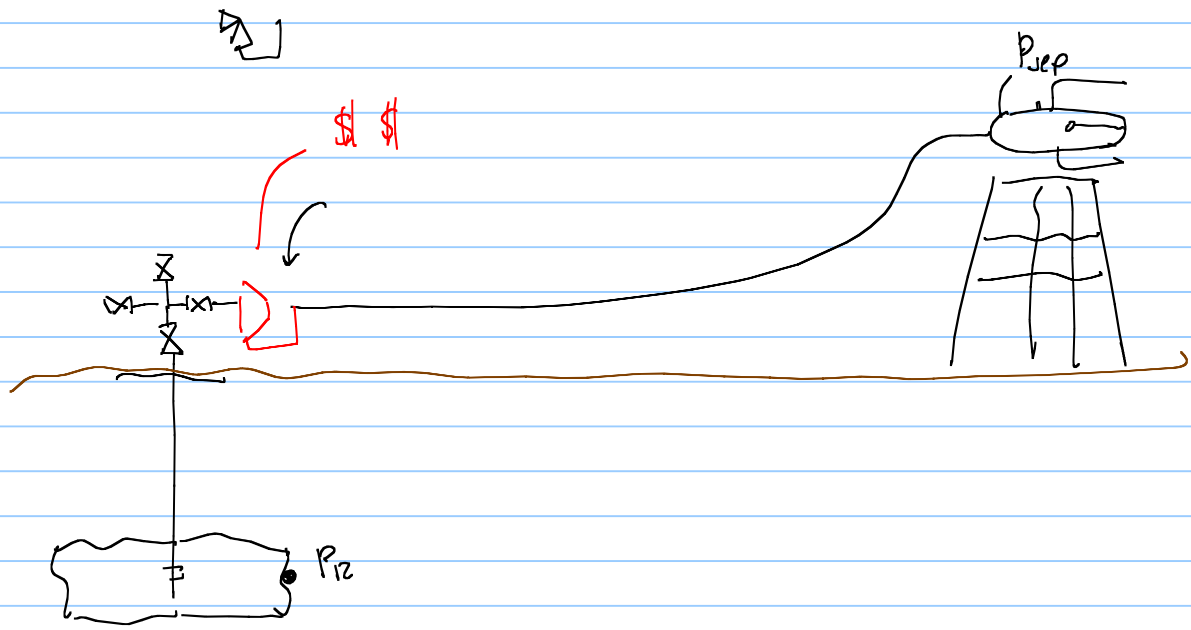
use flowline equation

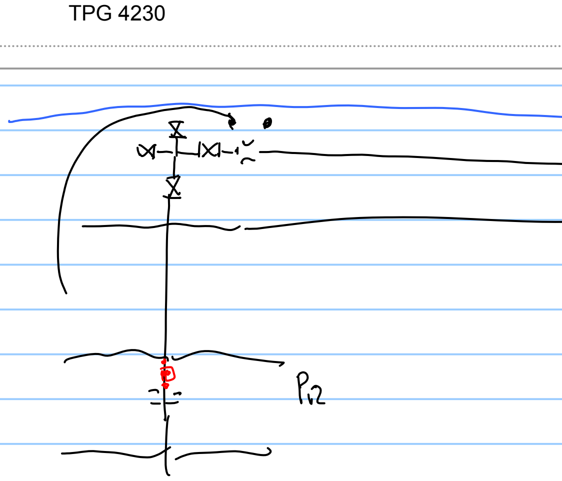
$$q_{\bar{g}} = C_{FL} \left(P_{wh}^2 - P_{sep}^2 \right)^{0.5}$$

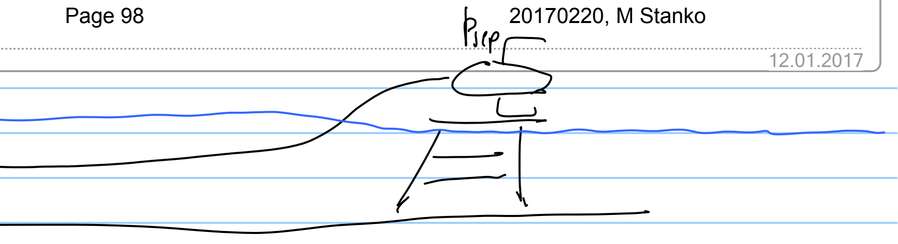
$$P_{wh} = \sqrt{P_{sep}^2 + \left(\frac{q}{C_{FL}} \right)^2}$$

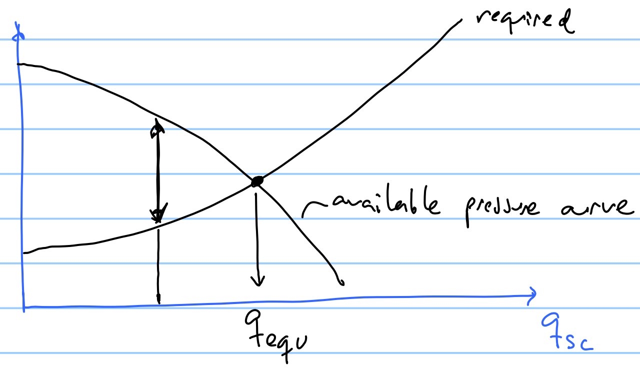
			IPR	TPR (tubing performance relationship)		Flowline PR	
time	P_R	$q_{\bar{g}}$ assume ($0 \rightarrow q_s$)	P_{wf}	$P_{wh\,avail}$	P_{sep}	$P_{wh\,req}$	Error ($P_{wh\,avail} - P_{wh\,req}$)


Pwh
Pwhavail
30 bara
ΔPchoke
pump (liquid)
compressor (gas)
Pwhreq
0
0
qtarget
qequil
q

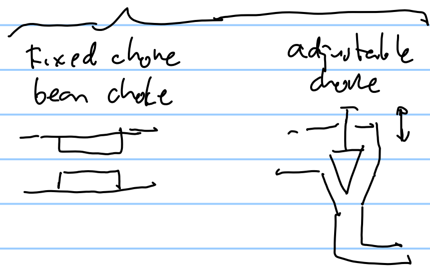

$ $
Psep
PR





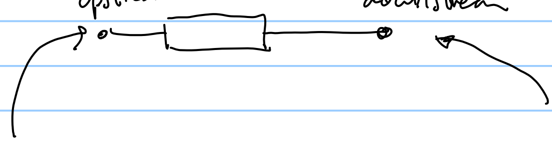


when we have adjustable elements in my production system:
choke, pump (the rotational speed can be changed)
gas lift the gas lift injection rate can be changed:



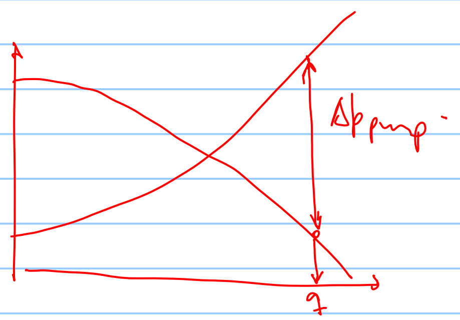
there are two ways to calculate equilibrium

1: Removing the component from the system and applying equilibrium exactly at that location



is useful for design. (when a new component will be acquired or replaced)
when the numerical model is not available or is very uncertain and complex
e.g. multiphase boosters
multiphase chokes

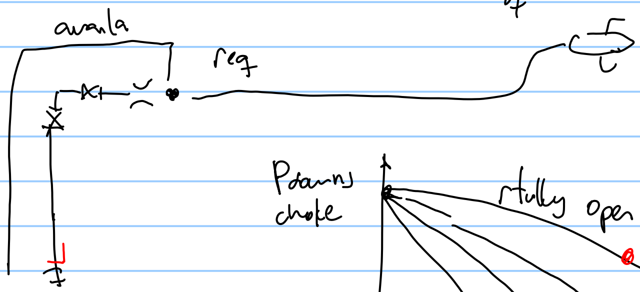
ESP design

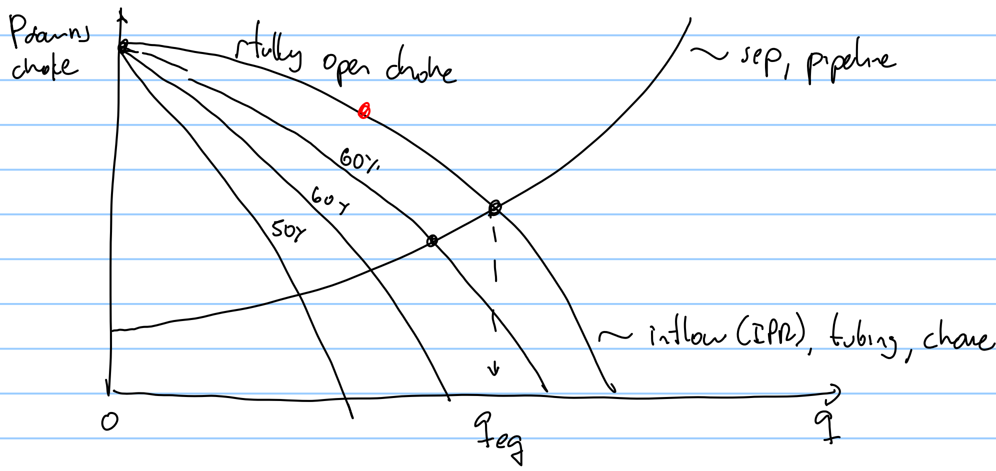


the desired rate and Δp have to be verified against the equipment afterwards

ESP power
300 Hp → 2000 Hp

2: Including the component in the available or required pressure curves





if a particular model is available and an equation is also available

ESP ~ $\Delta p = a(f)\, q_{act}^2 + b(f)\, q_{act} + c(f)$

choke $\Delta p = d \cdot q_{act}^2$

actual local volume rates at p, T at inlet of the components

commercial software use this mode
Pipesim, gap, prosper, Reo, pipephase

solving for a desired rate

$$q_{sc} = c_d A_2 p_1 \left(\frac{T_{sc}}{p_{sc}}\right) \sqrt{2 \frac{R}{M_g Z_1 T_1}} \sqrt{\left(\frac{k}{k-1}\right)\left[\left(\frac{p_2}{p_1}\right)^{\frac{2}{k}} - \left(\frac{p_2}{p_1}\right)^{\frac{k+1}{k}}\right]}$$

for a dry gas well with a choke.

assume an opening.
calcula the intersection ~ q^*
check if $q^* = q_{desired}$?
if yes → finish
if not

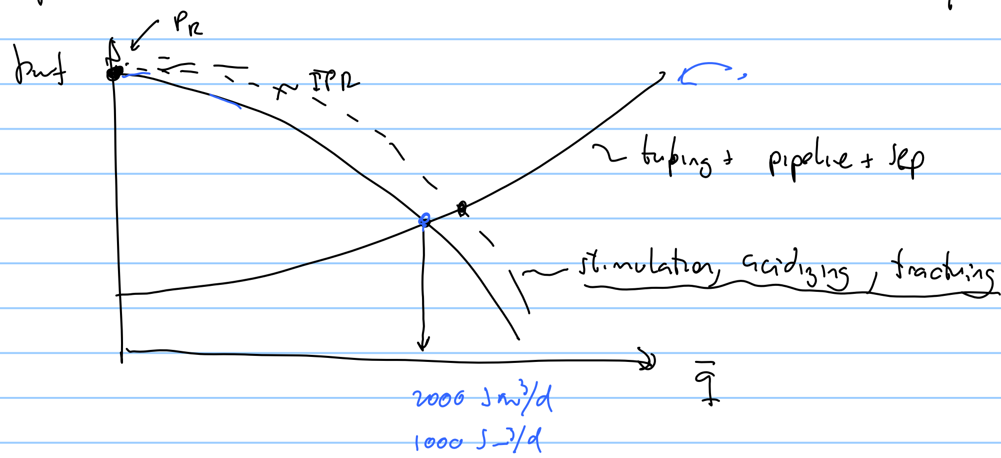
— newton method

wrongly called optimization in comercial software

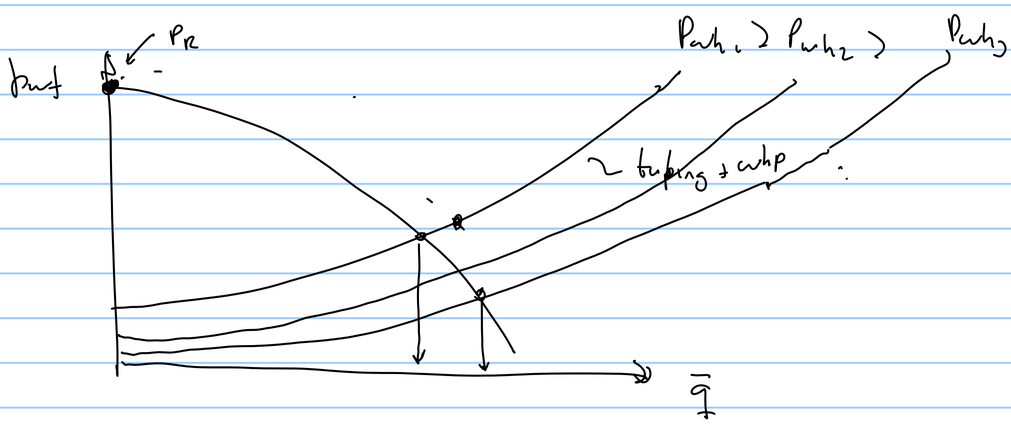
(−) the component model is usually highly non-linear

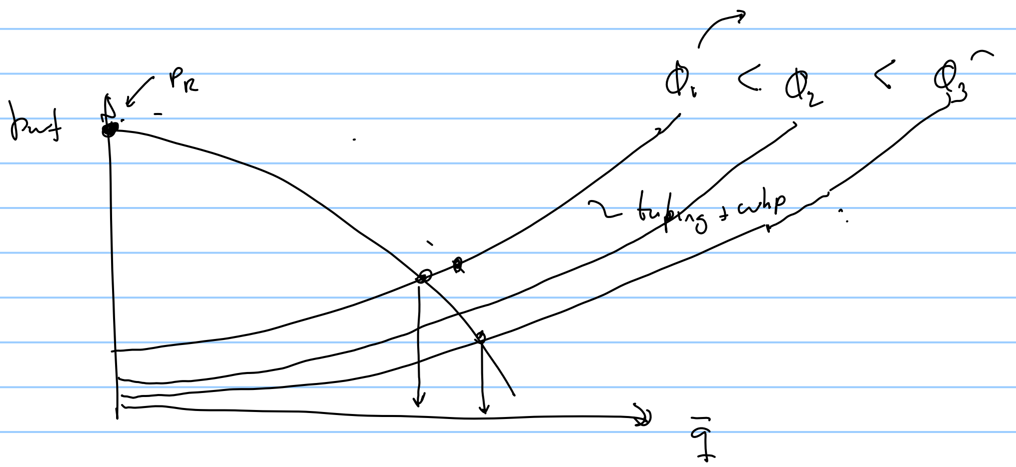
(−) takes more time to evaluate

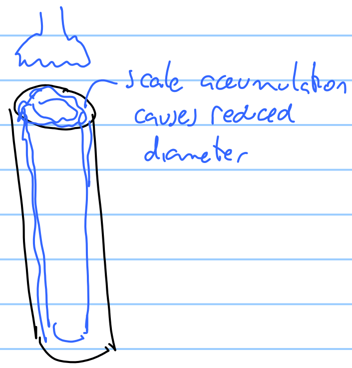
- the operator (engineer) can affect the available and required pressure curves



$$q = C(P_R^2 - P_{wf})^n$$







Equilibrium analysis can be performed for diagnosis!

During the field design process

① Reservoir engineers use reservoir simulator with $P_{wf,min}$, target rate

Repeat simulation find optimum N_{well}, RF, max NPV

define for each well $(q(t))$

back and forth communication

when the production layout is defined!

② Production engineers: is that rate feasible?

the rate is not feasible!

the rate is feasible :)

Reservoir simulator + production simulator

coupling

- what happens when we have multiphase flow? simultaneous flow of gas, oil and water in parts of the production system

IPR

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

$q_{\bar{w}} = q_L \cdot wc = (q_{\bar{o}} + q_{\bar{w}})\, wc$

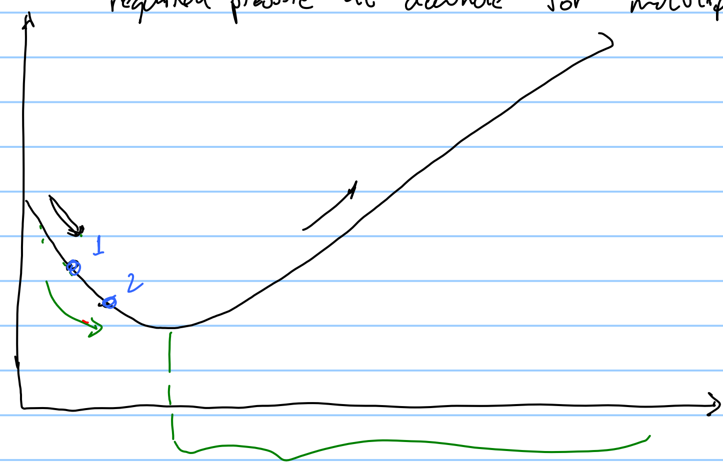
$q_{\bar{w}} = \dfrac{q_{\bar{o}}\, wc}{(1-wc)}$ wc is a fraction $(0-1)$

what happens with the flow in conduits?

Ole Jørgen Mydal

required pressure at downhole for multiphase flow

P_{wf}

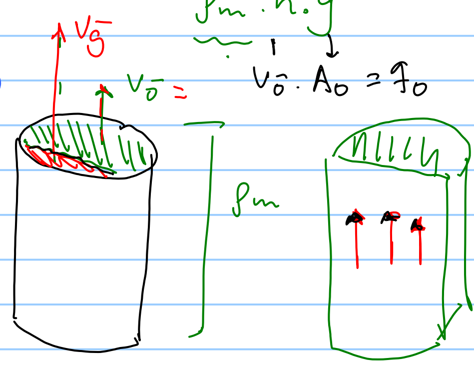


$\Delta p_{tubing} = \Delta p_{hydrostatic} + \Delta p_{friction}(q)$

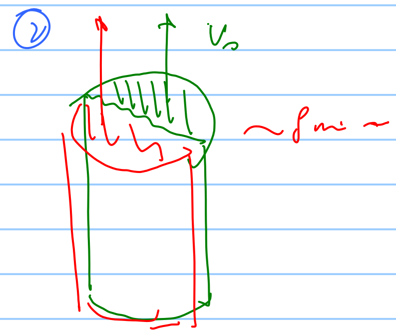
$\rho_m \cdot h \cdot g$

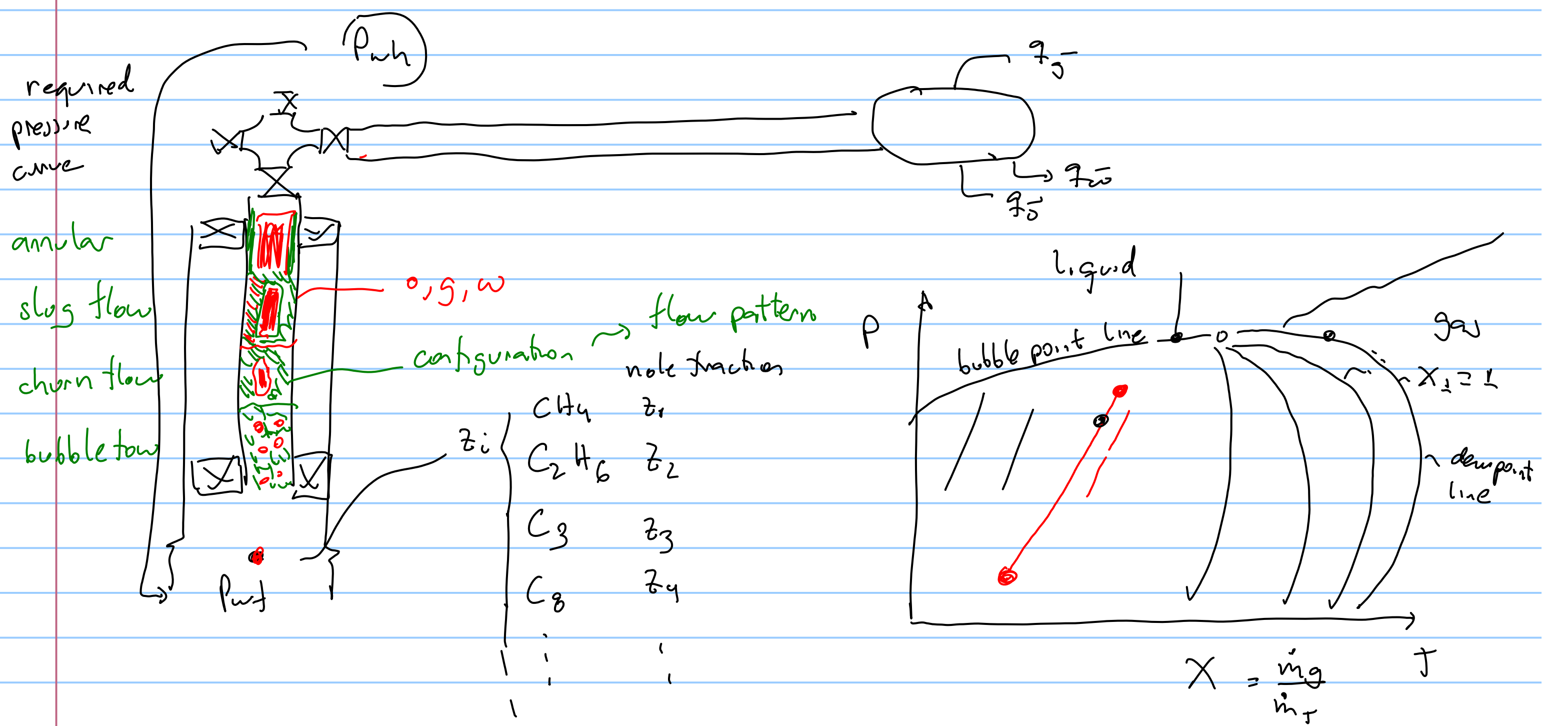
① $v_{\bar{g}}$, $v_{\bar{o}} =$ $v_{\bar{o}} \cdot A_o = q_o$

ρ_m

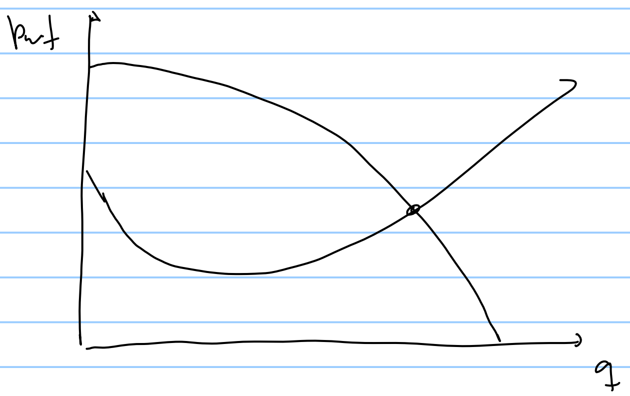


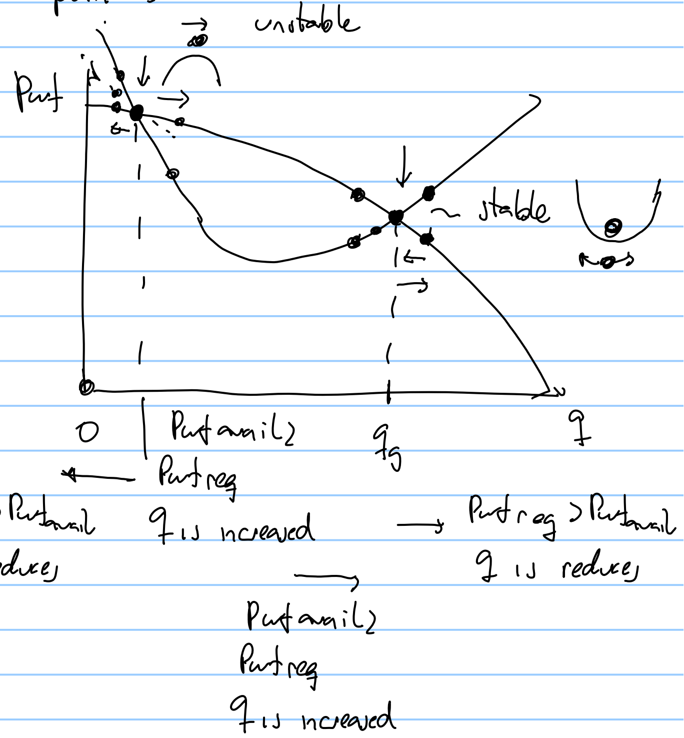
the gas velocity is high enough such that it starts pulling the liquid up, reducing the gas velocity and increasing the liquid velocity





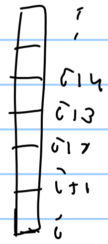
what are the consequences for the equilibrium point?





for multiphase flow pressure drop calculations are time consuming

- stepwise maner
- flash ~> determining amount of oil and gas
- determine slip between phases
- ↳ calculate ΔP

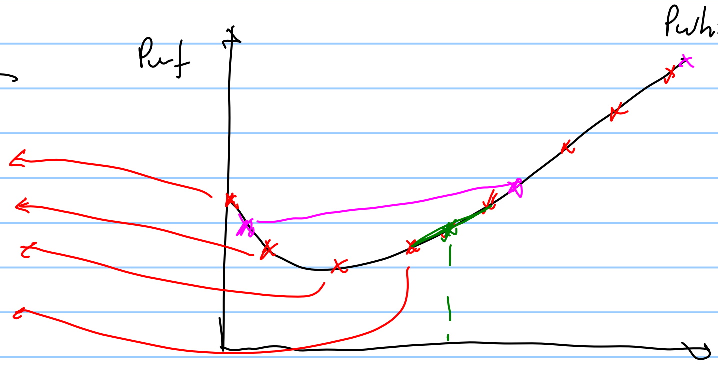


to save time, TPR is pre computed and stored in tables beforehand

Tubing table VLP vertical lift performance
TT

$P_{wh} = P_{wh_1}$

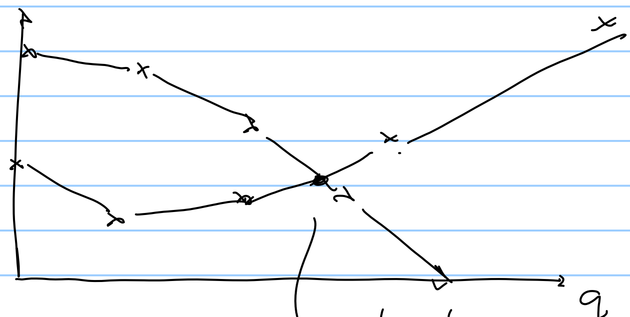
q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–			



later we use the table as our multiphase proxy.
perform interpolation on the table

there has to be a appropriate number of points on the table such as $P_{wf\,interpolated} \simeq P_{wf\,calc}$

Linear interpolation is fast and cheap



intersection of two straight lines ~> computationally cheaper than non linear solver there will be several tables for different wellhead pressures

$P_{wh} = P_{wh_1}$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

$P_{wh} = P_{wh_2}$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

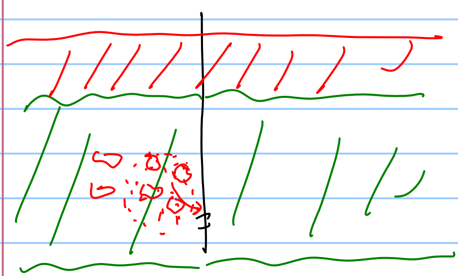
$P_{wh} = P_{wh_3}$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

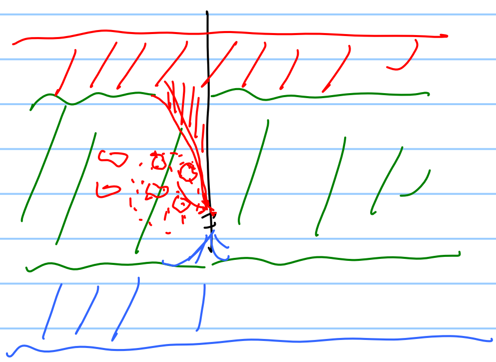
$P_{wh} = P_{wh_4}$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

with time the well GOR changes, WC change



with the depletion
$S_g \uparrow$ around wellbore, $Kr_g \rightarrow$ more gas flow towards the wellbore the GOR $\uparrow$



gas coning
water coning

So usually it is necessary to build tables for different GORs and WCs

$P_{wh} = P_{wh_1}$ GOR$_1$, WC$_1$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

$P_{wh} = P_{wh_2}$ GOR$_1$, WC$_1$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

$P_{wh} = P_{wh_3}$ GOR$_1$, WC$_1$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

$P_{wh} = P_{wh_4}$ GOR$_1$, WC$_1$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

$P_{wh} = P_{wh_1}$ GOR$_2$, WC$_1$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

$P_{wh} = P_{wh_2}$ GOR$_2$, WC$_1$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

$P_{wh} = P_{wh_3}$ GOR$_2$, WC$_1$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

$P_{wh} = P_{wh_4}$ GOR$_2$, WC$_1$

q_o	q_g	q_w	P_{wf}	T_{wh}
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–
–	–	–	–	–

this increases the number of tables required significantly

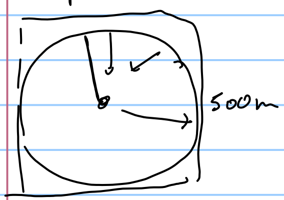
$$N_{points} = \underbrace{N_{rates}}_{\text{typically} \sim 10} \times \underbrace{N_{P_{wh}}}_{\sim 6} \times \underbrace{N_{GORs}}_{\sim 8} \times \underbrace{N_{WCUTs}}_{\sim 5} = 1440 \text{ runs } !$$

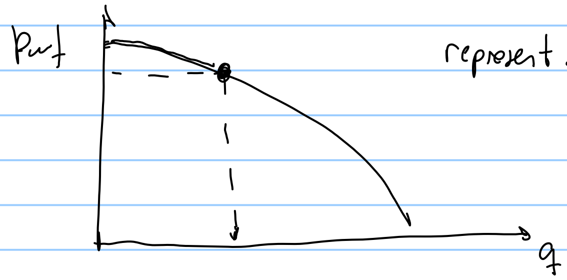
Inflow deliverability

Inflow performance relationship:

for a given time, for a given P_R, for a given depletion state

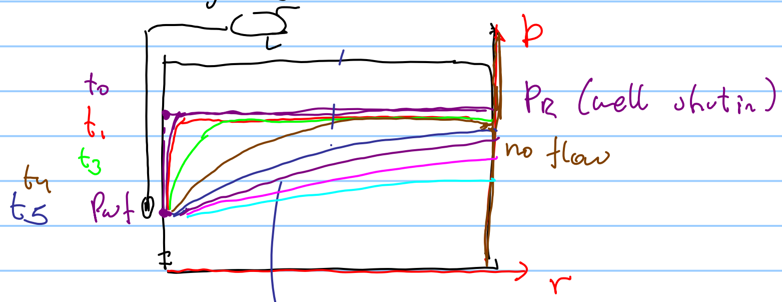
top view

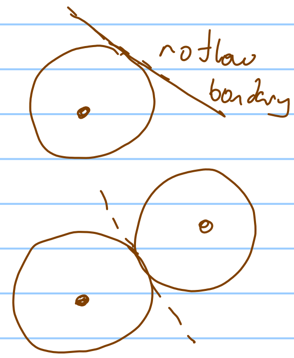




represents the flow behavior of the near wellbore formation

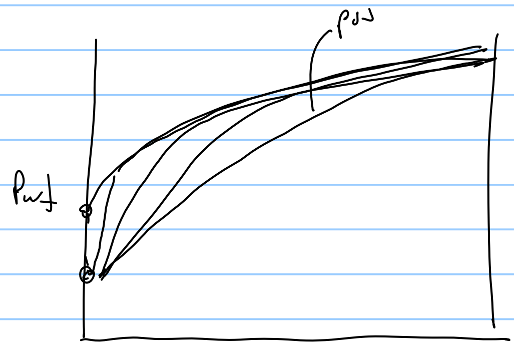
Reservoir engineers use reservoir simulator.

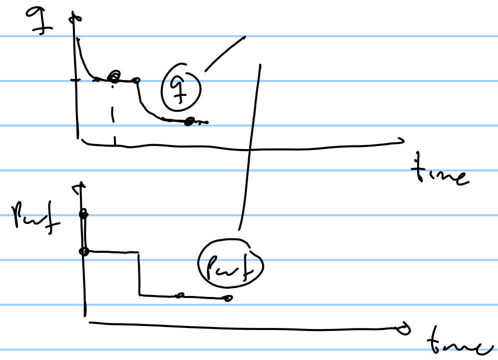




stabilized flow (pressure perturbation reaches the outer bound)

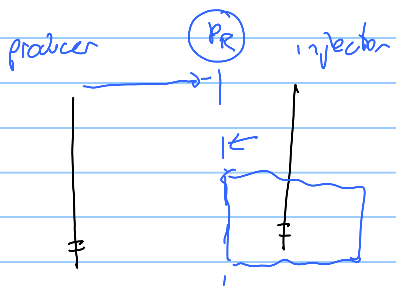
IPR applies usually for stabilized flow / pss pseudo steady state





IPR: contains information about

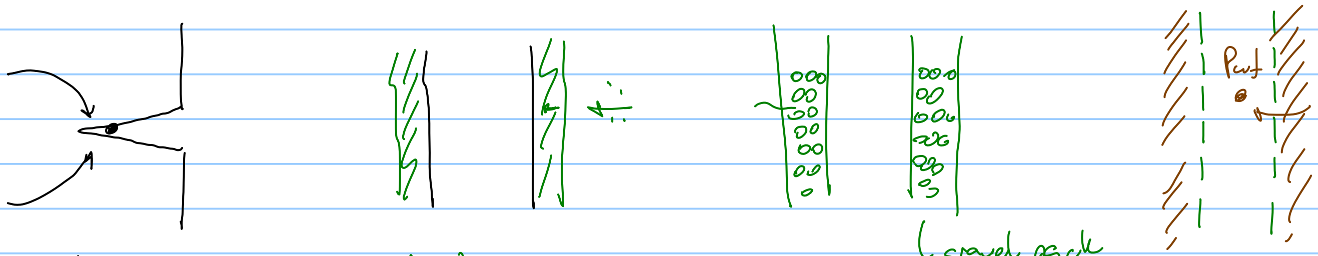
- location and type of outer bound
  - no flow
  - constant pressure



- permeability of formation (rock properties) k_z, k_x, k_y
- fluid properties and their variation with p, $\sim$ $v = \frac{k}{\mu}\frac{dp}{dr}$

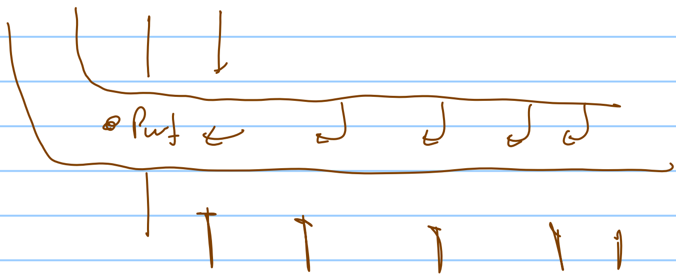
- oil, gas and water saturation in the drainage area $\rightsquigarrow$ k_{ro}, k_{rg}, k_{rw}
  S_o, S_g, S_w

- Restricted flow towards the wellbore

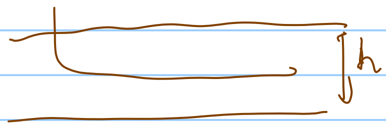


perforation mud damage gravel pack

- for horizontal well, the IPR captures sometimes flow in the wellbore



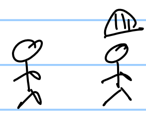
- well radius
- formation thickness



- Volume average pressure of the drainage area (p_R)

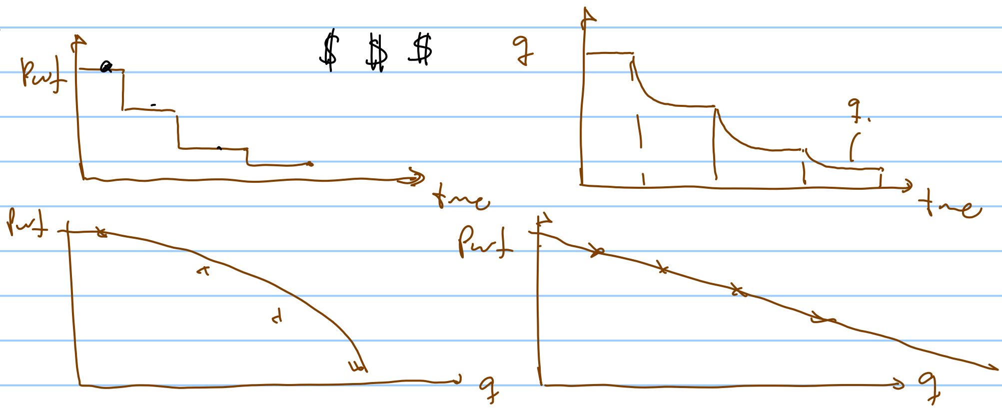
- high velocity effect (non Darcy) $v = \frac{k}{\mu}\frac{dp}{dr}$ $av + cv^2 = \frac{k}{\mu}\frac{\partial p}{\partial r}$

- the convergence effect of the flow towards the wellbore



two methods to estimate IPR

- well test



Some equation typically used are

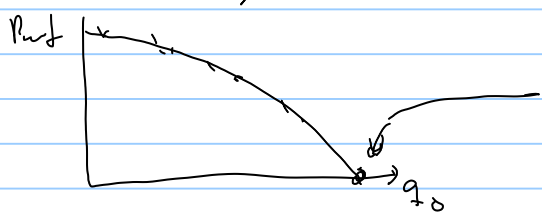
- Linear IPR ~ (undersaturated oil + water) $q_L = J\,(P_R - P_{wf})$

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

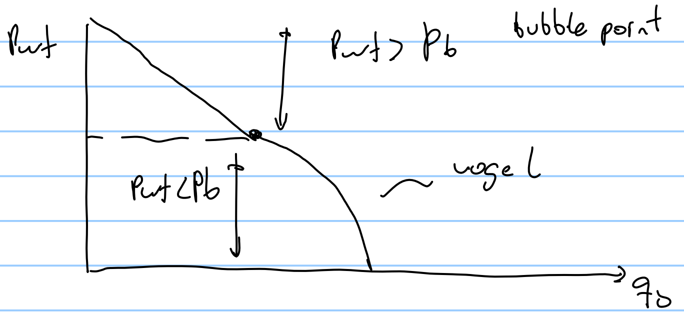
- Backpressure equation (gas saturated oil) $q = C\,(P_R^2 - P_{wf}^2)^n$

- Vogel equation (saturated oil) $q_{\bar{o}} = \underbrace{q_{o\,max}}_{q_o \,@\, P_{wf}=1\text{ bar}} \cdot \left(1 - 0.2\,\frac{P_{wf}}{P_R} - 0.8\left(\frac{P_{wf}}{P_R}\right)^2\right)$

AOF. absolute open flow



- Composite IPR (saturated and undersaturated oil)



- with time the IPR changes ~ it is necessary to run well test again

- IPR can be also estimated analytically. useful for field design (no test data is available) expression are derived from differential equations conservation of mass and

$$\frac{k}{\mu} 2\pi h \frac{\partial}{\partial r}\left(r \frac{\partial p}{\partial r} \right) = 2\pi h \phi c r \frac{\partial p}{\partial t}$$

customize the equation for each situation, well geometry. and solve it

some examples

for gas

unit conversion constant

$$q_g = \frac{\pi k h T_{sc} a}{T_R P_{sc} \left(\ln\left(\frac{r_e}{r_w}\right) - 3/4 + S \right)} \int_{P_{wf}}^{P_R} \left(\frac{2p}{\mu_g z} \right) dp$$

for oil

unit conversion constant

$$q_{\bar{o}} = \frac{2\pi k h a}{\ln\left(\frac{r_e}{r_w}\right) - 3/4 + S} \int_{P_{wf}}^{P_R} \frac{K_{ro}}{\mu_o B_o} dp$$

$K_{ro} = f(S_o)$

for under saturated oil $K_{ro} \leq 1$ if you have connate water $\frac{K_o}{K}$

S_o = constant

K_{ro} = value less than 1

$\frac{K}{\mu_o B_o}$ = constant with P

$$q_{\bar{o}} = \underbrace{\frac{2\pi k h}{\left(\ln\left(\frac{r_e}{r_w}\right) - 3/4 + S \right)} \frac{1}{\mu_o B_o}}_{J} (P_R - P_{wf})$$

Evaluation of exercise set 1:

- 100%

20% report /presentation | 20% problem 1 | 20% problem 2 | 25% problem 3 | 15% problem 4

for future deliveries 20% deduction for every day delivered late!

Production potential

Dry gas reservoir → uniform reservoir pressure

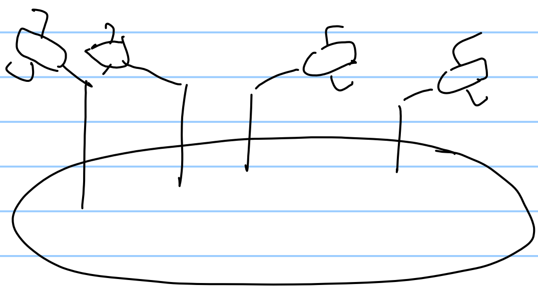
Standalone well →

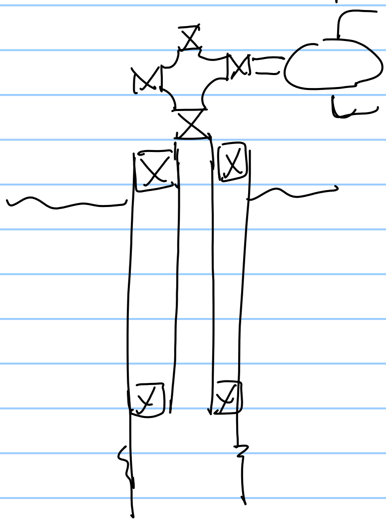
N wells

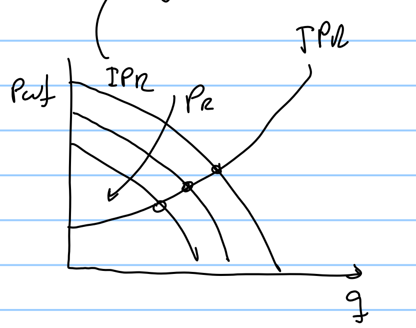
all wells are identical, IPR, TPR same

P_{sep}

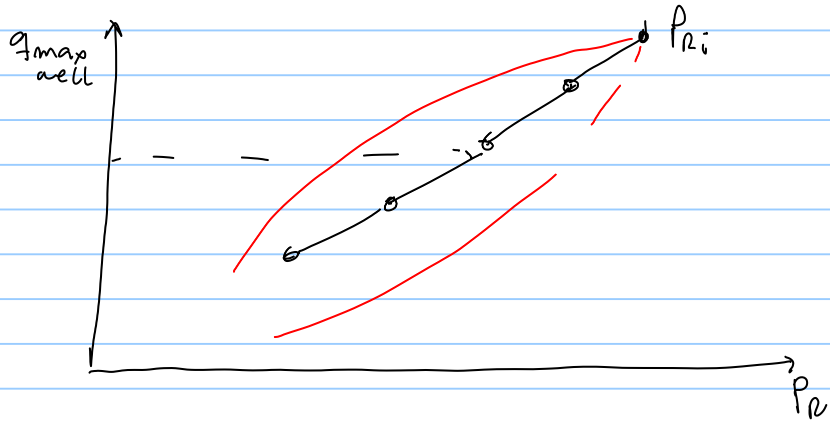
$$q_g = C_R \left(P_R^2 - P_{wf}^2\right)^n$$



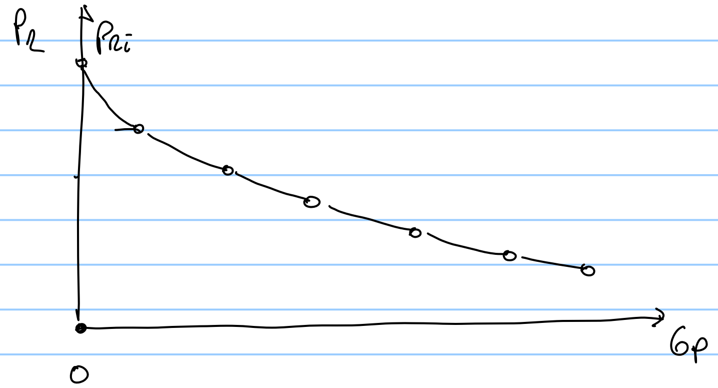


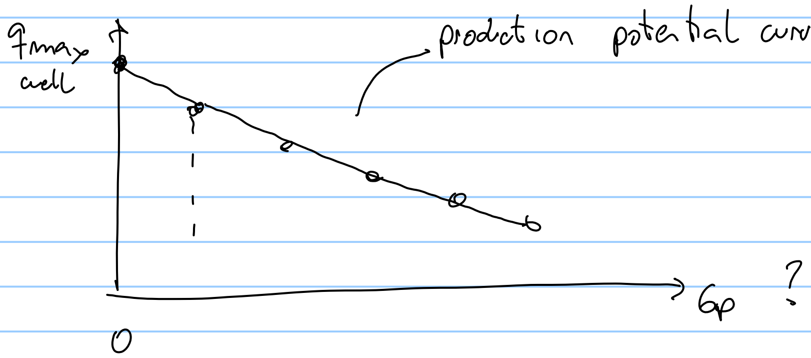


maximum rate from the well will go down with reservoir pressure

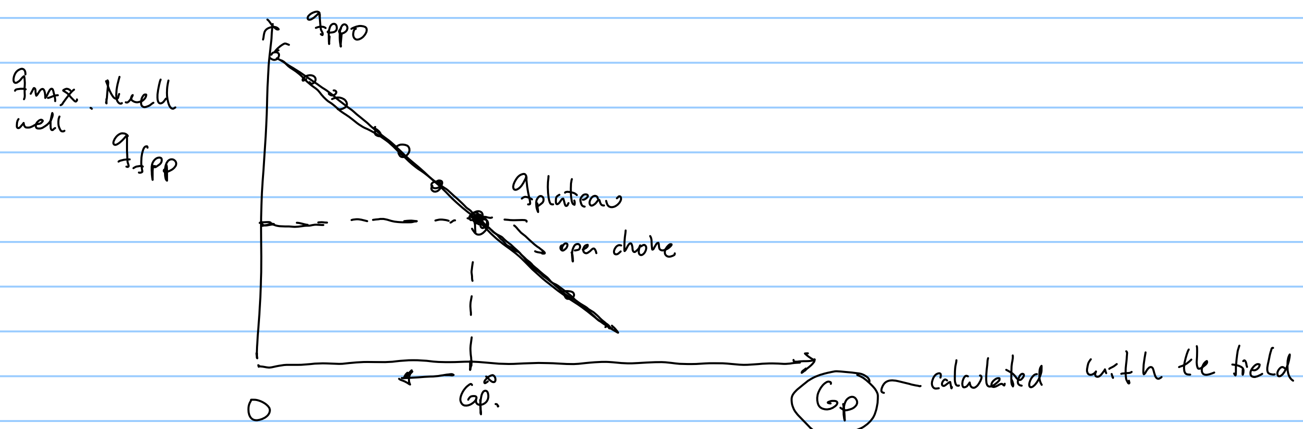


p_R according to material balance $p_R(t) = f(G_p)$ $\quad G_p = \int_0^t q_g \, dt$





for the field:



G_p^* is the cumulative production at which the $q_{fpp} = q_{plateau}$

$$t_{plateau} = \left(\frac{G_p^*}{q_{plateau} \cdot N_{day/year}} \right).$$

Until now, to find plateau length you perform a stepwise calculation in time

time	$q_{open\ choke}$	$q_{produced}$	if $q_{openchoke} > q_{produced}$ ⇒ platea
t_1 .			
t_2 .	-	-	—
t_3 .			
t_4			

Deriving the production profile using the production potential. always open choke

for dry gas $\boxed{q_{fpp} = q_{ppo} - m\, G_p}$ (1) $q_f = q_{fpp}$

$$\boxed{G_p = \int_0^t q_f \, dt} \quad (2)$$

$$q_f = q_{ppo} - m \int_0^t q_f \, dt$$

derive with respect to time

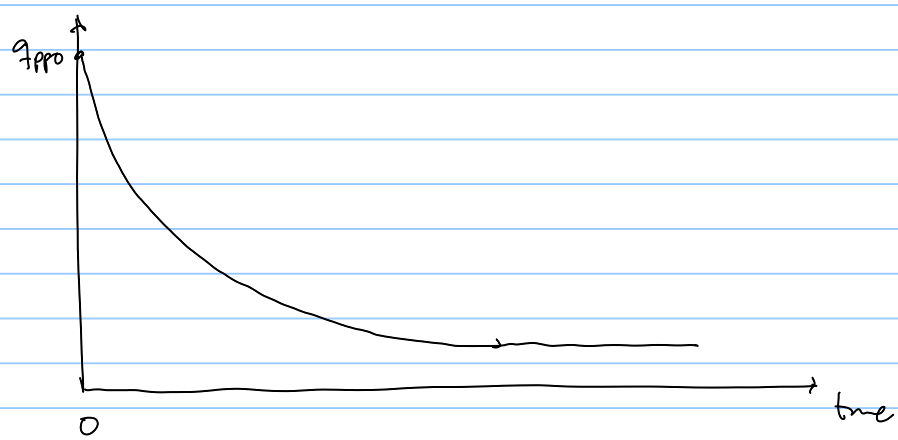
$$\frac{d q_f}{dt} = -m q_f$$

$$\int_{q_{ppo}}^{q(t)} \frac{d q_f}{q_f} = \int_0^t -m \, dt$$

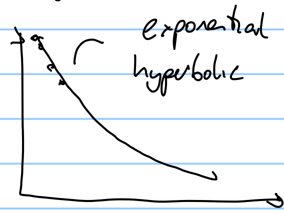
q_{ppo} — production potential @ $t=0$, @ $P_R = P_{Ri}$

$$\ln q_f \Big|_{q_{ppo}}^{q(t)} = -m(t-0)$$

$$\boxed{q_f = q_{ppo} \cdot e^{-mt}} \quad \text{eq (1)}$$



material balance
res simulator
DCA



eq 1 gives you a decline shape for the rate

it can be applied for decline periods (producing at open choke) using appropriate bounds in the integral

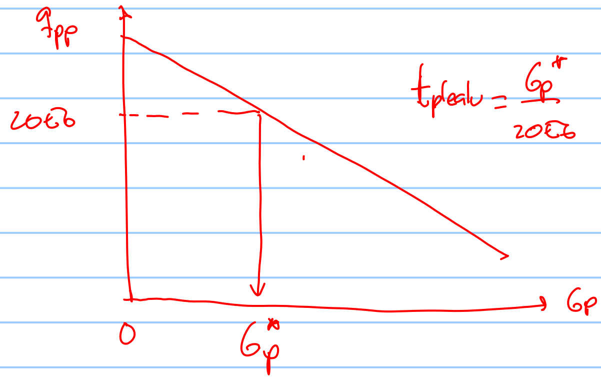
$$\int_{q_{ppo}}^{q(t)} \frac{d q_f}{q_f} = \int_0^t -m \, dt$$

$P_{wf} = BHP$

$\left(P_{wf}^{avail} - P_{wf}^{req}\right)^2$ $q_{plateau}$ = desired

$q_{plateau\,1}$ 10E6 Sm³/d

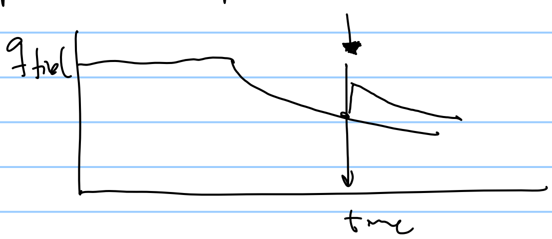
time	G_p	P_R	q_{field} (open choke)	$P_{wf\,avail}$ co-current (IPR)	$P_{wf\,reqe}$ counter current TPR	P_{xp}	Error	(q_{field})
t_1	$\boxed{0}$	P_{Ri}	$\boxed{\ }$				$\boxed{\ }$	if $q^{open\,choke} > q_{desired}$: $q_{desired}$
t_2	$\boxed{\ } + \left(q_{field} \cdot (t_2 - t_1) \cdot N_{days/year}\right)$							else $q_{open\,choke}$
t_3								
t_4								
⋮								

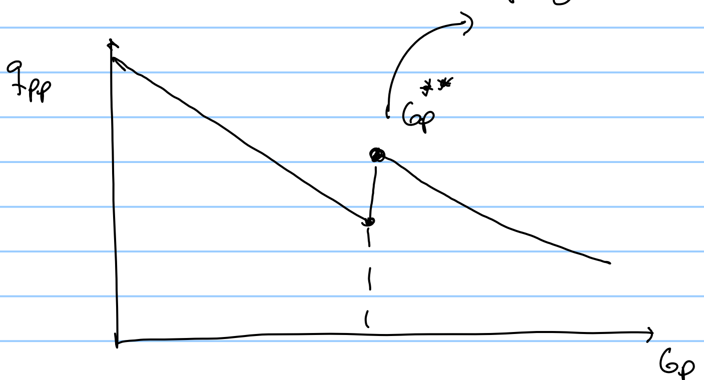


what happens if $q_{plateau} = q_{plateau\,2}$ (20 E6 Sm³/d)

what are the limitations?

- changes in the production system → change n_i wells
  ↳ are applied at a particular day

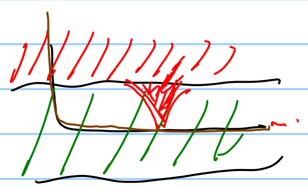




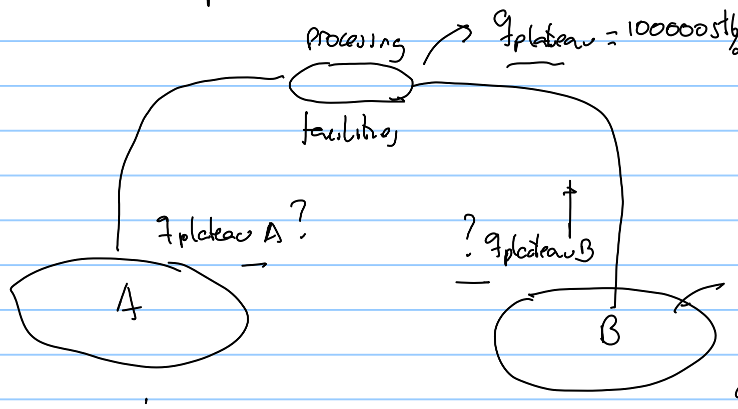
- IPR $f(P_R)$, $f(G_p)$

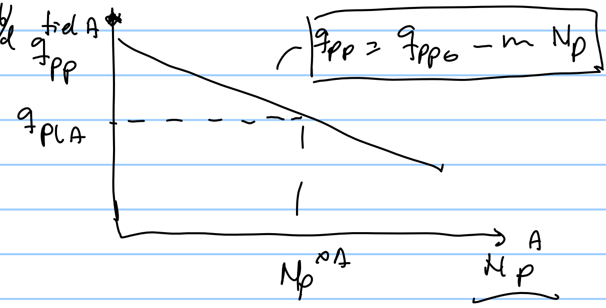
critical coning pressure

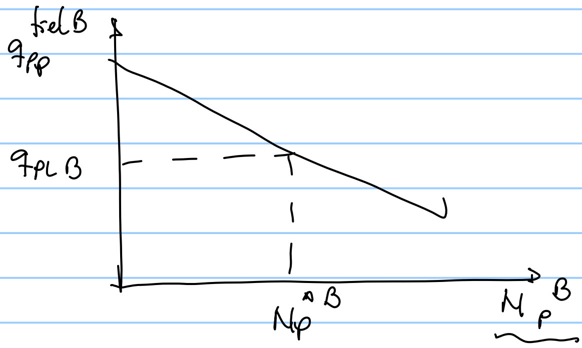
$P_{wf} > P_c$



take a example with two reservoirs







if $t_{plateau}$ field is to be maximixed
then $t_{plateau}^{A} = t_{plateau}^{B}$

iterative procedure

assume $q_{plateau\,A}$

calculate $q_{pleau\,B} = \overset{100000}{q_{pleateau}} - q_{plateau\,A}$

go to the production potential curve
read N_p^{*A}, N_p^{*B}

calculate $t_{plateau\,A}$, $t_{plateau\,B}$

$$\frac{N_p^{*A}}{q_{plateau\,A} \cdot N_{day/year}}$$

is $t_{plateau\,A} = t_{plateau\,B}$? NO

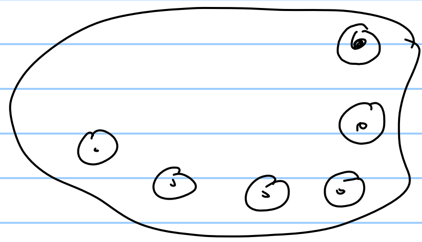
YES

$q_{plateau\,A}$, $q_{plateau\,B}$ is the optimum solution

---

in big reservoirs $q_{pp\,well} \neq f(N_{p\,field})$

$q_{pp\,well} = f(N_{p\,well})$



Example 1: Production potential of a system with two standalone wells

Assume that there is a field with two (2) standalone wells, and that the production potential of each well can be expressed as a function of the cumulative production of each individual well:

$$q_{pp}^{i} = f\left(Q_P^{i}\right) \qquad \text{Eq. 11}$$

In this case the production profile can be computed separately for each well from the production potential curve and then add them up to obtain the field production profile. Please note that the field production potential for a given field cumulative production is not unique. This is because there are different ways to achieve the same field cumulative production (e.g. in a two well system, produce more from well 1 than 2, produce equal, or produce more from well 2 than 1).

As an example, consider the production system with 2 standalone wells shown in Fig. 14.a. The production potential of each well is presented in Fig. 14.b. Wells will be produced at constant rate initially, with plateau rates q_{P1} and q_{P2} and, when the plateau rate is no longer feasible, they will be produced at the production potential.

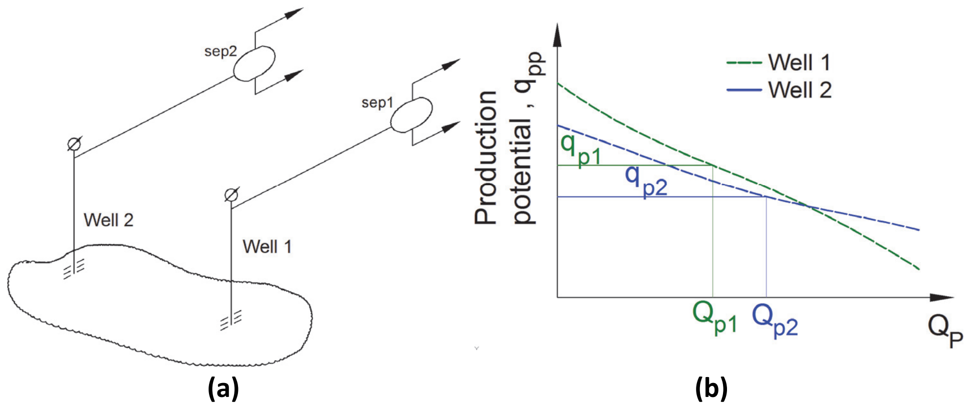


Fig. 14. Example case: 2 standalone wells

The plateau duration of each well can be very easily calculated by intersecting the individual plateau rate with the production potential curve of each well. This yields a plateau duration of $t_{p1}=Q_{P1}/q_{P1}$, for well 1 and $t_{p2}=Q_{P2}/q_{P2}$ for well 2. After the plateau ends, the production profile of each well follows the potential.

