TPG4230 – Field development and Operations

Associate professor: Milan Stanko (IGP). → Well construction and production systems.
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lectures thurdays 12:15 - 14:00 (P12)
Friday 10:15 - 13:00

Teaching assistant

I Gust Angga

Additional exercise sessions to be defined later!

Evaluation → 60% final exam

Spring	ORD	Written examination	60/100	D	2019-05-25	09:00

40% Home exercises 4-5 sets (3-4 questions) work in groups of 3-4
Delivery on blackboard { penalty for late delivery
Inspera? -20% per each day

Tools to use in class/home exercise → excel (VBA Visual basic for applications)
↳ Hysys (process simulator form.ntnu.no)
Dwsim http://dwsim.inforside.com.br/

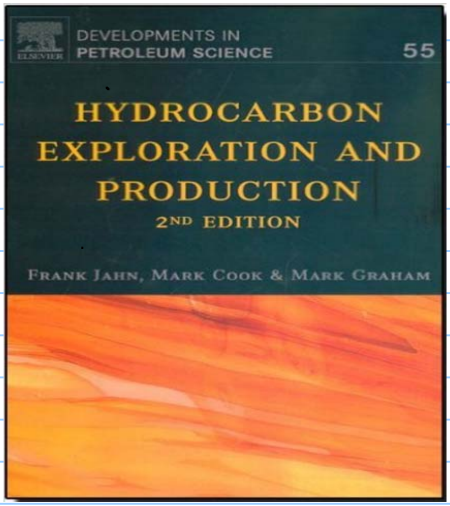
all class material will be posted on my website http://www.ipt.ntnu.no/~stanko/files/Courses/TPG4230/ 2019/

video files available on youtube channel https://www.youtube.com/channel/UCWMfsCe1NQMgx4UZWrVvFgA

office 230 (2nd floor)

Guest lectures (Monday 14:15-1500) start 21.01 end 15.04 P13

Refesence group
- Markus Nielsen
- Armen Hiwa



DEVELOPMENTS IN PETROLEUM SCIENCE 55

HYDROCARBON EXPLORATION AND PRODUCTION

2ND EDITION

FRANK JAHN, MARK COOK & MARK GRAHAM

Field development and operations

- change mindset
- trapped with an existing system
  - exploit advantages
  - reduce and mitigate deficiencies

Goal: maximize value (profit) to shareholders in a safe and environmentally responsible manner

take decisions of main features of field

- define / find problem
- collect information
- identify alternatives
- Analyse evidence
- choose an alternative

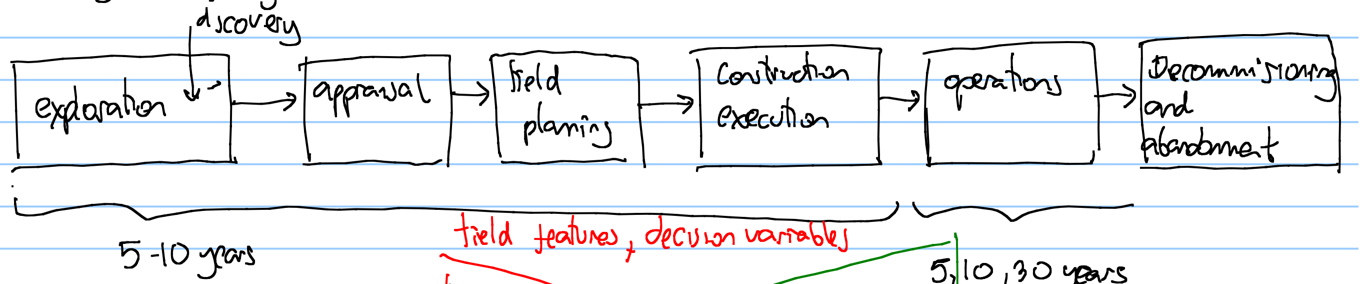
Performance indicator (KPI)

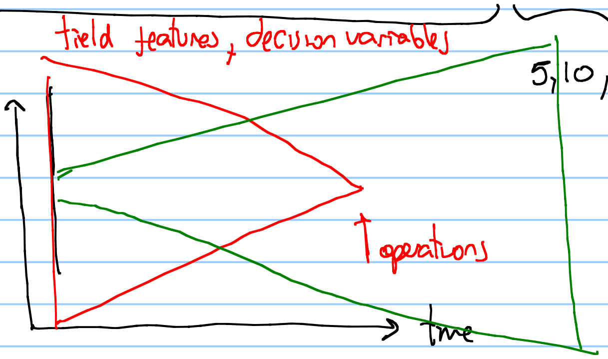
- overview of field development process
  - life cycle of oil and gas field
- Economic indicators

Technical aspects / constraints

- field performance (coupled system reservoir + wells + Surface network) Artificial lift, boosting
- Production system and configuration
- flow assurance
- Marine considerations for field development

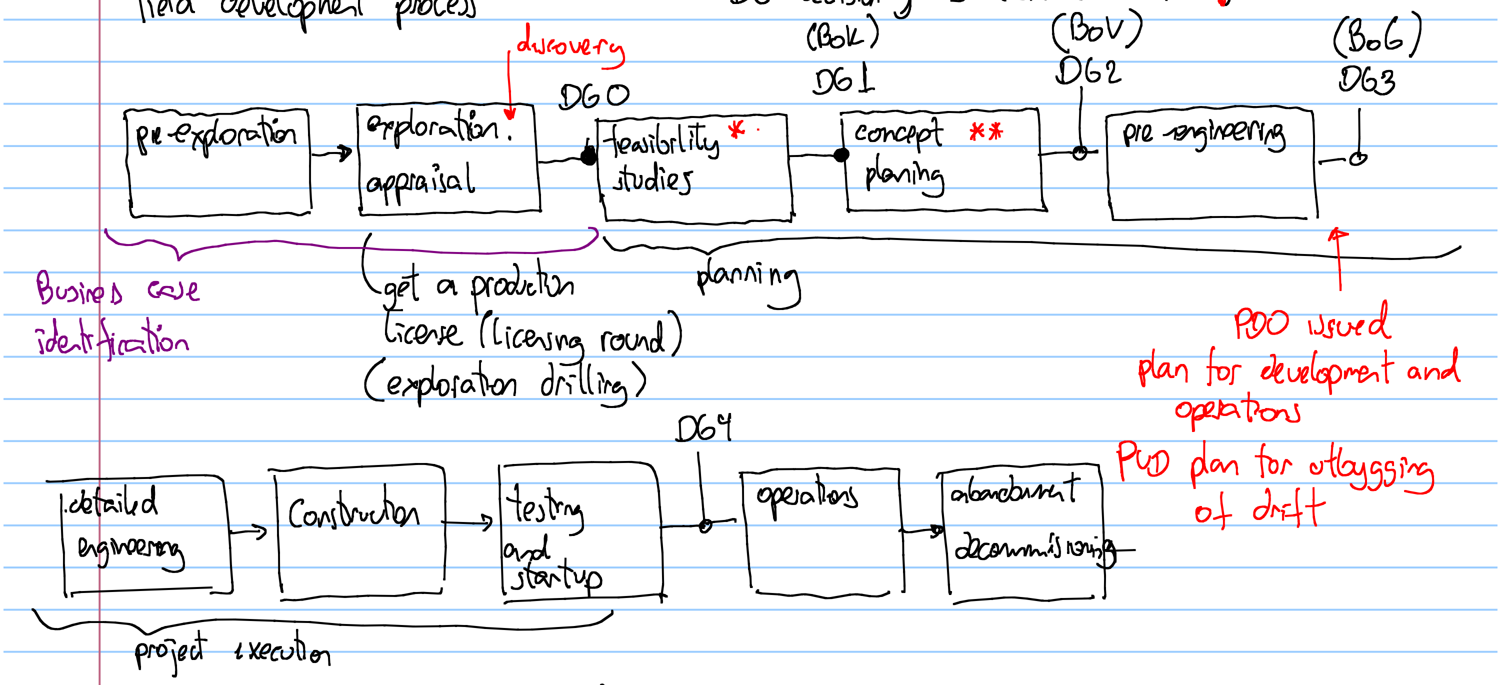
Life cycle of hydrocarbon field





field development process

DG decision gates (Eriksen method)



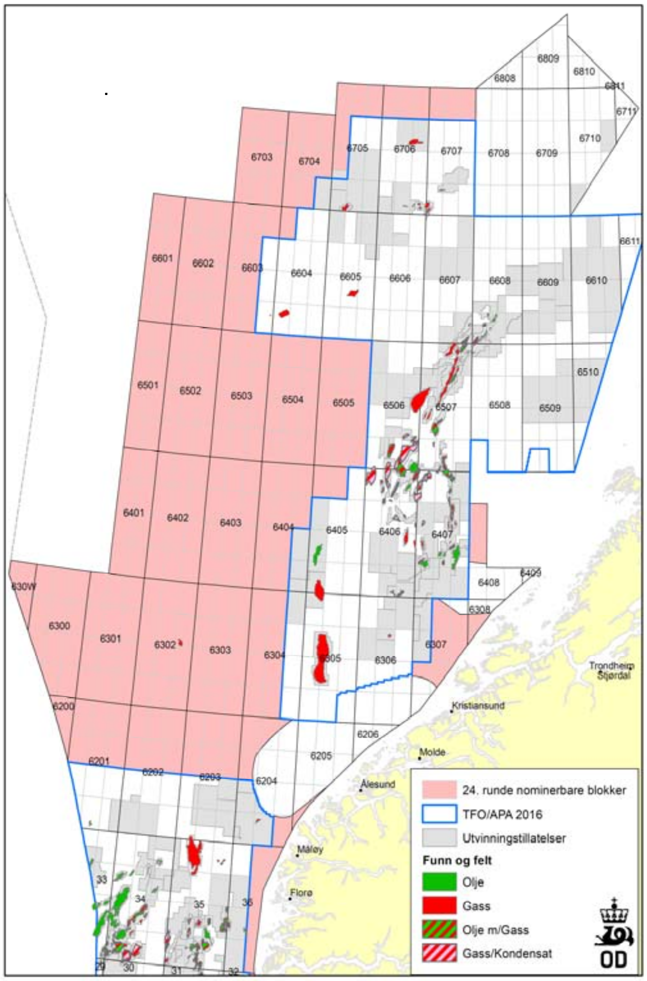
* find alternatives to develop the field

** develop further all alternatives and choose one (the best)

BoK Beslutning om Konkretisering

BoV Beslutning om videreføring

BoG Beslutning om execution



- fees $34000\ \frac{NOK}{Km^2}$ 1^{rst} year

  $68000\ \frac{NOK}{Km^2}$ 2^{nd}

  $137000\ \frac{NOK}{Km^2}$

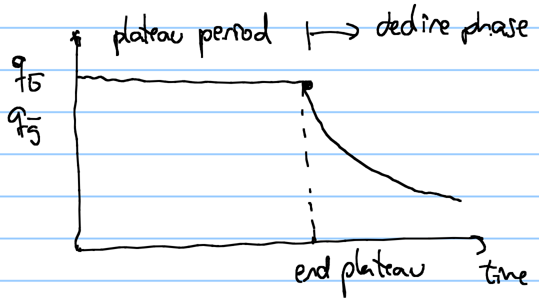
DG0 : SOC statement of commerciality
- wait
- more appraisal
- relinquish license
- sell the discovery

Field performance

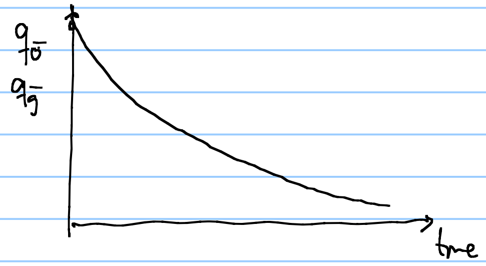
- $q_{\bar{o}}$, $q_{\bar{g}}$ vs. time

two ways to produce field

mode A (plateau mode) mode B (decline mode)



(physical constraint system)
(or other?)

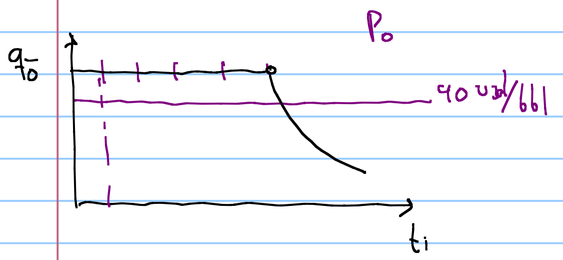


Review production data of fields in the Norwegian Continental shelf http://www.ipt.ntnu.no/~stanko/files/Files/20170402_NCS_Production_Data.xlsx

Production scheduling : deciding how much the field will produce with time
predicting " " " " " " " "

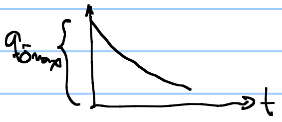
Mode A

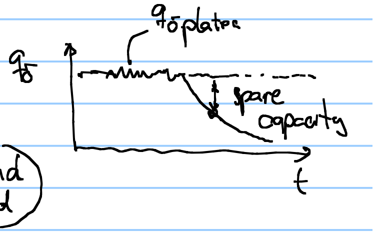
- Standalone developments
- new fields
- need to develop whole infrastructure
- big - medium size

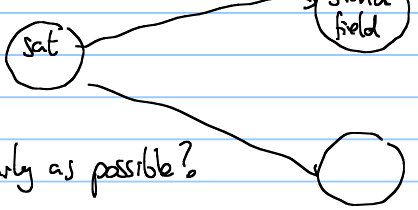


Mode B

- Satellite field
- Using existing facilities (from a neighbouring field)
- produce as much as possible, as early as possible
- small size

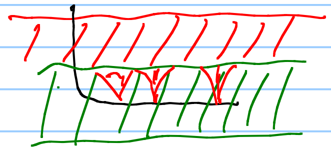






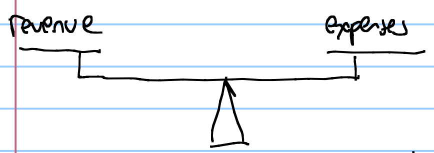
why not produce as much as possible, as early as possible?

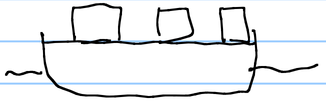
- requirement from authorities to meet recovery factor



e.g. early gas coning might reduce recovery factor

- ↑ plateau gives you higher revenue

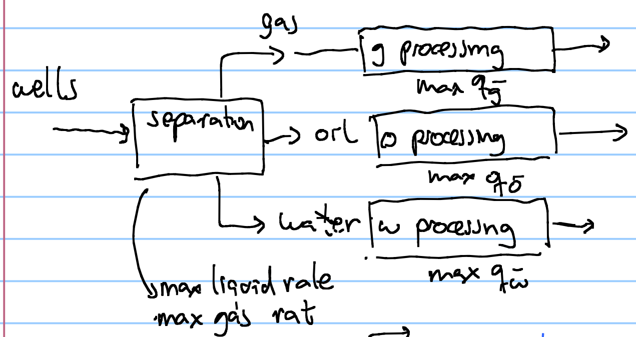


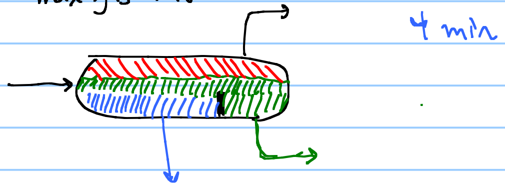


↑ plateau → bigger and higher capacity processing facilities
→ bigger offshore structure
→ more wells

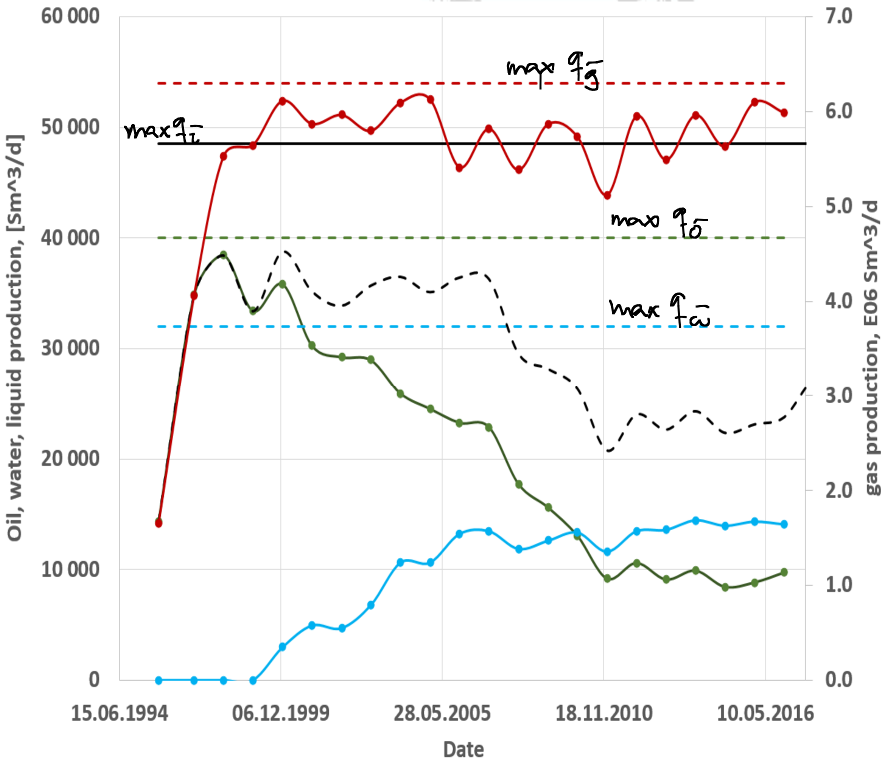
- Run sensitivity analysis on plateau height to define rate that maximizes economic value (NPV net present value)

- Plateau ends usually due to two reasons
  - system cannot produce more
  - reach a limit on the processing facilities





An example from Heidrun



Rule of thumb plateau rate for oil fields (1-5 years)

annual offtake of 0.1 (TRR) total recoverable reserves

$0.1 \cdot N_{po}$

N initial oil in place

$N \cdot R_F = N_{po}$

ultimate oil cumulative production

Goliat $N = 180$ E6 stb ;

$RF = 30\%$

$N_{po} = 54$ E6 stb

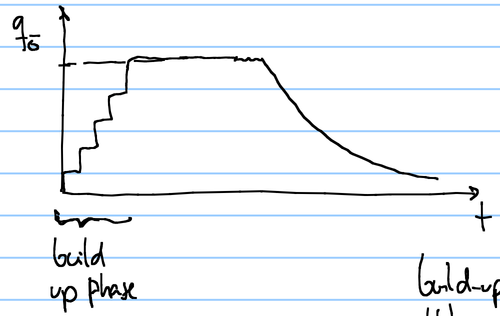
$54 \cdot E6 \cdot 0.1$ stb $= 5.4$ E6 stb

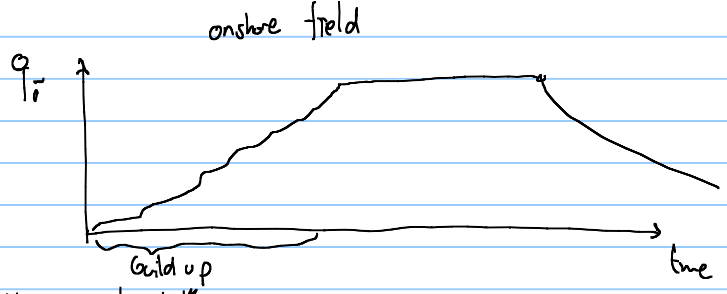
$$q_{op} = \frac{5.4 \text{ E6}}{365} \approx 15000 \text{ stb/d}$$

uptime 90-95%

for gas fields (0.02-0.05) TRR plateau (10-30 years)

Onshore vs. offshore (page 4 of reference material)

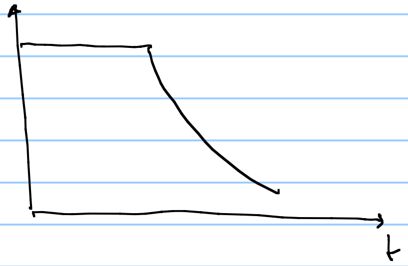




build-up phase is short!
offshore - big investment to have offshore structure and processing facilities in place ~ to start producing

for onshore fields in remote locations the production profile is very similar to offshore fields!

no build up (pre-drilled wells)



gas vs. oil fields

oil
- easy to transport
- sold on market
- transportation by pipeline or tanker

gas
- need infrastructure (pipeline system)
- based on contracts / rate / time
  - penalty
  - swing factor

more information on page 9 (references)

- LNG liquified natural gas
  LNG plant in field U$
  LNG receiving terminal
  Special tanker

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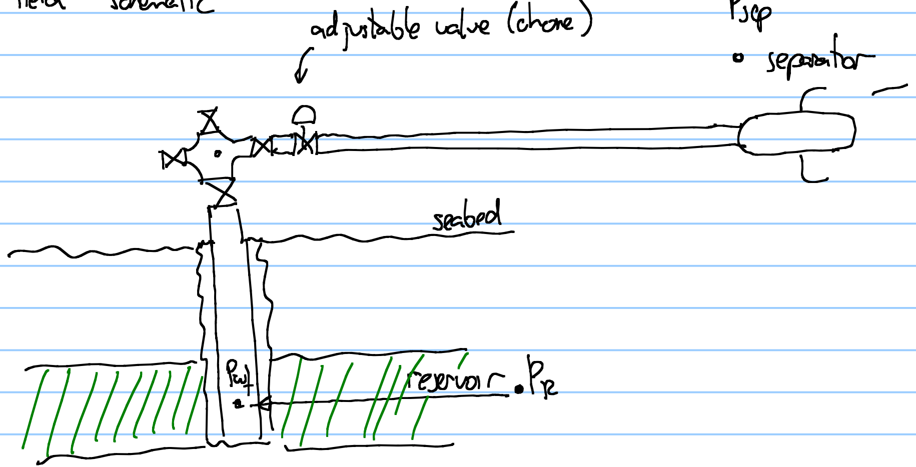
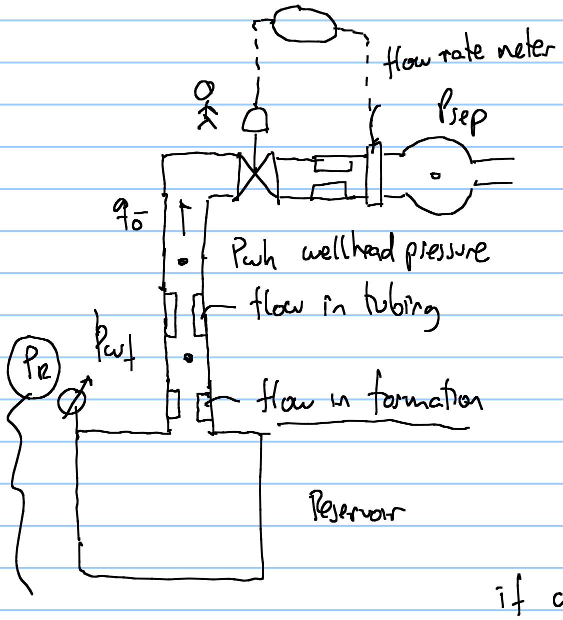
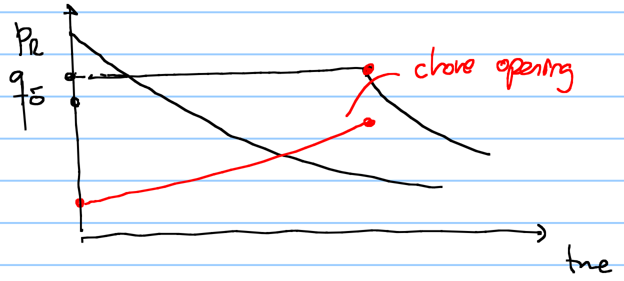
field schematic



Mechanical analogue of field

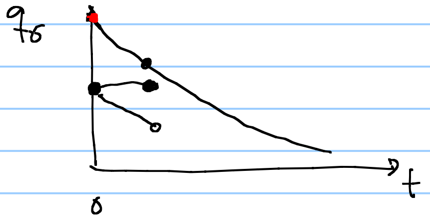


$q_o = f(P_R, P_{sep}, \text{choke opening})$



if choke is open

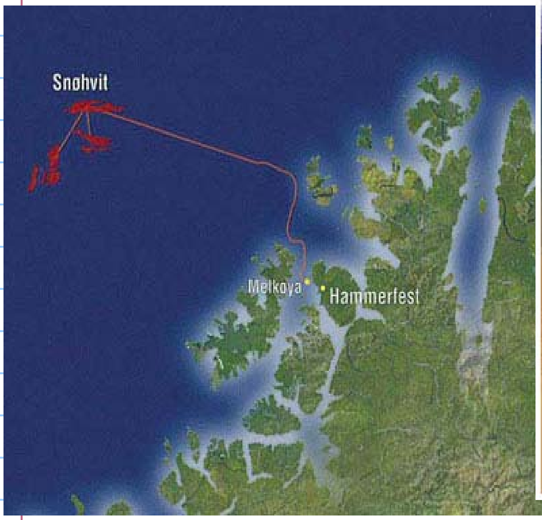
$q_o = (P_R, P_{sep}, \Delta p_{choke})$

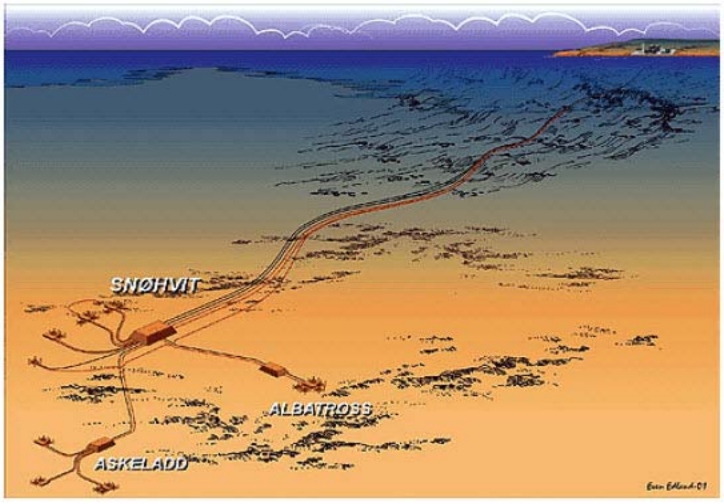


Produce your own field!

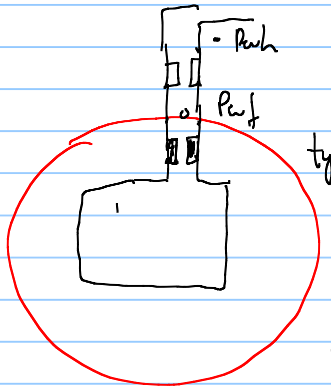
http://www.ipt.ntnu.no/~stanko/Field_Simulator.html

Class exercise:





- Neglect flow in wells, flowline, pipeline.
- Only using reservoir model



Estimate production profile and revenue of Snøhvit

typical Reservoir simulator : Eclipse
: CMG
Sensor

Model assumptions : homogeneous reservoir
high connectivity
all wells are identical
→ high permeability , transient is very short
Dry gas (no condensation)

reservoir pressure — initial res pressure — cumulative gas production

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

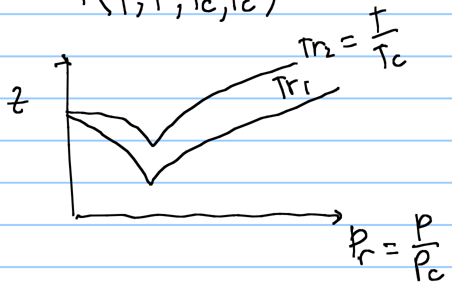
initial gas in place

deviation factor

$f(p, T, P_c, T_c)$

$$G_p = \int_0^t q_g(t)\,dt$$

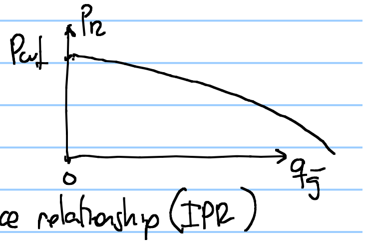
Sm^3/d — in years



$f(T_R, P_R)$

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

$f(T_R, P_i)$



Backpressure equation for Δp loss in formation

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

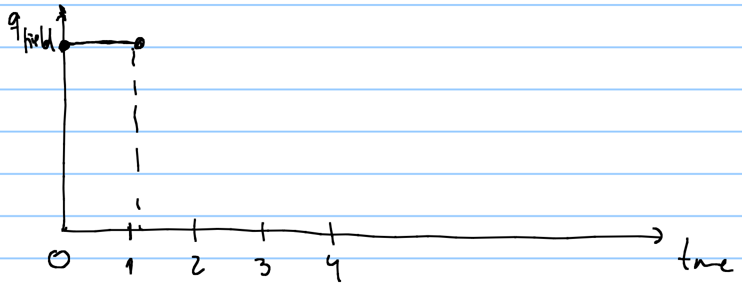
Inflow performance relationship (IPR)

our control variable P_{wf}

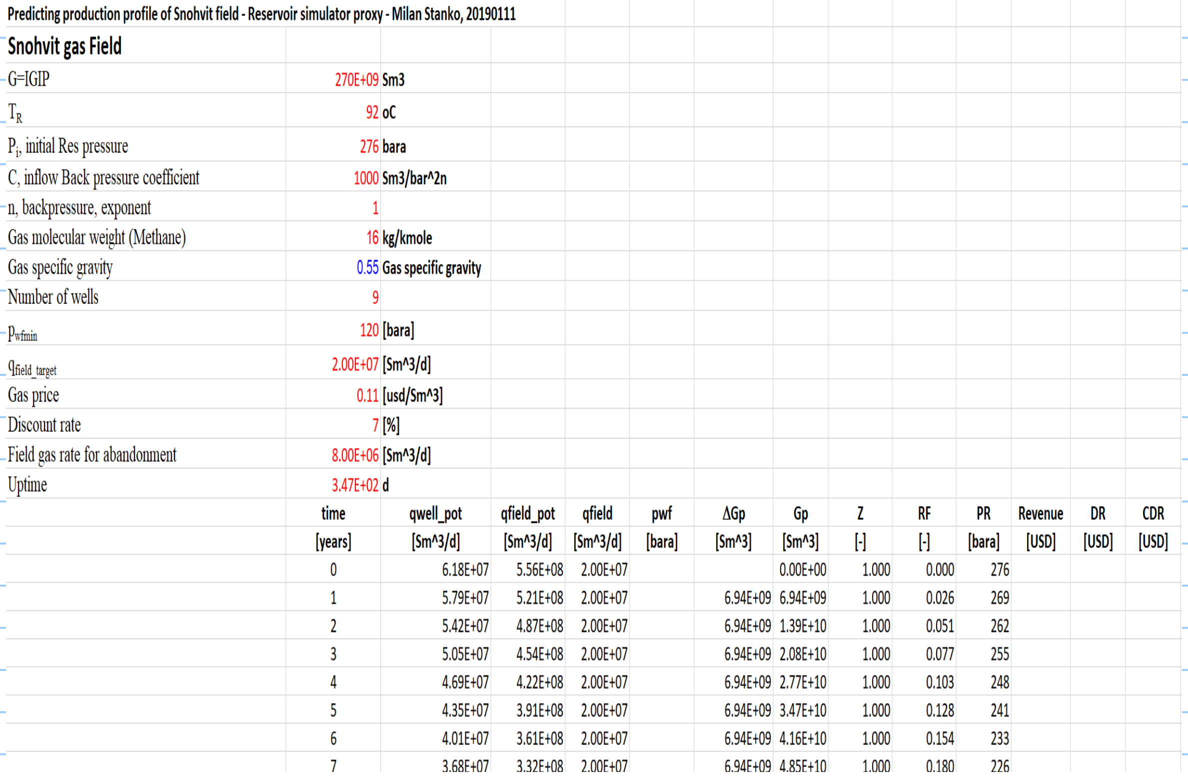
? what is P_{wf} when choke is fully open?

define $P_{wf\,min}$ = 120 bara

$$q_{field} = N_{wells} \cdot q_{we} = N_{wells}\, C\left(P_R^2 - P_{wf}^2\right)^n \quad 20\ E6\ Sm^3/d$$



assumption $Z \approx const$ $Z \approx 1$

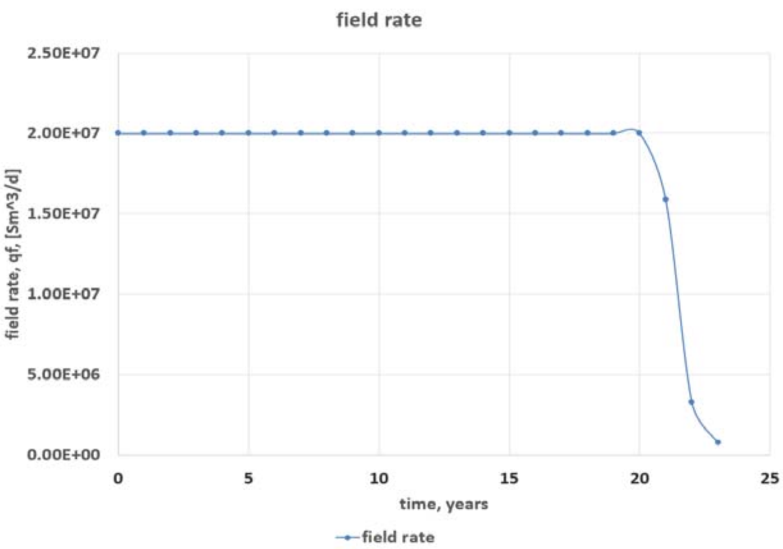


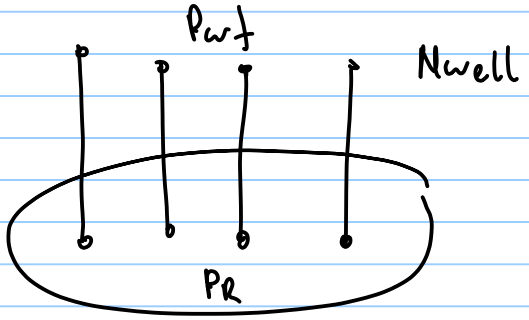
Predicting production profile of Snohvit field - Reservoir simulator proxy - Milan Stanko, 20190111

Snohvit gas Field

G=IGIP	270E+09	Sm3
T_R	92	oC
P_i, 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	9	
P_{wfmin}	120	[bara]
q_{field_target}	2.00E+07	[Sm^3/d]
Gas price	0.11	[usd/Sm^3]
Discount rate	7	[%]
Field gas rate for abandonment	8.00E+06	[Sm^3/d]
Uptime	3.47E+02	d

time	qwell_pot	qfield_pot	qfield	pwf	ΔGp	Gp	Z	RF	PR	Revenue	DR	CDR
[years]	[Sm^3/d]	[Sm^3/d]	[Sm^3/d]	[bara]	[Sm^3]	[Sm^3]	[-]	[-]	[bara]	[USD]	[USD]	[USD]
0	6.18E+07	5.56E+08	2.00E+07			0.00E+00	1.000	0.000	276			
1	5.79E+07	5.21E+08	2.00E+07		6.94E+09	6.94E+09	1.000	0.026	269			
2	5.42E+07	4.87E+08	2.00E+07		6.94E+09	1.39E+10	1.000	0.051	262			
3	5.05E+07	4.54E+08	2.00E+07		6.94E+09	2.08E+10	1.000	0.077	255			
4	4.69E+07	4.22E+08	2.00E+07		6.94E+09	2.77E+10	1.000	0.103	248			
5	4.35E+07	3.91E+08	2.00E+07		6.94E+09	3.47E+10	1.000	0.128	241			
6	4.01E+07	3.61E+08	2.00E+07		6.94E+09	4.16E+10	1.000	0.154	233			
7	3.68E+07	3.32E+08	2.00E+07		6.94E+09	4.85E+10	1.000	0.180	226			





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

$$q_f = N_{wells}\, C\left(P_R^2 - P_{wf}^2\right)^n$$

$$\downarrow$$

$$q_{f\_potential} = q_f\left(P_{wf} = P_{wf\,min}\right) = N_{wells}\, C\left(P_R^2 - P_{wf\,min}^2\right)^n$$

if $q_{f\_target\,rate} < q_{f\_potential}$ then

$$q_f = q_{f\_target\_rate}$$

$$\overset{\checkmark}{q_{f\_target\,rate}} = \overset{\checkmark}{N_{well}}\, \overset{\checkmark}{C}\left(\overset{\checkmark}{P_R^2} - \overset{?}{P_{wf}^{*2}}\right)^{\overset{\checkmark}{n}}$$

else $q_{f\_target\,rate} \geq q_{f\_potential}$ then

$$q_f = q_{f\_potential}$$

$$P_{wf} = P_{wf\,min}$$

to improve calculations:

Z $\qquad P\overset{1/\rho}{V} = ZRT$

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

$$\gamma_g = \frac{MW_g}{MW_{air}} = \frac{MW_g}{28.97}$$

$$MW_g = \sum_{i=1}^{N_{comp}} z_i\, MW_i$$

Sutton[1] suggests the following correlations for hydrocarbon gas mixtures.

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

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

accurate representation of the Standing-Katz chart using a Carnahan-Starling hard-sphere EOS,

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

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

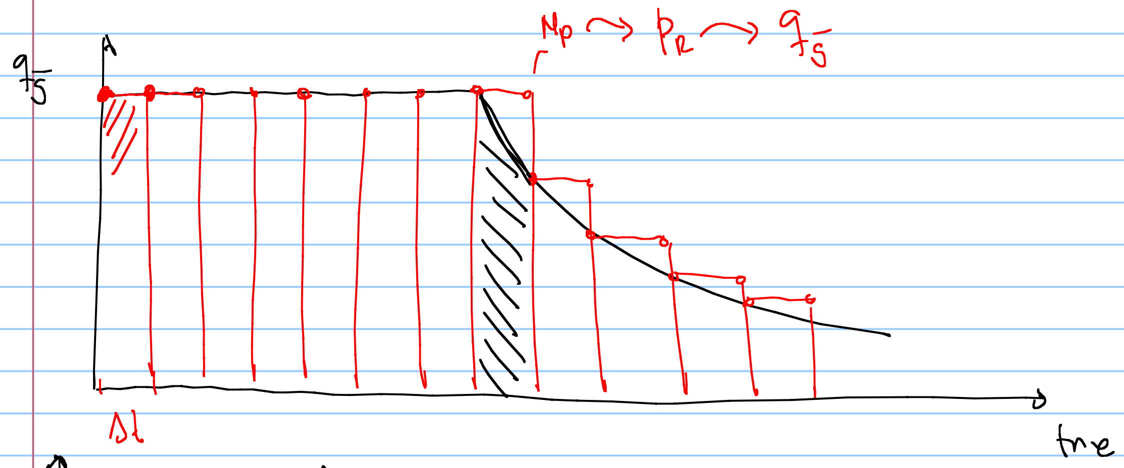
The reduced-density parameter, y (the product of a van der Waals covolume and density), is obtained by solving

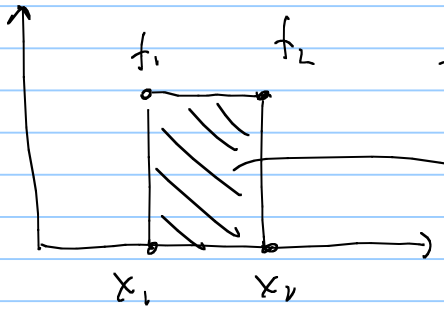
$$\begin{aligned} f(y) = 0 = &-\alpha p_{pr} + \frac{y + y^2 + y^3 - y^4}{(1-y)^3} \\ &- (14.76t - 9.76t^2 + 4.58t^3)y^2 \\ &+ (90.7t - 242.2t^2 + 42.4t^3)y^{2.18+2.82t}, \ldots\ldots\ldots (3.43) \end{aligned}$$

$$\begin{aligned} \text{with } \frac{df(y)}{dy} = &\frac{1 + 4y + 4y^2 - 4y^3 + y^4}{(1-y)^4} \\ &- (29.52t - 19.52t^2 + 9.16t^3)y \\ &+ (2.18 + 2.82t)(90.7t - 242.2t^2 + 42.4t^3) \\ &\times y^{1.18+2.82t}. \ldots\ldots\ldots\ldots (3.44) \end{aligned}$$

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

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





trapezoidal rule

$$Area = (f_1 + f_2)\,\frac{(x_2 - x_1)}{2}$$

at time "i" t_i , q_i ΔG_{i+1}

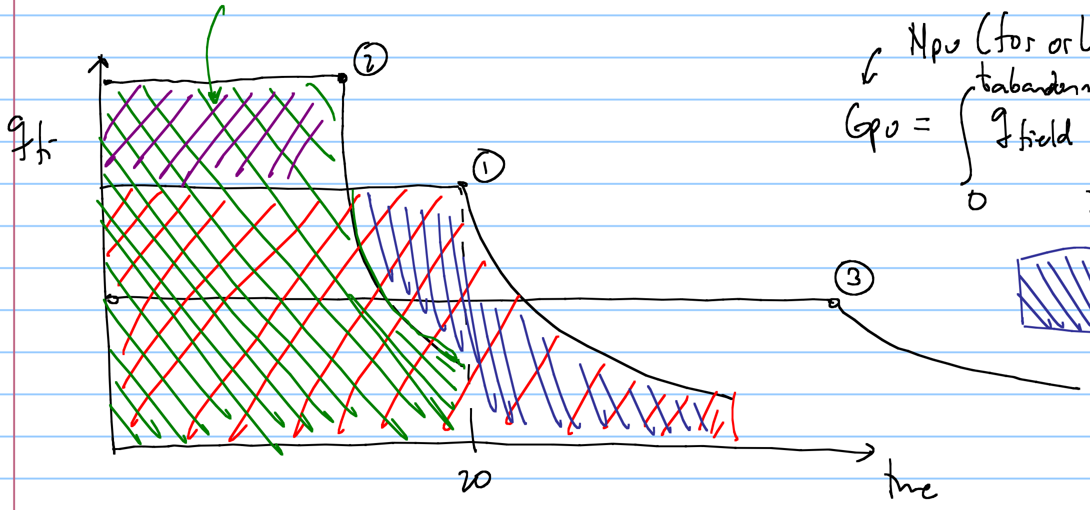
time	q	Gp	ΔGp	p_R
⋮				
t_i	q_i	G_{p_i}		
t_{i+1}	q_{i+1}?	$G_{p_{i+1}}$	ΔG_{p_i}	

$$G_{p_{i+1}} = G_{p_i} + \Delta G_{p_i}$$

rectangular approximation $\Delta G_{p_i} = q_i (t_{i+1} - t_i) \cdot N_{days/year}$

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

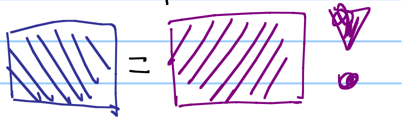
(implicit integration method that requires iterative solving !)



N_{pu} (for oil)

$$G_{pu} = \int_0^{t_{abandonment}} q_{field}\, dt$$

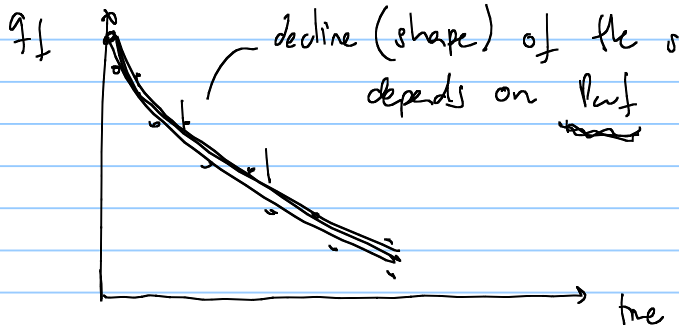
if $G_{pu}^{①} = G_{pu}^{②}$



$G_{pu}^{①} \approx G_{pu}^{②} \approx G_{pu}^{③}$

the higher plateau ⤳ the shorter the plateau

- if operating in constant pressure mode



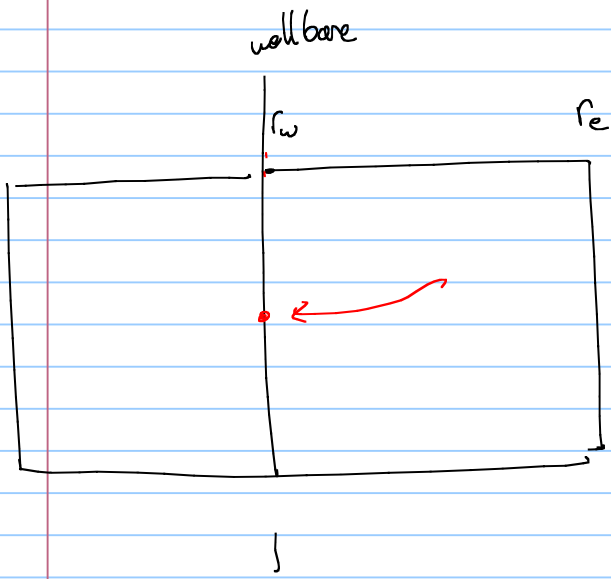
decline (shape) of the slope depends on P_{wf}

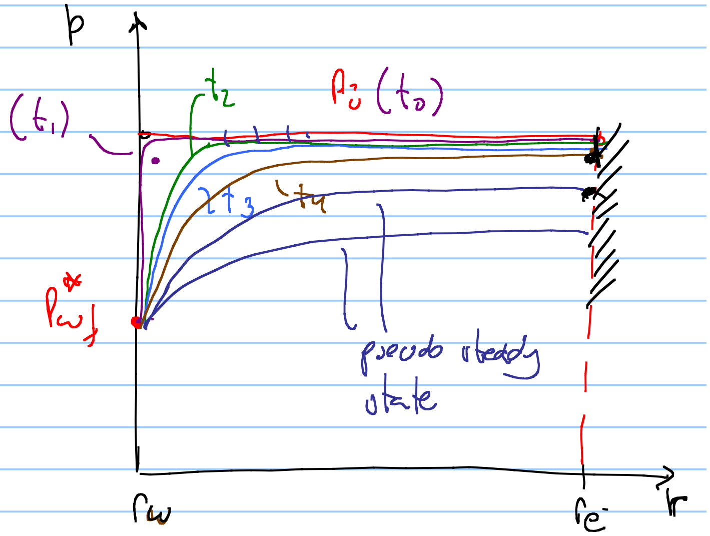
Short comment on IPR equation used :

Backpressure gas equation $q_g = C(P_R^2 - P_{wf}^2)^n$

→ • steady state or pseudo steady state regime
$\underline{S}S$ $\underline{P}SS$

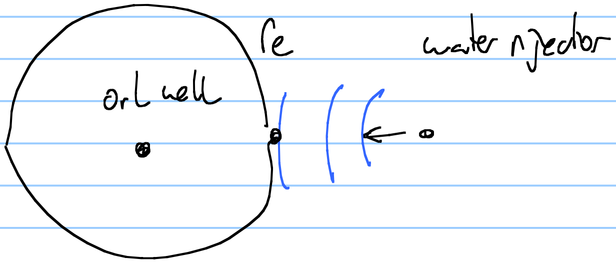
• low pressure (~100 bara)





time from t0 – t4 (when rate changes reach boundary)

↳ transient regime



tss tpss
↓ → time to pseudo steady state
time to steady state

tss is f (k)
↳ permeability

• if tss, tpss is long (months, years)
shale gas, shale oil, tight oil, tight oil

• after transient if P(re) = constant
then steady state

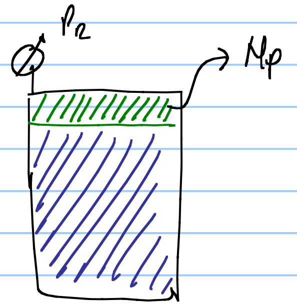
in $\underline{SS}$, $\underline{PSS}$ $\quad q_{well} = f(\underline{P_R}, \underline{P_{wf}})$

in transient $\quad q_{well} = f(P_i, P_{wf}, \underline{t})$

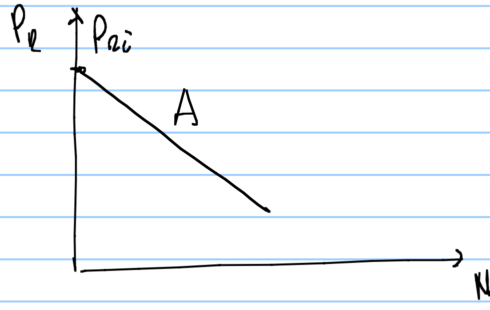
- Undersaturated oil reservoir with underlying large aquifer

$P_R > P_b$ for whole production time (no gas in formation)

$P_{wf} > P_b$ ⌐ bubble point pressure



$$\underline{P_R} = P_{Ri} - \underline{A} \cdot N_p$$



compressibility

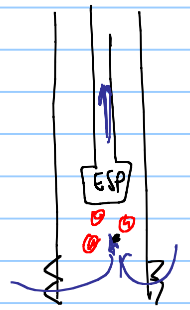
$$A = \frac{B_o(p)}{\underbrace{N}_{\text{initial oil in place}} B_{oi} C_o + N B_{oi} \frac{C_w \cdot S_{wi} + C_f}{S_o} + \underbrace{V_a}_{\text{aquifer volume}} \phi_a (C_w + C_f) B_w}$$

$$R_f = \frac{N_{po}}{N}$$

- wells are operated with ESP electric submersible pumps

there is a $P_{wf\,min}$

$$P_{wf\,min} = P_b(T_R)$$



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

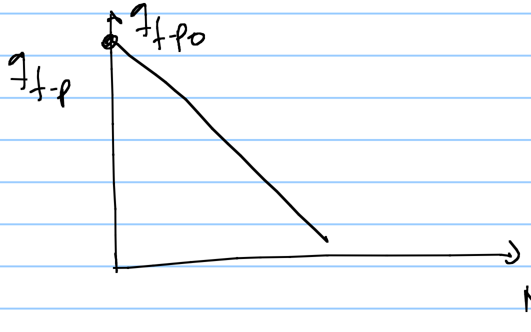
· flow of liquid only

$$q_{field} = N_{wells} \cdot J \left(P_R - P_{wf}\right)$$

$$q_{field\_potential} = N_{wells} \cdot J \left(P_{Ri} - A \underbrace{N_p}_{} - P_{wf\,min}\right)$$

$$q_{field\_potential} = -\underbrace{N_{well} \cdot J \cdot A}_{m} N_p + \underbrace{N_{well} \cdot J \left(P_{Ri} - P_{wf\,min}\right)}_{\downarrow}$$

$$\underbrace{q_{f\_p} = -m N_p + q_{f\_po}}_{}$$



$$q_{plateau} = q_{f\_p} = -m N_p^{*} + q_{f\_po}$$

if

$N_p = 0 \longrightarrow N_p^{*}$

$q_{field} = q_{plateau}$

$$N_p^{*} = q_{plateau} \cdot t_p \cdot \frac{N_{day}}{year}$$

plateau duration

$$q_{plateau} = -m\, q_{plateau} \cdot t_p \cdot N_{days/year} + q_{f\_po}$$

$$t_p = \frac{q_{f\_po} - q_{plateau}}{m\, q_{plateau} \cdot N_{day/year}}$$

$$t_p = \frac{1}{N_{day}} \frac{1}{m} \left(\frac{q_{f\_po}}{q_{plateau}} - 1\right) \leftarrow$$

$$t_p = \frac{1}{N_{day}} \frac{1}{N_w \cdot A \cdot J} \left(\frac{\left(P_{i} - P_{wf\,min}\right) J \cdot N_{wells}}{q_{plateau}} - 1\right)$$

$$t_p = \frac{1}{N_{days}} \frac{1}{\underline{A}} \left(\frac{P_i - \overline{P_{wf\,min}}}{\underline{q_{plateau}}} - \frac{1}{N_w \cdot J'} \right)$$

Bigger reservoir (↑N) → ↓A → ↑t_p

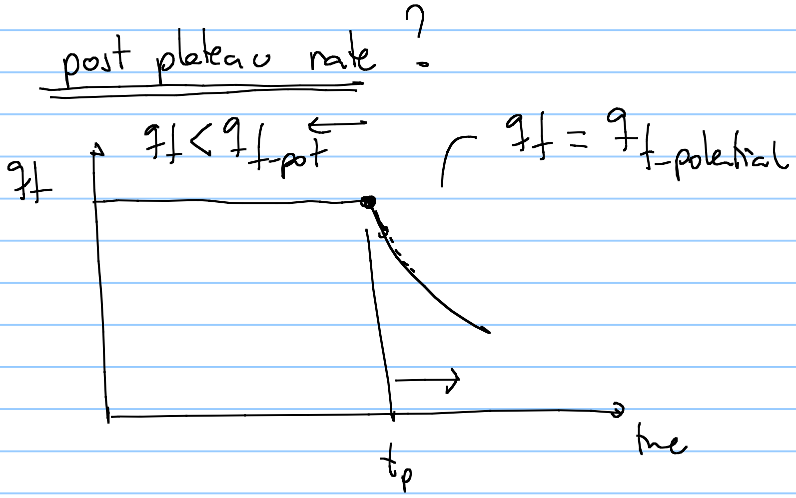
more wells (↑N_w) → ↑t_p

more productive wells (↑J) → ↑t_p

lower P_{wf_min} → ↑t_p

higher plateau ↑q_{platea} → ↓t_p

post plateau rate ?



$$q_{f-p} = -m \underset{\sim}{N_p} + q_{f-po}$$

$$N_p = \int_0^t q_f \, dt = \underbrace{\int_0^{t_p} q_{pla} \cdot dt}_{plateau} + \underbrace{\int_{t_p}^{t} q_{f-p} \, dt}_{decline}$$

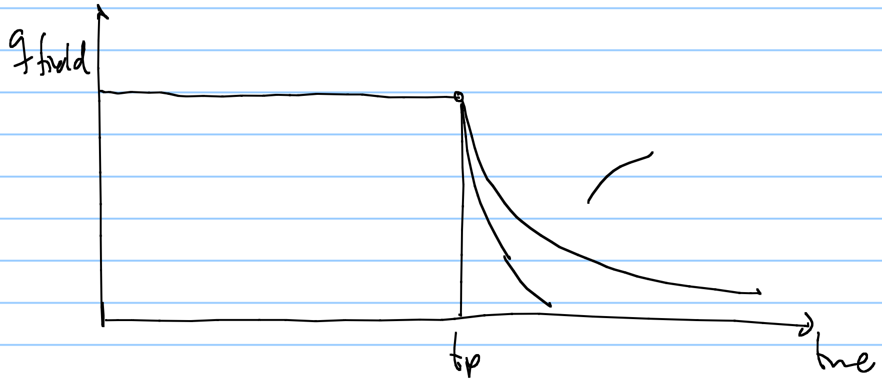
$$q_{f-p} = -m \, q_p \cdot t_p - m \cdot \int_{t_p}^{t} q_{f-p} \, dt + q_{f-po}$$

$$t_p = \frac{1}{m} \left(\frac{q_{f-po}}{q_{plateau}} - 1 \right)$$

$$q_{f-p} = q_{plateau} - m \int_{t_p}^{t} q_{f-p} \, dt$$

a solution of this equation is

$$q_{f-p} = q_{plateau} \cdot e^{\underbrace{-m}_{A \cdot N_{wells} \cdot J}(t-t_p)}$$



if $\overset{OOIP}{N}$ ↑ A ↓ longer decline

if N_{wells} ↑ m ↑ sharper decline

if J ↑ m ↑ sharper decline

Group activity

-Perform this activity in groups of 3 people

Description of the tasks:

1. Read (and understand) the power point presentation named “Field development process”. If one of the group members has a doubt about it, try to clarify it with your group mates or do a web search.
2. Pick one of the other documents provided.
3. Review the index, perform a quick scanning and skimming of the document (http://www.butte.edu/departments/cas/tipsheets/readingstrategies/skimming_scanning.html) and pick a section, or a topic that you believe is relevant and interesting to learn more about. (It could be one over which you and your groupmates have some previous background on the matter). The topic should be related to some of the tasks that are typically performed in the life planning (and decommissioning) of an oil and gas field. It is possible to pick more than one topic (for example, if people in your team have different background)
4. Read the section and prepare a power point presentation to present to your other classmates, take into account the following:
   a. The presentation should last around 10 min.
   b. One person or all in your team can contribute/present.
   c. You are encouraged to find media, pictures, diagrams, example cases on the web to help you explain a topic. (remember to include the source on the slides)
   d. If you explain a topic that requires very deep prior knowledge, it helps if you give a short introduction to the topic. Remember, quality is better than quantity!
   e. Be prepared to answer questions from the audience about the topic you presented.

There will be a kahoot quiz session afterwards where some of the topics in the documents will be reviewed, and there might be some questions about the topic you are presenting, therefore, your presentation could surely benefit others!

Your powerpoint presentation will be delivered as part of Exercise set 1. You will have time to polish it afterwards before you make the final delivery.

Suggestions:

- Task 1 should take about 20-30 min
- Tasks 2-4 should take about 60 min. Make sure all team members contribute.

Class quiz

Hide answers

Q1: What does SOC stands for?

- Statement of Commitment

  This is a wrong answer
- Statement of Commerciality

  This is a correct answer
- Statement of Conflict

  This is a wrong answer
- Statement of Contribution

  This is a wrong answer

Q2: How many decision gates do we normally have in a field development process?

- 3

  This is a wrong answer
- 5

  This is a correct answer
- 4

  This is a wrong answer
- 6

  This is a wrong answer

Q3: How do we call the project management process that is commonly used in field development ?

- Status-gate

  This is a wrong answer

- Phase-gate

  This is a correct answer

- Waterfall

  This is a correct answer

- Stage-gate

  This is a correct answer

Q4: Which of the following activities are normally performed during a business case identification

- Scouting, pre-exploration, prospect identification , Seismic

  This is a correct answer

- Prepare the PDO

  This is a wrong answer

- Create a reservoir model

  This is a wrong answer

- Discovery assessment, appraisal, reserve estimation

  This is a correct answer

Q5: What subphases are in the project planning?

- Feasibility studies, concept planning, detailed engineering

  This is a wrong answer

- Feasibility studies, concept planning, pre-engineering

  This is a correct answer

- Business case identification, Feasibility studies, pre-eng

  This is a wrong answer

- Feasibility studies, concept planning, tech. requirements

  This is a wrong answer

Q6: Flow assurance issues are evaluated in the project planning phase

- True

  This is a correct answer

- False

  This is a wrong answer

Q7: The life cycle of a hydrocarbon field is comprised of

- Exploration, appraisal, planning

  This is a correct answer

- Construction and execution

  This is a correct answer

- Production and operations

  This is a correct answer

- Abandonment and decommisioning

  This is a correct answer

Q8:PDO stands for

- Plan for Design and Operations

  This is a wrong answer

- Plan for Development and Optimization

  This is a wrong answer

- Plan for Development and Operations

  This is a correct answer

- Plan for Utbygging og Drift

  This is a correct answer

Q9: In the field development process, what follows after the project planning?

- Appraisal

  This is a wrong answer

- Project execution

  This is a correct answer

- Identification of Business case

  This is a wrong answer

- Operations

  This is a wrong answer

Q10: What does FEED stand for?

- First End Engineering Design

  This is a wrong answer

- Field End Engineering design

This is a wrong answer

- Front End Established Design

This is a wrong answer

- Front End Engineering Design

This is a correct answer

Q11: What of the tasks below are not performed during decommissioning?

- Remove and bury subsea pipelines

This is a wrong answer

- well plugging and abandonment

This is a wrong answer

- debottlenecking

This is a correct answer

- recovery of material and recycling of equipment

This is a wrong answer

Q12:which of the following statements is false?

- Field production mode A is always followed by mode B

This is a wrong answer

- A field could be produced using mode b and then mode a

This is a wrong answer

- production mode B is typically used for standalone projects

This is a correct answer

- In production mode A, the wellhead choke is opened gradually

This is a wrong answer

Q13: Which one of the following tasks are performed during the business case identification phase?

- Probabilistic reserve estimation

  This is a correct answer

- simplified economic valuation of reserves

  This is a correct answer

- appraisal

  This is a correct answer

- Apply and obtain a production license

  This is a correct answer

Q14: As a rule of thumb, how much is the annual offtake of an oil field in the north sea?

