Note Title 10.01.2016

TPG4230 Field development and operations

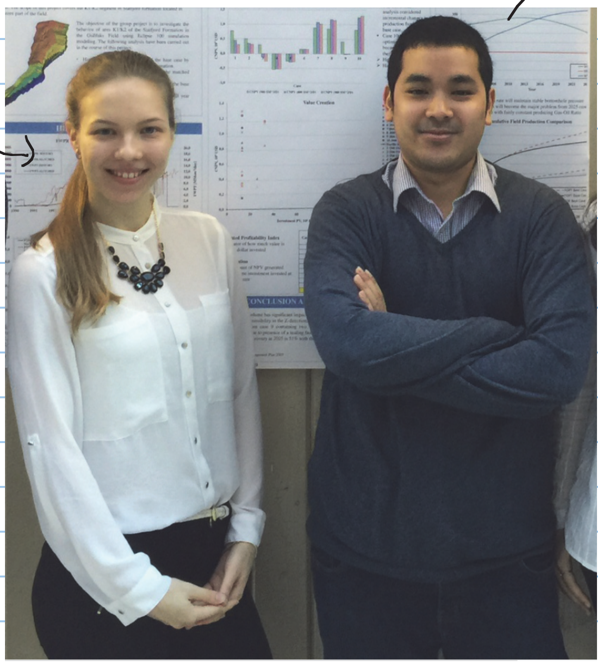
Prof. Milan Stanko

- Classes P1 mondays 15:15-17:00 } theory and exercises
  tuesdays 14:15-17:00

- student assistants

Reizky Azhar

Anna Danilova

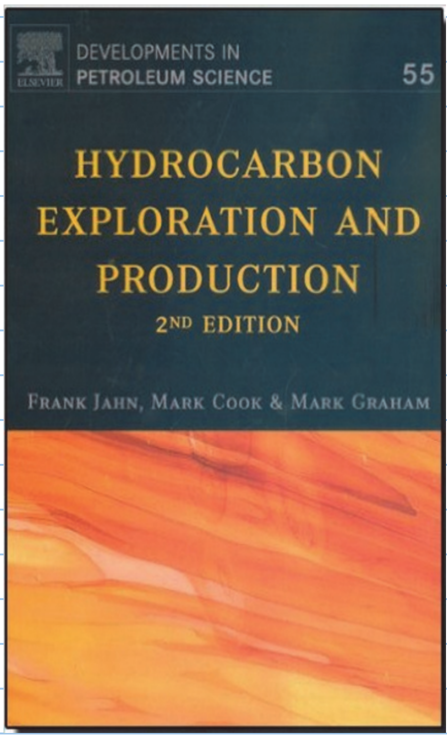


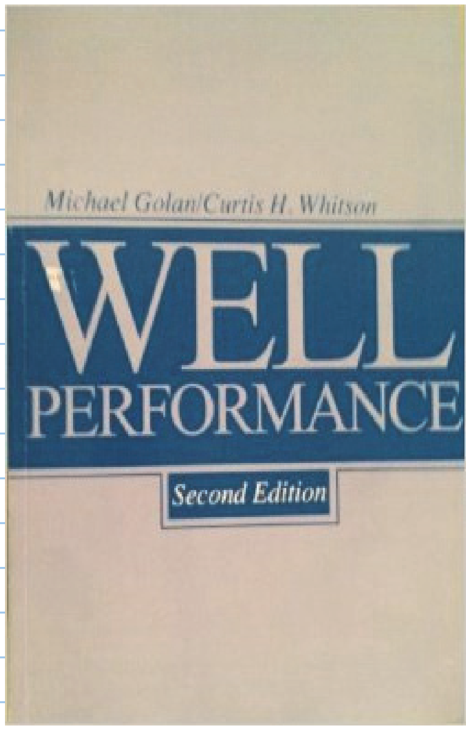
- Evaluation : 40% mandatory exercises 5-6 exercises
  : 60% written examination 2016.06.06 Kl. 09:00

Reference group: Per Henrik Fjeld

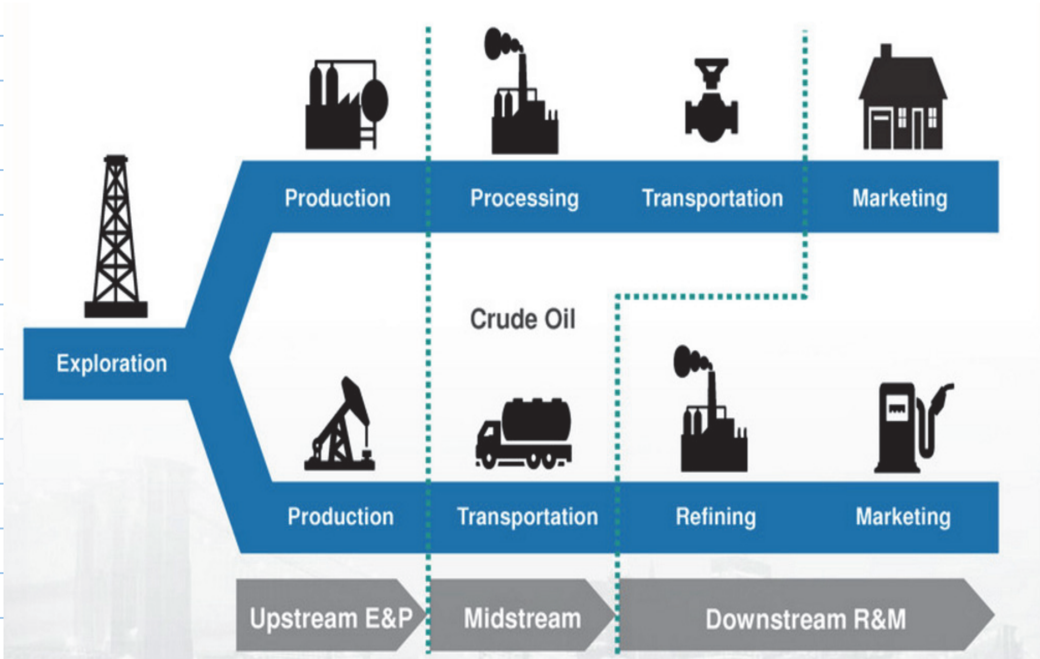
Guest lecturers : Prof. Michael Golan
Prof. Curtis Whitson
Dr. Jesus De Andrade

Bibliography




Field development and operations : E&P Exploration and production, upstream sector




where are we?

when in the life of the field is this course located

# Life cycle of an oil and gas field

Design and planning

Installation and deployment

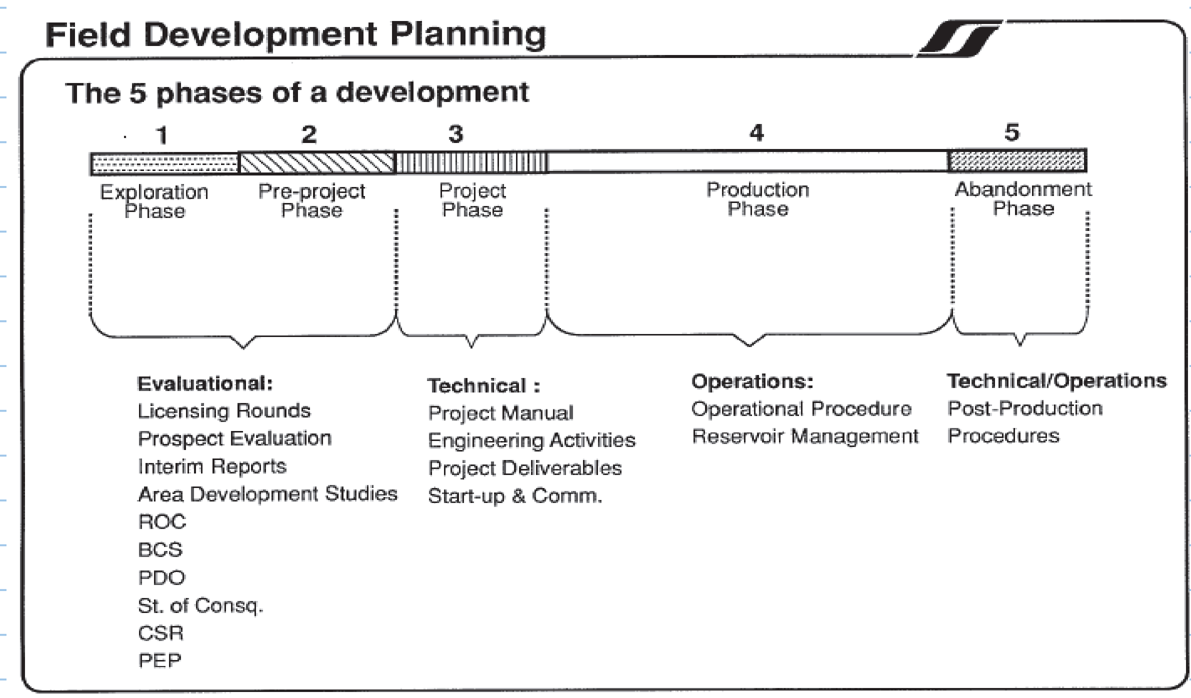
Pre-exploration → Exploration — Discovery → Appraisal → Pre-project phase → project execution → operations → abandonment and decommissioning

go further?

Field development and operations

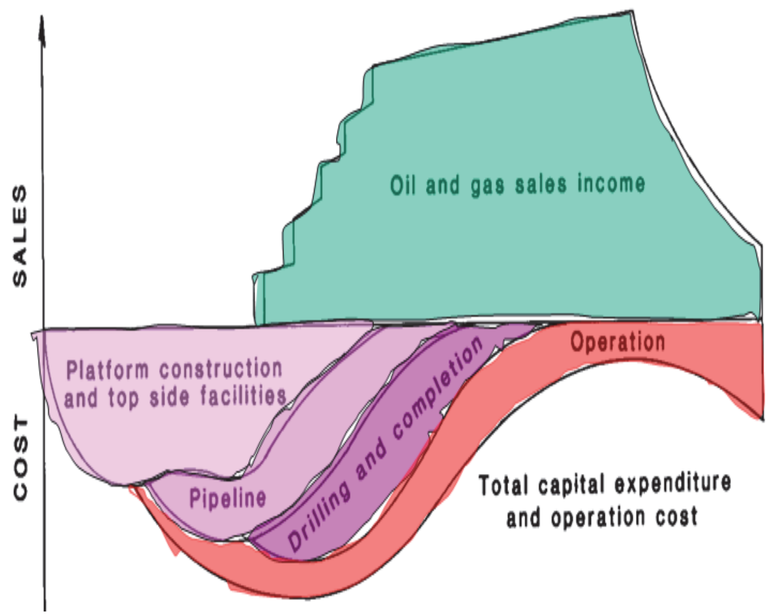
- development:
  - flexibility
  - sensitivity analysis, scenarios
  - uncertainty
  - optimization
- operations:
  - locked with a particular system, cope with its deficiencies and exploit its advantages
  - optimization, effectivization. ↑ profit ↓ cost
  - maintenance and troubleshooting.

focused on offshore developments, on the Norwegian sector.



Both in the development phase or during operations it is very important to look at the cash flow, cost and revenue of the asset.

## Revenue and Cost Profiles




## The Ultimate driver in E&P operations

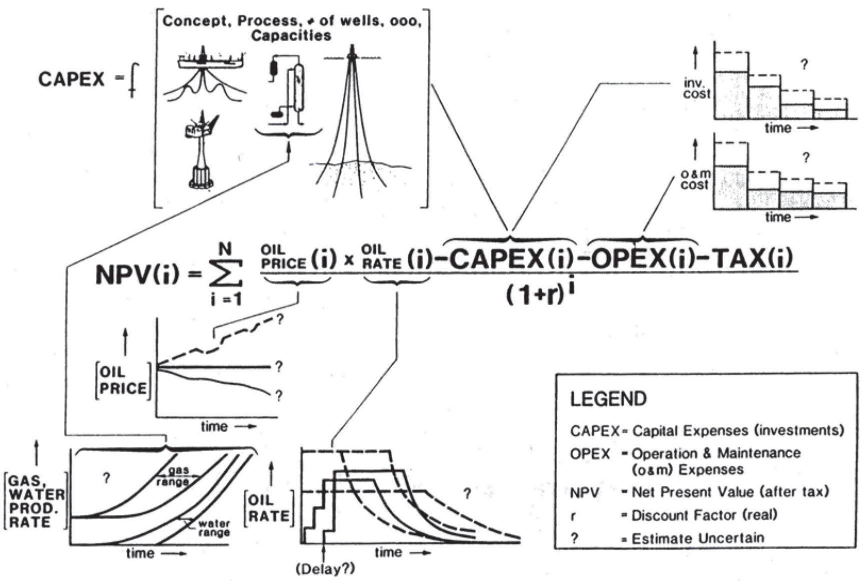
$$NPV = \sum_{i=0}^{N} \frac{\text{OIL PRICE}(i) \times \text{OIL PROD}(i) - \text{CAPEX}(i) - \text{OPEX}(i) - \text{TAX}(i)}{(1+r)^{i}}$$

Production profile

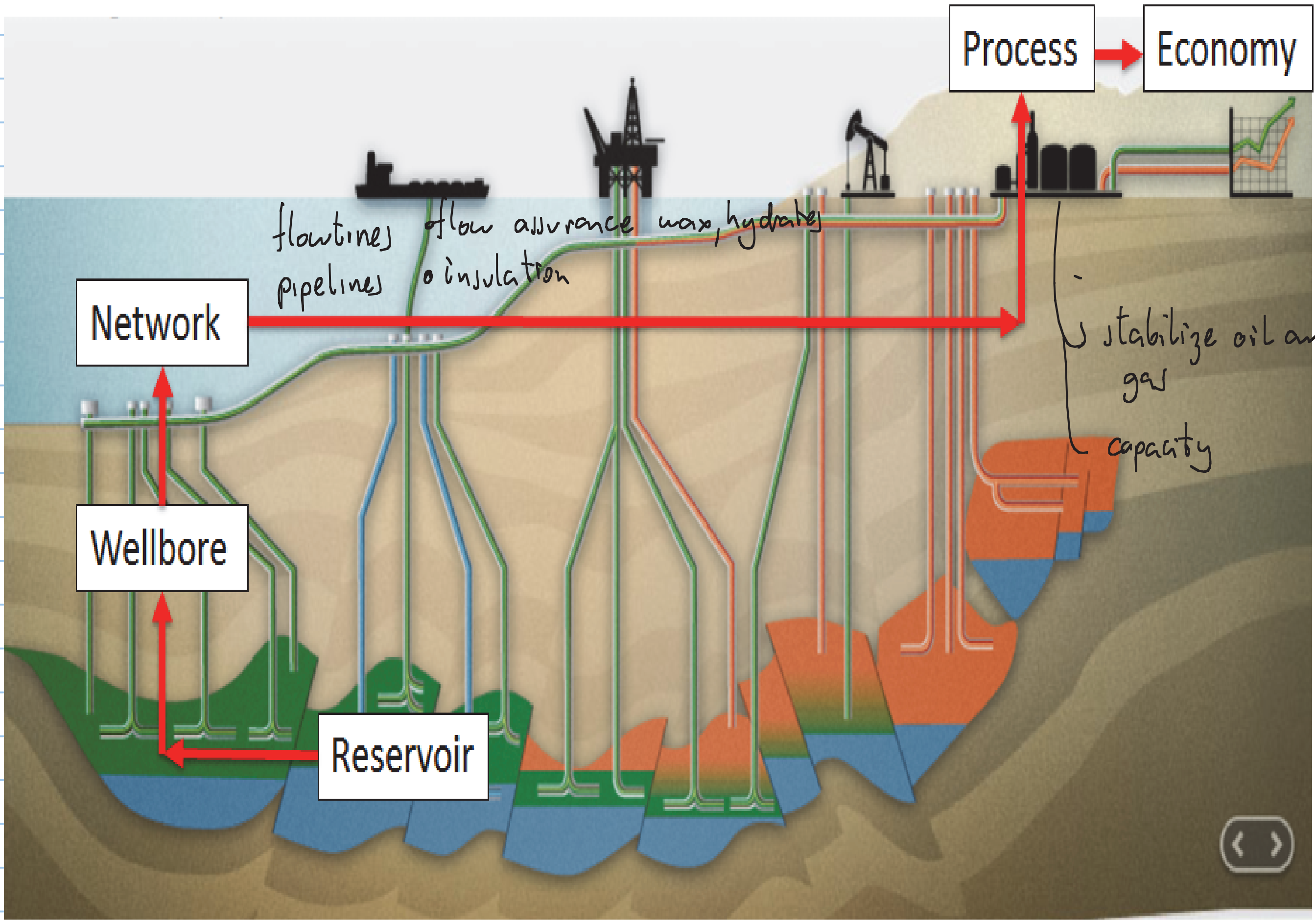
defined by field performance

The hydrocarbon production is the most important cash generator in a petroleum asset

# What can we control?




Components defining the field performance




flowlines
pipelines
flow assurance wax, hydrates
• insulation

stabilize oil and gas
capacity

· deviated
horizontal
· well architecture
• well completion
• Artificial lift

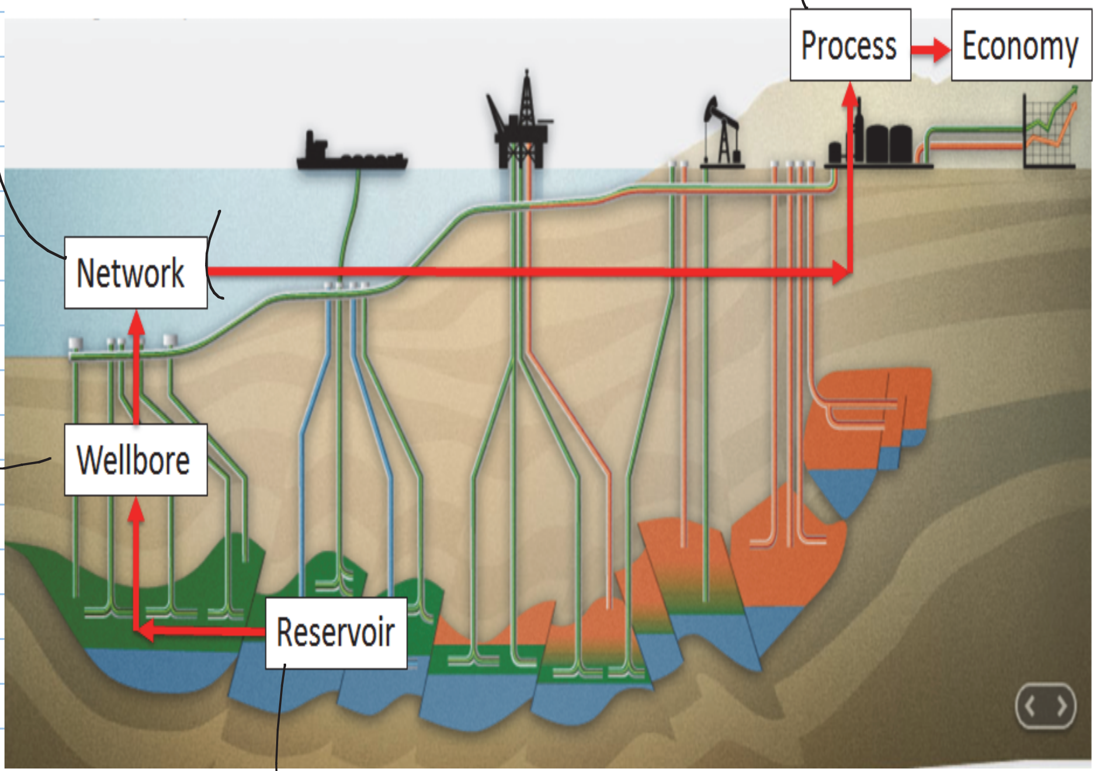
Recoverable reserve
· initial pressure
• Reservoir characteristics
• Geological structures
• pressure support
• fluid characteristics
• reservoir communication

Commercial software used in the oil industry to compute field performance

**ReO**

pipesim
Gap

HYSYS
UNISIM




PROSPER
pipesim
pipephase
**WellFlo**

- ECLIPSE
- CMG
- MORE
- SENSOR
- material balance { MBAL, SOS
- Decline curve analysis (DCA)
- Reveal

IAM
Integrated asset modeling
- RESOLVE
- IAM (Avocet)
- Pipe-it

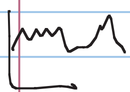
Skills to exercise and develop in this course

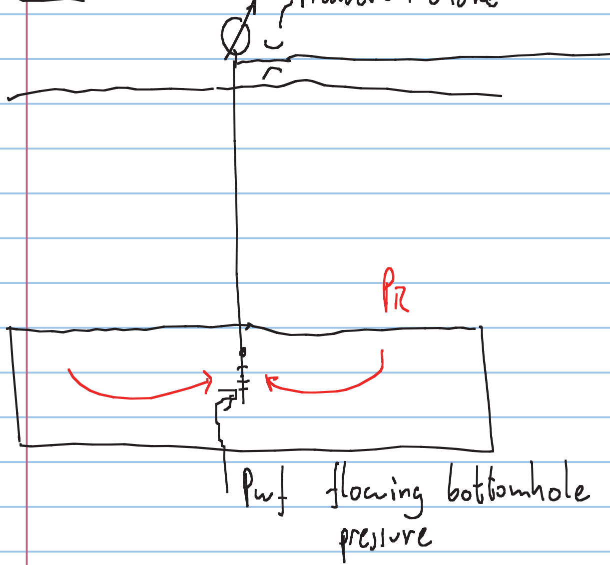
- specific to oil and gas industry:
  - field architecture
  - well technology
  - process and flow technology
  - control and instrumentation
  - offshore technology

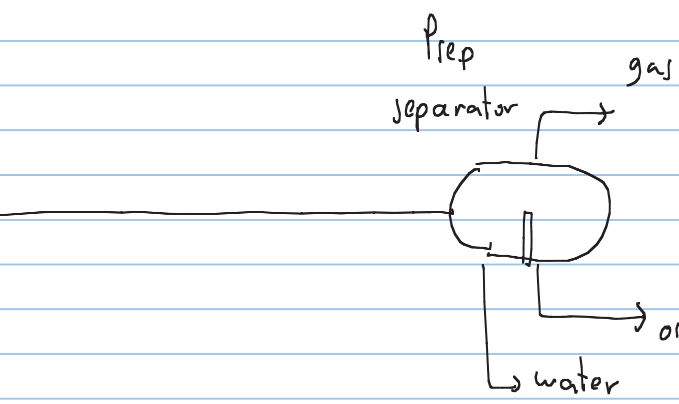
- generic : engineering courses
  - Fluid mechanics
  - thermodynamics
  - math and data handling, statistics
  - economical analysis

Production profile ⇝ production scheduling — how much the field is going to produce
" " each well is going to produce

Simplified Production system





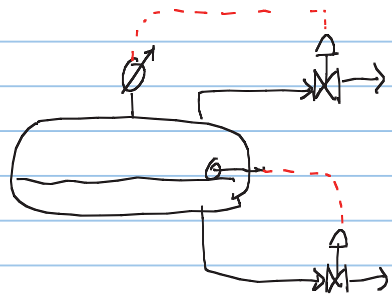

kg/s
mech

kgmol/s
che.

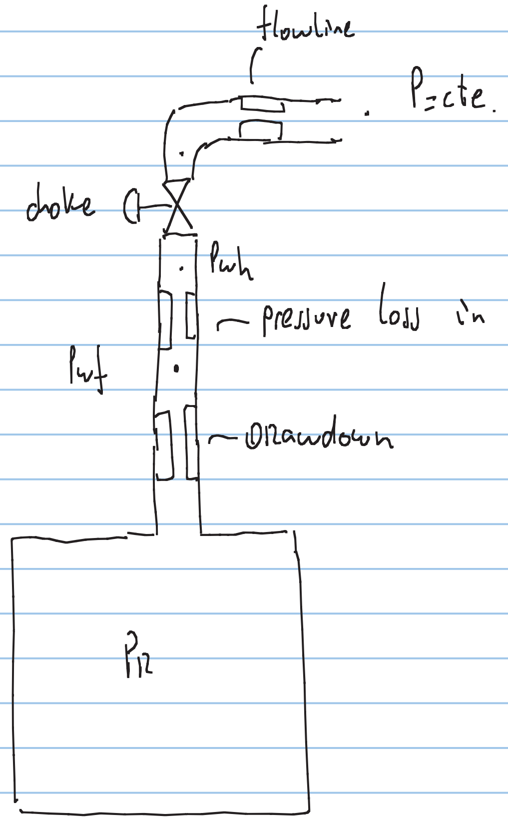
$Sm^3/d$

Sbbl/d

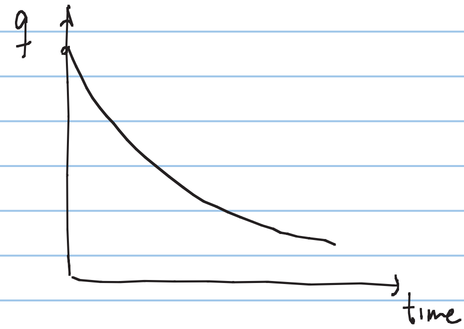
scf/d

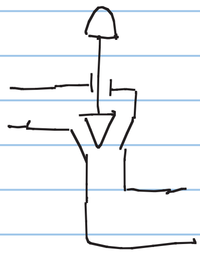


Analogy of the production system



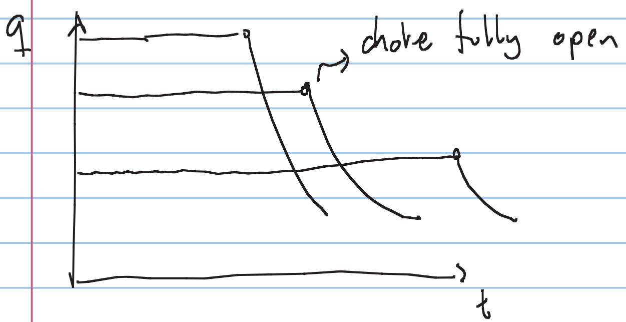

$q \propto P_R - P_{sep}$



<u>mode A: constant rate</u>

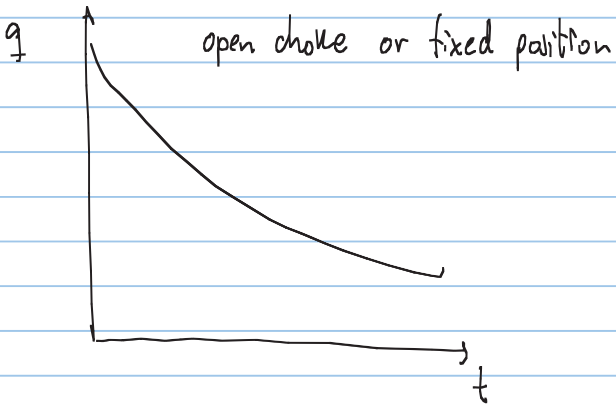
- Requires a constant adjustment of the choke




- when is it used?:
- standalone development
- build the infrastructure from scratch.

<u>mode B: constant pressure</u>

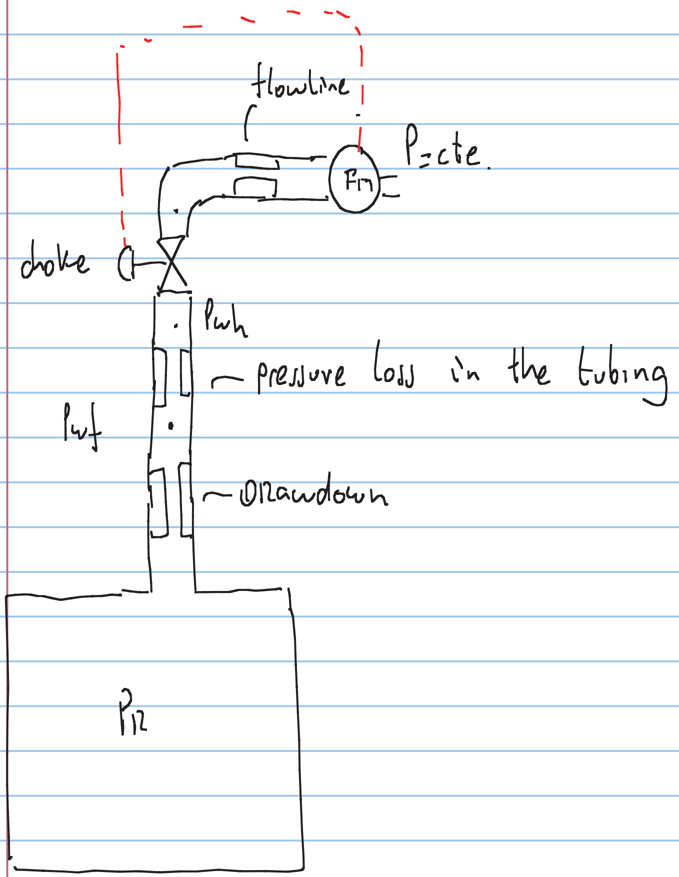
- choke is left at a fixed position




as much as possible, as fast as possible

- satellite field to tie-in to an existing field with spare capacity
- no new for new infrastructure

go to our field simulator:

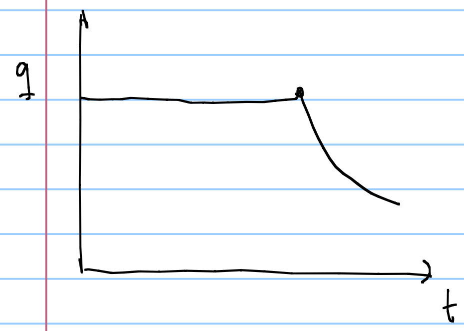

flowline
P=cte.
choke
Pwh
pressure loss in the tubing
Pwf
DRawdown
PR

- Friday: tentative day for consultation hours with the assistants.
  - Discussions or forum facility on itslearning

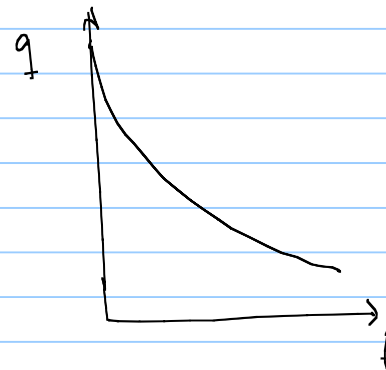
Outline for today:
- Production schedule
- Arquitecture of production systems

<u>mode A</u>

Constant rate



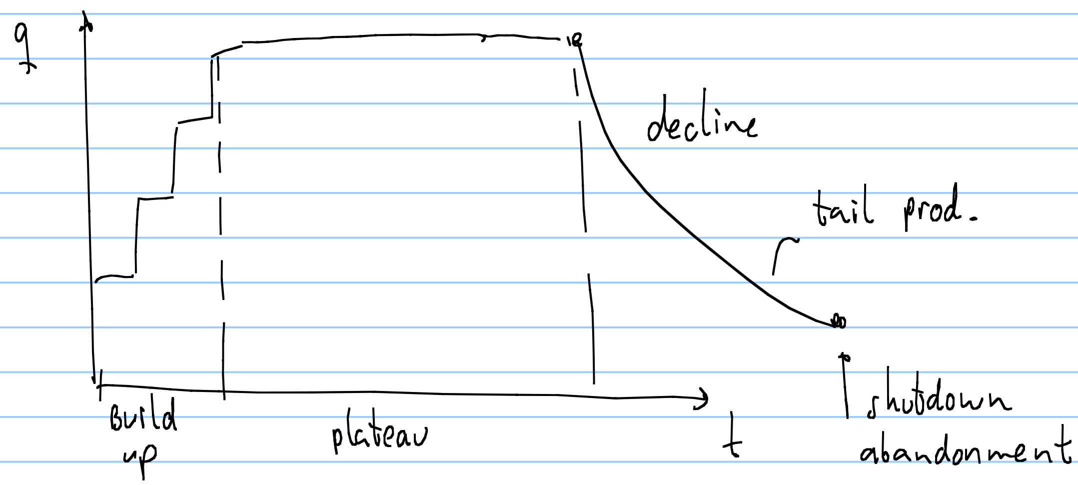

<u>Mode B</u>

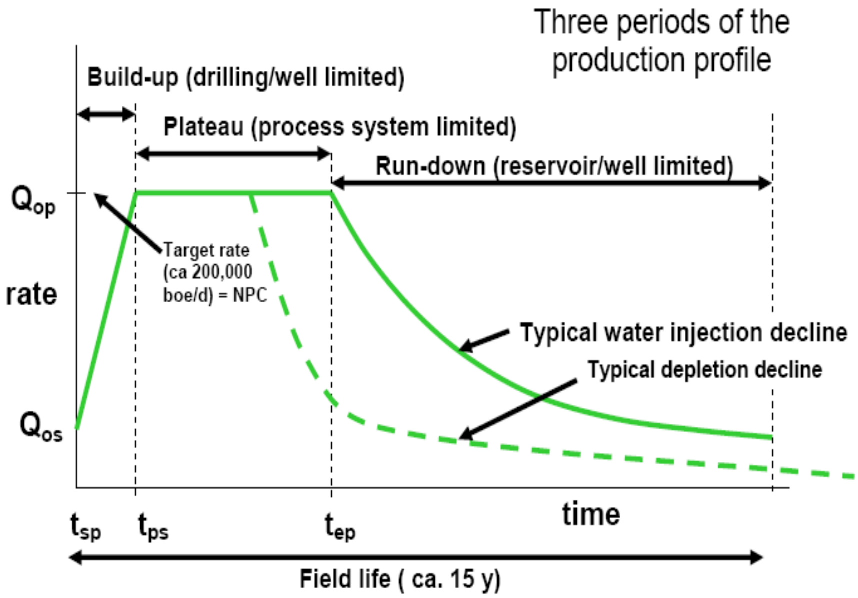


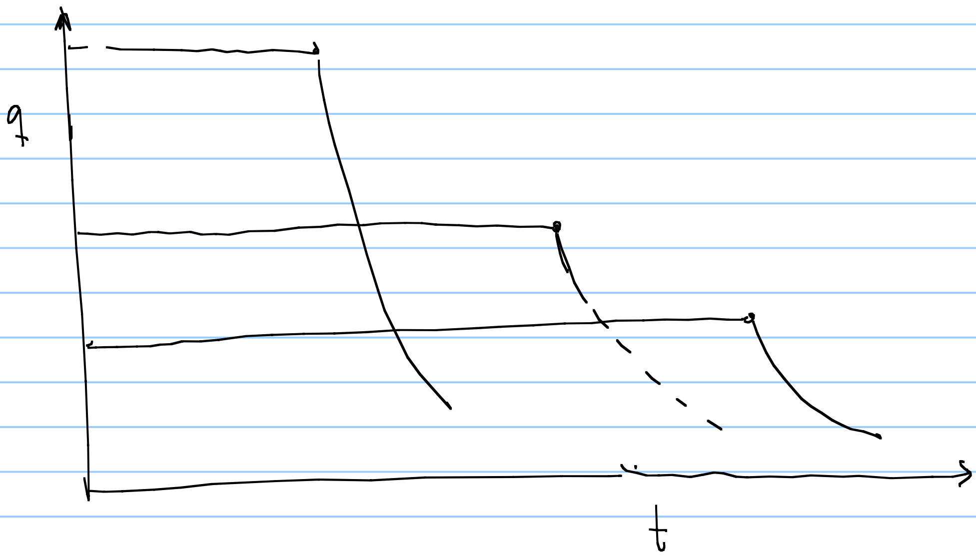

Gas fields
- Sales contract (long term)
- Costumer
- infrastructure
  - pipeline
  - LNG ~> special plant to liquify sending to receiving terminal

- Snowhite
- Edvarg Grieg

- Morvin field satellite to Åsgard






rule of thumb to determine plateau rate
↳ first order estimation.

for oil fields annual offtake = $\underbrace{TRR}_{\text{total recoverable reserves}} \cdot 0.1$ → 8-10 years

total recoverable reserves { produced economically with existing technology

$$TRR = \begin{matrix} IOIP\,(N) \\ IGIP\,(G) \end{matrix} \cdot RF$$

Q

27% 35% 50%

1970 1990 2010

for gas fields annual offtake = 0.035 . TRR

$\hookrightarrow$ G. RF

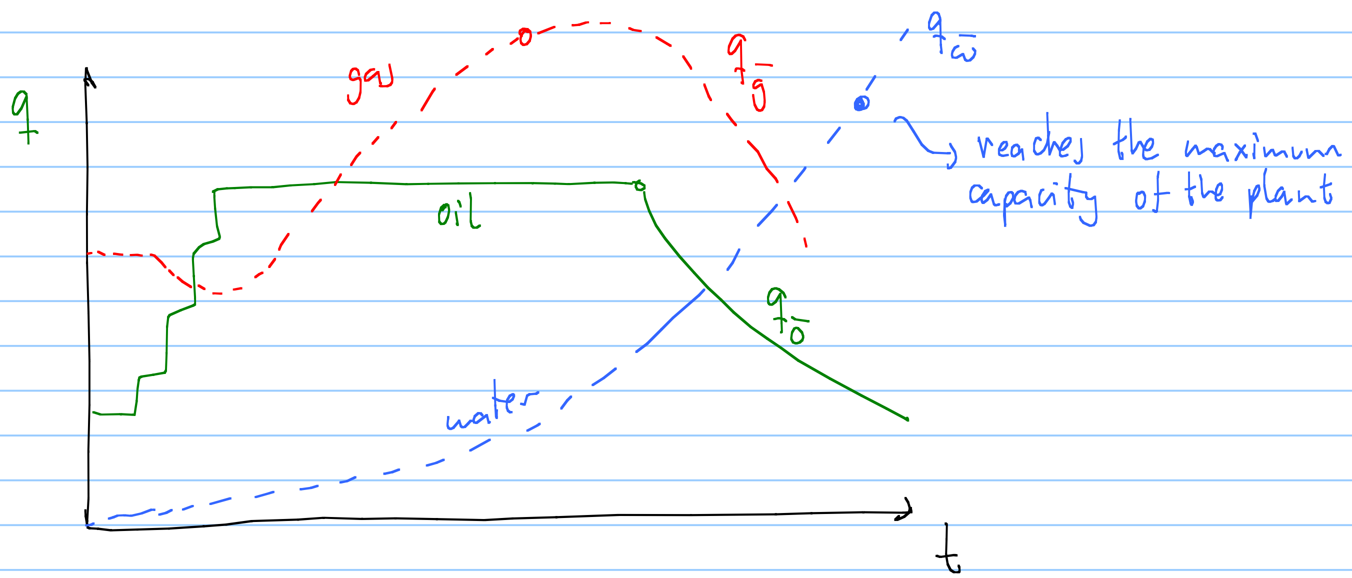
$\hookrightarrow$ Sm$^3$

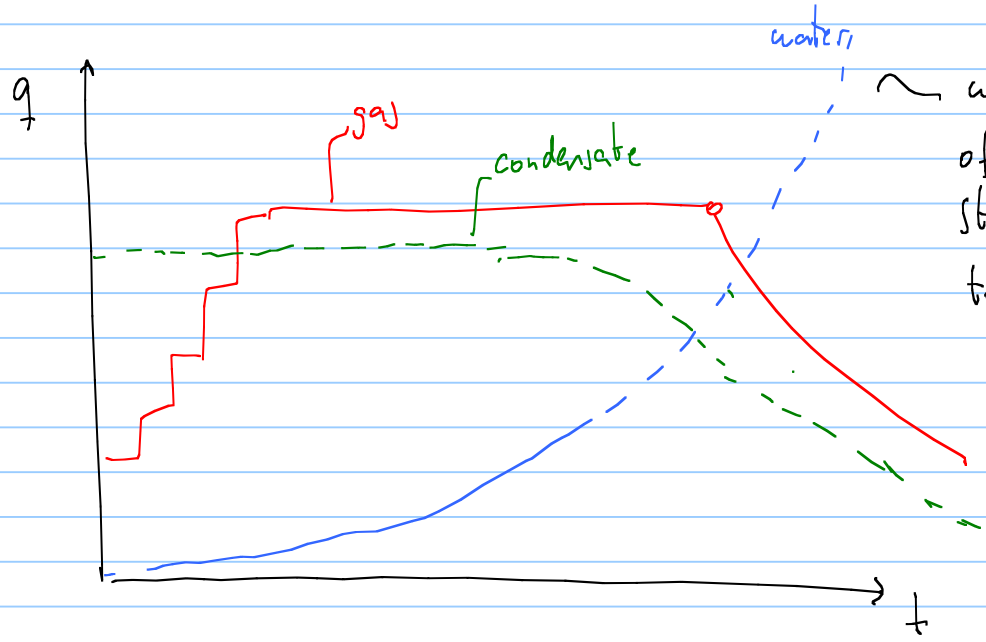
$$\text{field rate} = \frac{\text{Annual offtake } (\ )}{\text{N° operational days in the year [d]}} = \left[ Sm^3/d \right]$$

Associated fluids coming with the main production fluid should be also taken into account

oil field $\rightsquigarrow$ gas production, water production

gas field $\rightsquigarrow$ condensate, water production






~ water, high content of liquid in the gas stream is very negative to the life of the well.

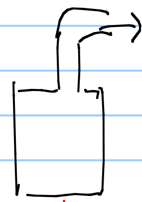
~ reduction in the income

Single well + reservoir behaves like a tank.

sep pressure is constant.

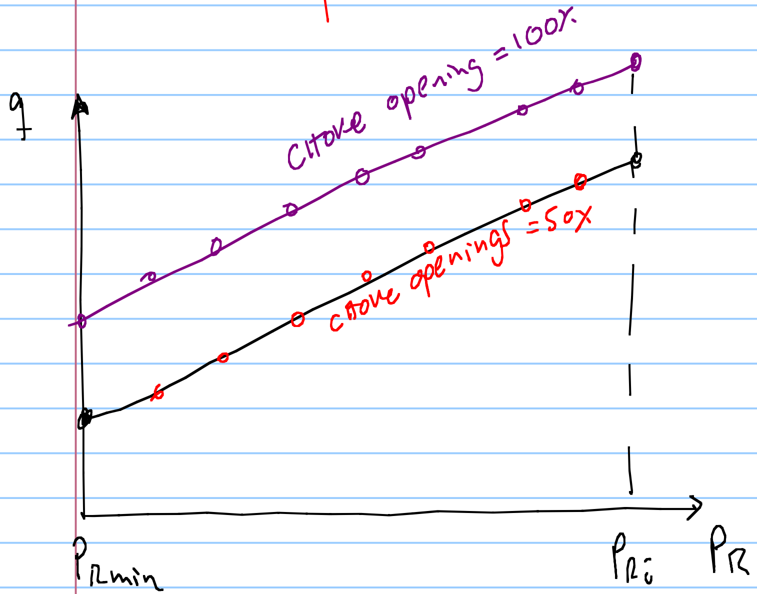
$$q = f(P_R, P_s) \Rightarrow q = f(P_R) \text{ if choke is fixed}$$

what is left, what I have, taken



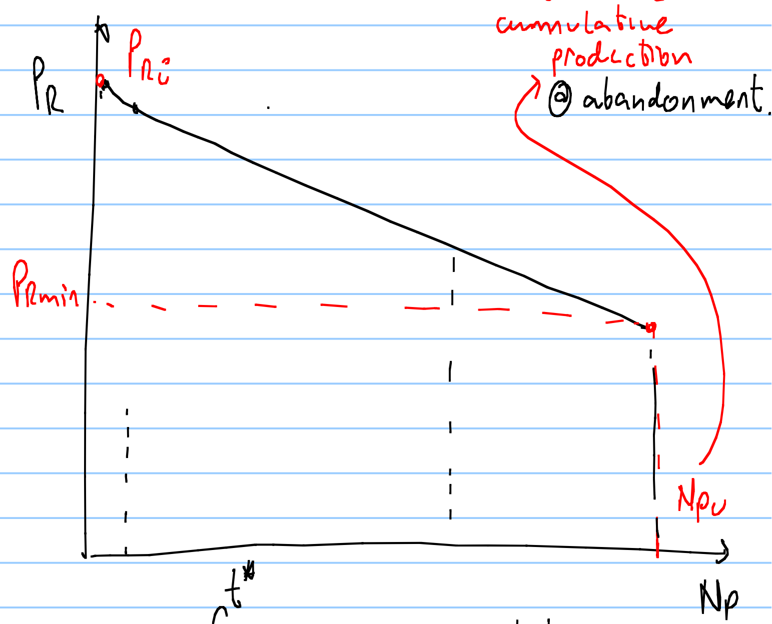
$$A = N - N_p$$
$$G - G_p$$

Production engineering calculations




Reservoir engineering calculations.

ultimate cumulative production @ abandonment.



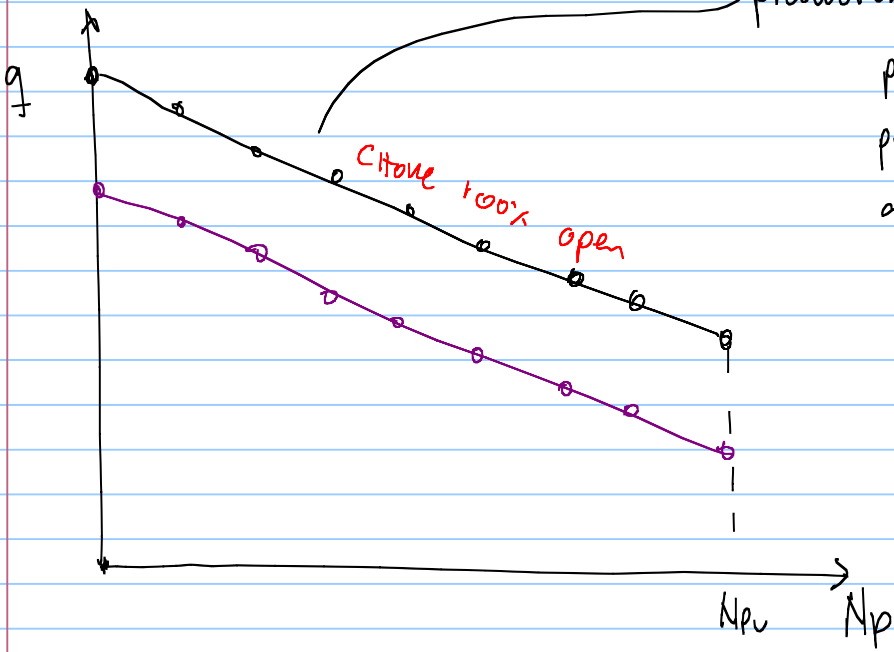

they are not necessarily linear be careful!

$$N_p(t^*) = \int_0^{t^*} q_o(t)\,dt$$ cummulative production, how much I have taken out of the reservoir.

flow potential: $q_{pp}$

production potential: is the maximum production rate that my production system* can deliver at a given
- Reservoir pressure
- Np
- Depletion state of the reservoir

↳ • fully open choke
• artificial lift.




* well + pipeline + sep
• network

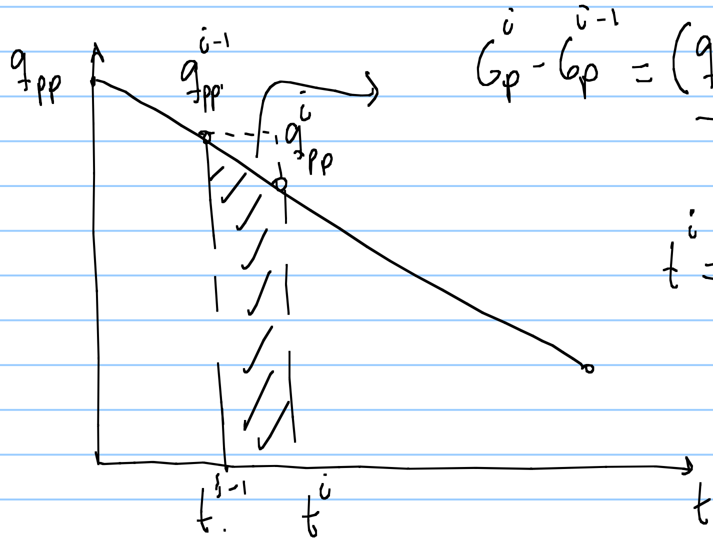
Case 1: Produce all the time at production potential (open choke)

how do I estimate production schedule q vs. t

having $q_{pp}$ vs $G_p$
as a collection of points?

NPV, cash flow, cost, revenue is calculated time-based and not $G_p$ based

$$G_p = \int_0^{t^*} q_{\bar{g}} \cdot dt \qquad q_{\bar{g}} = q_{pp} \sim \text{discretize the integral}$$



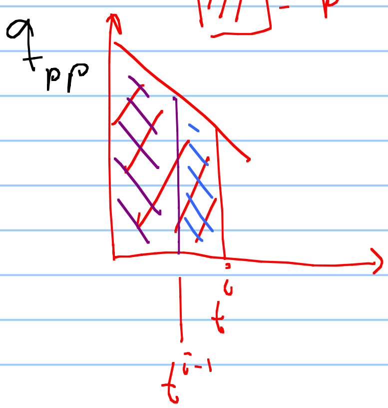

$$G_p^i - G_p^{i-1} = \frac{\left(q_{pp}^i + q_{pp}^{i-1}\right) \cdot \left(t^i - t^{i-1}\right)}{2} \quad Sm^3$$

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

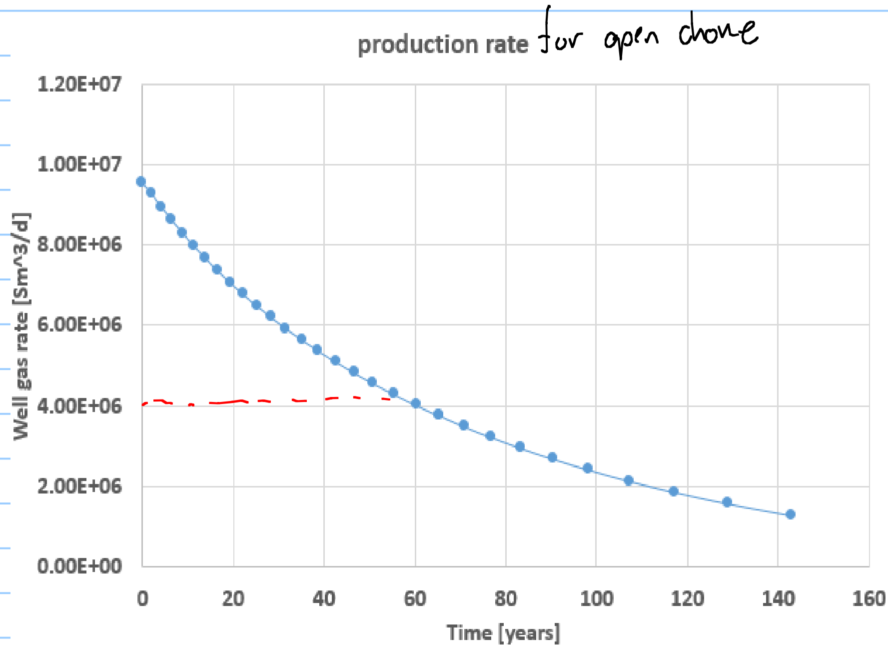
↳ $Sm^3/d$

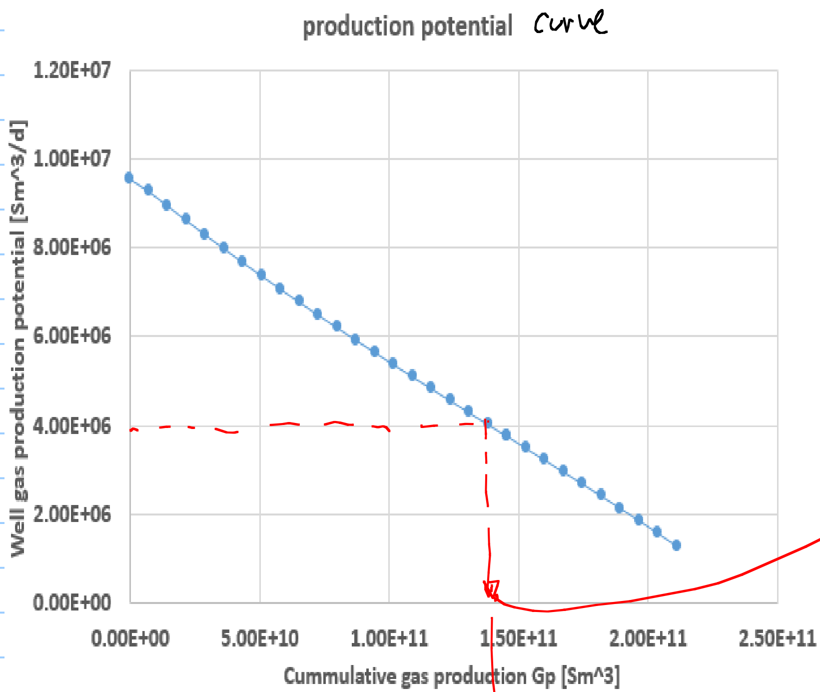
$= G_p^{i}$ $\quad = G_p^{i-1}$

$= G_p^{i} - G_p^{i-1}$




all the time producing at prod. potential.



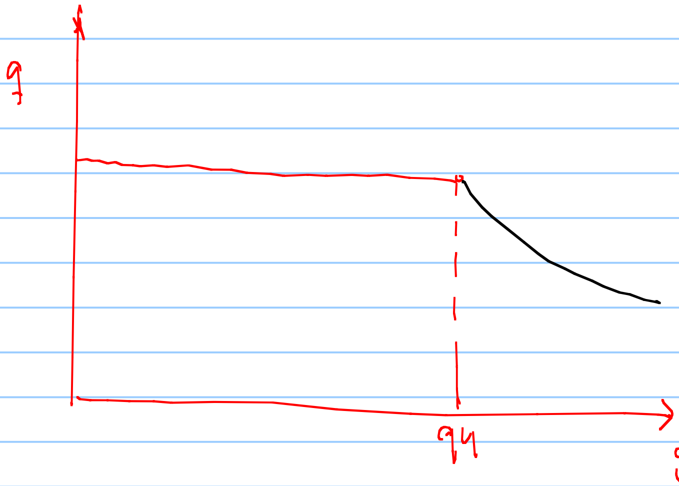

<u>Case 2</u>

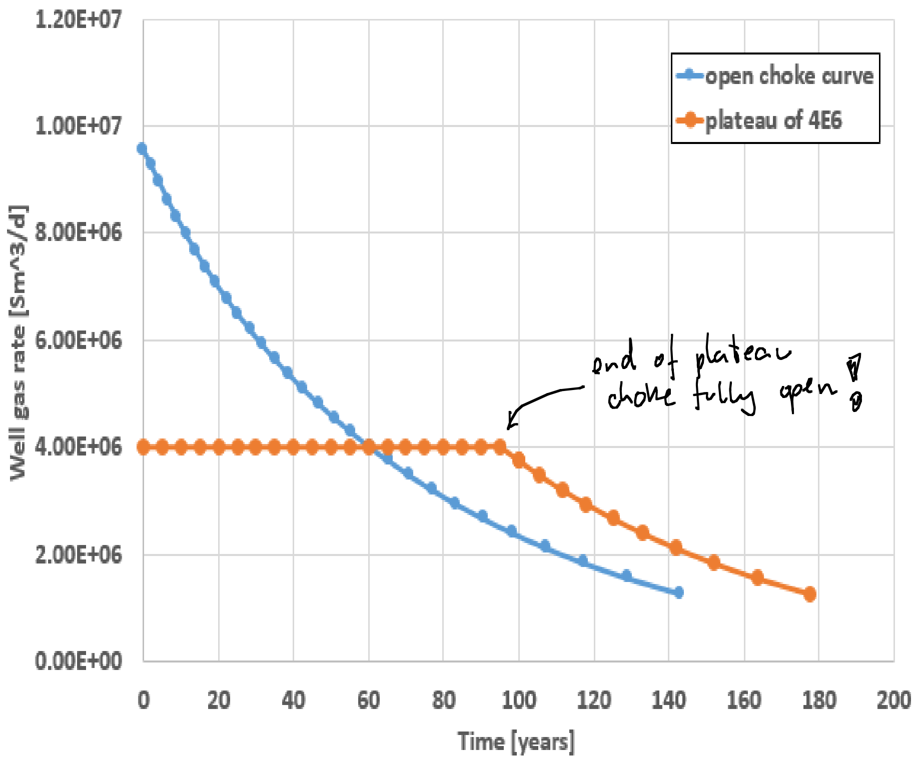
we wish to produce 4E6 $Sm^3/d$ from the well on mode A. Calculate the duration of the plateau?

$$t_{plateau} = \frac{G_p^{*}}{q_{plateau} \cdot 365}$$

up to this $G_p^{*}$, $P_R^{*}$ the well is able to provide the rate that we want. after that the production potential is less than the desired plateau rate.

for plateau of 4E6 $Sm^3/d$




Estimating production profile for the full field

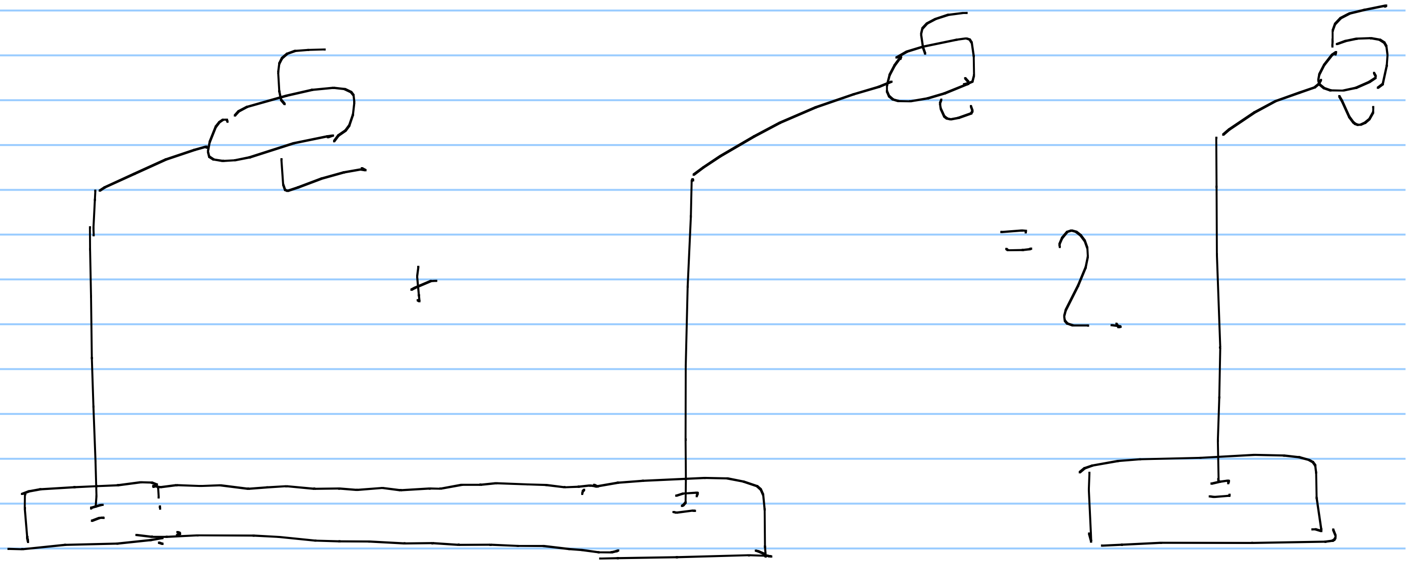
$G = IGIP = 2.7E11\ Sm^3$ $\qquad$ $RF = 0.90$

$$q_{plateau} = \frac{TRR \cdot 0.035}{355\ day/year} = \frac{0.90 \cdot 2.7E11 \cdot 0.035}{355} = 24\ E6\ Sm^3/d$$

Single well rate (recommendation of the reservoir engineer, avoid sand production, erosion, etc.)

As a first approximation $N_{wells} = 8$ $\qquad$ $3E6\ Sm^3/d$

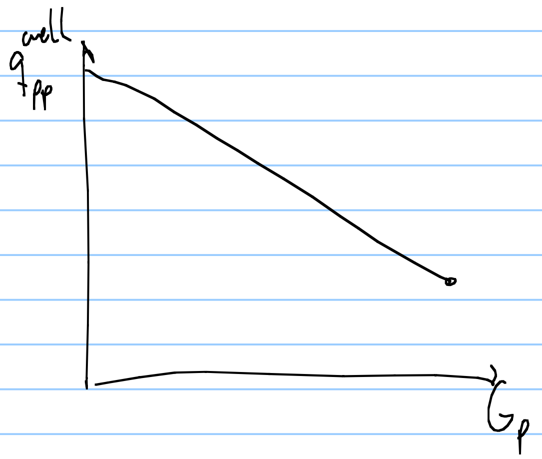
We will assume at this point that all wells are identical and that the production potential of a group of wells is just the production potential of a single well multiplied by the number of wells

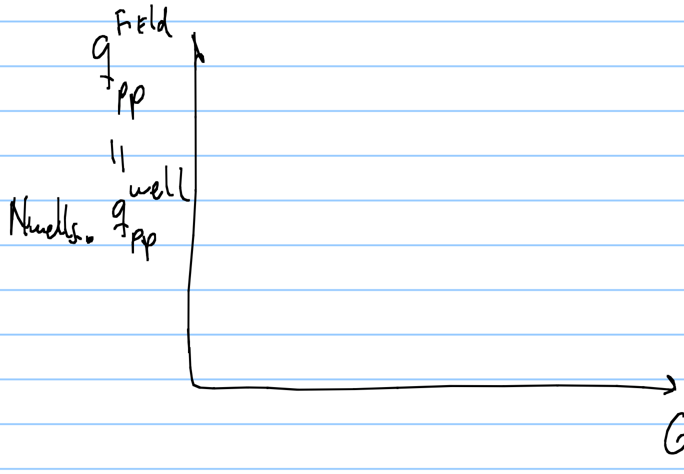


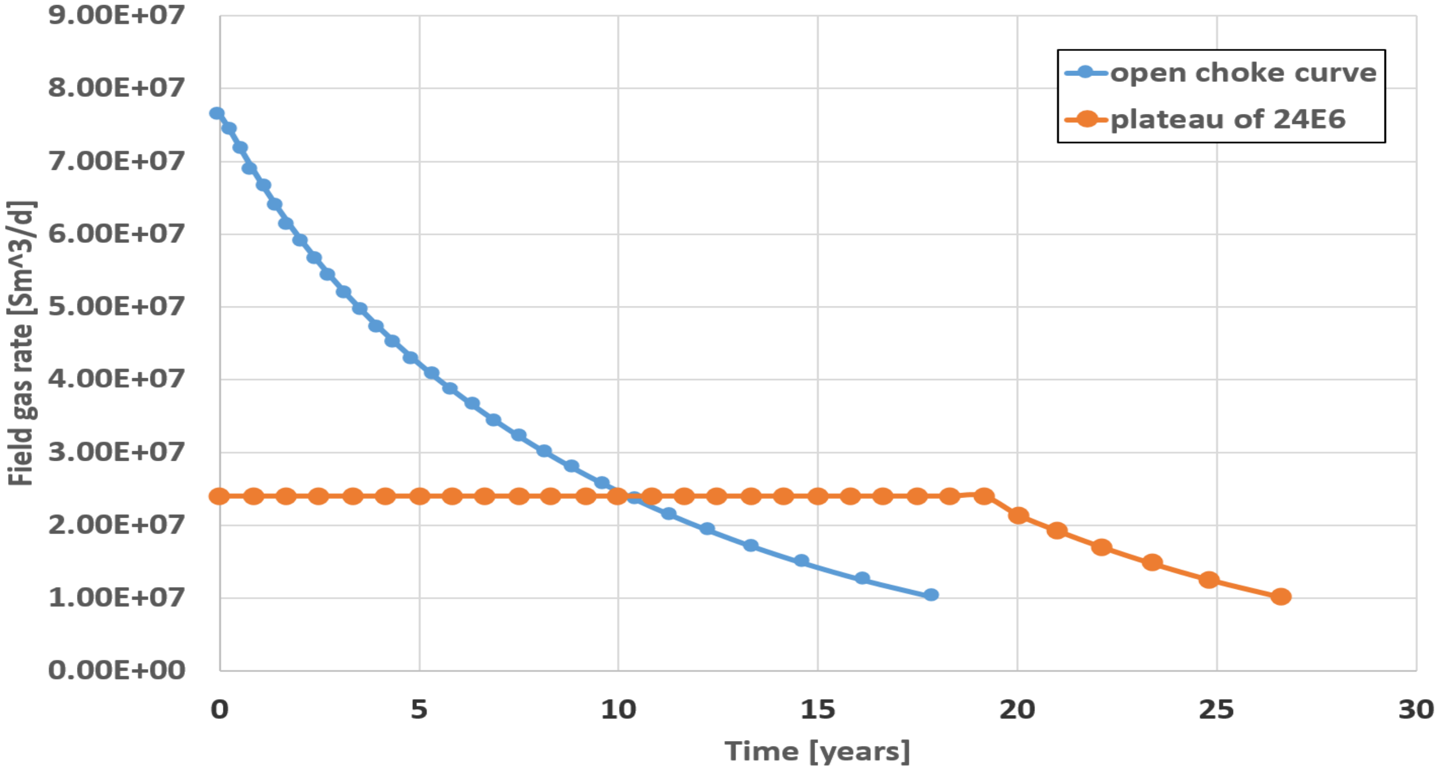

no interference between the wells in the surface production system

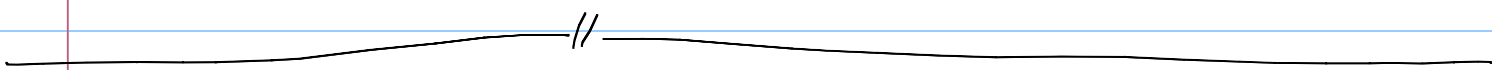
In reality, if the wells production is connected by flowlines and pipelines, there could be hydra interference between them so the production potential of a group of wells is not additive.

sharing, usually

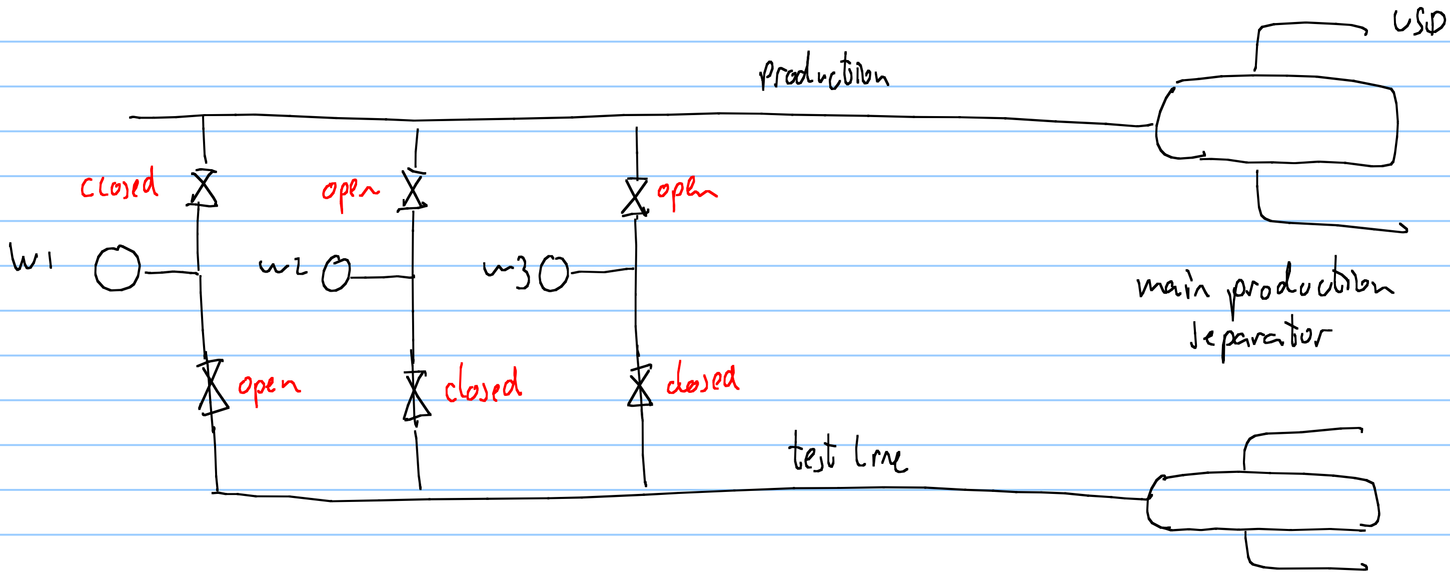


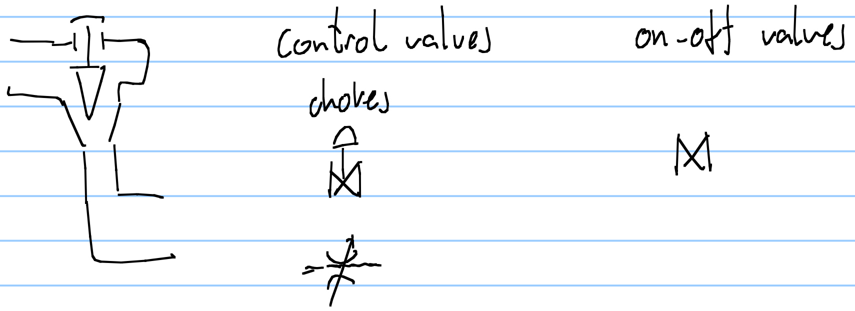





Arquitecture of the production system

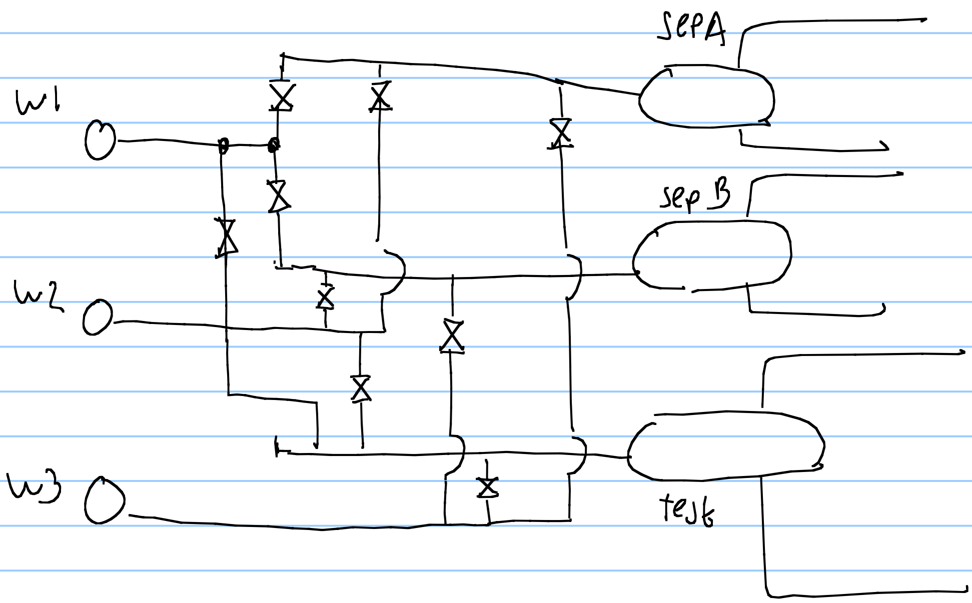


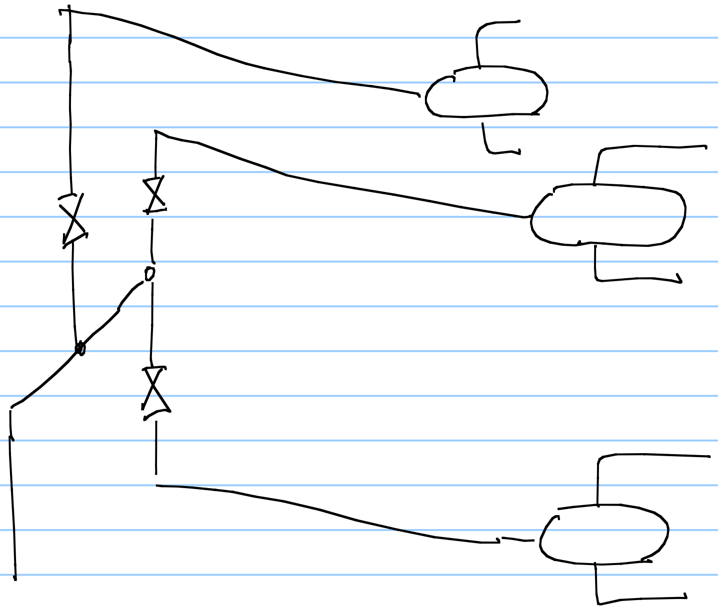




test separator

- measure rate
- fluid sampling
- potential of the well
- fluid properties
- detect bad wells, ↑GOR (gas-oil ratio), ↑WC (watercut)
- match reservoir model
- verify reservoir recovery
- split the cake allocation

Class exercise



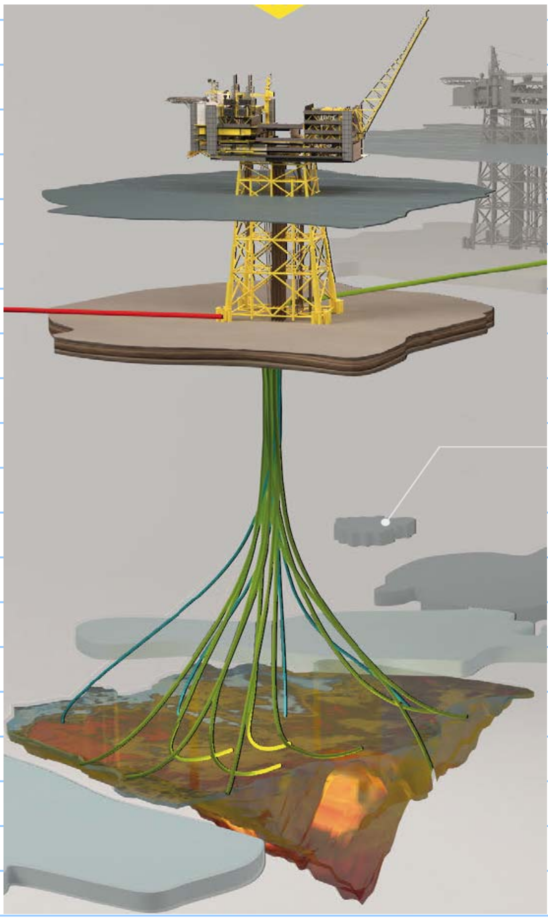


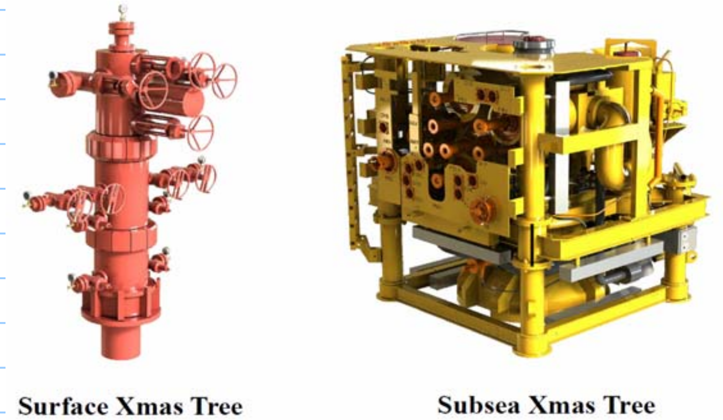
An Isometric view

Test and production manifolds on an Onshore field

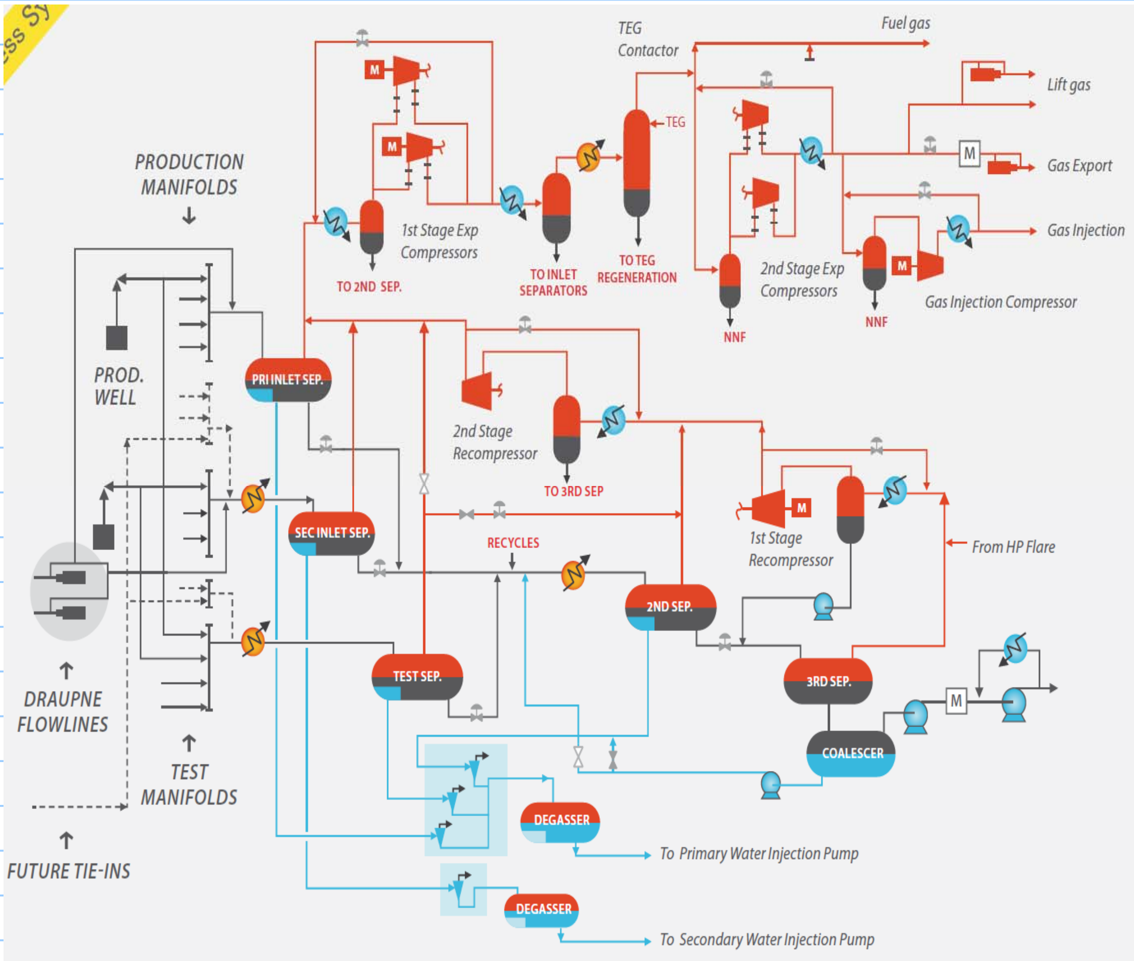
no need for separator, just
production manifold and test
manifold
single phase oil + water
measure ~ coriolis meter

Test and production manifolds on an offshore field

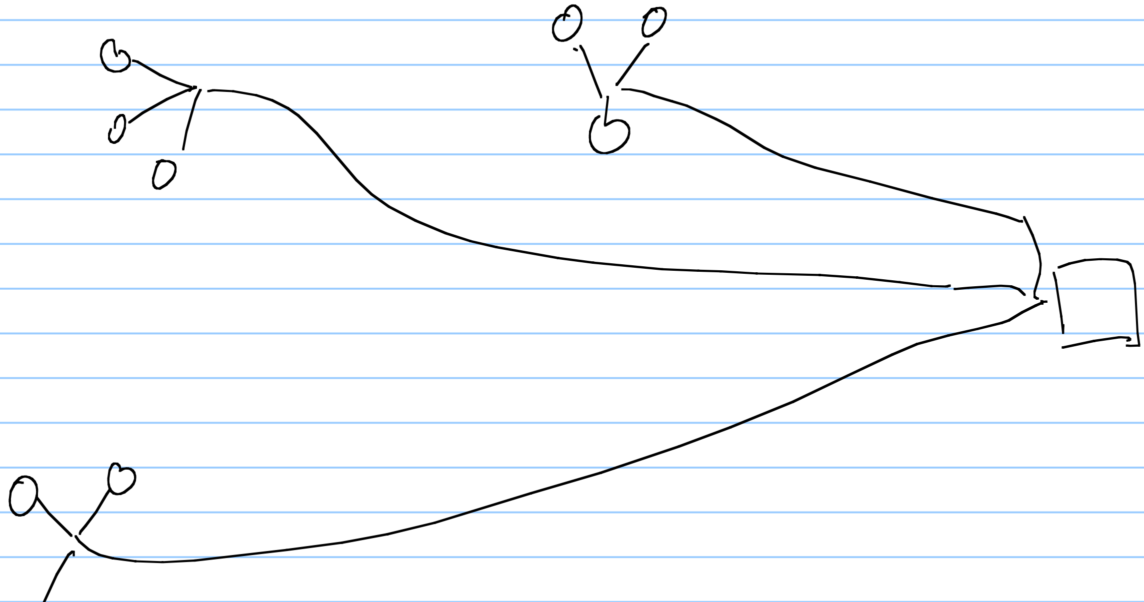




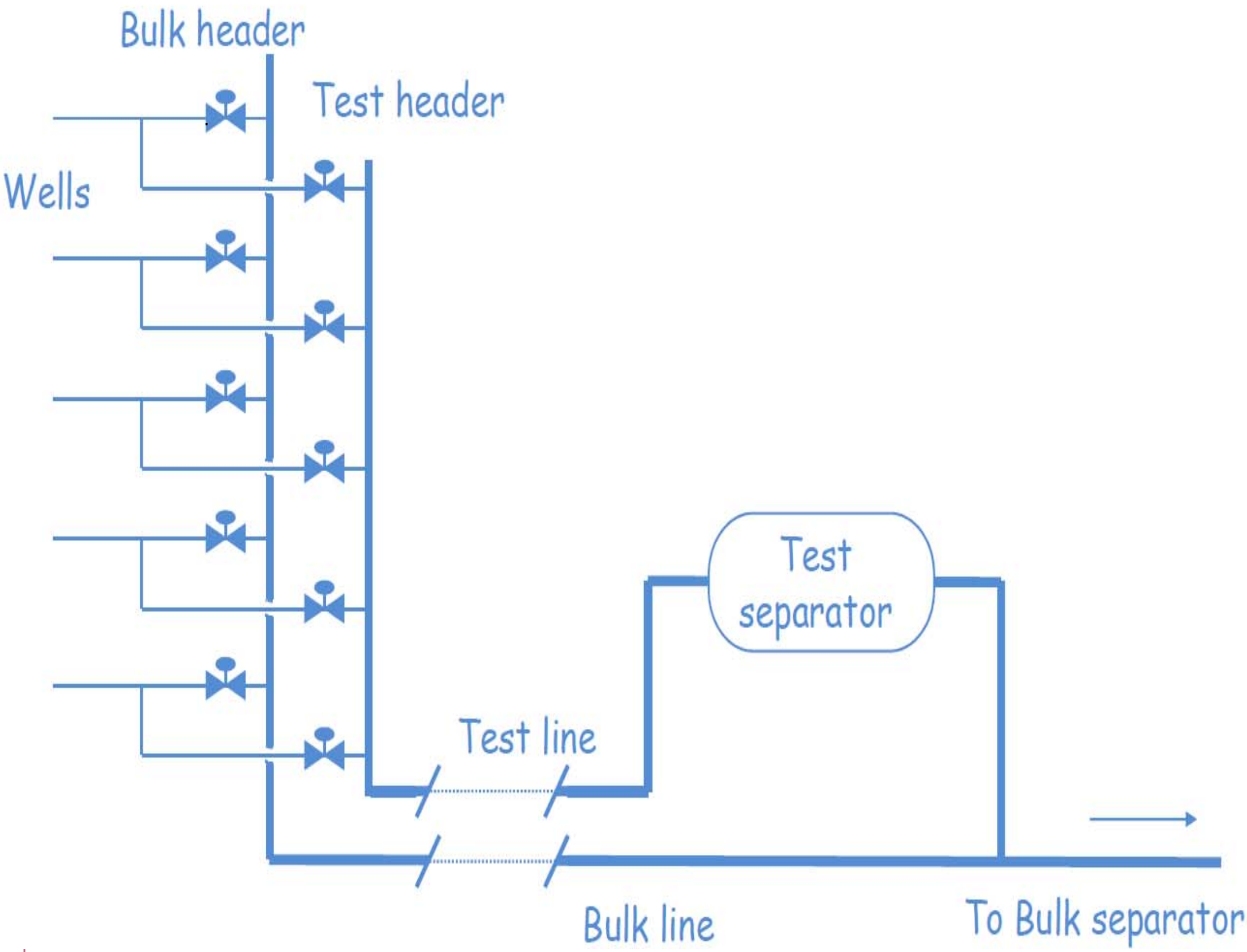

A dry christmas tree vs. a wet christmas tree



Onshore fields and test separators



"Portable" test separators


Bulk header
Test header
Wells
Test separator
Test line
Bulk line
To Bulk separator

20160118 TPG4230

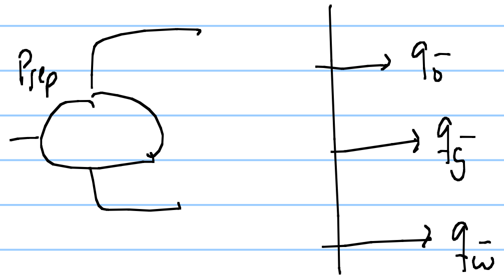
Note Title 18.01.2016

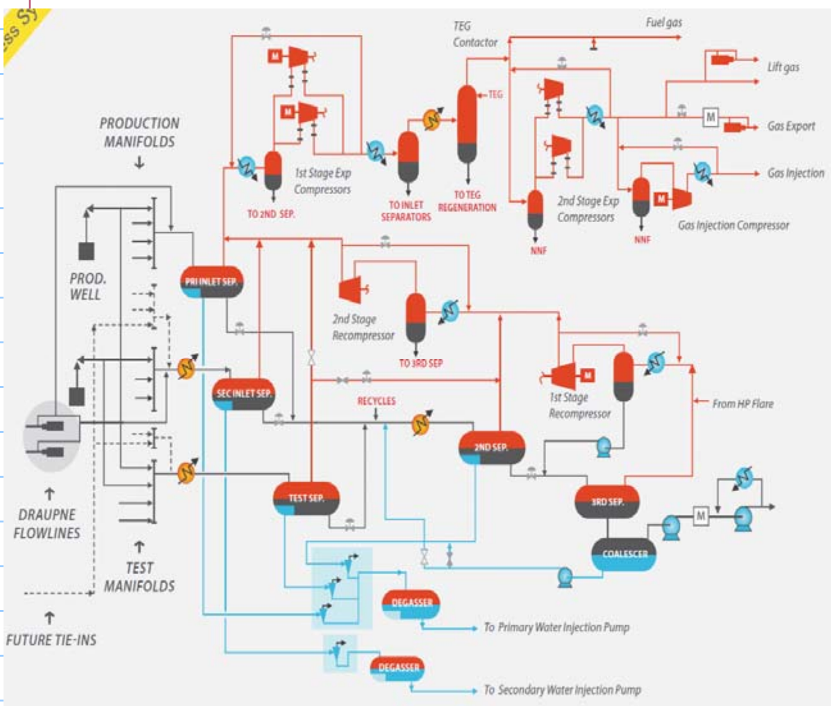
menu: • Production potential : • how to estimate production profile from

$q_{pp} \rightarrow Q_p$

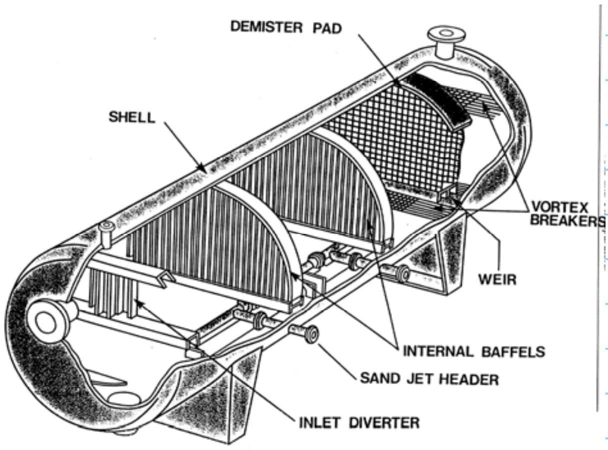
• Excel implementation

Separator





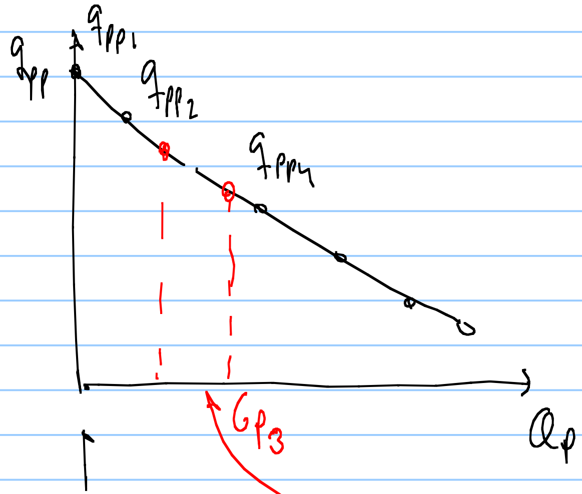




look how the equipment looks like in real life!