A typical reservoir management problem consists of how to define well rates to maximize field plateau duration when a fixed field rate is desired. If individual well plateau rates are to be kept constant, this can be achieved by finding the plateau rates for which the plateau end occurs at the same time. If the production potential curves are straight lines the following procedure is suitable:

The production potential curve for well 1:

$$q_{pp1} = -m_1 \cdot Q_{P1} + q_{ppo1} \qquad \text{Eq. 12}$$

The cumulative production at which the production potential (q_{pp1}) is equal to the plateau rate (q_{p1}), i.e. Q_{Pp1}, is:

$$Q_{Pp1} = \frac{q_{ppo1} - q_{p1}}{m_1} \qquad \text{Eq. 13}$$

Similarly for well 2:

$$Q_{Pp2} = \frac{q_{ppo2} - q_{p2}}{m_2} \qquad \text{Eq. 14}$$

Then the plateau duration has to be the same for both wells:

$$t_{p1} = \frac{Q_{Pp1}}{q_{p1}} = t_{p2} = \frac{Q_{Pp2}}{q_{p2}} \qquad \text{Eq. 15}$$

Substituting Eq. 13 and 14 in Eq. 15:

$$\frac{q_{ppo1} - q_{p1}}{m_1 \cdot q_{p1}} = \frac{q_{ppo2} - q_{p2}}{m_2 \cdot q_{p2}} \qquad \text{Eq. 16}$$

$$\frac{q_{ppo1}}{q_{p1}} - 1 = \frac{m_1}{m_2} \cdot \left(\frac{q_{ppo2}}{q_{p2}} - 1 \right) \qquad \text{Eq. 17}$$

Eq. 17 has two unknowns, therefore one more equation is needed. Clearing q_{p2} from the expression of the total plateau rate:

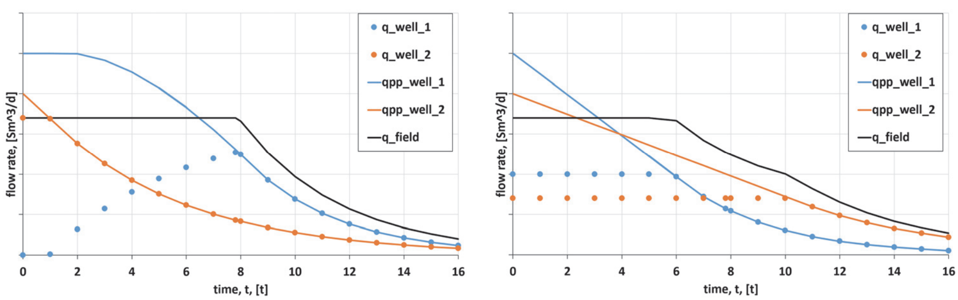
$$q_{p2} = q_p - q_{p1} \qquad \text{Eq. 18}$$

Substituting Eq. 18 in Eq. 17 yields:

$$q_{p1}^{\,2} \cdot (m_1 - m_2) + q_{p1} \cdot (q_{ppo1} \cdot m_2 + m_2 \cdot q_p - m_1 \cdot q_p + m_1 \cdot q_{ppo2}) - q_{ppo1} \cdot m_2 \cdot q_p = 0 \qquad \text{Eq. 19}$$

Eq. 19 can be solved with the quadratic formula to find q_{p1}.

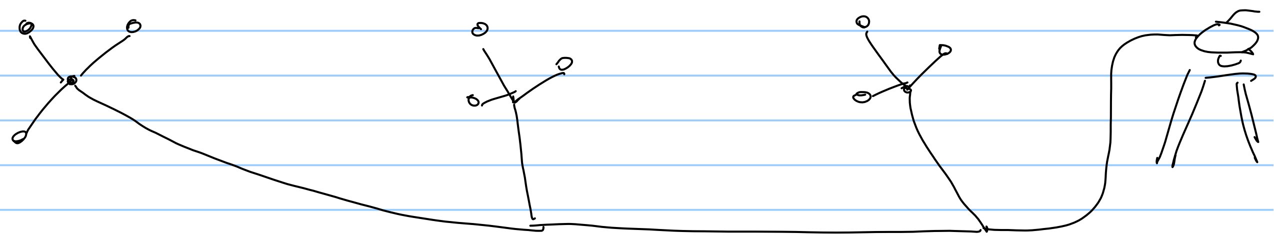
Please note that there are infinite alternatives to produce the field at plateau rate as shown in Fig. 15. Each option will yield a different field plateau duration.



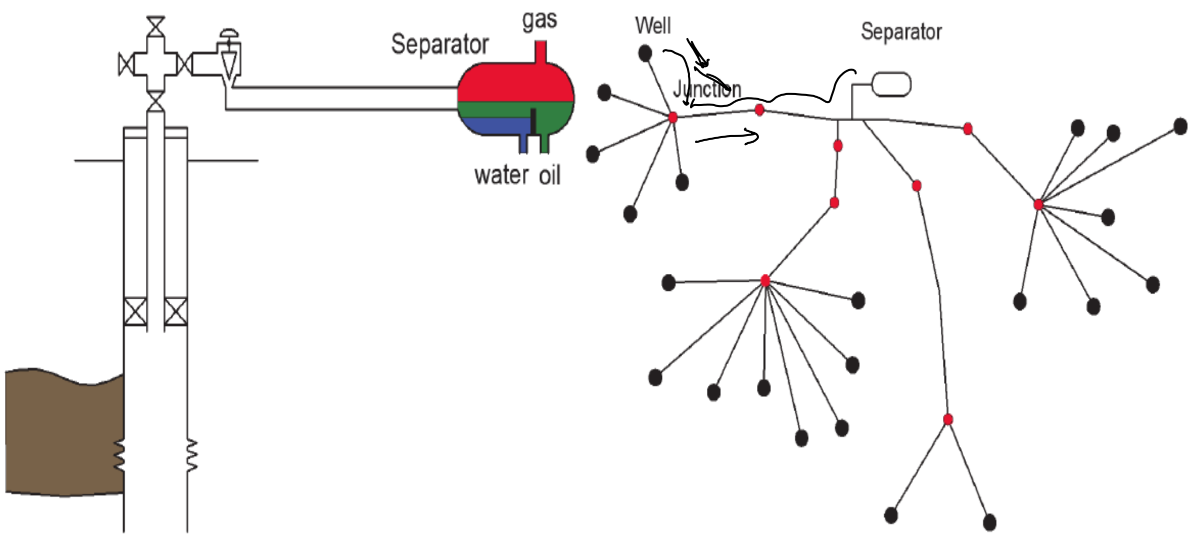
(a) (b)

Production networks

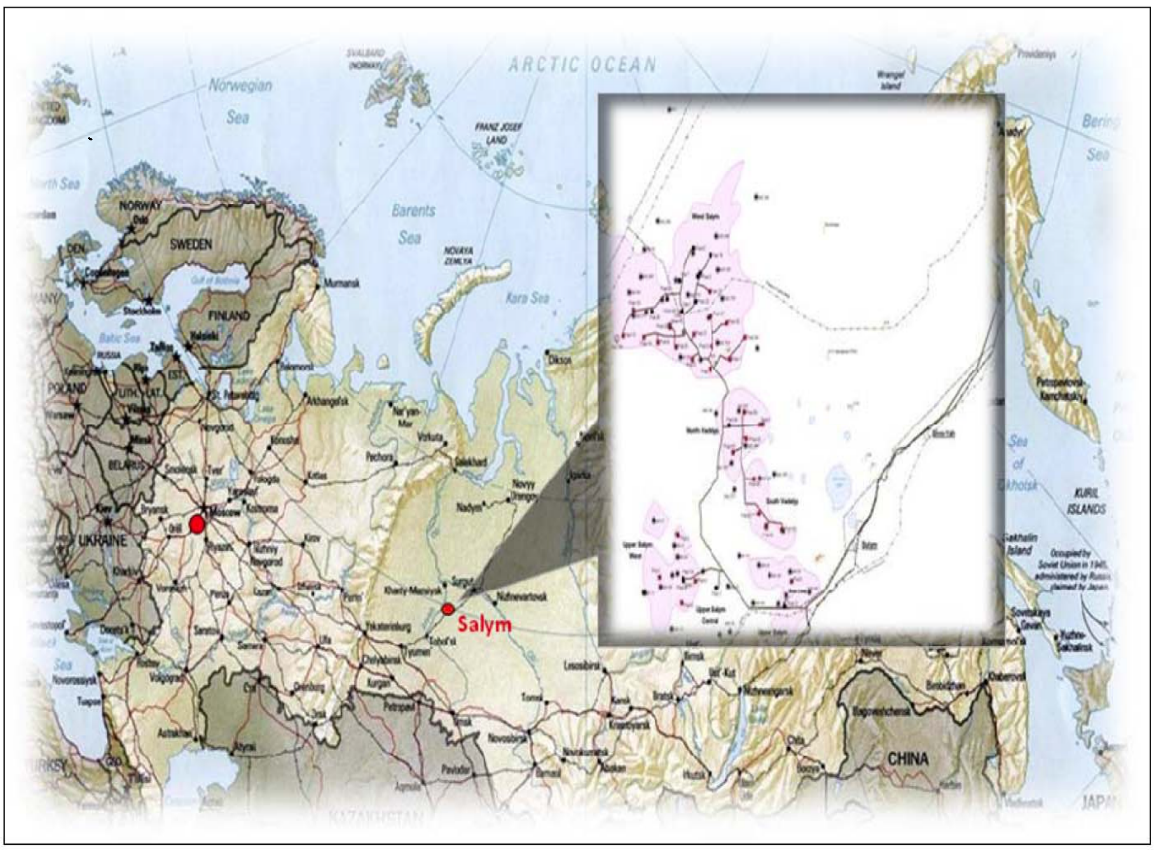
system of flowlines that commingle the production from the individual well and take it to processing facilities

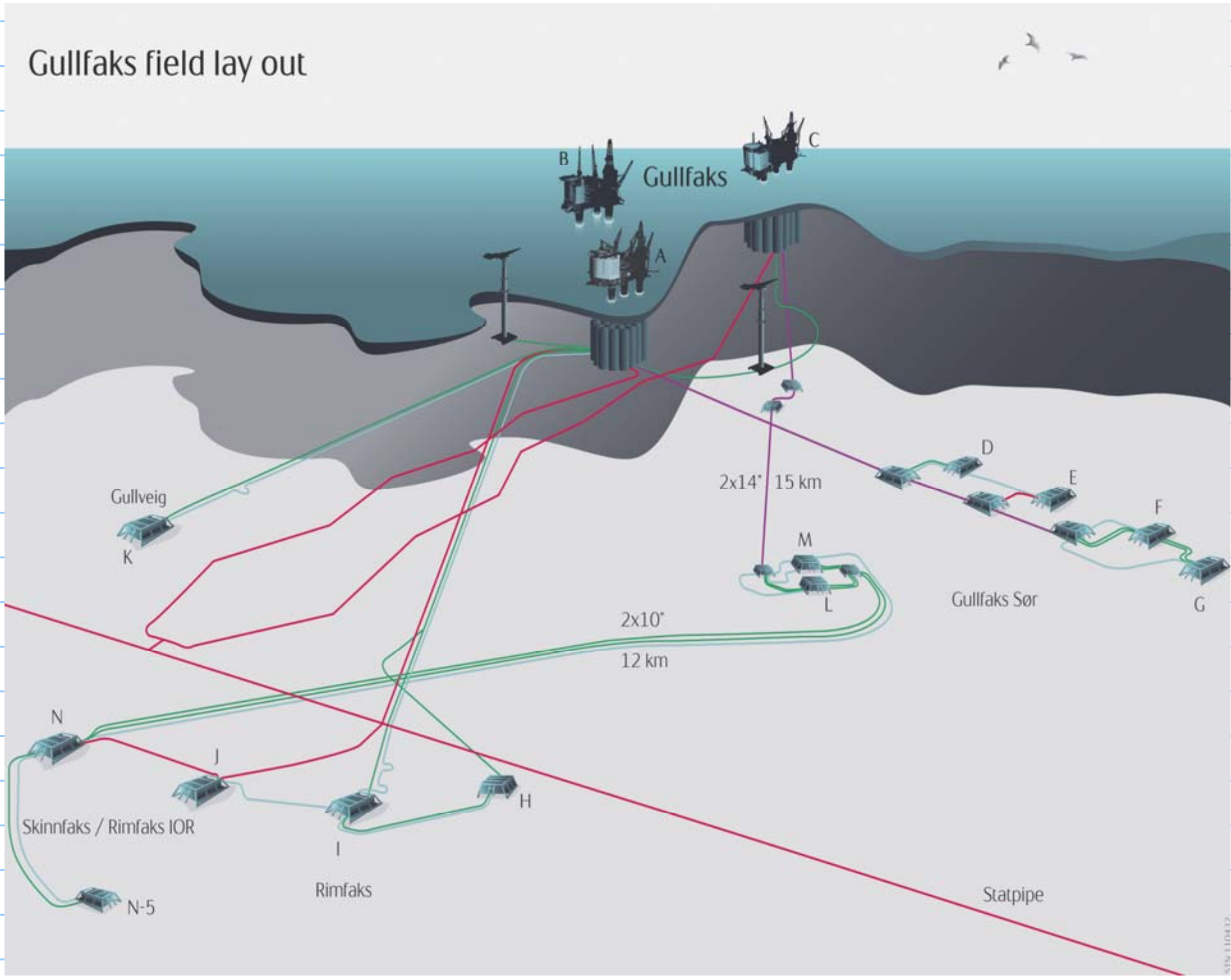


Subsea wells

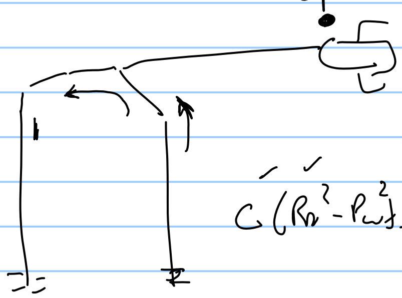


(a) (b)

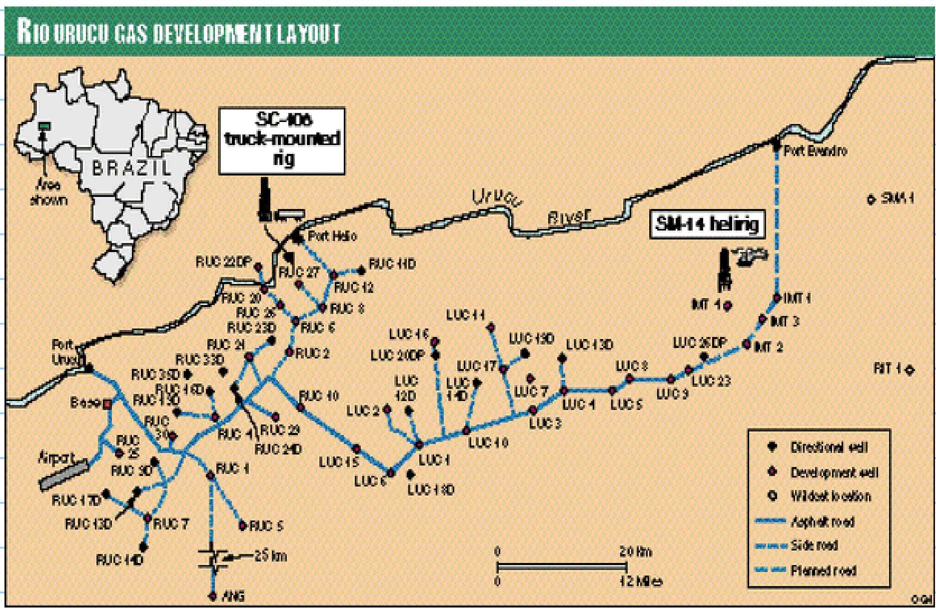




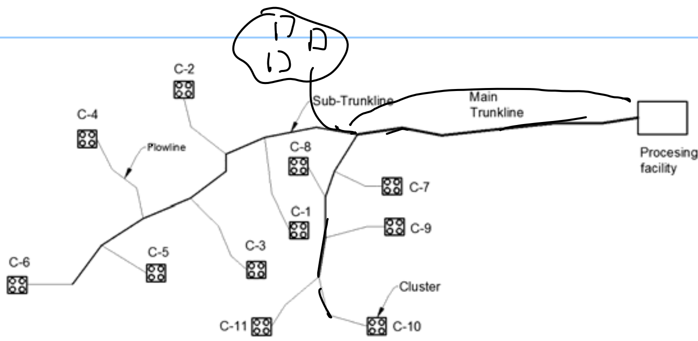
in networks there is interdependence between wells



$$C(P_R^2 - P_{wf}^2)$$



Rubiales field




60m
60m


Bahrain
Qatar
Sharjah
Riyadh
Al Hofuf
Mesaieed
Abu Dhabi
Saudi Arabia
Kharj
Ghayathi
United Arab Emirates
Al Ain
Al Qua'a
Al Majmaah
Ar Rass
Al Duwadimi
Al Aflaj
SHAYBAH OIL FIELD
Wadi Addawasir
Bishah
Sabt Alalayah
Oman
Oroug Bani M'aradh Wildlife Sanctuary
Khamis Mushait
Abha


10m/20m

(sabkah)

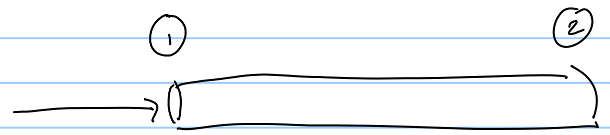
Note Title 12.01.2017

MENU FOR TODAY

- Work in groups on problem 1 exercise set Nr 3. ⇝ production scheduling using flow equilibrium

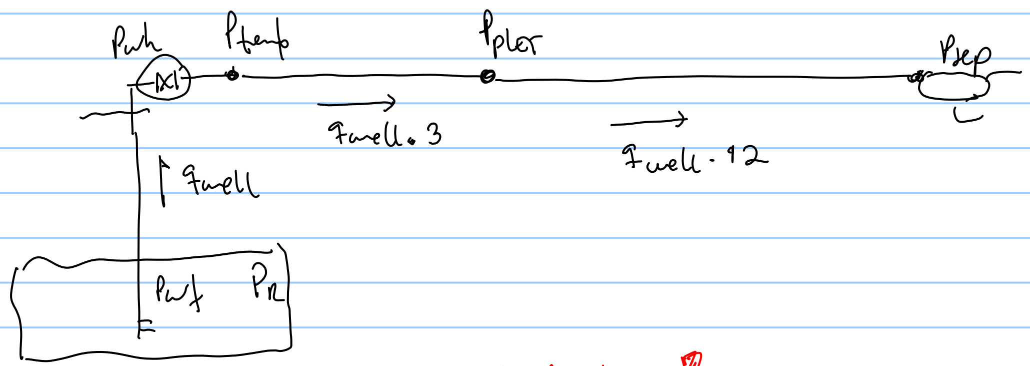
http://folk.ntnu.no/stanko/Courses/TPG4230/2017/Exercises/Exercise_03

- Network solving → flow equilibrium in networks ⇝ theory
- Work in groups on problem 2 exercise set Nr 3. ⇝ using flow equilibrium



points 1 and 2 are defined by the flow direction. 1 inlet, upstream
2 outlet, downstream.

in our problem



Equilibrium point is the wellhead choke!

co-current calculations:

co-current from reservoir to wh ⇝ IPR pwf, using P_1 (P_R) calculate P_2 (P_{wf}) using qwell

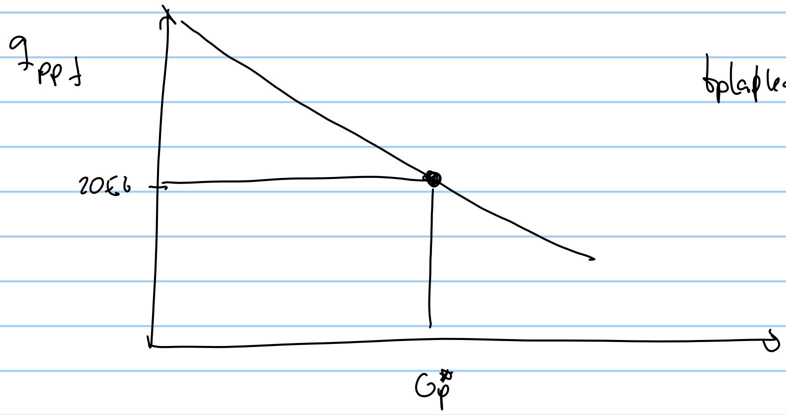
co-current from bottom-hole to wellhead ⇝ tubing P_2, using P_1 (P_{wf}) calculate P_2 (P_{wh}) using qwell

counter current calculations

- counter current from sep to pplet, use tubing eq, tubing P_1, using P_2 (P_{sep}) calculate P_1 (P_{PLET}) using qfield, (Remember to use C_{PL}, and S_{PL}!)
- counter current from pplet to template. use line P_1, using P_2 (P_{PLET}) calculate P_1 (P_{templ}) using qtemp

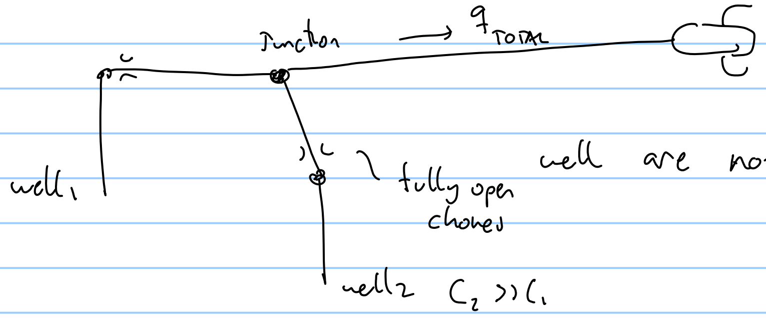
$\Delta p_{choke} = P_{wh} - P_{Temp}$

TASK 2: comments



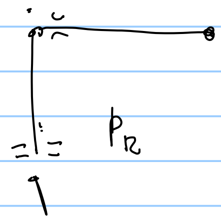
$$t_{plateau} = \frac{G_p^*}{2E6 \cdot 360}$$

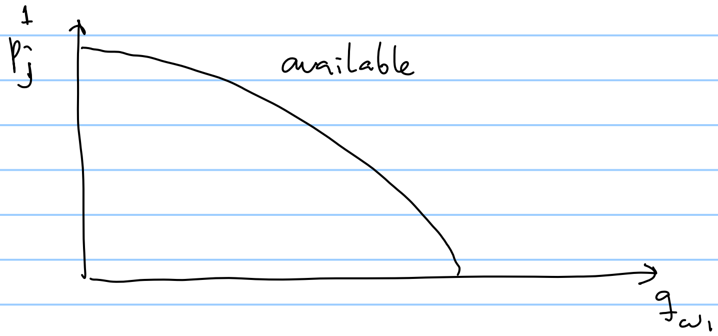
flow equilibrium in production networks

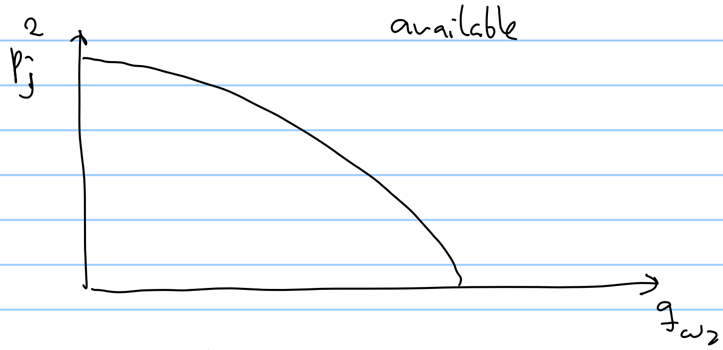


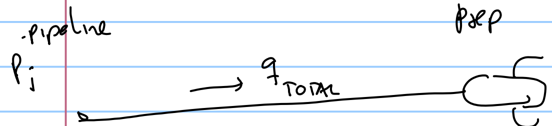
well are not identical, producing differently

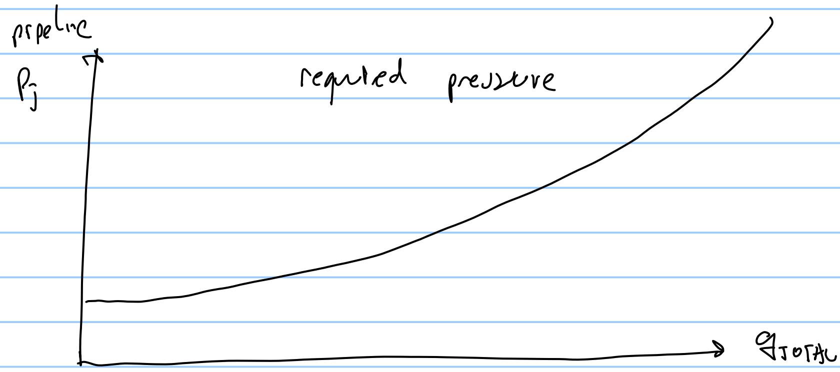
$C_2 \gg C_1$



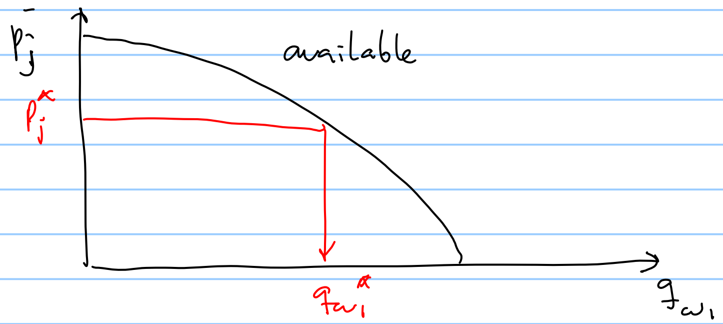




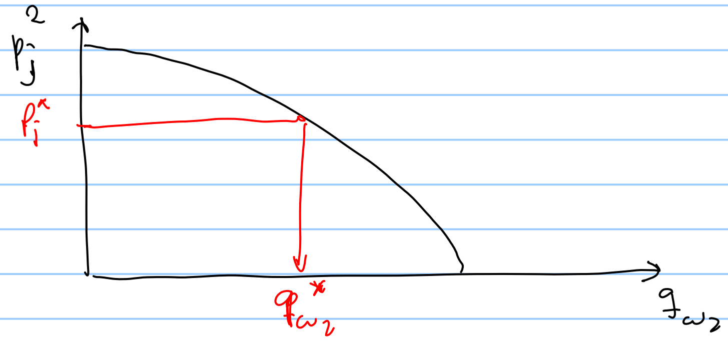




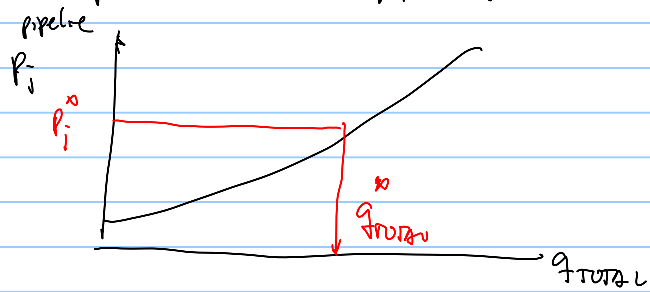
- Assume a unique junction pressure p_j^*
- from available pressure curve of well 1 calculate q_{w_1}



- from available pressure curve of well 2 calculate q_{w_2}



- from the required pressure curve of pipeline, calculate q_{TOTAL}



- Verify mass conservation in the junction

is $q_{TOTAL}^* = q_{w_1}^* + q_{w_2}^*$? NO

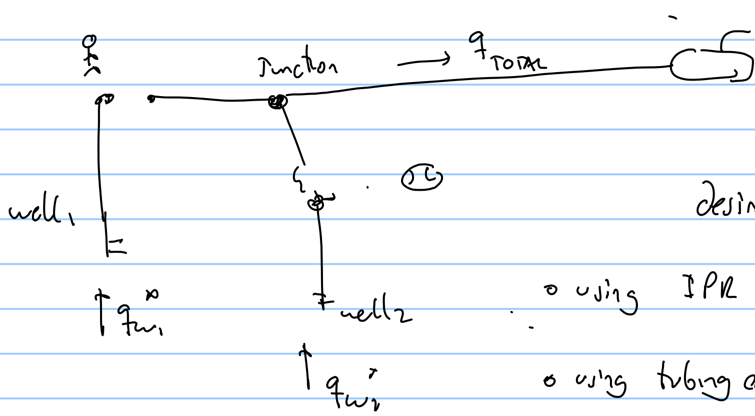
YES

p_j^*, $q_{w_1}^*$, $q_{w_2}^*$, q_{TOTAL}^* are the equilibrium conditions

the equilibrium point is often calculated numerically, graphically is more difficult with increasing number of junctions.

Equations	unknowns	Nr equ	Nr unknowns
IPR eq w_1 IP eq w_2	q_{w_1}, q_{w_2}, P_{wf_1}, P_{wf_2}	2	4
tubing eq 1 tubing eq 2	P_{wh_1}, P_{wh_2}	4	6
flowline 1, flowline 2	P_J	6	7
Pipeline eq	q_{TOTAL}	7	8
mass conservation in the junction $q_{TOTAL} = q_1 + q_2$		8	8 ✓

Fixed rate calculation method for networks.



desired rates $q^*_{w_1}$, $q^*_{w_2}$

- using IPR and q^*_w calculate P_{wf_1}, P_{wf_2}
- using tubing equation, P_{wf}, q_w calculate P_{wh_1}, P_{wh_2}
- using pipeline equation, P_{sep}, $q^*_{TOTAL} = q^*_{w_1} + q^*_{w_2}$ calculate P_J
- using flowline equations for each well, P_J, $q^*_{w_1}$, $q^*_{w_2}$ calculate P_{dc_1}, P_{dc_2} dc -- downstream of choke

verify if $P_{wh,1} > P_{dc1}$

$P_{wh,2} > P_{dc2}$

if there are adjustable elements A network can be considered as a function that provides well rates with certain setting of the adjustable element

output

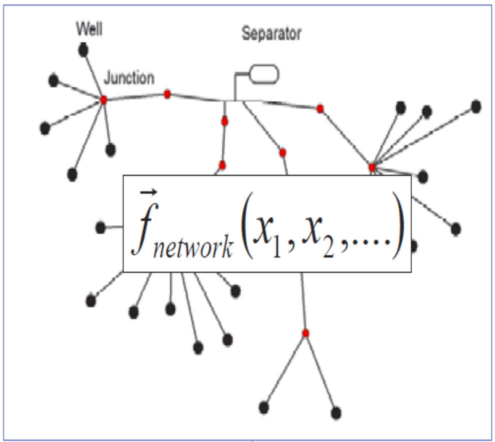
input

choke opening 1

choke opening 2

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

INPUT



OUTPUT

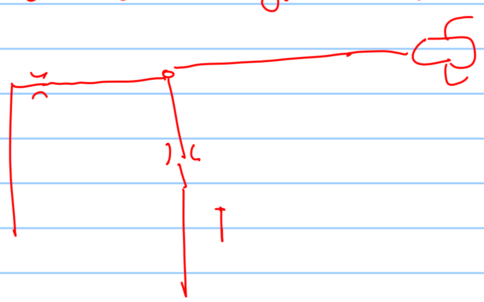
- **Well flow rates**
- Pressure and temperature along the system

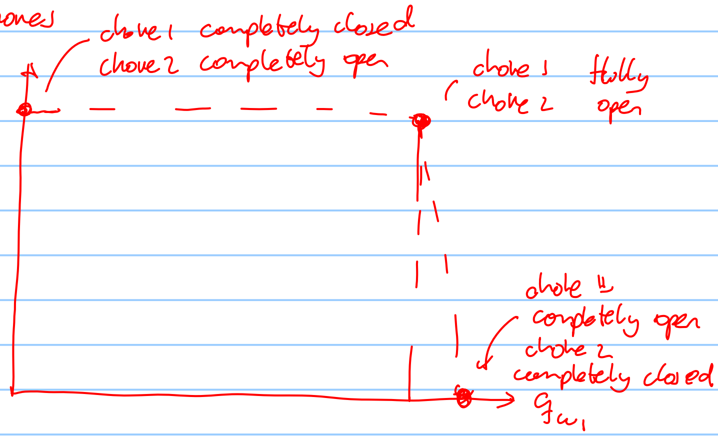
INPUT

- 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.

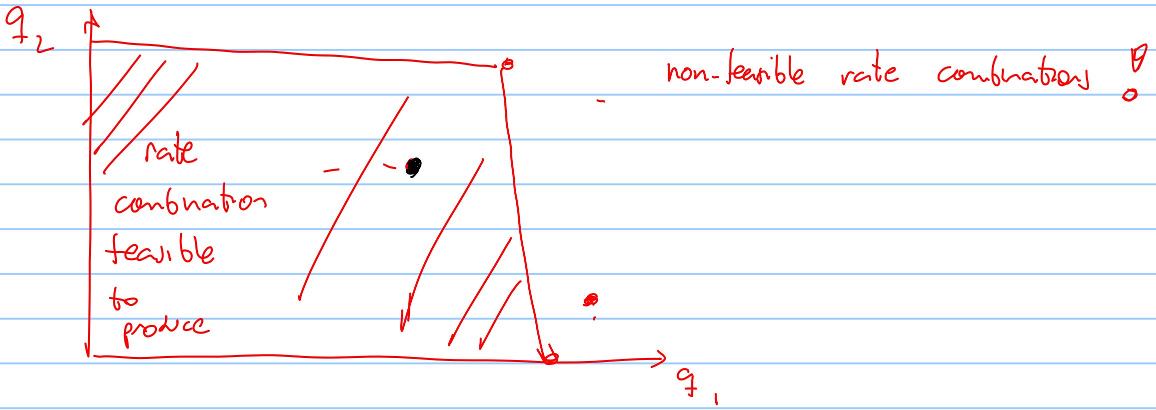
These usually vary during the life of the field.

for the two well system with wellhead chokes



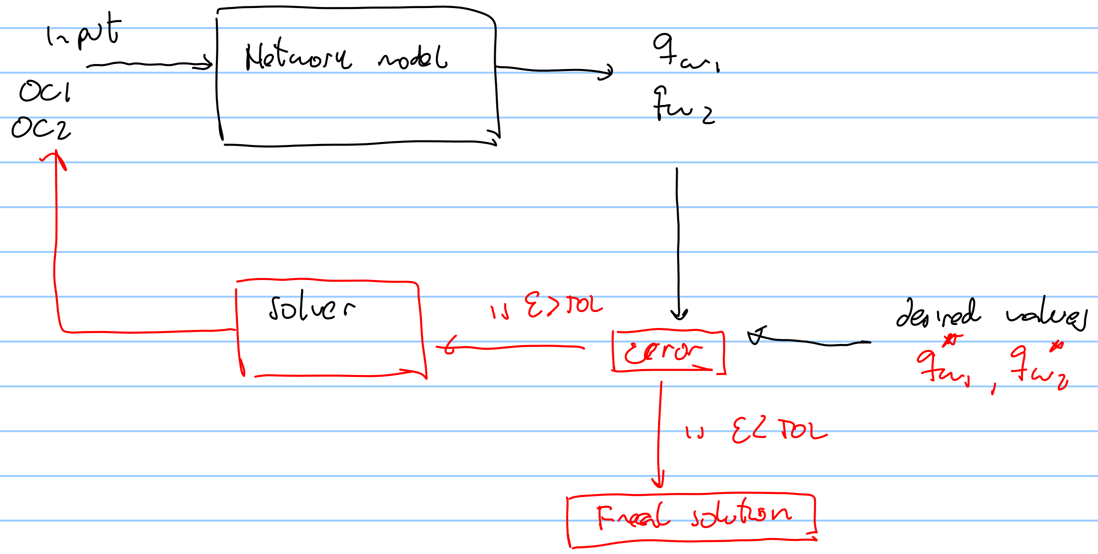


if I run my network with infinite combination of choke openings



in commercial software the process of finding the settings of adjustable elements that give a certain rate combination (q_{w1}^*, q_{w2}^*) is wrongly called optimization!

opening of choke OC



Comments about exercise set 2, problem 3

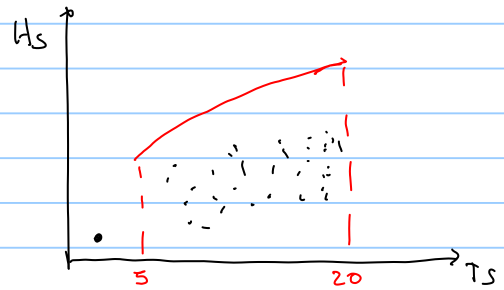
(1.5, 0.5) ⤳ (x, -)'

(17.5, 15.5)

Spectral Peak period (T_p) [s]

Hs [m]	0-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24	24-25	Sum
0-1	15	290	1367	2876	3716	3527	2734	1849	1138	656	362	192	101	52	26	13	7	3	2	1	0	0	0	18927
1-2	1	81	1153	5308	12083	17323	18143	15262	10980	7053	4169	2316	1229	631	315	155	75	36	17	8	4	5	1	96348
2-3	0	2	94	1050	4532	10304	15020	15953	13457	9752	5991	3403	1795	894	426	197	88	39	17	7	3	1	1	83026
3-4	0	0	2	72	686	2782	6171	8847	9189	7493	5082	2991	1577	762	345	148	61	24	9	4	1	0	0	46246
4-5	0	0	0	2	51	433	1645	3495	4807	4750	3638	2286	1229	584	251	100	37	13	5	1	0	0	0	23327
5-6	0	0	0	0	2	39	294	1037	2069	2664	2440	1709	968	463	193	72	25	8	2	1	0	0	0	11986
6-7	0	0	0	0	0	2	32	215	692	1264	1485	1228	767	382	159	57	18	5	1	0	0	0	0	6307
7-8	0	0	0	0	0	0	2	27	157	447	730	762	555	302	130	46	14	4	1	0	0	0	0	3177
8-9	0	0	0	0	0	0	0	2	23	112	276	392	355	223	104	38	11	3	1	0	0	0	0	1540
9-10	0	0	0	0	0	0	0	0	2	19	77	160	192	148	79	31	9	2	0	0	0	0	0	719
10-11	0	0	0	0	0	0	0	0	0	2	16	50	85	85	55	24	8	2	0	0	0	0	0	327
11-12	0	0	0	0	0	0	0	0	0	0	2	12	29	40	33	18	7	2	0	0	0	0	0	143
12-13	0	0	0	0	0	0	0	0	0	0	0	2	8	15	17	12	5	2	0	0	0	0	0	61
13-14	0	0	0	0	0	0	0	0	0	0	0	0	2	5	7	6	4	1	0	0	0	0	0	25
14-15	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3	2	1	0	0	0	0	0	9
15-16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	4
16-17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17-18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sum	16	373	2616	9308	21070	34410	44041	46687	42514	34212	24268	15503	8892	4587	2143	921	372	146	55	22	8	6	2	292172

VBA scripts
for i = -
for j - -
$\cdot$(x,)



• Problem 4 Comments about exercise set 2, problem 4

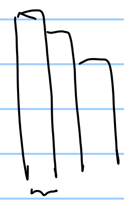
time ΔNp Pr q field

0
1 (1 month)
2

Pr

f( )

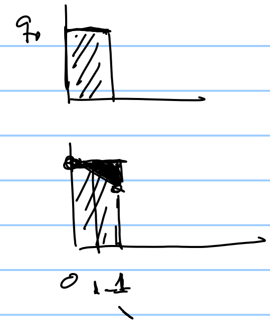
Sol



for problem 4 use rectangular integration instead of trapezoidal for calculating ΔNp to avoid converging in every time step.

assume (P_R)
↳ $q_{o max}$
↳ $q_{o field}$
↳ Np —interpolate table→ P_R^*

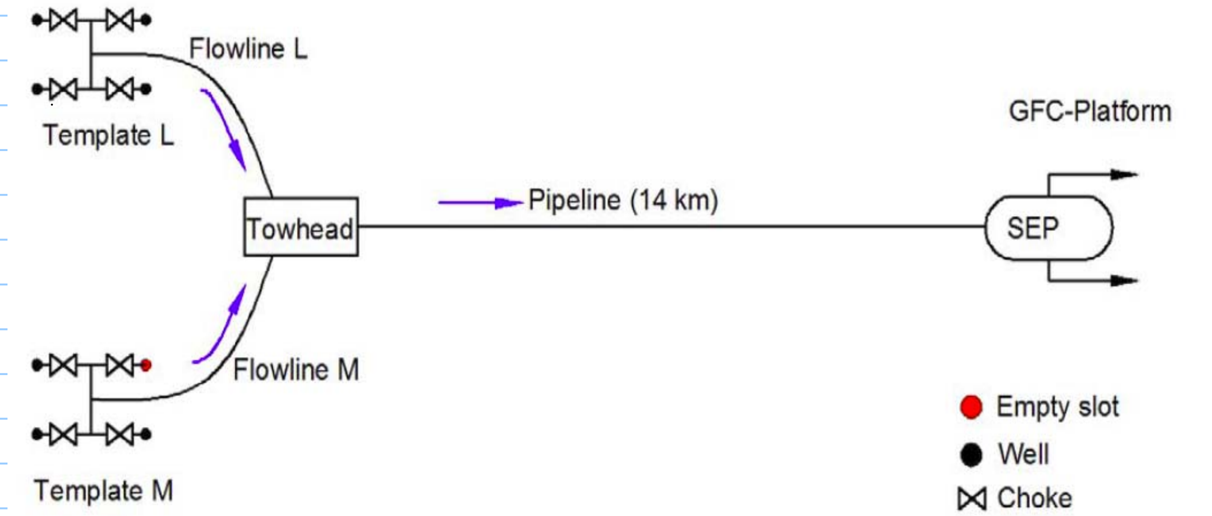
is P_R assume $= P_R^*$

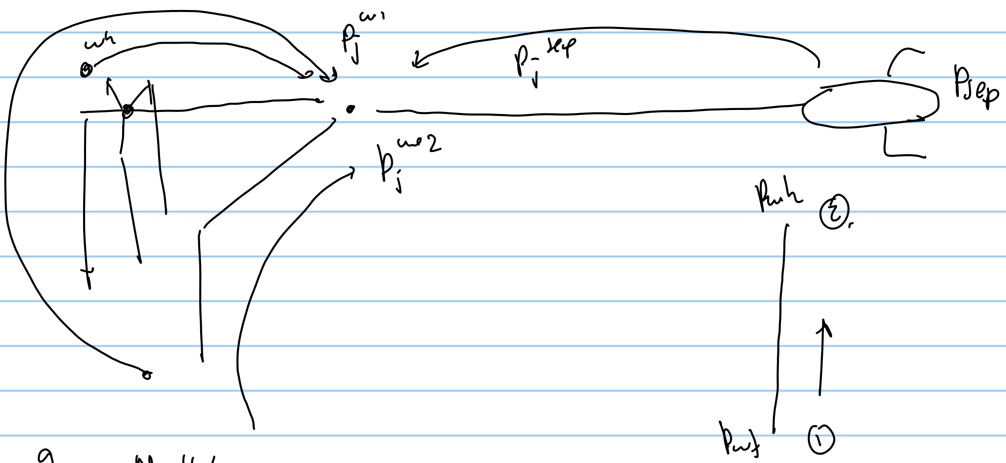


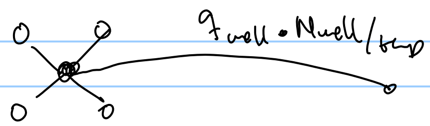
time	N_p	P_R	q produce		
0	0	-			
1					

$N_p = q_{o\,previous} \cdot (\; - \;) \cdot N_{days\,now}$

Topic for today: network solving - class exercise







$$\frac{p_j^{w1} + p_j^{w2} + p_j^{sep}}{2} = P_{av}$$

$$p_j^{w1} - P_{av} \rightsquigarrow 0$$

TPG4230, Milan Stanko, 20170228														
Separator pressure, psep	60		bara											
	Nwells	pR [bara]	pwf [bara]	C [Sm^3/bar^2n]	n	qg [Sm^3/d]	Ct [Sm^3/bar]	S	pwh [bara]	qtemp [Sm^3/d]	Cfl [Sm^3/bar]	ptowhead[bara]	error [bara^2]	
Template L	4	145	99.6	1000	0.8	1.72E+06	38152	0.43	66.6	6.89E+06	1403054	66.5	0.0	
Template M	3	102	80.4	700	0.8	5.27E+05	41163	0.34	66.5	1.58E+06	1397663	66.5	0.0	
Pipeline									qfield [Sm^3/d]=	8.47E+06	296439	66.5	0.0	
											average p, [bara]=	66.5	0.0	=Error

the reservoir engineer want to produce 1.5 E6 from each well in template L

5 E05 from " " " " M

is that possible?

TPG4230, Milan Stanko, 20170228														
Separator pressure, psep	60		bara											
	Nwells	pR [bara]	pwf [bara]	C [Sm^3/bar^2n]	n	qg [Sm^3/d]	Ct [Sm^3/bar]	S	pwh [bara]	qtemp [Sm^3/d]	Cfl [Sm^3/bar]	ptowhead[bara]	ptemp[bara]	Deltapchoke[bar]
Template L	4	145	108.1	1000	0.8	1.50E+06	38152	0.43	78.0	6.00E+06	1403054		65.3	12.8
Template M	3	102	81.9	700	0.8	5.00E+05	41163	0.34	67.9	1.50E+06	1397663		65.1	2.8
Pipeline									qfield [Sm^3/d]=	7.50E+06	296439	65.1		
											average p, [bara]=			

TENTATIVE PLAN !

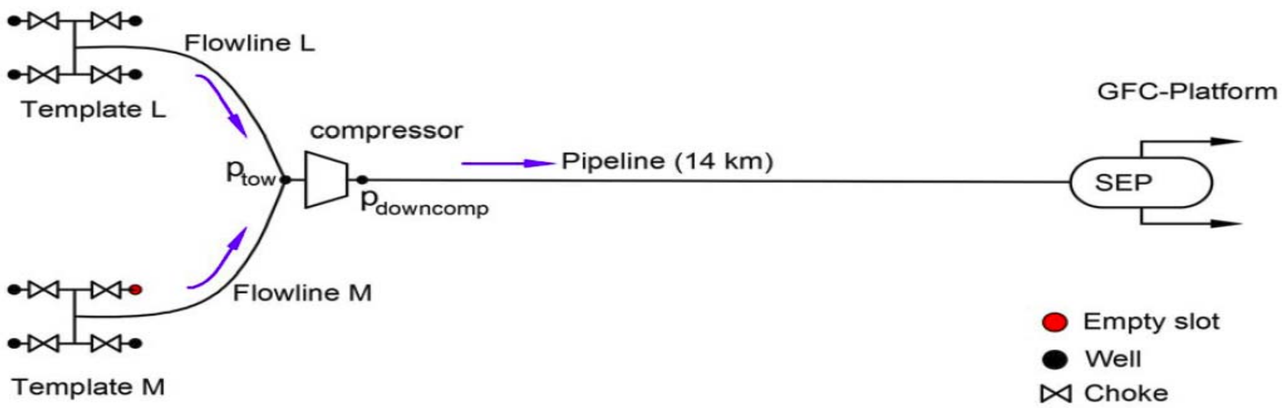
2^{nd} exercise deadline is 06.03

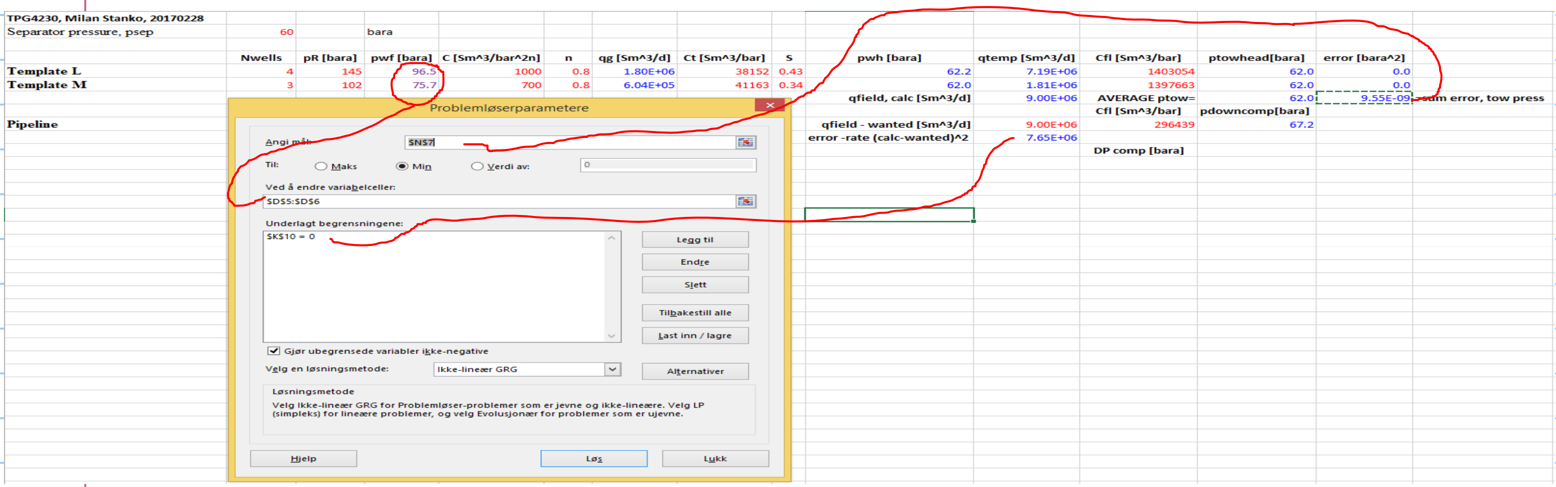
3^{rd} exercise deadline is 21.03

4^{th} exercise deadline is 09.04 ± 90 days

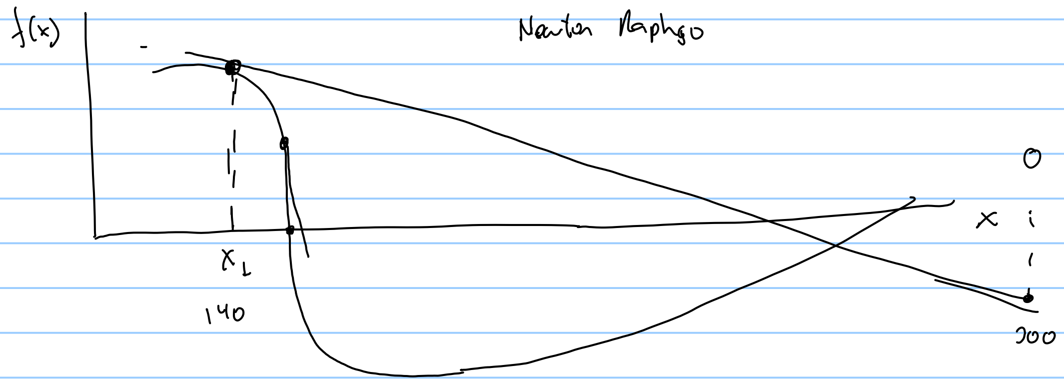
5^{th} exercise deadline is 05.05

task 2.

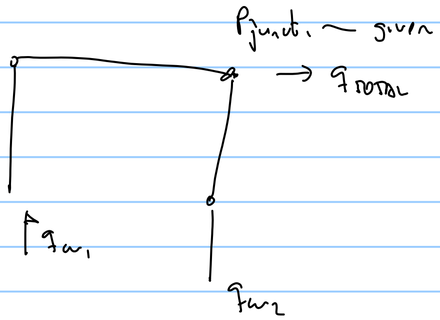




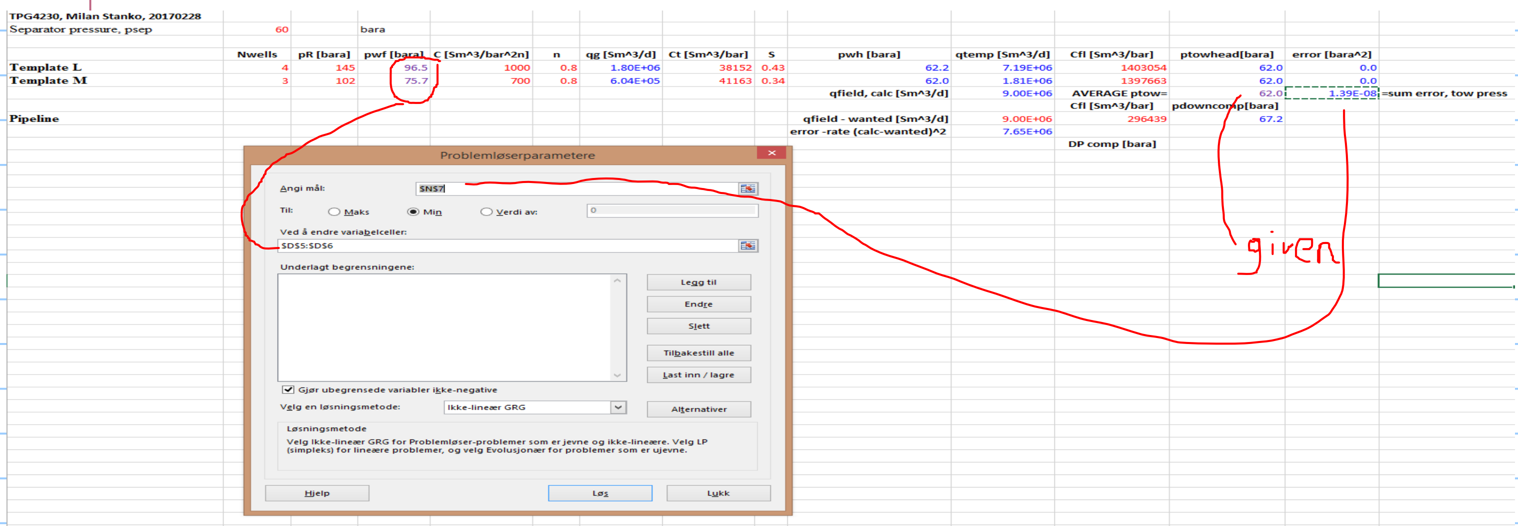
This initial setup of the solver, although sounds logical, gives VALUE! errors problems and doesn't converge. some of the bottomhole pressures tried give a negative number inside the square root. Maybe it is related with the shape of the function:
! Investigate this issue more in detail in the assignment!



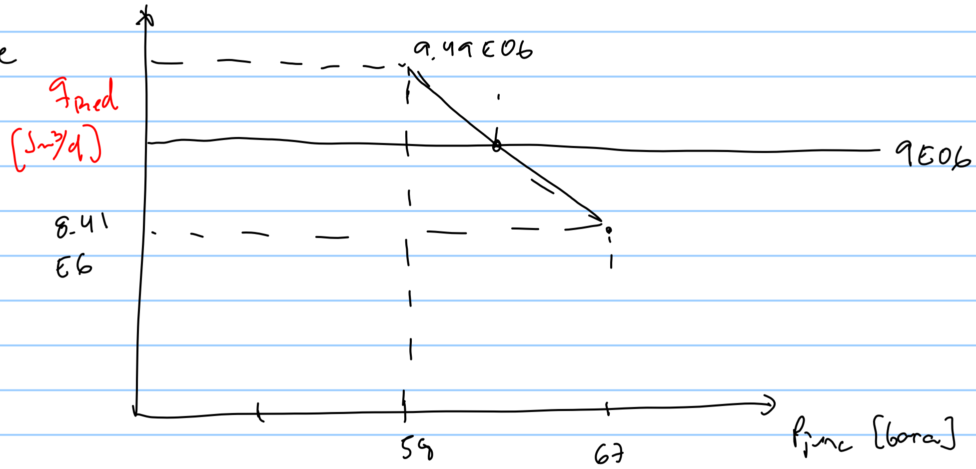
An alternative approach is suggested, "Manual solution", analyzing and converging this problem separately:



provide pav at the towhead, and take out the field rate constraint out of the solver setting. Run for several values of pav at the towhead to find the one that gives exac
09E06 Sm^3/d

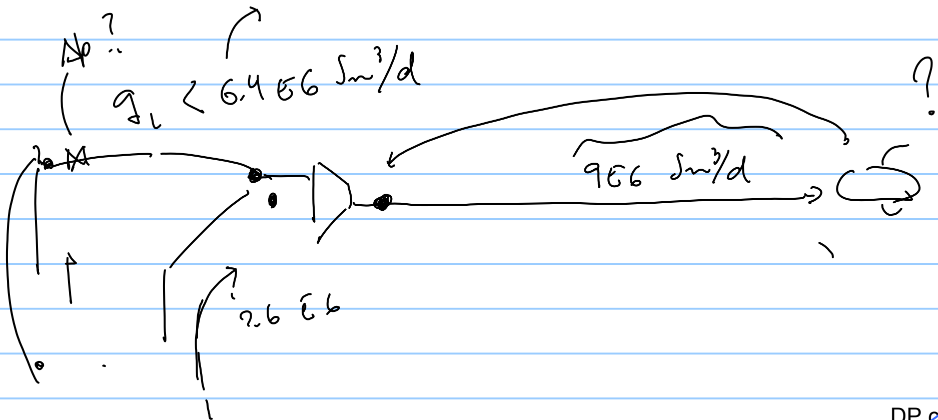


for our case



task 3

One way of solving the problem is to fix the rates in the system, 6.4 E06 Sm^3/d for template L, 2.6E06 Sm^3/d for template M and 9E06 Sm^3/d for the pipeline. Calculations are performed in the following way:
-Counter current calculation in pipeline from separator to compressor discharge.
-Co current calculations in template M from reservoir to suction of the compressor. Template M is NOT choked, thus w can perform calculations without problems.
-The DP of the choke in wells of template L is unknown. So, co-current calculations have to be carried from reservoir t wellhead, to find pressure upstream the choke and counter current calculations from the compressor suction (towheac the template (downstream the choke) the difference in pressure is the choke pressure drop.