- 10% of the TRR

  This is a correct answer

- 3% of the TRR

  This is a wrong answer

- 5% of the TRR

  This is a wrong answer

- 0.1% of the TRR

  This is a wrong answer

Q15: When is the reservoir pressure maintenance strategy planned in an offshore development?

- from the begginning

  This is a correct answer

- after some years producing the field

  This is a wrong answer

Q16:BONUS: what are the names of the members of the reference group?

- Martinus, Ahmed

  This is a wrong answer

- Armen, Markus

  This is a correct answer

- Marius, Armen

  This is a wrong answer

- Markus, Ahmed

  This is a wrong answer

Q17: During the feasibility studies one or more development concepts must be identified and analyzed

- true

  This is a correct answer

- false

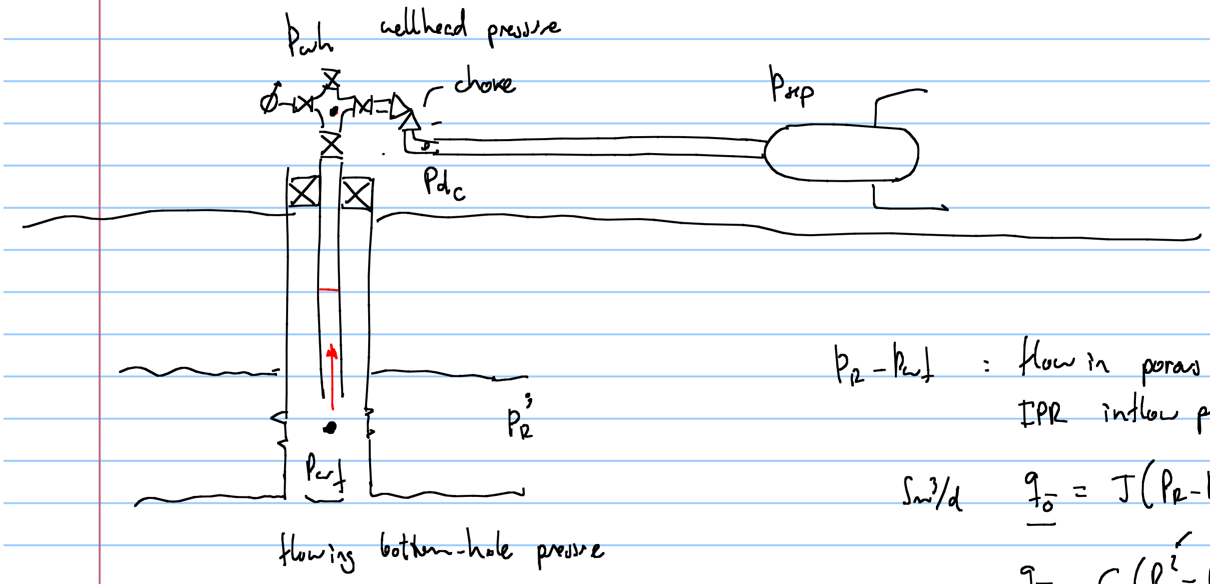
  This is a wrong answer

Presentation in groups of the topics:
-Volve discovery report - Exploration (Sindre, Alexander, Faraz)
-Visund PDO - Production and drilling technology (Mathilde, Joakim, Seok Ki)
-Ivar Aasen consequence report - Topside processing and development concept (Sigurd, Johanne)
-Hebron field PDO - Petrophysics (Gibran, Salma, Fadhil)

In some fields, water disposal is done through injection wells (either for pressure maintenance or to a disposal formation). Therefore, if there is an issue with the wells (loss of injectivity, plugging) this affects the water disposal capacity and can create a bottleneck in water production, requiring to reduce the oil rate of the field. Some examples are Visund and Peregrino.
The injectivity is often maintained by creating fractures in the near-wellbore formation.

A brief recap was given about of the analytical development of field production profile for plateau and post-plateau periods for an understaturated oil reservoir with underlying aquifer and produced with ESP pumps

flow equilibrium in dry gas production systems

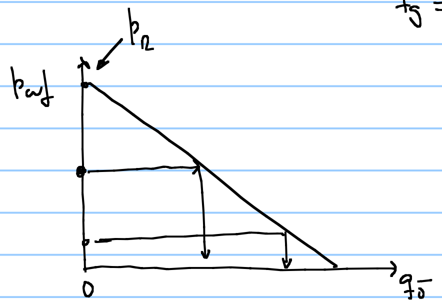


$p_R - p_{wf}$: flow in porous media

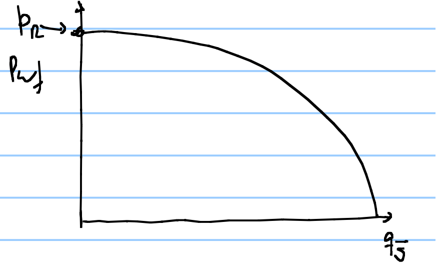
IPR inflow performance relationship

Sm³/d $q_o = J(p_R - p_{wf})$ PSS

$q_g = C(p_R^2 - p_{wf}^2)^n$ PSS ~ low p



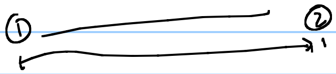
undersaturated oil, water injection



Dry gas
saturated oil
saturated gas

$p_{wf} \rightarrow p_{wh}$

flow in tubing (pipe)



$Re = \frac{\rho \Phi V}{\mu}$, $\varepsilon = \frac{e}{\Phi}$

$$\underbrace{z_1 + \frac{p_1}{\rho \cdot g} + \frac{V_1^2}{2g}}_{h_1} = \underbrace{z_2 + \frac{p_2}{\rho \cdot g} + \frac{V_2^2}{2g}}_{h_2} + f \frac{L}{\Phi} \frac{V^2}{2g}$$

A. THE TUBING RATE EQUATION IN VERTICAL AND DEVIATED GAS-WELLS

Author: Prof. Michael Golan

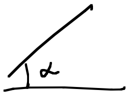
DERIVATION FROM FIRST PRINCIPLES (PURE SI SYSTEM)

page 133 ~ Compendium.

$$p_{wf}^2 = p_t^2 \cdot e^S + \frac{8 \cdot f_M}{\pi^2 \cdot D^5 \cdot g \cdot \cos(\alpha)} \cdot \left(\frac{p}{T}\right)_{sc}^2 \cdot (Z_{av} \cdot T_{av})^2 \cdot (e^S - 1) \cdot q_{sc}^2 \qquad \text{Eq. A-19}$$

Multiplying and dividing the second term on the right-hand side with:

$$S = 2 \cdot \frac{M_g \cdot g}{Z_{av} \cdot R \cdot T_{av}} \cdot L \cdot \cos(\alpha) = 2 \cdot \frac{28.97 \cdot \gamma_g \cdot g}{Z_{av} \cdot R \cdot T_{av}} \cdot L \cdot \cos(\alpha) \qquad \text{Eq. A-20}$$



$$p_{wf}^2 = p_t^2 \cdot e^S + \frac{28.97}{R} \cdot \left(\frac{p}{T}\right)_{sc}^2 f_M \cdot L \cdot \gamma_g \cdot Z_{av} \cdot T_{av} \cdot \frac{(e^S - 1)}{S \cdot D^5} \cdot q_{sc}^2 \qquad \text{Eq. A-21}$$

Solving for the flow rate:

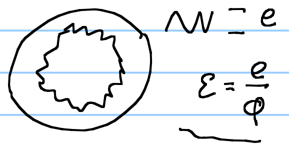
$$q_{sc} = \left(\frac{\pi}{4}\right) \cdot \left(\frac{R}{M_{air}}\right)^{0.5} \cdot \left(\frac{T_{sc}}{p_{sc}}\right) \cdot \left(\frac{D^5}{\underbrace{f_M}_{\text{friction moody}} \cdot L \cdot \gamma_g \cdot \underbrace{Z_{av}} \cdot \underbrace{T_{av}}}\right)^{0.5} \cdot \left[\left(p_{wf}^2 - p_t^2 \cdot e^S\right) \cdot \left(\frac{S}{e^S - 1}\right)\right]^{0.5} \qquad \text{Eq. A-22}$$

friction moody

$Re \sim V$

$T_{av} = \frac{T_{wf} + T_{wh}}{2}$

$Z_{av} = \frac{Z_{wf} + Z_{wh}}{2}$



$Re = \frac{\rho\, d\, V}{\mu}$

Gas in fully turbulent regime,

$$f_F = \frac{0.00437}{D^{0.224}}$$

fanning

$f_m = \frac{f_F}{4}$

tubing constant

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

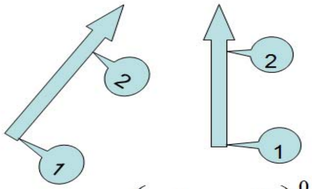
$D \uparrow, C_T \uparrow$

Tubing flow Equation-Dry gas

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

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

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



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

$P_{wh} \rightarrow P_{dc}$ (downstream of choke) $\rightsquigarrow$ eq. $f(q_{g}, P_{wh}, P_{dc})$

page 140 in Compendium

Appendix B: Choke Equations M. Stanko

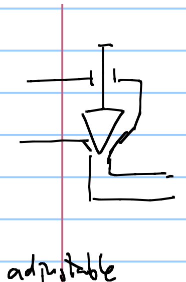
B. CHOKE EQUATIONS

UNDERSATURATED OIL FLOW

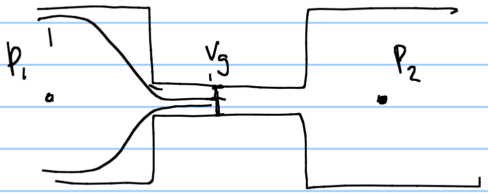
Based on a frictionless flow contraction from an upstream point 1 to a downstream point 2.

The single-phase Bernoulli equation for steady state frictionless flow along a streamline, neglecting elevation changes, is:

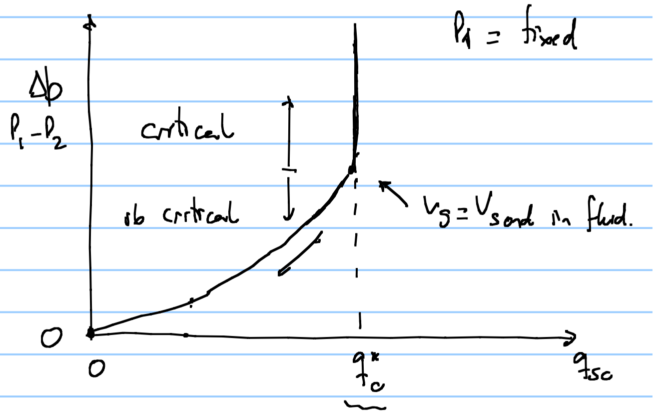
$$\frac{dp}{\rho} + V \cdot dV = 0 \qquad \text{Eq. B-1}$$



adjustable choke



fixed choke
bean choke



empirical constant to account for vena contracta effect

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

$k = \frac{C_p}{C_v}$

$P_{dc} \rightarrow P_{sep}$ flow in pipeline (pipe, conduit)

$$q_g = C_{FL}\left(\frac{P_{dc}^2}{e^s} - P_{sep}\right)^{0.5}$$

if horizontal line?
$s = 0$

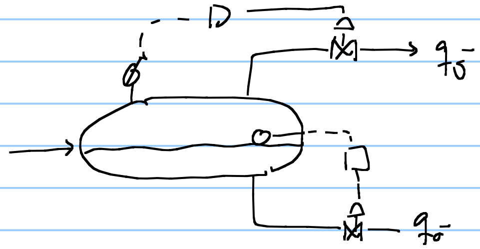
$$\underset{\sim}{q_g} = C_{FL}\left(\underline{P_{dc}^2} - P_{sep}^2\right)^{0.5}$$

C_{FL} = const. $\underset{\sim}{\frac{s e^s}{e^s - 1}}$ | $s = 0$

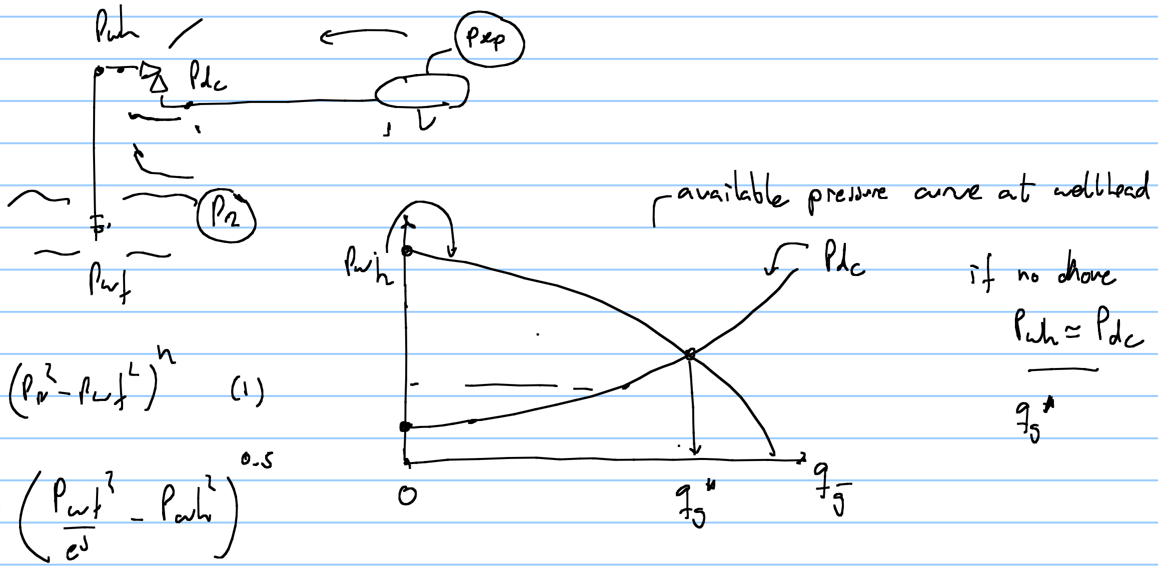
L'Hopital

$$\lim_{s \to 0} \frac{s e^s}{e^s - 1} = 1$$

		unknowns	equation
IPR	$\overset{?}{q_g} = \overset{\checkmark}{C}\left(\overset{\checkmark}{p_R}^2 - \overset{?}{p_{wf}}\right)^{\overset{\checkmark}{n}}$	2	1
tubing	$q_g = C_T\left(\frac{p_{wf}^2}{e^s} - \overset{\checkmark}{p_{wh}}^2\right)^{0.5}$	1	1
choke	$f\left(\overset{\checkmark}{q_g}, \overset{\checkmark}{p_{wh}}, \overset{?}{p_{dc}}\right)$	1	1
pipeline	$q_g = C_{PL}\left(p_{dc}^2 - \overset{\checkmark}{p_{sep}}^2\right)^{0.5}$		1
		4	4



Graphical solution



$$q_g = C\left(p_R^2 - p_{wf}^2\right)^n \quad (1)$$

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

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

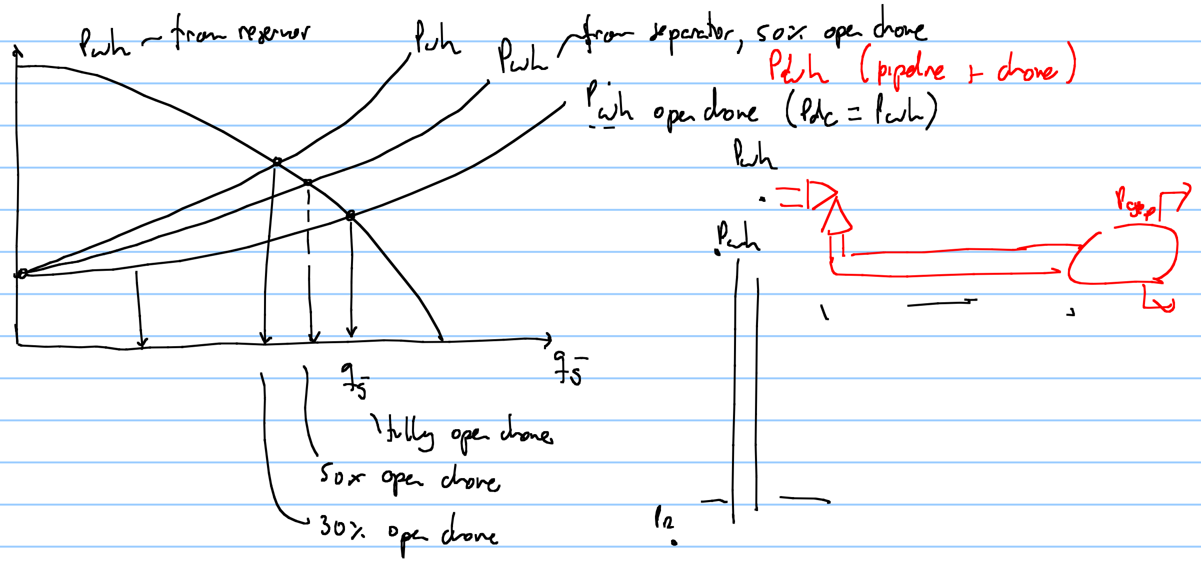
$$q_g = \left(p_{dc}^2 - p_{sep}^2\right)^{0.5} \cdot C_{PL}$$

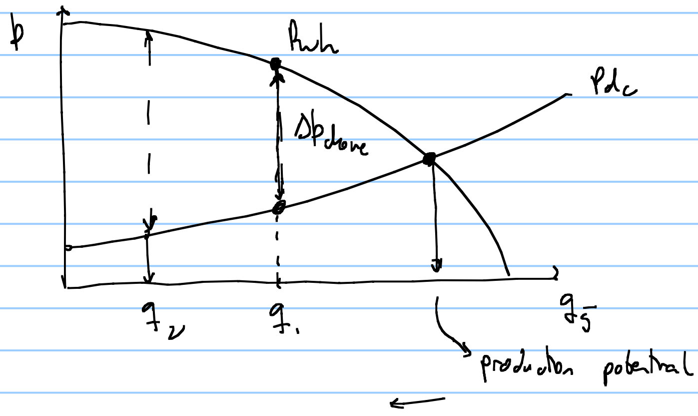
$$p_{dc} = \left(p_{sep}^2 + \left(\frac{q_g}{C_{PL}}\right)^2\right)^{0.5}$$

substitute (2) in (1)

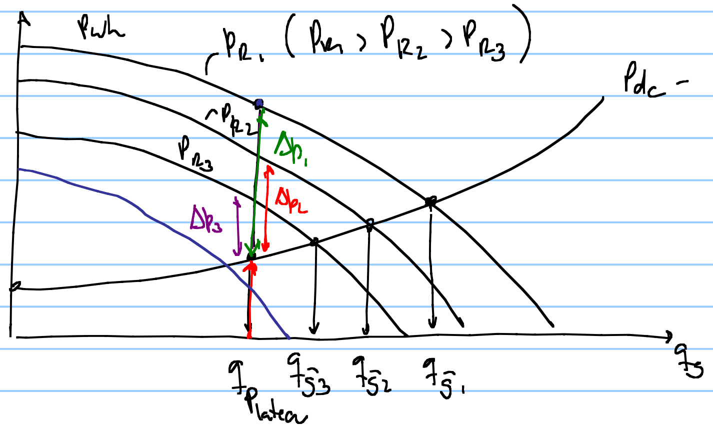
$$q_g = C\left(p_R^2 - e^s\left(p_{wh}^2 + \left(\frac{q_g}{C_T}\right)^2\right)\right)$$

if $q_g = 0$ $p_{wh}^2 = \frac{p_R^2}{e^s}$





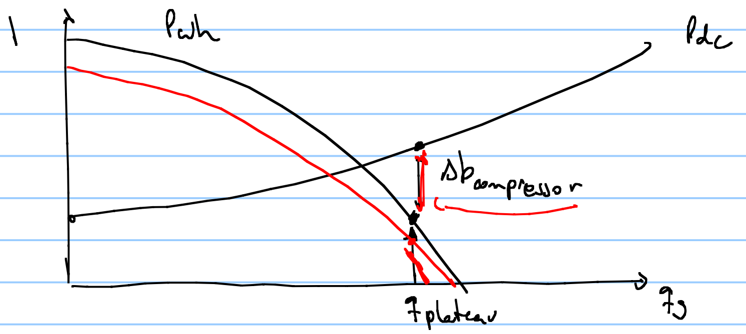
what happens with time?

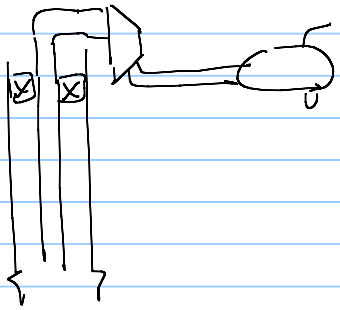


t_1 , P_{R_1} , Δp_1

t_2 , G_{P_2} , P_{R_2} , Δp_2

t_3 , G_{P_3} , P_{R_3} , Δp_3

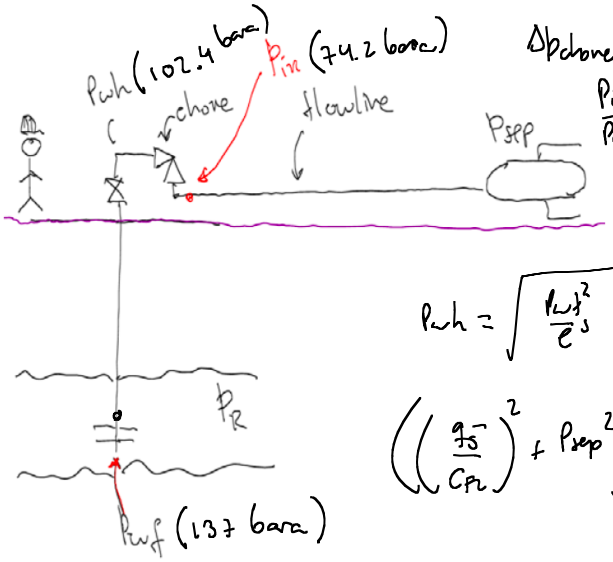




find a compressor q_g plateau, $\Delta p_{compressor}$.

Class exercise

1. For the dry gas production system shown in the figure below, what is the choke pressure drop required (in bar) for the system to deliver a rate of 2.5 E6 Sm³/d.



$\Delta p_{choke} = 28.14$ bar

$\frac{P_{in}}{P_{wh}} = 0.72$

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

$\left(\left(\frac{q_g}{C_{FL}}\right)^2 + P_{sep}^2\right)^{0.5} = P_{in}$

Inflow equation:

$q_{\bar{g}} = C_R \cdot \left(p_R^2 - p_{wf}^2\right)^n$

With

C_R = 104 Sm³/d/bar^2n

n= 0.9

p_R = 304 bara

Tubing equation:

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

C_T = 4.41 E4 Sm³/d/bar

S = 0.31

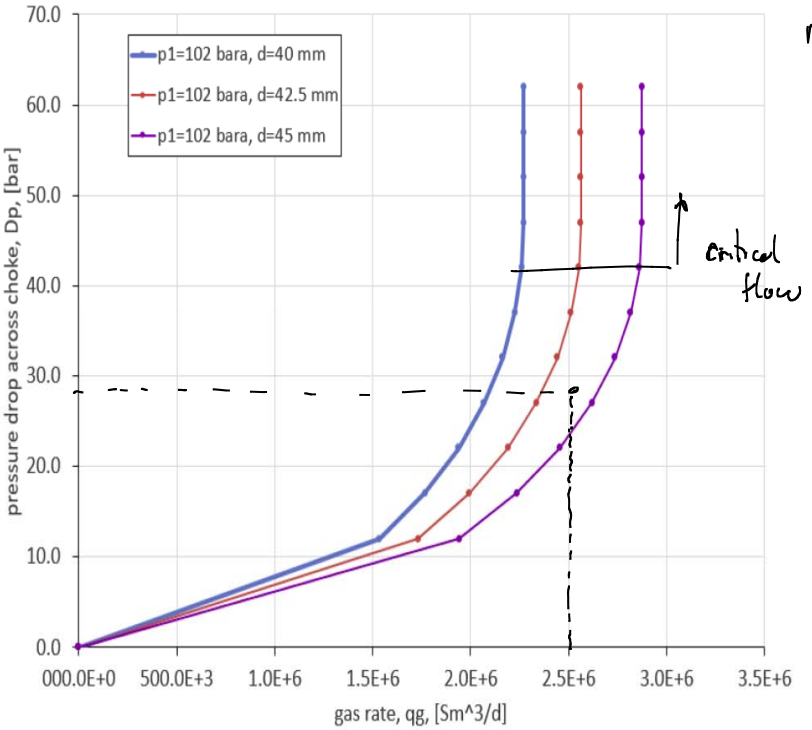
Flowline wellhead-separator:

$q_{\bar{g}} = C_{FL} \cdot \left(p_{in}^2 - p_{sep}^2\right)^{0.5}$

C_{FL} = 4E4 Sm³/d/bar

p_{sep} = 40 bara

2. Based on the choke performance maps shown below, what is (approximately) the required choke diameter (in mm) to provide the desired rate of 2.5 E6 Sm³/d. Use the wellhead pressure and choke pressure drop calculated in exercise 2. Will the choke operate in the critical or subcritical regime?



rule of thumb
critical flow occurs when

$\frac{P_{dc}}{P_{wh}} \leq 0.5 - 0.6$

$\Delta p_{critical} = P_{wh} - P_{dc}$

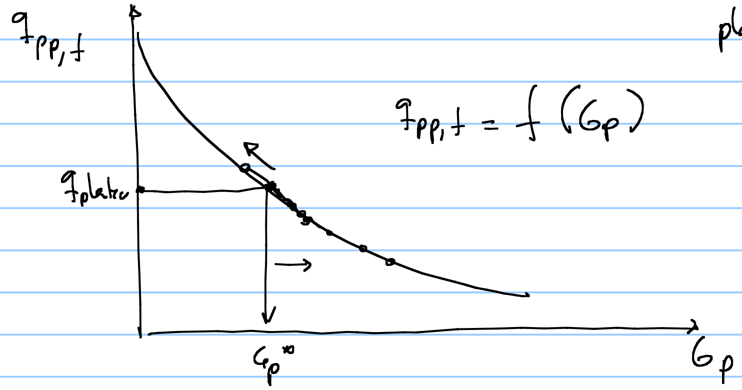
$P_{wh} - 0.6 \cdot P_{wh}$

$0.4\ P_{wh}$

$\Delta p = 0.4 \cdot 102$
$= 40.8$ bara

for open choke $q_g = 2.67$ E6 Sm³/d

production potential of field



$q_{pp,f} = f(G_p)$

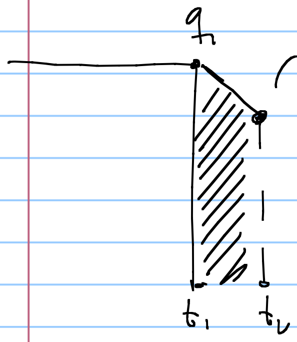
plateau period is over when $q_{plateau} = q_{pp,f}$

for $t > t_p$, produce at potential

$t < t_p$, produce at plateau

how can this curve be used for predicting post plateau profile?

$q_{field} = q_{pp,f}$



$q_2 = q_{pp,f}$

$$(\overset{?}{G_{p_2}} - \overset{\checkmark}{G_{p_1}}) = (\overset{\checkmark}{t_2} - \overset{\checkmark}{t_1})(\overset{\checkmark}{q_1} + \overset{?}{q_2}) \cdot 0.5$$

assume q_2 ($< q_1$)

compute G_{p_2}

calculate $q_{pp,f}$ with G_{p_2}

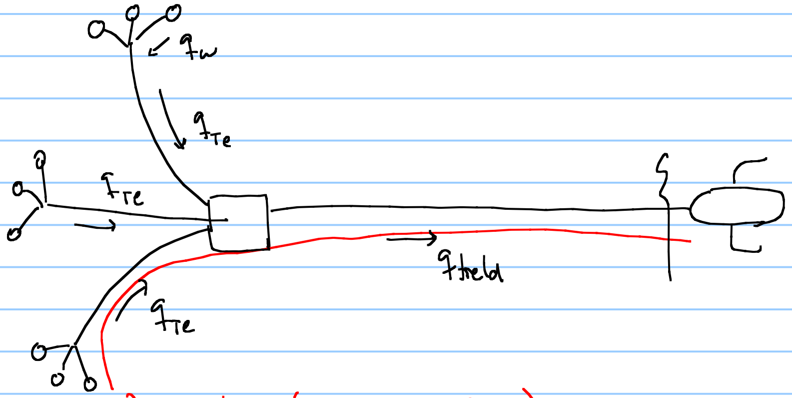
check if $q_{pp,f} = q_2$?

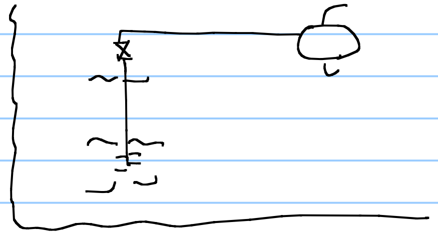
no

yes

solution

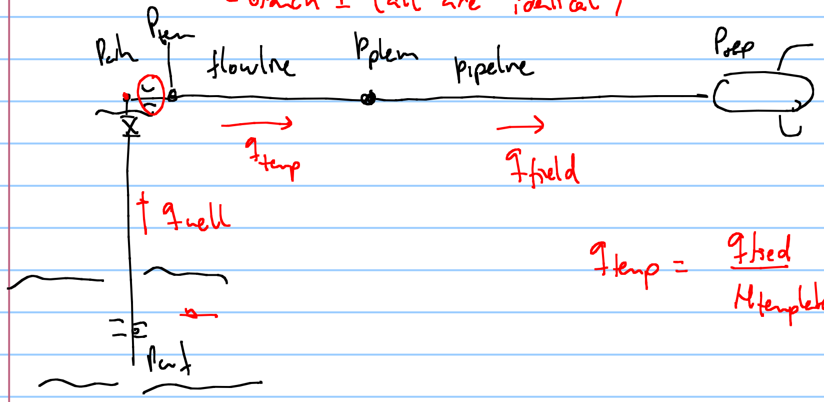
Plan :
- comments on exercise set 2.
- Review of last lecture topics
- Reservoir – Production simulators integration
- Asset / field value chain model
- NPV calculations





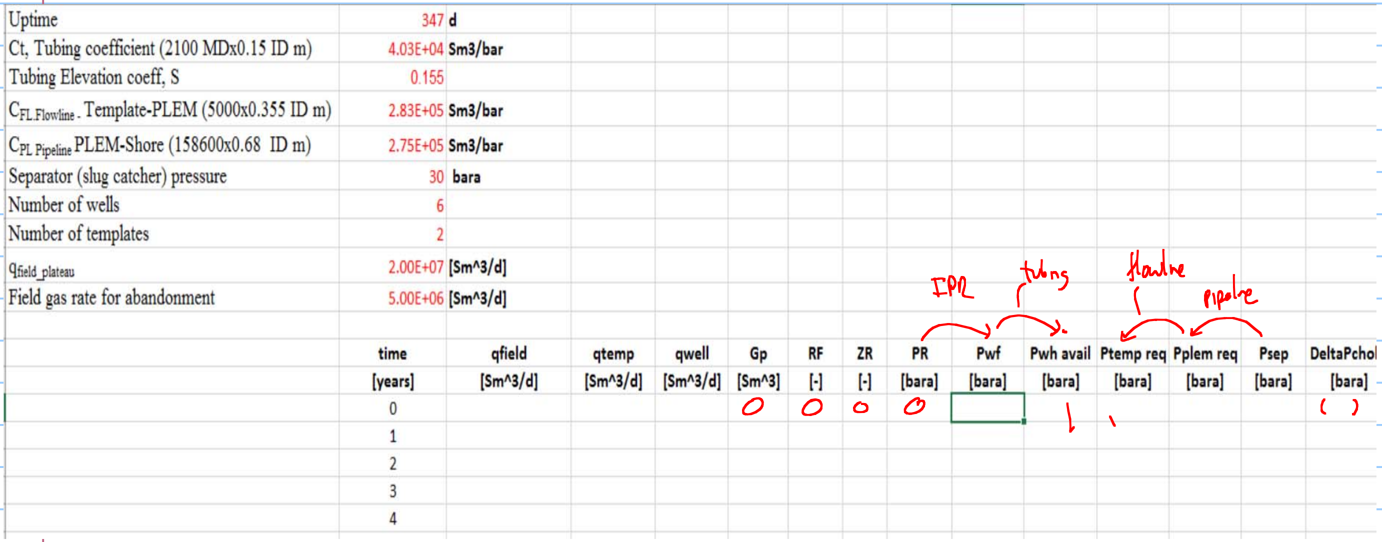
Graph 1 (all are identical)

commingling / gathering network
- all wells are identical
- all templates are symmetrically position with respect to plem
- same nrs. wells on each template



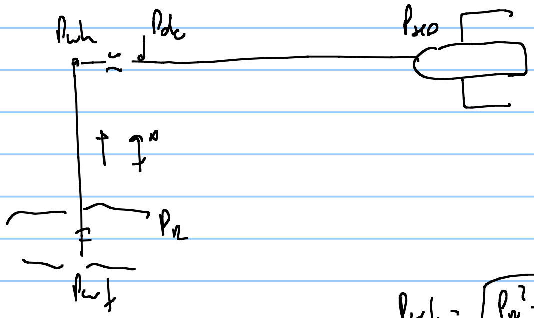
$$q_{temp} = \frac{q_{field}}{N_{templates}}$$

$$q_w = \frac{q_{field}}{N_{wells}}$$



Uptime	347	d
Ct, Tubing coefficient (2100 MDx0.15 ID m)	4.03E+04	Sm3/bar
Tubing Elevation coeff, S	0.155	
$C_{FL\ Flowline}$ - Template-PLEM (5000x0.355 ID m)	2.83E+05	Sm3/bar
$C_{PL\ Pipeline}$ PLEM-Shore (158600x0.68 ID m)	2.75E+05	Sm3/bar
Separator (slug catcher) pressure	30	bara
Number of wells	6	
Number of templates	2	
$q_{field\_plateau}$	2.00E+07	[Sm^3/d]
Field gas rate for abandonment	5.00E+06	[Sm^3/d]

time	qfield	qtemp	qwell	Gp	RF	ZR	PR	Pwf	Pwh avail	Ptemp req	Pplem req	Psep	DeltaPchol
[years]	[Sm^3/d]	[Sm^3/d]	[Sm^3/d]	[Sm^3]	[-]	[-]	[bara]	[bara]	[bara]	[bara]	[bara]	[bara]	[bara]
0				0	0	0	0						( )
1													
2													
3													
4													



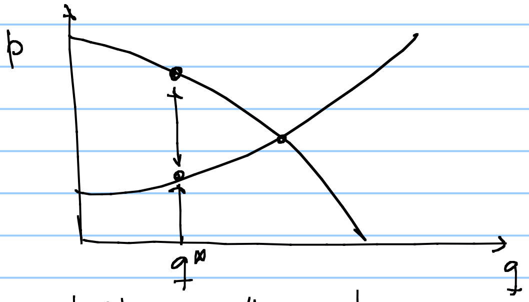
$$P_{wf} = \sqrt{P_R^2 - \left(\frac{q}{C}\right)^2}$$

Two modeling options

1: Remove controllable element

compute available pressure upstream

compute required pressure downstream



if $\Delta p > 0$ then rate is feasible

if $\Delta p < 0$ then rate is not feasible

- Include choke model (adjustable equipment)

- $q_{target} = q^*$

1: Assume choke opening (A_2)

2: Solve system of equations (iterative process) network solving

3: Result q_1

4: Compare

is $q_1 = q^*$ not

yes

A_2 is solution, rate is feasible

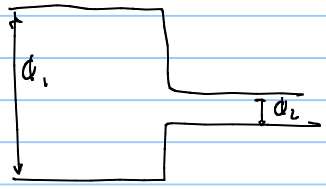
- $q_g = C\left(P_R^2 - P_{wf}^2\right)^n$

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

$$q_g = C_d A_2 p_1 \left(\frac{P_{sc}}{T_{sc}}\right)\sqrt{\frac{2R}{z_1 T_1 M_w}\,\frac{k}{k-1}\left(\left(\frac{P_{dc}}{P_{wh}}\right)^{2/k} - \left(\frac{P_{dc}}{P_{wh}}\right)^{\frac{k+1}{k}}\right)}$$

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

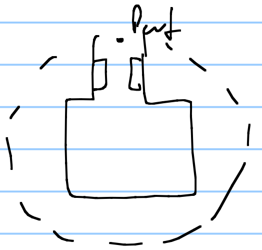
$$A_2 = \pi \frac{d_2^2}{4}$$

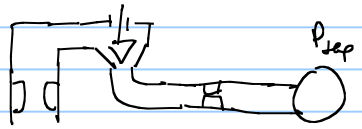


1-4 is also an iterative process often called "optimization"

if $A_2 \rightarrow A_{2max}$ without meeting the target rate, then the rate is not feasible

So far we have reservoir simulator and production simulator in the same "platform" software, tool





in industry

typically developed, updated and run by reservoir simulation department

- ECLIPSE
- MBAL
- SENSOR
- Intersect
- OPM
- MRST
- CMG

} commercial tools

typically developed, updated and run by production simulation department

- GAP/PROSPER
- Pipesim
- OLGA
- LEDA flow
- Reo
- pipeflow

} commercial tools

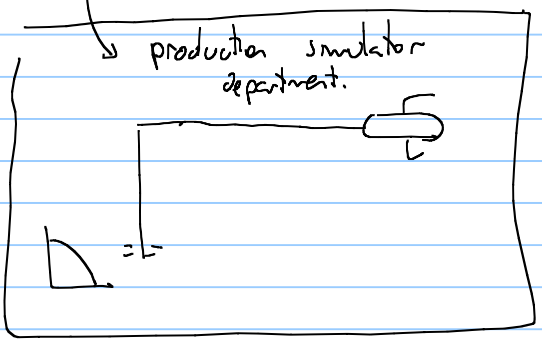
typical industrial workflow to get production profiles:

Reservoir simulator department

- increase RF
- well placement
- pressure maintenance strategy
- enhanced oil recovery
- assume $P_{wf,min}$

results →

time	p_R	q_w	GOR	WC



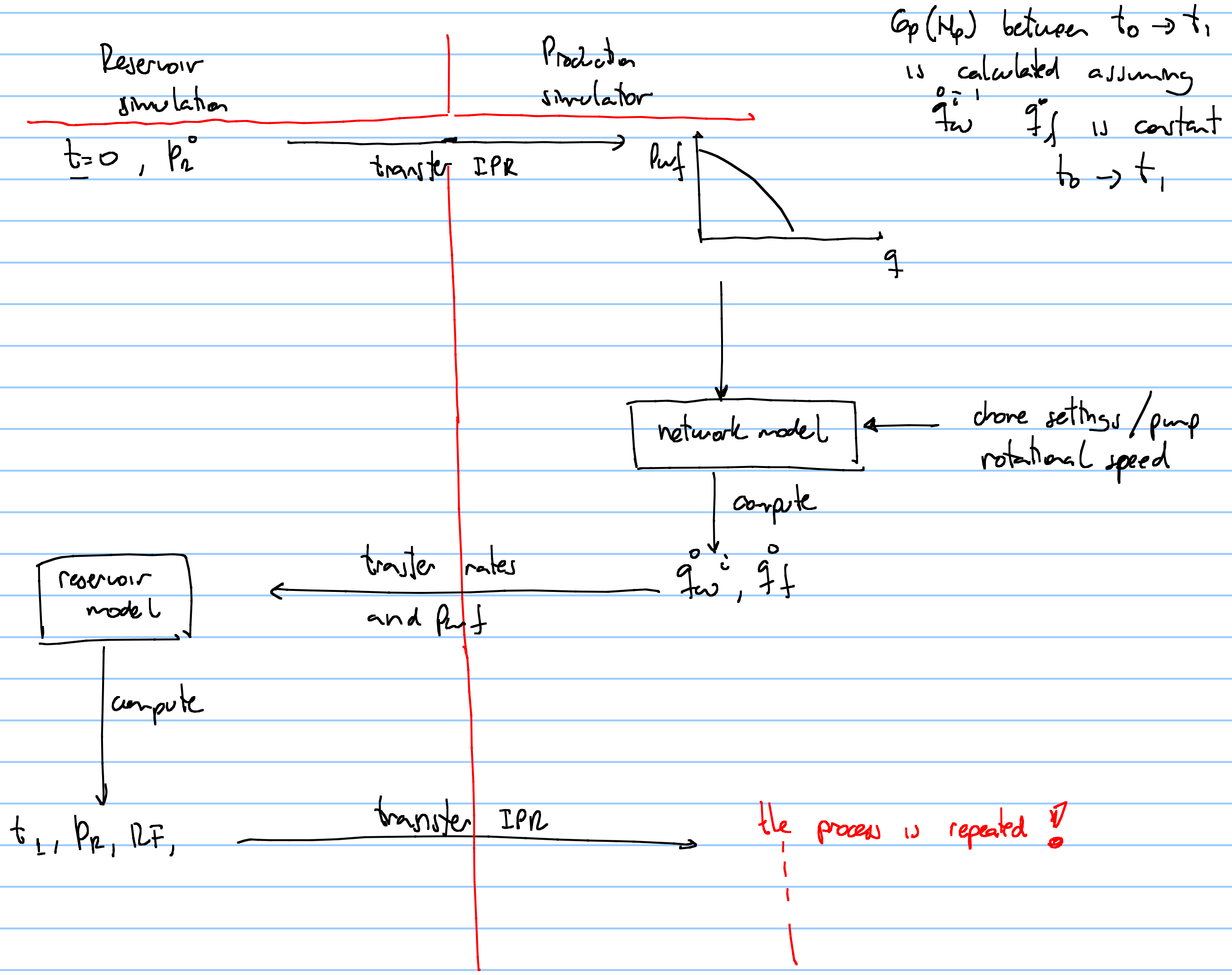
↓ results

rate feasibility

time	q_w	GOR	wc	feasibility (yes, no)	Action.
t_1					↑q, ↓q
t_2					
t_3					

feedback

Coupling reservoir and production simulators. Example of an explicit strategy

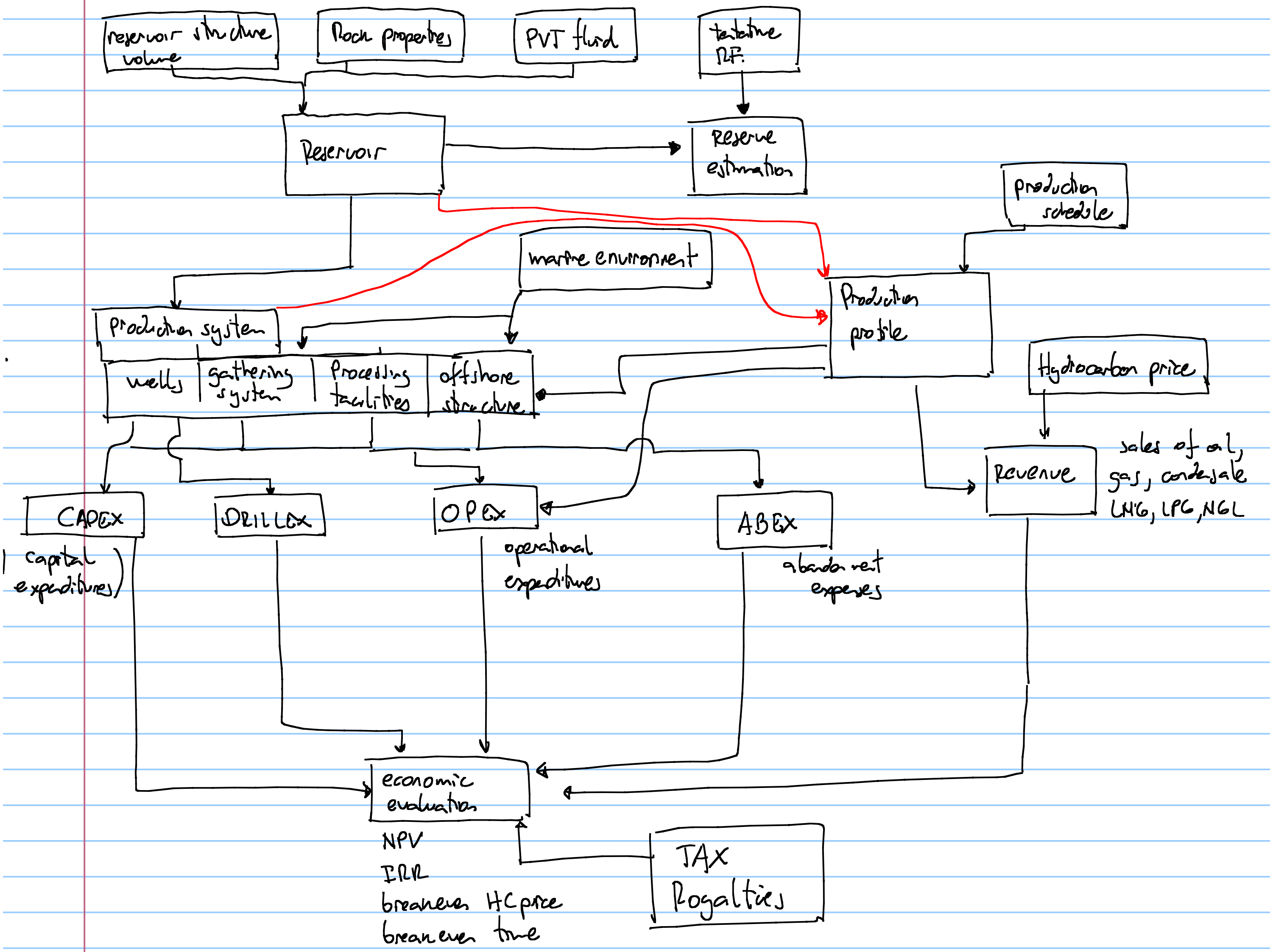


for an implicit coupling, the reservoir simulation step must be re-run.

typically explicit coupling with small Δt, is equivalent to implicit coupling

Commercial software to couple reservoir + production models → IAM Avocet (schlumberger)
(integrated asset modeling)
→ Resolve.
→ Pipe-it

to take decisions about field development, the company establishes value chain model of asset



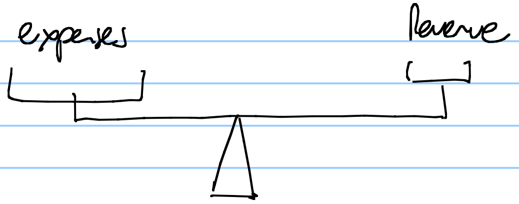
CAPEX:
- engineering studies (salaries, consultants, contractors)
- processing facilities (separators, pumps, compressors, water injection, gas injection, water/oil/gas treatment)
- offshore structure (cost of platform, FPSO, TLP, GBS → gravity based structure)
  living quarters
  auxiliary equipment (power system)
- subsea system (template, X-mas tree, flowline, pipelines, metering, risers umbilical, control system
- export system

design
manufacturing
installation

DRILLEX :
- drilling rate of drilling vessel
- materials → well completion
- well head
- test while drilling (DST, logging, pressure test, sampling)
- drilling tools

OPEX :
- salaries of workers
- insurance
- maintenance
- equipment
- well intervention
- Power
- Production chemical { hydrate inhibitor, demulsifier, wax inhibitor, corrosion inhibitor
- pigging
- transportation and export

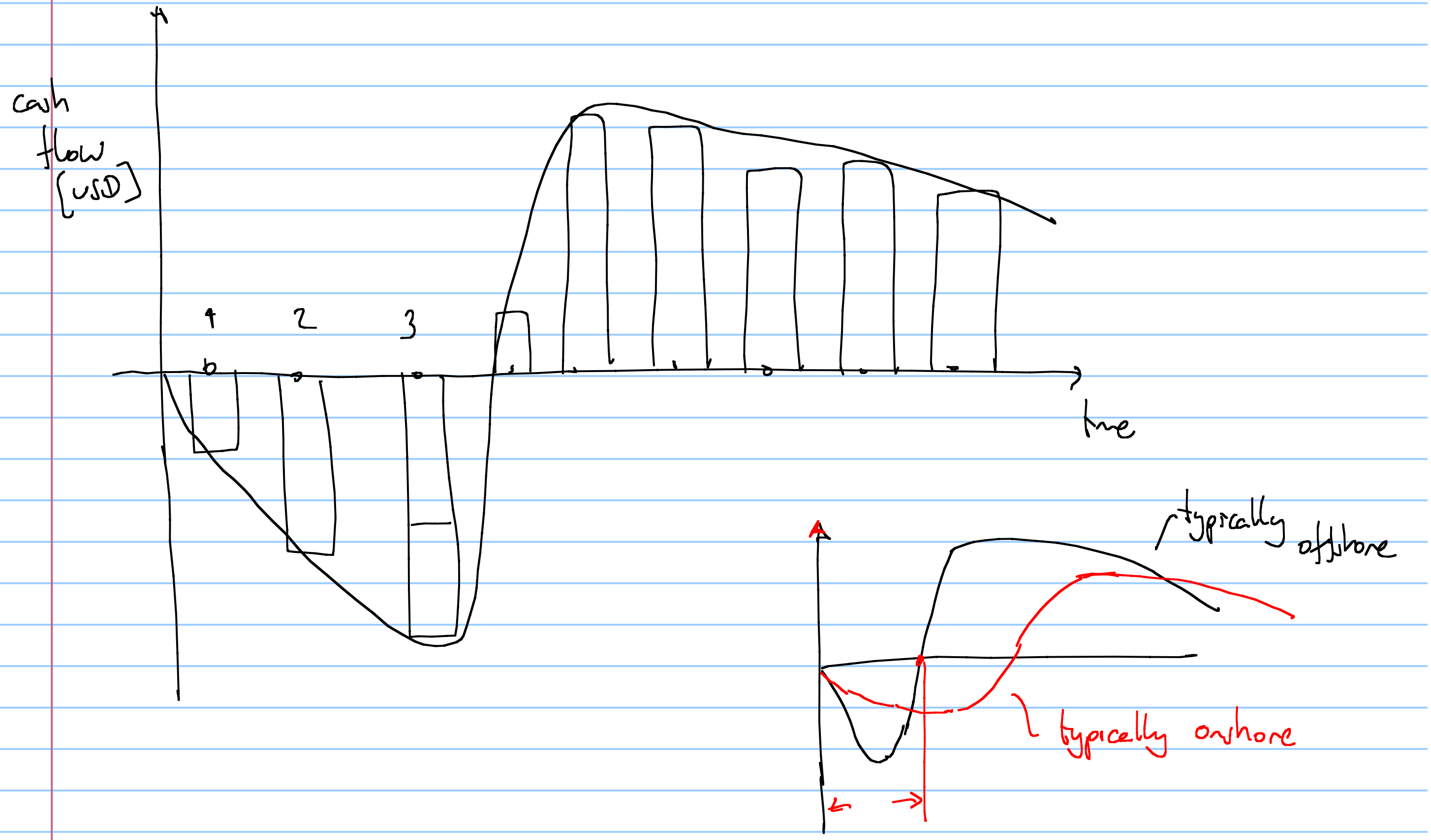
ABEX :
- well plugging
- removal of facilities, structure, pipeline
- cleaning



Cash flow calculations

Year	Gas/oil volumes	Revenue	CAPEX	OPEX	DRILLEX	Cash flow.	Cummulative CF	DCF
1	0	0	—	0	—	Revenue -	→ ☐	
2	0	0	—	0	—	expenses	→ ☐+☐	
3	0	0	—	0	—			
4	0	0	—	0	— — —			
,	—	—	0	—	—			
,	—	—	0	—	0			
,		—	0	—	0			
,	—	—	0	—	0			
,		—	0	—	0			

NPV = ΣDCF



Discounted cash flow

$$PV = \boxed{FV}\,\frac{1}{(1+\underset{\uparrow}{i})^{t}}$$

t ~ year counter

i ↳ discount rate (6 - 15 %)

$$DCF = CF \cdot \frac{1}{(1+i)^{t}}$$

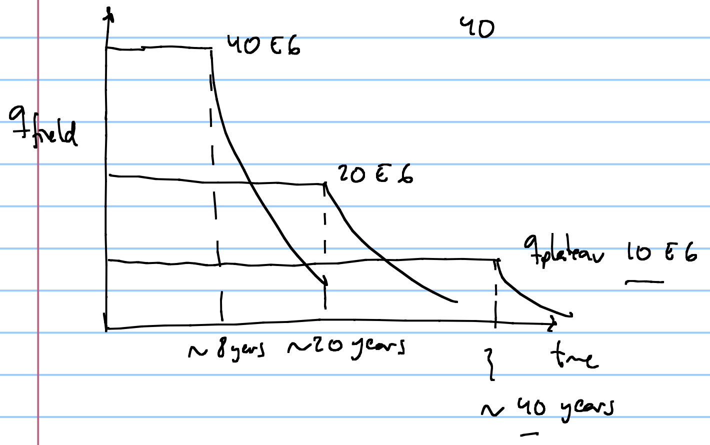
$$NPV = \sum_{t=1}^{N_{years}} \frac{CF_t}{(1+i)^{t}}$$

Menu :
- Quick go-through exercise set "1"
- Networks (surface and downhole)

Exercise set 1

$q_{plateau}$ field $[10^6\ Sm^3/d]$	N_{well}
10	4
20	6
30	9
40	12

16 cases/combinations to run



- 15 - 25 years gas contract
- rule of thumb for plateau rate for gas field

(2.5 - 5%) Gpu

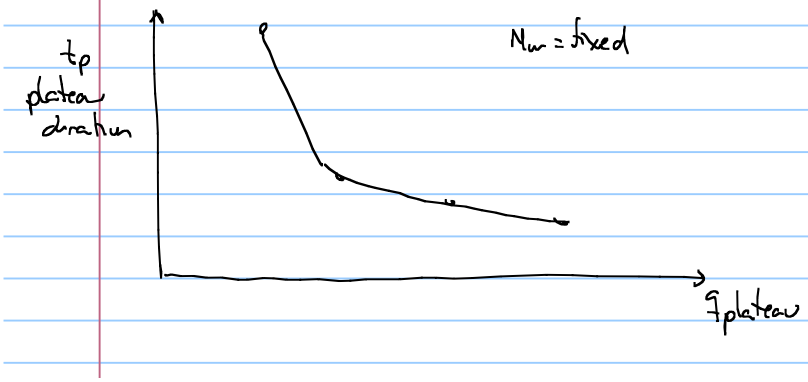
G = 270 E9 Sm³

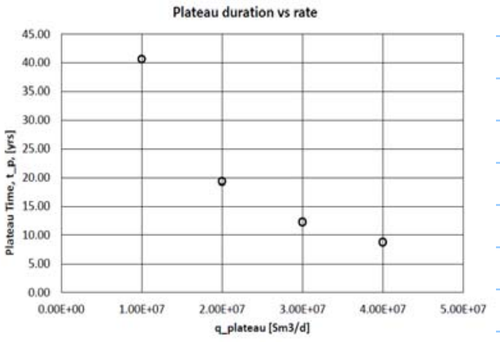
RF = 0.5

Gpu = 135 E9 Sm³

$$q_{plateau_{2.5\%}} = \frac{135\ E9 \cdot 0.025}{365 \cdot 0.95} = 10\ E6\ Sm^3/d$$

$$q_{plateau_{5\%}} = 20\ E6\ Sm^3/d$$





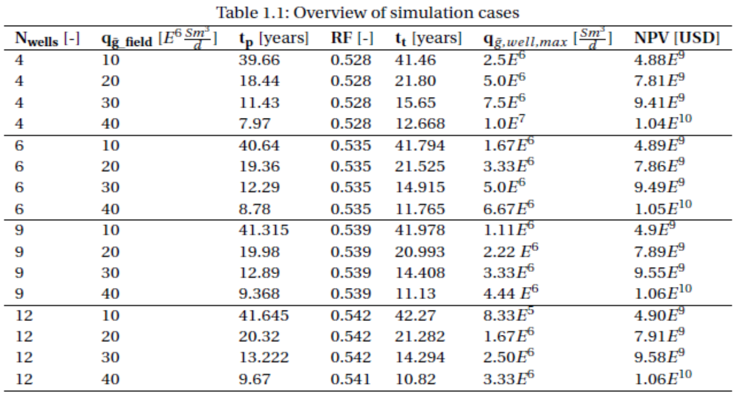
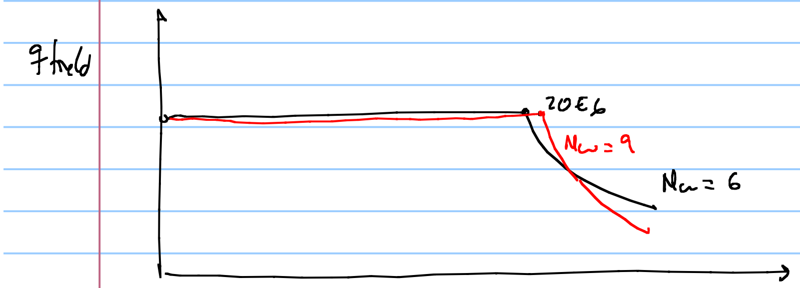
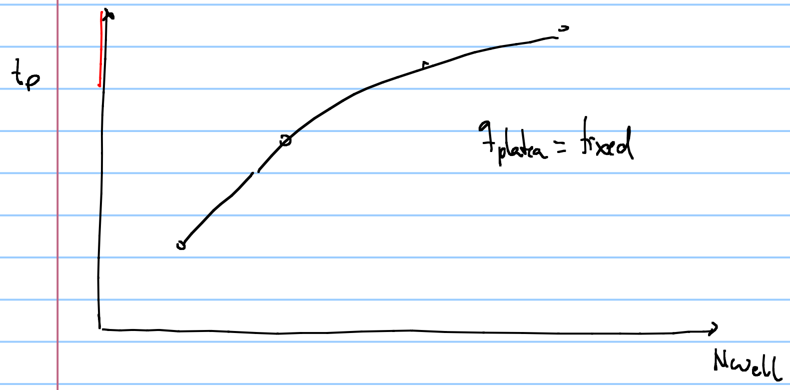
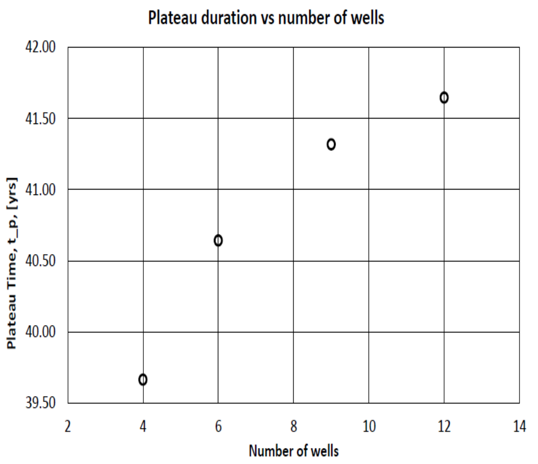