---

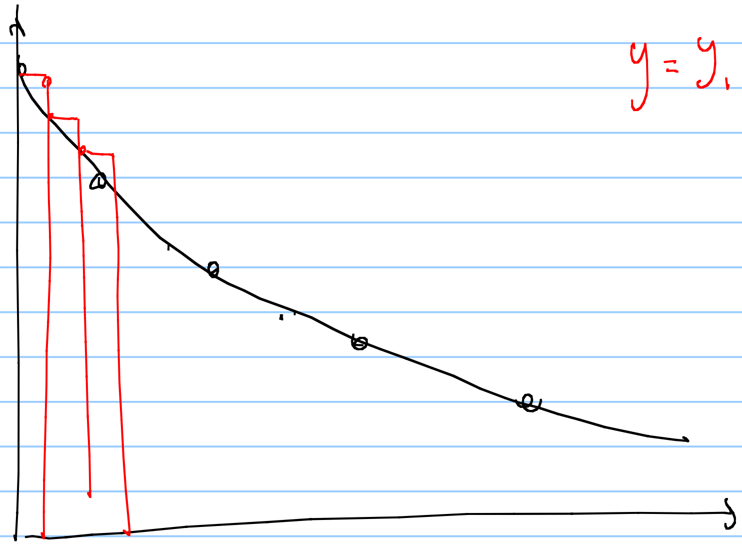
• Production potential     sequential calculations     open choke



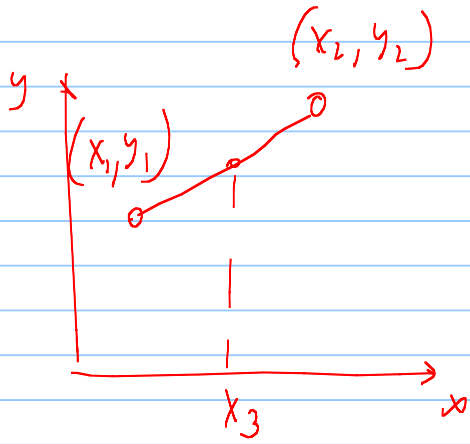

| $t$ | $q$ | $G_p$ | $q_{pp}$ |
|---|---|---|---|
| 0 | $q_{pp1}$ | 0 | $q_{pp1}$ |
| 0.5 | $q_{pp2}$ | $q_{pp1}(0.5-0).355$ | $q_{pp2}$ |
| 1 | $q_{pp3}$ | $1) + q_{pp2}(1-0.5)355$ | $q_{pp3}$ |

$0 \rightarrow 0.5 \quad q_{pp1}$

operational days in a year = 355



$$y = y_1 + \frac{(y_2 - y_1)}{(x_2 - x_1)}(x_3 - x_1)$$

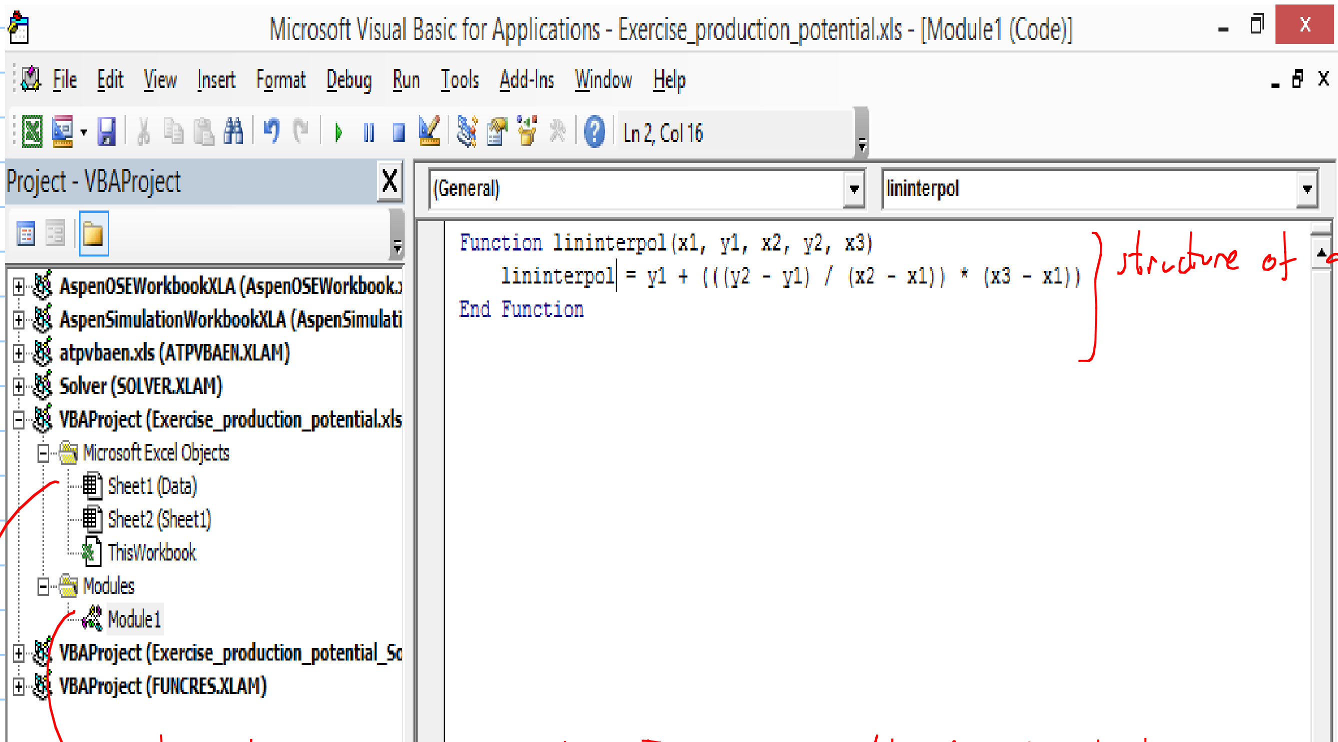



Excel + VBA (visual basic for applications)

Reduce trust settings to minimum – enable all macros

$\boxed{Alt}$ + $\boxed{F11}$ to access VBA environment

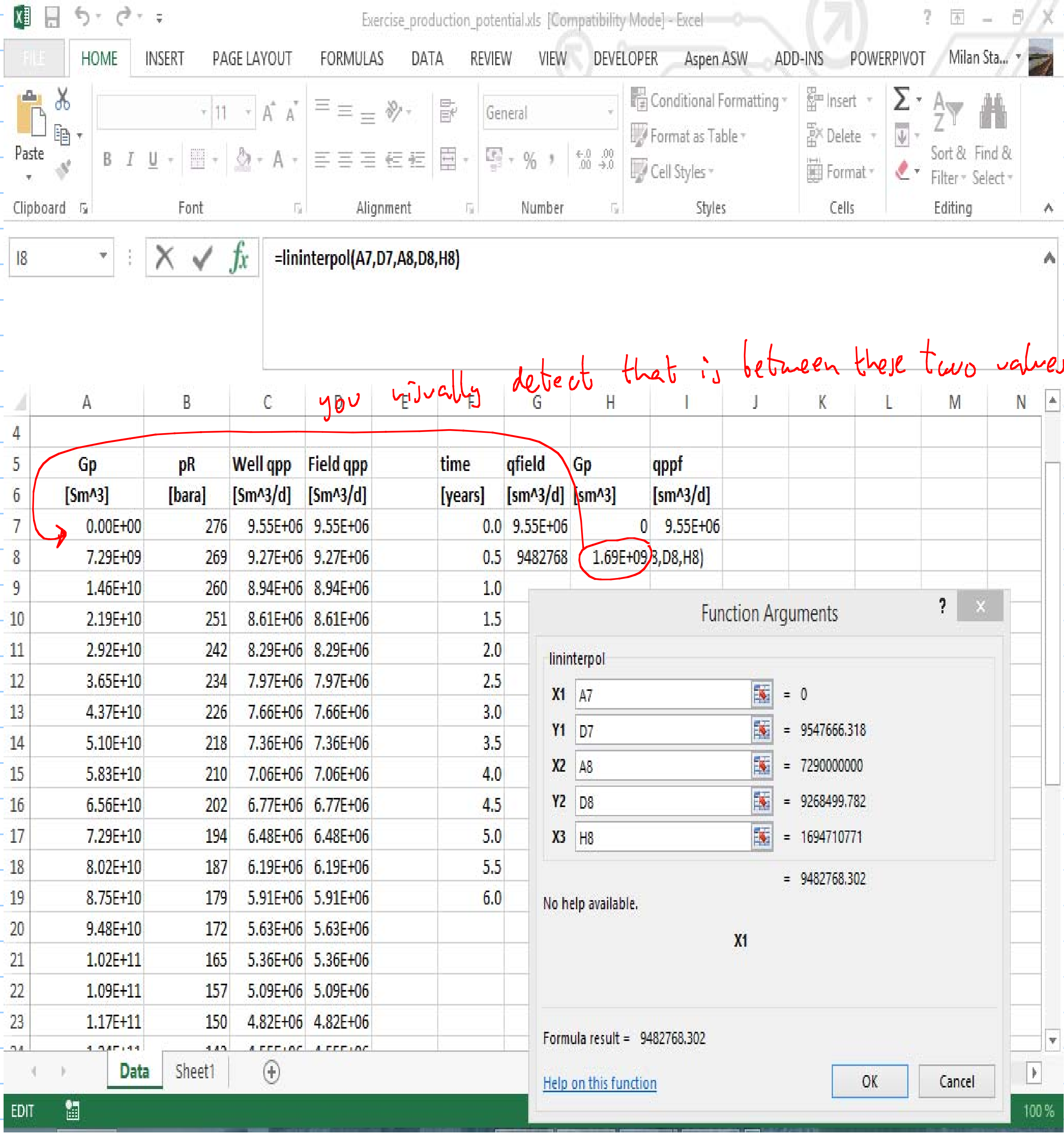
UDF .. User defined function




} structure of a UDF

→ when placed in a module, it is available for all sheets in an excel file.

→ when placed in a sheet, it is only available for that sheet.



Exercise_production_potential.xls [Compatibility Mode] - Excel

I8 =lininterpol(A7,D7,A8,D8,H8)

you visually detect that is between these two values, $x_1$, $x_2$

| | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|
| 4 | | | | | | | | | |
| 5 | Gp | pR | Well qpp | Field qpp | | time | qfield | Gp | qppf |
| 6 | [Sm^3] | [bara] | [Sm^3/d] | [Sm^3/d] | | [years] | [sm^3/d] | [sm^3] | [sm^3/d] |
| 7 | 0.00E+00 | 276 | 9.55E+06 | 9.55E+06 | | 0.0 | 9.55E+06 | 0 | 9.55E+06 |
| 8 | 7.29E+09 | 269 | 9.27E+06 | 9.27E+06 | | 0.5 | 9482768 | 1.69E+09 | 3,D8,H8) |
| 9 | 1.46E+10 | 260 | 8.94E+06 | 8.94E+06 | | 1.0 | | | |
| 10 | 2.19E+10 | 251 | 8.61E+06 | 8.61E+06 | | 1.5 | | | |
| 11 | 2.92E+10 | 242 | 8.29E+06 | 8.29E+06 | | 2.0 | | | |
| 12 | 3.65E+10 | 234 | 7.97E+06 | 7.97E+06 | | 2.5 | | | |
| 13 | 4.37E+10 | 226 | 7.66E+06 | 7.66E+06 | | 3.0 | | | |
| 14 | 5.10E+10 | 218 | 7.36E+06 | 7.36E+06 | | 3.5 | | | |
| 15 | 5.83E+10 | 210 | 7.06E+06 | 7.06E+06 | | 4.0 | | | |
| 16 | 6.56E+10 | 202 | 6.77E+06 | 6.77E+06 | | 4.5 | | | |
| 17 | 7.29E+10 | 194 | 6.48E+06 | 6.48E+06 | | 5.0 | | | |
| 18 | 8.02E+10 | 187 | 6.19E+06 | 6.19E+06 | | 5.5 | | | |
| 19 | 8.75E+10 | 179 | 5.91E+06 | 5.91E+06 | | 6.0 | | | |
| 20 | 9.48E+10 | 172 | 5.63E+06 | 5.63E+06 | | | | | |
| 21 | 1.02E+11 | 165 | 5.36E+06 | 5.36E+06 | | | | | |
| 22 | 1.09E+11 | 157 | 5.09E+06 | 5.09E+06 | | | | | |
| 23 | 1.17E+11 | 150 | 4.82E+06 | 4.82E+06 | | | | | |

Function Arguments

lininterpol

| | | | |
|---|---|---|---|
| X1 | A7 | = | 0 |
| Y1 | D7 | = | 9547666.318 |
| X2 | A8 | = | 7290000000 |
| Y2 | D8 | = | 9268499.782 |
| X3 | H8 | = | 1694710771 |
| | | = | 9482768.302 |

No help available.

X1

Formula result = 9482768.302

Help on this function

OK Cancel

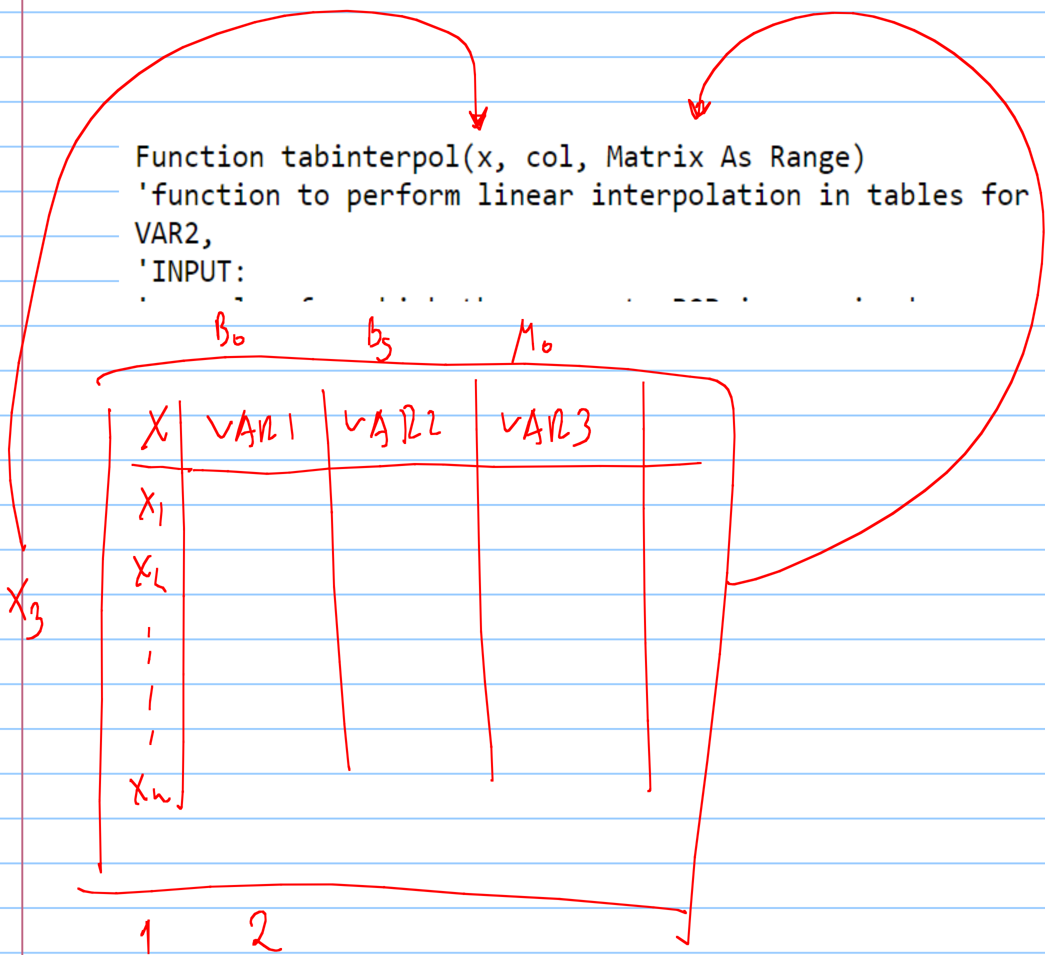
$X = G_p$

$y = q_{pp}$

i want to obtain $q_{ppf}$ with $G_p$

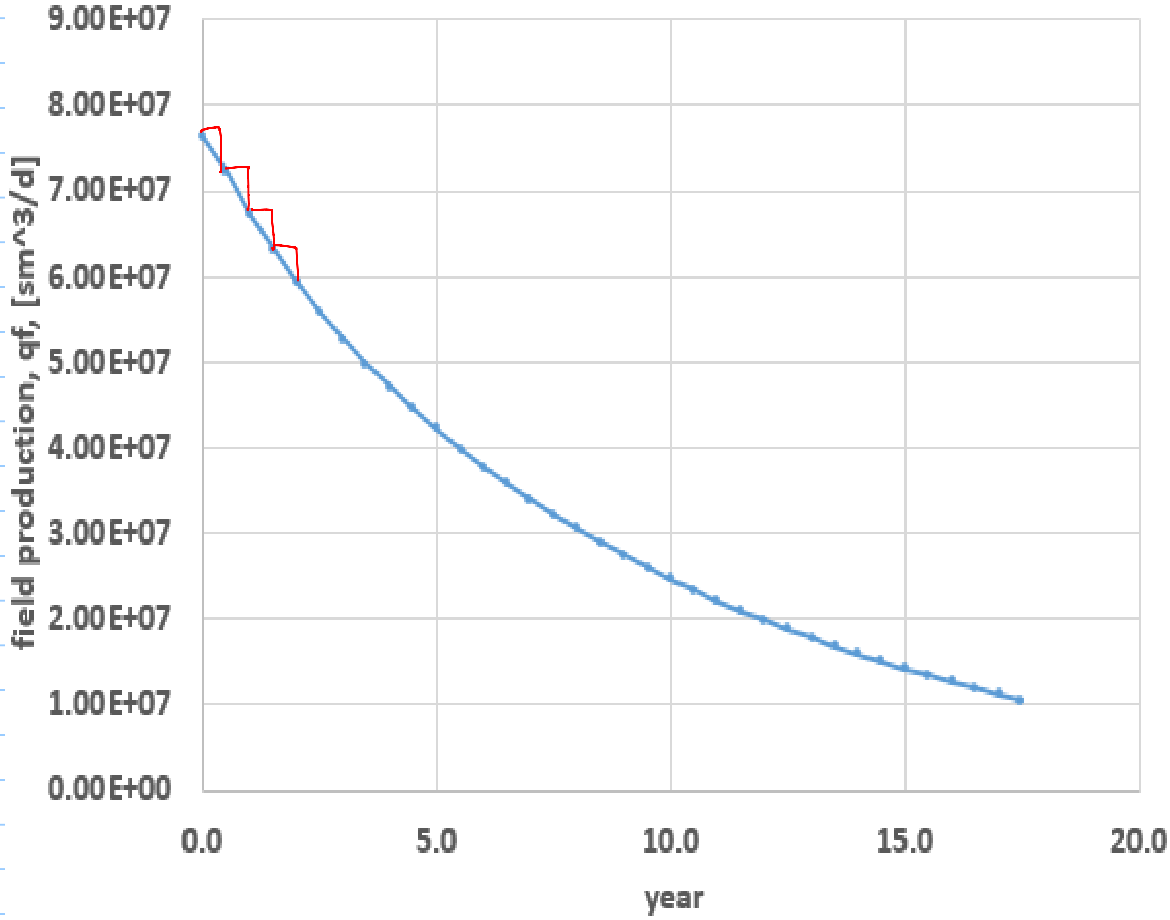
the drawback of this approach is that i have to go manually to each timestep and detect $x_1, y_1, x_2, y_2$.

```
Function tabinterpol(x, col, Matrix As Range)
'function to perform linear interpolation in tables for properties VAR1,
VAR2,
'INPUT:
```




SUM | =tabinterpol(H10,4,$A$7:$D$37)

| | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|
| 1 | N Wells | | 8 | | | | | | |
| 2 | G | [Sm^3] | 2.7E+11 | | | | | | |
| 3 | Field production | [Sm^3/d] | 2.00E+07 | | | | | | |
| 4 | | | | | | | | | |
| 5 | Gp | pR | Well qpp | Field qpp | | time | qfield | Gp | qppf |
| 6 | [Sm^3] | [bara] | [Sm^3/d] | [Sm^3/d] | | [years] | [sm^3/d] | [sm^3] | [sm^3/d] |
| 7 | 0.00E+00 | 276 | 9.55E+06 | 7.64E+07 | | 0.0 | 7.64E+07 | 0 | 7.64E+07 |
| 8 | 7.29E+09 | 269 | 9.27E+06 | 7.41E+07 | | 0.5 | 7.19E+07 | 1.36E+10 | 7.19E+07 |
| 9 | 1.46E+10 | 260 | 8.94E+06 | 7.15E+07 | | 1.0 | 6.73E+07 | 2.63E+10 | 6.73E+07 |
| 10 | 2.19E+10 | 251 | 8.61E+06 | 6.89E+07 | | 1.5 | 6.32E+07 | 3.83E+10 | =tabinterpo |
| 11 | 2.92E+10 | 242 | 8.29E+06 | 6.63E+07 | | 2.0 | 5.94E+07 | 4.95E+10 | 5.94E+07 |
| 12 | 3.65E+10 | 234 | 7.97E+06 | 6.38E+07 | | 2.5 | 5.59E+07 | 6.00E+10 | 5.59E+07 |
| 13 | 4.37E+10 | 226 | 7.66E+06 | 6.13E+07 | | 3.0 | 5.28E+07 | 7.00E+10 | 5.28E+07 |
| 14 | 5.10E+10 | 218 | 7.36E+06 | 5.89E+07 | | 3.5 | 4.98E+07 | 7.93E+10 | 4.98E+07 |
| 15 | 5.83E+10 | 210 | 7.06E+06 | 5.65E+07 | | 4.0 | 4.71E+07 | 8.82E+10 | 4.71E+07 |
| 16 | 6.56E+10 | 202 | 6.77E+06 | 5.41E+07 | | 4.5 | 4.45E+07 | 9.65E+10 | 4.45E+07 |
| 17 | 7.29E+10 | 194 | 6.48E+06 | 5.18E+07 | | 5.0 | 4.22E+07 | 1.04E+11 | 4.22E+07 |
| 18 | 8.02E+10 | 187 | 6.19E+06 | 4.95E+07 | | 5.5 | 3.99E+07 | 1.12E+11 | 3.99E+07 |
| 19 | 8.75E+10 | 179 | 5.91E+06 | 4.73E+07 | | 6.0 | 3.78E+07 | 1.19E+11 | 3.78E+07 |
| 20 | 9.48E+10 | 172 | 5.63E+06 | 4.51E+07 | | 6.5 | 3.58E+07 | 1.26E+11 | 3.58E+07 |
| 21 | 1.02E+11 | 165 | 5.36E+06 | 4.29E+07 | | 7.0 | 3.40E+07 | 1.32E+11 | 3.40E+07 |
| 22 | 1.09E+11 | 157 | 5.09E+06 | 4.07E+07 | | 7.5 | 3.22E+07 | 1.38E+11 | 3.22E+07 |
| 23 | 1.17E+11 | 150 | 4.82E+06 | 3.85E+07 | | 8.0 | 3.05E+07 | 1.44E+11 | 3.05E+07 |
| 24 | 1.24E+11 | 143 | 4.55E+06 | 3.64E+07 | | 8.5 | 2.90E+07 | 1.49E+11 | 2.90E+07 |
| 25 | 1.31E+11 | 136 | 4.28E+06 | 3.42E+07 | | 9.0 | 2.74E+07 | 1.54E+11 | 2.74E+07 |
| 26 | 1.39E+11 | 129 | 4.01E+06 | 3.21E+07 | | 9.5 | 2.60E+07 | 1.59E+11 | 2.60E+07 |
| 27 | 1.46E+11 | 122 | 3.75E+06 | 3.00E+07 | | 10.0 | 2.47E+07 | 1.64E+11 | 2.47E+07 |
| 28 | 1.46E+11 | 122 | 3.75E+06 | 3.00E+07 | | 10.5 | 2.34E+07 | 1.68E+11 | 2.34E+07 |
| 29 | 1.53E+11 | 115 | 3.48E+06 | 2.78E+07 | | 11.0 | 2.21E+07 | 1.72E+11 | 2.21E+07 |
| 30 | 1.60E+11 | 108 | 3.21E+06 | 2.57E+07 | | 11.5 | 2.10E+07 | 1.76E+11 | 2.10E+07 |
| 31 | 1.68E+11 | 101 | 2.94E+06 | 2.35E+07 | | 12.0 | 1.99E+07 | 1.80E+11 | 1.99E+07 |
| 32 | 1.75E+11 | 94 | 2.67E+06 | 2.14E+07 | | 12.5 | 1.88E+07 | 1.84E+11 | 1.88E+07 |
| 33 | 1.82E+11 | 87 | 2.40E+06 | 1.92E+07 | | 13.0 | 1.78E+07 | 1.87E+11 | 1.78E+07 |
| 34 | 1.90E+11 | 80 | 2.13E+06 | 1.70E+07 | | 13.5 | 1.68E+07 | 1.90E+11 | 1.68E+07 |
| 35 | 1.97E+11 | 73 | 1.85E+06 | 1.48E+07 | | 14.0 | 1.59E+07 | 1.93E+11 | 1.59E+07 |
| 36 | 2.04E+11 | 66 | 1.56E+06 | 1.25E+07 | | 14.5 | 1.51E+07 | 1.96E+11 | 1.51E+07 |
| 37 | 2.11E+11 | 59 | 1.27E+06 | 1.02E+07 | | 15.0 | 1.42E+07 | 1.99E+11 | 1.42E+07 |
| 38 | | | | | | 15.5 | 1.34E+07 | 2.01E+11 | 1.34E+07 |




Calculations for plateau mode. Plateau rate of 20 E6 Sm^3/d

| time [years] | qfield [sm^3/d] | Gp [sm^3] | qppf [sm^3/d] |
|---|---|---|---|
| 0.0 | 2.00E+07 | 0 | 7.64E+07 |
| 0.5 | 2.00E+07 | 3.55E+09 | 7.53E+07 |
| 1.0 | 2.00E+07 | 7.10E+09 | 7.42E+07 |
| 1.5 | 2.00E+07 | 1.07E+10 | 7.29E+07 |
| 2.0 | 2.00E+07 | 1.42E+10 | 7.17E+07 |
| 2.5 | 2.00E+07 | 1.78E+10 | 7.04E+07 |
| 3.0 | 2.00E+07 | 2.13E+10 | 6.91E+07 |
| 3.5 | 2.00E+07 | 2.49E+10 | 6.78E+07 |
| 4.0 | 2.00E+07 | 2.84E+10 | 6.66E+07 |
| 4.5 | 2.00E+07 | 3.20E+10 | 6.54E+07 |
| 5.0 | 2.00E+07 | 3.55E+10 | 6.41E+07 |
| 5.5 | 2.00E+07 | 3.91E+10 | 6.29E+07 |
| 6.0 | 2.00E+07 | 4.26E+10 | 6.17E+07 |
| 6.5 | 2.00E+07 | 4.62E+10 | 6.05E+07 |
| 7.0 | 2.00E+07 | 4.97E+10 | 5.93E+07 |
| 7.5 | 2.00E+07 | 5.33E+10 | 5.82E+07 |
| 8.0 | 2.00E+07 | 5.68E+10 | 5.70E+07 |
| 8.5 | 2.00E+07 | 6.04E+10 | 5.58E+07 |
| 9.0 | 2.00E+07 | 6.39E+10 | 5.47E+07 |
| 9.5 | 2.00E+07 | 6.75E+10 | 5.36E+07 |
| 10.0 | 2.00E+07 | 7.10E+10 | 5.24E+07 |
| 10.5 | 2.00E+07 | 7.46E+10 | 5.13E+07 |
| 11.0 | 2.00E+07 | 7.81E+10 | 5.02E+07 |
| 11.5 | 2.00E+07 | 8.17E+10 | 4.91E+07 |

For all these years, production potential is greater than plateau rate, that means that it is feasible to produce it!

How to find plateau duration with Excel solver?

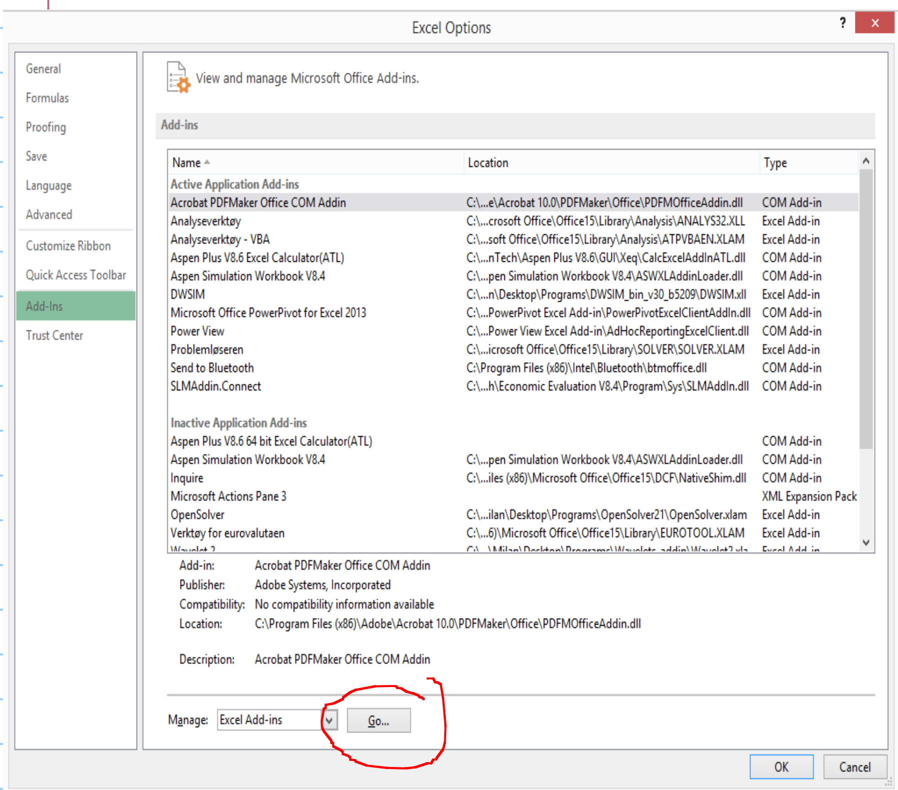
| | | | |
|---|---|---|---|
| 24.0 | 2.00E+07 | 1.70E+11 | 2.27E+07 |
| 24.5 | 2.00E+07 | 1.74E+11 | 2.17E+07 |
| 25.0 | 2.00E+07 | 1.78E+11 | 2.06E+07 |
| 25.2 | 2.00E+07 | 1.79E+11 | 2.02E+07 |
| 26.0 | | 1.85E+11 | 1.85E+07 |
| 26.5 | | 1.85E+11 | 1.85E+07 |

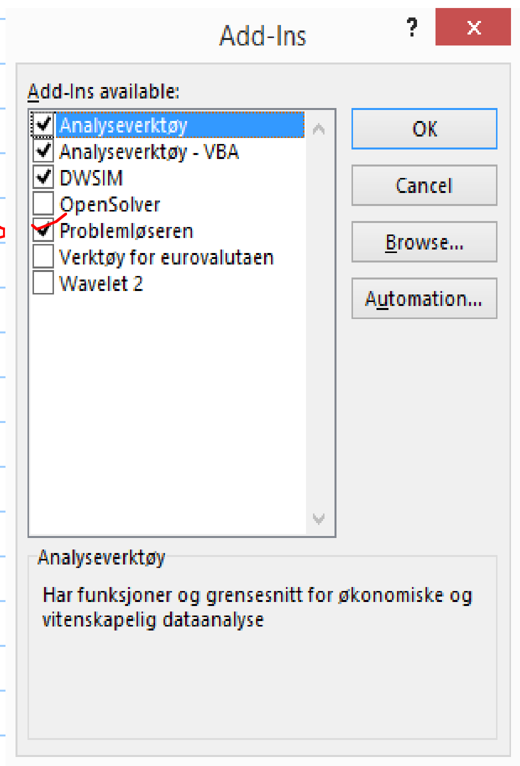
gpp

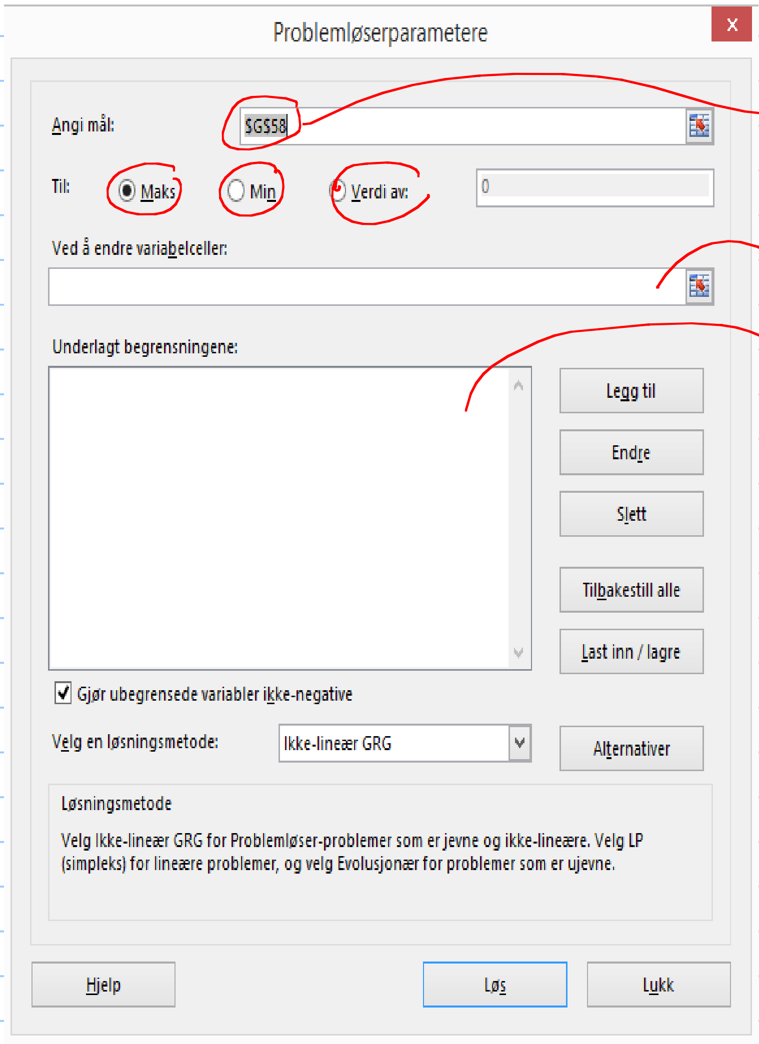
g

should be the same, by changing

Activate the solver in Excel: File, options---Add-ins






objective cell, max, min, drive to a certain value

cells to change, variables

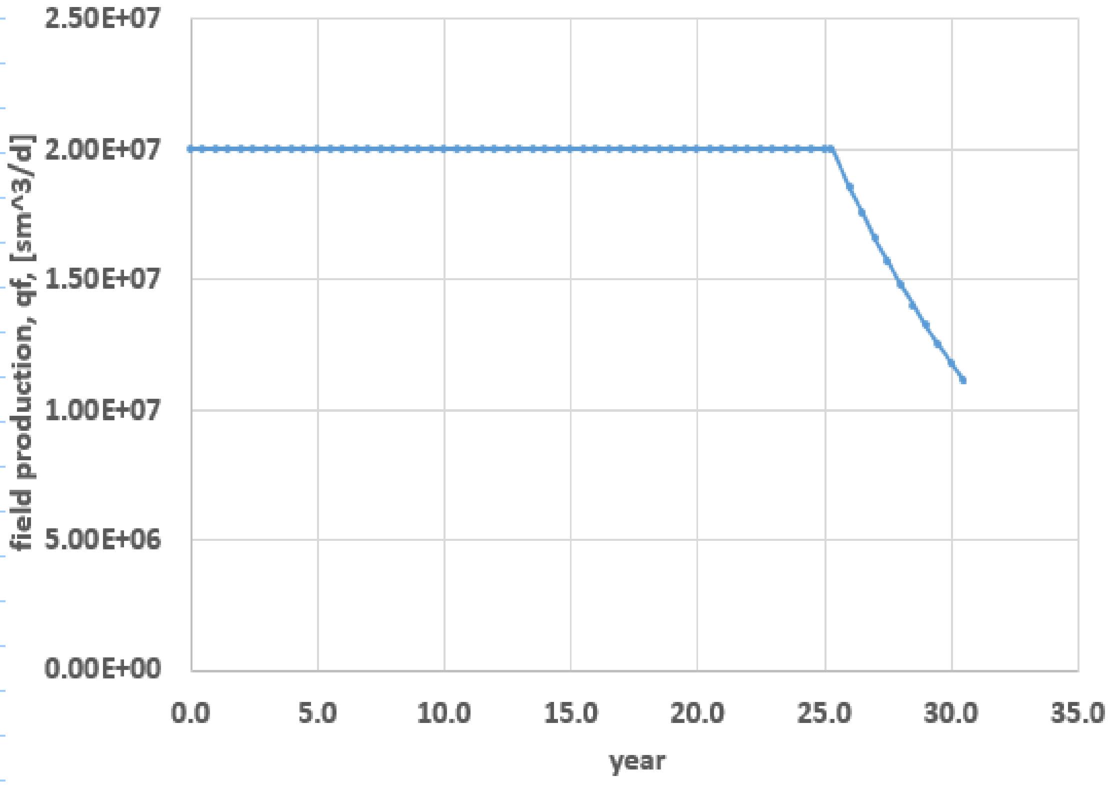
constraints:

- operational constraints
- variable bounds to help the solver

| | | | | | | |
|---|---|---|---|---|---|---|
| | | 22.5 | 2.00E+07 | 1.60E+11 | 2.59E+07 | |
| | | 23.0 | 2.00E+07 | 1.63E+11 | 2.48E+07 | |
| | | 23.5 | 2.00E+07 | 1.67E+11 | 2.38E+07 | |
| | | 24.0 | 2.00E+07 | 1.70E+11 | 2.27E+07 | |
| | | 24.5 | 2.00E+07 | 1.74E+11 | 2.17E+07 | |
| | | 25.0 | 2.00E+07 | 1.78E+11 | 2.06E+07 | Error |
| End of plateau | | 25.291 | 2.00E+07 | 1.80E+11 | 2.00E+07 | =(I58-G58)^2 |
| | | 26.0 | 1.85E+07 | 1.85E+11 | 1.85E+07 | |
| | | 26.5 | 1.75E+07 | 1.88E+11 | 1.75E+07 | |

After plateau, the field its producing at is production potential

| | | | | | | |
|---|---|---|---|---|---|---|
| End of plateau | | 25.291 | 2.00E+07 | 1.80E+11 | 2.00E+07 | 1.38778E-17 |
| | | 26.0 | 1.85E+07 | 1.85E+11 | 1.85E+07 | |
| | | 26.5 | 1.75E+07 | 1.88E+11 | 1.75E+07 | |
| | | 27.0 | 1.66E+07 | 1.91E+11 | 1.66E+07 | |
| | | 27.5 | 1.57E+07 | 1.94E+11 | 1.57E+07 | |
| | | 28.0 | 1.48E+07 | 1.97E+11 | 1.48E+07 | |
| | | 28.5 | 1.40E+07 | 1.99E+11 | 1.40E+07 | |
| | | 29.0 | 1.32E+07 | 2.02E+11 | 1.32E+07 | |
| | | 29.5 | 1.25E+07 | 2.04E+11 | 1.25E+07 | |
| | | 30.0 | 1.18E+07 | 2.06E+11 | 1.18E+07 | |
| | | 30.5 | 1.11E+07 | 2.08E+11 | 1.11E+07 | |




it might not be possible to produce at the production potential (specially for early times)

- damage to the formation (sand production)
- gas coning, water coning
- erosion problems
- critical flow ⤳ limitation in the maximum rate

But it is important to estimate the behavior of the production potential to estimate plateau duration.

TPG 4236 - 20160119



- Monday 25.01.2016 Prof. Michael Golan
- tuesday 26.01.2016 Dr. Mahmoud Etemaddar, Sevan Marine

"Deep water field development planning"

## Summary of yesterday

- Expertise using excel: UDF, VBA, solver, linear interpolation in tables

table interpolator: excel solver doesn't work properly with this function

| | time [years] | qfield [sm^3/d] | Gp [sm^3] | qppf [sm^3/d] | | |
|---|---|---|---|---|---|---|
| | 0.0 | 2.00E+07 | 0 | 7.64E+07 | | |
| | 0.5 | 2.00E+07 | 3.55E+09 | 7.53E+07 | | |
| | 1.0 | 2.00E+07 | 7.10E+09 | 7.42E+07 | | |
| | 1.5 | 2.00E+07 | 1.07E+10 | 7.29E+07 | | |
| | 2.0 | 2.00E+07 | 1.42E+10 | 7.17E+07 | | |
| | 2.5 | 2.00E+07 | 1.78E+10 | 7.04E+07 | | |
| | 3.0 | 2.00E+07 | 2.13E+10 | 6.91E+07 | | |
| | 3.5 | 2.00E+07 | 2.49E+10 | 6.78E+07 | | |
| | 4.0 | 2.00E+07 | 2.84E+10 | 6.66E+07 | | |
| | 4.5 | 2.00E+07 | 3.20E+10 | 6.54E+07 | | |
| | 5.0 | 2.00E+07 | 3.55E+10 | 6.41E+07 | | |
| | 5.5 | 2.00E+07 | 3.91E+10 | 6.29E+07 | | |
| | 6.0 | 2.00E+07 | 4.26E+10 | 6.17E+07 | | |
| | 6.5 | 2.00E+07 | 4.62E+10 | 6.05E+07 | | |
| | 7.0 | 2.00E+07 | 4.97E+10 | 5.93E+07 | | |
| | 7.5 | 2.00E+07 | 5.33E+10 | 5.82E+07 | | |
| | 8.0 | 2.00E+07 | 5.68E+10 | 5.70E+07 | | |
| | 8.5 | 2.00E+07 | 6.04E+10 | 5.58E+07 | | |
| | 9.0 | 2.00E+07 | 6.39E+10 | 5.47E+07 | | |
| | 9.5 | 2.00E+07 | 6.75E+10 | 5.36E+07 | | |
| | 10.0 | 2.00E+07 | 7.10E+10 | 5.24E+07 | | |
| | 10.5 | 2.00E+07 | 7.46E+10 | 5.13E+07 | | |
| | 11.0 | 2.00E+07 | 7.81E+10 | 5.02E+07 | | |
| | 11.5 | 2.00E+07 | 8.17E+10 | 4.91E+07 | | |
| | 12.0 | 2.00E+07 | 8.52E+10 | 4.80E+07 | | |
| | 12.5 | 2.00E+07 | 8.88E+10 | 4.69E+07 | | |
| | 13.0 | 2.00E+07 | 9.23E+10 | 4.58E+07 | | |
| | 13.5 | 2.00E+07 | 9.59E+10 | 4.47E+07 | | |
| | 14.0 | 2.00E+07 | 9.94E+10 | 4.37E+07 | | |
| | 14.5 | 2.00E+07 | 1.03E+11 | 4.26E+07 | | |
| | 15.0 | 2.00E+07 | 1.07E+11 | 4.15E+07 | | |
| | 15.5 | 2.00E+07 | 1.10E+11 | 4.05E+07 | | |
| | 16.0 | 2.00E+07 | 1.14E+11 | 3.94E+07 | | |
| | 16.5 | 2.00E+07 | 1.17E+11 | 3.84E+07 | | |
| | 17.0 | 2.00E+07 | 1.21E+11 | 3.73E+07 | | |
| | 17.5 | 2.00E+07 | 1.24E+11 | 3.63E+07 | | |
| | 18.0 | 2.00E+07 | 1.28E+11 | 3.52E+07 | | |
| | 18.5 | 2.00E+07 | 1.31E+11 | 3.42E+07 | | |
| | 19.0 | 2.00E+07 | 1.35E+11 | 3.31E+07 | | |
| | 19.5 | 2.00E+07 | 1.38E+11 | 3.21E+07 | | |
| | 20.0 | 2.00E+07 | 1.42E+11 | 3.11E+07 | | |
| | 20.5 | 2.00E+07 | 1.46E+11 | 3.00E+07 | | |
| | 21.0 | 2.00E+07 | 1.49E+11 | 2.90E+07 | | |
| | 21.5 | 2.00E+07 | 1.53E+11 | 2.79E+07 | | |
| | 22.0 | 2.00E+07 | 1.56E+11 | 2.69E+07 | | |
| | 22.5 | 2.00E+07 | 1.60E+11 | 2.59E+07 | | |
| | 23.0 | 2.00E+07 | 1.63E+11 | 2.48E+07 | | |
| | 23.5 | 2.00E+07 | 1.67E+11 | 2.38E+07 | | |
| | 24.0 | 2.00E+07 | 1.70E+11 | 2.27E+07 | | |
| | 24.5 | 2.00E+07 | 1.74E+11 | 2.17E+07 | | |
| | 25.0 | 2.00E+07 | 1.78E+11 | 2.06E+07 | Error | |
| eau | 25.291 | 2.00E+07 | 1.80E+11 | 2.00E+07 | 1.38778E-17 | 20000000 |
| | 26.0 | 1.85E+07 | 1.85E+11 | 1.85E+07 | | 18487362 |

table interpolator

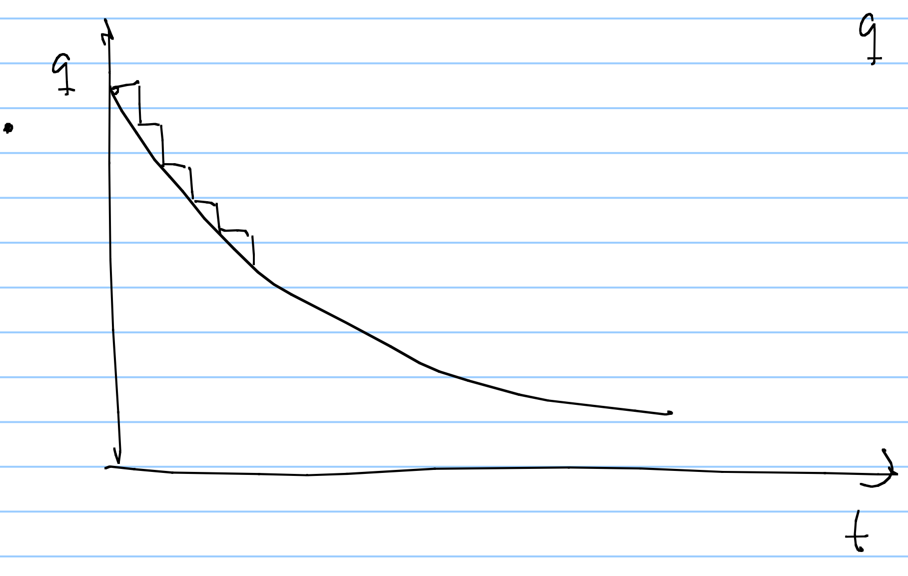
← linear interpolator

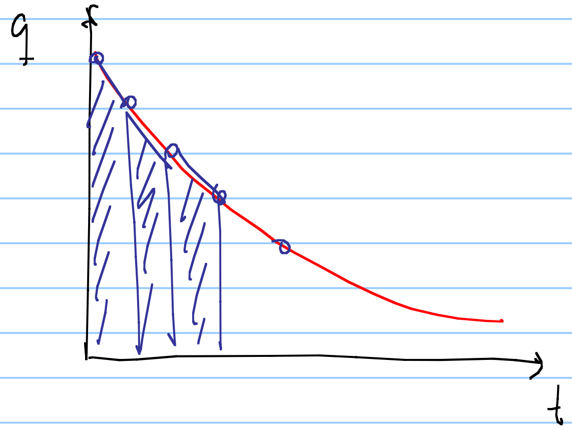
- Calculation of the production profile: sequential
    - choose a timestep
    - decide how I want to produce
        - mode a
        - mode b
    - for current $G_p^i \xrightarrow{\text{linear interpolation}} q_{pp}$
        - if mode a $q_{pp} > q_{pla}$
        - if mode b $q_f = q_{pp}$
    - rectangle method: constant production
      $G_p^{i+1}$.

- Two examples: open choke, plateau mode.

//

- Calculation of production profile
- Exercise 1 - clarification
- Architecture of the production system



Producing with open choke, calculate $q$ v.s. $t$ using sequential calculations and trapezoidal integration

---

- Name of variable, symbol, units
- plots: font size big enough 16-18, Bold thickness of line

Red: Input (user given input)

Blue: Result of a calculation

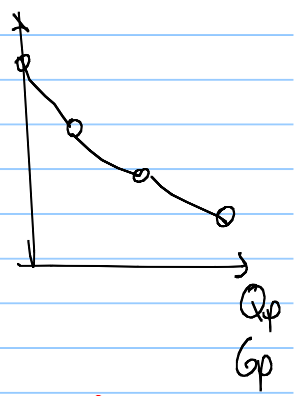
Violet: constant

excel etiquette

---

Using the trapezoidal method to calculate cumulative production

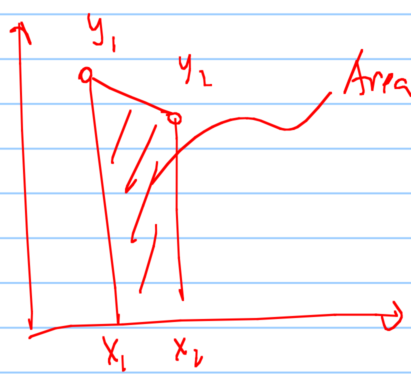
open choke rate



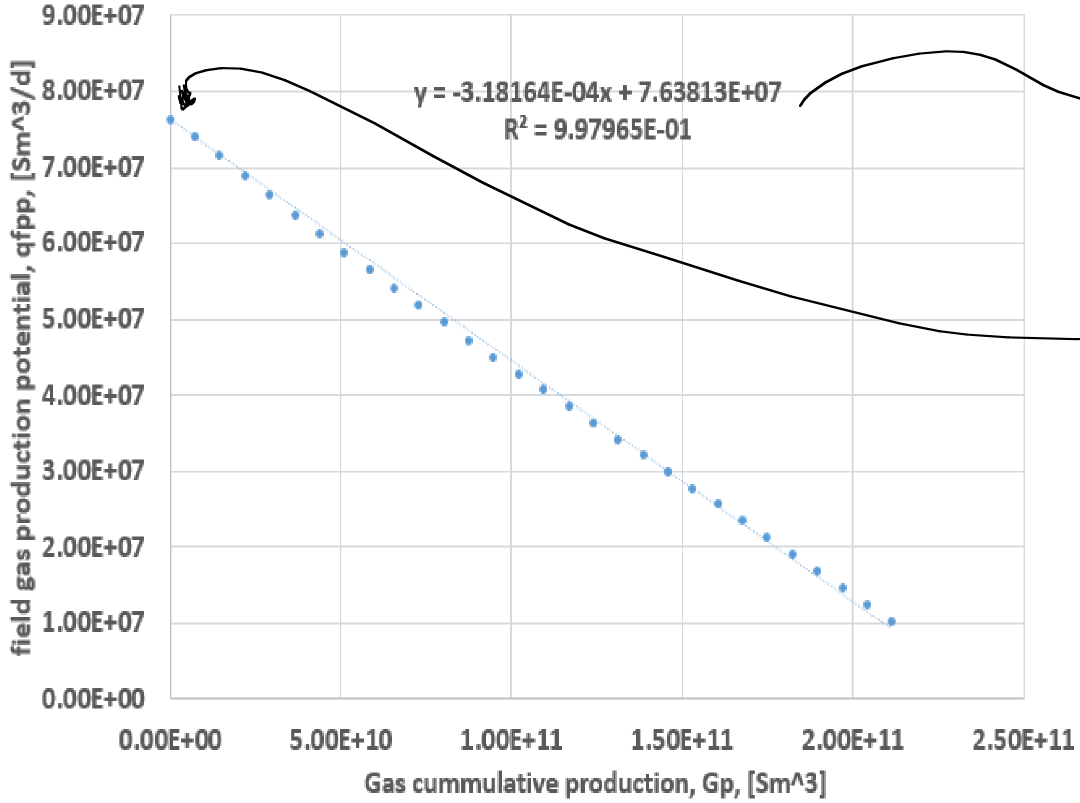

| | time [y] | $q_f$ [$Sm^3/d$] | $G_p$ [$Sm^3$] | $q_{pp}$ [$Sm^3/d$] | Error |
|---|---|---|---|---|---|
| $t_1$ | 0 | $q_{pp_1}$ | 0 | $q_{pp_1}$ | |
| $t_2$ | 0.5 | $q_{pp_1} \cdot 0.9$ | $\frac{(q_{f_1}+q_{f_2})(t_2-t_1)}{2} \cdot \frac{Nds}{year}$ | $q_{pp2}$ | $(q_{pp_2}-q_{f_2})^2$ |
| | 1 | | | | |
| | 1.5 | | | | |
| | 2 | | | | |
| | 2.5 | | | | |
| | ⋮ | | | | |

Assume $q_{f_2} = q_{pp_1} \cdot 0.9$

$Sm^3/d \left(\frac{365d}{1year}\right)$ years




$$\text{Area} = \frac{(y_1+y_2)(x_2-x_1)}{2} = \frac{(q_1+q_2)(t_2-t_1)}{2}$$




$q_{fpp} = -m \cdot G_p + q_{fppo}$

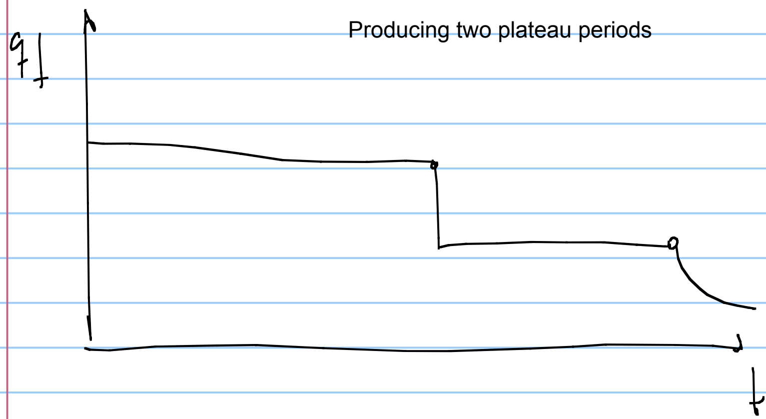
value of

set of instructions

```
Sub test()
    For i = 8 To 69
        SolverReset
        OBJSTRING = "$J$" & (i)
        VARSTRING = "$H$" & (i)
        SolverOk SetCell:=Range(OBJSTRING), MaxMinVal:=3, valueof:="1e-10", ByChange:=VARSTRING
        SolverSolve UserFinish:=True
    Next
    'Reading Results
End Sub
```

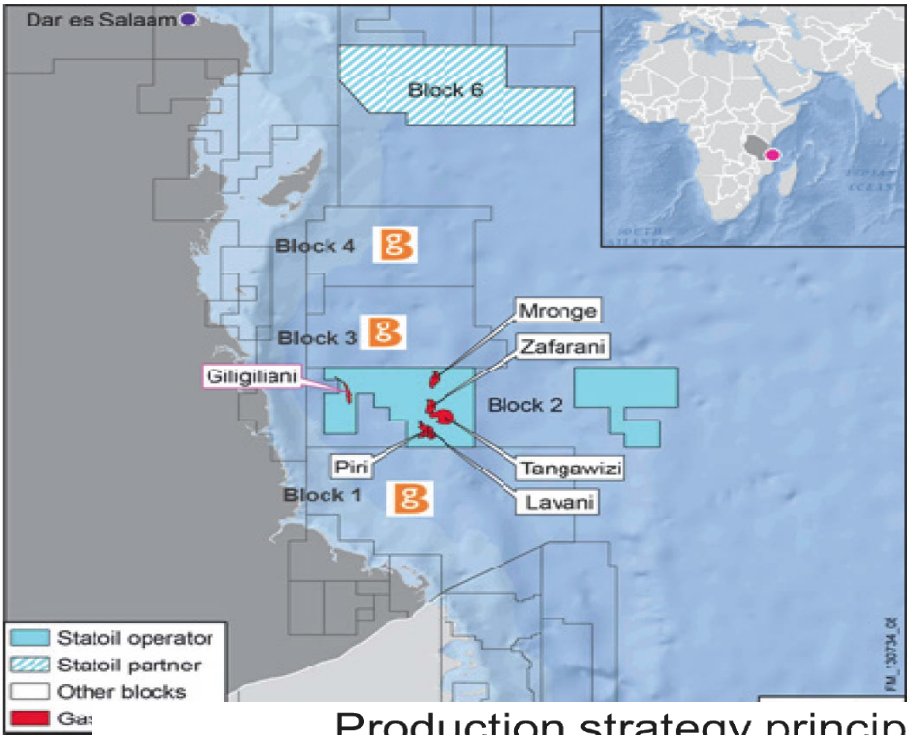
| time | qf | Gp | qfpp | error |
|---|---|---|---|---|
| [year] | [Sm^3/d] | [Sm^3] | [Sm^3/d] | |
| 0.0 | 7.64E+07 | 0 | 7.64E+07 | |
| 0.5 | 7.22E+07 | 1.32E+10 | 7.22E+07 | 0 |
| 1.0 | 6.82E+07 | 2.56E+10 | 6.82E+07 | 0 |
| 1.5 | 6.45E+07 | 3.74E+10 | 6.45E+07 | 0 |
| 2.0 | 6.09E+07 | 4.86E+10 | 6.09E+07 | 0 |
| 2.5 | 5.76E+07 | 5.91E+10 | 5.76E+07 | 0 |
| 3.0 | 5.44E+07 | 6.90E+10 | 5.44E+07 | 5.55112E-17 |
| 3.5 | 5.14E+07 | 7.84E+10 | 5.14E+07 | 0 |
| 4.0 | 4.86E+07 | 8.73E+10 | 4.86E+07 | 0 |
| 4.5 | 4.59E+07 | 9.57E+10 | 4.59E+07 | 5.55112E-17 |
| 5.0 | 4.34E+07 | 1.04E+11 | 4.34E+07 | 0 |
| 5.5 | 4.10E+07 | 1.11E+11 | 4.10E+07 | 0 |
| 6.0 | 3.88E+07 | 1.18E+11 | 3.88E+07 | 5.55112E-17 |
| 6.5 | 3.66E+07 | 1.25E+11 | 3.66E+07 | 0 |

Producing two plateau periods




# Tanzania gas development – flow assurance challenges


*H Holm*
*Statoil ASA, Norway*


Production strategy principles

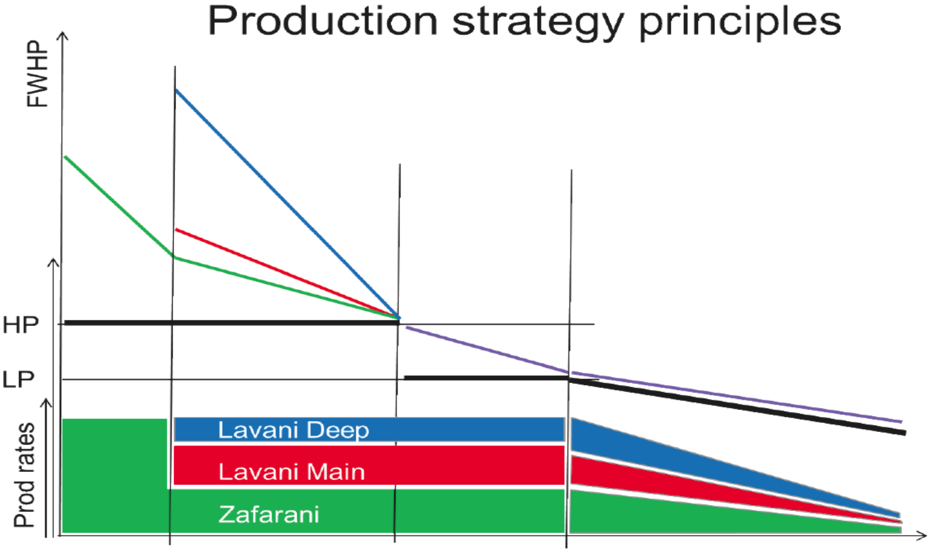
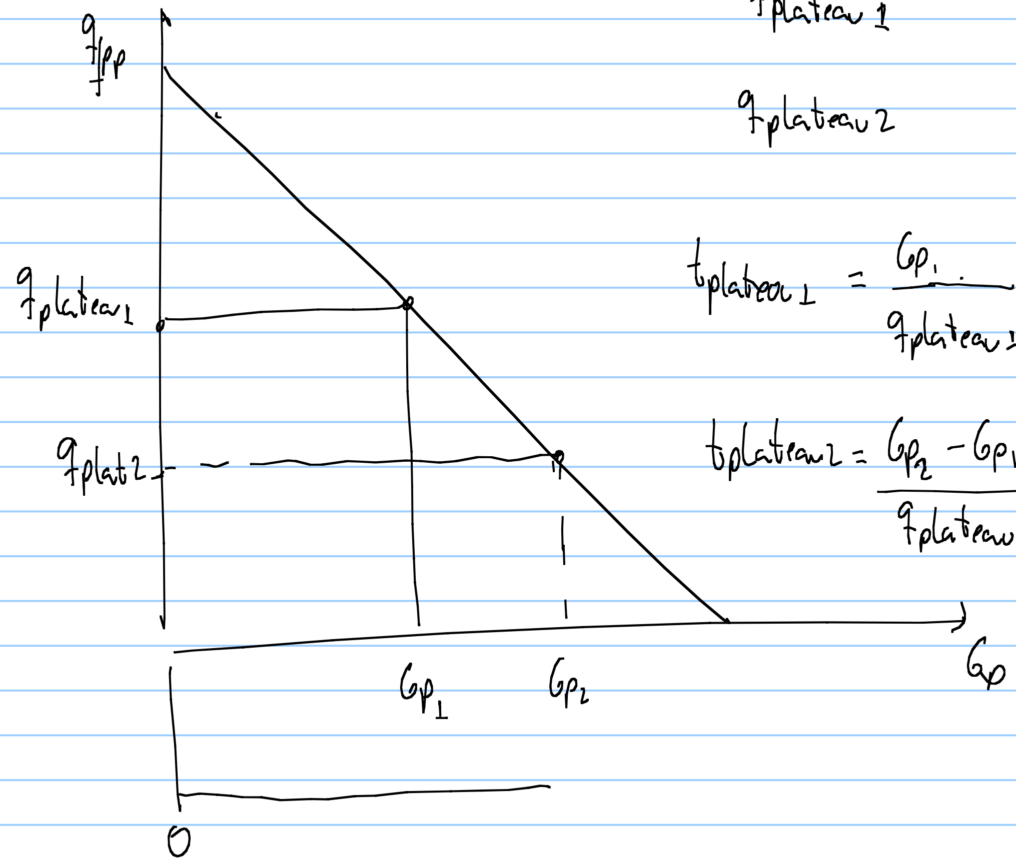



**Figure 9 Production strategy inhomogeneous reservoirs**

$q_{plateau\,1}$

$q_{plateau\,2}$




$$t_{plateau\,1} = \frac{G_{p1}}{q_{plateau\,1}}$$

$$t_{plateau\,2} = \frac{G_{p2} - G_{p1}}{q_{plateau\,2}}$$

---

Calculating production profile analytically

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

producing all the time at open choke.

$$q = q_{pp}$$

$$Q_p(t) = \int_0^t q_{pp} \, dt$$

$$\begin{cases} q_{pp} = -m\,G_p + q_{pp0} \end{cases}$$

production potential at initial conditions

$$G_p = \frac{-q_{pp} + q_{pp0}}{m}$$

Snowhite example

It might actually look different for other cases

$$\frac{q_{pp0} - q_{pp}}{m} = \int q_{pp} \, dt$$

$$q_{pp0} - q_{pp} = \int m\, q_{pp} \, dt \qquad \frac{d}{dt}$$

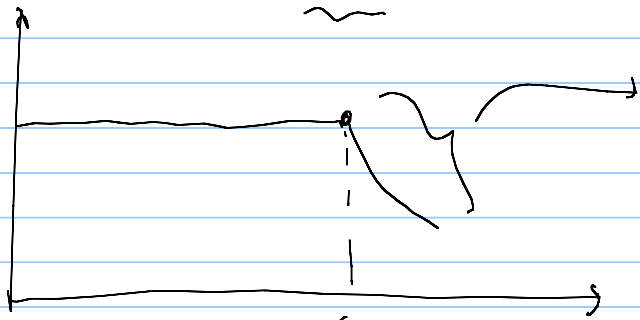
$$-\frac{d q_{pp}}{dt} = m\, q_{pp}$$

$$\int_{q'_{ppo}}^{q_{pp}(t)} \frac{dq_{pp}}{q_{pp}} = \int_0^t -m\,dt$$

$$\ln\left(q_{pp}\right)\Big|_{q_{ppo}}^{q_{pp}(t)} = -m(t-0)$$

$$\ln\left(\frac{q_{pp}(t)}{q_{ppo}}\right) = -m(t-0)$$

$$q_{pp}(t) = \underset{\sim}{q_{ppo}} \cdot e^{-m(t-0)} \qquad G_p = 0$$



for this period, use $q_{pp}(t) = q^*_{ppo}\, e^{-m(t-t^*)}$

with * values at plateau end.

$G_p$ ↳ @ end of the plateau

Decline curve analysis ~

$$q(t) = q_i / e^{\left\{D_i / \left[1-\left(p_{wf}/\overline{p}_R\right)\right]\right\}t}$$

TABLE 1—SUMMARY OF PRODUCTION DECLINE EQUATIONS

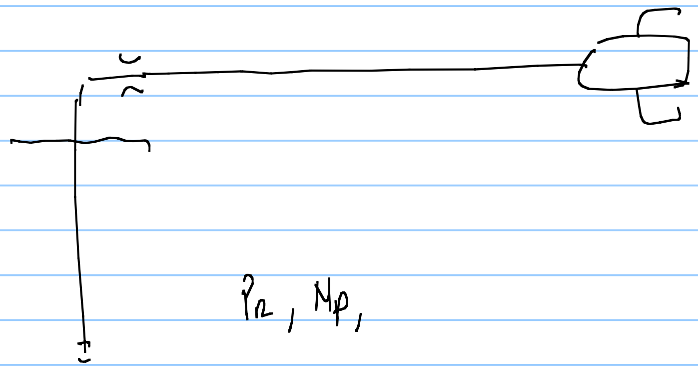
| Decline Type | Hyperbolic | Exponential | Harmonic |
|---|---|---|---|
| Rate–Time | $q(t) = q_i / \left(1 + bD_i t\right)^{1/b}$ | $q(t) = q_i / e^{D_i t}$ | $q(t) = q_i / \left(1 + D_i t\right)$ |

# DECLINE CURVE ANALYSIS USING TYPE CURVES

by

M. J. Fetkovich
SPE, Phillips Petroleum Co.

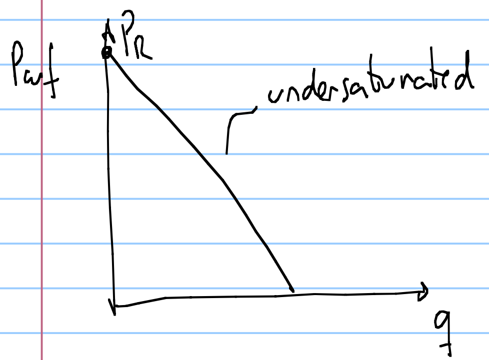
How do we calculated the production potential

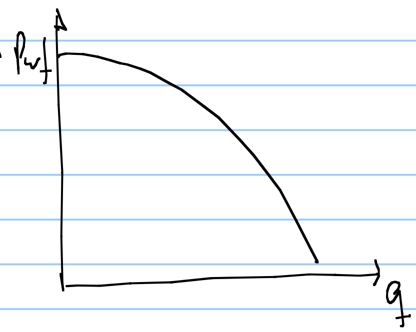



→ hydraulic equilibrium in the production system with open choke. calculate the rate.

→ production simulators
- Pipesim
- GAP

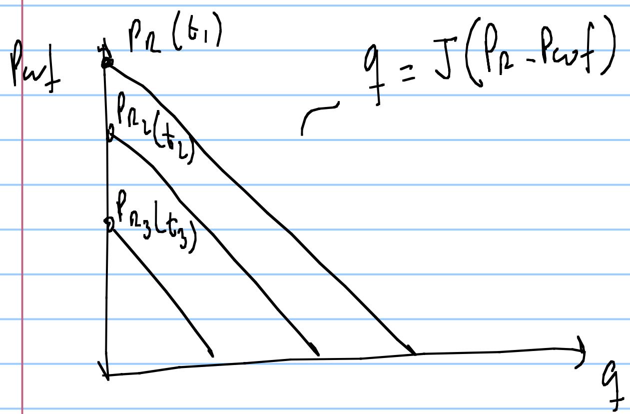
IPR



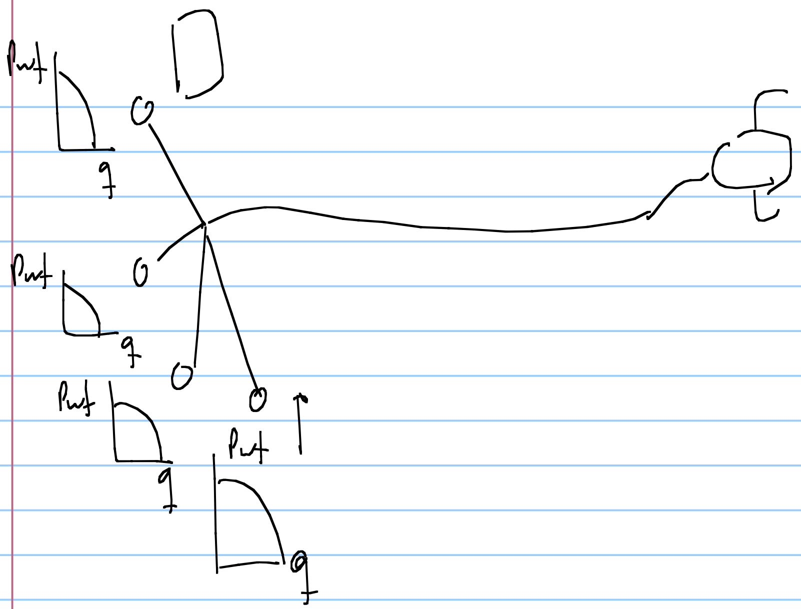




$q = f(P_R - P_{wf})$

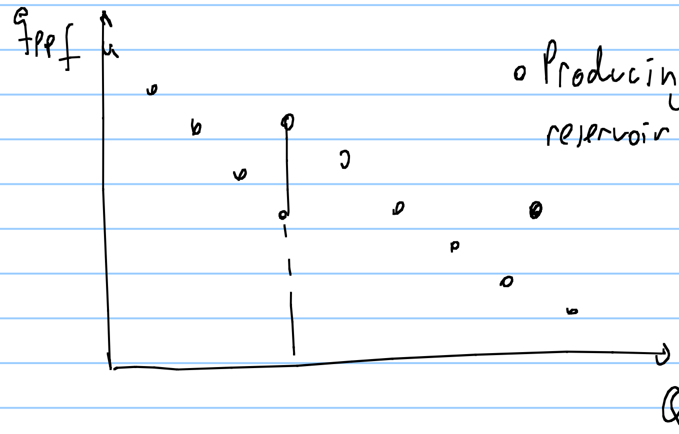
IPR: pseudo-steady state representation of the deliverability of the reservoir at a given $P_R$, $N_p$,




$q = J(P_R - P_{wf})$




- Some complexities to calculate the production potential
  - IPR changes with depletion
  - GOR, WC of each well changes with depletion
  - Changes in the production system
    - adding new wells
    - add boosters
    - add Artificial lift
  - Producing from different reservoir units




$Q_p^1$ $Q_p^2$

Usually, for calculating field performance we use:

- Coupled models reservoir + production system
  implicit coupling

Reservoir simulation

set of equations

production simulator

Set of equations

solve all equations simultaneously, time consuming, not very practical

$\boxed{\text{explicit coupling}}$ to compute field performance.

$\boxed{\text{Reservoir simulator}}$

$\boxed{\text{production simulator}}$

$t_1$, $G_p^1$ IPRs $\longrightarrow$ $q_{pp_1}$

$q_{pp_2}$

$q_{pp_3}$

$q_{plateau_1} < q_{pp_1}$

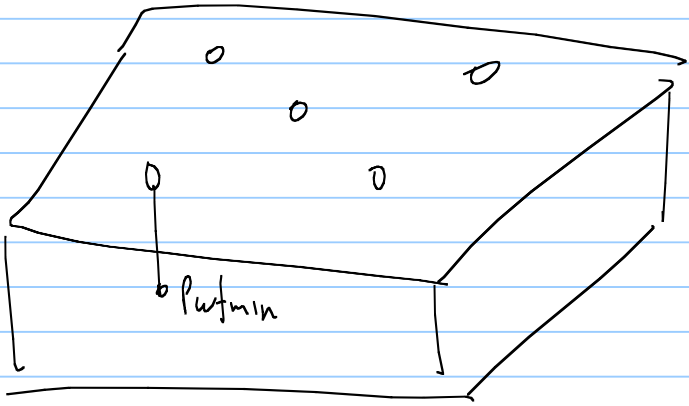
$q_{plateau_2} < q_{pp_2}$

run simulation for one time step with the rates

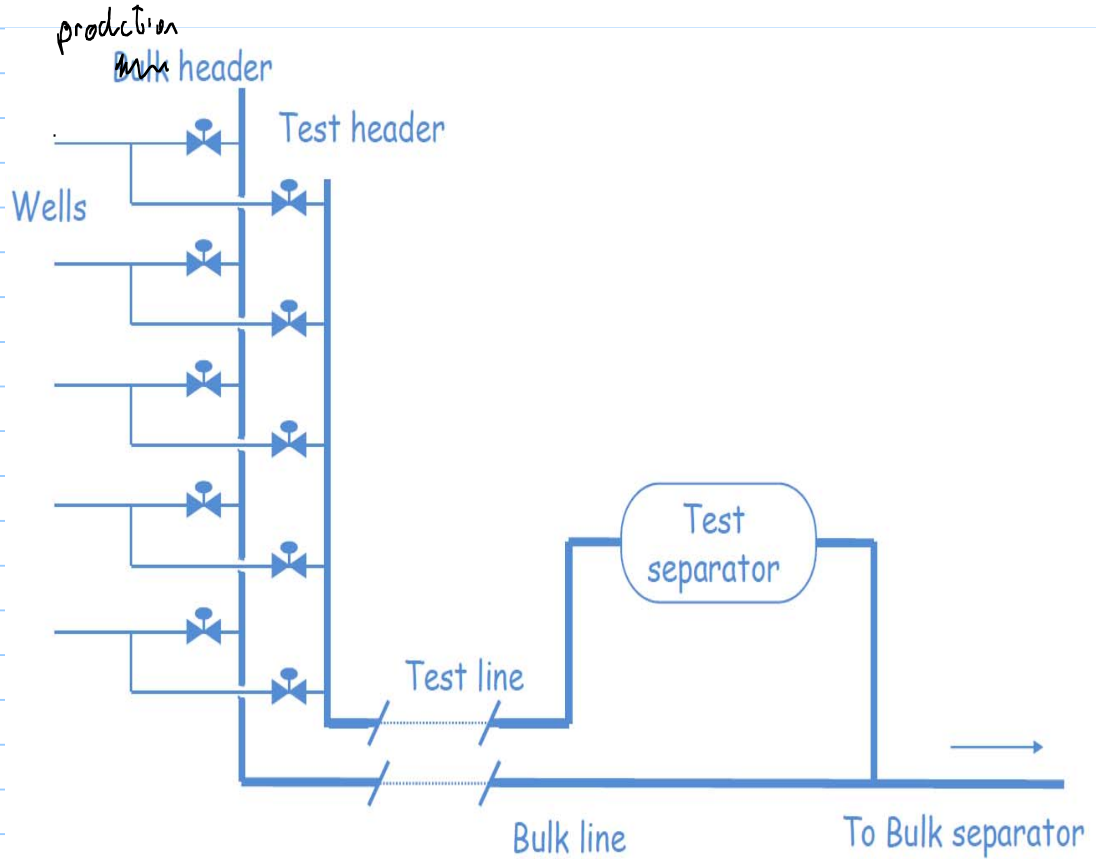
$G_p^2$ IPRs $\longrightarrow$ Production simulator

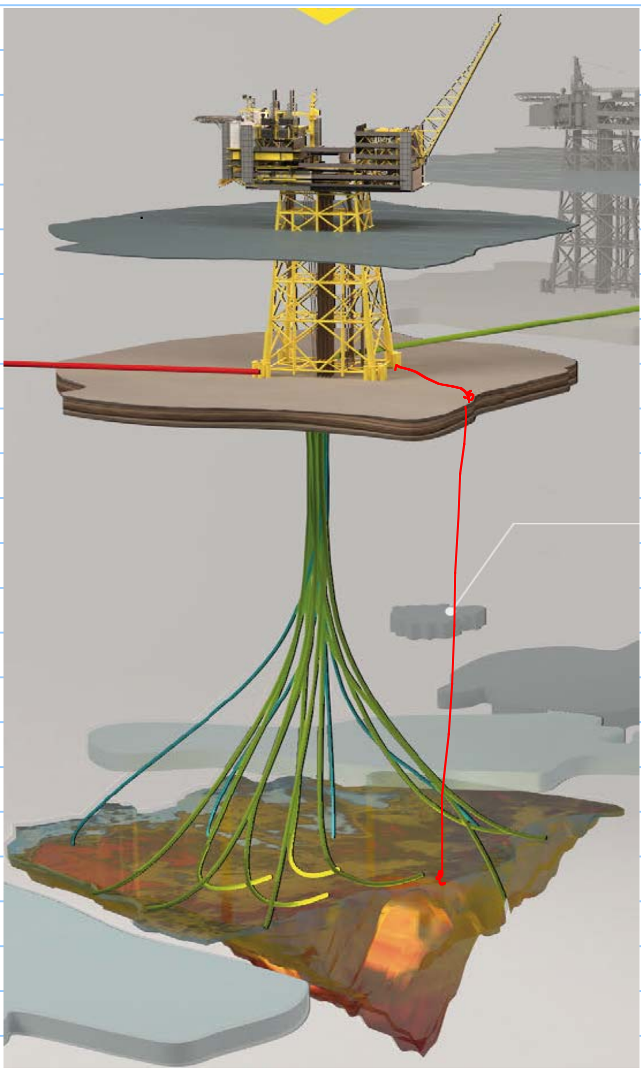
Very often the reservoir simulator is used standalone, with a minimum flowing bottomhole pressure to represent network backpressure

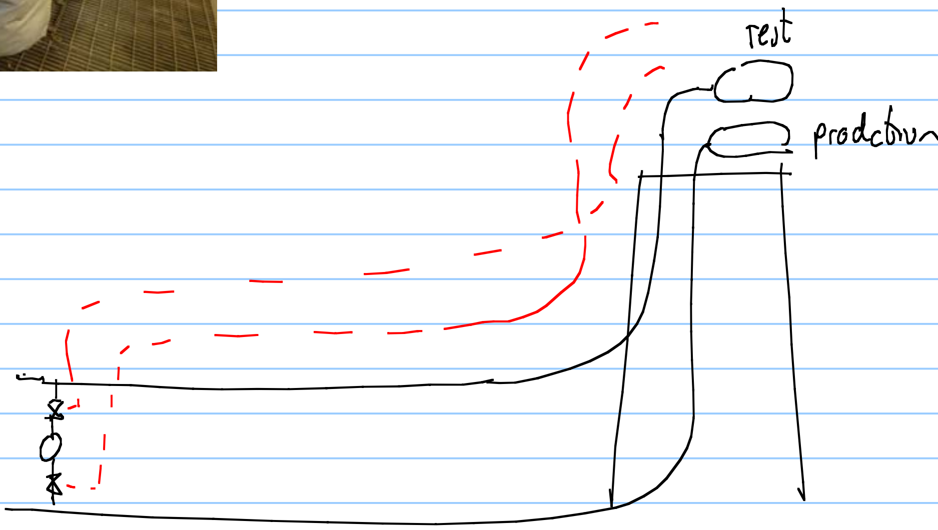
this is not always an accurate representation of the production system (well, pipeline, flowline, sep).



architecture of production systems

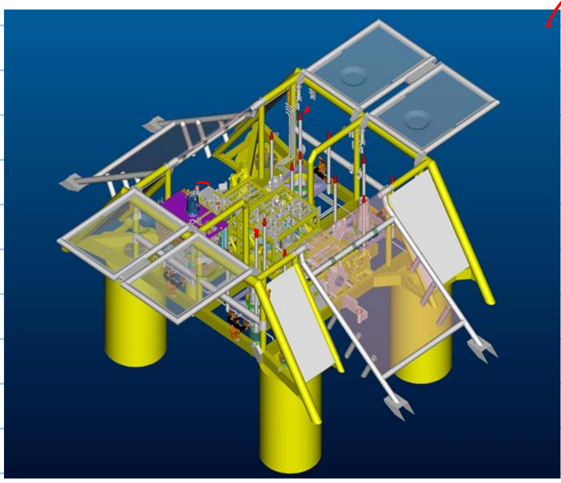


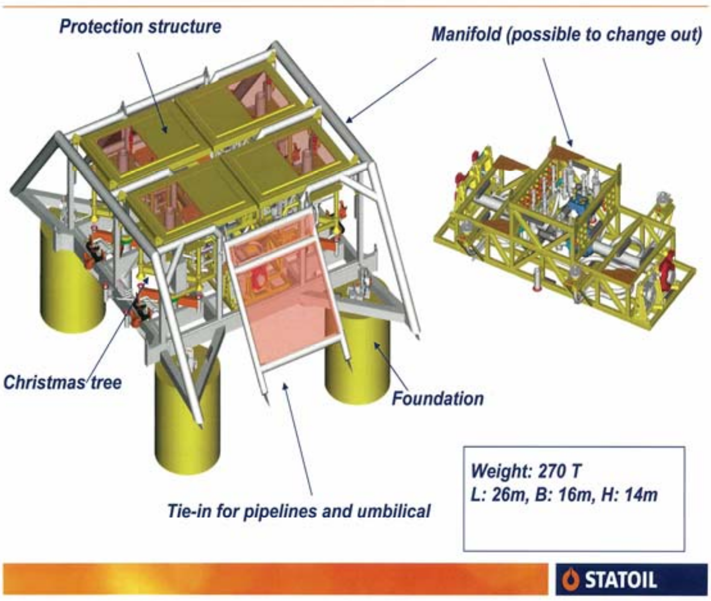



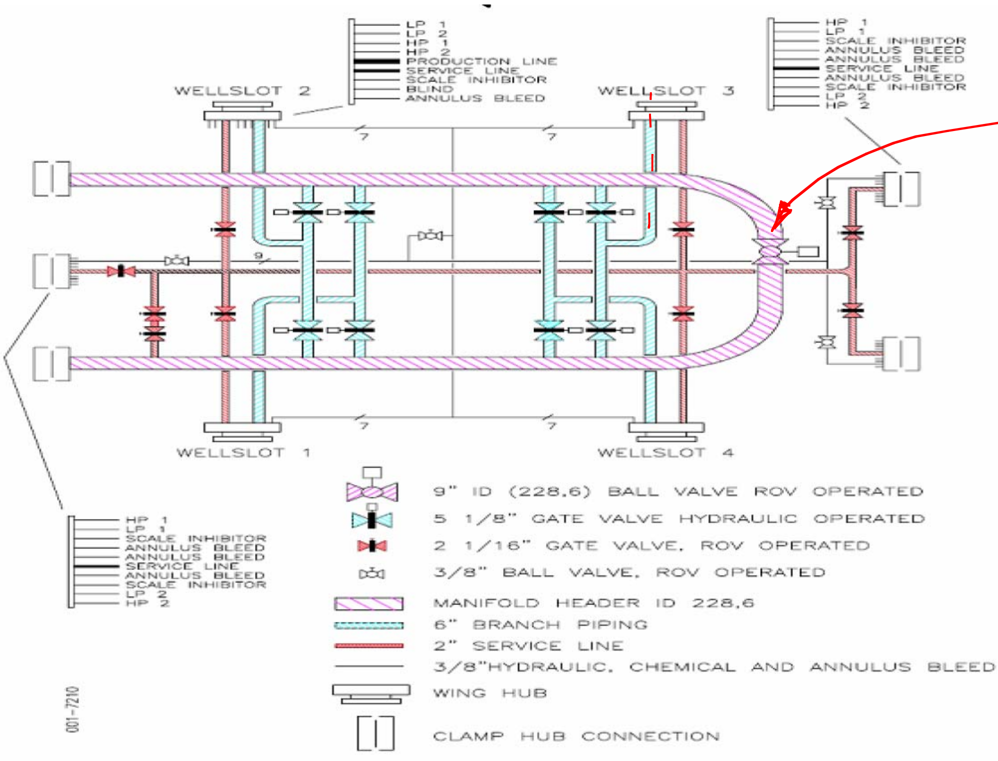



template

statoil 3/4

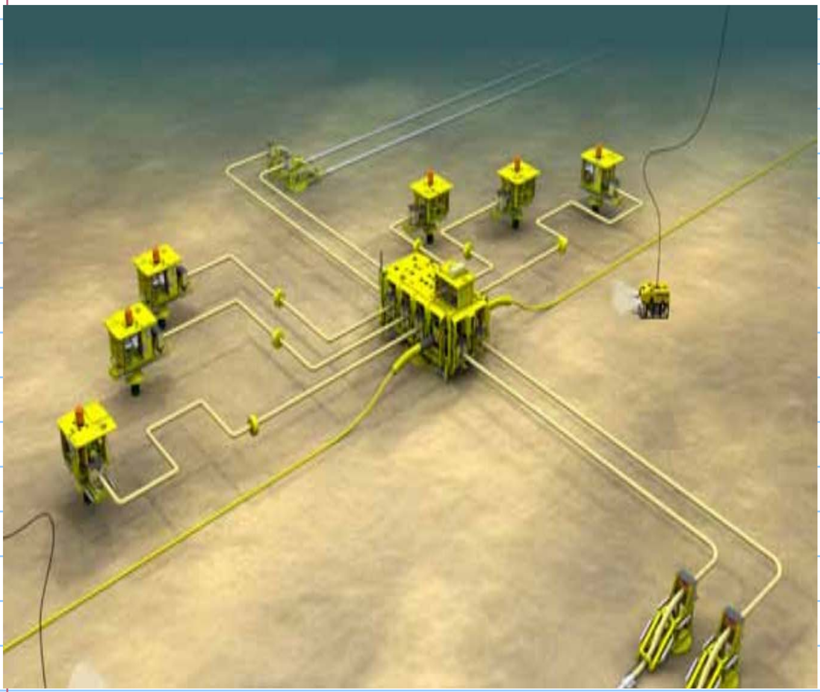


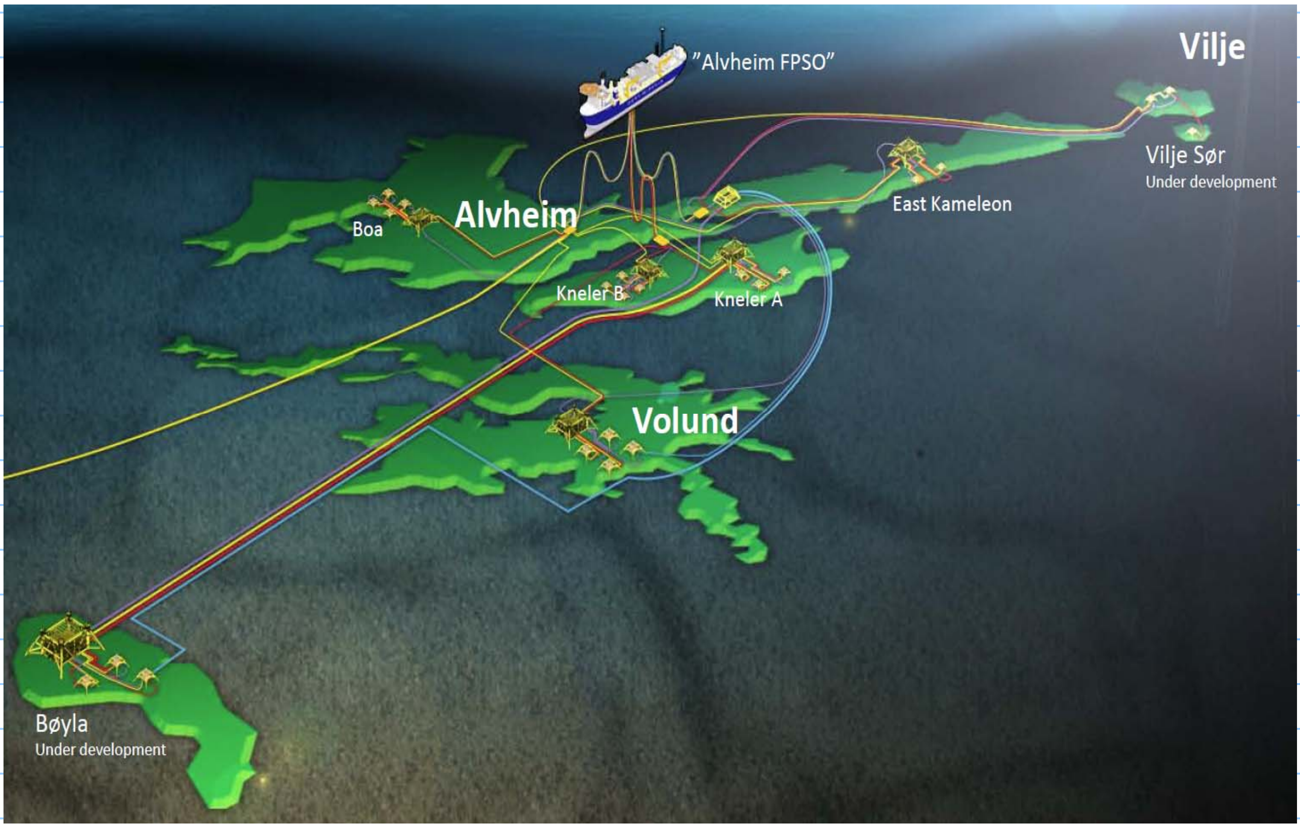



crossover valve

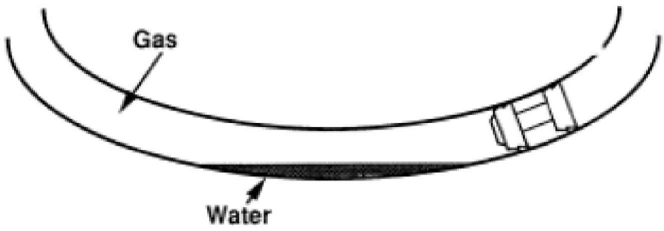
satellite wells



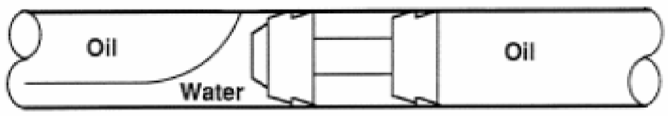


function of test and production line : for pigging operations.