Counter-current

DP choke = pwh-ptemp

Co-current

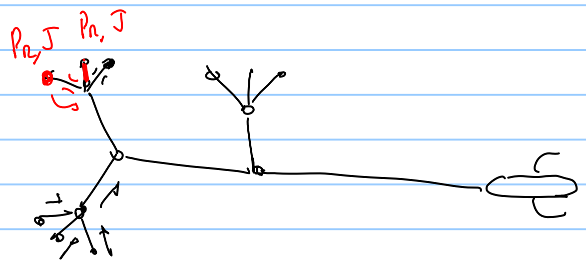
given

TPG4230, Milan Stanko, 20170228														
Separator pressure, psep		60	bara											
	Nwells	pR [bara]	pwf [bara]	C [Sm^3/bar^2n]	n	qg [Sm^3/d]	Ct [Sm^3/bar]	S	pwh [bara]	Ptemp [bara]	Deltapchoke [bara]	qtemp [Sm^3/d]	Cfl [Sm^3/bar]	ptowhead[bara]
Template L	4	145	104.4	1000	0.8	1.60E+06	38152	0.43	73.3	41.8	31.5	6.40E+06	1403054	41.5
Template M	3	102	55.3	700	0.8	8.67E+05	41163	0.34	41.6	41.6	0.0	2.60E+06	1397663	41.5
											qfield, calc [Sm^3/d]	9.00E+06	AVERAGE ptow=	
													Cfl [Sm^3/bar]	pdowncomp[bara]
Pipeline											qfield - wanted [Sm^3/d]	9.00E+06	296439	67.2
											error -rate			
													DP comp [bara]	25.7

Co-current

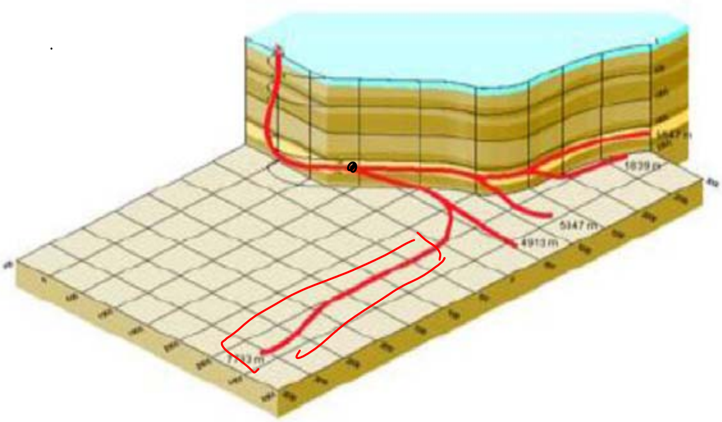
counter-current

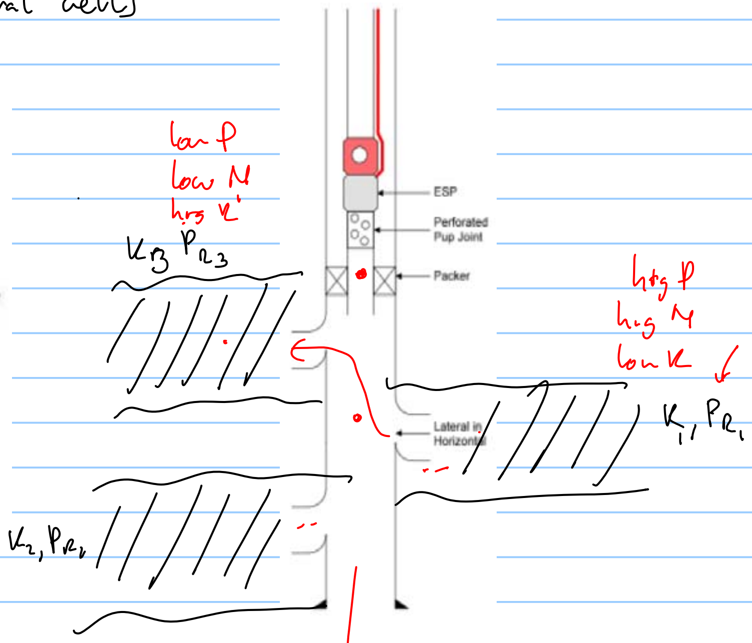
- Next class 09.03.2017 will be in P2. MBAL, PROSPER, GAP
  (mbal; flowing single well; → networks)
  (PETEX (Petroleum experts)
  10 Academic licenses available.



- • Pressure calculated counter-current and co-current is the same for a given point.
  • mass balance → surface rates should be conserved

- We have downhole networks: multilateral wells

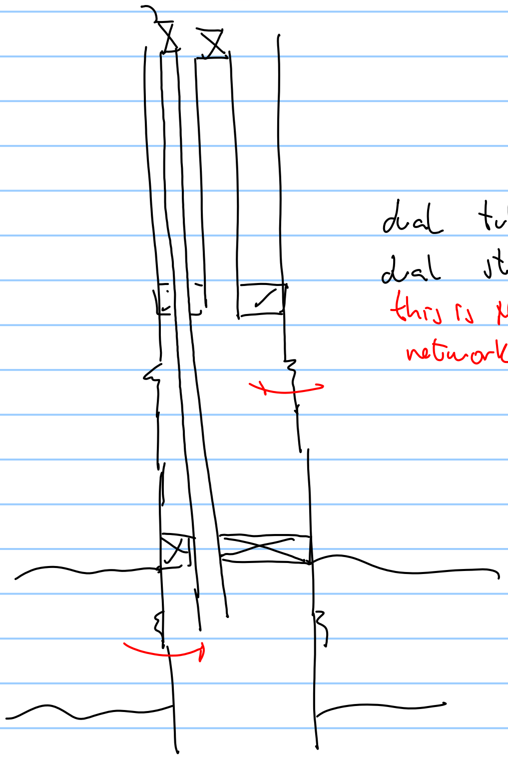




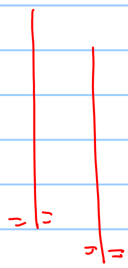
multilayer

if P_{Ri} are different one might have cross flow between formations

↑ P_R formation "charge" other formations.

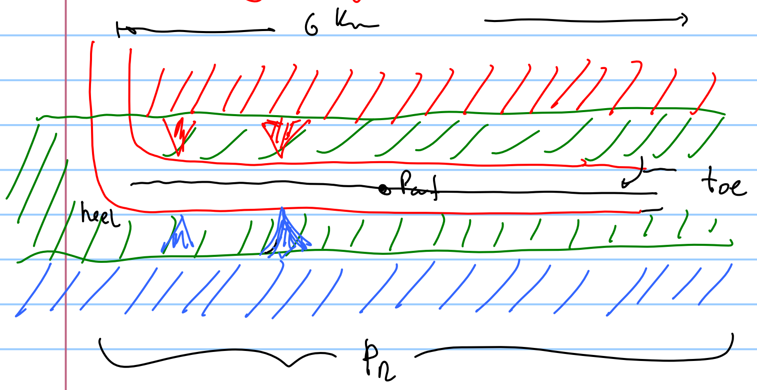


dual tubing completions
dual strings completion
this is NOT a downhole network!



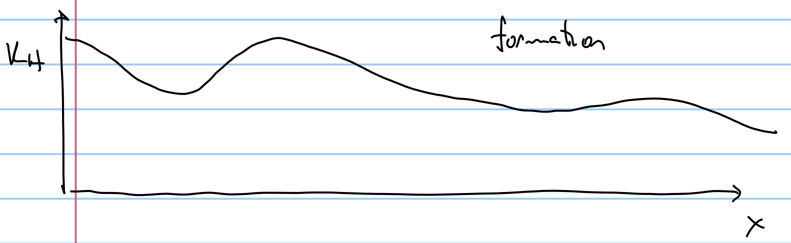
Inflow control devices (ICD) to control (passive or active) the rates coming out of a given formation, section)

in coning horizontal wells



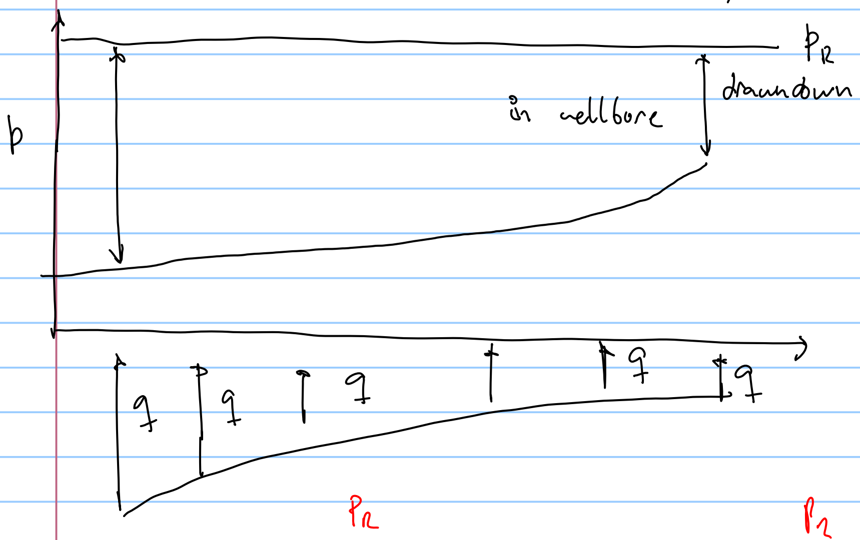
$\frac{\Delta p}{\Delta x} \propto \frac{1}{k}$

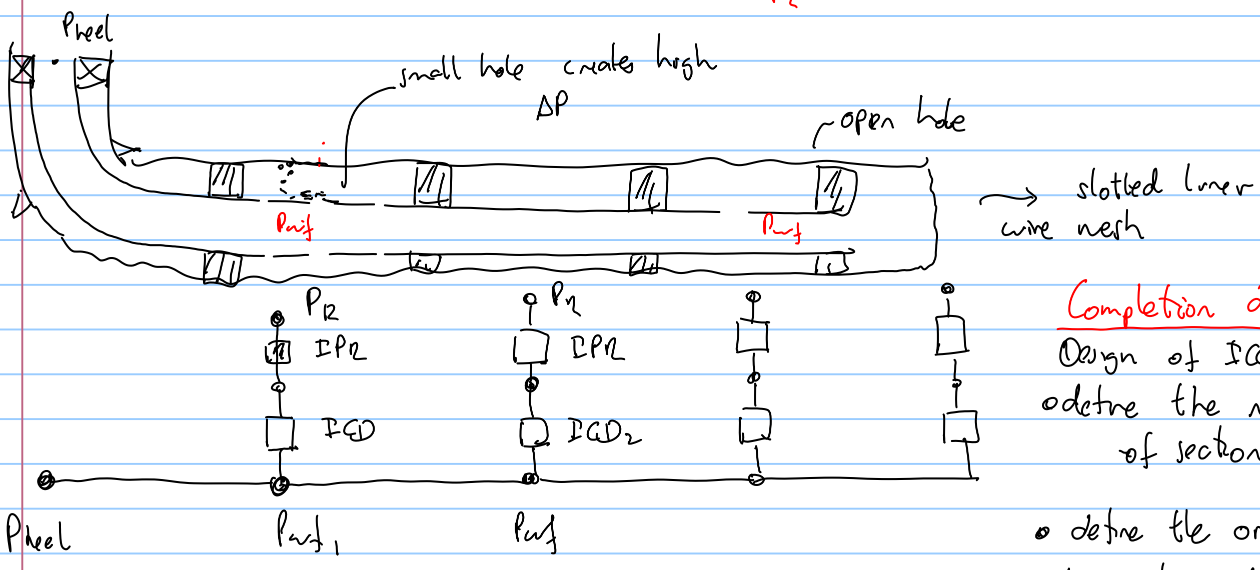
$q = \frac{k}{\mu} \frac{\partial p}{\partial r}$



this causes an uneven distribution of inflow, of reservoir rates along the wellbore

which can cause coning, uneven depletion, etc

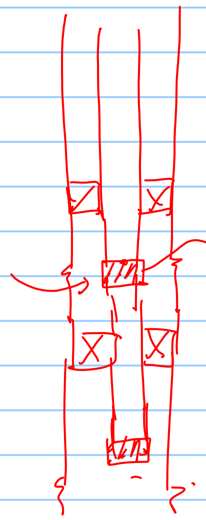




Completion design

Design of ICD
- define the number of sections
- define the orifice diameter and number of orifices

Netool ~> Weatherford ? commercial simulator to design completions.



downhole control device

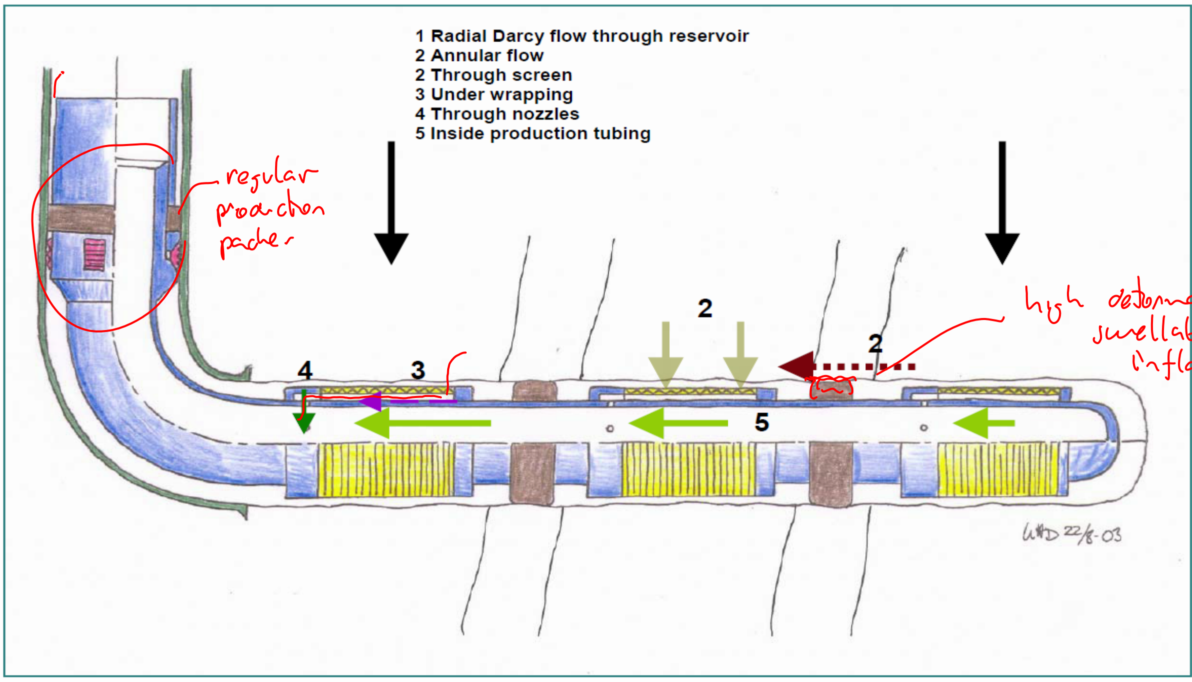
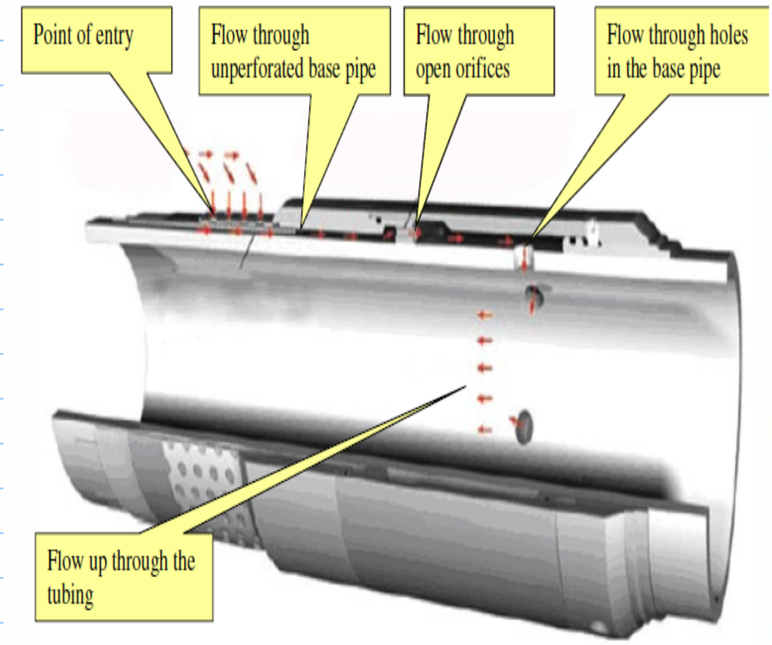


Figure-8 Functioning and interplay of an ICD completion architecture. Fluids enter the screen and flow between the axial wires and the un-perforated base pipe into the ICD housing, before passing throug
issues are properly analyzed and put in the right perspective to achieve



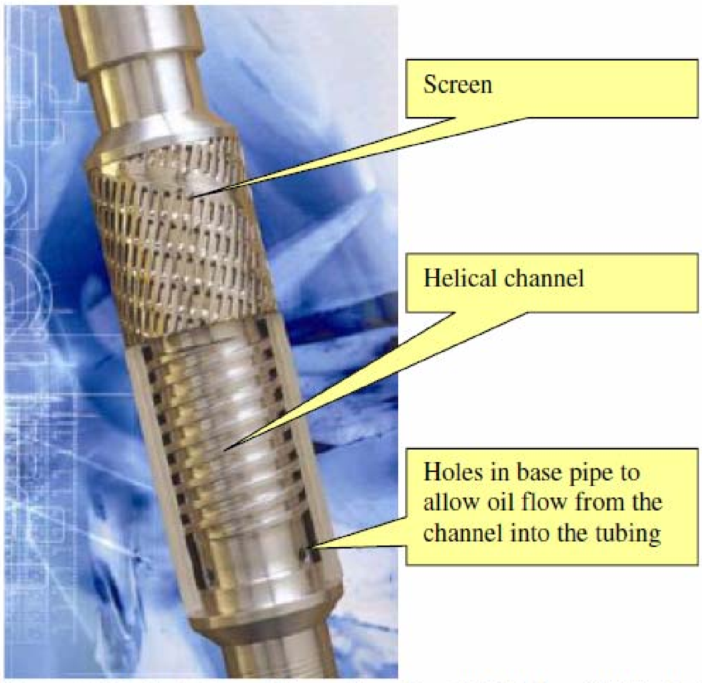


Figure 14 Helical channel type, EqualizerTM, Baker Oil Tools [22]

So far we have discussed passive inflow control devices

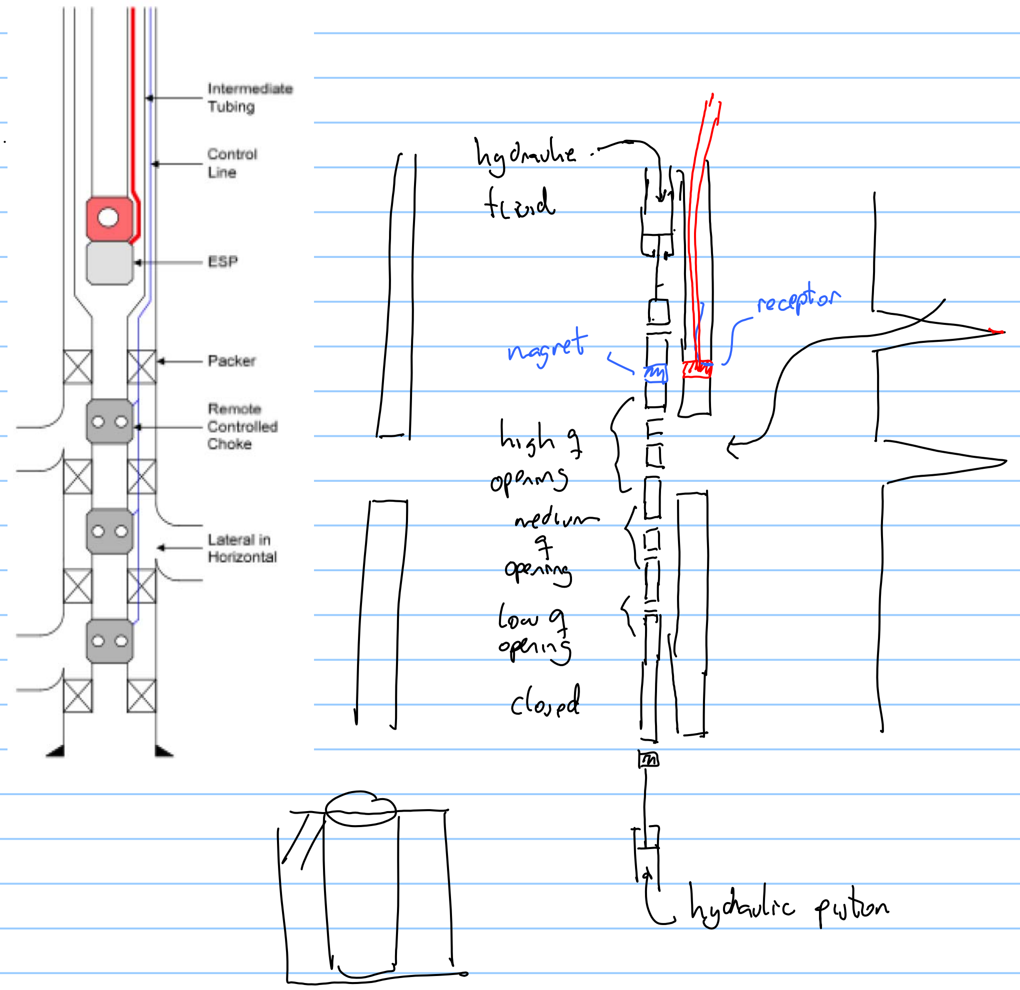
but we also have active inflow control devices (ICV)

$\underbrace{\text{(ICV)}}_{\text{inflow control valve}}$

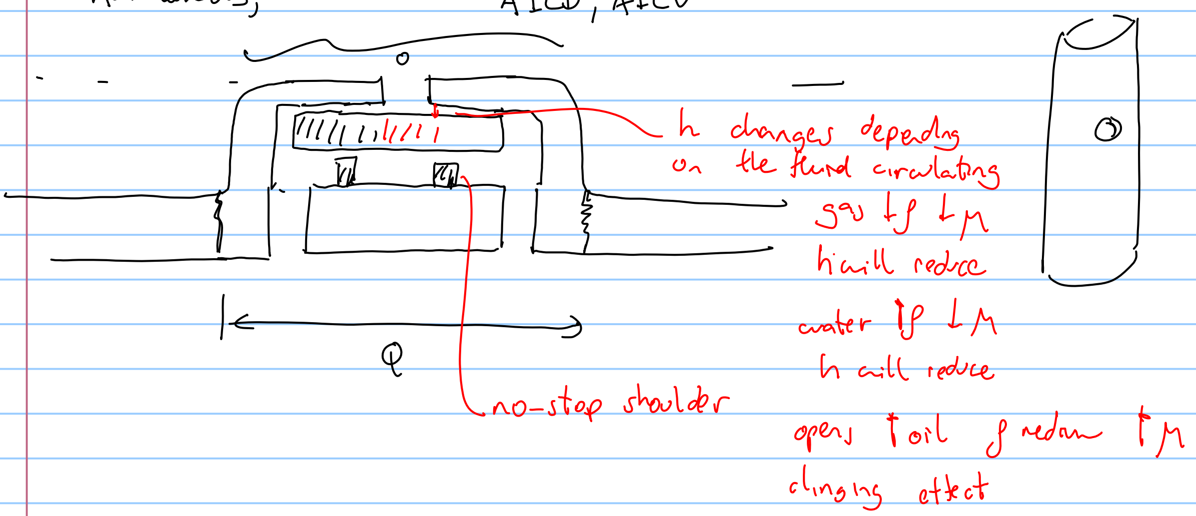
manually activated

{downhole adjustable choke}

autonomous

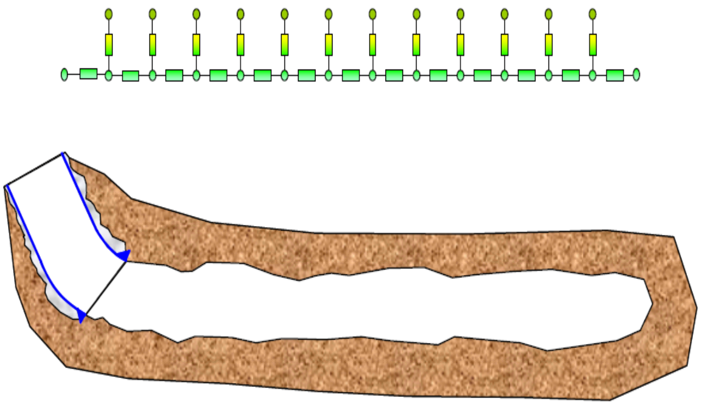


• Autonomous, AICD, AICV



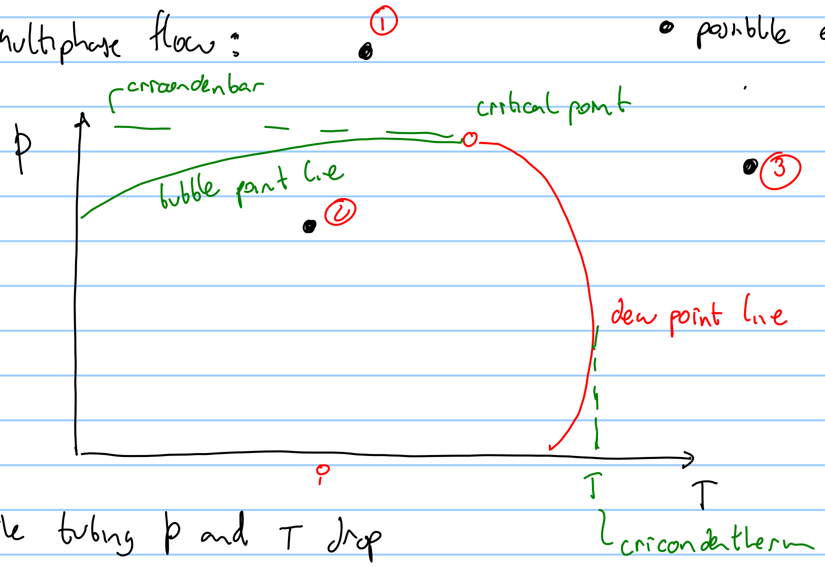
if there is a big variation of reservoir properties along the wellbore
it is also necessary to use network solving.

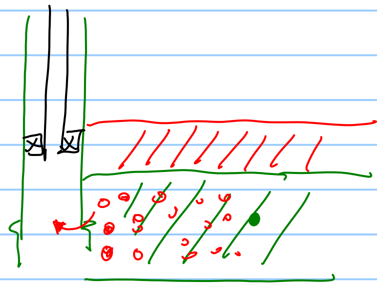
- **Horizontal well with Open Hole completion**
  - **Including damage zone**

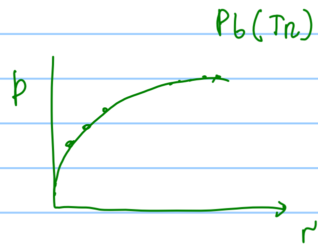


Multiphase flow:

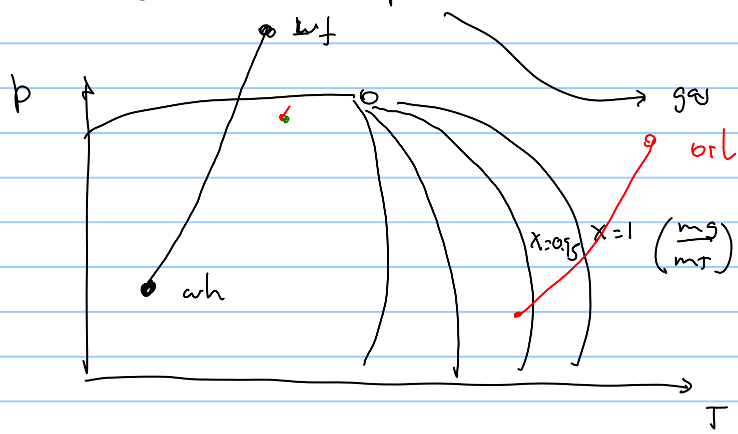
• possible entry points to wellbore



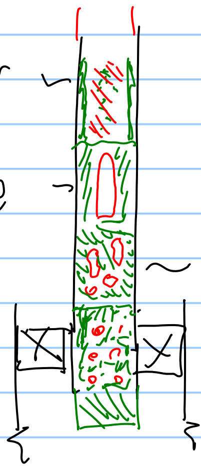




in the tubing p and T drop

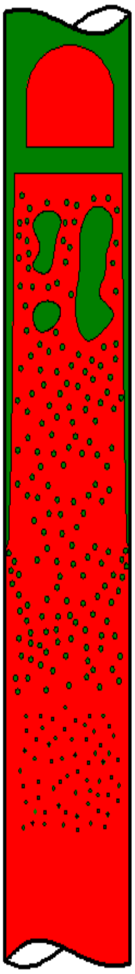


gas liberates from oil or
oil liberates from gas



flow patterns
different way how
the fluids are
spatially arranged

course on multiphase flow,
TEP4250 Ole jørge Hydal {

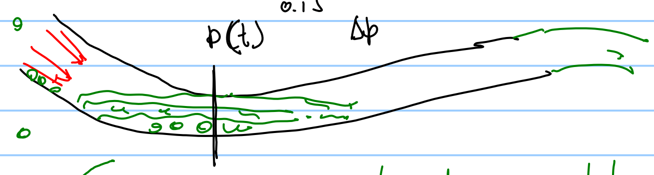


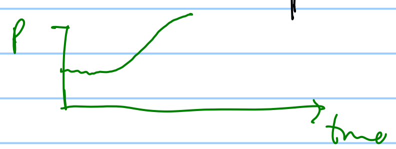
- be able to estimate Δp, ΔT with length

  due to variation in p, T, and the variation in flow patterns, the Δp calculation have to be made in a stepwise manner.

  → subdivide the tubing in segments!

- there are two ways to study multiphase flow
  - steady state $\left\{ \frac{\partial}{\partial t} = 0 \right.$
    (pipesim, pipephase, ReO, prosper, gap
  - transient



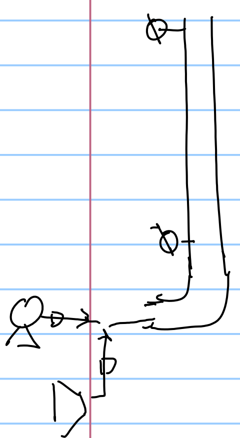


$\frac{\partial}{\partial t} \neq 0$

- liquid accumulation in gas transportation pipelines
- slugging
- slugging in risers

commercial tools : OLGA, LedaFlow.
transient multiphase flow simulator

- there are two approaches to analyze multiphase flow



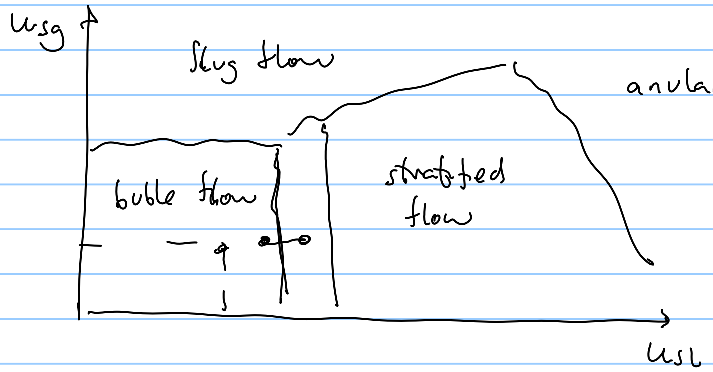
- correlation-based, Beggs and Brill, Orkiesewki, Ansari and Ros, Hagedorn and Brown

correlations develop based on experimental data, some physics and limited range of applicability

Superficial velocity $v_{sL} = \frac{q_L}{A_p} \rightarrow m^3/s$

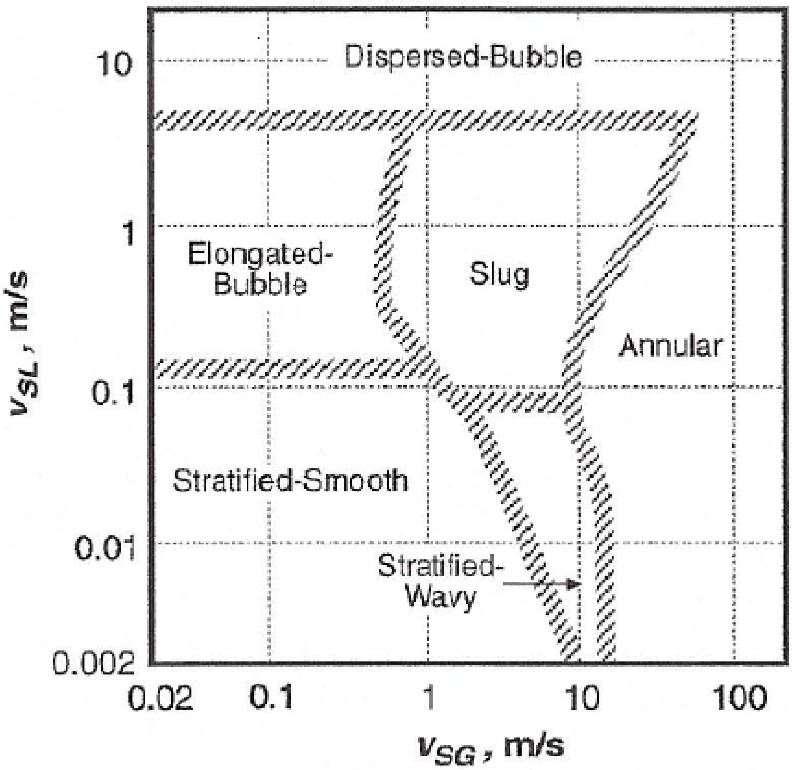
A_p ~ cross section area of pipe (πr^2)

$v_{sg} = \frac{q_g}{A_p}$



this plots depends on fluid properties $\left\{ \begin{array}{l} \rho_o, \rho_g \\ \mu_o, \mu_g \\ \sigma_{og} \end{array} \right.$

inclination, pipe diameter



Mandhane

- mechanistic modeling → applying { mass conservation for each phase
  momentum conservation { to each phase / to the mixture
  → closure laws derived empirically (by exp)

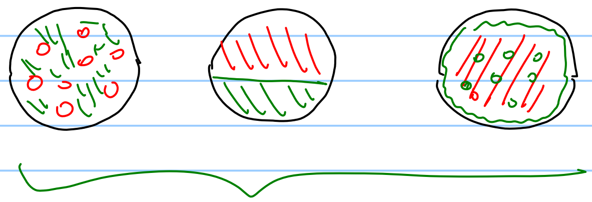
$$-\frac{dp}{dL} = \underbrace{-\left.\frac{dp}{dL}\right)_F}_{\text{friction}} \underbrace{-\left.\frac{dp}{dL}\right)_G}_{\text{gravity}} \underbrace{-\left.\frac{dp}{dL}\right)_A}_{\text{acceleration}}$$

momentum equation mixture

$$-\frac{dp}{dL} = \frac{2}{d} f_{TP(F)} \rho_{TP} v_{TP}^2 + \rho_{TP} g \sin\theta + \rho_{TP} v_{TP} \frac{dv_{TP}}{dL},$$

} momentum eq. for the mixture

ρ_{TP} → density of the mixture



$A_L + A_g = A_p$

if we assume $v_g = v_L$
- homogeneous model
- no slip model

{ bubble flow, mist flow

$\dot{m}_g$ [kg/s] $\dot{m}_L$ [kg/s]

ρ_g ρ_L @ P, T

local flow rate $q_g = \dfrac{\dot{m}_g}{\rho_g}$ $q_L = \dfrac{\dot{m}_L}{\rho_L}$

$$\underbrace{v_g = \frac{q_g}{A_g} \qquad v_L = \frac{q_L}{A_L}}$$

if homogeneous model

$v_L = v_g \Rightarrow \dfrac{q_g}{A_g} = \dfrac{q_L}{A_L}$ $A_L = A_p - A_g$

$$A_p - A_g = \frac{q_L}{q_g} A_g$$

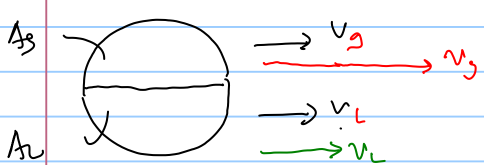
$$A_p = \left(\frac{q_L}{q_g} A_g + A_g\right)$$

$$\frac{A_p}{A_g} = \left(\frac{q_L}{q_g} + 1\right)$$

$$\frac{A_g}{A_p} = \frac{1}{\dfrac{q_L}{q_g} + 1} = \left(\frac{q_g}{q_L + q_g}\right)$$ ~ gas volume fraction (λ_g)

$$\underline{\rho_m = \lambda_g \rho_g + \underbrace{(1-\lambda_g)}_{\lambda_L} \rho_L}$$

usually $u_L \neq u_g$

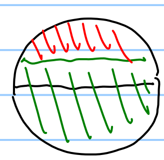


$q_g = v_g \cdot A_g$ ↑ ↓

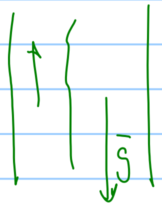
$q_L = v_L \cdot A_L$ ↓ ↑

if the gas travels faster than liquid

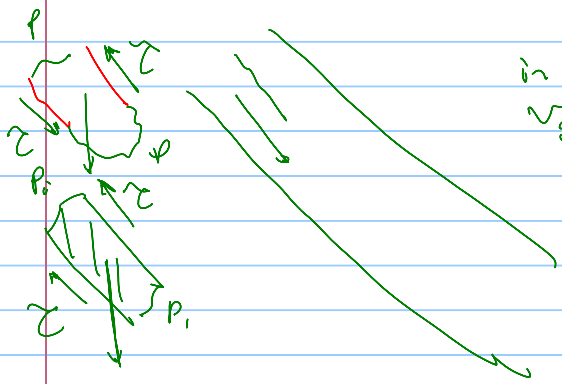
liquid holdup $= H_L = \dfrac{A_L}{A_p}$ with slip



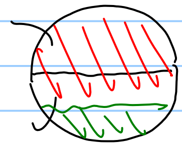
$H_L \neq \lambda_L$ $\rho_m = H_L \rho_L + (1-H_L)\rho_g$



in upwards flow gravity pulls liquid down, thus $v_g > v_L$



in downwards flow gravity helps liquid down thus $v_g < v_L$

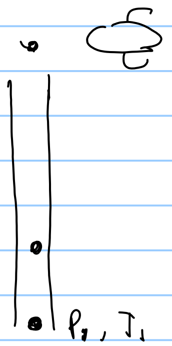


Calculating the real fluid velocities: $v_L = \frac{q_L}{A_L} = \frac{q_L}{H_L A_p} = \left(\frac{u_{SL}}{H_L}\right)$

$$v_g = \frac{q_g}{(1-H_L)A_p} =$$

- How to perform multiphase calculation in conduits

① Depart from a point with know p, T. assume rate. calculate the rest with GOR, WC. (depth)



p_1, T_1

$\uparrow q_{\bar{o}}, q_{\bar{g}}, q_{\bar{w}}$

② Covert from sc to local conditions

Black oil

compute black oil properties from table, correlation

$$\begin{bmatrix} q_g \\ q_o \\ q_w \end{bmatrix} = \begin{bmatrix} \frac{B_g}{1-R_s \cdot r_s} & \frac{-B_g \cdot R_s}{1-R_s \cdot r_s} & 0 \\ \frac{-B_o \cdot r_s}{1-R_s \cdot r_s} & \frac{B_o}{1-R_s \cdot r_s} & 0 \\ 0 & 0 & B_w \end{bmatrix}_{(p,T)} \cdot \begin{bmatrix} q_{\bar{g}} \\ q_{\bar{o}} \\ q_{\bar{w}} \end{bmatrix}$$

obtain q_g, q_o q_w

compositional model (EOS) Peng Robinson, SRK composition is available

z_i: C_1 z_{c_1}; C_2 z_{c_2}; C_3 c_{c_3}

calculate the mass fraction of oil and gas $x_g = \frac{m_g}{m_T}$ @ p, T

Calculate $\dot{m}_g$, $\dot{m}_L$ @ p, T

with $\dot{m}_T$

- calculate q_g, q_o using properties ρ_g, ρ_o

(v_{SL}, v_{Sg})

- with input v_{SL}, v_{Sg}, ϕ, inclination, $\underbrace{\varepsilon}_{\text{roughness}}$, $\rho_g, \rho_L, \mu_g, \mu_L, \sigma_{og}, \sigma_{ow}, \sigma_{gw}$

$\underbrace{\qquad\qquad\qquad\qquad}_{\text{multiphase expert}}$

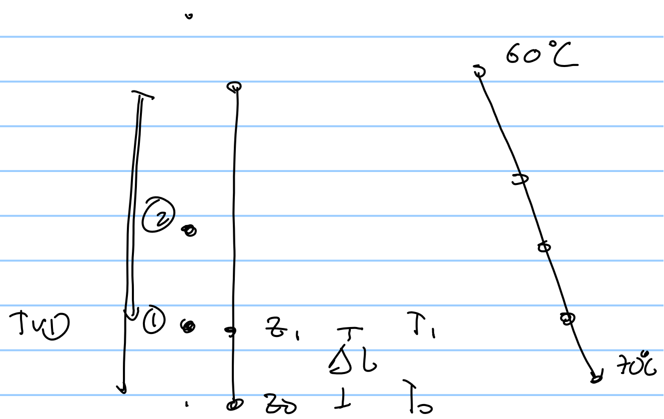
→ give me $\boxed{\frac{dp}{dz}}$

- ODE
numerical integration of ODE { explicit, implicit } { Euler's method, Corrector predictor, Runge-Kutta etc }

$\frac{dP}{dz}$ { with starting point $P = P_0$ @ $z = z_0$ }

Euler's method

$$P_1 = P_0 + \Delta L \cdot \left.\frac{dP}{dL}\right|_{z_0}$$



for the next point one needs to have T_1 beforehand

or if a Temperature drop model is available $T = f(z)$

AND Repeat !

CLASS EXERCISE

fluid calculator to calculate $x_0 = \frac{m_o}{m_T}$, ρ_S, ρ_g need a fluid model, calculator

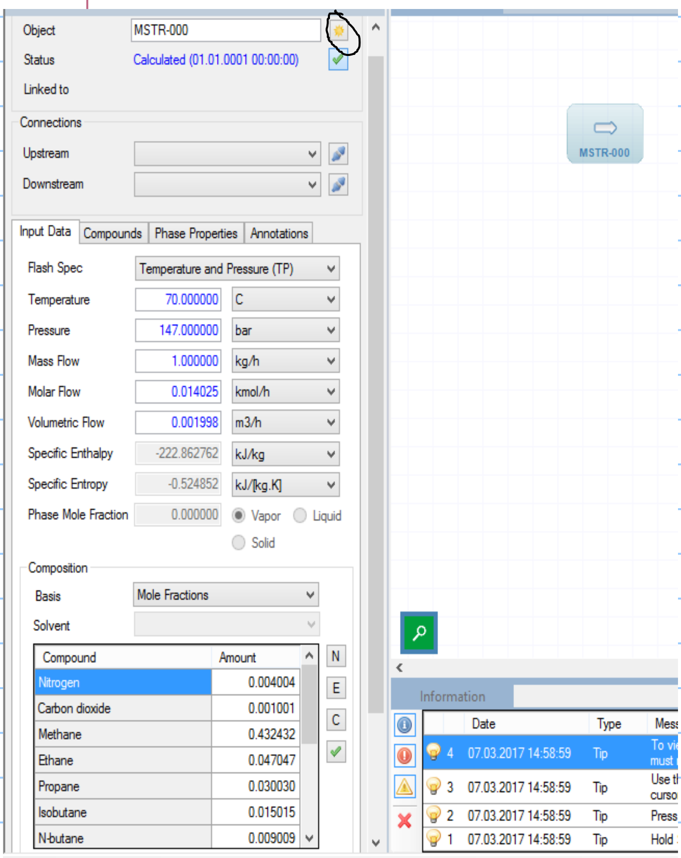
Compositional { HYSYS process simulator, DWSIM }

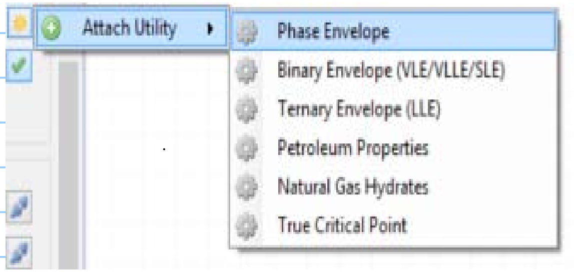
http://dwsim.inforside.com.br/wiki/index.php?title=Main_Page

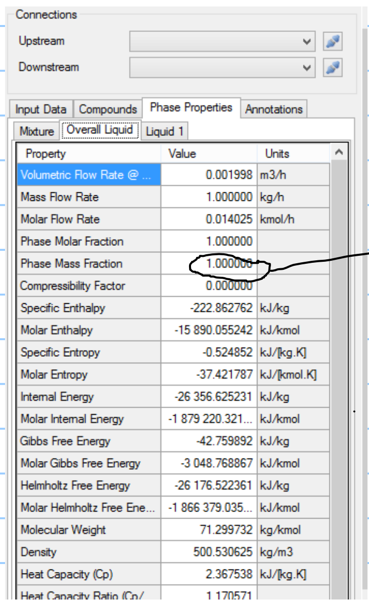
=G4*1000*G11/(24*3600)

	B	C	D	F	G
1	TPG4230, Prof. Milan Stanko, 20170307				
2		Mole %	Mole frac		
3	Nitrogen	0.4	0.004	qo [Sm^3/d]	1000
4	CO2	0.1	0.001	qg [E03 Sm^3/d]	200
5	Methane	43.2	0.432	pwf [bara]	147
6	Ethane	4.7	0.047	TR [C]	70
7	Propane	3.0	0.03	ID [m]	0.12
8	i-butane	1.5	0.015	Well TVD Depth [m]	2500
9	n-butane	0.9	0.009	Twh [C]	60
10	neo-pentane	0.0	0	Sc oil density [Kg/m^3]	850
11	i-pentane	0.8	0.008	Sc gas density [Kg/m^3]	0.91
12	n-pentane	0.5	0.005		
13	Hexanes	1.8	0.018		
14	Heptanes	4.1	0.041	mosc [kg/s]	9.8
15	Octanes	5.0	0.05	mgsc [kg/s]	=G4*1000*G
16	Nonanes	3.8	0.038	mt [kg/s]	11.9
17	Decanes	30.1	0.301		

	TVD	p	T	Liquid Mass fraction	mo	mg	deno	deng	qo	qg	vso	vsg	dp/dx
	[m]	[bara]	[C]	[-]	[kg/s]	[kg/s]	[kg/m^3]	[kg/m^3]	[m^3/s]	[m^3/s]	[m/s]	[m/s]	[bara/m]
1	2500	147	70										
2	1000												
3	500												
4	0												

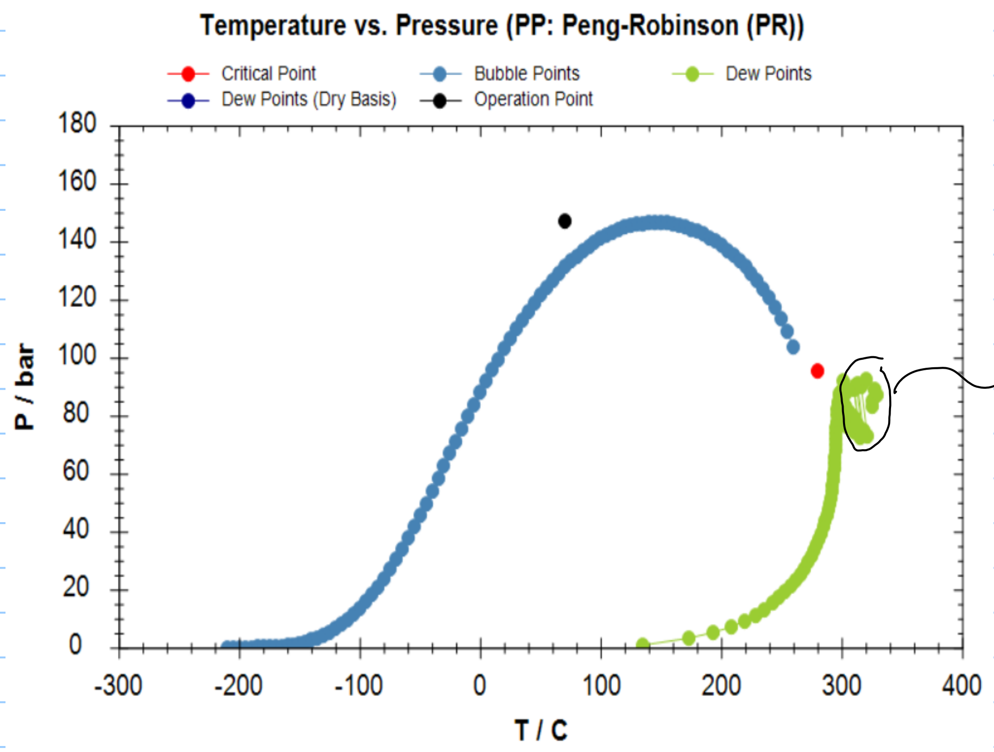






Property	Value	Units
Volumetric Flow Rate @ ...	0.001998	m3/h
Mass Flow Rate	1.000000	kg/h
Molar Flow Rate	0.014025	kmol/h
Phase Molar Fraction	1.000000	
Phase Mass Fraction	1.000000	
Compressibility Factor	0.000000	
Specific Enthalpy	-222.862762	kJ/kg
Molar Enthalpy	-15 890.055242	kJ/kmol
Specific Entropy	-0.524852	kJ/[kg.K]
Molar Entropy	-37.421787	kJ/[kmol.K]
Internal Energy	-26 356.625231	kJ/kg
Molar Internal Energy	-1 879 220.321...	kJ/kmol
Gibbs Free Energy	-42.759892	kJ/kg
Molar Gibbs Free Energy	-3 048.768867	kJ/kmol
Helmholtz Free Energy	-26 176.522361	kJ/kg
Molar Helmholtz Free Ene...	-1 866 379.035...	kJ/kmol
Molecular Weight	71.299732	kg/kmol
Density	500.530625	kg/m3
Heat Capacity (Cp)	2.367538	kJ/[kg.K]
Heat Capacity Ratio (Cp/...	1.170571	

100% liquid !

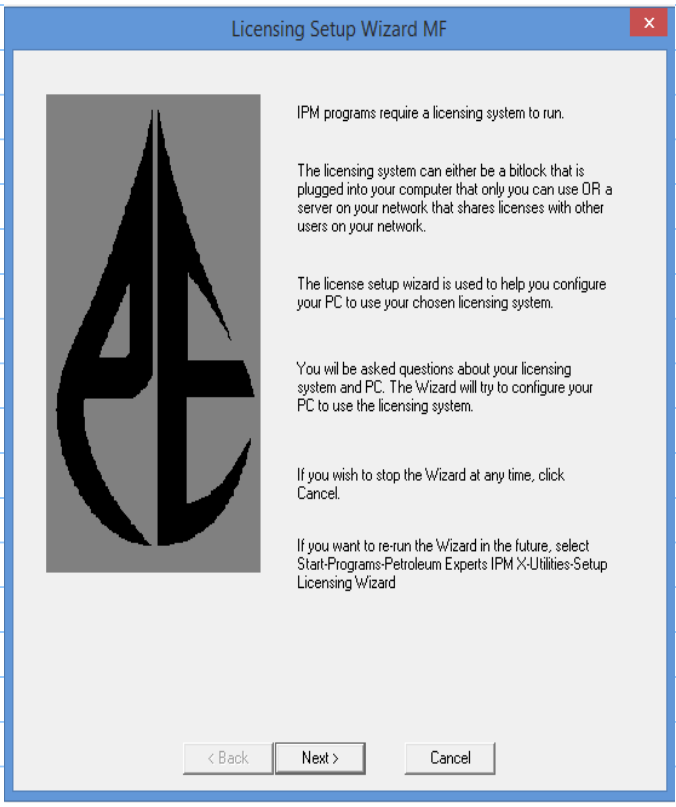


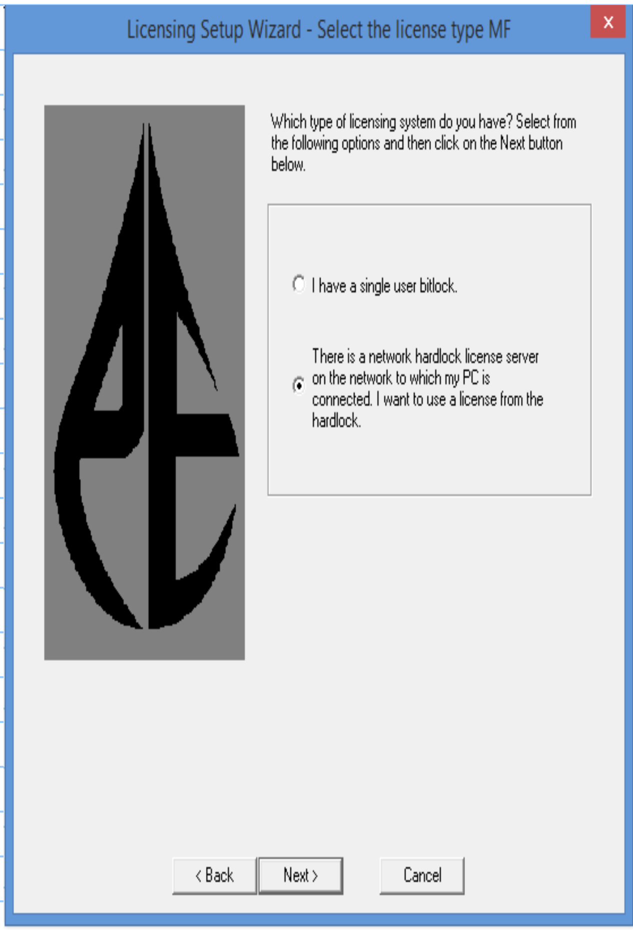
convergence error of the software

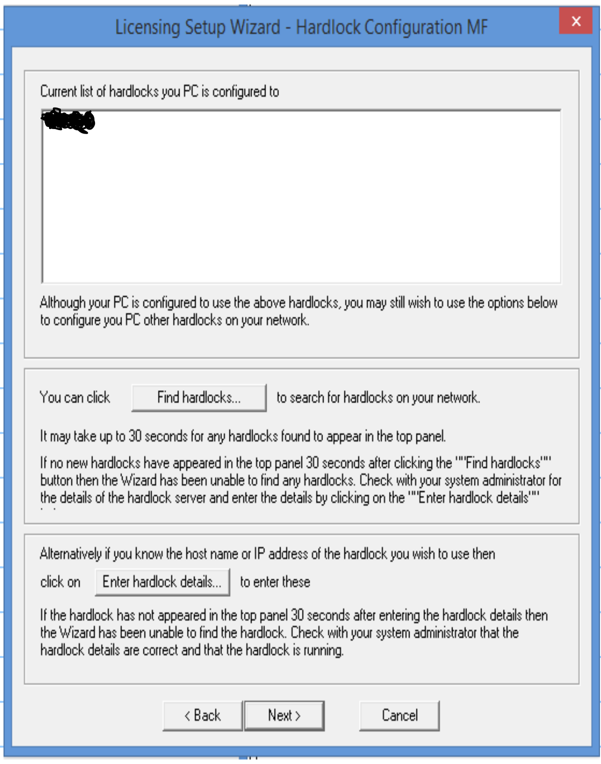
	TVD	p	T	Liquid Mass fraction	mo	mg	deno	deng	qo	qg	vso	vsg	dp/dx
	[m]	[bara]	[C]	[-]	[kg/s]	[kg/s]	[kg/m^3]	[kg/m^3]	[m^3/s]	[m^3/s]	[m/s]	[m/s]	[bara/m]
1	2500	147	70	1	11.9	0.0							
2	1000												
3	500												
4	0												

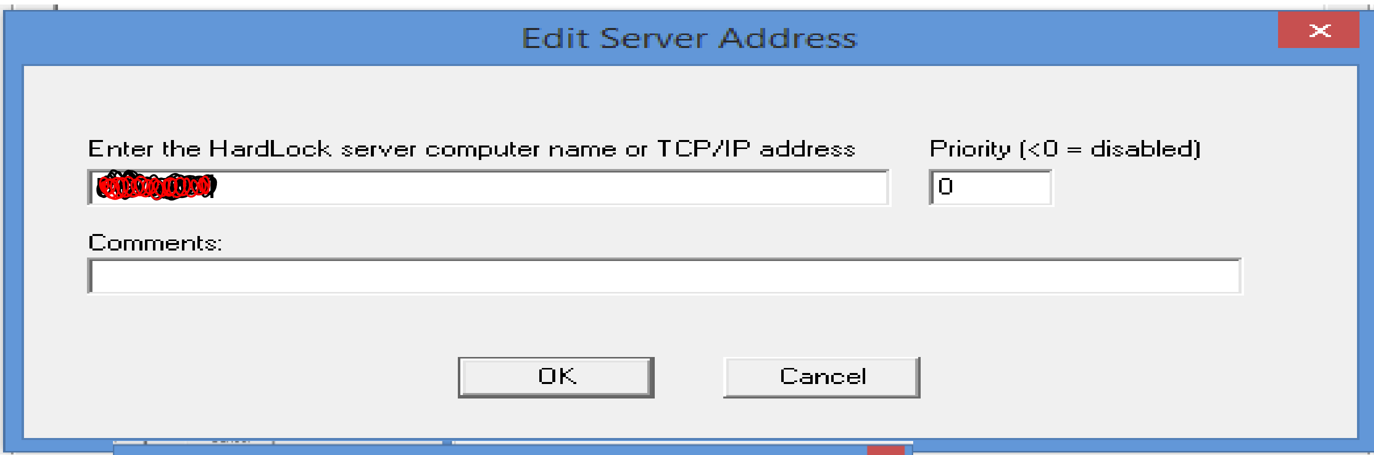
Software suite from Petroleum Experts: UK, Edinburgh

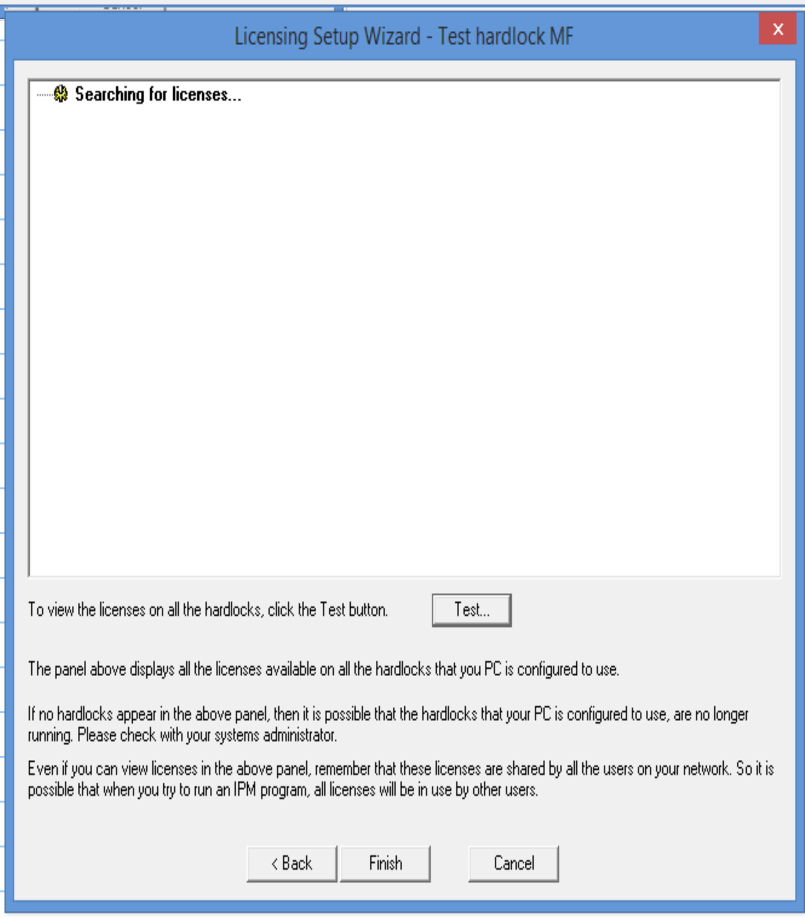
IPM Integrated petroleum management
- MBAL ~ material balance
- Prosper* ~ well modeling
- GAP* ~ networks and production systems (optimization)
- Reveal ~ res. simulator
- PVTP ~ fluid analysis and modeling
- Resolve ~ coupling between reservoir + production system
- IAM integrated asset modeling






Licensing Setup Wizard - Hardlock Configuration MF
Current list of hardlocks you PC is configured to
[redacted]
Although your PC is configured to use the above hardlocks, you may still wish to use the options below to configure you PC other hardlocks on your network.
You can click
Find hardlocks...
to search for hardlocks on your network.
It may take up to 30 seconds for any hardlocks found to appear in the top panel.
If no new hardlocks have appeared in the top panel 30 seconds after clicking the ""Find hardlocks"" button then the Wizard has been unable to find any hardlocks. Check with your system administrator for the details of the hardlock server and enter the details by clicking on the ""Enter hardlock details""
Alternatively if you know the host name or IP address of the hardlock you wish to use then
click on
Enter hardlock details...
to enter these
If the hardlock has not appeared in the top panel 30 seconds after entering the hardlock details then the Wizard has been unable to find the hardlock. Check with your system administrator that the hardlock details are correct and that the hardlock is running.
< Back
Next >
Cancel


Edit Server Address
Enter the HardLock server computer name or TCP/IP address
[redacted]
Priority (<0 = disabled)
0
Comments:
OK
Cancel


Licensing Setup Wizard - Test hardlock MF
Searching for licenses...
To view the licenses on all the hardlocks, click the Test button.
Test...
The panel above displays all the licenses available on all the hardlocks that you PC is configured to use.
If no hardlocks appear in the above panel, then it is possible that the hardlocks that your PC is configured to use, are no longer running. Please check with your systems administrator.
Even if you can view licenses in the above panel, remember that these licenses are shared by all the users on your network. So it is possible that when you try to run an IPM program, all licenses will be in use by other users.
< Back
Finish
Cancel

<u>Exercise in Prosper and GAP, TPG4230, Milan Stanko, 20170309.</u>

1. **<u>Subsea oil well modeling in Prosper</u>**

<u>Fluid information:</u>

Use the black oil correlation of Glasø (p_b, R_s, B_o) and Beal (viscosity) to model your PVT behavior.