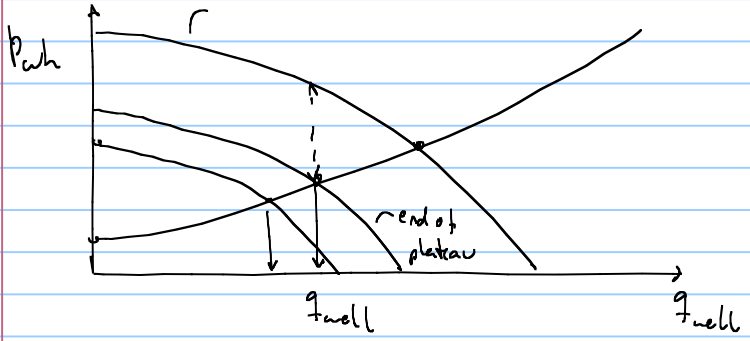
Table 1.1: Overview of simulation cases

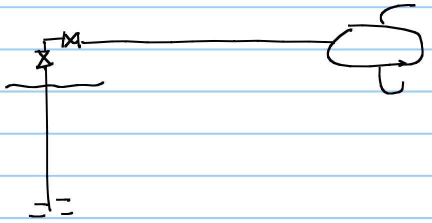
N_{wells} [-]	$q_{\bar{g}\_field}$ $[E^6 \frac{Sm^3}{d}]$	t_p [years]	RF [-]	t_t [years]	$q_{\bar{g},well,max}$ $[\frac{Sm^3}{d}]$	NPV [USD]
4	10	39.66	0.528	41.46	$2.5E^6$	$4.88E^9$
4	20	18.44	0.528	21.80	$5.0E^6$	$7.81E^9$
4	30	11.43	0.528	15.65	$7.5E^6$	$9.41E^9$
4	40	7.97	0.528	12.668	$1.0E^7$	$1.04E^{10}$
6	10	40.64	0.535	41.794	$1.67E^6$	$4.89E^9$
6	20	19.36	0.535	21.525	$3.33E^6$	$7.86E^9$
6	30	12.29	0.535	14.915	$5.0E^6$	$9.49E^9$
6	40	8.78	0.535	11.765	$6.67E^6$	$1.05E^{10}$
9	10	41.315	0.539	41.978	$1.11E^6$	$4.9E^9$
9	20	19.98	0.539	20.993	$2.22\ E^6$	$7.89E^9$
9	30	12.89	0.539	14.408	$3.33E^6$	$9.55E^9$
9	40	9.368	0.539	11.13	$4.44\ E^6$	$1.06E^{10}$
12	10	41.645	0.542	42.27	$8.33E^5$	$4.90E^9$
12	20	20.32	0.542	21.282	$1.67E^6$	$7.91E^9$
12	30	13.222	0.542	14.294	$2.50E^6$	$9.58E^9$
12	40	9.67	0.541	10.82	$3.33E^6$	$1.06E^{10}$

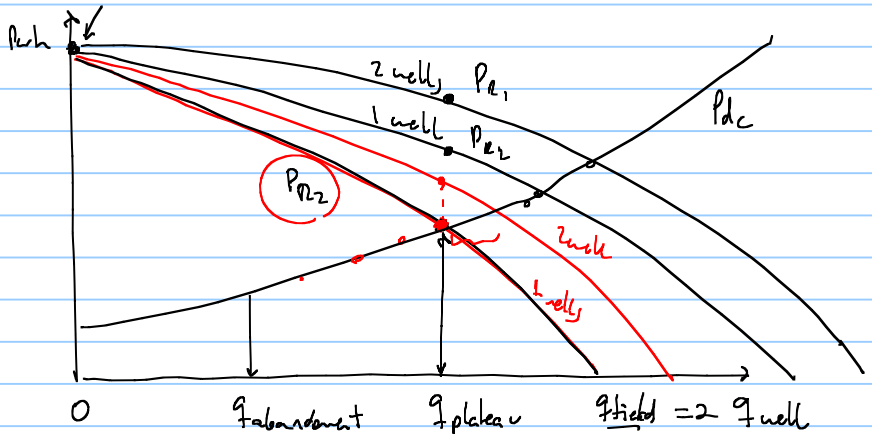


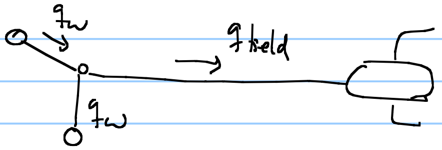










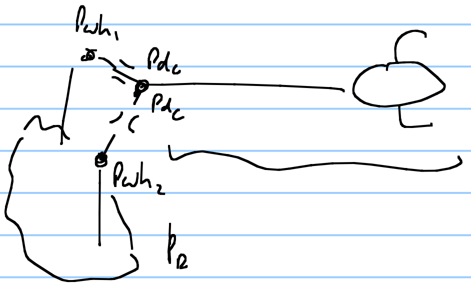


$$q_w = \frac{q_{field}}{2}$$

$$q_{field} = \text{const}$$

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

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



$$P_{wf} = \left(p_R^2 - \frac{q_{\bar{g}}}{C}^{1/n}\right)^{0.5}$$

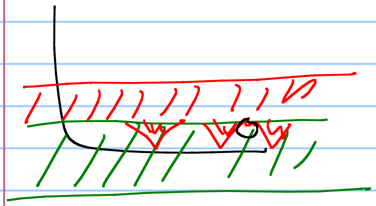
$$P_{wh} = \left[\left[\underset{\sim}{p_R^2} - \left(\frac{q_{\bar{g}}}{\underline{C}}\right)^{1/n}\right]\frac{1}{e^s} - \left(\frac{q_{\bar{g}}}{\underline{C_T}}\right)^2\right]^{0.5}$$

if 1 well $q_{\bar{g}} = q_{field}$ P_{wh_1}

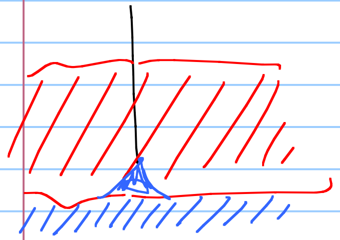
if 2 well $q_{\bar{g}} = \frac{q_{field}}{2}$ P_{wh_2}

$\rightarrow$ $P_{wh_1} < P_{wh_2}$

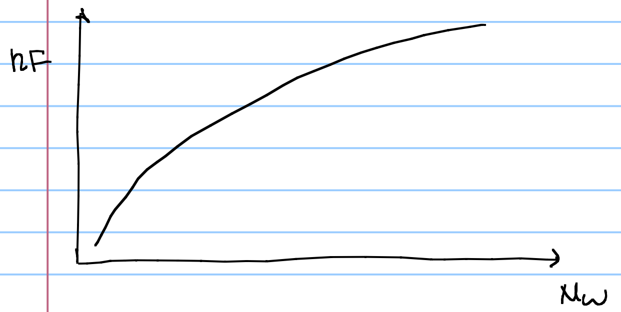
Nw is fixed, RF vs $q_{plateau}$? No change. for a fixed number of wells $q_{field} = 5\ E6\ Sm^3/d$ is reached at the same p_R^* and $\underline{p_R^*}$ for $\underline{MB}$ $f(\underline{G_p})$

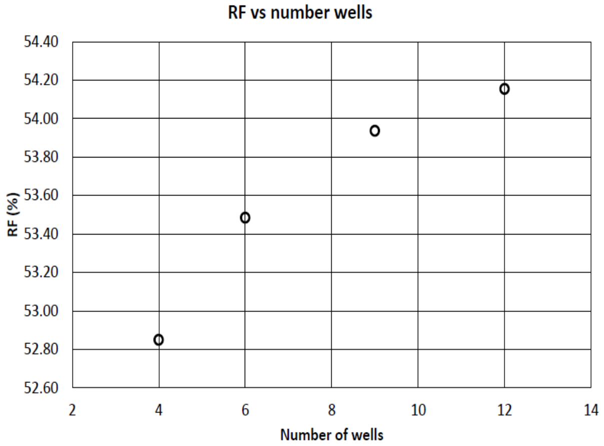


- gas coning
- reduced productivity
- water/aquifer breakthrough

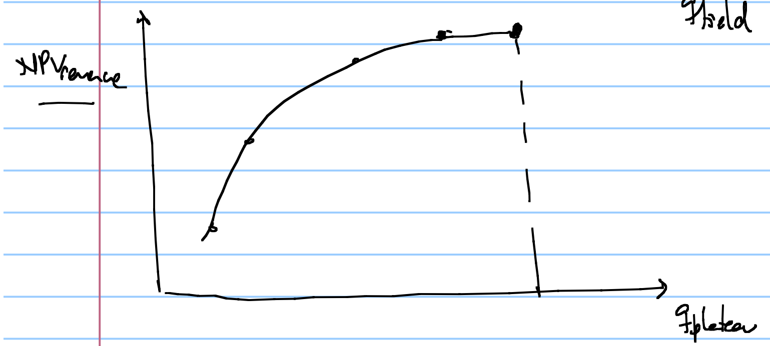


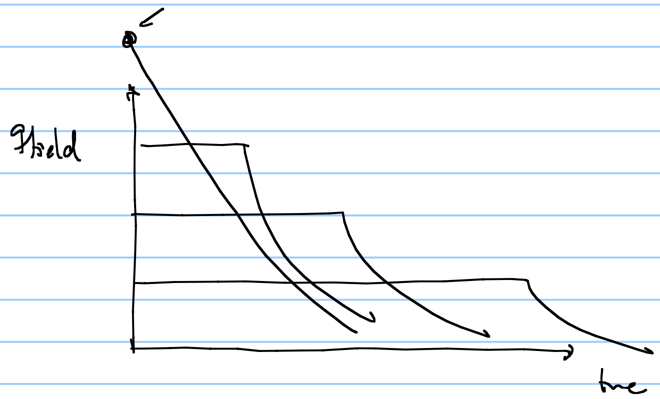
RF vs. Nw





NPV$_{revenue}$ vs. plateau rate





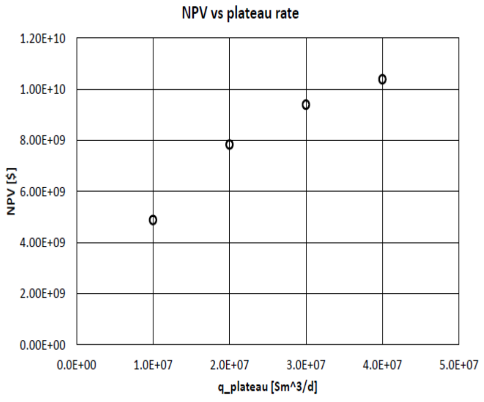


Figure 1: Economic evaluation as a function of plateau flow rates with 1E7 Sm3/d plateau rate

Table 1.1: Overview of simulation cases

N_{wells} [-]	$q_{\bar{g}\_field}$ $[E^6 \frac{Sm^3}{d}]$	t_p [years]	RF [-]	t_t [years]	$q_{\bar{g},well,max}$ $[\frac{Sm^3}{d}]$	NPV [USD]
4	10	39.66	0.528	41.46	$2.5E^6$	$4.88E^9$
4	20	18.44	0.528	21.80	$5.0E^6$	$7.81E^9$
4	30	11.43	0.528	15.65	$7.5E^6$	$9.41E^9$
4	40	7.97	0.528	12.668	$1.0E^7$	$1.04E^{10}$
6	10	40.64	0.535	41.794	$1.67E^6$	$4.89E^9$
6	20	19.36	0.535	21.525	$3.33E^6$	$7.86E^9$
6	30	12.29	0.535	14.915	$5.0E^6$	$9.49E^9$
6	40	8.78	0.535	11.765	$6.67E^6$	$1.05E^{10}$
9	10	41.315	0.539	41.978	$1.11E^6$	$4.9E^9$
9	20	19.98	0.539	20.993	$2.22\ E^6$	$7.89E^9$
9	30	12.89	0.539	14.408	$3.33E^6$	$9.55E^9$
9	40	9.368	0.539	11.13	$4.44\ E^6$	$1.06E^{10}$
12	10	41.645	0.542	42.27	$8.33E^5$	$4.90E^9$
12	20	20.32	0.542	21.282	$1.67E^6$	$7.91E^9$
12	30	13.222	0.542	14.294	$2.50E^6$	$9.58E^9$
12	40	9.67	0.541	10.82	$3.33E^6$	$1.06E^{10}$

NPVrevenue vs Nwells

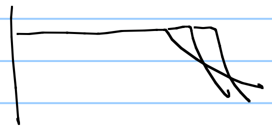
Nw	NPV [E9 USD]
4	7.81
6	7.86 -200 E6=0.2 E9 USD
9	7.89 -500 E6 = 0.5 E9 USD
12	7.91 -800 E6 = 0.8 E9 USD

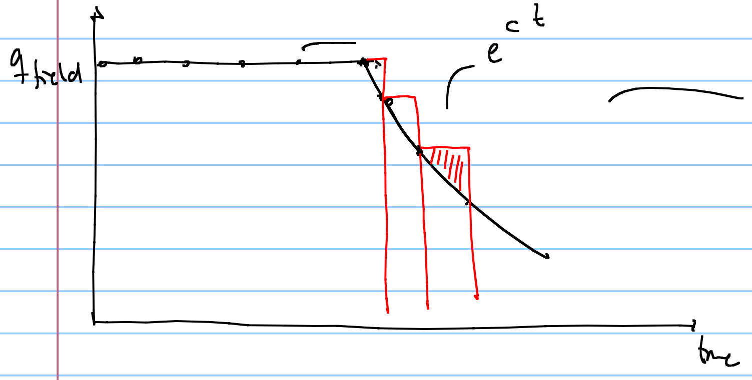
Cost per well ≈ 100 E6 USD

Nw	NPV [E9 USD] (considering drillex)
4	7.81
6	7.66
9	7.39
12	7.11

In this cases doesn't make sense to drill more wells to produce the same plateau!

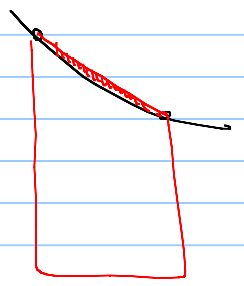
the additional and early production we get does not compensate for the cost!



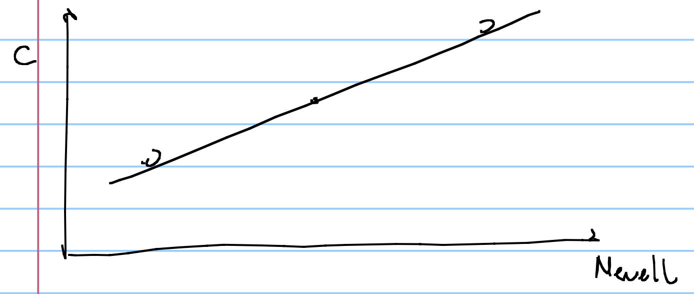


e^{ct}

— trapezoidal rule $\frac{q_{i-1} + q_i}{2} (t_i - t_{i-1})$



assume q_i ←
↓
Gp
↓
P_R not
↓
q_i^* same → solution



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

$$q_{field} = q_{plateau}$$

$$t_p = \left(\frac{q_{ppo}}{q_{plateau}} - 1\right)\frac{1}{m}$$

$$m = \overset{\downarrow}{N_w} \cdot A \cdot \overset{\downarrow}{J}$$

$$q_{pp} = -\underset{\sim}{m}\, G_p + \underbrace{q_{ppo}}_{\sim N_w}$$

$$A = f\left(\frac{1}{N}\right)$$

↑ initial oil in place

this development is NOT valid for dry gas.

for dry gas:

$$p_R = \frac{Z_R \cdot p_i}{Z_i} - \frac{Z_R \cdot p_i}{Z_i \cdot G} \cdot G_p$$

Neglecting downstream bottom-hole:

Maximum field production

$$q_f = N_w \cdot C \cdot (p_R - p_{wf,min})^n$$

$$\left(\frac{q_f}{N_w \cdot C}\right)^{\frac{1}{n}} + p_{wf,min} = p_R$$

Substituting in the material balance equation

$$\left(\frac{q_f}{N_w \cdot C}\right)^{\frac{1}{n}} + p_{wf,min} = \frac{Z_R \cdot p_i}{Z_i} - \frac{Z_R \cdot p_i}{Z_i \cdot G} \cdot G_p$$ ← solve this!

BUT surprisingly we find the decline is exponential and e^{ct} the coefficient depends on Nw

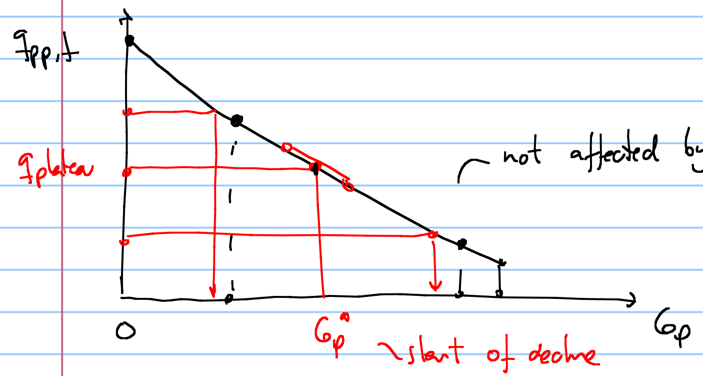
a big subsea dry gas well might produce 3E06 Sm³/d

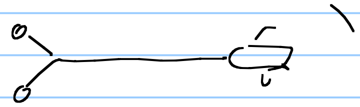
↳ coning

↳ Sand production / hole integrity

↳ erosion in tubing (tubing size) (9")

Using field production potential

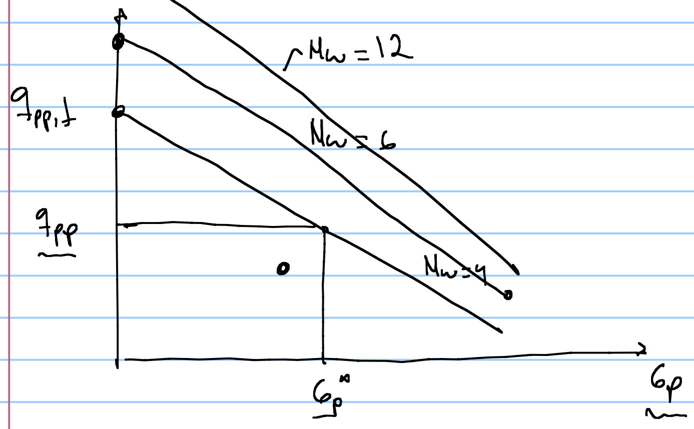


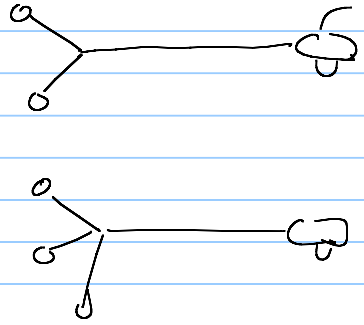


⌒ not affected by plateau rate (is the same production system)

$$t_p = \frac{G_p^*}{q_{plateau}\ \frac{N_{day}}{year}} =$$

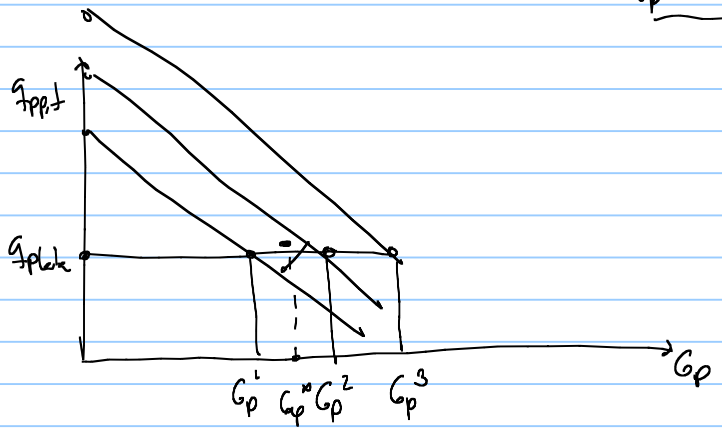
field production potential with N_w





Problem 2 of exercise set 2

$$\left. \begin{array}{l} q_{plateau} \\ t_p = 8 \text{ years} \end{array} \right\} G_p^*$$

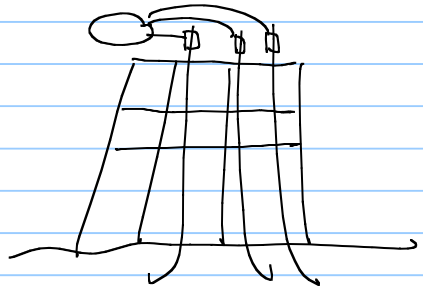


if $G_p^1 > G_p^*$

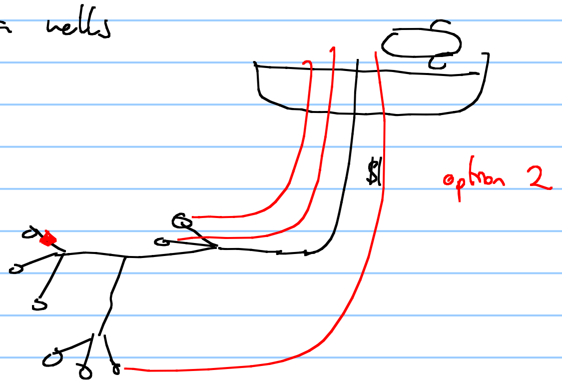
$q_{plateau} \cdot t_p > G_p^*$

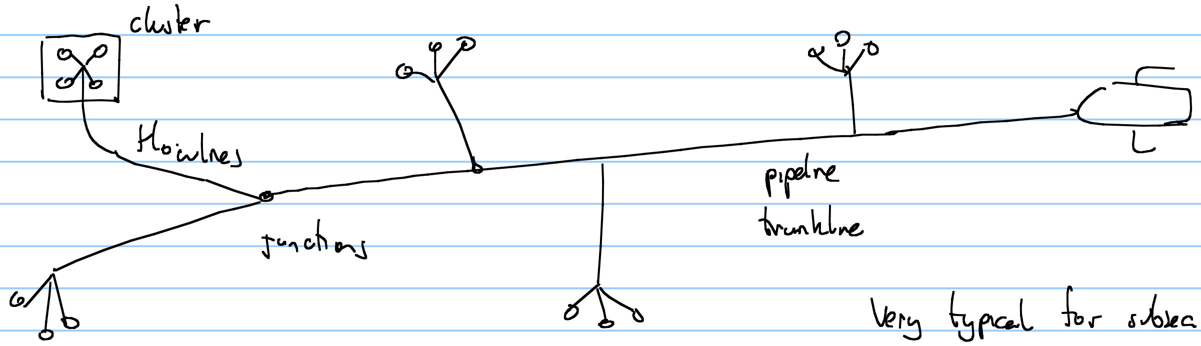
$> q_{plateau} \cdot t_p^{desired}$

Network   System of pipes that commingle, gather production from several well and take it to processing facilities

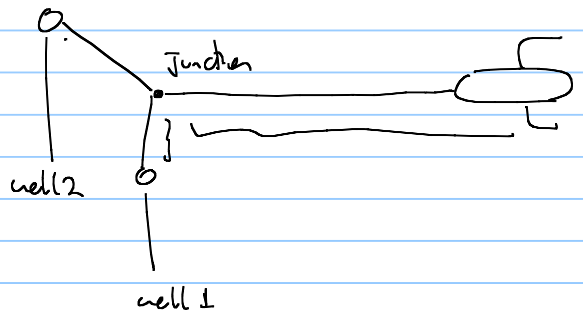


Subsea wells





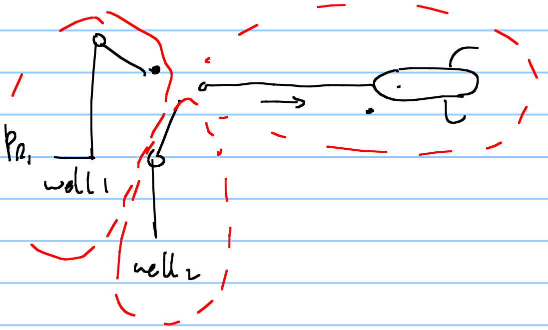
Very typical for subsea wells

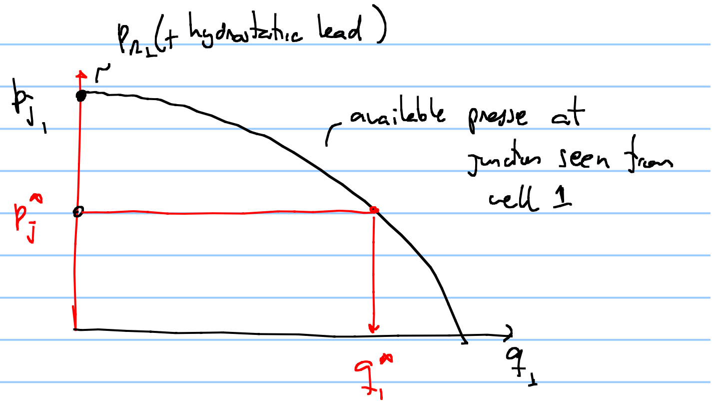


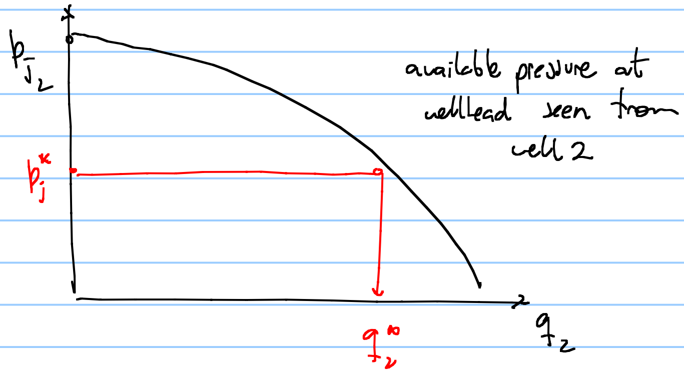
dry gas network.

X-mas trees of 1 and 2 are very close to junction

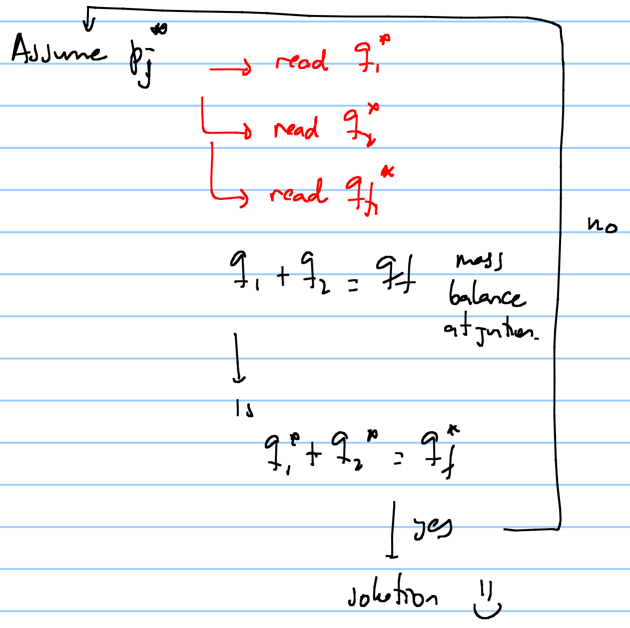
		Nr. Unknowns	Nr. equations
IPR 1	$q_1 = C_1 \left(P_{R_1}^2 - P_{wf_1}\right)^n$	2	1
TPR 1	$q_1 = C_{T_1} \left(\frac{P_{wf_1}^2}{e^{S_1}} - P_{wh_1}^2\right)^{0.5}$	1	1
IPR 2	$q_2 = C_2 \left(P_{R_2}^2 - P_{wf_2}^2\right)^n$	2	1
TPR 2	$q_2 = C_{T_2} \left(\frac{P_{wf_2}^2}{e^{S_2}} - P_{wh_2}^2\right)^{0.5}$	1	1
pipeline	$q_1 + q_2 = C_{PL} \left(\underline{P_J^2} - P_{sep}^2\right)^{0.5}$	1	1
proximity	$P_{wh_1} = P_J$		1
	$P_{wh_2} = P_J$		1
		7	7







if no choke $p_{j_1} = p_{j_2} = p_j$



Assume p_j^*

→ read q_1^*

→ read q_2^*

→ read q_t^*

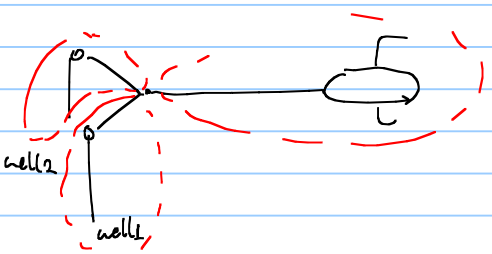
$q_1 + q_2 = q_t$ mass balance at junction

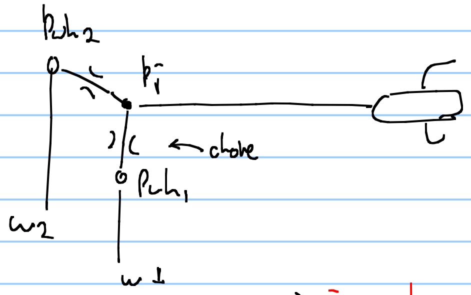
is $q_1^* + q_2^* = q_t^*$

yes → solution :)

no

- Networks
- Boosting → liquid pumping in well (ESP)





1st approach (more general, computationally expensive) → set q_1^*, q_2^*

FPR flowline performance relationship

Co: choke opening

Equations	Unknowns	equations
IPR_1		
IPR_2		
TPR_1		
TPR_2		
FPR		
→ $\Delta p_{\text{choke}_1} = f_1(q_1, Co_1)$		
$\Delta p_{\text{choke}_2} = f_2(q_2, Co_2)$		

you need two layer iterative process.

assume Co_1, Co_2 ←

↓

solve network

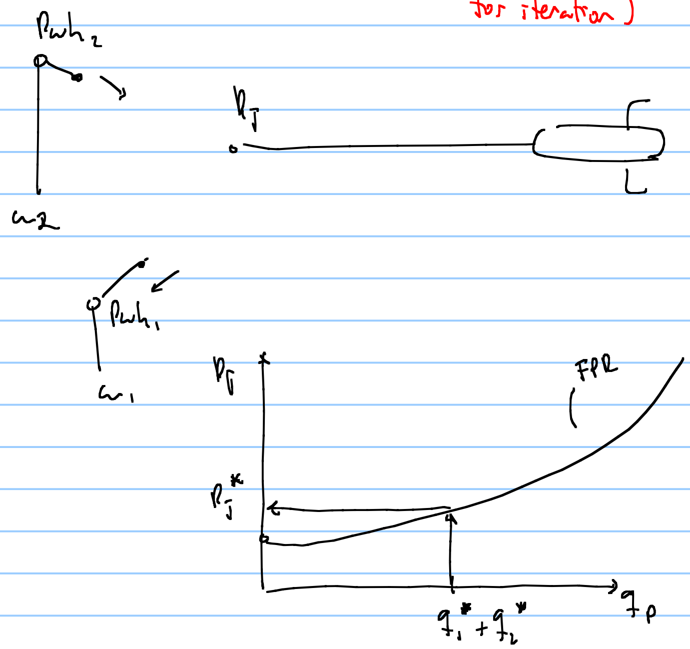
↓

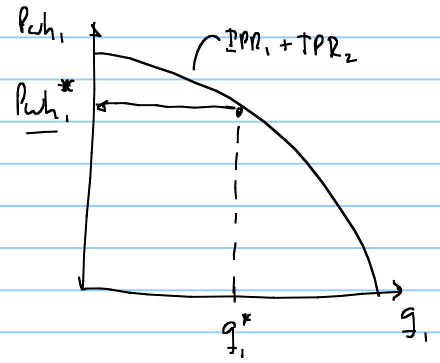
calculate q_1, q_2 — not

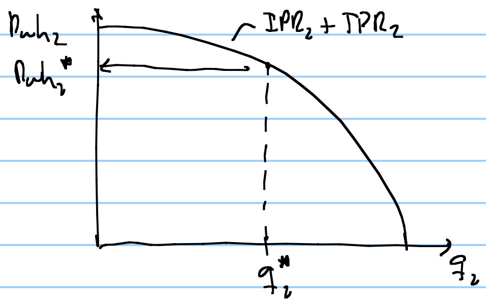
↓ same q_1^*, q_2^*

solution

2nd approach (smarter, no need for iteration)



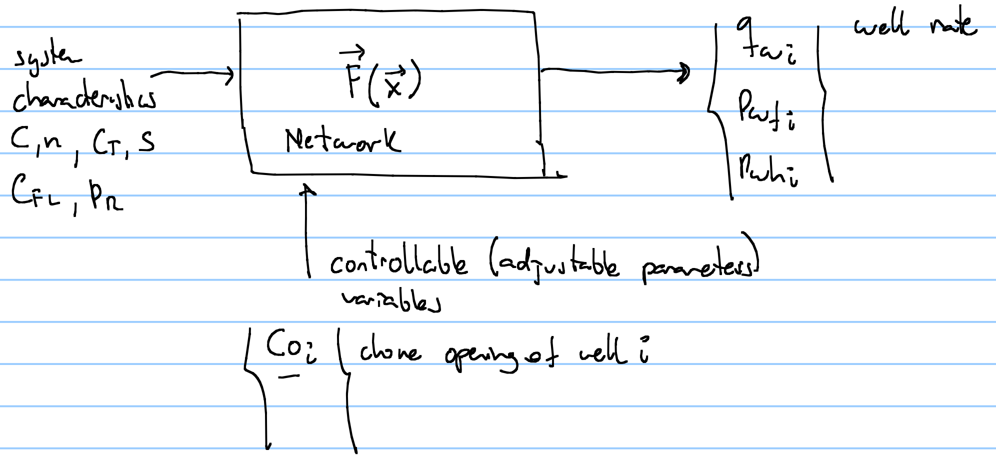




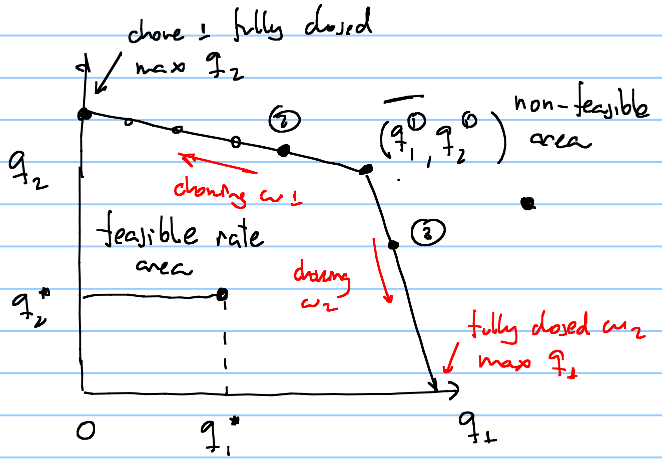
q_1^* is feasible only if $P_{wh_1}^* > P_J^*$

q_2^* is feasible ONLY if $P_{wh_2}^* > P_J^*$

for 1st approach, it is sometimes useful to visualize the network as a function



CO_i has an effect on the results. for our two well system:

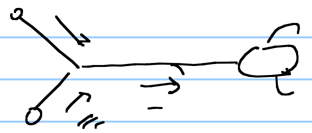


① $Co_1 = 100\%$ $Co_2 = 100\%$ (open)

$q_1^{①}$ $q_2^{①}$

② $Co_1 = 80\%$ $Co_2 = 100\%$

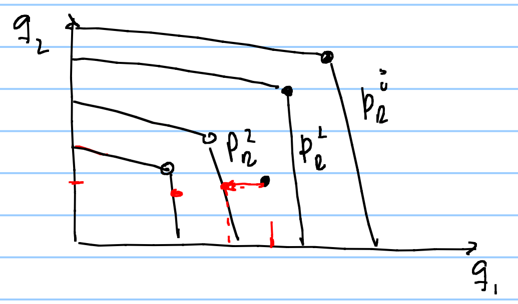
$q_2^{②}$ $\bar{q}_1^{②}$



③ $Co_1 = 100\%$ $Co_2 = 80\%$)

q_1 ↑ q_2 ↓

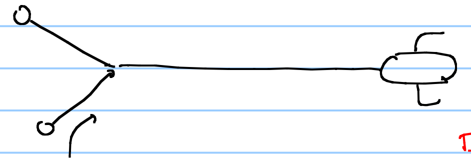
what happens with the when p_R ↓



initial reservoir pressure

$p_R^i > p_R^1 > p_R^2$

example of solution using excel



no chokes

☐ input ☐ calculated ▨ decision variable

	P_R	C	n	P_{wf}	q	C_T	S	P_j	C_{FL}	P_{sep}	Error
well 1	☐	☐	☐	▨	☐	☐	☐	▨			$(P_j - P_{av})^2$
well 2	☐	☐	☐	▨	☐	☐	☐	▨			$(P_j - P_{av})^2$
flowline					$q_1 + q_2$			▨	▨	▨	$(P_j - P_{av})^2$
							P_{av}	▨			$\Sigma(\quad)$

use this as the objective function

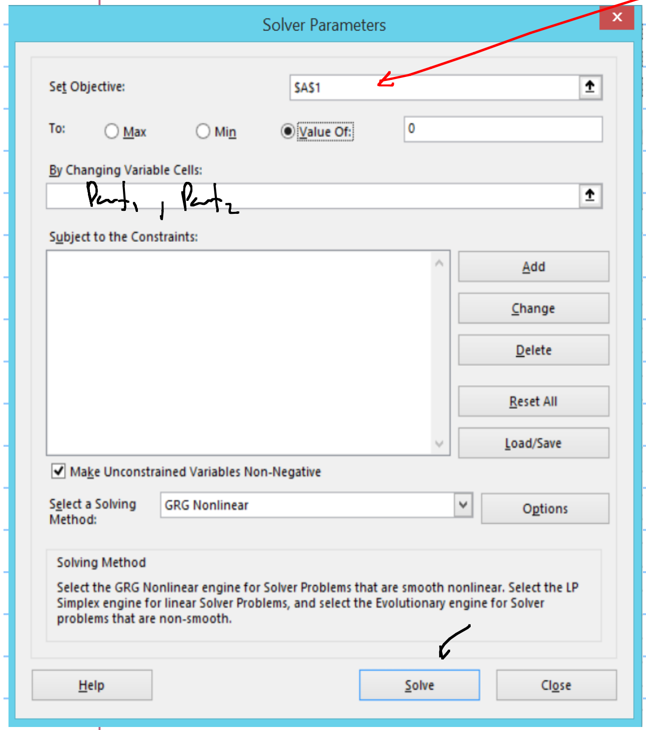
If iterating with q the following could happen

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

$$P_{wf} = \underline{\sqrt{P_R^2 - \left(\frac{q}{C}\right)^{1/n}}}$$

P_{wf} on the other hand, i know the bounds

$$P_{sep} \le P_{wf} \le P_R$$



Solver Parameters

Set Objective: A1

To: ○ Max ○ Min ● Value Of: 0

By Changing Variable Cells: P_{wf_1}, P_{wf_2}

Subject to the Constraints:

☑ Make Unconstrained Variables Non-Negative

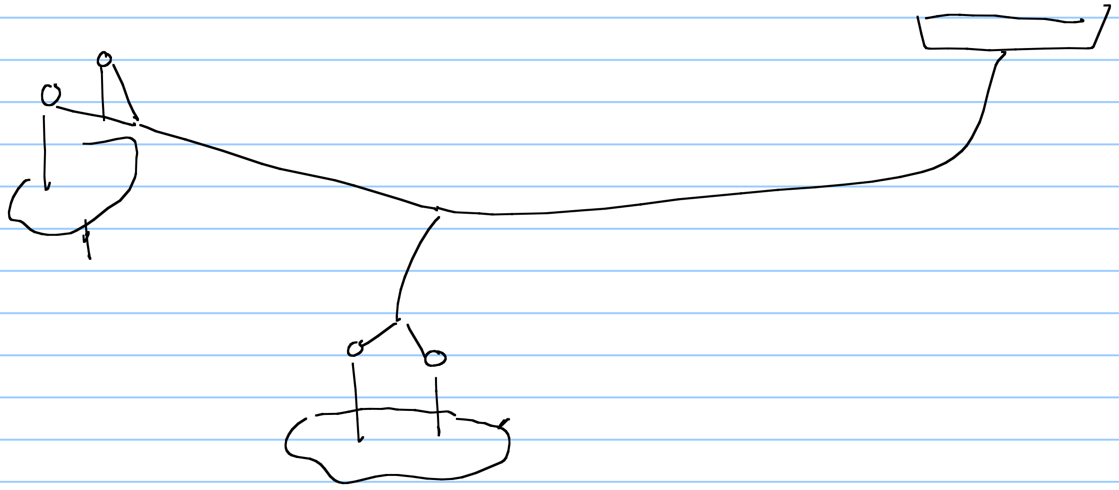
Select a Solving Method: GRG Nonlinear

Solving Method

Select the GRG Nonlinear engine for Solver Problems that are smooth nonlinear. Select the LP Simplex engine for linear Solver Problems, and select the Evolutionary engine for Solver problems that are non-smooth.

in solver, i cannot make 3 cell equal, only maximize, minimize or "have equal to" one cell

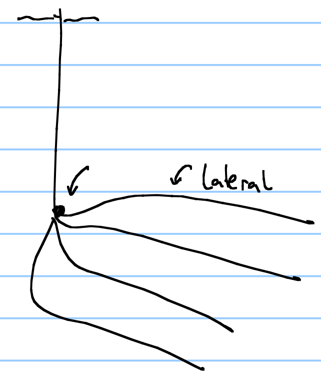
Another complexity is having well in the same network that are producing from different reservoirs

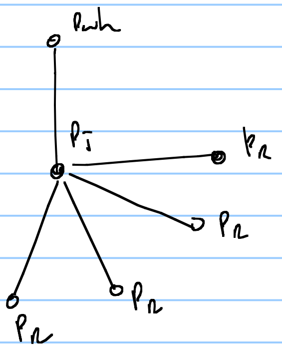


time	P_{R_1}	z_1	G_{p_1}	P_{R_2}	z_2	G_{p_2}
0	0	0	0	0	0	0
1						
2						

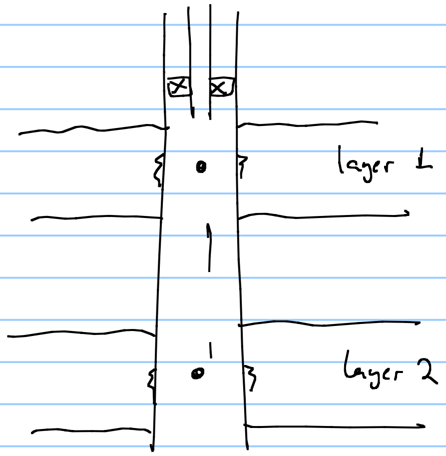
Network solving can also be used for downhole networks

multi-lateral well s

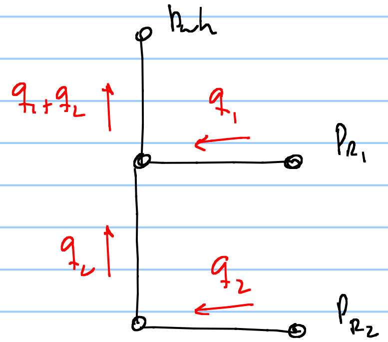


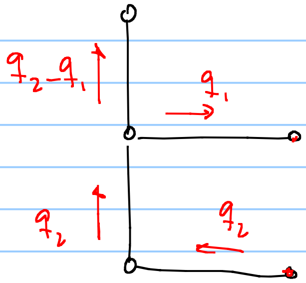


multi-layer wells

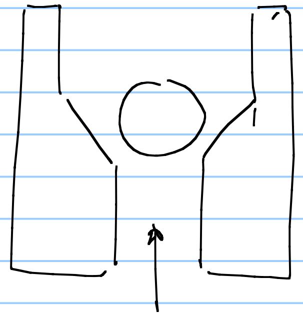


if layer deplete very differently

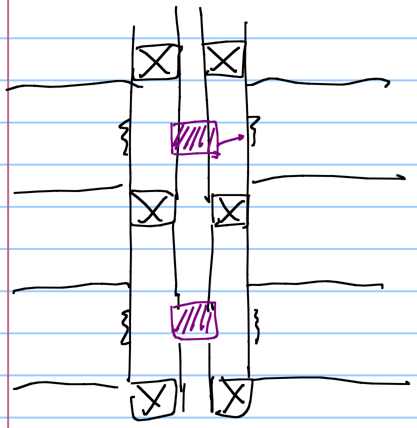




in well, a check valve is typically placed at X-mas tree to avoid back flow



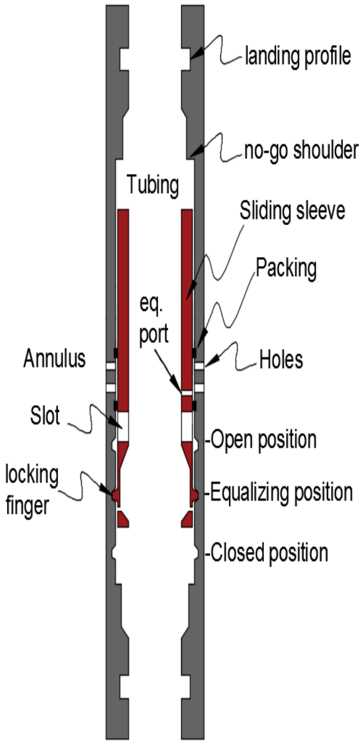
in well sometimes we use sliding sleeves



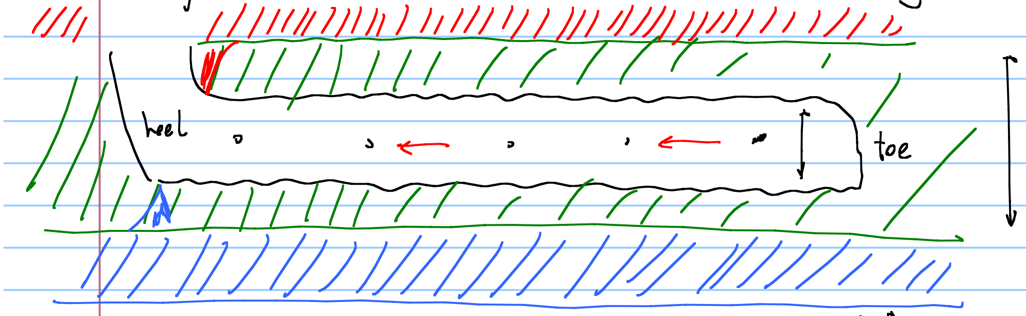
▨ sliding sleeve

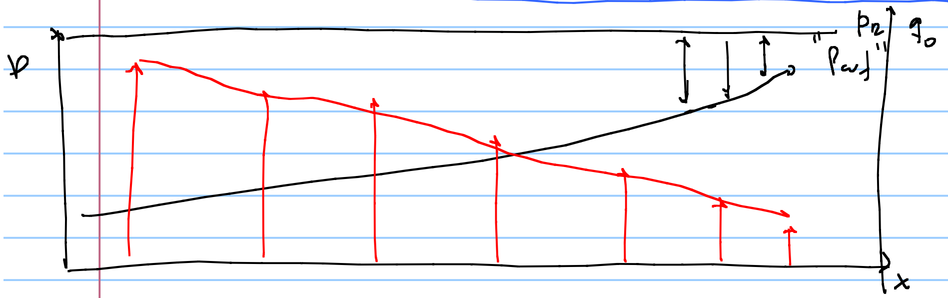
Inflow control device ICD

Inlow control valve (choke) ICV

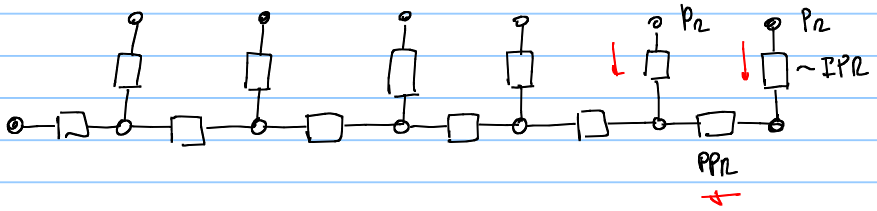


horizontal well can be studied with network theory

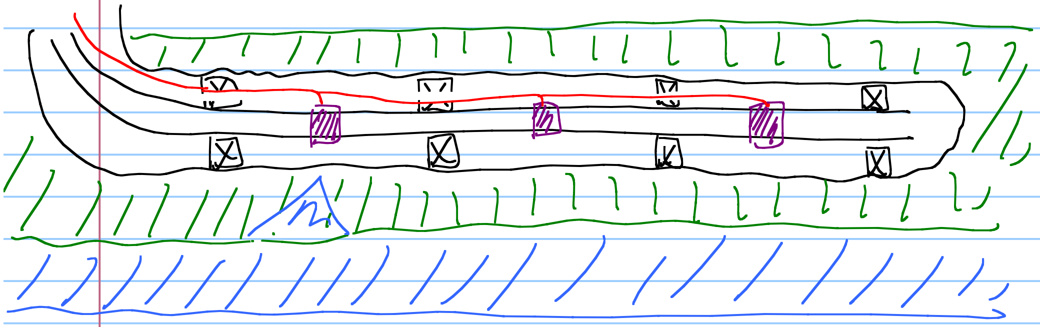


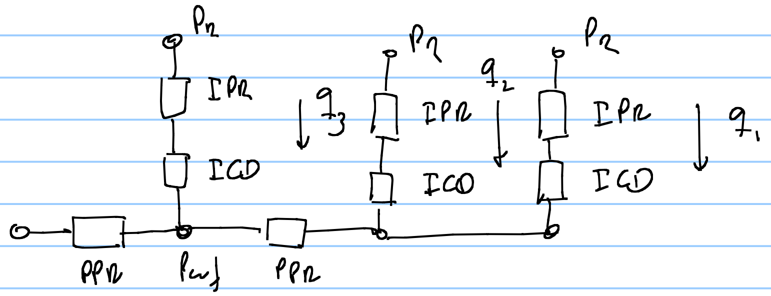


$q_o = J(p_R - p_{wf})$



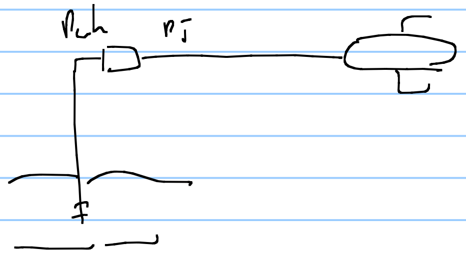
to improve drainage

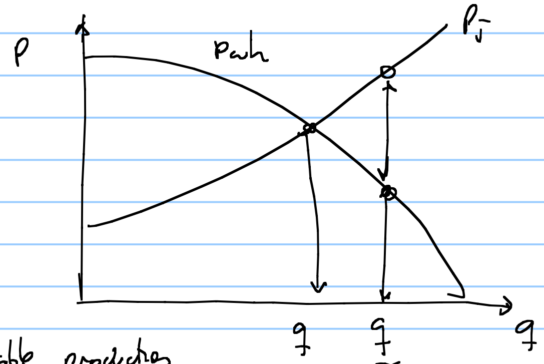




change Δp accross each ICD to get $q_1 \simeq q_2 \simeq q_3$

Boosting : adding energy to fluid (pressure increase)





low $ (low API, high viscosity)

- from the beggining (to get profitable production rates)
- later while production (to prolong plateau)

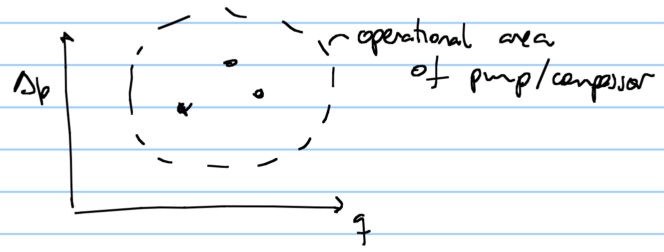
q^* Δp^*

two different types

<u>well level</u>
Artificial lift

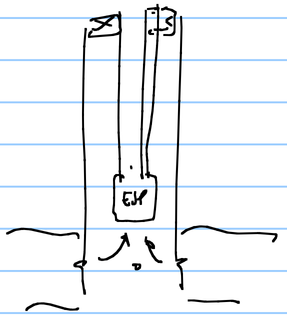
<u>system level</u> (group of wells)
boosting is typically
- two-phase gas + liquid flowing through pump
- gas compression
- separate and pump gas and liquid separatedly

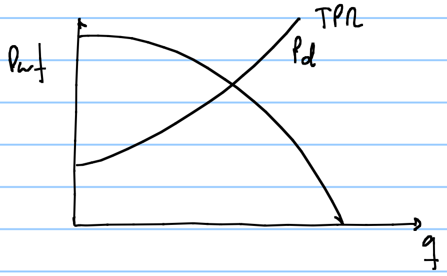
q^* Δp^* is this combination feasible

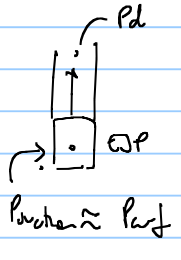


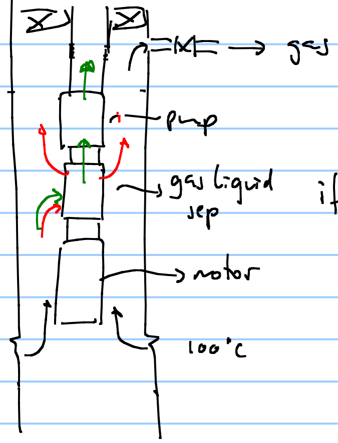
Artificial lift, electric submersible pump (ESP) pump for mainly liquid.

typically installed as close as possible to formation

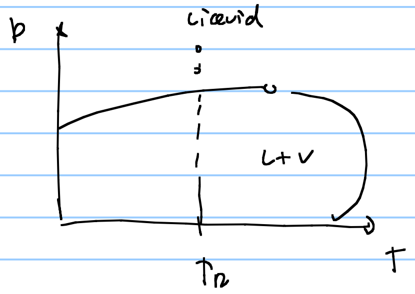


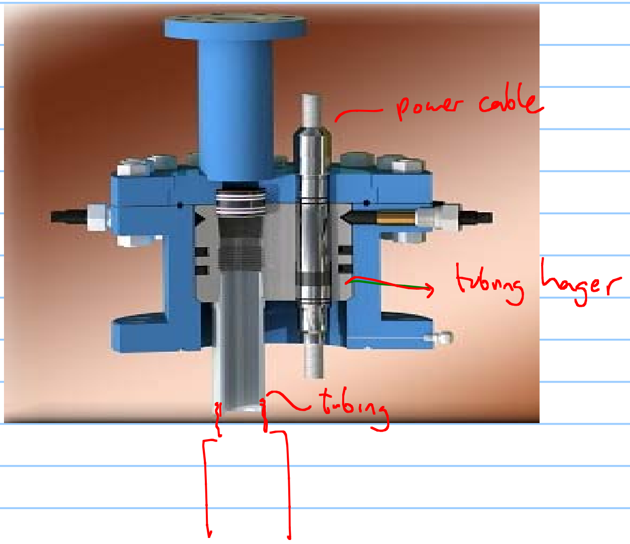


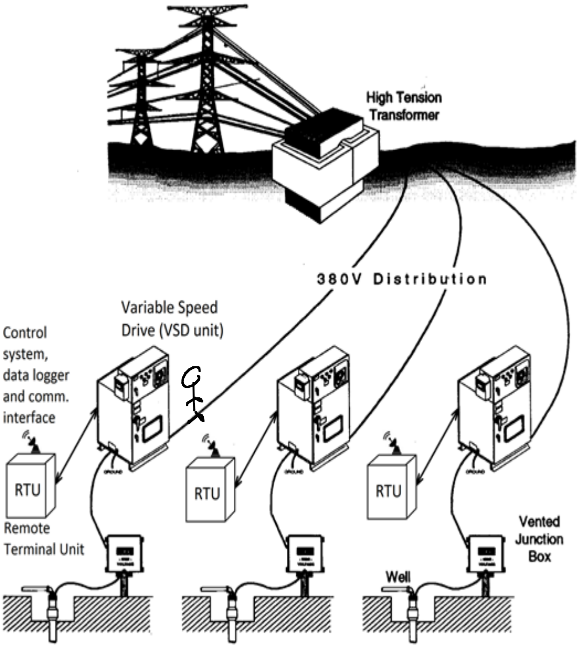


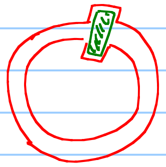


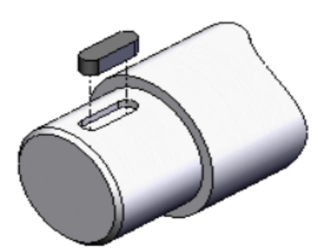
if $P_{wc} < P_{bubble\ point}$ → there will be gas

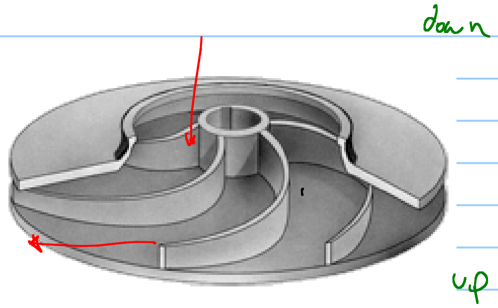






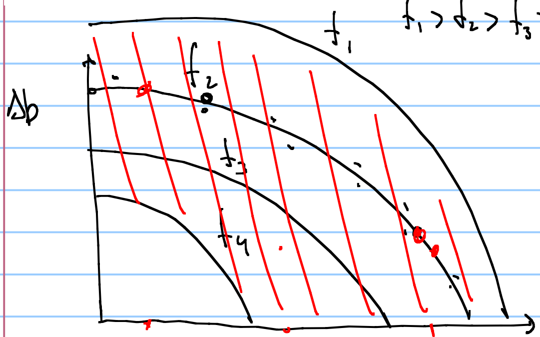






Armais Arutunoff

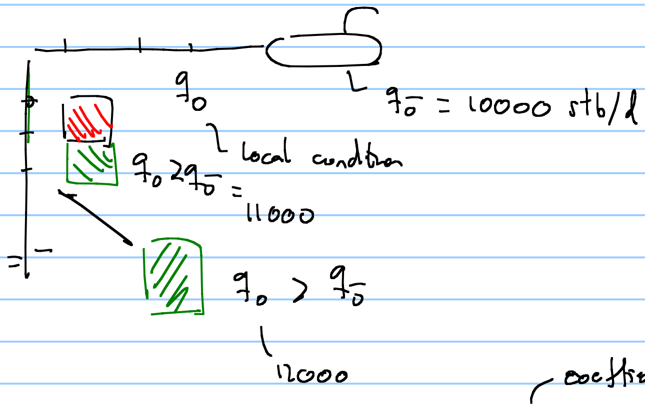
$f_1 > f_2 > f_3 > f_4$ $\quad$ $30hz \leq f \leq 70hz$



$$\underbrace{P_{ower}}_{\text{fixed}} = \frac{\Delta p \cdot q}{\eta_H}$$

for a collection of stages (pumps in series)

$q \sim \cancel{[Sm^3/d]}$ $[m^3/d]$ at inlet conditions

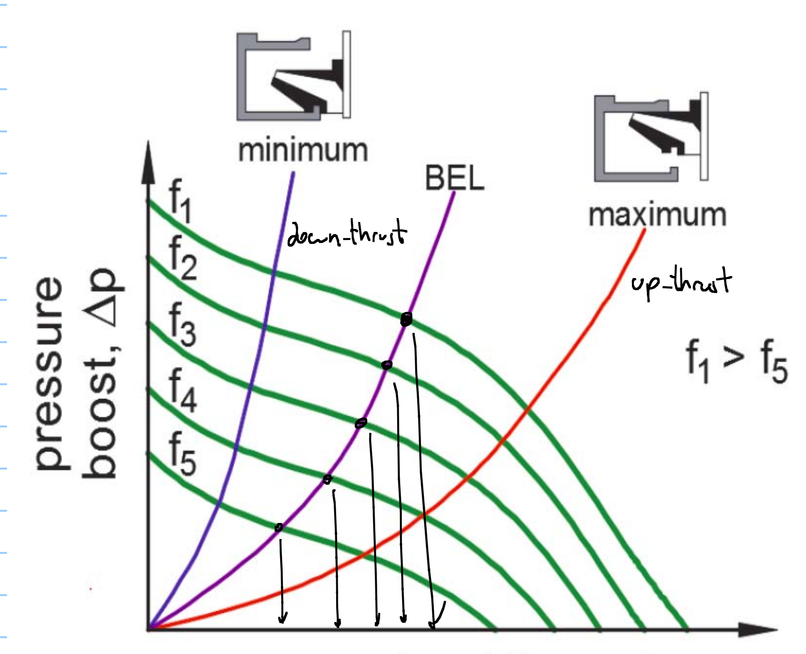


coefficient calculated @ fref = 60 Hz / 50 hz

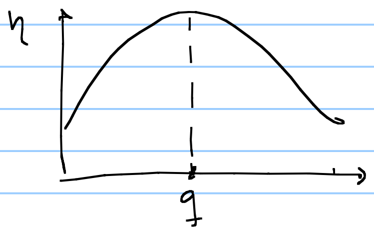
pump equation $\Delta p = \rho_{mix} \cdot \left(a\, q^4 + b\, q^3 + c\, q^2 + d\, q + e\right)$

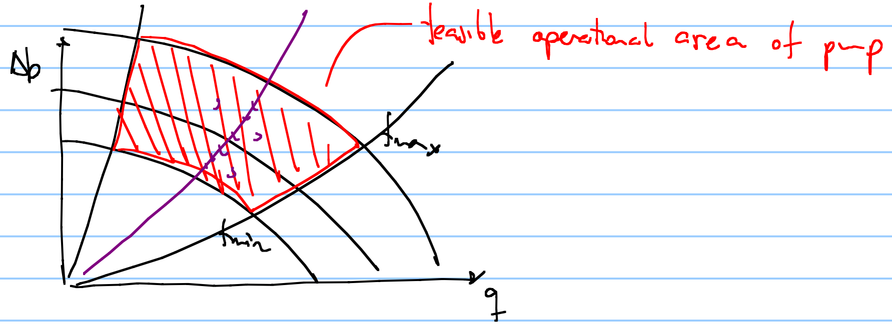
for another frequency $\Delta p = \rho_{mix} \left(a \left(q \frac{fref}{f}\right)^4 + b \left(q \left(\frac{fref}{f}\right)^3\right) + c \left(\frac{q\, fref}{f}\right)^2 + d\, \frac{fref}{f} q + e\right]$

there is another contraint to the pump map: upthrust - down-thrust region (floating impeller)

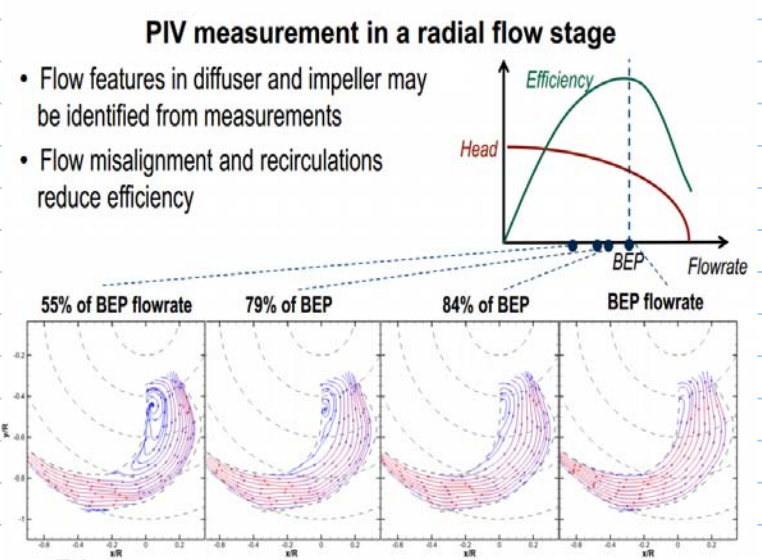


$$P = \frac{\Delta p \cdot q}{\eta_H}$$





feasible operational area of pump

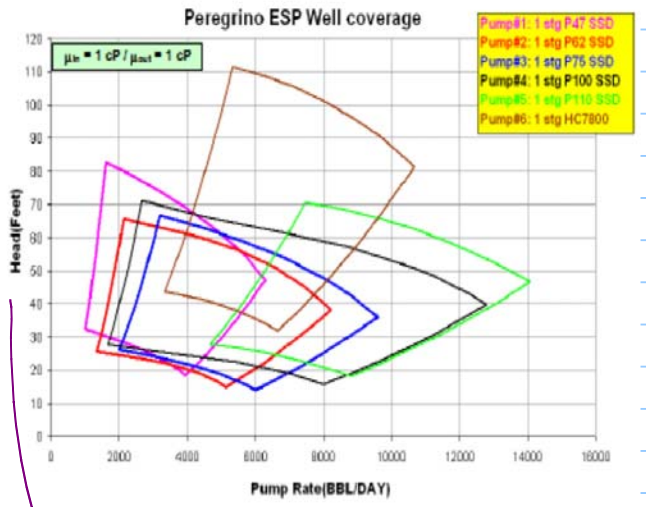


PIV measurement in a radial flow stage

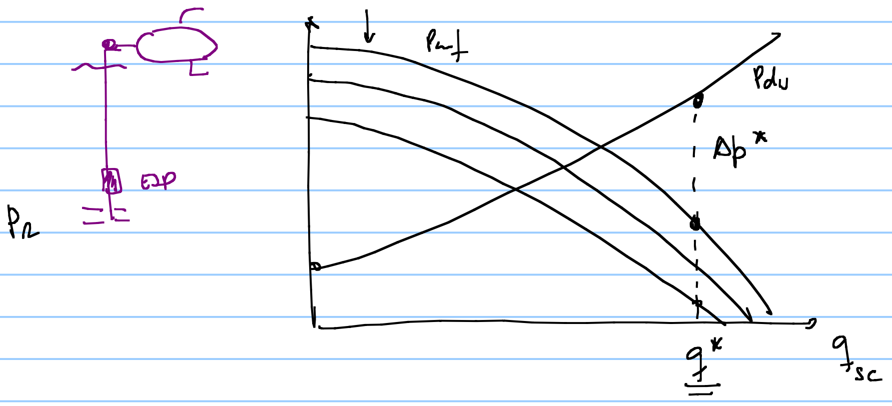
- Flow features in diffuser and impeller may be identified from measurements
- Flow misalignment and recirculations reduce efficiency

Example of stall region in diffuser passage (measured)

SPE-14MEAL-14017-PP-MS • Measurement and Unsteady Simulation of Internal Flows within Stages • J Dusting

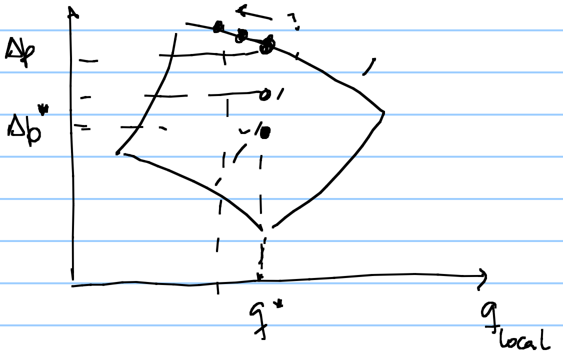


$\frac{\Delta p}{\rho} = \Delta h$ head



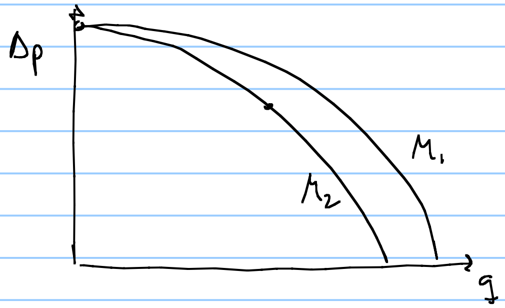
with time, $P_R \downarrow$

$\Delta p^* \uparrow$



$q_{local} \approx q_{sc}$ no gas is coming out of solution

viscosity affect the curve of pump



$M_2 > M_1$

Questions (8)

Hide answers

Q1: What is the relationship between plateau duration and plateau rate?