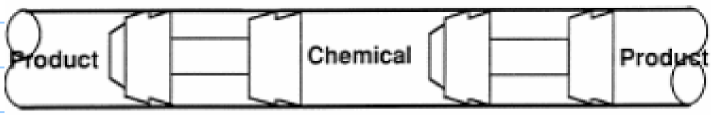
**Removing water in a gas flow system**



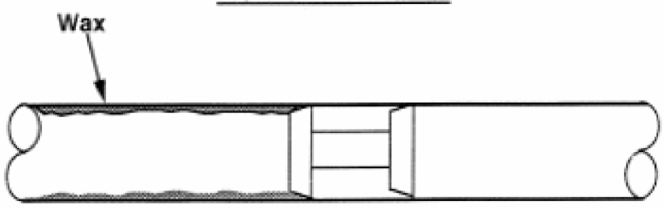

**Removing water in a oil system**

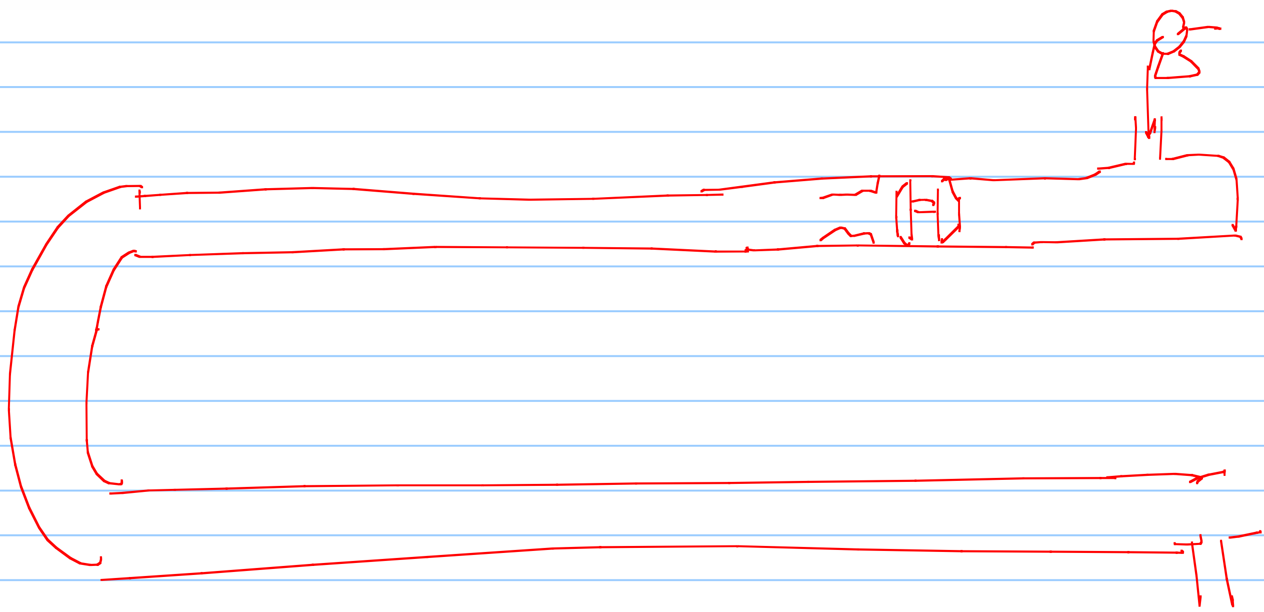


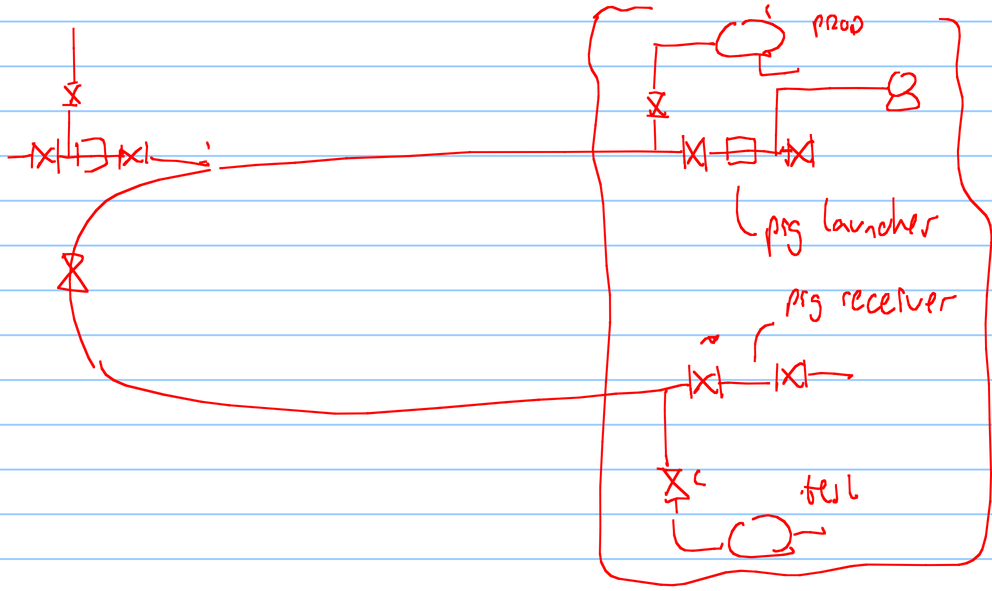

**Treating by chemicals**



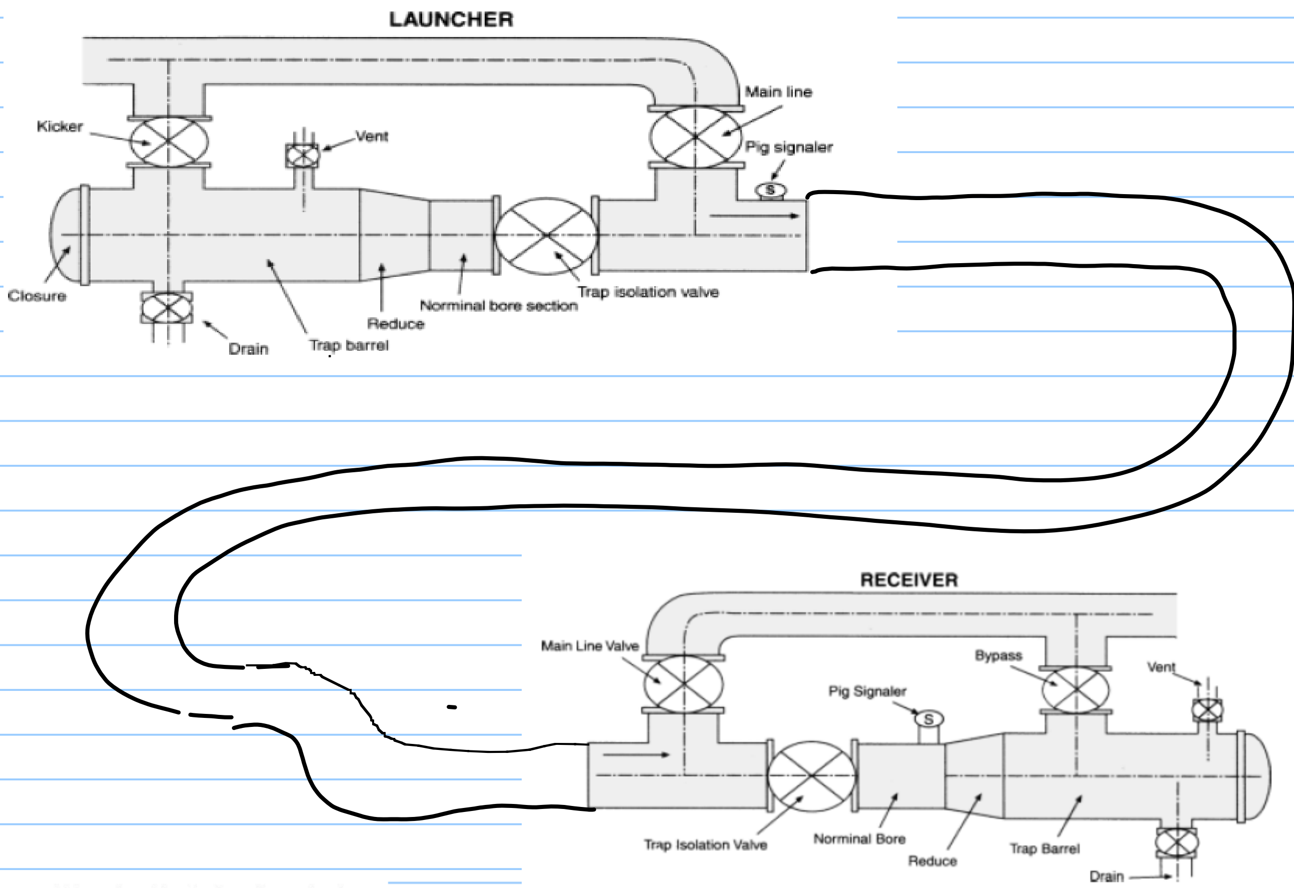

**Removal of Wax**



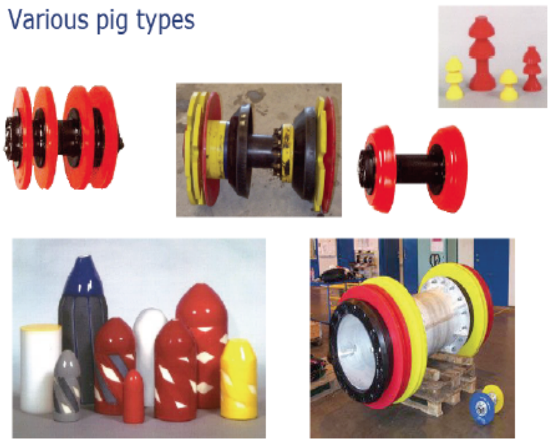



Pigging animation: https://www.youtube.com/watch?v=CDHtL-J1Xxo

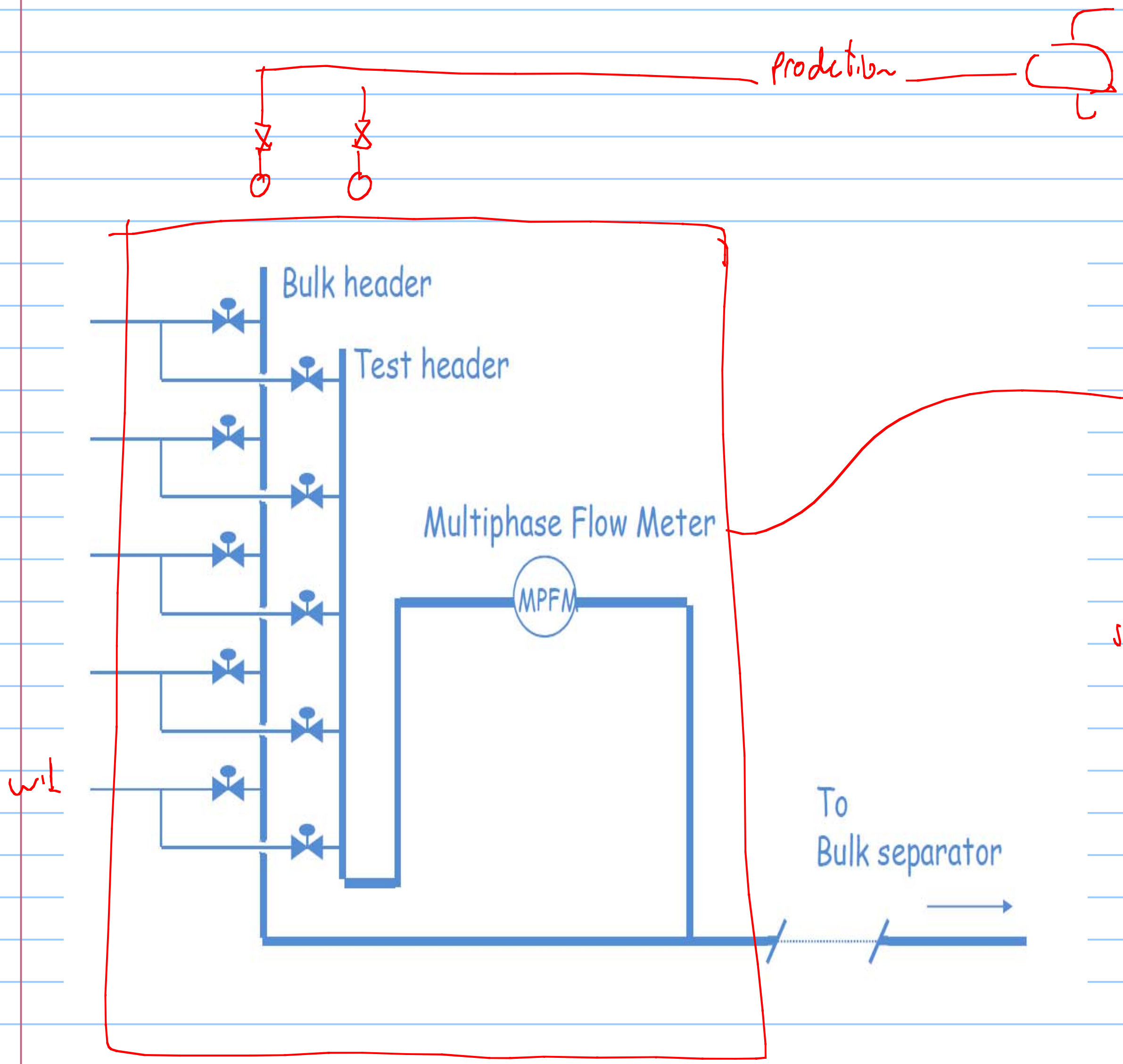



## Wax plug-North Sea line pigging

## Various pig types

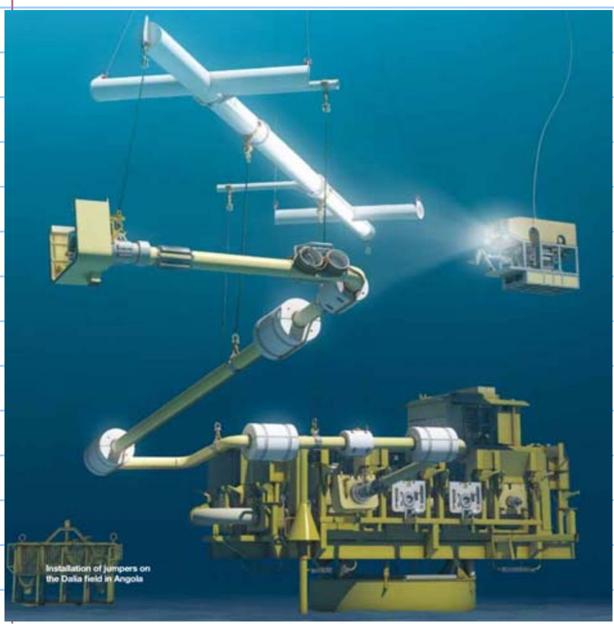


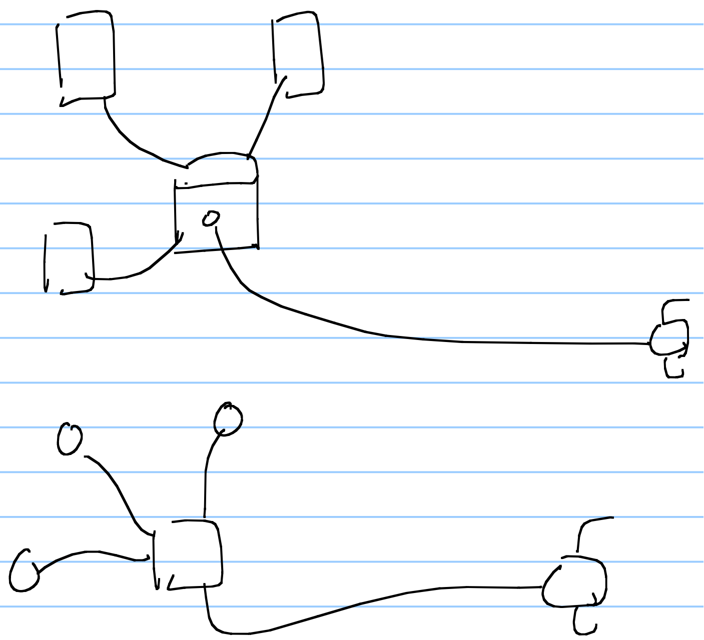
offshore pigging   offshore pig launcher.




can measure
$q_o$
$q_g$
$q_w$ without
separating.

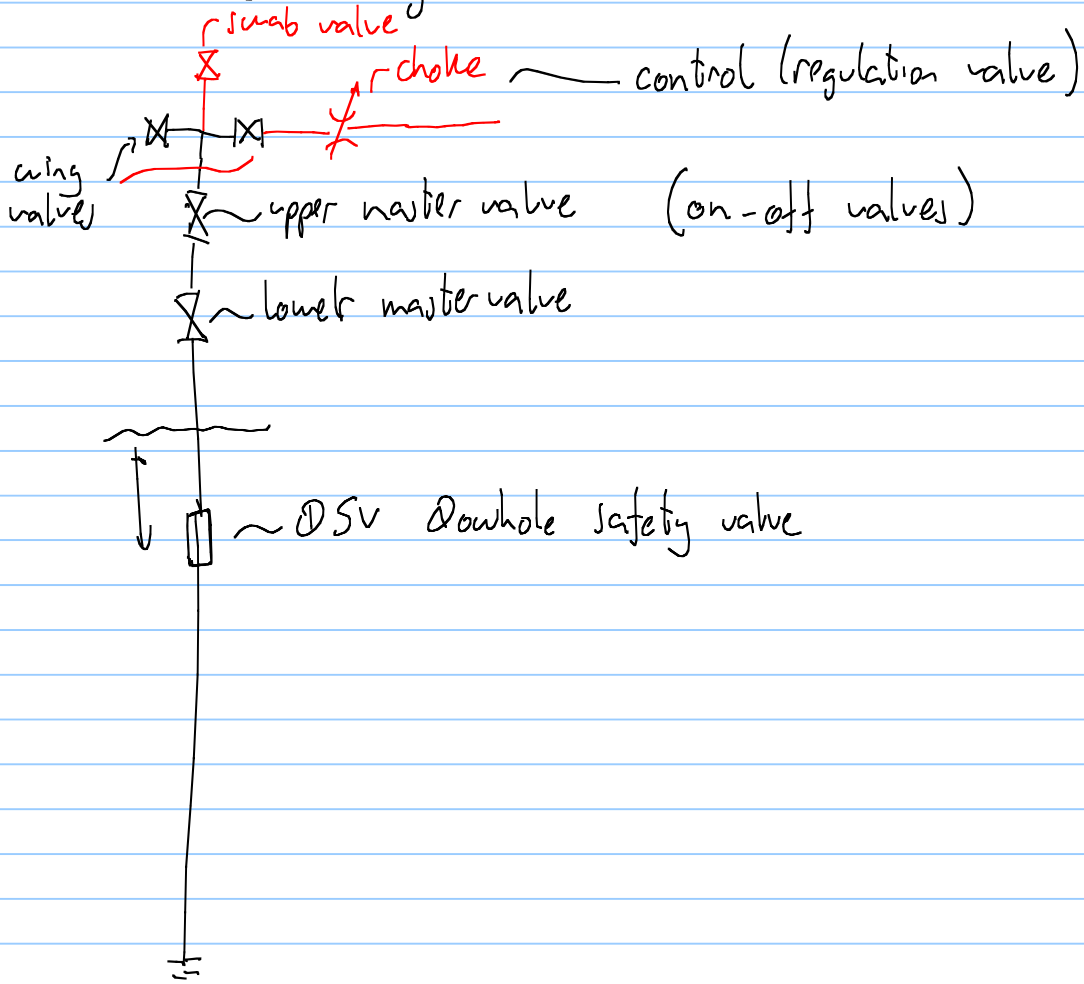
Connectors between well template, satellite well to manifold



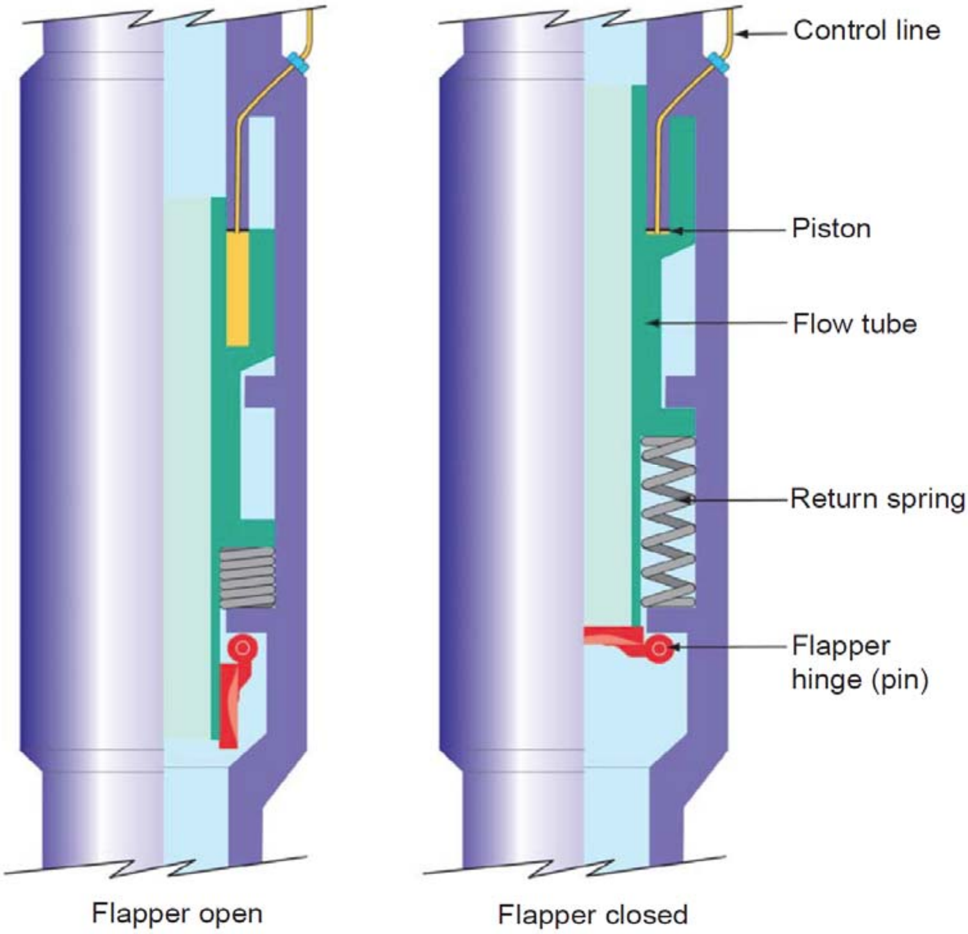



Installation of a spool using the vertical connection system (VCS)

main valves that you have in a well



SSSV subsurface safety valve.



Michael Golan, substitute for Prof Milan Stanko

Notice on tomorrow lecture:

- subject: " concept selection for Deep water field Development " by

Mahmoud Etemaddar

Sevan Marin A/S OSLO

what are we doing in field development engineering?

In a nute shell we do the following:

Field Development

- Identify development scenarios
- prepare details of each scenario
- study and analize each scenario
- Rank the various scenarios
- select the scenario to use (the best case scenario)

Three alternative development concepts:

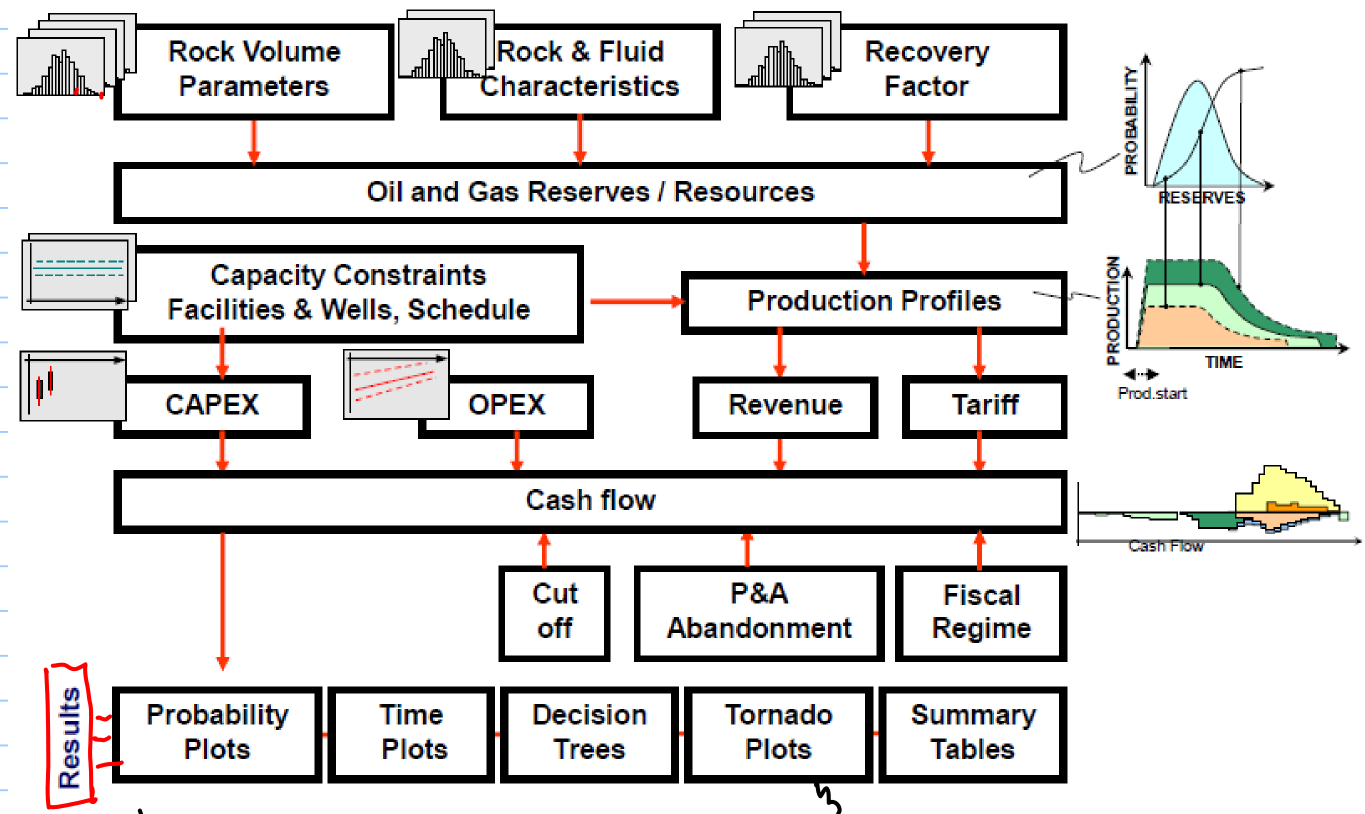
- Subsea 
- FPSO 
- Stand alone 

Issues analized for each scenario:

| Economy | schedual | Risk/uncertainties and decision |
|---|---|---|
| cost | Organization | Decision in uncertain environment |
| Revenue | activities (CTR catalog) | |
| cash flow | Resources | |
| NPV/IRR | time line | |
| | project management tool | |

Example

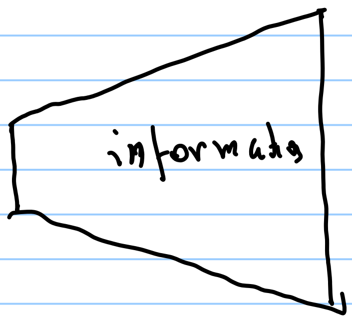
# Capturing the Uncertainties




The unique nature of offshore environment:

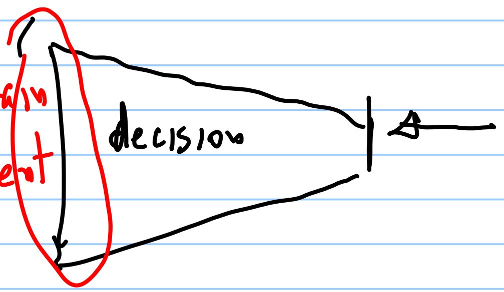
sensitivity analysis

"The biggest decisions have to be taken upfront (Early in the planning phase)




limited information up front

decision in uncertain environment




major decisions up front

time

time - Life cycle of an offshore field

Modern field planning processes and the outcome decision are base on some form of probabilistic analysis

# Deterministic vs. probabilistic approach

How can input risk and uncertainty be quantified?

| DETERMINISTIC | | | |
|---|---|---|---|
| PARAMETER 1 | 'high' | 'base' | 'low' |
| PARAMETER 2 | 'high' | 'base' | 'low' |
| PARAMETER 3 | 'high' | 'base' | 'low' |
| PARAMETER 4 | 'high' | 'base' | 'low' |
| PARAMETER 5 | 'high' | 'base' | 'low' |

Low case

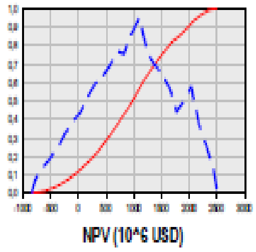
Base case

High case

- Three discrete outcomes
- Base Case ≠ Expected for the project
- High case and low case are extremely unlikely to occur

| PROBABILISTIC | |
|---|---|
| PARAMETER 1 | Distribution |
| PARAMETER 2 | Distribution |
| PARAMETER 3 | Distribution |
| PARAMETER 4 | Distribution |
| PARAMETER 5 | Distribution |

Simulation




- Full range of possible outcomes
- True expected NPV
- True P90
- True P10
- Correct comparison and ranking of options

The rest of the lecture will be dedicated to probabilistic analysis

# Probabilistic Estimation

We will us probabilistic apprach to quantify uncertainty and risk

Probability is described as a measure of our (or someone else's) opinion as to the likelihood of a future event occurring. For example, in the toss of a coin, one would estimate there was a 50% chance the coin is a "head." That estimate of 50% represents the probability (in a person's view) of the likelihood of a future event occurring - the coin coming up heads. That estimate is based on past experience tossing coins and the assumption the coin was fair, i.e., only had one head, edges were not beveled, and so on.

Another method of arriving at the 50% estimate would be to toss the coin a large number of times - say 1 000 000. Based on that experiment, one might say the probability of obtaining a head on one fair toss is 0.5 (or 0.501 or 0.499, etc.). This is called sampling the population. In this case, the population is infinite and the sample space is 1 000 000 tosses of the coin. Unfortunately, in the business world one is seldom able to sample the population before making a business decision. One must rely on probability estimates which are based on limited data and personal experience.

probabilistic methods provides a structured apprach to account for the uncertainty.

Probabilistic methods help to ensure that quoted quantities are appropriate relative to the requirements of certinty

For example The stock Exchange commision (SEC) in the USA has very strict rules on how to includ uncertainty in reporting reserves.

Important

Probabilistic methods do not introduce new information, nor do they introduce radical changes in the qantitative scale of the problem. Rather, they bring clarity to the expressions of certainty or uncertainty.

Before starting our refreshment revision of probability we need to state two basic rules of probability

1. The probability assigned to a possible event must be a positive number between 0 and 1(0 and 100%), where 0 represents an impossible event and 1 represents a certain event.

   If a set of events is mutually exclusive and exhaustive (covers all possible outcomes) then the total of the probabilities of the events must add to 1.

2. Rule 2 implies that if there is 30% probability that we obtain sucessful discovery well, then there is 70% probability the we have unsuccessful well

# calculating probability

given a company with 78 employess.
Study the pattern of sick-leave days in the company

| Parameter | Frequency | Relative fequency | Cummulative Frequency |
|---|---|---|---|
| Number of sick days per employee | No of employees with Xi sick days | Probability | |
| Xi | fi | fi/sum (fi) | |
| 0 | 12 | 0.154 | 0.154 |
| 1 | 14 | 0.179 | 0.333 |
| 2 | 19 | 0.244 | 0.577 |
| 3 | 13 | 0.167 | 0.744 |
| 4 | 9 | 0.115 | 0.859 |
| 5 | 7 | 0.090 | 0.949 |
| 6 | 4 | 0.051 | 1.000 |
| Sum= | 78 | 1 | |

## Definitions

**Mean** The same as expected value. Arithmetic average of all the values in the distribution. The preferred decision parameter. (called also Averge)

$$\bar{X} = \frac{\sum X_i f_i}{\sum f_i} = \frac{186}{78} = 2.3$$

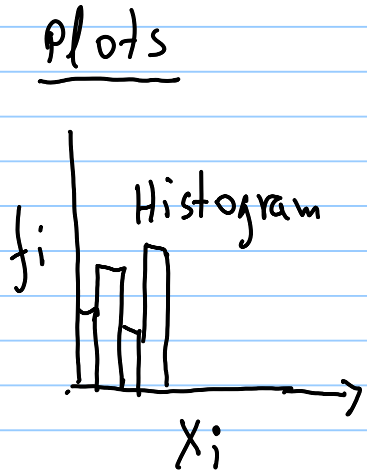
**Mode** Most likely value. The peak of the frequency distribution. Base case?

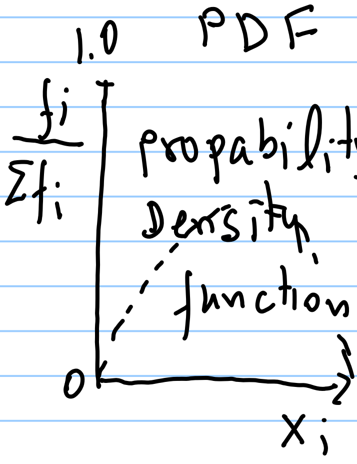
from the table = 19

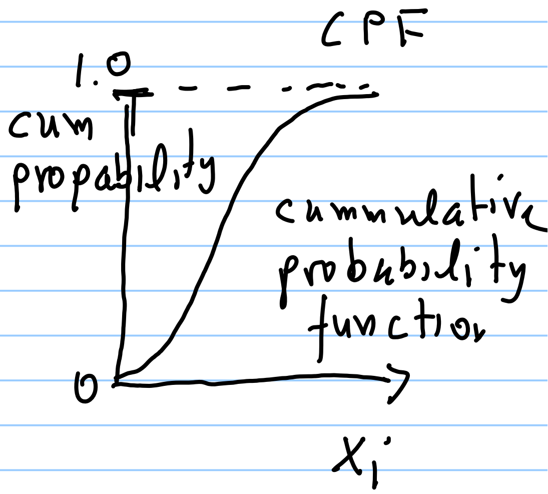
**P50** Equal probability to have a higher or lower value than the P50 value. Often referred to as the Median.

$$= \frac{\sum f_i}{2} = \frac{78}{2} = 39$$

## Plots



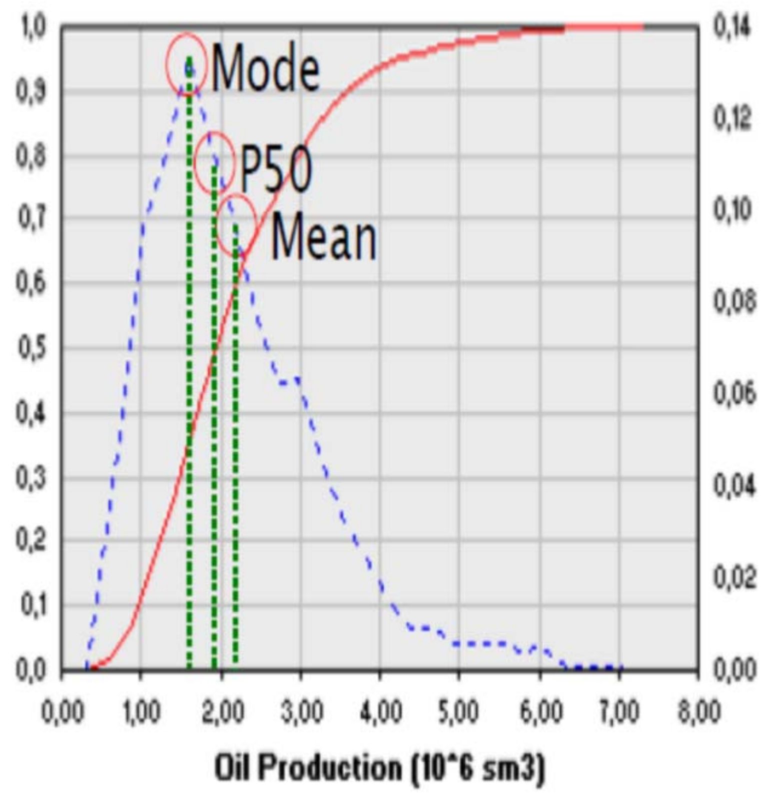

The working process to generate propability information is then

Events table → frequency table → relative frequency probability → cummulative probability

PDF (relative frequency probability) CPF (cummulative probability)

## Statistical Measures we obtain from PDF and CPF

| Oil | |
|---|---|
| Mean | 2,16 |
| Mode | 1,59 |
| St.dev | 1,10 |
| P0 | 0,33 |
| P5 | 0,78 |
| P10 | 1,00 |
| P25 | 1,39 |
| P50 | 1,93 |
| P75 | 2,75 |
| P90 | 3,62 |
| P95 | 4,20 |
| P100 | 7,32 |



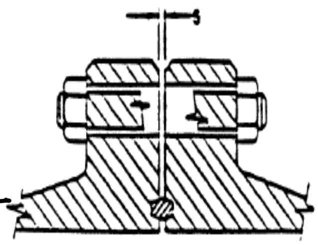
## Another example

Given a torque measurment of 34 bolts in a form of event table ( sample vs parameter)

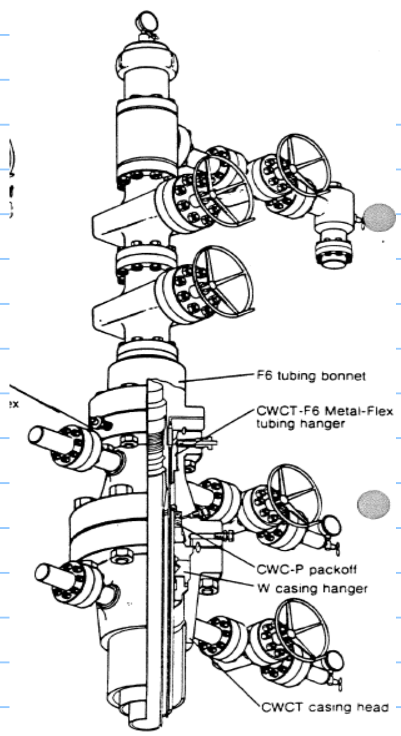
| Samle No | Paremeter measured makeup lb-ft |
|---|---|
| 1 | 11 |
| 2 | 12 |
| 3 | 13 |
| 4 | 14 |
| 5 | 14 |
| 6 | 15 |
| 7 | 15 |
| 8 | 15 |
| 9 | 15 |
| 10 | 15 |
| 11 | 15 |
| 12 | 15 |
| 13 | 15 |
| 14 | 16 |
| 15 | 16 |
| 16 | 16 |
| 17 | 17 |
| 18 | 17 |
| 19 | 17 |
| 20 | 17 |
| 21 | 18 |
| 22 | 18 |
| 23 | 18 |
| 24 | 18 |
| 25 | 18 |
| 26 | 18 |
| 27 | 18 |
| 28 | 19 |
| 29 | 19 |
| 30 | 20 |
| 31 | 19 |
| 32 | 19 |
| 33 | 19 |
| 34 | 15 |


Torque meter

Torque

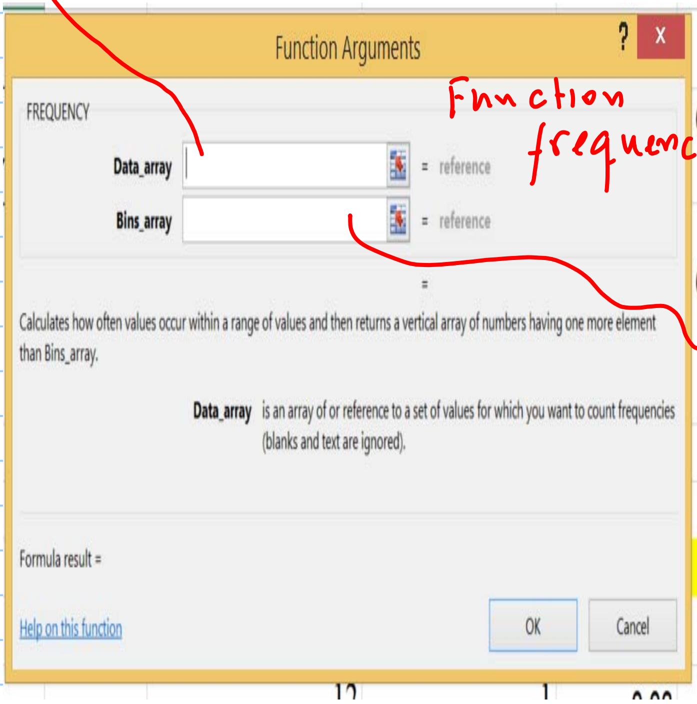


API TYPE 6B FLANGE



How to transform event diagram to frequency diagram?

| Event Table | | | Requency Table | | PDF | CPF |
|---|---|---|---|---|---|---|
| No | Measured makeup Torque | | Torque range-parameter-Xi | fi Frequency | Relative frequency = probabilit | |
| event number | lb-ft | | lb-ft | | | |
| 1 | 11 | | 11 | 1 | 0.0294 | 0.0294 |
| 2 | 12 | | 12 | 1 | 0.0294 | 0.06 |
| 3 | 13 | | 13 | 1 | 0.0294 | 0.09 |
| 4 | 14 | | 14 | 2 | 0.0588 | 0.15 |
| 5 | 14 | | 15 | 9 | 0.2647 | 0.41 |
| 6 | 15 | | 16 | 3 | 0.0882 | 0.50 |
| 7 | 15 | ? | 17 | 4 | 0.1176 | 0.62 |
| 8 | 15 | | 18 | 7 | 0.2059 | 0.82 |
| 9 | 15 | | 19 | 5 | 0.1471 | 0.97 |
| 10 | 15 | | 20 | 1 | 0.0294 | 1.00 |
| 11 | 15 | | Sum= | 34 | 1.0000 | |
| 12 | 15 | | | | | |
| 13 | 15 | | | | | |
| 14 | 16 | | | | | |
| 15 | 16 | | | | | |
| 16 | 16 | | | | | |
| 17 | 17 | | | | | |
| 18 | 17 | | | | | |
| 19 | 17 | | | | | |
| 20 | 17 | | | | | |
| 21 | 18 | | | | | |
| 22 | 18 | | | | | |
| 23 | 18 | | | | | |
| 24 | 18 | | | | | |
| 25 | 18 | | | | | |
| 26 | 18 | | | | | |
| 27 | 18 | | | | | |
| 28 | 19 | | | | | |
| 29 | 19 | | | | | |
| 30 | 19 | | | | | |
| 31 | 19 | | | | | |
| 32 | 19 | | | | | |
| 33 | 20 | | | | | |
| 34 | 15 | | | | | |




Function frequency

| Frequency Table | | | |
|---|---|---|---|
| Paremeter | Frequency | Probability | Cummulative Probability |
| Measured Torque Makeup lb-ft | Frequency of occurrence number of cases | Relative Frequency (PDF) | Cummulative Probability Function |
| less than 11 | 0 | 0.00 | 0.00 |
| 11 | 1 | 0.03 | 0.03 |
| 12 | 1 | 0.03 | 0.06 |
| 13 | 1 | 0.03 | 0.09 |
| 14 | 2 | 0.06 | 0.15 |
| 15 | 9 | 0.26 | 0.41 |
| 16 | 3 | 0.09 | 0.50 |
| 17 | 4 | 0.12 | 0.62 |
| 18 | 7 | 0.21 | 0.82 |
| 19 | 5 | 0.15 | 0.97 |
| 20 | 1 | 0.03 | 1.00 |
| Sum= | 34 | 1.00 | |

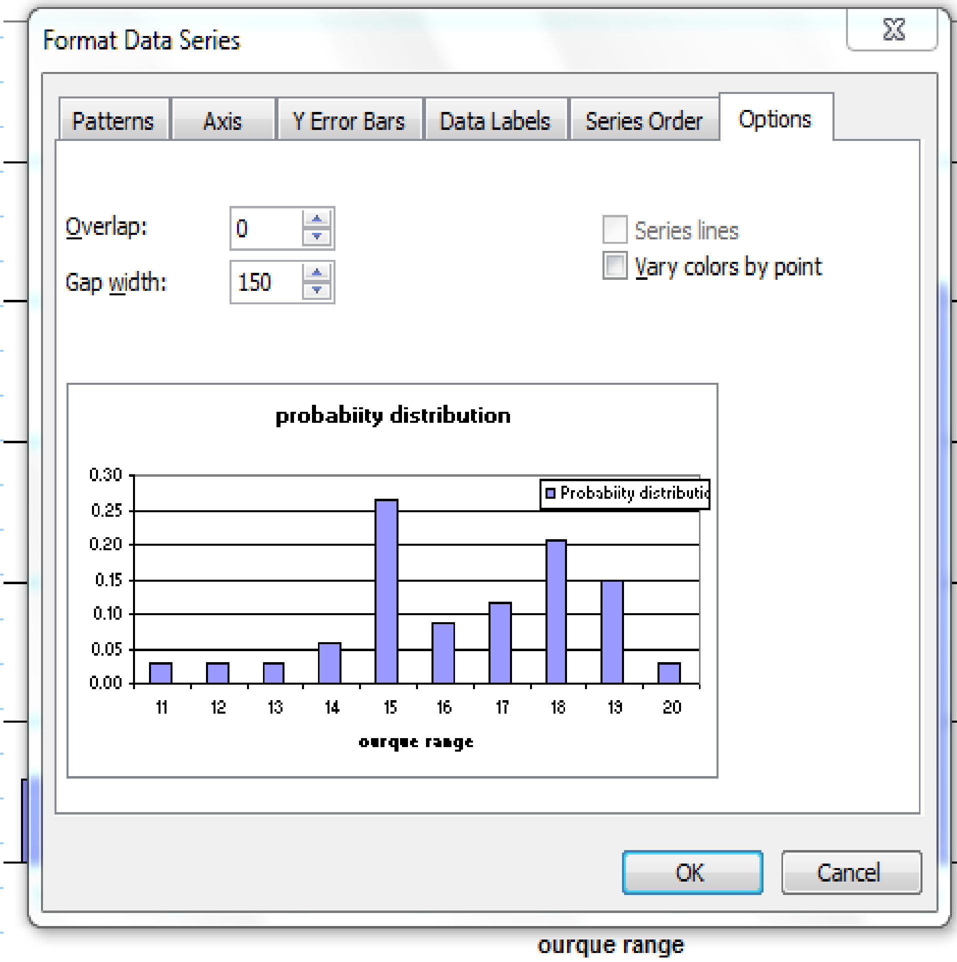
Defining the "range" in the frequency diagram

10.5 — 11.5 ⇒ 11
11.5 - 12.5 = 12
⋮
18.5 - 19.5 = 19

this column is called
Parameter column
or bin column

working prosses with frequency function

1. prepare the Bin column
2. mark the frequency column (to the right of the Bin column)
3. call the function "frequency"
4. mark the
   1. Data column
   2. bin column
5. confirm by CTL+shift+RTN

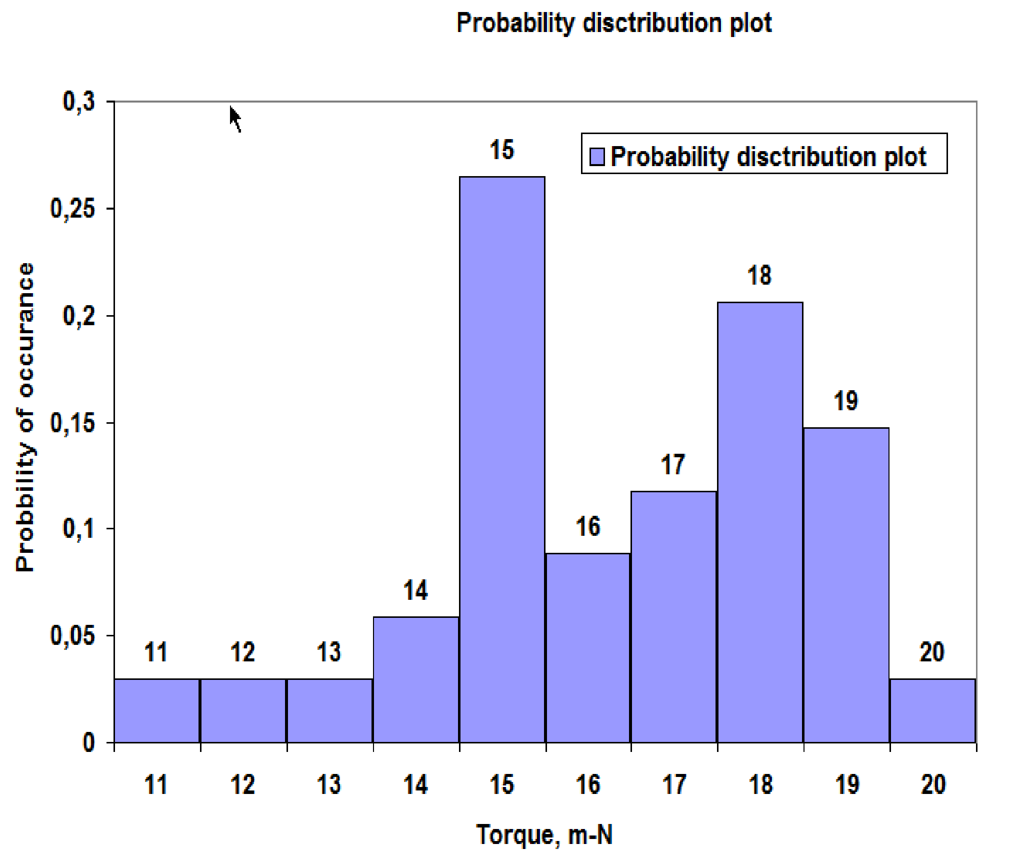



plot the Histogram!

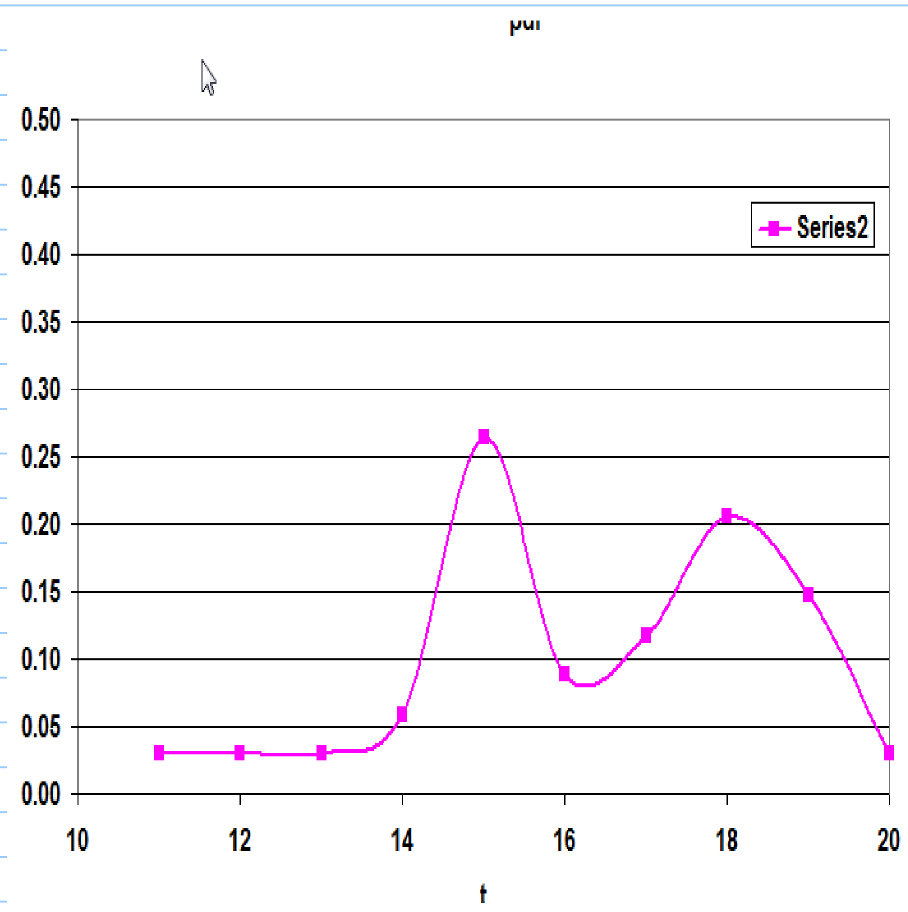
No good!!!
you need to eliminate the space between the columns

1. click on a bar
2. get "format date series"
3. Reduce gap

Discrete PDF = Histogram important !!!

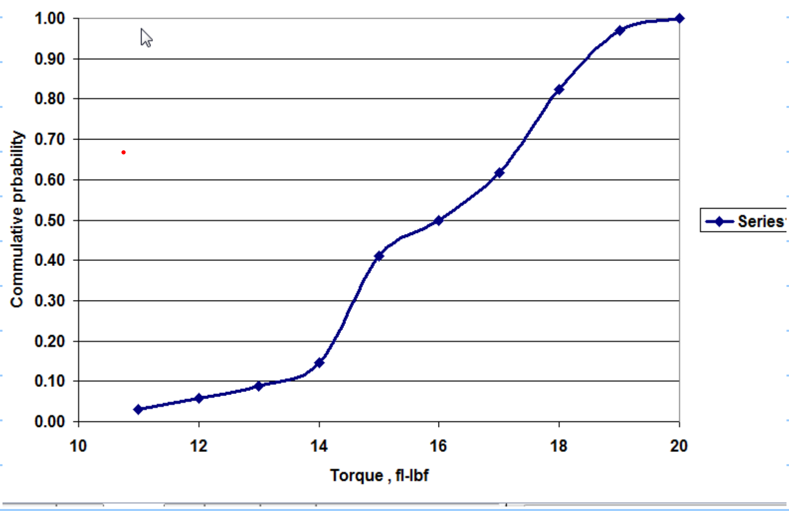



Now with reduced gap of the data series



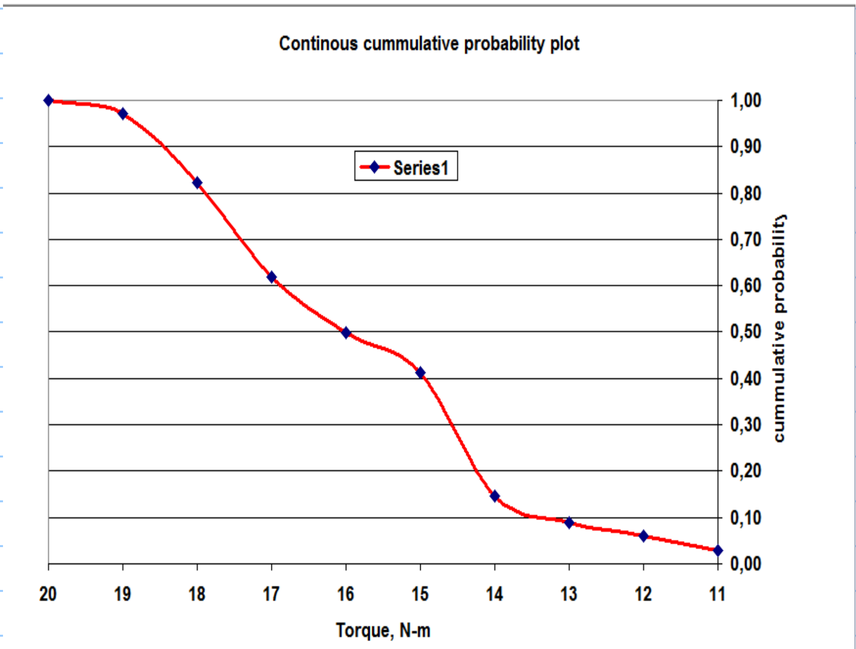

continous PDF

This is a "data scatter" type plot



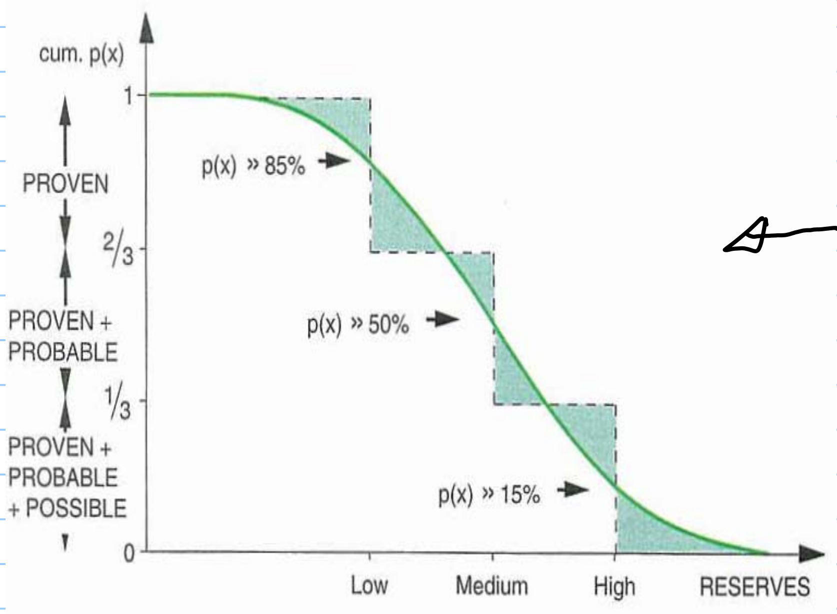

CPF

in the oil industry, when reporting reserve size we normally inverse X axis




CDF
often called
Expetation
curve

Format Axis
↳ scale
↳ inverse Axis




Expectation curve on the size of the reserves in the oil and gas industry

# Estimating Initial Reserves

- Initial oil in place

$$IOIP = N = \frac{Ah\theta(1-S_w)(N/G)}{B_o}$$

- Initial Gas in place

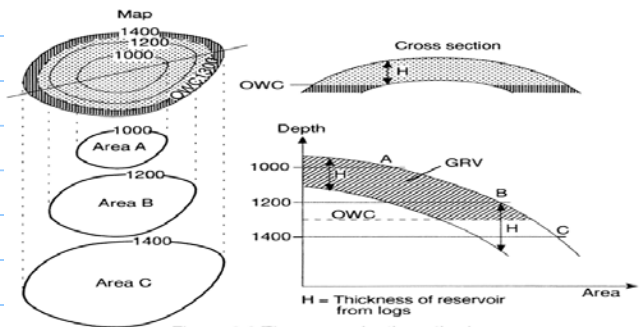
$$IGIP = G = \frac{Ah\theta(1-S_w)(N/G)}{B_g}$$


# Information needed for IOIP estimation

- Reservoir architecture $\Sigma(hA)$
- Porosity distribution $\phi(xyz)$
- Saturation distribution $(1-s_w)$
- net oil zone $(N/G)$
- Reservoir fluids volumetric behavior $B_o$

Gross Rock volume estimate

Geology tool box



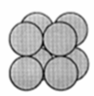

## Porosity

a measure of the space available for storage of petroleum hydrocarbon

Porosity is defined as the ratio of the void space in a rock to the bulk volume of that rock multiplied by 100 to express in per cent

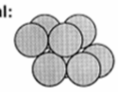
Idealistic:

Cubic:



$$\text{Porosity} = \frac{\text{Pore volume}}{\text{Bulk volume}} = 47.6\ \%$$

Rhombohedral:



$$\text{Porosity} = \frac{\text{Pore volume}}{\text{Bulk volume}} = 25.96\ \%$$

Real life:

Fractures

Sandstone, Clay, Limestone, etc

Porosity (examples:)

Statfjord: 20 - 35 %
Frigg: 27 - 30 %
Ekofisk: 15 - 48 %

The main problem is reserve estimation is uncertainty

## Uncertainties in IOIP Estimation

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

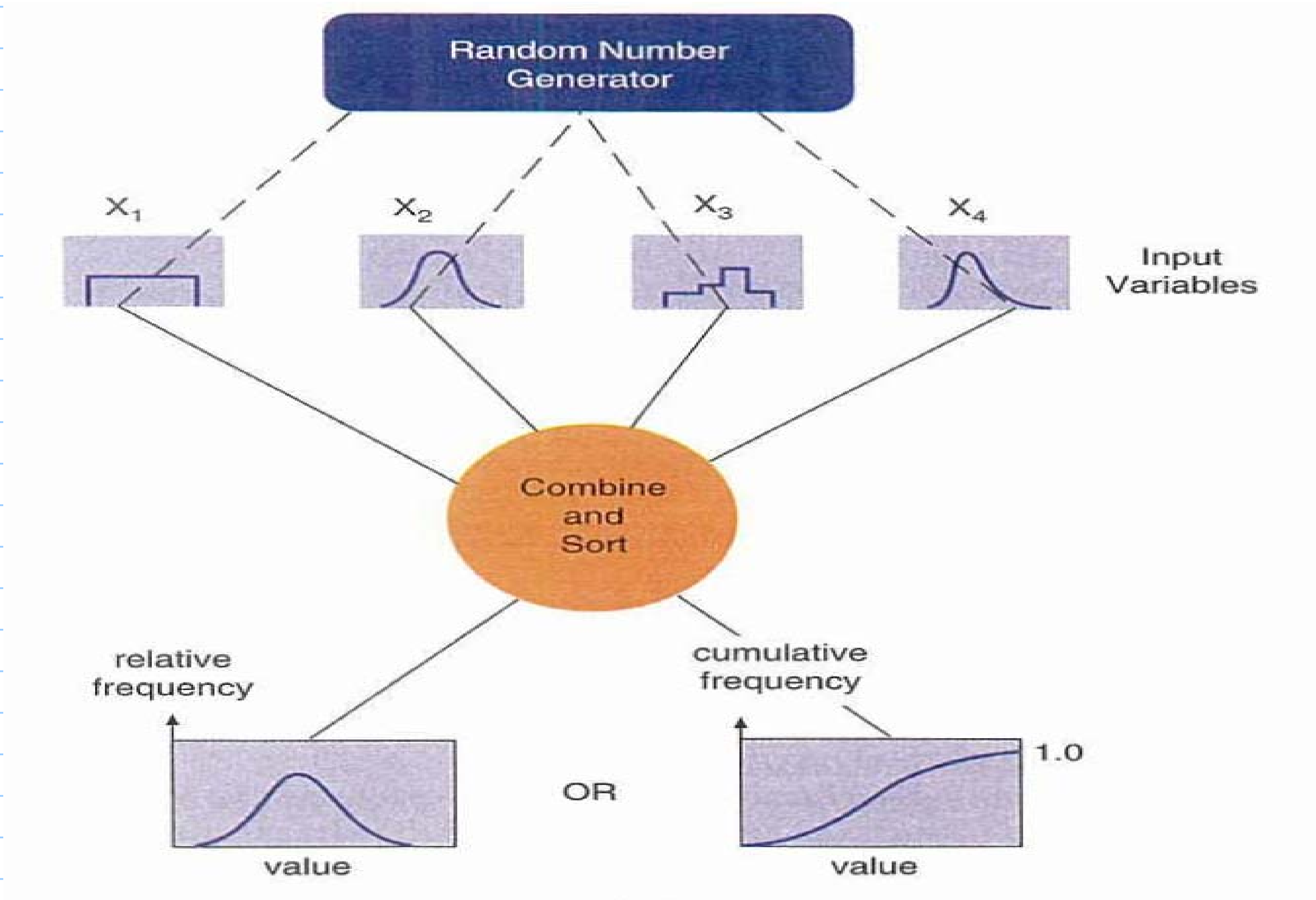
NTNU

We are going to use statistical simulation technique to present an average reserve size. This is needed for the planning but also required by the regulatory bodies such as NYSE (New York Stock Exchange)

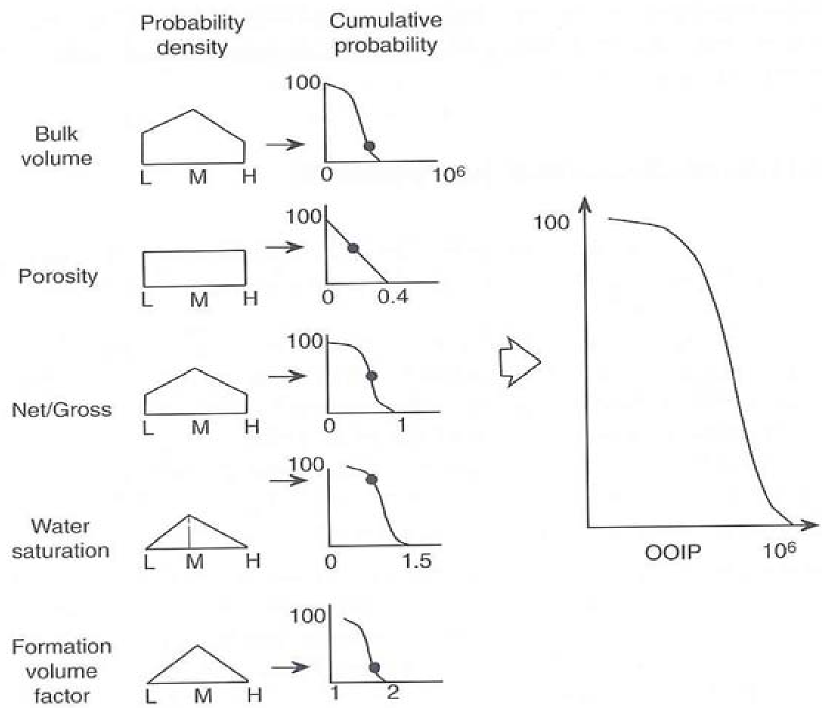
### What is Monte Carlo Analysis?

It uses random number generation, rather than analytic calculations, to combine distributions

It is increasingly popular due to high speed personal computers



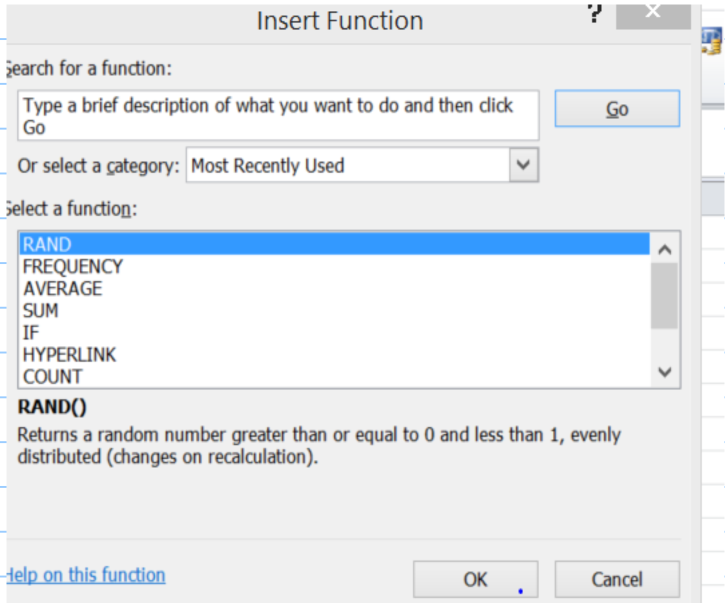

# Probabilistic Approach to Reserve Estimate



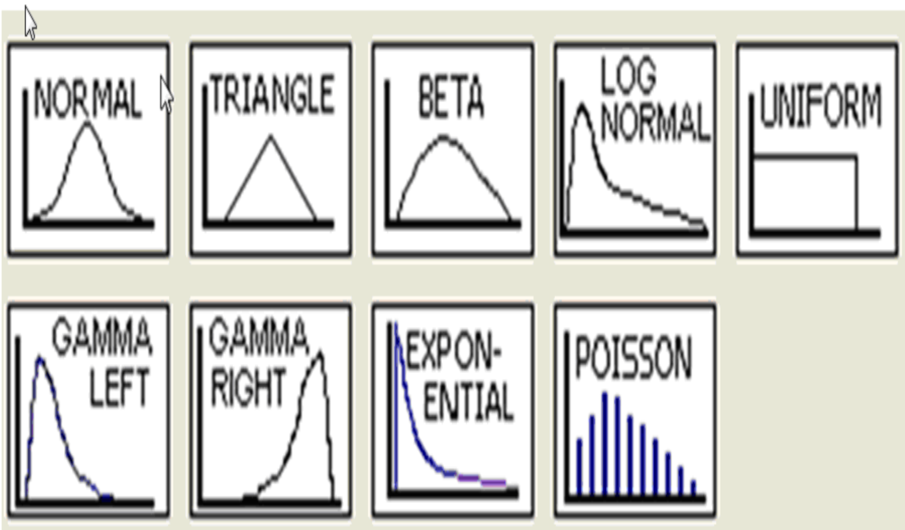
# Excell Random number generator

## What happens when I enter =*RAND()* in a cell?

When you enter the formula =*RAND()* in a cell, you get a number that is equally likely to assume any value between 0 and 1. Thus, around 25 percent of the time, you should get a number less than or equal to .25; around 10 percent of the time you should get a number that is at least .90, and so on.



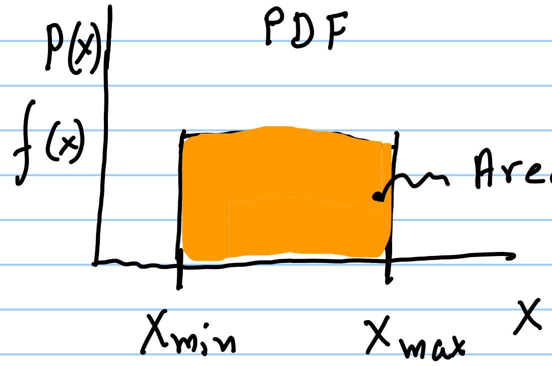

There are various types of distribution

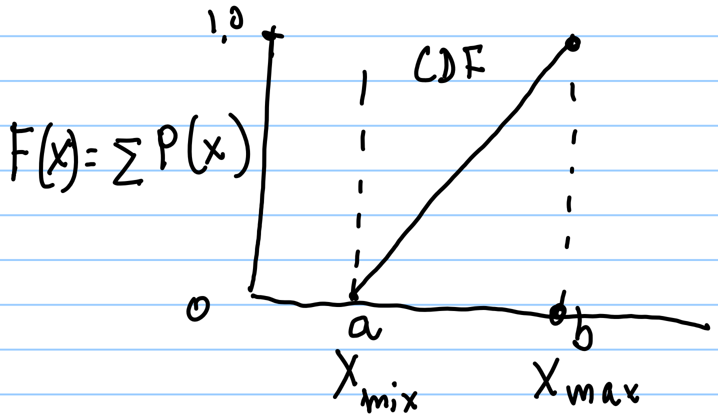



Empirical experience in the oil industry suggest to use two type of probability distributions in reserve estimation (a) Uniform, (b) Triangle. These are somewhat subjective probabilities based on the beliefs of professionals (with high salary)

# The properties of the distributions

## uniform distribution



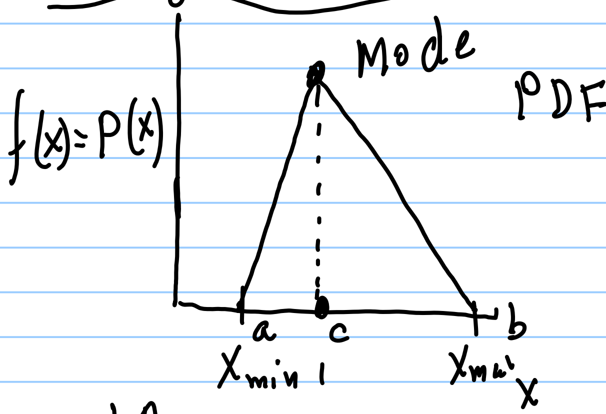




$$\boxed{X = X_{min} + U_r\left(X_{max} - X_{min}\right)}$$

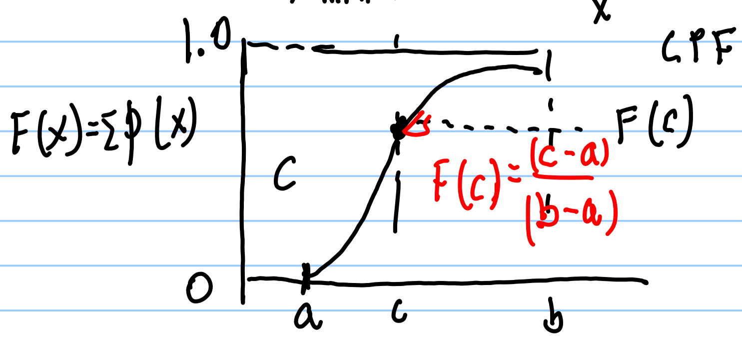
U is random number between 0 and 1.0

and is generated in Excell by function RAND( )

## Triangle distribution




given
$X_{min} = a$
$X_{max} = b$
$X_{mode} = c$
$U$ = Random number $0 \le U \le 1.0$




for $0 < U < F(c)$

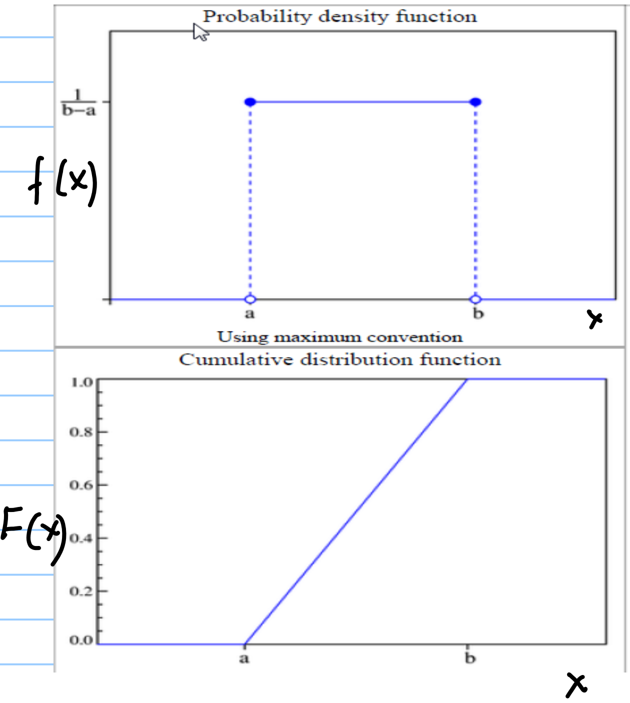
$$X = a + \sqrt{U(b-a)(c-a)}$$

for $U > F(c)$

$$X = b - \sqrt{(1-U)(b-a)(b-c)}$$

once again, and again, and again, the properties of the probability functions

## uniform probability function




Probability density function

$$f(x)=\begin{cases}\frac{1}{b-a} & \text{for } a \le x \le b,\\ 0 & \text{for } x<a \text{ or } x>b,\end{cases}$$

**Cumulative distribution function**

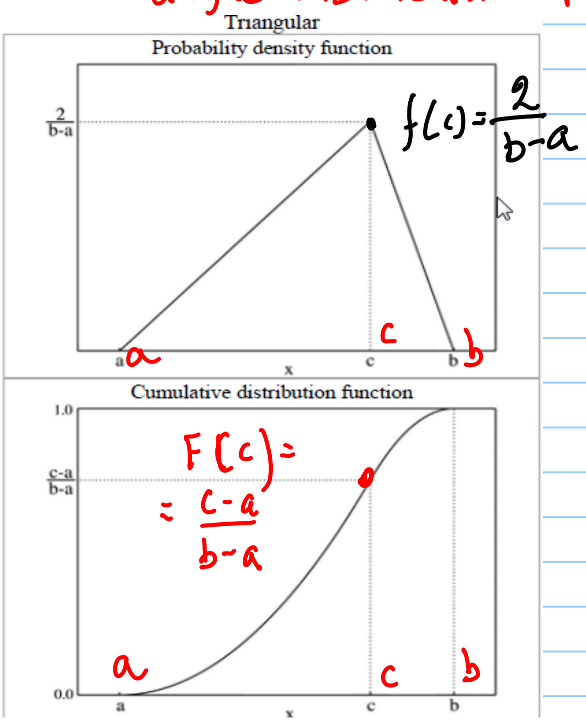
The cumulative distribution function is:

$$F(x)=\begin{cases}0 & \text{for } x<a\\ \frac{x-a}{b-a} & \text{for } a\le x<b\\ 1 & \text{for } x\ge b\end{cases}$$

u = random number between 0 and 1

$$\boxed{x = a + u\,(b-a)} \leftarrow \quad ! \; ! \; !$$

## Triangle distribution Function




$$\begin{cases} X = a + \sqrt{U(b-a)(c-a)} & \text{for } 0 < U < F(c)\\ X = b - \sqrt{(1-U)(b-a)(b-c)} & \text{for } F(c) \le U < 1\end{cases}$$

x is the value of the variable generated from u, a, b, c.

Example of calculating IOIP (N) using Monte Carlo simulation

simple case – unifor distribution

$$\boxed{\begin{aligned}
V_R &= V_{min} + u(V_{max} - V_{min}) \\
\phi &= \phi_{min} + u(\phi_{max} - \phi_{min}) \\
S_o &= S_{o\,min} + u(S_{o\,max} - S_{o\,min}) \\
G/N &= G/N_{min} + u(G/N_{max} - G/N_{min}) \\
B_o &= B_{o\,min} + u(B_{o\,max} - B_{o\,min})
\end{aligned}}$$

given data

| | | | | $s_o=(1-s_w)$ | |
|---|---|---|---|---|---|
| | Rock Volun | Porosity | N/G | Saturation | Bo |
| | bbl | fraction | fraction | fraction | Res bbl/STB |
| Min | 2.0E+9 | 0.2 | 0.3 | 0.8 | 1.35 |
| Max | 2.2E+9 | 0.3 | 0.5 | 0.9 | 1.6 |
| | | | | | |

| | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|
| 1 | | $s_o=(1-s_w)$ | | | | | |
| 2 | **N/G** | **Saturation** | **Bo** | | | Distribution | |
| 3 | fraction | fraction | Res bbl/STB | | | **Unifrom** | **Triangula** |
| 4 | 0.3 | 0.8 | 1.35 | | **Average(IOIP)=** | 122.6E+6 | |
| 5 | 0.5 | 0.9 | 1.6 | | | | Iteratio |
| 6 | | | | | Upper bound= | | 52.9E+ |
| 7 | | | | | Error less than %= | 2 | 419 |
| 8 | **N/G** | **Saturation** | **Bo** | **IOIP** | | | |
| 9 | fraction | fraction | Res bbl/STB | STB | | | |
| 10 | 0.32 | 0.86 | 1.52 | 111.9E+6 | | | |
| 11 | 0.34 | 0.84 | 1.57 | 96.1E+6 | | | |
| 12 | 0.31 | 0.86 | 1.40 | 116.5E+6 | | | |
| 13 | 0.38 | 0.80 | 1.42 | 98.8E+6 | | | |
| 14 | 0.40 | 0.84 | 1.50 | 127.4E+6 | | | |
| 15 | 0.44 | 0.87 | 1.55 | 114.3E+6 | | | |
| 16 | 0.44 | 0.90 | 1.53 | 141.7E+6 | | | |
| 17 | 0.39 | 0.87 | 1.55 | 114.8E+6 | | | |
| 18 | 0.39 | 0.87 | 1.36 | 105.1E+6 | | | |
| 19 | 0.35 | 0.87 | 1.36 | 115.7E+6 | | | |
| 20 | 0.41 | 0.88 | 1.39 | 165.0E+6 | | | |
| 21 | 0.41 | 0.81 | 1.36 | 150.4E+6 | | | |
| 22 | 0.44 | 0.88 | 1.59 | 120.7E+6 | | | |
| 23 | 0.45 | 0.89 | 1.49 | 131.1E+6 | | | |
| 24 | 0.38 | 0.87 | 1.39 | 146.3E+6 | | | |
| 25 | 0.49 | 0.85 | 1.38 | 182.2E+6 | | | |
| 96 | 0.33 | 0.88 | 1.54 | 90.9E+6 | | | |
| 97 | 0.31 | 0.82 | 1.45 | 76.6E+6 | | | |
| 98 | 0.31 | 0.86 | 1.39 | 93.5E+6 | | | |
| 99 | 0.42 | 0.82 | 1.36 | 124.7E+6 | | | |
| 100 | 0.37 | 0.89 | 1.60 | 111.0E+6 | | | |
| 101 | 0.32 | 0.87 | 1.56 | 111.3E+6 | | | |
| 102 | 0.48 | 0.83 | 1.39 | 164.8E+6 | | | |
| 103 | 0.34 | 0.86 | 1.38 | 133.0E+6 | | | |
| 104 | 0.34 | 0.84 | 1.52 | 106.7E+6 | | | |
| 105 | 0.45 | 0.86 | 1.36 | 160.2E+6 | | | |
| 106 | 0.44 | 0.85 | 1.38 | 144.7E+6 | | | |
| 107 | 0.40 | 0.86 | 1.53 | 105.4E+6 | | | |
| 108 | 0.39 | 0.89 | 1.55 | 113.0E+6 | | | |
| 109 | 0.42 | 0.82 | 1.41 | 114.8E+6 | | | |

100 iteration

with regard to number iterations recommended the will be different discussion

To generate expectation curve

1. sort the IOIP column according to increase value. Determine the range, min, max
2. generate a frequency table
3. generate probability table and PDF
4. generate CPF
5. The plote of CPF is the expectation curve

Now we will do the same with assumption of triangle distribution for the input parameters

Given data, 3000 iterations !