Solution GOR = 142 Sm^3/Sm3 Producing GOR = 142 Sm^3/Sm^3 Oil gravity = 30 API (876 Kg/m^3) Gas gravity = 0.76 At initial conditions no water.	Formation Water salinity = 23000 ppm No H2S, CO2, N2. Heat capacity of oil = 2.219 KJ/Kg/K Heat capacity of gas = 2.1353 KJ/Kg/K Heat capacity of water = 4.1868 KJ/Kg/K

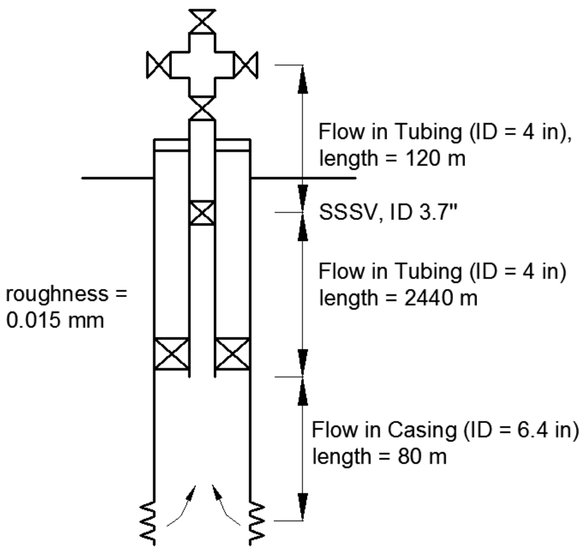
<u>Well layout:</u>

Deviation survey

MD [m]	TVD [m]
0	0
123	122
1059	1036
2164	2103
2640	2560

Geothermal gradient

MD [m]	T [C]
0	4
2640	100



Overall heat transfer coefficient = 45 W/m^2 K

<u>Reservoir info:</u>

Producing from a single layer
Reservoir pressure = 360 bara
Reservoir temperature = 100 C
Water cut = 0%

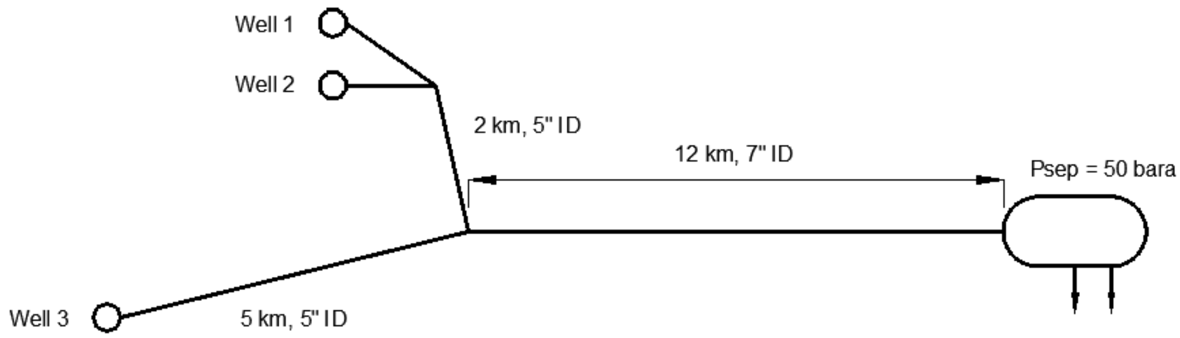
Productivity index = 12 Sm^3/d/bara

Tasks:

- Set up a prosper model of a subsea oil well.
- Report the bubble point pressure at reservoir temperature as predicted by the BO correlation.
- Estimate the producing rate using flow equilibrium assuming that the well is producing against a constant wellhead pressure of 100 bar. Is it correct to assume a linear productivity index?.
- Generate and export lift curves to be used in GAP (in the following exercise). p_{wh} range: 30-150 bara, GOR range: 141 – 500 Sm^3/Sm^3. WC range: 0 – 50 %

2. **Modeling of a subsea network with three oil wells in GAP**

The layout of the production network layout is shown below. The S riser is not included in the figure. Assume that the water depth is 300 m, and the separator is 30 m above the sea level. The production riser is a lazy "S" riser with a total length of 700 m.



The wells have the same layout as the well created in the previous section, but with different GOR, WC and PI as specified in the table below:

Well	GOR [Sm^3/Sm^3]	WC [%]	PI [Sm^3/d/bara]
Well 1	142	0	12
Well 2	200	40	8
Well 3	250	20	15

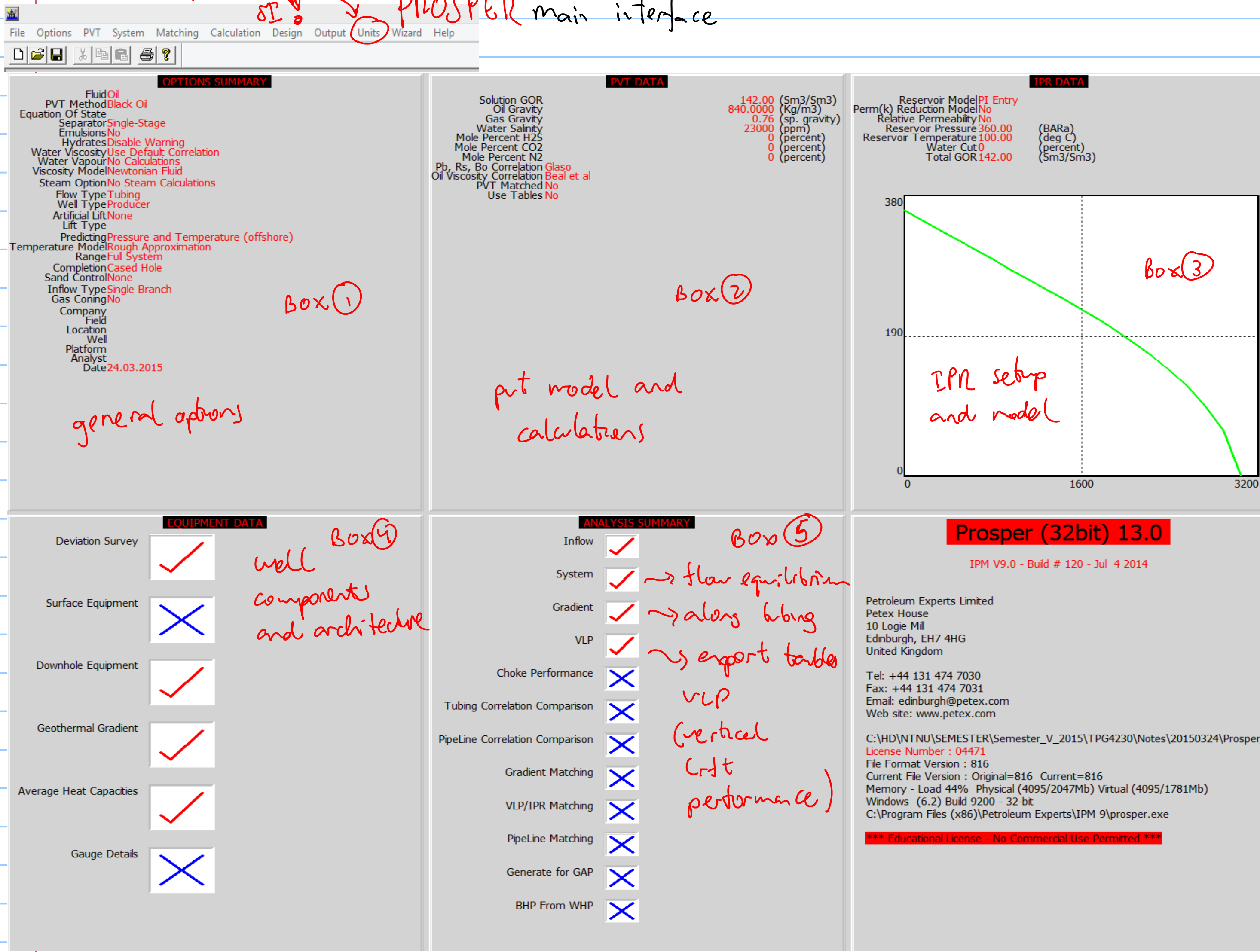
Tasks:

- Build the GAP model of three subsea wells producing to a FPSO.
- Calculate the natural equilibrium flow of the network. Report the flow potential of each well and calculate their split factor.
- Now, assume that the system has to be operated at a constant rate of 2000 Sm^3/d. Try the following methods:
  - Adding a constraint to the separator, add a choke pressure drop (controlled), and run an optimization.
  - Adding a constraint to the wells, and run an optimization

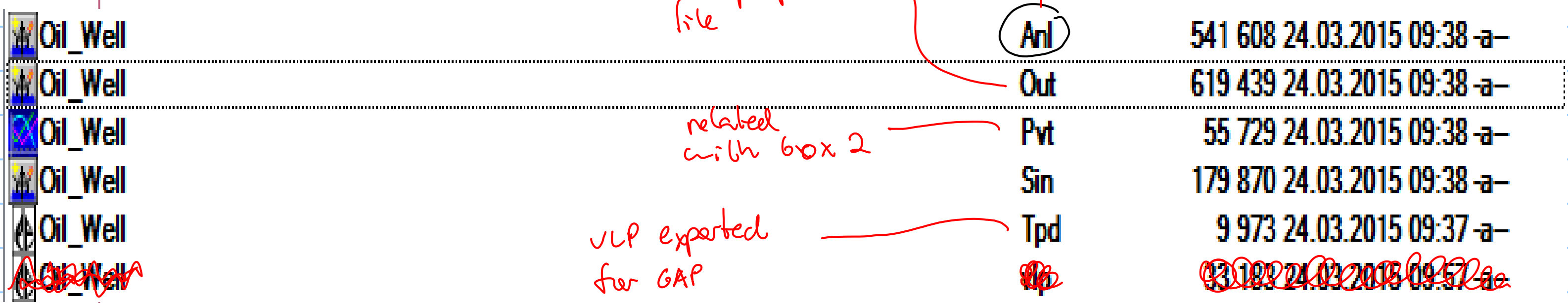
Exercise available here:
http://folk.ntnu.no/stanko/Courses/TPG4230/2017/Class_files/20170309/Exercise_in_Prosper_and_GAP.pdf

use Norwegian SI !

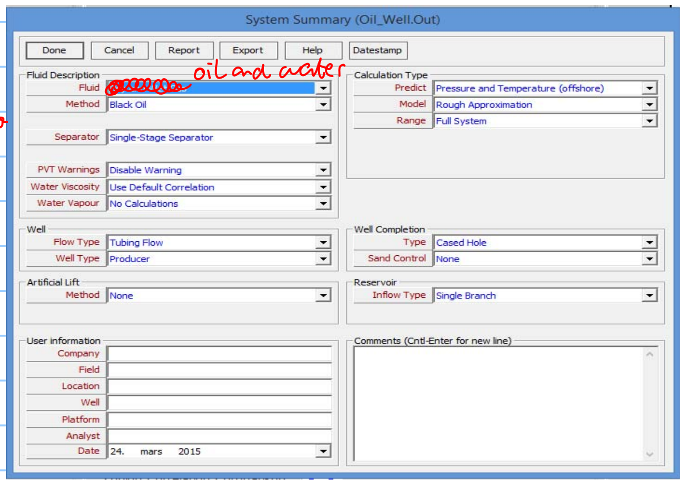
PROSPER main interface



Prosper file structure



Double click to access each box:

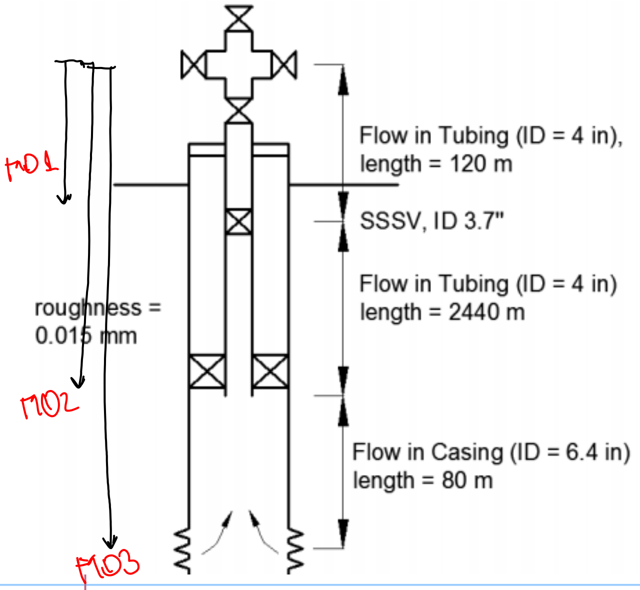


- Remember to save your file.
- the first box has to be completed to input in the other boxes

In prosper the convention to input downhole equipment is:

locate yourself at the well head (x-mas tree) and list, from top down, how many different sections do you observe: flow in tubing, flow in SSSV, flow in tubing and flow in casing.

- Introduce each one on the table. the measured depth is the depth of the end of the section measured from the well head.

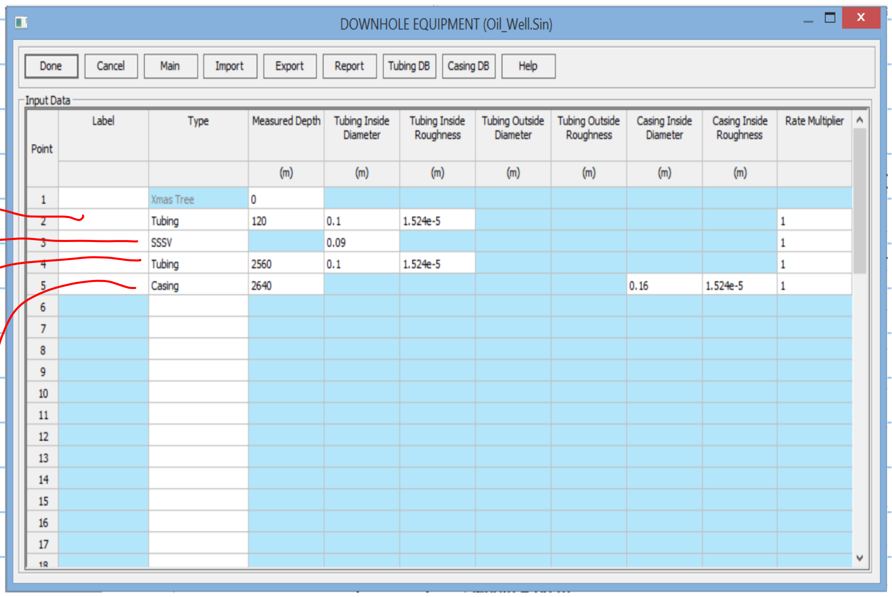


MO1

MO1 (we assume that the SSSV has no length

MO2

MO3



DOWNHOLE EQUIPMENT (Oil_Well.Sin)

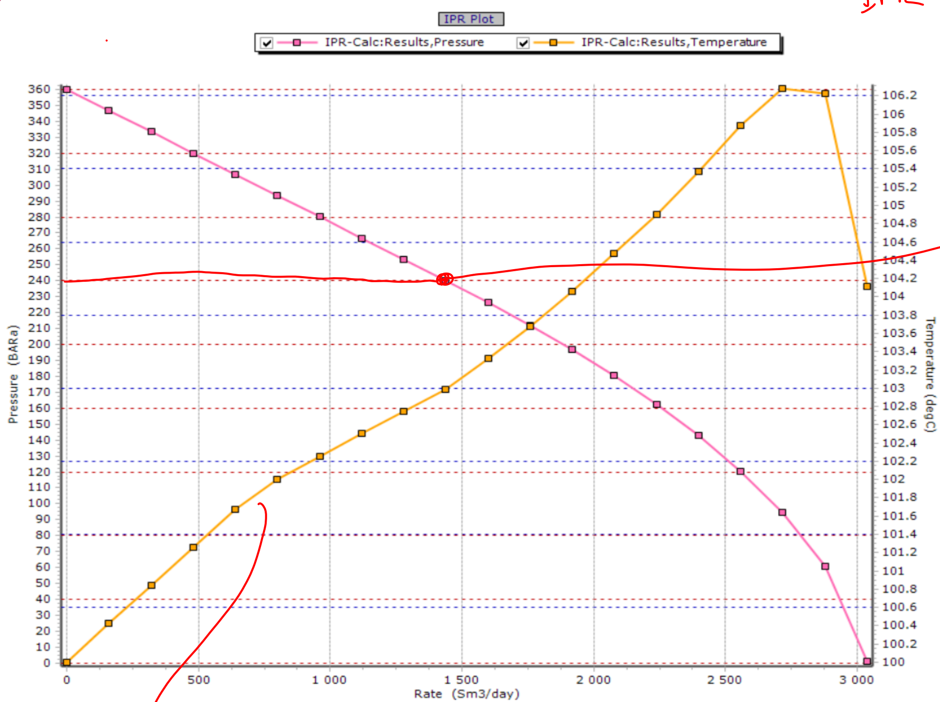
Done | Cancel | Main | Import | Export | Report | Tubing DB | Casing DB | Help

Input Data

Point	Label	Type	Measured Depth (m)	Tubing Inside Diameter (m)	Tubing Inside Roughness (m)	Tubing Outside Diameter (m)	Tubing Outside Roughness (m)	Casing Inside Diameter (m)	Casing Inside Roughness (m)	Rate Multiplier
1		Xmas Tree	0							
2		Tubing	120	0.1	1.524e-5					1
3		SSSV		0.09						1
4		Tubing	2560	0.1	1.524e-5					1
5		Casing	2640					0.16	1.524e-5	1
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										

IPR

- Before leaving the IPR
- module remember to click "calculate". In that way the IPR is available for further calculations



→ Pb (@ Tr)

bellow this Pwf the curve will deviate from the straight line.

here, PROSPER assumes that Tr ≠ Twf. this is because the fluid experiences an expansion process from Pr ⟶ Pwf.

this expansion process is often modeled as isenthalpic, meaning $h_R = h_{wf}$

P_R, T_R —— P_{wf}, T_{wf} ?

h_R h_{wf}

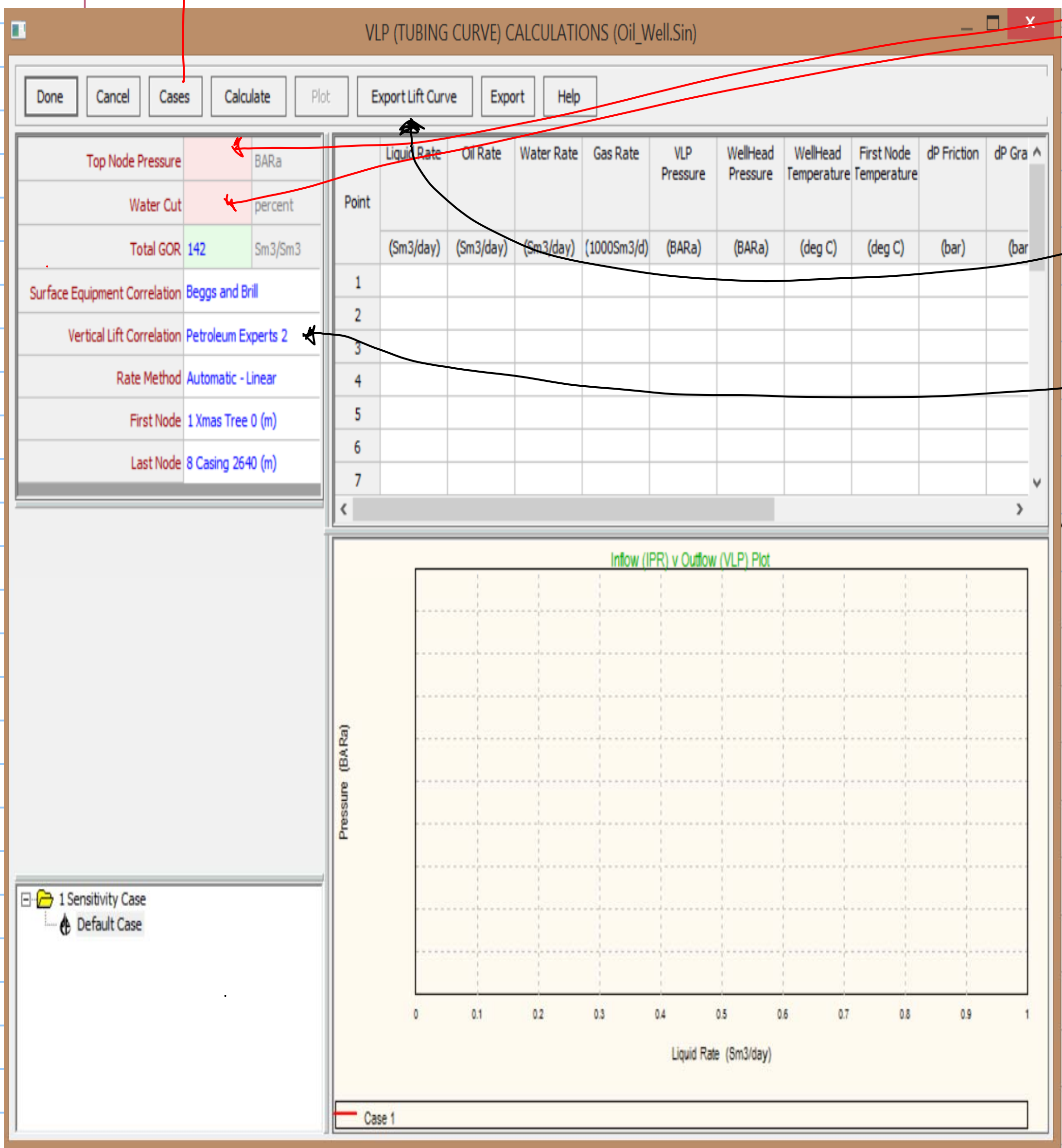
with h_{wf} and P_{wf} it is possible to calculate T_{wf}.

VLP

in "cases", the expected variations of GOR, WC, Pwh are input. To be able to access it, make sure that you filled these two boxes:

to export the curves use

multiphase "expert"



2.8.1.3.1 VLP Correlation Applications

Fancher Brown is a no-slip hold-up correlation that is provided for use as a quality control. It gives the lowest possible value of VLP since it neglects gas/liquid slip it should always predict a pressure, which is less than the measured value. Even if it gives a good match to the measured down hole pressures, Fancher Brown should not be used for quantitative work. Measured data falling to the left of Fancher Brown on the correlation comparison plot indicates a problem with fluid density (i.e. PVT) or field pressure data. **This is thus essentially, a correlation for quality control purposes.**

For oil wells, ***Hagedorn Brown*** performs well for slug flow at moderate to high production rates but well loading is poorly predicted. Hagedorn Brown should not be used for condensates and whenever mist flow is the main flow regime. Hagedorn Brown under predicts VLP at low rates and should not be used for predicting minimum stable rates.

Duns and Ros Modified The Duns and Ros Modified correlation is derived from the Duns and Ros Original correlation. The original correlation was modified by Petroleum Experts to overestimate the pressure drop in oil wells for the slug flow regime. This correlation should not be used for calculating the pressure drop in the wellbore or pipelines and hence should not be used for lift curve generation either. **This correlation should only be used for quality checking of the input well test data.**

Duns and Ros Original The Duns and Ros Original Correlation is derived from the original published method. In **PROSPER** the original Duns and Ros correlation has been enhanced and optimised for use with condensates. This correlation performs well in mist flow cases and may be used in high GOR oil wells and condensate wells.

Petroleum Experts correlation combines the best features of existing correlations. It uses the Gould et al flow map and the Hagedorn Brown correlation in slug flow, and Duns and Ros for mist flow. In the transition regime, a combination of slug and mist results is used.

Petroleum Experts 2 includes the features of the PE correlation plus original work on predicting low-rate VLPs and well stability.

Petroleum Experts 3 includes the features of the PE2 correlation plus original work for viscous, volatile and foamy oils.

Petroleum Experts 4 is an advanced mechanistic model for any angled wells (including downhill flow) suitable for any fluid (including Retrograde Condensate).

Petroleum Experts 5. The PE5 mechanistic model is an advancement on the PE4 mechanistic model. PE4 showed some instabilities (just like other mechanistic models) that limited its use accross the board. PE5 reduces the instabilities through a calculation that does not use flow regime maps as a starting point.
PE5 is capable of modelling any fluid type over any well or pipe trajectory. This correlation accounts for fluid density changes for incline and decline trajectories. The stability of the well can also be verified with the use of PE5 when calculating the gradient traverse, allowing for liquid loading, slug frequency, etc. to be modelled.

Petroleum Experts 6 includes the features of the PE3 correlation plus original work on the affects that water cut can have on a viscous oil.

Orkiszewski correlation often gives a good match to measured data. However, its formulation includes a discontinuity in its calculation method. The discontinuity can cause instability during the pressure matching process; therefore its use is not encouraged.

Beggs and Brill is primarily a pipeline correlation. It generally over-predicts pressure drops in vertical and deviated wells.

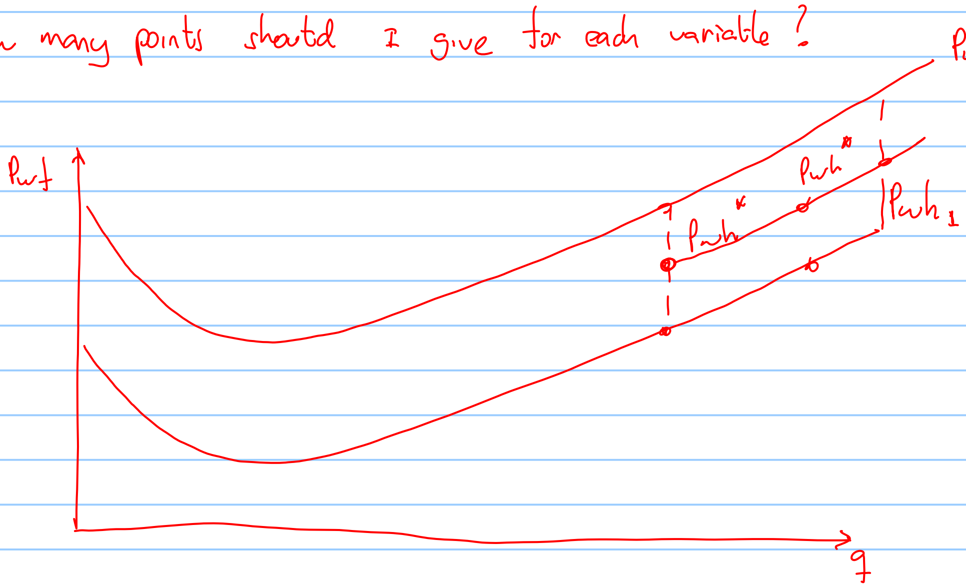
Gray correlation gives good results in gas wells for condensate ratios up to around 50 bbl/MMscf and high produced water ratios. Gray contains its own internal PVT model which over-rides **PROSPER**s normal PVT calculations.

Hydro 3P (internal) is a mechanistic model and considers three phase flow.

➲ There is no universal rule for selecting the best flow correlation for a given application. It is recommended that the Correlation Comparison always be carried out. By inspecting the predicted flow regimes and pressure results, the User can select the correlation that best models the physical situation.

Further details can be found in the **PROSPER** Appendix B | Multiphase Flow Correlations.

how many points should I give for each variable ?

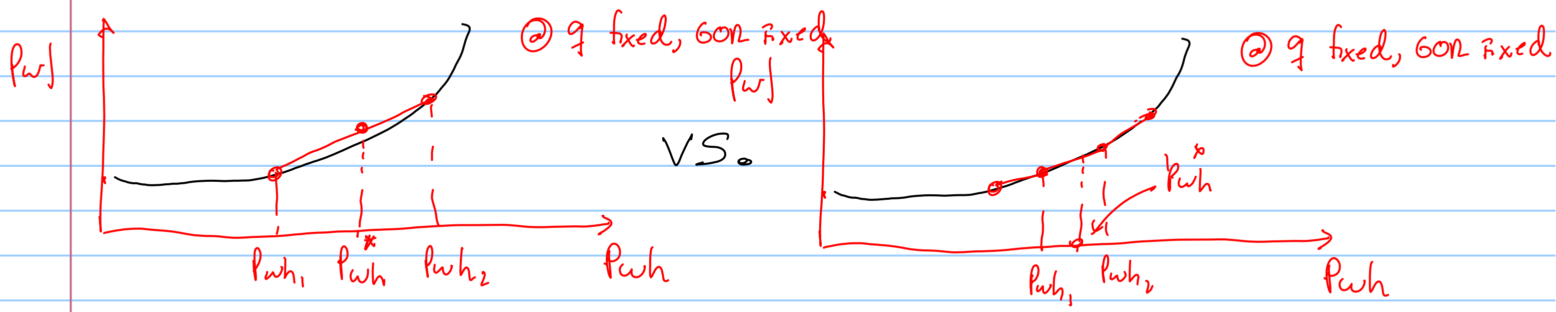


if i need Pwf for Pwh^* between

$Pwh_1 \leq Pwh^* \leq Pwh_2$

it will interpolate between the two curves above

if Pwh_1 is relatively close to Pwh_2 the interpolation error will be small.



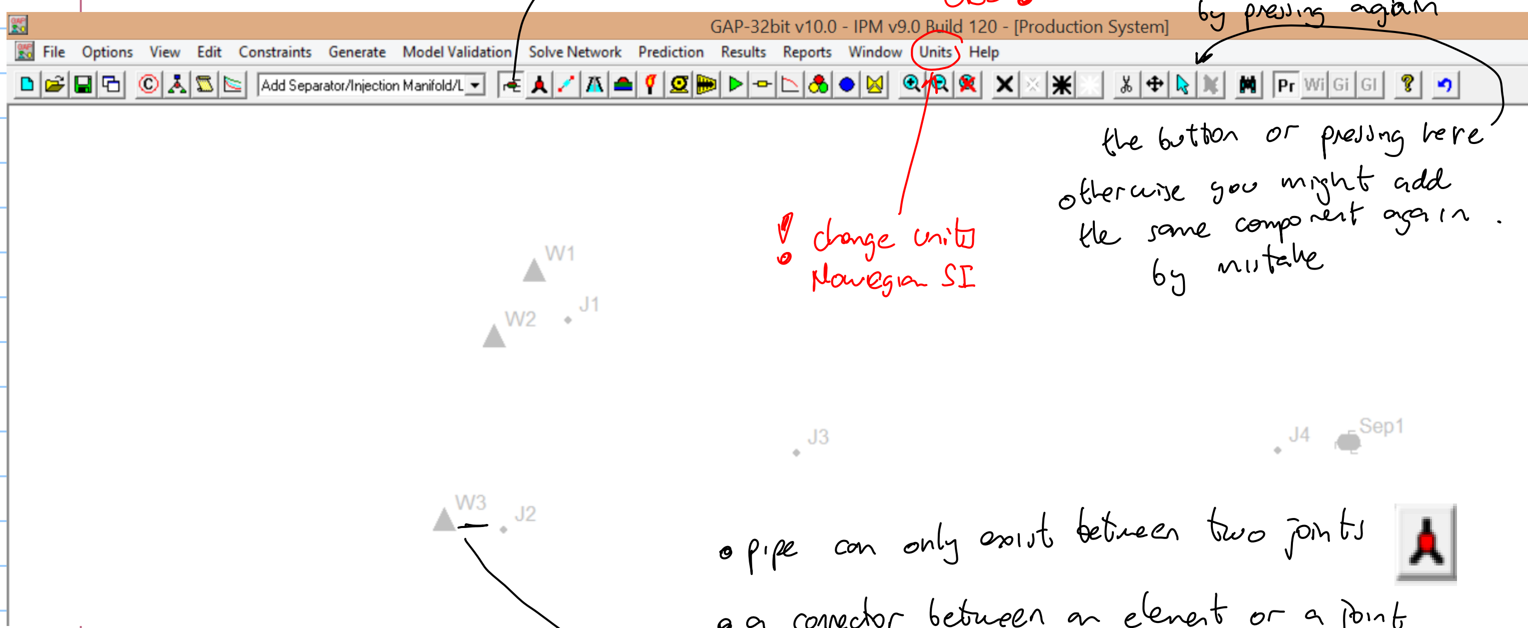
Prosper manual available here : C:\Program Files (x86)\Petroleum Experts\IPM 9\pdf\prosper

GAP network.

make the network layout

click on the element an click again in the canvas where you want to place it.

OBS ! remember to unselect it by pressing again the button or pressing here otherwise you might add the same component again by mistake.

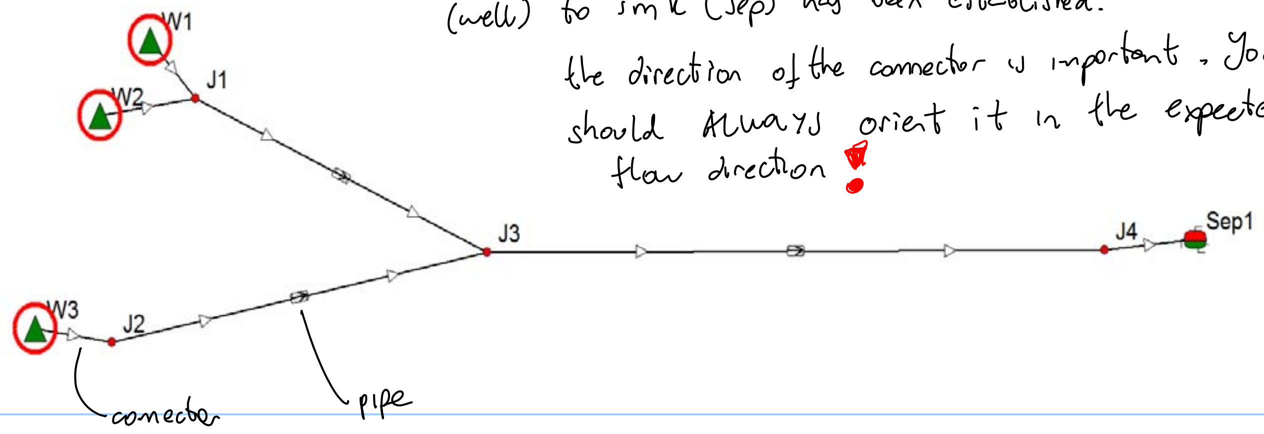


! change units Norwegian SI

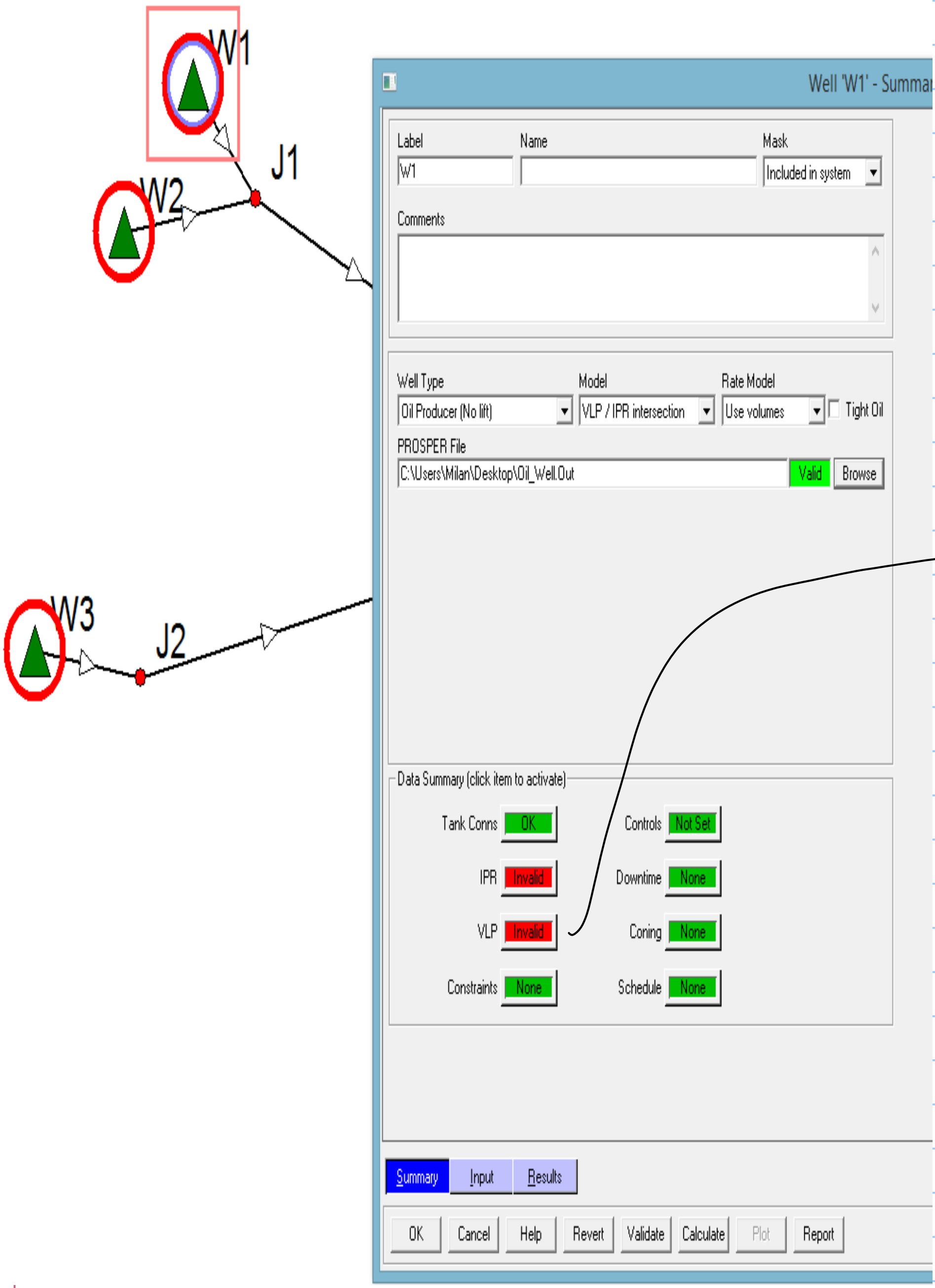
- pipe can only exist between two joints
- a connector between an element or a joint just means that the Pwh of W3 is equal to P_{J2}, have the same rates and conditions

the colors become bright when a full flow path from source (well) to sink (sep) has been established.

the direction of the connector is important. You should ALWAYS orient it in the expected flow direction!

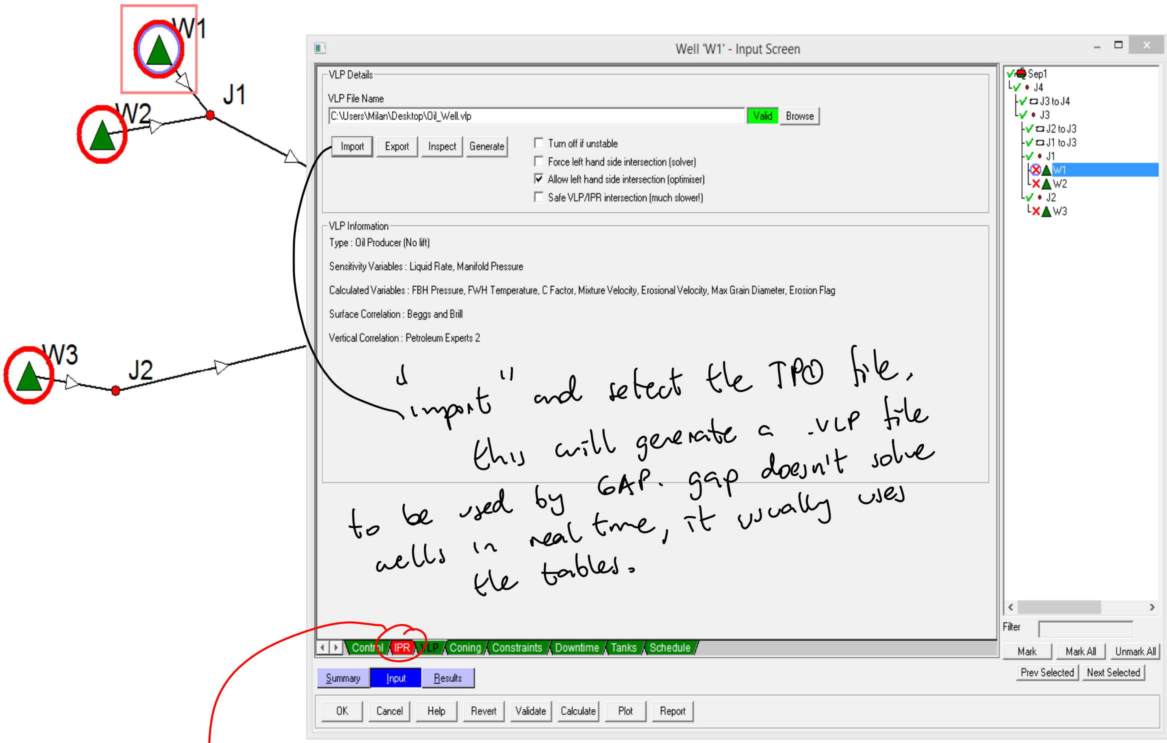


Double click on the wells and link all of them to the prosper file we just created



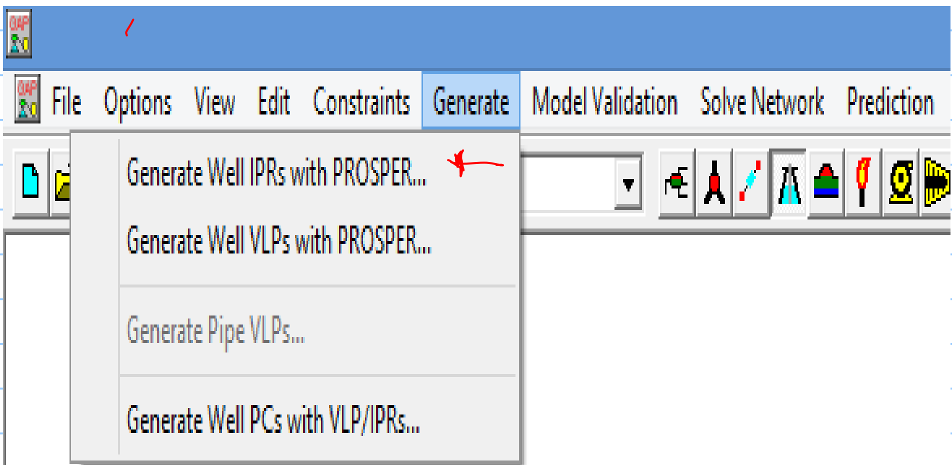
click here to assign the VLP.

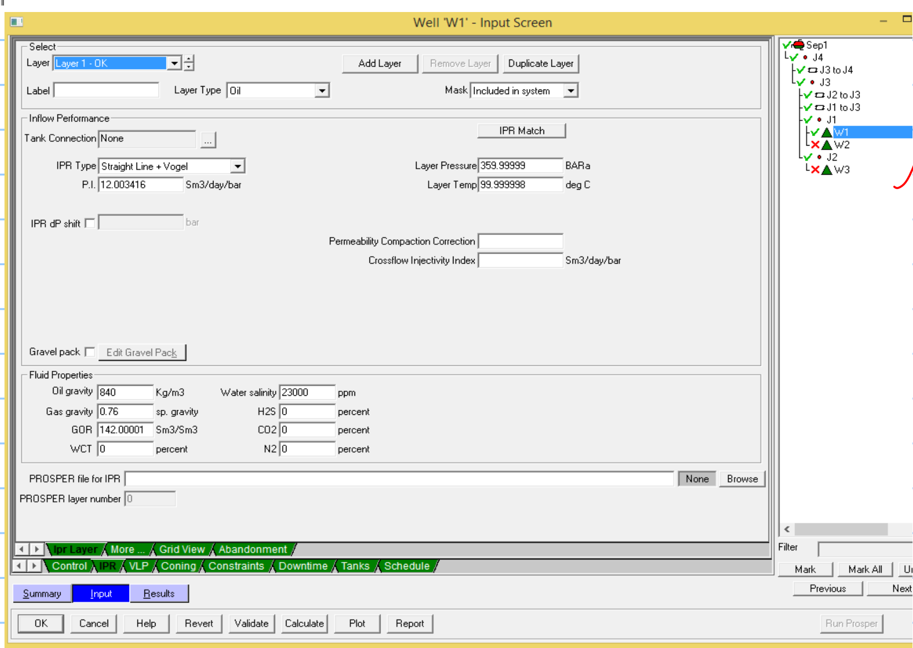
we will assume that all wells have the same layout architecture.



"import" and select the TPO file, this will generate a .VLP file to be used by GAP. gap doesn't solve wells in real time, it usually uses the tables.

IPR hasn't been defined. To transfer it from prosper to GAP go to "Generate IPR"





the IPR is transferred and then can be modified as defined in GAP.

Creating MBAL file, TPG4230, Milan Stanko, 20170314.

Fluid information:

Use the black oil correlation of Glasø (p_b, R_s, B_o) and Beal (viscosity) to model your PVT behavior.

Solution GOR = 142 Sm^3/Sm3 Producing GOR = 142 Sm^3/Sm^3 Oil gravity = 30 API (876 Kg/m^3) Gas gravity = 0.76 At initial conditions no water.	Formation Water salinity = 23000 ppm No H2S, CO2, N2.

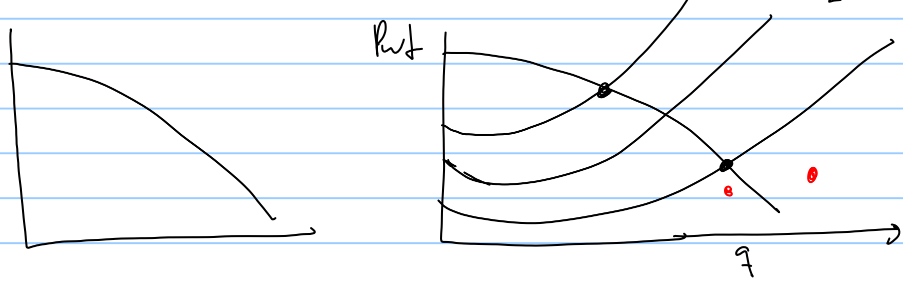
Temperature: 100 C
Initial pressure: 360 bara
Porosity: 0.3
Connate water saturation: 0.15
Original oil in place: 60 MSm^3
Start of production: 01.04.2017
Water influx: Small Pot aquifer, 180 MSm^3
Rel Perm: Corey Functions

	Residual Saturation	End Point	Exponent
	fraction	fraction	
Krw	0.15	1	1
Kro	0.15	0.8	1
Krg	0.01	0.9	1

Some coments about the usage of commercial simulators:

- QC input and results of simulator

$P_{wh_1} > P_{wh_2} > P_{wh_3}$

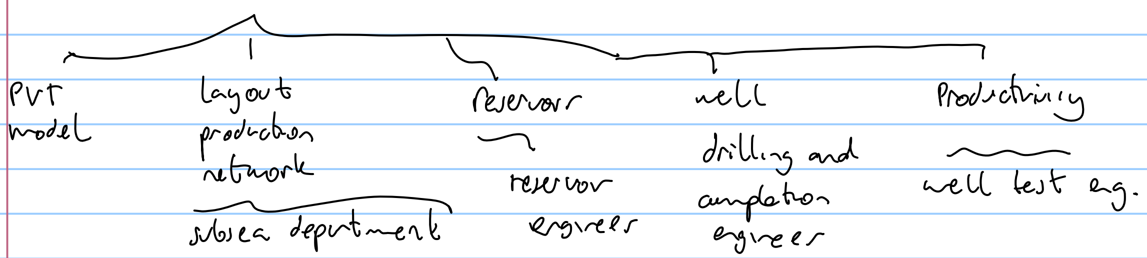


- Garbage in → Garbage out.

USE THE MANUAL!!

information.

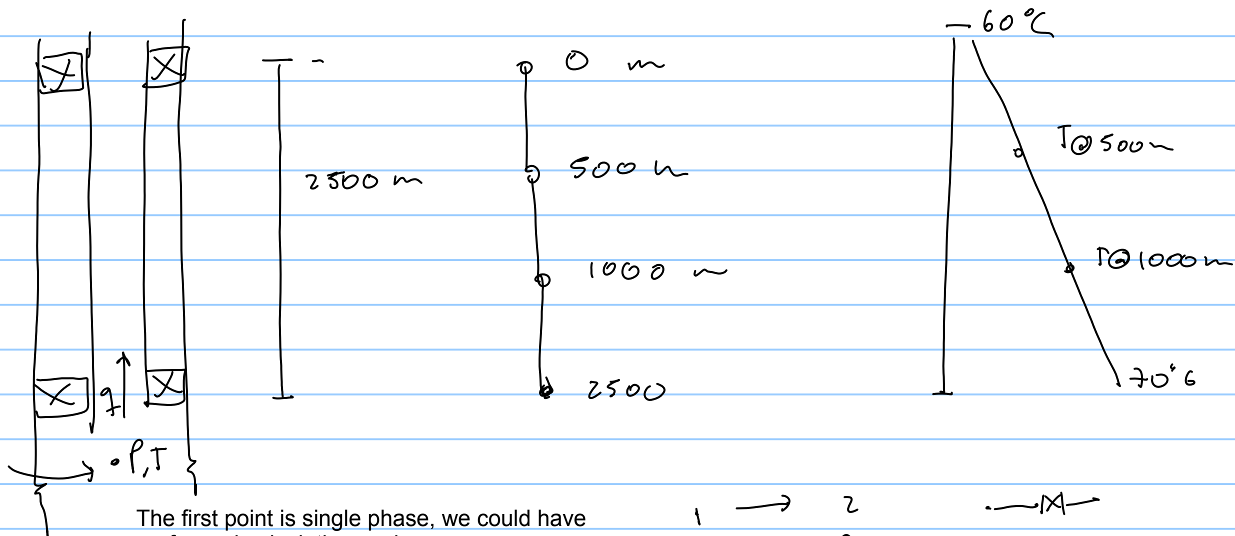
Information comes from many different sources



Extremely important for IAM integrated asset modeling.

-Have up-to-date information
-QC information

- Class exercise about pressure drop calculations in conduits with multiphase flow



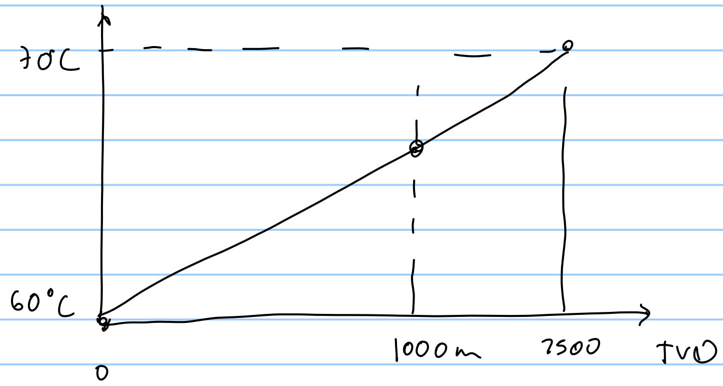
The first point is single phase, we could have performed calculations using:

$h_1 = h_2$

$$\frac{P_1}{\rho_1 g} + z_1 + \frac{v_1^2}{2g} = \frac{P_2}{\rho_2 g} + z_2 + \frac{v_2^2}{2g} + h_f$$

Bernoulli conservation equation for incompressible fluid

$$h_f = f \frac{L}{\Phi} \frac{v^2}{2g} \qquad h_{ac} = K \frac{V^2}{2g}$$



$$\left(\frac{70-60}{2500-0}\right) = \left(\frac{70-T}{2500-1000}\right)$$

T

1500 $\rho = 1000\ kg/m^3$

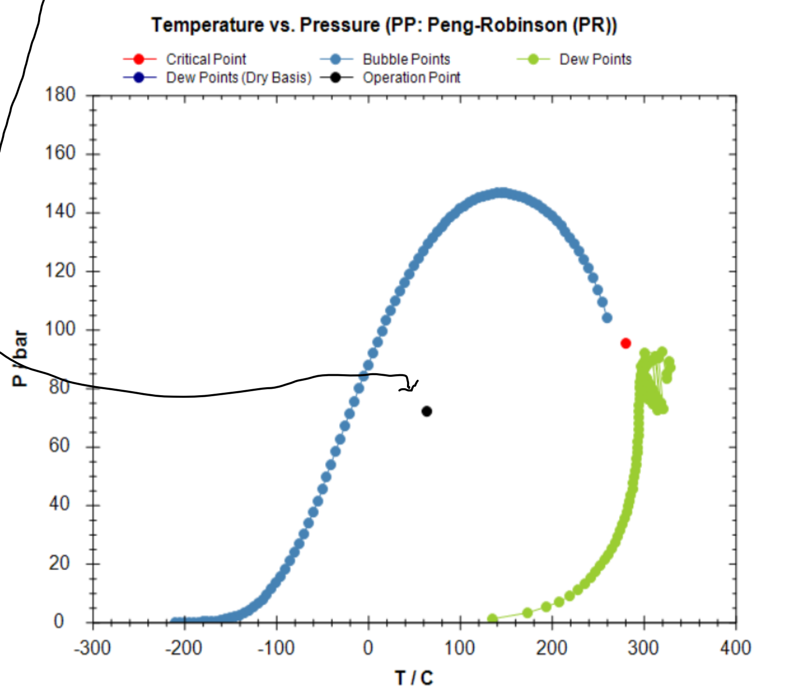
$1500 \cdot 1000 \cdot \frac{9.81}{10}$

{ 1 kg/m^3
150-200

$\frac{1500000}{5}$

30 bar

	TVD	p	T	Liquid Mass fraction	mo	mg	deno	deng	qo	qg	vso	vsg	dp/dx
	[m]	[bara]	[C]	[-]	[kg/s]	[kg/s]	[kg/m^3]	[kg/m^3]	[m^3/s]	[m^3/s]	[m/s]	[m/s]	[bara/m]
1	2500	147	70	1	11.9	0.0	500.5	-	0.024	0.000	2.11	0.00	0.050285
2	1000	72	64	0.933	11.1	0.8	578.4	52.9	0.019	0.015	1.70	1.34	0.032234
3	500	55											
4	0												



Chapter 8: Flow assurance management in production systems

Flow assurance consists in ensuring uninterrupted flow of hydrocarbon streams from the reservoir to the point of sale according to production plan. Flow assurance is particularly relevant for deep subsea systems with relatively long transportation distances (5-150 km) and low surrounding temperatures. In this type of systems if there is a problem intervention and remediation has to be done remotely and it is usually time consuming and very expensive.

Flow assurance focuses on three main aspects:

1. Avoid flow restrictions (excessive pressure drop, blockage or intermittent production).
2. Safeguard the structural integrity of parts of the production system from damages caused by internal flow.
3. Maintain the functionality and operability of components in the production system.

There are multiple issues that are typically addressed in flow assurance:

- Formation and deposition of wax.
- Formation of hydrates.
- Formation and accumulation of scale
- Flow induced vibrations (FIV)
- Asphaltene formation and deposition
- Slugging
- Erosion
- Emulsion
- Corrosion
- Pressure surges during shutdown and startup.

Fig. 1 shows where these issues usually occur in the production system.

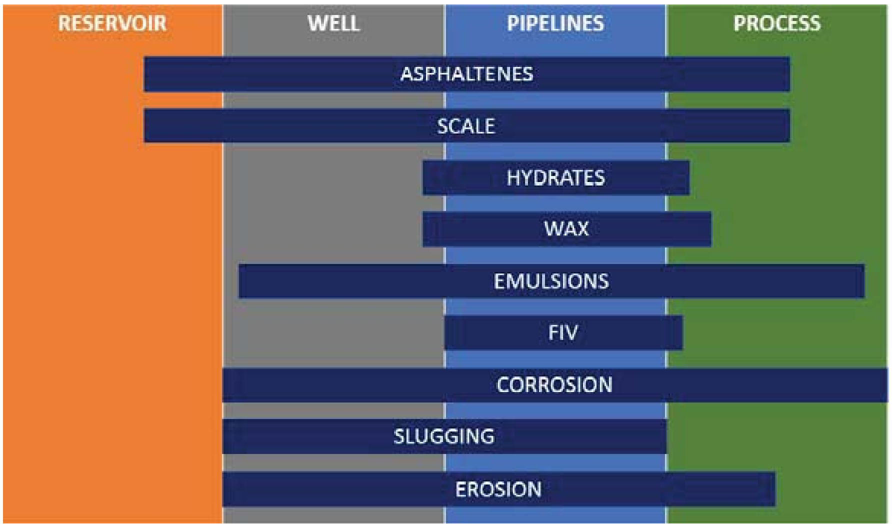
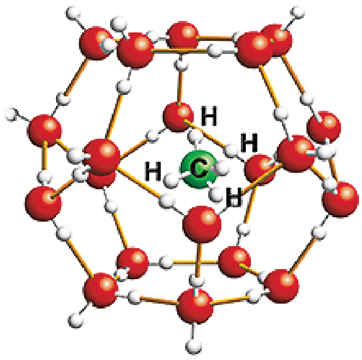


Fig. 1. Flow assurance problems and their typical location in the production system

HYDRATES

Hydrates are solid substances where water molecules (in liquid phase) form a cage-like structure that hosts small (< 9 Å diameter) molecules (Fig. 2). The small molecules are usually methane, ethane, propane, butane, carbon dioxide, nitrogen. The cage-type structure is formed due to hydrogen bonding of water molecules (the water molecule tends to spacially create two positives and a negative pole).

(a)



(b)

Fig. 2. A) appearance of a hydrate plug, b) molecular structure of a methane hydrate

Hydrates contains a much higher proportion of water than the hydrocarbon component. For example a methane hydrate (called methane clathrate) with molecular formula $4CH_4{\cdot}23H_2O$ (MW = 478) has a molar proportion of 85% (23/27) water and 15% (4/27) methane.

However, this doesn't necessarily indicate that they contain small amounts of gas. For example one cubic meter of methane clathrate (of an approximate density of 900 kg/m^3) contains 1.88 (900/478) kmoles of hydrate, of which there are 7.53 (1.88*4) kmoles of methane. 7.53 kmoles of methane at standard conditions correspond to 178.4

Sm^3! ($V_{SC}=n_{moles}\cdot R\cdot T_{SC}/p_{SC}$). For a cubic meter to contain the same amount of gaseous methane at standard temperature, it would have to be compressed at 180.4 bara (p= 7.53 kmol$\cdot R\cdot T_{SC}/1\ m^3$).