- They are independent of each other

  This is a wrong answer

- The higher the plateau rate, longer the plateau

  This is a wrong answer

- The higher the plateau rate, shorter the plateau

  This is a correct answer

Q2:when producing in plateau mode, what is the effect of increasing the number of wells?

- Plateau duration remains unchanged

  This is a wrong answer

- Plateau duration is prolonged

  This is a correct answer

- Plateau duration is shortened

  This is a wrong answer

Q3: What is the reason why increasing the number of wells prolongs plateau duration?

- The available pressure calculated from reservoir is higher

  This is a correct answer

- The required pressure to flow against separator is lowered

This is a wrong answer

- The production potential of the system increases

  This is a correct answer

Q4: What is the production potential of a field?

- The maximum rate the field can produce at a given time

  This is a correct answer

- The rate calculated when all chokes are open

  This is a wrong answer

- The flow equilibrium rate

  This is a wrong answer

- The rate calculated when all pumps are at maximum speed

  This is a wrong answer

Q5: Why is production potential (pp) a function of cumulative production (Qp)?

- It is NOT a function of cumulative production

  This is a wrong answer

- pp is a function of pR, and pR is a function of Qp

  This is a correct answer

- The IPR depends on Qp only.

  This is a correct answer

Q6: If the production potential vs cumulative production is linear, the decline is exponential

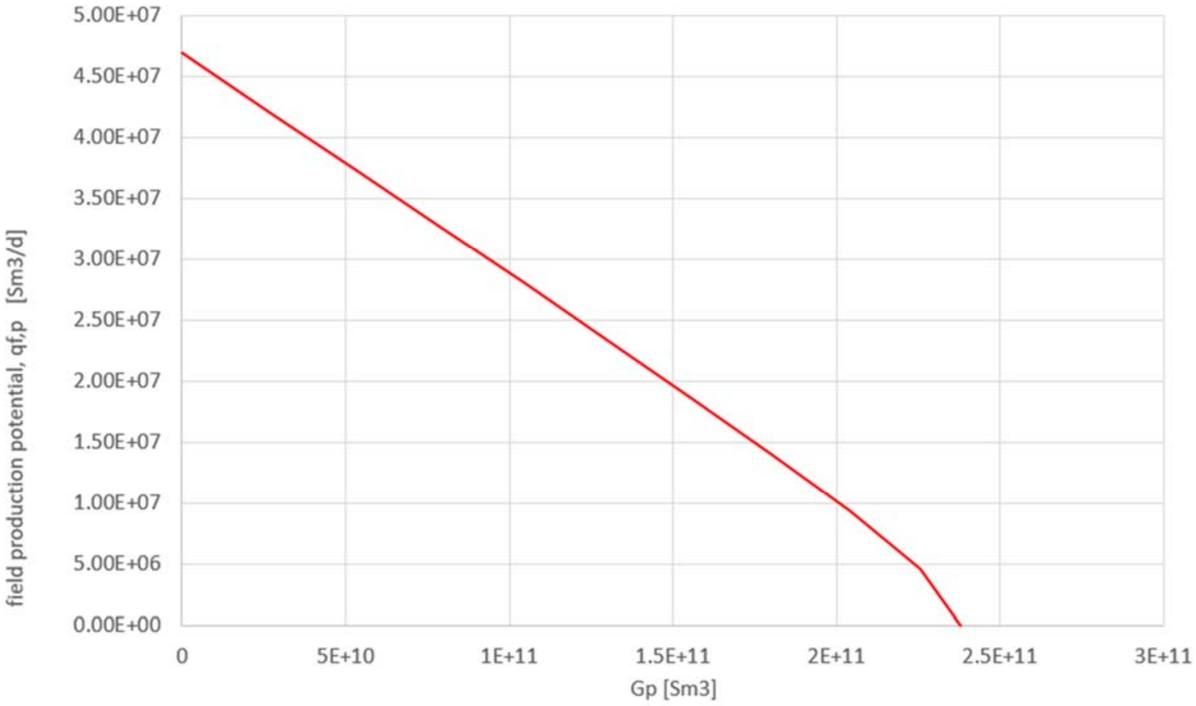
- FALSE

  This is a wrong answer

- TRUE

  This is a correct answer

Q7: For the following production potential curve, what is the plateau duration for 30 E06 Sm3/d



- 15 years

  This is a wrong answer

- 5 years

  This is a wrong answer

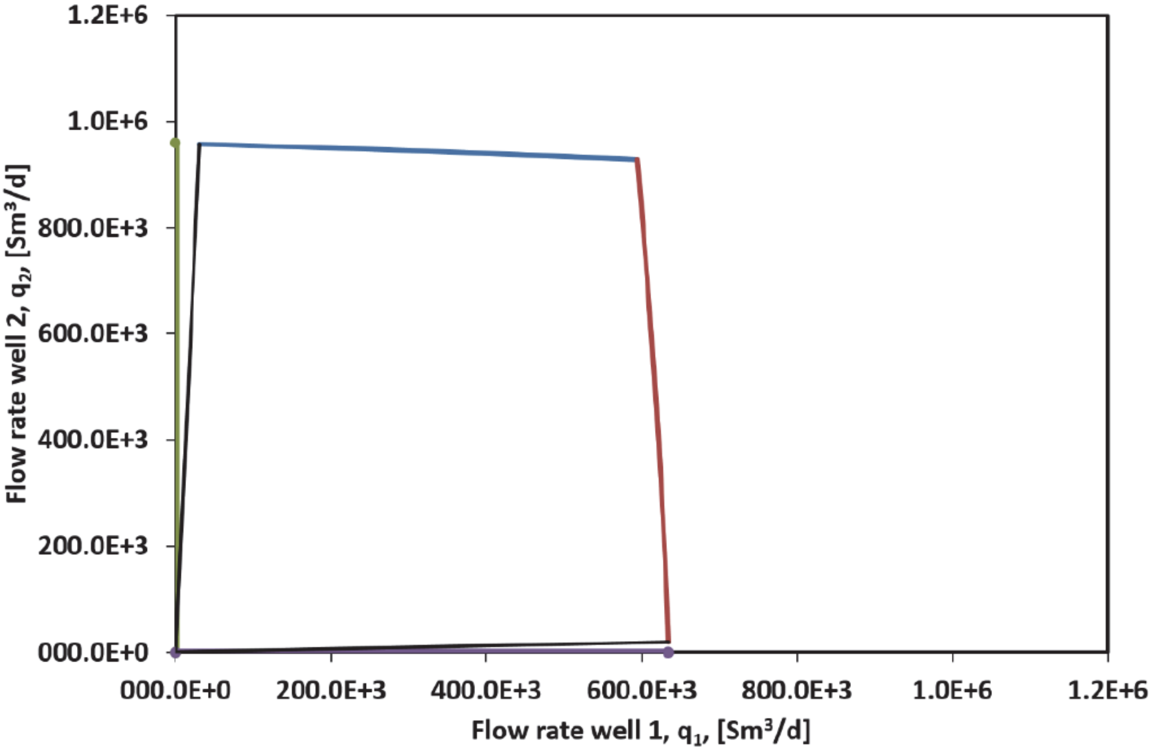
- 3 years

  This is a wrong answer

- 8 years

  This is a correct answer

Q8: For two wells producing to a common line, rates q1=200E3 and q2=1e6 are feasible



- TRUE

  This is a wrong answer

- FALSE

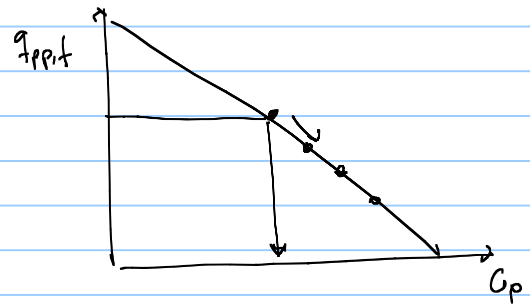
  This is a correct answer

- Re-cap Kahoot quiz
- Problem 2, exercise set 2

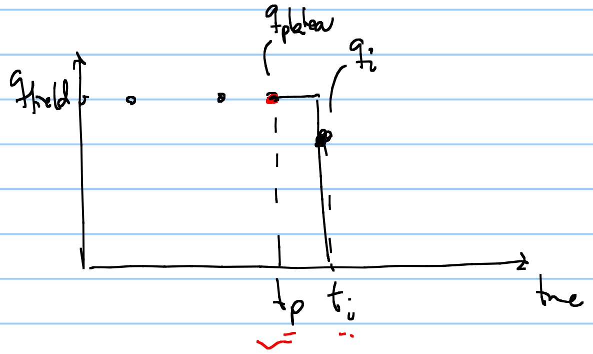
$$\boxed{q_{pp,t}} = N_w\left(-m\,\overset{P_R}{\boxed{G_p}} + q_{ppo}\right)$$

flow equilibrium calculations if well model and network model are available
↳ impose P_{wmin} if reservoir simulator

plateau period q_f = constant
t_p



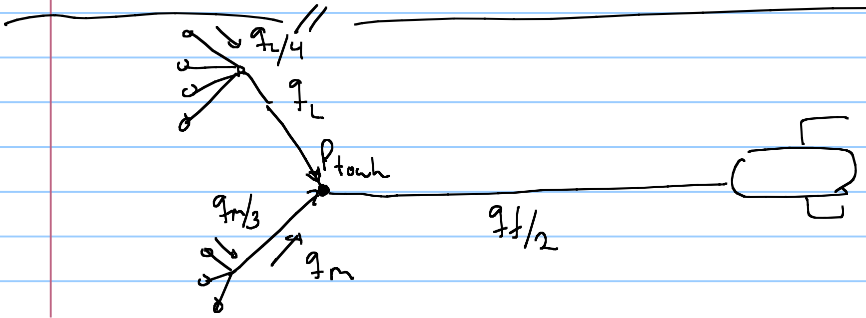
$$G_{p_i} = G_{p_{i-1}} + 0.5\left(q_i + q_{i-1}\right).\left(t_i - t_{i-1}\right) \quad (1)$$



$$q_{field} = N_w\left(-m\,G_p + q_{ppo}\right).$$

$$q_i = N_w\left(-m\,G_{p_i} + q_{ppo}\right) \quad (2)$$

time	q_{field}	G_p	$q_{pp,t}$
0	$q_{plateau}$	0	$q_{pp,t}$
1	"		
2	"		
	"		
t_p	$q_{plateau}$	□	
t_i	○	□ $+ q_{plateau}(t_i - t_p)$ →	○
t_{i+1}	○ ?		○



Problem 1, exercise set 3.

to estimate how much each reservoir unit should produce in plateau rate one often uses the potential

① at the "0" run a flow equilibrium calculation with open choke

$$q_{pp\_L}$$

$$q_{pp\_m}$$

$$q_{pp\_field}$$

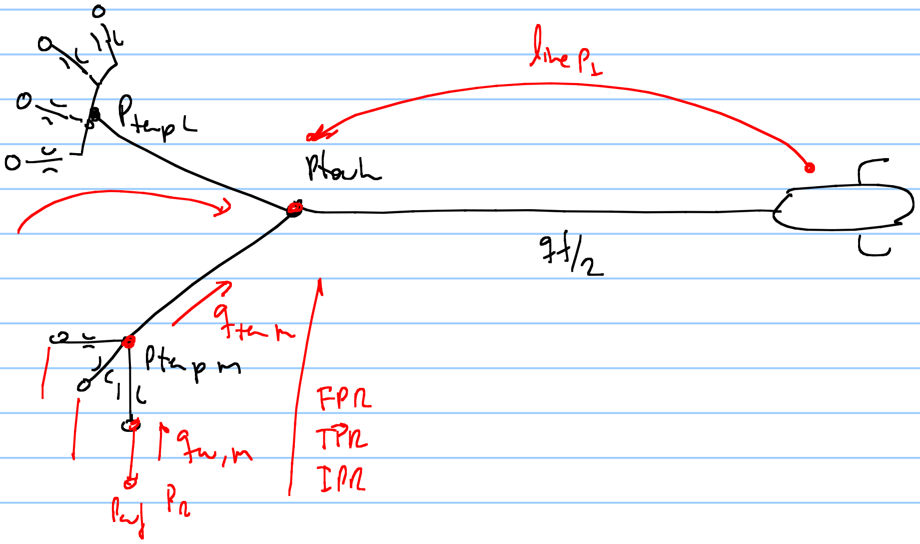
② calculate production split factor

$$f_L = \frac{q_{pp\_L}}{q_{pp\_field}} \qquad f_m = \frac{q_{pp\_m}}{q_{pp\_field}}$$

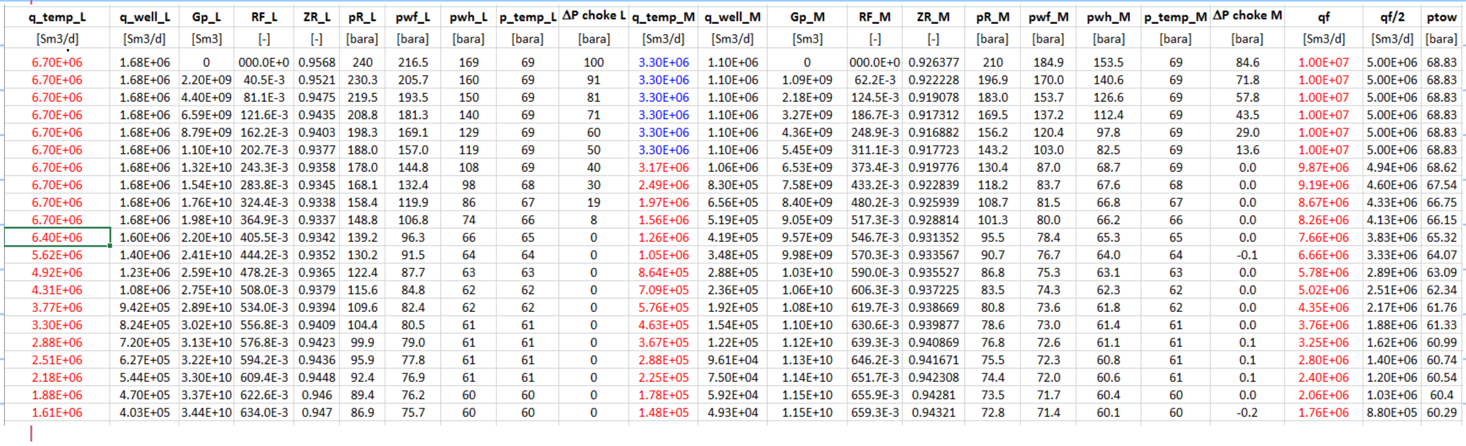
③ Calculate production split at plateau rate

$$\underline{q_{plateau\_L}} = q_{plateau\ field} \cdot f_{\_L}$$

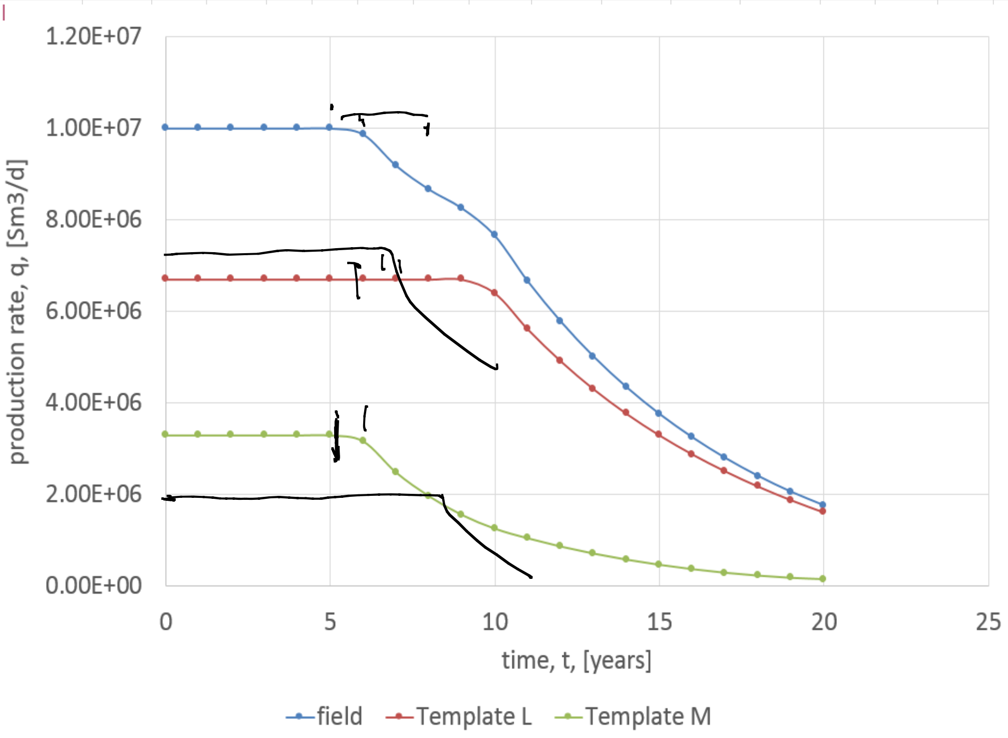
$$\underline{q_{plateau\_m}} = q_{plateau\_field} \cdot f_{\_m}$$

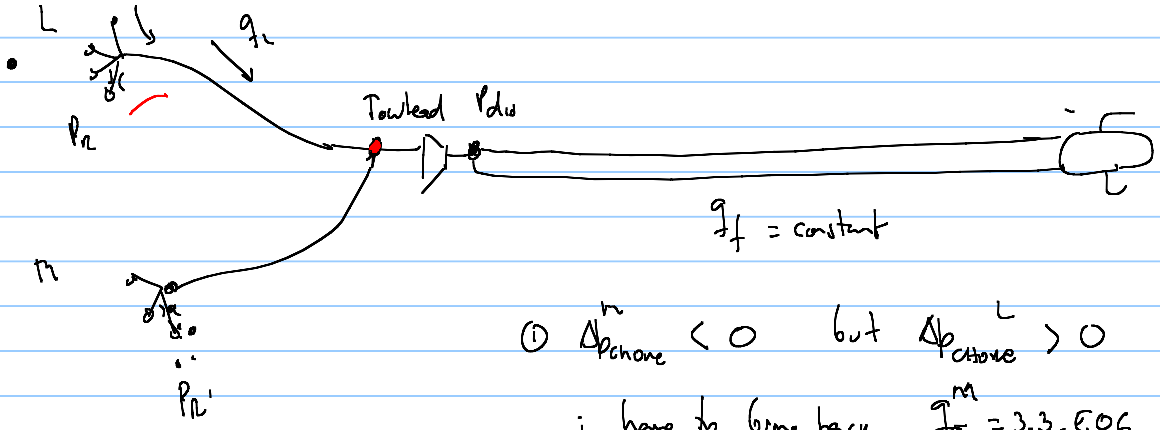


Class exercise → Problem 1, exercise set 3.



q_temp_L	q_well_L	Gp_L	RF_L	ZR_L	pR_L	pwf_L	pwh_L	p_temp_L	ΔP choke L	q_temp_M	q_well_M	Gp_M	RF_M	ZR_M	pR_M	pwf_M	pwh_M	p_temp_M	ΔP choke M	qf	qf/2	ptow
[Sm3/d]	[Sm3/d]	[Sm3]	[-]	[-]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm3/d]	[Sm3/d]	[Sm3]	[-]	[-]	[bara]	[bara]	[bara]	[bara]	[bara]	[Sm3/d]	[Sm3/d]	[bara]
6.70E+06	1.68E+06	0	000.0E+0	0.9568	240	216.5	169	69	100	3.30E+06	1.10E+06	0	000.0E+0	0.926377	210	184.9	153.5	69	84.6	1.00E+07	5.00E+06	68.83
6.70E+06	1.68E+06	2.20E+09	40.5E-3	0.9521	230.3	205.7	160	69	91	3.30E+06	1.10E+06	1.09E+09	62.2E-3	0.922228	196.9	170.0	140.6	69	71.8	1.00E+07	5.00E+06	68.83
6.70E+06	1.68E+06	4.40E+09	81.1E-3	0.9475	219.5	193.5	150	69	81	3.30E+06	1.10E+06	2.18E+09	124.5E-3	0.919078	183.0	153.7	126.6	69	57.8	1.00E+07	5.00E+06	68.83
6.70E+06	1.68E+06	6.59E+09	121.6E-3	0.9435	208.8	181.3	140	69	71	3.30E+06	1.10E+06	3.27E+09	186.7E-3	0.917312	169.5	137.2	112.4	69	43.5	1.00E+07	5.00E+06	68.83
6.70E+06	1.68E+06	8.79E+09	162.2E-3	0.9403	198.3	169.1	129	69	60	3.30E+06	1.10E+06	4.36E+09	248.9E-3	0.916882	156.2	120.4	97.8	69	29.0	1.00E+07	5.00E+06	68.83
6.70E+06	1.68E+06	1.10E+10	202.7E-3	0.9377	188.0	157.0	119	69	50	3.30E+06	1.10E+06	5.45E+09	311.1E-3	0.917723	143.2	103.0	82.5	69	13.6	1.00E+07	5.00E+06	68.83
6.70E+06	1.68E+06	1.32E+10	243.3E-3	0.9358	178.0	144.8	108	69	40	3.17E+06	1.06E+06	6.53E+09	373.4E-3	0.919776	130.4	87.0	68.7	69	0.0	9.87E+06	4.94E+06	68.62
6.70E+06	1.68E+06	1.54E+10	283.8E-3	0.9345	168.1	132.4	98	68	30	2.49E+06	8.30E+05	7.58E+09	433.2E-3	0.922839	118.2	83.7	67.6	68	0.0	9.19E+06	4.60E+06	67.54
6.70E+06	1.68E+06	1.76E+10	324.4E-3	0.9338	158.4	119.9	86	67	19	1.97E+06	6.56E+05	8.40E+09	480.2E-3	0.925939	108.7	81.5	66.8	67	0.0	8.67E+06	4.33E+06	66.75
6.70E+06	1.68E+06	1.98E+10	364.9E-3	0.9337	148.8	106.8	74	66	8	1.56E+06	5.19E+05	9.05E+09	517.3E-3	0.928814	101.3	80.0	66.2	66	0.0	8.26E+06	4.13E+06	66.15
6.40E+06	1.60E+06	2.20E+10	405.5E-3	0.9342	139.2	96.3	66	65	0	1.26E+06	4.19E+05	9.57E+09	546.7E-3	0.931352	95.5	78.4	65.3	65	0.0	7.66E+06	3.83E+06	65.32
5.62E+06	1.40E+06	2.41E+10	444.2E-3	0.9352	130.2	91.5	64	64	0	1.05E+06	3.48E+05	9.98E+09	570.3E-3	0.933567	90.7	76.7	64.0	64	-0.1	6.66E+06	3.33E+06	64.07
4.92E+06	1.23E+06	2.59E+10	478.2E-3	0.9365	122.4	87.7	63	63	0	8.64E+05	2.88E+05	1.03E+10	590.0E-3	0.935527	86.8	75.3	63.1	63	0.0	5.78E+06	2.89E+06	63.09
4.31E+06	1.08E+06	2.75E+10	508.0E-3	0.9379	115.6	84.8	62	62	0	7.09E+05	2.36E+05	1.06E+10	606.3E-3	0.937225	83.5	74.3	62.3	62	0.0	5.02E+06	2.51E+06	62.34
3.77E+06	9.42E+05	2.89E+10	534.0E-3	0.9394	109.6	82.4	62	62	0	5.76E+05	1.92E+05	1.08E+10	619.7E-3	0.938669	80.8	73.6	61.8	62	0.0	4.35E+06	2.17E+06	61.76
3.30E+06	8.24E+05	3.02E+10	556.8E-3	0.9409	104.4	80.5	61	61	0	4.63E+05	1.54E+05	1.10E+10	630.6E-3	0.939877	78.6	73.0	61.4	61	0.0	3.76E+06	1.88E+06	61.33
2.88E+06	7.20E+05	3.13E+10	576.8E-3	0.9423	99.9	79.0	61	61	0	3.67E+05	1.22E+05	1.12E+10	639.3E-3	0.940869	76.8	72.6	61.1	61	0.1	3.25E+06	1.62E+06	60.99
2.51E+06	6.27E+05	3.22E+10	594.2E-3	0.9436	95.9	77.8	61	61	0	2.88E+05	9.61E+04	1.13E+10	646.2E-3	0.941671	75.5	72.3	60.8	61	0.1	2.80E+06	1.40E+06	60.74
2.18E+06	5.44E+05	3.30E+10	609.4E-3	0.9448	92.4	76.9	61	61	0	2.25E+05	7.50E+04	1.14E+10	651.7E-3	0.942308	74.4	72.0	60.6	61	0.1	2.40E+06	1.20E+06	60.54
1.88E+06	4.70E+05	3.37E+10	622.6E-3	0.946	89.4	76.2	60	60	0	1.78E+05	5.92E+04	1.15E+10	655.9E-3	0.94281	73.5	71.7	60.4	60	0.0	2.06E+06	1.03E+06	60.4
1.61E+06	4.03E+05	3.44E+10	634.0E-3	0.947	86.9	75.7	60	60	0	1.48E+05	4.93E+04	1.15E+10	659.3E-3	0.94321	72.8	71.4	60.1	60	-0.2	1.76E+06	8.80E+05	60.29





① $\Delta p^{M}_{choke} < 0$ but $\Delta p^{L}_{choke} > 0$

; have to bring back $q_f^M = 3.3.E06$

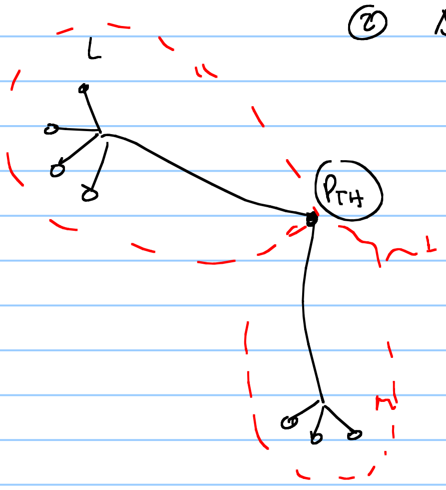
In template M, move from P_{wf} → P_{wh} → P_{temp} → $P_{towhead}$

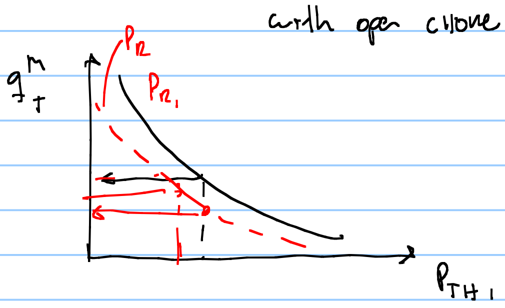
$q_f^L = 6.7\ E06\ Sm^3/d$

with P_{TOWH}, verify that $\Delta p^{L}_{choke} > 0$

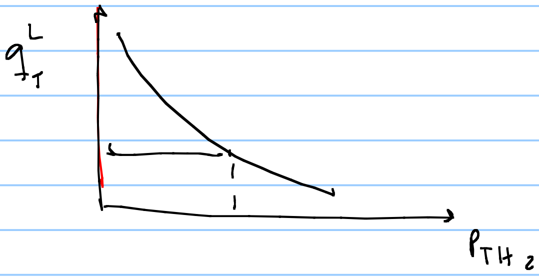
② $\Delta p^{L}_{CHOKE} < 0$ $\Delta p^{M}_{CHOKE} < 0$

with open choke





TEMPLATE L



$P_{TH_1} = P_{TH_2}$

But $q^{L}_{T} + q^{M}_{T} = 10\ E06$

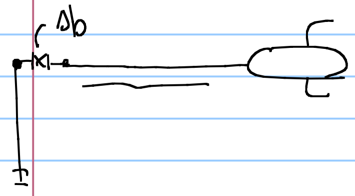
- Methods to prolong plateau production
- Orientation for solving problem 2 exercise set 3
    - Single phase pressure drop
    - oil water mixtures (emulsion)
    - ESP constraints
- compression?

Method to prolong plateau production:

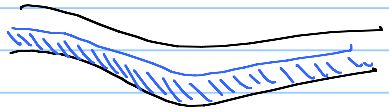
Short comment on discount factor

$$1661.70 \frac{USD}{661} \qquad \frac{1}{(1+0.07)^3} = 0.81(1.70) =$$

- increase number of wells ($)
- Adding energy to system
    - → boosting (compressing / pumping)
    - → Artificial lift (ESP) ($)

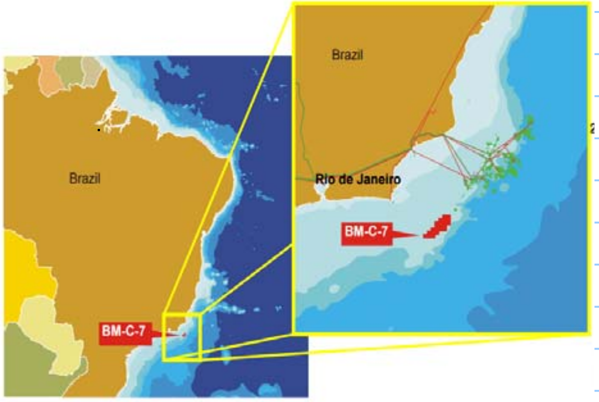


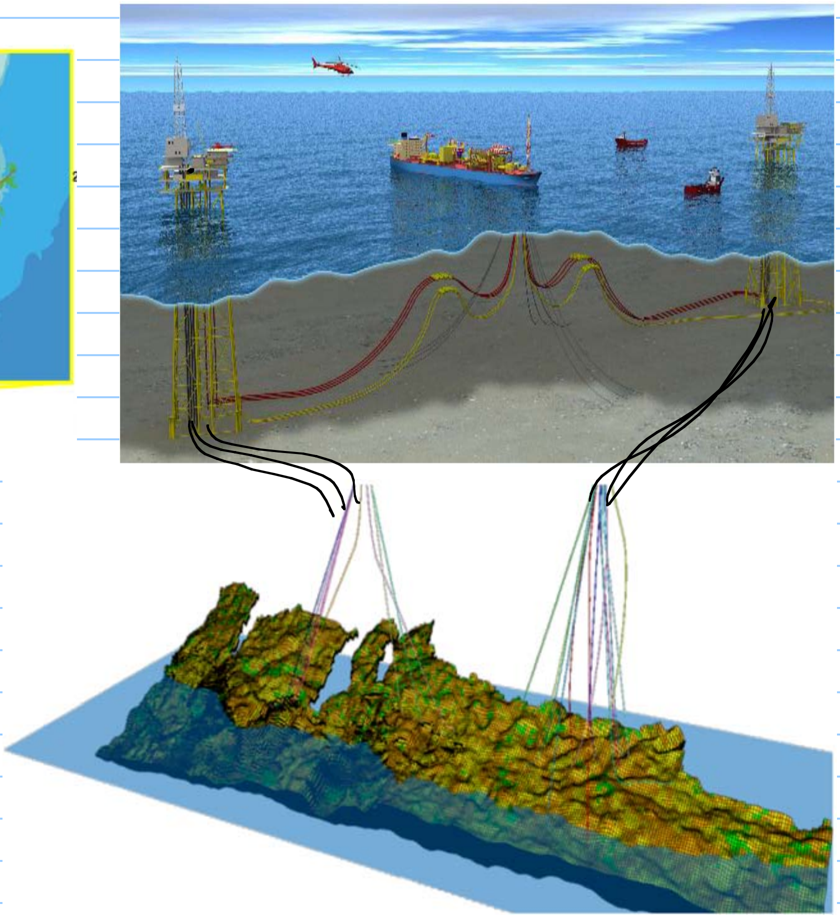
- making "C" bigger fracturing, well stimulation
- making "C_T" bigger
    - → increase tubing size $
    - → remove solid deposition



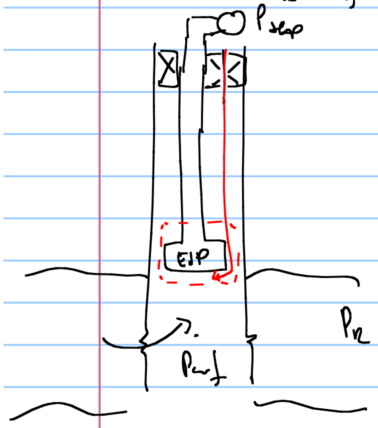
- making C_{FL} bigger
    - → increase pipe size
    - → perform pigging
- decrease P_{sep} ~ careful with requirement of process plant
- Pressure support mechanism
- Re-distribution of production among well } careful with max allowable drawdown ($P_R - P_{wf}$), q_{max}

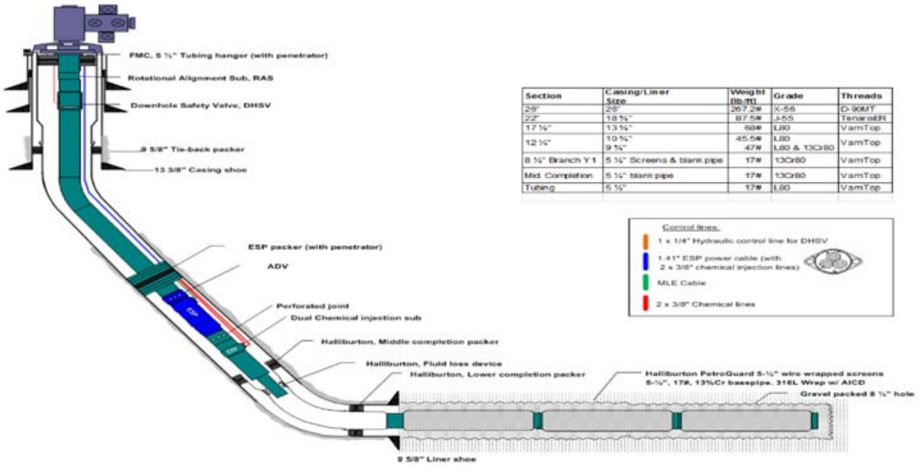
- Problem 2 of exercise set 3.





- the amounts of oil and water are changing with time





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

$P_{suction} = P_{inlet}$ pump

$P_R \rightarrow P_{wf}$ IPR equation $\underbrace{q_{liqu}}_{q_{oil} + q_w} = J(P_R - P_{wf})$

$P_{wf} \rightarrow P_{suc}$

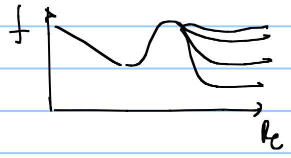
① → ②

$h_1 = h_2$

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

single phase and incompressible fluid

$$h_f = f\frac{L}{\phi}\cdot\frac{v^2}{2g}$$ moody friction factor



line P_1

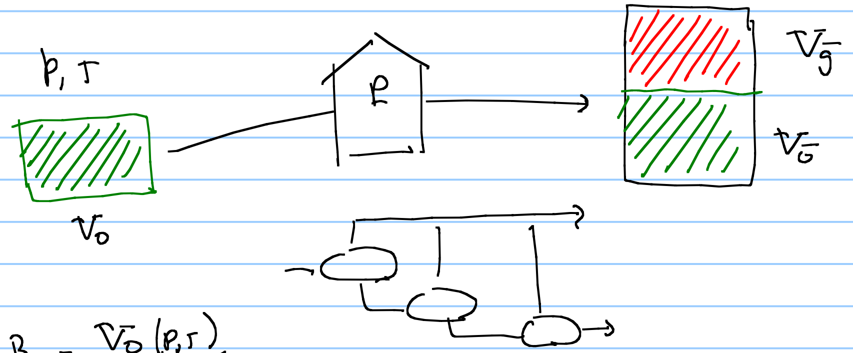
$v_2 \simeq v_1$

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

$$v = \frac{q}{A} = \frac{q\,4}{\pi\phi^2}$$

eq. 1 $$P_1 = (z_2 - z_1)\rho g + f\frac{L}{\phi}\rho\frac{8q^2}{\pi^2\phi^5} + P_2$$ } pipe equation for single phase flow

q is the local rate @ P, T IS NOT the same as $\bar{q}_o$ $\bar{q}_w$ $\bar{q}_L$



oil volume factor $B_o = \frac{V_o(P,T)}{\bar{V}_o(P_{sc},T_{sc})}$ → 1.8 volatile oils

1 for dead oil

for this exercise $B_o = 1$ for all P,T $q_o = \bar{q}_o$

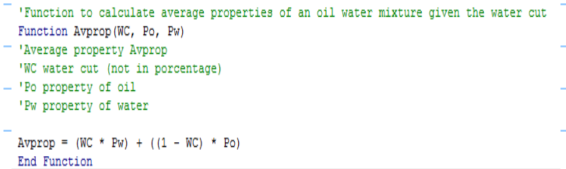
$B_w = 1$ $q_w = \bar{q}_w$

$q_L = \bar{q}_L$

$P_{wf} \rightarrow P_{wh}$ use eq. 1 with $P_1 = P_{wf}$, $P_2 = P_{wh}$

$q = q_{liq}$

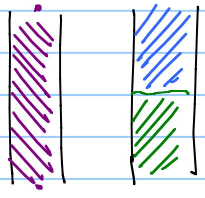
$$\rho = \rho_{mix} = \rho_o(\alpha_o) + \rho_w(\alpha_w) = \rho_o(1-\alpha_w) + \rho_w\cdot\alpha_w$$



```
'Function to calculate average properties of an oil water mixture given the water cut
Function Avprop(WC, Po, Pw)
'Average property Avprop
'WC water cut (not in porcentage)
'Po property of oil
'Pw property of water

Avprop = (WC * Pw) + ((1 - WC) * Po)
End Function
```

↳ volume fraction $\alpha_o = \frac{q_o}{q_o + q_w}$

$\alpha_w = \frac{q_w}{q_o + q_w}$

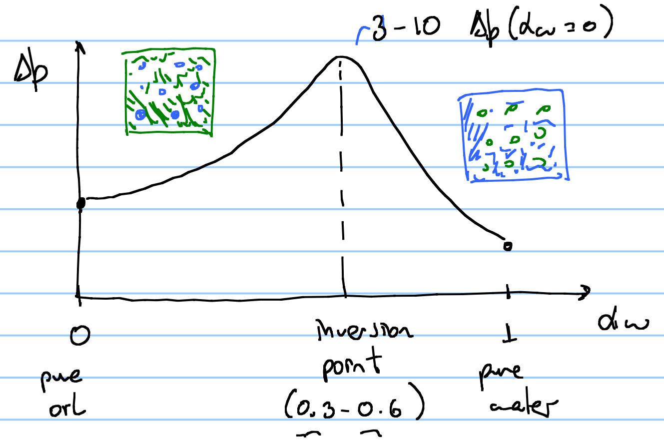


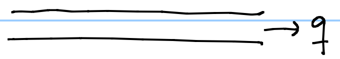
water cut $wc = \frac{\bar{q}_w}{\bar{q}_o + \bar{q}_w}$ for our exercise $wc = \alpha_w$

we need viscosity for Reynolds number to estimate f

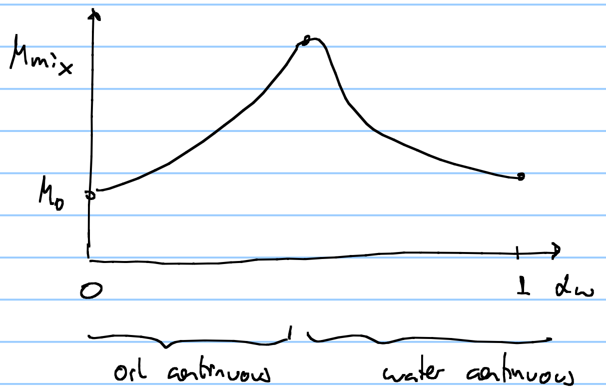
some people use $\mu_m = \mu_o(1-\alpha_w) + \mu_w(\alpha_w)$ not accurate for emulsions

emulsion



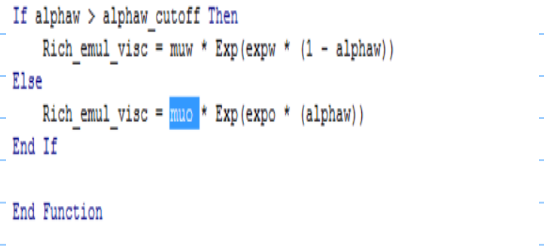


during the life of the field typically WC increases. If there is risk of emulsion this must be taken into account!



Richardson equation

$$\mu_m = \mu_o \cdot e^{C_o \alpha_w} \qquad \mu_m = \mu_w \cdot e^{C_w(1-\alpha_w)}$$



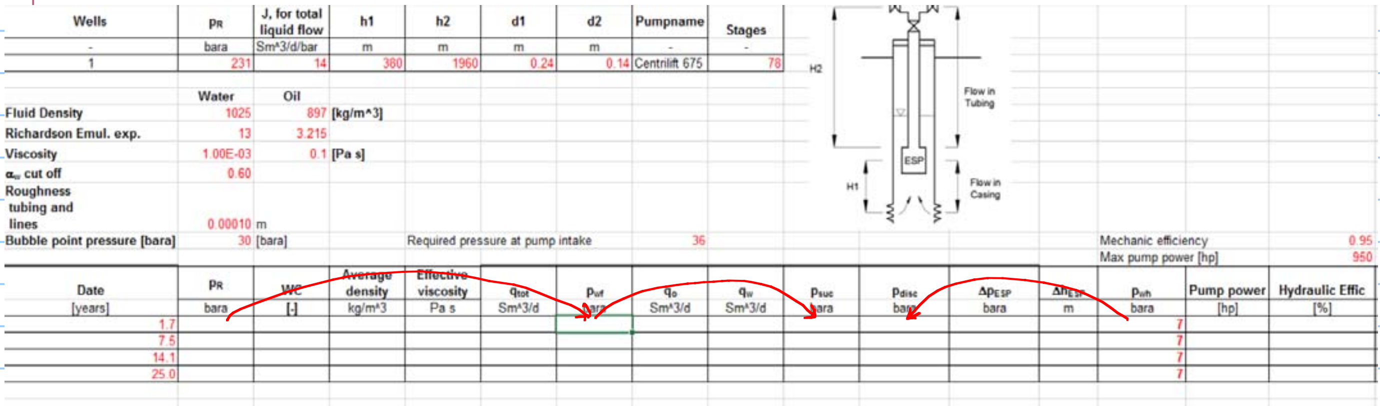
```
Function Rich_emul_visc(muo, muw, alphaw, expo, expw, alphaw_cutoff)
If alphaw > alphaw_cutoff Then
    Rich_emul_visc = muw * Exp(expw * (1 - alphaw))
Else
    Rich_emul_visc = muo * Exp(expo * (alphaw))
End If

End Function
```

$P_R \longrightarrow P_{wf} \rightarrow$ IPR

$P_{wf} \longrightarrow P_{wh} \rightarrow$ single phase Δp with $\underline{\rho_{mix}}, \mu_{mix}$

$P_{wh} \longrightarrow P_{dis}$ / P_{outlet} $\rightarrow$ single phase Δp with $\underline{\rho_{mix}}\ \mu_{mix}$

method 1 : equilibrium removing ESP



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

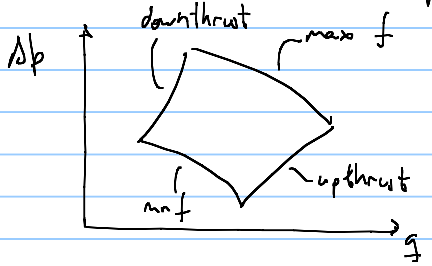
Mechanic efficiency 0.95

Max pump power [hp] 950

Date	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
[years]	bara	[-]	kg/m^3	Pa s	Sm^3/d	bara	Sm^3/d	Sm^3/d	bara	bara	bara	m	bara	[hp]	[%]
1.7													7		
7.5													7		
14.1													7		
25.0													7		

how to know if the pump works?

- $P_{disch} > P_{suc}$
- $P_{suc} \geq P_b$
- the operational point should fall on the operational envelope of pump



- Power required ≤ Power motor

in consistent units

$$P = \frac{\Delta p \cdot q}{\eta_H \cdot \eta_m}$$

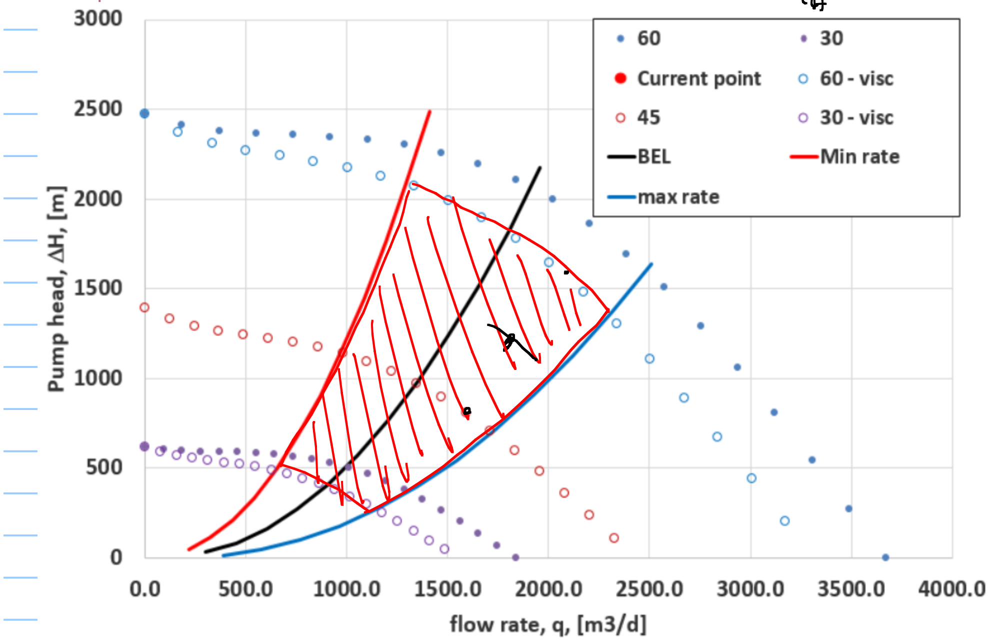
assume $\eta_m = 1$

$$\frac{Pa}{\eta_H} \cdot m^3/s$$

Δp q

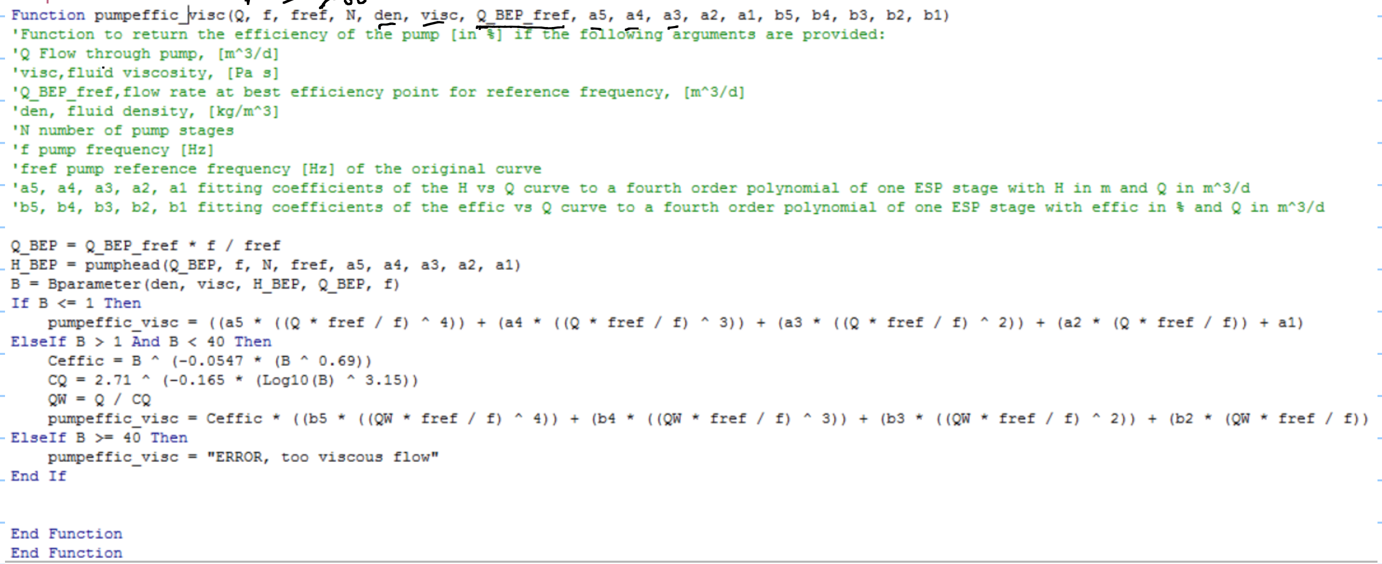
$$\Delta h = \frac{\Delta p}{\rho}$$

the map depends on viscosity

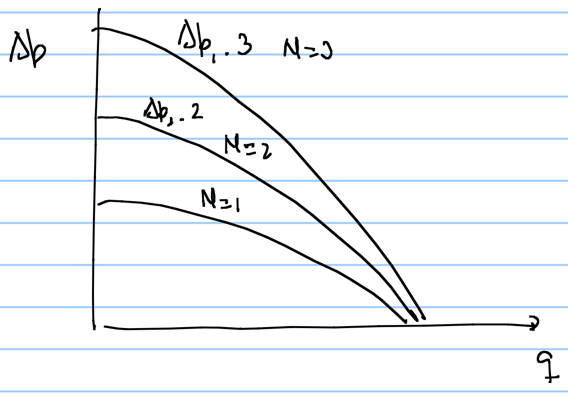


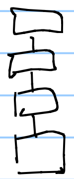
function for hydraulic efficiency $N=78$ $q_{-BEP} = 1987.$

$\frac{q_{liq}}{60}$ f (from interpolation)

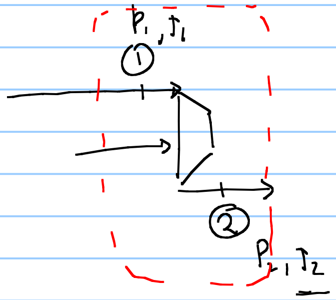


```
Function pumpeffic_visc(Q, f, fref, N, den, visc, Q_BEP_fref, a5, a4, a3, a2, a1, b5, b4, b3, b2, b1)
'Function to return the efficiency of the pump [in %] if the following arguments are provided:
'Q Flow through pump, [m^3/d]
'visc,fluid viscosity, [Pa s]
'Q_BEP_fref,flow rate at best efficiency point for reference frequency, [m^3/d]
'den, fluid density, [kg/m^3]
'N number of pump stages
'f pump frequency [Hz]
'fref pump reference frequency [Hz] of the original curve
'a5, a4, a3, a2, a1 fitting coefficients of the H vs Q curve to a fourth order polynomial of one ESP stage with H in m and Q in m^3/d
'b5, b4, b3, b2, b1 fitting coefficients of the effic vs Q curve to a fourth order polynomial of one ESP stage with effic in % and Q in m^3/d

Q_BEP = Q_BEP_fref * f / fref
H_BEP = pumphead(Q_BEP, f, N, fref, a5, a4, a3, a2, a1)
B = Bparameter(den, visc, H_BEP, Q_BEP, f)
If B <= 1 Then
    pumpeffic_visc = ((a5 * ((Q * fref / f) ^ 4)) + (a4 * ((Q * fref / f) ^ 3)) + (a3 * ((Q * fref / f) ^ 2)) + (a2 * (Q * fref / f)) + a1)
ElseIf B > 1 And B < 40 Then
    Ceffic = B ^ (-0.0547 * (B ^ 0.69))
    CQ = 2.71 ^ (-0.165 * (Log10(B) ^ 3.15))
    QW = Q / CQ
    pumpeffic_visc = Ceffic * ((b5 * ((QW * fref / f) ^ 4)) + (b4 * ((QW * fref / f) ^ 3)) + (b3 * ((QW * fref / f) ^ 2)) + (b2 * (QW * fref / f))
ElseIf B >= 40 Then
    pumpeffic_visc = "ERROR, too viscous flow"
End If


End Function
End Function
```





Compression (gas)

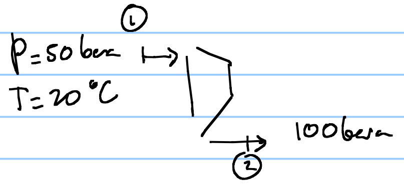


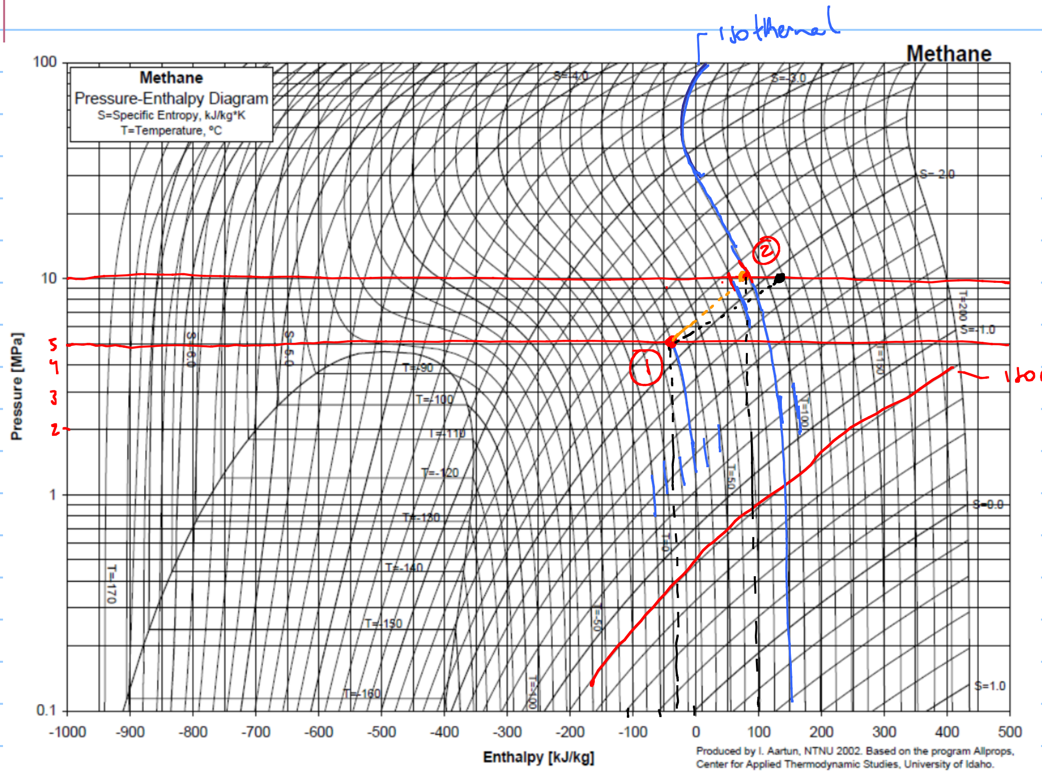
$$\dot{Q} - \dot{W} = \dot{m}\left(e_1 - e_2\right)$$

$$\underset{0}{\cancel{\dot{Q}}} - \dot{W} = \dot{m}\left(\cancel{\frac{v_1^2}{2g}} + \cancel{z_1} + h_1 - \cancel{\frac{v_2^2}{2g}} - \cancel{z_2} - h_2\right)$$

$$\underline{\dot{W}} = \dot{m}\left(\underline{h_1 - h_2}\right)$$

for Gullfaks exercise





Produced by I. Aartun, NTNU 2002. Based on the program Allprops, Center for Applied Thermodynamic Studies, University of Idaho.