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 1 | **Montecarlo Simulation** | | | | | |
| 2 | *Triangular distribution - Oil reservoir* | | | | | |
| 3 | | | | | *So=(1-Sw)* | |
| 4 | | **Rock Volume** | **Porosity** | **N/G** | **Saturation** | **Bo** |
| 5 | | bbl | - | - | - | Res bbl/STB |
| 6 | Min (a)= | 2.00E+09 | 0.2 | 0.3 | 0.8 | 1.35 |
| 7 | Mode (c)= | 2.15E+09 | 0.24 | 0.41 | 0.87 | 1.4 |
| 8 | Max ( b) | 2.20E+09 | 0.3 | 0.5 | 0.9 | 1.6 |
| 9 | f(c)= | 1.00E-08 | 2.00E+01 | 1.00E+01 | 2.00E+01 | 8.00E+00 |
| 10 | F(c)= | 7.50E-01 | 4.00E-01 | 5.50E-01 | 7.00E-01 | 2.00E-01 |

| | A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| 1 | Montecarlo Simulation | | | | | | |
| 2 | *Triangular distribution - Oil reservoir* | | | | | | |
| 3 | | | | | *So=(1-Sw)* | | |
| 4 | | Rock Volume | Porosity | N/G | Saturation | Bo | |
| 5 | | bbl | - | - | - | Res bbl/STB | |
| 6 | Min (a)= | 2.00E+09 | 0.2 | 0.3 | 0.8 | 1.35 | |
| 7 | Mode (c)= | 2.15E+09 | 0.24 | 0.41 | 0.87 | 1.4 | |
| 8 | Max ( b) | 2.20E+09 | 0.3 | 0.5 | 0.9 | 1.6 | |
| 9 | f(c)= | 1.00E-08 | 2.00E+01 | 1.00E+01 | 2.00E+01 | 8.00E+00 | |
| 10 | F(c)= | 7.50E-01 | 4.00E-01 | 5.50E-01 | 7.00E-01 | 2.00E-01 | |
| 11 | | | | | | | |
| 12 | *Montecarlo simulation:* | | | | | | |
| 13 | index | Rock Volume | Porosity | N/G | Saturation | B0 | IOIP |
| 14 | - | bbl | - | - | - | Res bbl/STB | STB |
| 15 | 1 | 2.09E+09 | 0.2 | 0.4 | 0.9 | 1.55 | 109.8E+6 |
| 16 | 2 | 2.16E+09 | 0.2 | 0.4 | 0.9 | 1.43 | 130.8E+6 |
| 17 | 3 | 2.04E+09 | 0.3 | 0.4 | 0.8 | 1.39 | 122.6E+6 |
| 18 | 4 | 2.06E+09 | 0.2 | 0.4 | 0.8 | 1.46 | 97.2E+6 |
| 2992 | 2978 | 2.15E+09 | 0.2 | 0.4 | 0.9 | 1.43 | 139.4E+6 |
| 2993 | 2979 | 2.04E+09 | 0.3 | 0.4 | 0.9 | 1.39 | 127.4E+6 |
| 2994 | 2980 | 2.16E+09 | 0.2 | 0.4 | 0.9 | 1.55 | 102.1E+6 |
| 2995 | 2981 | 2.10E+09 | 0.3 | 0.4 | 0.9 | 1.49 | 115.3E+6 |
| 2996 | 2982 | 2.04E+09 | 0.3 | 0.4 | 0.9 | 1.39 | 161.0E+6 |
| 2997 | 2983 | 2.12E+09 | 0.2 | 0.5 | 0.9 | 1.40 | 151.0E+6 |
| 2998 | 2984 | 2.18E+09 | 0.3 | 0.4 | 0.9 | 1.49 | 123.4E+6 |
| 2999 | 2985 | 2.11E+09 | 0.2 | 0.4 | 0.9 | 1.41 | 137.6E+6 |
| 3000 | 2986 | 2.10E+09 | 0.2 | 0.4 | 0.9 | 1.44 | 119.2E+6 |

Hoja1 Probability Plot Cum Probability Plot

| *IOIP Montecarlo Parameters* | | | |
|---|---|---|---|
| %Error= | 2 % | | |
| Mean= | 124.8E+6 | →Error= | 2.50E+06 |
| Max= | 176.6E+6 | | |
| Min= | 83.4E+6 | | |
| N iterations= | 2097 | *(iterations required)* | |

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

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

Function X(a, b, c)
U = Rnd()
Fc = (c - a) / (b - a)

If 0 < U < Fc Then
X = a + (U * (b - a) * (c - a)) ^ 0.5
Else
X = b - ((1 - U) * (b - a) * (b - c)) ^ 0.5
End If
End Function
```

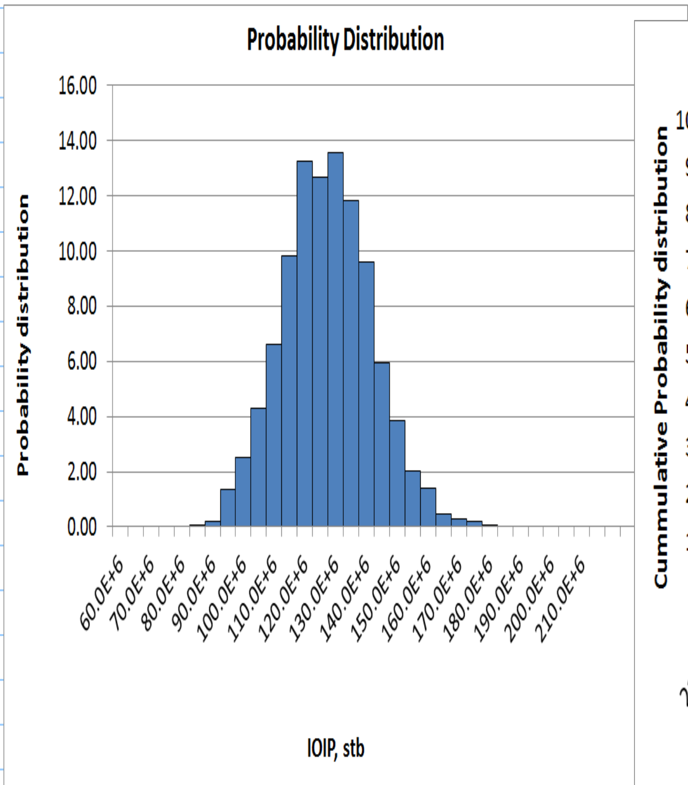
The above IOIP column can be translated to frequency table, PDF, CPF (expectation curve)

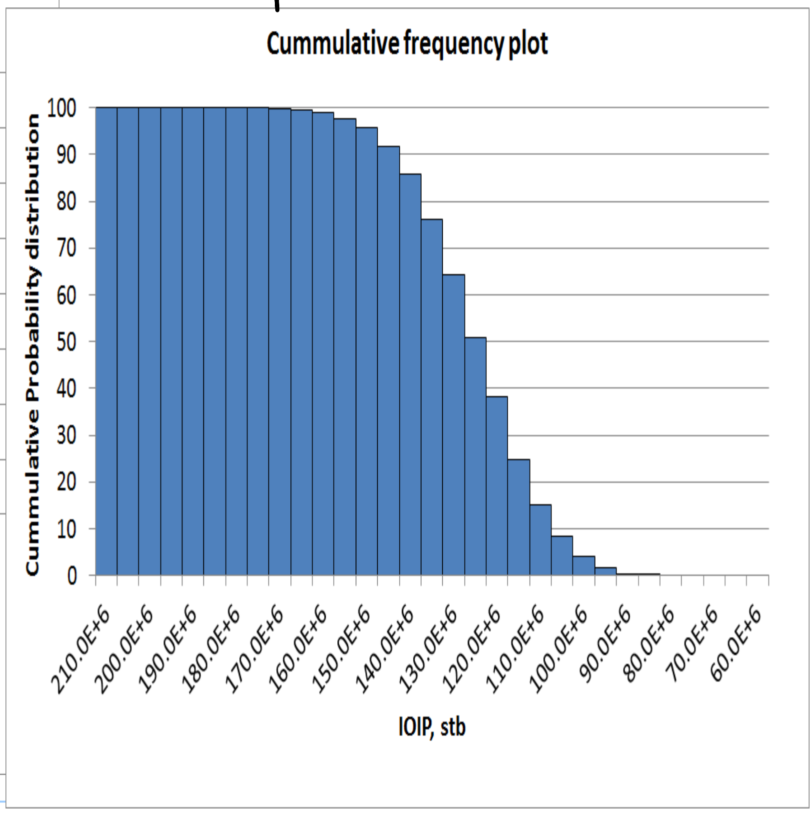
This is done automatically in Excel (Remember the procedure from event table to frequency table?)

*Distributions:*

| IOIP | Probability frequency | Relative probability | Cummulative distribution |
|---|---|---|---|
| 60.0E+6 | 0.00 | 0.00 | 0.00 |
| 65.0E+6 | 0.00 | 0.00 | 0.00 |
| 70.0E+6 | 0.00 | 0.00 | 0.00 |
| 75.0E+6 | 0.00 | 0.00 | 0.00 |
| 80.0E+6 | 0.00 | 0.00 | 0.00 |
| 85.0E+6 | 2.00 | 0.07 | 0.07 |
| 90.0E+6 | 6.00 | 0.20 | 0.27 |
| 95.0E+6 | 41.00 | 1.37 | 1.64 |
| 100.0E+6 | 75.00 | 2.51 | 4.15 |
| 105.0E+6 | 128.00 | 4.29 | 8.44 |
| 110.0E+6 | 198.00 | 6.63 | 15.07 |
| 115.0E+6 | 293.00 | 9.81 | 24.88 |
| 120.0E+6 | 395.00 | 13.23 | 38.11 |
| 125.0E+6 | 379.00 | 12.69 | 50.80 |
| 130.0E+6 | 405.00 | 13.56 | 64.37 |
| 135.0E+6 | 353.00 | 11.82 | 76.19 |
| 140.0E+6 | 287.00 | 9.61 | 85.80 |
| 145.0E+6 | 178.00 | 5.96 | 91.76 |
| 150.0E+6 | 115 | 3.85 | 95.61 |
| 155.0E+6 | 60 | 2.01 | 97.62 |
| 160.0E+6 | 42 | 1.41 | 99.03 |
| 165.0E+6 | 14 | 0.47 | 99.50 |
| 170.0E+6 | 8 | 0.27 | 99.77 |
| 175.0E+6 | 6 | 0.20 | 99.97 |
| 180.0E+6 | 1 | 0.03 | 100.00 |
| 185.0E+6 | 0 | 0.00 | 100.00 |
| 190.0E+6 | 0 | 0.00 | 100.00 |
| 195.0E+6 | 0 | 0.00 | 100.00 |
| 200.0E+6 | 0 | 0.00 | 100.00 |
| 205.0E+6 | 0 | 0.00 | 100.00 |
| 210.0E+6 | 0 | 0.00 | 100.00 |
| 215.0E+6 | 0 | 0.00 | 100.00 |
| 220.0E+6 | 0 | 0.00 | 100.00 |
| 225.0E+6 | 0 | 0.00 | 100.00 |
| 230.0E+6 | 0 | 0.00 | 100.00 |
| $\Sigma n_i=$ | 2986 | | |

If you can do all of that you are quality as a petroleum engineer that can produce values



Comment on the UDF in the triangle distribution

**From a brief web search [redacted] it seems that Rad() in VBA is not volatile function like RAND() in excel and it does not recalculated each time we punch F9. There are all kind of trick to overcome it but it seems complication. Also, there is something about IF that make re-calculation of Rad complicatiod**

**See**

http://www.decisionmodels.com/calcsecretsj.htm

Jesus De Andrada

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

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

Function X(a, b, c)
U = Rnd()
Fc = (c - a) / (b - a)

Application.Volatile (True)
If U < Fc Then
X = a + (U * (b - a) * (c - a)) ^ 0.5
Else
X = b - ((1 - U) * (b - a) * (b - c)) ^ 0.5
End If

End Function
```

## 5.4 Definitions and Rules

| | |
|---|---|
| **Probability** | The extent to which an event is likely to occur measured by the ratio of the number of favorable cases to the whole number of cases possible.[1] Note that the probability used in reserves estimation is a subjective probability, quantifying the likelihood of a predicted outcome. |
| **Probability Density Function (pdf)** | Probability as a function of one or more variables, such as a hydrocarbon volume. |
| **Cumulative Probability Distribution Function (Cdf); Survival Function (Sf)** | To each possible value of a variable, a Cdf (Sf) assigns a probability that the variable does not exceed (does exceed) that value. The "SPE/WPC Petroleum Reserves Definitions" use survival function in the statement: *"If probabilistic methods are used, there should be at least 90% probability that the quantities actually recovered will equal or exceed the estimate."* |
| **Measures of Centrality** | The different measures of centrality defined below coincide only when pdfs are symmetrical. This is seldom the case for reserves. In general, and for most practical purposes, they differ. |
| **Mean, Expectation, or Expected Value** | The mean is also known as the expectation or the expected value. It is the average value over the entire probability range, weighted with the probability of occurrence. $Mean = \sum_{i=1}^{n} x_i \cdot P(x_i) \text{ or } \int x \cdot P(x) \cdot d(x)$ where $x$ = reserve value and $P(x)$ = probability of $x$. The mean is by far the most important measure of centrality. It behaves like a single deterministic measure of reserves in aggregation and would be the number to look for if reserves are to be reflected by a single neutral number with no optimism or conservatism. |
| **Mode, or Most Probable Value** | The mode is another name for the most probable value. It is the reserves quantity where the pdf. has its maximum value. Believing more strongly in this estimate than any other, a deterministic evaluation of reserves with no optimism or conservatism is likely to produce the mode. |
| **Median (also known as P50)** | The value for which the probability that the outcome will be higher is equal to the probability that it will be lower. |
| | **Measures of Dispersion** |
| **Percentiles** | The quantity for which there is a certain probability, quoted as a percentage, that the quantities actually recovered will equal or exceed the estimate. |
| **P90** | The quantity for which there is a 90% probability that the quantities actually recovered will equal or exceed the estimate. In reserves estimation, this is the number quoted as the proven value. |
| **P50, or Median** | The quantity for which there is a 50% probability that the quantities actually recovered will equal or exceed the estimate. |
| **P10** | The quantity for which there is a 10% probability that the quantities actually recovered will equal or exceed the estimate. |
| **Variance** | The variance is calculated by adding the square of the difference between values in the distribution and the mean value and calculating the arithmetic average. $s^2 = \frac{\sum_{i=1}^{n}(x_i - \mu_i)}{n} = \int_a^b (x-\mu)^2 f(x)dx$ where $x$ = reserve,  = mean, and $f(x)$ = pdf. It is convenient to square the differences, as this avoids that positive and negative values cancel. The same effect may be obtained by taking absolute values of the difference, but the mathematical properties of such a measure are not as elegant as those of the variance. |
| **Standard Deviation** | The square root of the variance. |

# Concept Selection
# for
# Deep Water Field Development Planning

By
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At
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Department of Petroleum Engineering and Applied Geophysics
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26.01.2016

## Carrier History: Mahmoud Etemaddar

- 2013-Now: Sevanmarine AS, Senior Naval Architect
- 2009-2013: NTNU, Department of Marine Tech. PhD Candidate
- 2007-2009: IOEC, Head Engineer
- 2005-2007: Fulton Yacht Shipyard, Naval Architect
- 1999-2005: MSc in Offshore Engineering

## Objectives

**The main goal:**
To introduce a methodology for concept selection for offshore deep water fields development.

- Overview of offshore oil field development planning process.
- Main stackholders.
- Main decision drivers.
- Information and data to be generated.
- Sources of uncertainity and methods to handl them.
- Necessary information for concept selection.
- Structured concept selection methodology.
- An example.
- Questions



## Time Table

- **Part I**: Deep Water Field Development Planning (45 min)
- **Part II**: Concept Selection Process(35-40 min)
- **Part III**: Example (35-40 min)

## Why This Topic

- My personal concern.
- Was not touch upon properly during my education.
- One of the main challenges for all operators.
- Interdiciplinary task.

What should you expect after this lecture:

- You will be familiar with concept selection process for deep water offshore oil and gas fields.
- This presentation only give you an introduction.
- You will not be a deep water field developer.



## Classification Offshore Oil and Gas Fields

To reduce the effort to select proper Technology, Strategies, Cost Estimation Methods for field development.

- **Water Depth (production):**
  - Shallow Water: < 420m (Bullwinkle Jacket)
  - Intermediate Water: 420m - 1000m
  - Deep Water: 1000m to 2000m
  - Ultra Deep Water: > 2000m
- **Environment Condition (100-year):**
  - Harsh Environment: 16 < Hs , 25 < WS (Northsea WOS)
  - Moderate Environments: 8 < Hs < 16 , 15 < WS < 25
  - Benign Environment: Hs < 8, WS<15 (West Africa)
- **Reserves Size:**
  - Marginal Reservoirs: Reserves < 75 mmboe
  - Medium Size Reservoirs: 75 < Reserves < 175 mmboe
  - Large Reservoirs: 175 < Reserves < 1500 or larger

**Hs**: Significant Wave Height [m], **WS**: Wind Speed [m/s]

## Classification Offshore Oil and Gas Fields

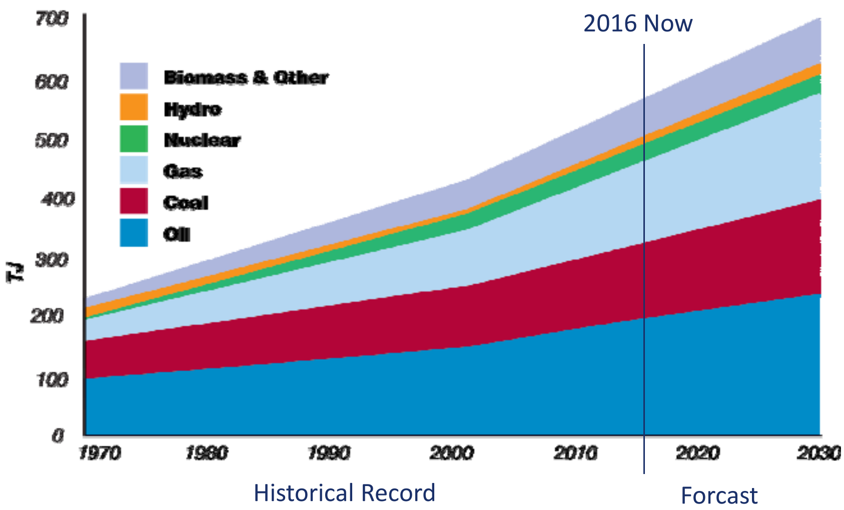
To reduce the effort to select proper Technology, Strategies, Cost Estimation Methods for field development.

- **Hydrocarbon Type:**
- Oil Reservoir
- Gas Reservoir
- Oil and Gas Reservoir
- **Pressure and Temperature:**
- LPLT
- MPMT
- HPHT



## Why Deep Water

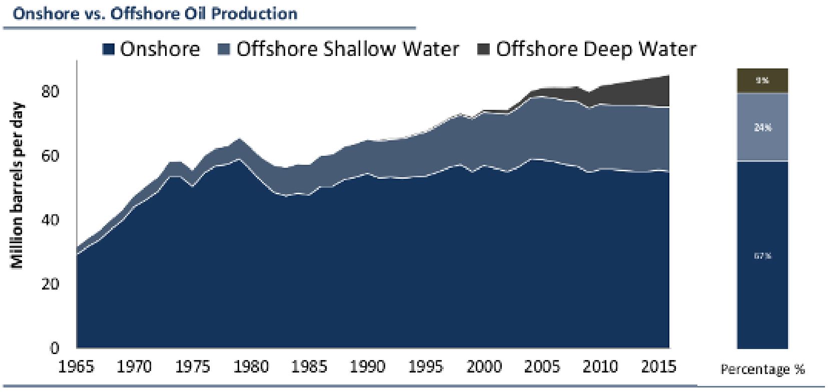
- Global Energy Demand is increasing.
- Oil and gas still make a major contributions.



## Why Deep Water

- Onshore oil production has passed the peak and declining (4%-8% /year).
- Shallow water offshore production is declining.
- Only deepwater (>1000 m) production contribution is increasing :

**From 9% now to 35% in 2030 (forcast)**




*Sources: Infield Systems, BP*



## Why Deep Water

Deep water offshore oil and gas E&P is more challenging !
What makes offshore oil field development different from onshore and shallow water offshore ?

## Why Deep Water

- Technology has been developed for deepwater exploration and production, up to 3000m.
- What still makes the business difficult compare to onshore and shallow waters?
  - Higher capital , drilling and exploration costs.
  - High uncertainities in most of commercial parameters: well performance and recovery and oil price.
  - Substantial risks: remote area, harsh environments, HPHT reservoirs.



## Fundamental Questions to be Considered

When should concept selection process be started ?

What is the required information ?

How should we make a decision based on the available information ?

Who are participating in the concept selection?

## Typical Offshore Oil and Gas Field Life Cycle

Concept selection is a subset of a multi-diciplinary process:
FIELD DEVELOPMENT PLANNING

**Acquire**
- Government
- Size of the block
- Location
- Bidding Process

**Explore**
- Geological Study
- Exploration method
- Exploration tech.
- Location
- Reservoir

**Appraise**
- Dimensions
- Field Life
- Characteristics
- Production rate
- Reserves

**Select**
- Technically Feasible
- Economically Viable
- Revenue
- Investment
- High uncertainty

**Define**
- Engineering

**Execute**
- Procurement
- Construction
- Transportation
- Installation

**Operate**
- Commissioning
- Start -up
- O & M
- Safety

**Abandon**
- Remove: Environment
- Reuse: Commercial benefits.

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## Importance of Field Deveopment Planning

- First FPU 1986 : Green Canyon 29 Semi-Submersible
- 1986 – 1999: 12 FPU were sanctioned (Spar, Semi-sub and TLP) by **major** operators.
- 2000 – 2001: Boom in using FPU, 14 FPU in GOM (11xDryTree+3xWet Tree) **independent** operators came to the game.
- 2000- 2005: 13 FPU were sanctioned in GOM (10xDryTree+3xWet Tree)

Reason for acceleration:

High price of oil and gas.
Lack of oil and gas for US and UK 1970s.
Relatively low Upsream capital cost.

High competition for acquiring the new leases and increasing the production.

Move the operators towards faster and cheaper solusions.

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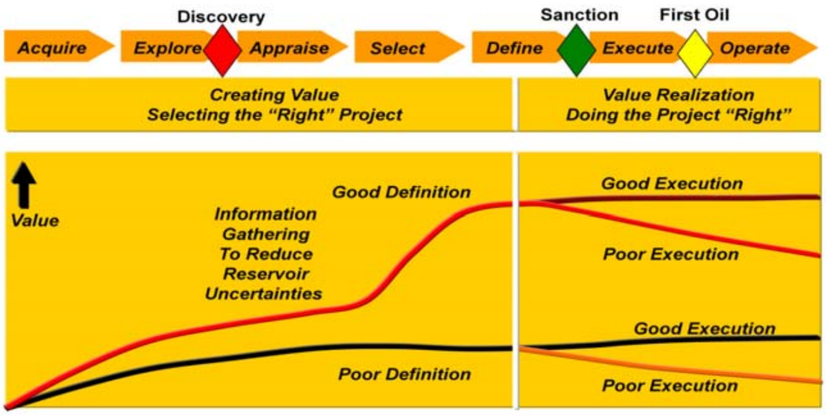
## Importance of Field Deveopment Planning

- An assessment of existing projects (2005) revealed that a significant percentage of deep water offshore oil and gas reserves were underperformed technically and commercially, due to *poorly executed field development planning*.
- The reason was operators intention for faster and cheaper developments.

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## Objective of Field Development Planning

- The main objective of field development planning is the selection of plan that satisfies an operator's commercial, strategic and risk requirements, subjected to regional and site constraints. The main objective is to maximize the revenue for a given investment.

UI = NPV/NPI

PLAN


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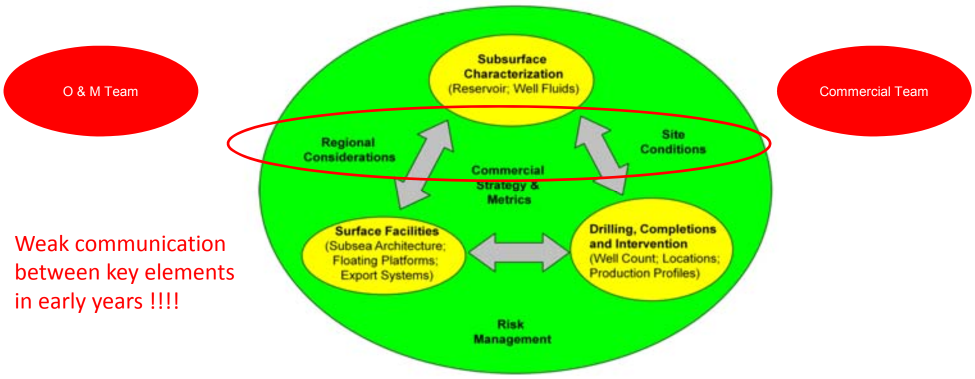
## Key Elements in FDP

- This requires continuous and effective collaboration and alignment amongst main stakeholders: Subsurface, Well Construction, Surface Facility, Operation and Commercial Teams.

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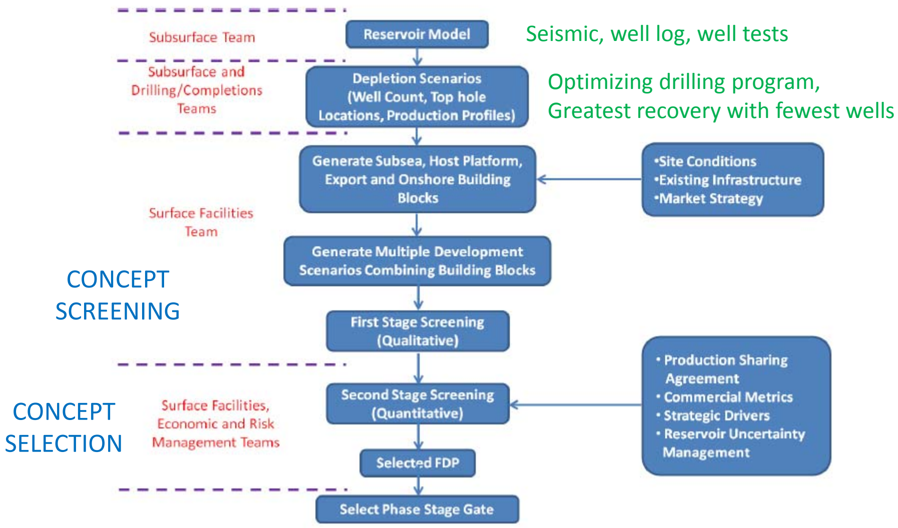
## Overview of Methodology for Concept Selection

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## Main Input Parameters and Their Effects

A. Reservoir Geometry and Geology (greatest impact)
   - Recovery factor and flow rates.
   - Well count, location and construction.
   - Secondary recovery methods.

B. Fluid Properties
   - Subsea and topside design.
   - Operation and maintenance( hydrate, wax and deposits, corrosion).

C. Drilling and Completion
   - Well management and well intervention frequency.

D. Regional Considerations and Regulations: block size, infrastructure, contract.

E. Site Characteristics: water depth, metocean condition, bathymetry.

F. Operator Strategy: type of the operator company.



## Main Input Parameters and Their Effects

Relative importance of the parameters: Reservoir Geology and Geometry.

| Key Reservoir Properties | Units | Impact on Key Field Development Components | | | |
|---|---|---|---|---|---|
| | | Well Construction | Well Completion (Rate & Recovery) | Well Count | Secondary Recovery (Injection, Boosting) |
| **Rock Properties** | | | | | |
| **Permeability** | md | Low | High | Low | High |
| **Porosity** | % | Low | Med | Low | High |
| **Productivity Index** | psi/bpd/ft | Low | High | Low | High |
| **Geometry & Stratigraphy** | | | | | |
| **Thick Overlaying Salt Diapir** | ft | High | Low | Low | Low |
| **Single or Stacked** | | Med | High | Med | Low |
| **Payzone Thickness** | ft | Low | High | High | Med |
| **Depth to Payzone** | ft below mudline | High | High | Low | High |
| **Areal Extent** | Sq. miles. | Med | Med | High | Low |
| **Connectivity** | | Med | Med | High | Low |

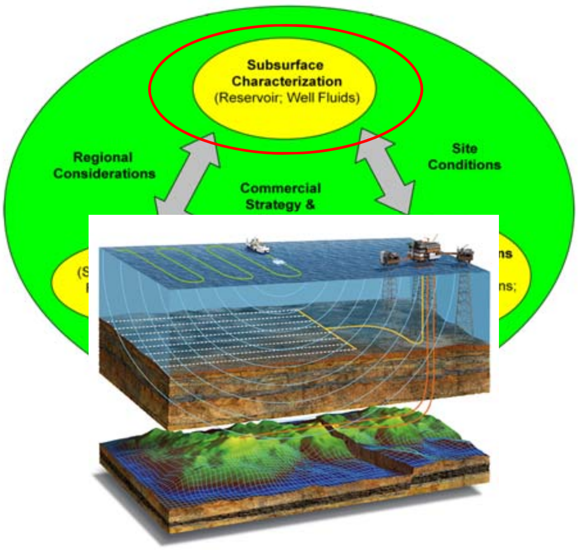
## Main Input Parameters and Their Effects

Relative importance of the parameters: Fluid Characteristics.

| Key Reservoir Fluid Parameters | Units | Estimated Range of Values | Impact on Key Field Development Components | | | |
|---|---|---|---|---|---|---|
| | | | Process | Flow Assurance | Secondary Recovery | Subsea, Flowlines, Risers |
| Low API Gravity | ° | < 20° | High | Med | Low | Low |
| High Viscosity | cp | > 100 cp | Med | High | Med | Low |
| Low Shut-in Pressure | psi | < 5000 psi | Med | High | High | Low |
| High Shut-in Pressure | psi | > 15,000 psi | Low | Low | Low | High |
| Low Temperature | °F | < 150°F | Med | Med | High | Low |
| High Temperature | °F | > 250°F (or 300 °F) | Med | Low | Med | High |
| Low GOR | scf/stb | < 500 scf/stb | Low | Med | Med | Low |
| High GOR | scf/stb | > 2,000 scf/stb | Med | Low | Med | Low |
| High $CO_2$, $H_2S$, Chlorides | ppm | 20,000ppm; 100 ppm; 100,000 ppm | High | Low | Med | High |
| High Asphaltenes | % | CII > 1 | Med | Med | Med | Low |
| High Wax Appearance Temperature | °F | > 95°F | Med | Med | Med | Low |

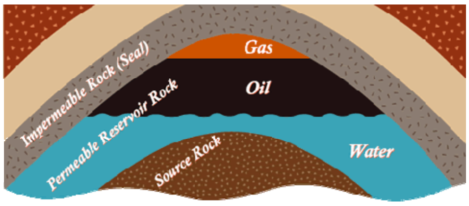


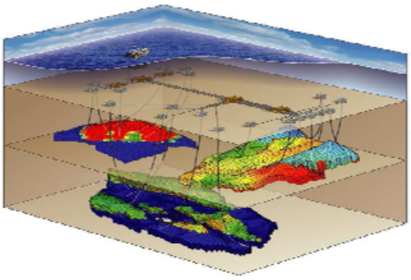
## Subsurface Team



## Field Development Phases: Oil and Gas Reservoir

- An oil and gas reservoir is characterised by:
  - Geometry: areal extend, dimensions and connectivity .
  - Rock properties: lithology, porosity and permeability.
  - Hydrocarbon type and saturations.
  - Oil-Water and Oil-Gas contact lines.
  - Fluid physical properties: API, GOR, WOR, Pressure, Temp.
  - Fluid system and chemical compositions.
  - Driving mechanisms: recovery factor and recovery methods
  - Flow rate and pressure variation over time



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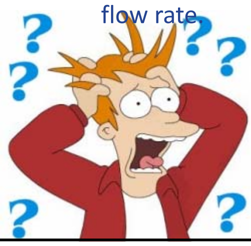
## Field Development Phases: Exploration

- The first step after acquiring the lease.
- **Goal:** The goal is to find an economic oil and gas reserves.
- **Task:** Suitable locations for exploration drilling and TD.
- **Activity:** Wildcat drilling, setp-out drilling and measurements.
- **Exploration Team:** Geologists, geophysicists, drilling engineers, reservoir engineers, mud loggers
- **Exploration Methods:** Satellite Survey, gravitymeter, magnetometer and Seismic (*horizontal resolution*), exploration drilling, MWD, LWD (well loging), core samples (*vertical resolution*), well testing (DST, WLFT, IPT).
- Initial reservoir model is prepared for development: reservoir geometry, rock properties, fluid characteristics, reservoir pressure and flow rate.



Big Question ?
Is it an economical oil and gas reservoir ?
($ 10-100 mUSD answer)
Substantial uncertainty in the measurements and reservoir information.

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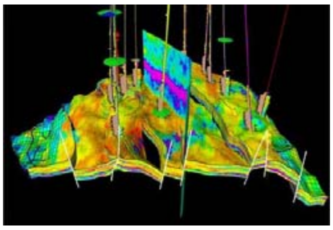
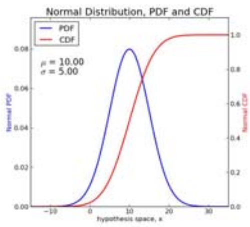
## Field Development Phases: Appraisal

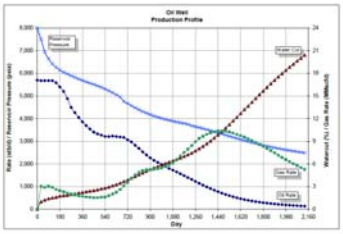
- **Goal:** Improving the quality of the data and reducing uncertainty.
- **Outcome:** Well fluid characteristics, OOIP, Recoverable oil, production profile, with sufficient uncertainty.
- **Method:** More appraisal wells will be drilled, more measurements.
- **Subsurface Team:** provide robust model of a reservoir from seismic data, appraisal wells and well logs and well tests.
- **Tools**: Multiple simulation with varying well count and location and type, tuning PDF for stochastic parameters.



Reservoir Model




Tuning PDF - CDF

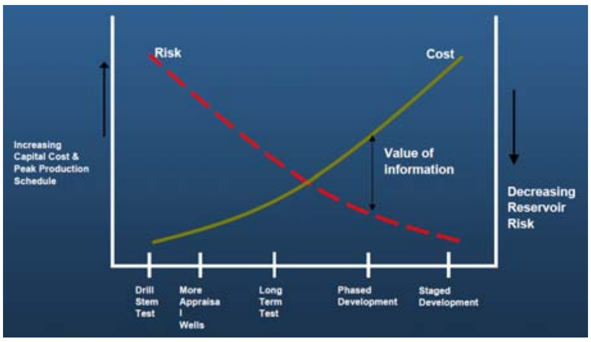


Production & Pressure



## Field Development Phases: Appraisal

- There are several methods and strategies to reduce uncertainty.
- There is a trade off between capital cost and uncertainty.
- Methods:
  - Drill stem test.
  - More appraisal wells.
  - Extended well test.
  - Early production.
  - Staged development.
- Application Depends on:
  - ✓ Reservoir size and Char.
  - ✓ Operator Strategy
  - ✓ Available Technology.



## Field Development Phases: Appraisal

Comparison of methods:

| Strategy | Description | Duration (months) | Pros | Cons | Examples |
|---|---|---|---|---|---|
| Drill Stem Test | Single Well producing to MODU, gas flared | 1-2 per well | • Relatively low cost (\$100M - \$150M per well);<br>• MODU can be used for testing. | • Some (but insufficient) well performance data<br>• Limited well connectivity data | Jack (Lower Tertiary, GOM) |
| More Appraisal Wells and Sidetracks | Drill additional appraisal wells to define extent and connectivity of reservoir | 6-12 per well | • Some wells designed as keepers<br>• More reservoir data and improved reservoir model | • Increased cycle time to sanction<br>• Limited well performance data | |
| Extended Well Test | Single well producing to production platform | 6-12 | • Improved confidence in well performance and recovery<br>• Better definition of reservoir connectivity | • 18-24 months to mobilize production platform<br>• Capex in \$400M - \$600M range | Roncador (Campos Basin, Brazil) |
| Phased Development (Early Production System) | Multiple wells producing to mobile production platform; gas exported or injected | 36-60+ | • Significant reduction in well performance and reservoir connectivity risk;<br>• Test enabling technologies and completions;<br>• Optimize full field development plan to capture reservoir upside. | • Significant Capex (\$1B \$3B) outlay<br>• 36+ months to mobilize platform | Cascade & Chinook (Lower Tertiary, GOM) |
| Staged Development | Bring wells online to a production platform in stages | Life of field | • Flexibility to capture reservoir upside<br>• Maximize reservoir recovery | • Largest Capital investment and longest schedule to peak production among all options | Perdido (Lower Tertiary, GOM) |



## A Glance to the Mathematics

- Original oil in Place (OOIP) Volumetric Method

$$OOIP = 7758 \times A \times h \times \theta \times OS / FVFo$$
$$Ga = OOIP \times GOR$$

A: Areal Extent (Seismic, drilling, reservoir modeling)
h: Net pay (Seismic, drilling, reservoir modeling)
$\theta$: Porosity (well log, core sampling)
os: Oil Saturation (well test)
FVFo: Oil Formation Volume Factor

$$OGIP = 43560 \times A \times h \times \theta \times OS / FVFg$$

These parameters are *stochastic time varying* parameters.

## A Glance to the Mathematics

- Oil Production Rate:

$$Q=7.08 \times K \times h \times (Pe-Pw) / MuxBxln(Re-Rw)$$

- Q:  Oil Flow Rate (bopd)
- h: Net pay (Seismic, drilling, reservoir modeling)
- K: oil effective permeability
- Pe: Formation Pressure
- Pw: Well bore pressure
- Mu: Viscosity
- B: Formation Volume Factor
- Re: Drainage radius
- Rw: Well bore pressure

- Well test and curve fitting (simple models)
  - Exponential
  - Harmonic
  - Hyperbolic

- Sophisticated models: Reservoir model and energy balance methods



## Integration of All Uncertainties

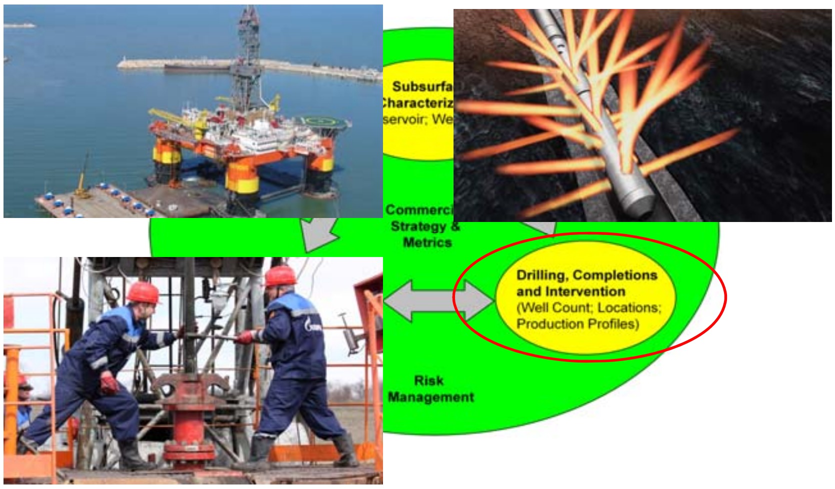
It is difficult to make a decision on multi-variable stochastic problems.

As suggested by SPE (Society of Petroleum Engineers):
For financial evaluation, uncertainty  in all parameters should be integrated into production profile :

- Production profiles are calculated for three different confidence level:
  - Proven: 90%
  - Probable: 50%
  - Possible: 10%

Field development will be based on one of these three values depending on strategy and commercial risk of the operator.
Typicaly 50% will be used.

## Drilling, Completions and Intervention Team






## Well Construction and Intervention.

- Well Construction:
  - **Construction:** Location, depth and direction, well casing.
  - **Type of the well:** production, water or gas injection.
  - **Type of completion:** Perforation zone and sequence, perforation method.
  - **Main Decision:** DVA or nonDVA

  Direct effect on productivity and frequency of well intervention. (Operation Costs)

- Well Intervention and Workover:
  - **Options:** From production platform or Workover unit (MODU)
  - Depends on well type, construction and reservoir properties.
  - **Typical services:** (Heavy to light) Casing repair, Recompletion, Replacement of downhole boosting pump, logging

## Well Construction and Intervention.

During operation:
- Well have to be periodically re-entered for reservoir management, remediation and recompletion.

Sand Production

Well Cleanup

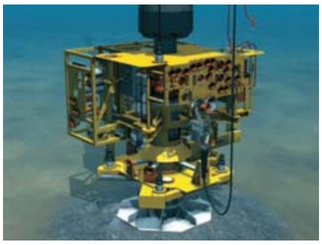
Re-Perforation



## Well Construction and Intervention.

- Main decision is well type and access: (location of X-mas tree)
  - Subsea well (wet tree) with DVA or non DVA
  - Surface well (dry tree) with DVA

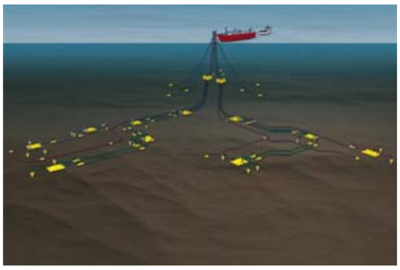
Dry Tree



Wet Tree

## Well Construction and Intervention.

- Wet Tree or Subsea Well :
  - ➢ Lower CAPEX but higher OPEX
  - ➢ Lower Recovery (5%-10% lower than dry tree)
  - ➢ Low pressure reservoir.
  - ➢ Greater flexibility for well placements and field architecture.
  - ➢ Suitable for high uncertainty reservoir and multiple sub-economic reservoirs development.
  - ➢ All host units support wet tree.
  - ➢ DVA and nonDVA are possible.



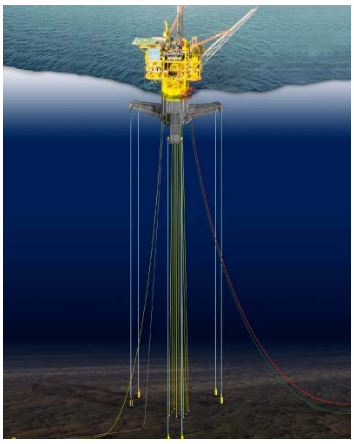


## Well Construction and Intervention.

Dry Tree or Surface well:

- ➢ Higher CAPEX but lower OPEX.
- ➢ Higher Recovery
- ➢ High pressure reservoir
- ➢ Only Fixed platform, TLP, SPAR
- ➢ Only DVA

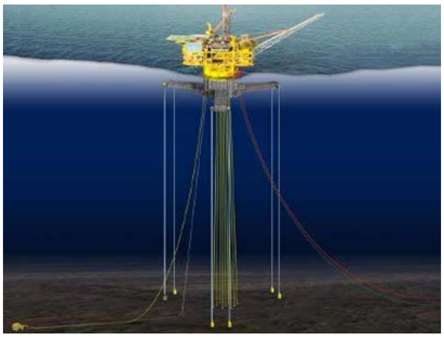
- Dry tree requires direct access to the well and Top Tension Risre.
- Full drilling package on FPU requires Dry Tree
- Requirements for full drilling package depends on the size of the reservoir and number of the wells: (GOM, 170 mmboe, 12 wells)



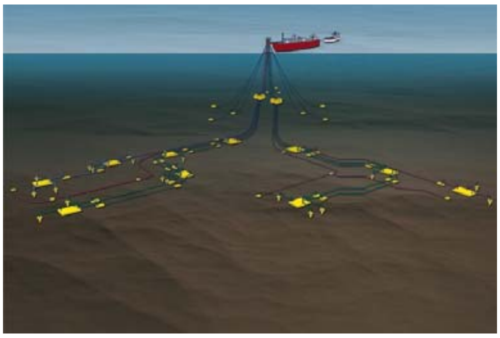
A TLP with Dry Tree System
Central well cluster

## Well Construction and Intervention.

- Selection depends on areal extend and complexity of the reservoir.
  - Small and compact reservoir: Surface tree with central well cluster architecture.
  - Stacked, highly faulted and arealy extended reservoirs: subsea tree with satellit well architecture tieback to the manifold.



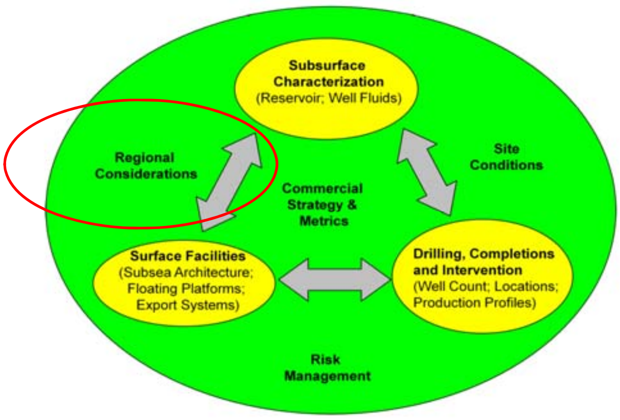
small and compact reservoir



FPSO with satellit well architecture
stacked, faulted, arealy extended reservoir



## Regional Considerations



## Regional Considerations

Have a significant impact on the NPV and FDP process.

- **Block size:** 10 sq. mile to 230 sq. Miles: development strategies
- **Infrastructures:** Pipeline, and development in the area and available production units.
- **Market Influence:** Availability of vendors and engineering companies, construction yards. Tide market (2000-2001) increases the development costs and schedule
- **Local contents:** Effect on local economy, job, industry
- **Regulations:** Host country dictates the terms and conditions, Flag type (Johns Acts), single hull, double hull, flaring of gas, distance to the market, HSE regulations.
- **Contract terms and conditions with host country:** Type of contract, Production sharing contract, concession contract, service contract: Risk to the operator, capital cost recovery, taxes and royalities.
- **Sustainable Developments:** Authorities prefer concepts which provides greater economical benefits and lower environmental impacts.

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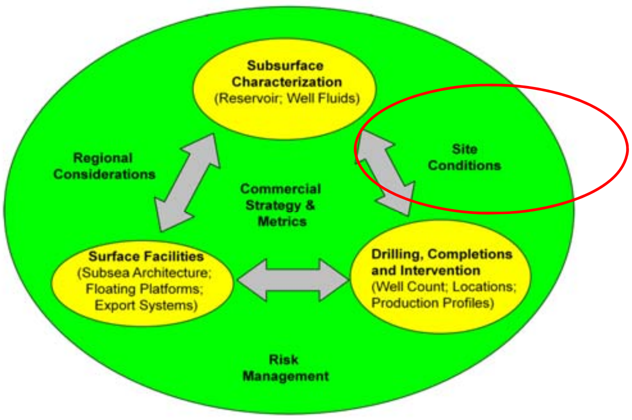
## Site Characteristics and Conditions

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## Site Characteristics and Conditions

Field architecture and floating platform are highly influenced by:

- **Water Depth:** drilling costs, design and installation of risers and mooring systems and pipeline, temperature at seabed and flow assurance.
- **Bathymetry and Geology:** Subsea flowline installation costs, anchor design
- **Metocean Condition:** Installation window, cost of facilities
- **Remoteness:** increases cost and risk of installation, favors the concepts with minimize offshore installation and operation, multiple reservoirs with single hub platform

These data should be provided prior to undertaking the facility development plan.



## Operator Strategies

- Strategies of the operator depends on the type and size of the operator company.
- Type of the oil companies:
  - **Independent Oil Companies:** Premier-Oil, VNG Norge.
  - **International Oil Companies:** Shell, EXON, BP, SLB
  - **National Oil Companies:** NIOC, Petrobras, Statoil

- Operator positions for trade-off pairs:
  - CAPEX vs OPEX
  - Standardization vs Improvement
  - Proven Technology vs Innovative Technology
  - Min Capacity vs Future Capacity

## Operator Strategies

- Independent Oil Companies:
  - 15% of deep water offshore production
  - Focus on small to medium size fields (75-175 MMBOE)
  - Join with other operators to share the risk.
  - Prefer leasing strategy over owning &
    tieback over self production facility.
  - Short development cycle time.
  - Small engineering teams with fast tracks.
  - First user of new technologies, more flexible towards vendors.
  - Subsurface is the largest team.
  - Confidentiality is high.



## Operator Strategies

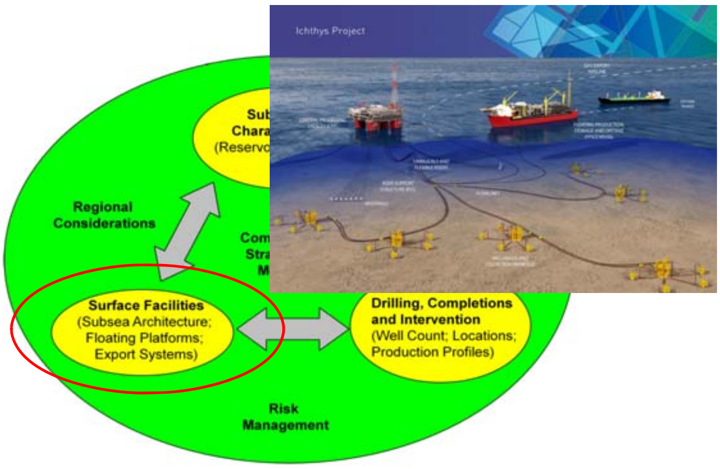
- International or Integrated Oil Companies:
  - 50% of deep water offshore production
  - Focus on medium to large size fields (>175 MMBOE)
  - Using their own technology as long as possible.
  - More process driven stage gates which increases
    development cycle time to first oil.
  - Prefer to use proven technology.
  - Standardized technology, less flexible towards vendors.

## Operator Strategies

- National Oil Companies:
  - 35% of deep water offshore production.
  - Focus on global development plan and basin development rather than block development.
  - Phased development strategy.
  - Early production users to reduce uncertainty.
  - Higher risk margins.
  - Exploration results can be publicly available.



## Surface Facility Team



## Concept Screening & Concept Selection Process

A Review:
Concept selection is a subset of field development planning.
Exploration and appraisal phases provide required information for concept selection.
Success of concept selection phase highly depends on the quality of the data provided in the previous phases.

**Subsurface, Drilling and Completion Team:**
Multiple depletion senarios:
- Well count, locations and type.
- Drilling and workover and well intervention.
- Production Profile.
- Fluid composition
- Recovery Methods.
- Dry tree or Wet tree
- Well intervention, methods and frequency
- Drilling requirements during production

**Surface Facility Team:**
Corresponding development senarios:
- Field Subsea Architectures
- Host units: Hull type, mooring and risers
- Workover and Well intervention package.
- Exporting methods.

**Commercial and Management Team:**
- NPV
- NPI
- Risk Assessment

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## Concept Screening & Concept Selection Process

Overal differences ?

| | Concept Screening | Concept Selection |
|---|---|---|
| Definition | Primary Systems | Basic Design (Pre-FEED) |
| Cost Estimation | Class 5 | Class 4 |
| Risk Assessment | Optional | Mandatory |
| Qualitative Ranking | Attribute level | Sub-attribute |
| Stochastic Analysis | Mandatory | Optional |

Simmilar process, different in the accuracy and level of implementation.

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## Concept Screening and Study

Facility Framing Workshop with representatives from all stakeholders present early in the selected phase.

The purpose of this workshope is:
- To establish the objectives of the project.
- Strategies to reach this objectives.
- Establish Design Basis and Functional Requirements
- Generate Concept Development Matrix
- Generate Development Scenarios (10-80)
- Develop decision drivers and ranking methodology



## Concept Screening & Concept Selection Process

Main Steps:
Input: Field depletion scenarios

1. Establish basis of design and functional requirements.
2. Establish ranking criteria and methodology.
3. Identify building blocks from proven technologies.
4. **Concept Screening:** 1st stage definition, Combining building blocks to generate different development scenarios. (10 – 80 scenarios) ranking and comparing different scenarios (5-10): Qualitative and quantitative
5. **Concept Selection:** 2nd stage definition, ranking and comparison (5-10)
6. Use tie-breakers and operator strategy for final decision (if more than 1)
7. International benchmarking
8. Concept definition.

## Concept Screening & Concept Selection Process

It is a two steps process

- Concept Screening:
  - ✓ To identify all possible solutions (80)
  - ✓ Technically feasible
  - ✓ Economically viable: Rough cost estimation (cost class 5)
  - ✓ Reduce the number of scenarios to 5-10 for concept selection
  - ✓ Identify the optimum number of wells (for marginal fields)

- Concept Selection:
  - ✓ Main objective: Maximizing the profit.
  - ✓ Select the best concept.
  - ✓ More accurate cost estimation and assessment is required.



## Design Basis Documents

In the early concept screening.
Provides the framework and the constraint within which the development team must operate.
As a minimum it should include:

- **Reservoir characteristics and depletion plan:** well count and seabed locations, fluid properties, production profiles, enhanced recovery, reservoir management. (Well count may be fixed or not, size and uncertainty of the reservoir)
- **Drilling and Completion:** Well location, Rig specification, Durations, workover type and frequencies.
- **Site and regional conditions:** Water depth, metocean data, seabed bathymetry and geohazards, infrastructure and logestics, local content requirements.

## Functional Requirements

- Processing: Deck space and payload sensitivity
- Storage and Export: Hull and Geometry
- Well Access: Motion
- Drilling and Workover: Motion and Deck Space
- Enhanced Recovery



## Ranking Strategies and Methods

Ranking Methodology and Strategy can be categorized:

- Quantitative or Qualitative
- Deterministic or Stochastic assessment
- Cost estimation accuracy and class

- Qualitative Ranking :
  - Uncountable parameters: operability, constructability, installation ease
  - Less accuracy is required.
  - Technical issues.

- Quantitative Ranking:
  - Countable parameters: cost, time and schedule
  - More accuracy is required

## Ranking Strategies and Methods

**Economic Factors** (significant number of parameters but summerized by):

- NPV : (cash inflow-cash outflow, discount rate) Production Profile, Field Life, Sale Price
- NPI : CAPEX, DRILEX (# well), OPEX, ABEX
- UI=NPV/NPI
- Stochastic analysis is required in early stage due to uncertainty

AACE issued International Recommendation Practices on Estimate Classification:

- Cost Class 5: Concept screening and study, cost dispersion +100% to -50%
- Cost Class 4: Concept Selection, cost dispersion +50% to -25%

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## Ranking Strategies and Methods

**Noneconomic factors** that drives an operator's decision:

- Construction Period
- Operability
- Fabrication
- Reliability
- Risk Assessment

Qualitative or Semi-Quantitative Parameters

Can be evaluated into two levels:

- Attributes: Concept screening
- Sub-Attributes: Concept Selection

General Decision Drivers:

- Minimizing technical risk.
- Maximizing hydrocarbon recovery.
- Constructability.
- Schedule to first oil. (expected execution and installation period)
- Expandability: Flexibility for future expansion.
- Flexiblity to adapt to reservoir uncertainity.

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## Concept Screening and Study

Concept Definition for Concept Screening:
Objective is to define all surface facility components to a level sufficient for class 5 (-50% to 100%) capex, opex and schedule estimation.

- Use available commercial (OGM) or inhouse databases:
- Typical required inputs are:
  1. Basic subsea equipments: flowlines, manifold, Ch. Tree, risers
  2. Number of wells, Production profiles, Hydrocarbon sale price
  3. Basic topside components and capacities
  4. Type of host unit and required displacement

Step 2: Calculate NPV and NPI
Step 3: Compare different concepts based on UI as a function of NPV. (No. Wells)
Step 4: Choose the concepts which pass NPV and UI threshould.



## Concept Selection

Concept Definition for Concept Selection:
Objective is to define all surface facility components to a level sufficient for class 4 (+50% to -25%), capex opex and schedule estimation.

- Size flowlines, risers and pipelines and determine arrival condition by simple flow assurance simulation.
- Specify the topside, drilling and workover equipments and make an initial layout by process simulation, PFD, P&ID.
- Make initial sizing of the hull to support topside, riser, mooring weight.
- Performe stability and motion analysis to ensure operability and survivability in extreme conditions to design mooring and riser system.
- Make an execution plan for design, fabrication, integration, transportation, installation and commisioning to estimate capex and schedule.
- Cost and schedule estimation, Compare and rank scenarios.
- Risk assessment.
- Validate by benchmarking against similar projects.

## Risk Assessment

A relative risk assessment will be performed including:
- Technical
- Execution
- Operational
- Safety
- Commercial risks



## Tie Breakers

When economic and performance indications of two concepts are indistinguishable an operatore's tie breaker will be used:

**HSE:** Concepts with larger deck, gives greater separation between hazardus and non-hazardus areas

**Flexibility:** Scenarios provide more felexibility, both for contracting and to adapt to the reservoir uncertainity are prefered.

**Mobility:** Ease of decommissioning and relocation to other fields

## Building Blocks

Building Bloks:
A deep water facility development scenario can be constructed from the following building blocks:

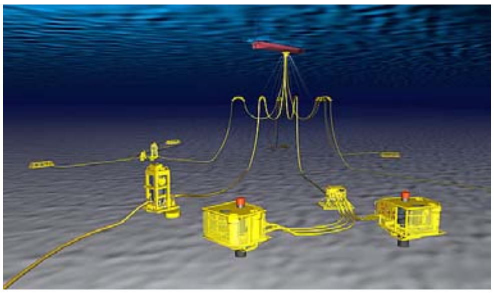
| Subsea Production | Enhanced Recovery | Drilling Platform | Host Production Platform | Export System | Onshore Facility |
|---|---|---|---|---|---|
| •Single well tieback<br>•Cluster well manifold with dual flowline tieback | •Mudline Separation and ESPs<br>•Multiphase Pumps<br>•Subsea Gas Compression<br>•Gas Lift<br>•Gas Injection<br>•Water Injection | •Mobile Offshore Drilling Unit<br>•Tender Assist Wellhead Spar<br>•Full drilling wellhead Spar<br>•Tender assist wellhead TLP<br>•Full drilling wellhead TLP | •Dry Tree Spar with Drilling<br>•Dry Tree Spar with Workover<br>•Wet Tree Spar<br>•Dry Tree TLP with Drilling<br>•Dry Tree TLP with Workover<br>•Wet Tree TLP<br>•Shipshape FPSO<br>•Cylindrical FPSO<br>•Production Semisub<br>•Production/ Drilling Semisub<br>•FLNG<br>•Existing Host<br>•Fixed Platform | •Oil Pipeline<br>•Gas Pipeline<br>•Oil shuttle tanker<br>•LNG shuttle Tanker<br>•FSO with Oil Shuttle | •Oil Tank Farm / Terminal<br>•Gas Processing Plant<br>•Gas to Liquids Plant<br>•Gas to Power Plant<br>•LNG Plant |

Subsea Systems + Enhanced Recovery + Drilling Platforms
\+ Production Platforms + Export Systems + Onshore Facilities
= Facility Development Options



## Building Blocks: Subsea Systems

A subsea systems consists of an assemblage of:
- Trees and wellheads, Manifolds, Jumpers
- Umblicals and Flowlines
- Pipeline End Termination

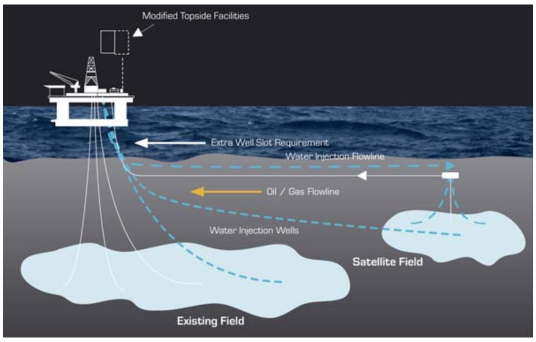


Basic Building Bloks:
1. Single well tieback
2. Multiple wells manifolded tieback

Subsea Architecture is driven by
- Number of wells
- Location of wells
- Distance to host unit
- Subsea bathymetry
- Fluid properties to determine the flow line dimention.
- Arrival production rate, temperature and pressure at PLEM.

## Building Blocks: Enhanced Recovery

Basic building blocks:
- Downhole boosting.
- Gas lift
- Gas injection
- Water injection



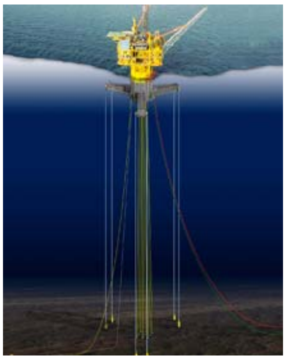

Secondary and enhanced (tertiary) recovery methods.
- Steam flooding
- Fire floodin
- Chemical injection
- Polymer injection



## Building Blocks: Drilling Platforms

Depend on the size of the reservoir and type and distanceof the well.

Basic Building Blocks:
•Tender assissted drilling
• MODU
• Permanent Drilling Platform.



Satellite well system with subsea well. MODU or drill ship.

Single drill center and Surface well. Tender assissted or Drilling Platform.

## Building Blocks: Drilling Platforms

MODU

Amirkabir

wet Tree
satellite Well
heavy workover

Tender Assissted Drilling

West Alliance TLP

dry Tree
well Cluster
heavy workover
payload limit

Full Drilling Package

TLP Mars GOM

dry tree
well cluster
drilling and
workover

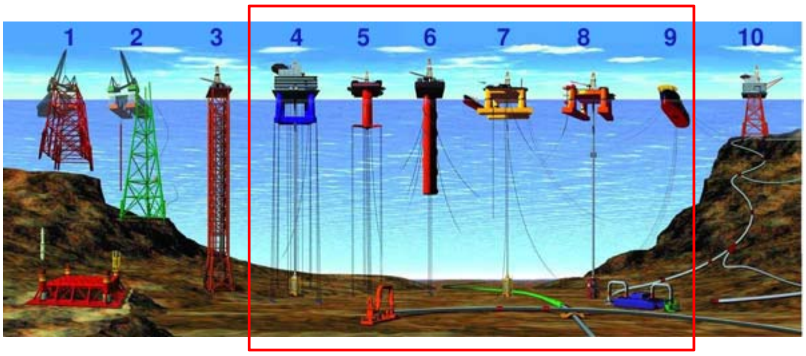


## Building Blocks: Drilling Platforms

Guideline for early decision on Key Platform Functions

| Reservoir | Drill Centers | Wet or Dry Tree Development | Drilling, Workover or Production Rig |
|---|---|---|---|
| Small | Single | Wet | Production |
| Medium, stacked or compact | Single | Dry | Workover |
| Large, staked or compact | Single | Dry | Drilling |
| Large, areal extensive | Multiple | Wet | Production |
| Multiple, sub-economic | Multiple | Wet | Production |

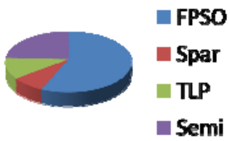
## Building Blocks: Host Platforms




Consists of:

- Topsides.
- Hull.
- Station-keeping system.
- Riserer system.

Host platform:
With drilling and workover
With only workover
Without drilling and workover

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## Building Blocks: Host Platforms

Fundamental differences between the floating platform:

- Drilling and Workover Capacities
- DryTree or WetTree Support
- Storage Capacity
- Scalability to water depth and payloads
- Heave and Pitch motions.
- Execution risks: Construction, Installation and Operation, Abondenment and Reuse.

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## Building Blocks: Host Platforms

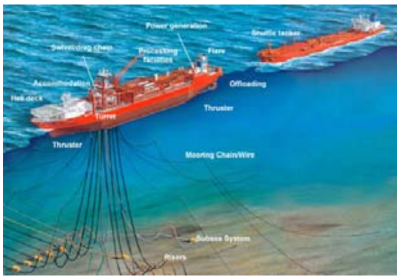
| | | Spar | TLP | Semisubmersible | FPSO |
|---|---|---|---|---|---|
| Variants | | Classic, Truss or Cell | Classic, Extended, MOSES or Sea-star | Conventional or Deep-draft | Shipshaped or cylindrical |
| Functionality | | Dry/Wet Trees; Surface BOP drilling, completion, intervention | Dry/Wet Trees; Surface BOP drilling, completion, intervention | Wet Trees; Subsea BOP drilling, completion, intervention | Wet Trees; Subsea BOP drilling possible in mild conditions; Integrated oil storage |
| Constraints | Water Depth | Dual Barrier HP production riser to 5000 ft | Tendons to about 5000 ft. | Limited envelope of SCR applicability | Tower or wave risers required |
| | Topside Payload | < 20,000 tons dry weight | None | None | None |
| Offshore Installation, Integration, Commissioning | | Complex offshore operations; high execution risk | Relatively complex offshore operations; moderate execution risk | Relatively simple offshore operations; low execution risk | Simple offshore operations; low execution risk |
| Decommissioning, Relocation and Expansion Flexibility | | Difficult and costly | Difficult and costly | Simple | Simple |



## Building Blocks: Export Systems

Export methods depends on:

- Distance to the market.
- Distance to the available infrastructures: pipeline.
- Storage capacity of host platform.
- Field life and neighbouring fields.




Possible methods:

- Oil and Gas Pipeline .
- Direct shuttle tanker offloading (no onsite storage)
- Shuttle tanker offloading  (with FSU or FPSO)
- LNG carrier (FLNG)

## Building Blocks: Onshore Facilities

- Tank farm and Loading terminal.
- LNG Plant.
- Gas to liquid plant.
- Gas to wire plant.



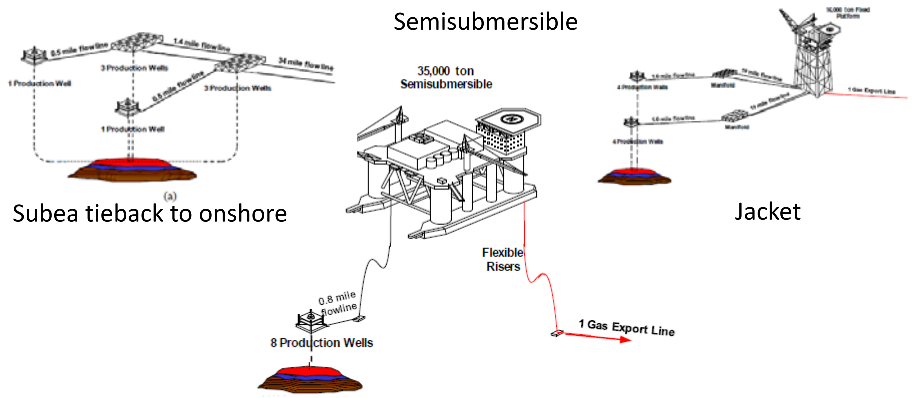
## Example: Concept Screening

Case Study: A gas field
After exploration and appraisal
Initial number of scenarioes: 1x4x4x2X4 = 128

| Field Development Concept Matrix | | | | |
|---|---|---|---|---|
| Hydrocarbon | Hub | Well Type | Transport | # Wells |
| Gas | Submersible | Vertical | Tanker | 4 |
| | Fixed Platform | Directional | Pipeline | 6 |
| | Subsea | Horizontal | | 8 |
| | FLNG | Multi | | 10 |

## Example: Concept Screening

- Technical feasibility leads to final 12 scenarios:
  - 4 subsea well systems: 4, 6, 8, 10
  - 3 Host platform: Tieback, Jacket, Semisub






## Example: Concept Screening

- NPI are calculated from total cost:
  - ➢ CAPEX
  - ➢ DRILLEX
  - ➢ OPEX
  - ➢ ABEX

Cost of infrastructure, drilling, operation and abandonment

| | 4 Wells | 6 Wells | 8 Wells | 10 Wells |
|---|---|---|---|---|
| Tie Back | 1372 | 1651 | 1930 | 2209 |
| Semi | 1695 | 1974 | 2253 | 2532 |
| Jacket | 2045 | 2324 | 2603 | 2882 |

- NPV are calculated from :
  - ➢ Hydrocarbon sale price
  - ➢ Production profile P50 for number of wells

## Example: Concept Screening

- NPV and UI should be maximized simultaneously.

- Tie back system gives the max NPV.
- For jacket and semi, NPV and UI are maximized simultatneously with 6 wells.
- For tie back 6 wells should be selected as there is a risk of 25% production loss if one well is below its expected production rate.

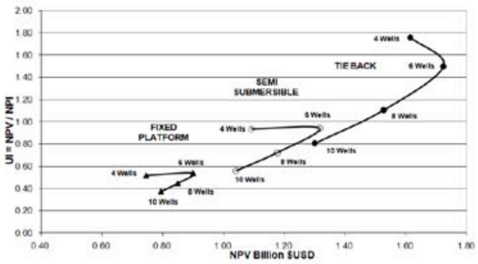


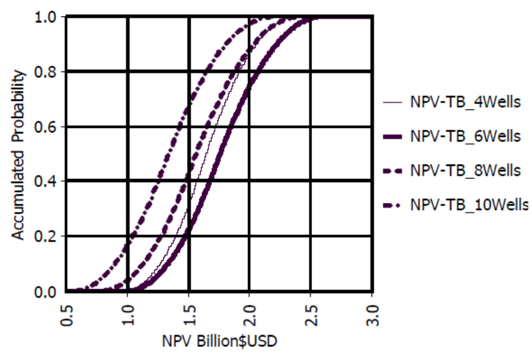

**Figure 3. Optimizing the number of wells for a gas field based on economical indicators.**



## Example: Concept Screening

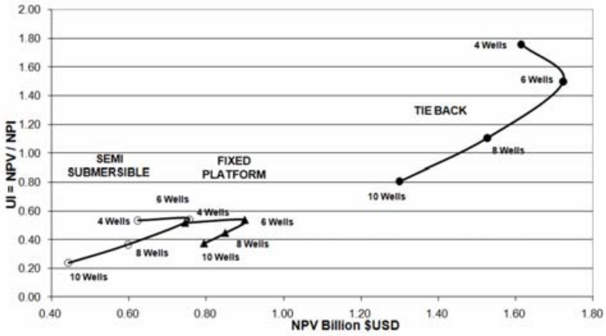
- There is high uncertainty in the cost estimation which need to be captured by a Montecarlo simulation for NPV and NPI.
- A triangular distribution is asigned to the main input parameters based on the min, mean and max value recommended by experts.
- CDF for NPV will be calculated for each case.

| Tie Back | Triangular Probability Distribution | | |
|---|---|---|---|
| | Minimum | Medium | Maximum |
| Gas Price ($US/MCF) | $5.50 | $7.32 | $9.50 |
| Cost (MM $USD) | | Class 5 - 4 | |
| Well | $125.56 | $139.52 | $153.46 |
| Shore Station | $186.69 | $207.43 | $228.17 |
| Pipe | $211.00 | $234.44 | $257.89 |
| Subsea System | $63.61 | $70.68 | $77.75 |
| Umbilicals | $64.85 | $72.05 | $79.26 |
| OPEX | $161.30 | $179.23 | $197.15 |
| ABEX | $45.31 | $50.34 | $55.37 |



## Example: Concept Screening

- This method only relies on economical indexes.
- If we include the noneconomic parameter such as schedule to first oil, result will be different.
- Subsea Tieback and Jacket: 3 years
- Semisubmersible: 5 years




- Economic evaluation alone is not be sufficient for final decision.



## Example: Concept Selection

For concept selection, scenarioes should be compared in sub-attribute levels.

Analytical Hierarchy Process (AHP):
A decition making method to prioritize concepts under qualitative multiple attributes decision drivers.
We have to select the attributes that can make difference between all the concepts.
Step 1: Selection of attributes and sub-attributes with brainstorming multi-diciplinary workshop (drilling, sybsea systems, flow assurance, pipeline, floating system, process)

## Example: Concept Selection

Selection of Attributes and Subattributes

| Attributes | Sub-attributes |
|---|---|
| Operability | Easy to start or shut down<br>Production management<br>Gas quality at the delivery point<br>Operation flexibility |
| Fabrication & Installation | Easy to fabricate<br>Easy to install<br>Availability of drilling equipments |
| Time to First Production& Costs | Total cost<br>Utility Index<br>Time to first production |
| Reliability | Prevention of flow assurance events<br>Inspection, maintenance, repair<br>redundancy |



## Example: Concept Selection

Ranking the selected attributes according to the importance in the exploitation systems.
A criteria for weight is defined:

| Weights for attributes and sub attributes comparison | |
|---|---|
| Absolutely more important | 9 |
| Very strongly more important | 7 |
| Strongle more important | 5 |
| Weakly more important | 3 |
| Equally important | 1 |
| Weakly less important | 1/3 |
| Strongly less important | 1/5 |
| Very strongly less important | 1/7 |
| Absolutely less important | 1/9 |

## Example: Concept Selection

Make a pairwise comparison and weight the attributes.
Normalaize the columns and sum-up the rows in normalized matrix.

| Attribute Weighting | | | | | |
|---|---|---|---|---|---|
| **Attribute Weighting:** | 1. Operability | 2. Fabrication and Installation | 3. Time to First Production and Cost | 4. Reliability | |
| 1. Operability | 1 | 5.000 | 1.000 | 3.000 | |
| 2. Fabrication and Instalation | 0.200 | 1 | 0.200 | 0.143 | |
| 3. Time to First Production and Cost | 1.000 | 5.000 | 1 | 1.000 | |
| 4. Reliability | 0.333 | 7.000 | 1.000 | 1 | |
| **Summation:** | 2.533 | 18.000 | 3.200 | 5.143 | |
| **Normalization:** | | | | | **Weights** |
| 1. Operability | 0.395 | 0.278 | 0.313 | 0.583 | **0.3921** |
| 2. Fabrication and Installation | 0.079 | 0.056 | 0.063 | 0.028 | **0.0562** |
| 3. Time to First Production and Cost | 0.395 | 0.278 | 0.313 | 0.194 | **0.2949** |
| 4. Reliability | 0.132 | 0.389 | 0.313 | 0.194 | **0.2569** |
| **Summation:** | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 |

Weight of each attribue is the final result.



## Example: Concept Selection

Rank the field development concepts from 1 to 4 for each sub attribute.

Normalize the ranking by attribute and sub attribute weights.

Sum-up the results for each concept to get final ranking result.

| | | | | Pair-Wise Rating | | | Normalised Pair-Wise Rating | | |
|---|---|---|---|---|---|---|---|---|---|
| **Attributes** | **Attribute Weight** | **Sub-Attribute** | **Sub-Attribute Weight** | **Tie-Back** | **Fixed Platform** | **Floating System** | **Tie-Back** | **Fixed Platform** | **Floating System** |
| **1. Operability** | 0.39 | | | | | | | | |
| | | Easy to start or shut down | 0.11 | 3 | 4 | 4 | 0.126 | 0.168 | 0.168 |
| | | Production management | 0.41 | 3 | 4 | 4 | 0.484 | 0.645 | 0.645 |
| | | Gas quality at the delivery point | 0.12 | 4 | 4 | 4 | 0.189 | 0.189 | 0.189 |
| | | Operative flexibility | 0.36 | 2 | 3 | 3 | 0.283 | 0.425 | 0.425 |
| **2. Fabrication and Installation** | 0.06 | | | | | | | | |
| | | Easy to fabricate | 0.11 | 4 | 3 | 2 | 0.024 | 0.018 | 0.012 |
| | | Easy to Install | 0.26 | 3 | 3 | 2 | 0.044 | 0.044 | 0.029 |
| | | Availability of drilling equipment | 0.63 | 2 | 2 | 3 | 0.071 | 0.071 | 0.107 |
| **3. Time to First Production and Cost** | 0.29 | | | | | | | | |
| | | Total cost (TC) | 0.11 | 4 | 3 | 2 | 0.125 | 0.094 | 0.063 |
| | | Utility index (UI) | 0.63 | 4 | 3 | 2 | 0.747 | 0.560 | 0.374 |
| | | Time to first production | 0.26 | 4 | 3 | 3 | 0.307 | 0.230 | 0.230 |
| **4. Reliability** | 0.26 | | | | | | | | |
| | | Prevention of flow assurance events | 0.45 | 2 | 3 | 4 | 0.234 | 0.350 | 0.467 |
| | | Insp maintenance and repair (IMR) | 0.09 | 4 | 3 | 2 | 0.093 | 0.070 | 0.047 |
| | | Redundancy | 0.45 | 3 | 4 | 4 | 0.350 | 0.467 | 0.467 |
| | | **Pair-Wise Rating** | Excellent | Good | Average | Poor | **3.08** | **3.33** | **3.22** |
| | | **Value** | 4 | 3 | 2 | 1 | | | |

## Example: Concept Selection

The concept selection based on economic indexes:

- Tie-Back
- Semi-Sub
- Jacket

The concept selection based on non-economic indexes:

- Jacket
- Semi-Sub
- Tie-Back

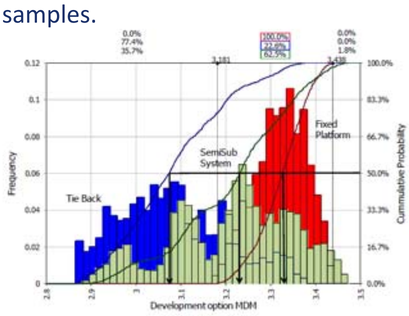


## Example: Concept Selection

- In MDM method, engineering judgment is used to define the attributes and weights.
- This can vary depending on the experience of the people, time frame, available information.
- Effect of variation in the attribute weights must be studied with stochastic analysis.
- Define a triangular distribution for attribute weights.
- Performe montcarlo simulation, 10,0000 samples.

**Table 13. Attributes weight value range.**

| Attributes | Lower Value | Base Case | Upper Value |
|---|---|---|---|
| 1. Operability | 0.18 | 0.39 | 0.57 |
| 2. Fabrication and Installation | 0.03 | 0.06 | 0.09 |
| 3. Time to First Production and Cost | 0.13 | 0.29 | 0.53 |
| 4. Reliability | 0.14 | 0.26 | 0.46 |

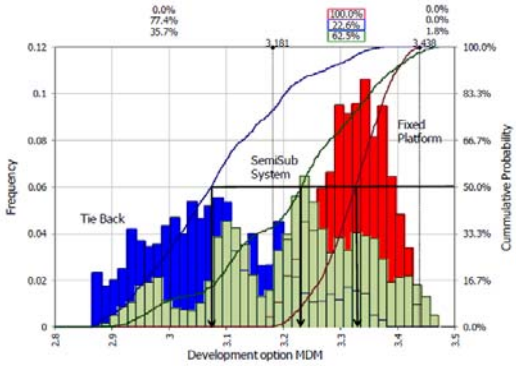


## Example: Concept Selection

Ranking MDM results after stochastic analysis:

- Shows the range of MDM value for each concept and probability.
- Jacket gives the highest MDM.
- The median values for all three concepts are:
  - Jacket = 3.32
  - Semi = 3.23
  - Tie-Back = 3.07

This stochastic analysis confirms the deterministic Results.






## Example: Concept Selection

Risk Assessment:
To finalize the results from concept selection risk assessment should be performed.
It is a semi-quantitative assessment.

Risk Definition: Probability of occurrence X severity of concequence

Procedure:

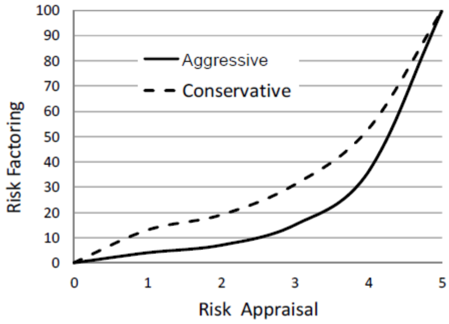
- Make a list of all possible risk events: previous records or FMEA workshope
- Determine the probability of occurrence for each event
- Specify the risk attributes which will be affected by risk events:
  - Health and safety
  - Environment
  - Asset Value
  - Project schedule

## Example: Concept Selection

Probability of occerrence:
Use a scale of 1 to 5.
For qalitative probability assignment risk taker are divided into to group:

- Aggresive risk takers
- Conservative risk takers

A risk factoring profile is defined to distinguish risk takers.

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## Example: Concept Selection

Impact severity of risk events on attributes is apprised by a group of experts from the established guideline and operator's safety policy.
Impact severity appraisal is also weighted by the same factoring curve.

| Impact Severity Appraisal | Health and Safety | Environment | Asset Value | Project Schedule |
|---|---|---|---|---|
| **Exceptional (5)** | Fatalities/Serious impact on public. | Major or extended duration/Full scale response | 20% or more of total asset value | Schedule impacted more than 2 years |
| **Substantial (4)** | Serious lost time injury to personnel/ Limited impact on public | Serious environmental damages/ Significant resources needed to respond | 5% to <20% of total asset value | Schedule impacted more than 6 month but less than 2 years |
| **Significant (3)** | Restricted work case/Minor impact on public | Moderate environmental damages/ Limited resources needed to respond | 1% to <5% of total asset value | Schedule impacted more than 3 month but less than 6 months |
| **Moderate (2)** | Medical treatment for personnel/ No impact on public | Minor impact/No response needed | 0.1% to <1% of total asset value | Schedule impacted more than 1 month but less than 3 months |
| **Negligible (1)** | Minor impact on personnel | No damages | <0.1% of total asset value | Insignificant schedule slippage: <1 month |

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## Example: Concept Selection

The resulted table will be: Weighted probability of occerrence X weighted impact severity X Weight of the attributes. The mean square root gives final risk weight of each event.

**Table 9. Risk assessment for tie back development option.**

| FIELD DEVELOPMENT OPTION: TIE BACK | | | RISK ATTRIBUTES Risk event impact severity on attributes (Appraisal) | | | | Weight of risk event impact severity on attributes (Factoring) | | | | RISK ASSESSMENT OF EVENTS | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 0.25 | 0.25 | 0.25 | 0.25 | | | | | | | | | |
| RISK EVENT | Probability of Ocurrence (Appraisal) | Weight of Probability of Occurrence (Factoring) | Health and Safety | Environment | Asset Value | Project Schedule | Health and Safety | Environment | Asset Value | Project Schedule | Health and Safety | Environment | Asset Value | Project Schedule | RISK EVENT WEIGHT |
| 1. Change of reservoir information, well type and future growth. | 4 | 36 | 1 | 1 | 3 | 2 | 4 | 4 | 15 | 7 | 36 | 36 | 135 | 63 | 16 |
| 2. Damage to pipelines / umbilicals due to mooring lines or anchors failure. | 3 | 15 | 3 | 3 | 4 | 3 | 15 | 15 | 36 | 15 | 56 | 56 | 135 | 56 | 17 |
| 3. Equipment failure during commissioning and starting up. | 3 | 15 | 3 | 3 | 3 | 3 | 15 | 15 | 15 | 15 | 56 | 56 | 56 | 56 | 15 |
| 4. Infrastructure / pipelines failure during installation. | 3 | 15 | 3 | 3 | 3 | 3 | 15 | 15 | 15 | 15 | 56 | 56 | 56 | 56 | 15 |
| 5. Delay of infrastructure to start up | 4 | 36 | 1 | 1 | 3 | 3 | 4 | 4 | 15 | 15 | 36 | 36 | 135 | 135 | 18 |
| 6. Problems during well construction | 4 | 36 | 3 | 3 | 3 | 3 | 15 | 15 | 15 | 15 | 135 | 135 | 135 | 135 | 23 |
| 7. Control system failures during operation | 3 | 15 | 3 | 3 | 3 | 3 | 15 | 15 | 15 | 15 | 56 | 56 | 56 | 56 | 15 |
| 8. Flow assurance problems (plugs formation) | 4 | 36 | 3 | 2 | 4 | 4 | 15 | 7 | 36 | 36 | 135 | 63 | 324 | 324 | 29 |
| 9. Slug catcher flooding | 3 | 15 | 3 | 2 | 3 | 3 | 15 | 7 | 15 | 15 | 56 | 26 | 56 | 56 | 14 |
| 10. Hurricanes | 5 | 100 | 3 | 3 | 3 | 3 | 15 | 15 | 15 | 15 | 375 | 375 | 375 | 375 | 39 |
| | | | | | | | | | | | OPTION RISK WEIGHT | | | | 20 |

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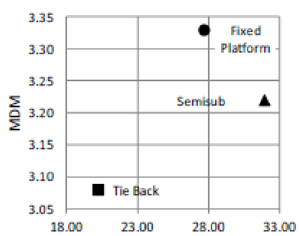
## Example: Concept Selection

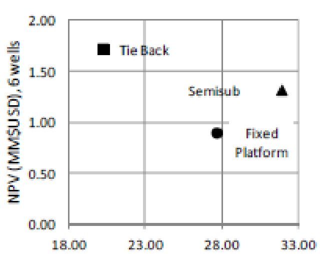
The previous procedure will be performed for all concepts.
The rsults from risk assessment can be combined with multi-atribute decision model and NPV calculation for final selection

**Table 11. Summary of risk weights and MDM evaluations.**

| Development Option | Risk Weight | MDM |
|---|---|---|
| Tie Back | 20.24 | 3.08 |
| Fixed Platform | 27.65 | 3.33 |
| Semisubmersible | 31.90 | 3.22 |



(a) Risk Weight



(b) Risk Weight

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## Conclusions

- Concept selection for deep water field development is a multidisciplinary task and needs contribution from: Subsurface, drilling and completion, surface facility, operation and maintenance, management and commercial team.
- A structured methology to generate, screen and select the right development concept is required.
- Concept selection is performed when the uncertainty in the critical parameters which determine the commercial success of the project is high. Addressing subsurface data uncertainty in the facility design phase is important.
- Deepwater facility design is highly depends on subsurface data.
- Success of FDP highly depends on: Quality of information, skills of subsurface team, technology and reservoir modeling.



## References

**Ref 1.** Selecting the Right Field Development Plan for Global Deepwater Development, DOT 2012, Richard D Souza and Shiladitya Basu, Ray Fales

**Ref 2.** Field Development Planning and Floating Platform Concept Selection for Global Deepwater Developments, OTC 2011, Richard D Souza and Shiladitya Basu, Granherne

**Ref 3.** Concept Selection for Hydrocarbon Field Development Planning. J. Efrain Rodiguez-Sanchez, J. Martin Godoy- Alcantra, Israel Ramirez-Antonio, Nov 2012,

**Ref 4.** Concept Selection and Design Principles, CH1, Floating Structures: a guide for design and analysis, N.D.P. Barltrop, ISBN 1870553357

**Ref 5.** Challenges and Decisions in Developing Multiple Deepwater Fields, OTC 2004, B.F. Thurmond, D. B. L. Walker,

**Ref 6.** System Selection for Deepwater Production Installation, OTC 2001, Paul L. Dorgant, Stephen W. Balient, George

**Ref 7.** Managing Subsurface Uncertaintiesin Deepwater Facilities Design, Souza R.D, Vitucci M., DOT 2013, Woodlands, Texas

**Ref 8.** Guidance on the Content of Offshore Oil and Gas Field Development Plans,UK government Service and Information Website

## Acknowledgement

Prof. Milan Stanko, Dep. Petroleum Engineering and Applied Geophysics
Prof. Michael Golan, Dep. Petroleum Engineering and Applied Geophysics

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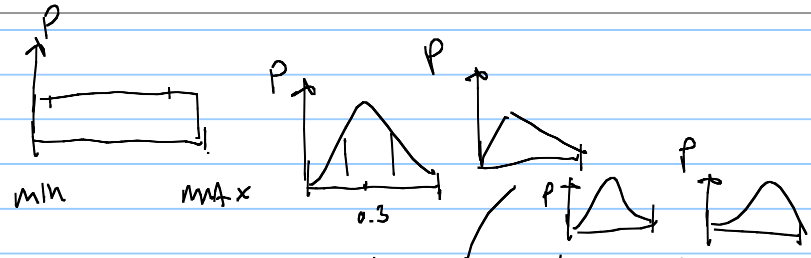
# Thanks for Your Attention

# Questions ?

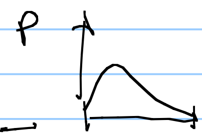
Note Title 01.02.2016

last week




with uncertainty we want to move from deterministic to ~ probabilistic

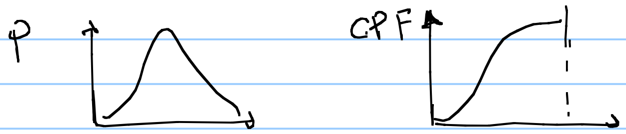
$$\text{TRR} = \frac{V_R \cdot \Phi \cdot (1-S_w) \cdot N_{TG} \cdot F_{RV}}{B_o}$$



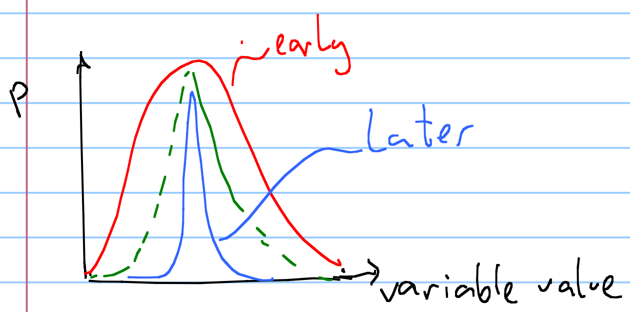

Monte carlo simulation

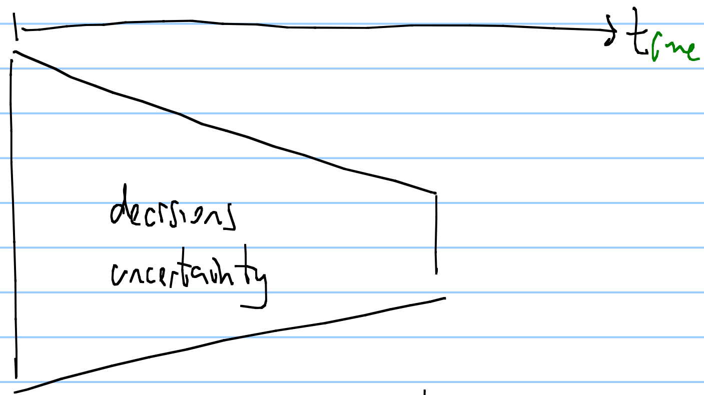
maximum number of iterations.

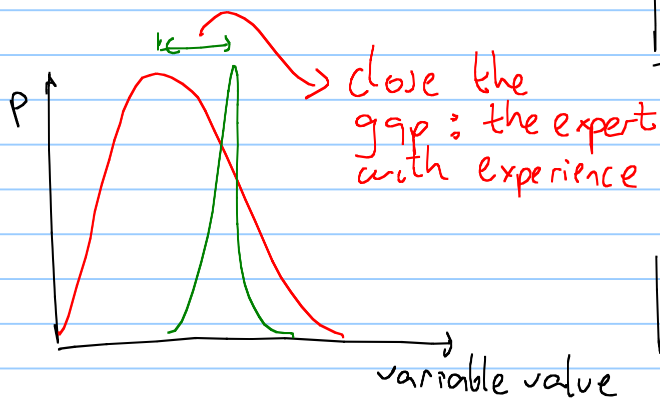
$N_{pu}$, $G_{pu}$, $Q_{pu}$

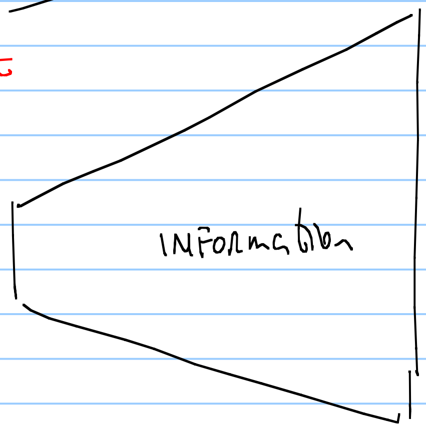



allows to make better plans and decision.