Hydrates form only if **ALL** following ingredients are present:

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

An example of the hydrate formation region is shown in Fig. 3. The actual line depends mainly on the fluid composition, but, as a rule of thumb, it happens at high pressure and low temperatures. For example at a pressure of 12 bar, the hydrate formation temperature is 4 C.

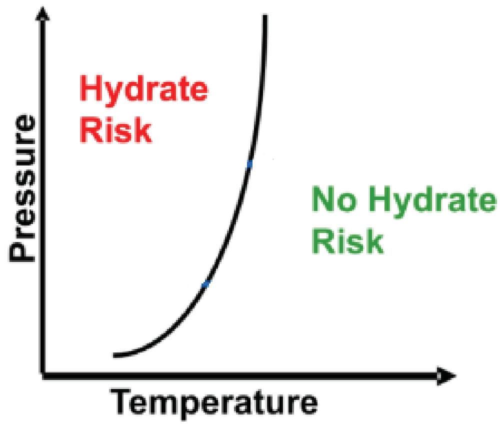


Fig. 3. Hydrate formation region

The hydrate formation line can be predicted by empirical expressions (that are a function of the specific gravity of the gas), or using equilibrium calculations with an Equation of State. Hydrate equilibrium calculations resemble to Vapor Liquid equilibria by finding p and temperature conditions that make equal the chemical energy of the component in the hydrate phase and liquid and gas phases.

Consequences of hydrates for flow assurance

If the pressure and temperature of the fluid flowing along the production system falls inside the hydrate formation region, hydrates will start to form. Hydrates usually form at the liquid-gas interphase where free water and small hydrocarbon molecules are in contact. The mixing and turbulence of the flow further increases the contact between the two thus causing the formation of more hydrates. Hydrates then start to agglomerate until they eventually plug the pipe (Fig. 4).

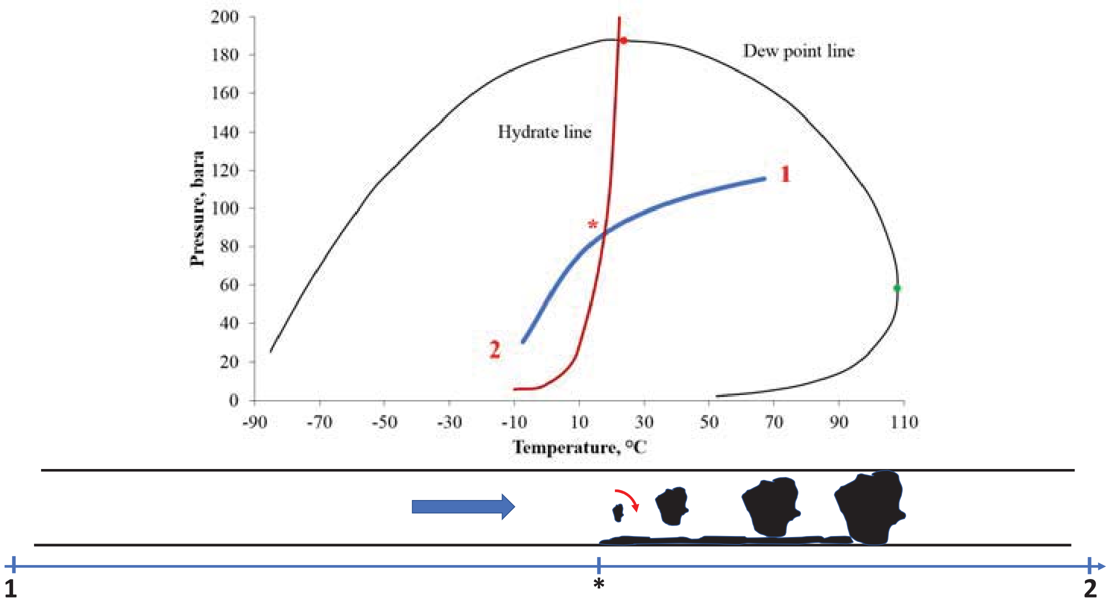


Fig. 4. Evolution of p and T of the fluid when flowing along the production system

Hydrates can also form when the production is stopped and the stagnant fluid begins to cool by transferring heat with the environment.

Management

The traditional strategy to manage hydrates is to avoid their formation. There are two main techniques commonly used to prevent the formation of hydrates:

- Keep the fluid conditions out of the hydrate formation region. This is done mainly by reducing the rate of temperature drop of the fluid (reducing the lateral spread of the blue line in Fig. 4). This is achieved in practice by two methods: better insulation or electrical heating of the pipe.

Please note that insulation works effectively for a flowing system, but when production is stopped, usually some other control method must be used as the fluid will eventually cool down during a long period.

Electrical heating is usually not cost effective for long transportation distances.

- Reduce the hydrate formation region. The equilibrium pressure and temperature of hydrate formation can be affected by adding liquid inhibitors (typically Mono-ethylene-glycol MEG, Tri-ethylene-glycol TEG or methanol MEOH) to the water phase. Inhibitors interfere with the formation of hydrogen bonds by keeping water molecules apart. As a consequence, the hydrate formation line will be shifted to the left (as shown in Fig. 5).

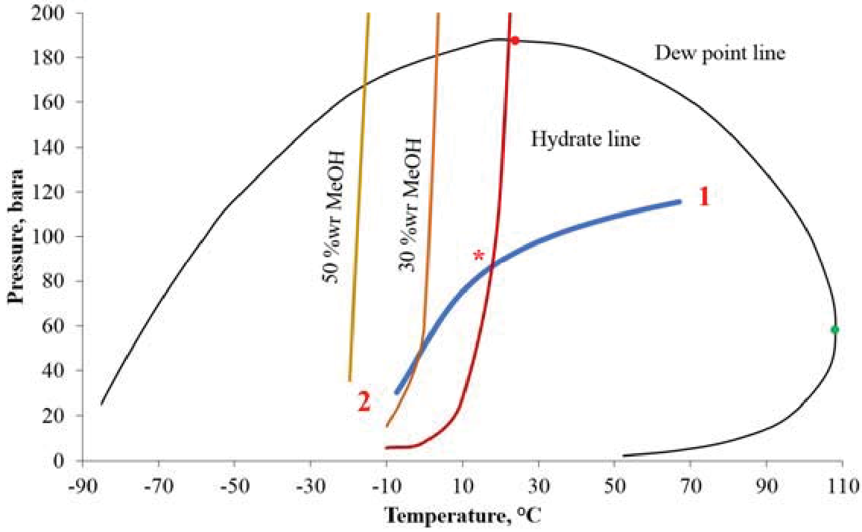


Fig. 5. Effect of inhibitor injection on the hydrate line

Typical concentrations of inhibitors used are 30-60 in weight %. For example the Snøhvit field has a Water Gas ratio of 6 E-6 Sm^3/Sm^3. The plateau production of the field is 20 MSm^3/d, thus it produces around 120 Sm^3/d of water, or, equivalently, 120 000 kg/d of water. If we assume that the inhibitor concentration used is 50 in weight %, then this gives 120 000 kg/d of MEG that must be continuously injected on the field. MEG is usually reclaimed in the processing facilities. Otherwise, it will represent a daily cost of 60 000 – 180 000 USD (assuming a MEG cost between 0.5 – 1.5 USD/kg).

Please note that the inhibitor must be present in the water phase for it to be effective, thus evaporation to the gas phase has to be taken into account when estimating the required amounts of inhibitor.

Inhibitors are also injected when preparing to shut down production, to make sure hydrates will not form due to the cooling of the fluid.

During the last years, many experts have proposed to use a less conservative hydrate control strategy where we allow hydrates to form, but impede their agglomeration and carry the slurry together with the production fluids. This can be performed by injecting special types of chemicals, or by using cold flow. However, up to date there are limited field cases where this type of management is performed.

SLUGGING

Slugging consists on intermittent flow of gas and liquid in the production system (Fig. 6).

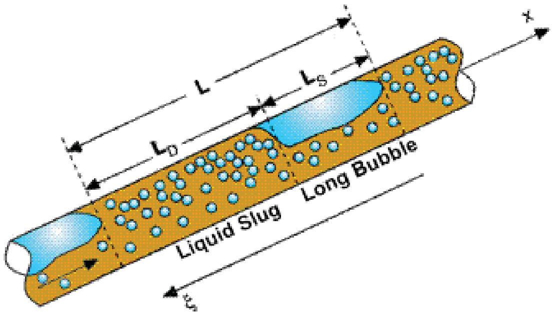


Fig. 6. Slug in a pipe section

There are two main types of slugging:

- Hydrodynamic slugging: It occurs spontaneously at a particular combination of flow velocities of liquid and gas and it depends strongly on the fluid properties and pipe inclination. As an example, Fig. 7 shows the flow pattern map for a horizontal pipe and certain fluid properties. There is a particular combination of operational velocities where the flow will arrange itself in a slug flow configuration.

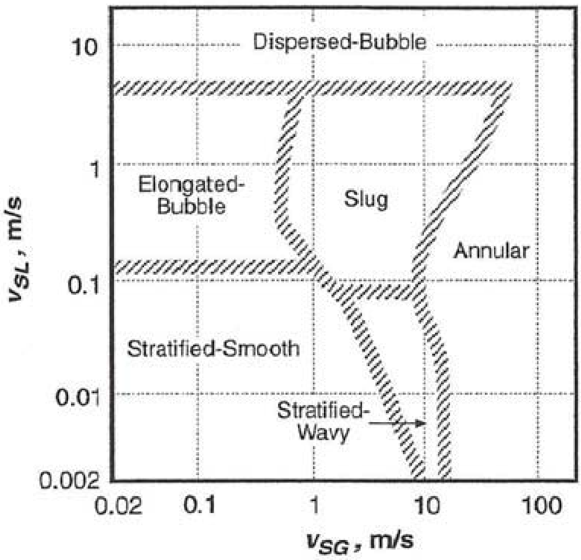


Fig. 7. Flow pattern map for an horizontal pipe (After Mandhane et al. 1974)

- Terrain slugging: Terrain slugging is mainly due to cyclic accumulation of liquid in the production system (especially in lower points). This happens in undulating well trajectories, transportation flowlines with varying topology of the seabed and in risers.

An example of slugging in a s-shaped production riser is shown in Fig. 8. Liquid accumulates in the lowest pipe section and blocks the flow of gas (a). The liquid level starts increasing and the gas pressure in the horizontal line also increases (b). Eventually, the liquid floods the second floor of the riser (c). Gas pressure increases until it is sufficient to flush out almost all the liquid in the riser (d).

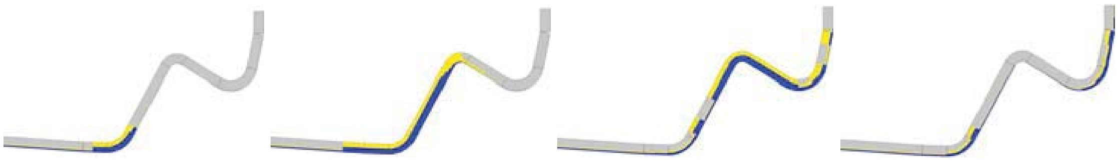


Fig. 8. Stages of severe slugging in an S-shaped riser.

Consequences of slugging

The main consequence of slugging is that production rates and pressures will fluctuate in time which is often detrimental to the proper operation of the downstream processing facilities. In gravity separators for example, a sudden inlet of liquid might increase significantly the liquid level, causing liquid carryover, activating the warnings for high liquid level and even triggering a shutdown alarm.

Slugging also causes vibration in flowlines, manifolds, risers which can develop in structural damages due to elevated stress levels and fatigue.

Management

Slugging can be, to some extent, predicted during the design phase of the field using commercial multiphase flow simulators such as Leda, Olga and FlowManager. If it is detected and it has high severity (long slug lengths, frequencies that coincide with the natural frequency of the structure, relevant pressure fluctuations), potential solutions are to change the routing of the flowline, refill or dig some sections of the seabed that can cause liquid accumulation or changing the pipe diameter. Smaller pipe diameters increase the gas velocity, increasing the drag of the gas on the liquid thus reducing the liquid deposition. However, too small pipe diameters also cause higher pressure drops that reduce overall production rates.

If slugging is occurring in an existing production system, some approaches that have been used successfully in the past are to apply gas lift in the riser base or to use the topside choke to change dynamically the backpressure on the line and “control” the slug.

SCALING

Scaling is the precipitation of minerals compounds (constituted by Na, K, Mg, Ca, Ba, Sr, Fe, Cl) from the produced water and their deposition on pipe walls. Scale occurs when the solubility of the minerals in the water decreases due to changes in pressure and temperature, due to mixing of waters of different sources, injection of CO_2. Minerals usually deposit on surface areas that are rough or have irregularities (e.g. valve components).

(a) (b)

Fig. 9. Scale accumulation in a a) pipe, b) choke

There are two main types of scales that usually occur in production systems:

- Carbonate scales. These scales are formed when CO_2 dissolved in the water disassociates in carbonate ions CO_3^{-2} and join with some of the aforementioned minerals (typically calcite $CaCO_3$, Iron carbonate $FeCO_3$). Their precipitation is mainly due to reduction in pressure (due to flow in restrictions, valves, chokes) or increases in temperature. This type of scale can be removed with acid.
- Sulphate scales: These scales are formed by the sulphate ion SO_4^{-2} that is present in seawater (Barite $BaSO_4$, Gypsum $CaSO_4 \cdot 2H_2O$, Anhydrite $CaSO_4$, Celestite $SrSO_4$). It precipitates out of solution when waters from different sources are mixed (e.g. seawater used for injection and production water from the aquifer or formation). The pressure has little influence in the precipitation, but the increase in temperature can reduce further the solubility. This type of scale must be removed mechanically.

Consequences

Scaling causes gradual blockage of the flow path and loss of functionality in production equipment (Subsurface safety valves, chokes).

Management

Studies are usually performed on the produced water to determine if it will be prone to form scale at the pressure and temperature conditions encountered in the production system. Moreover, special attention must be payed to situations where there is mixing of water from different sources, CO_2 injection.

Scaling is usually avoided by using chemicals (scale inhibitors) that attach themselves to the scale ions and impede growth. Coating can help to prevent deposition on the surfaces but when damaged (e.g. due to erosion) their effectivity is reduced dramatically.

If scale forms in a component of the production system, the removal technique depends on the type of scale. Carbonates can be removed by acid injection and sulphates can only be removed mechanically.

EROSION

Erosion is the gradual damage and loss of material from the wall of components of the production system (valves, pipes, bends, etc. Fig. 10) due to the repeated impingement of solid particles (sand) or droplets at high velocity.

Fig. 10. Erosion damage in a cage-type choke.

Consequences

Structural damage, vibration, leaks and corrosion (due to the removal of the protective coating).

Management

Erosion is usually accounted for in the field design phase. The design process sizes the equipment such that the velocities are below certain limit value that gives an acceptable erosional rate. These calculations usually consider the velocity of impingement, the angle of impingement, the amount of solid particles and the wear resistance of the material.

There are some standards that give guidelines how to estimate erosive wear for common pipe components (e.g. DNV Recommended Practice RP O501). However, complex geometries usually require in-depth studies (e.g. using computational fluid dynamics, CFD) to estimate erosion prone areas, fluid velocities, angle of impingement, etc. An example is shown in Fig. 11.

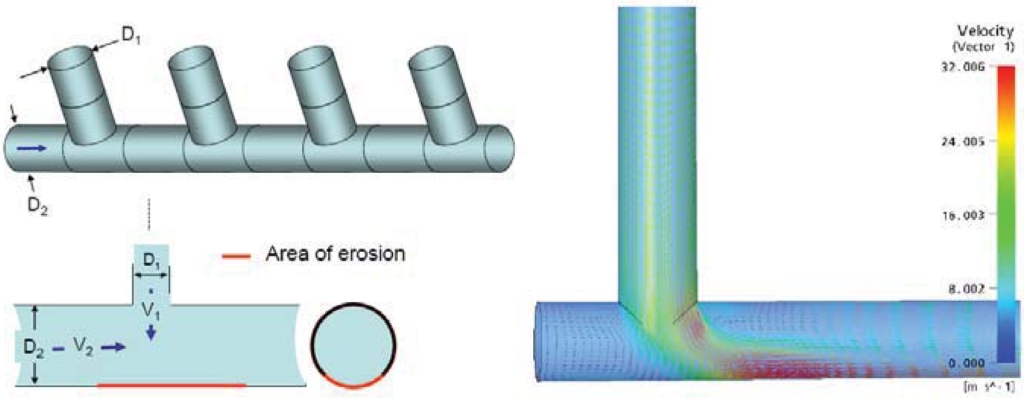
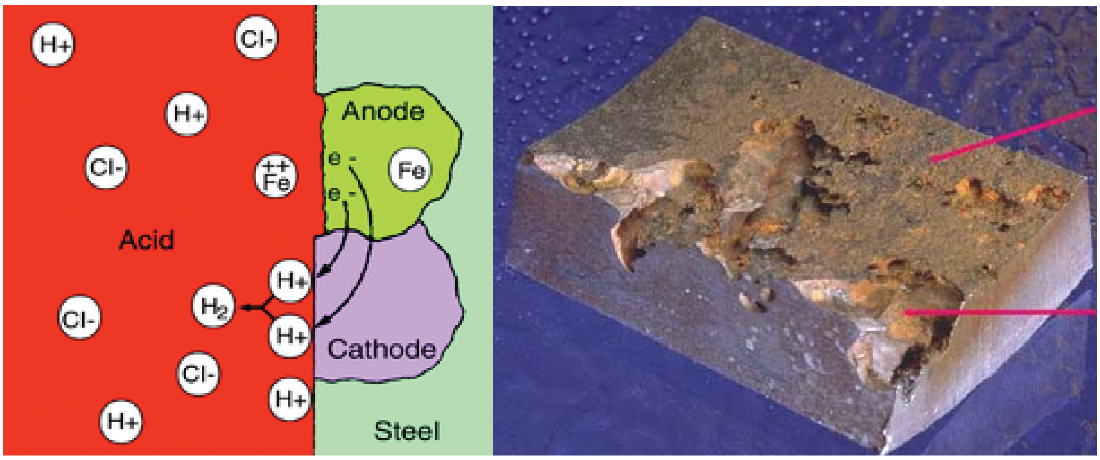


Fig. 11. CFD simulation of erosion in a production header

If erosion is detected in an existing production system then, when possible, components might be reevaluated and replaced with geometries that are less susceptible to erosion. Alternatively, if corrosion is due to excessive sand production from the reservoir, the only alternative is then reduce the well rate to limit sand production.

CORROSION

Corrosion is an electrochemical reaction where steel is converted to rust and occurs when metal is in contact with water. Two locations are established in the metal, a cathode and an anode. In the anode, iron loses electrons and becomes a positively charged ion. This ion further reacts with water and oxygen in the surrounding media to form rust. The cathode receives the electrons of the anode and generates by-products (such as hydrogen H_2) with other ions.



(a) **(b)**

Fig. 12. a) Ilustration or a corrosion reaction b) corrosion on the tubing surface

Corrosion can occur virtually anywhere in the production system where water is in contact with metal (casing, tubing, flowlines, pipelines, tanks, pumps, etc.). In transportation pipes, corrosion usually occurs at the pipe bottom where water is transported, in low pipe sections where water accumulates or at the top of the pipe due to splashing and condensation of water droplets (also known as TLC, Top of line corrosion).

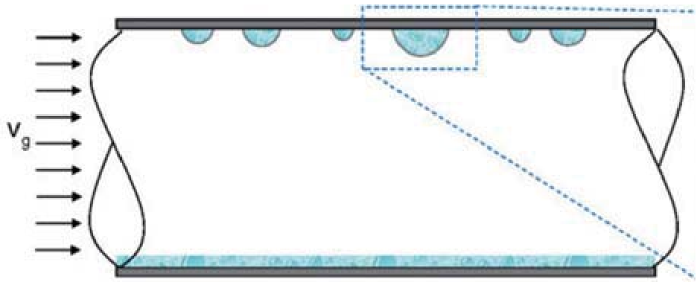


Fig. 13. Wet gas flow in a horizontal flowline depicting top of line condensation

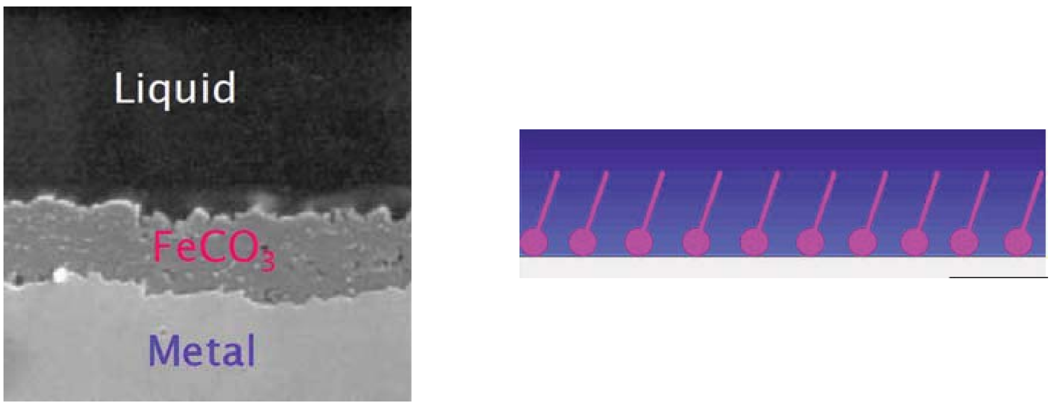
Consequences

Corrosion on an unprotected pipe can cause losses of 1-20 mm of pipe thickness per year, leading ultimately to structural damage and leakages. Rust particles can also travel downstream and cause problems such as plugging other components.

Management

The measures to mitigate corrosion can be divided into two main principles:

- Eliminate the contact between water from steel. This can be done by applying a protective layer on the steel surface, for example with coating (which might be eventually damaged due to sand erosion), creating a layer of protective oxide on the steel (Fig. 14 a) or by using inhibitors (Fig. 14 b).



(a) **(b)**

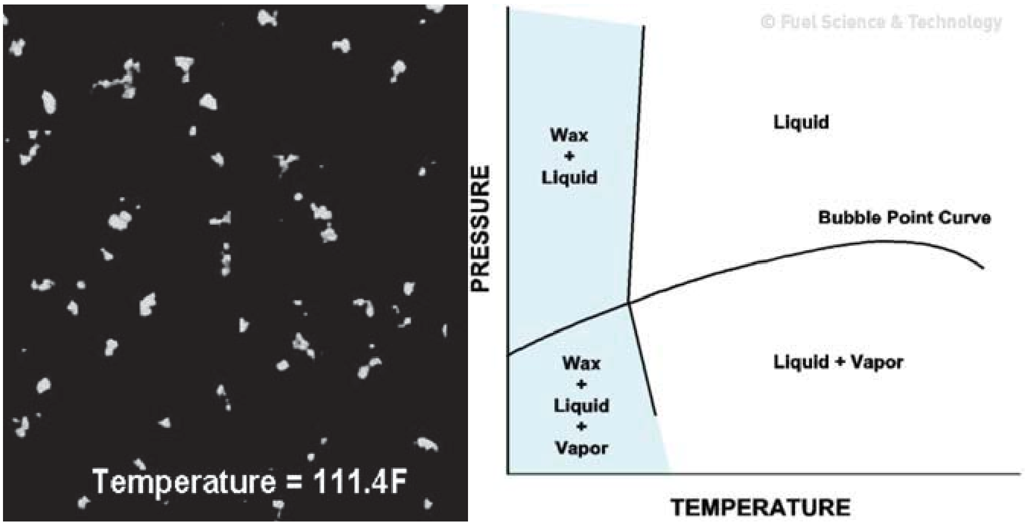
Fig. 14. Protective layer of $FeCO_3$ formed on the metal surface b) inhibitors attached to the metal surface

- Use steel materials with higher resistance to corrosion. For example alloy steels. This is usually feasible for wells, but it becomes too expensive for flowlines and pipelines.

WAX DEPOSITION

Wax deposition occurs when long alkane chains (C18+) precipitate out of solution from the oil, agglomerate and deposit on the pipe walls.

In a waxy crude, when temperature is reduced down to a certain value (for North sea crudes this happens around 30-40 C), some wax crystals will start to precipitate and become visible. The temperature when this occurs is called cloud point or WAT (wax appereance temperature).



(a) (b)

Fig. 15. a) Wax crystals visible in a crude at WAT, b) WATs at different pressures in the phase diagram

The WAT depends on oil composition, type and molar amounts of alkanes, pressure, cooling rate. Wax crystals typically attach to nucleating agents present in the oil (asphaltenes[6], fine sand, clay, water, salt), form wax “clusters” and grow.

If the temperature is reduced further down to the pour point, the oil becomes solid-like and stops flowing.

[6] Asphaltenes are coal-like solids that also have the tendency to precipitate out of the crude. They are high molecular weight compounds containing poly-aromatic carbon rings with nitrogen, sulphur, oxygen and heavy metals such as vanadium and nickel.

Fig. 16. Crude oil not flowing once the pour point is reached

Wax deposition occurs when ALL the following ingredients are present:

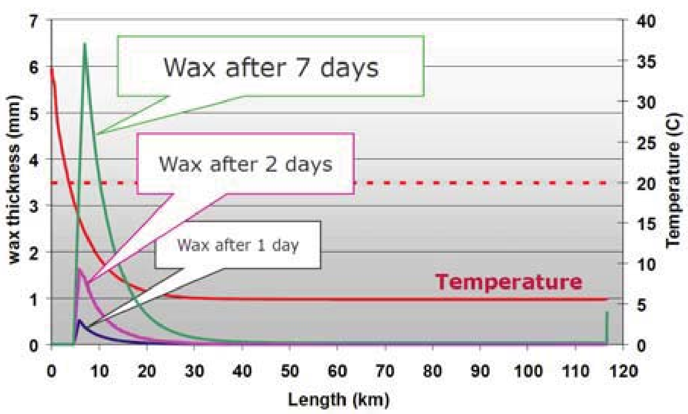
- Wax-prone components in the oil composition (long alkane chains).
- Temperature below WAT.
- Pipe wall colder than the fluid such that there is a temperature profile in the fluid reducing towards the pipe wall (temperature gradient).
- Irregularities on the wall where wax clusters attach.

Wax deposits age with time and become more rigid (thus more difficult to remove).

Consequences

In flowlines and pipelines:

- Increases pressure drop due to the increase in pipe roughness.
- Reduction of cross section area.
- Pipe blockage.



(a) (b)

Fig. 17. a) wax plug retrieved topside (Statfjord B), b) evolution of the wax thickness in a pipeline with time.

- The presence of wax crystals in the fluids changes its rheology (e.g. making it non Newtonian or with a higher effective viscosity).
- During shut-downs, the temperature of the fluid can reach the pour point of the crude, causing it not to flow (gelling).

Management

The first step in developing a wax management strategy is to test the crude oil in the laboratory and measure and quantify all of its properties relevant for deposition.

A common management method for wax is to perform frequent pigging. Pigging consists in sending a device (pig) inside the pipe that scraps the wax deposits and pushes them forward. Pigs are usually sent and received from the processing facilities thus two pipelines must be installed. There are also subsea pig launchers, but this is economic only for systems with very low pigging frequency.

Pigging frequency is usually estimated by performing numerical simulations to compute the profile of deposited wax along the flowline with time. With this, the total amount of wax deposited in the system at any given time is estimated. There is a maximum length and weight of wax that can be pushed through the pipe, given by the maximum allowable pressure that the pipe can tolerate. The required pigging frequency is given by the time at which that wax amount is reached.

Other techniques used are keeping the fluid outside of the wax formation region. This is done by thermal insulation or electrical heating. However, for long flowlines, electrical heating is usually very expensive and insulation alone is not enough to keep temperature high. Thus in most cases insulation or electrical heating are often used to reduce wax deposition rates together with pigging.

Chemical inhibitors that are also often injected. Chemical inhibitors work by reducing the cloud point of the crude or by preventing further agglomeration of wax crystals. As with insulation, in many systems this doesn't eliminate completely the problem but it helps slowing down the deposition rate. Please note that chemical inhibitors are expensive.

If the seabed temperature is below or equal the pour point of the oil, then it is necessary to inject chemical inhibitors before shutting down the system to avoid gelling.

In recent years pipe coating has been proposed as a technique to avoid wax attaching to pipe walls. However it is not yet field tested.

In systems with wax-prone oils the pressure drop between end points of flowlines should be closely monitored. Any unexplained increase might indicate wax deposition and must be immediately addressed.

OIL-WATER EMULSIONS

Oil-water emulsions are fine and stable dispersions of oil droplets in water or water droplets in oil (Fig. 18). The formation of emulsions depends on a variety of factors such as the dynamics of multiphase flow, the properties of oil and water such as viscosity and interfacial tension, the shear stress (mixing) experienced by the mixture, chemical compounds present in the oil-water interface. In production systems, the mixing is typically generated when commingling production from different sources, due to the violent expansion across the choke, flow through multiphase pumps, etc.

(a) (b)

Fig. 18. a) oil (red) and water (White) originally separated, b) oil and water emulsion after vigorous stirring in a blender

Consequences

In pipe flow, emulsions often exhibit the behavior presented in Fig. 19. For a fixed volumetric rate of the mixture ($q_o + q_w$), if one measures the pressure drop along a pipe segment for several water volume fractions, it will increase with water volume fraction until a maximum is reached and then it will decline abruptly. The water volume fraction that has the highest pressure gradient is called the inversion point. Please note that the increase in pressure drop is significant (more 2.5 times the one for pure oil in the figure).

When increasing the water fraction, at the inversion point the dispersion changes from an oil in water dispersion to a water in oil dispersion.

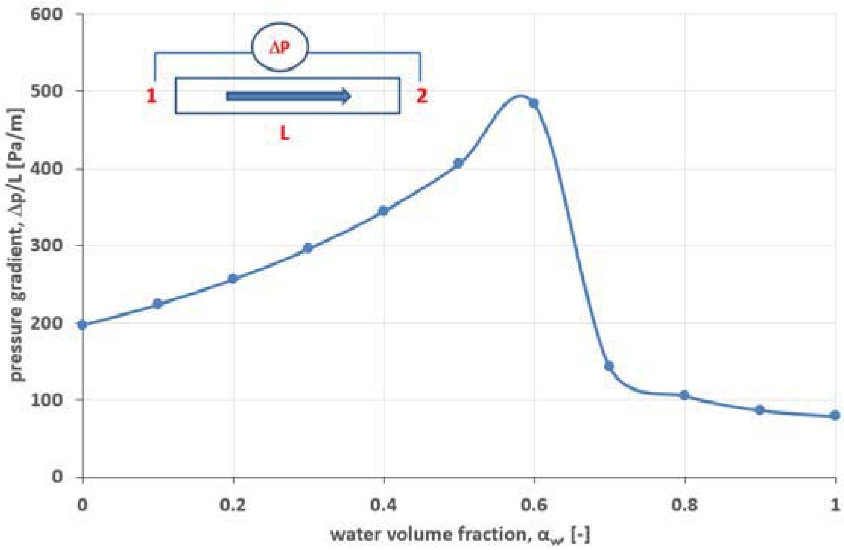


Fig. 19. Measured pressure drop in a horizontal pipe keeping the total flow rate constant and changing water volume fraction, $q_w/(q_w+q_o)$

Using an homogeneous model (single fluid with average properties) one can back-calculate the effective mixture or "emulsion" viscosity that the mixture should have to provide the pressure drop measured (Fig. 20). For the particular case, the emulsion viscosity at the inversion point (570 cp) is 7.1 times the viscosity of the oil (80 cp).

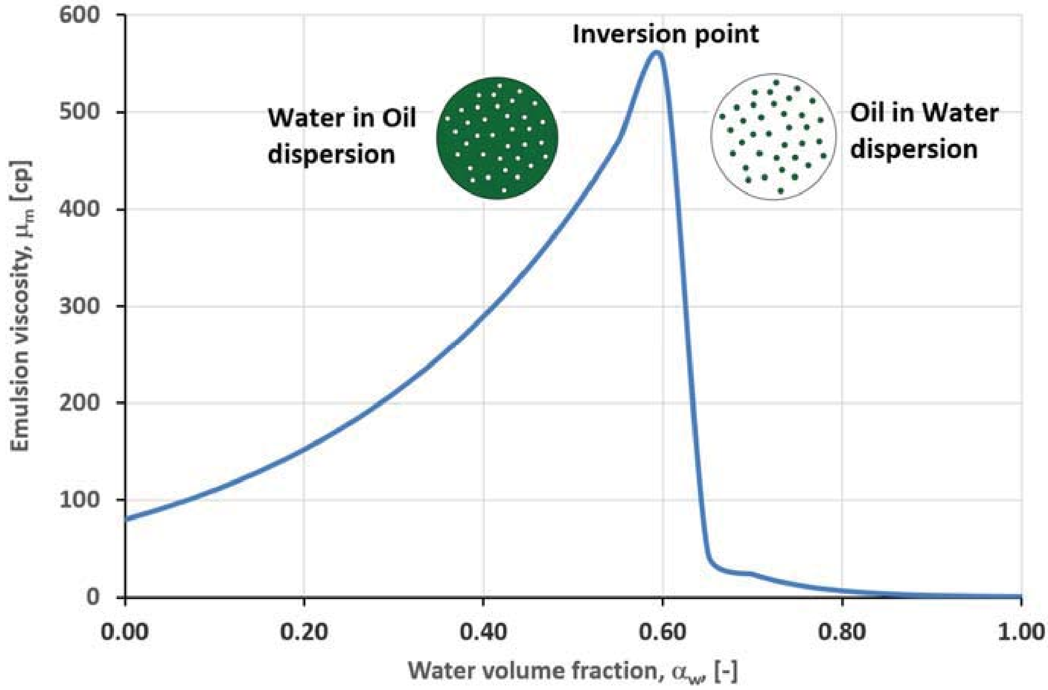


Fig. 20. Mixture viscosity behavior versus water volume fraction exhibited by the oil water mixture

There are many expressions used to represent the behavior shown in Fig. 20 that are later used in emulsion pressure drop models. Most of them require data measured in the lab to tune their coefficients. As an example, the Richarson model is shown below.

For oil continuous

$$\mu_m = \mu_o \cdot e^{n_o \cdot \alpha_w}$$

For water continuous

$$\mu_m = \mu_w \cdot e^{n_w \cdot (1-\alpha_w)}$$

Eq. 1.

Consequences

Emulsions can cause excessive pressure drops in pipe segments and components, which can reduce dramatically production rates, pumping capacity of electric submersible pumps, etc. Moreover, stable emulsions are difficult to separate in processing facilities thus creating bottlenecks and fluid disposal problems.

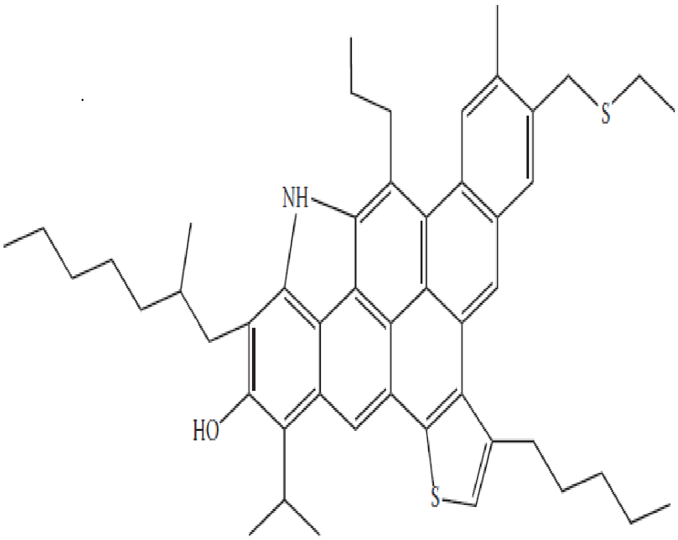
Management

During the field design phase, the capacity oil and water system to form emulsions can be somewhat studied with laboratory tests (shaking bottle tests). However, these results have sometimes limited applicability partly because the shear magnitudes (mixing) applied in the laboratory conditions are very different from the mixing experienced in the field.

When there is mixing of streams with different water cut, the inversion point must be avoided.

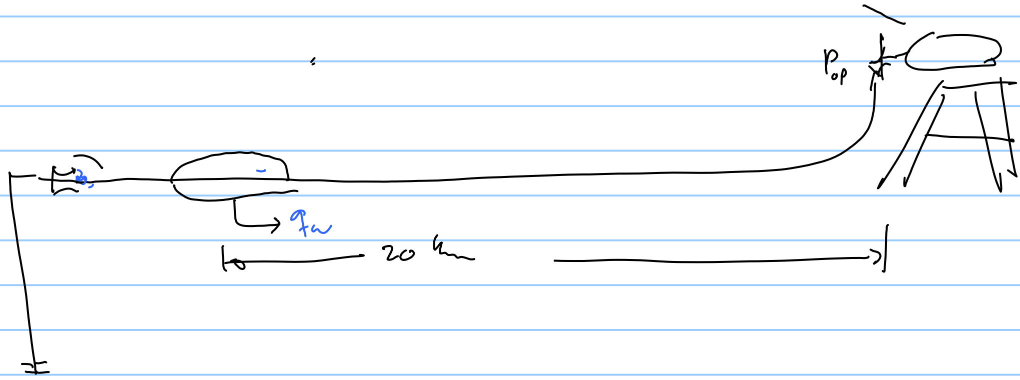
Often, chemical substances such as demulsifiers and light oils (diluent) are injected into the stream to reduce the stability of the emulsion. Light oils reduce the viscosity of the formation oil, thus helping separation. Demulsifiers are chemicals that attach themselves to the interface between oil and water promoting separation.

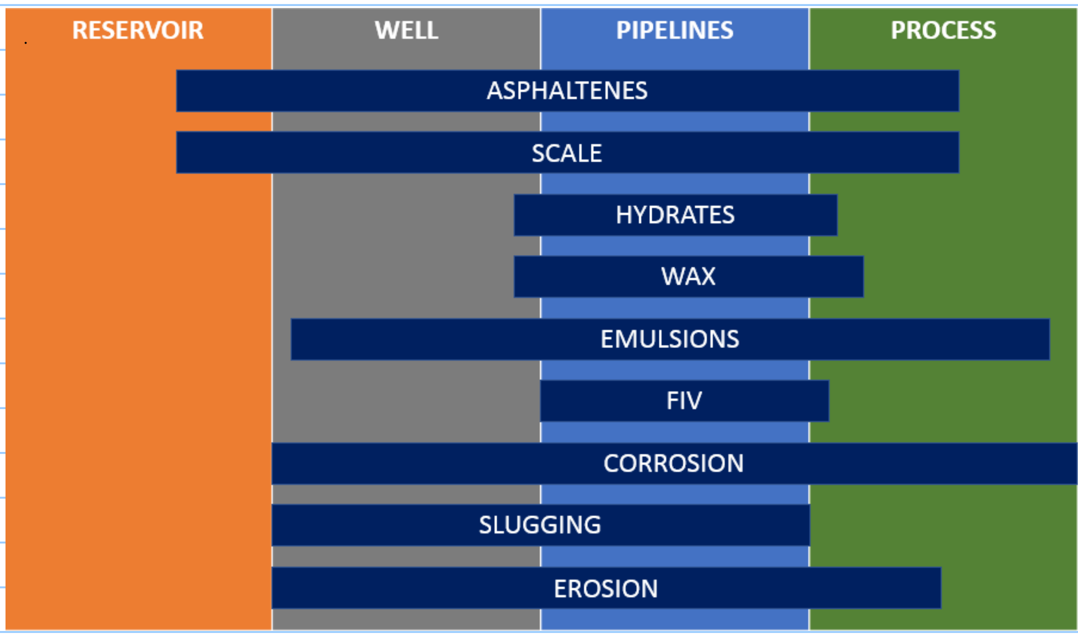
asphaltene molecule

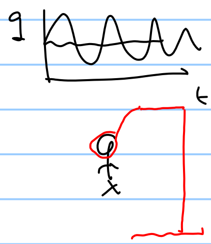


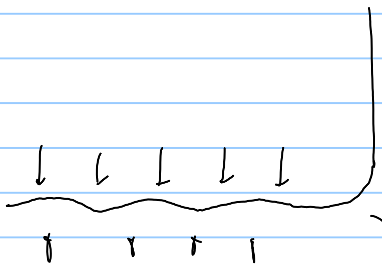
emulsion

$$\rho_{mix} = \rho_w \alpha_w + (1-\alpha_w)\rho_o$$









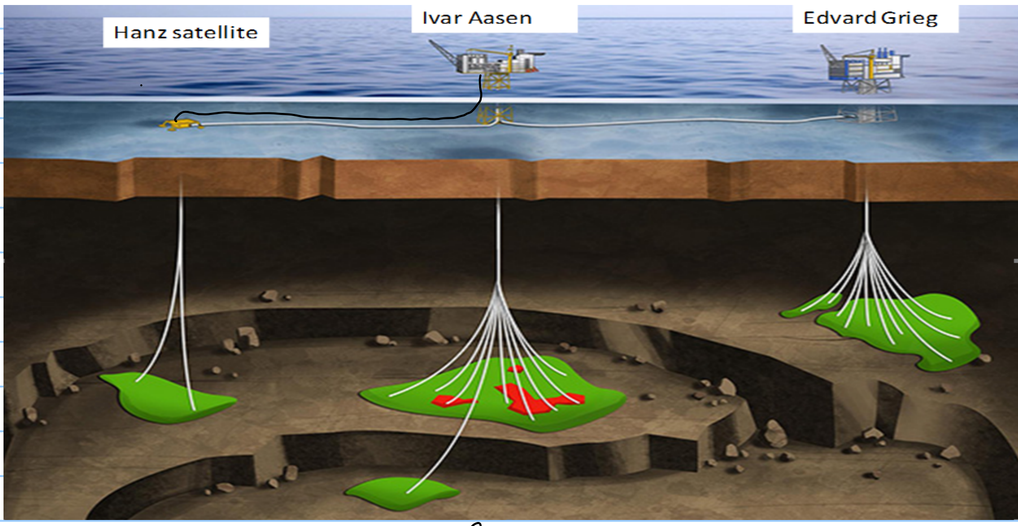
slugging in wells

- Others issues to consider are:
  - bacteria (biocide)
  - against corrosion O_2, H_2S (scavengers for O_2 H_2S sequestration)
  - anti foamers — liquid + gas
  - DRA ~ Drag reducing agent ~ reduce Δp in pipe

Production chemicals → cost
→ compatibility
→ environmental impact

EOR processes ~ polymers
→ nanoparticles

→ many of production chemicals will end up in liquid phase ~ oil — better for environ, bad for refinery
→ water → injection
→ disposal to sea — under allowable concentration



Ivar Aasen Consequence study

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.

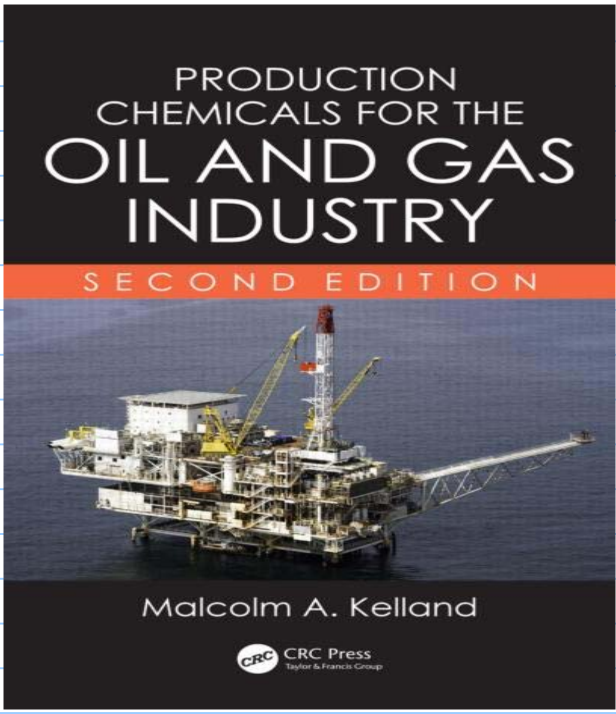
scale
detergen
floculat
wax

hemmer: inhibitor

- continuous
- periodic
- as required. ← to remove scale deposits → during shutdown period — hydrate, wax

most of these chemicals are not recovered, reclaimed

except MEG, MEOH, TEG



1. Increased Δp, flow restriction, blockage
2. integrity problems
3. Loss in functionality of components

Summary table

flow assurance issue	consequence	corrective measures
Slugging	1, 2, 3	selection of ϕ, trajectory of pipeline, filling or digging the seabed, control scheme. slug catcher ~ 1st stage separator
wax	1	insulation design, heat tracing, requirement of pigging loop, chemical inhibitor ~ amounts to inject, distribution system
hydrate	1, 3	insulation design, heat tracing, chemical inhibitor ~ amounts, distribution system
scale	1, 3	chemical inhibitor ~ amounts, distribution system, in well injection

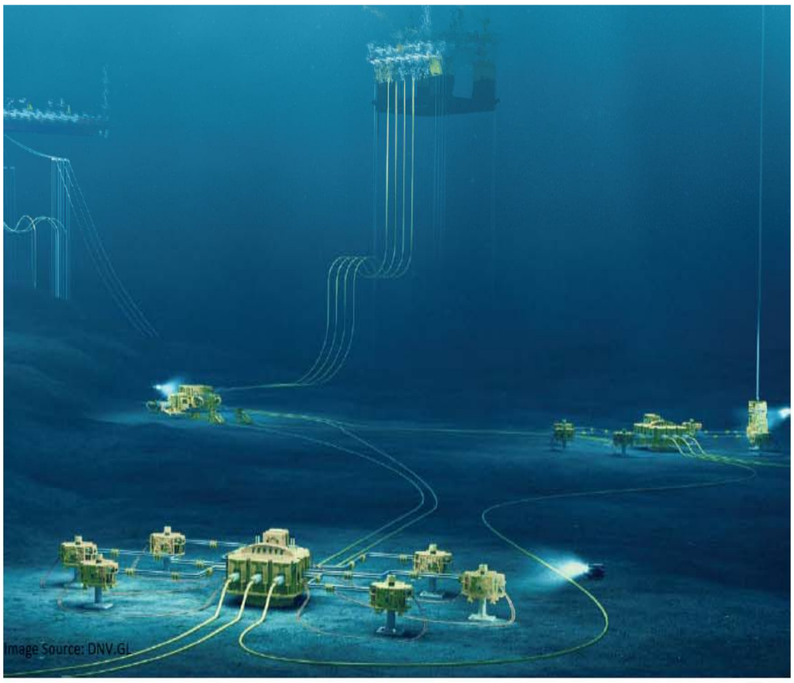
Erosion	2, 3	• pipe size and diameter • flowline dimensioning • component dimensioning
Corrosion	2	chemical inhibitor → amounts → distribution system in well injection
Emulsion	1	chemical inhibitor → amounts → distribution system in well injection

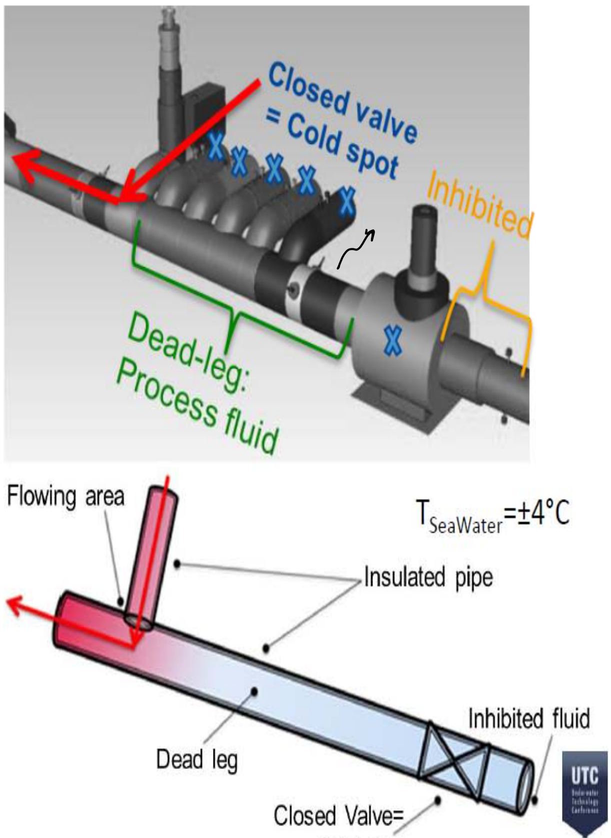
design and study of flow assurance problems in dead legs is also importants

places where there is no flow during normal operations

Subsea manifold and dead-leg geometry

- Dead-legs are inherently present





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Considerations during field development:

Early studies → many development options
↳ detect potential showstoppers { slugging, wax, hydrate }

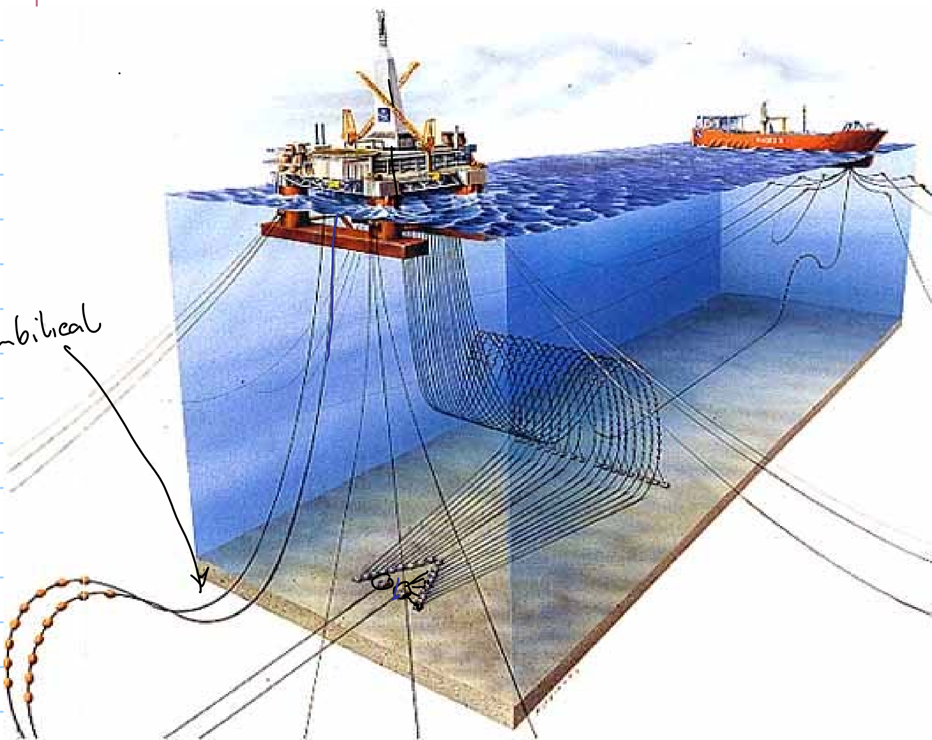
↳ FEED → (Front End Engineering design)
a specific alternative selected
↳ in detail study → hydrate management plan
↳ wax management plan
↳ detailed pipeline design
↳ prediction of temperature, velocities, pressures in components (dead legs, erosion, cold spots)
FIV

↳ EPC Engineering Procurement Construction

- Tools used for analysis
  - multiphase flow simulator {hysys, gap, pipesim}
  - transient flow simulators {olga, leda, Flow manager}
    ↳ predict { P, T, $\alpha_o, \alpha_g, \alpha_w$ along the pipe for different times.
  - PVT analysis
    - lab test
    - develop a EOS that represents with an acceptable accuracy my fluid
    - Wax (WAT), hydrate, scale, emulsion
  - Lab test → predict erosion rates
  - CFD computational fluid dynamics { V_x, V_y, V_z, P, T in a 3D domain
  - FEA Finite element analysis { displacement, stresses in a 3D geometry
  - Standards ~ cookbook, Recommended practice.