50 bara → MPa

5 MPa

P_{dis} = 100 bara

10 MPa

isoentropy lines

$T_2 \simeq 85°C$

$$\dot{W}_s = \dot{m}\,(h_{2s} - h_1)$$

$$\dot{W}_s = 78 \frac{kg}{s} \cdot \left(100 \frac{kJ}{kg} + 25 \, kJ/kg \right) = 9837 \frac{kJ}{s} =$$

9.8 MW

$$q_g = 10\,E6 \; Sm^3/d$$

$$\rho_g = 0.68 \; kg/m^3$$

$$\dot{m}_g = \underline{10\,E6 \cdot 0.68} \; \frac{1\,d}{24\,h} \; \frac{1\,h}{3600\,s} = 78 \; kg/s$$

plan

- A (few) more comments to problem 2, exercise set 3
- Compression

- fixes to excel sheet
  - VBA function for ESP Power
  - coefficients for efficiency expression are on sheet


ESP Performance_water

there two methods to solve the exercise

Method 1

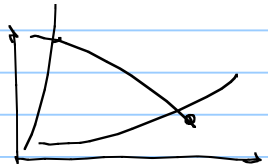
- remove the ESP
- make flow equilibrium at pump
  estimate available pressure at suction
  required pressure at discharge
- verify p_{suc}
  Required power $\left\{ \eta_H \text{(VBA)} \right.$ f visual interpolat.
  falls on map
  $P_{disc} - P_{suc} > 0$

Method 2

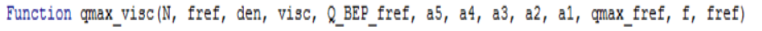
- include the ESP model
- use wellhead as equilibrium point
  $P_R \rightarrow P_{wf}$ (IPR)
  $P_{wf} \rightarrow P_{suc}$ (pipe eq.) (assume $\underline{f}$)
  $P_{suc} \rightarrow P_{disc}$ (ESP equation)
  $P_{disc} \rightarrow P_{wh}$ (pipe equi)
  P_{wh} avail.
  $P_{wh\,neasured} = 7$ bara

  change $f_{assumed}$ until $P_{wh\,calc} = 7$ bara

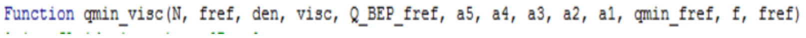
- Honor the pump constraints $30 \leq f \leq 60\,hz$
  $P \leq P_{max}$
  $P_{suc} \geq P_b \cdot F_s$ (safety factor)



$q_{min}(f,\mu) \leq q \leq q_{max}(f,\mu)$

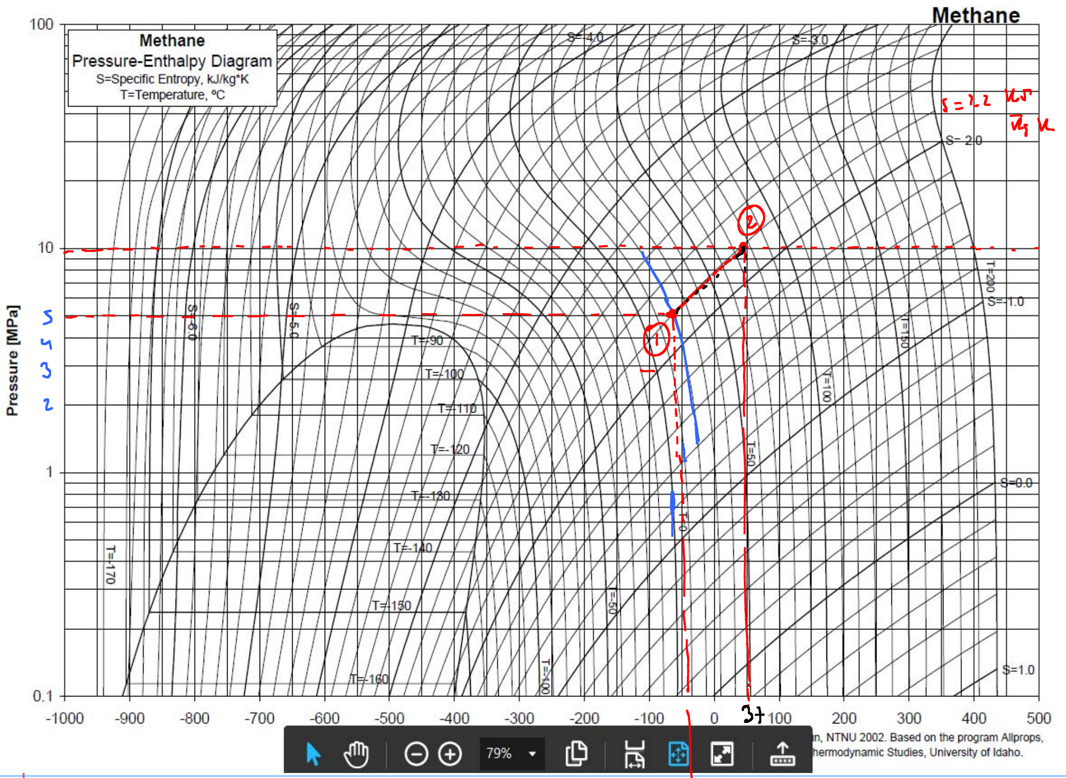


```
Function qmax_visc(N, fref, den, visc, Q_BEP_fref, a5, a4, a3, a2, a1, qmax_fref, f, fref)
```



```
Function qmin_visc(N, fref, den, visc, Q_BEP_fref, a5, a4, a3, a2, a1, qmin_fref, f, fref)
```

Compression



…n, NTNU 2002. Based on the program Allprops, …hermodynamic Studies, University of Idaho.

$P_{suc}, t_{suc} = 50$ bara

20 °C

↓

$P_{disc} = 100$ bara

$T_{dis} = 75$ °C

−67 kJ/kg

outlet temperature of the compressor has to be closely monitored → if too high (140°C)

- integrity of downstream pipe
- integrity of compressor seals
- inhibitor vaporization
  - hydrate inhibitor
  - scale inhibitor

$$\dot{W} = \dot{m}(h_2 - h_1)$$

$$= 78.\ \text{kg/s}\ (37 + 67) = 8112\ \frac{\text{kJ}}{\text{s}} = \underline{8.1\ \text{MW}}$$

current compressor installations subsea
Aasgard P = 11 MW
gullfaks P = 6 MW

isentropic expansion (P, T)

$$\left(\frac{P_2}{P_1}\right)^{\frac{k-1}{k}} = \left(\frac{T_{2s}}{T_1}\right)$$

↳ absolute units (K, °R)

$$\underline{\underline{k}} = \frac{C_p(T)}{C_v(T)}$$

$$\underbrace{k = 1.30 - 0.31(\gamma_g - 0.55)}$$

$$(293.15\ \text{K}) \cdot \left(\frac{100}{50}\right)^{\frac{1.3-1}{1.3}} = T_{2s}$$

$$T_{2s} = 344\ \text{K} = 70\ ^\circ\text{C} \quad \text{if isentropic}$$

the real compression process can be represented as polytropic $p \cdot v^n = \text{const}$

polytropic exponent

↳ specific volume

real process $\left(\frac{T_2}{T_1}\right) = r_p^{\frac{n-1}{n}}$

$T_2 > T_{2s}$ $\frac{T_{2s}}{T_1} = \underline{r_p^{\frac{n-1}{n}}}$ ↳ $\frac{T_2}{T_1} = r_p^{\boxed{\frac{k-1}{k}}}$

$r_p^{\frac{n-1}{n}} > r_p^{\frac{k-1}{k}}$ $n > k$

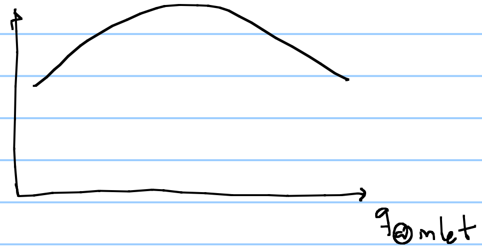
0 - 1

polytropic efficiency $\eta_p = \frac{k-1}{k}\frac{n}{n-1}$ η

dry gas compressor have a polytropic efficiency (0.6 - 0.8)

assume $\eta_p = 0.7$, $n =$

$\eta_p = f(q_{@\,inlet})$



$$\eta_p \frac{k}{k-1} = \frac{n}{n-1}$$

$$\frac{k-1}{k\eta_p} = 1 - \frac{1}{n}$$

$$\frac{1}{n} = 1 - \left(\frac{k-1}{k\eta_p}\right)$$

$$n = \frac{1}{1-\left(\frac{k-1}{k-\eta_p}\right)}$$

$$n = 1.5$$

$$T_2 = T_1 (r_p)^{\frac{0.5}{1.5}} = 293.15\,K \left(\frac{100}{50}\right)^{\frac{0.5}{1.5}} = 96\,°C$$

required compression power $P = \frac{\Delta h_p \cdot \overset{kg/s}{\dot{m}}}{\eta_p \cdot \eta_m}$ [W]

$$\Delta h_p = \underbrace{T_{suc}}_{[K]} \cdot \underbrace{Z_{av}}_{\frac{Z_{suc}+Z_{disc}}{2}} \cdot \underbrace{\overset{\text{specific gas}}{R}}_{\left(\frac{R_u}{MW_g}\right)\ \left[\frac{J}{kg\,K}\right]} \frac{n}{n-1}\left(r_p^{\frac{n-1}{n}} - 1\right) \quad \left[J/kg\right]$$

polytropic exponent

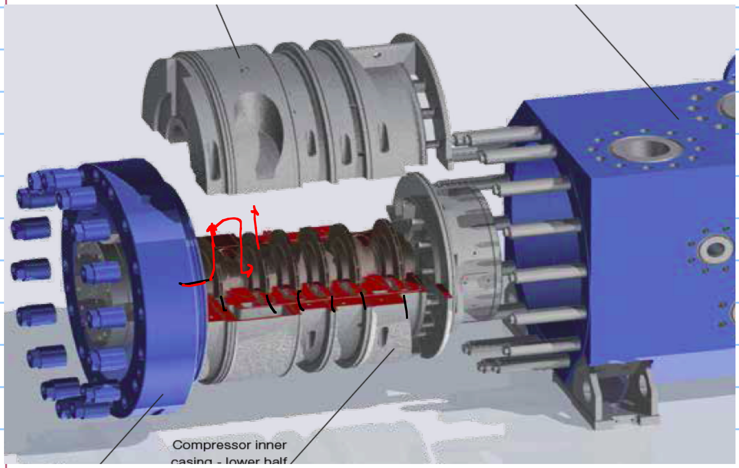
R_u universal gas constant 8314 $\frac{J}{kmol\ K}$

Tsuc for problem 1 exercise set 3 is 70°C

Dry gas compressor is made up of several stages | stages = rotor → give energy to fluid { increasing kinetic energy

stator → convert kinetic energy to pressure

typically (4-8 stages)



Aasgard centrifugal compressor MAN

↳ 6-7 stages

$P_{suc} = 50$ bara

$T_{suc} = 20$ °C

↓

$\boxed{1^{st} \text{ stage}}$

↓

P_1

T_1

↓

Usually two assumptions $\eta_{p_{STAGE}} = \eta_{p_{compressor}} = 1.5$

r_p per stage is constant

$$\frac{P_1}{P_{suc}} \quad \frac{P_2}{P_1} \quad \frac{P_3}{P_2} \quad \frac{P_4}{P_3} \quad \frac{P_5}{P_4} \quad \frac{P_{disc}}{P_5} = \left(\frac{P_{disc}}{P_{suc}}\right)$$

$$\left(r_{p_{stage}}\right)^{n_{stages}} = r_{p_{compressor}}$$

$$r_{p_{stage}} = \left(r_{p_{compressor}}\right)^{1/n_{stages}}$$

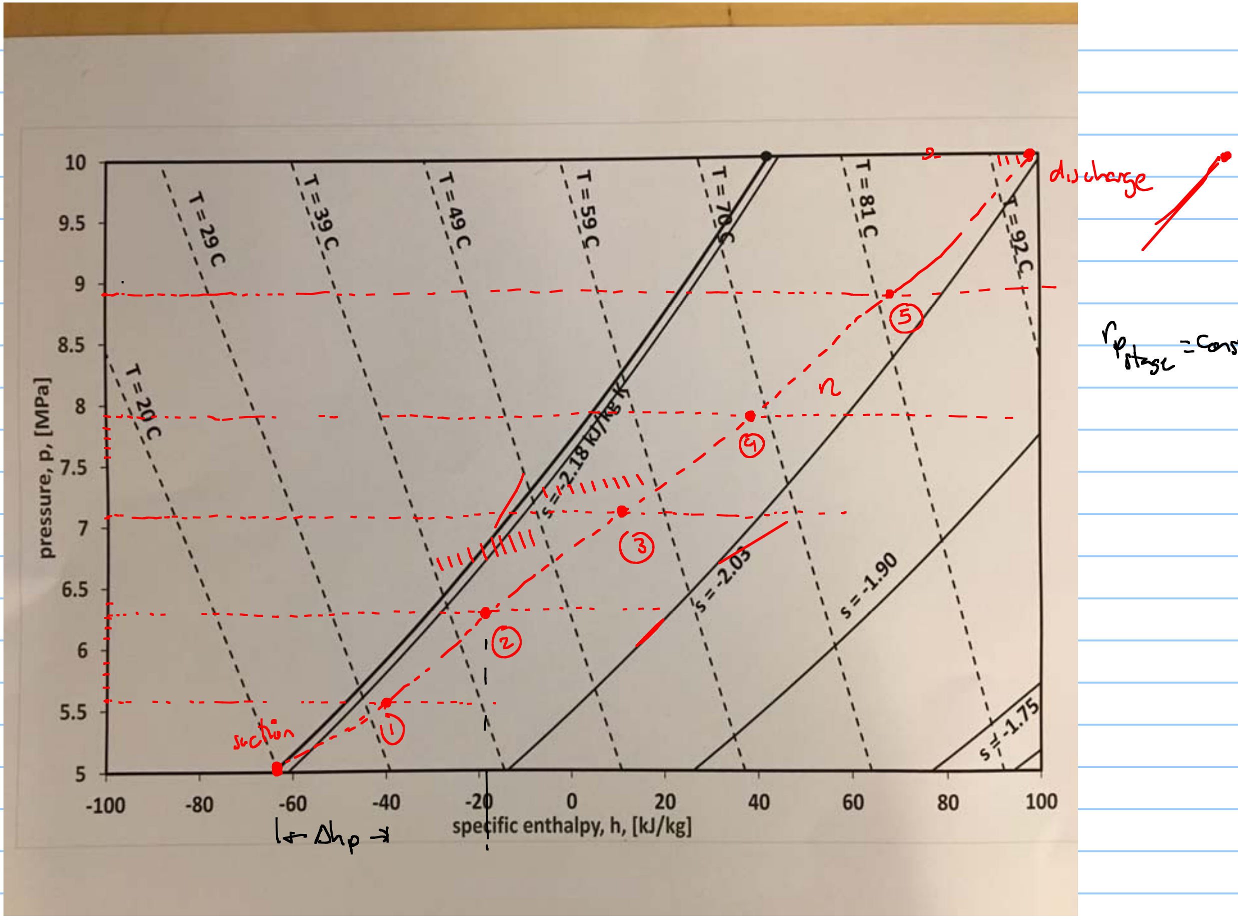
Calculate outlet conditions of each stage.

$$\left(\frac{P_{stage\ i}}{P_{stage\ i-1}}\right)^{\frac{n-1}{n}} = \left(\frac{T_{stage\ i}}{T_{stage\ i-1}}\right)$$

$$r_{p_{stage}} = \left(r_{p_{comp}}\right)^{1/n_{stages}}$$

$$r_{p_{compressor}} = \frac{100}{50}$$

Stage	P [bara]	T [°C]	T [K]
inlet			
1			
2			
3			
4			
5			
outlet			



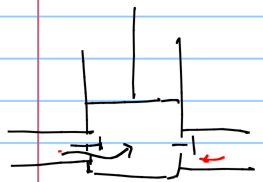
$r_{p_{stage}}$ = constant

another design approach $\Delta p_{stage} \simeq$ constant this gives a different r_p per stage
an uneven amount of energy
transferred in each stage

TENTATIVE DATE FOR DELIVERY OF EXERCISE SET 3 : 08.03.2019

Operational map of dynamic compressor (axial or centrifugal)

↳ typically used for high volume
high rate low-medium Δp

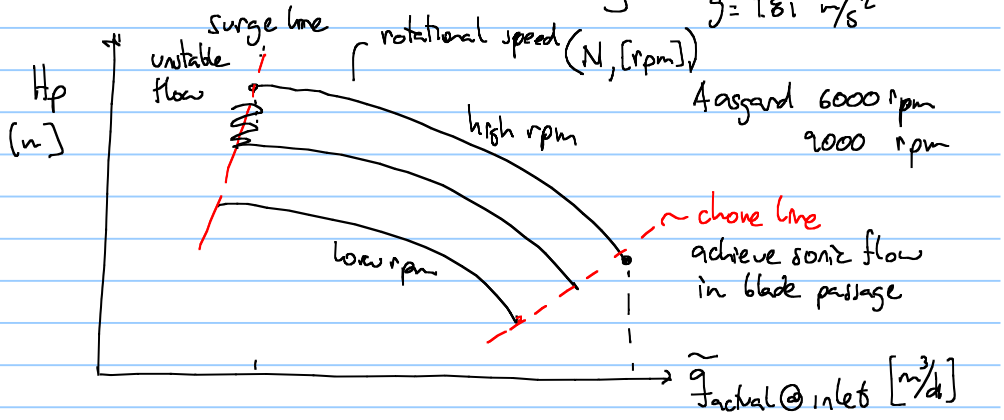


positive displacement machine

low rate
high Δp

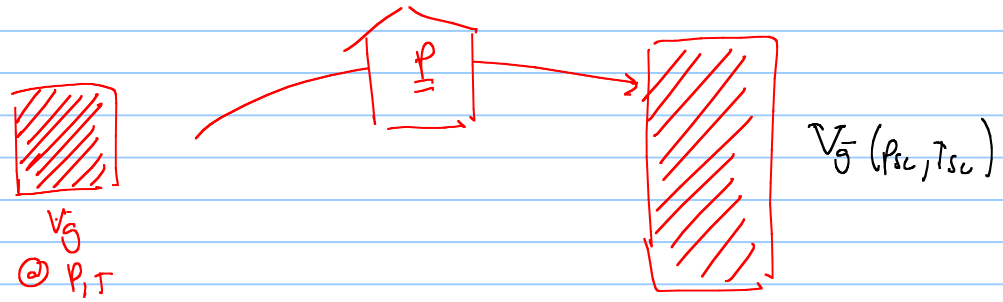
Δh_p polytropic head $H_p = \frac{\Delta h_p}{g}$ [m]

$g = 9.81$ m/s²



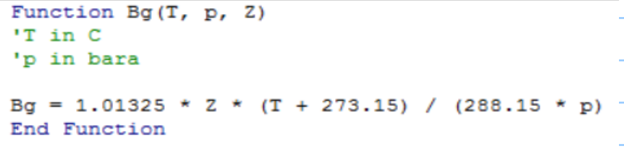
Aasgard 6000 rpm
9000 rpm

achieve sonic flow in blade passage

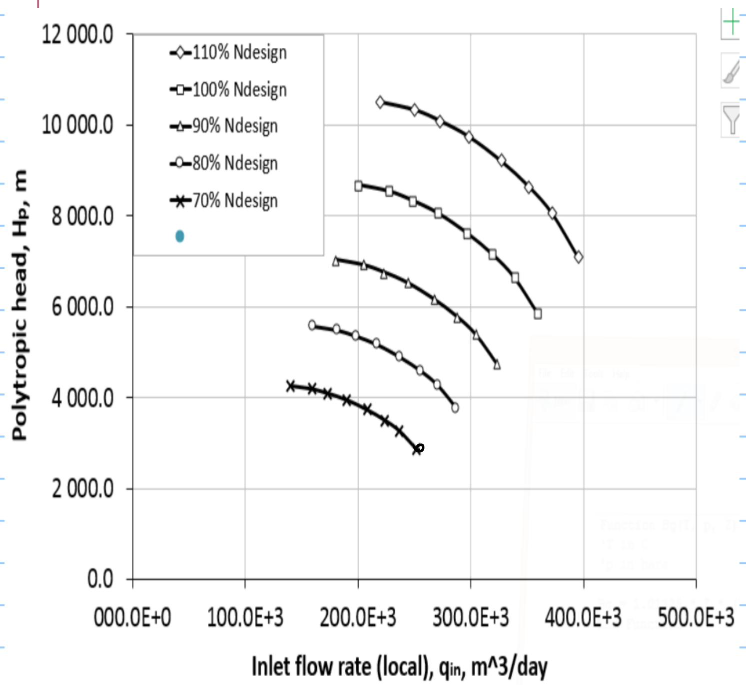


$$B_g = \frac{V_g(p,T)}{\bar{V}_g} \ll 1 \quad \sim 10^{-2}, 10^{-3}$$

$$q_{suction} = q_g \cdot \underbrace{B_g(p_{suc}, T_{suc})}$$



```
Function Bg(T, p, Z)
'T in C
'p in bara

Bg = 1.01325 * Z * (T + 273.15) / (288.15 * p)
End Function
```



this map is made with measured performance conditions generated at a test facility

T_{suc}^{test} ambient temperature

p_{suc}^{test} p = 1.01325 bara

$\underline{Mw} = 28.97$ kg/kmol

to find performance for actual operating conditions and fluids one has to convert each point in the map by using the following equations:

$$q_{new} = \underset{\sim}{q_{test}} \left(\frac{k_{new}}{k_{test}} \cdot \frac{Mw_{test}}{Mw_{new}} \cdot \frac{T_{new}}{T_{test}} \right)^{0.5}$$

[in K]

$$Hp_{new} = Hp_{test} \frac{k_{new}}{k_{test}} \cdot \frac{Mw_{test}}{Mw_{new}} \cdot \frac{T_{new}}{T_{test}}$$

to avoid calculating one new map for each year one can convert the operating condition H_p, q_{act} to "test" conditions

$$\left(\frac{k_{new}}{k_{test}} \cdot \frac{MW_{test}}{MW_{new}} \cdot \frac{T_{new}}{T_{test}}\right)^{-0.5} q_{actual} = q_{test}$$

$$Hp_{test} = Hp_{new}\left(\frac{k_{new}}{k_{test}} \cdot \frac{MW_{test}}{MW_{new}} \cdot \frac{T_{new}}{T_{test}}\right)^{-1}$$

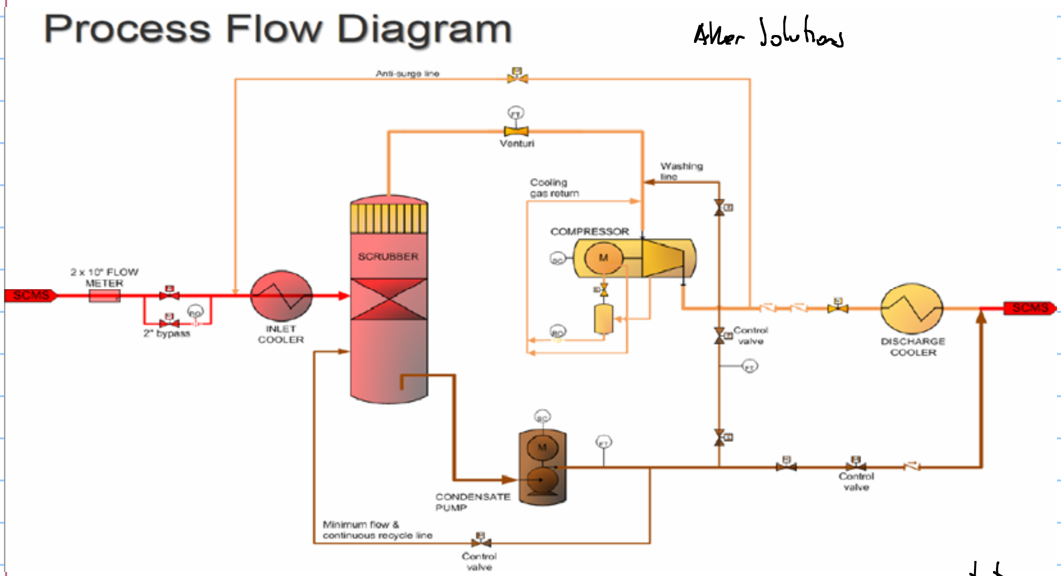
operational constraints for compressor:

- required power < motor power
- $T_{outlet} < T_{max}$ → { seal integrity, pipe integrity, inhibitor (liquid phase) }
- q_{act} H_p should fall on map)
- $P_{suc} > P_{min}$ (sometimes)

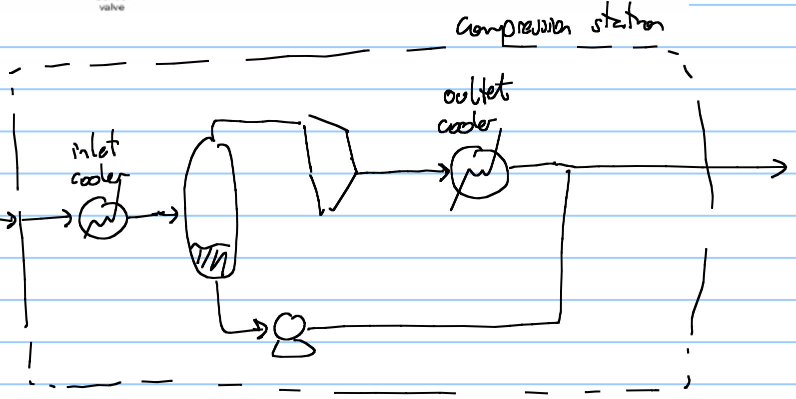
as a rule of thumb $\underline{r_p} \approx 3$

Process Flow Diagram

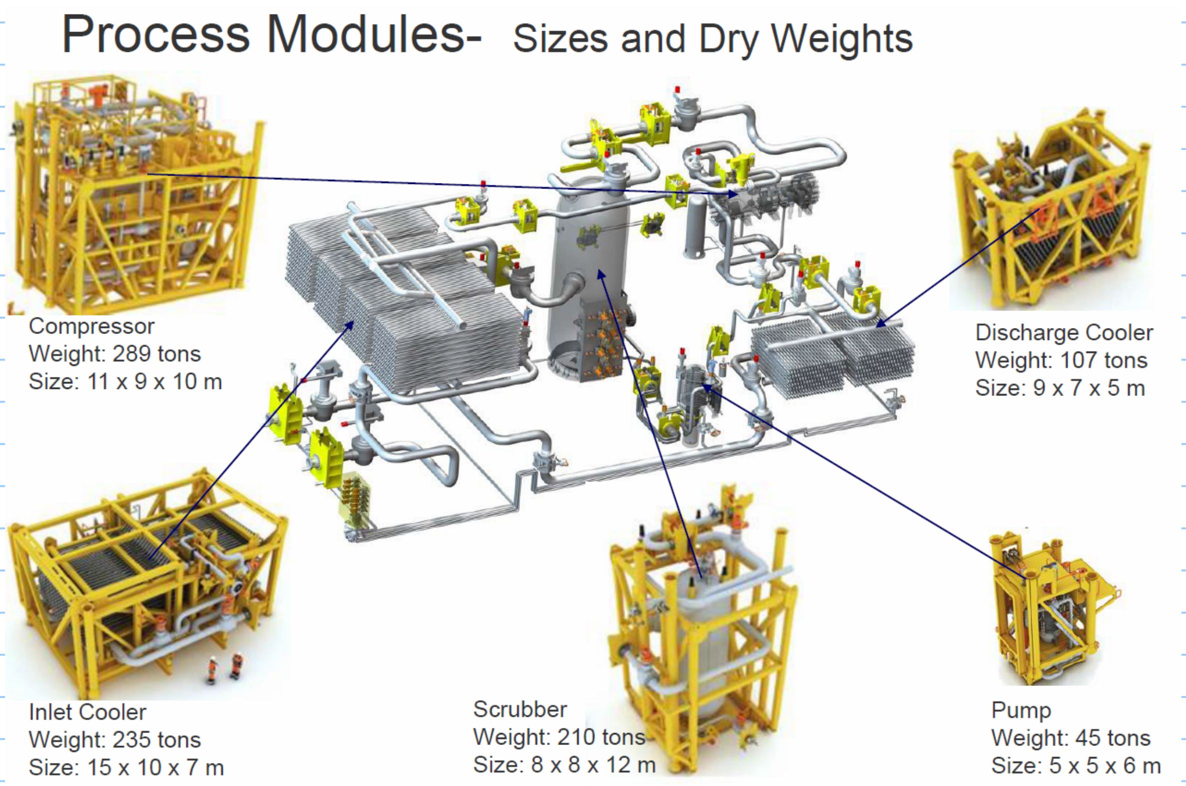
After Solutions



in Aasgard



inlet cooler
- lower outlet temperature
- remove liquid
- require less compression power for same Δp



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

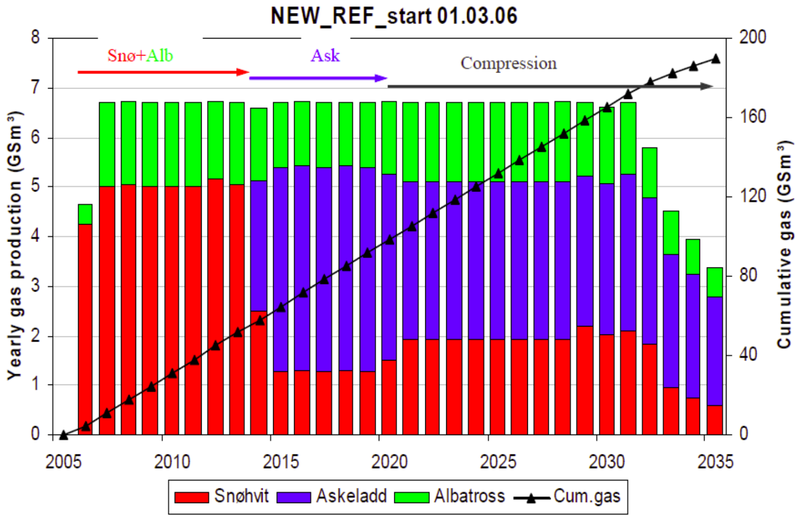
Scrubber
Weight: 210 tons
Size: 8 x 8 x 12 m

Pump
Weight: 45 tons
Size: 5 x 5 x 6 m

Compressor by MAN

compression station by Aker Solutions

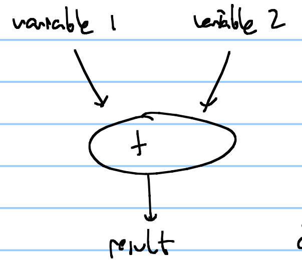
Production profile (20,8mill. Sm³/sd – 6,7 GSm³/år)



- Uncertainty quantification

especially big during the development phase

One way already covered. Ceteris Paribus → sensitivity analysis → purpose evaluate how KPI (key performance indicator) varies with input



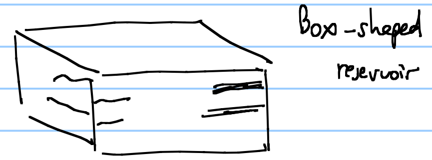
does not allow to evaluate ALL possible outcomes

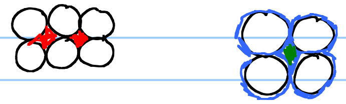
Probabilistic reserve estimation

$$\underline{\underline{N}} = \frac{V_R \cdot \Phi \; S_o \; N_{TG}}{B_o}$$

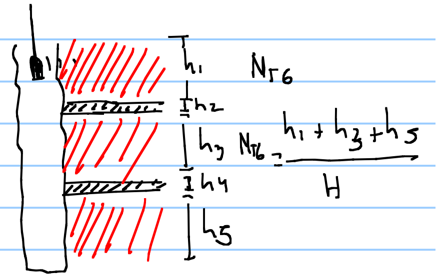
net to gross

OOIP





there are variations on all variables in that formula



$$N_{TG} = \frac{h_1 + h_3 + h_5}{H}$$

A probability distribution is typically used for variables that are uncertain

An example Φ 2287 core samples taken from exploration wells

Sample	Measured
1	Φ_1
2	Φ_2
3	Φ_3
4	Φ_4
.	.
.	.
.	.

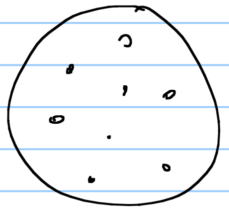
Φ_{min}

Φ_1

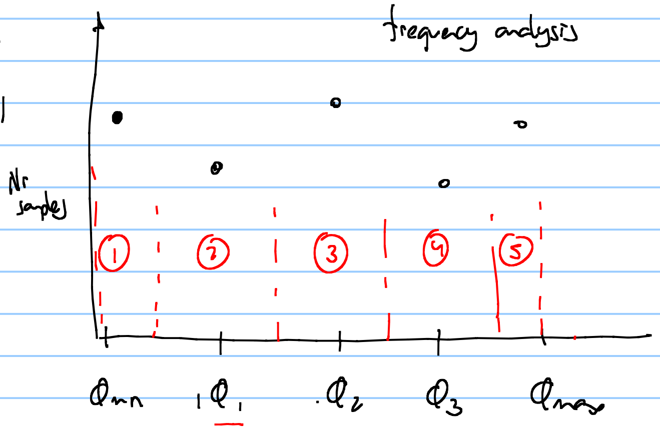
Φ_2

Φ_3

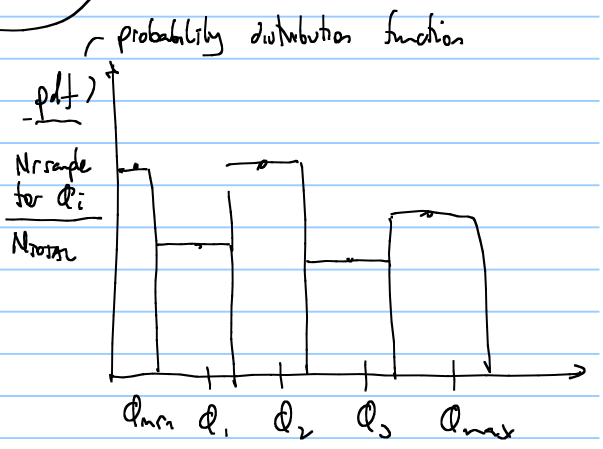
Φ_{max}



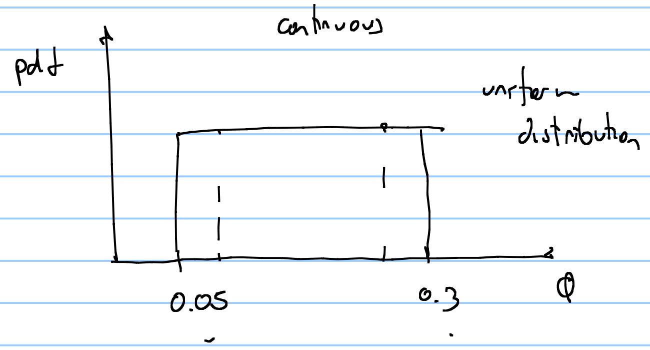
frequency analysis



discrete probability distribution function

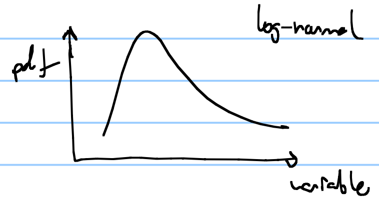


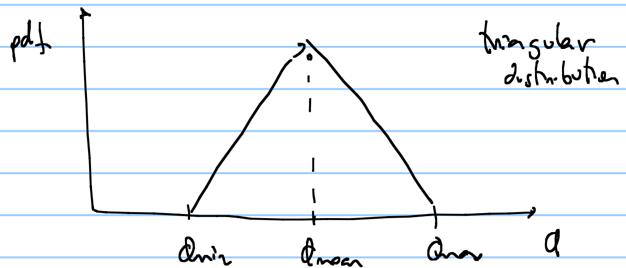
if I haven't made any measurements of porosity, I can assume a distribution

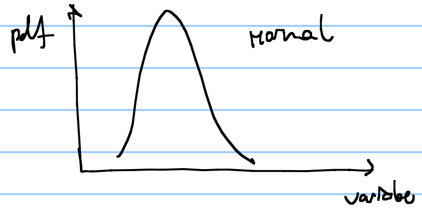


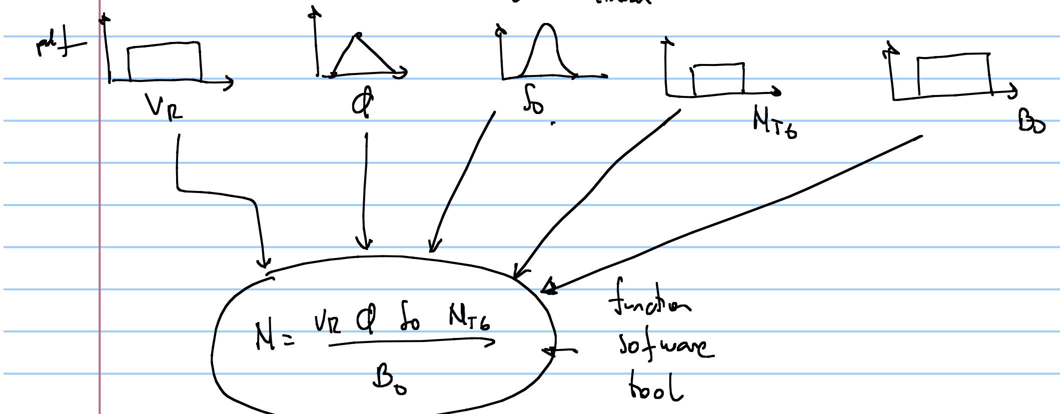
$\phi_{min} = 0.05$

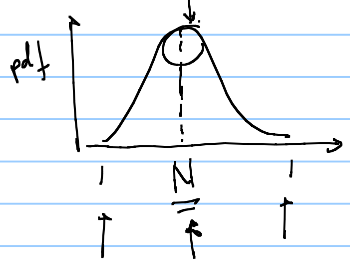
$\phi_{max} = 0.30$











the output distribution is affected by
- the distribution of input ←
- the type of function ←

Needed for:

Business identification phase

PDO

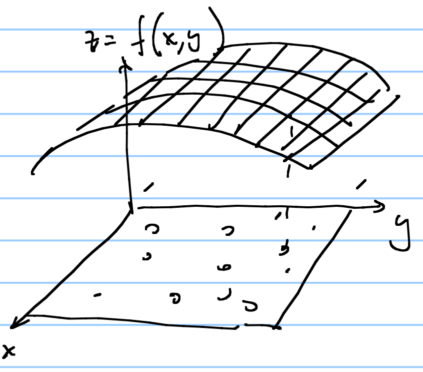
How to calculate the pdf of the output?

Sampling methods

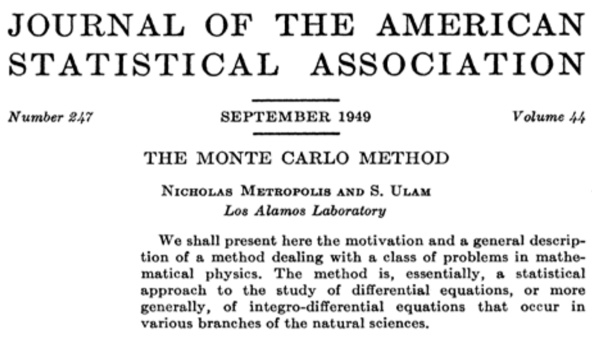
Random sampling

$x_1 \; y_1 \rightarrow z_{11}$

$x_1 \; y_2 \rightarrow z_{12}$



this is called Monte-Carlo method



JOURNAL OF THE AMERICAN STATISTICAL ASSOCIATION

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THE MONTE CARLO METHOD

NICHOLAS METROPOLIS AND S. ULAM
Los Alamos Laboratory

We shall present here the motivation and a general description of a method dealing with a class of problems in mathematical physics. The method is, essentially, a statistical approach to the study of differential equations, or more generally, of integro-differential equations that occur in various branches of the natural sciences.

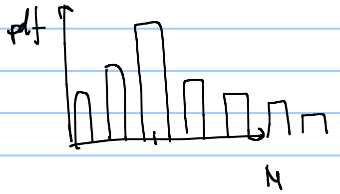
to calculate pdf of output

repeat for N times

- assume a random number for input (for each variable)
- run simulation / calculate output
- Register / store output

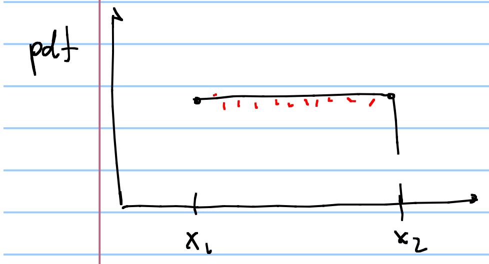
Apply a frequency analysis on output

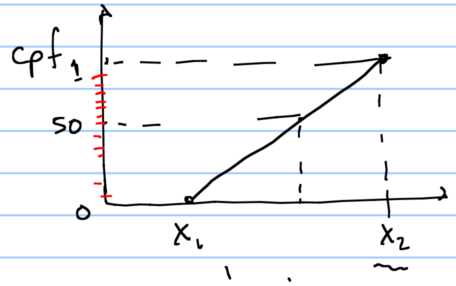
obtain pdf



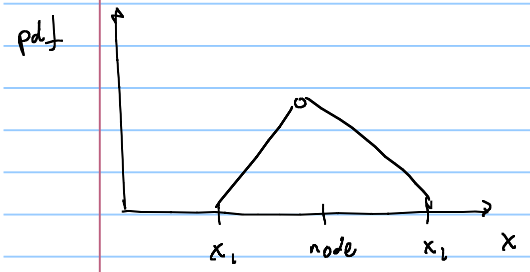
N should be chosen such as the resulting pdf doesn't change significantly

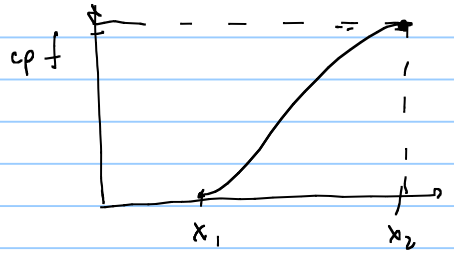
the random sampling is typically done on cpf (cumulative probability function)

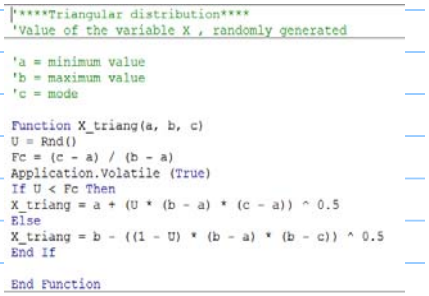




$X = X_{min} + RAN()(X_{max} - X_{min})$

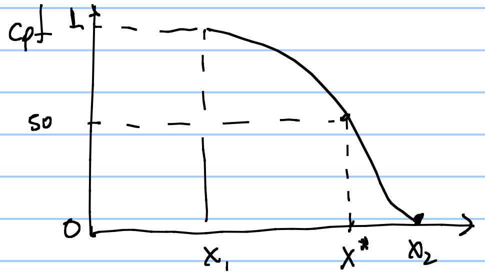




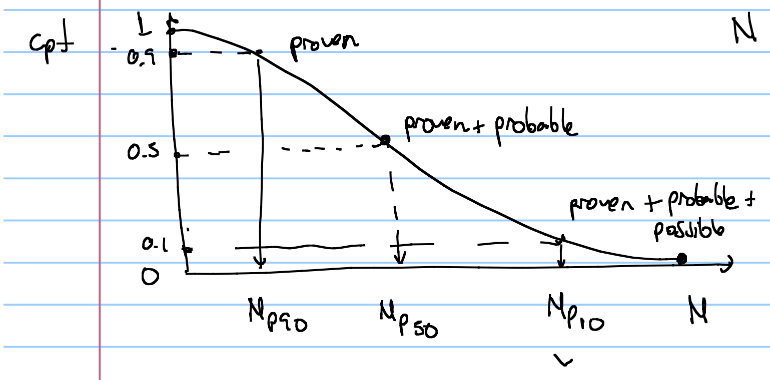


```
'****Triangular distribution****
'Value of the variable X , randomly generated

'a = minimum value
'b = maximum value
'c = mode

Function X_triang(a, b, c)
U = Rnd()
Fc = (c - a) / (b - a)
Application.Volatile (True)
If U < Fc Then
X_triang = a + (U * (b - a) * (c - a)) ^ 0.5
Else
X_triang = b - ((1 - U) * (b - a) * (b - c)) ^ 0.5
End If

End Function
```

cpf can also be plotted



for reserves we used the "reversed" cpf



N_{P90} there is 90% probability that N is equal or higher than P90

N_{P50} there is 50% probability that N is equal or higher than P50

N_{P10} there is 10% probability that N is equal or higher that P10

Some companies / countries use different %

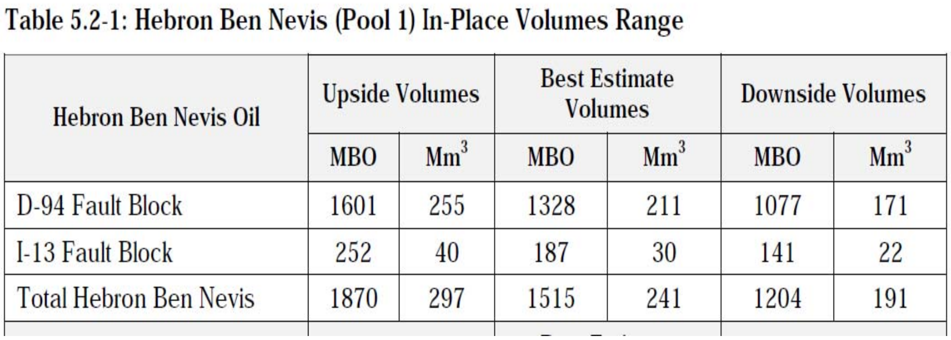
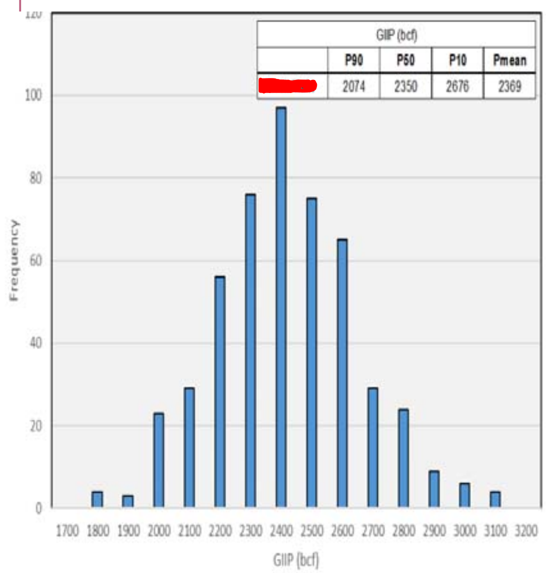


Table 5.2-1: Hebron Ben Nevis (Pool 1) In-Place Volumes Range

Hebron Ben Nevis Oil	Upside Volumes		Best Estimate Volumes		Downside Volumes	
	MBO	Mm³	MBO	Mm³	MBO	Mm³
D-94 Fault Block	1601	255	1328	211	1077	171
I-13 Fault Block	252	40	187	30	141	22
Total Hebron Ben Nevis	1870	297	1515	241	1204	191

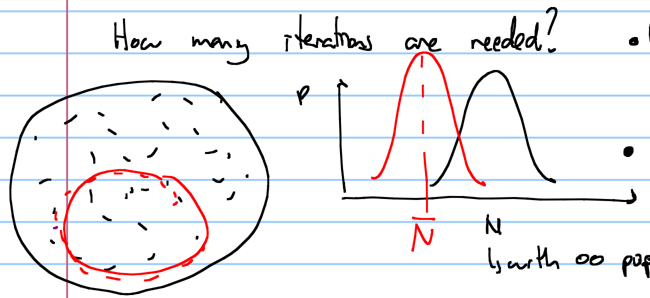


GIP (bcf)				
	P90	P50	P10	Pmean
[redacted]	2074	2350	2676	2369

the applicability of Monte Carlo depends on the running time of "function" "simulator"

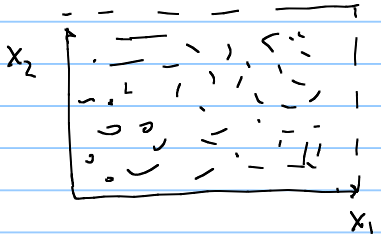
How many iterations are needed?

- Procedure 1 trial and error increase "N" until results don't change



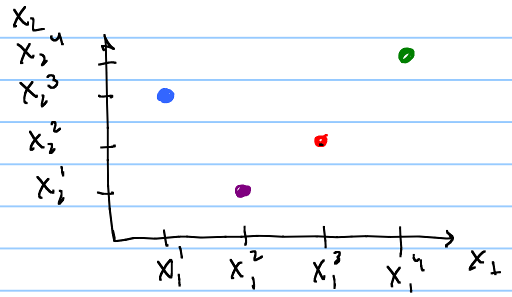
- $n_t = \left(\frac{3 \cdot S_x}{Error}\right)^2$ 3-1 standard deviation central limit theorem

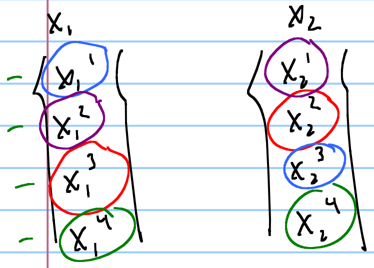
3-7% $\bar{N}$ ~ average of simulation point there are other sampling method



Latin hypercube

create N points for each variable. N is the number of simulations





Simulation 1

$x_1^3 \; x_2^2$ →

Simulation 2

○ ○

Simulation 3

○ ○

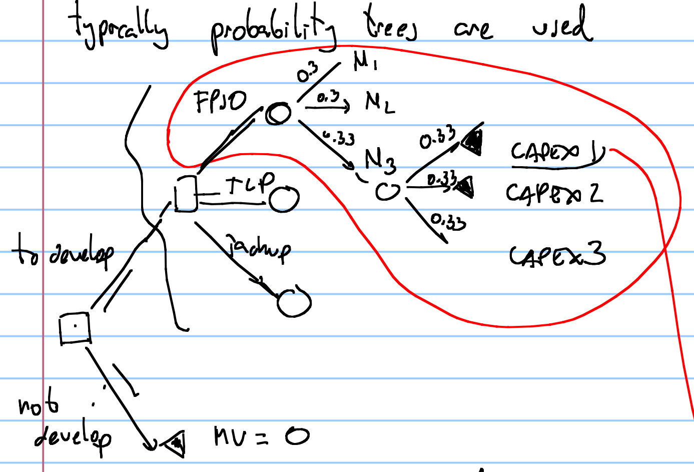
Simulation 4

What happens when Monte Carlo takes a very long time? → impractical

When I have non-continuous variables?

FPSO
TLP
Jackup

typically probability trees are used



□ decision nodes

○ chance nodes

◀ terminal node

Layer 1	Layer 2	Layer 3	Layer 4
develop decision	offshore structure	reserve size	cost

chance nodes come with a probability!

→ FPSO, N_3, CAPEX 1

EMV expected monetary value (NPV)

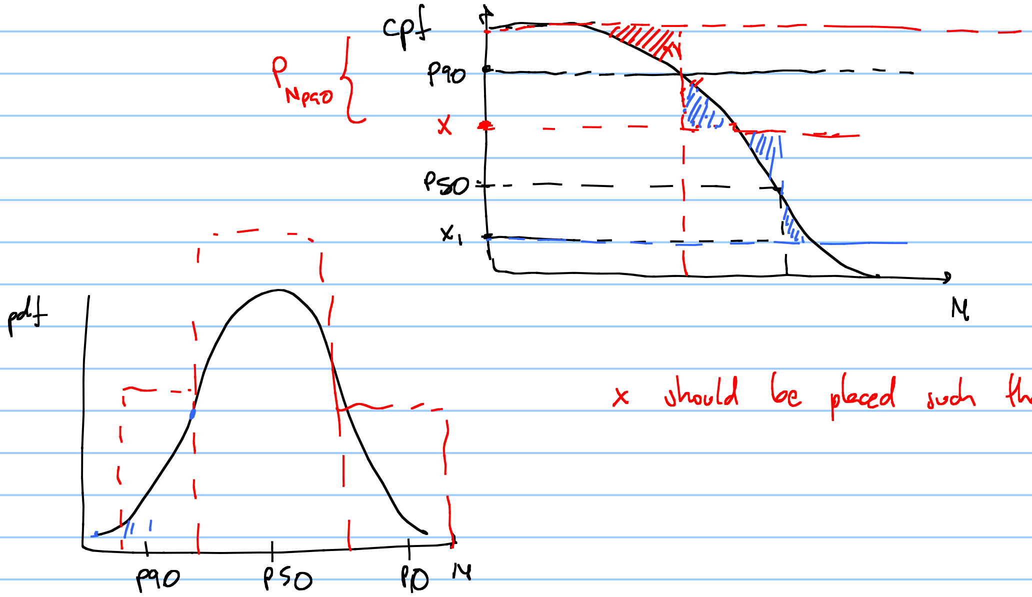
Probability of option

$P_{N_3} \cdot P_{CAPEX_1} = 0.33 \cdot 0.33$

If I wish to use $N_1 = P10$ what are Probabilities?

$N_2 = P50$

$N_3 = P90$



x should be placed such that ▨ = ▨

option' to calculate the EMV of a branch

$$EMV_{branch} = \sum_{i=1}^{N} P_i \, EMV_i$$ of all options on that branch

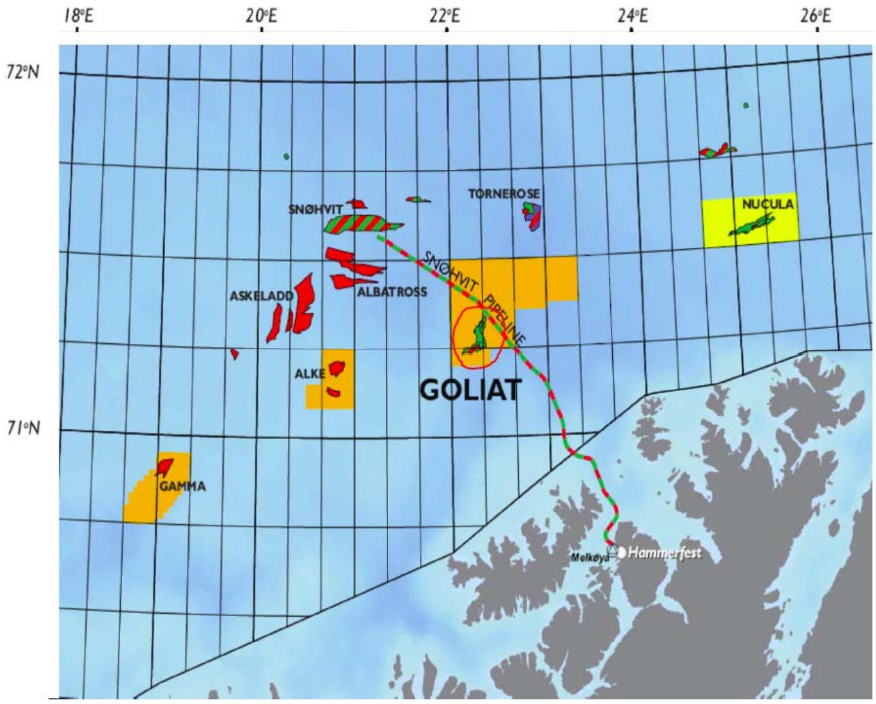
Class Exercise

Problem 1: Estimation of porosity probability distribution from exploration drilling data.

Exxon mobil has collected 2287 core samples from six cored wells in the Ben Nevis reservoir of the Hebron development. Porosity has been measured for all samples (see the results in the attached excel file). Using this data, calculate the probability distribution function of porosity in the reservoir.

Problem 2: Probabilistic estimation of Original oil in place of the Kobbe Formation

The company ENI has found a reservoir in the Barents sea, Kobbe, 50 km south of the Snøhvit field and 80 km from the LNG plant of Snøhvit in Hammerfest (Melkøya). The water depth in the area is 360 – 420 metres and, luckily, is an ice-free area. The company is evaluating to produce it and baptized the field: Goliat.



The reservoir contains oil with a thin overlying gas cap and it lies approximately 1800 meters beneath the seabed. The static reservoir pressure is 190 bar.

As part of the early development studies and as required by the Norwegian authorities, your first task is to perform a probabilistic estimation of the total recoverable reserves and the original oil in place of the Kobbe reservoir. The subsurface group has provided (in the excel sheet attached) information on the factors needed to calculate hydrocarbon pore volume: rock volume, net to gross, oil saturation, porosity (all based on a triangular probability distribution). The oil formation volume factor is represented by a uniform distribution.

Assumptions and extra information:

Use the following equation to calculate Initial oil in place (N):

$$N = \frac{V_R \cdot \varphi \cdot S_o \cdot \left(N_{TG}\right)}{B_o}$$

All the input information given is uncertain and reported as a uniform or triangular distribution (min, max or Min, Mode, Max). The details of the distributions have been given in class.