## Determining the number of iterations

The total error (absolute) $= \dfrac{3\sigma}{\sqrt{N}} = \varepsilon$

$\varepsilon$ = total error

$N$ = number of iterations

$\sigma$ = The standard deviation of the random variable that is simulated

Thus $N = \left(\dfrac{3\sigma}{\varepsilon}\right)^2$

Estimate the upper bound on $\sigma$ to use in the formula

$$\boxed{\sigma_{upper} = \text{STDEVP}[\text{MAX}, \text{MIN}, \text{AVERAGE}]}$$

**STDEVP(number1,number2,...)**

Calculates standard deviation based on the entire population given as arguments (ignores logical values and text).

MAX, MIN, AVERAGE } of the entire population of the random variable

Estimate the total error $\varepsilon$, given minimum error %

$$\boxed{\varepsilon = \text{AVERAG(all population)} \cdot \frac{\text{Error \%}}{100}}$$

$\left\{ \text{e.g. error\%} = 2\% \qquad \varepsilon = \text{AVERAGE} \cdot \dfrac{1}{50} \right\}$

Example 2% error = 0.02 Average = $\dfrac{\text{Average}}{50}$

$$N = \left(\frac{3\sigma \quad 50}{(\text{AVERAGE})}\right)^2$$

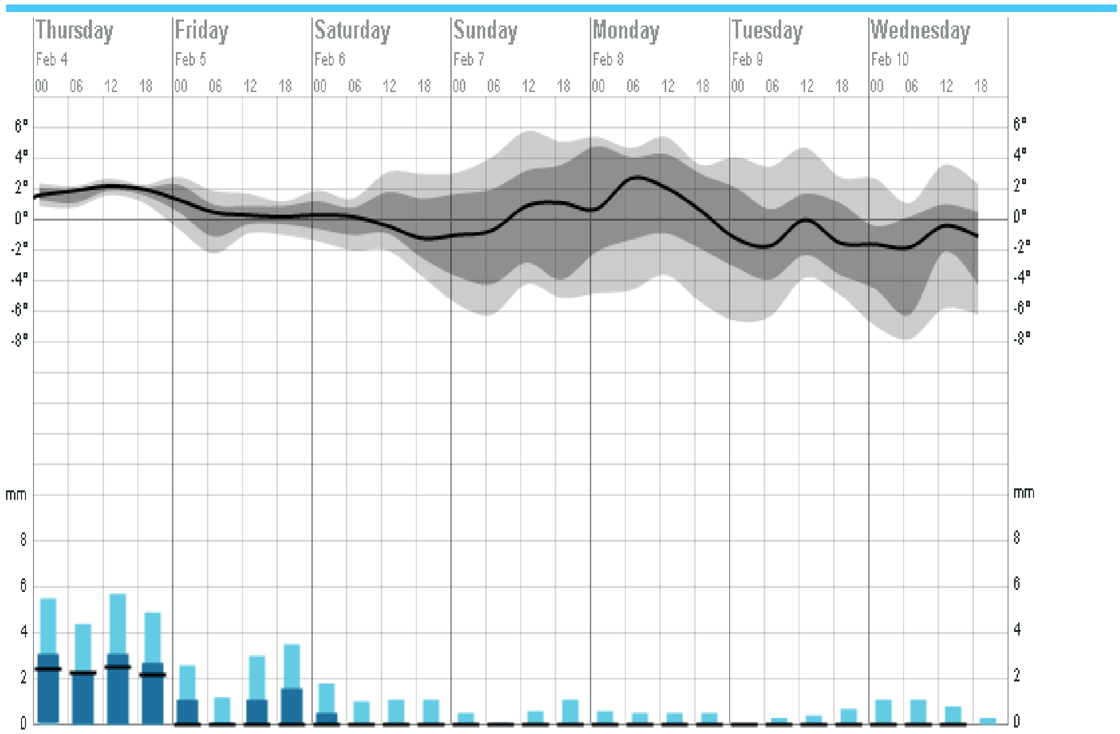
$\overline{\text{Mean}} \xrightarrow{\text{Approach}} \text{Average}$

Atribute level. How to assign a quantitative value to an attribute

**Table 6. Attributes weights.**

| | | | | | |
|---|---|---|---|---|---|
| | | Attribute Weighting | | | |
| **Attribute Weighting:** | 1. Operability | 2. Fabrication and Installation | 3. Time to First Production and Cost | 4. Reliability | |
| 1. Operability | 1 | 5.000 | 1.000 | 3.000 | |
| 2. Fabrication and Instalation | 0.200 | 1 | 0.200 | 0.143 | |
| 3. Time to First Production and Cost | 1.000 | 5.000 | 1 | 1.000 | |
| 4. Reliability | 0.333 | 7.000 | 1.000 | 1 | |
| **Summation:** | 2.533 | 18.000 | 3.200 | 5.143 | |
| **Normalization:** | | | | | **Weights** |
| 1. Operability | 0.395 | 0.278 | 0.313 | 0.583 | **0.3921** |
| 2. Fabrication and Installation | 0.079 | 0.056 | 0.063 | 0.028 | **0.0562** |
| 3. Time to First Production and Cost | 0.395 | 0.278 | 0.313 | 0.194 | **0.2949** |
| 4. Reliability | 0.132 | 0.389 | 0.313 | 0.194 | **0.2569** |
| **Summation:** | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 |

evolution of uncertainty with time




Long time forecast is quite reliable for temperature when the grey area has a narrow spread. Likewise it is quite reliable for precipitation when the blue bars are short.

The long time forecast is uncertain when the gray area has greater spread, and the blue bars are long.

Comments about the exercise set 1:

3.3

how to find fields rate to maximize plateau length

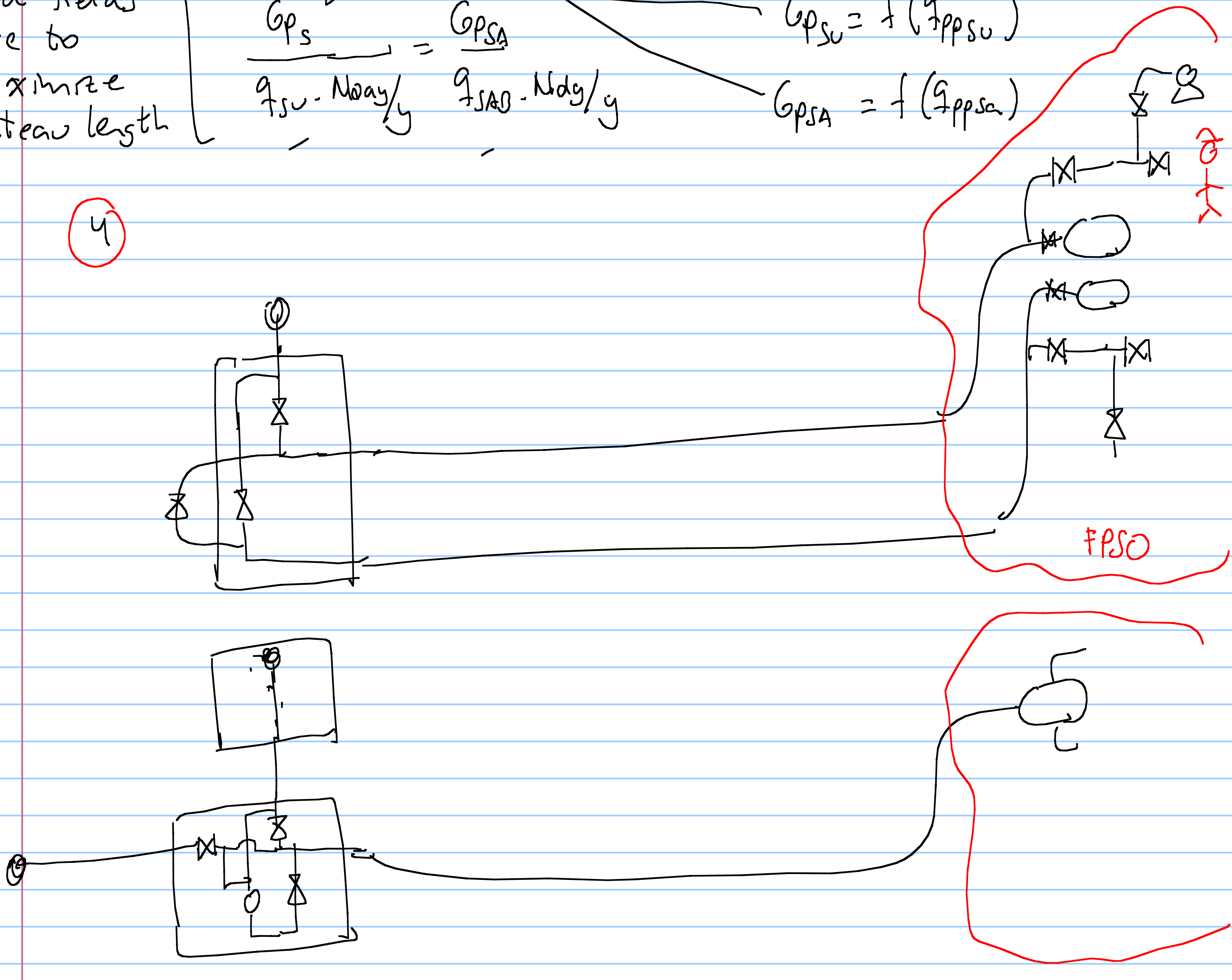
$$q_{SU} + q_{SA} = 170\,000 \text{ stb/d}$$

$$\frac{G_{pS}}{q_{SU} \cdot N_{day}/y} = \frac{G_{pSA}}{q_{SAB} \cdot N_{dg}/y}$$

$$G_{pSU} = f(q_{ppSU})$$

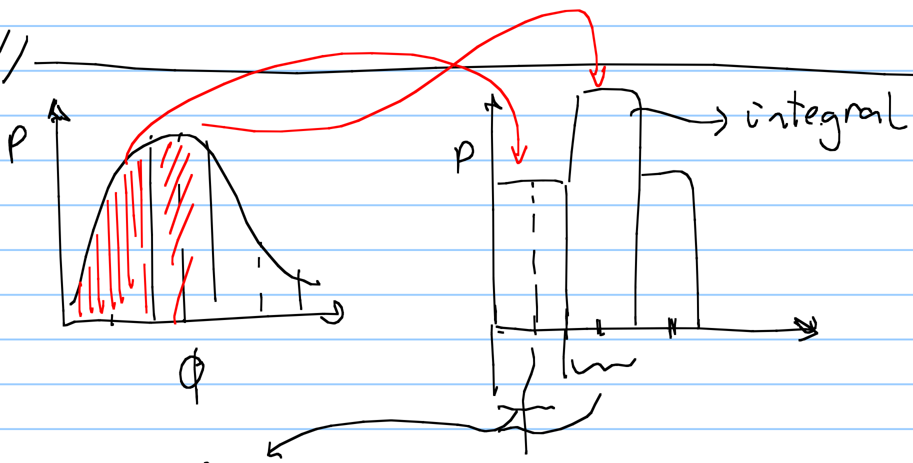
$$G_{pSA} = f(q_{ppSA})$$

4




Probabilistic distribution

how to convert a continuous distribution to a discrete? $\Phi_{max}$




$\Phi_{min}$ $\qquad \left(\frac{\Phi_{max}-\Phi_{min}}{3}\right) \qquad \left(\frac{\Phi_{max}-\Phi_{min}}{3}\right)\Big/2 + \Delta\Phi$

## Decision tree for probabilistic analysis:

**oil prices**

| value | probability |
|---|---|
| 20 | 0.7 |
| 10 | 0.3 |

**Cost of facilities**

| | |
|---|---|
| 20 E9 USD | 0.8 |
| 35 E9 USD | 0.15 |
| 45 E9 USD | 0.05 |

**TRR**

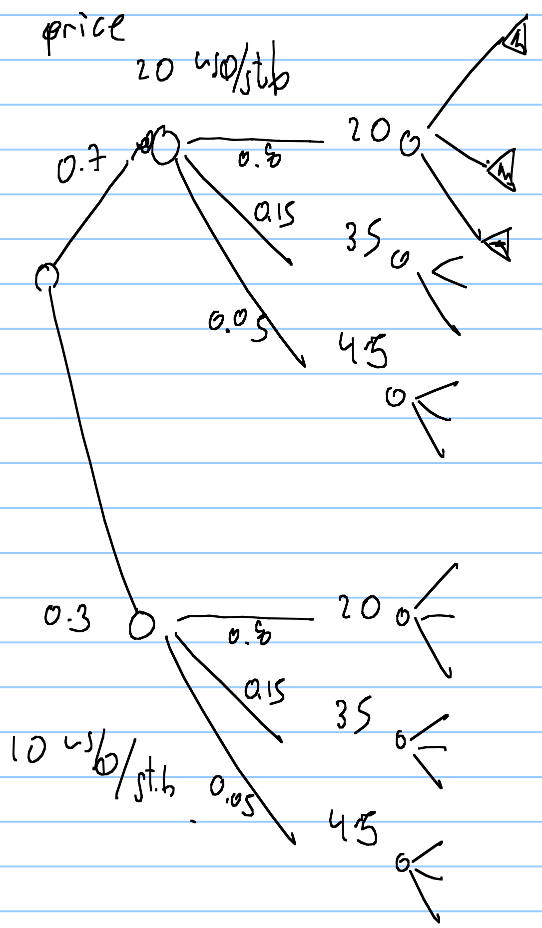
| stb | |
|---|---|
| 20 E6 | 0.2 |
| 50 E6 | 0.5 |
| 60 E6 | 0.3 |

example

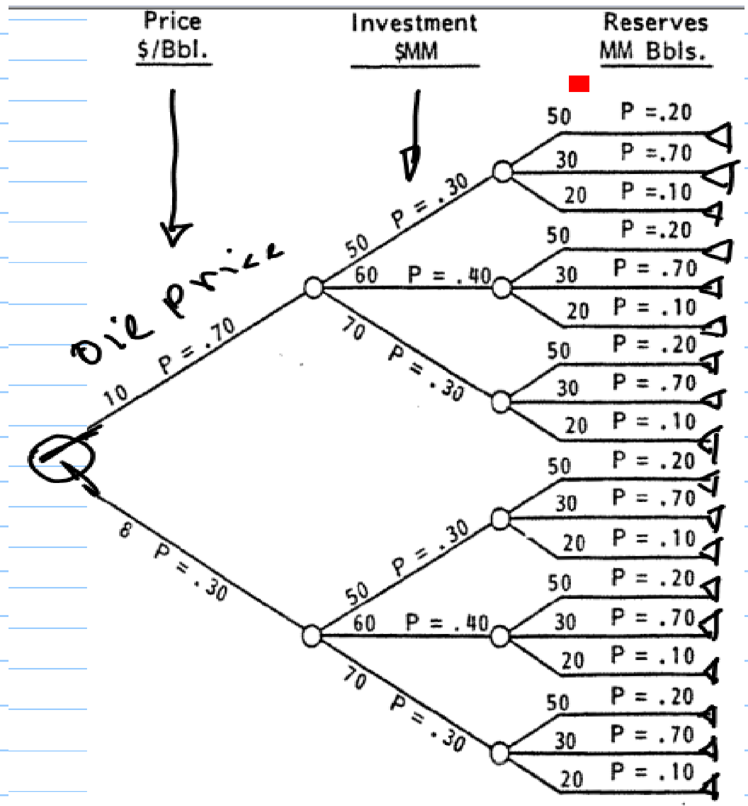
o chance node

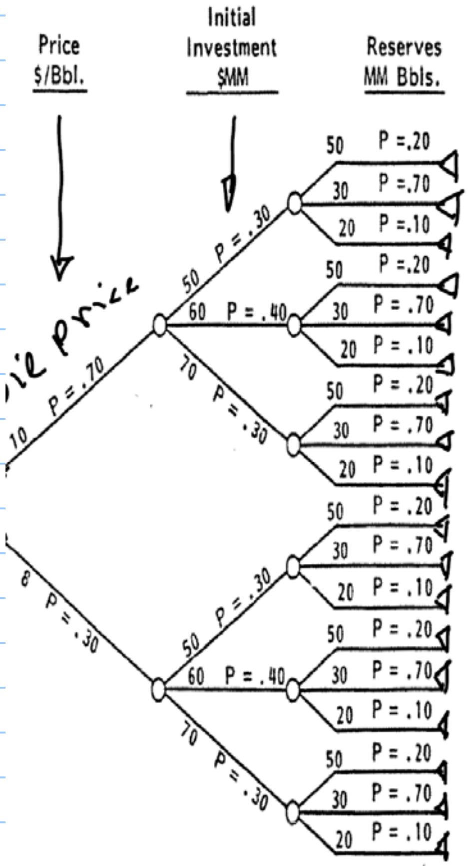
□ decision node

◁ end node



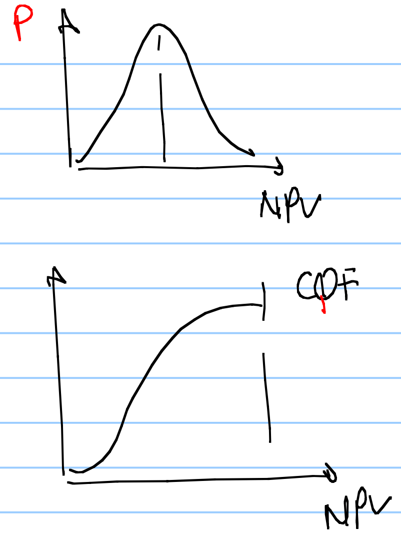

all chance nodes, no decisions.



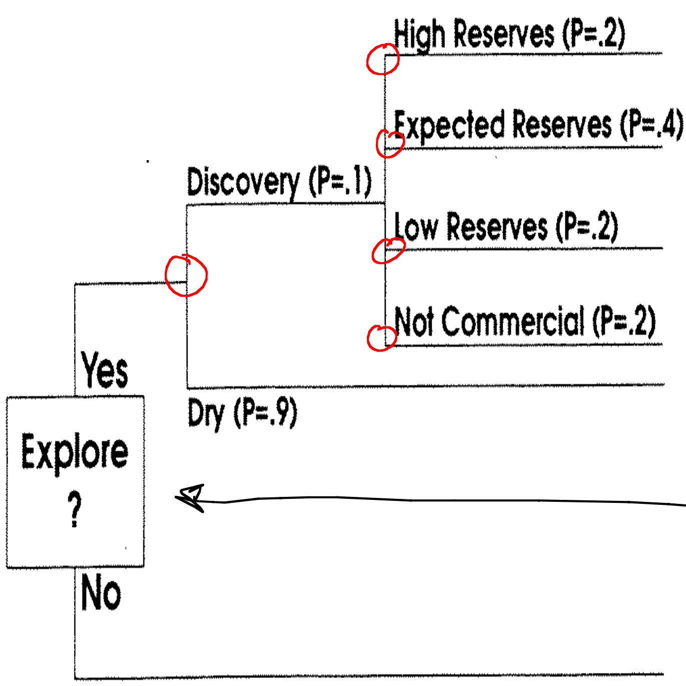



| Case | Prob. | NPV | NPV x Prob. |
|---|---|---|---|
| 1 | .042 | 60 | 2.52 |
| 2 | .147 | 15 | 2.21 |
| 3 | .021 | -10 | -0.21 |
| 4 | .056 | 53 | 2.97 |
| 5 | .196 | 8 | 1.57 |
| 6 | .028 | -17 | -0.48 |
| 7 | .042 | 46 | 1.93 |
| 8 | .147 | 1 | 0.15 |
| 9 | .021 | -24 | -0.50 |
| 10 | .018 | 35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

Weighted Avg. NPV 9.55




Used often when deciding if to drill further or not.




| i | $Prob_i$ | $NPV_i$ | $Prob_i \times NPV_i$ |
|---|---|---|---|
| 1 | 0.02 | A | (.02) A |
| 2 | 0.04 | B | (.04) B |
| 3 | 0.02 | C | (0.2) C |
| 4 | 0.02 | D | (.02) D |
| 5 | 0.90 | E | (.90) E |
| 6 | 1.00 | 0 | 0 |

it is possible to compute a weigth average NPV for this branch. to take this decision

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

Economic calculations

Equity
- share holders
- pension funds
- insurance companies

capital

Loans
- bank
- individuals
- trusts, bonds

capital

NTNU oil inc

(-) DRILLEX

expenditures
- daily rig fee
- services
- equipment

(-) CAPEX
- processing facilities
- design and engineering
- manifolds, boarding equipment, pipelines
- installation

(-) OPEX
- disposal of streams {water treatment
- salary personnel
- energy consumption
- maintenance
- injection water
- stimulation
- export
- modifications

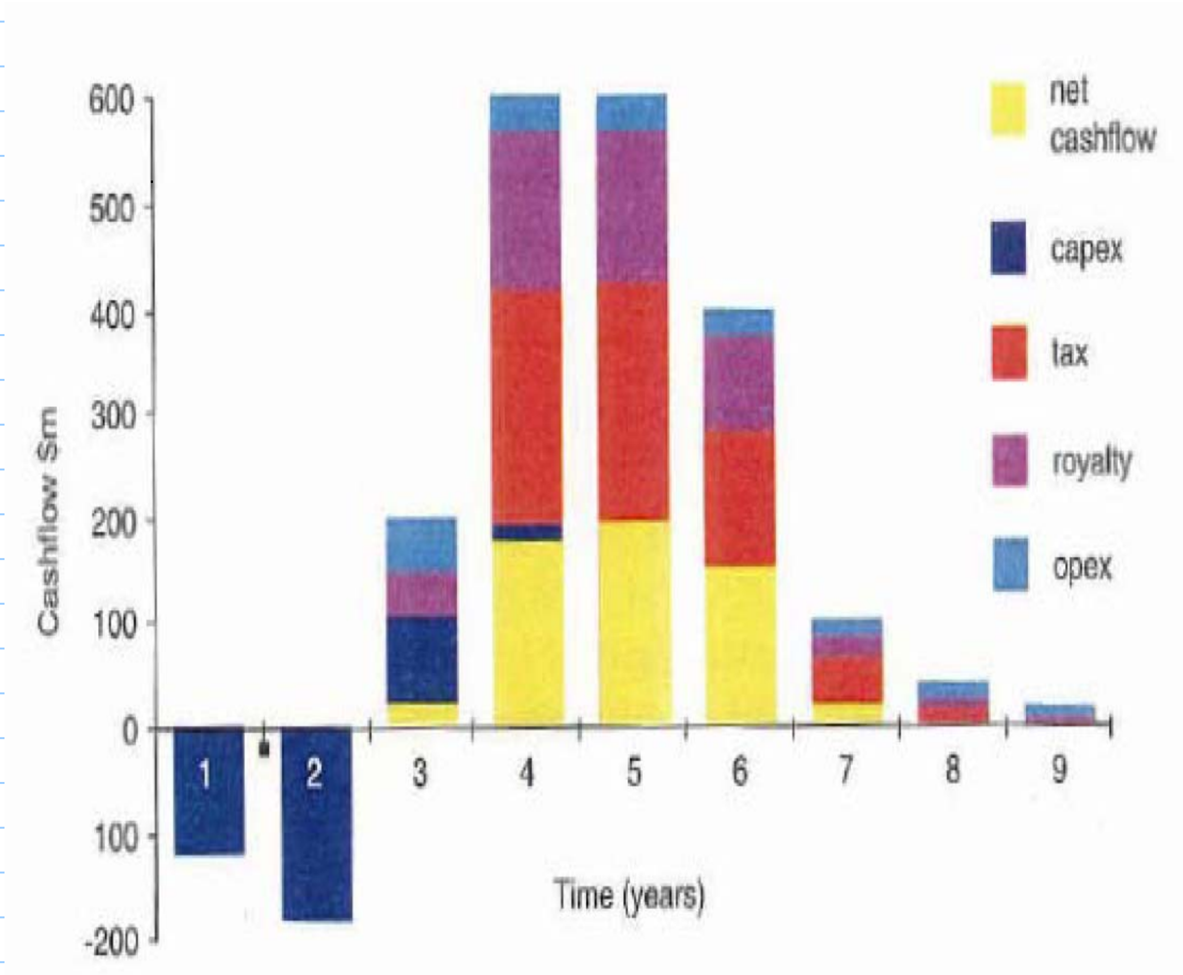
(-) ABEX
- plug and abandon the wells
- decomissioning of equipment
- ⋮

(-) TAX and Royalties
- 27% ~ oil tax
- 51% ~ special tax

(+)
- Revenues. (sales of oil, gas, condesate)
- LNG
- LPG

cash flow = Revenues - expenses

= (revenues - DRILLEX - CAPEX - OPEX - TAX)




when (+) the cash flow goes to → pay back financial obligations (loan interest)
pay shareholders (dividends)
reinvestment at NTNU oil

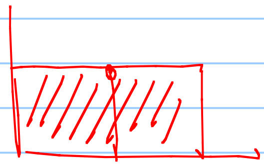
Economical calculations are usually performed by the end of the year

| End of year [years] | DRILLEX | CAPEX | OPEX | REVENUES | TAX | CASH flow | cash flow present value | cumulative NPV |
|---|---|---|---|---|---|---|---|---|
| 0 | | | | | | | $\cdot \frac{1}{(1+i)^n}$ | |
| 1 | | | | | | | | + |
| 2 | | | | | | | | + |
| 3 | | | | | | | | |
| 4 | | | | | | | | |

(NPV)

## DEFINITION of 'Present Value - PV'

The current worth of a future sum of money or stream of cash flows given a specified rate of return. Future cash flows are discounted at the discount rate, and the higher the discount rate, the lower the present value of the future cash flows. Determining the appropriate discount rate is the key to properly valuing future cash flows, whether they be earnings or obligations.



CAPEX

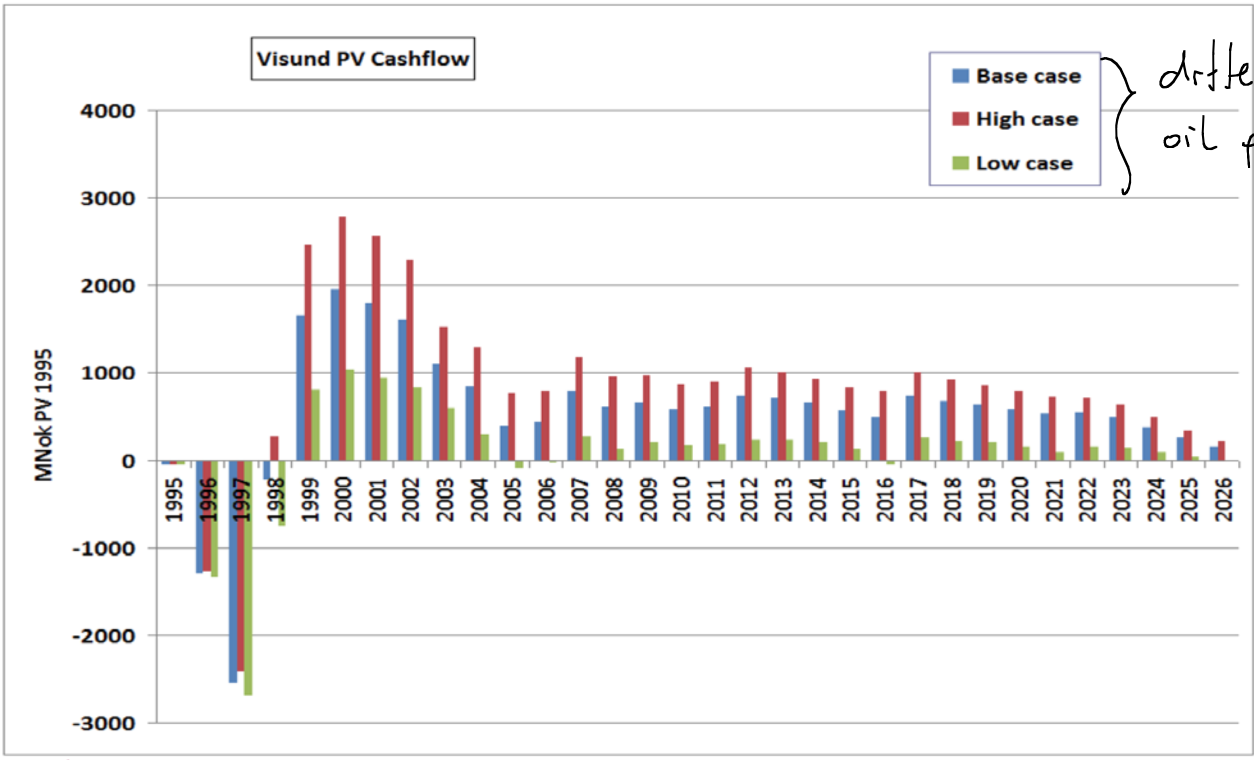
present value

Future value

$$PV = \frac{FV}{(1+i)^n}$$

n° years in the future

yearly interest rate




different oil prices.

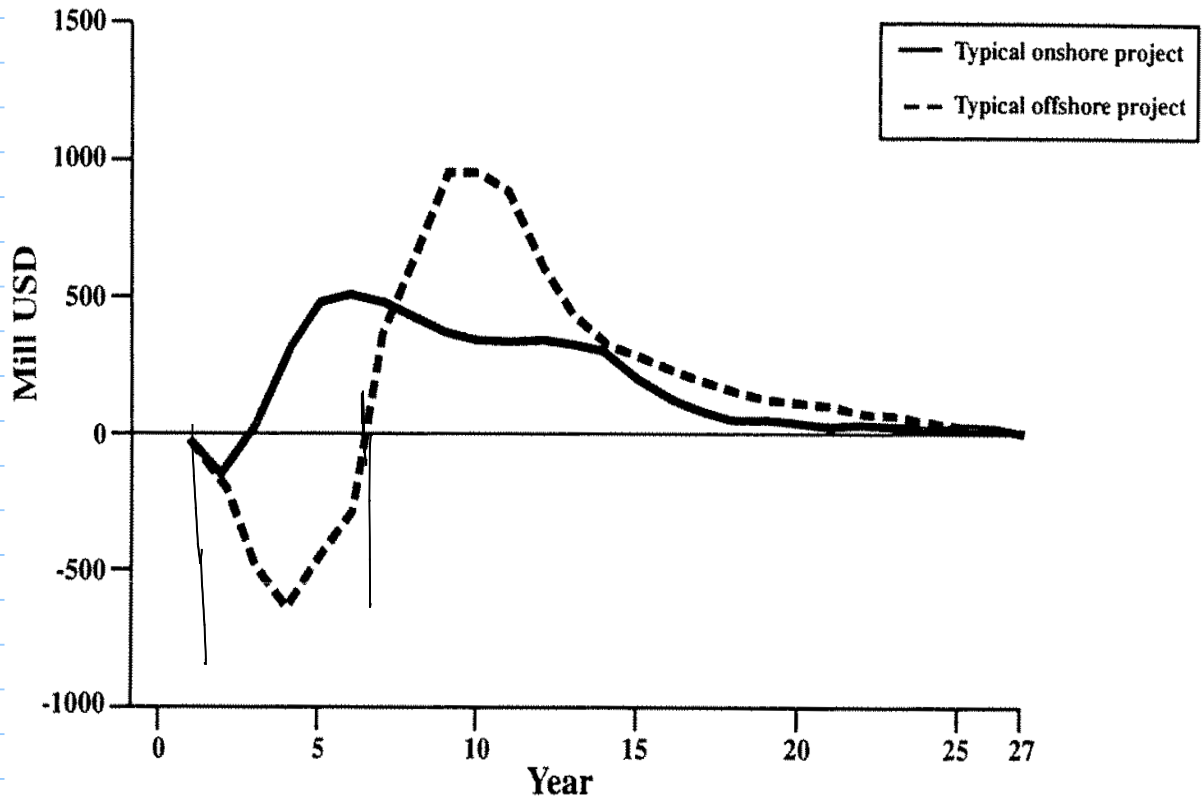
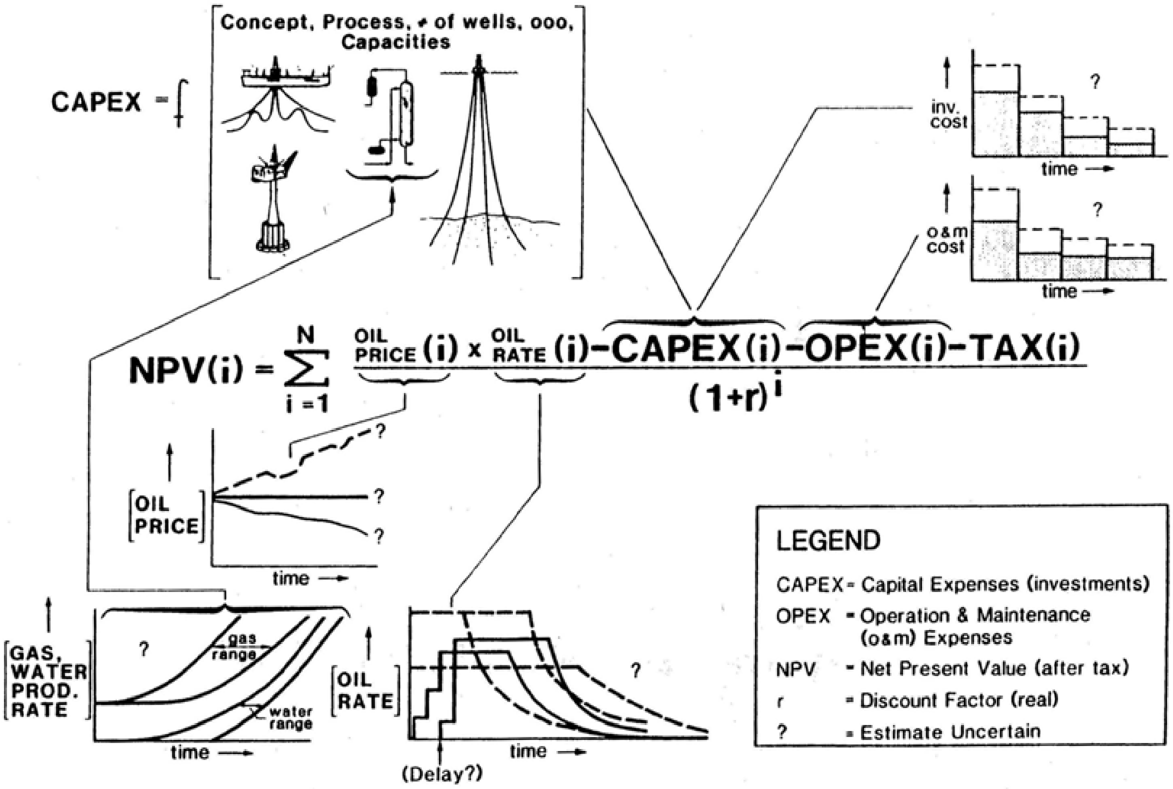



Fig. 9. Typical before tax cash flow profiles for offshore and onshore projects.

# What can we control?



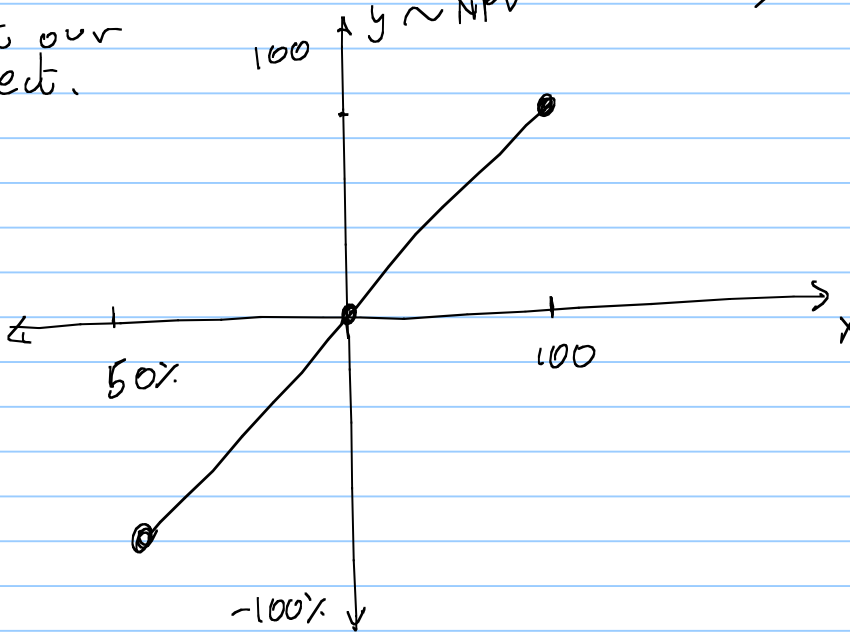

$$NPV(i) = \sum_{i=1}^{N} \frac{\text{OIL PRICE}(i) \times \text{OIL RATE}(i) - CAPEX(i) - OPEX(i) - TAX(i)}{(1+r)^i}$$

$\boxed{\text{spider plot}}$ → $\boxed{\text{ceteris paribus}}$

a simplistic tool to see which parameter affects most our project.

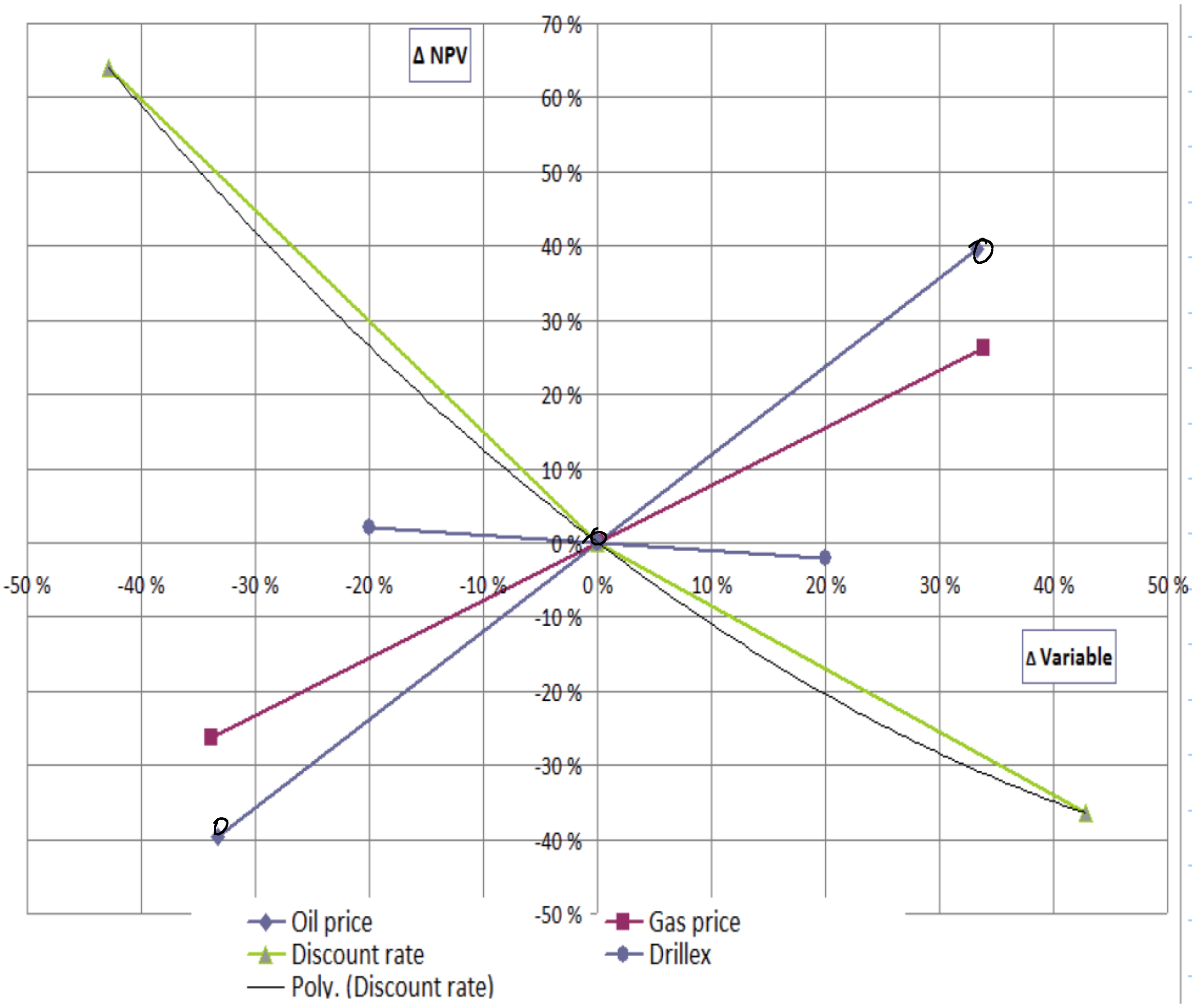
e.g. 30 $/stb

$$\frac{y - y_{base}}{y_{base}} \times 100$$




parameter that we want to change

$$\frac{X - X_{base}}{X_{base}} 100$$

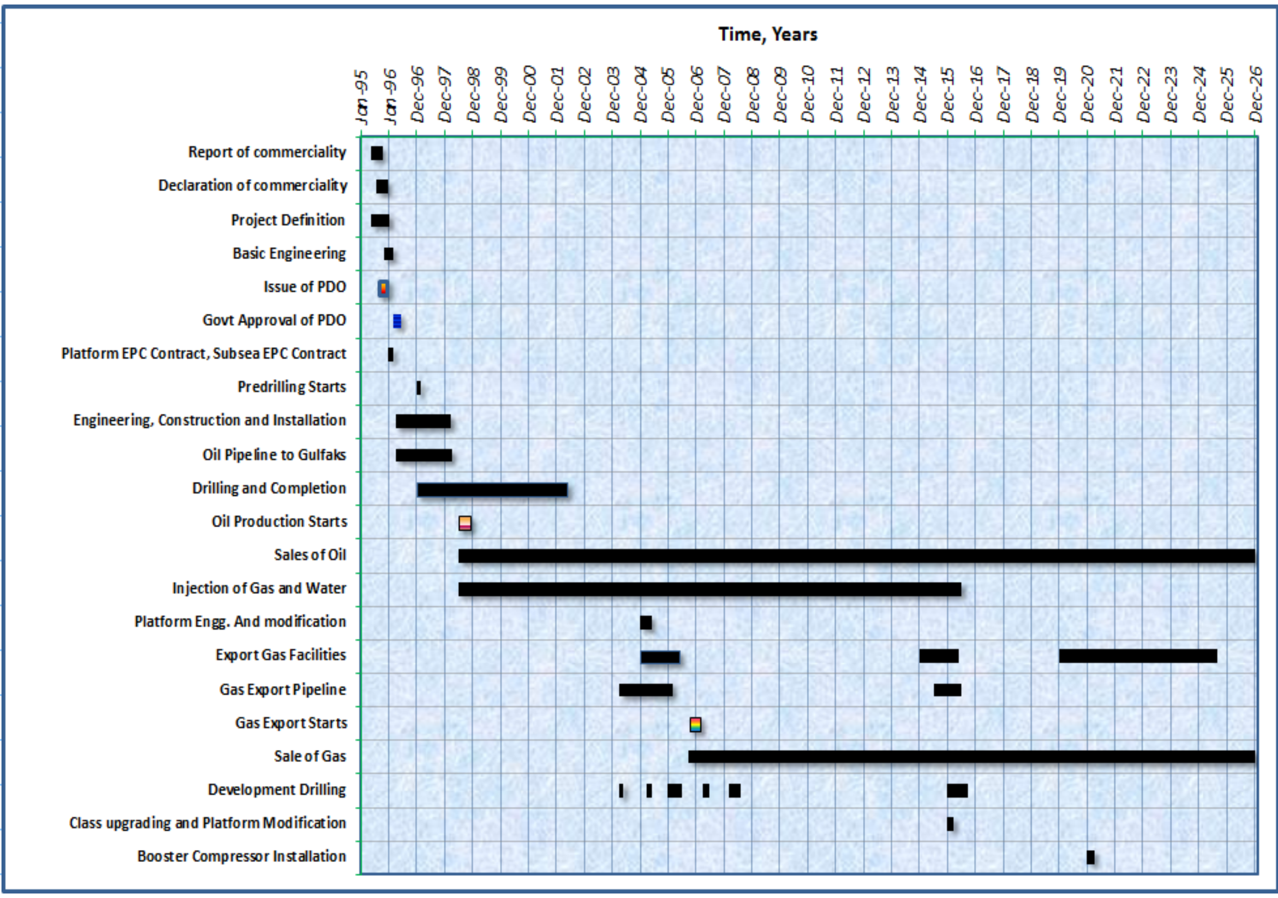



| oil price $X_1$ | gas price $X_2$ | $X_3$ | NPV | $X_{normalize}$ | $y_{normalized}$ |
|---|---|---|---|---|---|
| $X_{min}$ | $X_2$ base | | $NPV_{min}$ | | |
| $X_{base}$ | $X_2$ base | | $NPV_{base}$ | | |
| $X_{max}$ | $X_2$ base | | $NPV_{max}$ | | |
| $X_{base}$ | $X_2$ max | | $NPV_{max}$ | | |
| $X_{base}$ | $X_2$ base | | NPV base | | |
| $X_{base}$ | $X_2$ min | | $NPV_{min}$ | | |

plot series "oil price"

plot series "gas price"

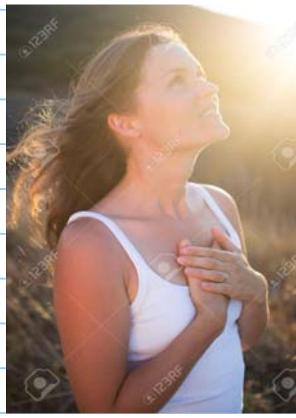
# Gantt chart : a very important tool for Project management




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

*Henry Gantt*

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

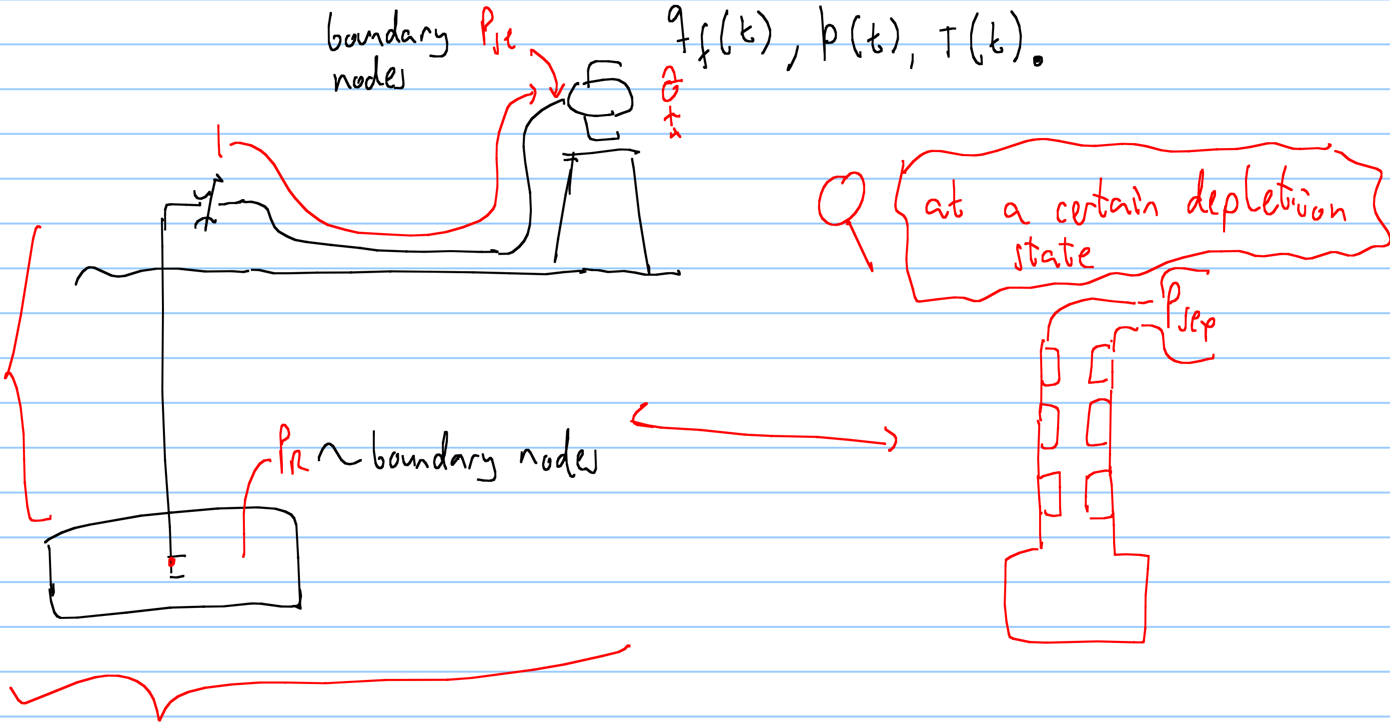


https://www.smartsheet.com/blog/gantt-chart-excel

| ACTIVITY CODE | NAME | START | DURATION | END |
|---|---|---|---|---|
| A | | 1 | 2 | 3 |
| B | | 2 | 5 | 7 |

flow equilibrium ⟶ performance of a production system (field)

$q_f(t)$, $p(t)$, $T(t)$.




- Reservoir (model) ⤳ simpler than reservoir simulator

well
- Pressure and temperature drop in circular/annular sections of pipe, accessories (restriction, slots, valve)

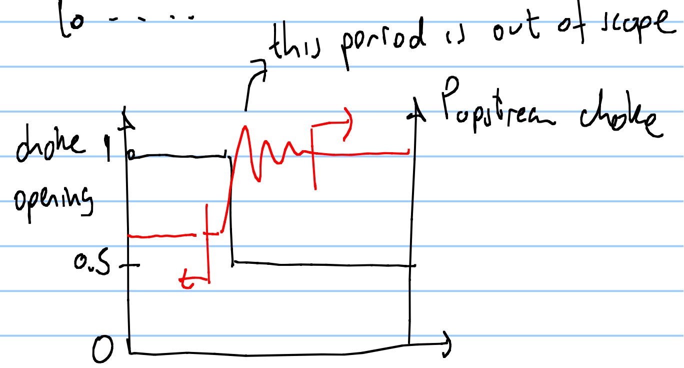
choke
- $\Delta p$, $\Delta T$ in the choke

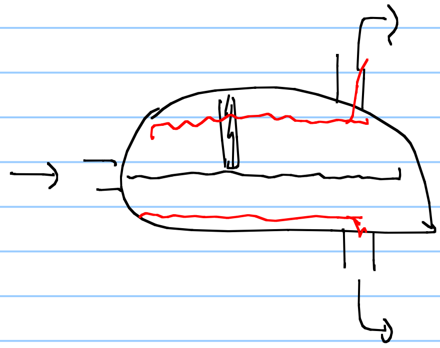
pipeline
- p, T drop calculations in circular sections of pipes, accessories, valve

production system simulator
- set of equations: $\Delta p$, $\Delta T$
- fluid behavior:
  - $pV = nRT \cdot Z$ — EOS
    - Redlich-Kwong
    - Peng-Robinson
    - ...
  - BO model
- → steady state analysis — $\frac{\partial}{\partial t}$

- well testing
- flow assurance

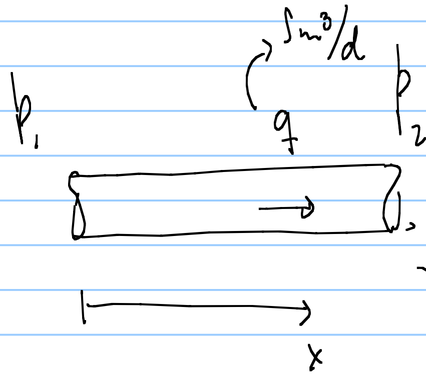
→ transient models





example of multiphase flow transient
slugging arriving to a separator

Analogy for available and required pressure curves




gas flowing through a pipe

three calculation options:

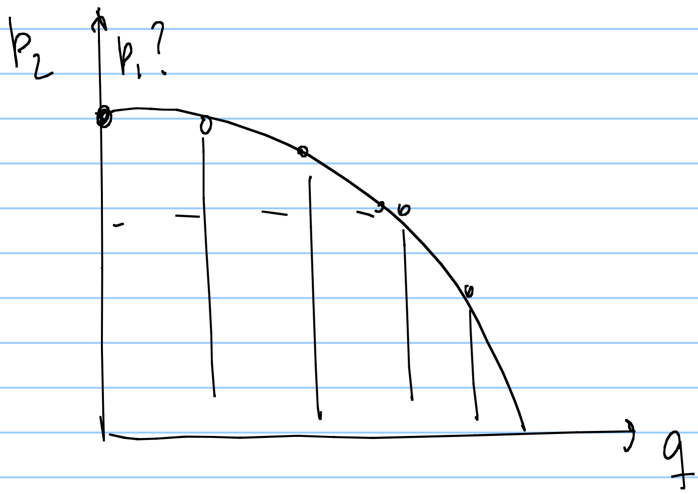
① $p_1, p_2 \rightarrow q$

② $p_1, q \rightarrow p_2$

③ $p_2, q \rightarrow p_1$

$$\left.\frac{dp}{dx}\right|_{TOTAL} = \left.\frac{dp}{dx}\right|_{friction} + \left.\frac{dp}{dx}\right|_{hydrostatic} + \left.\frac{dp}{dx}\right|_{acceleration}$$

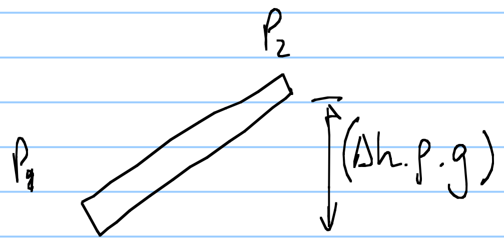
$p_1$ fixed $\quad q$ changing $\quad q \uparrow \; \Delta p \uparrow \quad p_2 = p_1 - \Delta p$




available pressure curve

in this case when $q = 0$

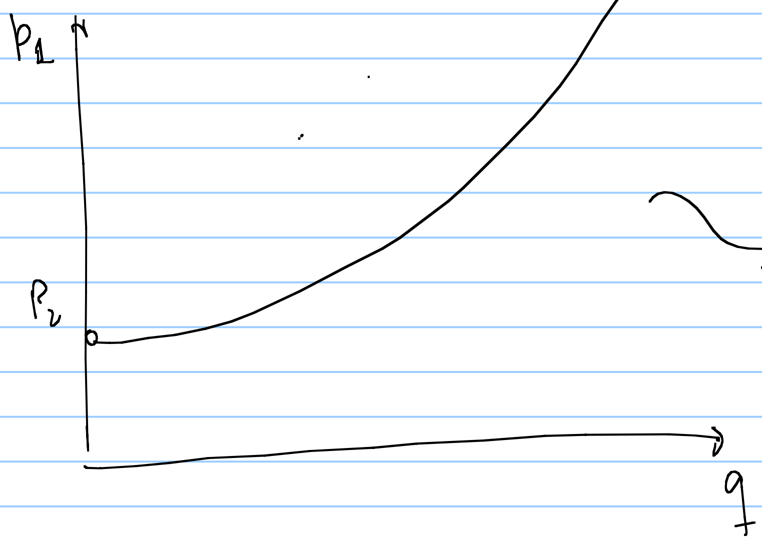
$P_2 \neq P_1$




$P_2$ constant $\quad q \uparrow$

non linear

$\Delta p = f(q)$



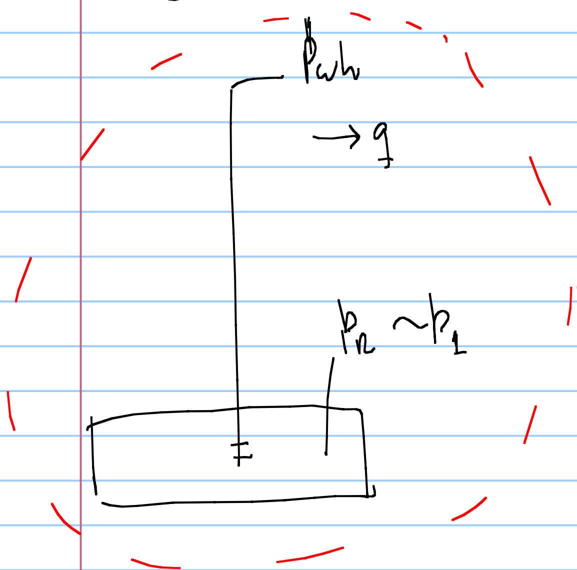

$P_1 = P_2 + \Delta p$

required pressure curve.

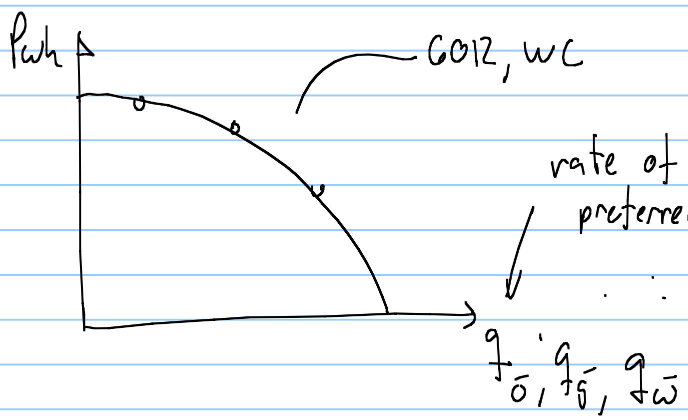
- Bilal
- Elshad

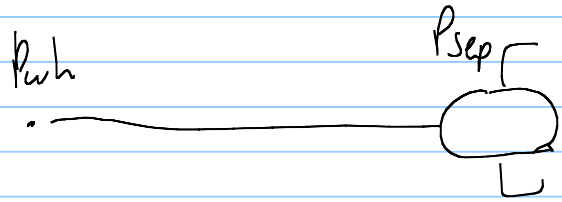
reference group.

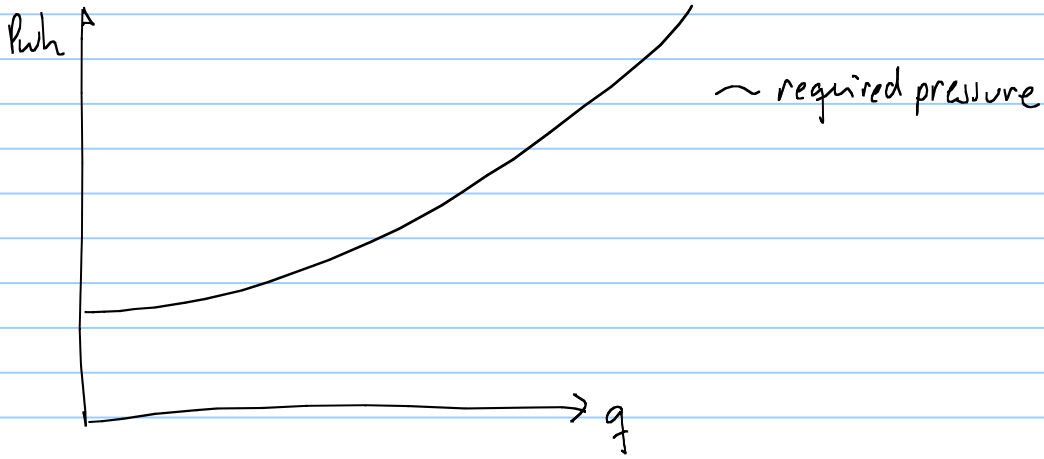
going back to our production system



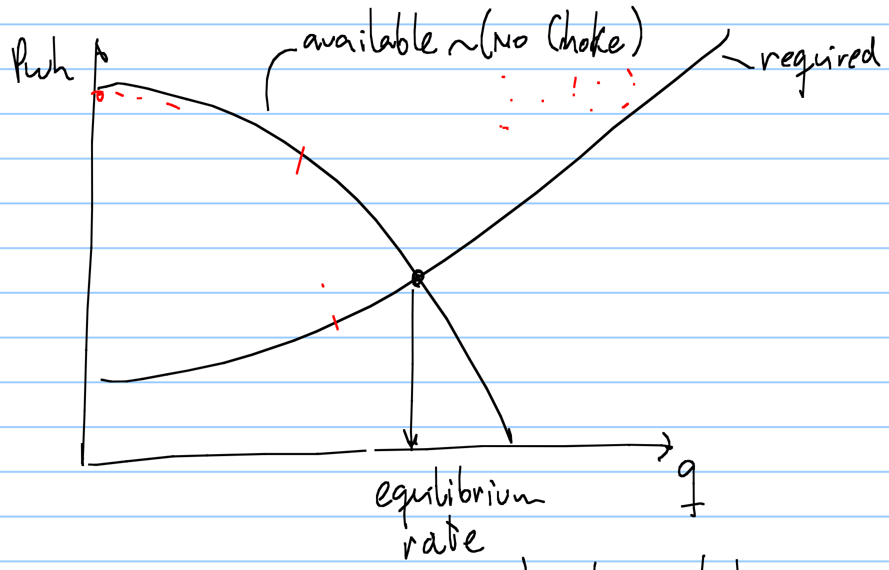

one point in time ($Q_p$)



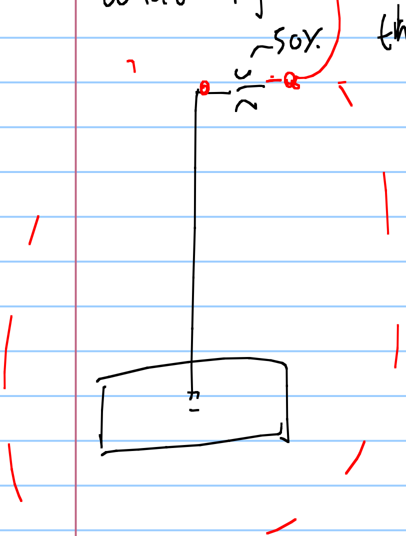



how to calculate the equilibrium flow rate




what if we include the choke

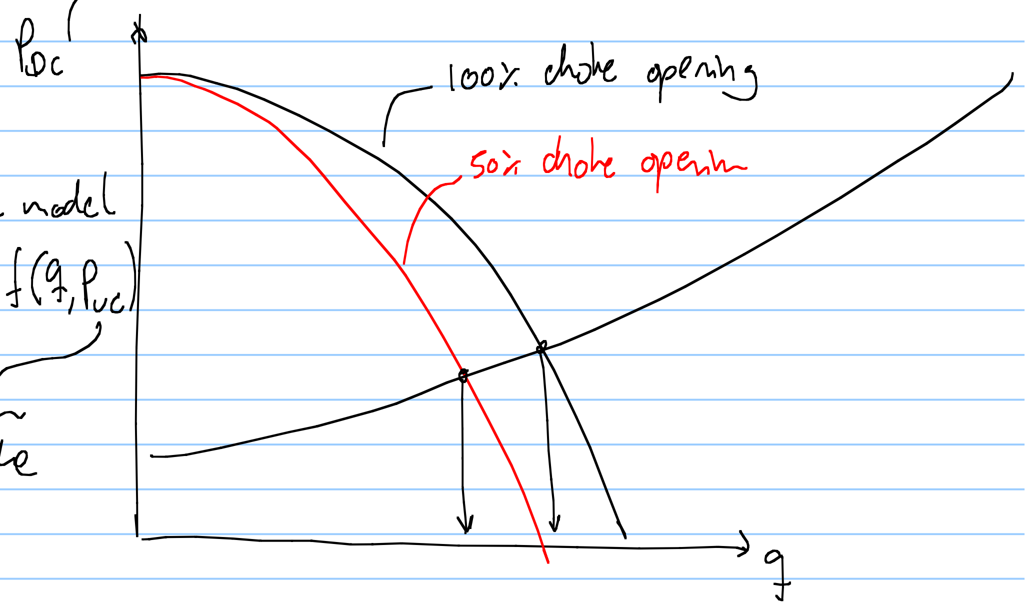



choke model

$\Delta p = f(q, P_{uc})$

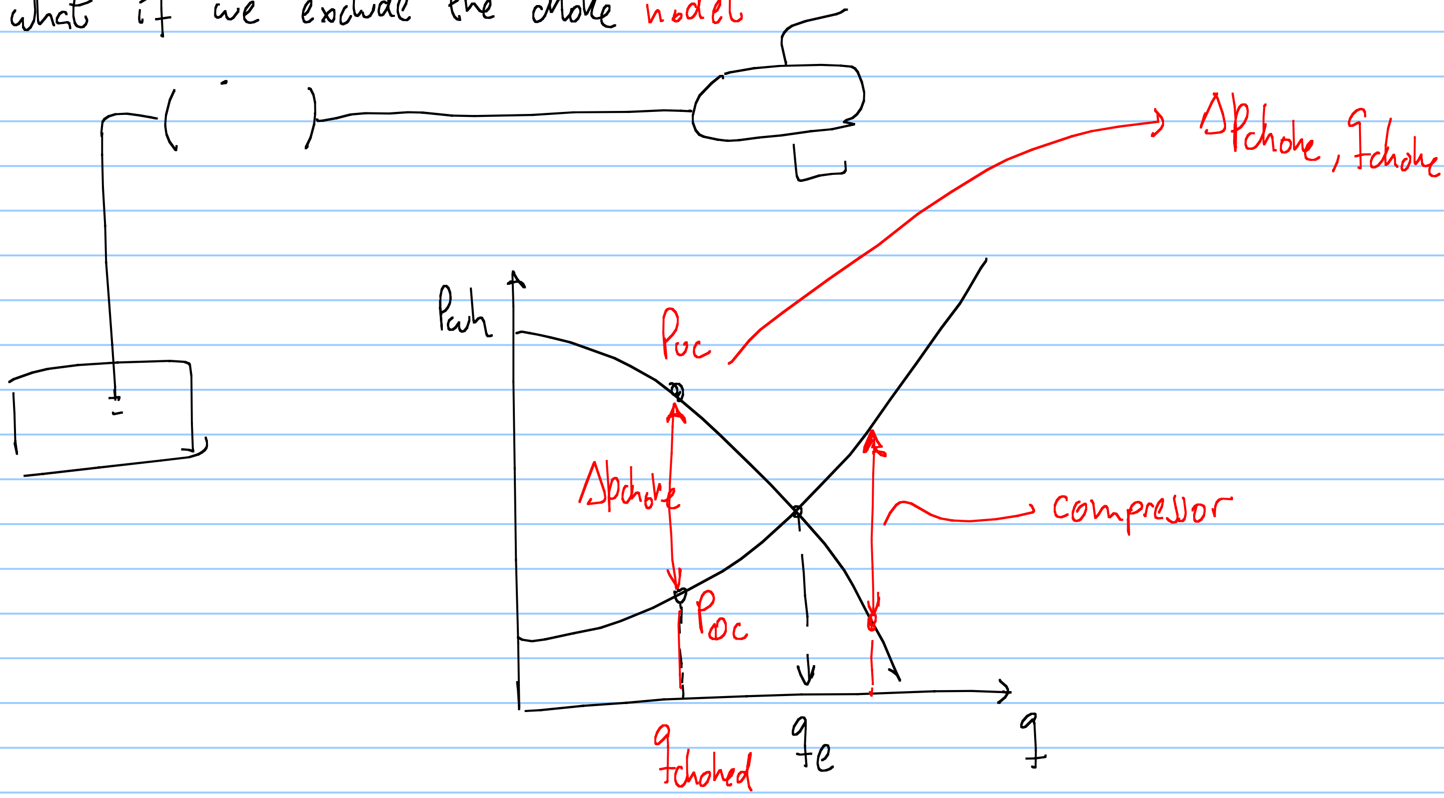
upstream choke

downstream choke



what if we exclude the choke model

useful for design
not so accurate models



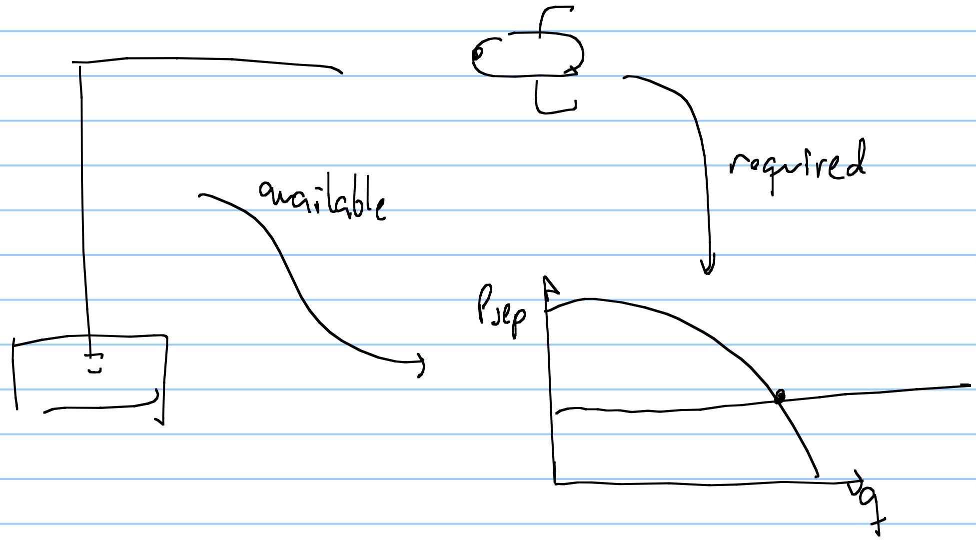

where to do equilibrium

**bottomhole**

- Boosting design
- artificial lift design
- control reservoir simulator

**wellhead**

- allocation
- field design
- condition monitoring



look in detail into the components of the production system

- Reservoir deliverability

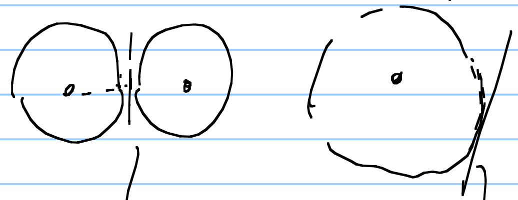
→ IPR
- equation
- collection of points

inflow performance relationship

(representation of the (pseudo) steady state of the well


flowing bottomhole pressure.

- information about conditions away from the wells, boundary



seal

neighboring producers

- flow restrictions in the formation
$k, \mu, \rho$

near wellbore
- skin damage
- perforations
- fracks

- convergence effect

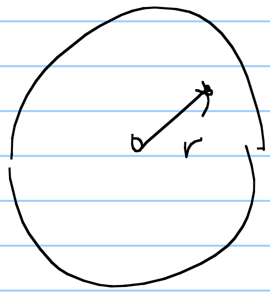

how do we get IPR → analytical derivation radial well undersaturated

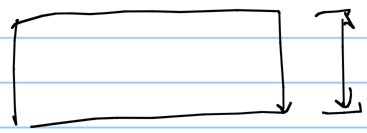
compressibility

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

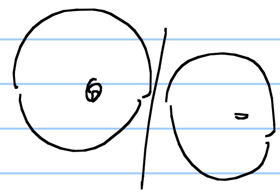
PDE partial differential equation,

Boundary condition (BC)





- Fixed pressure
  - injection
- no flow boundary

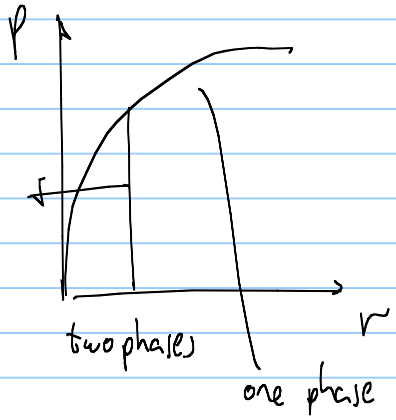


$$q_o = \frac{kh(p_R - p_{wf})}{141.2\mu_o B_o \ln(0.61 r_e/r_w)}$$

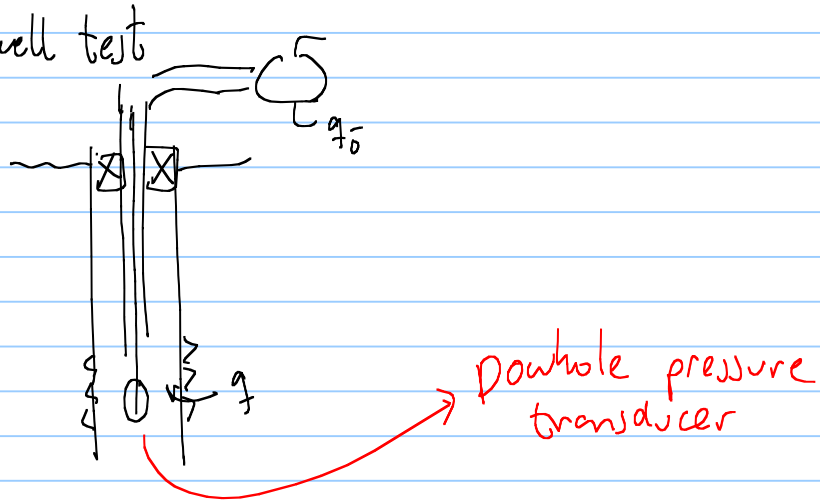
$r_w$: wellbore radius

$r_e$: outer bound radius

$B_o$: oil formation volume factor

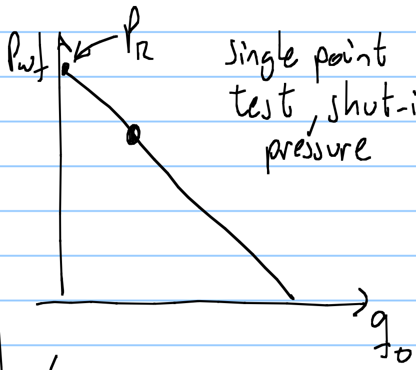



- well test



# How does the IPR looks like?

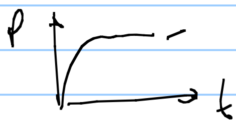
## Undersaturated oil



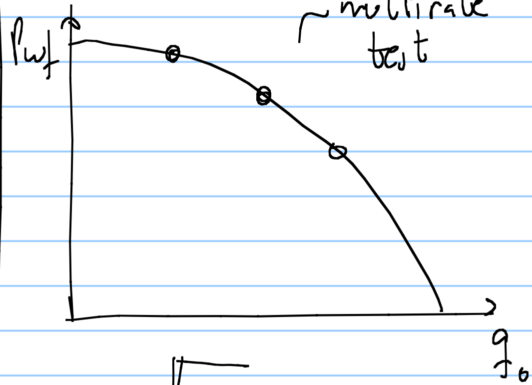

single point test, shut-in pressure

$$q_o = J\left(P_R - P_{wf}\right)$$

productivity index




## gas, saturated oil

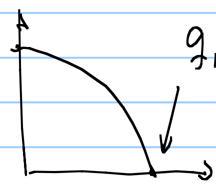



multirate test


stabilization period

Vogel equation (sat. oil)

$$\frac{q}{q_{max}} = 1 - 0.2\frac{P_{wf}}{\overline{P}_R} - 0.8\left(\frac{P_{wf}}{\overline{P}_R}\right)^2$$



$q_{max}$ AOFP

Backpressure equation (gas)

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

$$0.5 \leq n < 1$$

how to find C and n for the backpressure equation from a collection of points?

well test results

| $P_{wf}$ | $q$ | $P_{wf\,calc}$ | $\varepsilon$ |
|---|---|---|---|
| $P_R$ | 0 | | |
| $P_{wf_1}$ | $q_1$ | $\boxed{\phantom{x}}$ $P_{wf_1 cal}$ | $(P_{wf} - P_{wf\,cal})^2$ |
| $P_{wf_2}$ | $q_2$ | $P_{wf_2 calc}$ | |
| $P_{wf_3}$ | $q_3$ | $P_{wf_3 calc}$ | |
| | | | $\Sigma\varepsilon$ |

$C = \boxed{\phantom{x}}$

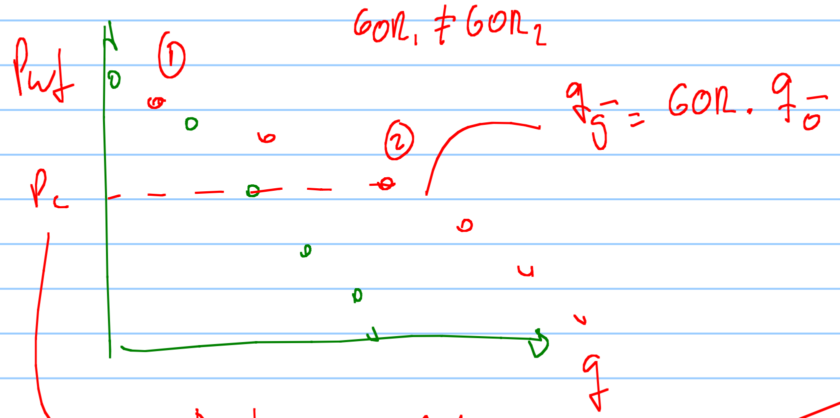
$n = \boxed{\phantom{x}}$

program UDF $P_{wf}$ vs $q$

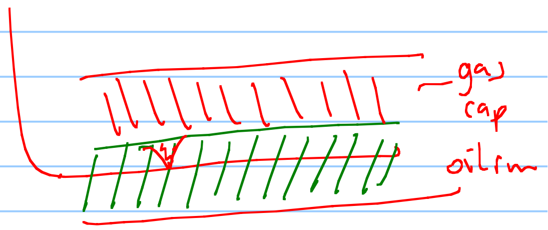
$$P_{wf} = \sqrt{P_R^2 - \left(\frac{q_g}{C}\right)^{1/n}}$$

$GOR_1 \neq GOR_2$

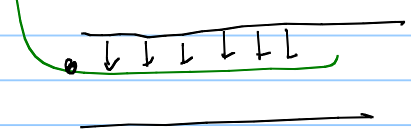
$q_g = GOR \cdot q_o$

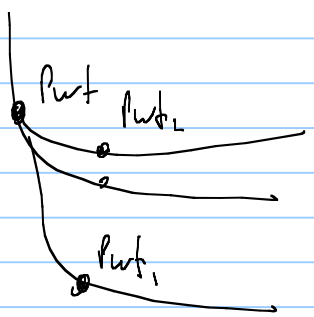



critical coning $P_{wf}$




How do we define bottom-hole pressure → vertical well { in front of the perforation

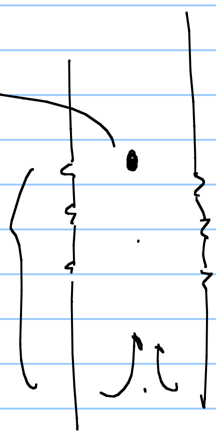





in these cases the IPR has information about the flow in the wellbore

last point where there is fluid coming from the formation

100

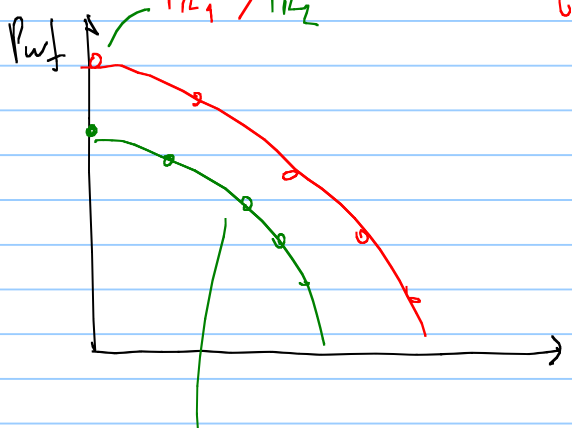


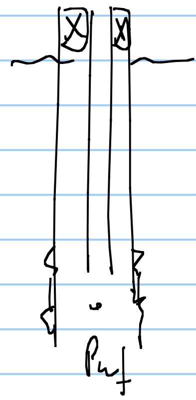
Sometimes is better to use
a collection of points GOR, WC (f) $P_{wf}$

| $P_{wf}$ | $q_o$ | $q_g$ | $q_w$ |
| --- | --- | --- | --- |
| | | | |

IPR does it change with time? $\rightsquigarrow$ IPR changes with time but

$P_{R_1} > P_{R_2}$ $t_1 < t_2$




for single phase gas an undersaturated liquid the equation coefficients remain constant

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

are going to remain constant with depletion

$$q = J\left(P_R - P_{wf}\right)$$

constant

- tubing equation (flow in a circular conduit)

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

single phase liquid

single phase gas

$$\left.\frac{dp}{dx}\right|_{TOTAL} = \left.\frac{dp}{dx}\right|_f + \left.\frac{dp}{dx}\right|_h + \left.\cancel{\frac{dp}{dx}}\right|_a$$

0

along the pipe

$f(p, T)$

$f(\rho, \Delta h)$

# The Tubing Rate Equation in Vertical and Deviated Gas-Wells (*Metric and Oilfield units*)

## Summary

The rate equation for the tubing in vertical gas-wells corrected for wellhead datum level is:

**In practical metric units** (m, bara, Sm$^3$/d, $^oK$)

$$q_{sc} = 0.986(10^9)\left[\frac{D^{2.612}e^{s/2}}{Z_{av}T_{av}\sqrt{(e^s-1)}}\right]\left(p_w^2 - p_t^2\right)^{0.5}$$

**In field units** (Mscf/d, psia, $^oR$, ft for depth, and ,in, for pipe diameter)

$$q_{sc} = 292.9\left[\frac{D^{2.612}e^{s/2}}{Z_{av}T_{av}\sqrt{(e^s-1)}}\right]\left(p_w^2 - p_t^2\right)^{0.5}$$

The equations were derived from the pressure loss equation in gas wells using the average temperature and compressibility approach. The empirical Moody friction factor used is, in field units (D in Inch), $f_M = \dfrac{0.01748}{D^{0.224}}$, and in metric units (D in m), $f_M = \dfrac{0.0077}{D^{0.224}}$. These expressions for friction factor are based on measurements in gas wells by :V.Smith (1950), which were adopted as the norm in Gas Engineering Handbooks (Katz et.al, or ERCB) and Gas Engineering textbooks. In deviated wells, the right hand side of the rate equation is multiplied by $(\cos\alpha)^{0.5}$ where $\alpha$ is the inclination angle from the vertical direction.

## Development of the Equation from First Principles (pure SI system)

Neglecting the acceleration term in the momentum equation, the pressure gradient at any point in the pipe is the sum of the hydrostatic and the frictional gradients:

$$-\frac{dp}{dl} = \rho g\cos\alpha + f_M\frac{\rho u^2}{2D}$$

or

$$-\frac{dp}{dl} = \rho g\cos\alpha + f_F\frac{2\rho u^2}{D} \qquad (1)$$

Where $\alpha$ is the inclination angle from the vertical direction.

When the units are in British Engineering unit system, the equation becomes:

$$-\frac{dp}{dl} = \rho\frac{g}{g_c}\cos\alpha + f_M\frac{\rho u^2}{2g_cD}$$

and in oil field unit system, where pressure is expressed in psia, it is written as

$$-144\frac{dp}{dl} = \rho\frac{g}{g_c}\cos\alpha + f_M\frac{\rho u^2}{2g_cD}$$

Returning to the SI equation, expressing the density in terms of the Equation of State, and the flow velocity in terms of mass flow rate, $u = \dfrac{\dot{m}}{\rho A}$, gives:

$$-\frac{dp}{dl} = \left(\frac{pM_g}{Z\,R\,T}\right) g\cos\alpha + \frac{8\,f\,m^2}{\pi^2\,D^5}.\frac{Z\,R\,T}{pM_g} \tag{2}$$

Defining:

$$C_1 = \frac{M_g}{Z\,R\,T}\;g\;\cos\alpha \tag{3}$$

and

$$C_2 = \frac{8\,f\,m^2}{\pi^2\,D^5}.\frac{Z\,R\,T}{M_g} \tag{4}$$

and substituting into Eq.(2) gives

$$-dp = \left(C_1\,p + \frac{C_2}{p}\right)\,d\,l \tag{5}$$

or

$$dl = -\frac{dp}{C_1 p + \left(\frac{C_2}{p}\right)} = -\frac{p\,dp}{C_1 p^2 + C_2} \tag{6}$$

To integrate this equation a new variable U, is defined,

$$U = C_1\,p^2 + C_2 \tag{7}$$

$$d\,U = 2\,C_1\,p\,d\;p \tag{8}$$

The U and dU substituted into Eq.(6) to gives:

$$d\,l = -\left(\frac{1}{U}\right)\left(\frac{1}{2\,C_1}\right)\,d\,U \tag{9}$$

Integrating Eq.(9) between points 1 and 2:

$$\int_1^2 d\,l = -\frac{1}{2\,C_1}\int_1^2 \frac{d\,u}{u} \tag{10}$$

gives

$$(l_2 - l_1) = L = -\frac{1}{2\,C_1}\ln\left(\frac{U_2}{U_1}\right) = -\frac{1}{2\,C_1}\ln\left(\frac{C_1\,p_2^2 + C_2}{C_1\,p_1^2 + C_2}\right) \tag{11}$$

or

$$\frac{C_1\,p_2^2 + C_2}{C_1\,p_1^2 + C_2} = e^{-2\,L\,C_1} \tag{12}$$

Defining

$$S = 2\,L\,C_1 = 2\frac{M_g}{Z\,R\,T}\;g\;L\cos\alpha \tag{13}$$

Eq.(12) becomes

$$\frac{C_1\, p_2^2 + C_2}{C_1\, p_1^2 + C_2} = e^{-S} \tag{14}$$

Which can be rearranged such that

$$p_1^2 = p_2^2 e^S + \left(\frac{C_2}{C_1}\right)(\,e^S - 1) \tag{15}$$

Dividing Eq.(4) by Eq.(3) gives:

$$\frac{C_2}{C_1} = \frac{8\ f\ m^2 (Z\ R\,T\ )^2}{\pi^2\ D^5\ M_g^2\ g\ \cos\alpha} \tag{16}$$

Converting the mass flow rate to volumetric flow-rate expressed at standard conditions using Eq.(17)

$$m = \rho_{sc}\ q_{sc} = \left(\frac{p}{T}\right)_{sc} \frac{M_g}{R} . q_{sc} \tag{17}$$

results in

$$\frac{C_2}{C_1} = \frac{8\ f}{\pi^2\ D^5}\left(\frac{p}{T}\right)_{sc}^2 \frac{(Z\,T\,)^2}{g\ \cos\alpha}\, q_{sc}^2 \tag{18}$$

Substituting Eq. 18 into Eq.15

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

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

$$s = 2\frac{M_g g}{Z_{av} R T_{av}} L \cos\alpha = 2\frac{(28.97)\gamma_g g}{Z_{av} R T_{av}} L \cos\alpha \tag{20}$$

$$p_{wf}^2 = p_t^2\ e^S + \left(\frac{16}{\pi^2}\right)\ \frac{(28.97)}{R}\left(\frac{p_{SC}}{T_{SC}}\right)^2 f_M\ L\,\gamma_g\ Z_{av}\ T_{av}\ \frac{(\,e^S\ -\ 1\,)}{S\ D^5}\, q_{sc}^2 \tag{21}$$

Solving for the flow rate:

$$q_{sc} = \left(\frac{\pi}{4}\right)\left(\frac{R}{M_{air}}\right)^{0.5}\left(\frac{T_{SC}}{P_{SC}}\right)\left[\frac{D^5}{\gamma_g\, f_M Z_{av} T_{av}\ L}\right]^{0.5}\left[\left(p_{wf}^2 - p_t^2\, e^S\,\right)\left(\frac{s}{e^S\ -\ 1}\right)\right]^{0.5} \tag{22}$$

This equation relates the pressure at the top and the bottom of the tubing.

In integrated gas field studies, it is convenient to analyze the flow of the entire production system using the wellhead or the top of the well as a reference datum level. Mike Fetkovich has suggested this approach in a 1975 paper. He rearranged the flow equation as follows:

$$q_{sc} = \left(\frac{\pi}{4}\right)\left(\frac{R}{M_{air}}\right)^{0.5}\left(\frac{T_{SC}}{P_{SC}}\right)\left[\frac{D^5}{\gamma_g\, f_M Z_{av} T_{av}\ L}\right]^{0.5}\left[\left(\frac{p_{wf}^2}{e^S} - p_t^2\right)\left(\frac{s e^S}{e^S\ -\ 1}\right)\right]^{0.5} \tag{23}$$

Substituting ; $\frac{p_{wf}^{2}}{e^{S}} = p_w^2$ ,

$$q_{sc} = \left(\frac{\pi}{4}\right)\left(\frac{R}{M_{air}}\right)^{0.5}\left(\frac{T_{SC}}{P_{SC}}\right)\left[\frac{D^5}{\gamma_g f_M Z_{av} T_{av} L}\right]^{0.5}\left[\left(p_w^2 - p_t^2\right)\left(\frac{se^S}{e^S - 1}\right)\right]^{0.5} \qquad (24)$$

where $p_w$ represent the flowing bottom hole pressure expressed at wellhead datum level . The quantity, $p_w$. is actually the bottom-hole flowing pressure minus the hydrostatic pressure of the gas column.