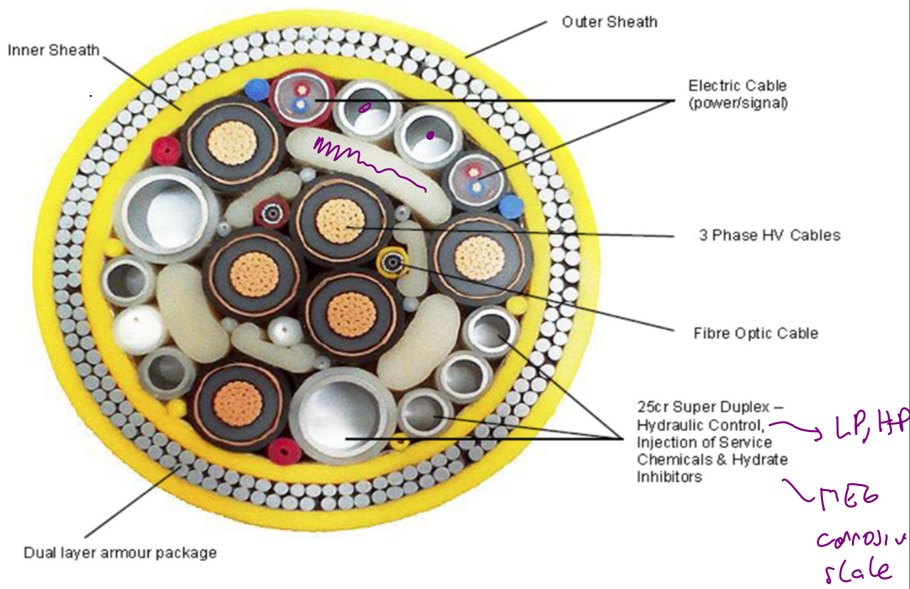
delivery system for production chemicals :

umbilical



Njord

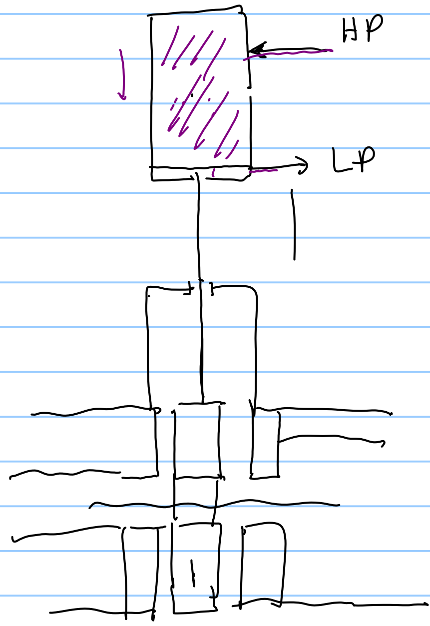
CDU
control distribution unit
SDU
subsea distribution unit

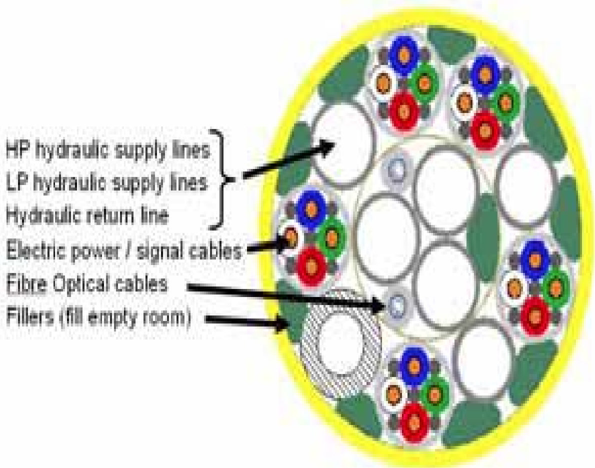


→ LP, HP

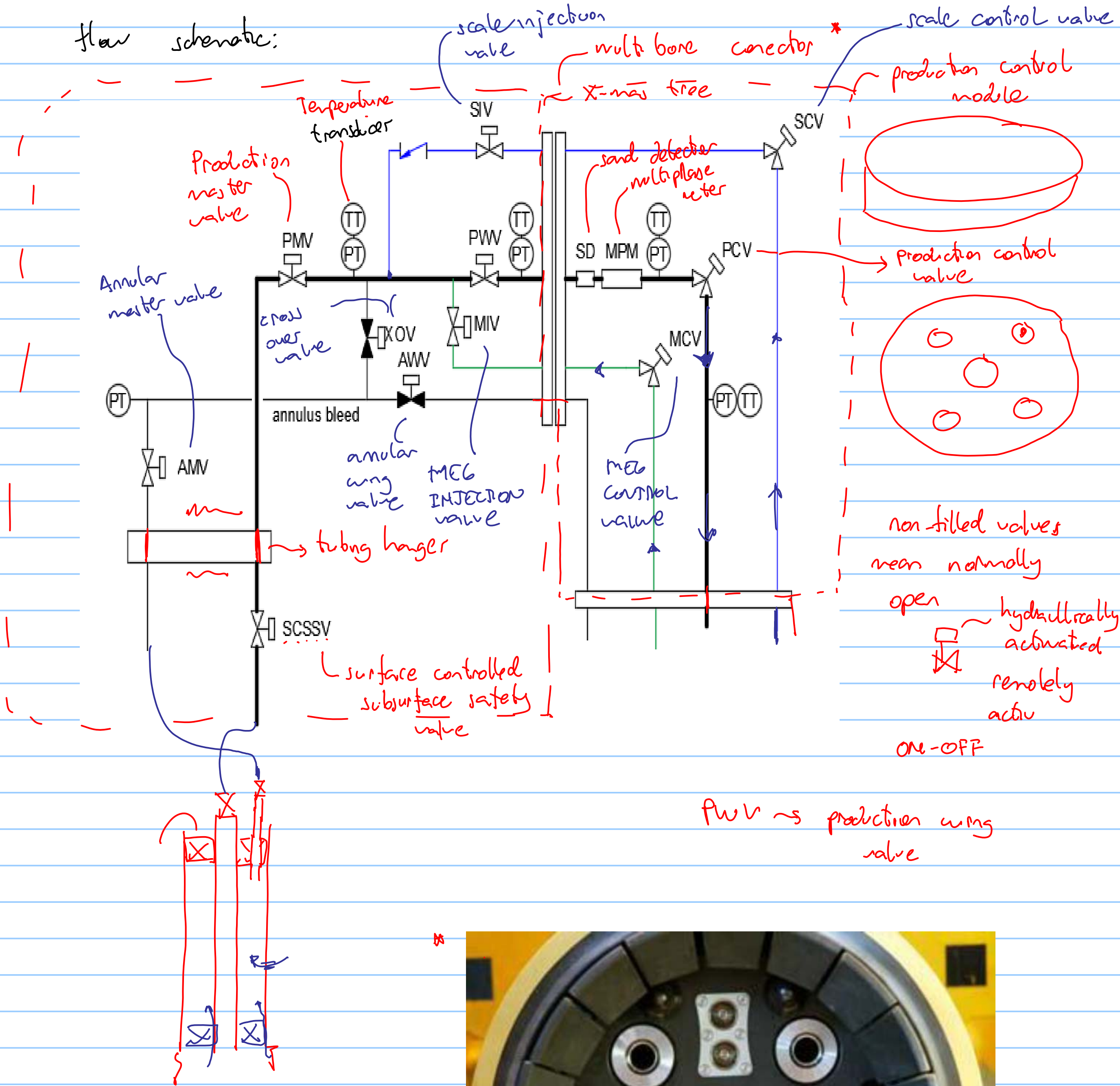
MEG
corrosion
scale

Figure 3 – Umbilical Cross Section Example

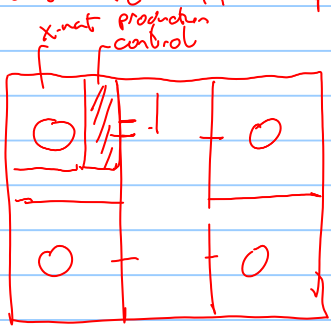


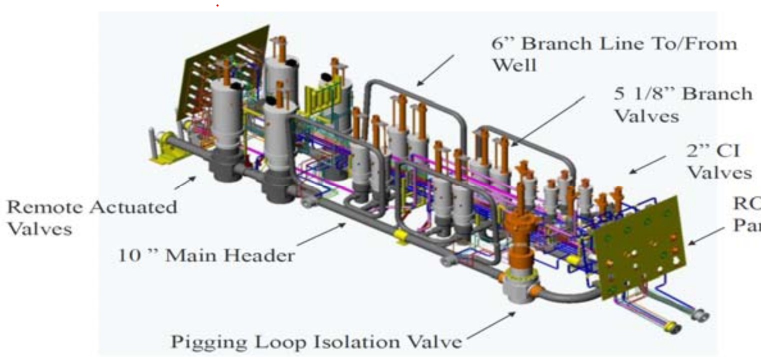


flow schematic:

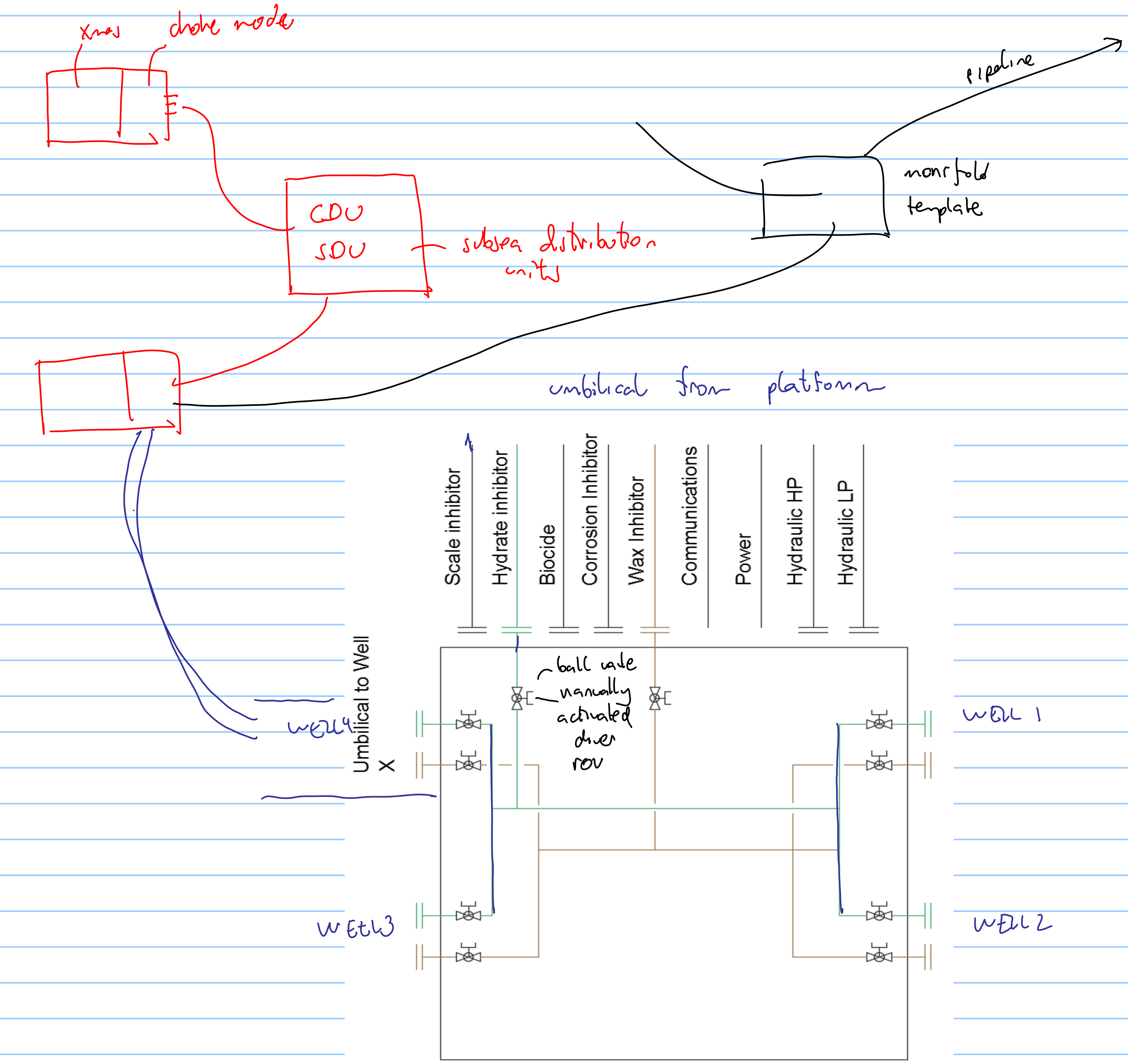


if the wells are in templates

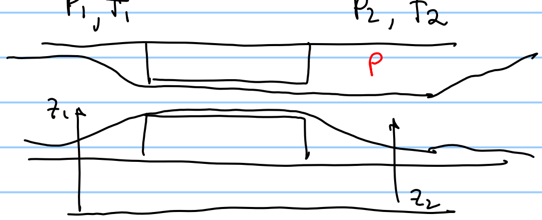




sf well are satellite



fluid Cooling due to expansion in chokes

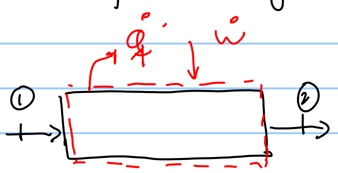


$\Delta p = P_1 - p_2$

$T_1 \approx T_R$

T_2 might be very different from T_1, specially if mainly gas

1st law of thermodynamics for open systems



$$\dot q - \dot w = \dot m \left(u_2 + \frac{P_2}{\rho_2} + \cancel{z_2 g} + \cancel{\frac{v_2^2}{2}} - u_1 + \frac{P_1}{\rho_2} + \cancel{z_1 g} - \cancel{\frac{v_1^2}{2}} \right)$$

for chokes $\dot q = 0$ $\quad z_1 \approx z_2 \quad v_1 \approx v_2$

$\dot w = 0$

h enthalpy

$h = u + pv \qquad v = \frac{1}{\rho}$

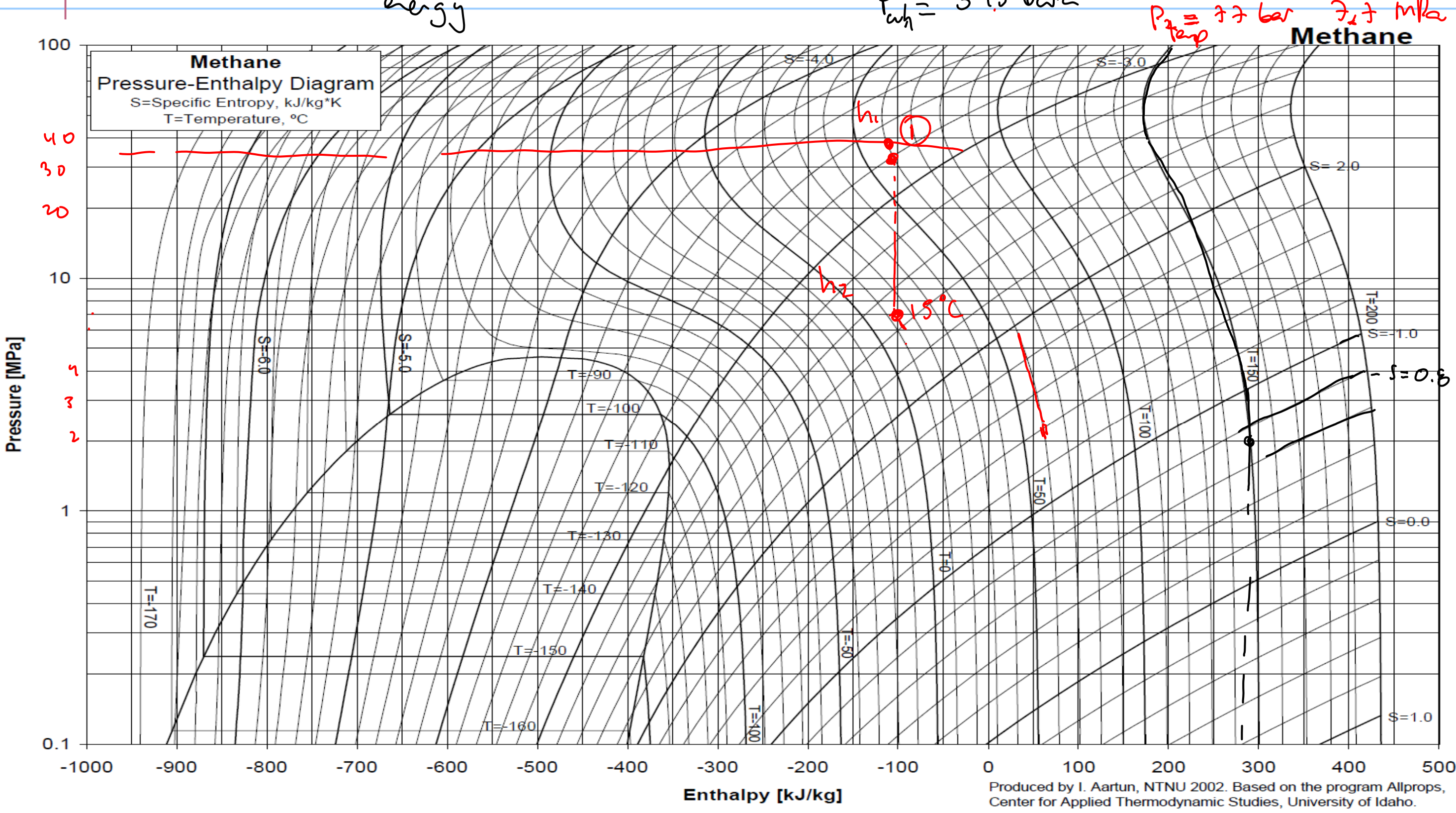
↳ internal energy

for values $h_1 = h_2$ isenthalpic

$T_1 = 70°C$

$P_{wh} = 343$ bara

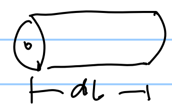
$\Delta P_{choke} = 267$ bara



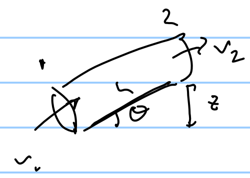
Temperature drop in pipe ~ conduits

$$\dot{q} - \cancel{\dot{w}} = \dot{m}\left(u_2 + \frac{P_2}{\rho_2} + \cancel{z_2} g + \cancel{\frac{v_2^2}{2}} - u_1 + \frac{P_1}{\rho_2} + z_1 g - \cancel{\frac{v_1^2}{2}}\right)$$

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



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



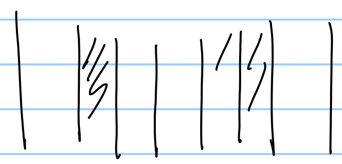
$$\frac{dz}{dL} = \sin(\theta)$$ pipe inclination

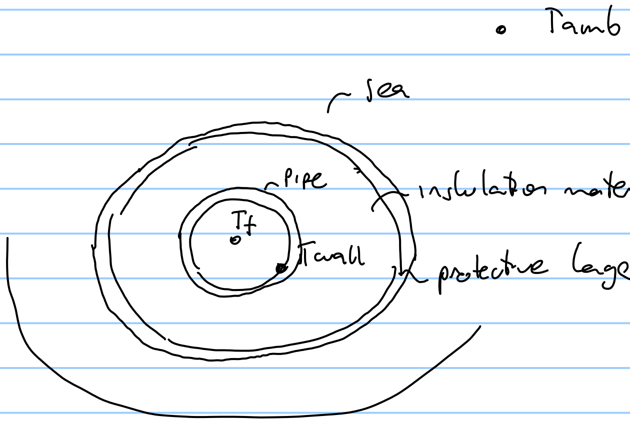
$$\underbrace{\frac{d\dot{q}}{dL}} = \dot{m}\left(\underbrace{\frac{dh}{dL}}_{EOS} + \sin\theta\, g + \underbrace{v\frac{dv}{dL}}_{\frac{dp}{dL}}\right)$$

fluid model

$h = f(p, T)$

the cross section of a pipe segment

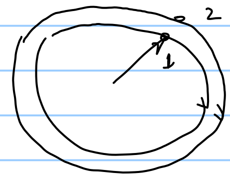




heat transfer

in solids conduction

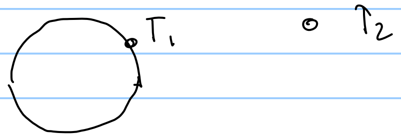
$$\dot{q} = 2\pi L \cdot \underbrace{k}_{\text{conductivity of material}} \left(\frac{T_1 - T_2}{\ln\left(\frac{r_2}{r_1}\right)} \right)$$



- pipe wall
- insulation material
- soil.

in liquid convection → free → forced convection

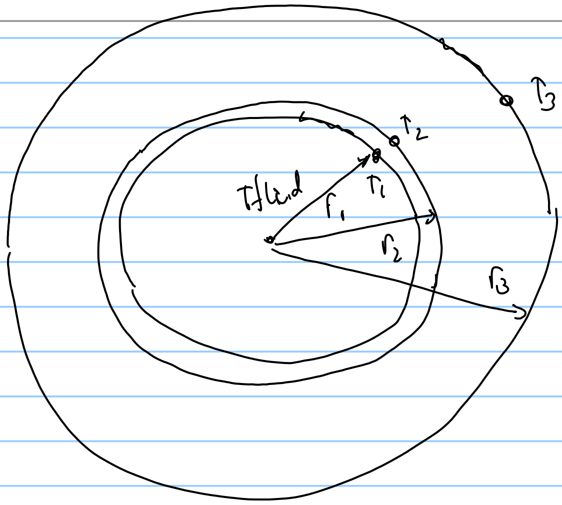
$$\dot{q} = 2\pi r L h (T_1 - T_2)$$



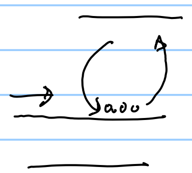
$$\left(T_f - \cancel{T_{wall}}\right) = \frac{\dot{q}}{2\pi r L h_{int}}$$

$$\left(\cancel{T_{wall\,in}} - T_{wall\,out}\right) = \frac{q}{2\pi r L k} \ln\left(\frac{r_2}{r_1}\right)$$

$$\left(T_f - T_{amb}\right) = \dot{q} \left(\overset{con}{} + \overset{cond_1}{} \overset{cond_2}{} \overset{con\,3}{} \overset{con\,n}{} \right)$$



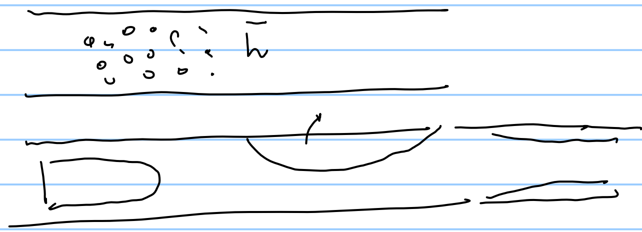
Free convection



Sea bed ∘ T_{amb}

- forced convection on internal flow

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



∘ Conduction in pipe wall

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

∘ Conduction in insulating layer

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

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

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

∘ Convection in sea

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

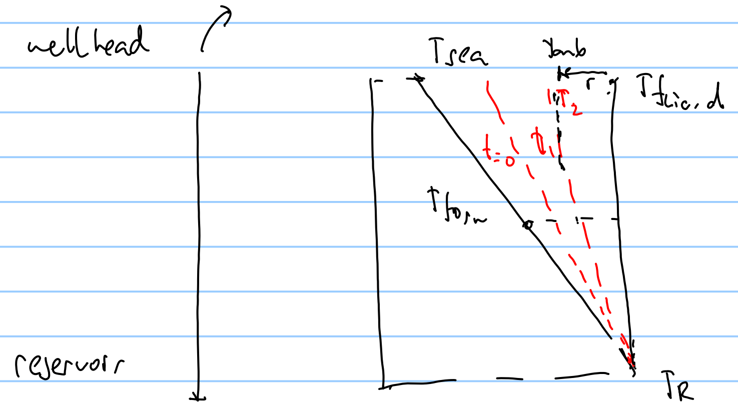
in these equations clear the Temperature difference and sum them up:

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

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

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

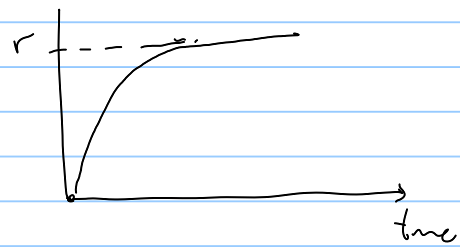
overall heat transfer coefficient referred for outer area



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

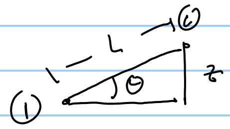
Tamb will be located at an position r that varies with time.!

Ramey - Stanford (1956)



Energy equation in the fluid:

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



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

$$\frac{d\dot{q}}{dL} = \dot{m}\left(\frac{dh}{dL} + \cancel{v\frac{dv}{dL}}_{0} + \sin(\theta) g\right)$$

(p, T) EoS correlation

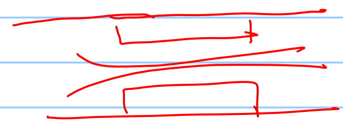
• neglecting velocity changes along the pipe ~ heavy oil + water

if liquid

• $dh = C_p(T)\, dT$

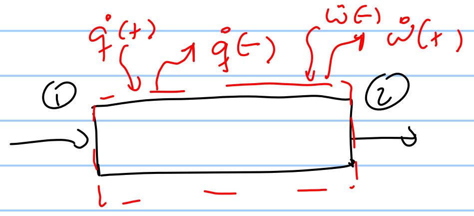
for gas, compressible fluid, Joule thompson

$$dh = C_p(T)\, dT + \underbrace{\mu_J \cdot dp}_{\text{neglect}}$$



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

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



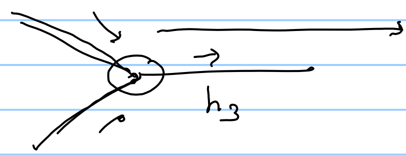
$$-2\pi r_{out} U_{out} (T - T_{amb}) = \dot m C_p \frac{dT}{dL} + \dot m g \sin\theta$$

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

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

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

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



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

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

$$m_1 h_1 + \dot m_2 h_2 = \dot m_3 h_3$$

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

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

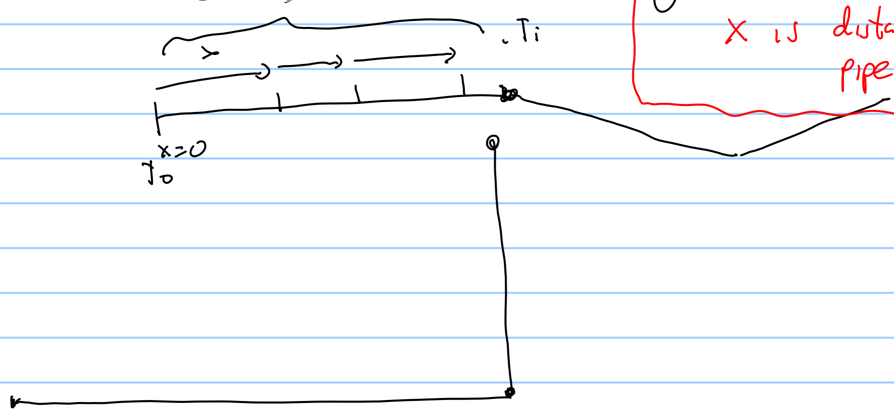
$$e^{\frac{x}{A}}\cdot T(x) - T_0 = \left(\frac{T_{amb}}{A} + \frac{\sin(\theta)\cdot g}{c_p}\right)\cdot A\cdot\left(e^{\frac{x}{A}} - 1\right)$$

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

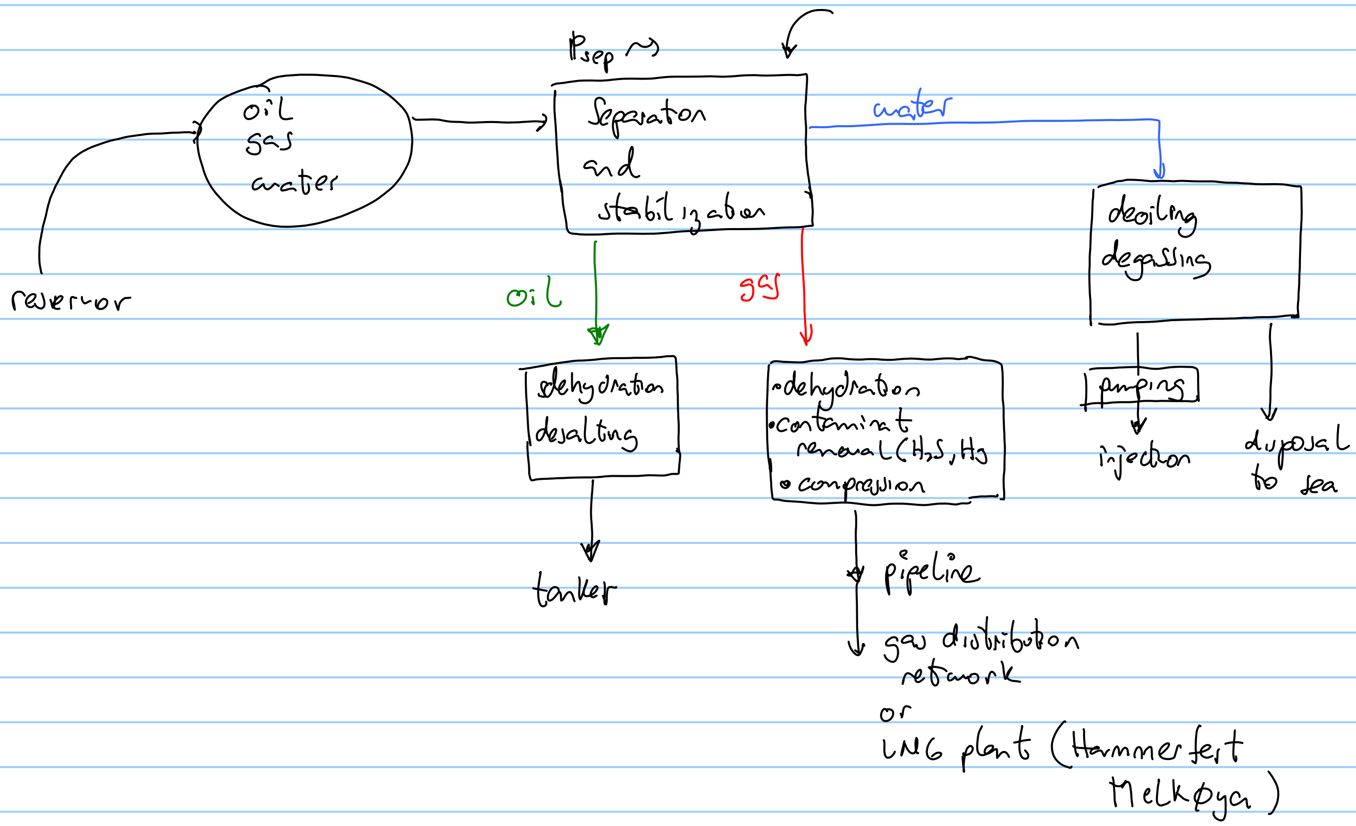
this equation applies for a given pipe segment when U, C_p, θ, $\dot m$, r_{out}, remain constant.

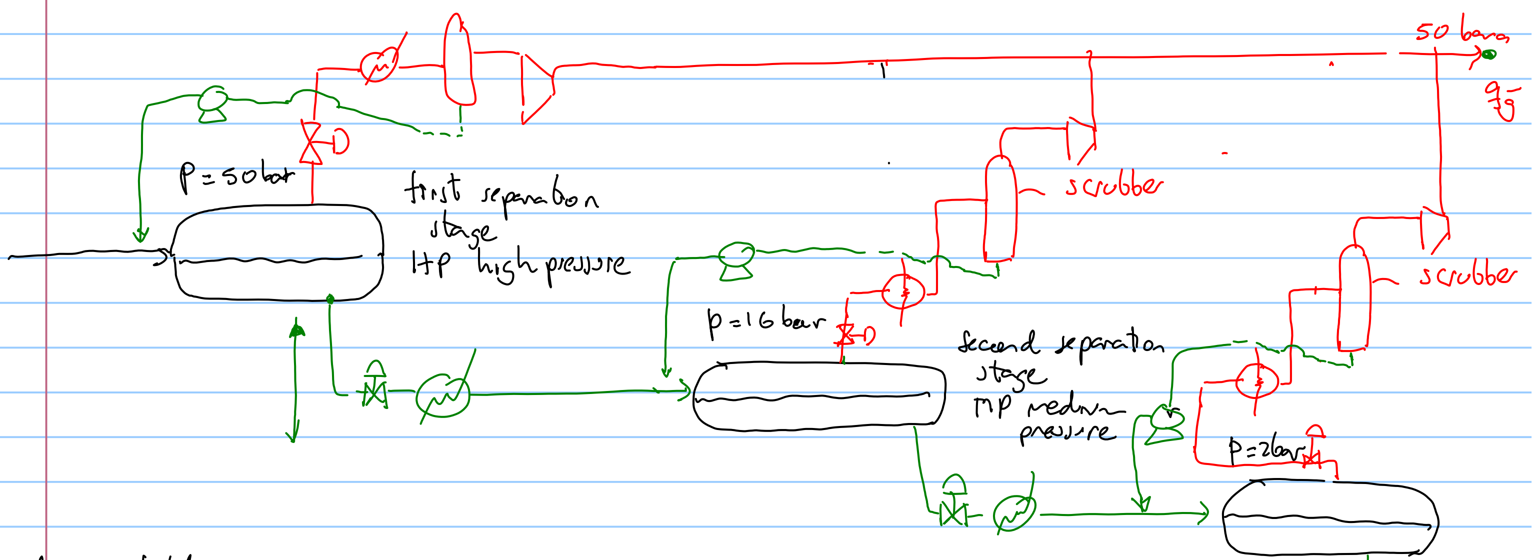
U

X is distance ALONG pipe.



Processing of hydrocarbon fluids ~> equipment on platform





(3rd separation
stage
LP low pressure

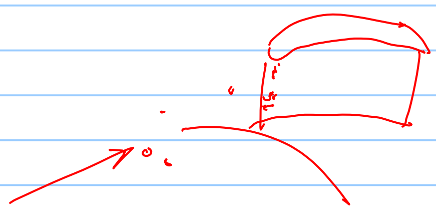
for oil fields
≈ 50 bara
for low GOR
oils

in the North Sea usually we
use 3 stages

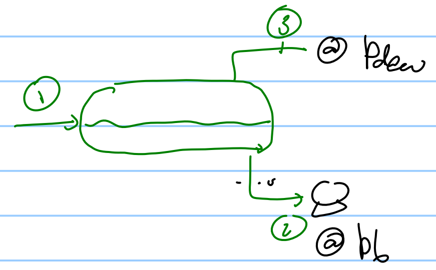
it can be down to 20 bara

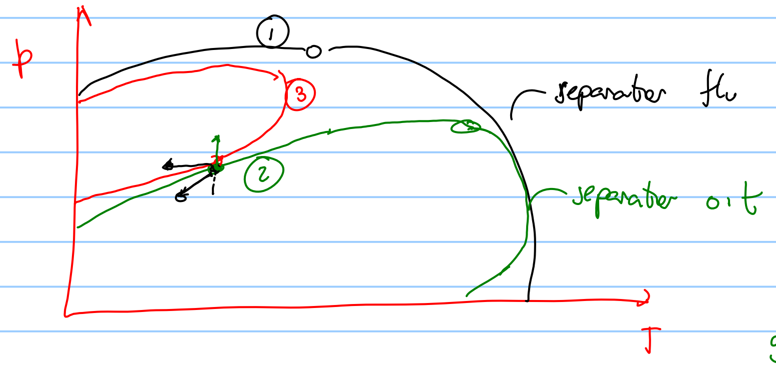
for gas
higher than 50 bara

compressor can only work with
gas (dry)

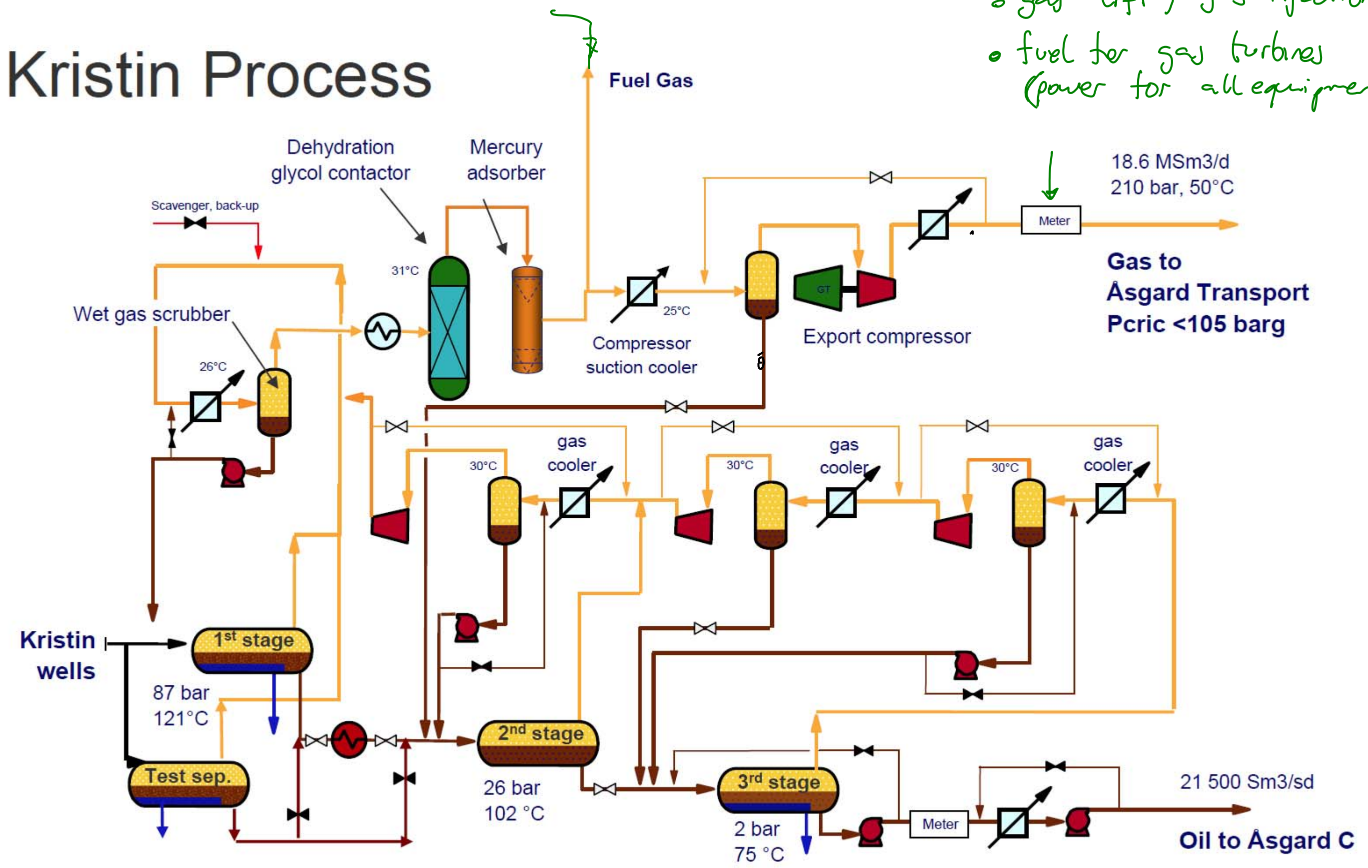


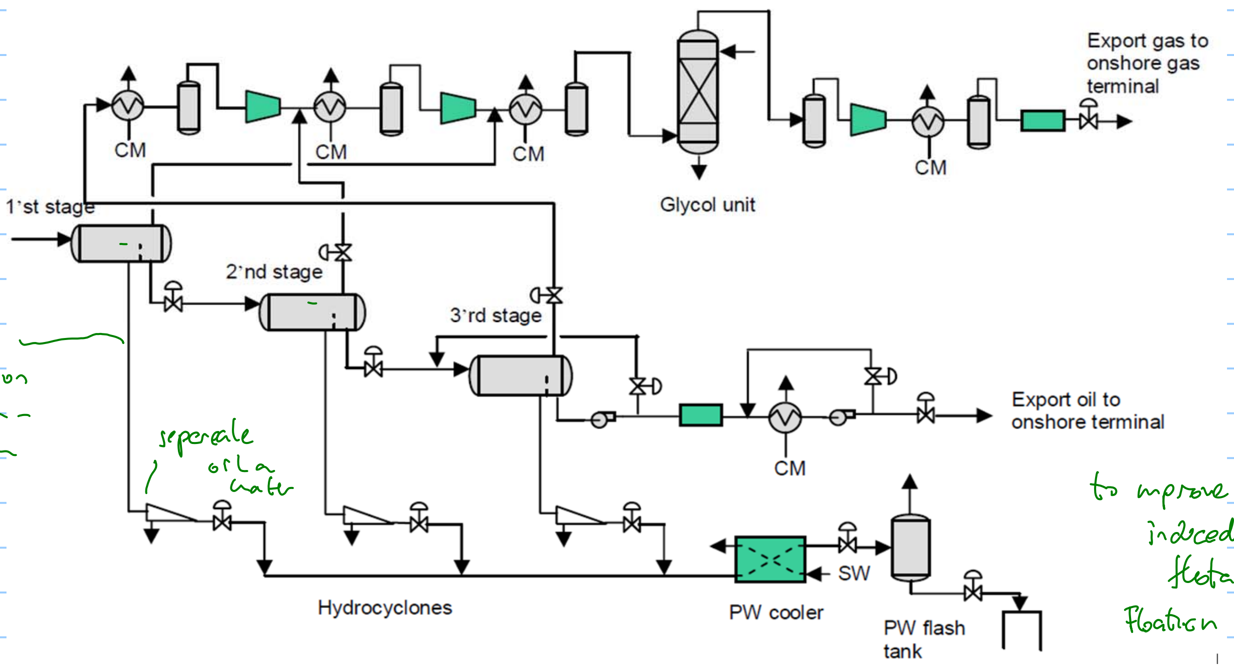
in every separation stage





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





Oiw concentration 1000ppm - 500ppm

separate oil and water

to improve separation induced gas flotation

Flotation units

Typical processing capacities of an oil field: $q_{\bar{o}}$: 8000 Sm³/d – 50000 Sm³/d

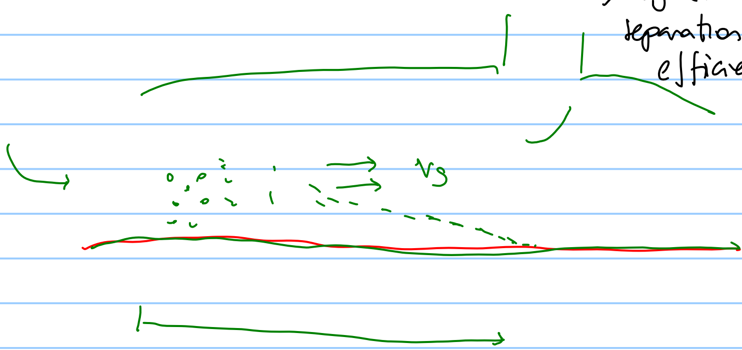
$q_{\bar{g}}$ = 1.5 – 8.5 E6 Sm³/d

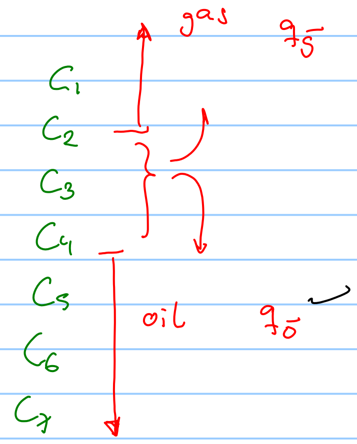
$p_{HP} \approx 50$ bara

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

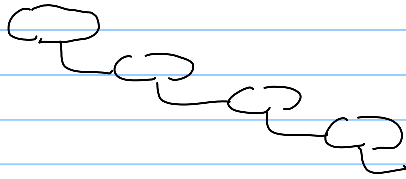
How processing facilities affect the field design process?

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





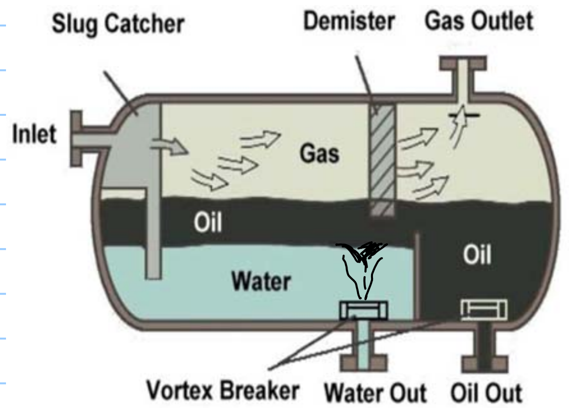
more separation stages also improve liquid recovery



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

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

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



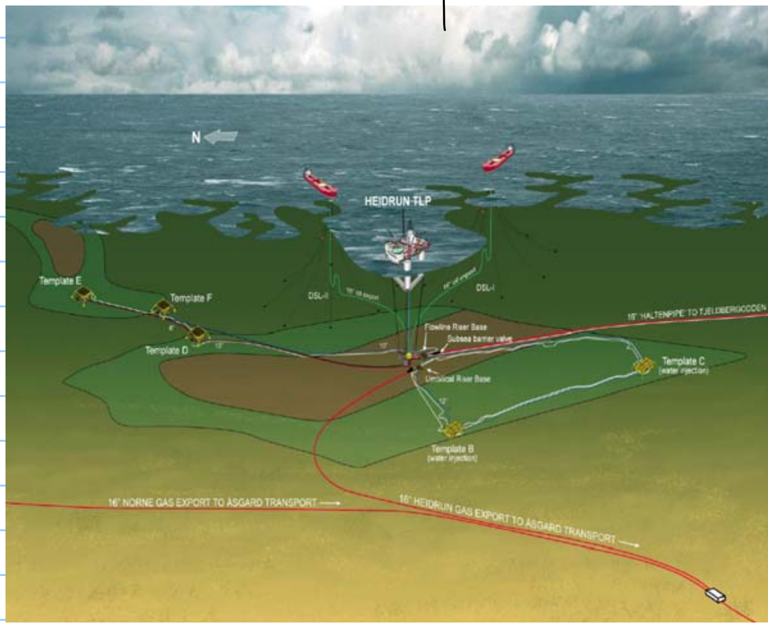
facilities have maximums of : processing capacity of gas { dehydration unit, compressor

processing capacity of water { cyclones

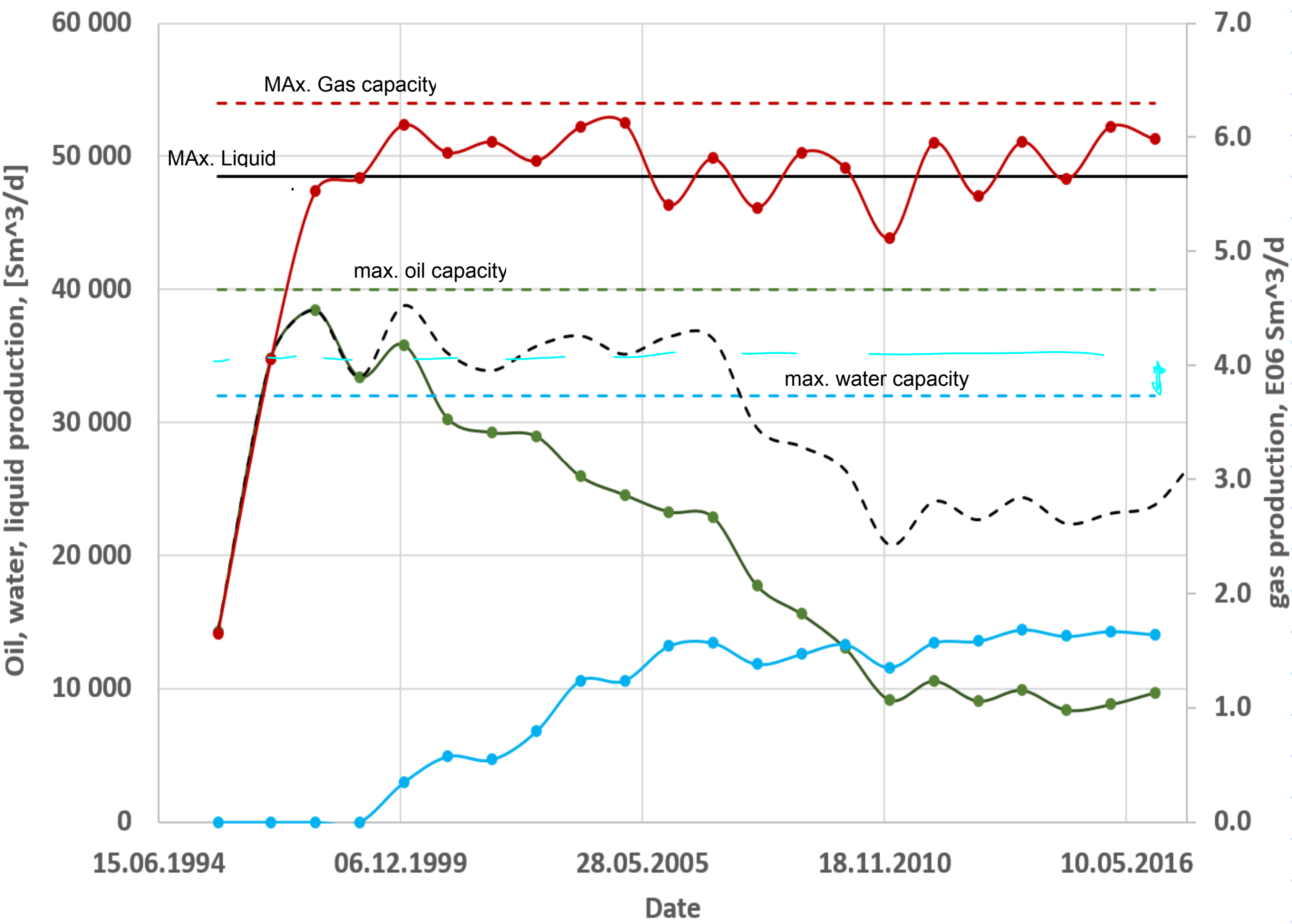
processing capacity of liquid { separator capacity, separator level

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

Let's look at the production profile of Heidrun:



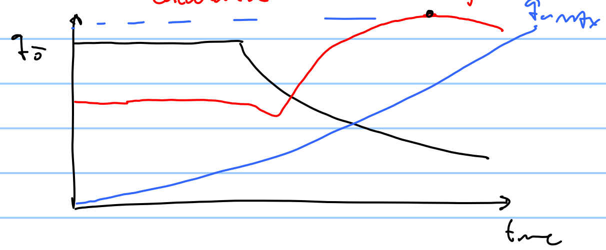
In Heidrun it looks like gas is at its maximum capacity, thus it migh indicate that the production of the field had to be choked back.



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

CAPEX of topside processing facilities: $\underbrace{f(q_o(t), q_g(t), q_w(t))}$

usually calculated with a reservoir model



during production actual profiles can be different than the profiles predicted during the design phase → GOR, WC

Be sure ! $q_{g\,fixed} \leq q_{g\,max}$ Processing facilities

$q_{w\,fixed} \leq q_{w\,max}$

$q_{i\,fixed} \leq q_{i\,max}$ → q_w occupies space that could potentially be used for oil.

the only way to ensure this is choking production.

we could use optimization for this. Ranking method

well usually have different GOR, WC

choosing which well to choke and which well to produce.

Determining optimum P of second stage separator to increase liquid recovery.

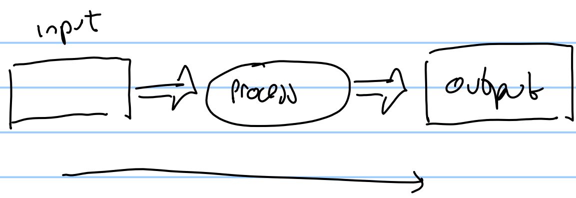
Hysys → simulating processes → processing facilities

→ compositional simulator EoS { Peng Robinson, SRK

→ Aspentech

Honeywell → UNISIM (same source code as Hysys but developed by another company).

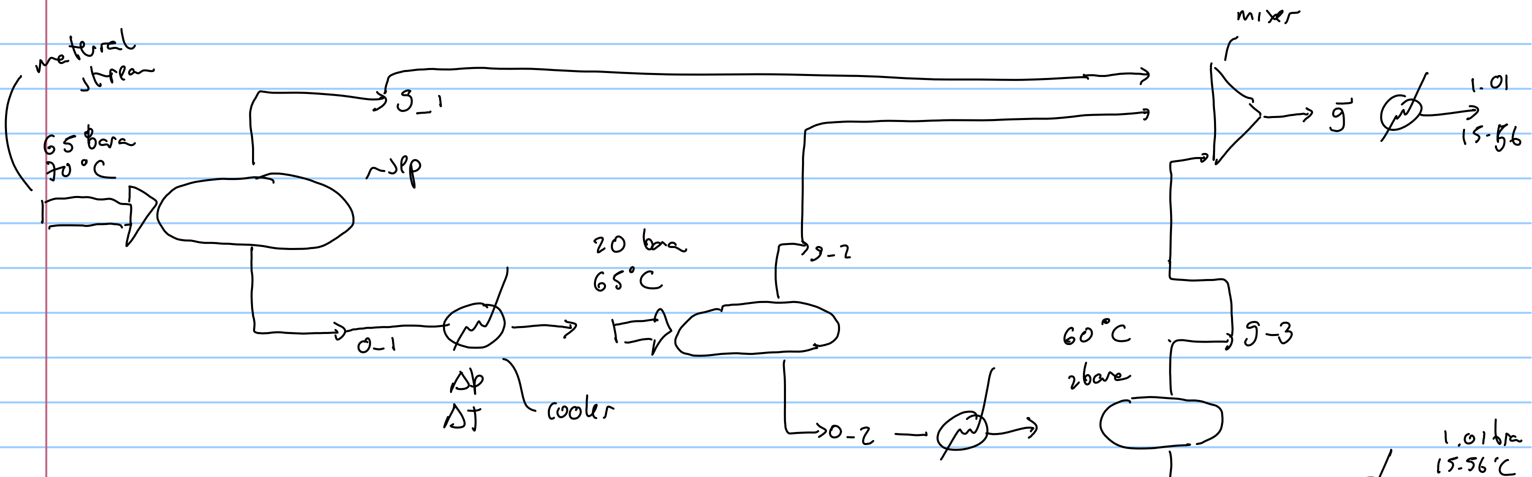
http://folk.ntnu.no/stanko/Courses/TPG4230/2017/Class_files/20170328/ Class exercise.



co-current

always downstream

always along the direction of flow

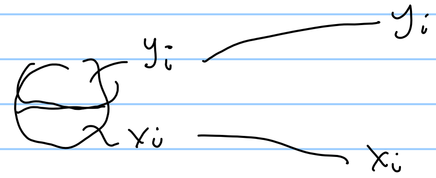


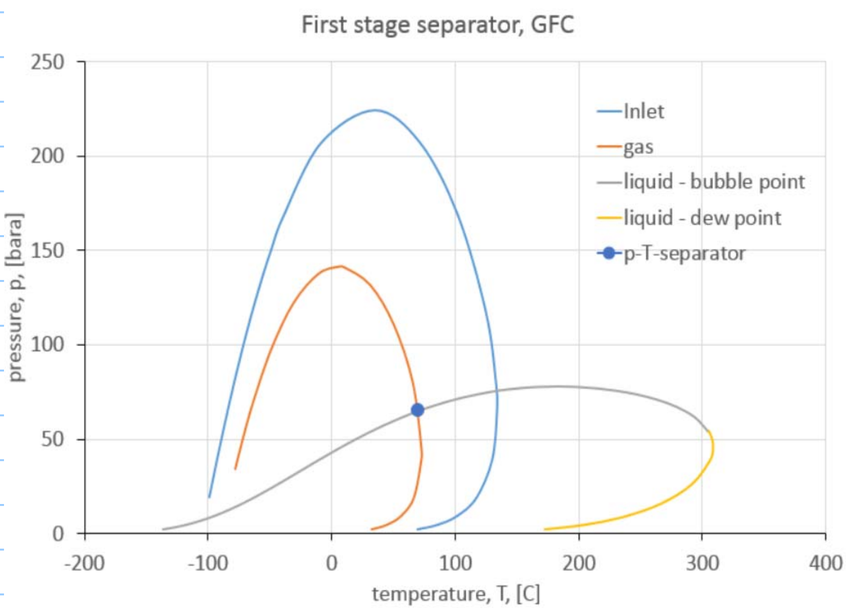
GOR : $\left[\frac{Sm^3}{Sm^3}\right]$

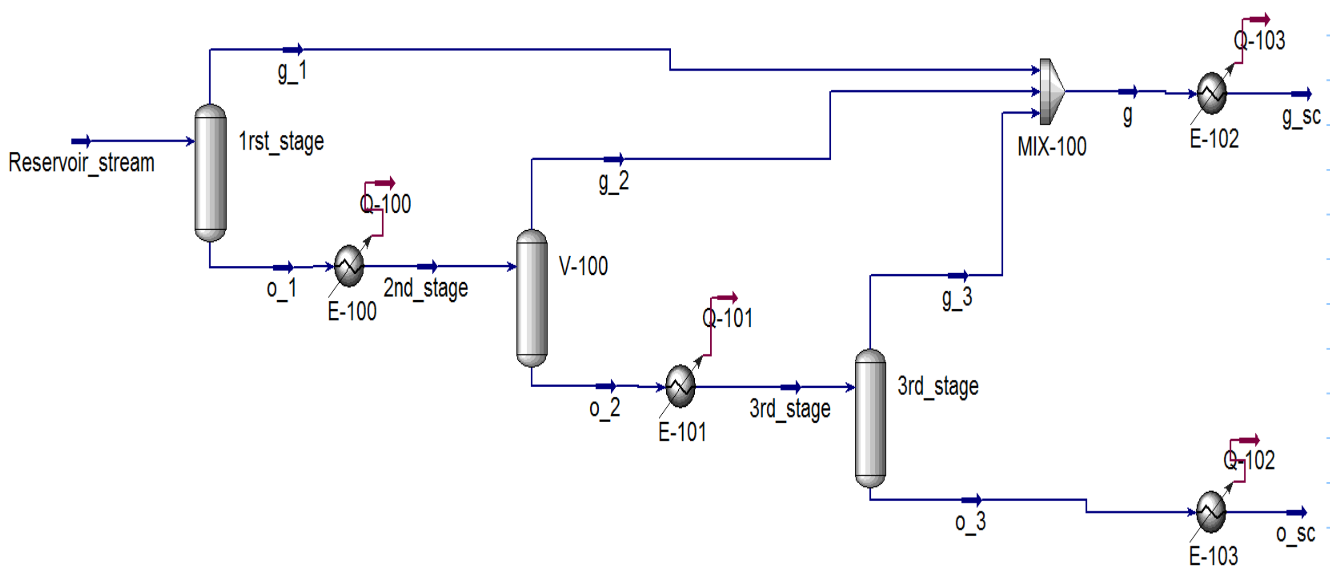
$p = 1.01325$ bara

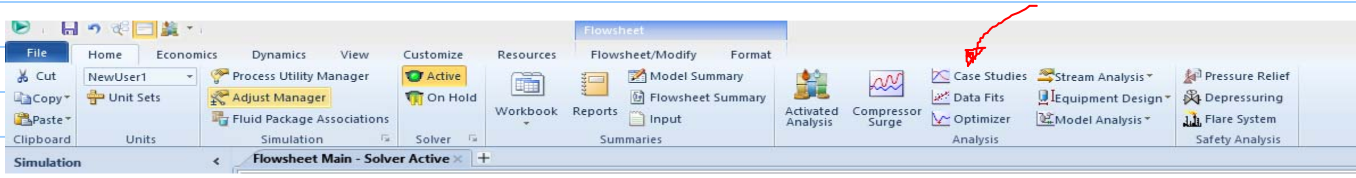
$T = 15.56$ °C

$z_i \rightarrow p, T$









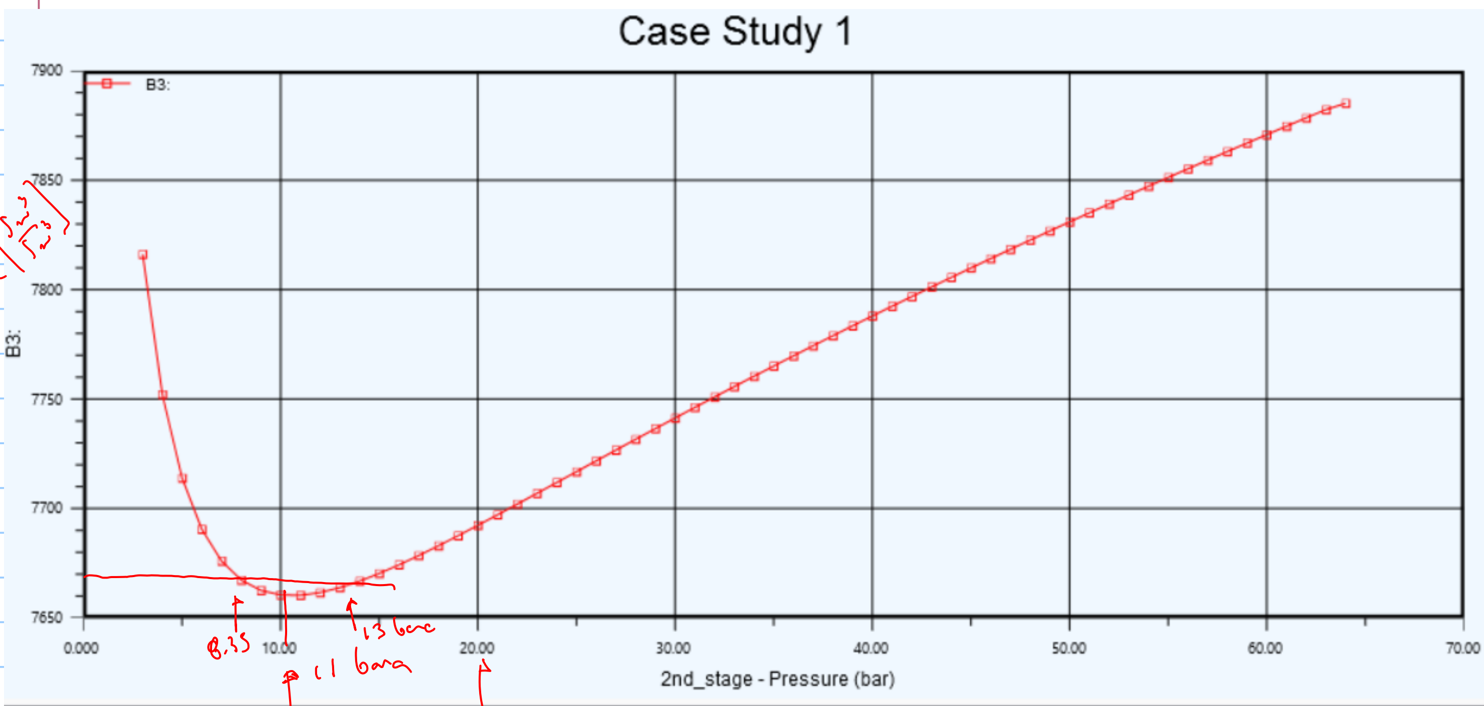
Case studies

Object	Variable	Independent	Include
2nd_stage	Pressure	Yes	☑
SPRDSHT-1	B3:	No	☑

x y

$y = f(x)$

$GOR = f(P_{mp})$



GOR = 7692 Sm^3/Sm^3

GOR = 7660 Sm^3/Sm^3

if q_g fixed = 7E6 Sm^3/d

P_{msep} = 20 bara q_{liquid} = 910.04 Sm^3/d

P_{msep} = 11 bara q_{liquid} = 913.83 Sm^3/d

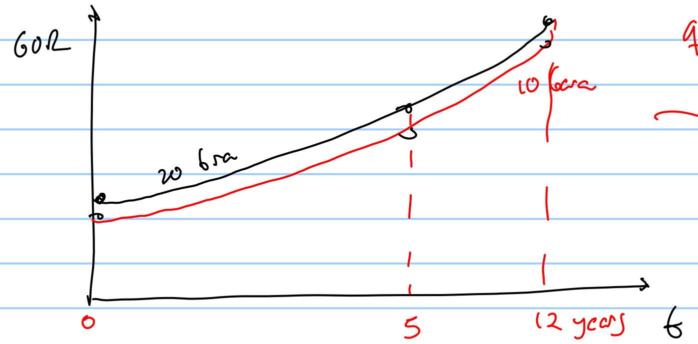
3.8 Sm^3/d

24 stb/d

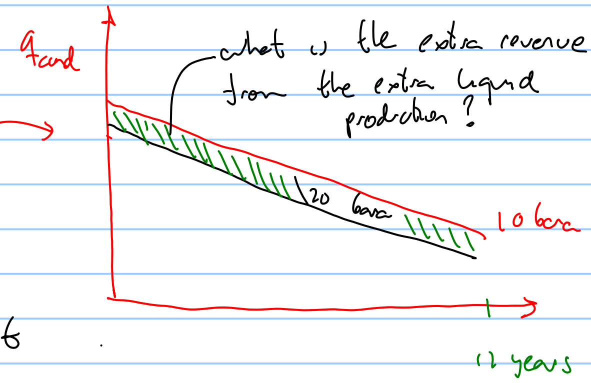
@ 50 usd/bbl ≈ 1200 usd/d

to compare the two options $P_{2nd\,stage}$ = 20 bara vs. 10 bara

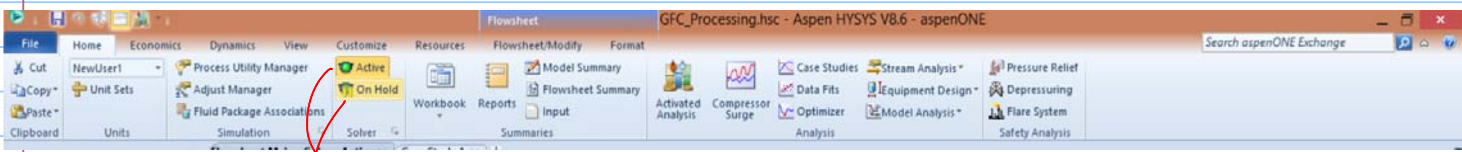
Compute GOR for all years



$$q_{cond} = \frac{q_{g,fred}}{GOR}$$



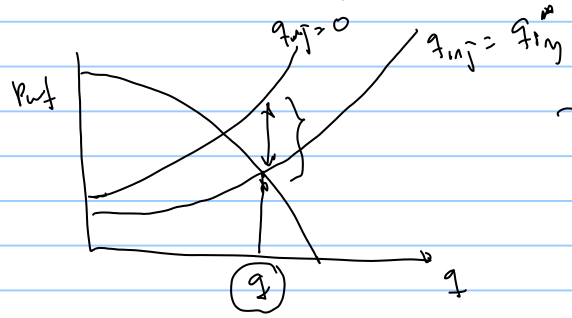
Other Hysys tricks



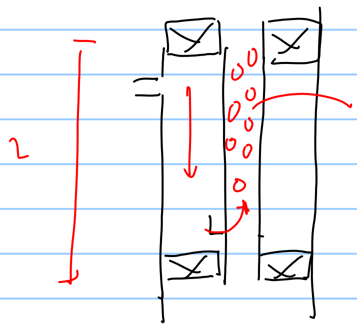
calculates everything all the time

doesn't calculate

Artificial lift: methods deployed in well to increase production aid natural flow



→ gas lift
reduce the density of the flowing mixture in the tubing by injecting gas



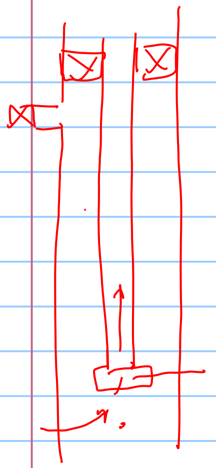
$$\rho_{mix} = \alpha\,\rho_g + (1-\alpha)\,\rho_L$$

$$\alpha = \frac{q_g}{q_o + q_g}$$

$$\Delta p = \rho \cdot L\, g \downarrow$$

• PCP Progressive cavity pump

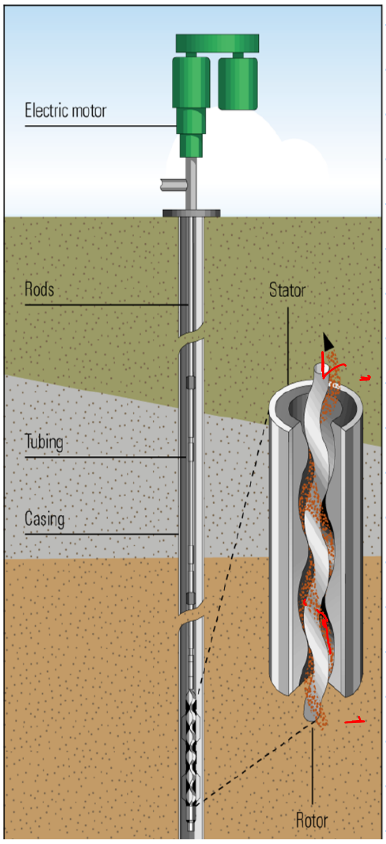
• rod pumping



pump { ESP PCP rod pump

if $P_{wf} \leq P_b$ then gas should be produced through annulus

if $P_{wf} \geq P_b$ single phase at pump suction



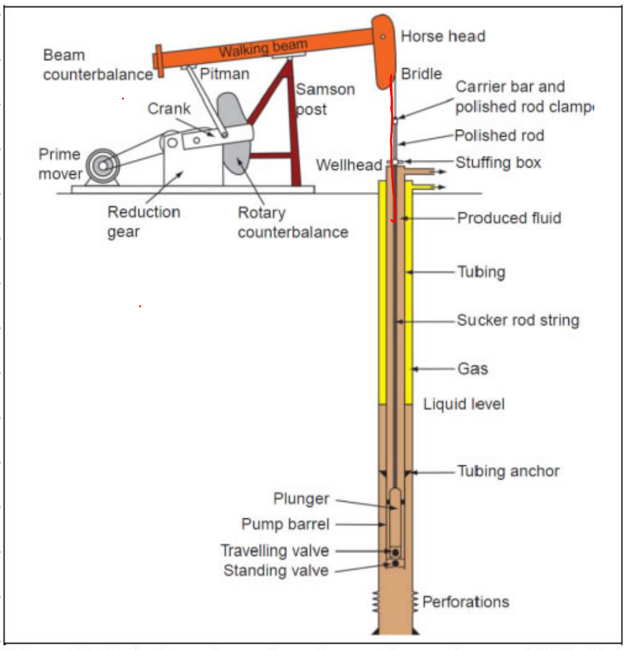
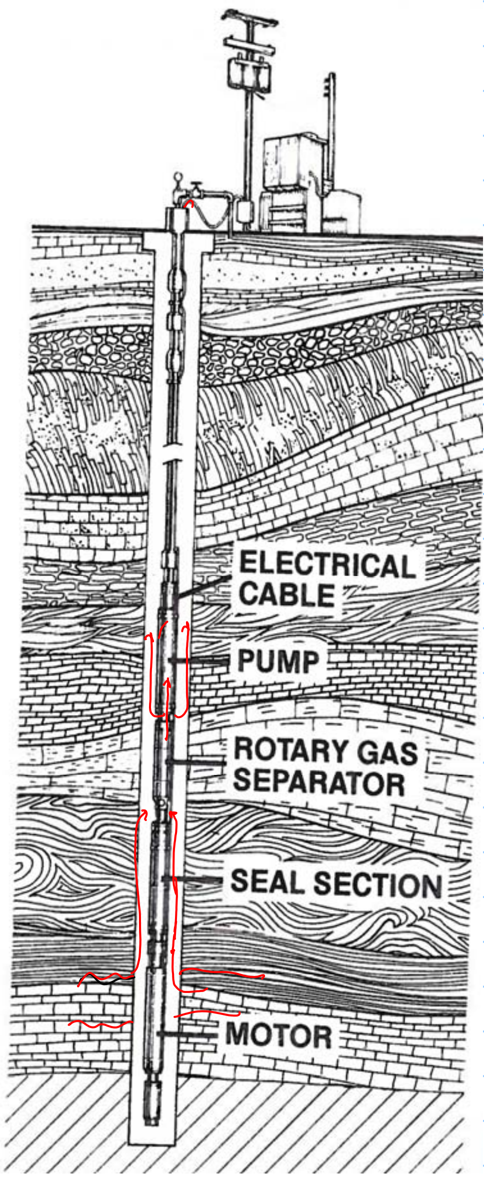


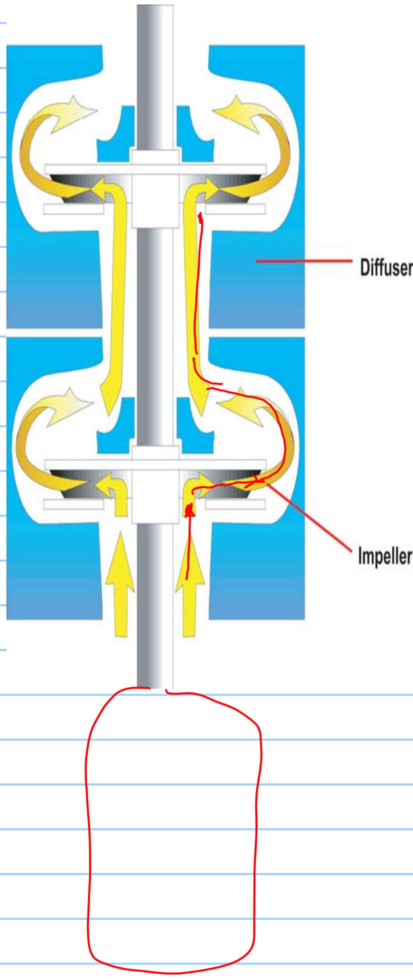
Figure 2. Typical configuration of a sucker rod pump (Bellarby, 2009).