Tasks:

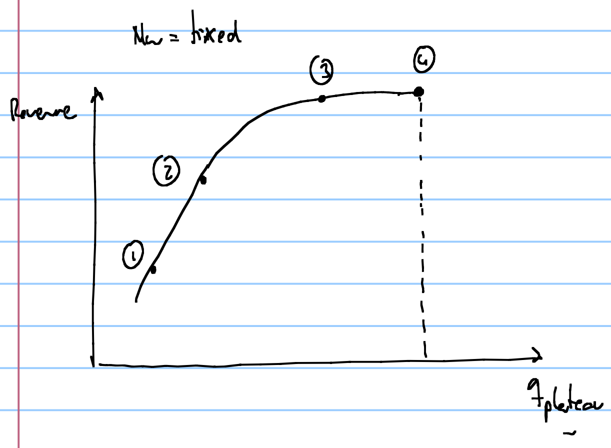
-Perform a Monte Carlo Simulation Study (using 500 and 5000 simulations) to obtain the expected value of the Total Recoverable Oil Reserves and the initial oil in place. Report the outcome as:

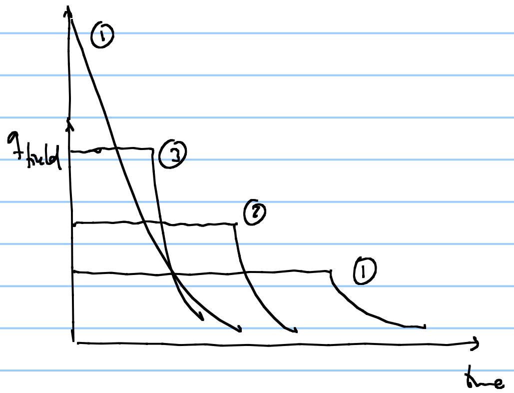
- Expected value (Mean or Average)
- Most probable value (mode)
- Median (P50), P10, P90
- Expectation curve for the Total Recoverable Oil Reserves (Plot of Cumulative Probability) and the initial oil in place
- Compare the results when using 500 and 5000 simulations

- Review of exercise set 2 → especially problem 1
- Short refreshment on MC. and probability trees

— // —

Exercise set 1

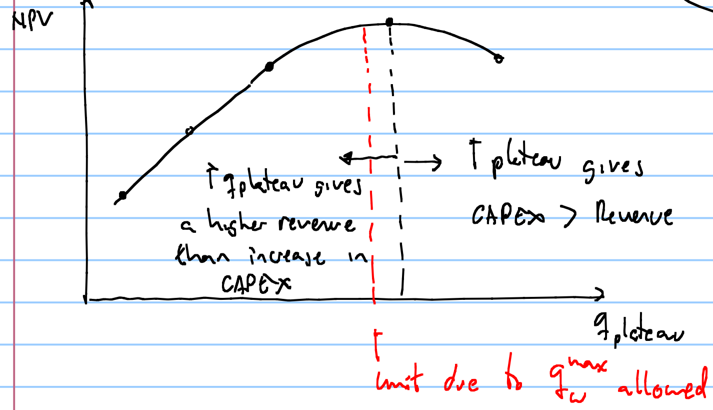




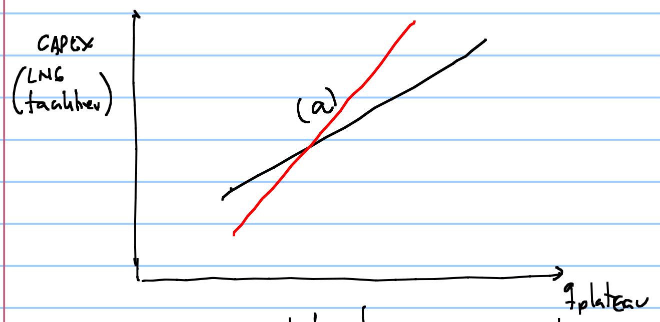
$$NPV = \underbrace{Revenue} - \underline{\underline{CAPEX}} - \underbrace{DRILLEX}_{Fixed / constant}$$

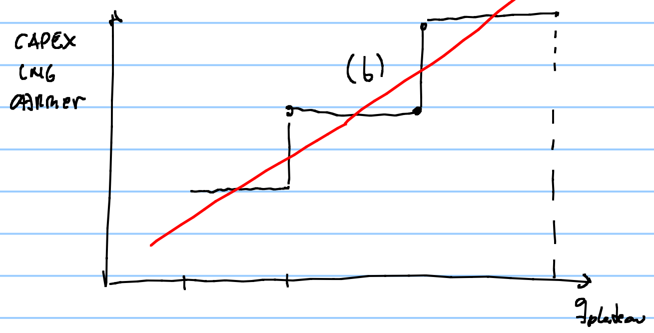
$$CAPEX_{Facilities} = f(q_{plateau})$$

Nw = fixed



for our case $CAPEX_{Facilities}$





valid for a range of variation of $q_{plateau}$

where is the maximum of NPV?

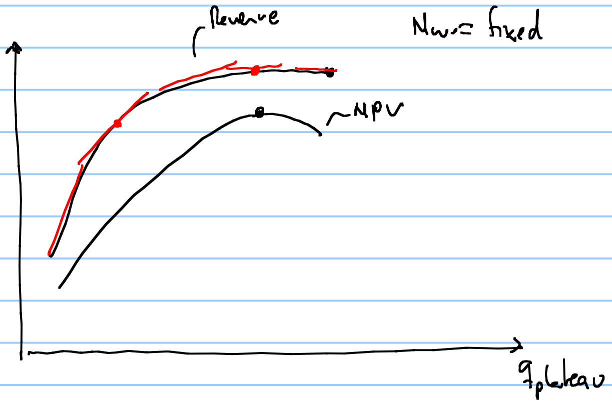
$$\frac{\partial NPV}{\partial q_{plateau}} = 0 \qquad NPV = Revenue - CAPEX - OPILEX$$

$$\frac{\partial Revenue}{\partial q_{plateau}} = \frac{\partial CAPEX}{\partial q_{plateau}}$$

affected by slopes "a" and "b"

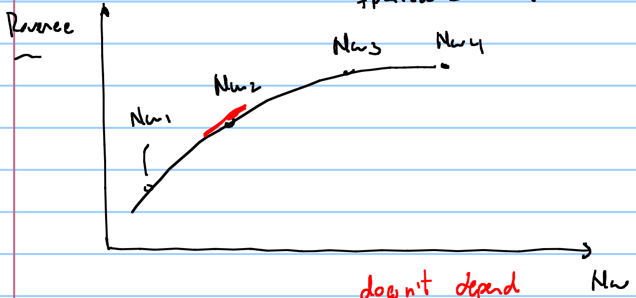
if LNG facilities only $\frac{\partial CAPEX}{\partial q_{plateau}} = a$

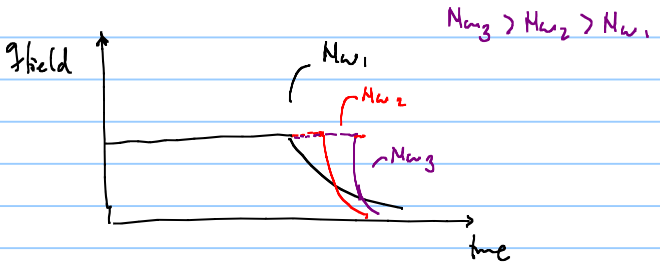
Nw = fixed



what about Nw?

qplateau = fixed





doesn't depend strongly on Nw in our case

NPV = Revenue − CAPEX − OPILEX

LNG plant
LNG carrier
subsea system
$= f(q_{plateau})$

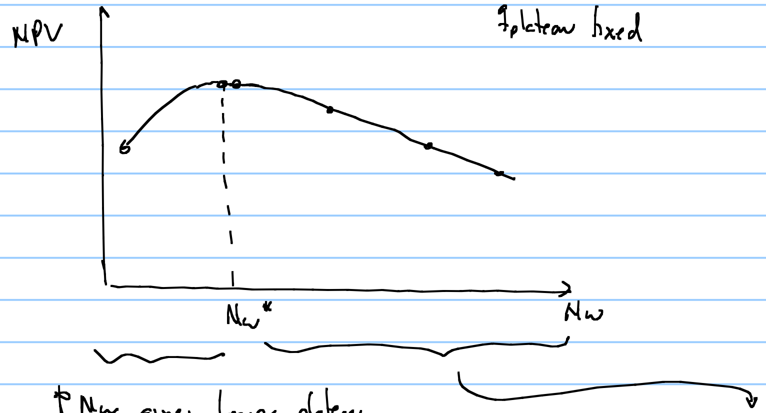
for a linear production potential (undersaturated oil case)

$$t_{plateau} = \left(\frac{q_{PPo}}{q_{plateau}} - 1\right)\frac{1}{m}$$

$$q_{PPo} = N_w \cdot q^{w}_{PPo}$$

$$m = \frac{1}{N_w A J}$$

$$t_{plateau} = \left(\frac{q^{w}_{PPo}}{q_{plateau}} - \frac{1}{N_w}\right)\frac{1}{AJ}$$



↑N_w gives longer plateau
increases the revenue
increase in revenue > increase in drillex

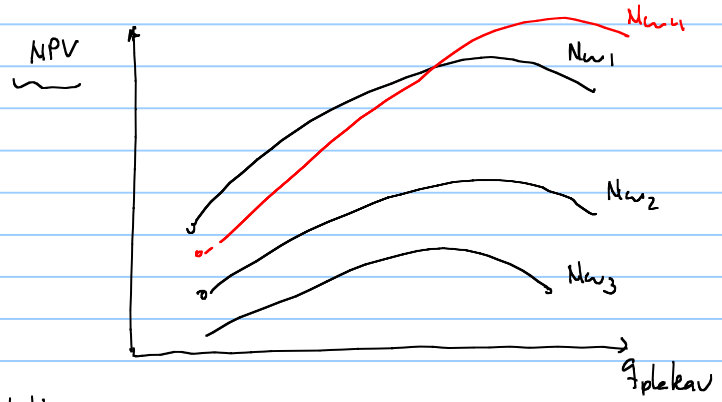
Increase in DRILLEX > increase in Revenue

$$\frac{\partial NPV}{\partial N_w} = 0 \qquad \frac{\partial Rev}{\partial N_w} = \underbrace{\frac{\partial DRILLEX}{\partial N_w}}_{\text{is a big number, } \frac{0.1}{N_w} \text{ 1E9 USD}}$$

→ that's where the maximum is located

NPV vs $q_{plateau}$ ✓ Nw is fixed

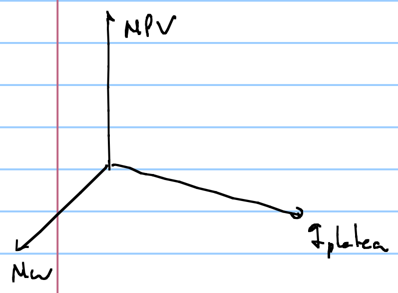
NPV vs Nw ✓ $q_{plateau}$ is fixed

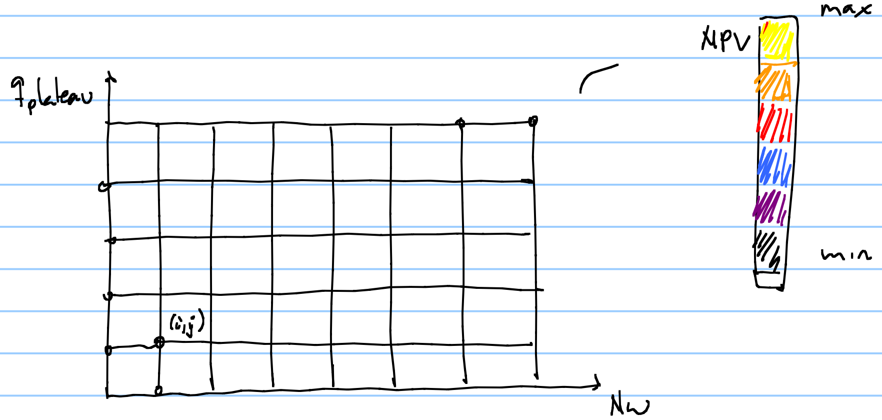


A better way:

Color map

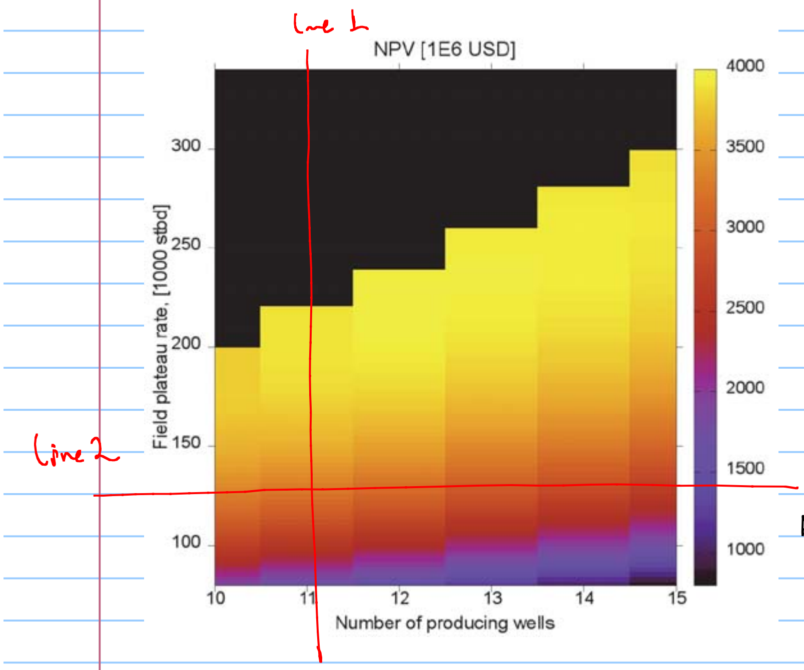
3D plot





evaluate all combinations i, j

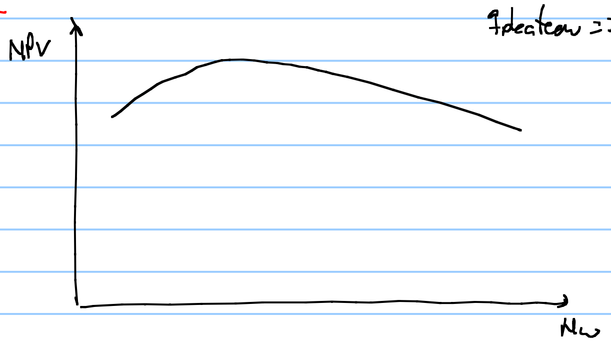
Example from the compendium, Page 102. offshore oil field, undersaturated.



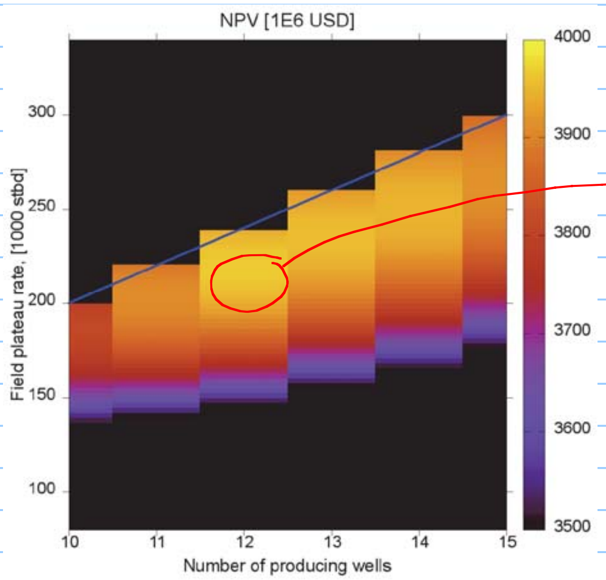
along line 1

along line 2

$q_{plateau}$ = fixed



adjusting the color scale for NPV:



best Nw vs. $q_{plateau}$ combination for this field

Nw = 12, $q_{plateau}$ = 210000 stb/d

$CAPEX_{\text{FACILITIES, LNG PLANT}} \neq f(Nw)$

in reality they are also affected by Nw

$CAPEX = CAPEX_{\text{offshore structure}} + CAPEX_{\text{subsea}} + CAPEX_{\text{TOPSIDE FACILITIES}} + CAPEX_{\text{LNG CARRIER TANKER}}$ (remaining OPEX)

subsea:
umbilicals
↳ manifolds
template
flowlines
pipeline

↳ it is also affected by Nw, specially for structure that houses wellheads/x-mas trees to estimate the cost of facilities one should include also

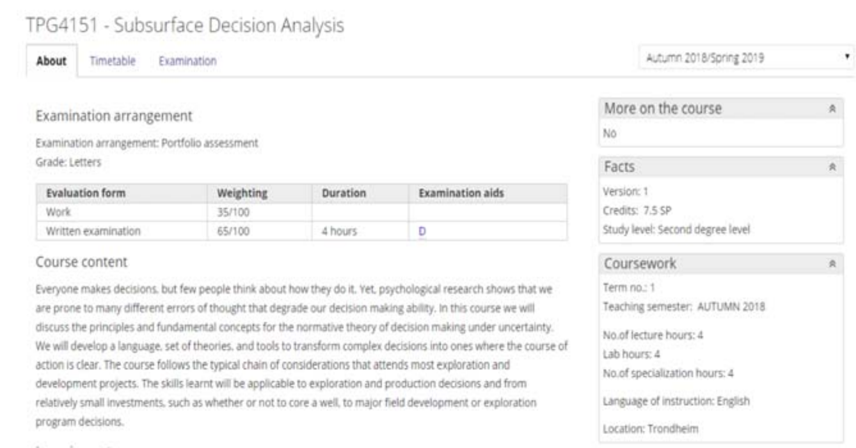
$q_{\bar{o}}$

$q_{\bar{w}}$

$q_{\bar{g}}$

$$CAPEX_{facilities} = f(\overset{\downarrow}{q_{\bar{o}max}}, \underline{\overset{\downarrow}{q_{\bar{g}max}}}, q_{\bar{w}max})$$

//



TPG4151 - Subsurface Decision Analysis

Examination arrangement

Examination arrangement: Portfolio assessment

Grade: Letters

Evaluation form	Weighting	Duration	Examination aids
Work	35/100		
Written examination	65/100	4 hours	D

Course content

Everyone makes decisions, but few people think about how they do it. Yet, psychological research shows that we are prone to many different errors of thought that degrade our decision making ability. In this course we will discuss the principles and fundamental concepts for the normative theory of decision making under uncertainty. We will develop a language, set of theories, and tools to transform complex decisions into ones where the course of action is clear. The course follows the typical chain of considerations that attends most exploration and development projects. The skills learnt will be applicable to exploration and production decisions and from relatively small investments, such as whether or not to core a well, to major field development or exploration program decisions.

More on the course

No

Facts

Version: 1

Credits: 7.5 SP

Study level: Second degree level

Coursework

Term no.: 1

Teaching semester: AUTUMN 2018

No.of lecture hours: 4

Lab hours: 4

No.of specialization hours: 4

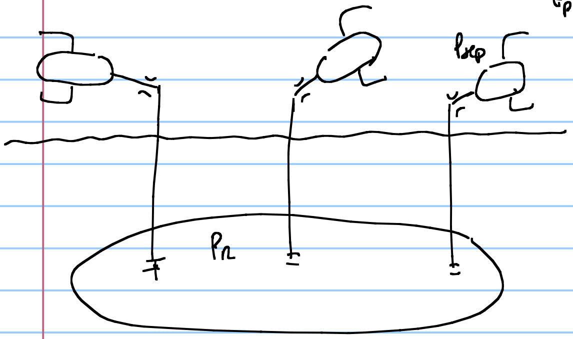
Language of instruction: English

Location: Trondheim

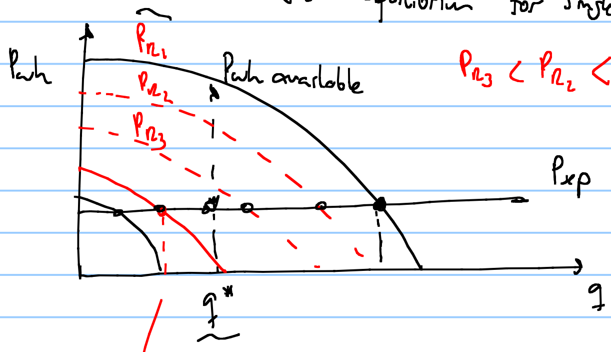
- Problem 2 exercise set 2

$q_{plateau} = 80000 \ Sm^3/d$ ✓

$t_{plateau} = 5$ years ✓



flow equilibrium for single well



$P_{R_3} < P_{R_2} < P_{R_1}$

with MB $P_R = f(G_p)$

$q_{eq} < q^*$ with eq $q_{fw}^{max} = f(P_R)$

single well production potential $\underbrace{q_{fw}^{pot} = q_{pp}^{w} - m\,G_p}$

no inference between $q_{field}^{pot} = N_w \left(q_{pp}^{w} - m\,G_p \right)$

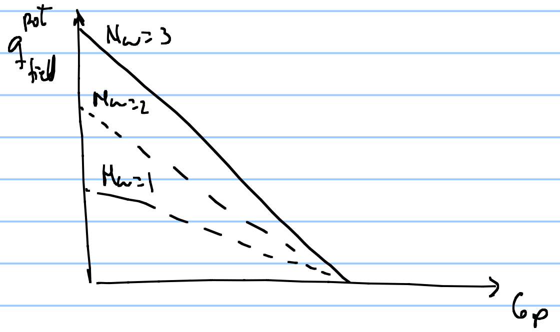
Approach Nr 1

Nwell 1 $N_w \cdot q_{well}^{pot}$

time	G_p	q_{well}^{pot}	q_{field}^{pot}	q_{field}
0	0			
1				
2				
3				
4				
5				
6				

if $q_{field}^{pot} > 80000 \ Sm^3/d$ then $80000 \ Sm^3/d$

else $q_{field} = q_{field}^{pot}$



$\left.\begin{array}{l} q_{plateau} = 80000 \ Sm^3/d \\ t_{plateau} = 5 \text{ year} \end{array}\right\} G_p^* = G_p^{plateau\ end} = 80000 . 5 . 365$

$q_{field}^{pot} @ G_p^{plateau\ end} \geq 80.000 \ Sm^3/d$

$q_{field}^{pot} = \left(q_{pp_0}^{w} - m\,G_p \right) N_w$

$\left(q_{pp_0}^{w} - m\,G_p^* \right) N_w \geq 80.000 \ Sm^3/d$

$N_w \geq \dfrac{80000}{q_{pp_0}^{w} - m\,G_p}$

for the post-plateau production profile ~> method 1

if q_{pp} is linear $t \leq t_{plateau}$ $q_{field} = q_{plateau}$

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

$$t_{plateau} = \left(\frac{q^{field}_{PPo}}{q_{plateau}} - 1 \right) \frac{1}{m}$$

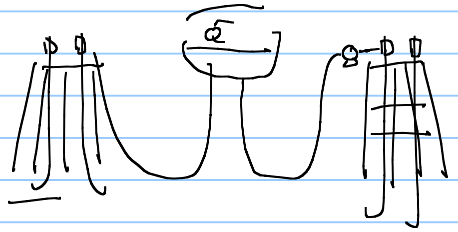
$m_{field} = m_{well} \cdot N_w$

$q^{field}_{PPo} = q^{w}_{PPo} \cdot N_{wells}$

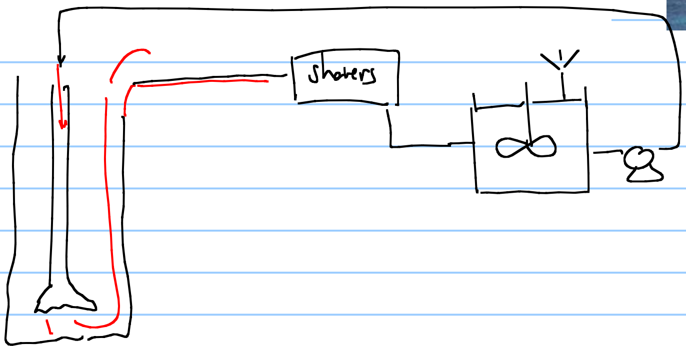
Offshore structures for oil and gas production

Not all of these are in the same offshore structure!

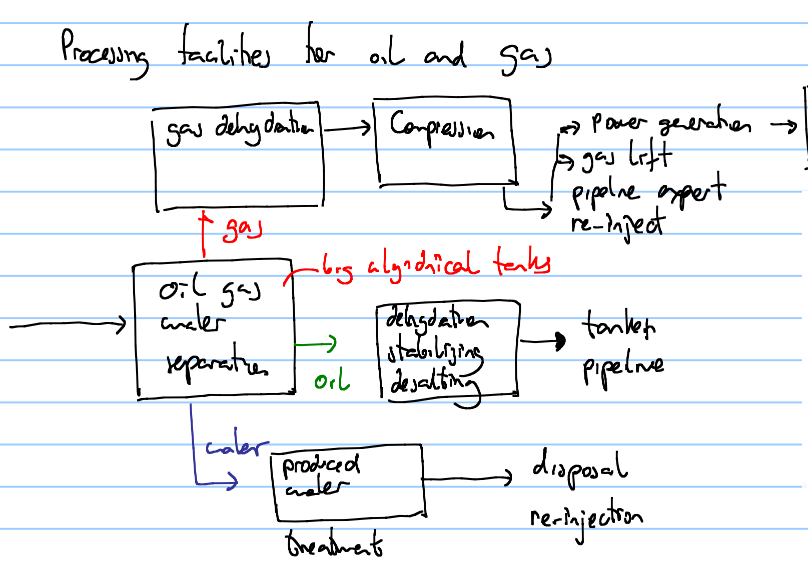
- Facilities for drilling and full intervention. This includes drilling tower, BOP, drilling floor, mud package, cementing pumps, storage deck for drill pipes and tubulars, drilling risers. (optional.) ↑ $
- Facilities for light well intervention. ~ wireline operations, coiled tubing
- Processing facilities: separator trains for primary oil, gas and water separation, gas processing train, water processing train.
- Gas injection system ✓
- Gas compression units for pipeline transport ✓
- Water injection system ✓
- Living quarters ✓
- Helideck. ✓
- Power generation. ~ gas turbine
- Flare system. → open/close valves
- Utilities (hydraulic power fluid, compressed air, drinking water unit, air condition system, ventilation and heating system)
- Bay for wellheads and christmas trees (optional) ~ dry X-mass tree
- Production manifolds ~> testing
- Oil storage ~>
- Facilities for oil offloading ~ to tanker
- Control system
- Monitoring system
- System for storage, injection and recovery of production chemicals (wax, scale, hydrate or corrosion inhibitors)
- Repair workshop

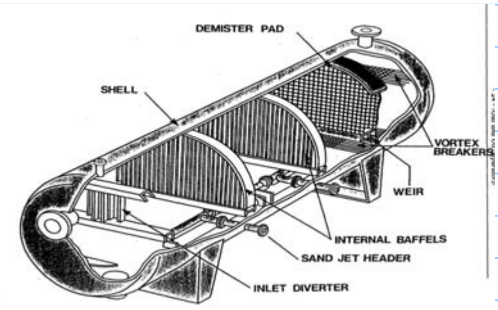


peregrino field



Processing facilities for oil and gas



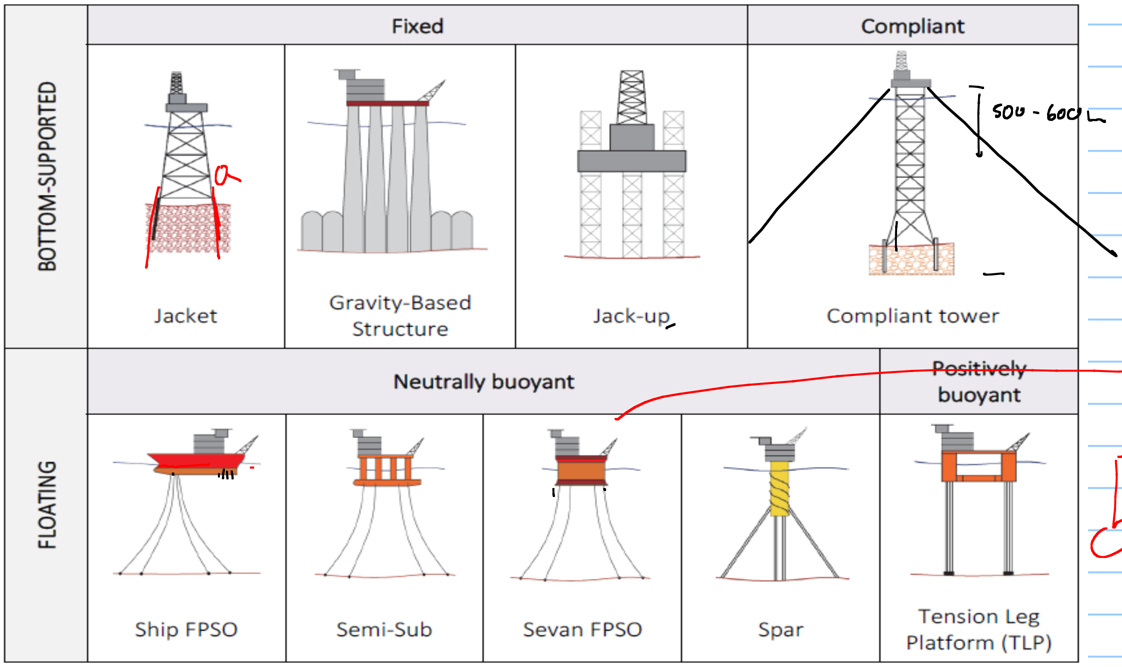


type of offshore structure for oil and gas production.

for intervention, deployment, drilling

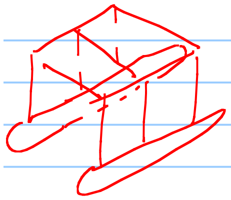
	Fixed			Compliant
Bottom supported	Jacket	GBS gravity Based structures	Jackup	compliant tower
	Neutrally bouyant			Positively bouyant
floating	FPSO	semi submersible	sevan FPSO	TLP

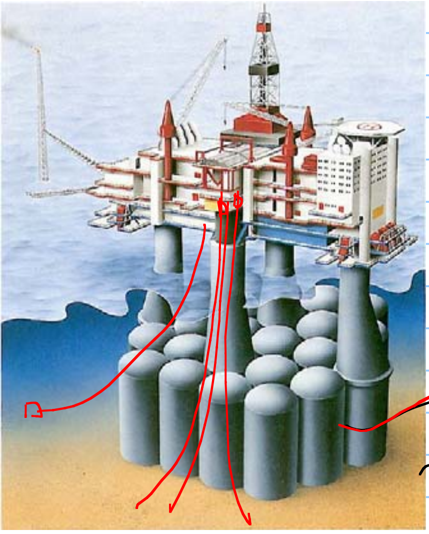
TLP — tension leg platform



GoM
Gulf of
mexico

Goliat (ENi)



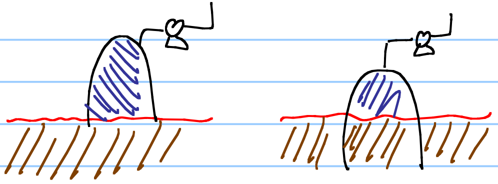


storage

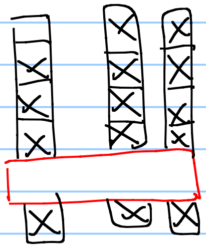
100 – 300000 Stb

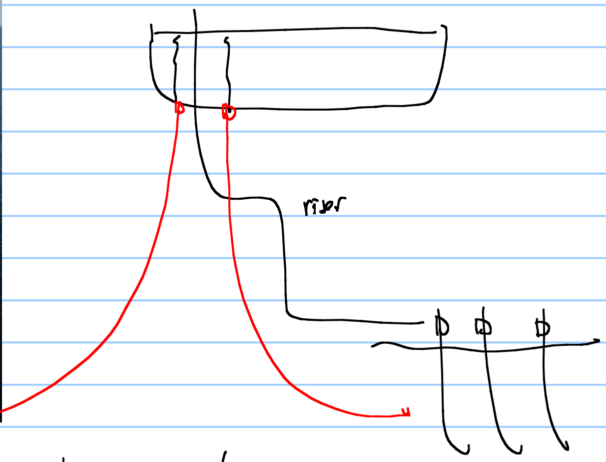
GBS

after pumping

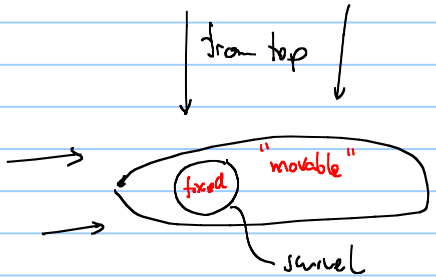


suction anchor



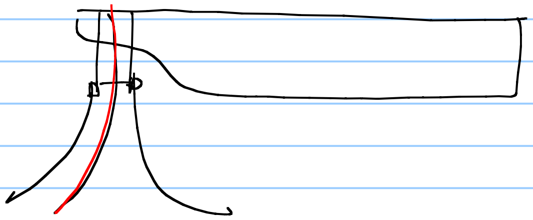


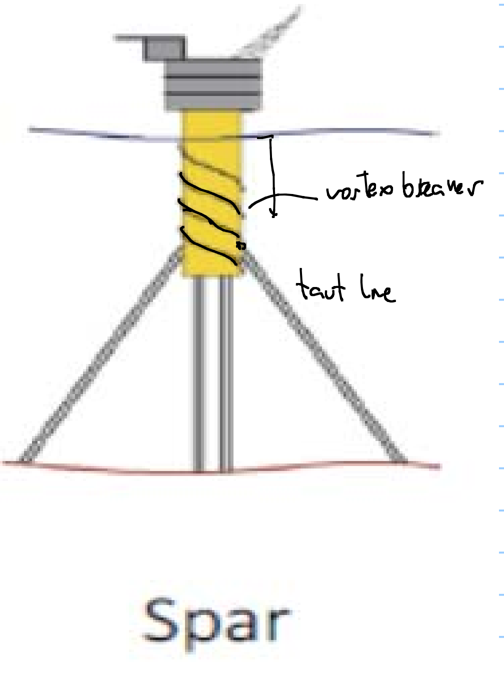
Big storage → 1 E06 → 3 E06 stb

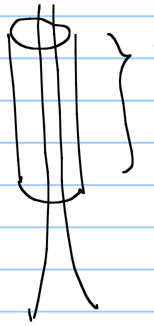


for rough weather conditions the FPSO often has to rotate

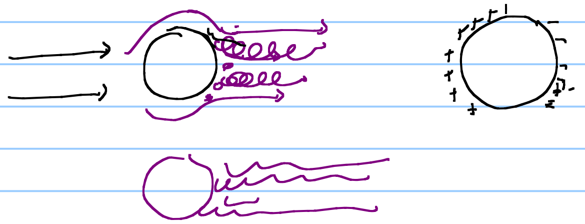
Asta Hansteen

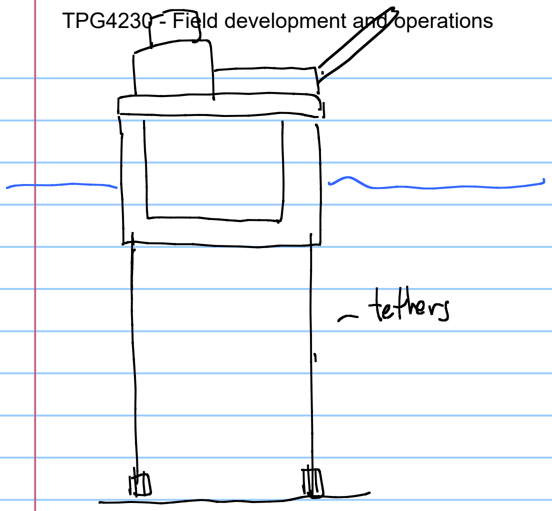


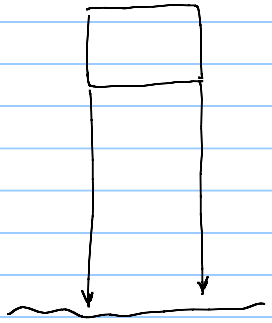


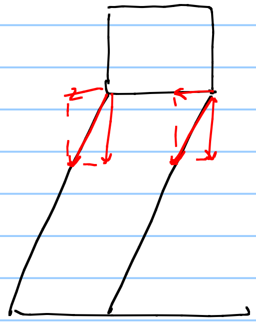


very long to reduce movement of structure



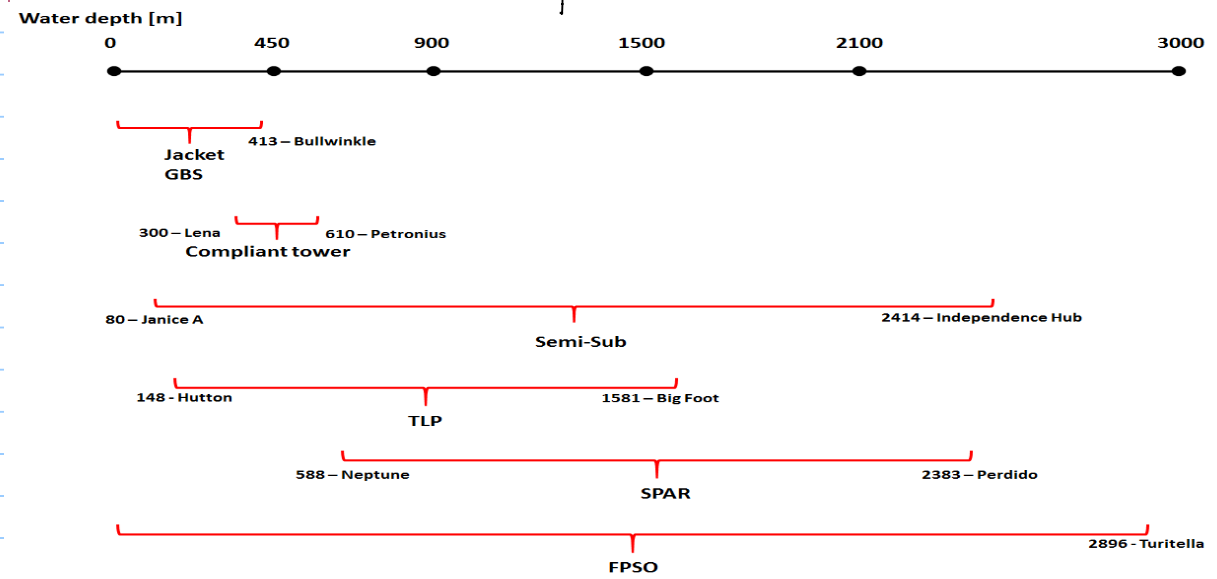






How do we select offshore structures: (technical reasons)

1: water depth
- <500-600 m → bottom-supported structured
- >500-600 → floating structure



2 • location of well tree → dry / → wet (subsea)

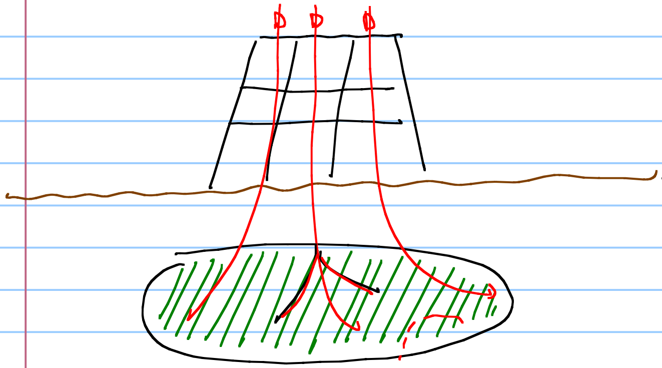
3 • Need for oil storage

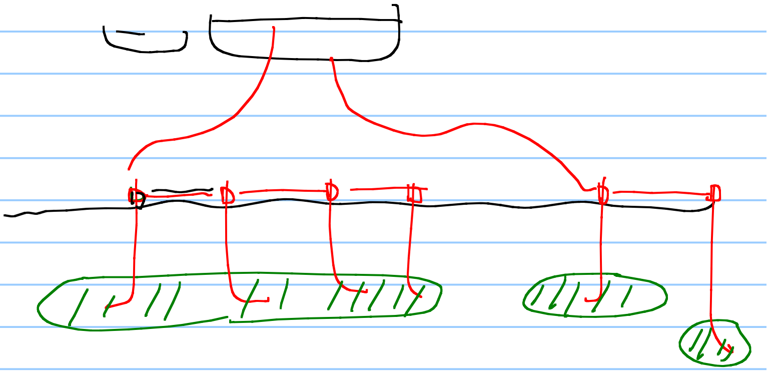
4 • marine loads

• Location of tree: - water depth dry X-mas tree is 1500 m water depth

- reservoir spread / structure

concentrated reservoir

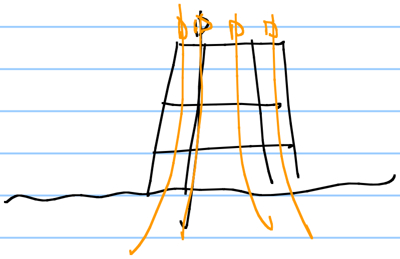




- well intervention needs = → tubing replacement
  → completion modification
  → artificial lift (ESP)

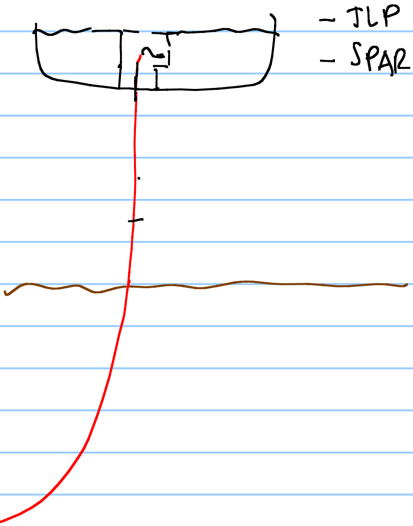
→ if frequent intervention is expected ~> dry with drilling package
" " " is not expected ~> wet

- infill drilling? → if yes ~> dry X-mass tree with drilling package



the only offshore structures that allow dry X-mass tree are:

- jacket
- jackup
- GBS
- compliant tower
- TLP
- SPAR



- Consideration when selecting an offshore structure (cont)
- Layout of production systems → (Subsea)

Vortex shedding (cool video) by Harvard science demonstrations

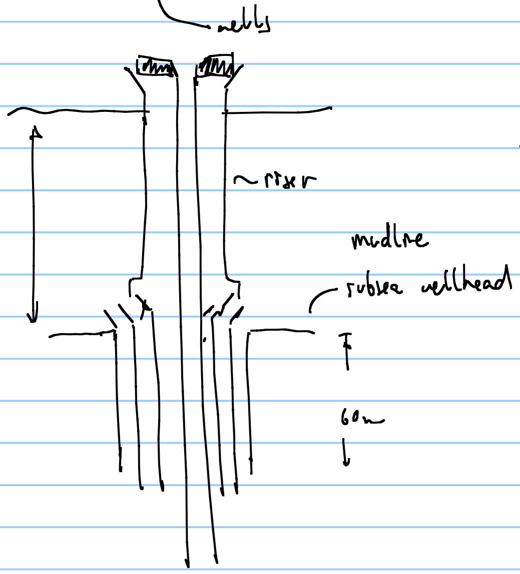
https://www.youtube.com/watch?v=_Hbbkd2d3H8&feature=youtu.be

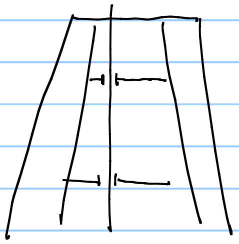
Structures that allow dry x-mas tree → Bottom-supported → if water depth is small, well are drilled like onshore

→ SPAR, TLP, Semi-sub?

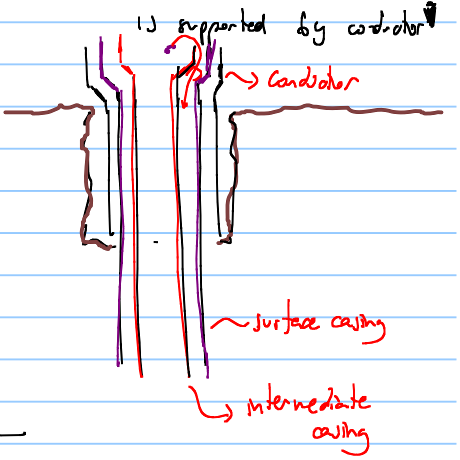
TLP → movement is restricted by tethers

SPAR → long hull limits movement





weight of the well is supported by conductor



for deep waters, the weight of the well is partly transfered to the soil with a subsea wellhead and partly supported by buoyancy cans or tensioners

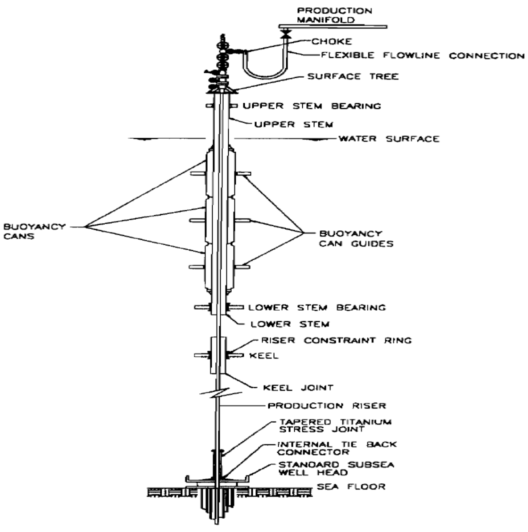


Figure 6 - Well System

OTC 8382

Neptune Project: Spar History and Design Considerations
R.S. Glanville, J.E. Halkyard, R.L. Davies, A. Steen, F. Frimm, Deep Oil Technology, Inc.

OTC 16199

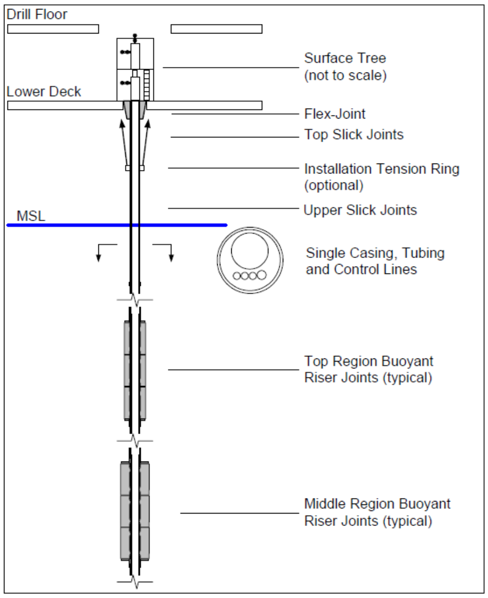
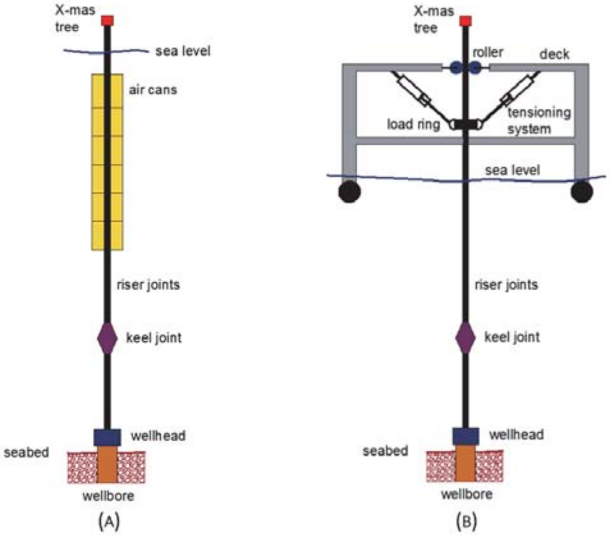
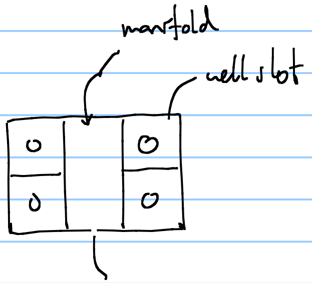


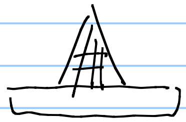
Figure 7a Production CVAR Stack-up (top half)

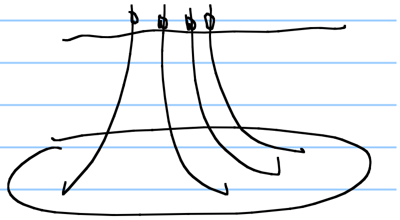


Layout of Subsea production systems

- template well (cluster)







♡ Norway

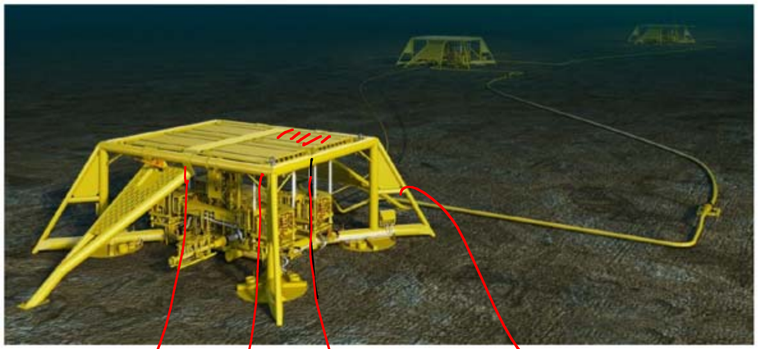
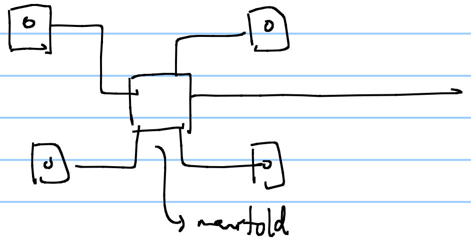
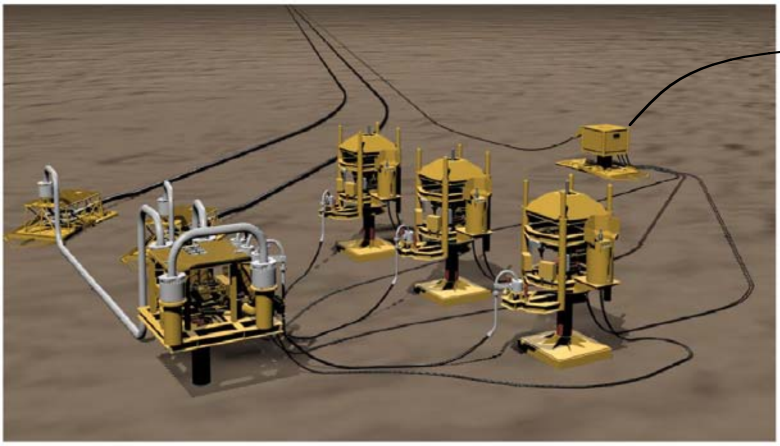


Figure 3.3 Typical NCS tie-back solution (Image: Statoil ASA)

Template (provides protection against fishing nets, etc.)

- clustered satellite wells → well are close to each other but are not on same template

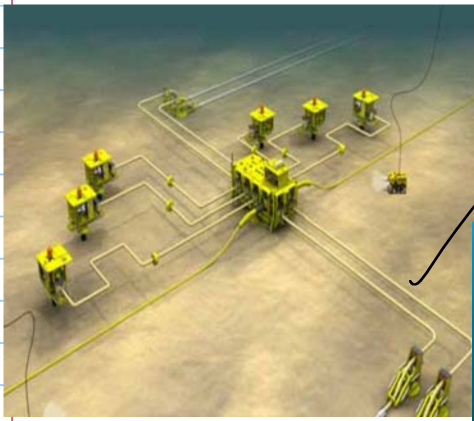




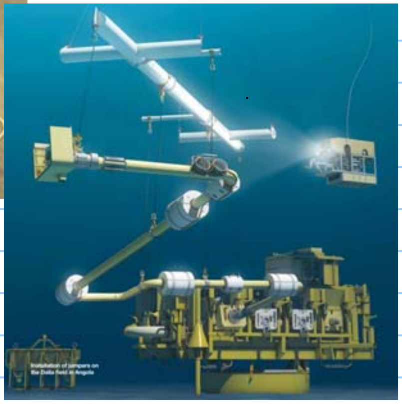
SDU subsea distribution unit

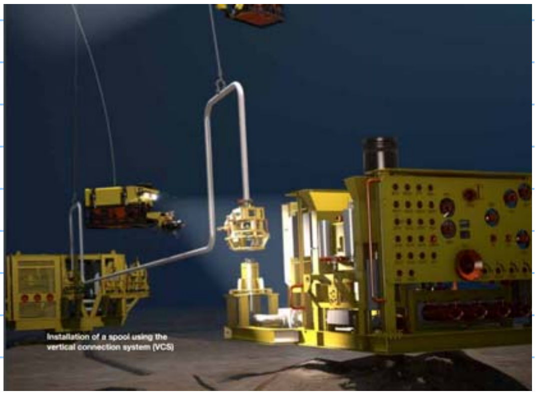
♡ GoM

Figure 3.4 Typical GOM subsea tie-back

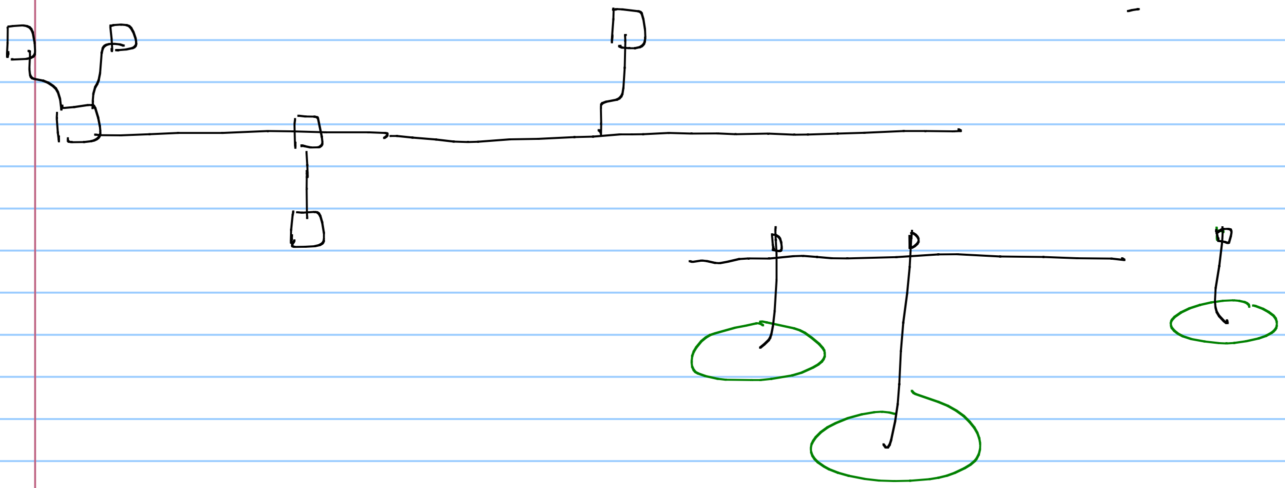


Jumper (rigid pipe)





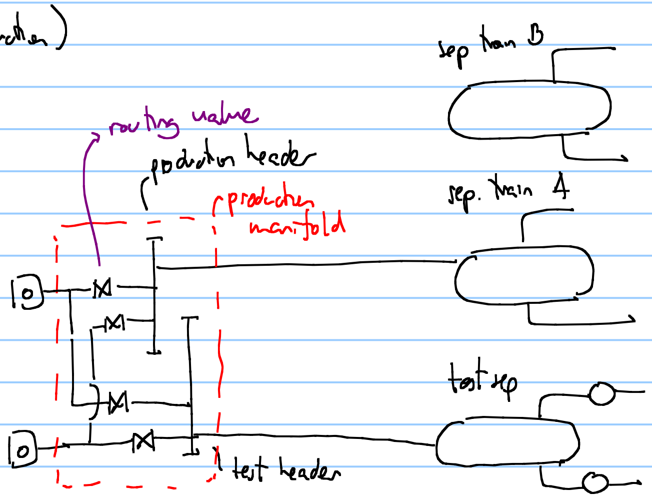
- satellite wells (not clustered). Expensive! (if many wells) drilling rig must be mobilized many times



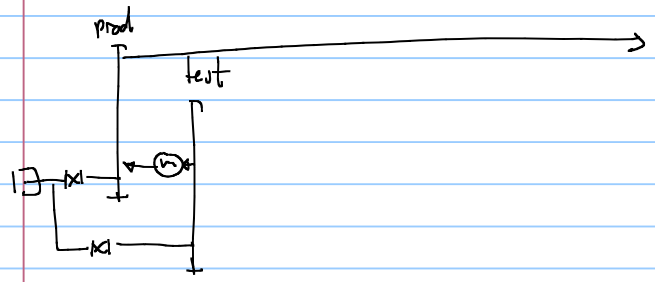
Important considerations for defining the layout of production system:

- need for testing wells (production)
- need for pigging

for onshore wells
/ platform wells
Dry X-mas trees



when multiple trains are used usually a routing study is perform to balance q_o, q_w, q_g for each train, to avoid bottlenecks



on land portable test separators are used

what about subsea ?

RESOLUÇÃO CONJUNTA ANP/INMETRO Nº 1, DE 10.6.2013 - DOU 12.6.2013 – RETIFICADA DOU 17.6.2013

7.2.7. Testes de poços

7.2.7.1. Nos casos em que os resultados dos ~~testes de poços sejam~~ utilizados somente para apropriação da produção aos poços, cada poço em produção deve ser testado com um intervalo entre testes sucessivos não superior a noventa dias, ou sempre que houver mudanças nas condições usuais de operação ou quando forem detectadas variações na produção.

90 day testing interval

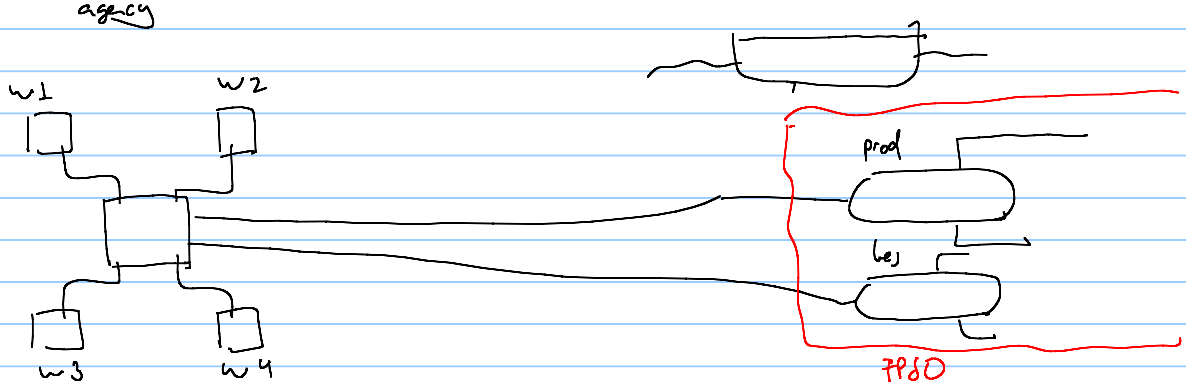
7.2.7.2. Quando os resultados dos testes de poços forem utilizados para apropriação da produção a um campo, em casos de medição fiscal compartilhada, cada poço em produção deve ser testado em intervalos não superiores a quarenta e dois dias, ou sempre que houver mudanças nas condições usuais de operação ou quando forem detectadas variações na produção.

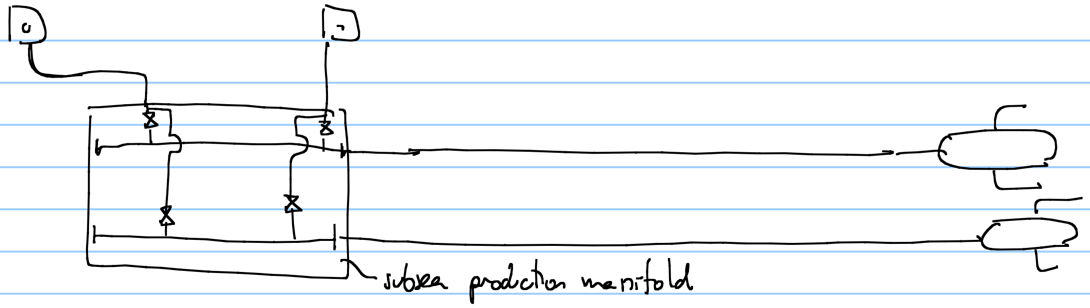
7.2.7.4. Devem ser utilizados separadores de testes ou tanques de testes nos testes de poços. Outros métodos de testes, utilizando novas tecnologias, devem ser previamente aprovados pela ANP.