The rate equation can be further rearranged by substituting

$$s = 2\frac{M_g g}{Z_{av} R T_{av}} L\cos\alpha = 2\frac{(28.97)\gamma_g g}{Z_{av} R T_{av}} L\cos\alpha = 2\frac{(28.97)\gamma_g g}{Z_{av} R T_{av}} H \qquad (25)$$

Giving (all in pure SI system):

$$q_{sc} = \frac{\pi}{4}\left(\frac{T_{SC}}{P_{SC}}\right)\left(2g\cos\alpha\right)^{0.5}\left[\left(\frac{D^5}{f_M}\right)^{0.5}\frac{e^{s/2}}{Z_{av} T_{av}\sqrt{(e^s - 1)}}\right]\left(p_w^2 - p_t^2\right)^{0.5} \qquad (26)$$

**In practical metric units**, where: Gas-rate=sm$^3$/d, Pressure =bara, Length =m, and Temperature = $^oK$ , the equation becomes:

$$q_{sc} = 86400\left[2(9.81)\cos\alpha\right]^{0.5}\frac{\pi}{4}\left(\frac{288}{1}\right)\left[\left(\frac{D^5}{f_M}\right)^{0.5}\frac{e^{s/2}}{Z_{av} T_{av}\sqrt{(e^s - 1)}}\right]\left(p_w^2 - p_t^2\right)^{0.5} \qquad (27)$$

or

$$q_{sc} = 86.56(10^6)\left(\cos\alpha\right)^{0.5}\left[\left(\frac{D^5}{f_M}\right)^{0.5}\frac{e^{s/2}}{Z_{av} T_{av}\sqrt{(e^s - 1)}}\right]\left(p_w^2 - p_t^2\right)^{0.5} \qquad (28)$$

In vertical wells H=L, and $\cos\alpha$ =1.

In fully turbulent flow (high Reynolds numbers), friction factor depends essentially on the relative roughness of the pipe, $\varepsilon / D$, and becomes independent of the eynolds number. Measurements in gas wells conducted by R.V.Smith, (1950), yielded a correlation for friction factor in tubings that became the norm for most equations used by the gas industry and which appear in engineering handbooks. Smith measurements are expressed in terms of friction factor as:

$$f_M = \frac{0.01748}{D^{0.224}\left[|1m|\left|\frac{39.37inch}{1m}\right|\right]^{0.224}} = \frac{0.0077}{D^{0.224}} \qquad (29)$$

When substituting into the rate equation gives:

$$q_{sc} = 0.986(10^9)\left[\frac{D^{2.612}e^{s/2}}{Z_{av} T_{av}\sqrt{(e^s - 1)}}\right]\left(p_w^2 - p_t^2\right)^{0.5} \qquad (30)$$

This is the metric version of the rate equation suggested by Fetkovich for integrated field studies.

**The rate equation in oilfield units**

In practical field units (psia, Mscf/D, ft, $^{o}R$), the datum corrected rate equation (eq 26) is

$$q_{sc} = (10^{-3})86400\frac{\pi}{4}\left(\frac{520}{14.7}\right)\left[2(32.17)\cos\alpha\right]^{0.5}\left[\left(\frac{D^5}{12^5 f_M}\right)^{0.5}\frac{e^{s/2}}{Z_{av}T_{av}\sqrt{(e^s-1)}}\right]\left(p_w^2-p_t^2\right)^{0.5}$$

Substituting the expression for Moody friction factor

$$q_{sc} = (10^{-3})86400\frac{\pi}{4}\left(\frac{520}{14.7}\right)\left[2(32.17)\cos\alpha\right]^{0.5}\left[\frac{D^5}{12^5\left(\frac{0.01748}{D^{0.224}}\right)}\right]^{0.5}\frac{e^{s/2}}{Z_{av}T_{av}\sqrt{(e^s-1)}}\left(p_w^2-p_t^2\right)^{0.5}$$

Which finally gives

$$q_{sc} = 292.9\left[\frac{D^{2.612}e^{s/2}}{Z_{av}T_{av}\sqrt{(e^s-1)}}\right]\left(p_w^2-p_t^2\right)^{0.5} \qquad (31)$$

**Fetkovich Rate Equation**

The equation used by Fetkovich in his 1975 is derived from the IOCC manual and is (rate is in mscf/d)

$$q_{sc} = \left[\frac{31.62e^{s/2}}{F_r Z_{av}T_{av}\sqrt{(e^s-1)}}\right]\left(p_w^2-p_t^2\right)^{0.5} \qquad (32)$$

where $F_r = \dfrac{0.10797}{D^{2.612}}$.

The relationship between $F_r$ and the friction factors is, by definition,:

$$F_r^2 = \frac{2.6665 f_F q^2}{D^5} = \frac{2.6665\left(\frac{f_M}{4}\right)q^2}{D^5}$$

where: D= inner tubing diameter, in and q is the gas rate in MMscf/D.

The dimensional expression $F_r$ has been introduced originally by Cullender and Smith (1956) to facilitate another method to calculated bottom hole pressure accounting for changes in temperature and compressibility factor. The IOCC preferred to apply it in its manual rather than the dimensionless friction factor (Oklahoma City People versus the rest of the world). By substituting the empirical value of $F_r$ to the rate equation it becomes:

$$q_{sc} = 292.9\left[\frac{D^{2.612}e^{s/2}}{Z_{av}T_{av}\sqrt{(e^s-1)}}\right]\left(p_w^2-p_t^2\right)^{0.5} \qquad (33)$$

For control purposes, the equation will be converted to practical metric units

$$q_{sc} = 292.9\left(\frac{1000}{1}\right)\left(\frac{1}{35.14}\right)\left[\frac{(39.37D)^{2.612}\,e^{s/2}}{Z_{av}1.8T_{av}\sqrt{(e^s-1)}}\right]\frac{14.7}{1}\left(p_w^2-p_t^2\right)^{0.5}$$

or

$$q_{sc} = 0.998(10^9)\left[\frac{D^{2.612}e^{s/2}}{Z_{av}T_{av}\sqrt{(e^s-1)}}\right]\left(p_w^2-p_t^2\right)^{0.5} \qquad (34)$$

## The pressure equations in practical field units (Metric)

The pure SI pressure equation developed earlier is

$$p_{wf}^2 = p_t^2\, e^S + \frac{8\, f_M}{\pi^2\, D^5\, g\, \cos\alpha}\left(\frac{p}{T}\right)_{sc}^2 (Z_{av}\, T_{av})^2 (\, e^S\; - 1)\, q_{sc}^2 \qquad (0.1)$$

or, when substituting values for the constants,

$$p_{wf}^2 = p_t^2\, e^S + \frac{8}{\pi^2\;\, 9.81}\left(\frac{10^5}{293}\right)_{sc}^2 f_M\, (Z_{av}\, T_{av})^2 \frac{(\, e^S\; - 1)}{D^5 \cos\alpha}\; q_{sc}^2 \qquad (0.2)$$

giving

$$p_{wf}^2 = p_t^2\, e^S + 9624\, f_M\, (Z_{av}\, T_{av})^2 \frac{(\, e^S\; - 1)}{D^5 \cos\alpha}\; q_{sc}^2 \qquad (0.3)$$

When converting to practical metric units, Sm$^3$/d, bara, m, The equation becomes

$$p_{wf}^2 = p_t^2\, e^S + \frac{9624}{\left(10^5\right)^2 \left(86400\right)^2}\, f_M\, (Z_{av}\, T_{av})^2 \frac{(\, e^S\; - 1)}{D^5 \cos\alpha}\; q_{sc}^2 \qquad (0.4)$$

or

$$p_{wf}^2 = p_t^2\, e^S + 1.295(10^{-16})\, f_M\, (Z_{av}\, T_{av})^2 \frac{(\, e^S\; - 1)}{D^5 \cos\alpha}\; q_{sc}^2 \qquad (0.5)$$

Similarly, the other form of the pressure equation in SI units

$$p_{wf}^2 = p_t^2\, e^S + \left(\frac{16}{\pi^2}\right) \frac{(28.97)}{R}\left(\frac{p_{SC}}{T_{SC}}\right)^2 f_M\; L\, \gamma_g\, Z_{av}\, T_{av}\, \frac{(e^S\; - 1\,)}{S\; D^5}\, q_{sc}^2 \qquad (0.6)$$

or

$$p_{wf}^2 = p_t^2\, e^S + 658\;\, f_M\;\, L\, \gamma_g\, Z_{av}\, T_{av}\, \frac{(e^S\; - 1\,)}{S\; D^5}\, q_{sc}^2 \qquad (0.7)$$

Giving in practical metric units

$$p_{wf}^2 = p_t^2\, e^S + 8.8(10^{-18})\;\, f_M\;\, L\, \gamma_g\, Z_{av}\, T_{av}\, \frac{(\, e^S\; - 1\,)}{S\; D^5}\, q_{sc}^2 \qquad (0.8)$$

## Appendix A

# The relationship between $f_M$ and the $F_r$ in the IOCC equation

***Interstate Oil Compact Commission "manual of Backpressure Testing of Gas Wells", Oklahoma City, Oklahoma***

Cullender and Smith (1956) introduced originally the dimensional expression $F_r$. It is a function of $f_M$, flow rate, and pipe diameter. Back calculating the friction factor from the $F_r$ used in the IOCC equation yields

$$f_F = \frac{0.00437}{D^{0.224}}$$
$$f_M = \frac{0.01748}{D^{0.224}} \qquad (0.9)$$

Starting with the IOCC equation as listed in Fetkovich's paper from 1975 (before dividing by $e^S$ for datum change):

$$p_{wf}^2 = p_t^2 e^S + \left[\frac{F_r q T_{av} Z_{av}}{31.62}\right]^2 (e^S - 1)$$

Rearranging,

$$p_{wf}^2 = p_t^2 e^S + \left[\frac{F_r T_{av} Z_{av}}{31.62}\right]^2 (e^S - 1) q_{SC}^2$$

where :

$F_r = \frac{0.10797}{D^{2.612}}$ and pipe diameter D is in inch, and the gas rate is in Mscf/d

(Note: there is an error in the pressure equation in the original 1975 paper where the equations are hand written, there the number 31.62 is wrongly written as 1000. The error has been corrected in later prints of the paper, also be aware that the rate equation in most gas engineering manuals is reported in MMscf/d, Fetkovich uses Mscf/d in his analysis)

For comparison, taking any of the widely used engineering equations, for example in the **SPE –Petroleum Engineering Handbook** (Chapter 34 "Wellbore Hydraulics" by Bertuzzi, Fetkovich, Poettmann and Thomas, equation 44) which applies Moody friction factor $f_m$,

$$p_1^2 = p_2^2 e^S + 25 f_m \, H \, \gamma_g \, Z \, T \frac{(e^S - 1)}{s D^5} q_{sc}^2 \qquad (0.10)$$

or, by substituting the expression for s

$$p_1^2 = p_2^2 e^S + 25 f_m \, Z_{ab}^2 \, T_{av}^2 \frac{(e^S - 1)}{0.0375 D^5} q_{sc}^2 \qquad (0.11)$$

or in the **The Canadian Energy Resource Conservation Board Manual on gas well testing** which applies Fanning friction factor (Note that Moody factor is 4x Fanning factor)

$$p_1^2 = p_2^2 e^S + 100 f_F \, H \, \gamma_g \, Z_{av} \, T_{av} \frac{(e^S - 1)}{s D^5} q_{sc}^2 \qquad (0.12)$$

The units in these two equations are: P= psia, H= vertical depth, ft, , q=flow-rate, MMscfd, d=inch, f=friction factor (dimensionless), and s is expressed by the following expression:

$$s = 2\frac{(28.97)\gamma_g g}{Z_{av} R T_{av}} H = 2\left[\frac{(28.97)(32.174)}{(10.732)(144)(32.174)}\right]\frac{\gamma_g}{Z_{av} T_{av}} H = 0.0375 \frac{\gamma_g}{Z_{av} T_{av}} H \qquad (0.13)$$

To back calculate the friction factor as implied by the IOCC equation, a comparison is made between the second terms on the right hand side of the IOCC and the ERCB equations (converting it from MMscf/d to Mscf/d as used by the IOCC).

$$\left[\frac{F_r T_{av} Z_{av}}{31.62}\right]^2 (e^S - 1) q_{SC}^2 = 100 f_F \; H \gamma_g Z_{av} T_{av} \frac{(e^S - 1)}{s\,D^5} q_{sc}^2 (10^{-6})$$

Substituting s in the denominator of the right hand side gives

$$1000\left[F_r T_{av} Z_{av}\right]^2 (e^S - 1) q_{SC}^2 = 100 f_F \; H \gamma_g Z_{av} T_{av} \frac{(e^S - 1)}{\left(0.0375 \frac{\gamma_g}{Z_{av} T_{av}} H\right) D^5} q_{sc}^2$$

which, when compared with the relevant term in IOCC equation gives:

$$\left[F_r\right]^2 = 0.1 f_F \; \frac{1}{(0.0375)\,D^5}$$

Solving for the Fanning Friction factor ,$f_F$

$f_F = \left[F_r\right]^2 (0.375)\,D^5$ and

and substituting $F_r = \dfrac{0.10797}{D^{2.612}}$, gives:

$f_F = \left[\dfrac{0.10797}{D^{2.612}}\right]^2 (0.375)\,D^5 = \dfrac{4.371(10^{-3})}{D^{0.224}} = \dfrac{0.00437}{D^{0.224}}$, which is equivalent to :

$$f_M = 4\left[\frac{0.10797}{D^{2.612}}\right]^2 (0.375)\,D^5 = \frac{17.484(10^{-3})}{D^{0.224}} = \frac{0.0174}{D^{0.224}}$$

The diameter, D, in both expressions is in Inch (While the pipe length in the equation is in ft).

## References for developing the rate equation

Katz, D.L., Cornel, D., Kobayashi, R., Poetmann, F.H., Vary, J.A. Elenbass, J.R., Weinaug, C.F.” Handbook of Natural Gas Engineering”, McGrraw-Hill Publishing Company, 1959

Smith, R.V. “Determining Friction Factors for Measuring Productivity of Gas Wells” Trans AIME, Vol **189:** (73) 1950

Energy Resources Conservation Board (ERCB) “Theory and Practice of the Testing of Gas Wells”, ERCB 73-34, Third Edition, 1975..

Katz, D.L., Lee, R.L., “Natural Gas Engineering-Production and Storage” McGraw-Hill Publishing Company (1990)

Young, K.L. “Effect of Assumptions Used to Calculate Bottom-Hole Pressures in Gas Wells” SPE paper 1626 (1966)

**References for the friction factor in gas wells**

Smith, R.V., Willims R.H., and Dewees, E.J. “Measurements of Resistance to Flow of Fluids in Natural Gas Wells” Trans AIME (**201**), 279, 1954

Cullender M.H., and Smith R.V. “ Practical solution of the Gas Flow Equations for Wells and Pipelines with Large Temperature Gradients” Trans AIME Vol **207** 281-287 (1956)

# Tubing flow Equation-Dry gas

$T_{sc} = 15.56\,°C$

$p_{sc} = 1.01325$ bar

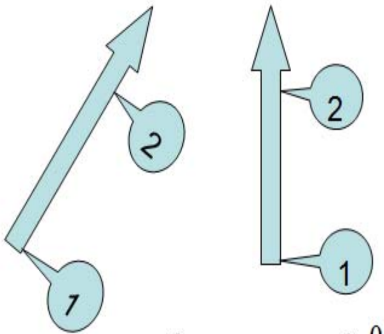
$z$

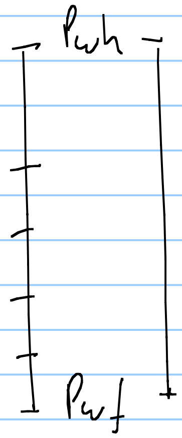
universal gas constan

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

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

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



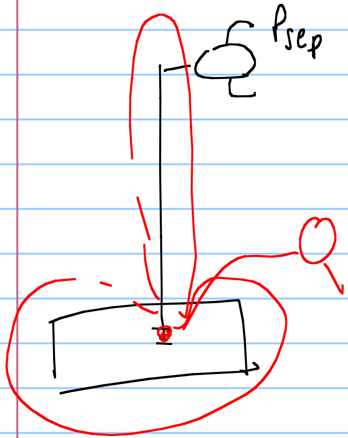




$$p_{\text{inlet}} = p_1 = e^{s/2}\left(p_2^2 + \frac{q_g^2}{C_T^2}\right)^{0.5} \qquad p_{wh} = p_2 = \left(\frac{p_1^2}{e^s} - \frac{q_g^2}{C_T^2}\right)^{0.5}$$

$p_1 = f(p_2, q_g)$ ~> single phase gas, constant inclination.

Exercise in excel.

Well hydraulic equilibrium   equilibrium point   bottom hole




Approximation $P_{wh} \simeq P_{sep}$

equilibrium point

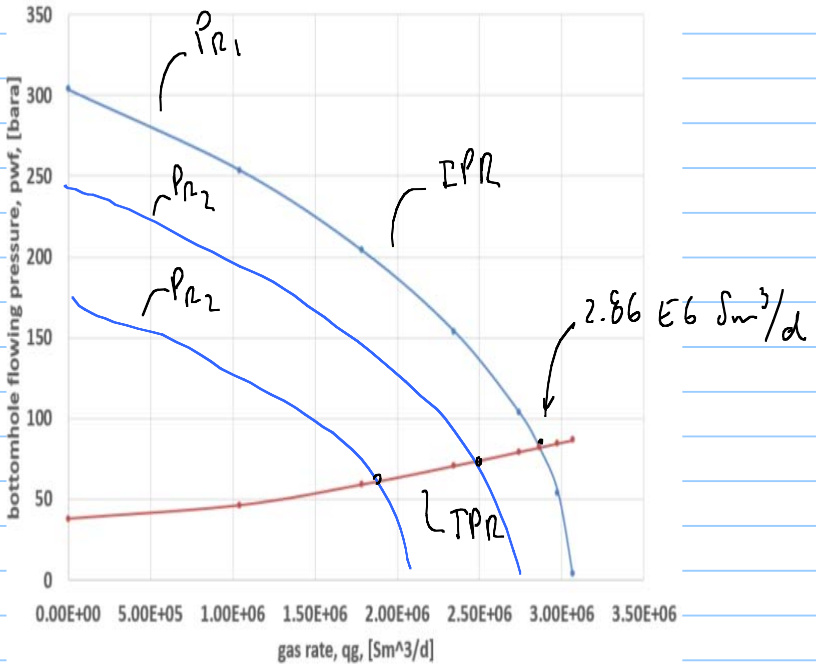
$$q = C_R\left(P_R^2 - P_{wf}^2\right)^n \qquad P_{wf} = \sqrt{\phantom{x}} \quad (-)$$

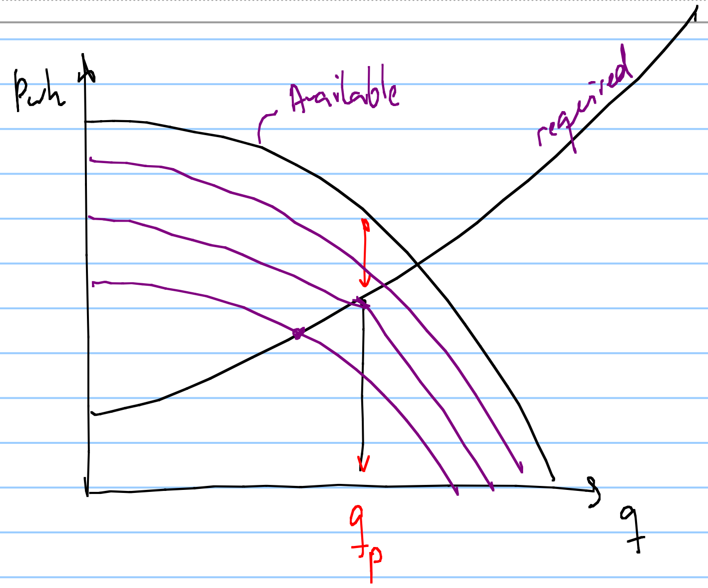
$$q_g = C_R \left(p_R^2 - p_{wf}^2\right)^n$$

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

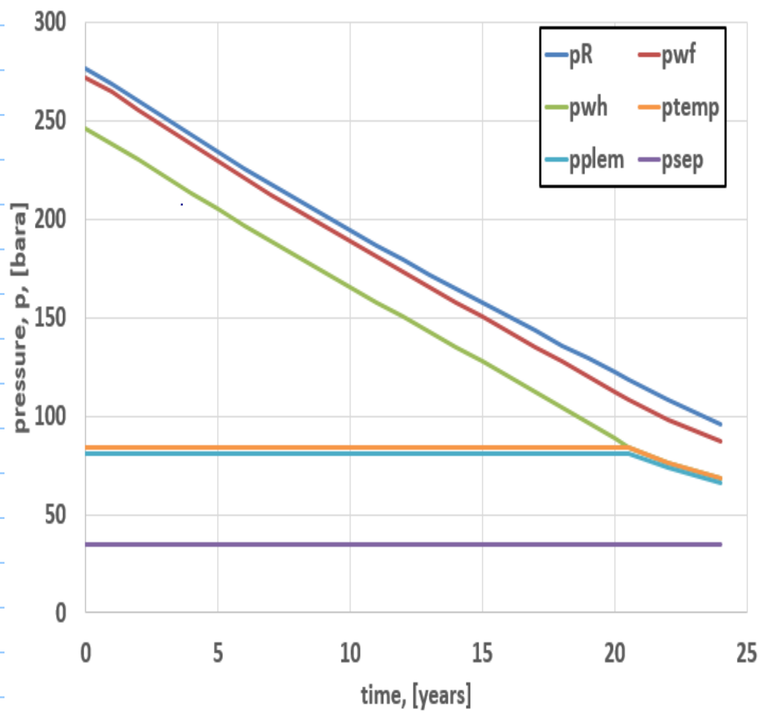
| | | | | | |
|---|---|---|---|---|---|
| **Eva no 3** | | | | | |
| pR | 304 | bara | | 290 | bara |
| C inflow | 104 | Sm3/d/(bar^2n) | | | |
| n, exponent | 0.9 | | | | |
| Tubing, $C_t$ | 4.25E+04 | Sm3/d/bar | | | |
| s-Elevation factor | 0.155 | | | | |
| pwh= | 35 | 50 | | 85 | bara |
| | | | | | |
| | | **IPR** | | **TPR** | |
| | | | | pwh=35 bara | |
| | | **pwf** | **q** | **pin** | **error** |
| | | **bara** | **Sm3/d** | **bara** | **(bar^2)** |
| | | 304 | 0.00E+00 | 38 | |
| | | 254 | 1.04E+06 | 46 | |
| | | 204 | 1.79E+06 | 59 | |
| | | 154 | 2.35E+06 | 71 | |
| | | 104 | 2.74E+06 | 79 | |
| | | 82 | 2.86E+06 | 82 | 7.47E-12 |
| | | 54 | 2.98E+06 | 85 | |
| | | 4 | 3.06E+06 | 87 | |

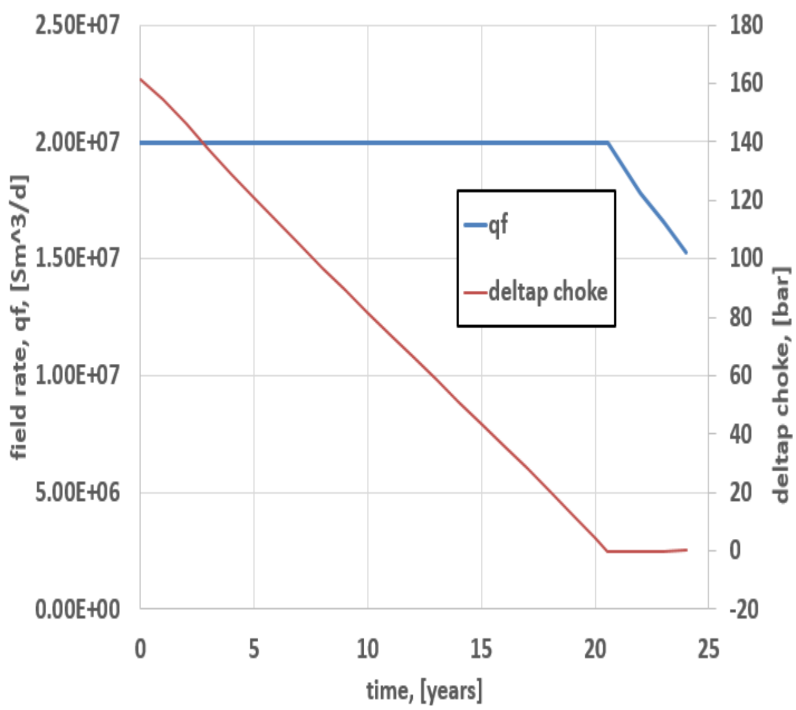
$p_{in}$




Pwh
Available
required
q
$q_p$


qf
time


pR
pwf
pwh
ptemp
pplem
psep
pressure, p, [bara]
time, [years]
300
250
200
150
100
50
0
0
5
10
15
20
25


qf
deltap choke
field rate, qf, [Sm^3/d]
deltap choke, [bar]
time, [years]
2.50E+07
2.00E+07
1.50E+07
1.00E+07
5.00E+06
0.00E+00
180
160
140
120
100
80
60
40
20
0
-20
0
5
10
15
20
25

## Snøhvit qas Field (Base Case Data)

| | | |
|---|---|---|
| G=IGIP | 270E+09 | Sm3 |
| Annual production rate | 0.027 | fraction of IGIP |
| Production days per year | 365 | day |
| $T_R$ | 92 | oC |
| Pi, initial Res pressure | 276 | bara |
| C, inflow Back pressure coefficient | 1000 | Sm3/bar^2n |
| n, backpressure, exponent | 1 | |
| Ct, Tubing coefficient (2100 MDx0.15 ID m) | 4.03E+04 | Sm3/bar |
| 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 | 35 | bara |
| Gas molecular weight (Methane) | 16 | kg/kmole |
| Gas specific gravity | 0.55 | Gas specific gravity |
| Number of templates | 3 | |
| Number of wells poer template | 3 | |
| Desired plateau | | years |
| qfield | 20.0E+6 | [Sm^3/d] |

1. Identical wells (i.e same PR CR, n, Ct, S)
2. System is Symmetric
3. Field Rate = 20 MMSCM

qwell = qg/no.of.wells
PR= ZR* P/Zi * (1-Gp/G)
Pwf = sqrt(Pr^2-qg/C) as n=1
Pwh = sqrt((pwf^2/e^s)-((qg/Ct)^2))
Psep
Pplem
Ptempl

| time [years] | qwell [Sm^3/d] | Gp [Sm^3] | Z | RF | PR [bara] | pwf [bara] | pwh [bara] | ptemp [bara] | qtemp [Sm^3/d] | qfield [Sm^3/d] | Pplem [bara] | Psep [bara] | Deltpchoke [bara] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 2.22E+06 | 000.0E+0 | 0.967 | 0.000 | 276 | 272 | 246 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 162 |
| 1 | 2.22E+06 | 7.3E+9 | 0.963 | 0.027 | 269 | 264 | 238 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 154 |
| 2 | 2.22E+06 | 14.6E+9 | 0.957 | 0.054 | 260 | 256 | 230 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 146 |
| 3 | 2.22E+06 | 21.9E+9 | 0.953 | 0.081 | 251 | 247 | 221 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 138 |
| 4 | 2.22E+06 | 29.2E+9 | 0.948 | 0.108 | 242 | 238 | 213 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 129 |
| 5 | 2.22E+06 | 36.5E+9 | 0.944 | 0.135 | 234 | 229 | 205 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 121 |
| 6 | 2.22E+06 | 43.7E+9 | 0.941 | 0.162 | 226 | 221 | 197 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 113 |
| 7 | 2.22E+06 | 51.0E+9 | 0.937 | 0.189 | 218 | 213 | 189 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 105 |
| 8 | 2.22E+06 | 58.3E+9 | 0.935 | 0.216 | 210 | 204 | 181 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 97 |
| 9 | 2.22E+06 | 65.6E+9 | 0.932 | 0.243 | 202 | 196 | 173 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 89 |
| 10 | 2.22E+06 | 72.9E+9 | 0.931 | 0.270 | 194 | 188 | 165 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 81 |
| 11 | 2.22E+06 | 80.2E+9 | 0.929 | 0.297 | 187 | 181 | 158 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 74 |
| 12 | 2.22E+06 | 87.5E+9 | 0.928 | 0.324 | 179 | 173 | 150 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 66 |
| 13 | 2.22E+06 | 94.8E+9 | 0.927 | 0.351 | 172 | 165 | 143 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 59 |
| 14 | 2.22E+06 | 102.1E+9 | 0.927 | 0.378 | 165 | 158 | 135 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 51 |
| 15 | 2.22E+06 | 109.4E+9 | 0.926 | 0.405 | 157 | 150 | 128 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 44 |
| 16 | 2.22E+06 | 116.6E+9 | 0.927 | 0.432 | 150 | 143 | 120 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 36 |
| 17 | 2.22E+06 | 123.9E+9 | 0.927 | 0.459 | 143 | 135 | 112 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 28 |
| 18 | 2.22E+06 | 131.2E+9 | 0.928 | 0.486 | 136 | 128 | 104 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 20 |
| 19 | 2.22E+06 | 138.5E+9 | 0.929 | 0.513 | 129 | 120 | 96 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 13 |
| 20 | 2.22E+06 | 145.8E+9 | 0.931 | 0.540 | 122 | 113 | 88 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 4 |
| 21 | 2.22E+06 | 149.7E+9 | 0.932 | 0.555 | 118 | 109 | 84 | 84 | 6.66E+06 | 2.00E+07 | 81 | 35 | 0 |
| 22 | 1.98E+06 | 160.4E+9 | 0.935 | 0.594 | 108 | 98 | 77 | 77 | 5.94E+06 | 1.78E+07 | 74 | 35 | 0 |
| 23 | 1.84E+06 | 166.9E+9 | 0.937 | 0.618 | 102 | 92 | 72 | 72 | 5.52E+06 | 1.66E+07 | 70 | 35 | 0 |
| 24 | 1.70E+06 | 172.9E+9 | 0.939 | 0.640 | 96 | 87 | 68 | 68 | 5.10E+06 | 1.53E+07 | 66 | 35 | 0 |

to find plateau end, use solver $\Delta p_{choke} = 0$ by changing time

to find rate when choke is fully open solver $\Delta p_{choke} = 0$ by changing $q_{well}$.

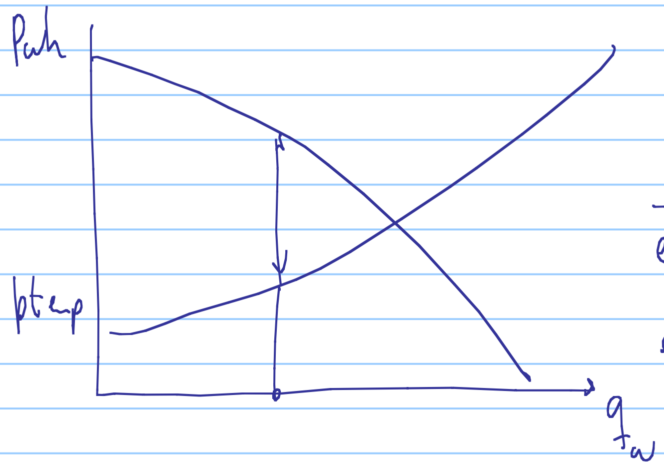
Score group

| | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| task 1 | | | | | 1 |
| task 2 | 1 | | | | 1 |
| task 3 | 1 | | | | |

challenges
Observations about the first task ?
errors
questions

$2^{nd}$ task plot wellhead performance relationship WPR : Available pressure considering IPR + tubing

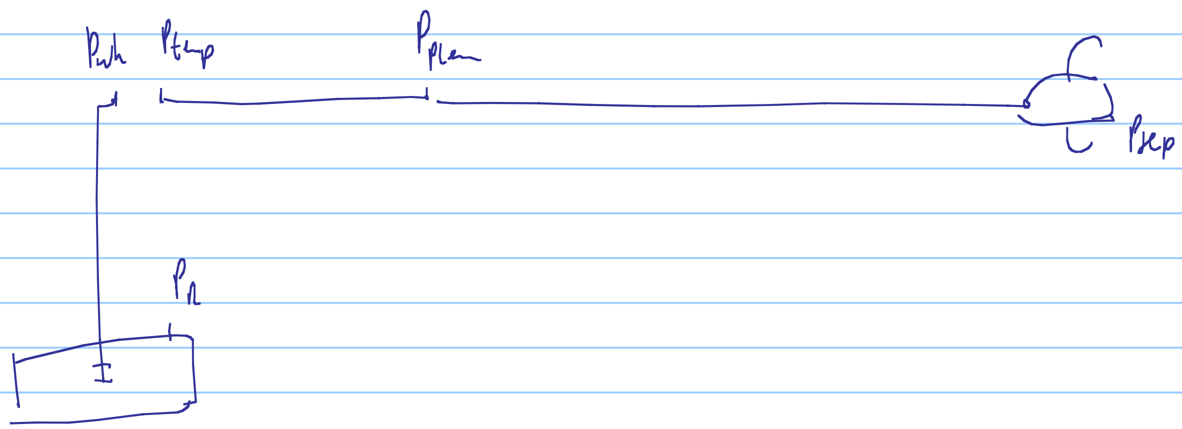
flowline + pipeline performance relationship : required pressure
flow in pipeline $P_{plem}$
flow in flowline template




for

| | |
|---|---|
| end of year | 0 |
| end of year | 10 |
| en of year | 15 |
| end of plateau | 20.54 |

indicate $\Delta p$ choke. (curren operating point)
indicate the production potential of the well.




$P_R$ [bara] = 276 bara
$t$ = 0 year

$q_{well}$ $p_{wf}$ $p_{wh}$ $p_{template}$ $p_{PLEM}$ $p_{sep}$

IPR

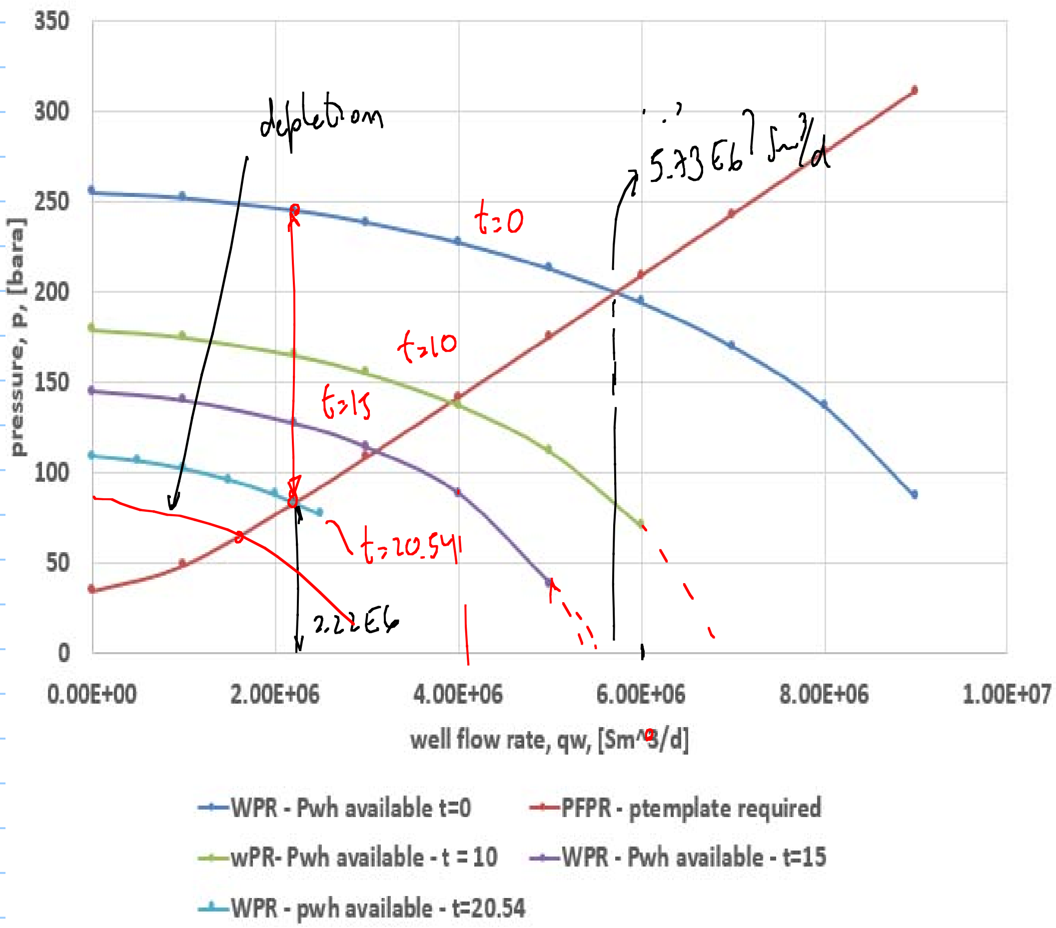
$q_{well} \cdot N_{temp}$, $N_{well}/temp$

[Sm³/d] [bara] [bara] [bara] [bara] [bara]

10

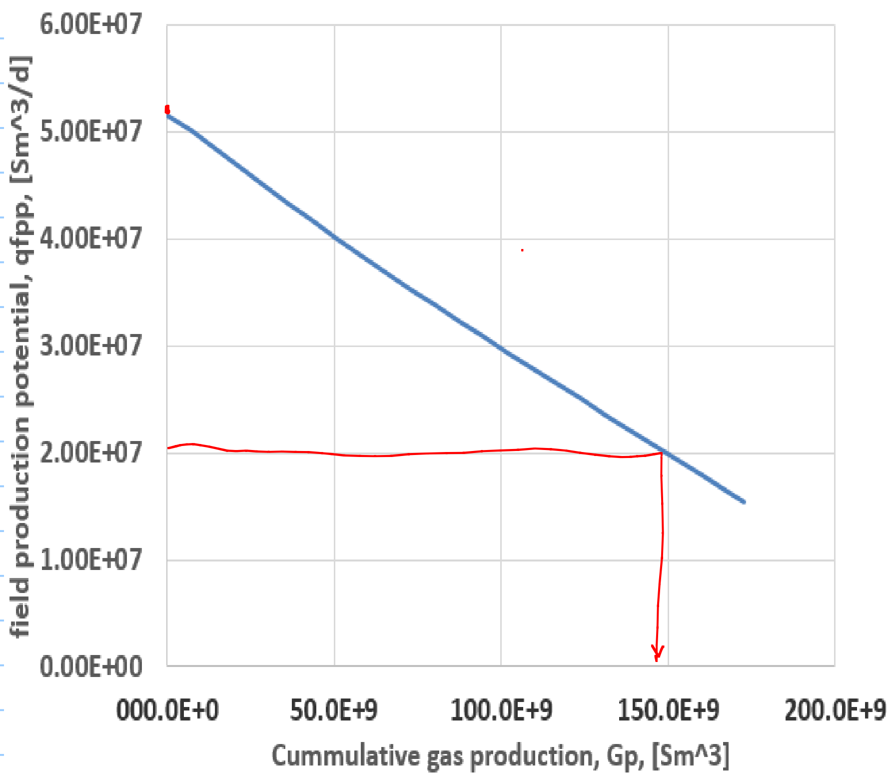
available required

~0



task 3. Compute $q_{fpp}$ vs $G_p$ for all points in my excel sheet. $G_p$

Compute plateau duration based on this curve.




| | |
|---|---|
| Gp for qfpp=20E6 = | 149.7E+9 |
| Number of plateau years | 20.54E+0 |

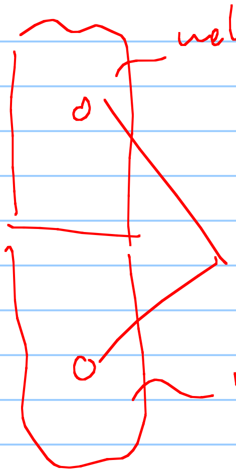
$$\frac{149.7E+9}{(20E6 \cdot 365)} = 20.54$$

every well 'i'

$IPR^i = f(G_p)$

const

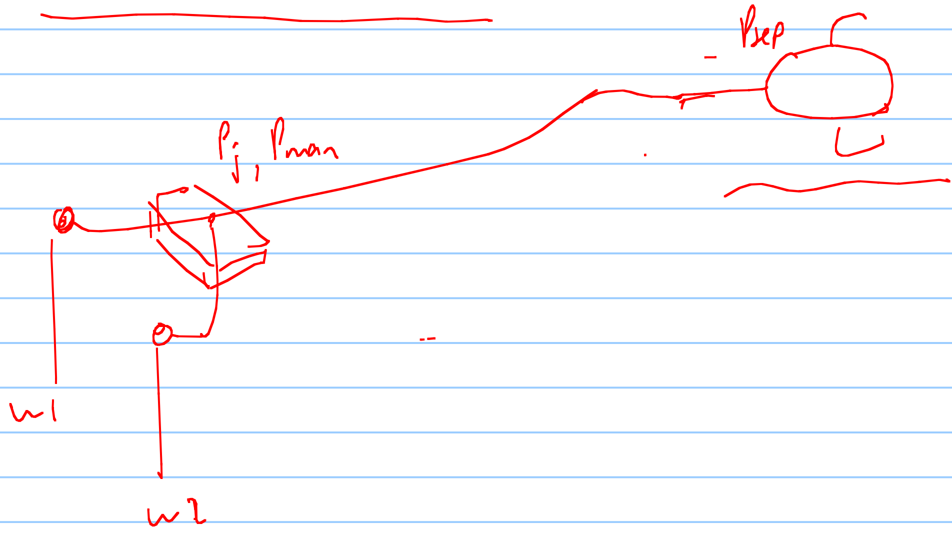
$q_g = C_R \cdot (P_R^2 - P_{wf}^2)^n$



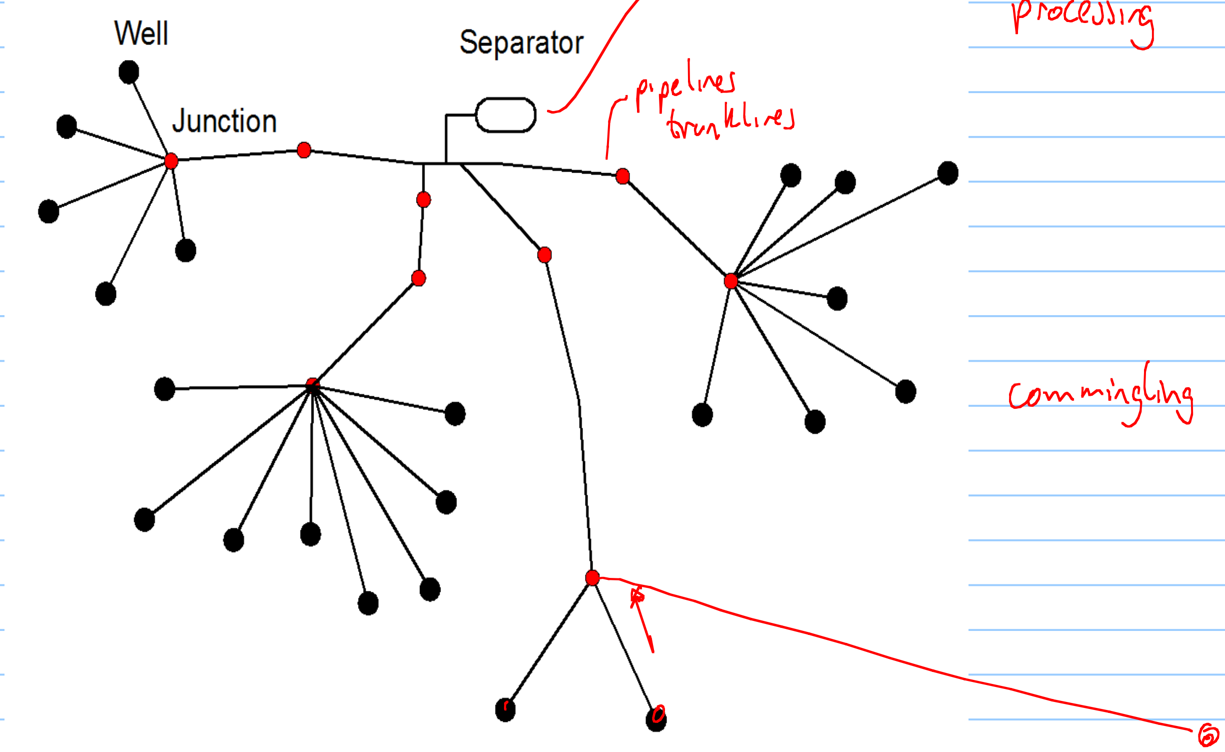
well 1 $IPR^1 = f(G_p^1)$

well 2 $IPR^2 = f(G_p^2)$

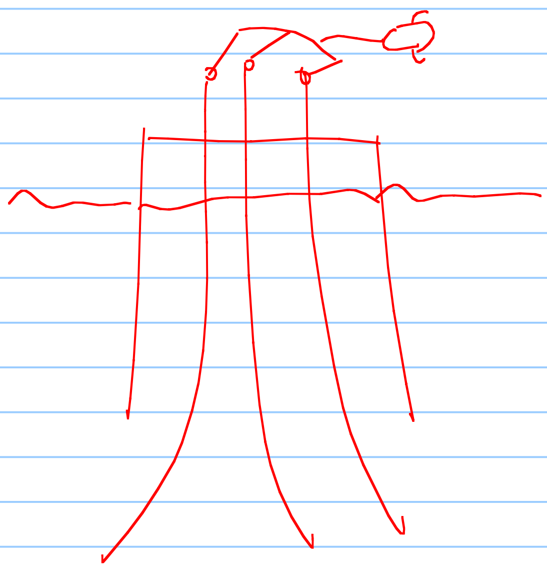
# Production networks



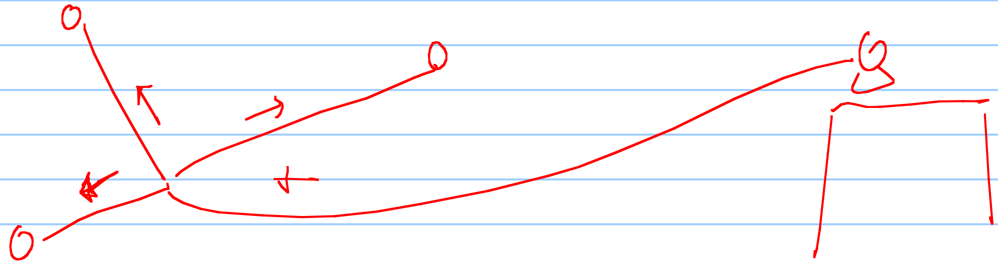

GOSP ~ gas oil separation and processing




commingling network



distribution networks $\begin{cases} \text{injection gas} \\ \text{injection } CO_2 \\ \text{injection water} \end{cases}$



• Some comments from last class

| time | qwell | Gp | Z | RF | PR | pwf | pwh | ptemp | qtemp | qfield | Pplem | Psep | Deltpchoke |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| [years] | [Sm^3/d] | [Sm^3] | | | [bara] | [bara] | [bara] | [bara] | [Sm^3/d] | [Sm^3/d] | [bara] | [bara] | [bara] |
| 0 | 2.22E+06 | 000.0E+0 | 0.967 | 000.0E+0 | 276 | 271.95 | 245.568 | 83.96564 | 6.66E+06 | 2.00E+07 | 81 | 35 | 162 |
| 1 | 2.22E+06 | 7.3E+9 | 0.963 | 27.0E-3 | 268.548 | 264.3839 | 238.387 | 83.96564 | 6.66E+06 | 2.00E+07 | 81 | 35 | 154 |
| 2 | 2.22E+06 | 14.6E+9 | 0.957 | 54.0E-3 | 259.8348 | 255.5287 | 229.9684 | 83.96564 | 6.66E+06 | 2.00E+07 | 81 | 35 | 146 |
| 3 | 2.22E+06 | 21.9E+9 | 0.953 | 81.0E-3 | 251.0633 | 246.6041 | 221.4669 | 83.96564 | 6.66E+06 | 2.00E+07 | 81 | 35 | 138 |
| 4 | 2.22E+06 | 29.2E+9 | 0.948 | 108.0E-3 | 242.4487 | 237.8281 | 213.0883 | 83.96564 | 6.66E+06 | 2.00E+07 | 81 | 35 | 129 |
| 5 | 2.22E+06 | 36.5E+9 | 0.944 | 135.0E-3 | 234.0167 | 229.2262 | 204.8559 | 83.96564 | 6.66E+06 | 2.00E+07 | 81 | 35 | 121 |
| 6 | 2.22E+06 | 43.7E+9 | 0.941 | 162.0E-3 | 225.7596 | 220.79 | 196.7603 | 83.96564 | 6.66E+06 | 2.00E+07 | 81 | 35 | 113 |

no decimal points!

$$q = C_T \left( \frac{P_1^2}{e^s} - P_2^2 \right)^{0.5}$$

$$P_2 = \left( \frac{P_1^2}{e^s} - \left( \frac{q}{C_T} \right)^2 \right)^{0.5}$$ will give error if

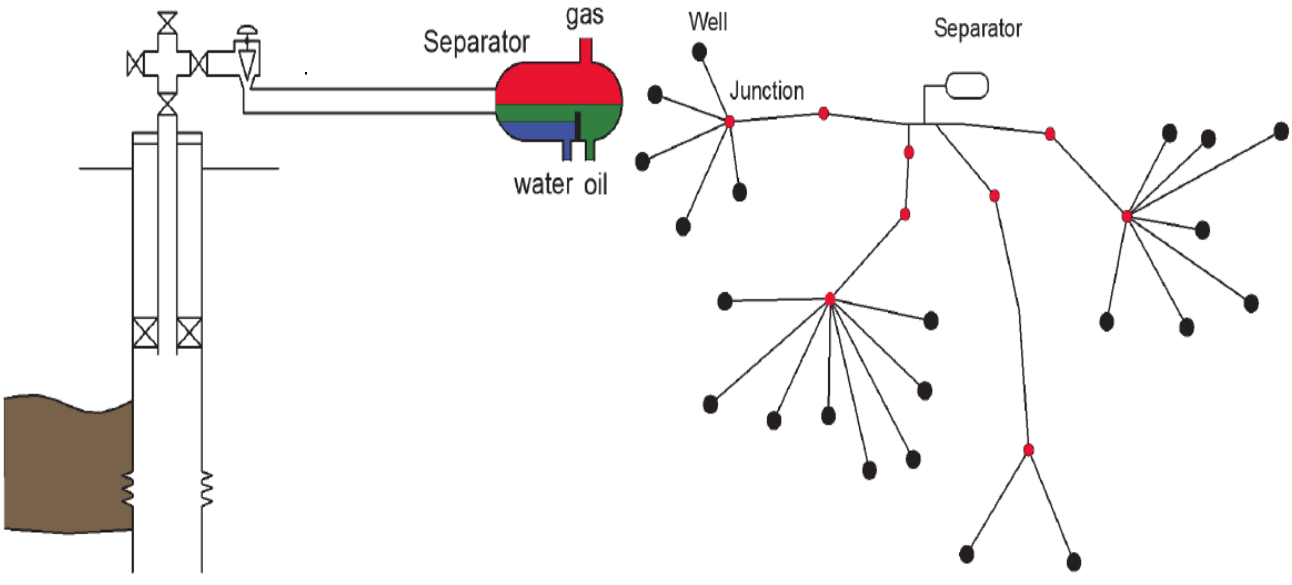
$$\frac{P_1^2}{e^s} < \frac{q^2}{C_T}$$

• be careful with initial assumptions of variables for calculating equilibrium!

might cause problems when computing co-current calculations of $\Delta p$.

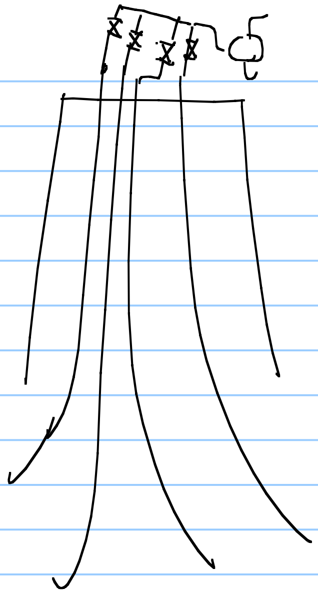
---

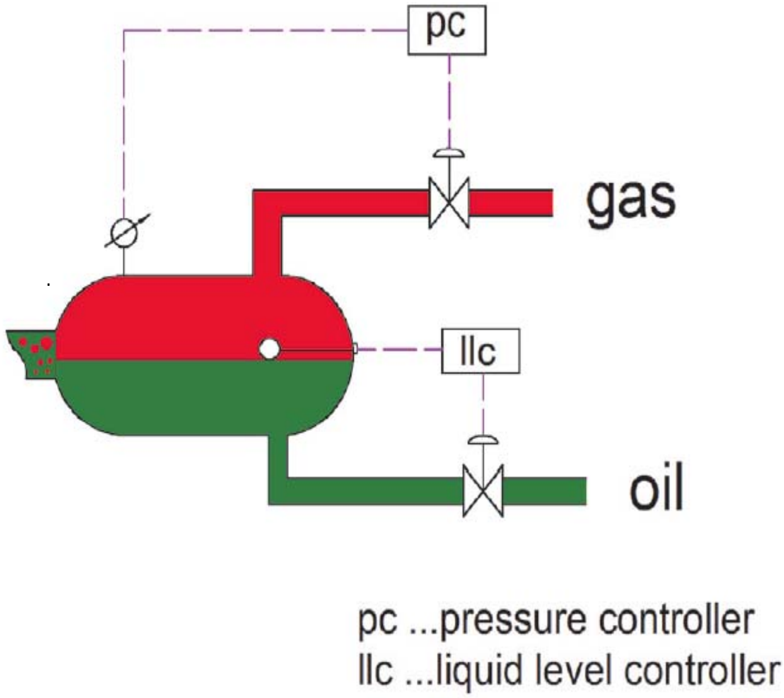
Architecture of a production system.




(a) standalone wells

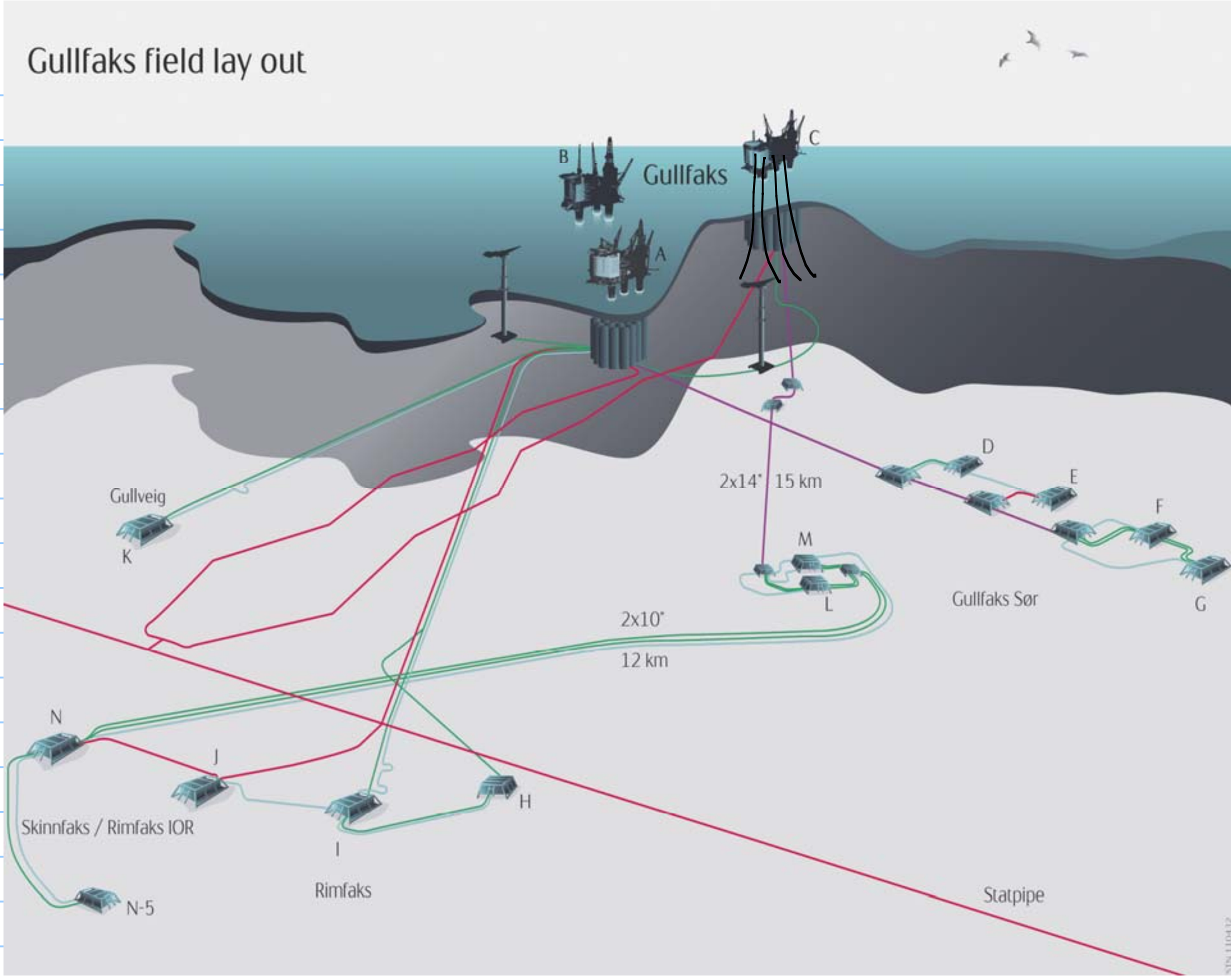
(b) commingling network

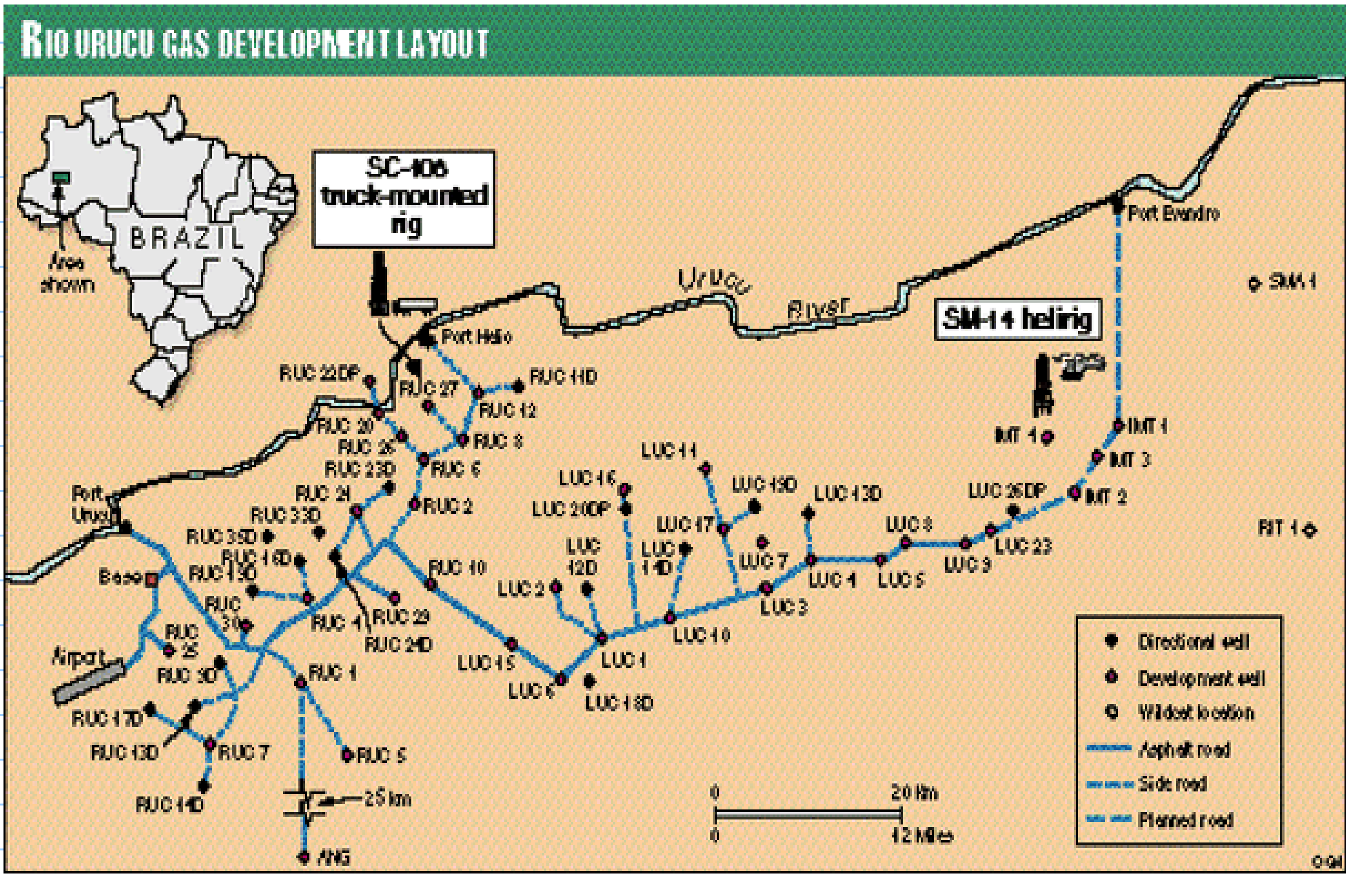


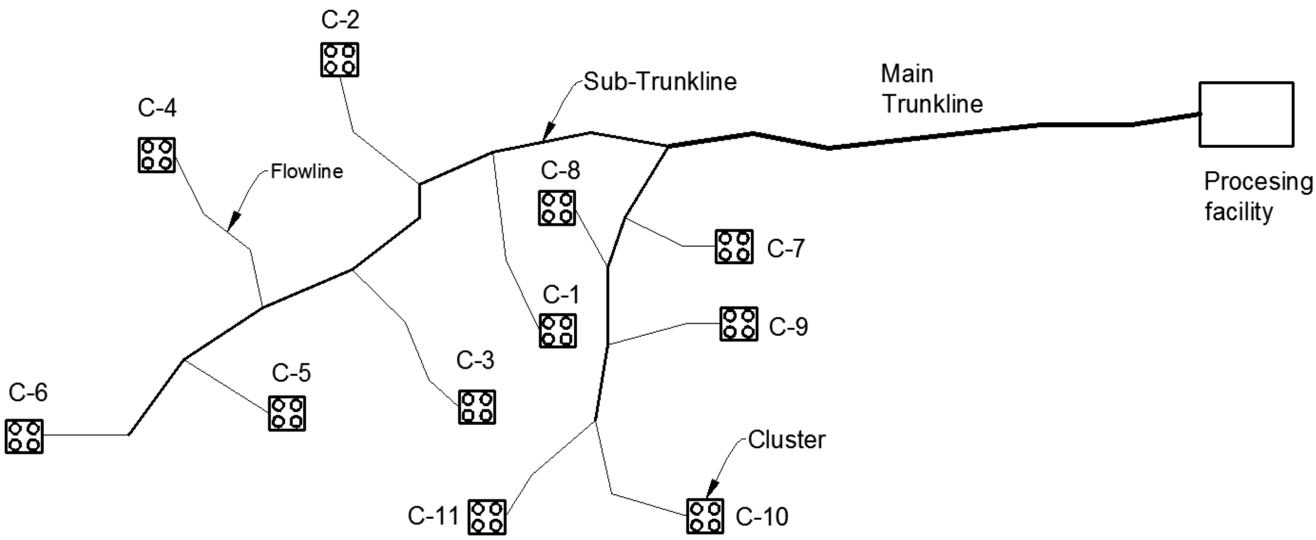



hydraulic dependency ends up at the separator.


Salym

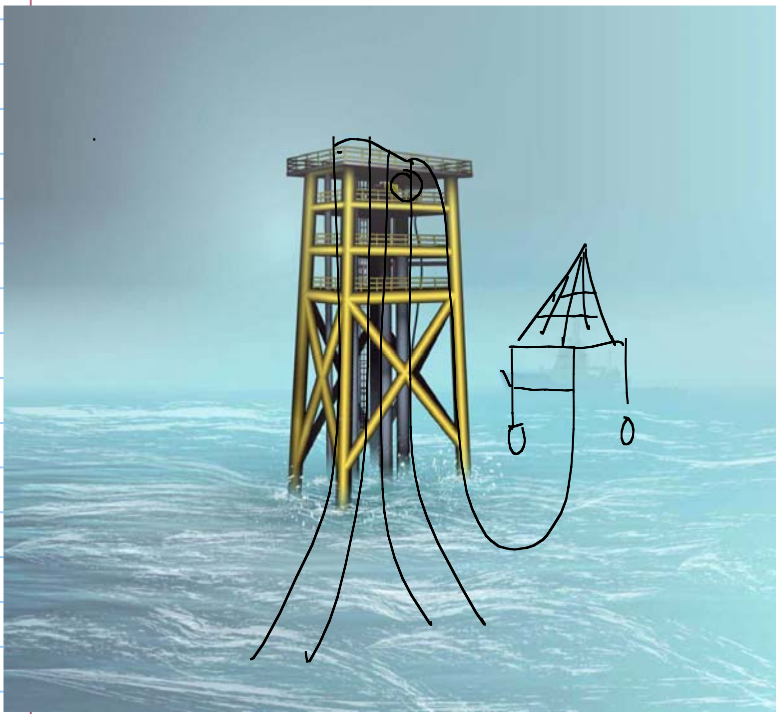

Gullfaks field lay out
B
C
Gullfaks
A
D
E
F
G
2x14" 15 km
M
L
Gullveig
K
Gullfaks Sør
2x10"
12 km
N
J
H
Skinnfaks / Rimfaks IOR
I
Rimfaks
N-5
Statpipe


RIO URUCU GAS DEVELOPMENT LAYOUT
BRAZIL
Area shown
SC-106 truck-mounted rig
Urucu River
Port Evandro
SM-14 helirig
Port Helio
Port Urucu
Base
Airport
IMT 1
IMT 3
IMT 2
RIT 1
RUC 22DP
RUC 27
RUC 12
RUC 20
RUC 6
RUC 2
RUC 21
RUC 33D
RUC 35D
RUC 16D
RUC 10
RUC 29
RUC 24D
RUC 1
RUC 25
RUC 30
RUC 17D
RUC 13D
RUC 7
RUC 5
RUC 14D
25 km
ANG
LUC 11
LUC 16
LUC 20DP
LUC 15D
LUC 13D
LUC 17
LUC 12D
LUC 14D
LUC 7
LUC 2
LUC 10
LUC 3
LUC 4
LUC 5
LUC 8
LUC 9
LUC 23
LUC 26DP
LUC 15
LUC 6
LUC 1
LUC 18D
Directional well
Development well
Wildcat location
Asphalt road
Side road
Planned road
0
20 km
0
12 Miles
OGJ

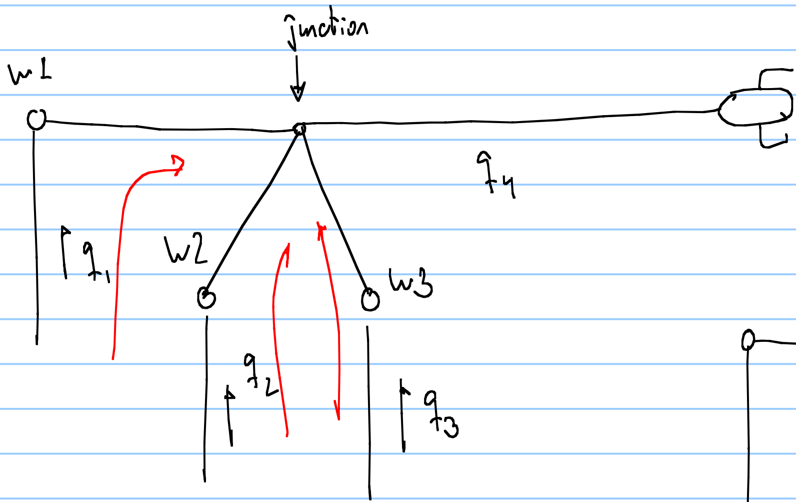

C-2
Sub-Trunkline
Main
Trunkline
C-4
Flowline
C-8
C-7
Procesing
facility
C-1
C-9
C-3
C-5
C-6
Cluster
C-11
C-10

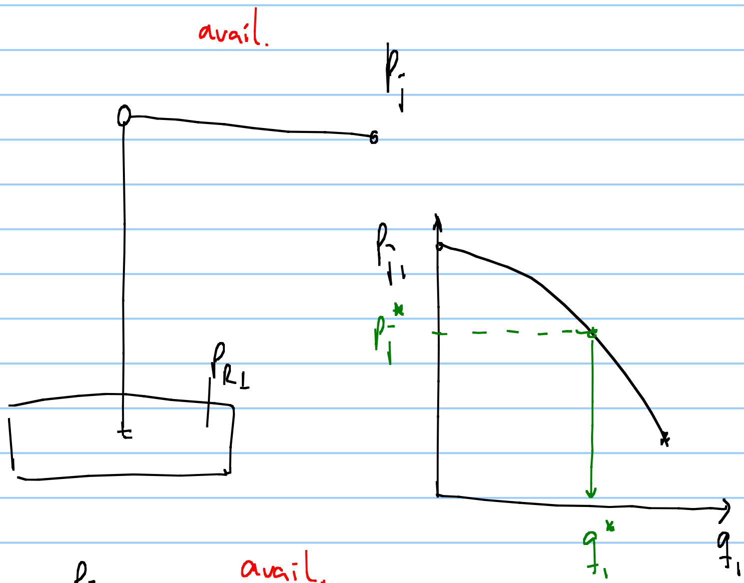

Caribbean Sea
Barranquilla
Cartagena
(Puerto Bahia)
PROMIGAS Pipeline
Coveñas
Colon
TRANSISTMICO Pipeline
Taboguilla
PANAMA
CR-1
SSJN-3
Guama
La Creciente
SSJN-7
SSJN-9*
Catguas
Ayacucho
Carbonera La Silla
Santa Cruz
Caño Limon-Coveñas Pipeline
Carbonera
Cerrito
VENEZUELA
ODC Pipeline
BICENTENARIO Pipeline
Caño Limon
Arauca
Banadia
Lla-41
Lla-7
Lla-55
CPE-1
Cor-24
OCENSA Pipeline
Vasconia
Las Quinchas
VMM-35
VMM-11
Cor-15*
Yamu
Araguaney
Arrendajo
Cubiro
La Dorada
Dindal
Muisca
Moriche
La Punta
Guaduas-Dorada Pipeline
Rio Seco
Monterrey
Rio Magdalena
Guaduas
Bogota
CPO-1
Pacific Ocean
Buganviles
Abanico
Guasimo
Cor-33
ODL Pipeline
Sabanero*
Chipalo
Quifa
CPO-12
CPO-14
OAM Pipeline
Rubiales/Piriri
CPE-6
VSM-12
Tenay
VSM-13
CPO-17*
TRANSANDINO Pipeline
Tumaco
Portofino
Topoyaco
Cag-6
Cag-5
Mecaya
Mansoya
Put-9
Tacacho
Terecay
COLOMBIA
ECUADOR
LEGEND
Exploration
E&P
Production
2012 JV & Acquisitions
Oil Pipelines
Gas Pipelines
Projects
Port (Oil & Liquids Facilities)
Capital City
Station
*The Company holds an indirect ownership interest of 49.999% in Maurel et Prom Colombia B.V.

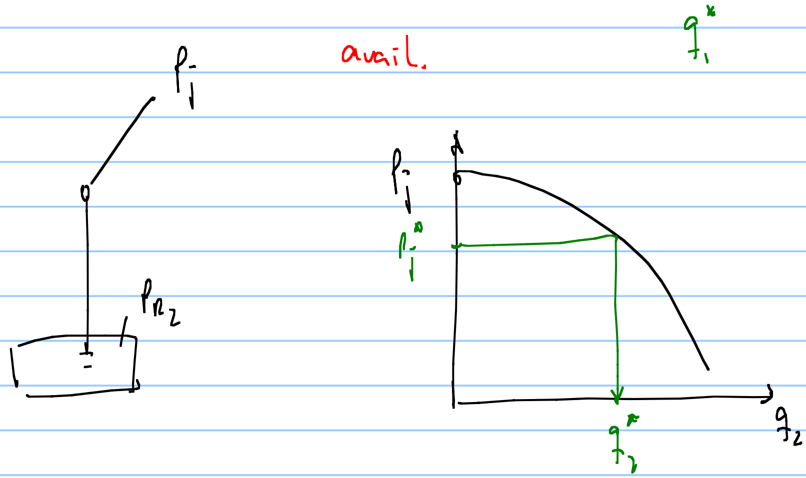

Bahrain
Qatar
Sharjah
Abu Dhabi
United Arab
Emirates
Saudi Arabia
Riyadh
Al Hofuf
Mesaieed
Ghayathi
Al Ain
Al Qua'a
Oman
Ar Rass
Al Majmaah
Al Duwadimi
Kharj
Al Aflaj
Wadi Addawasir
Bishah
Sabt Alalayah
Khamis Mushait
Abha
Oroug Bani M'aradh
Wildlife Sanctuary
SHAYBAH OIL FIELD

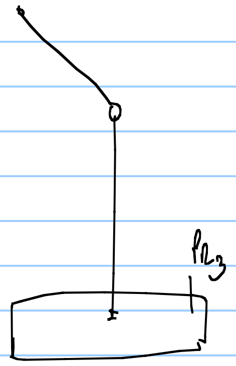


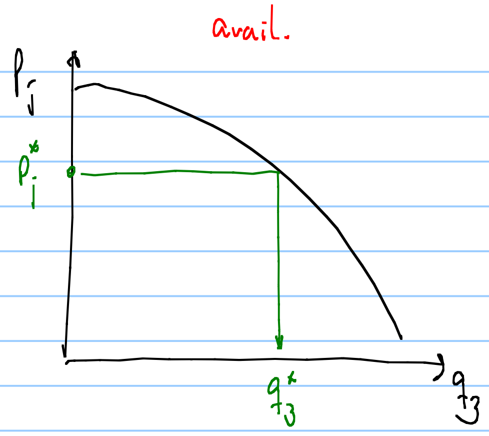
Hydraulic performance of production networks.



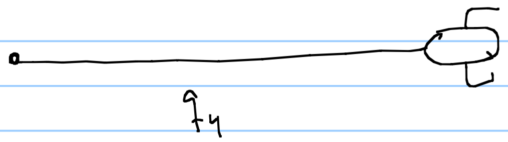



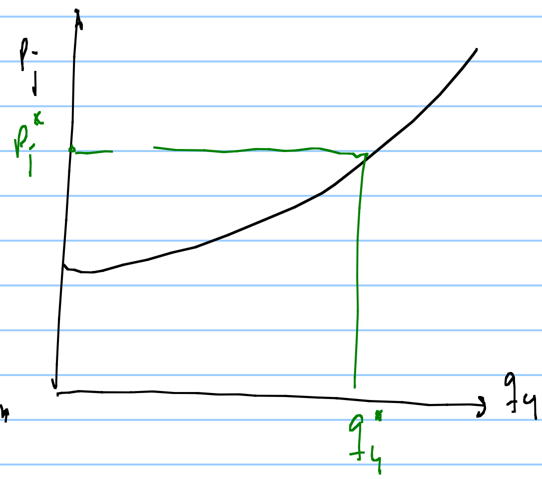






req




mass conservation in the junction

$$\boxed{q_4 = q_1 + q_2 + q_3} \rightarrow P_{j_1} = P_{j_2} = P_{j_3} = P_{j_4}$$

assumed Method to solve

1. Assume $P_j^*$

2: Read $q_1^*$, $q_2^*$, $q_3^*$, $q_4^*$

avail avail avail required

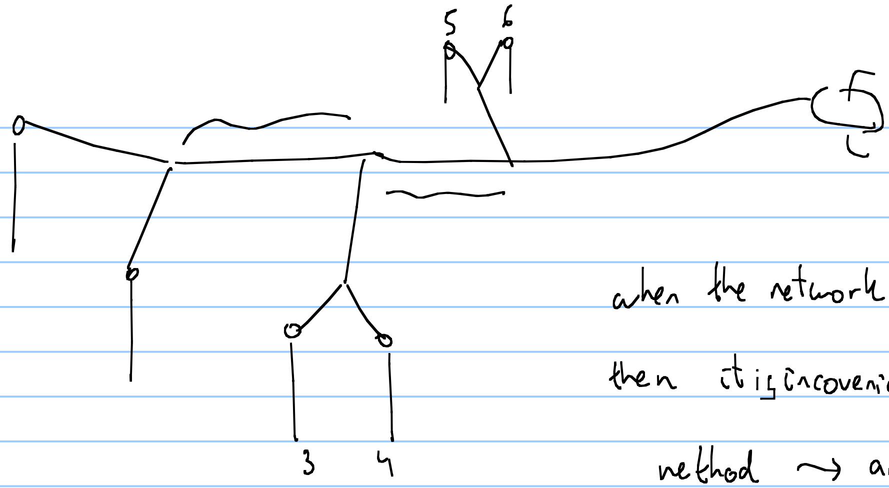
3: Check for mass conservation $q_1^* + q_2^* + q_3^* - q_4^* = 0$

---

iterating with rate

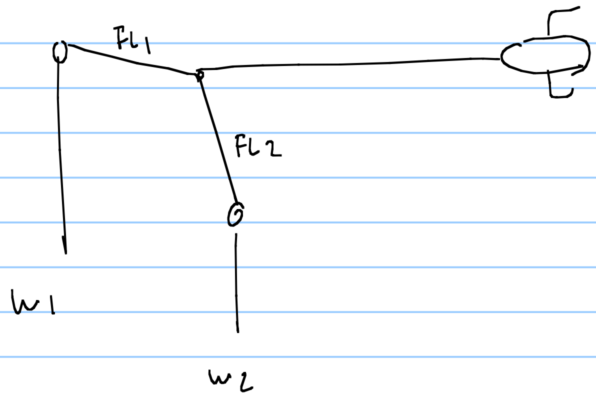
1. assume $q_1^* \rightarrow P_{j_1}^*$
2: assume $q_2^* \rightarrow P_{j_2}^*$
3: assume $q_3^* \rightarrow P_{j_3}^*$
4: $q_4^* = q_1^* + q_2^* + q_3^*$
5: with $q_4^*$ read $P_{j_4}^*$
6: check if

$$P_{j_1}^* = P_{j_2}^* = P_{j_3}^* = P_{j_4}^*$$




when the network is too complex then it is inconvenient to use the graphical method → analytical method

---




dry gas

| eq | unk. | | |
|---|---|---|---|
| 2 | 4 | IPR | $q_1 = C_{R_1}\left(P_{R_1}^2 - P_{wf_1}^2\right)^{n_1}$    $q_2 = C_{R_2}\left(P_{R_2}^2 - P_{wf_2}^2\right)^{n_2}$ |
| 2 | 2 | tubing | $q_1 = C_{T_1}\left(\frac{P_{wf_1}^2}{e^{S_1}} - P_{wh_1}^2\right)^{0.5}$    $q_2 = C_{T_2}\left(\frac{P_{wf_2}^2}{e^{S_2}} - P_{wh_2}^2\right)^{0.5}$ |
| 2 | 1 | flowlines | $q_1 = C_{FL_1}\left(P_{wh_1}^2 - P_J^2\right)^{0.5}$    $q_2 = C_{FL_2}\left(P_{wh_2}^2 - P_J^2\right)^{0.5}$ |
| 1 | 0 | pipeline | $q_1 + q_2 = C_{PL}\left(P_J^2 - P_{sep}^2\right)^{0.5}$ |
| 7 | 7 | | |

→ can solve this system of equations using a numerical method,

→ Newton-Raphson for a system of equations

# Network solving

## Nonlinear system of equations

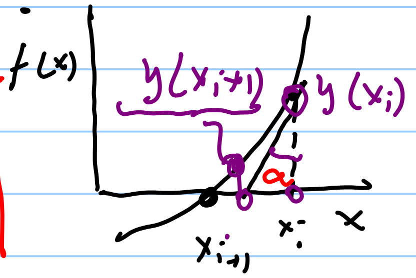
given a set of non-Liner equations (NLE).

$$f_1(x_1, x_2, \ldots, x_n) = 0$$
$$f_2(x_1, x_2, \ldots, x_n) = 0$$
$$\vdots$$
$$f_n(x_1, x_2, \ldots, x_n) = 0$$

find a set of values $x_1, x_2, \ldots, x_n$ that simultaneously results in all equation equaling zero

Recall Newton-Raphson root finding procedure of $f(x)=0$.

$$\boxed{tg\,\alpha = f'(x_i) = \frac{f(x_i) - 0}{x_i - x_{i+1}}}$$




Rearranging

$$\boxed{x_{i+1} = x_i - \frac{f(x_i)}{f'(x_i)}} \text{ or } \boxed{f' = \frac{f}{-dx}} \text{ or } \boxed{f'(x)\cdot dx = -f(x)}$$

This is Newton Raphson formula

**solution procedure** (for one NLE)

1. guss $x$
2. find $f(x)$ and $f'(x)$
3. calculate $dx = (x_{i+1} - x_i) = -\dfrac{f(x)}{f'(x)}$
4. update $x^{new} = x^{old} + dx$
5. calculate $f(x)^{new}$
6. If $f(x)^{new} \leq \varepsilon \rightarrow$ yes $\rightarrow$ Exit; no $\rightarrow$ go to 2

The graphical procedure is based on first-order Taylor series expansion

$$f(x_{i+1}) = f(x_i) + (x_{i+1} - x_i) f'(x_i)$$

One approach for solving a set of NLE is to use multi-dimensional version of Newton Raphson method for one equation above:
This is based on multi-dimension Taylor series expansion:

for example,

$f_1(x_1, x_2) =$

$f_2(x_1, x_2)$

$$f_1^{i+1} = f_1^i + \underbrace{(x_1^{i+1} - x_1^i)}_{dx_1} \frac{\partial f_1^i}{\partial x_1} + \underbrace{(x_2^{i+1} - x_2^i)}_{dx_2} \frac{\partial f_1^i}{\partial x_2}$$

$$f_2^{i+1} = f_2^i + \underbrace{(x_1^{i+1} - x_1^i)}_{dx_1} \frac{\partial f_2^i}{\partial x_1} + \underbrace{(x_2^{i+1} - x_2^i)}_{dx_2} \frac{\partial f_2^i}{\partial x_2}$$

Recal for single equation

$$f'(x) \cdot dx = -f(x)$$

we can prove (soon) that this equation is valid for set of equations and can be written as an Array Formula As matrix

$$\begin{bmatrix} \frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} \\ \frac{df_2}{\partial x_1} & \frac{\partial f_2}{\partial x_2} \end{bmatrix} \begin{bmatrix} dx_1 \\ dx_2 \end{bmatrix} = - \begin{bmatrix} f_1(x_1, x_2) \\ f_2(x_1, x_2) \end{bmatrix}$$

$$\boxed{\frac{\partial \bar{f}}{\partial x} \cdot d\bar{x} = -\bar{f}}$$

The partial derivative metrix is called the Jacobian of the system. Thus

$$J \begin{bmatrix} dx_1 \\ dy_1 \end{bmatrix} = -\begin{bmatrix} f_1 \\ f_2 \end{bmatrix}$$

$$\begin{bmatrix} dx_1 \\ dx_2 \end{bmatrix} = -J^{-1} \begin{bmatrix} f_1 \\ f_2 \end{bmatrix}$$

$$\begin{bmatrix} dx_1 \\ dx_2 \end{bmatrix} = -\frac{\begin{bmatrix} f_1 \\ f_2 \end{bmatrix}}{J} =$$

In algebric form:

$$dx_1 = \underbrace{x_1^{i+1} - x_1^{i}}_{dx_1} = -\frac{f_1 \frac{\partial f_2}{\partial x_2} - f_2 \frac{\partial f_1}{\partial x_2}}{\underbrace{\frac{\partial f_1}{\partial x_1} \cdot \frac{\partial f_2}{\partial x_2} - \frac{\partial f_1}{\partial x_2} \cdot \frac{\partial f_2}{\partial x_1}}_{\text{Determinant of the Jacobian}}}$$

$$dx_2 = x_2^{i+1} - x_2^{i} = -\frac{f_2 \cdot \frac{\partial f_1}{\partial x_1} - f_1 \frac{\partial f_2}{\partial x_1}}{\underbrace{\frac{\partial f_1}{\partial x_1} \frac{\partial f_2}{\partial x_2} - \frac{\partial f_1}{\partial x_2} \cdot \frac{\partial f_2}{\partial x_1}}_{\text{determinant of } J}}$$

in more general form (Jacobian form)

$$J = \begin{bmatrix} \frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} & \cdots & \frac{\partial f_1}{\partial x_n} \\ \frac{\partial f_2}{dx_1} & \frac{\partial f_2}{\partial x_2} & \cdots & \frac{\partial f_2}{\partial x_n} \\ \vdots & & & \\ \frac{\partial f_n}{\partial x_1} & \frac{\partial f_n}{\partial x_2} & \cdots & \frac{\partial f_n}{\partial x_2} \end{bmatrix}$$

The array equation is then

$$\begin{bmatrix} \frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} & \cdots & \frac{\partial f_1}{\partial x_n} \\ \frac{\partial f_2}{\partial x_1} & \frac{\partial f_2}{\partial x_2} & \cdots & \frac{\partial f_2}{\partial x_n} \\ \vdots & & & \\ \frac{\partial f_n}{\partial x_1} & \frac{\partial f_n}{\partial x_2} & \cdots & \frac{\partial f_n}{\partial x_2} \end{bmatrix} \begin{bmatrix} \Delta x_1 \\ \Delta x_2 \\ \vdots \\ \Delta x_n \end{bmatrix} = - \begin{bmatrix} f_1 \\ f_2 \\ \vdots \\ f_n \end{bmatrix}$$

$$\boxed{\begin{aligned} \{\bar{x}_i\}^T &= \lfloor x_1^i, x_2^i, \cdots x_n^i \rfloor \\ \{\bar{x}_{i+1}\}^T &= \lfloor x_1^{i+1}, x_2^{i+1}, \cdots x_n^{i+1} \rfloor \\ \{\bar{f}_i\}^T &= \lfloor f_1^i, f_2^i, \cdots f_n^i \rfloor \\ [J]\{\bar{x}_{i+1}\} &= -\{\bar{f}_i\} + [J]\{\bar{x}_i\} \end{aligned}}$$

This equation can be solved using technique such as Gaus Eliminatio

$$J_{ij}\,\bar{\Delta x}_j = -\bar{f}_i$$

$$\Delta x_j = -J_{ij}^{-1} \cdot f_i$$

$$x^{n+1} = x^n + \Delta x$$

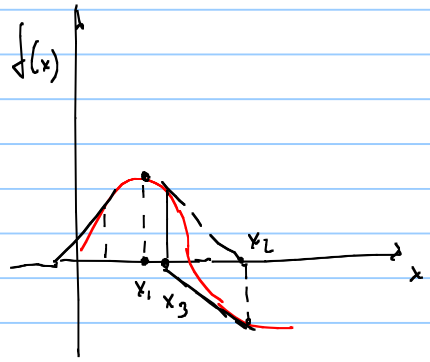
1. guss $x_j$
2. find $f(x)$ and $f'(x)$
3. calculate $dx = -\frac{f(x)}{f'(x)}$
4. update $x^{new} = x^{old} + dx$
5. got to 2 if necessary

Anothe apprach to solution of a set of NLE

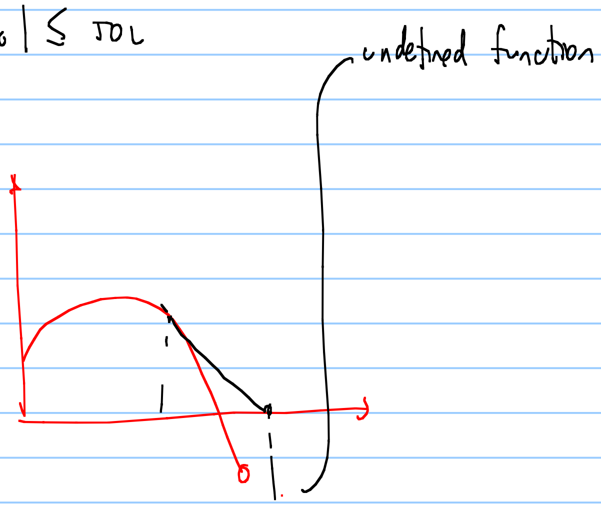
1. Formulate the non-Linear system as a single function

$$F(x) = \sum_{i=1}^{n} \left[ w_i f_i (x_1, x_2 \cdots x_n) \right]^2$$

The value of $\bar{x}$ that minimize the function represent the solution of the non-Linear system.
This formulation is a class of Problem call <u>non-Linear regrassion</u>



$|x_{i+1} - x_i| \leq TOL$

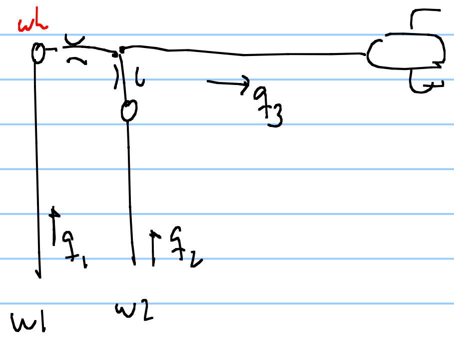


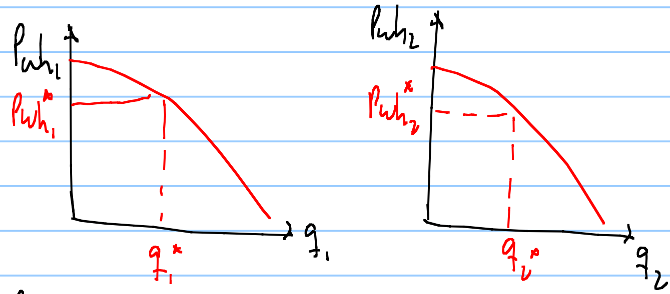
We have to make our equations "bulletproof" ⇝ avoid crashing of the solving algorithm

↳ useful for using commercial software !