- ESP Electric submersible pump. Russian engineer (Armais Arutunoff

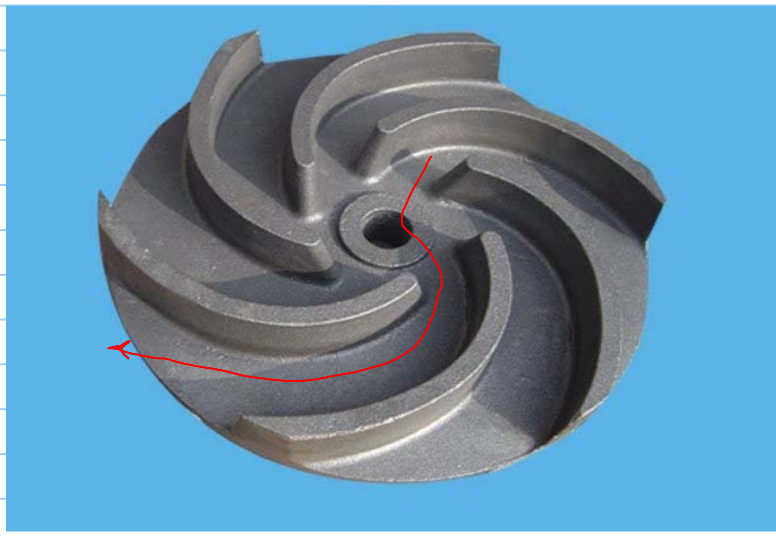
centrifugal pump installed in the wellbore
driving electrical motor is also in the wellbore

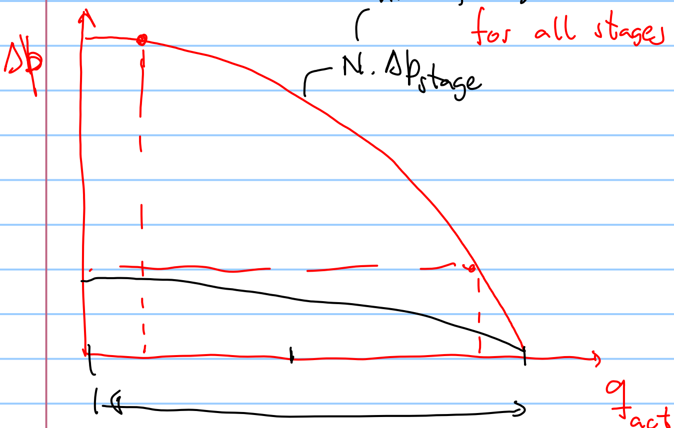
50 - 100 stages





$p_{wf} < p_b$





with $q_{required}$ and $\Delta p_{required}$ the $N_{stages} = \frac{\Delta p_{required}}{\Delta p_{stage}} \cdot F$

F: pancake factors

$$\Delta h = \frac{\Delta p}{\rho_{fluid}\, g}$$

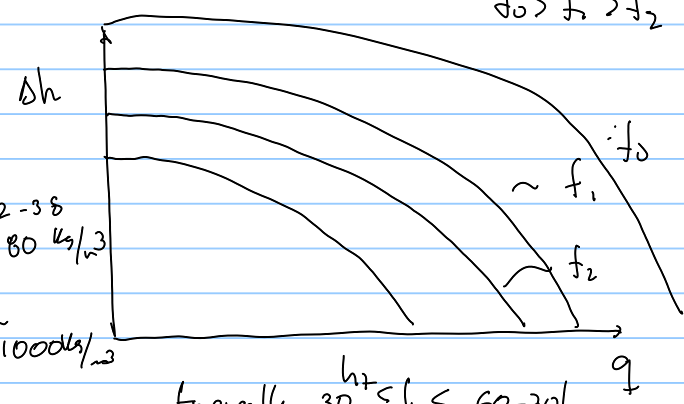
head

API ~ 32-38

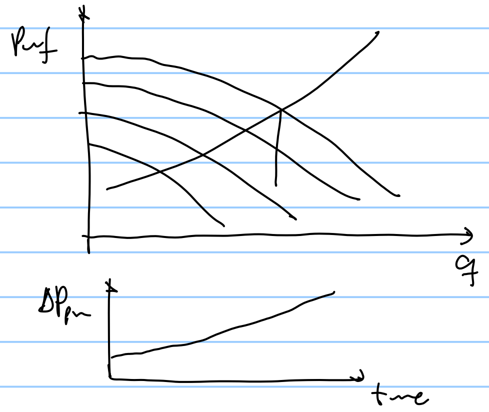
780 kg/m^3

10 ~ 1000 kg/m^3

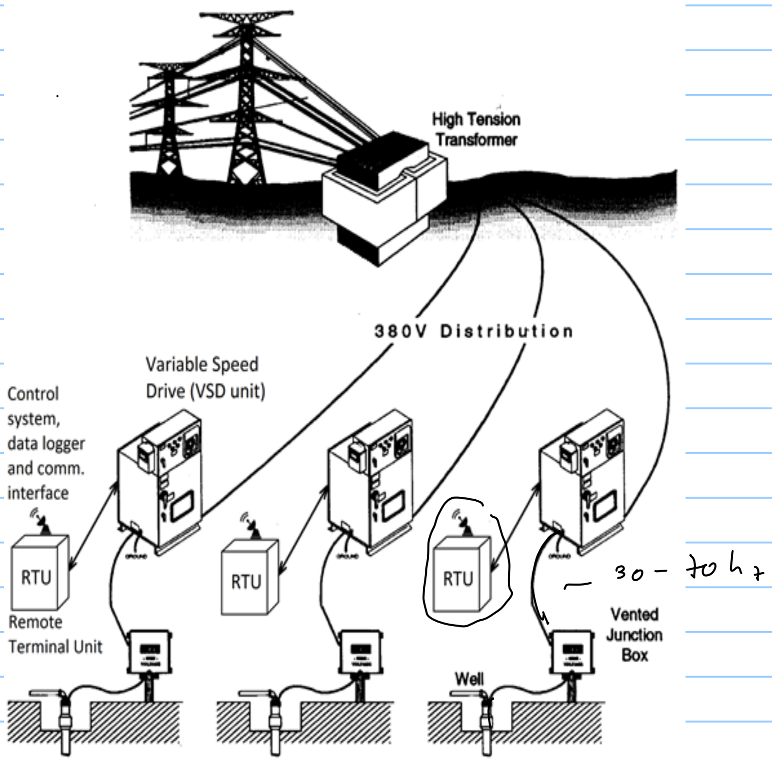
$f_0 > f_1 > f_2$

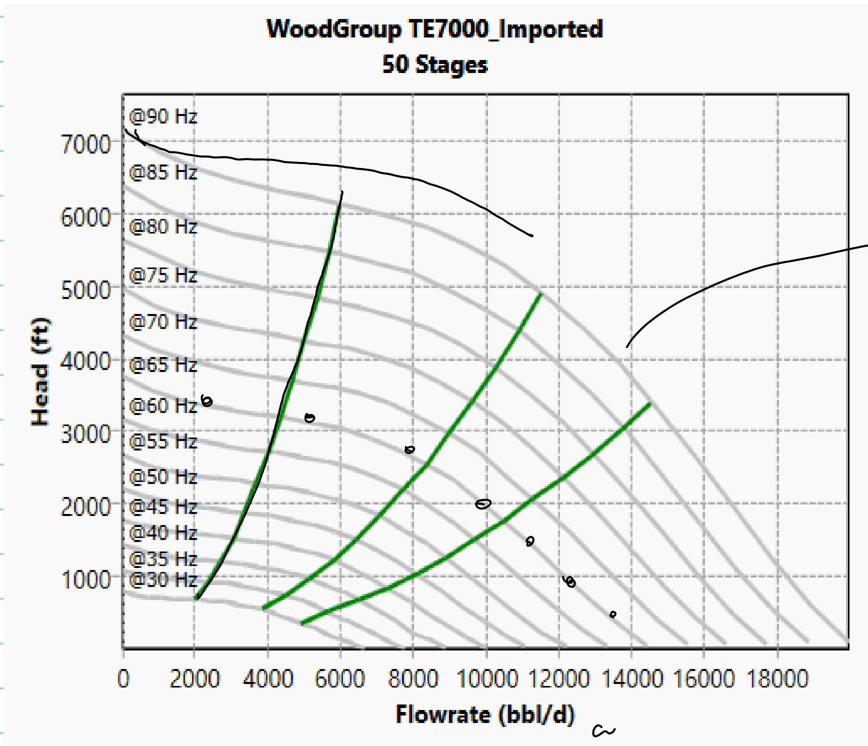


typically 30 Hz $\leq f \leq$ 60-70 Hz



change the rotational speed of pump





usually represented with a polynome

$$\Delta h = a q^4 + b q^3 + c q^2 + d q + e$$

tune a, b, c, d, e to measured data @ reference frequency $\begin{cases} 60\text{ Hz} \\ 50\text{ Hz} \end{cases}$

for another speed one use similarity law.

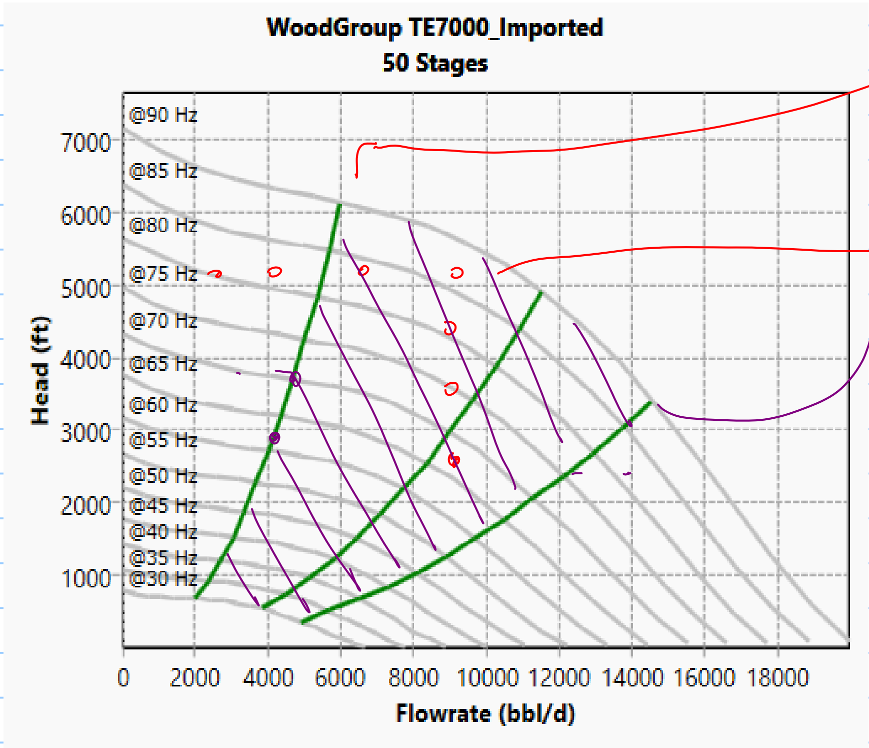
60 Hz

$$\frac{\Delta h @ f_1}{\Delta h @ f_2} = \left(\frac{f_1}{f_2}\right)^2$$

calculated for 60 hz

$$\Delta H = \left(a_4 \cdot \left(\frac{60\ hz}{f}\right)^4 \cdot q^4 + a_3 \cdot \left(\frac{60\ hz}{f}\right)^3 \cdot q^3 + a_2 \cdot \left(\frac{60\ hz}{f}\right)^2 \cdot q^2 + a_1 \cdot \left(\frac{60\ hz}{f}\right) \cdot q + a_0 \right) \cdot \left(\frac{f}{60\ hz}\right)^2$$

$$\frac{q_{@f_1}}{q_{@f_2}} = \left(\frac{f_1}{f_1}\right)$$



minimal flow rate line

maximum flow rate line

freq	q	Δp
1	q_1	Δp_1
2	q_2	Δp_2
3	q_3	Δp_3
4		
1		

$q_{min}(f) \leq q \leq q_{max}(f)$ for every frequency

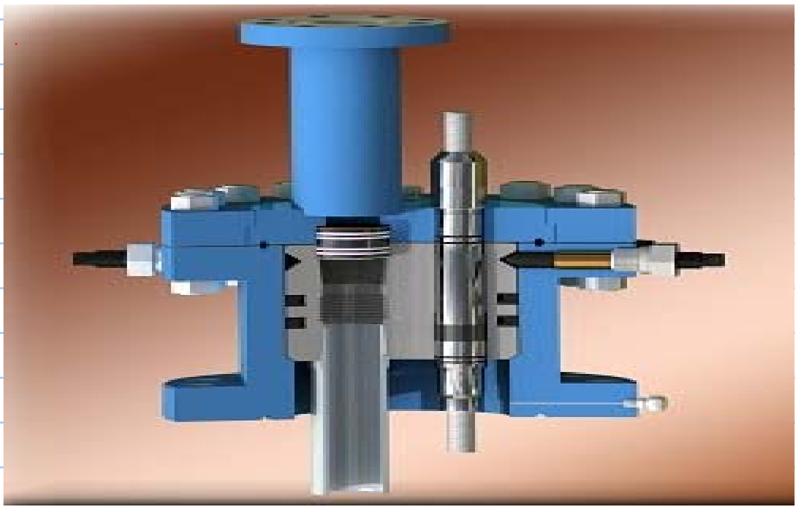
if not pump life is reduced dramatically!

typical pump life ≈ 2 years
5 years

not favorit for subsea installations due to increased maintenance frequency!

typical intervention time in subsea systems is 5 years.

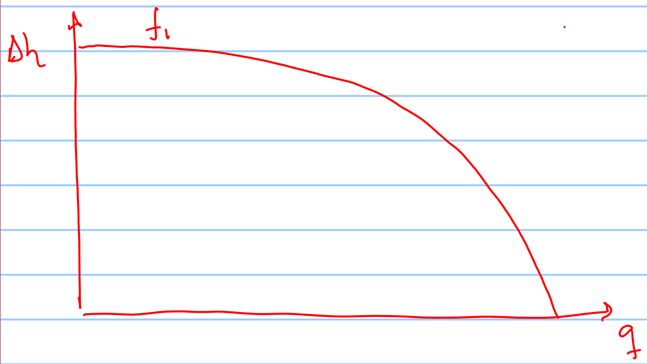
04.04.2017 . Multiphase subsea boosting
06.04.2017 . Production optimization
20.04.2017 . Course wrap-up



Operational limitations of ESP's so far

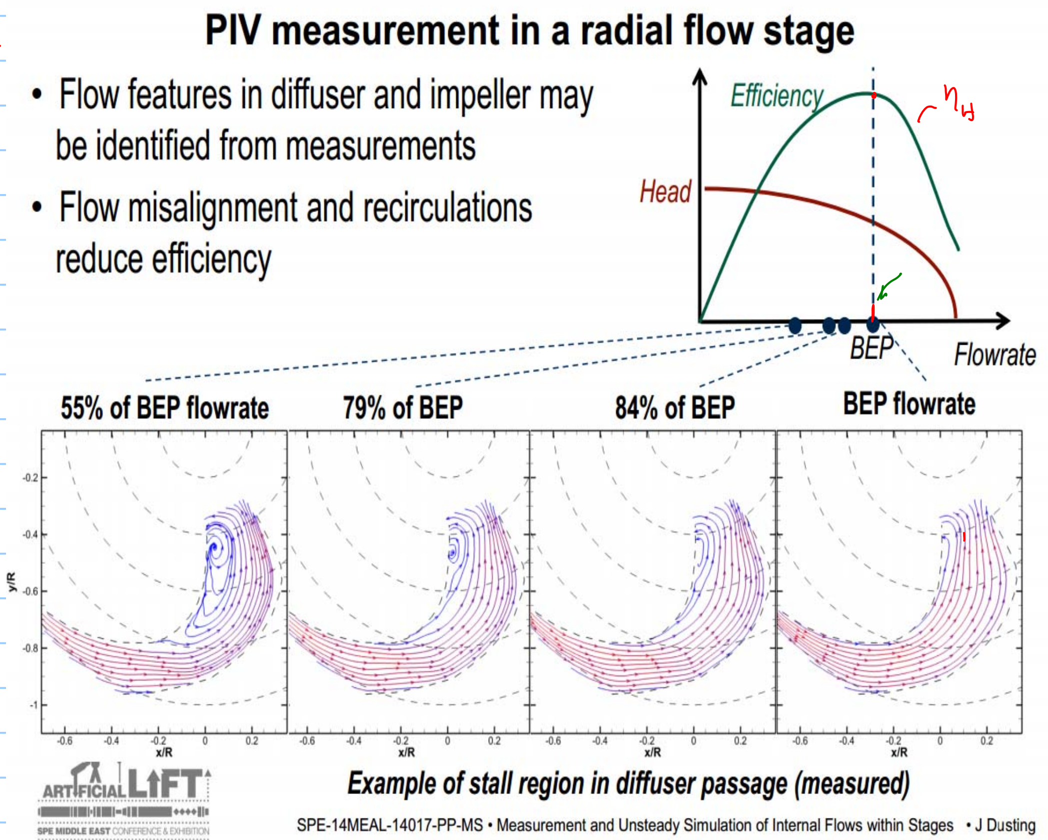
$30Hz \leq f \leq 70Hz$

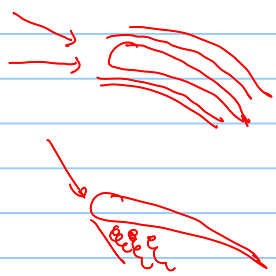
$\underbrace{P_{suc} > F \cdot P_b}$

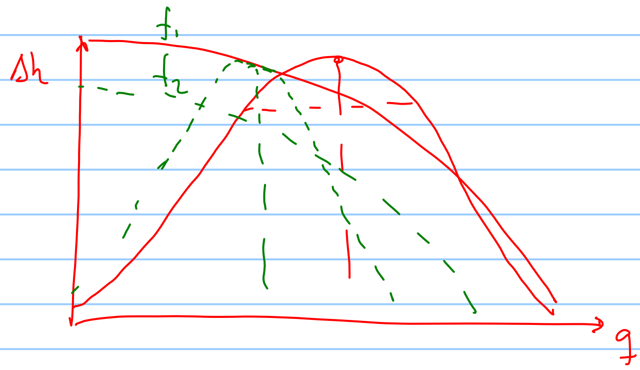


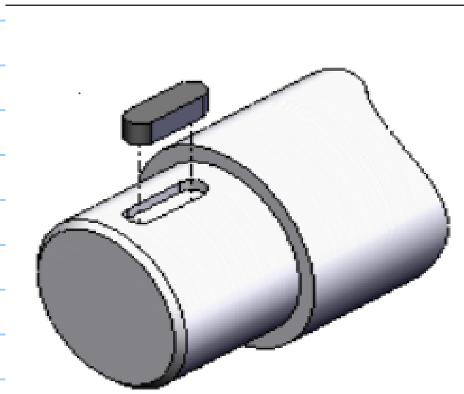
$$P_{pump} = \overbrace{\Delta p}^{P_{dis} - P_{suc}} \cdot \underbrace{q}_{\text{local conditions}} \cdot \frac{1}{\eta_H \cdot \eta_{mech}}$$

local conditions → fluid friction

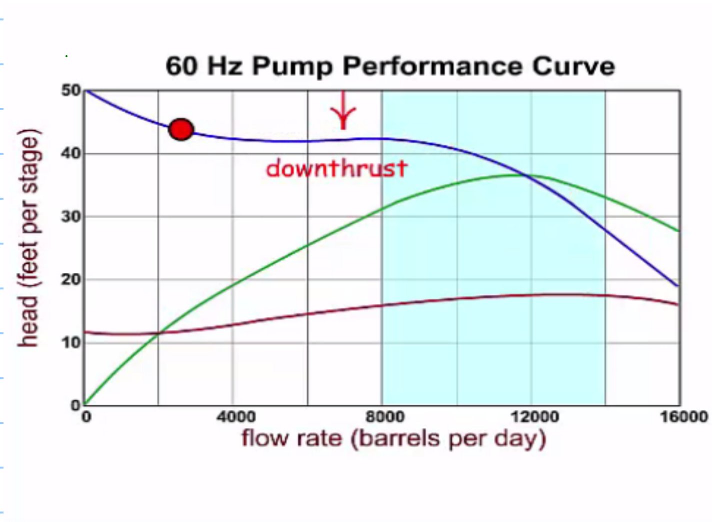


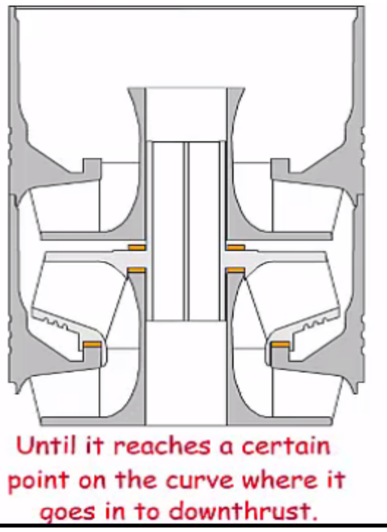


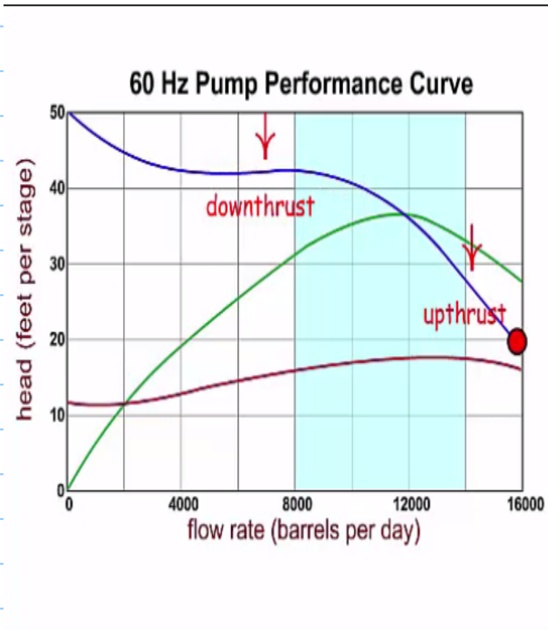


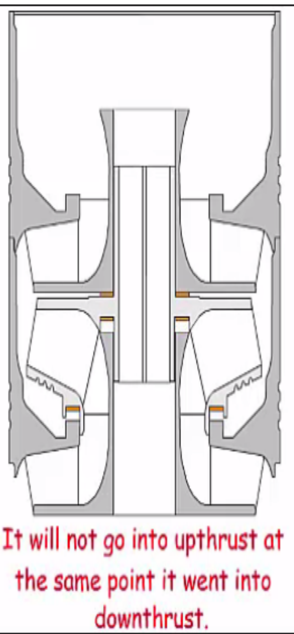


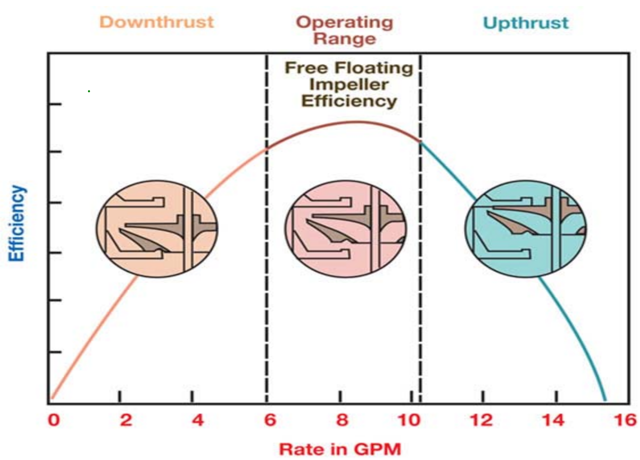
In mechanical engineering, a key is a machine element used to connect a rotating machine element to a shaft.

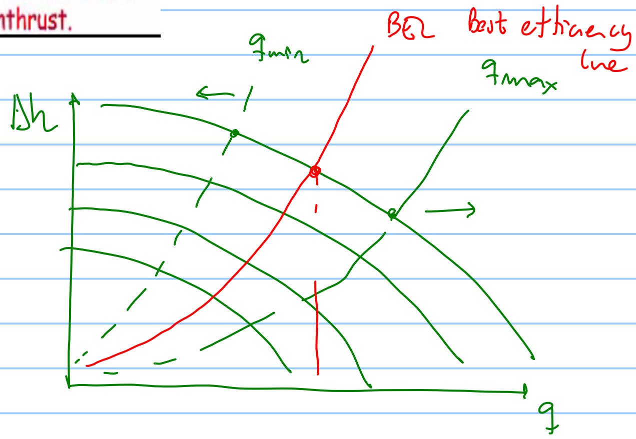


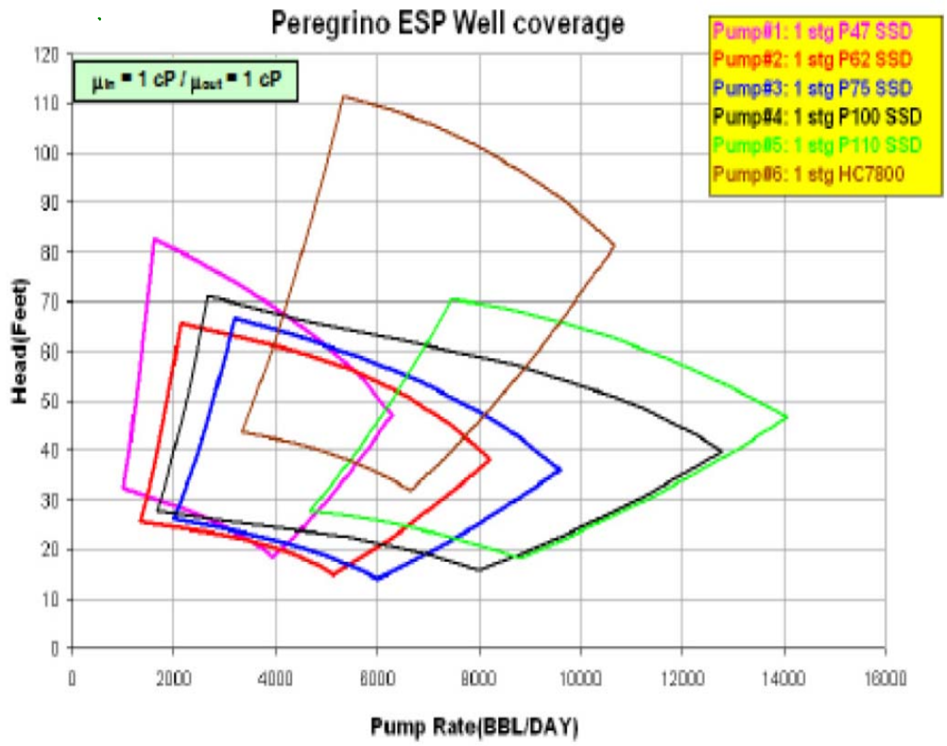


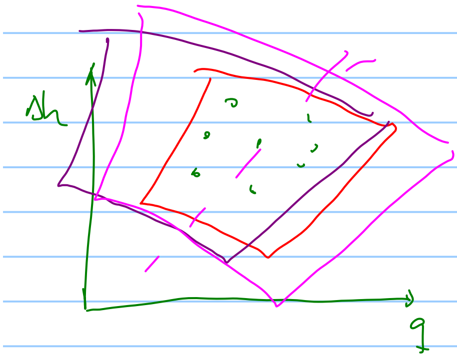








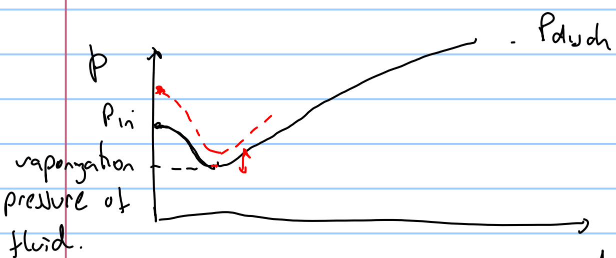




- maximum power capacity of motor (100 hp ~ 1600hp)

$$P = \frac{\Delta p \; q}{\eta_H \eta_m} \leq \text{Power installed}$$

- Cavitation

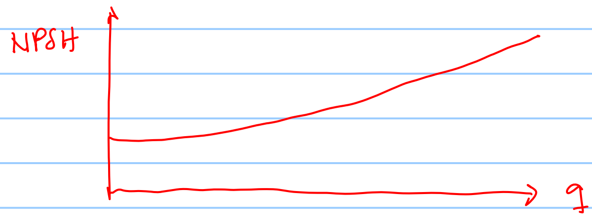


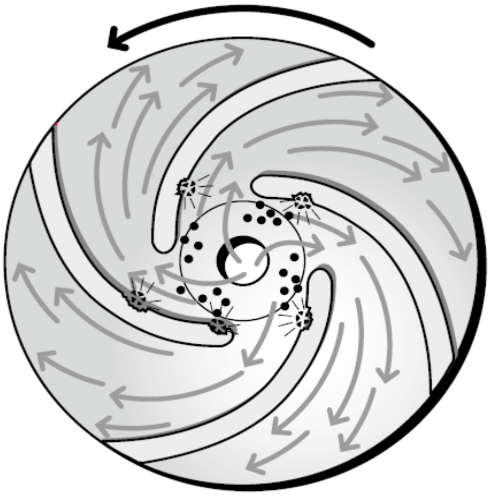
distance along the flowpath from pump inlet to pump outlet

Psuct > that plimit

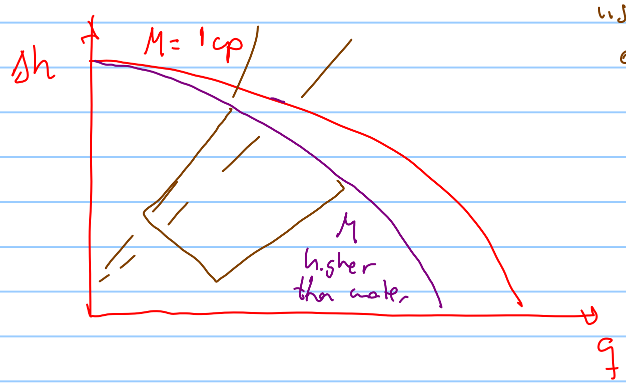
NPSH net positive suction head [m]

(Δp Δh
with ρ change to bara





Effect of viscosity

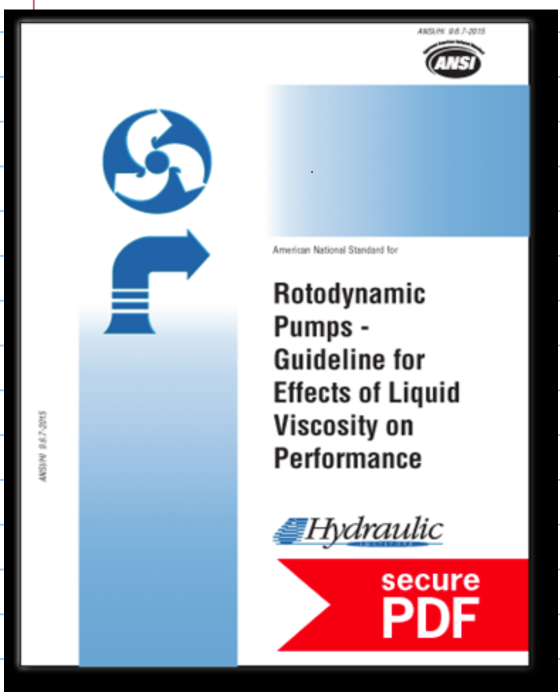


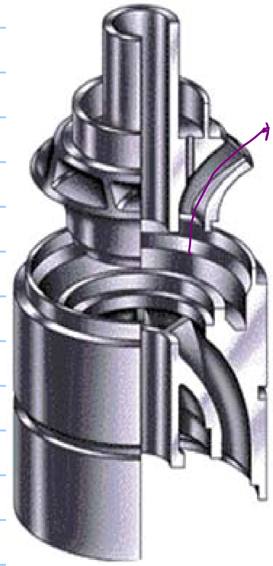
viscosity reduces the operational envelope of pump!

how to estimate pump performance with viscosity

↳ lab testing

↳ hydraulic institute method not 100% accurate!



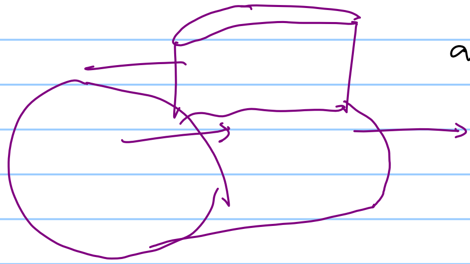


mixed flow
↳ axial
radial

Δp per stage is
usually.

very tolerant to gas

GVF ≈ 10%
gas volume fraction
↳ actual cond.
local cond

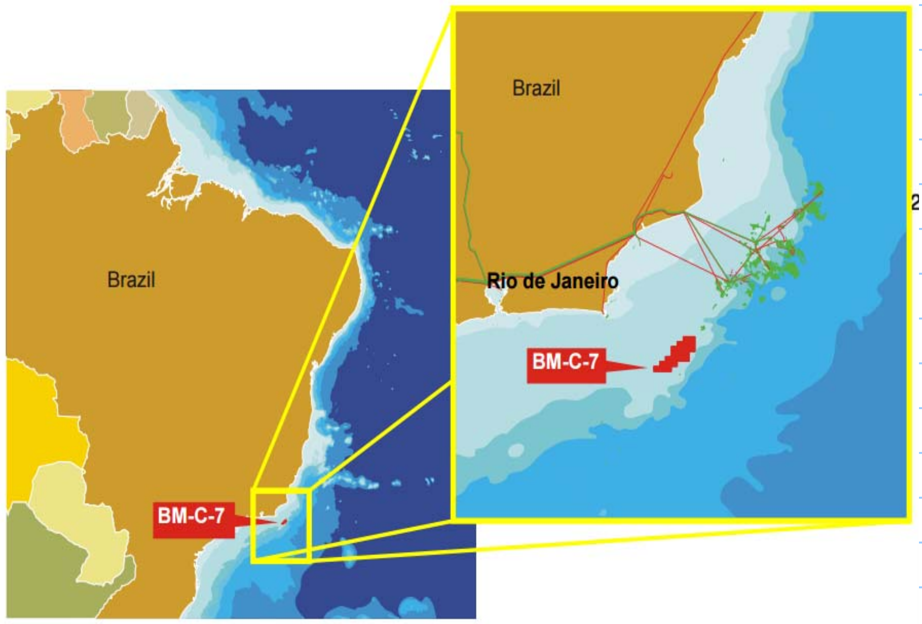


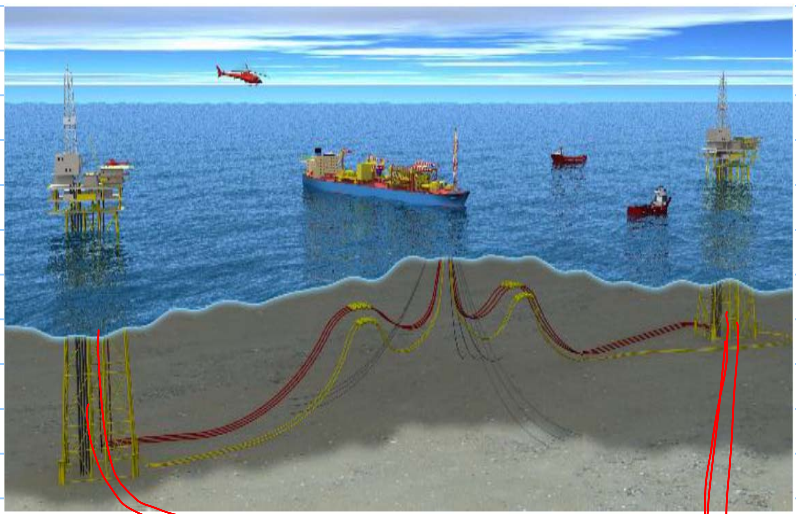
axial impeller. not used
in ESPs.

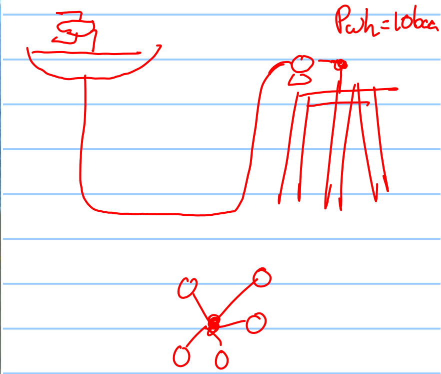
Class exercise

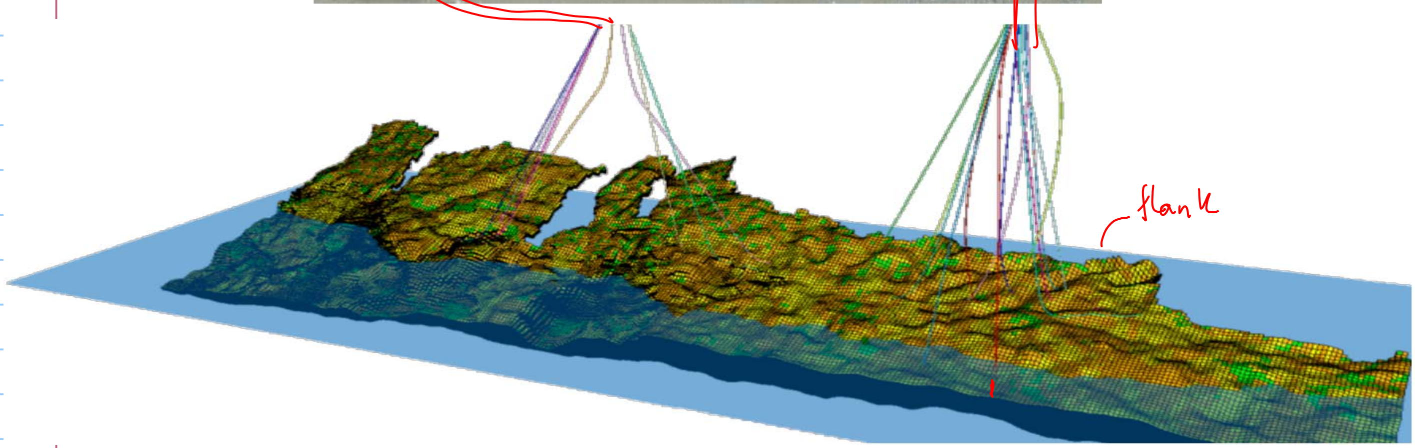
http://folk.ntnu.no/stanko/Courses/TPG4230/2017/Class_files/20170330/

the Peregrino field :

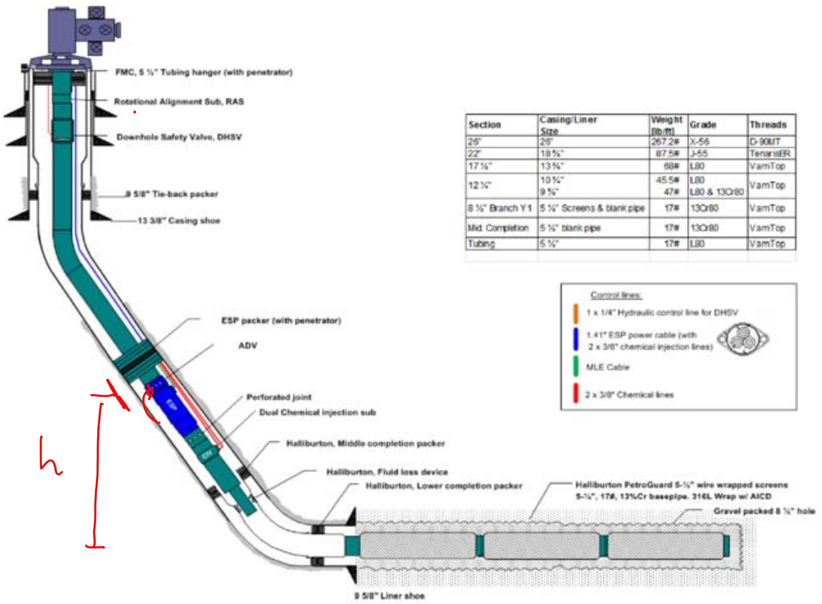








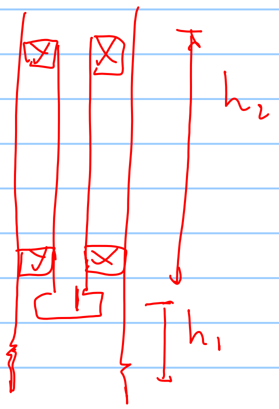
- LQ — living quarters
- Drilling module
- Movable drill rig
- Electrical plant
- Wellheads
- Booster pumps
- Water Injection
- Uptime 99% bracket



Section	Casing/Liner Size	Weight (lb/ft)	Grade	Threads
26"	26"	267.2#	X-56	D-90MT
22"	18 ⅝"	87.5#	J-55	TenarisER
17 ½"	13 ⅜"	68#	L80	VamTop
12 ¼"	10 ¾" 9 ⅝"	45.5# 47#	L80 L80 & 13Cr80	VamTop
8 ½" Branch Y1	5 ½" Screens & blank pipe	17#	13Cr80	VamTop
Mid. Completion	5 ½" blank pipe	17#	13Cr80	VamTop
Tubing	5 ½"	17#	L80	VamTop

Control lines:

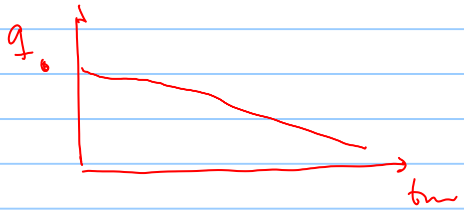
- 1 x 1/4" Hydraulic control line for DHSV
- 1.41" ESP power cable (with 2 x 3/8" chemical injection lines)
- MLE Cable
- 2 x 3/8" Chemical lines

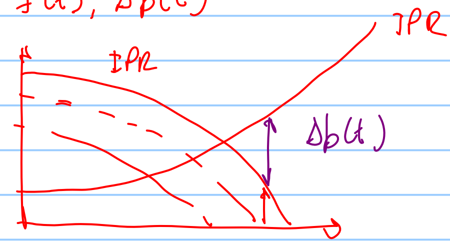


Design process of ESP for the field lifetime

Reservoir department → Production department

$q(t)$, P_{wf} — $q(t)$, $\Delta p(t)$

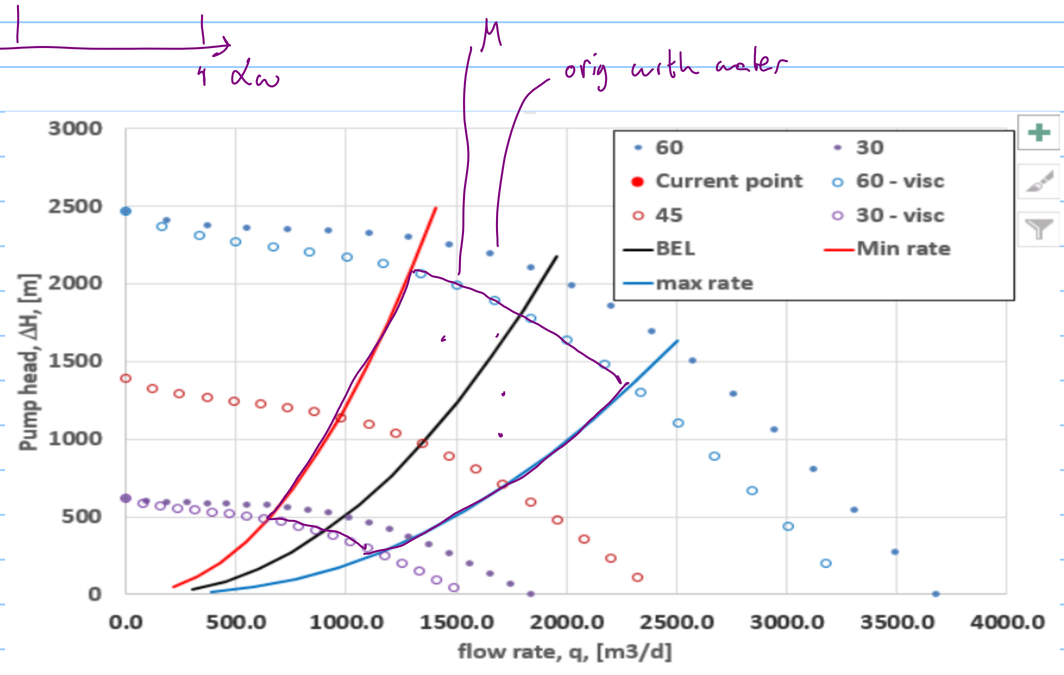




find an equipment such that
covers Δp, $q(t)$
for most of lifetime
with high efficiency
not gas at inlet
at affordable price

yes: select an ESP model
to produce $t_1 - t_3$
but you cannot produce in
this interval $t_3 - t_5$

Emulsion



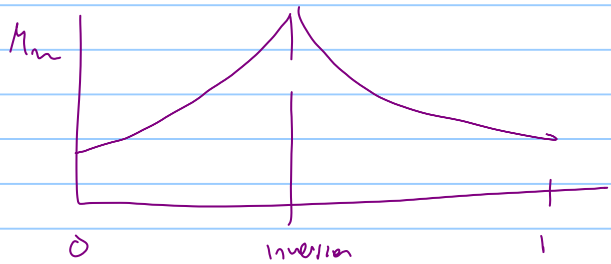
$q_{\bar{o}} = q_o$ no dissolved gas

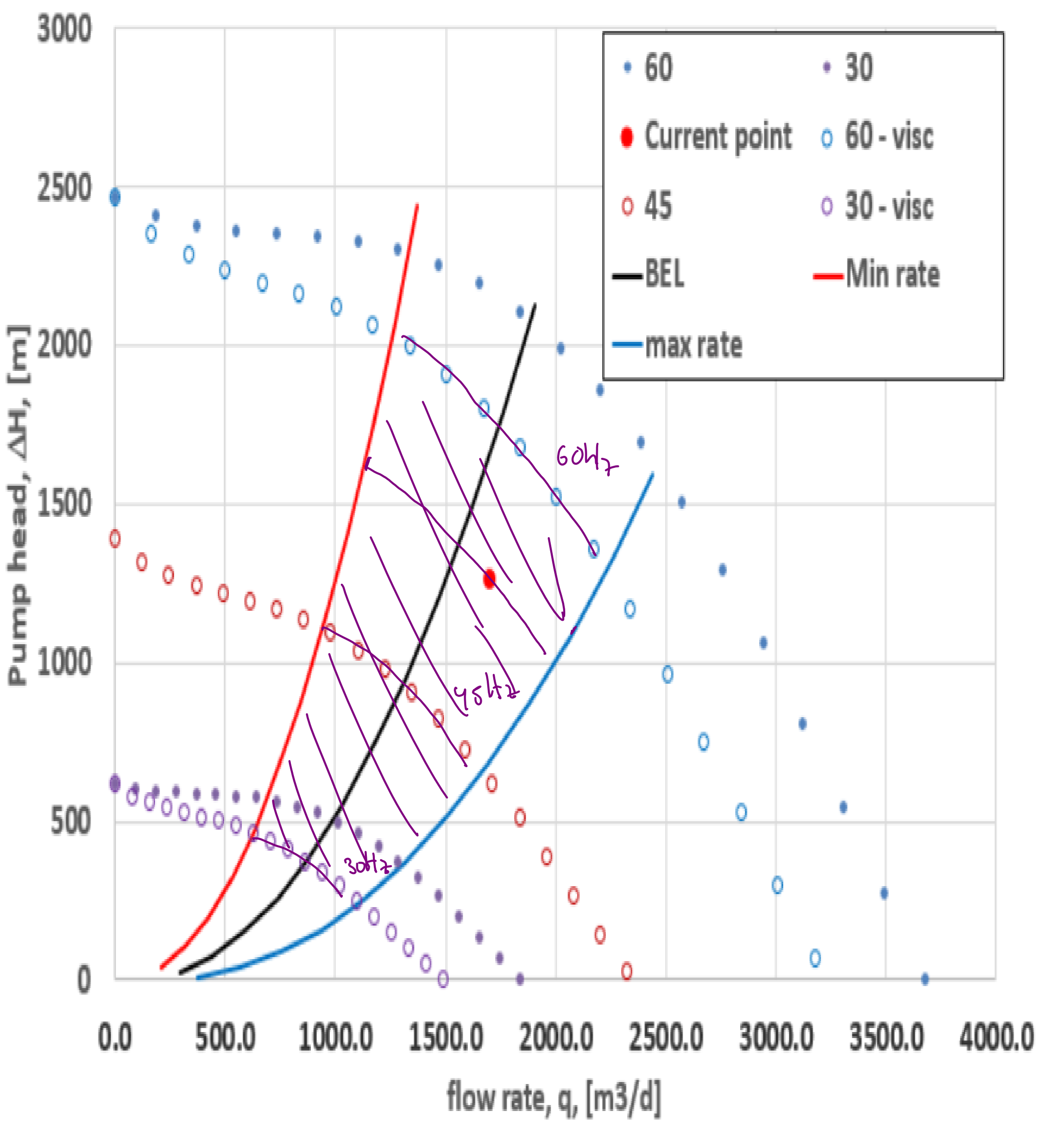
$q_{\bar{w}} = q_w$

$$\frac{q_{\bar{w}}}{q_{\bar{o}} + q_{\bar{w}}} = \frac{q_w}{q_o + q_w}$$

$$\rho_m = \alpha_w \rho_w + (1-\alpha_w)\rho_o$$

$$\mu_m = \mu_{conti}\, e^{c \cdot \alpha_{dispersed}}$$





$q = 1700\ Sm^3/d$

$\Delta p = 111$ bara

$\mu = 0.138$ Pa.s

$\rho = 910\ Kg/m^3$

$f \simeq 52.5$ Hz

$$P = \frac{\Delta p \cdot q}{\eta_H \, \eta_{mech}}$$

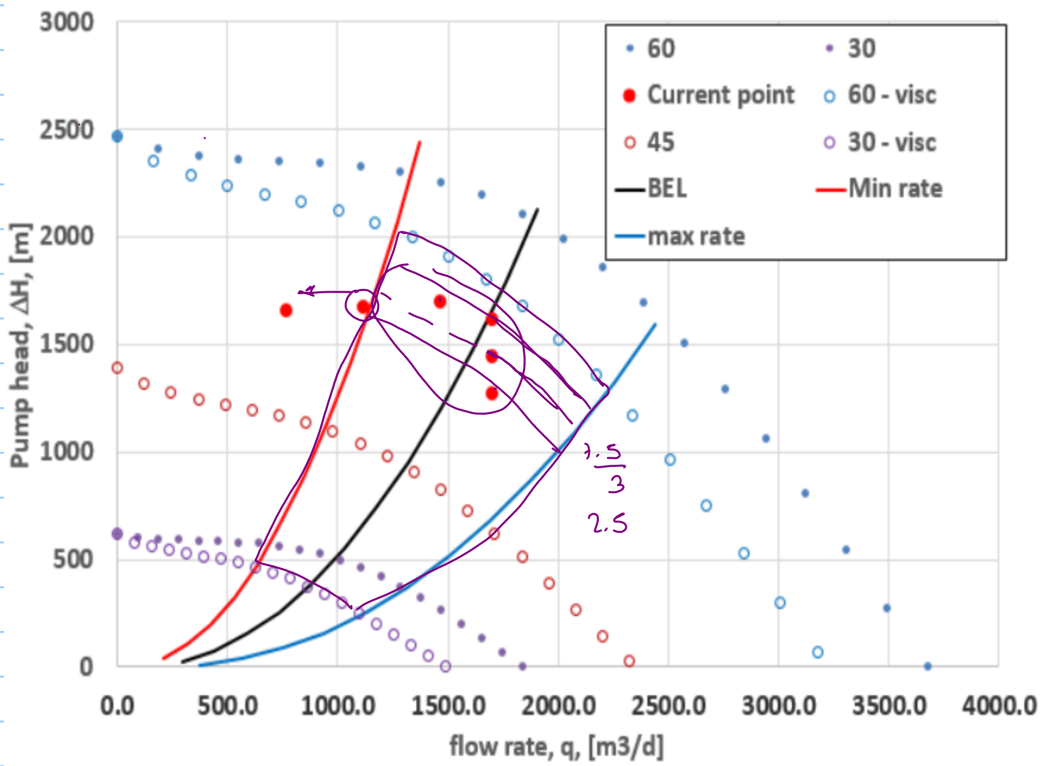
2017.03.30, TPG4230, Class Exercise, M. Stanko

Wells	p_R	J, for total liquid flow	h1	h2	d1	d2	Pumpname	Stages
-	bara	Sm^3/d/bar	m	m	m	m	-	-
1	231	14	380	1960	0.24	0.14	Centrilift 675	78

	Water	Oil	
Fluid Density	1025	897	[kg/m^3]
Richardson Emul. exp.	13	3.215	
Viscosity	1.00E-03	0.1	[Pa s]
α_w cut off	0.60		
Roughness tubing and lines	0.00010	m	
Bubble point pressure [bara]	30	[bara]	

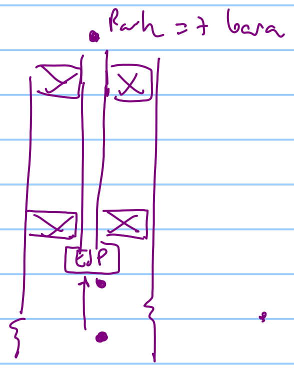
Required pressure at pump intake	36
Mechanic efficiency	0.95
Max pump power [hp]	760

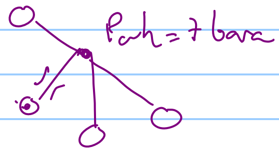
Wells	p_R	WC	Average density	Effective viscosity	q_{tot}	p_{wf}	q_o	q_w	p_{suc}	p_{disc}	Δp_{ESP}	Δh_{ESP}	p_{wh}	Pump power	Hydraulic Effic	frequency
-	bara	[-]	kg/m^3	Pa s	Sm^3/d	bara	Sm^3/d	Sm^3/d	bara	bara	bara	m	bara	[hp]	[%]	Hz
	231	0.10	910	0.138	1700	110	1530	170	75.6	188	113	1265	7	402.4	74.06	52.5
	215	0.10	910	0.138	1700	94	1530	170	59.6	188	129	1445	7	465.1	73.15	55.0
	200	0.10	910	0.138	1700	79	1530	170	44.6	188	144	1613	7	526.0	72.20	57.5
	175	0.10	910	0.138	1470	70	1323	147	36.0	187	151	1693	7	496.3	69.47	56.0
	150	0.10	910	0.138	1120	70	1008	112	36.0	185	149	1673	7	406.5	63.86	53.5
	125	0.10	910	0.138	771	70	694	77	36.0	184	148	1656	7	325.9	54.25	52.5



52.5
55
57.5

http://folk.ntnu.no/stanko/Courses/TPG4230/2017/Class_files/20170404/

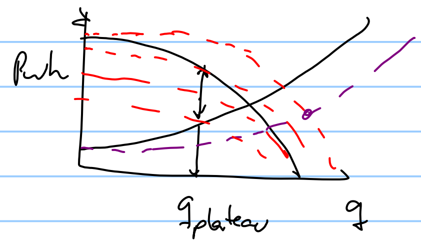




p_R	WC	Average density	Effective viscosity	q_{tot}	p_{wf}	q_o	q_w	p_{suc}	f	p_{disc}	Δp_{ESP}	Δh_{ESP}	$p_{wh\ calc}$	$p_{wh\ given}$	Hydraulic Effic	Pump power	qmin	qmax
30	[bara]		Required pressure at pump intake			36										Max power [hp]	950	
bara	[-]	kg/m^3	Pa s	Sm^3/d	bara	Sm^3/d	Sm^3/d	bara	[hz]	bara	bara	m	bara	bara	[-]	[hp]	[m^3/d]	[m^3/d]
231	0.10	910	0.138	1700	110	1530	170	75.7	53.0	188	113	1264	7.0	7	0.452	658.6	1121	1994
215	0.10	910	0.138	1700	94	1530	170	59.6	55.3	188	129	1445	7.0	7	0.455	748.5	1169	2079
200	0.10	910	0.138	1700	79	1530	170	44.6	57.4	188	144	1613	7.0	7	0.456	833.4	1213	2156
175	0.10	910	0.138	1470	70	1323	147	36.0	56.5	187	151	1693	7.0	7	0.438	786.6	1194	2124
150	0.10	910	0.138	1120	70	1008	112	36.0	54.1	185	149	1673	7.0	7	0.401	647.4	1144	2033
125	0.10	910	0.138	771	70	694	77	36.0	52.5	184	148	1656	7.0	7	0.344	513.3	1110	1973

Snøhvit, B2 Tanzania what can we do to prolong plateau?