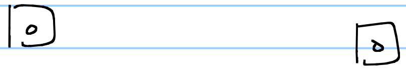
http://www.anp.gov.br/wwwanp/?dw=66648

(ANP National petroleum agency

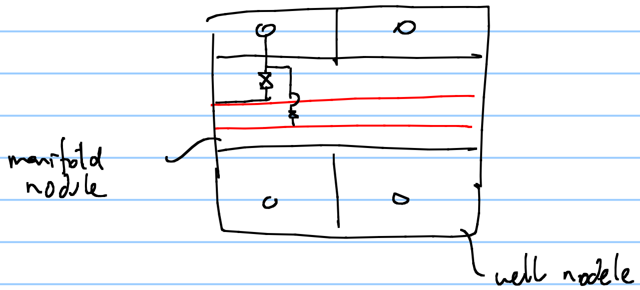
Must use test separator or test "tank" for well testing

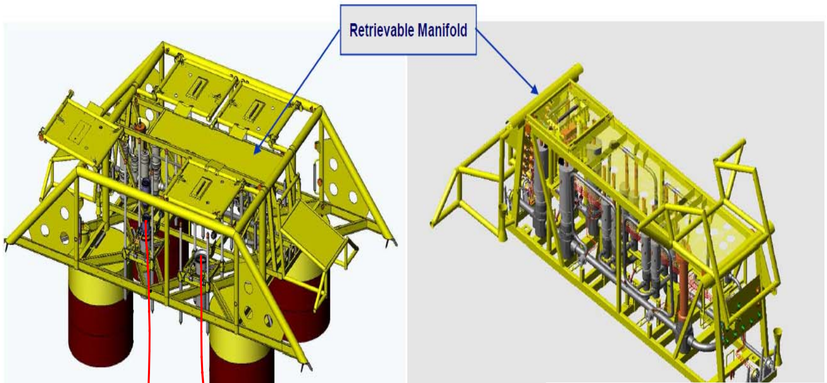




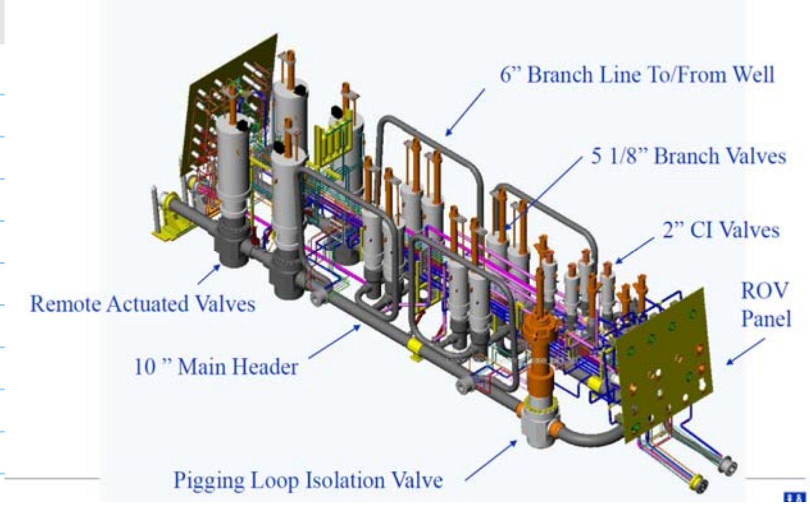


template clustered wells

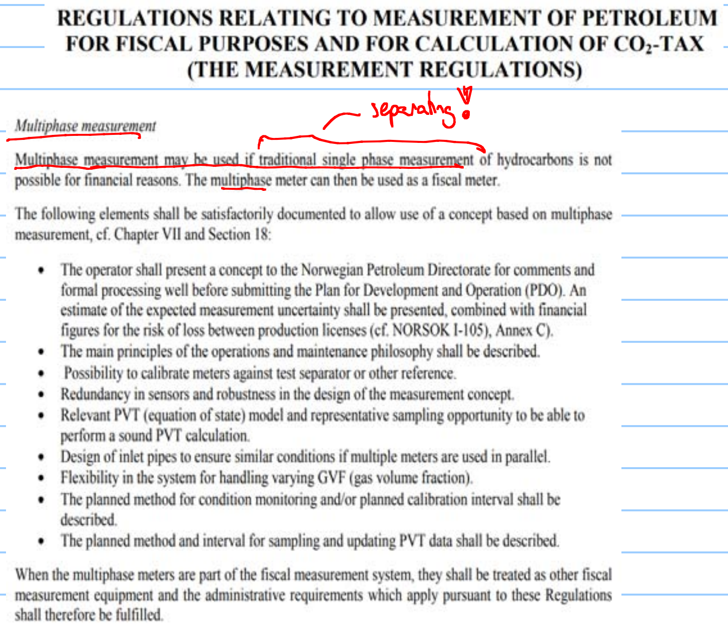




DNV



http://www.npd.no/Global/Engelsk/5-Rules-and-regulations/NPD-



REGULATIONS RELATING TO MEASUREMENT OF PETROLEUM FOR FISCAL PURPOSES AND FOR CALCULATION OF CO_2-TAX (THE MEASUREMENT REGULATIONS)

Multiphase measurement

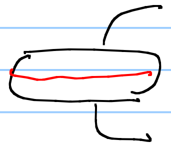
separating!

Multiphase measurement may be used if traditional single phase measurement of hydrocarbons is not possible for financial reasons. The multiphase meter can then be used as a fiscal meter.

The following elements shall be satisfactorily documented to allow use of a concept based on multiphase measurement, cf. Chapter VII and Section 18:

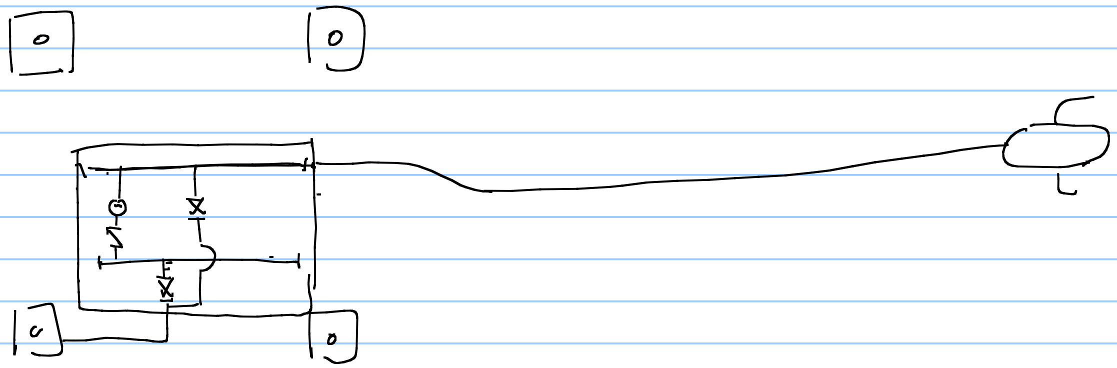
- The operator shall present a concept to the Norwegian Petroleum Directorate for comments and formal processing well before submitting the Plan for Development and Operation (PDO). An estimate of the expected measurement uncertainty shall be presented, combined with financial figures for the risk of loss between production licenses (cf. NORSOK I-105), Annex C).
- The main principles of the operations and maintenance philosophy shall be described.
- Possibility to calibrate meters against test separator or other reference.
- Redundancy in sensors and robustness in the design of the measurement concept.
- Relevant PVT (equation of state) model and representative sampling opportunity to be able to perform a sound PVT calculation.
- Design of inlet pipes to ensure similar conditions if multiple meters are used in parallel.
- Flexibility in the system for handling varying GVF (gas volume fraction).
- The planned method for condition monitoring and/or planned calibration interval shall be described.
- The planned method and interval for sampling and updating PVT data shall be described.

When the multiphase meters are part of the fiscal measurement system, they shall be treated as other fiscal measurement equipment and the administrative requirements which apply pursuant to these Regulations shall therefore be fulfilled.

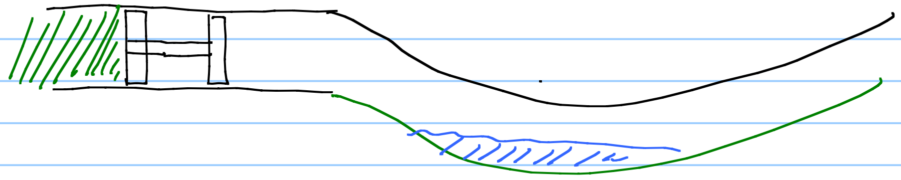


if multiphase meter is to be used

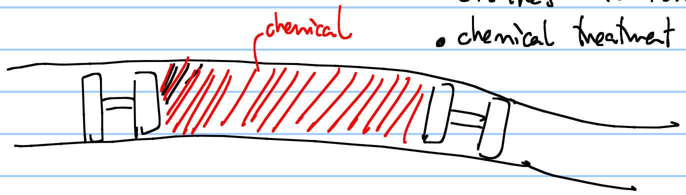
multiphase meter ON MMCSO



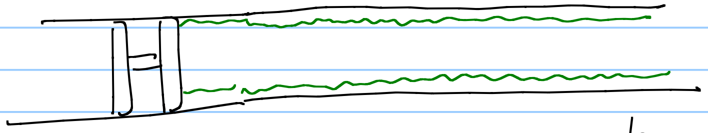
- Need for pigging : Send pig in the pipeline/flowline/manifold
  - gas line : to remove liquids



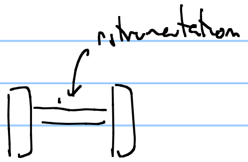
- oil lines : to remove water
- chemical treatment



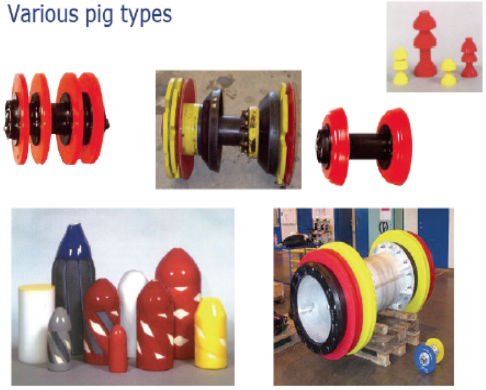
- wax scrapping



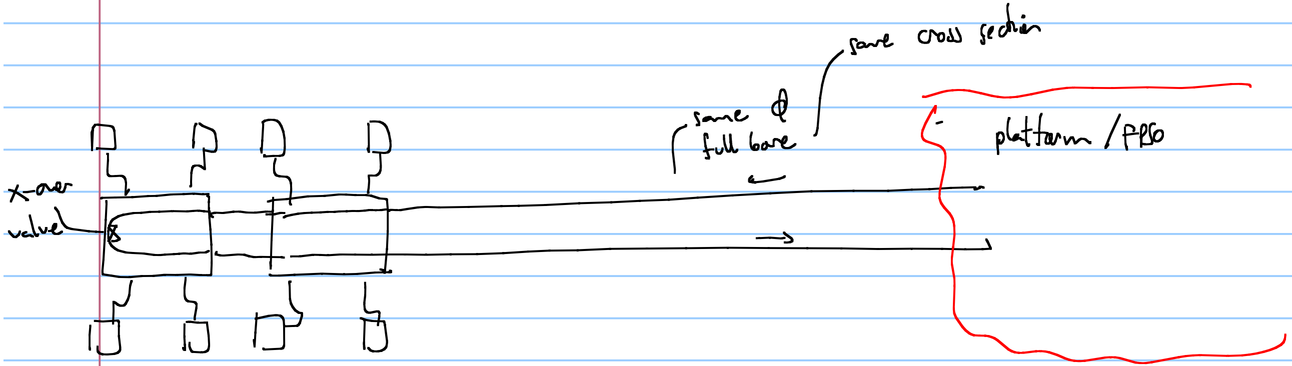
- cleaning
- inspection

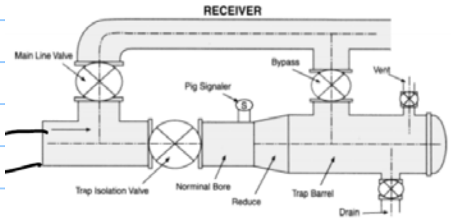


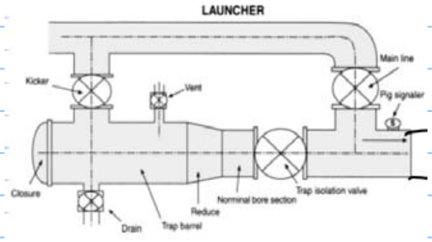
Various pig types



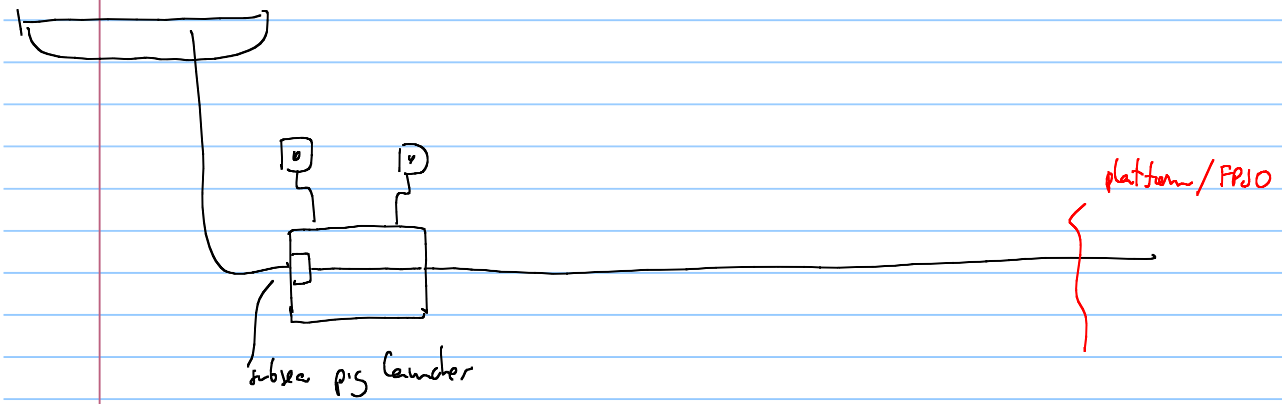
Wax plug-North Sea line pigging







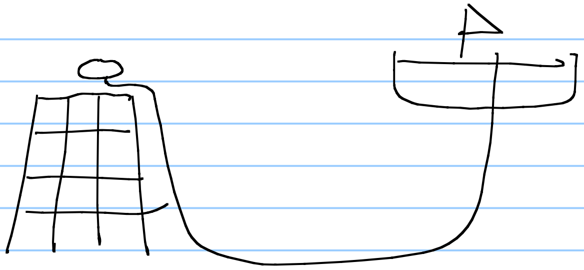
Pigging can also be performed by subsea launcher



- if frequent pigging is expected → a pigging loop must be deployed

if pigging is not required often / pipeline is very long ↳ subsea pig launcher

pigging is typically done in oil export flowlines to remove wax deposits

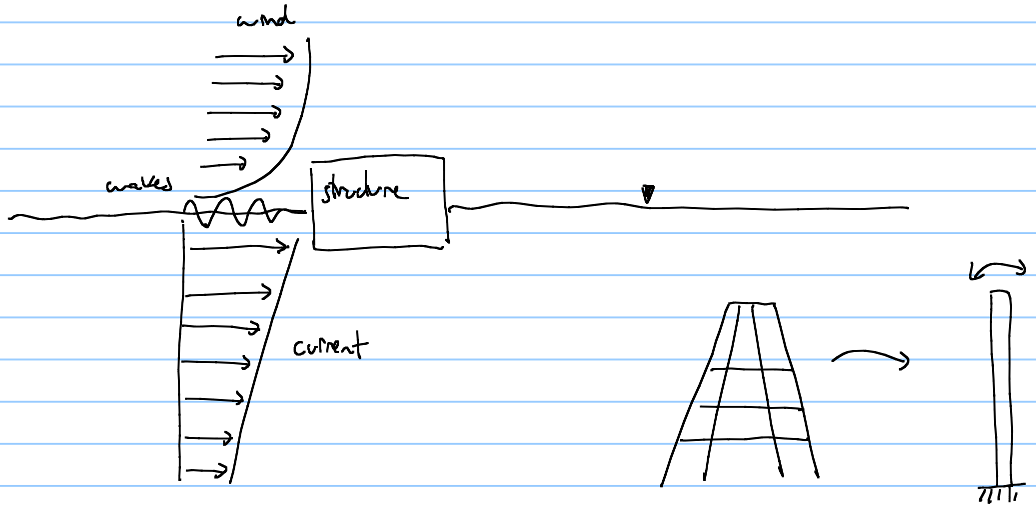


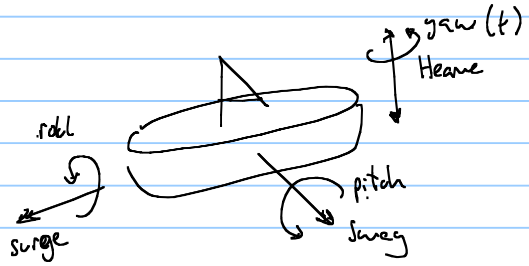
- Offshore structures for oil and gas production (cont)
- Excercise set 4

- storage capacity of offshore structure → accessibility
  → rough weather
  → political issues

- FPSO 1E6 stb - 3E06 stb
- GBS 150000 - 300000 stb
- SPAR 150 000 stb

- Marine loads on offshore structure



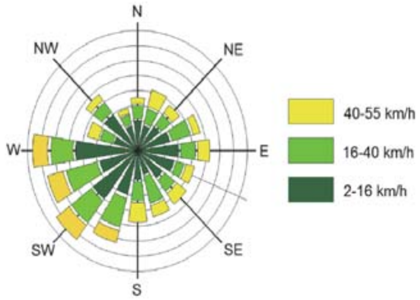


forces/marine loads on structure (t) → structure → movement (t)
→ stresses → maximum stress
→ long term (fatigue)

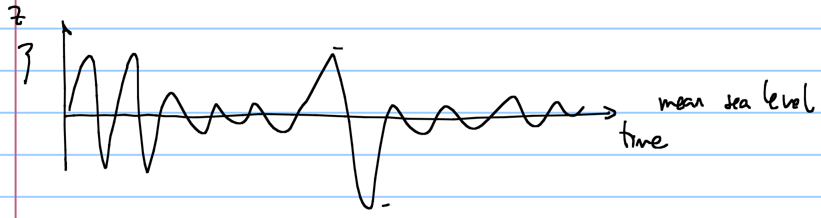
- magnitude
- frequency

wind
current
→ waves

- direction of wind
a fixed value is typically used for design



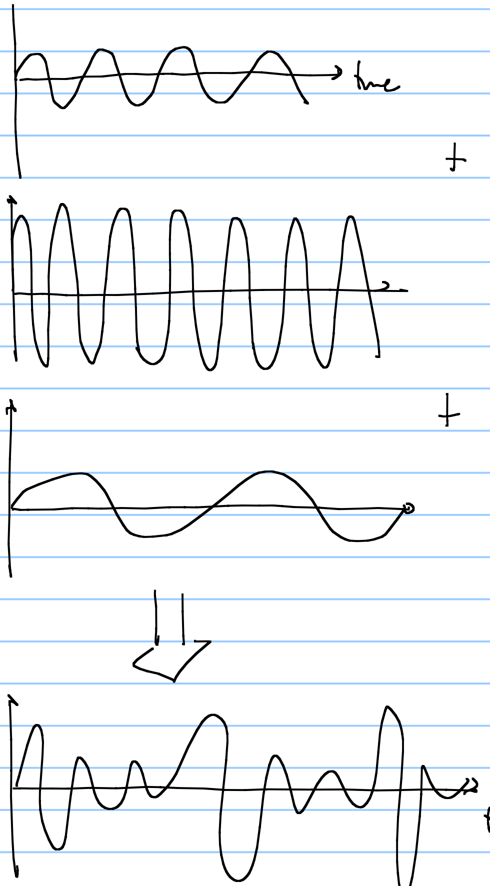
- current a fixed value is typically used for design. Variation with depth is important



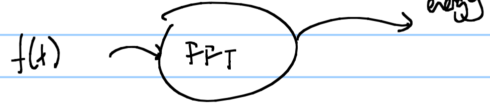
Fourier

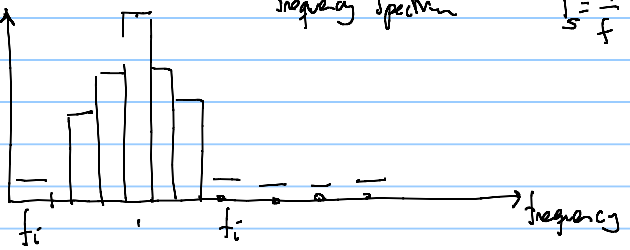
$$f(t) = \sum_{i=1}^{N} \underbrace{A_i}_{\text{amplitude (m)}} \sin(\overset{\text{angular frequency}}{\omega_i} t + \delta_i)$$

$$\omega_i = \overset{\text{frequency}}{f_i} \cdot 2\pi$$



FFT fast-fourier transform





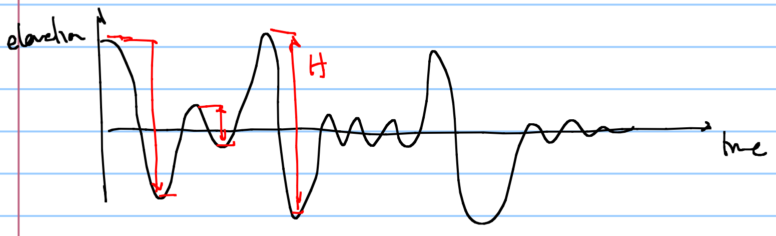
dominant frequency (spectral peak period
frequency spectrum $T_s = \frac{1}{f}$]

elevation

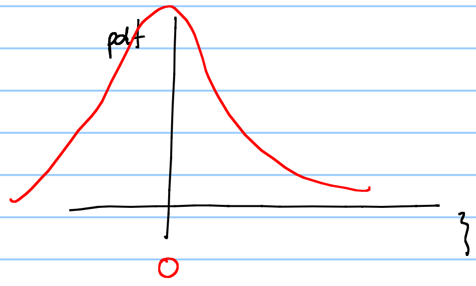
$$\zeta_i = \sqrt{2 \cdot \underbrace{S_i}_{\text{spectral energy}} \cdot \Delta\omega_i}$$

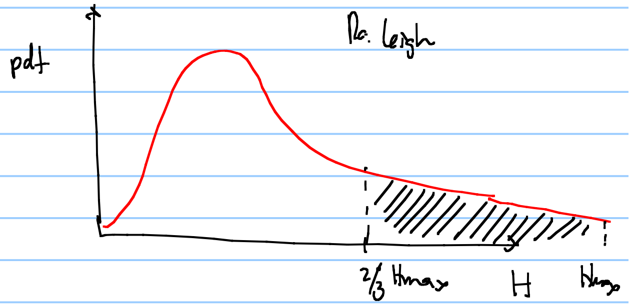
An assumption is made that Ts is relatively constant for a "sea-state" (3hrs)

in terms of magnitude instead of elevation, we use wave height



In a sea state ζ display a normal distribution





significant wave height Hs mean of Height in the Range Hmax → $\frac{2}{3}$ Hmax

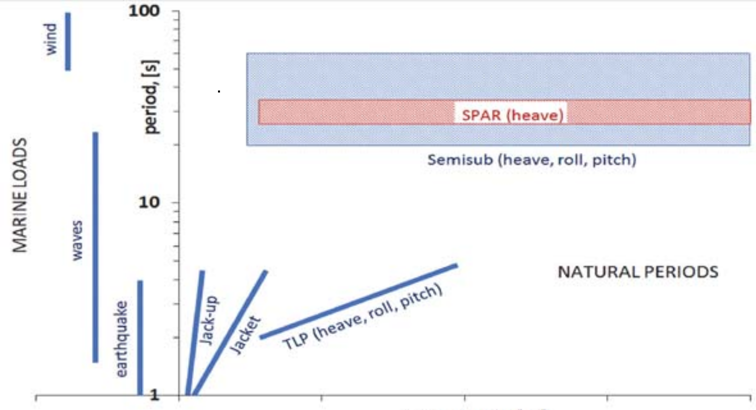
Typically we have to measure wave elevation data for about 2 years of area

$$N^{r}\ \text{sea states} = 2 \cdot \frac{24 \cdot 365}{3} = 5840$$

	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

to calculate movement and stress of offshore structure we typically use { laboratory test
numerical simulator

Every structure has a natural frequency → at which it exhibits maximum movement !



most frequent Tp of the area should be far away from the natural period of structure

PROBLEM 3: Routing configuration of subsea wells in the troll field.

The Troll field has 5 subsea wells (grouped in two templates, 3 wells in Template A and 2 wells in Template B) that have the possibility to flow to separator 1 or separator 2 on the platform.

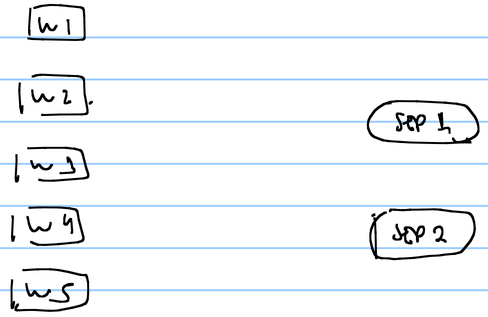
Make a sketch of the system considering the following:

- There are only two flowlines to the platform from both templates. The x-over valve for pigging is located in template B.
- There are 4 flowlines to the platform (2 from each template). Both templates have x-over valves for pigging.

Include routing valves and specify what is located on the template, and what is located topside.

Separator 1 and 2 have maximum capacities of water handling and gas handling (provided in the excel file attached). The current routing of wells is bottlenecking the separators thus requiring that production of some wells is choked.

Your task is to determine all possible routing combinations for the 5 wells and compute the total gas production rate and water production rate in both separators. Propose a routing strategy that allows honoring the separator constraints and provides a similar oil production through both separators.



w1 w2 w3 w4 w5

(2) (2) (2) (2) (2)

① ① ① ①

② ② ② 2

$2^5 = \underbrace{32}$

$q_{\bar{g}_1}$ $q_{\bar{g}_2}$

$q_{\bar{o}_1}$ $q_{\bar{o}_2}$

$q_{\bar{w}_1}$ $q_{\bar{w}_2}$

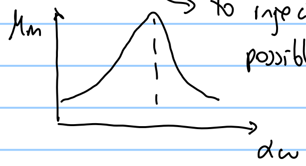
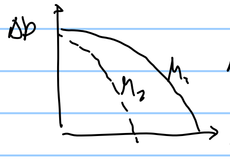
$q_{\bar{w}_1}^{max} > q_{\bar{w}_1}$ $q_{\bar{g}_1}^{max} > q_{\bar{g}_1}$

$q_{w_2}^{max} > q_{\bar{w}_2}$ $q_{\bar{g}_2}^{max} > q_{\bar{g}_2}$

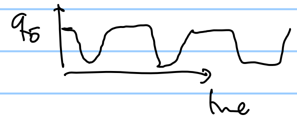
$q_{\bar{o}_1} \approx q_{\bar{o}_2}$

- Flow assurance considerations in field development

Ensure uninterrupted flow of hydrocarbons from reservoir to processing facilities:

Reservoir	Well	transportation	Process	Problems	Consequences/actions on field design
	ASPHALTENES			①, ③ ②	chemical dosing (on demand) (inhibitor)
		SCALE		①, ③ ②	chemical dosing (continuously) remedies (chemical injection (mechanical removal
	HYDRATE			①, ③, ②	chemical inhibitor { MeOH ~> "continuously" (high rate costly MEG chemical dosing (kinetics) pipeline heating (heat tracing) } affect field design and cost insulation
	WAX			①, ③	chemical inhibition (sporadically continuously) pipeline heating → affect the design of field pipeline insulation ↗ ↑ regular pigging → the thickness has to such that pigging can be performed keeping p bellow maximum allowable pipe pressure
		emulsions		①, ③	chemical dosing (demulsifiers) → at topside separator → to inject as close as possible to reservoir   $\mu_2 > \mu_1$ for ESP
	flow induced vibrations FIV			②	• mechanical design of component configuration
		corrosion		② ③	• chemical inhibitor • coating • Alloy steels ↗ applicable for wells. for flowlines pipelines is usually too expensive

SLUGGING ①, ③,② Intermitent flow of liquid/gas



master course multiphase transport

TEP4250 Ole Jørgen Nydal

- bigger separator (slug catcher)
- pipe dimensioning (diameter, routing)

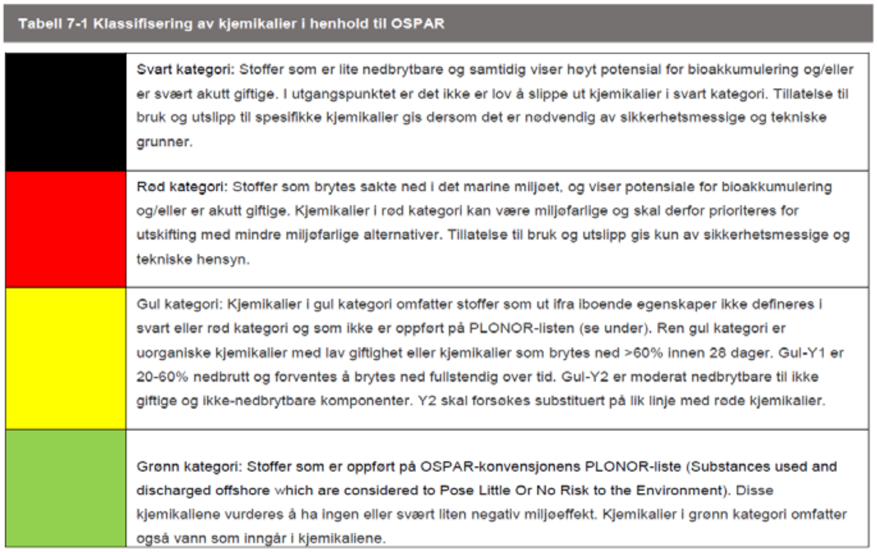
EROSION

- component/pipe dimensioning
- flow conditions

- foaming (hinders separation)
- H_2S, CO_2, O_2 (corrosion) ⇝ chemical (scavenger)
- Bacteria → topside biocide
  → well

Production chemicals book Production chemical for the oil and gas industry Malcolm Kelland

I need to inject a large amount of chemicals to solve/avoid many of these issues.



Tabell 7-1 Klassifisering av kjemikalier i henhold til OSPAR

⬛	**Svart kategori:** Stoffer som er lite nedbrytbare og samtidig viser høyt potensial for bioakkumulering og/eller er svært akutt giftige. I utgangspunktet er det ikke er lov å slippe ut kjemikalier i svart kategori. Tillatelse til bruk og utslipp til spesifikke kjemikalier gis dersom det er nødvendig av sikkerhetsmessige og tekniske grunner.
🟥	**Rød kategori:** Stoffer som brytes sakte ned i det marine miljøet, og viser potensiale for bioakkumulering og/eller er akutt giftige. Kjemikalier i rød kategori kan være miljøfarlige og skal derfor prioriteres for utskifting med mindre miljøfarlige alternativer. Tillatelse til bruk og utslipp gis kun av sikkerhetsmessige og tekniske hensyn.
🟨	Gul kategori: Kjemikalier i gul kategori omfatter stoffer som ut ifra iboende egenskaper ikke defineres i svart eller rød kategori og som ikke er oppført på PLONOR-listen (se under). Ren gul kategori er uorganiske kjemikalier med lav giftighet eller kjemikalier som brytes ned >60% innen 28 dager. Gul-Y1 er 20-60% nedbrutt og forventes å brytes ned fullstendig over tid. Gul-Y2 er moderat nedbrytbare til ikke giftige og ikke-nedbrytbare komponenter. Y2 skal forsøkes substituert på lik linje med røde kjemikalier.
🟩	Grønn kategori: Stoffer som er oppført på OSPAR-konvensjonens PLONOR-liste (Substances used and discharged offshore which are considered to Pose Little Or No Risk to the Environment). Disse kjemikaliene vurderes å ha ingen eller svært liten negativ miljøeffekt. Kjemikalier i grønn kategori omfatter også vann som inngår i kjemikaliene.

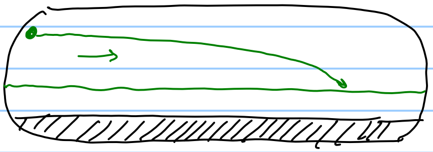
Consequences of FA issue

① increased Δp / flow restriction / flow reduction / blockage

② Integrity issues

③ loss of functionality of components / equipment

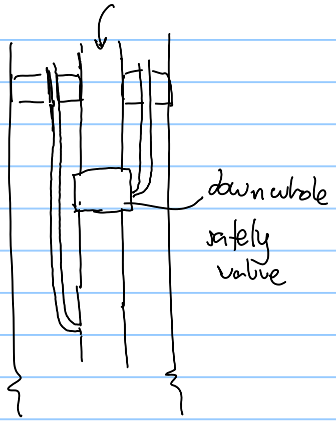
ASPHALTENE



reduce residence time in sep

reduce separation efficiency

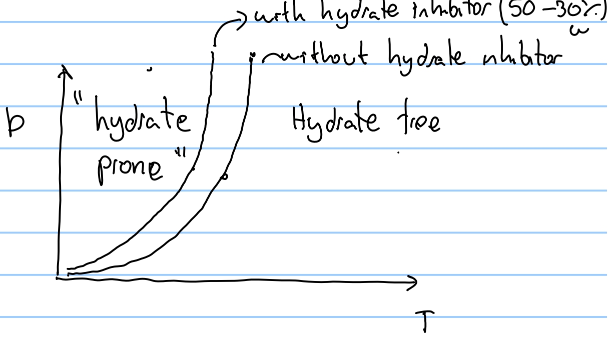
" " capacity



SCALE

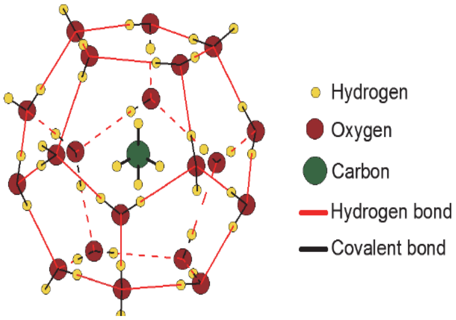
HYDRATES

①o particular combination of p, T (high p, low T)

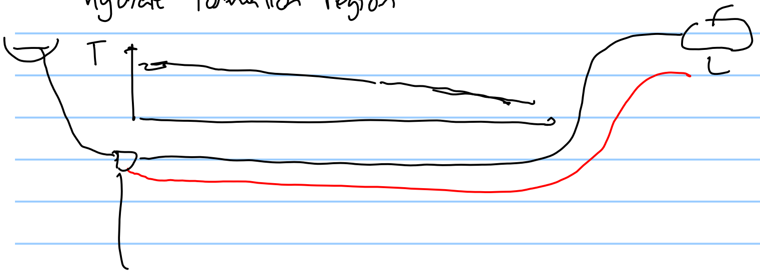


② free water

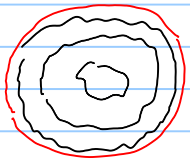
③ Small HC molecules C_1, C_2, C_3, C_4, N_2, CO_2

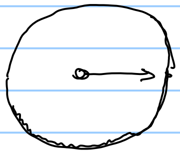


during shutdown, T will cool down and it likely enter hydrate formation region

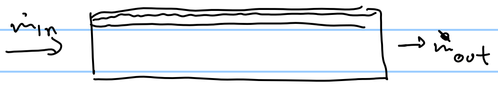


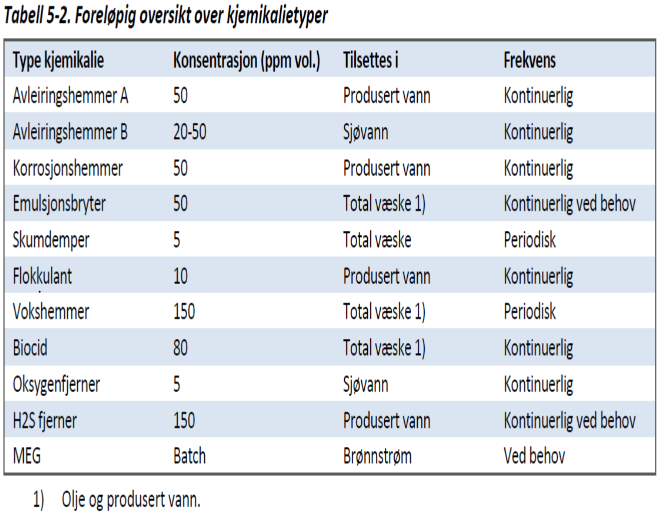
- ALKANES $C_{12} - C_{18}$
- T_{fluid} < WAT
  ↳ cloud point
- Temperature gradient in radial direction





$\frac{dT}{dr} \neq 0$





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.

Where is flow assurance considered in the field design process

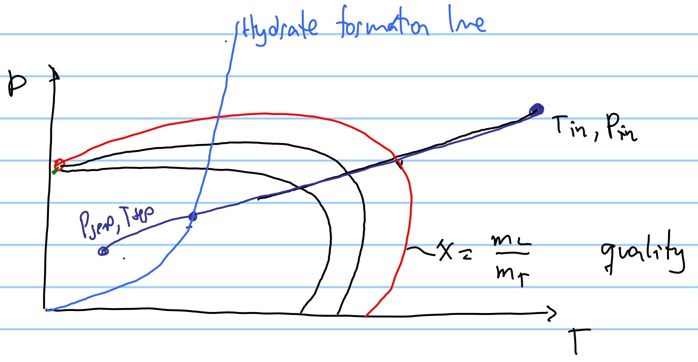
- Early studies (multiple alternatives) → map showstoppers
- FEED (leading to DG3) → flow assurance strategy to be delivered with PDO
  ↳ hydrate management strategy → chemicals
  wax " " ↘ system sizing / dimensioning
  " " " ↘ chemical distribution system
- EPC → refine flow assurance strategy

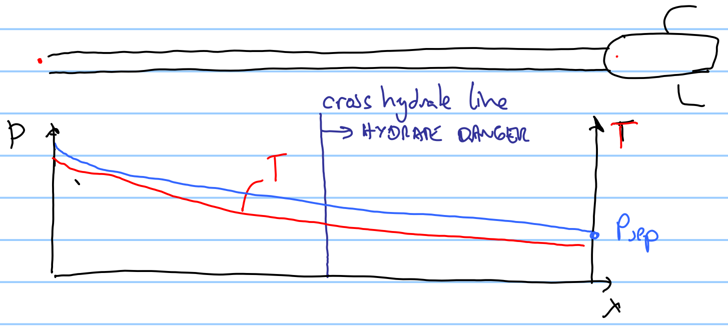
what tools are typically used? → flow calculations of $P, T, V, \overset{\text{volume fraction}}{\alpha_o}, \alpha_w, \alpha_g$

- → steady state $\frac{\partial}{\partial t} = 0$
- → trasient $\frac{\partial}{\partial t} \neq 0$ slugging, shutdown
- → 1D simulator (Pipesim, gap, OLGA, ledaflow)
- → 3D simulator (CFD computational fluid dynamics)

- laboratory tests
  - → oil ~ composition, wax deposition, hydrate formation
  - → water → mineral
  - → mixture
- standards

- Introduction to exercise set 5 - problem 1

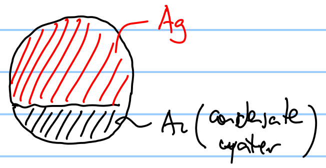




Hysys process simulator typically used for topside facilities Not very good for $\frac{dP}{dx}$ in pipe with multiphase flow

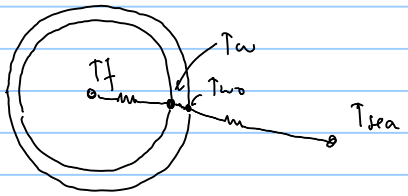
↳ gas
condensate
water

Liquid Holdup

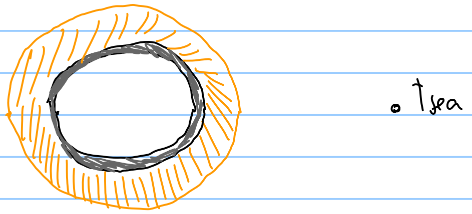


$$H_L = \frac{A_L}{A_g + A_L} \rightarrow [0-1]$$

naked pipe



insulated pipe



- lectures to finish before Easter (12.04)

- 5 exercise sets $\frac{40}{5} = 8$ points each
  ↳ deadline for 5th will be 12-04

For preparation for the exam:

- look into old exams (regular/resitting) and old exercise sets (from other years)

Due to cost, MEG and MeOH are usually re-claimed at topside facilities.
↳ reclaim unit → requires high T

Chemical distribution system → injection: at platform
↳ at well (bottom-hole / wellhead) ← performed from topside
↳ at pipeline/flowline. ←

the distribution is performed using umbilicals

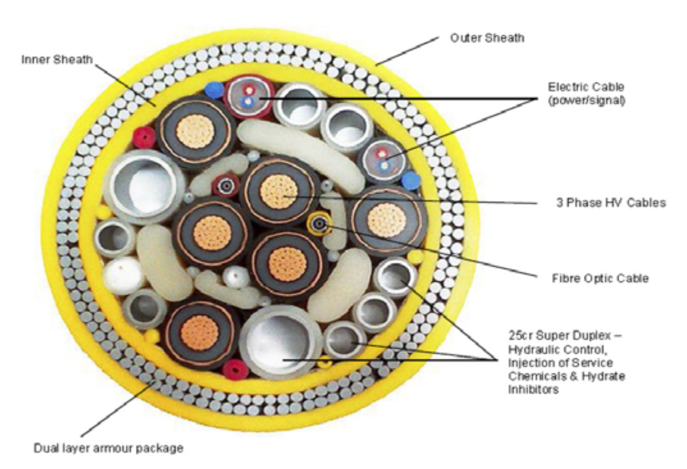
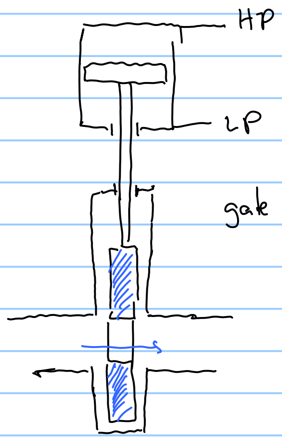
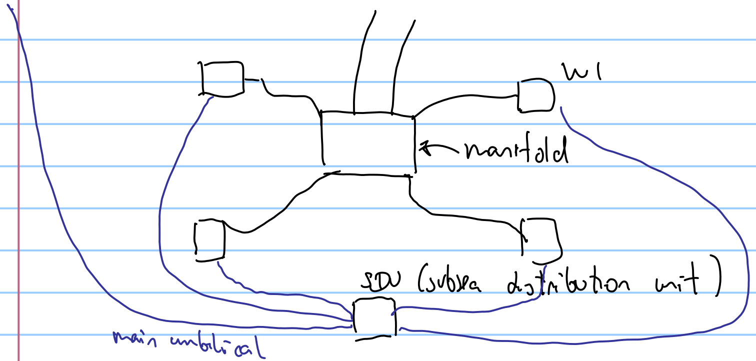


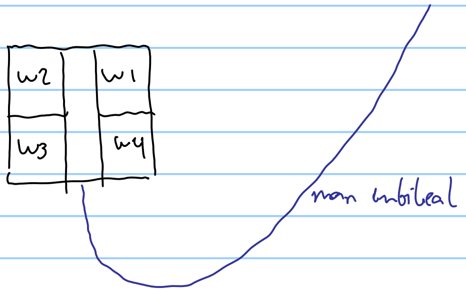
Figure 3 – Umbilical Cross Section Example

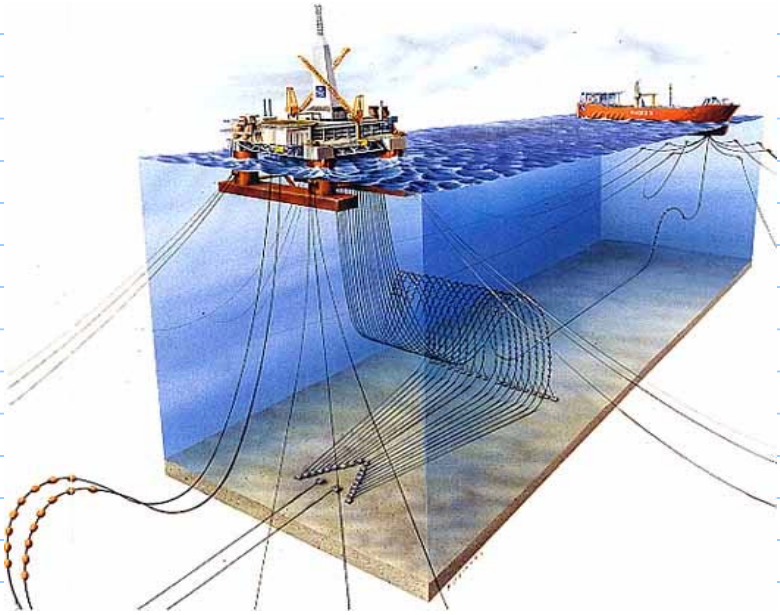
valve actuators



depending on architecture of subsea system

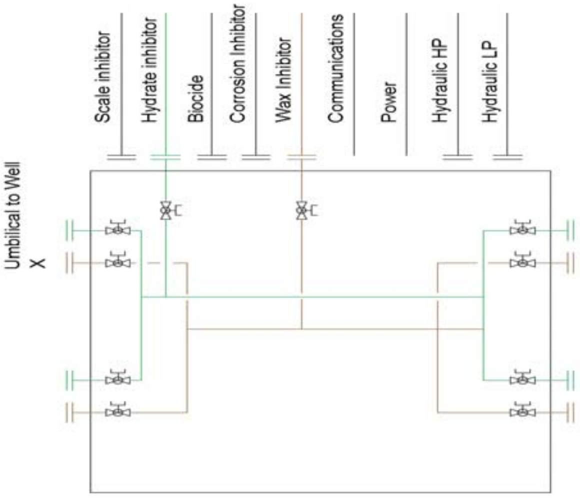




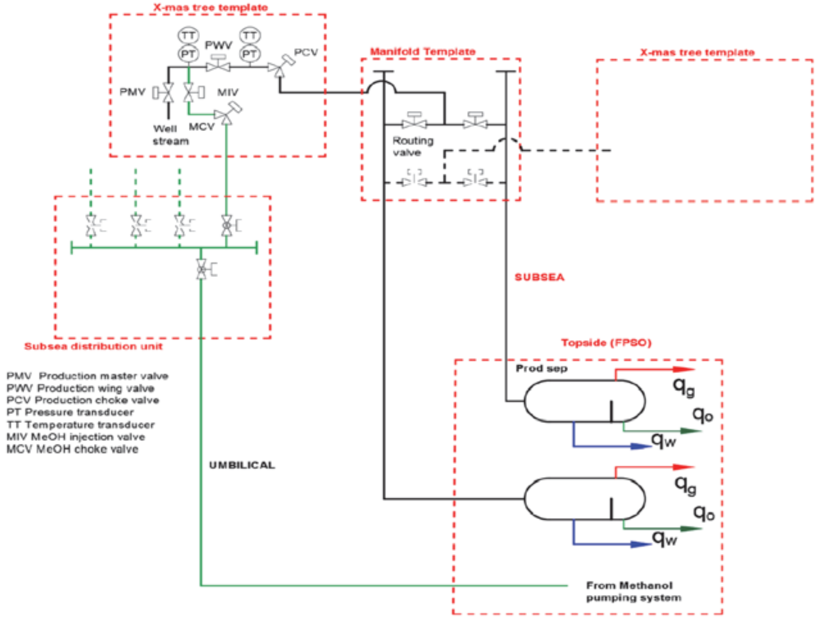


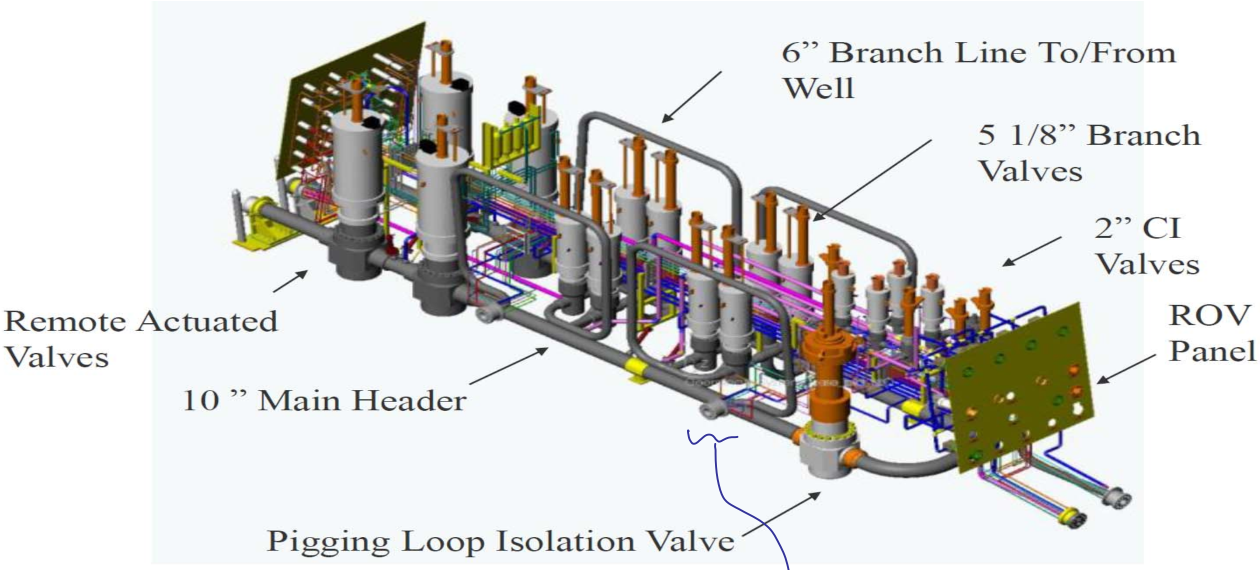
Njord

SDU

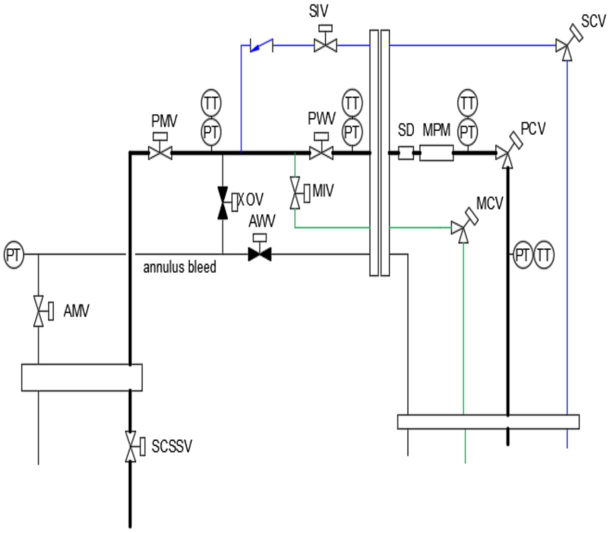


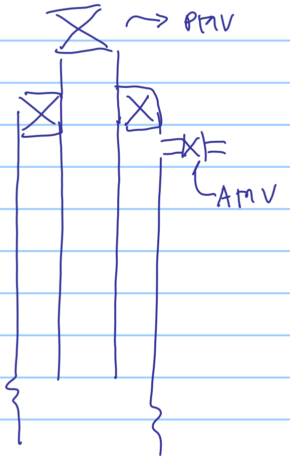
SDU

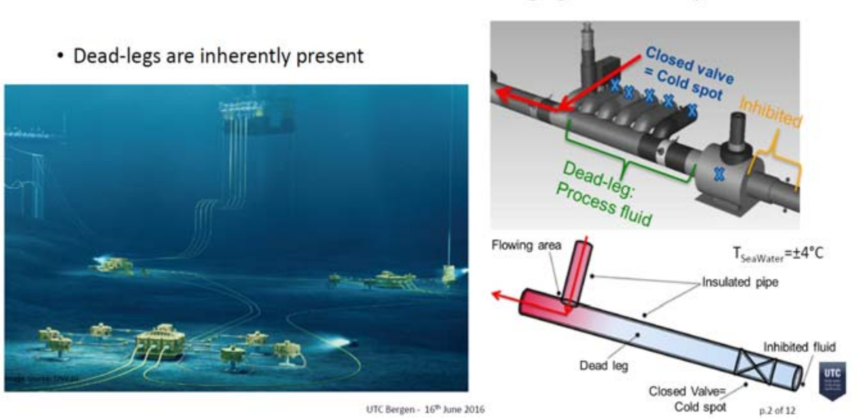




multi_bore connector







Subsea manifold and dead-leg geometry

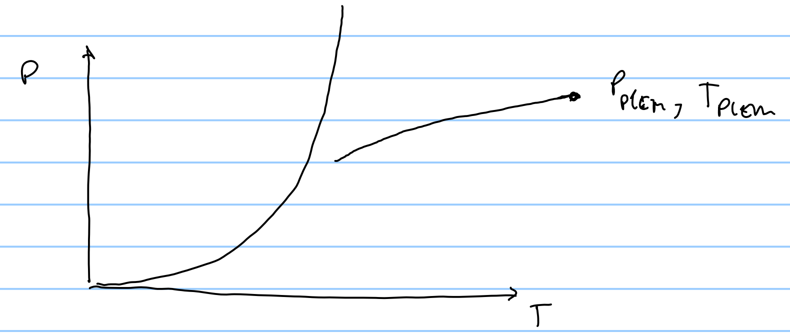
- Dead-legs are inherently present

UTC Bergen - 16th June 2016

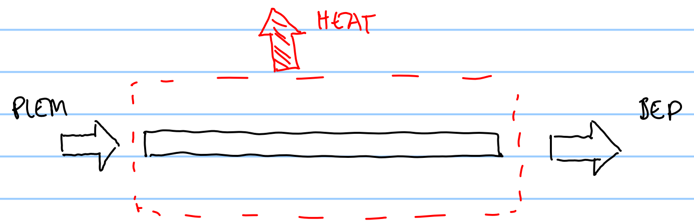
p.2 of 12

design of dead-leg geometry must be analyzed during FEED studies.