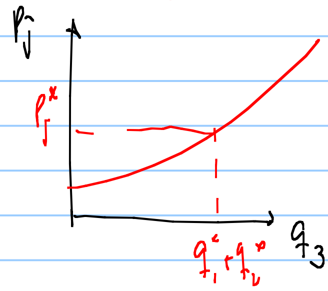
---

wells close to the junction → flowline can be neglected





- e.g. with production rates from the reservoir engineer obtained to ↑ RF } $q_1^*, q_2^*$



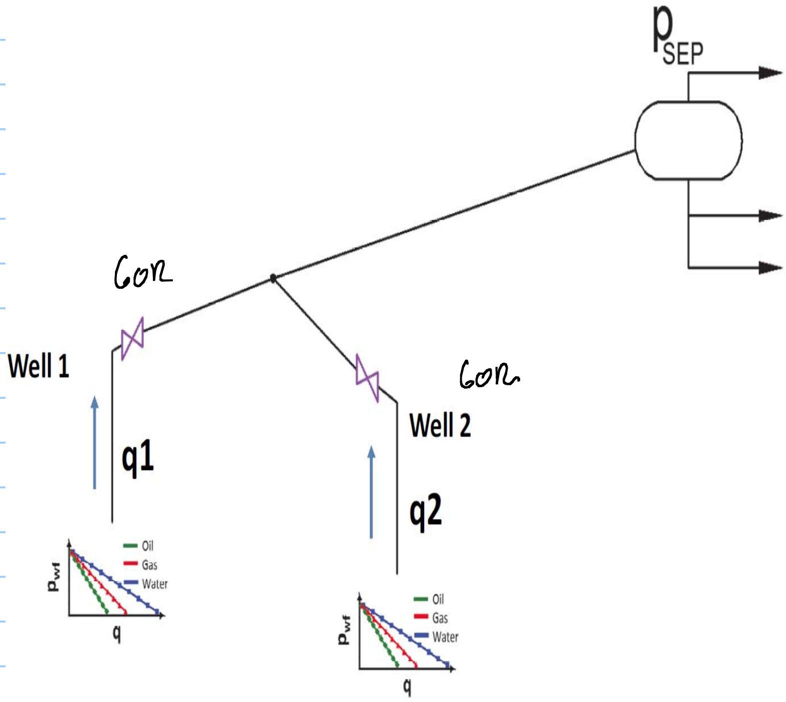
- use $q_1^*$ $\overset{\text{read}}{\rightsquigarrow}$ $P_{wh_1}^*$
- use $q_2^*$ $\overset{\text{read}}{\rightsquigarrow}$ $P_{wh_2}^*$
- use $q_1^* + q_2^*$ $\overset{\text{read}}{\rightsquigarrow}$ $P_j^*$
- Calculate choke $\Delta p$

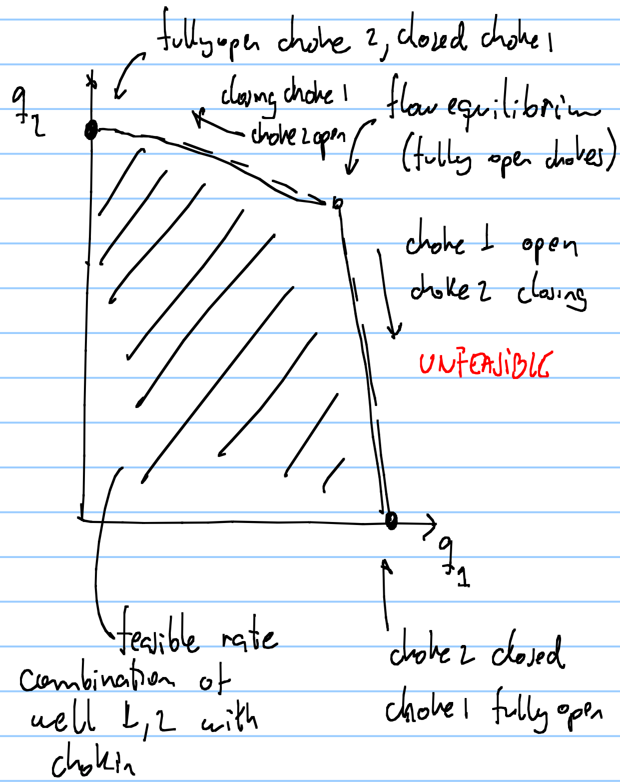
- $\Delta p_{choke_1} = P_{wh_1}^* - P_j^*$
- $\Delta p_{choke_2} = P_{wh_2}^* - P_j^*$

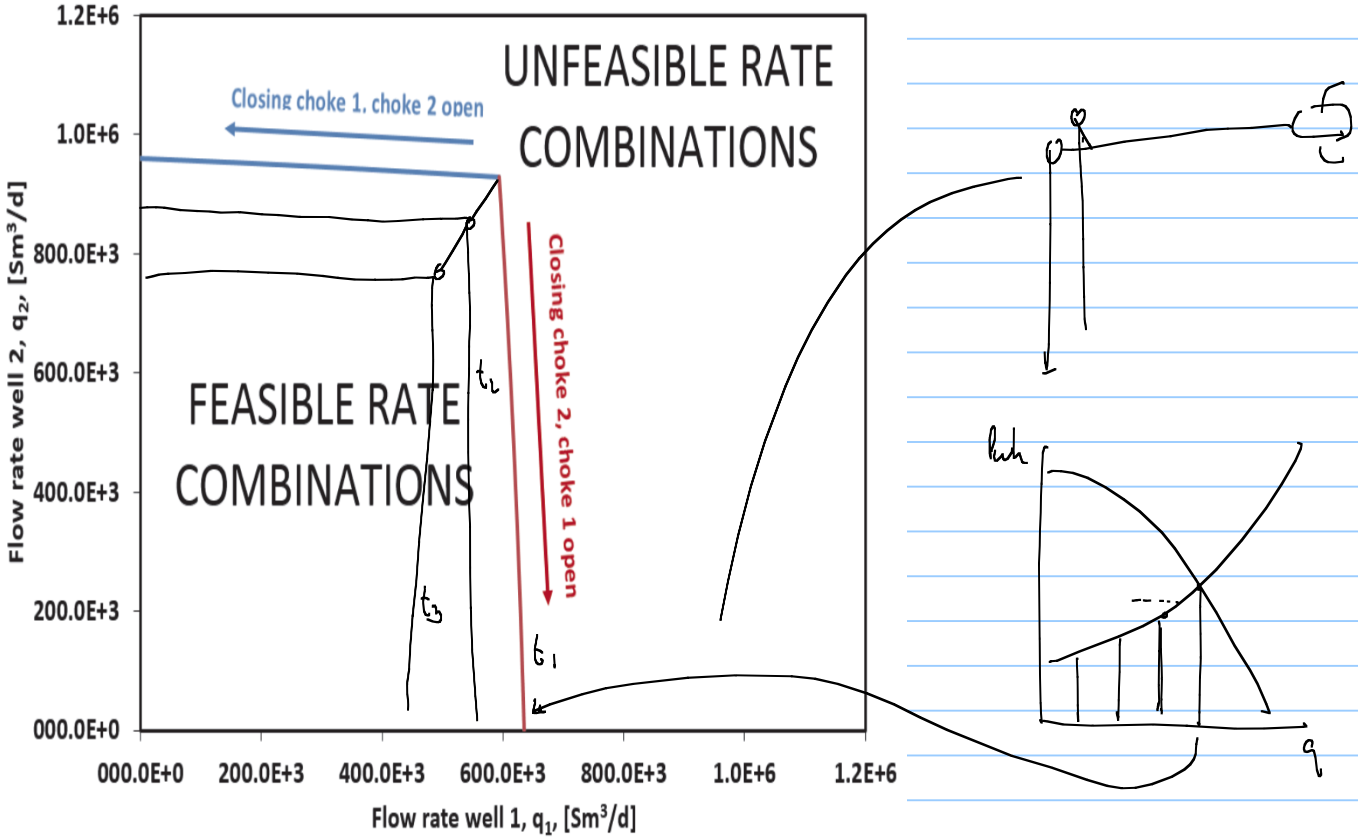
If the rates are feasible the $\Delta p_{choke_1} \geq 0$

$\Delta p_{choke_2} \geq 0$

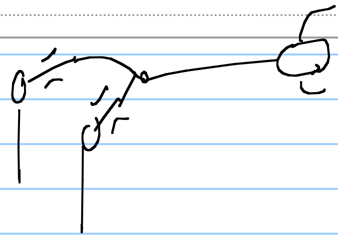

LAXMI BLESSING
NW5630

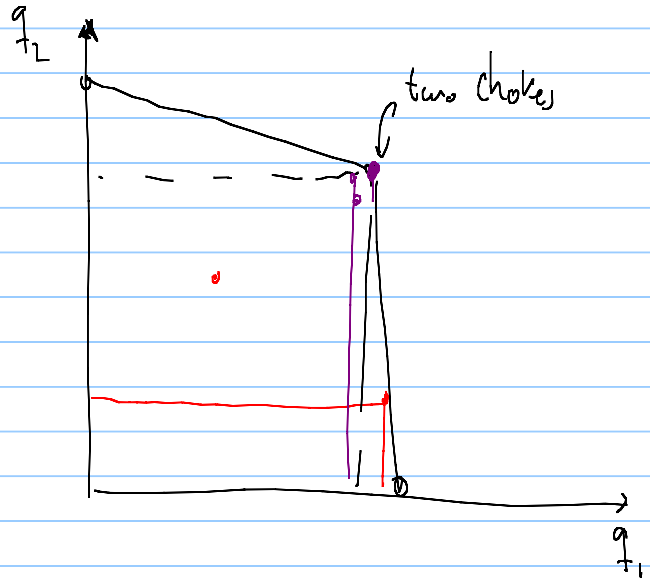

$p_{SEP}$
GOR
Well 1
q1
GOR
Well 2
q2
Oil
Gas
Water
$p_{wf}$
q

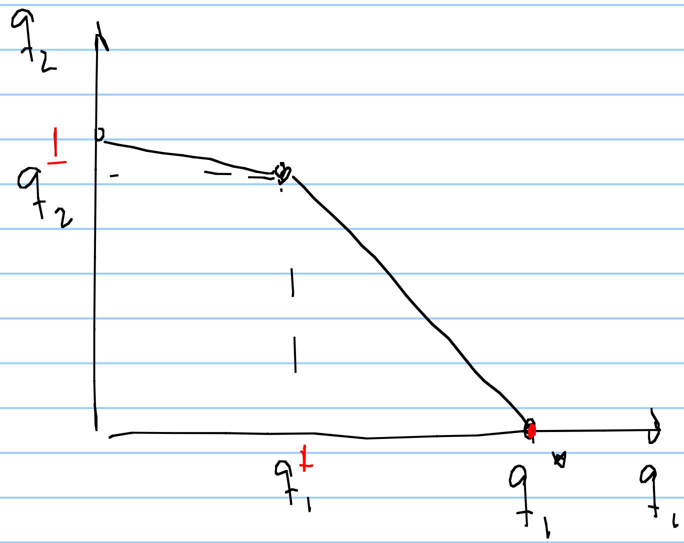

fully open choke 2, closed choke 1
$q_2$
closing choke 1
choke 2 open
flow equilibrium
(fully open chokes)
choke 1 open
choke 2 closing
UNFEASIBLE
$q_1$
feasible rate
combination of
well 1, 2 with
chokin
choke 2 closed
choke 1 fully open


UNFEASIBLE RATE COMBINATIONS
FEASIBLE RATE COMBINATIONS
Closing choke 1, choke 2 open
Closing choke 2, choke 1 open
Flow rate well 2, q2, [Sm³/d]
Flow rate well 1, q1, [Sm³/d]
1.2E+6
1.0E+6
800.0E+3
600.0E+3
400.0E+3
200.0E+3
000.0E+0
000.0E+0
200.0E+3
400.0E+3
600.0E+3
800.0E+3
1.0E+6
1.2E+6
t2
t3
t1
q

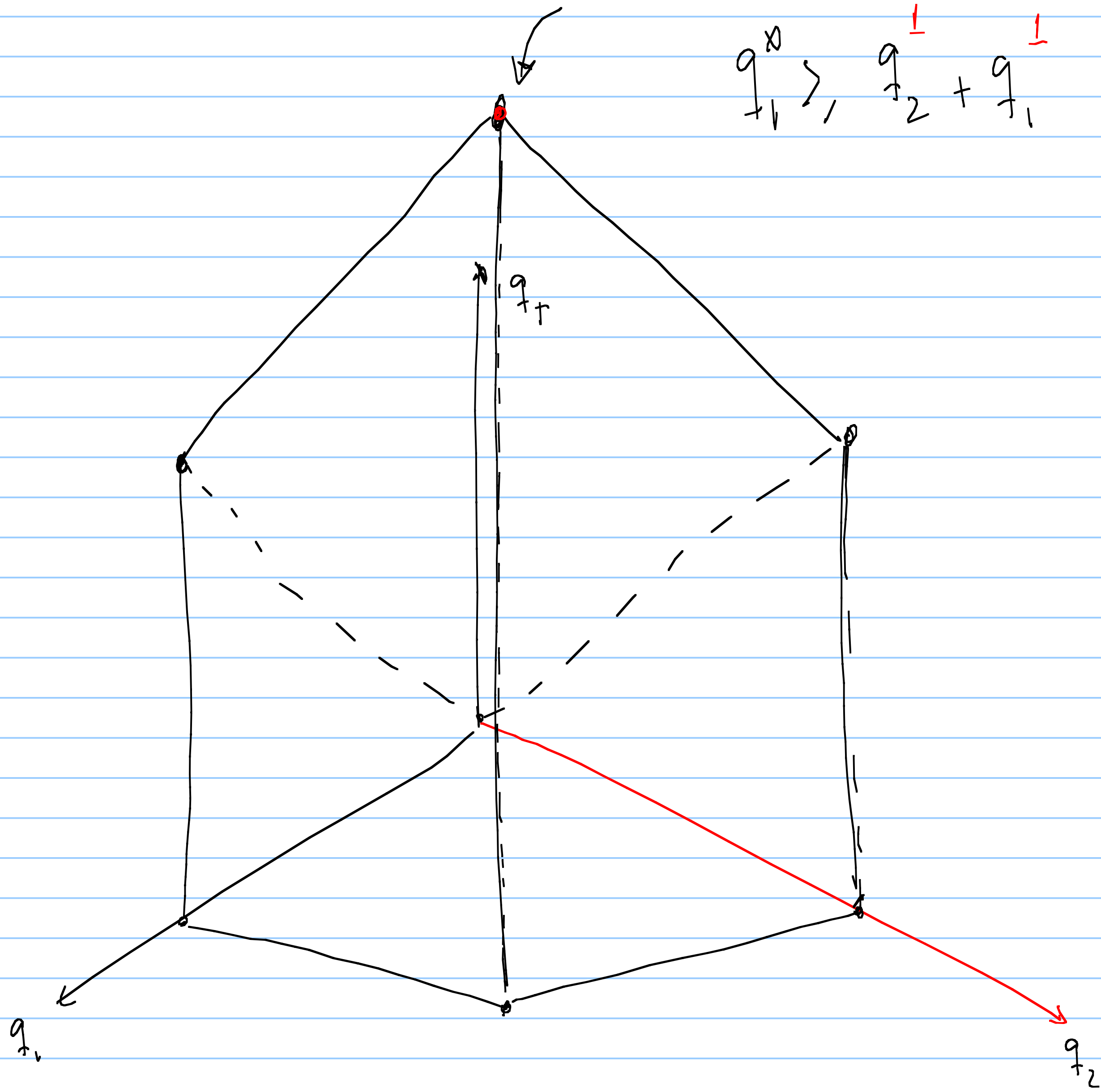
# Comment to choked well operating area



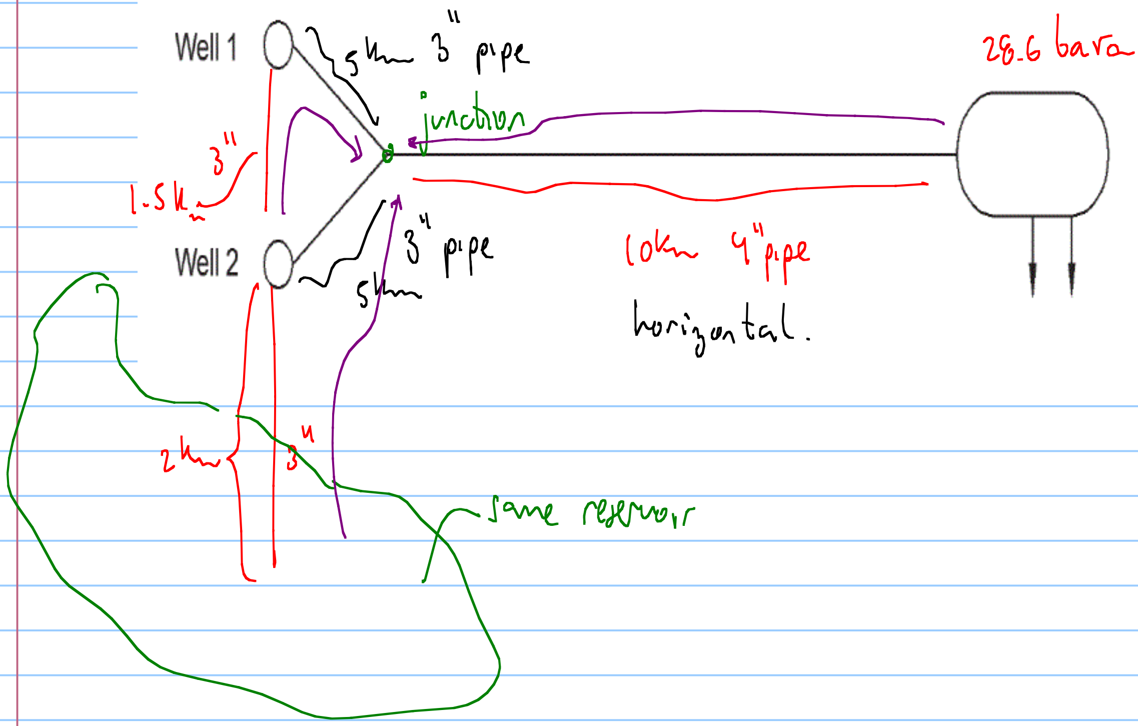



$$q_{t1}^{*} \geq q_{t2}^{1} + q_{t1}^{1}$$



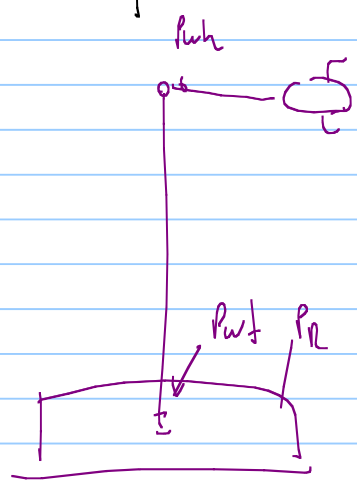
Excel exercise




Network of two gas wells

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | IPR | | Tubing | | Flowline | |
| Component Name | $p_R$ | C | n | S | Ct | Cfl | psep |
| | [bara] | [Sm^3/bar^2n] | | | [Sm^3/bar^2] | [Sm^3/bar^2] | [bara] |
| W_1 | 120 | 52 | 0.8 | 0.13 | 7680 | 8673 | |
| W_2 | 120 | 40 | 0.75 | 0.11 | 8600 | 7563 | |
| Pipeline | | | | | | 14080 | 28.6 |

1 Hydraulic equilibrium of the system (no choke)



| | IPR | | | Tubing | Flowline | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| $p_R$ | C | n | S | Ct | Cfl | psep | pwf | qg | pwh | pj |
| [bara] | [Sm^3/bar^2n] | | | [Sm^3/bar^2] | [Sm^3/bar^2] | [bara] | [bara] | [Sm^3/d] | [bara] | [bara] |
| 120 | 52 | 0.8 | 0.13 | 7680 | 8673 | | 110 | 25432 | 103 | 103 |
| 120 | 40 | 0.75 | 0.11 | 8600 | 7563 | | 110 | 13285 | 104 | 104 |
| | | | | | 14080 | 28.6 | | | | |

up to this point
co-current calculations.

| | IPR | | | Tubing | Flowline | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| $p_R$ | C | n | S | Ct | Cfl | psep | pwf | qg | pwh | pj |
| [bara] | [Sm^3/bar^2n] | | | [Sm^3/bar^2] | [Sm^3/bar^2] | [bara] | [bara] | [Sm^3/d] | [bara] | [bara] |
| 120 | 52 | 0.8 | 0.13 | 7680 | 8673 | | 110 | 25432 | 103 | 103 |
| 120 | 40 | 0.75 | 0.11 | 8600 | 7563 | | 110 | 13285 | 104 | 104 |
| | | | | | 14080 | 28.6 | | 3.87E+04 | | 29 |

Error

$(p_{j_1} - p_{j\,av})^2$

$p_{j_2}$ "

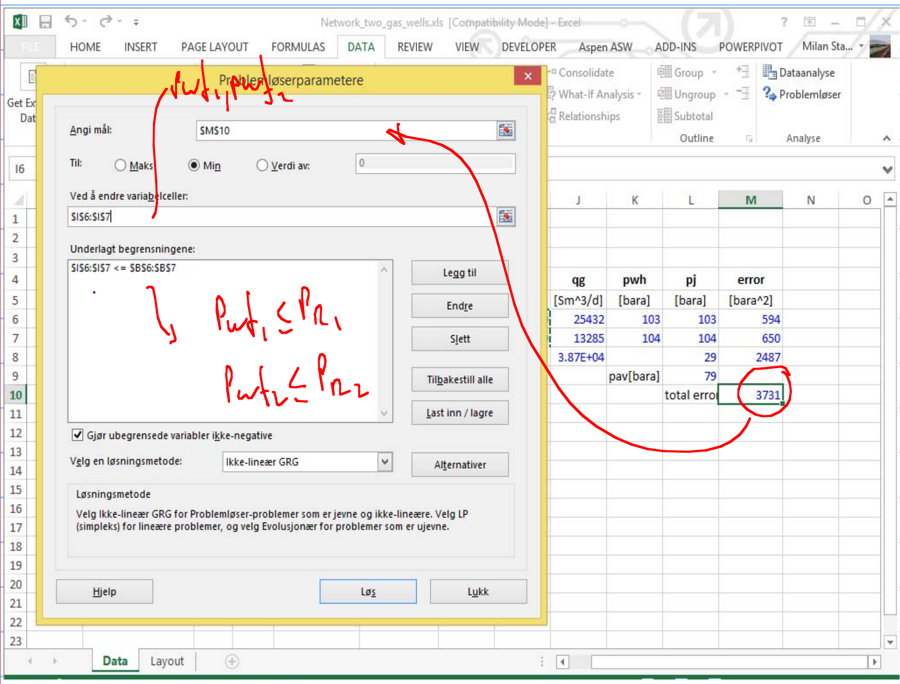
$(p_{j_3}$ " $)^2$

$\Sigma(\ )$

$p_{av}$ $\quad$ $4(\downarrow)$

solver objective $\rightarrow 0$

by changing



| | IPR | | Tubing | | Flowline | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $p_R$ | C | n | S | Ct | Cfl | psep | pwf | qg | pwh | pj | error |
| [bara] | [Sm^3/bar^2n] | | | [Sm^3/bar^2] | [Sm^3/bar^2] | [bara] | [bara] | [Sm^3/d] | [bara] | [bara] | [bara^2] |
| 120 | 52 | 0.8 | 0.13 | 7680 | 8673 | | 3 | 11[illegible]75 | #VALUE! | #VALUE! | #VALUE! |
| 120 | 40 | 0.75 | 0.11 | 8600 | 7563 | | 0 | 52581 | #VALUE! | #VALUE! | #VALUE! |
| | | | | | 14080 | 28.6 | | 1.63E+05 | | 31 | #VALUE! |
| | | | | | | | | | pav[bara] | #VALUE! | |
| | | | | | | | | | | total error | #VALUE! |

pwf is too low → q too high

Pwh is negative

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

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

is too big

Convergence using as starting point $p_{wf_1} = p_{wf_2} = 50$ bara.

| | IPR | | Tubing | | Flowline | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $p_R$ | C | n | S | Ct | Cfl | psep | pwf | qg | pwh | pj | error |
| [bara] | [Sm^3/bar^2n] | | | [Sm^3/bar^2] | [Sm^3/bar^2] | [bara] | [bara] | [Sm^3/d] | [bara] | [bara] | [bara^2] |
| 120 | 52 | 0.8 | 0.13 | 7680 | 8673 | | 38 | 101551 | 33 | 31 | 0 |
| 120 | 40 | 0.75 | 0.11 | 8600 | 7563 | | 34 | 49466 | 31 | 31 | 0 |
| | | | | | 14080 | 28.6 | | 1.51E+05 | | 31 | 0 |
| | | | | | | | | | pav[bara] | 31 | |
| | | | | | | | | | | total error | 0 |

Fixed production rate?

$q_{g_1} = 8063$ Sm³/d

$q_{g_2} = 3063$ Sm³/d

for choking, my point of interest is where the choke is


co-current from $P_R \to P_{wf} \to P_{wh}$

counter curren from $P_{sep} \to P_j \to P_{whreq1}$ or $P_{downstream\ choke}$

$\to P_{whreq2}$

| | IPR | | Tubing | | Flowline | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $p_R$ | C | n | S | Ct | Cfl | psep | qg | pwf | pwh avail | pj | pwhreq | deltap choke |
| [bara] | [Sm^3/bar^2n] | | | [Sm^3/bar^2] | [Sm^3/bar^2] | [bara] | [Sm^3/d] | [bara] | [bara] | [bara] | [bara] | [bar] |
| 120 | 52 | 0.8 | 0.13 | 7680 | 8673 | | 80000 | 69 | 64 | | 31 | 33 |
| 120 | 40 | 0.75 | 0.11 | 8600 | 7563 | | 30000 | 87 | 82 | | 30 | 52 |
| | | | | | 14080 | 28.6 | 110000 | | | 30 | | |
| | | | | | | total | | | | | | |

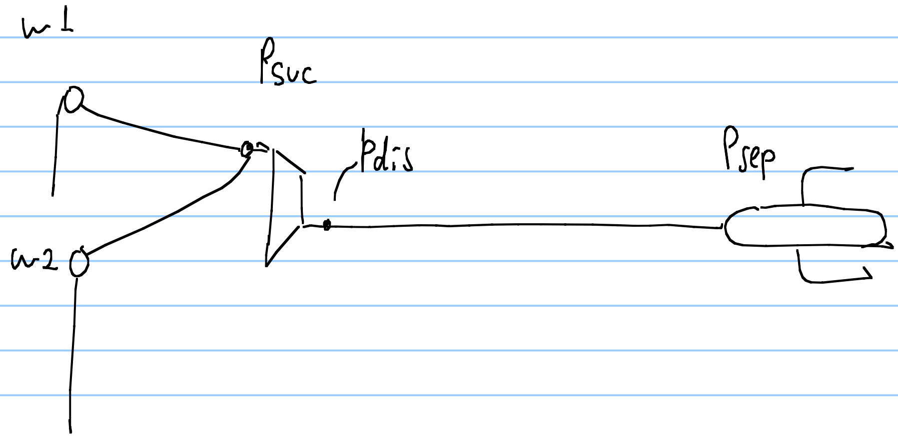
choke Δps to apply to get the desired rate

non-feasible rates

| | IPR | | Tubing | | Flowline | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $p_R$ | C | n | S | Ct | Cfl | psep | qg | pwf | pwh avail | pj | pwhreq | deltap choke |
| [bara] | [Sm^3/bar^2n] | | | [Sm^3/bar^2] | [Sm^3/bar^2] | [bara] | [Sm^3/d] | [bara] | [bara] | [bara] | [bara] | [bar] |
| 120 | 52 | 0.8 | 0.13 | 7680 | 8673 | | 80000 | 69 | 64 | | 31 | 32 |
| 120 | 40 | 0.75 | 0.11 | 8600 | 7563 | | 50000 | 31 | 28 | | 31 | -2 |
| | | | | | 14080 | 28.6 | 130000 | | | 30 | | |
| | | | | | | total | | | | | | |

Compression:

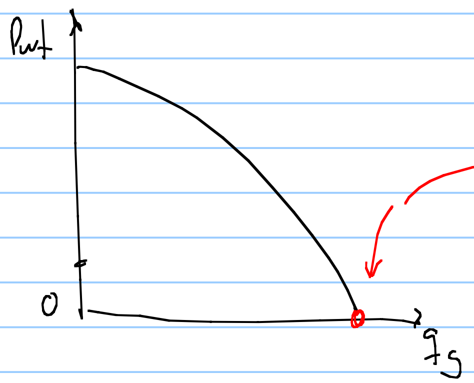
at a later stage (when $P_R = 40$ bars), you are evaluating to install a compressor in the system




fix the rate and estimate $\Delta p_{comp}$.

what is the maximum rate that I can get?

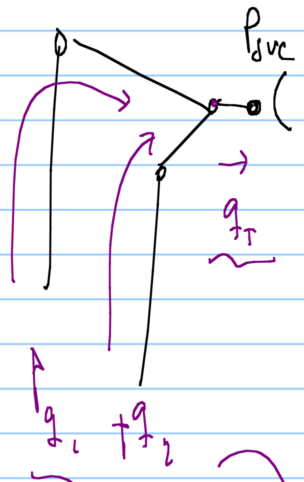
| | | IPR | | Tubing | | Flowline | | | |
|---|---|---|---|---|---|---|---|---|---|
| Component Name | $p_R$ | C | n | S | Ct | Cfl | psep | pwf | qg |
| | [bara] | [Sm^3/bar^2n] | | | [Sm^3/bar^2] | [Sm^3/bar^2] | [bara] | [bara] | [Sm^3/d] |
| W_1 | 40 | 52 | 0.8 | 0.13 | 7680 | 8673 | | 0 | 19024 |
| W_2 | 40 | 40 | 0.75 | 0.11 | 8600 | 7563 | | 0 | 10119 |
| Pipeline | | | | | | 14080 | 28.6 | | |
| | | | | | | | total | | |

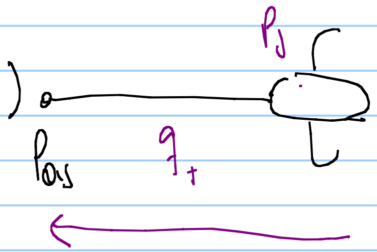



I want to produce 28000 $Sm^3/d$

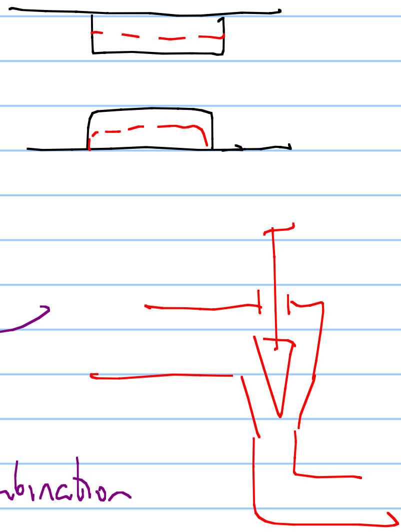
where is my equilibrium point?

open choke




bean choke, positive.



fixed rate

flow eq

unique $q_1, q_2$ combination
that gives $q_T$
that gives $P_{s1} = P_{suc2}$

$$q_1 + q_2 = 28000 \ Sm^3/d$$

$q_1$

$$q_2 = 28000 - q_1$$

| | IPR | | Tubing | | Flowline | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $p_R$ | C | n | S | Ct | Cfl | psep | qg | pwf | pwh | psuc | pdisc |
| [bara] | [Sm^3/bar^2n] | | | [Sm^3/bar^2] | [Sm^3/bar^2] | [bara] | [Sm^3/d] | [bara] | [bara] | [bara] | [bara] |
| 40 | 52 | 0.8 | 0.13 | 7680 | 8673 | | 18000 | 10 | 9 | 9 | |
| 40 | 40 | 0.75 | 0.11 | 8600 | 7563 | | 10000 | 5 | 5 | 4 | |
| | | | | | 14080 | 28.6 | 2.80E+04 | | | | 29 |

need a compressor

$P_{os} \geq P_{suc1}$, $P_{suc2}$

counter-current.

| IPR | | Tubing | | Flowline | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| C | n | S | Ct | Cfl | psep | qg | pwf | pwh | psuc | error | pdisc | Deltapcomp |
| [Sm^3/bar^2n] | | | [Sm^3/bar^2] | [Sm^3/bar^2] | [bara] | [Sm^3/d] | [bara] | [bara] | [bara] | [bara^2] | [bara] | [bar] |
| 52 | 0.8 | 0.13 | 7680 | 8673 | | 18231 | 9 | 8 | 8 | 0.0 | | 21 |
| 40 | 0.75 | 0.11 | 8600 | 7563 | | 9769 | 9 | 8 | 8 | 0.0 | | |
| | | | | 14080 | 28.6 | 2.80E+04 | | pav | 8 | | 29 | |
| | | | | | | | | | SUM= | 2E-28 | | |

use solver to change

to drive

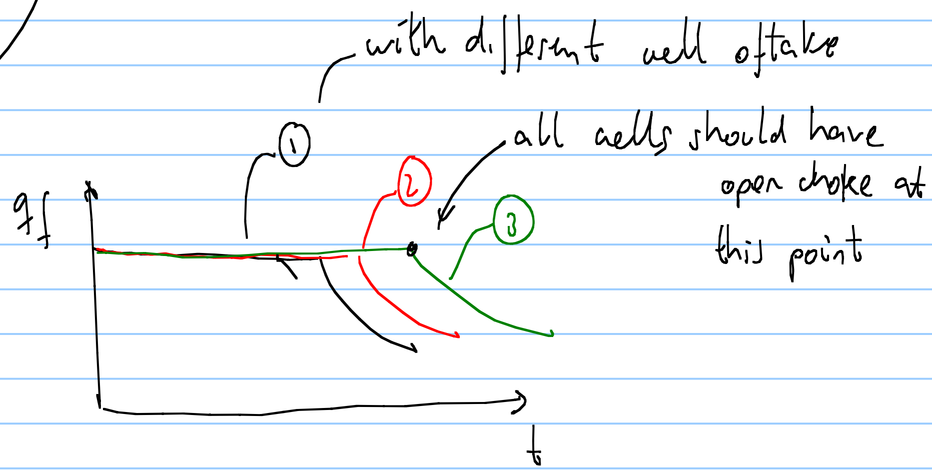
to zero

How to define well production scheduling? How to determine how much each well is going to produce with time?

Plateau mode (A)

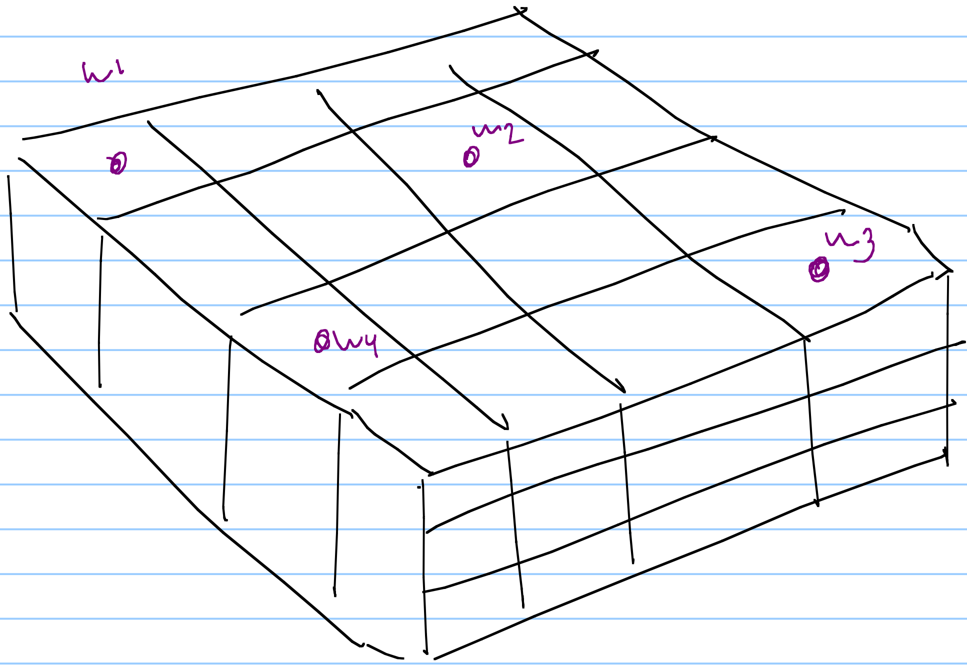
depletion mode (B)

mode A ? :



- try for all wells to enter into decline at the same time (open choke).

from reservoir simulator side




in the reservoir simulator each well needs two inputs at the boundary

- $P_{wf_{min}}$
- $q_{RATE}$ ⤳ target rate

in every time step the reservoir simulator tries first with $P_{wf_{min}}$ in the boundary ⤳ calculates a maximum rate

$$\underbrace{q_{max} = q^{i}_{POT}}_{\text{open potential}}$$

- if $q_{max} > q_{RATE_{i}}$ then i produce $q_{RATE}$
- if $q_{max} < q_{RATE}$ the i produce $q_{max}$

the well potential is used to split the plateau rate between wells

$$q_{F\,potential} = \sum_{i=1}^{\overset{\sim \text{N wells}}{N}} q^i_{pot} \qquad \chi_i = \frac{q_{i\,POT}}{q_{F\,POT}}$$

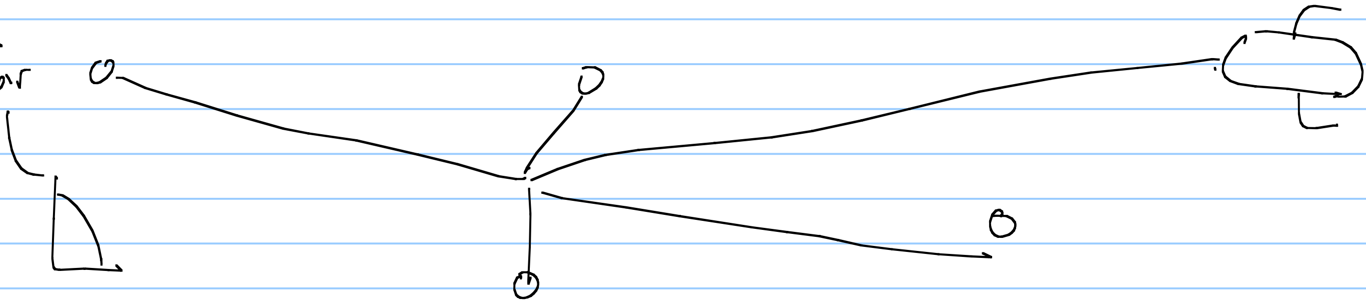
$$q^i_{well} = q_{plateau} \cdot \chi_i$$

~> ∘ do at the beginning and never change

∘ calculate potential at every time step and calculate new well rates

Another proposal using the production network.

bring IPR from reservoir



Calculate $\overbrace{\text{open choke}}^{oc}$ rates, $q^i_{oc}$

$$\chi_i^{prod} = \frac{q^i_{oc}}{\sum_{i=1}^{N} q^i_{oc}}$$

GAP (software for network simulation) is using this splitting method.

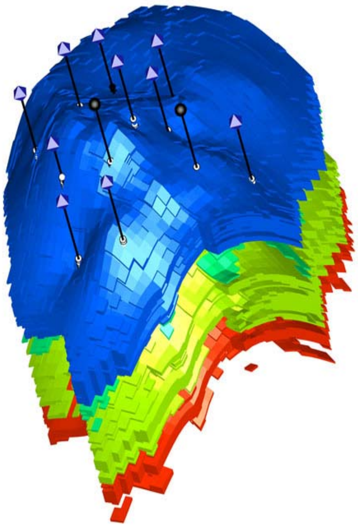
• Use model based optimization to define well production schedule

rate of each

$q_i(t)$

well with time

input ⇒



⇒ run lifetime simulation

RF

$Q_p$

change

optimize

optimization engine

Resolve
IAM (slb)
Pipe-it

integrated asset modeling software

for mode B, depletion

↳ the rate that each well produces comes from flow equilibrium.. ~ however, some changes can be introduced to the system to

: produce as much as possible

GOR WC ↑ with time and can overload the processing facilities

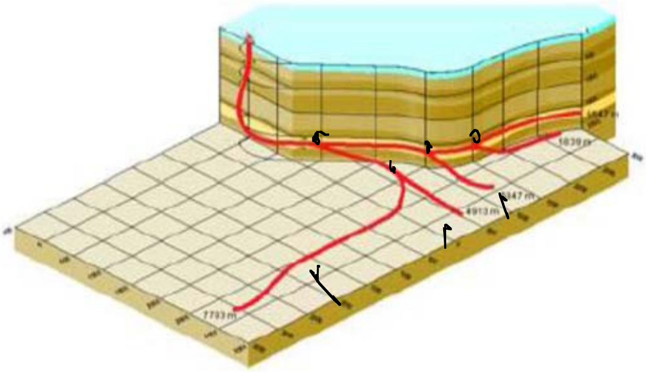
↳ decide to choke well that produce too much water or gas.

# DOWNHOLE NETWORKS

So far we have been dealing with surface networks.

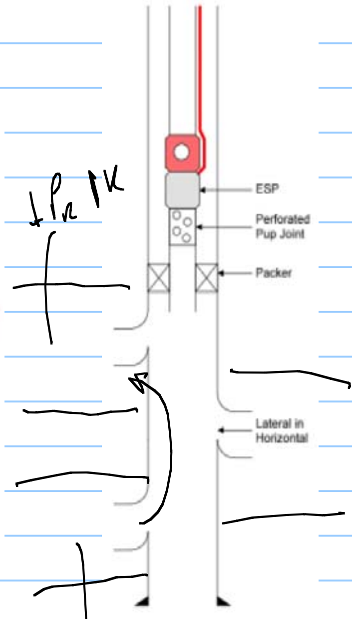
We have another type of network

multi-branch



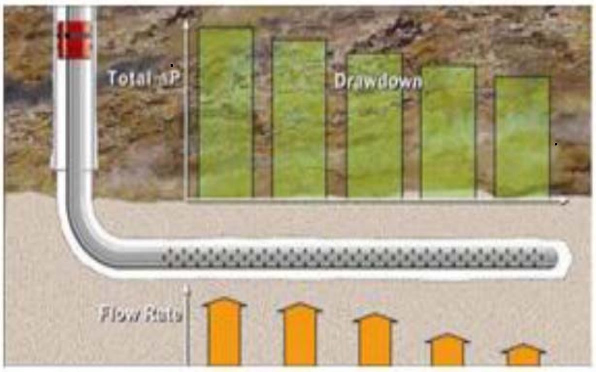
multi-layer

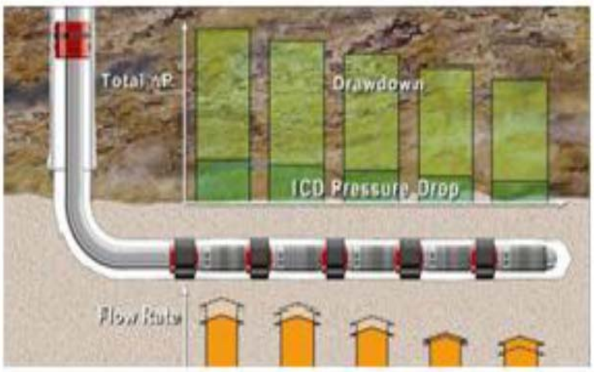
$\downarrow P_R \uparrow K$



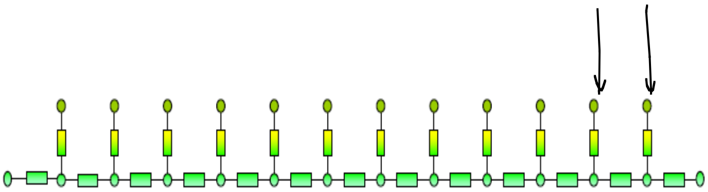

$\downarrow K \uparrow P_R$

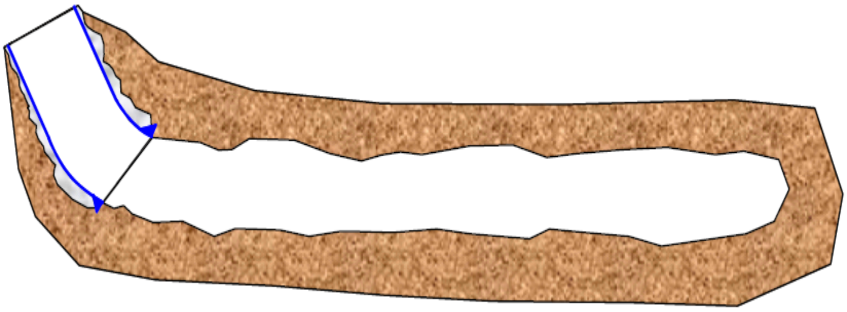
"You shall **not plow** with an ox and a **donkey together**.

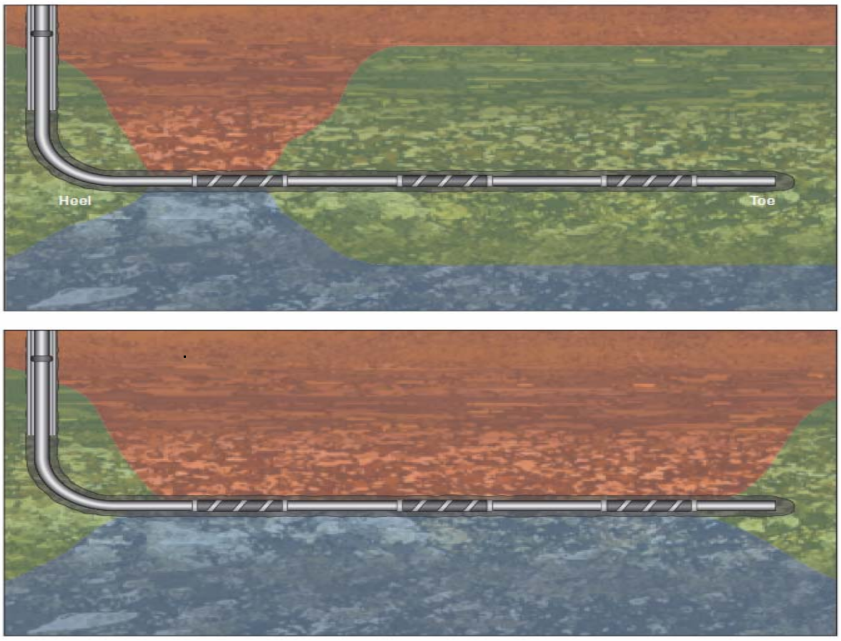


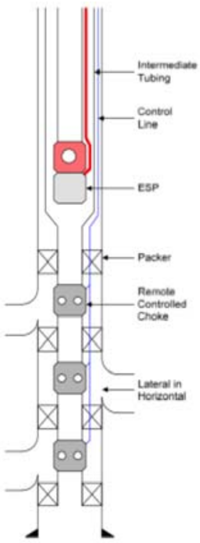
- **Horizontal well with Open Hole completion**
  - **Including damage zone**

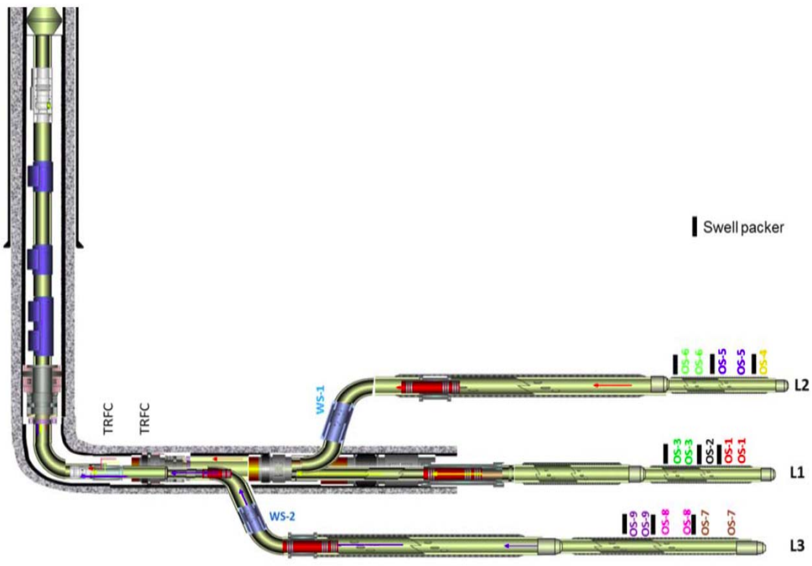







^ Heel-toe effect. Pressure losses along a horizontal wellbore in a homogeneous formation cause the flowing tubing pressure to be lower at the well's heel than at the toe. In time, and long before oil (green) from sections near the toe arrives at the wellbore, water (blue) or gas (red) is drawn to the heel (*top*), resulting in an early end to the well's productive life. Inflow control devices inside sand screen assemblies equalize the pressure drop along the entire length of the wellbore, promoting uniform flow of oil and gas through the formation (*bottom*) so that the arrivals of water and gas are delayed and simultaneous.

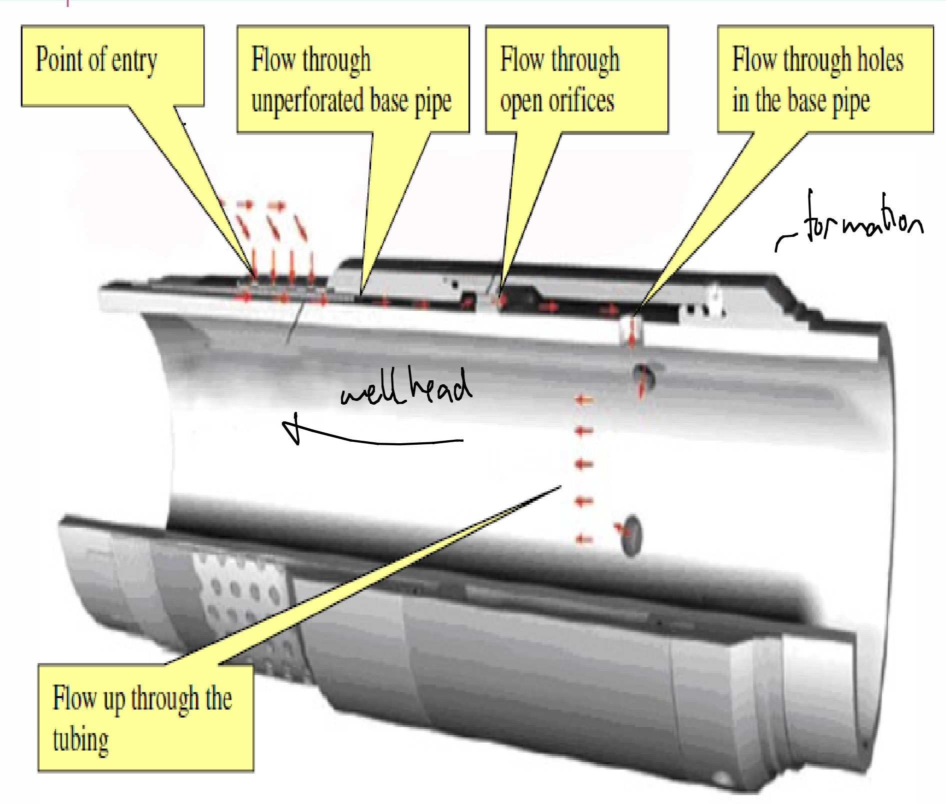


ICD inflow control device ~ passive ~> opening is fixed

ICV inflow control valve ~> active

Passive



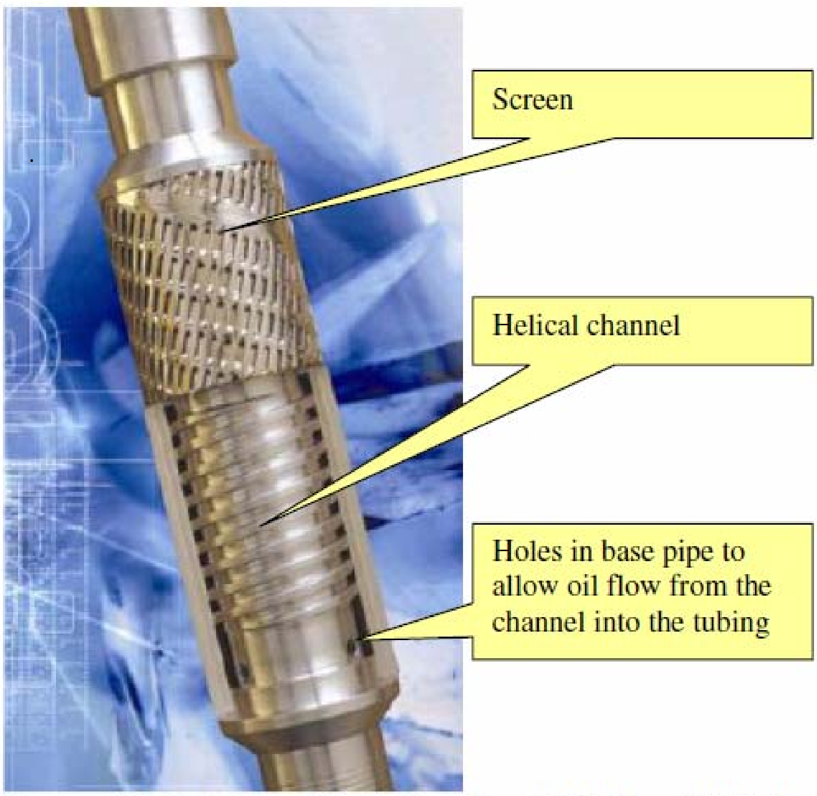




**Figure 14 Helical channel type, EqualizerTM, Baker Oil Tools [22]**

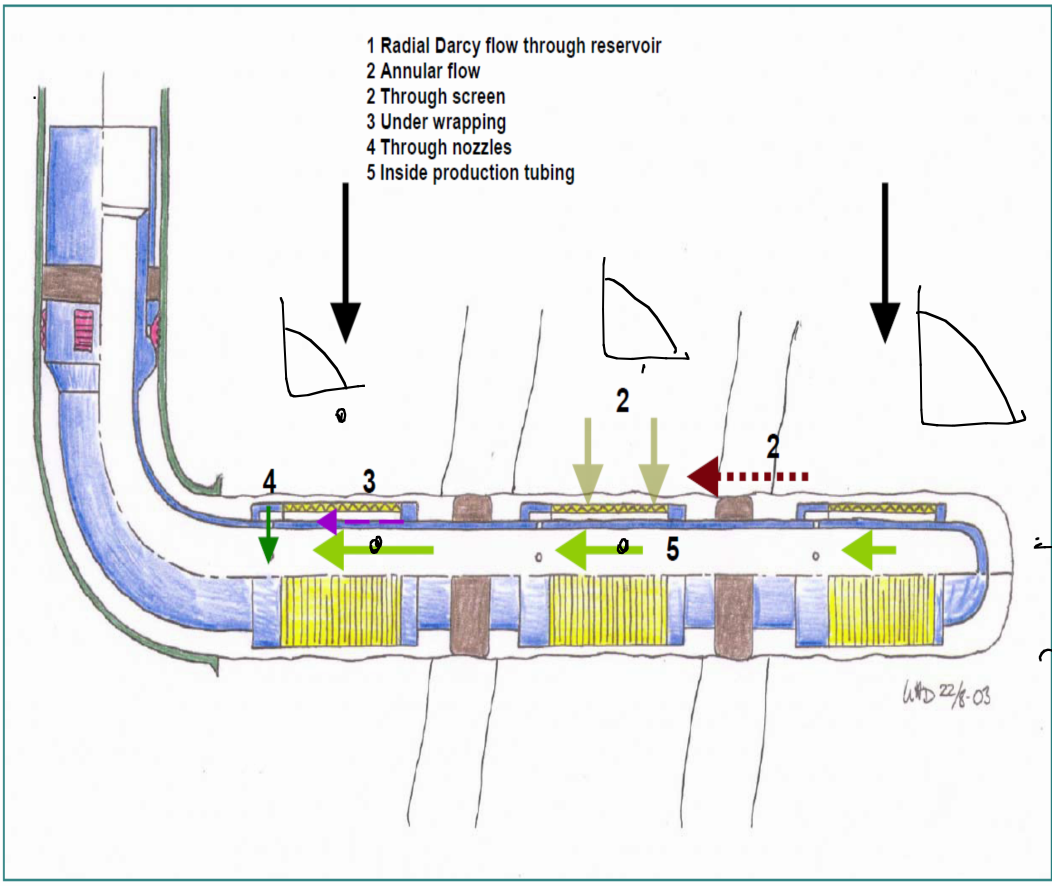
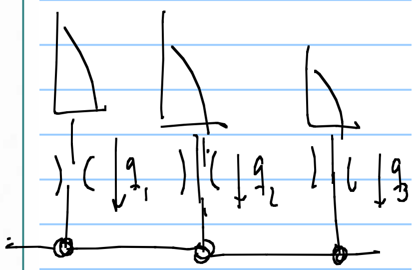
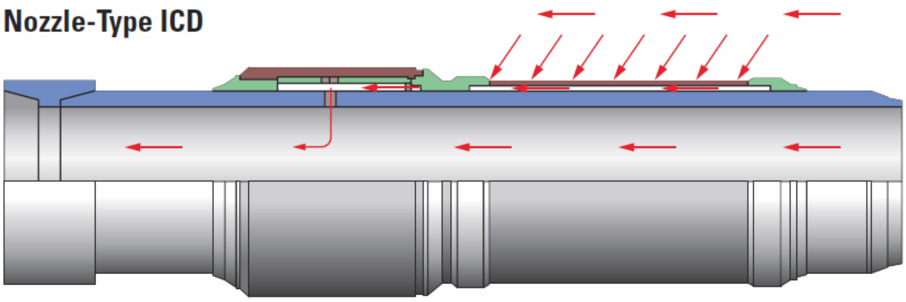



Figure-8 Functioning and interplay of an ICD completion architecture. Fluids enter the screen and flow between the axial wires and the un-perforated base pipe into the ICD housing, before passing through the nozzles and entering into the base pipe. All these flow issues are properly analyzed and put in the right perspective to achieve an optimal well completion design and solution.

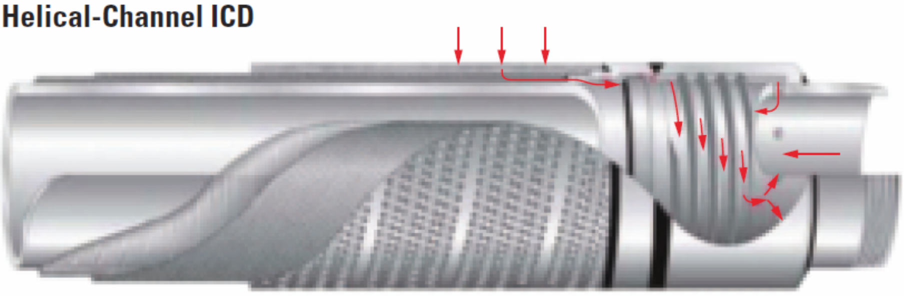


Net tool,
landmark ?
weatherford .
completion design.

**Nozzle-Type ICD**

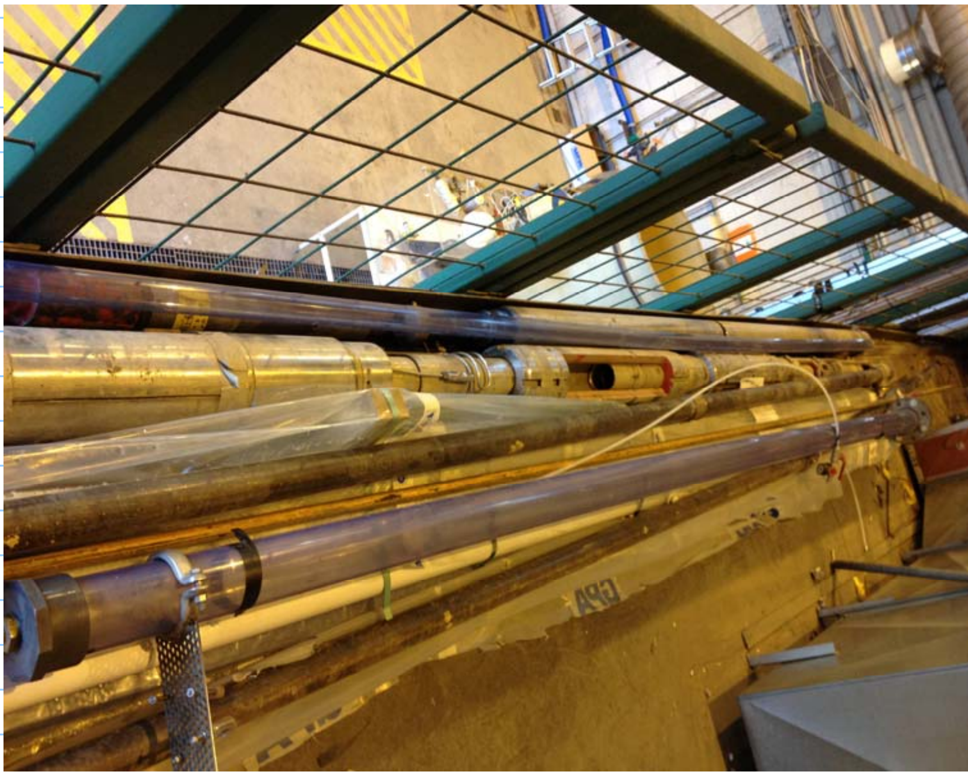


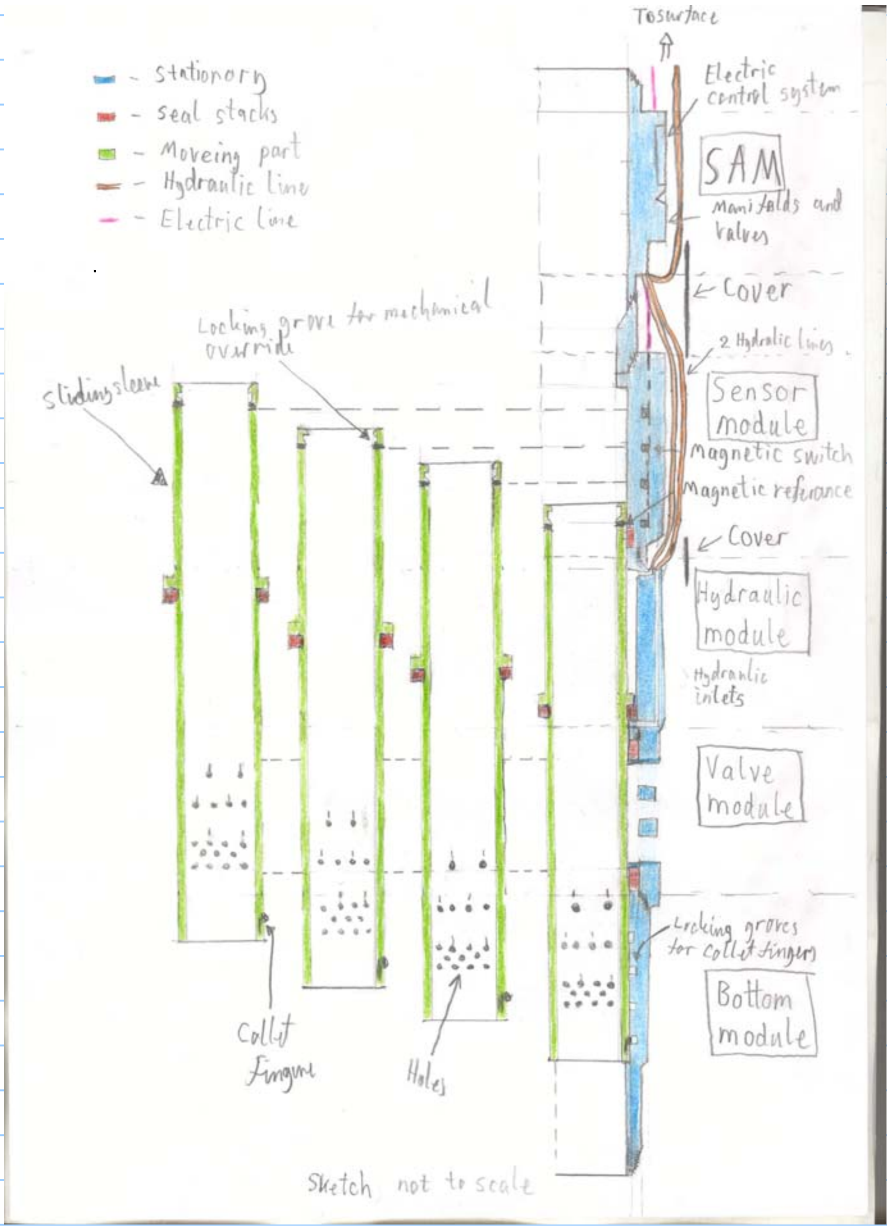
**Helical-Channel ICD**



^ Leading ICD types. Fluid from the formation (red arrows) flows through multiple screen layers mounted on an inner jacket, and along the annulus between the solid basepipe and the screens. It then enters the production tubing through a restriction in the case of nozzle- and orifice-based tools (*top*), or through a tortuous pathway in the case of helical- and tube-based devices (*bottom*).

active




To surface
- Stationary
- seal stacks
- Moveing part
- Hydraulic line
- Electric line
Electric control system
SAM
Manifolds and valves
Cover
2 Hydralic lines
Sensor module
magnetic switch
magnetic referance
Cover
Hydraulic module
Hydraulic inlets
Valve module
Locking groves for collet fingers
Bottom module
Locking grove for mechanical override
sliding sleeve
Collet fingers
Holes
Sketch not to scale

autonomous $\rightsquigarrow$ self regulable I control device (ICD)

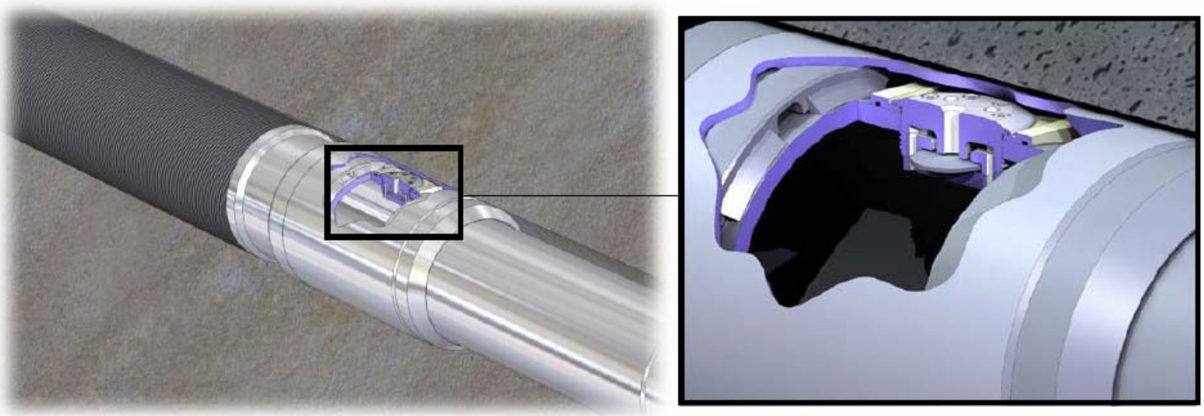


**Figure 1: Statoil's RCP valve conneted to the base pipe in a sand screen joint in the well.**

**Figure 2: Statoil's RCP valve**

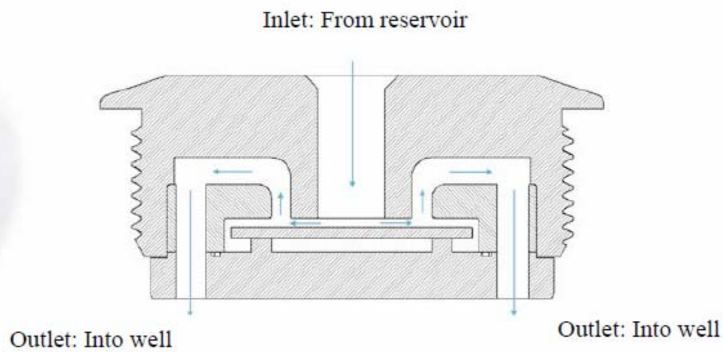
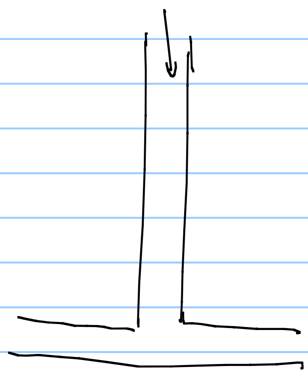
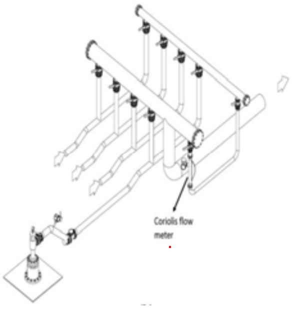
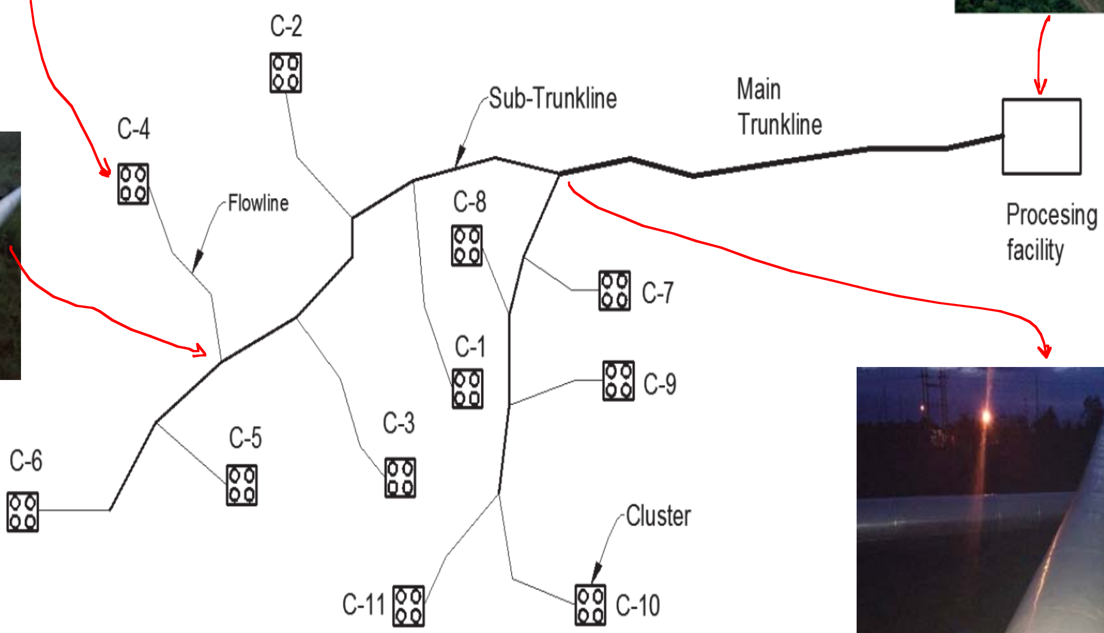



**Figure 3: Schematic sketch of Statoil's RCP valve**



# Production Networks




insulation material

Comment on ICD - ICV

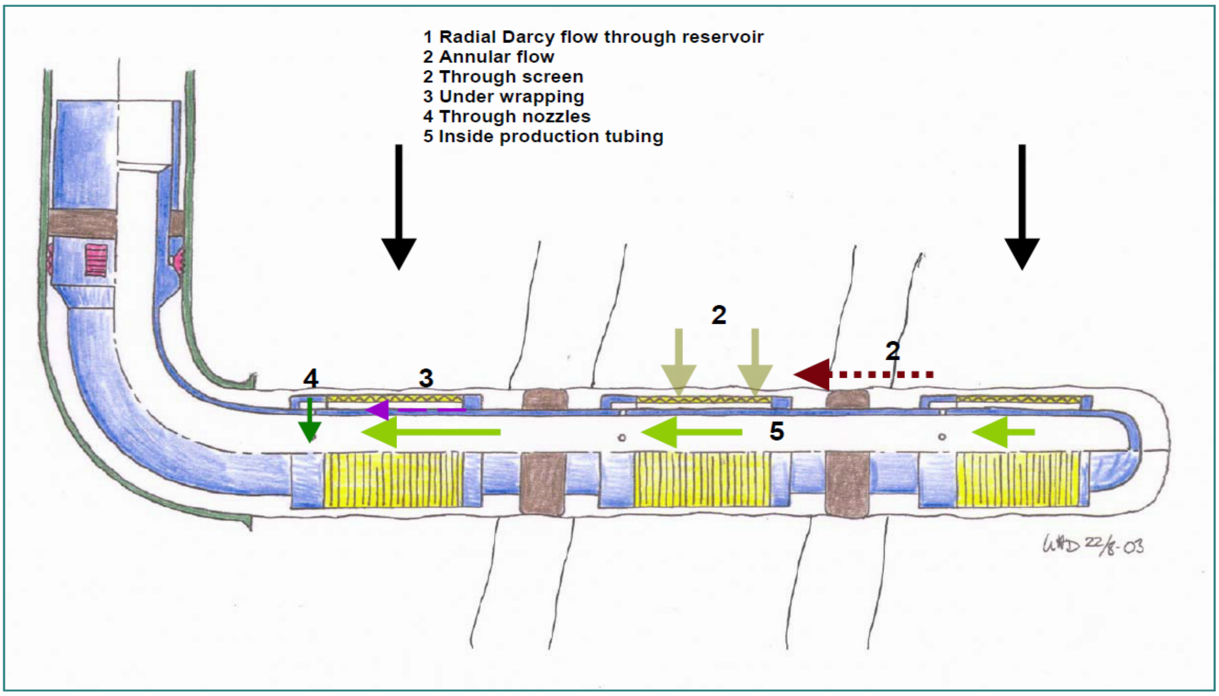
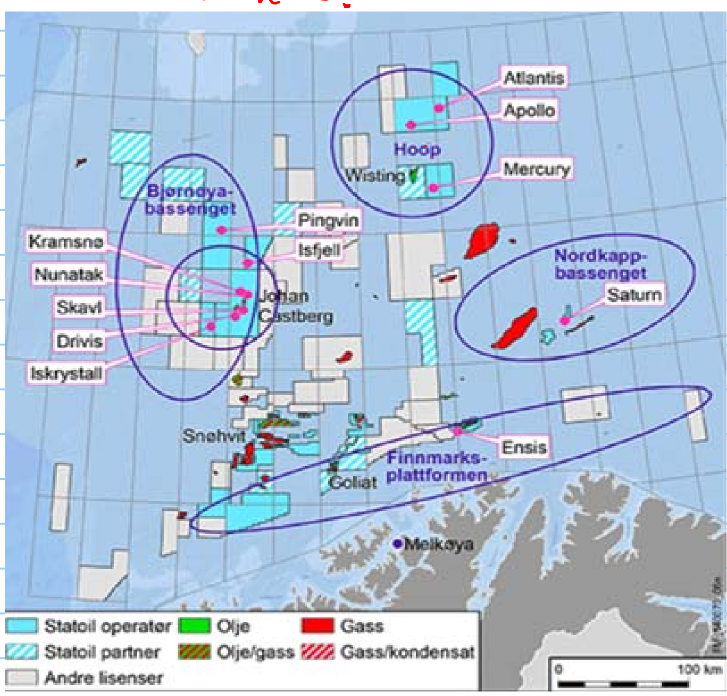



**Figure-8 Functioning and interplay of an ICD completion architecture. Fluids enter the screen and flow between the axial wires and the un-perforated base pipe into the ICD housing, before passing through the nozzles and entering into the base pipe. All these flow issues are properly analyzed and put in the right perspective to achieve an optimal well completion design and solution.**

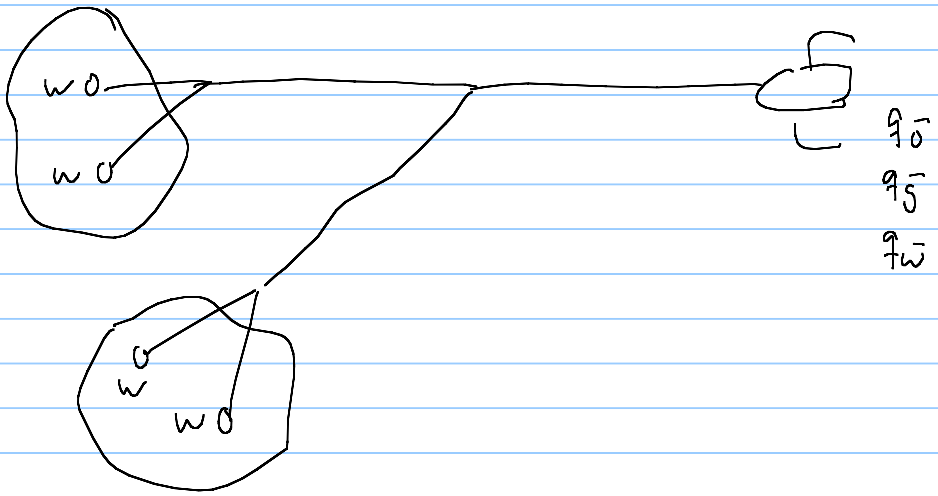
https://www.youtube.com/watch?v=E2g4hxGZP94

Comment on exercise 2!

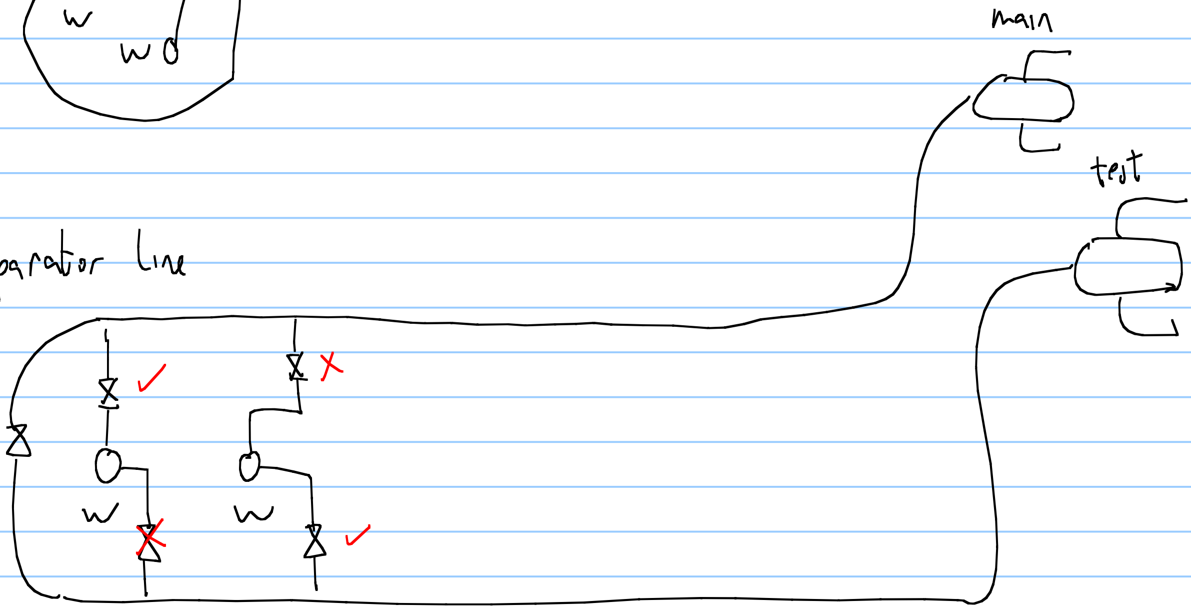


Allocation: determine or partition where the rates are coming from?

- ↳ reservoir
- ↳ well
- ↳ formation



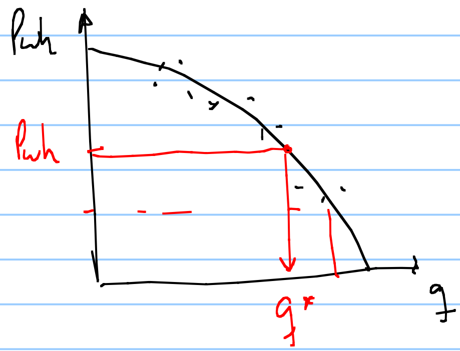

test separator line




- portable separators

• multiphase flow meter


• wellhead performance relationship




# Allocation (oil and gas)

From Wikipedia, the free encyclopedia

In the petroleum industry, **allocation** refers to practices of breaking down measures of quantities of extracted hydrocarbons across various contributing sources.[1] Allocation aids the attribution of ownerships of hydrocarbons as each contributing element to a commingled flow or to a storage of petroleum may have a unique ownership. Contributing sources in this context are typically producing petroleum wells delivering flows of petroleum or flows of natural gas to a commingled flow or storage.

The terms **hydrocarbon accounting** and allocation are sometimes used interchangeably.[2][3] Hydrocarbon accounting has a wider scope, taking advantages of allocation results, it is the petroleum management process by which ownership of extracted hydrocarbons is determined and tracked from a point of sale or discharge back to the point of extraction. In this way, hydrocarbon accounting also covers inventory control, material balance, and practices to trace ownership of hydrocarbons being transported in a transportation system, e.g. through pipelines to customers distant from the production plant.

In an allocation problem, contributing sources are more widely natural gas streams, fluid flows or multiphase flows derived from formations or zones in a well, from wells, and from fields, unitised production entities or production facilities. In hydrocarbon accounting, quantities of extracted hydrocarbon can be further split by ownership, by "cost oil" or "profit oil" categories, and broken down to individual composition fraction types. Such components may be alkane hydrocarbons, boiling point fractions,[4] and mole weight fractions.[5][6]

## Principles of Allocation:

**Proportion based allocation:** An allocation principal commonly used in the oil and gas industry is called proportional allocation. Proportional allocation assigns the quantity measured by reference meter (total system entitlement) back to incoming streams (sources) in proportional to the quantity measured by allocation meter in each stream. In other words, proportional allocation assign the difference between reference meter and sum of quantity by all allocation meters, either positive or negative, to each stream according to the relative quantity measured by allocation meters. The proportional allocation is irrespective of the measurement uncertainty in the allocation meters.

## Allocation Procedure:

The example of fundamental application of allocation is show in Fig1, where allocation meters Meter#1, Meter#2 and Meter#3 measure quantity $Q_1$, $Q_2$, $Q_3$ respectively in the incoming or source streams. Fluid from these three sources are comingled in the form of processing, pipeline or storage etc and output quantity $Q_R$ is measured by reference meter, Meter#R.

In the ideal situation, the summation of quantity measured by incoming source (allocation) flow meters, $Q_1$, $Q_2$, and $Q_3$ should be equal to the quantity measured by reference meter, $Q_R$, after accounting fuel consumption and flaring etc. However, in the practical world, they would not match and so rules are required to account for the differences.

Normally the quantity measured by reference meter is assumed to be true or accepted value, so the imbalance is allocated back to the allocation streams according to a defined allocation principle.

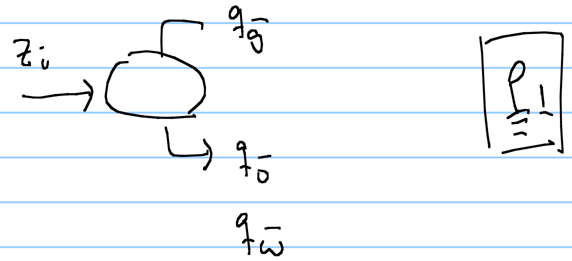
Reconcile the measurements of the meters with measurements at the
- tanker
- storage.

why do we want to do allocation?

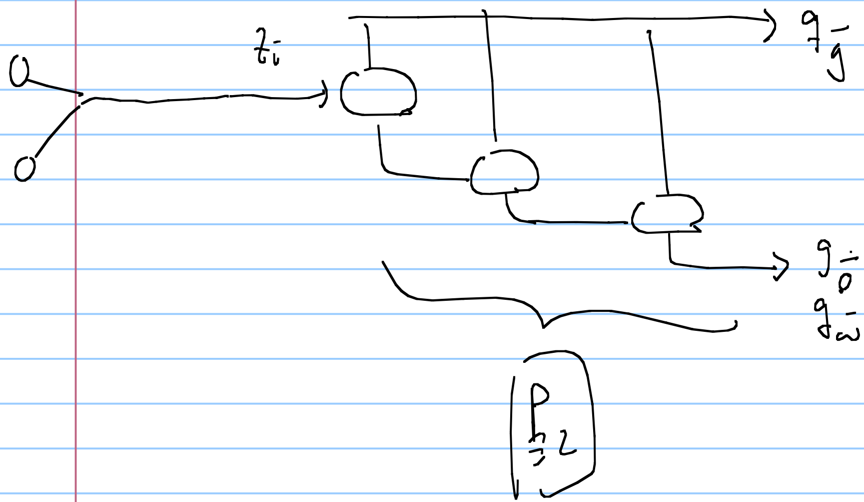
- Calculate partner share

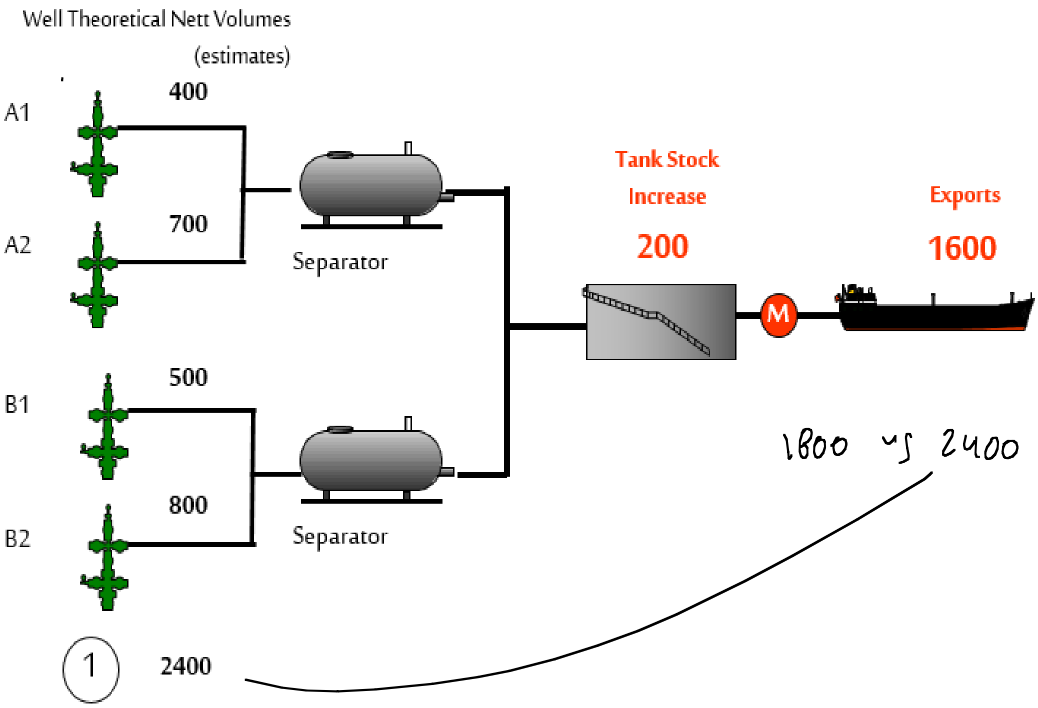
- Company revenue
- Tax payments, Royalty payments
- Governmental regulatory requirements.
- Verify and tune reservoir models, verify field management strategy
- production optimization and planning

- meter accuracy.