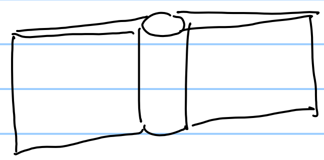
- increase available pressure $P_{wh\,avail}$
- decrease required pressure $P_{wh\,req}$



methods to increase available pressure:

- $q = C_R (P_R^2 - P_{wf}^2)^n$ Increase reservoir deliverability: acidizing, injecting chemical to improve permeability of near wellbore region $

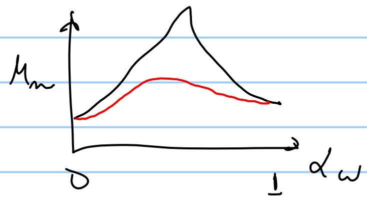
- fracturing. increase wellbore-formation exposure $



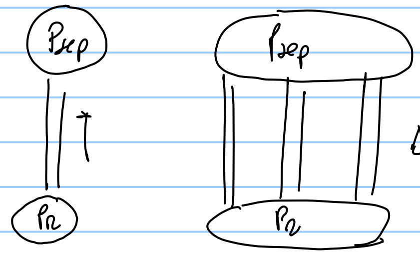
- multilaterals $
- multilayer (perforate in another segment)
- Inflow control devices.
  ↳ reduce the flow of other phases that affect the flow of the main phase $

- pressure support in reservoir: water injection, gas injection $

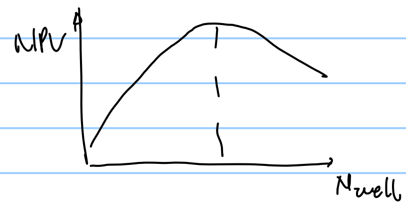
- tubing:
  - increase tubing ID
  - install artificial lift { ESP, PCP, jet pump, gas lift }
  - reduce μ of fluid ~ demulsifiers
    - ↳ diluent
    - ↳ lighter API oil



- increase the number of wells $

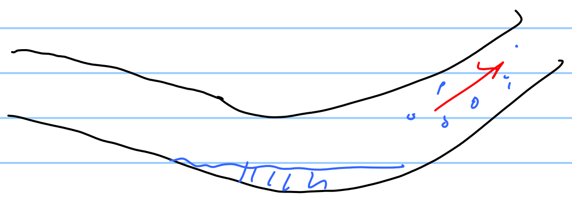


Δp in each conduit is less



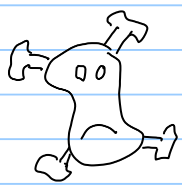
reducing required pressure

- changing size (ID) of transportation flowlines and pipelines ↑ID ↑$



WARNING ! Be careful with liquid accumulation in gas/liquid flow.

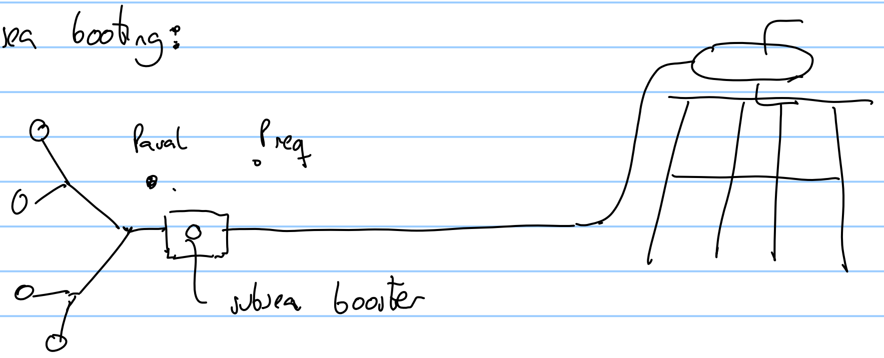
- a parallel pipeline !
- reduce μ_m → inject demulsifiers diluent.
- reduce separator pressure



~ big Change ~~chance~~ in topside / processing facilities

- subsea processing: separation of oil, gas, water to avoid unnecessary transportation losses. from seabed to topside

- Subsea boosting:



2 types of booster:
- single phase liquid, gas → requires separation before
- multiphase → oil, gas, water

two types of boosting principles

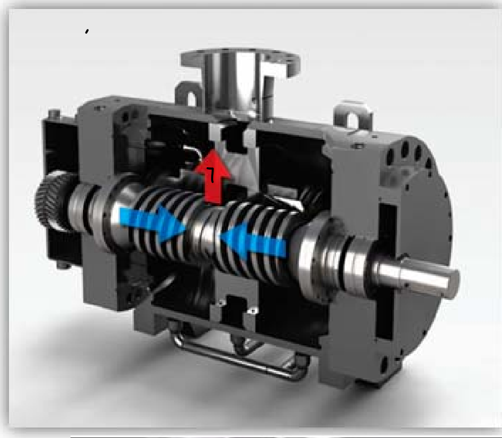
Positive displacement	Rotordynamic
• gives higher Δp	• gives medium → low Δp
• don't tolerate solids	• have some tolerance to solids.
• lower rates	• medium and high rates.

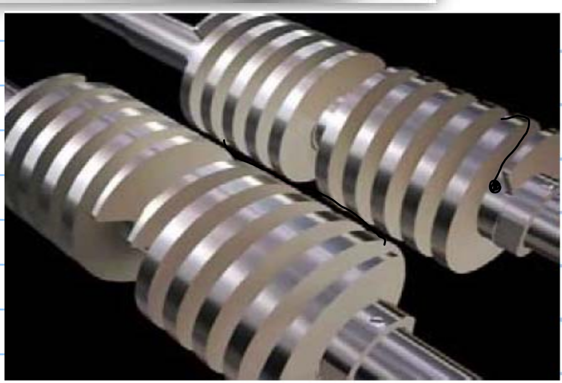
multiphase boosters

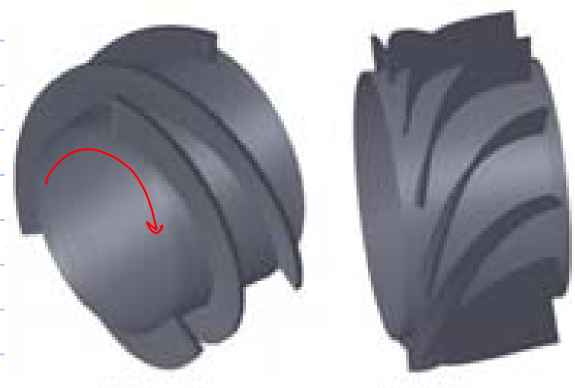
twin screw pump

HAP helico-axial pump.

Framo. OneSubsea



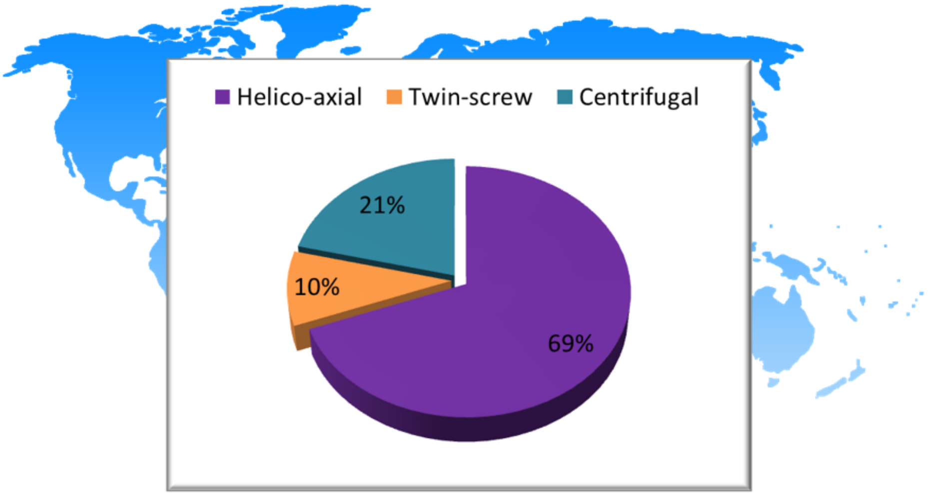




(a) Impeller (b) Diffuser

Subsea multiphase boosting around the world

52 subsea pumps in 23 locations in the World



From http://www.offshore-mag.com/

Wet gas compressor → lots of gas with some liquid. gas-liquid mixture is possible to model it as a single fluid with average properties.

Counter-rotating wet gas compressor.

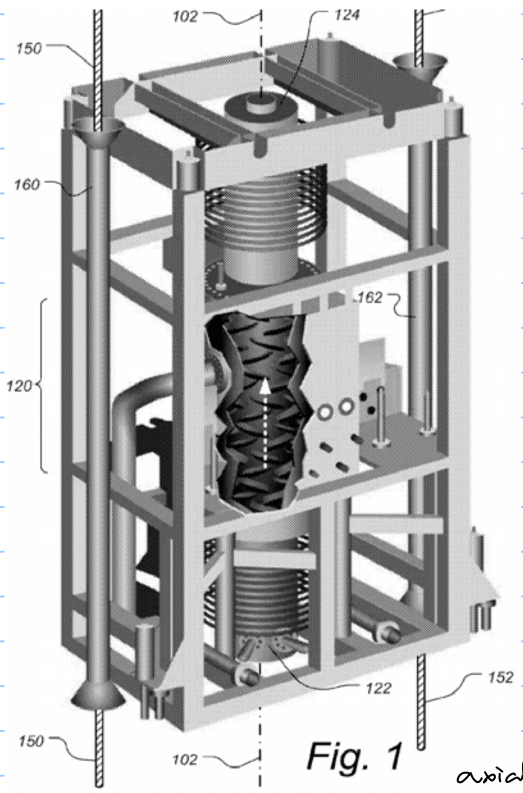


Fig. 1

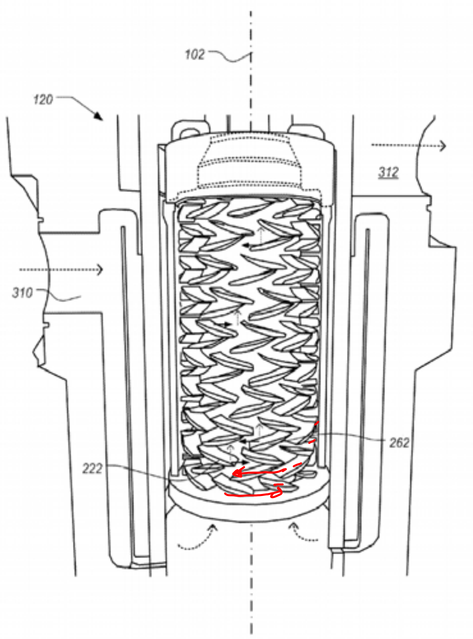


Fig. 3A

axial impellers { HAP / WGC } gives a lower ΔP

usually requires more stages than centrifugal for same Δp!

mixed flow

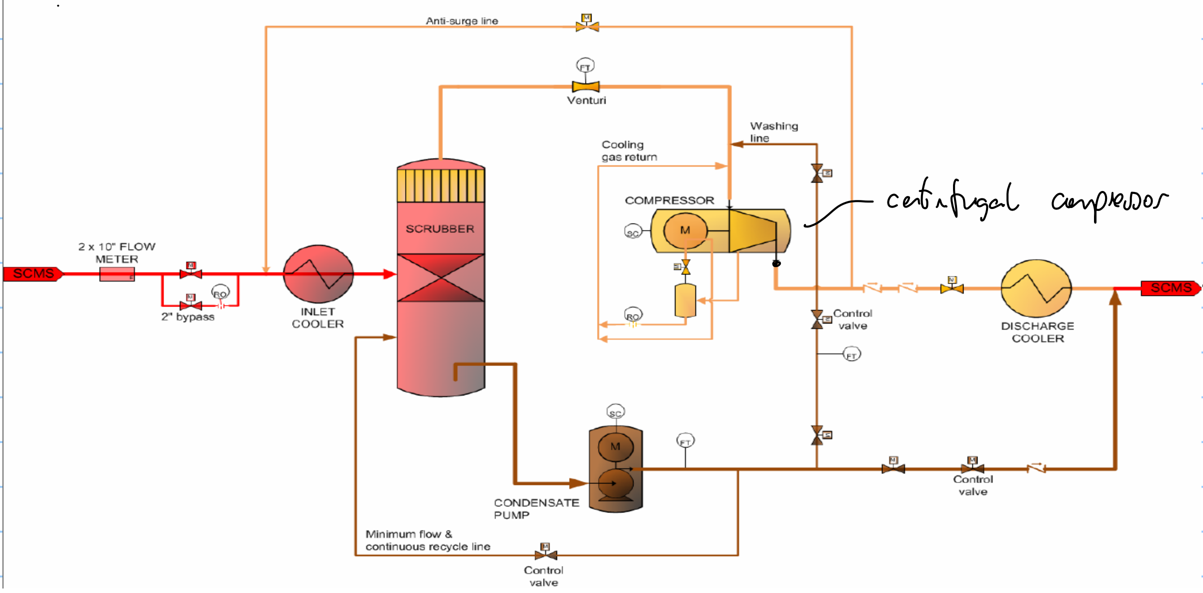
0 0.1 0.5 1 GVF gas volume fraction $\frac{q_g}{q_o + q_w + q_g}$

@ local conditions booster inlet

radial centrifugal impellers → high ΔP

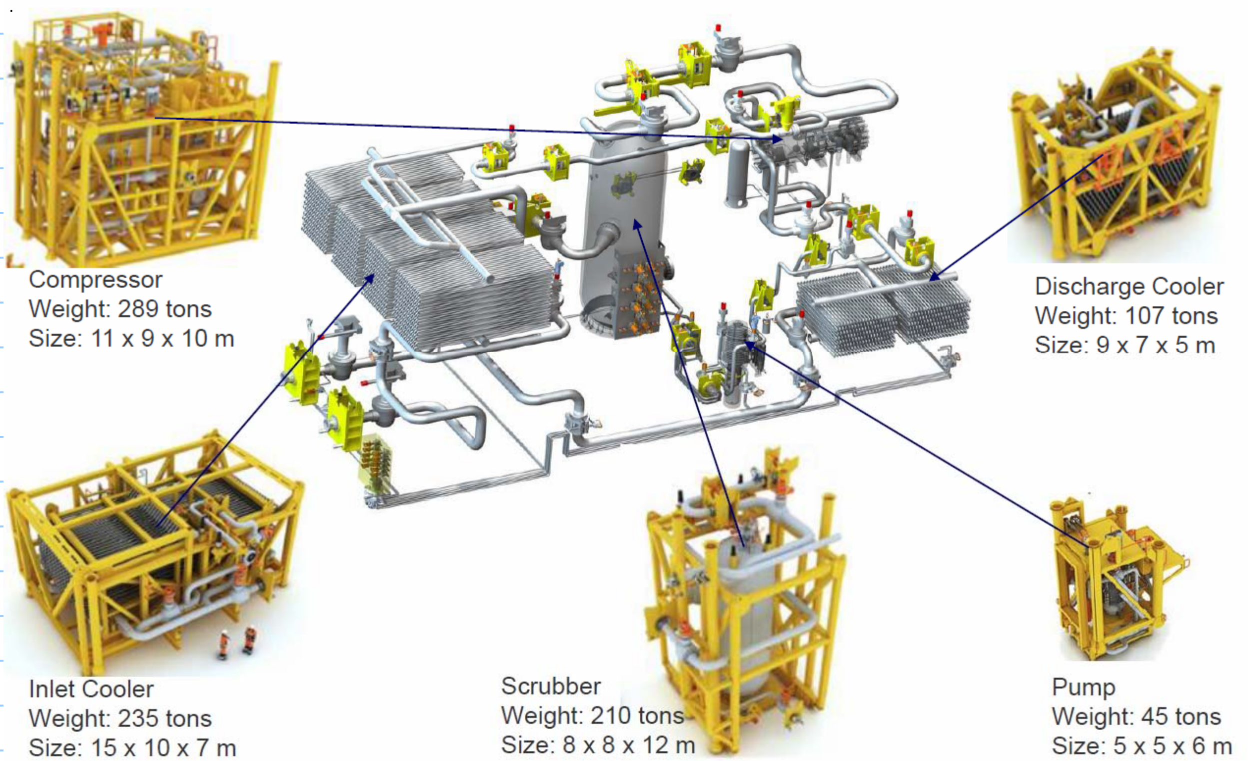
Single phase subsea boosters ⇝ separation before! Aasgard subsea compression
dry compressor + separation station

Process Flow Diagram



centrifugal compressor

Process Modules- Sizes and Dry Weights



Compressor
Weight: 289 tons
Size: 11 x 9 x 10 m

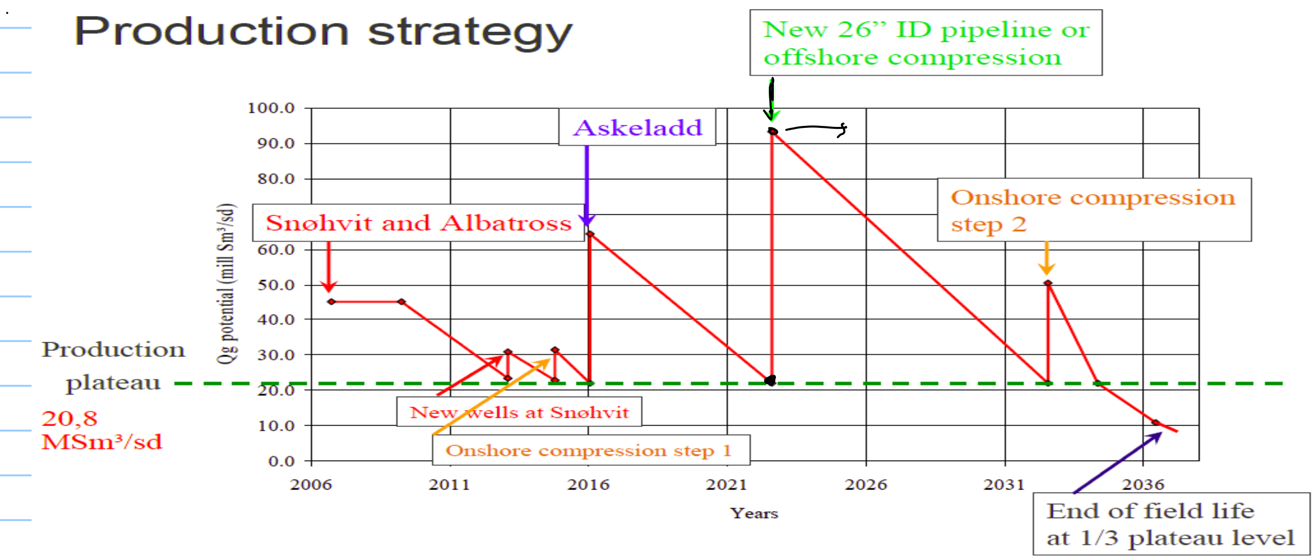
Discharge Cooler
Weight: 107 tons
Size: 9 x 7 x 5 m

Inlet Cooler
Weight: 235 tons
Size: 15 x 10 x 7 m

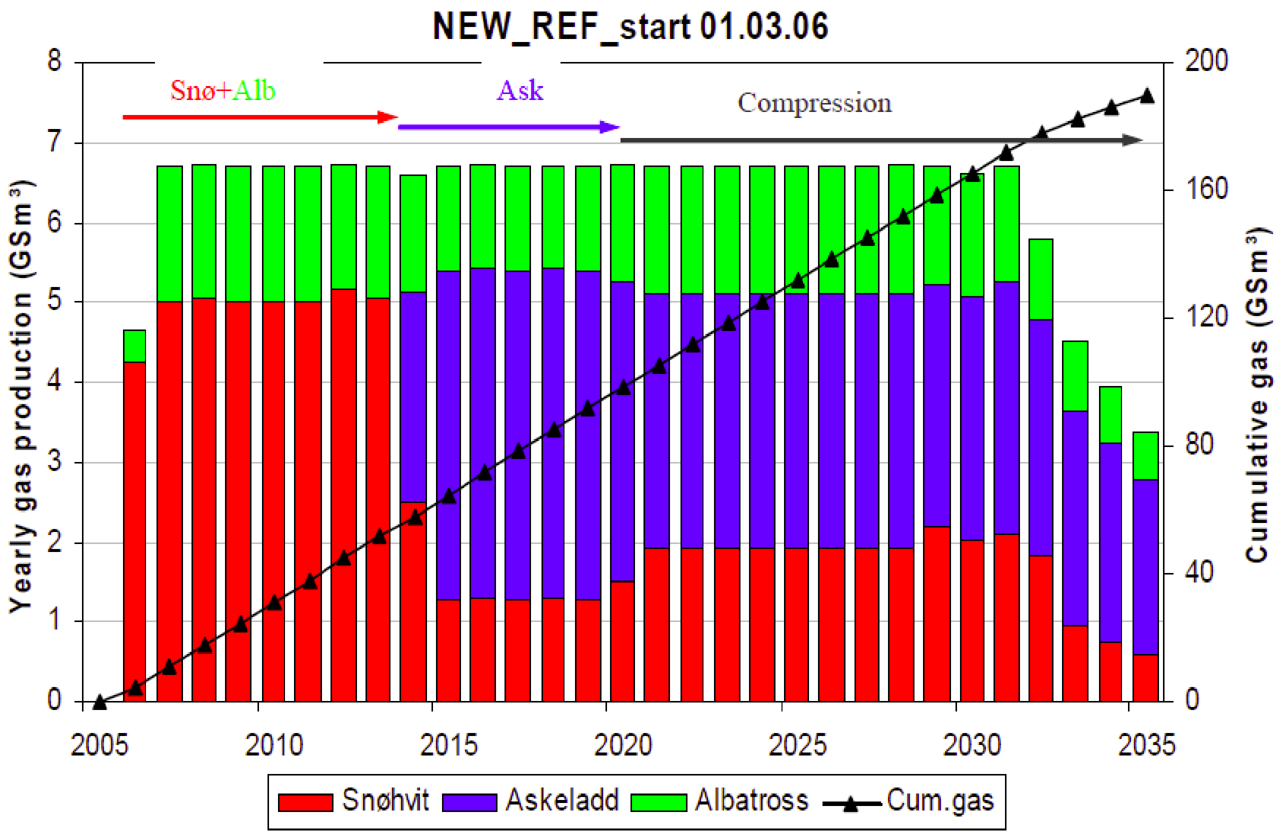
Scrubber
Weight: 210 tons
Size: 8 x 8 x 12 m

Pump
Weight: 45 tons
Size: 5 x 5 x 6 m

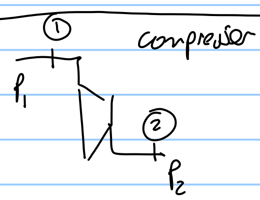
In particular, the Snøhvit field:



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



Refreshment in compressors $\qquad \dot{w} = \dot{m}\,\underbrace{(h_2 - h_1)}$



if I compress ideally:

$$\frac{T_{2s}}{T_1} = \left(\frac{p_2}{p_1}\right)^{\frac{k-1}{k}} = r_p^{\left(\frac{k-1}{k}\right)} \qquad s_1 = s_2$$

$$k = \frac{C_p(T)}{C_v(T)} = k\ f(T)$$

in reality the process is not isentropic!

the compression process is represented using a polytropic expansion

$pv^{n} = \text{const}$ — polytropic exponent

$$\frac{T_2}{T_1} = (r_p)^{\frac{n-1}{n}}$$

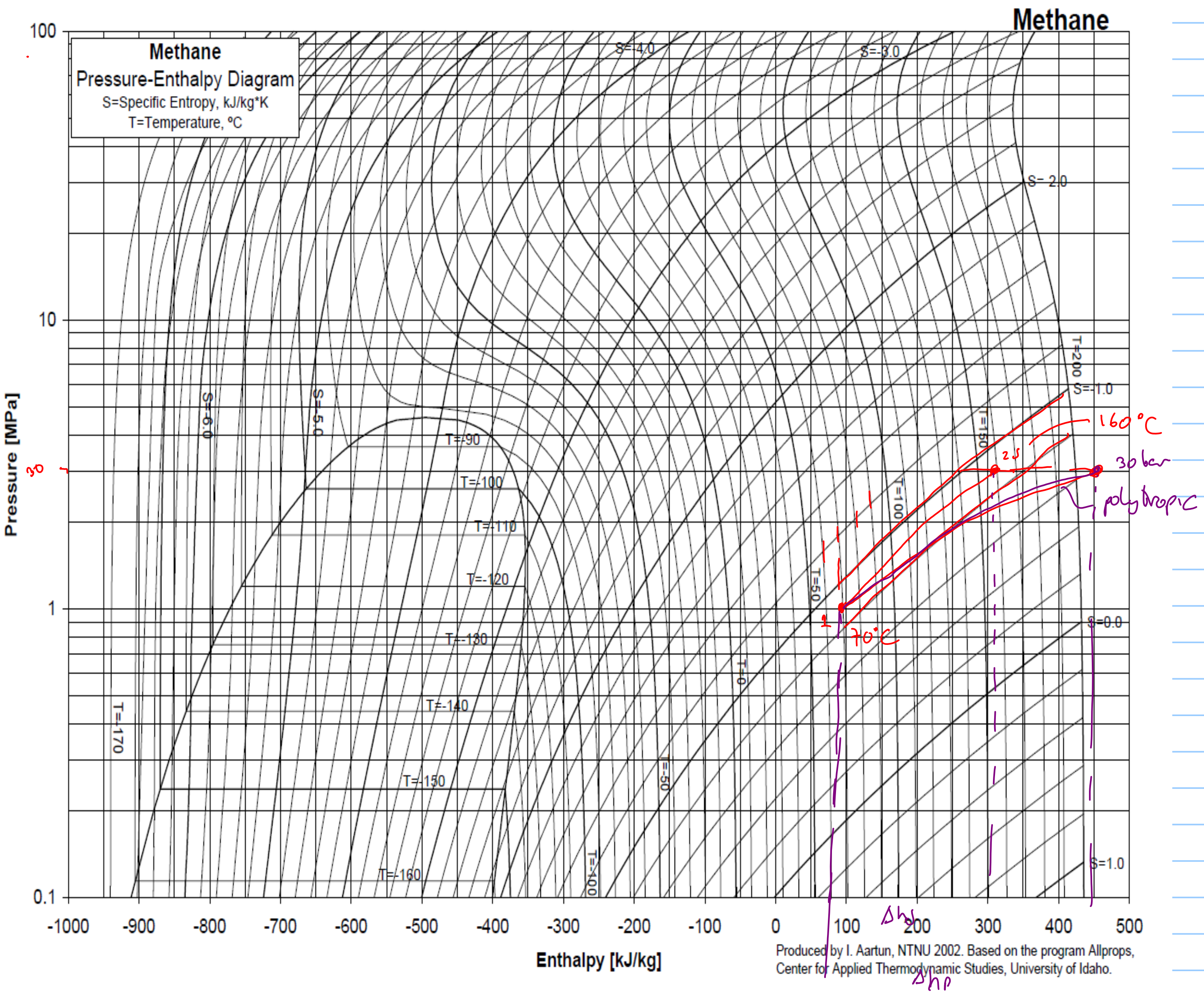
the real compression power requires is given by: $\approx c_p \underbrace{(T_2 - T_1)}_{\text{for liquids}} = h_2 - h_1$

polytropic enthalpy difference

$$P_{comp} = \frac{\dot{m}\,\Delta h_p}{(\eta_p \times \eta_m)} = \frac{\dot{m}}{\eta_p \eta_m} \cdot \underbrace{z_{av} \cdot \bar{R} \cdot \frac{n}{n-1}\left(r_p^{\frac{n-1}{n}} - 1\right) T_1}_{\Delta h_p}$$

$$\left(\frac{n-1}{n}\right) = \left(\frac{\kappa - 1}{\kappa \cdot \eta_p}\right)$$

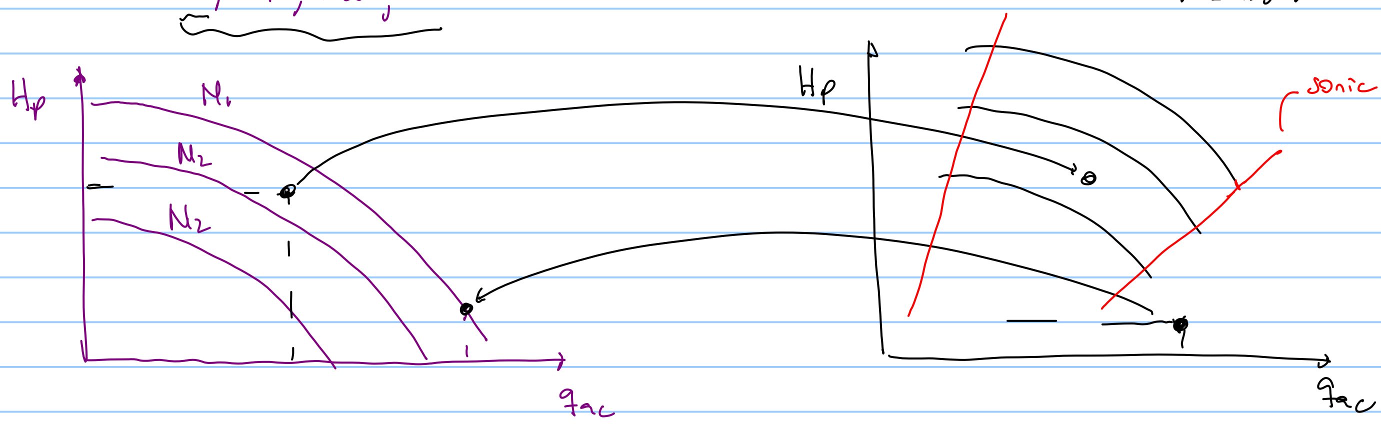
$$z_{av} = \frac{z_1 + z_2}{2} \qquad \bar{R} = \frac{R_u}{MW_{gas}}$$



$H_p = \frac{\Delta h_p}{g}$ ~> polytropic head

for P_1^*, T_1^*, M_w^*, K^*

test the compressor at $P_1 = 1.01325$ bara
$T_1 = 15.56°C$
$MW = 28.97$
$K = 1.3$?



to calculate compressor performance for other conditions different than test apply the following corrections:

$$q_{act} = q_{test} \sqrt{\frac{K_{ac}}{K_{test}}} \cdot \sqrt{\frac{MW_{TEST}}{MW_{ac}}} \cdot \sqrt{\frac{T_{ac}}{T_{test}}} \qquad q^{TEST}$$

$$H_p^{corrected} = \frac{MW_{Test}}{MW} \cdot \frac{T_1}{T_{1TEST}} \cdot \frac{K}{K_{TEST}} \cdot H_p^{test}$$

Compressors constraints :

- discharge $T \leq 150°C$ { • integrity pipeline • avoid vaporization glycol hydrate inhibitor • avoid damaging compressor seals

another assumption $\boxed{\eta_p = const \approx 0.7}$

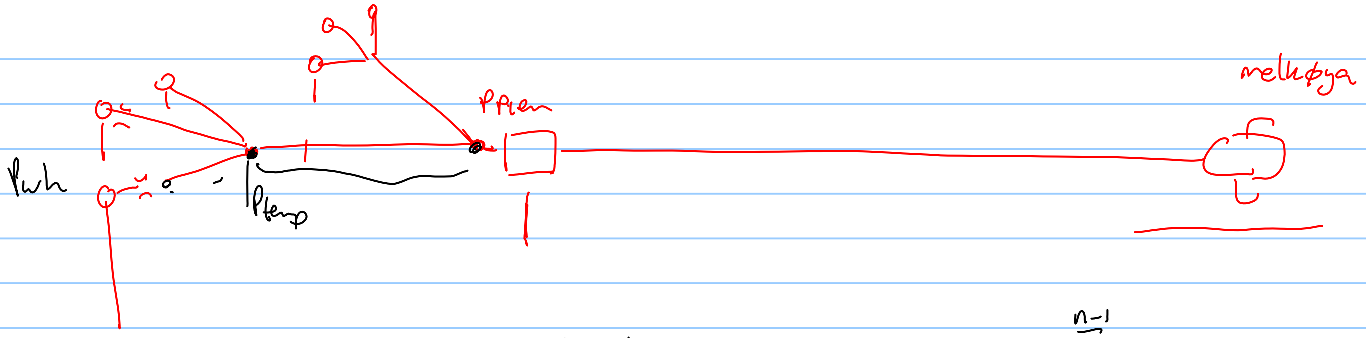
in reality $\eta_p = f(q_{act})$

- Power $\leq P_{max}$ (11 MW)
- $P_{suc} \geq 10$ bara { to activate seals }
- operational speed 9350 – 6800 rpm

$q_{min} \leq q \leq q_{max}$

surge. { flow back and forth in machine (unstable)

↳ sonic velocity in machine passages $M = 1$



estimate T_{outlet} $\qquad \frac{T_2}{T_1} = r_p^{\frac{n-1}{n}}$

estimate $\Delta h_p = z_{av} \cdot \bar{R} \cdot \frac{n}{n-1} \left(r_p^{\frac{n-1}{n}} - 1 \right) T_1$

calculate $H_p = \frac{\Delta h_p}{g}$ $\qquad \frac{8314}{\frac{kg}{kmol}} \frac{J}{kmol\, K} \; K \quad \frac{J}{kg}$

calculate $q_{act} = \underbrace{B_g(P,T)}_{} \cdot q_{sc}$

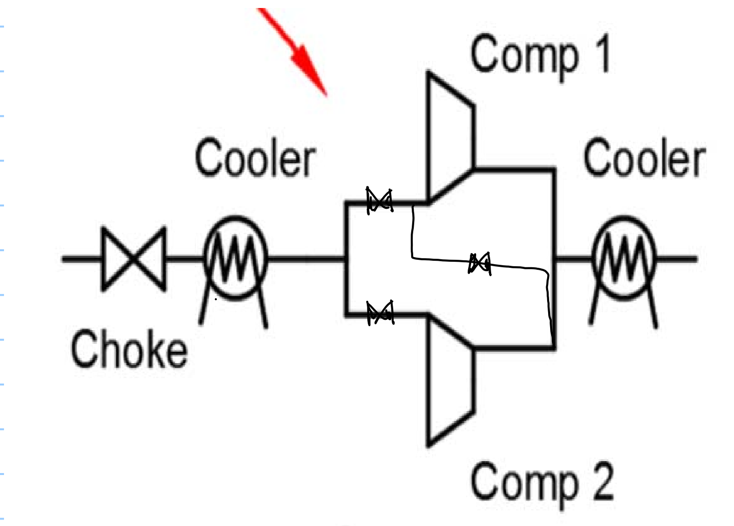
$$B_g = z \frac{T}{T_{sc}} \frac{P_{sc}}{P}$$

H_p, q_{act} $\longrightarrow$ convert to test conditions

plot in compressor map.

Help-comments for ex. 2 in Ex. set 5.

- choke at inlet reduce even more available pressure
- cool fluid upstream (30°C ΔT)
- cool fluid downstream (30°C ΔT)
- decide to use single or two compressors
- To reduce rate



k	1.30
Polytropic effic	0.7
Mech. Effic	0.95

204.9	82.0	78.6	30.0	6.7E+6	123
196.8	82.0	78.6	30.0	6.7E+6	115
188.8	82.0	78.6	30.0	6.7E+6	107
180.9	82.0	78.6	30.0	6.7E+6	99
173.1	82.0	78.6	30.0	6.7E+6	91
165.4	82.0	78.6	30.0	6.7E+6	83
157.8	82.0	78.6	30.0	6.7E+6	76
150.2	82.0	78.6	30.0	6.7E+6	68
142.6	82.0	78.6	30.0	6.7E+6	61
135.1	82.0	78.6	30.0	6.7E+6	53
127.5	82.0	78.6	30.0	6.7E+6	46
119.9	82.0	78.6	30.0	6.7E+6	38
112.2	82.0	78.6	30.0	6.7E+6	30
104.4	82.0	78.6	30.0	6.7E+6	22
96.5	82.0	78.6	30.0	6.7E+6	14

88.4	82.0	78.6	30.0	6.7E+6	6	Pplem req	Δp cho	Psuc	Tsuc	rp	deltap	np	n	Tdis	zsuc	zdisc	Bg @suc	qg_local	Δhp	m
82.0	82.0	78.6	30.0	6.7E+6	0	[bara]	[bara]	[ba	[C]	[-]	[bar]	[-]	[-]	[C]			[m^3/Sm^3]	[m^3/d]	[J/kg]	[kg/s]
80.1	80.1	76.6	30.0	6.7E+6	0	78.6	0		67	1.03	1.94	0.70	1.49	69.81	0.93	0.93	14.5E-3	289.3E+3	4126.15	155.5
71.1	71.1	67.1	30.0	6.7E+6	0	78.6			67	1.17	11.43	0.70	1.49	85.05	0.94	0.94	16.7E-3	332.7E+3	26754.95	155.5
61.8	61.8	57.1	30.0	6.7E+6	0	78.6			67	1.38	21.45	0.70	1.49	104.60	0.94	0.95	19.8E-3	394.5E+3	56384.84	155.5
51.5	51.5	45.8	30.0	6.7E+6	0	78.6			67	1.71	32.75	0.70	1.49	133.02	0.95	0.97	24.9E-3	497.1E+3	100283.54	155.5
39.6	39.6	31.9	30.0	6.7E+6	0	78.6			67	2.46	46.68	0.70	1.49	184.44	0.97	0.99	36.3E-3	724.1E+3	181242.31	155.5
23.8	23.8	3.9	30.0	6.7E+6	0	78.6			67	20.06	74.65	0.70	1.49	638.81	1.00	1.02	304.1E-3	6.1E+6	908936.00	155.5
ALUE!	#VALUE!	#VALUE!	30.0	6.7E+6	#VALUE!	78.6			67	#VALUE!	#VALUE!	0.70	1.49	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	155.5
ALUE!	#VALUE!	#VALUE!	30.0	6.7E+6	#VALUE!	78.6			67	#VALUE!	#VALUE!	0.70	1.49	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	155.5

- Production optimization:
  - increase oil or gas production!
  - Reduce cost
  - by using cost effective measures

In the industry, typical activities performed in optimization are:

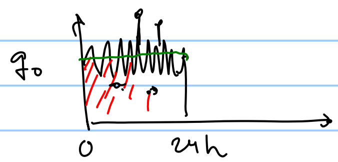
- Detect pipe section, component with high Δp. { . too small size
  . blockage
  .
- verify design conditions of equipment vs actual operating conditions.
- Study and analyze maintenance, installation, testing logistics, defect defficiencies, problems and take measures.
- identify sources with non attractive characteristics. (H_2S, WC), and limit their production
- review failure data and detect patterns
- identification and address of operational constraints or bottleneck.
- calibration of instrumentation
- identifying and monitoring KPIs
  $\underbrace{\text{KPIs}}_{\text{key performance indicators}}$

1 → - find settings of adjustable elements that give the maximum revenue and satisfy the multiple operational constraints.

mathematical procedure that can guarantee optimality.

tools used to perform optimization:
- historic data (reported)
- look at more frequent data

> 1000 sensors



- instrumentation
- experience from field operators.
- numerical models.

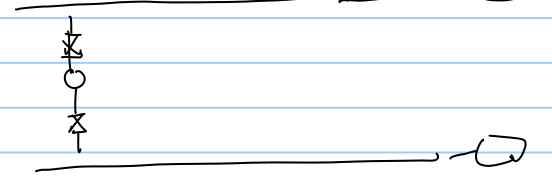
Formal-mathematical → Production optimization

short term

- min → weeks

(is neglects time effect, steady state)

- real-time production optimization
- gas-lift allocation ← gas lift rate
- routing ┌ open or close valve
- ESP systems (change f)
- processing opt.



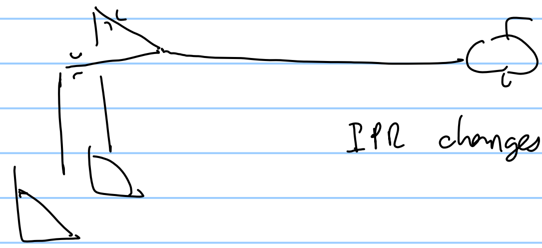
long-term

month → years

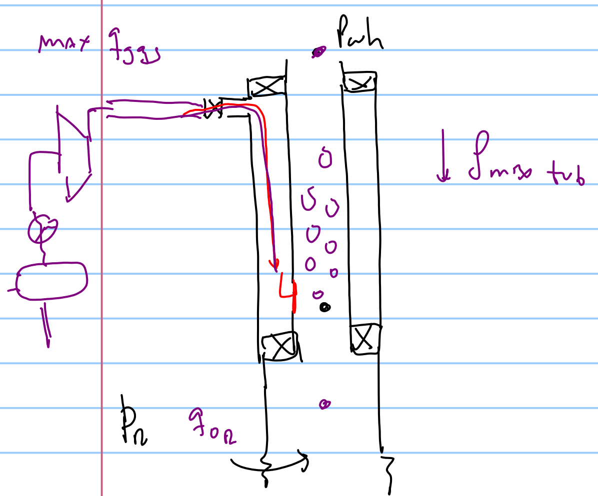
- reservoir control { find $q_o(t)$ (i ← nr. well) that gives max NPV, max RF

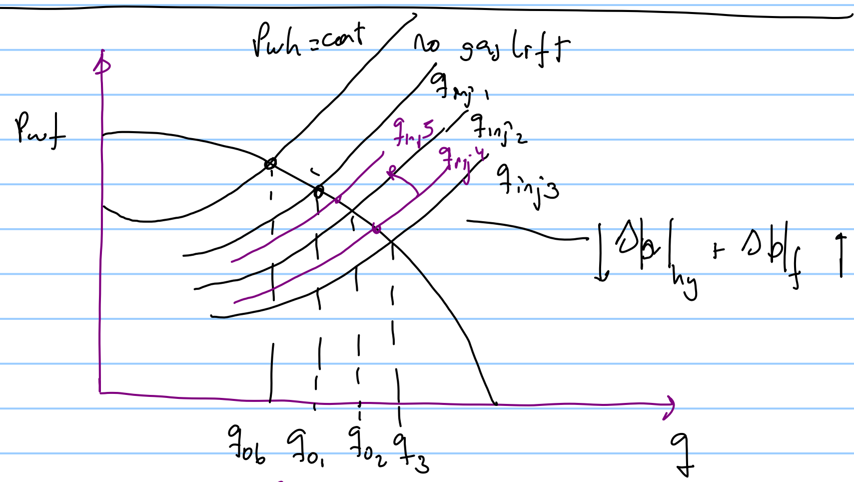
considering the time effect in a long time scale

- well placement



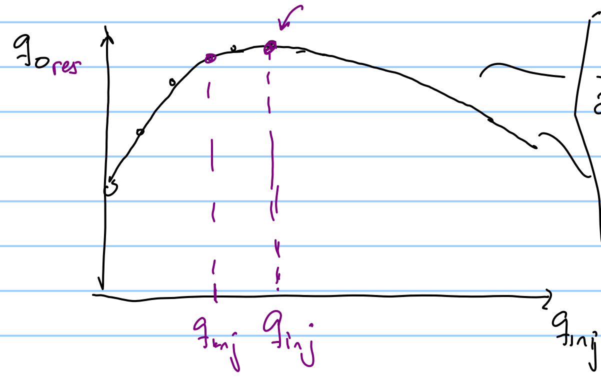
IPR changes with time





operational constrains have to be taken into account when performing optimization!

- gas capacity
- water processing capacity
- gas processing capacity



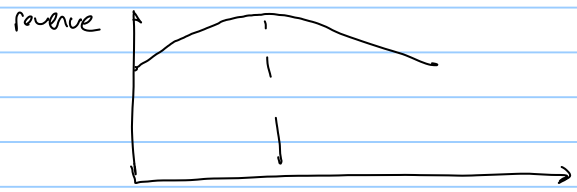
$$\frac{\partial q_o}{\partial q_{inj}} = 0 \quad q_{inj} = ?$$

$$\frac{\partial^2 q_o}{\partial q_{inj}^2} < 0$$

make this optimization on revenue

- gas coning
- water coning
- sand production
- power consumption
- erosion

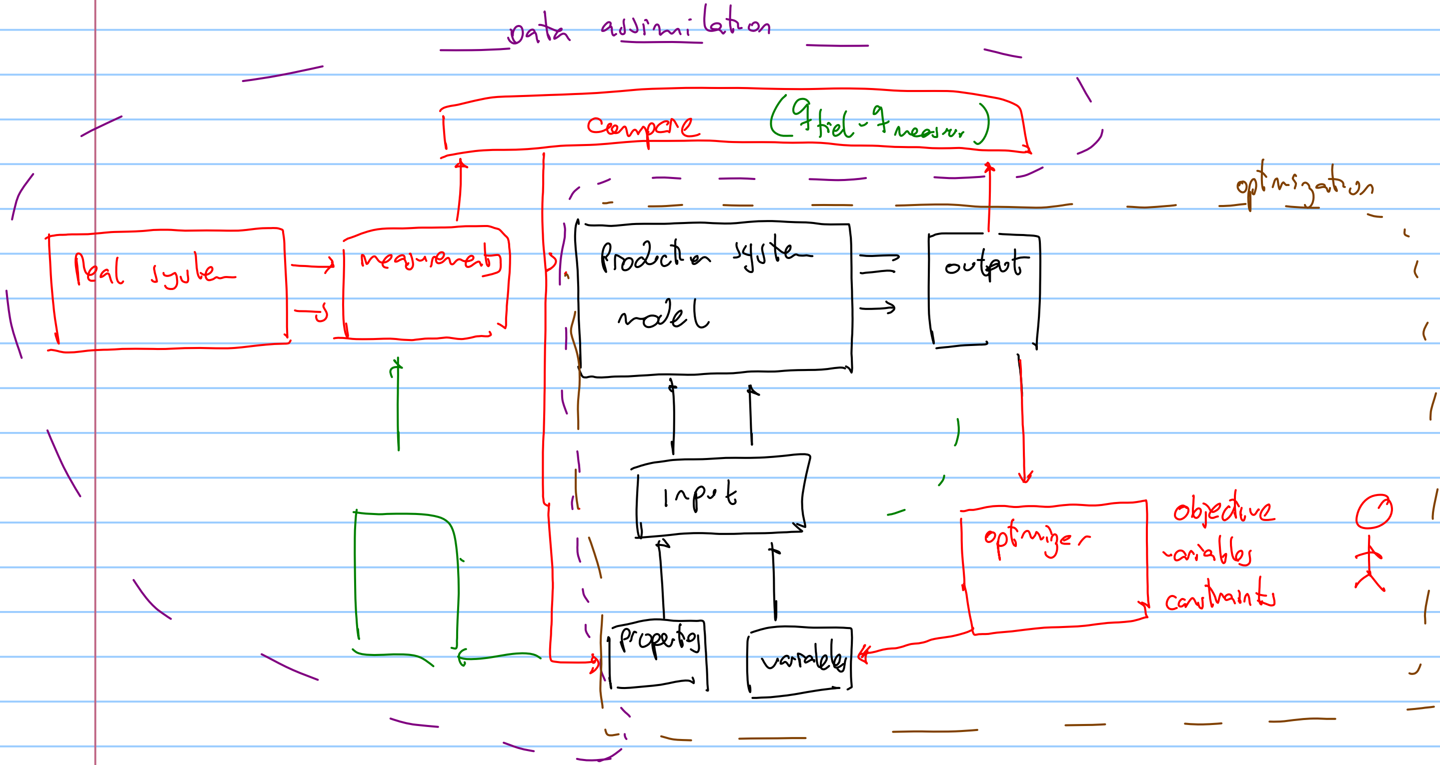
revenue = $q_o \cdot P_o - q_g \cdot P_w$ or revenue = $q_o \cdot P_o - \frac{kWh}{USD} \cdot Power$



An optimization problem consists on 3 things

- objective → max → q_o, q_g, RF, NPV
  - → min → cost, q_w, downtime, etc
- variable { choke position, well placement, gas lift rate, pump frequency, well routing } only the essential
- constraint {

for optimization we use numerical models

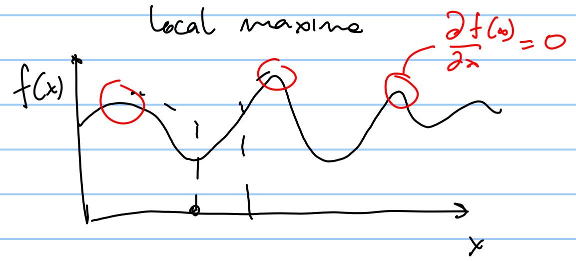


How is optimization performed?

- perform single or multiple evaluations of model for different input conditions
- estimating the next set of input conditions that you want to evaluate (algorithm).
- checking if the stopping criteria is met.

there are different types of optimization problems

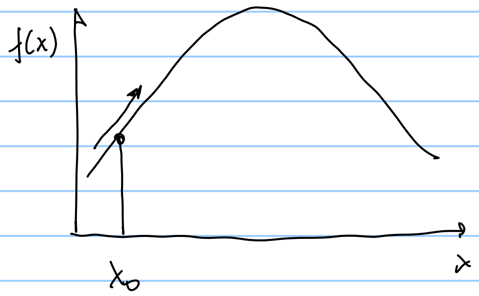
- variable type → continuous
  → integer
- constraints: constrained
  unconstrained
- linear vs non linear



run multiple starting points and verify that the solution doesn't change.

there are different methods to perform optimization:

- gradient based (derivative based)

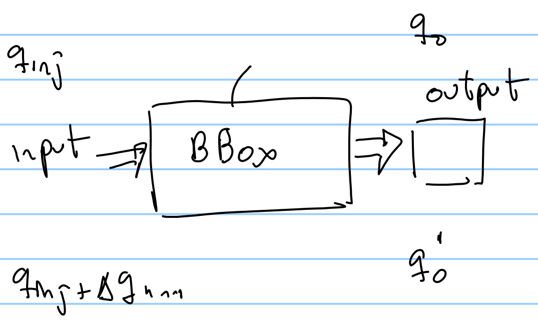


- move in the direction of gradient

Newton-Raphson type method

$$\left\{ \frac{\partial f}{\partial x} \right\} \quad \left| \frac{\partial^2 f}{\partial x^2} \right|$$

$$F(x_1, x_2, x_3, \ldots x_n)$$



for black box models — no access to equations

$\frac{\partial f}{\partial x}$ is estimated numerically

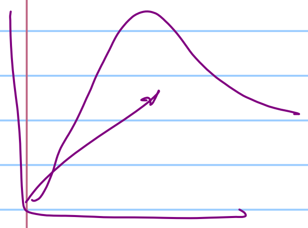
$$\frac{\partial f}{\partial x} \approx \frac{f(x + \Delta x) - f(x)}{\Delta x}$$

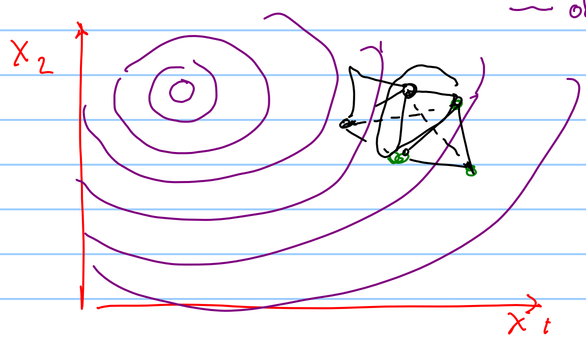
- for many variables is a prohibitive approach

- quick convergence

-

- heuristic methods. Some logic to chose the next point from the existing evaluations





Nelder-Mead

✓ Black box models

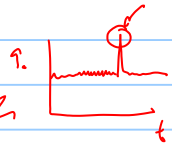
- Evolutionary methods. evaluate a group of individuals, select those who performed best and estimate new set of individuals

genetic algorith

to evaluate a whole population.

Last class 20.04.2017 !

Life cycle of a hydrocarbon field	Appreciation	NO	-	-
Field development workflow -Probabilistic reserve estimation -Cost estimation and NPV calculations	Appreciation/ configuration/ design	YES	Gant chart, NPV calculations, Spider plot, decision trees, Monte Carlo simulation, basic probability, tornado chart	Excel VBA
Offshore (and some onshore) field architectures and layout of production systems -Production manifold -Pigging facilities	Configuration	YES	Engineering diagrams and drawings.	-
Offshore structures for oil and gas production -Wave statistics -Loads	Configuration/ design	YES	Fast Fourier Transform for signal analysis. Probability distributions.	Excel VBA
Reservoir depletion and field performance -Production potential -Production scheduling -Flow equilibrium in production systems, choking and boosting -Flow performance of surface and downhole production networks	Design	YES	Flow in porous media. Material balance. Single and multiphase flow in conduits. Flow equilibrium	Excel VBA, Gap, Prosper, Mbal
Production Processing -Overview	Appreciation, Design	YES	Flash calculations and PVT behavior	Hysys, Excel VBA
Flow assurance -Modeling of gas and condensate transport in pipeline and hydrate formation -Simplified modeling of oil and water emulsions	Appreciation, Design	YES	Pressure and temperature drop in flowlines and pipelines	Hysys, Excel VBA
ESP fundamentals, design and plan for the field life	Design	YES	Pump performance. Operational constraints.. Production system analysis	Excel VBA
Early subsea boosting planning	Design	YES	Compressor performance. Operational constraints.	Excel VBA
~~Data management and allocation~~	~~Appreciation/ design~~	~~YES~~	~~Data analysis, filtering, QC, averaging, aggregating.~~	~~Excel VBA~~
Production optimization.	Design	YES	Basics on practical and mathematical optimization.	Excel VBA → solver solver
~~Integrated asset modeling~~	~~Appreciation~~	~~NO~~	~~-~~	~~-~~
Generic skills exercised			Modeling, Analysis, Problem solving, critical thinking, Excel skills, Excel etiquette, programming	
Additional skills gained by home and class exercises			Group work. Develop written and oral engineering communication skills.	



Spring	Written examination	60/100	C	2017-05-15	09:00	13:00
Spring	Work	40/100				

- 40 exercise
- 60 exam

ex 1 $\frac{6.8}{100}$ + ce

Content

- covered in class !
- topics covered in the exercises !, class exercises !
- additional material
  - compendium
  - offshore structures write-up
  - FD of Åsta Hansteen field

Exam:

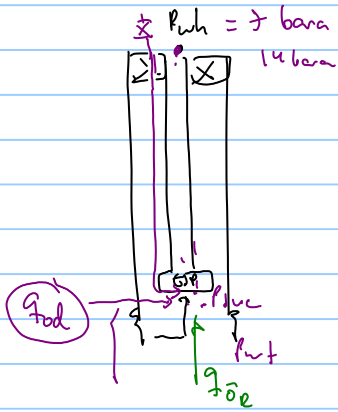
- Descriptive questions. {theory question}
- Sketch to explain and describe the system
- Hand calculations. {aided with plots / with some help expressions.

$q = C(P_R^2 - P_{wf}^2)^n$

-Design (schematically) and propose excel spreadsheets to perform calculations

C: Specified printed and hand-written support material is allowed. A specific basic calculator is allowed.

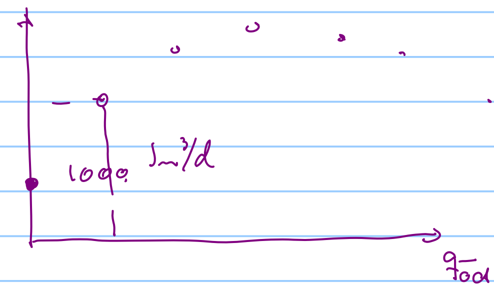
Check ITslearning: old exercises
old exams



$f = 50\,hz$

$q_{o_{ESP}} = q_{oR} + q_{od}$ | new $\mu_o = f$ blend; new $\mu_{mix} = f(wc)$ emulsion

P_R



$\% = \frac{q_{dil}}{q_{oR} + q_{dil}} \cdot 100$