Problem 1, exercise set 5



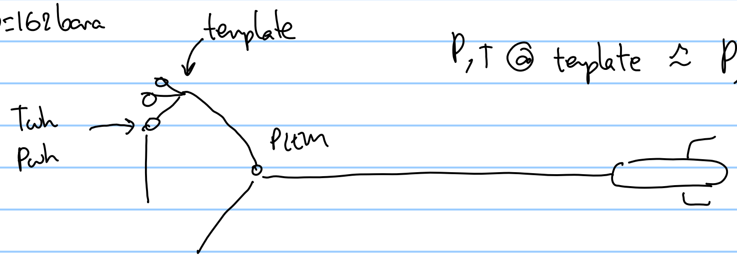
MEG (or MeOH)



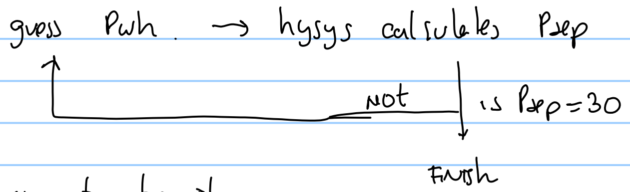
material stream, P, T, composition, rate { molar rate
volume rate
mass rate

ENERGY STREAM { HEAT
POWER

- in the plateau period there is a Δp across the choke

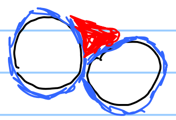


P,T @ template ≈ P,T @ PLEM



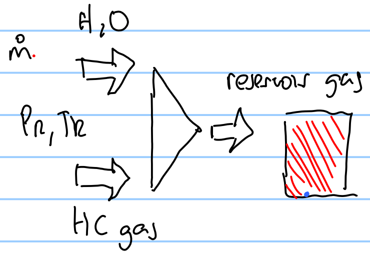
to make this process automatic, it is possible to use an adjust

- the wellhead stream must be saturated with water



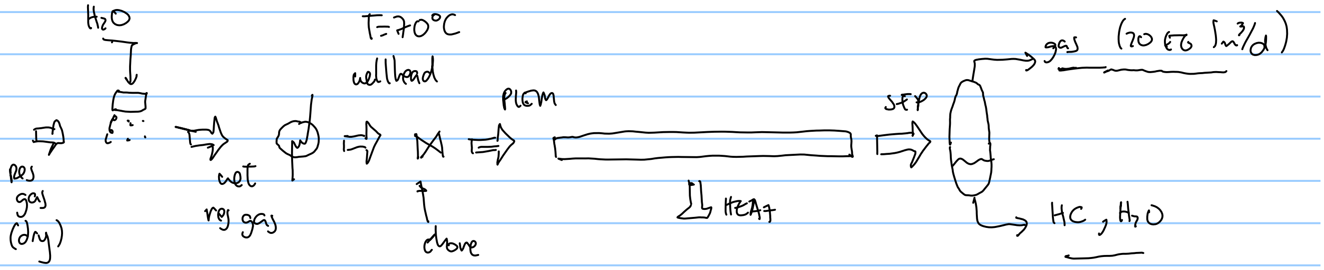
the gas is saturated with water @ P_R, T_R

↓ 276 bara   92°C



$$X = 0 = \frac{m_L}{m_L + m_V}$$

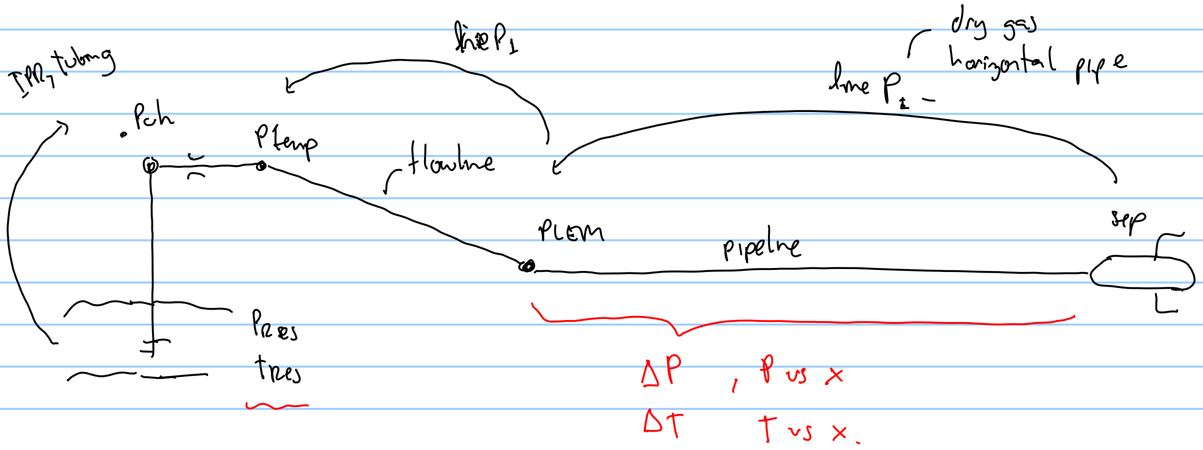
- the field gas rate is measured downstream the separator

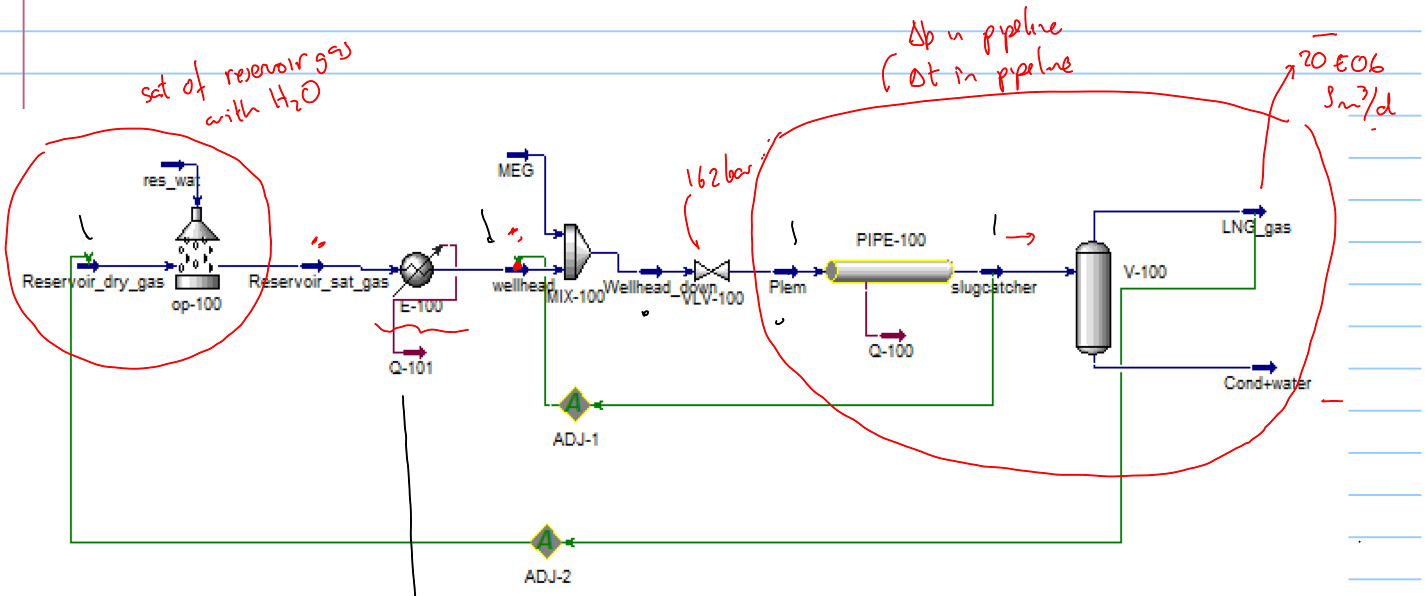


$$\dot{m}_g = 20\,E6\ Sm^3/d \cdot \rho_g$$

$$\dot{m}_T = \dot{m}_g + \dot{m}_{H_2O} + \dot{m}_{cond}$$

- more comments on problem 1 - ex. set 5
- Δp in Multiphase flow
- work with prob. 1 and prob 2 in class



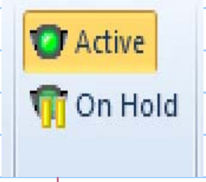


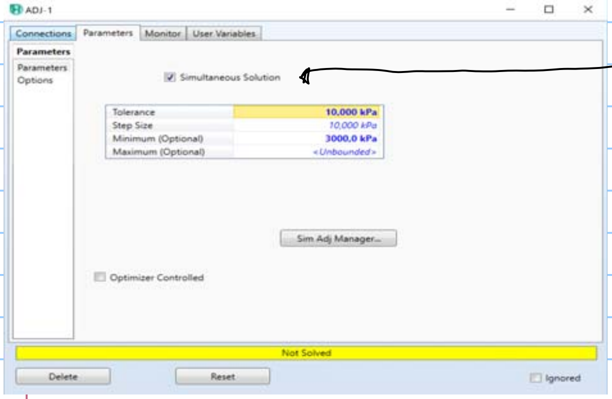
→ cooler ; can provide Pin, Tin, Pout, Tout and it will compute

Δp, ΔT, $\dot{Q}$

represents the Δp and ΔT a

- if a better model is used for pressure drop calculations in the pipeline it will probably yield:
  - shorter plateau
  - Δpchoke smaller →





☑ Simultaneous Solution

Tolerance	10,000 kPa
Step Size	10,000 kPa
Minimum (Optional)	3000,0 kPa
Maximum (Optional)	<Unbounded>

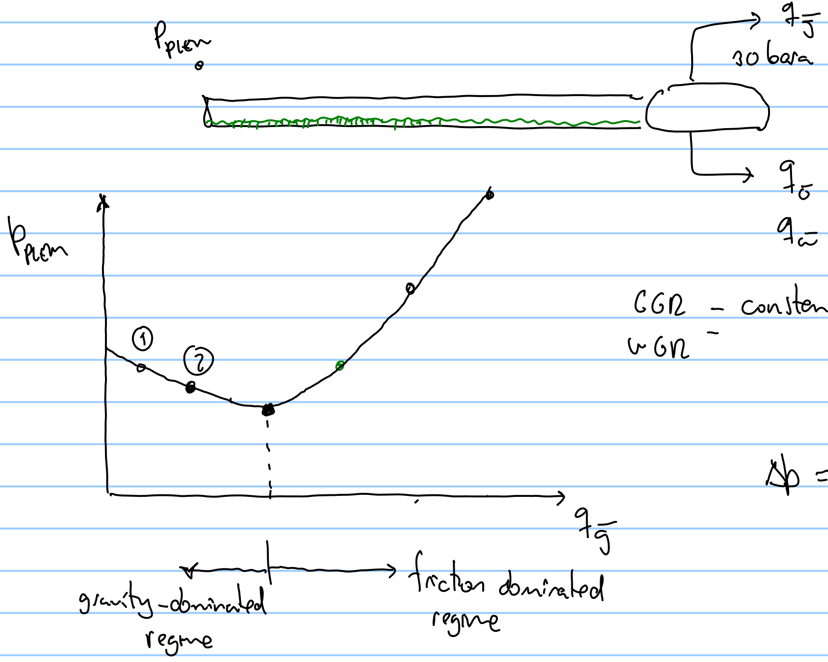
☐ Optimizer Controlled

Not Solved

☐ Ignored

remember to tick this field

- Multiphase flow in the production system



condensate-gas ratio

$$CGR = \frac{q_o}{q_g}$$

$$WGR = \frac{q_w}{q_g}$$

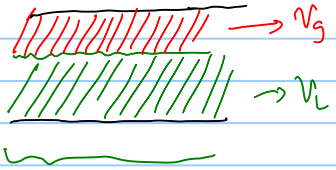
water-gas ratio

$$\Delta p = \underline{\Delta p_{friction}} + \Delta p_{hydrostatic}$$

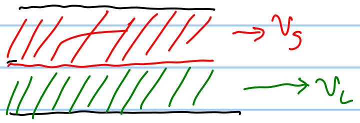
$\rho \cdot g \cdot \Delta z$

ρ_{mix}

①



②

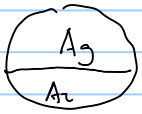


$$\rho_{mix} = \alpha_L \cdot \rho_L + \alpha_g \cdot \rho_g$$

$\rho_{mix} \downarrow$

α volume fraction

$$\alpha_g = \frac{A_g}{A}$$

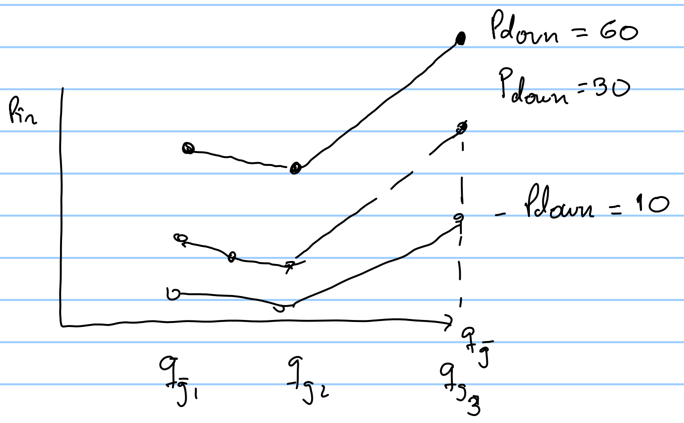


$$\alpha_L = \frac{A_L}{A}$$

Flow tables

$P_{down} = 30$ bara
CGR =
WGR

$q_{\bar g}$	P_{in}
$q_{\bar g_1}$	P_{in_1}
$q_{\bar g_2}$	P_{in_2}
$q_{\bar g_3}$	P_{in_3}

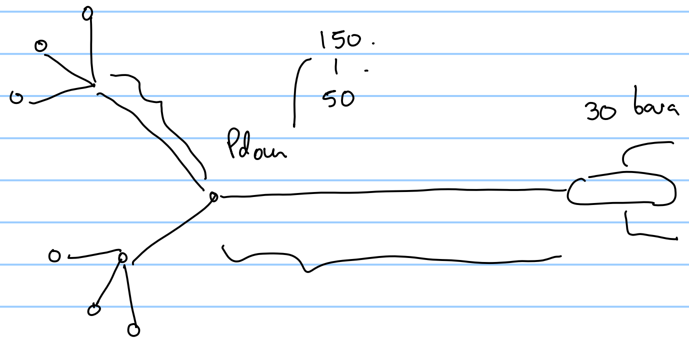


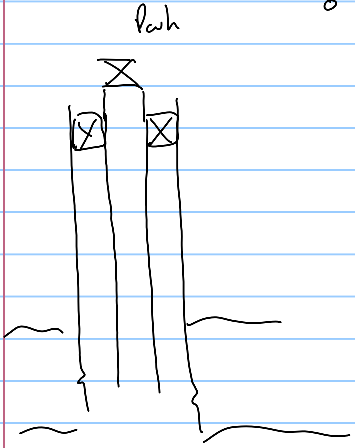
P_{down},then is not known $\rightarrow$ wells (P_{wh})
$\rightarrow$ flowline

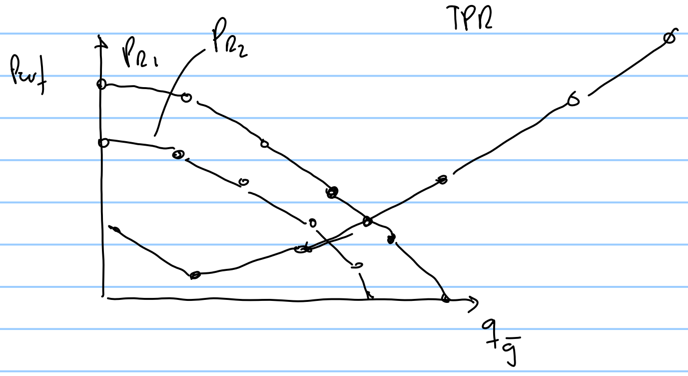
$P_{down\,1}$ – $P_{down\,3}$

$P_{down\,1}$		$P_{down\,2}$		$P_{down\,3}$	
CGR_1 WGR_1		CGR_1 WGR_1		CGR_1 WGR_1	
$q_{\bar g}$	P_{in}	$q_{\bar g}$	P_{in}	$q_{\bar g}$	P_{in}
x	x	x	x	x	x
x	x	x	x	x	x
x	x	x	x	x	x

$P_{down\,2} < P_{down} < P_{down\,3}$







tables have to be generated for all possible expected variations

IPR: GOR, WC, P_R
TPR $\rightarrow$ P_{wh}, GOR, WC, CGR, WGR

TPR with variation in Pwh, GOR, WC, $q_{\bar{g}}$

$q_{\bar{g}}$

Pwh	GOR	WC
min	min	min
max	max	max

$N_{Pwh} \times N_{GOR} \times N_{WC} \times N_{q_{\bar{o}}}$

$10 \times 10 \times 10 \times 10 = 10^4$ iterations to compute Pwf

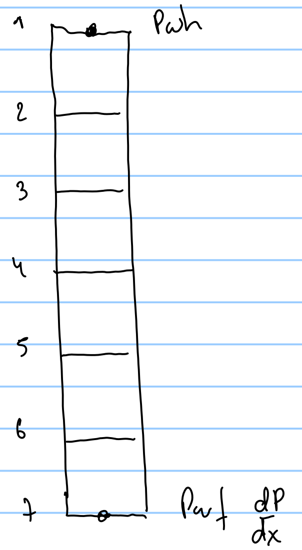
---

How P calculations are made in multiphase flow → ρ_o, ρ_g are changing with P,T along conduit

q_o, q_g, q_w (local rates) ~> v_o, v_g, v_w

↓

we perform calculation discretizing the pipe!



① depart from a point of "known" pressure. e.g. Pwh
temperature

② calculate fluid properties ~> $\rho_o, \rho_g, \rho_w, \mu_o, \mu_g, \mu_w, \sigma_{og}, \sigma_{ow}$
h_o, h_w, h_g

③ calculate q_o, q_w, q_g → Black oil tables
- B_o
- B_g
- R_s
- r_s

↳ EOS model z_i ~> P,T,

$$X_v = \frac{\dot{m}_g}{\dot{m}_o + \dot{m}_g}$$

↓

$\dot{m}_T$

$\dot{m}_g = X_v \cdot \dot{m}_T$

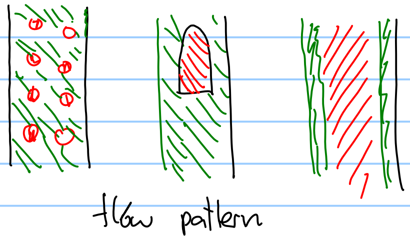
$\dot{m}_o = (1-X_v)\,\dot{m}_T$

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

$q_o = \dot{m}_o / \rho_o$

$V_g, V_L, \rho_o, \rho_g, \rho_w, \mu_o, \mu_g, \mu_w$
$\sigma_{og}, \sigma_{ow}, \sigma_{gw}$

④ Compute $\frac{dP}{dx}$ → multiphase flow "expert" (TEP4250)
- ↳ correlations
  - → Beggs Brill
  - → Hagedorn Brown
- ↳ mechanistic model
- ↳ commercial software



⑤ "integrate" the $\frac{dP}{dx}$ to 2

Euler $$\frac{P_2 - P_1}{\Delta L} = \frac{dP}{dx}\Big|_{①}$$

$$P_2 = \frac{dP}{dx}\cdot\Delta L + P_1$$

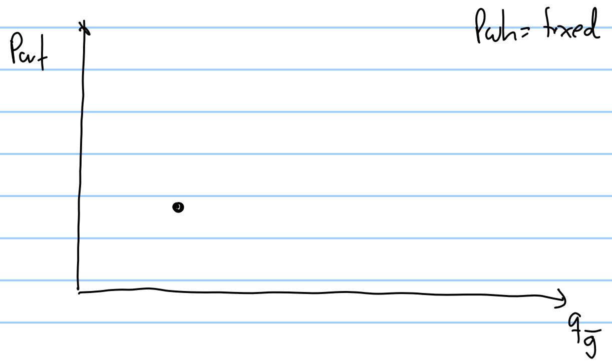
⑥ P_2, T_2, calculate fluid properties

q_o, q_g, q_w

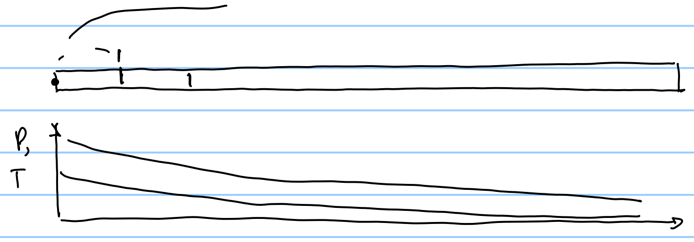
$\frac{dP}{dx}$

↓

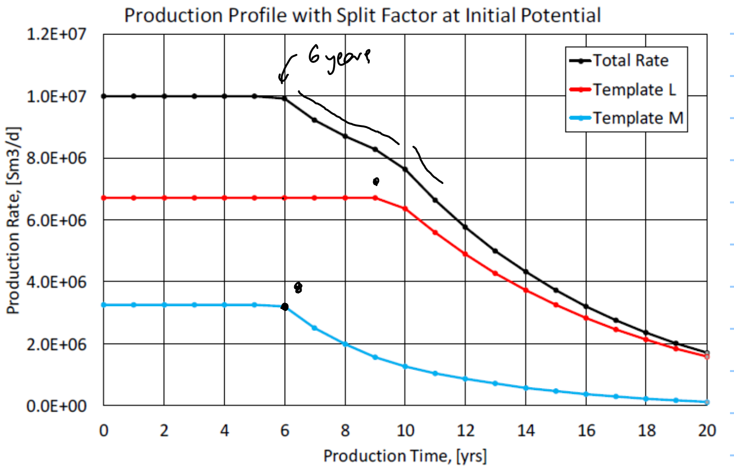
③



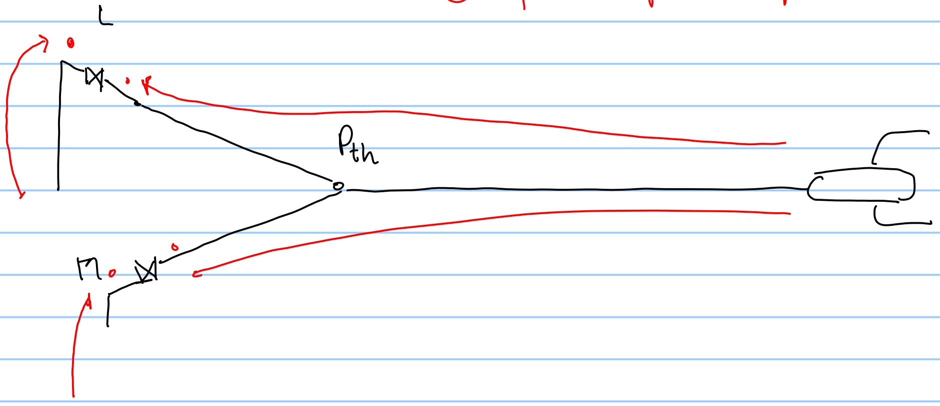
- Problem 2 . ex. set 5 $q_o = B_o(P,T)\cdot q_{\bar{o}}$ μ f(T)



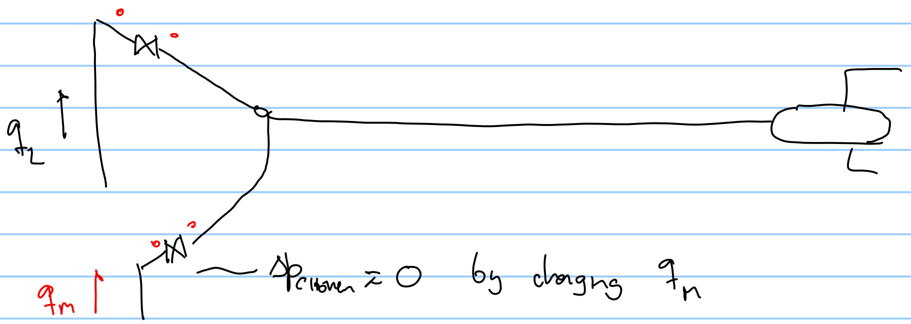
- Review of problem 1, ex. set 3
- Class exercise (exam problem)



① equilibrium point in plateau

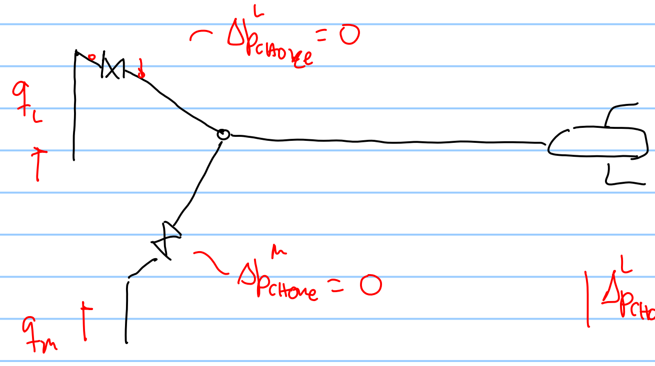


② template M enters in decline $\Delta p_{choke} \leq 0$



$\Delta p_{choke} \approx 0$ by changing q_M

③ template L enters in decline

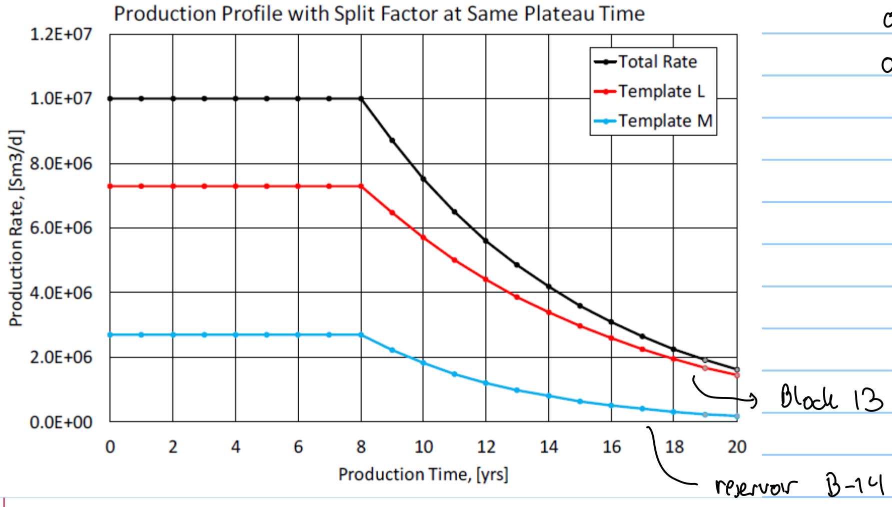


$|\Delta p^L_{choke}| + |\Delta p^M_{choke}| = 0$

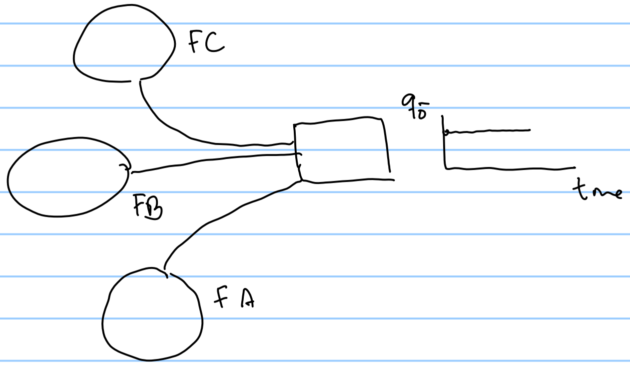
Changing the production splitting can change significantly the plateau duration.

0.73 template L

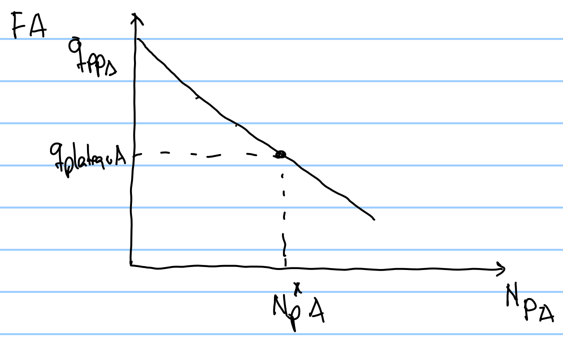
0.27 template M

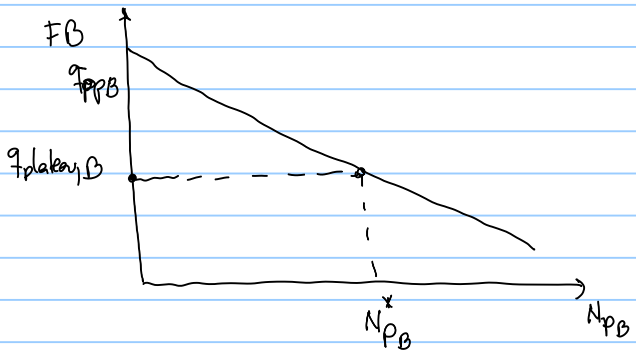


for multi-reservoirs systems



when 2 reservoirs





given $q_{f,plateau}$

chose $q_{plateau,A}$, read N_{pA}^*

$$t^A_{end,plateau} = \frac{N_{pA}^*}{q_{plateau,A} \cdot N_{day/year}}$$

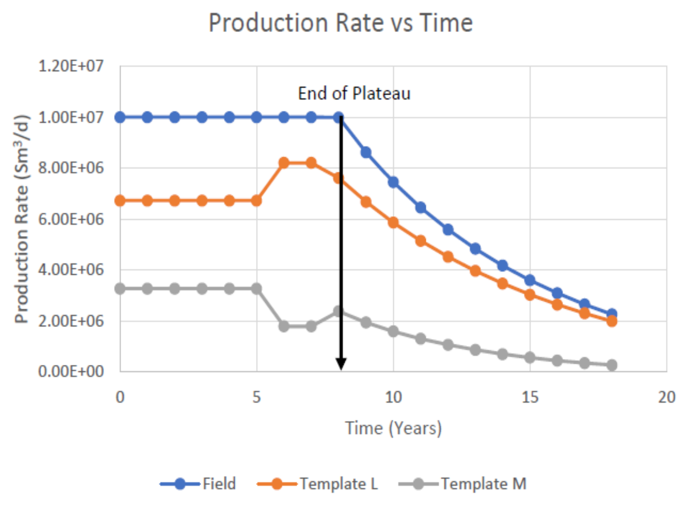
$$q_{plateau,B} = q_{field,plateau} - q_{plateau,A}$$

to maximize plateau duration

$$t^A_{end\,plateau} = t^B_{end\,plateau}$$

$$t^B_{end\,plateau} = \frac{N_{pB}^*}{q_{plateau\,B} \cdot N_{day/year}}$$

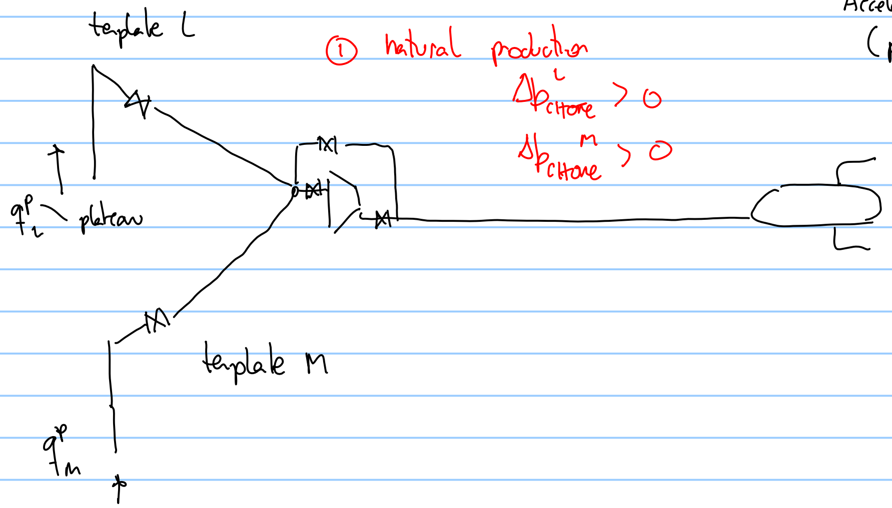
Note: be careful with constraints ! → maximum allowable production per well
API blending
CO_2, H_2S content
etc.



It is also possible to change production splitting mid-way

• Task 2. simplified compressor

compressor enables: higher recovery factor
Accelerates production
(prolonging plateau
higher values during tail production)
↳ recovering earlier
↑NPV

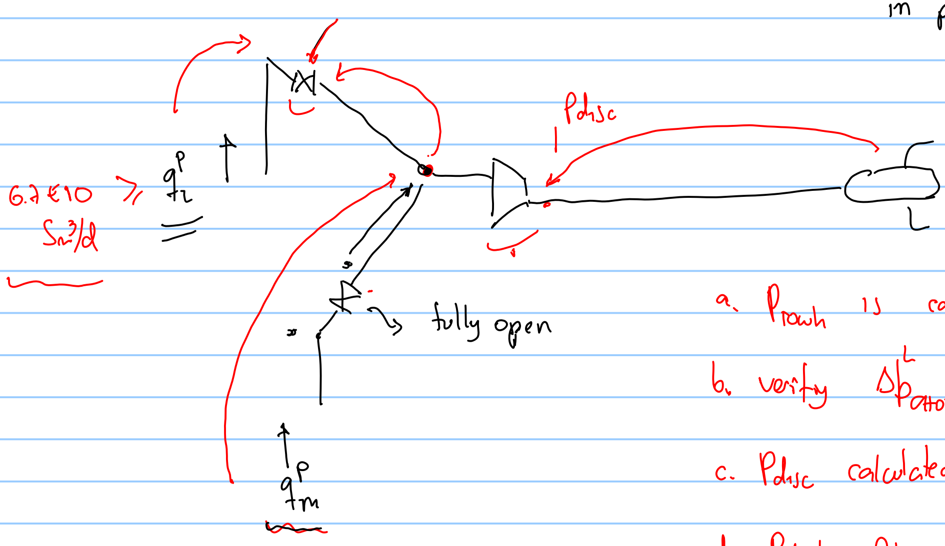


① natural production

$\Delta p^L_{choke} > 0$

$\Delta p^M_{choke} > 0$

② template M enters in decline, but we still want to produce it in plateau mode!



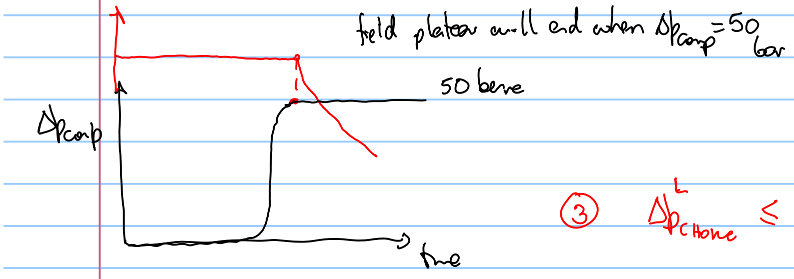
a. P_{towh} is calculated co-current from M

b. verify $\Delta p^L_{choke} > 0$

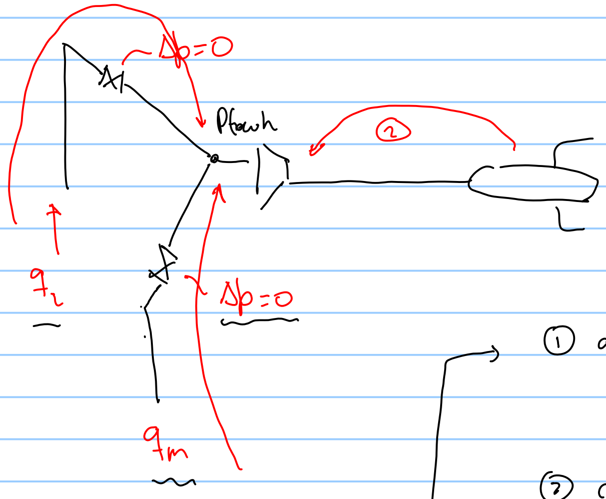
c. Pdisc calculated from Psep

d: $P_{disch} - P_{tow} > 0$

$P_{dis} - P_{tow} \leq 50$ bar



③ $\Delta p^L_{choke} \leq 0$ − fully open choke with $\Delta p_{comp} = 50$ bar



① assume $q_L < q_L^p$

$q_m < q_m^p$

② calculate Pdisch (counter-current from sep)

③ max qfield is obtained when Δp_{comp} is maximum, therefore:

$P_{towh} = -50 + P_{disch}$

④ move co-current to ptow from L and M and check if

$P_{towh} = P^M_{towh} = P^L_{tow}$?

not

yes

solution

alternative:

(4') move counter current from Ptowh to P_{temp}^{m}

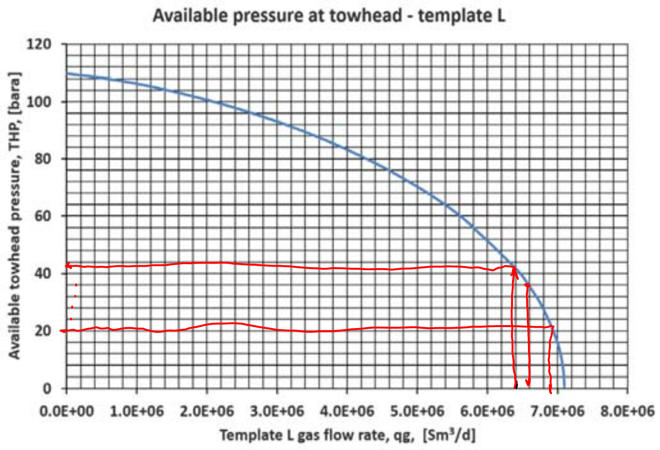
and Ptow → P_{temp}^{L}

move co-current from m to P_{wh}^{m}

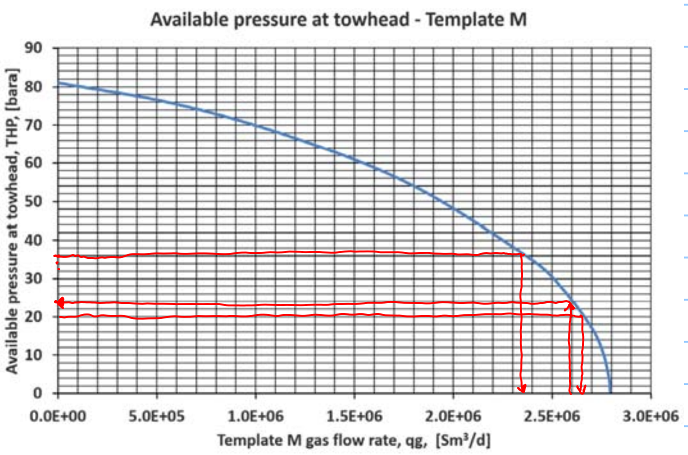
move co-current from L to P_{wh}^{L}

change q_L and q_m such that $\begin{cases} \Delta p^{m} = 0 \\ \Delta p^{L} = 0 \end{cases}$

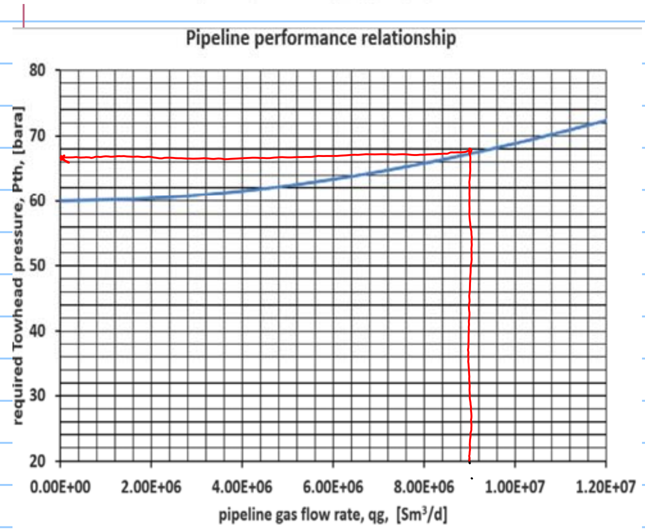
Class exercise:



Available pressure at towhead - template L



Available pressure at towhead - Template M



Pipeline performance relationship

$q_m + q_L = 9\ E06\ Sm^3/d$

① P_{disc} = 67 bara

② assume P_j = 20 bara

$q_L = 6.9\ E06\ Sm^3/d$

$q_m = 2.65\ E06\ Sm^3/d$

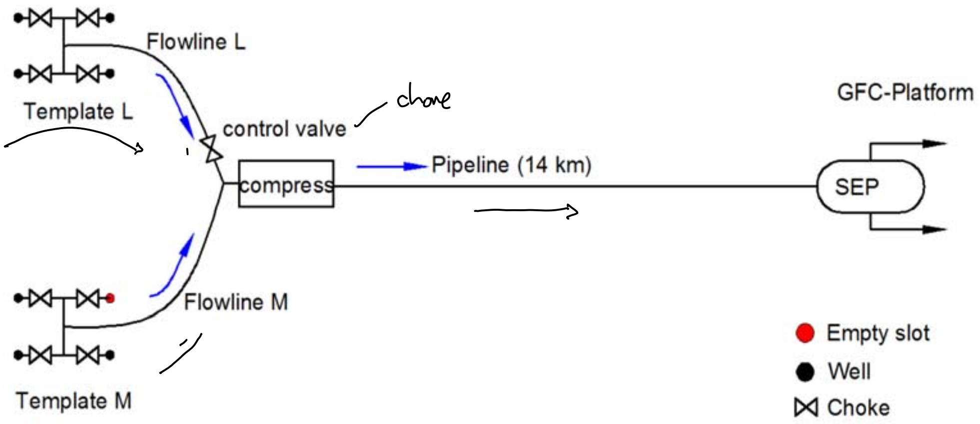
$q_f = 9.5\ E06\ Sm^3/d$

assume P_j = 36 bara

$q_m = 2.35\ E06\ Sm^3/d$

$q_L = 6.6\ E06\ Sm^3/d$

it is possible : $\Delta p_{comp} = 67 - 36 = 31$ bar



task 2.

$P_{disch} = 67$ bara $f(q_{field})$

$q_{field} = 9 E6$ Sm^3/d

$q_L = 6.4 E6$ Sm^3/d

$P_{upstream\ control\ valve} = 41$ bara

P_{wh}^{L}

$q_M = 7.6 E06$ Sm^3/d

$P_{wh}^{m} = P_{junct} = 24$ bara

$\Delta p_{choke}^{L} > 0$ $41 - 24 = 17$ bar

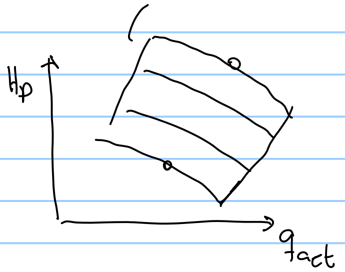
$\Delta p_{comp} > 0$ $67 - 24 = 43$ bar

- More discussion on exercise set 3.
- Class exercise P, T with multiphase flow.

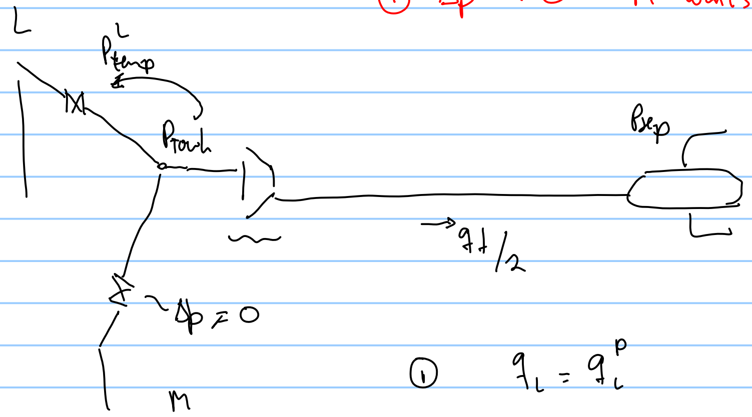
Problem 1 - Task 3 → operational map H_p, $q_{s\,actual}$ ✓

→ $T_{max,dis} = 120$ °C ✓

→ Power $\leq$ 12 MW ✓



① $\Delta p^{M} < 0$ M wants to enter in decline



① $q_L = q_L^{p}$

$q_M = q_M^{p}$

② $P_R^{L} \rightarrow P_{wh}^{L}$ co-current

$P_R^{M} \rightarrow P_{Touch}^{M}$ co-current $(\Delta p^{M}_{choke} \doteq 0)$

$P_{Touch}^{M} \rightarrow P_{temp}^{L}$ counter-current

③ $P_{sep} \rightarrow P_{disch}$ counter-current

④ $P_{wh}^{L} > P_{temp}^{L}$ ✓

$P_{dis} > P_{Touch}$

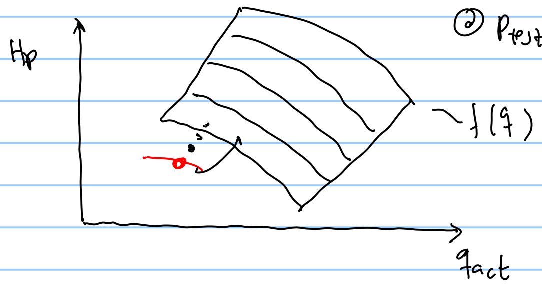
calculate

⑤ Power comp ✓

$T_{dis} = T_{suc} \cdot (r_p)^{\frac{n-1}{n}}$ ✓

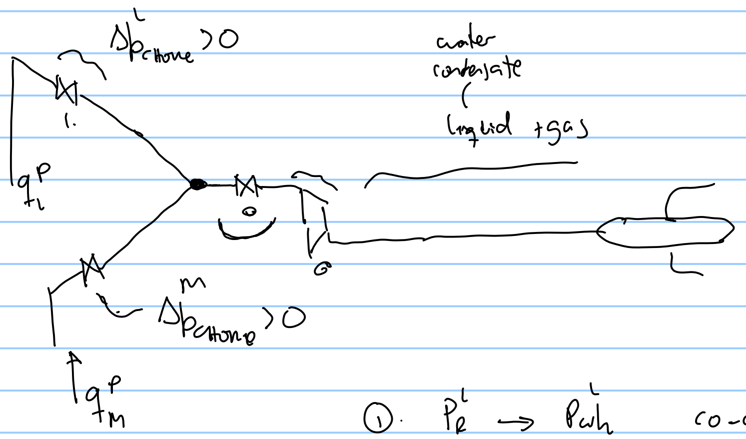
↳ [K], [°R]

H_p q_{act} → H_p^{test} q_{act}^{test}



② $P_{test}, T_{test}, MW_{test}$

I need to increase $\Delta p_{compressor}$



① $P_R^L \rightarrow P_{wh}^L$ co-current

② $P_R^m \rightarrow P_{wh}^m$ co-current

③ $P_{sep} \rightarrow P_{disch}$ counter current

④ assume $\Delta p_{comp} \rightarrow P_{suc}$ same as before

assume $\Delta p_{choke} \rightarrow P_{twh}$ ↪ 5

⑤ $P_{twh} \rightarrow P_{wh}^L$ counter current

$P_{twh} \rightarrow P_{wh}^m$ counter current

⑥ $\Delta p^m_{choke} > 0$

$\Delta p^L_{choke} > 0$

Power

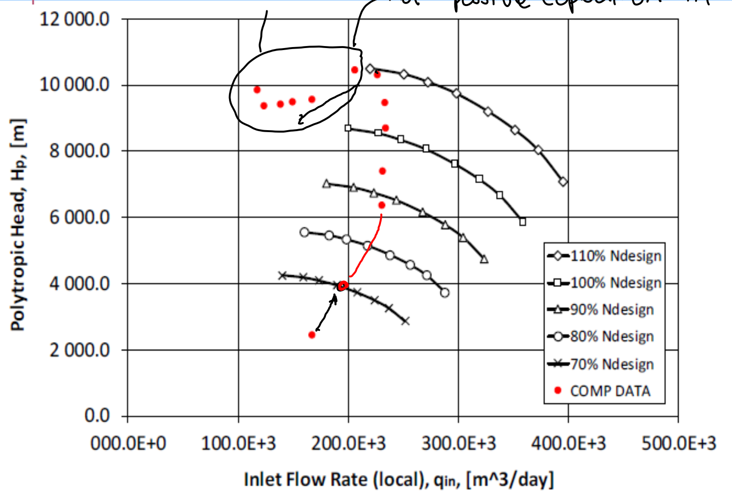
Tdisch

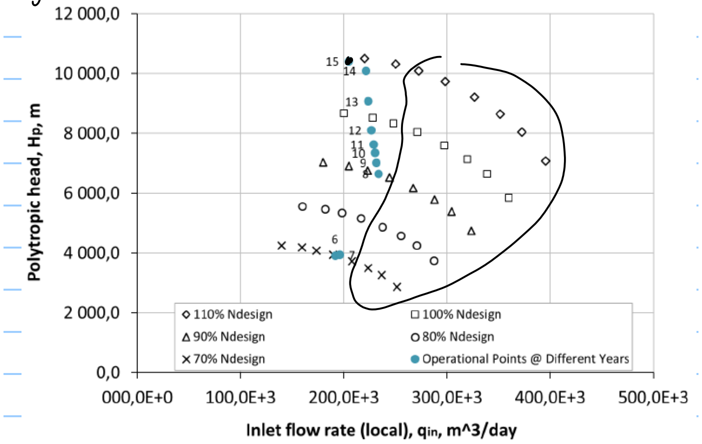
H_p^{test}, q_{act}^{test} }

time sequence

- $\Delta p^L_{extra} < 0$
- both templates enter in decline

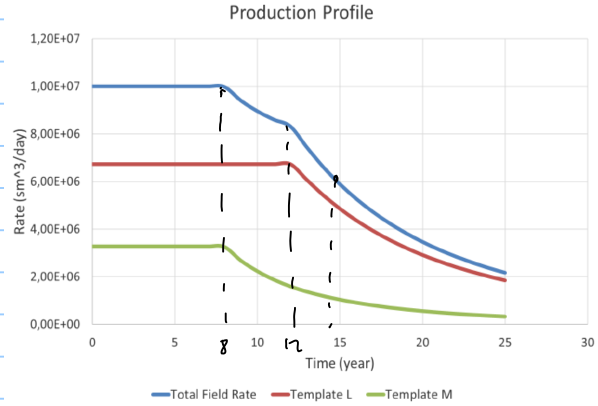
not possible (operation in surge)



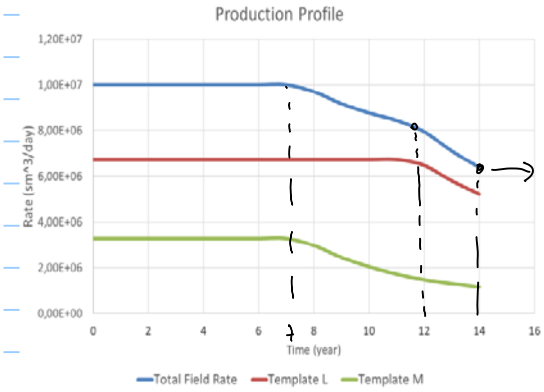


for our exercise the limit in compression power is reached (3-4) after compressor startup

Task 2



Task 3



no compressor can be used

be careful about minimum flow condition

Effect of cooler if the cooler is removed → Tdis become a limitation

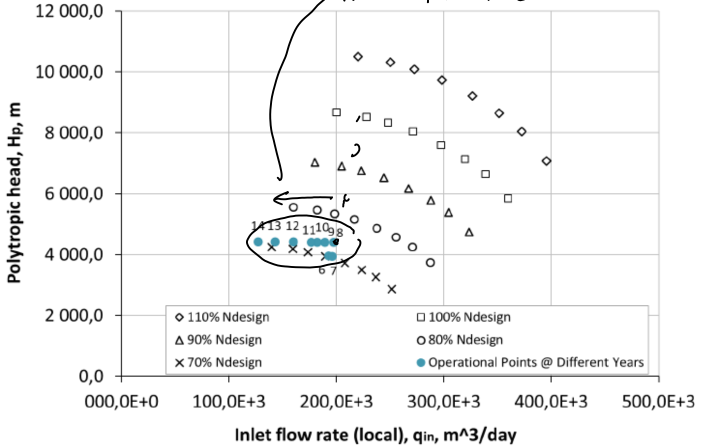
the q_{field} must be reduced

$q_{field} \downarrow \rightarrow \Delta p_{comp} \downarrow$

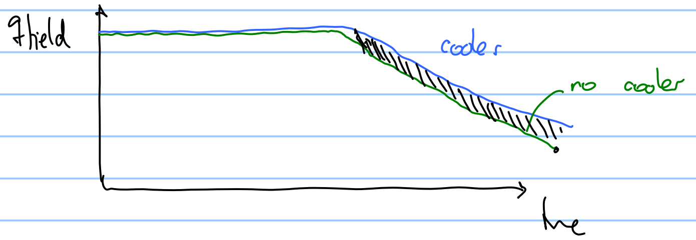
$\downarrow$

$T_{disch} \downarrow \leftarrow r_p \downarrow$

reduce field rate

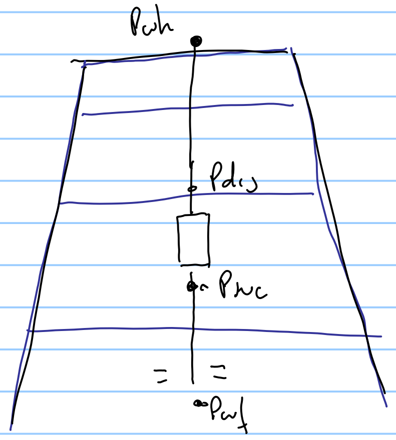


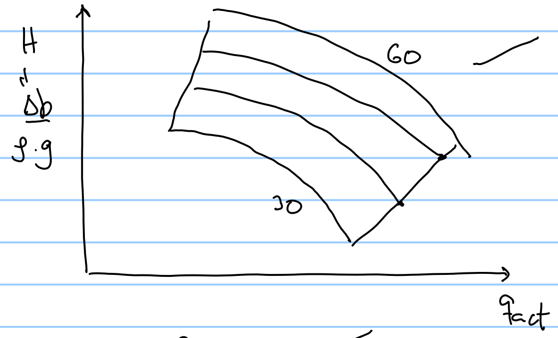
no cooler gives less production



- exercise 2

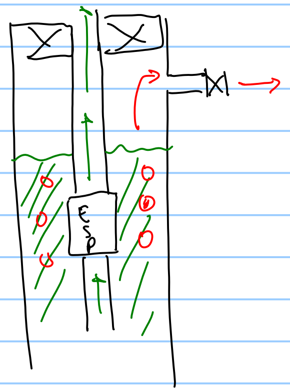
Power = 950 Hp ✓





$P_{suc} \geq P_b$. ✓

↳ all fluid is produced through tubing



① exclude pump model

two methods

ESP maps are provided

↳ ρ, μ

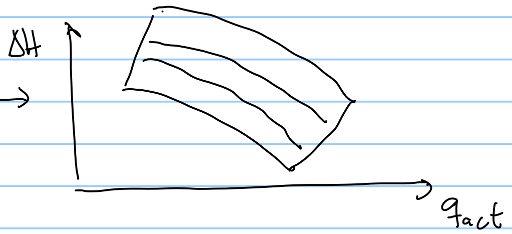
given

q_o

q_w

$wc = \frac{q_w}{q_o + q_w}$

↳ ρ_{av} , μ_{emul}



- co-current $P_R \to P_{wf} \to P_{suc}$

- counter-current $P_{wh} \to P_{disc}$

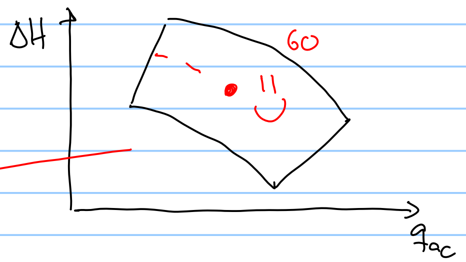
$$\Delta p_{esp} = \underline{P_{dis} - P_{suc}}$$

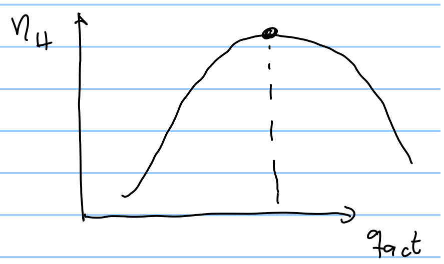
$$\Delta H_{esp} = \frac{\Delta p_{esp}}{\rho_{av} \cdot g}$$

$q_{ac} = q_{\bar{L}}$ neglecting gas, assuming incompressible

if NOT ! $q_{act} = B_o(P_{suc}, T_{suc}) \cdot q_{\bar{o}} + B_w(P_{suc}, T_{su}) \cdot q_{\bar{w}}$

- plot the point





check $P_{suc} \geq P_b$ (bubble point pressure at T_{suc})

$$Power = \frac{\Delta p_{esp} \cdot q_{act}^{suc}}{\eta_m \, \eta_H}$$

$\eta_H = f(q_{act}, f, \mu, \rho)$

$\uparrow$ f_{ref}

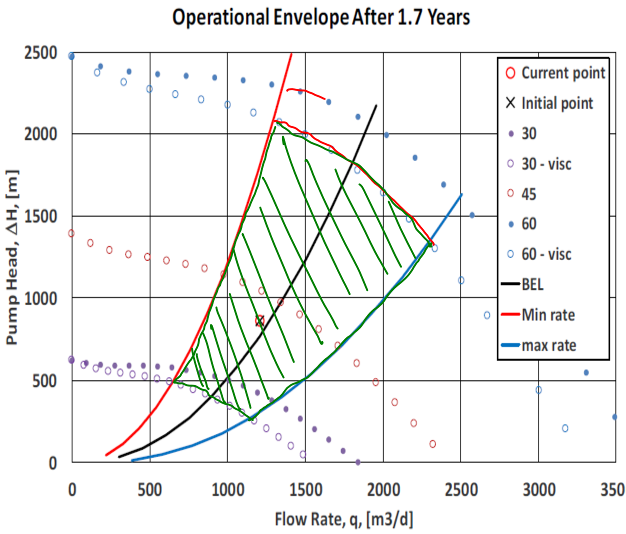
q_{BEP}

Best efficiency point

estimate f graphically

use VBA function pumpeff_visc($\underbrace{\quad\quad}_{q_{BEP}}$

use { coefficients ΔH vs q, η vs q } for water !



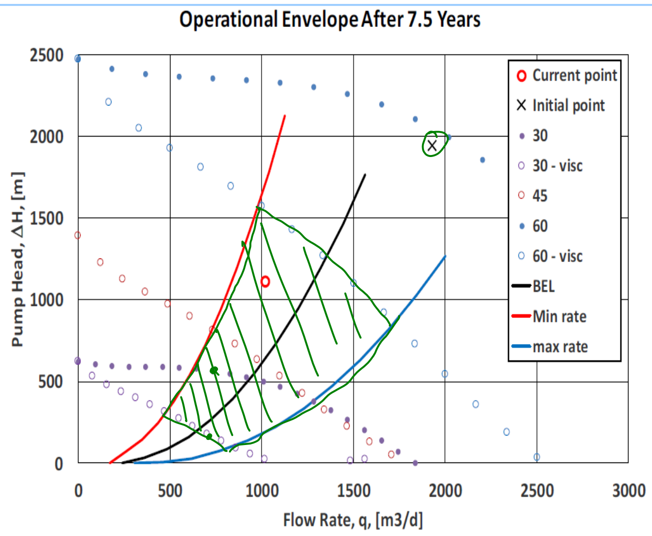
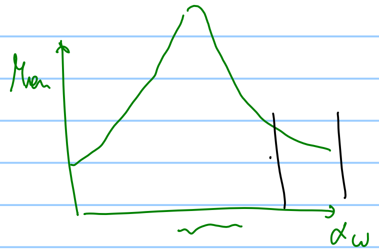
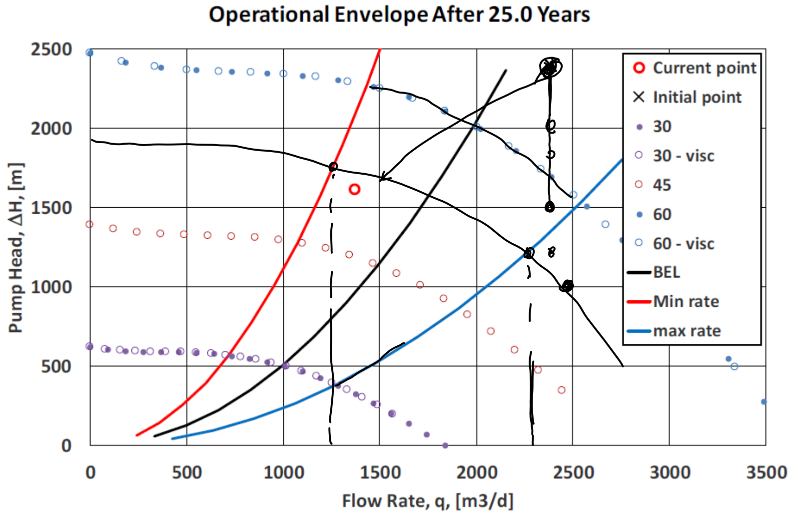
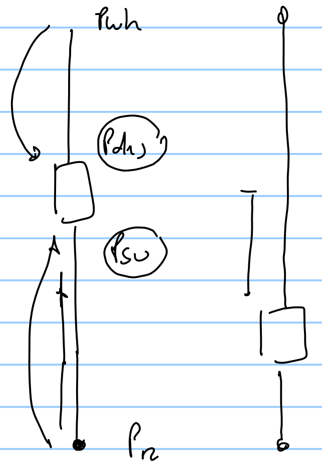


Figure 7 - The operational envelope of the ESP after 7.5 years

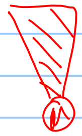


$$\underbrace{P_{suct} < P_b}_{\uparrow}$$





- Increase "J" → P_{suc} ↑
  → Δp_{pump} ↓



- change ESP model
- change ESP motor (bigger)

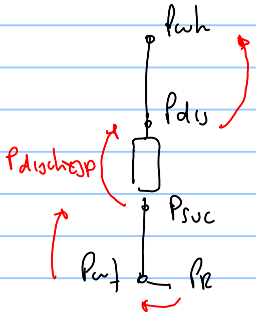
Method 2: use the pump model (equation) (VBA function Pdischarge_pump_visc)

↳ $a_s - a_1$ for water

↳ q_{BEP}

C_Q

C_H



using f as a "guess"

$P_{wh} \neq 7$ bara

change f until $P_{wh} = 7$ bara

↳ if solver fails → numerical reasons { starting seed, N_{it}, TOL

→ non feasible solutions

$$\Delta h_{tsp} = \frac{\Delta p_{tsp}}{\rho_{av} \cdot g}$$

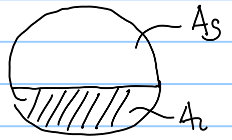
q_{mm} = VBA function

q_{mass} = VBA function

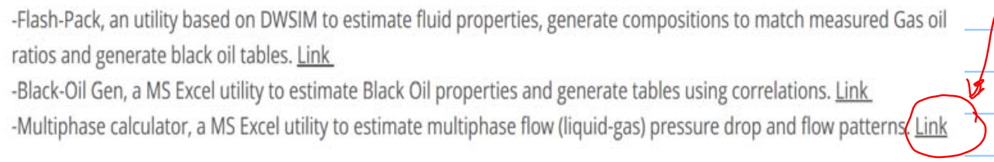
◦ Class exercise. for $\frac{dP}{dx}$ calculator (multiphase aspect)

liquid superficial velocity $u_{sL} = \frac{q_L}{A}$ ~ cross section pipe area

gas superficial velocity $u_{sg} = \frac{q_g}{A}$



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



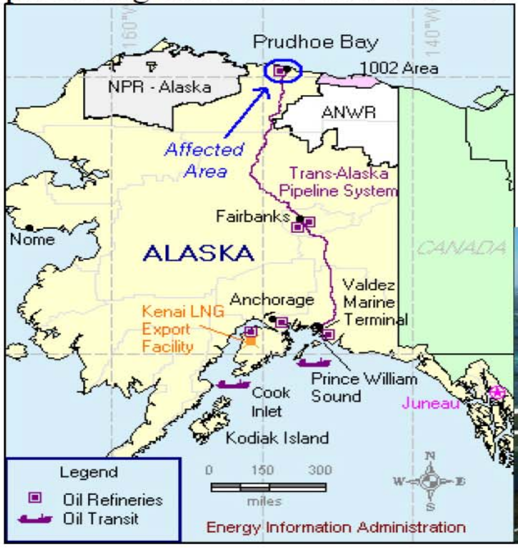
-Flash-Pack, an utility based on DWSIM to estimate fluid properties, generate compositions to match measured Gas oil ratios and generate black oil tables. Link

-Black-Oil Gen, a MS Excel utility to estimate Black Oil properties and generate tables using correlations. Link

-Multiphase calculator, a MS Excel utility to estimate multiphase flow (liquid-gas) pressure drop and flow patterns. Link

Estimating well IPR with test data

The Prudhoe bay field is a large oil field on Alaska's North Slope. The field has been producing since 1977 and it is currently producing around half a million barrels per day.



The field has 1330 wells, from which 591 are naturally flowing. The wells shut-in pressure is 166 bara (corresponding to a reservoir pressure of 400 bara). The wells are arranged in production modules that provide protection and insulation to the Christmas trees from the harsh artic environment. The various modules are connected through flowlines to the main

$$\dot{m}_T = q_{\bar{o}}\, \rho_{\bar{o}} + q_{\bar{g}}\, \rho_{\bar{g}}$$

$\dot{m}_T$ $\quad$ $\dot{m}_o$ $\quad$ $\dot{m}_g$

with hysys $\underbrace{P, T, z_i} \longrightarrow x_o \qquad x_g = 1 - x_o$

$\hookrightarrow \dfrac{m_L}{m_L + m_V} \qquad \dfrac{m_V}{m_L + m_V}$

$$\dot{m}_o = x_o \cdot \dot{m}_T$$

$$\dot{m}_g = x_g \cdot \dot{m}_T$$