- 


when using portable-test separators the surface process is different



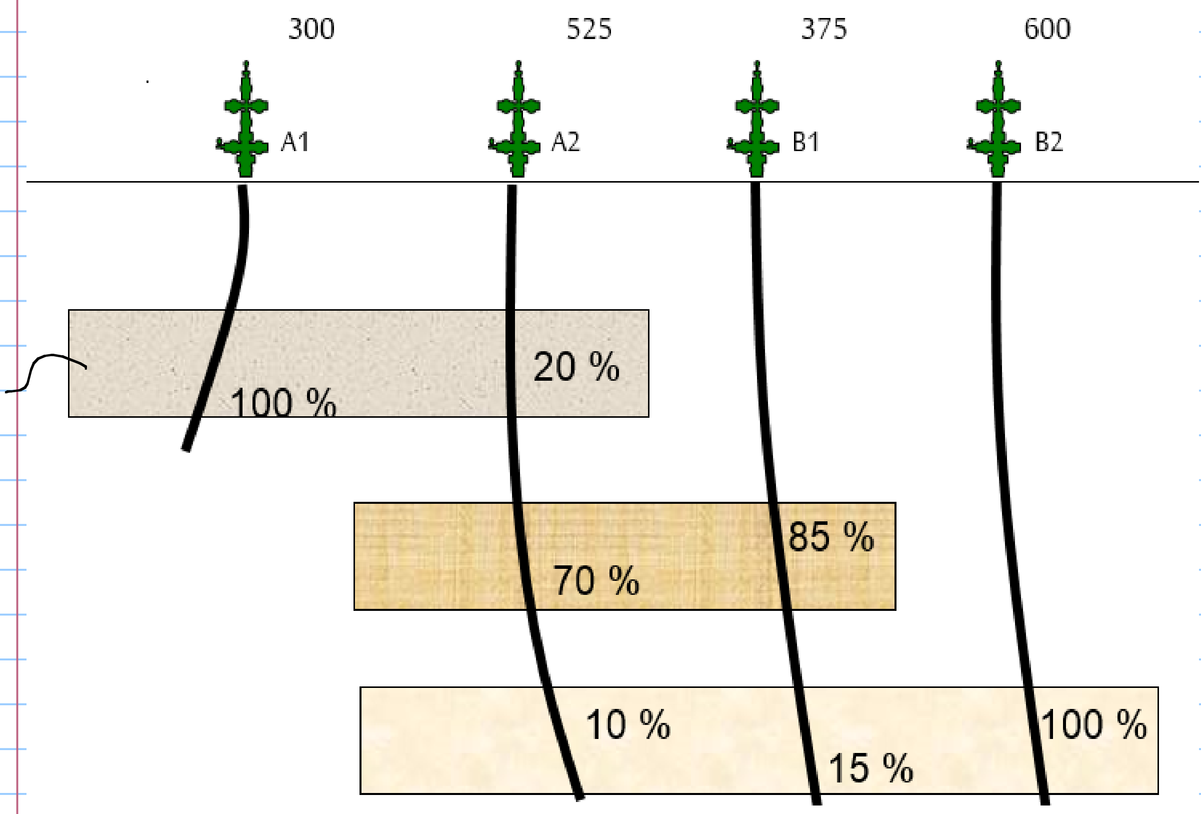




1800 vs 2400

Calculate a reconciliation factor: $f = \frac{1800}{2400} = 0.75$

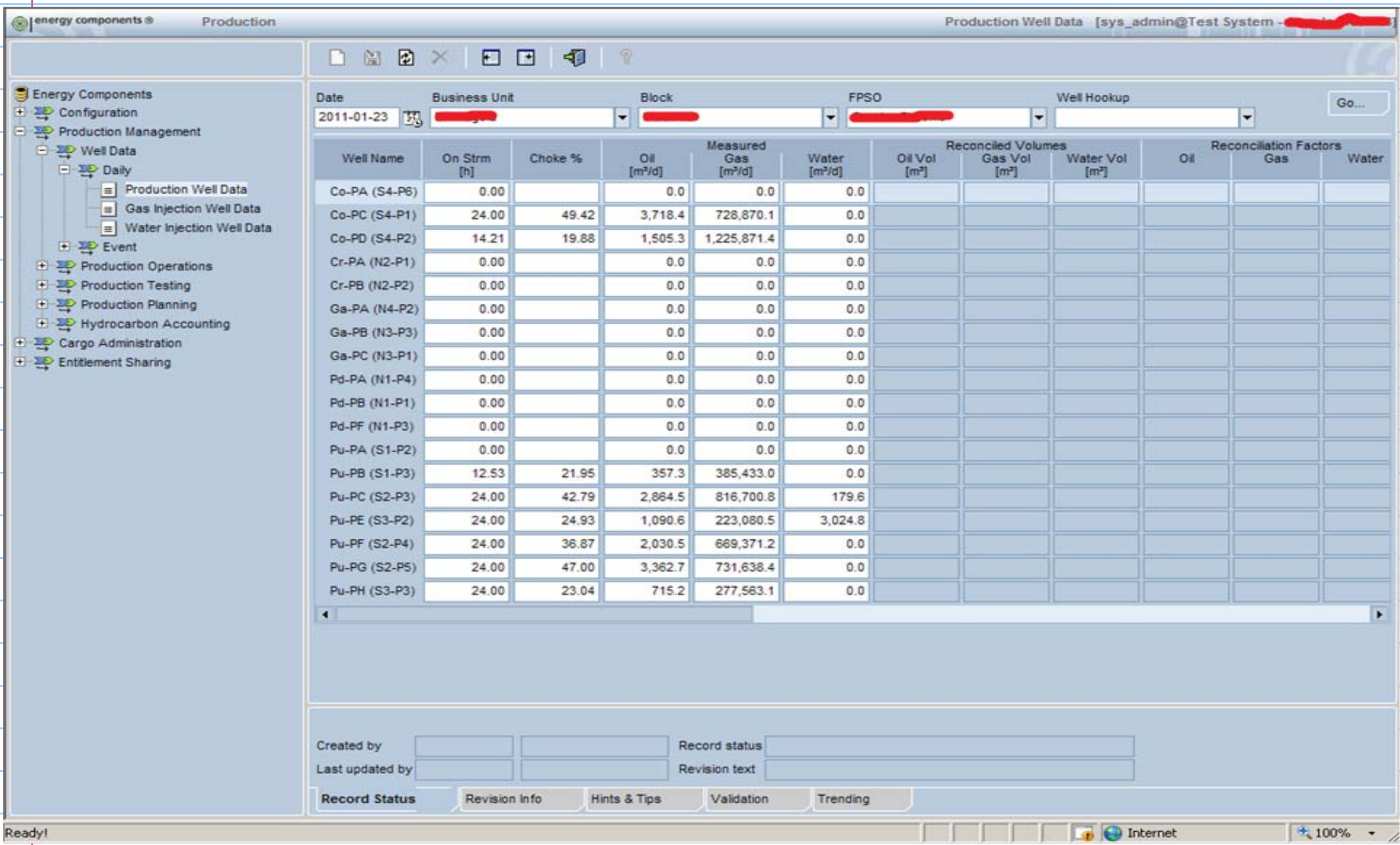
with this factor, it is possible to scale the well rates

| | old rate [$Sm^3/d$] | new rate [$Sm^3/d$] |
|---|---|---|
| | 400 | 300 |
| 0.75 | 700 | 525 |
| | 500 | 375 |
| | 800 | 600 |



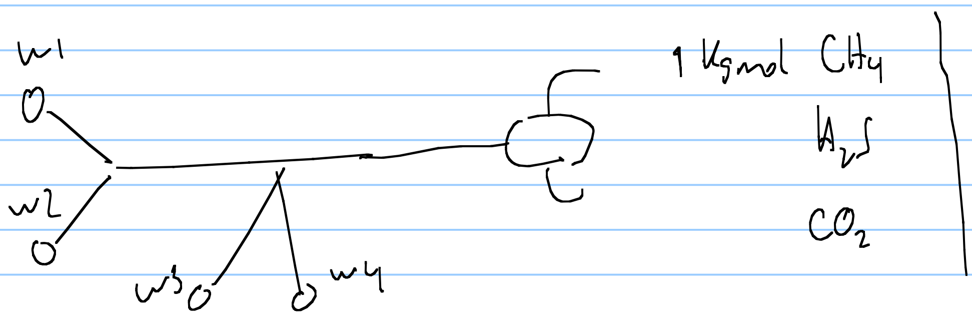

- production logging
- downhole meters
- Downhole network simulation

# Energy Components – Tieto




| Well Name | On Strm [h] | Choke % | Measured Oil [m³/d] | Measured Gas [m³/d] | Measured Water [m³/d] | Reconciled Volumes Oil Vol [m³] | Reconciled Volumes Gas Vol [m³] | Reconciled Volumes Water Vol [m³] | Reconciliation Factors Oil | Reconciliation Factors Gas | Reconciliation Factors Water |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Co-PA (S4-P6) | 0.00 | | 0.0 | 0.0 | 0.0 | | | | | | |
| Co-PC (S4-P1) | 24.00 | 49.42 | 3,718.4 | 728,870.1 | 0.0 | | | | | | |
| Co-PD (S4-P2) | 14.21 | 19.88 | 1,505.3 | 1,225,871.4 | 0.0 | | | | | | |
| Cr-PA (N2-P1) | 0.00 | | 0.0 | 0.0 | 0.0 | | | | | | |
| Cr-PB (N2-P2) | 0.00 | | 0.0 | 0.0 | 0.0 | | | | | | |
| Ga-PA (N4-P2) | 0.00 | | 0.0 | 0.0 | 0.0 | | | | | | |
| Ga-PB (N3-P3) | 0.00 | | 0.0 | 0.0 | 0.0 | | | | | | |
| Ga-PC (N3-P1) | 0.00 | | 0.0 | 0.0 | 0.0 | | | | | | |
| Pd-PA (N1-P4) | 0.00 | | 0.0 | 0.0 | 0.0 | | | | | | |
| Pd-PB (N1-P1) | 0.00 | | 0.0 | 0.0 | 0.0 | | | | | | |
| Pd-PF (N1-P3) | 0.00 | | 0.0 | 0.0 | 0.0 | | | | | | |
| Pu-PA (S1-P2) | 0.00 | | 0.0 | 0.0 | 0.0 | | | | | | |
| Pu-PB (S1-P3) | 12.53 | 21.95 | 357.3 | 385,433.0 | 0.0 | | | | | | |
| Pu-PC (S2-P3) | 24.00 | 42.79 | 2,864.5 | 816,700.8 | 179.6 | | | | | | |
| Pu-PE (S3-P2) | 24.00 | 24.93 | 1,090.6 | 223,080.5 | 3,024.8 | | | | | | |
| Pu-PF (S2-P4) | 24.00 | 36.87 | 2,030.5 | 669,371.2 | 0.0 | | | | | | |
| Pu-PG (S2-P5) | 24.00 | 47.00 | 3,362.7 | 731,638.4 | 0.0 | | | | | | |
| Pu-PH (S3-P3) | 24.00 | 23.04 | 715.2 | 277,563.1 | 0.0 | | | | | | |

## Compositional allocation

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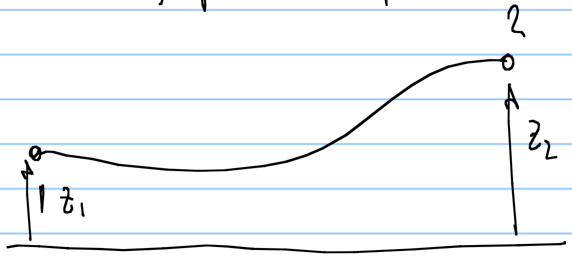
Calculation of pressure drop in conduits with liquid: (oil, water)




$$h_1 = h_2$$

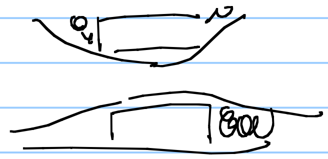
$$\frac{P_1}{\rho g} + z_1 + \frac{v_1^2}{2g} = \frac{P_2}{\rho g} + z_2 + \frac{v_2^2}{2g}$$

pipe length

flow velocity

frictional losses $\quad \Delta h_f = f \frac{L}{\phi} \frac{v^2}{2g}$

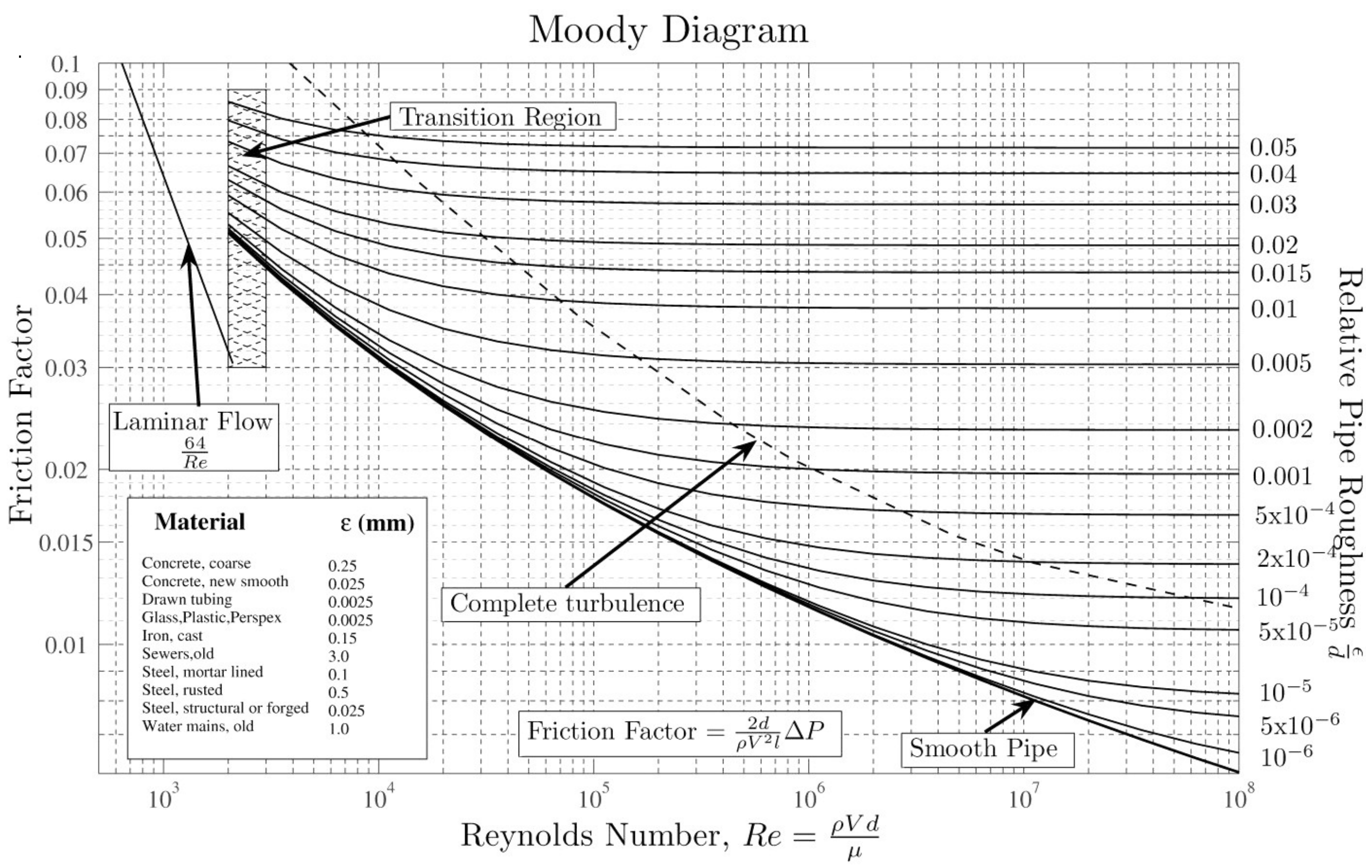
inner diameter



localized pressure drop $\quad \Delta h_{acc} = K \cdot \frac{v^2}{2g}$

loss coefficient

$$\Delta h_{acc} = f \frac{L_{eq}}{\phi} \frac{v^2}{2g}$$




$$\frac{1}{\sqrt{f}} = -1.8\log_{10}\left[\left(\frac{\varepsilon/D}{3.7}\right)^{1.11} + \frac{6.9}{\mathrm{Re}}\right]$$ [7]

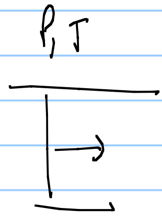
| Fitting Type | | K |
|---|---|---|
| **Pipe Entry Losses** | | |
| Square Inlet | | 0.50 |
| Re-entrant Inlet | | 0.80 |
| Slightly Rounded Inlet | | 0.25 |
| Bellmouth Inlet | | 0.05 |
| **Pipe Intermediate Losses** | | |
| Elbows R/D < 0.6 | 45° | 0.35 |
| | 90° | 1.10 |
| Long Radius Bends (R/D > 2) | 11¼° | 0.05 |
| | 22½° | 0.10 |
| | 45° | 0.20 |
| | 90° | 0.50 |
| **Tees** | | |
| (a) Flow in line | | 0.35 |
| (b) Line to branch flow | | 1.00 |
| **Sudden Enlargements** | | |
| Ratio | d/D | |
| | 0.9 | 0.04 |
| | 0.8 | 0.13 |
| | 0.7 | 0.26 |
| | 0.6 | 0.41 |
| | 0.5 | 0.56 |
| | 0.4 | 0.71 |
| | 0.3 | 0.83 |
| | 0.2 | 0.92 |
| | <0.2 | 1.00 |
| **Sudden Contractions** | | |
| Ratio | d/D | |
| | 0.9 | 0.10 |
| | 0.8 | 0.18 |
| | 0.7 | 0.26 |
| | 0.6 | 0.32 |
| | 0.5 | 0.38 |
| | 0.4 | 0.42 |
| | 0.3 | 0.46 |
| | 0.2 | 0.48 |
| | <0.2 | 0.50 |

| Fitting Type | | K |
|---|---|---|
| **Gradual Enlargements** | | |
| Ratio d/D | q = 10° typical | |
| | 0.9 | 0.02 |
| | 0.7 | 0.13 |
| | 0.5 | 0.29 |
| | 0.3 | 0.42 |
| **Gradual Contractions** | | |
| Ratio d/D | q = 10° typical | |
| | 0.9 | 0.03 |
| | 0.7 | 0.08 |
| | 0.5 | 0.12 |
| | 0.3 | 0.14 |
| **Valves** | | |
| Gate Valve (fully open) | | 0.20 |
| Reflux Valve | | 2.50 |
| Globe Valve | | 10.00 |
| Butterfly Valve (fully open) | | 0.20 |
| Angle Valve | | 5.00 |
| Foot Valve with strainer | | 15.00 |
| Air Valves | | zero |
| Ball Valve | | 0.10 |
| **Pipe Exit Losses** | | |
| Square Outlet | | 1.00 |
| Rounded Outlet | | 1.00 |

$$z_1 + \frac{P_1}{\rho g} + \cancel{\frac{V_1^2}{2g}} = z_2 + \frac{P_2}{\rho g} + \cancel{\frac{V_2^2}{2g}} + f\frac{L}{\phi}\frac{V^2}{2g}$$

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

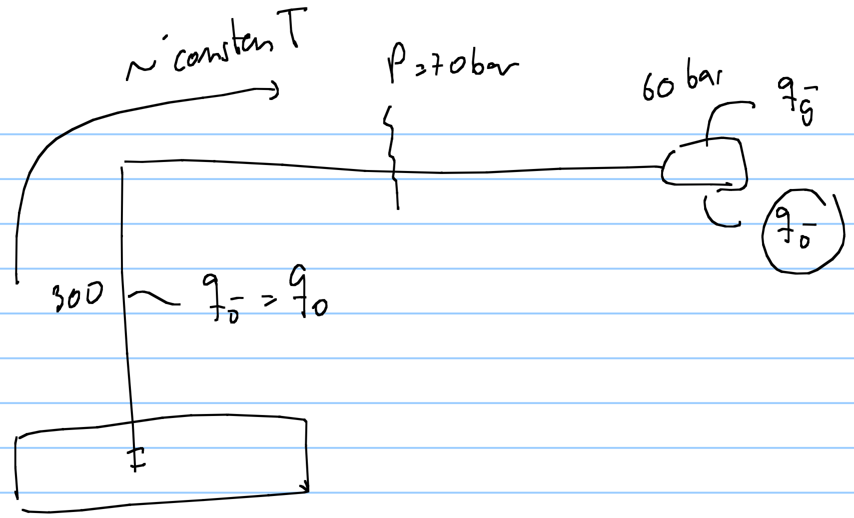
? $[m^3/s]$




$$\rho g\left[(z_1 - z_2) + \frac{P_1}{\rho g} - \frac{f L 8 q^2}{\pi^2 \phi^5 g}\right] = P_2$$

we need a way to convert from Standard conditions rate to local rates

$P_b(T) \approx 70$ bar




- undersaturated oil system low bubble point pressure ⇝ Heavy oils

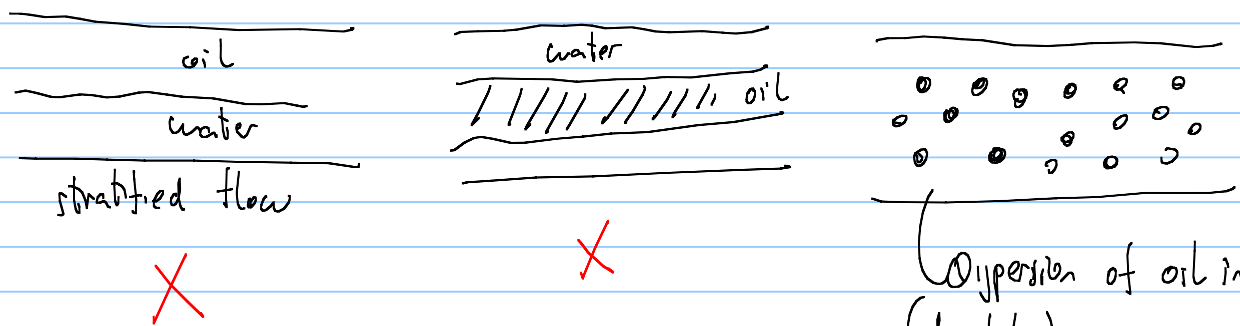
properties change along the production system $\rho$, $\mu$ due to $P$ and $T$

a stepwise calculation is required !

$q_o$ depends $P$, $T$.

- undersaturated oil + water

phases arrange themselves in different configurations in the pipe

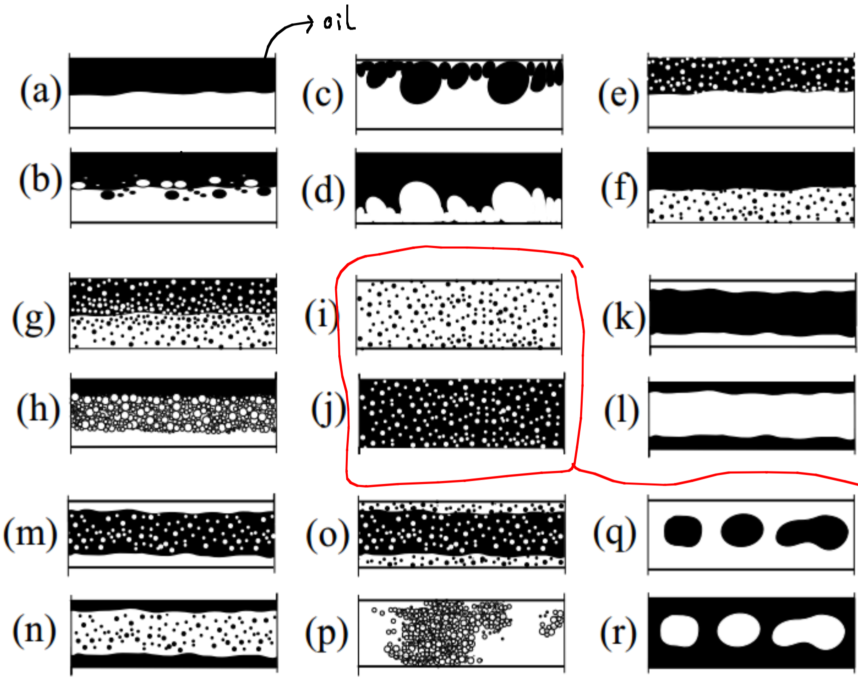



Dispersion of oil in water (droplets)

of water in oil

Note Title 23.02.2016

Water + oil flow




flow patterns. Spatial arrangement/configuration of phases in the pipe while flowing.

fine dispersion

droplets of oil in water

droplets of water in oil

behave "almost" like a single fluid.

It is possible to use modified version pressure drop for liquid flow

① ⟶ ②

$$P_2 = \rho \cdot g \left[ (z_1 - z_2) + \frac{P_1}{\rho g} - f \frac{L}{\phi} \frac{V^2}{2g} \right]$$

$\rho, \mu$

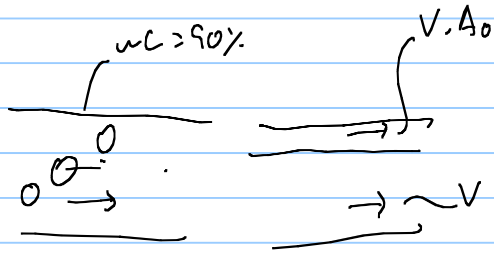
$$Re = \frac{\rho \phi V}{\mu} \qquad V = \frac{q}{A} = \frac{\dot{m}/\rho}{A}$$

for oil and water $\rho_m = \alpha_o \rho_o + \alpha_w \cdot \rho_w$

↳ volume fraction $\quad \alpha_o = \dfrac{q_o}{q_o + q_w} \quad \alpha_w = \dfrac{q_w}{q_o + q_w} \quad \alpha_o + \alpha_w = 1$

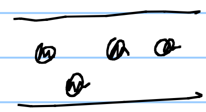
$$V_m = \frac{q_o + q_w}{A}$$

what to do with viscosity?



we use the mixture viscosity $\mu_m = (\alpha_o)\mu_o + \alpha_w \mu_w$ usually not a good approximation

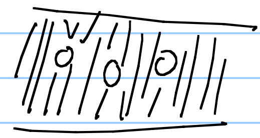
use the viscosity of the fluid that is wetting the wall (continuous fluid) $\rightsquigarrow$ water continuous



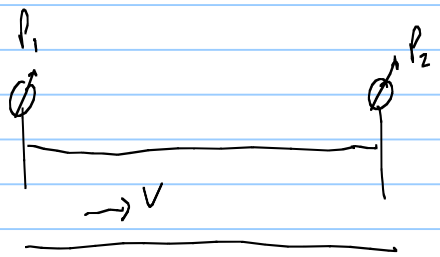
$\sim \mu = \mu_w$

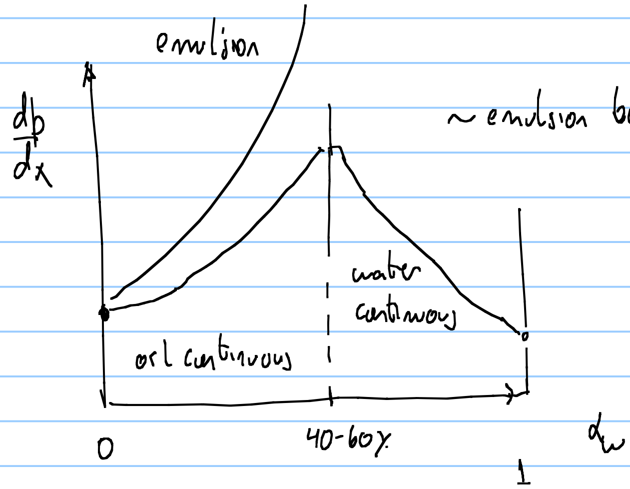
$\alpha_o \uparrow$ or $\alpha_w \uparrow$

oil continuous

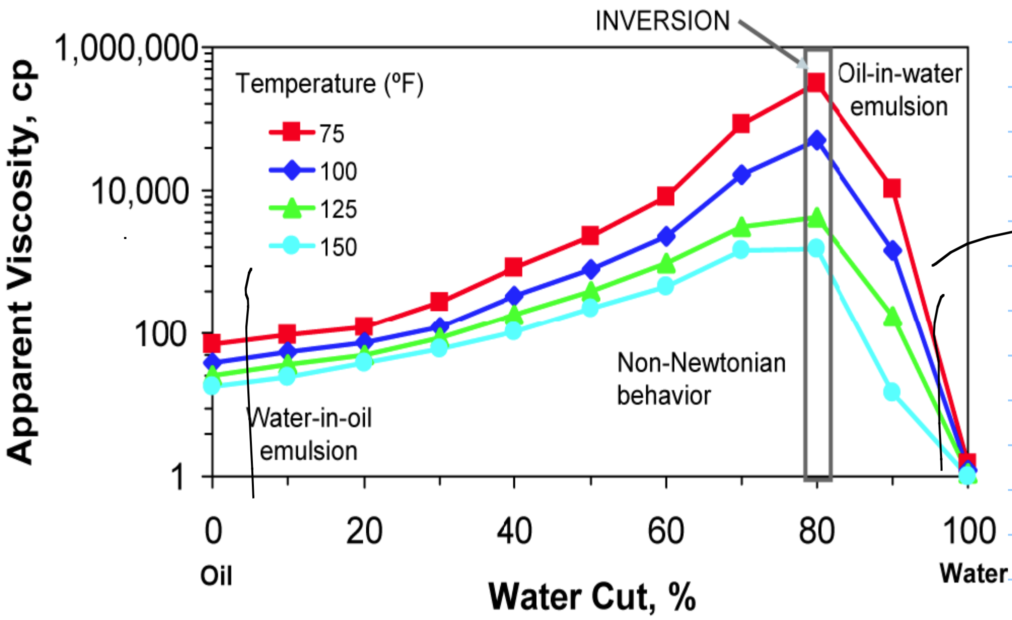


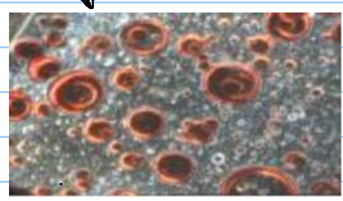
$\sim \mu = \mu_o$




~ emulsion behavior



perform experimental measurements

Richardson formula

- Valle (2000)

$$\mu_{rel} = \mu_{rel}\left( \Phi_d / (\Phi)_{\mu=\mu_{rel0}} \right) = \frac{1}{(1 - K_0 K_F(\gamma) \cdot \Phi_d)} = \left[ 1 + \frac{\dfrac{\Phi_d}{(\Phi)_{\mu=\mu_0}}}{\dfrac{\mu_0^{0.4}}{\mu_0^{0.4} - 1} - \dfrac{\Phi_d}{(\Phi)_{\mu=\mu_0}}} \right]^{2.5}$$

$$\mu_m = \mu_o \cdot e^{\overset{C_o}{\cancel{3.215}} \frac{WC}{100}}$$

$$\mu_m = \mu_w \cdot e^{\overset{C_w}{\cancel{3.089}} \left( 100 - \frac{WC}{100} \right)}$$

- Brinkmann (1956)

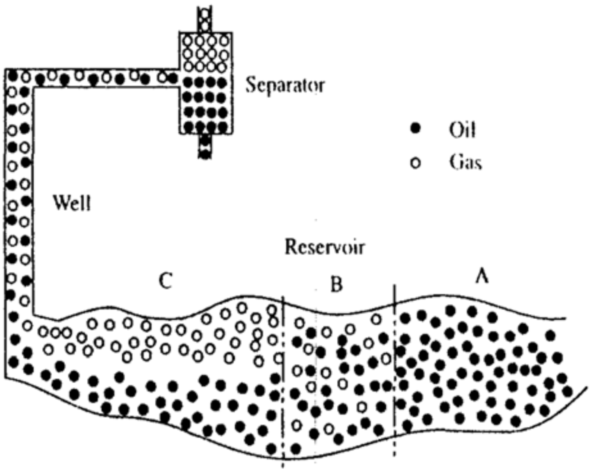
$$\mu_{rel} = (1 - \Phi_d)^{-2.5}$$

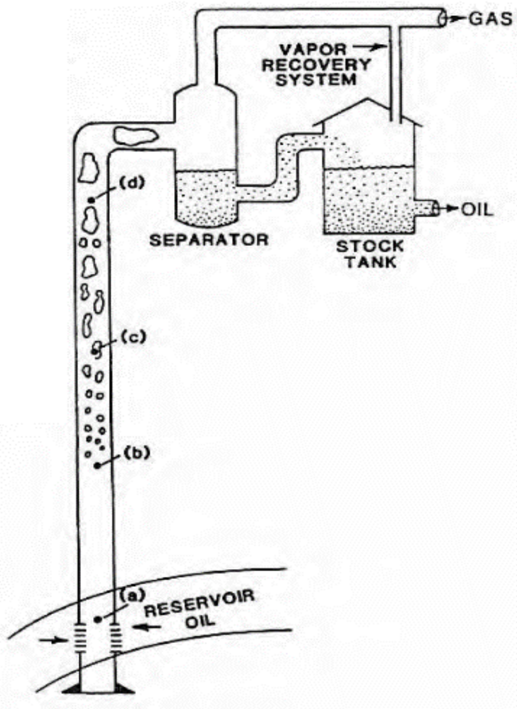
volume fraction of the dispersed phase

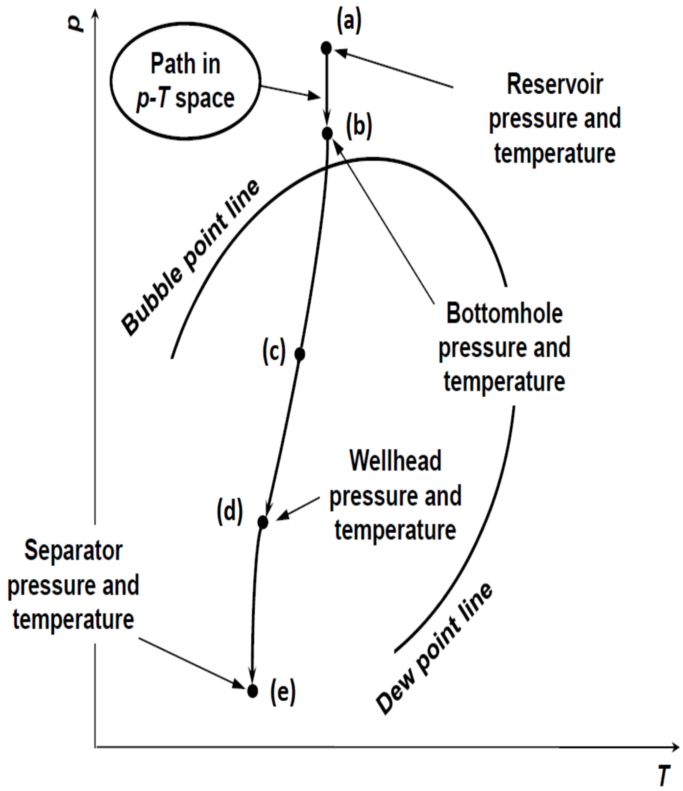
$$\frac{\mu_{mix}}{\mu_o} = (1 - \alpha_w)^{-2.3} \qquad \mu_m = \mu_w \cdot (1 - \alpha_o)^{-2.5}$$

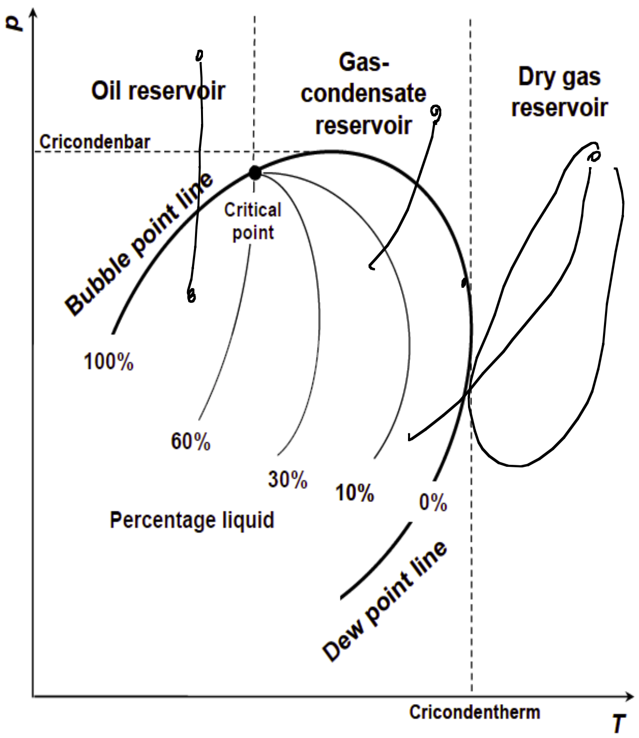
- Multiphase flow ~ simultaneous flow of
  - gas ~ vapour phase
  - oil ~ liquid phase
  - water ~ liquid phase

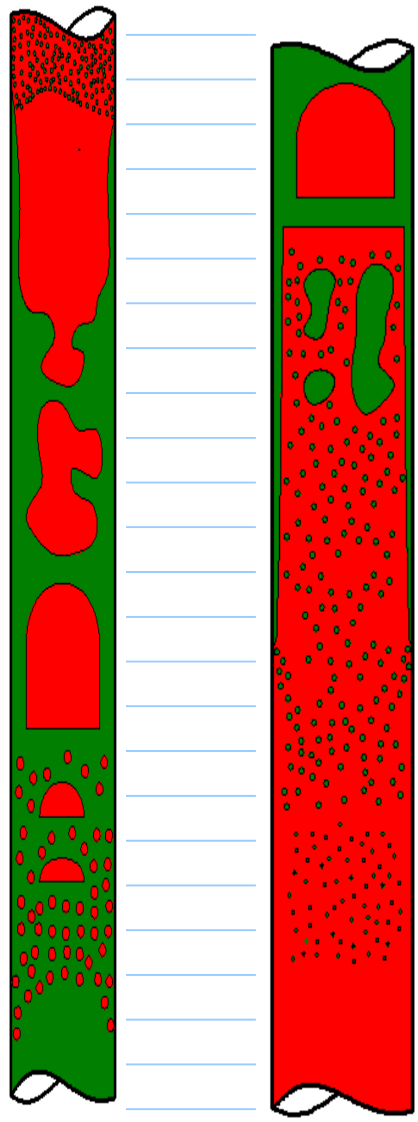
  very frequently they are treated as single liquid phase with equivalent properties

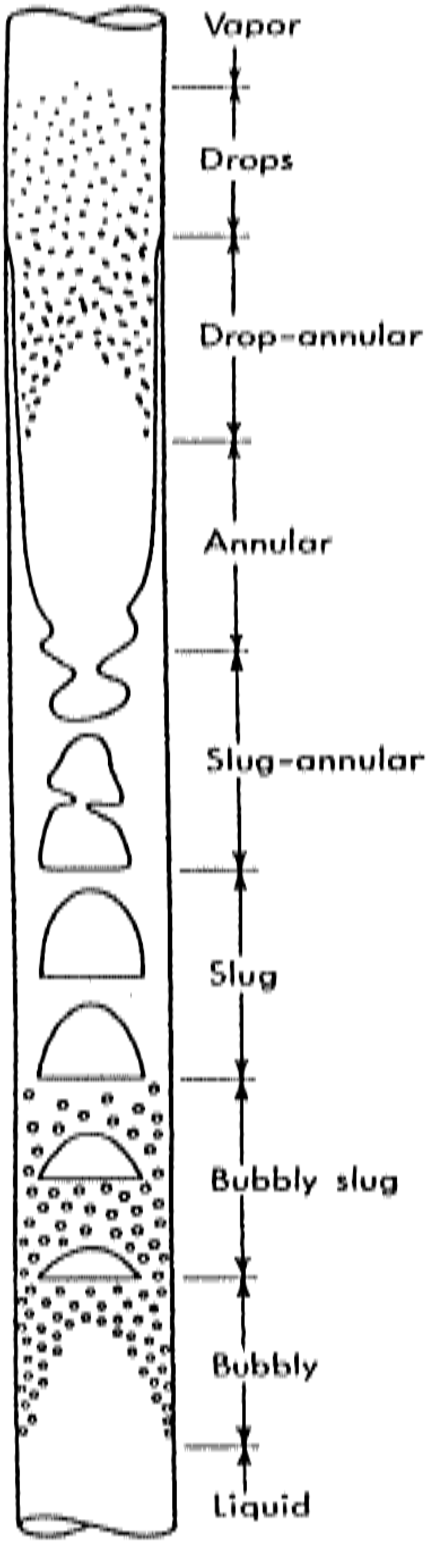



GAS
VAPOR RECOVERY SYSTEM
(d)
SEPARATOR
STOCK TANK
OIL
(c)
(b)
(a)
RESERVOIR OIL


p
(a)
Path in p-T space
Reservoir pressure and temperature
(b)
Bubble point line
Bottomhole pressure and temperature
(c)
Wellhead pressure and temperature
(d)
Separator pressure and temperature
(e)
Dew point line
T


p
Oil reservoir
Gas-condensate reservoir
Dry gas reservoir
Cricondenbar
Critical point
Bubble point line
100%
60%
30%
10%
0%
Percentage liquid
Dew point line
Cricondentherm
T





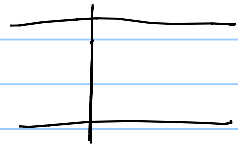

flow pattern identification is not all the time black and white

→ EPT ~> Multiphase flow ~> prof. Ole Jørgen Nydal

TEP 4250

classification

- Steady state $\frac{\partial}{\partial t} = 0$



$\frac{\partial \alpha_o}{\partial t} = 0$

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

→ pipesim, gap, prosper, wellflow, olga, leda

→ olga, leda

$$f = \frac{\Delta p}{\left\{\frac{v^2}{2g}\right.}\left(\frac{\phi}{L}\right) \qquad Re = \quad \Bigg\} \text{ Moody diagram}$$

why not use the same approach as for single phase flow in multiphase flow (adimensional number)?

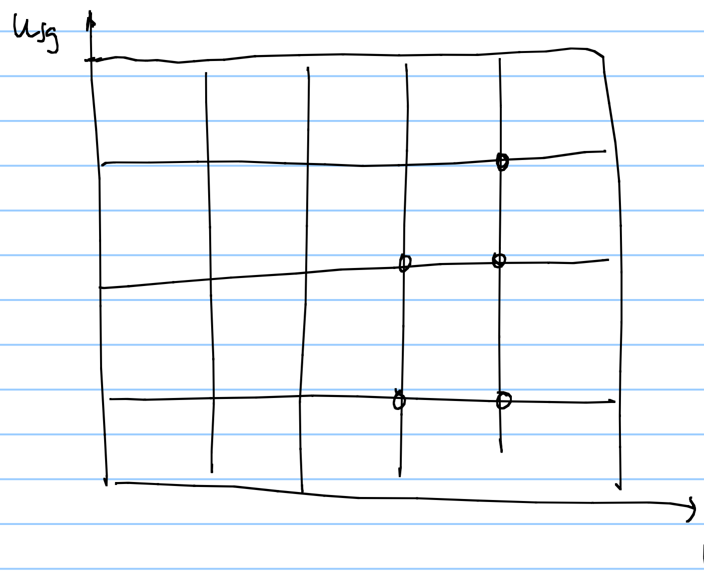
A large number of adimensional numbers (to cover all possible pipe configurations, fluid properties, flow conditions) and it is very difficult to find a correlation between them.

- Gas-liquid flows

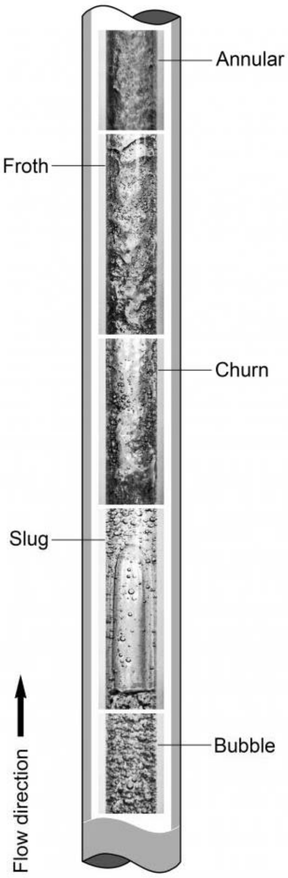
Use sort of an adimensional number: superficial velocities $u_{sL} = \frac{q_L}{A}$ (liquid; $A$ → cross section area of pipe)

$$u_{sg} = \frac{q_g}{A}$$

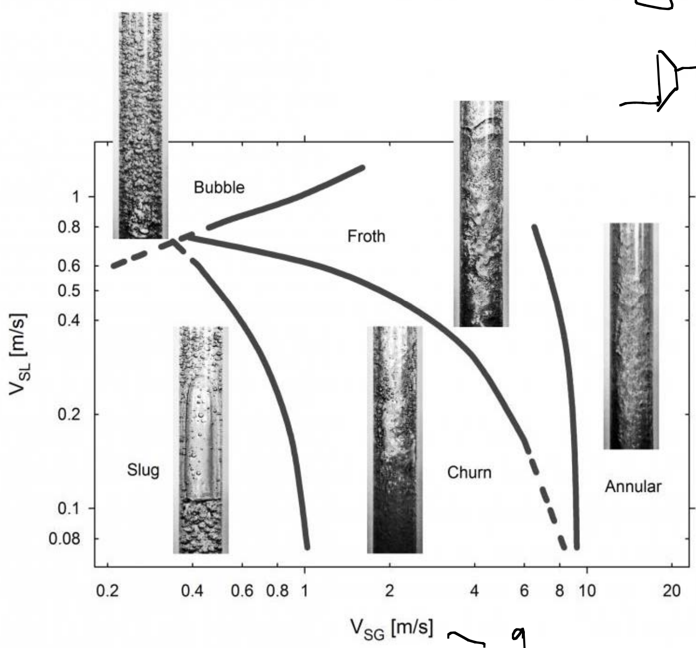
flow pattern map



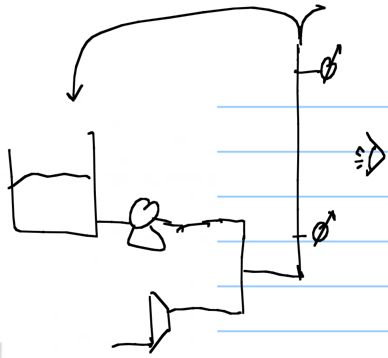

→ for a given inclination, fluid properties, pipe diameter, $\varepsilon$, wall material

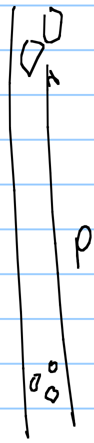


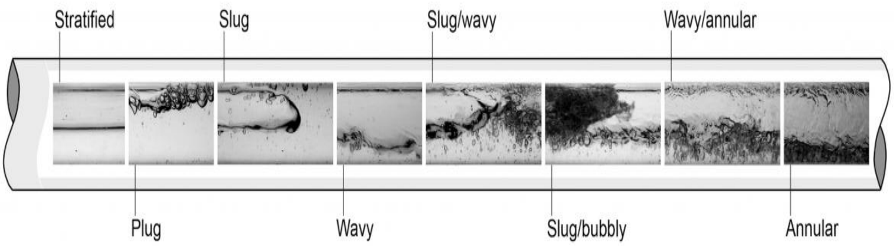

$\frac{q_L}{A}$

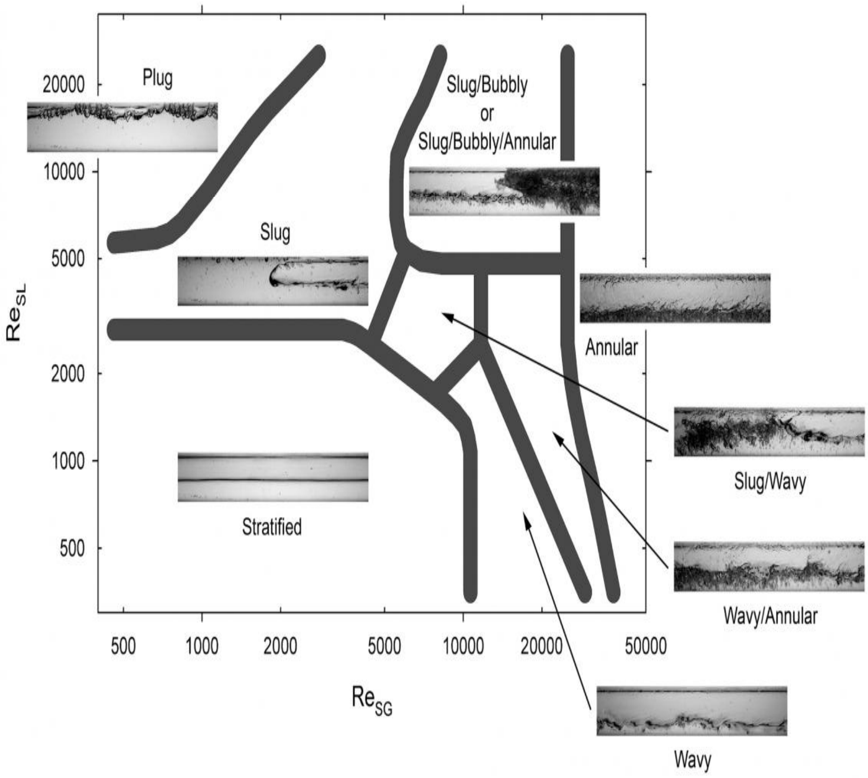


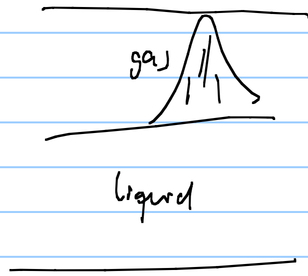

$\sim \frac{q_g}{A}$







multiphase flow pattern and pressure drop is dictated by a balance between forces:

- mixing forces
- segregation forces

turbulence
inertia (velocity)
gravitational acceleration
viscosity
surface tension

Ways to compute multiphase flow in production engineering:

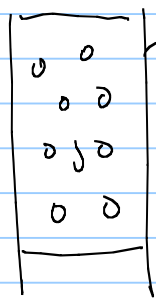
- Correlation-based, equation based on tuning with experimental data
- mechanistic modeling: applying continuity equation
  momentum equation
  energy equation

  ⇓

  solve the system of equations.

correlations derived from experiments

the number of equations used depend on the flow pattern



1 momentum equation

2 mass conservation equation

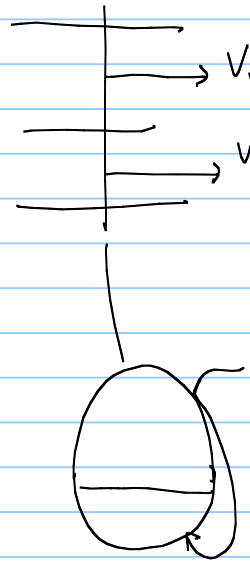
1- Identification of flow patterns

2- Computation using the appropriate model.

2 mass conservation equation

2 momentum conservation equation

two phases gas - liquid




~ homogeneous flow

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

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

$q_L , q_g$

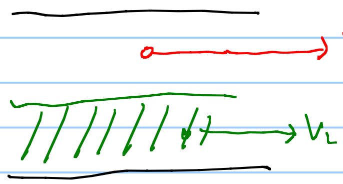
non slip volume fraction

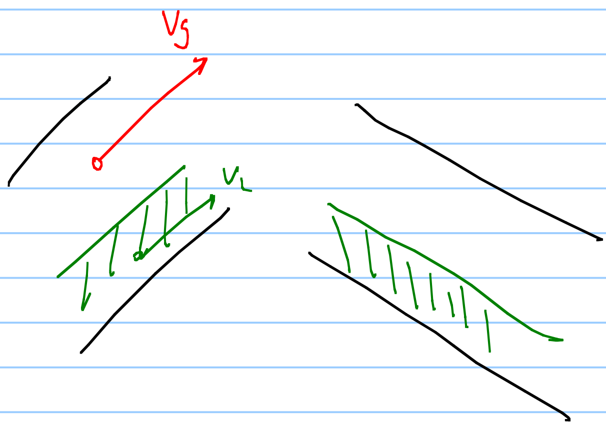
$$A_L = \frac{q_L}{V_m}$$

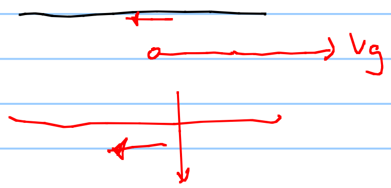
$$A_g = \frac{q_g}{V_m}$$

$$\lambda_L = \frac{q_L/\cancel{V_m}}{\frac{q_L}{\cancel{V_m}} + \frac{q_g}{\cancel{V_m}}} = \frac{q_L}{q_L + q_g}$$

in the general case $V_L \neq V_g$




$$H_L = \frac{A_L}{A}$$ ~ Holdup

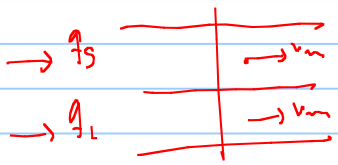
if $V_g > V_L$ . $q_L , q_g$

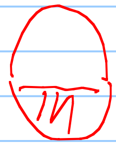
$H_L$ $\lambda_L$


$q_g = V_g \cdot A_g'$ $q_g = V_m \cdot A_g$

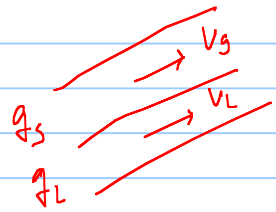
$$u_g = \frac{q_g}{A(1-H_L)} \qquad u_g = \frac{u_{sg}}{(1-H_L)}$$

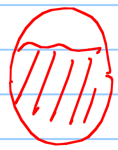
$$u_L = \frac{q_L}{A(H_L)} \qquad u_L = \frac{u_{sL}}{H_L}$$



$$\lambda_L = \frac{q_L}{q_g + q_L}$$

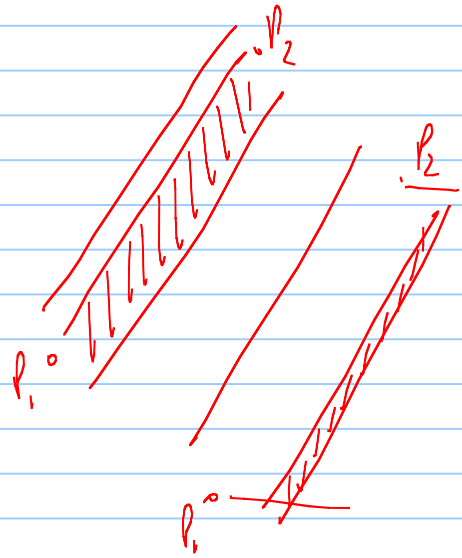


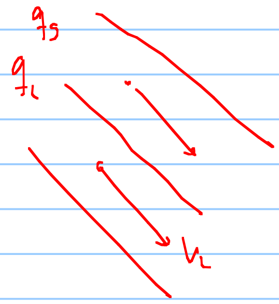



$$H_L = \frac{A_L}{A}$$

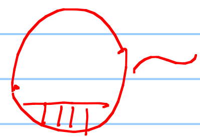
$V_g > V_L$

$H_L > \lambda_L$




$V_L > V_g$



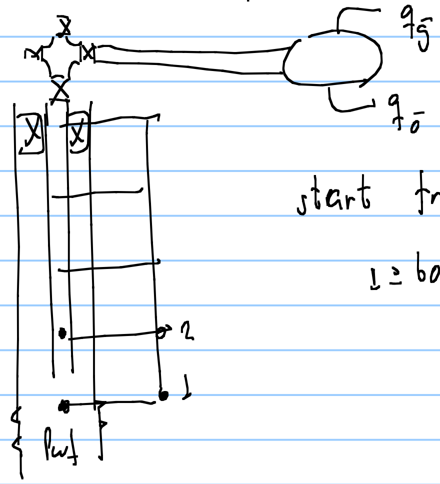
$$H_L = \frac{A_L}{A}$$

$H_L < \lambda_L$

$V_s = V_g - V_L$

↳ slip velocity

Multiphase flow pressure drop in conduits




start from a point of known pressure and known temperature

1: bottom-hole $P_{wf}$, $T_R$

$q_{\bar{o}} \longrightarrow q_o$ calculate local flow rates | BO tables, BO correll, EOS ($z_G$)

$q_{\bar{g}} \longrightarrow q_g$ @ P, T

2: Calculate fluid properties @ P, T conditions | BO table, BO correlation, EOS ($z_i$) ↳ composition

$\rho_o, \rho_g, \rho_w, \sigma_{og}, \sigma_{ow}, \sigma_{wg}, \mu_o, \mu_g, \mu_w$

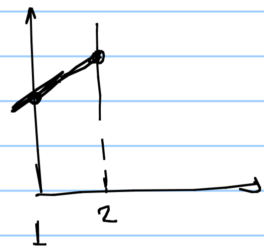
3. System properties: $\phi$ (diameter), $\varepsilon$ (roughness), $\theta$ inclination, entry effects

4. Go to our multiphase flow expert
- software: olga, leda
- correlation
- expert

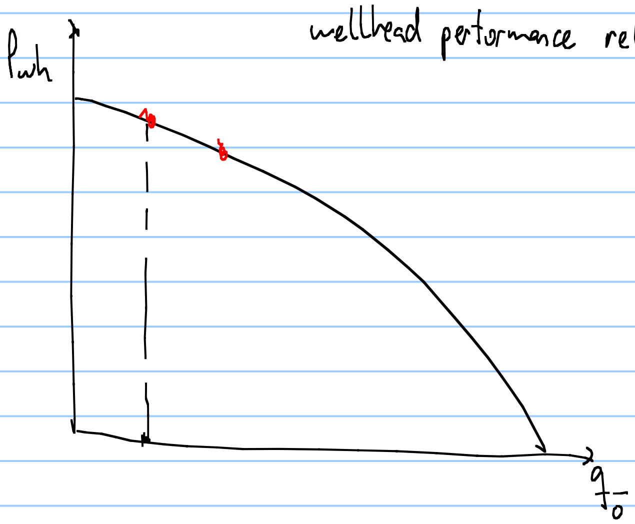
with information gathered in 2, 3, 4 $\rightarrow \frac{dp}{dL}$ $\rightarrow$ along the direction of the conduit

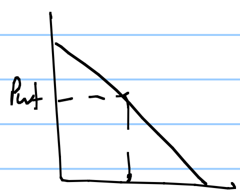
$\left.\frac{dp}{dL}\right|_{\substack{x=\text{bottomhole} \\ p=p_{wf}}}$, $P_0 = P_{wf}$ } numerical integration
- euler's method
- Runge-Kutta $\rightarrow$ $\boxed{\text{RK4, explicit}}$

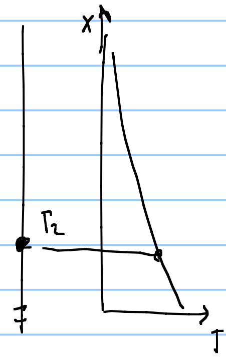
$$P_2 = P_1 + \Delta L \cdot \left.\frac{dP}{dL}\right|_{\substack{L=L_0 \\ P=P_0}}$$




e.g. to calculate wellhead performance relationship



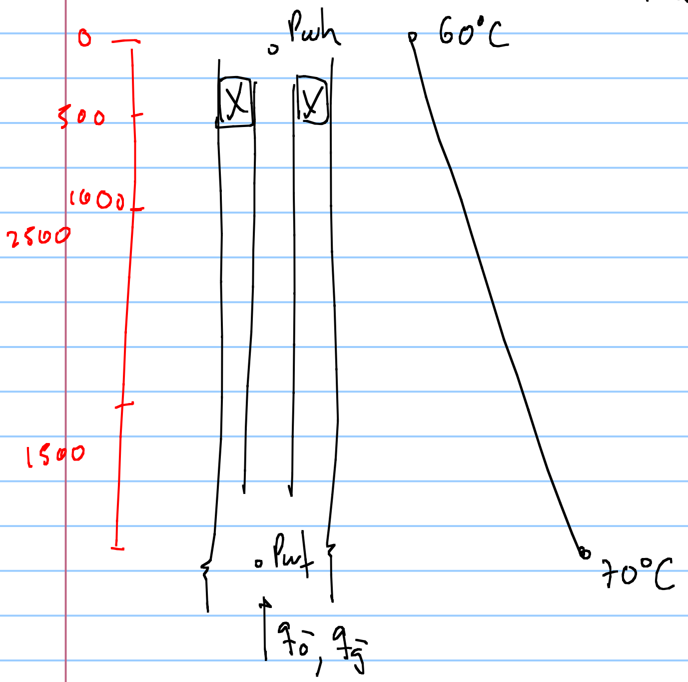




for point 2, I repeat the steps, but I am missing $T_2$.
- assume a temperature distribution
- need a model that tells me $\frac{dT}{dL}$

$$\frac{dT}{dL}, \left.\frac{dP}{dL}\right|_{T_1, P_{wf}}$$

Class exercise, Calculate WPR, we want to calculate $P_{wh\,avail}$ for a given rate $q_{\bar o}, q_{\bar g}$




| | Mole % | Mole frac | | | |
|---|---|---|---|---|---|
| Nitrogen | 0.4 | 0.004 | | qo [Sm^3/d] | 1000 |
| CO2 | 0.1 | 0.001 | | qg [E03 Sm^3/d] | 200 |
| Methane | 43.2 | 0.432 | | pwf [bara] | 147 |
| Ethane | 4.7 | 0.047 | | TR [C] | 70 |
| Propane | 3.0 | 0.03 | | ID [m] | 0.12 |
| i-butane | 1.5 | 0.015 | | Well TVD Depth [m] | 2500 |
| n-butane | 0.9 | 0.009 | | Twh [C] | 60 |
| neo-pentane | 0.0 | 0 | | Sc oil density [Kg/m^3] | 850 |
| i-pentane | 0.8 | 0.008 | | Sc gas density [Kg/m^3] | 0.91 |
| n-pentane | 0.5 | 0.005 | | | |
| Hexanes | 1.8 | 0.018 | | | |
| Heptanes | 4.1 | 0.041 | | mosc [kg/s] | |
| Octanes | 5.0 | 0.05 | | mgsc [kg/s] | |
| Nonanes | 3.8 | 0.038 | | mt [kg/s] | |
| Decanes | 30.1 | 0.301 | | | |

1: $q_o$, $q_g$ from $q_{\bar o}, q_{\bar g}$ $\qquad \dot m_o, \dot m_g$

$$\dot m_o = q_{\bar o} \cdot \rho_{\bar o}$$

one method: Calculate total mass flow rate

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

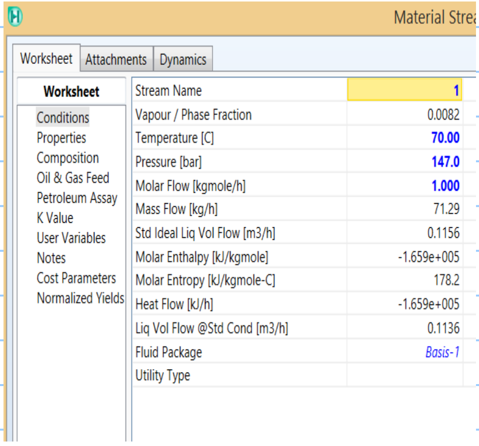
$\dot m = 11.9$ kg/s → total mass flow rate circulating in the tubing

$$q_o @ P_{wf}, T_{wf} = \dot m_o @ P_{wf}, T_{wf} / \rho_o @ P_{wf}, T_{wf}$$

$$q_g @ P_{wf}, T_{wf} = \dot m_g @ P_{wf}, T_{wf} / \rho_g @ P_{wf}, T_{wf}$$

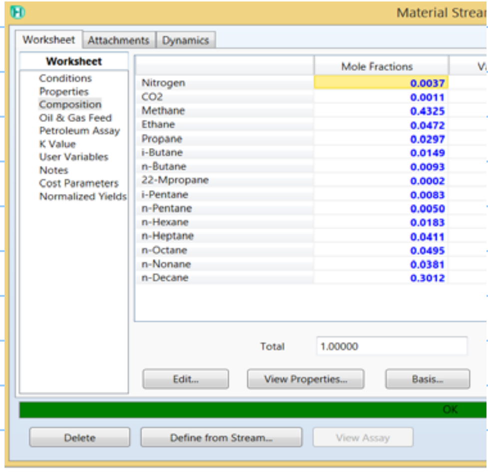
it is necessary to estimate $\dot m_o$ and $\dot m_g$ @ $P_{wf}, T_{wf}$.

we are going to use HYSYS as a fluid properties generator



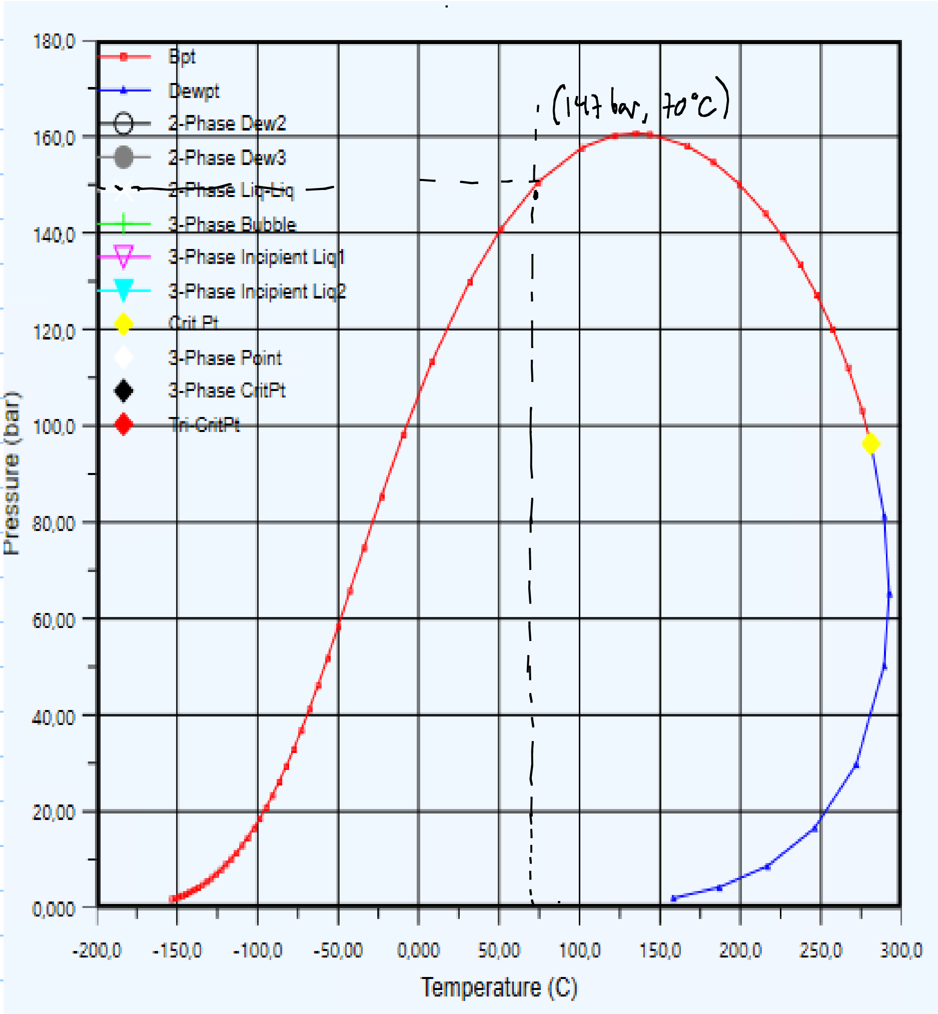
| Stream Name | 1 |
|---|---|
| Vapour / Phase Fraction | 0.0082 |
| Temperature [C] | 70.00 |
| Pressure [bar] | 147.0 |
| Molar Flow [kgmole/h] | 1.000 |
| Mass Flow [kg/h] | 71.29 |
| Std Ideal Liq Vol Flow [m3/h] | 0.1156 |
| Molar Enthalpy [kJ/kgmole] | -1.659e+005 |
| Molar Entropy [kJ/kgmole-C] | 178.2 |
| Heat Flow [kJ/h] | -1.659e+005 |
| Liq Vol Flow @Std Cond [m3/h] | 0.1136 |
| Fluid Package | Basis-1 |
| Utility Type | |





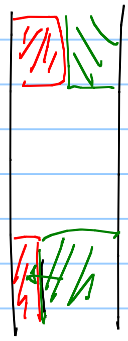
| | Mole Fractions |
|---|---|
| Nitrogen | 0.0037 |
| CO2 | 0.0011 |
| Methane | 0.4325 |
| Ethane | 0.0472 |
| Propane | 0.0297 |
| i-Butane | 0.0149 |
| n-Butane | 0.0093 |
| 22-Mpropane | 0.0002 |
| i-Pentane | 0.0083 |
| n-Pentane | 0.0050 |
| n-Hexane | 0.0183 |
| n-Heptane | 0.0411 |
| n-Octane | 0.0495 |
| n-Nonane | 0.0381 |
| n-Decane | 0.3012 |
| Total | 1.00000 |







| | |
|---|---|
| mosc [kg/s] | 9.8 |
| mgsc [kg/s] | 2.1 |
| mt [kg/s] | 11.9 |



from hysy @ $P_{wf}$, $T_R$

mass fraction

$$X_{Lfraction} = \frac{\dot{m}_{liquid}}{\dot{m}_T}$$

$$\dot{m}_o = 11.9.(0.9975) =$$

| | TVD | p | T | Liquid Mass fraction | mo | mg | deno | deng | qo | qg | vso | vsg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | [m] | [bara] | [C] | [-] | [kg/s] | [kg/s] | [kg/m^3] | [kg/m^3] | [m^3/s] | [m^3/s] | [m/s] | [m/s] |
| 1 | 2500 | 147 | 70 | 0.9978 | 11.9203 | 0.02628 | 569 | 116 | 0.0209 | 0.00023 | 1.851 | 0.020 |

go to your multiphase expert (multiphase calculator public_xslm)

| FLUID PROPERTIES | | | | |
|---|---|---|---|---|
| $\mu_o$ | [Pa s] | 2.095E-04 | | |
| $\mu_g$ | [Pa s] | 1.787E-05 | | |
| $\sigma_{og}$ | [N/m] | 0.009 | | |
| $\rho_o$ | [kg/m^3] | 569 | | |
| $\rho_g$ | [kg/m^3] | 116 | dp/dx | Flow pattern |
| | | | [Pa/m] | [-] |
| **OPERATING CONDITIONS** | | | 5659.60 | Bubble |
| Usl | [m/s] | 1.851 | | |
| Usg | [m/s] | 0.020 | | |
| **PIPING CHARACTERISTICS** | | | | |
| Angle (from hor.) | [rad] | 1.571 | | |
| Diameter | [m] | 0.12 | | |
| Roughness | [m] | 1.50E-05 | | |

$$P\Big|_{1500m} = P\Big|_{2500m} - \frac{dP}{dL}\Big|_{2500m} \cdot (1500\,m) = 147\text{ bara} - 0.05657\ \text{Bara}/m \cdot 1500\,m$$

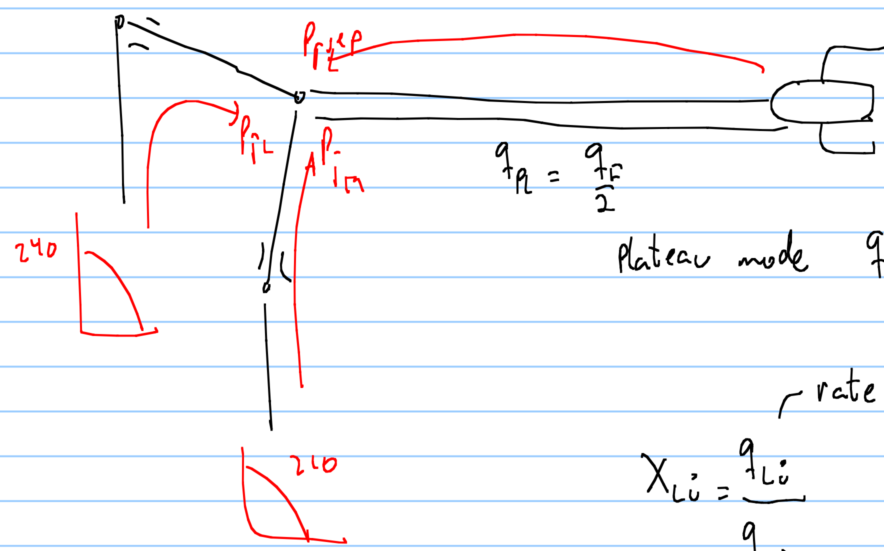
$$P_{@1000m} = 62\ \text{Bara}.$$

find $T_{@1000m}$ by interpolating between $60°C \rightarrow 70°C$

repeat !

Note Title 29.02.2016

# Problem 2 : Comments




$q_{Fi}$ → field rate at 2009

> 10E6 $Sm^3/d$

$q_{FL} = \frac{q_F}{2}$

Plateau mode $q_{FG} = 10\ E6\ Sm^3/d$

$X_{Li} = \frac{q_{Li}}{q_{Fi}}$ ← rate of template L at initial time

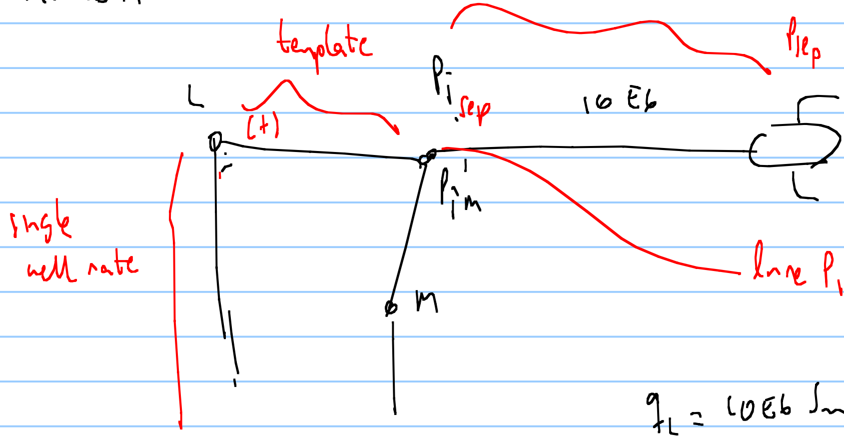
$X_{mi} = \frac{q_{mi}}{q_{Fi}}$ ← rate of template m at initial time

well rates

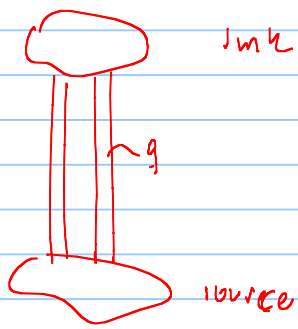
$q_L = \frac{10E6 \cdot X_{Li}}{N_{well\ L}} =$

$q_m = \frac{10E6 \cdot X_{mi}}{N_{wells\ m}} =$

Procedure when deltapchoke of one template <0

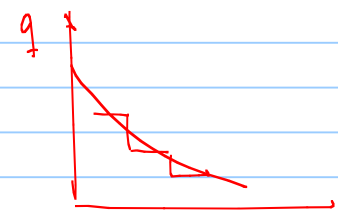



$q_L = 10E6\ Sm^3/d - q_m$




| time | $q_L$ | $q_m$ | $\Delta p_{choke\ L}$ | $\Delta p_{choke\ m}$ |
|---|---|---|---|---|
| 0 | | | | |
| 1 | | | | |
| 2 | | | | |
| ⋮ | | | | |
| → 6 | $q_L^*$ | $q_m^*$ | (+) | (−) |

• explicit coupling :

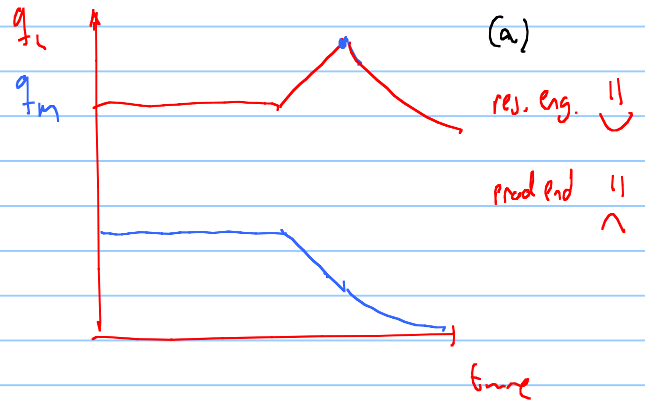


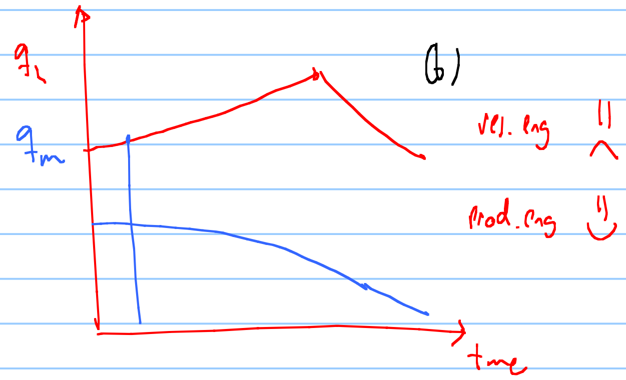

• implicit coupling

explicit coupling with small time step (months) $\underset{\text{same results as}}{\overset{\text{gives the}}{\approx}}$ implicit

b; $P_{Rm}, P_{RL}$ ⇝ run open choke network simulation ~ $q_F$) 10E6 Sm³/d
⇝ calculate the split factors $x_{m}^{i}$ $x_{Li}$
→ calculate template rates at each time step.

time
0
1
2
3




$IPR_{well} = f(G_p)$

$q_{well_{pot}} = f(G_p)$

in real life

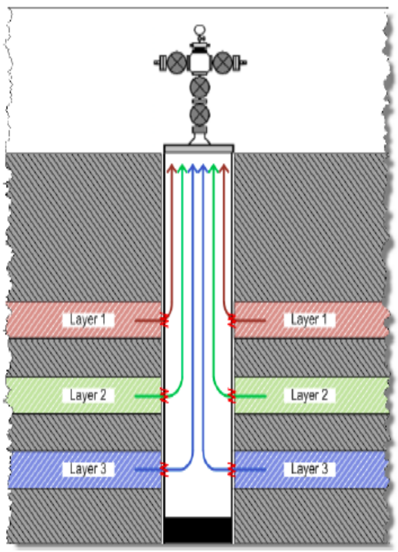
$q_{wellpot} = f(G_p, q_{well}(t))$

Problem 3

$$q_1 + q_2 + q_3 = C_{T_1, wh}\left(\frac{P_{wf_1}^2}{e^{S_3}} - P_{wh}^2\right)^{0.5}$$

$$q_2 + q_3 = C_{T_{21}}\left(\frac{P_{wf_2}^2}{e^{S_2}} - P_{wf_1}^2\right)^{0.5}$$

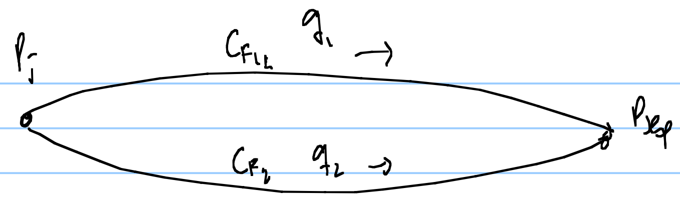
$$q_3 = C_{T_{23}}\left(\frac{P_{wf_3}^2}{e^{S_1}} - P_{wf_2}^2\right)^{0.5}$$




~ $C_{R_1}(P_{R_1}^2 - P_{wf_1}^2)^n = q_1$

~ $C_{R_2}(P_{R_2}^2 - P_{wf_2}^2)^n = q_2$

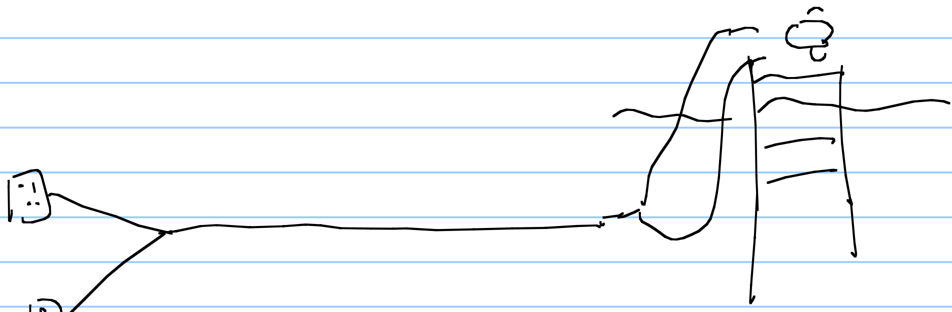
~ $C_{R_3}(P_{R_3}^2 - P_{wf_3}^2)^n = q_3$



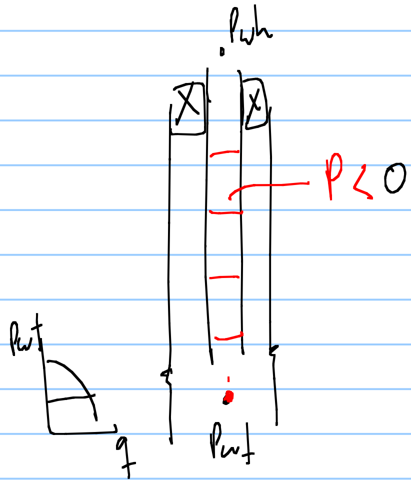

$$q_1 = C_{FL_1}\left(P_j^2 - P_{sep}^2\right)^{0.5} \qquad q_1 = q_2$$

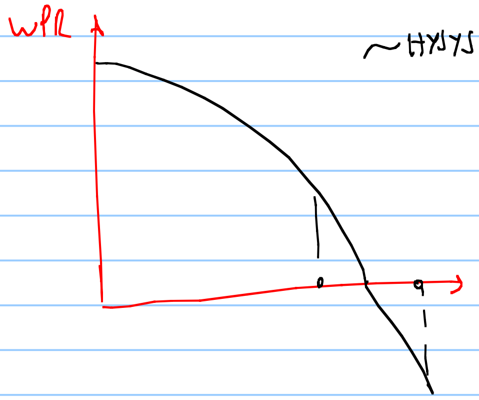
$$q_2 = C_{FL_2}\left(P_j^2 - P_{sep}^2\right)^{0.5} \qquad C_{FL_1} = C_{FL_2}$$

$$\cancel{2}\left(\frac{q_F}{2}\right) = \cancel{2}\, C_{FL}\left(P_j^2 - P_{sep}^2\right)^{0.5}$$



Unstable rate splitting in risers.




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

dP =

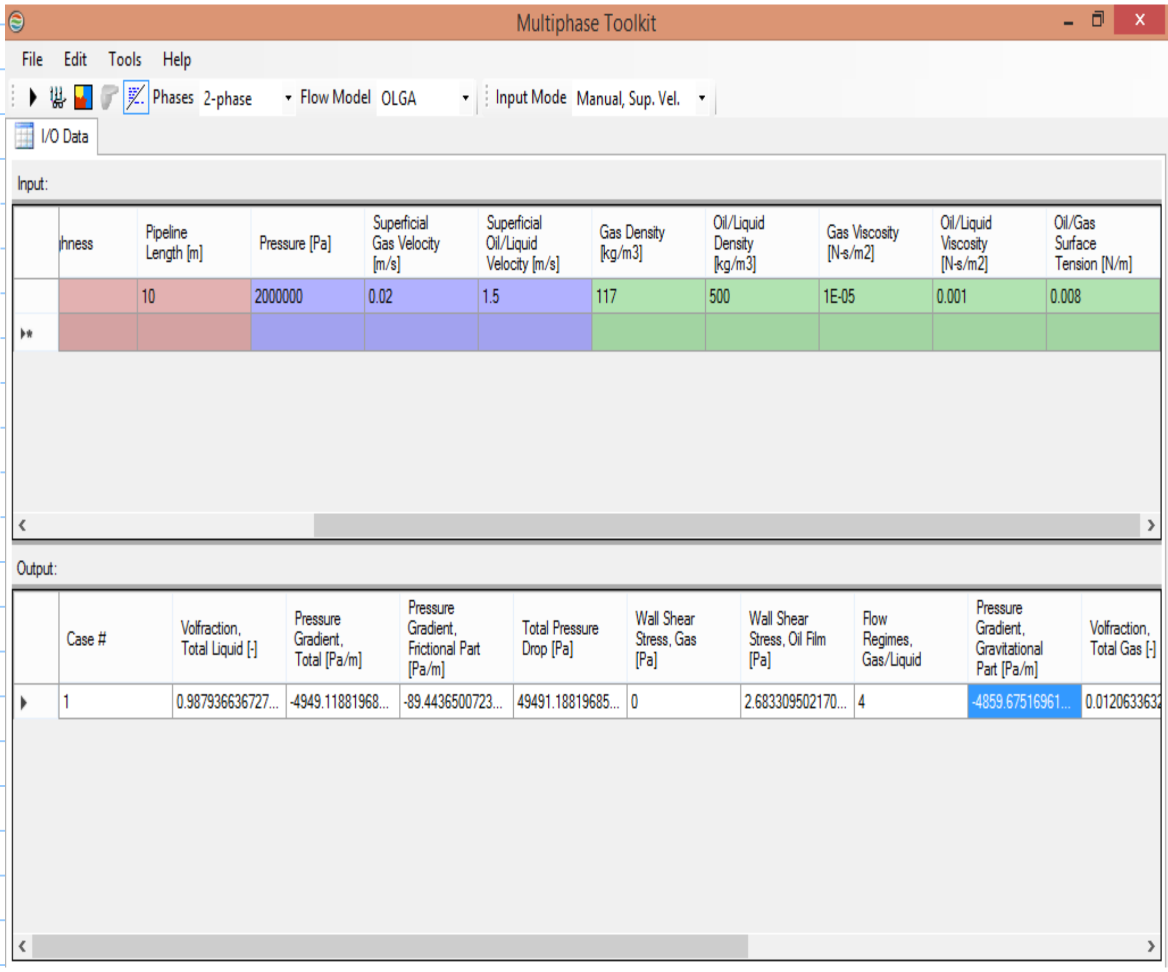
$$-\frac{dp}{dL} = \frac{2}{d} f_{TP(F)} \rho_{TP} v_{TP}^2 + \rho_{TP}\, g \sin\theta + \rho_{TP} v_{TP} \frac{dv_{TP}}{dL},$$

How to match field measured pressure drop data to a mechanistic model:

Stick constants in your pressure drop expressions (equations) and tune the constants to the data!

↝ point model

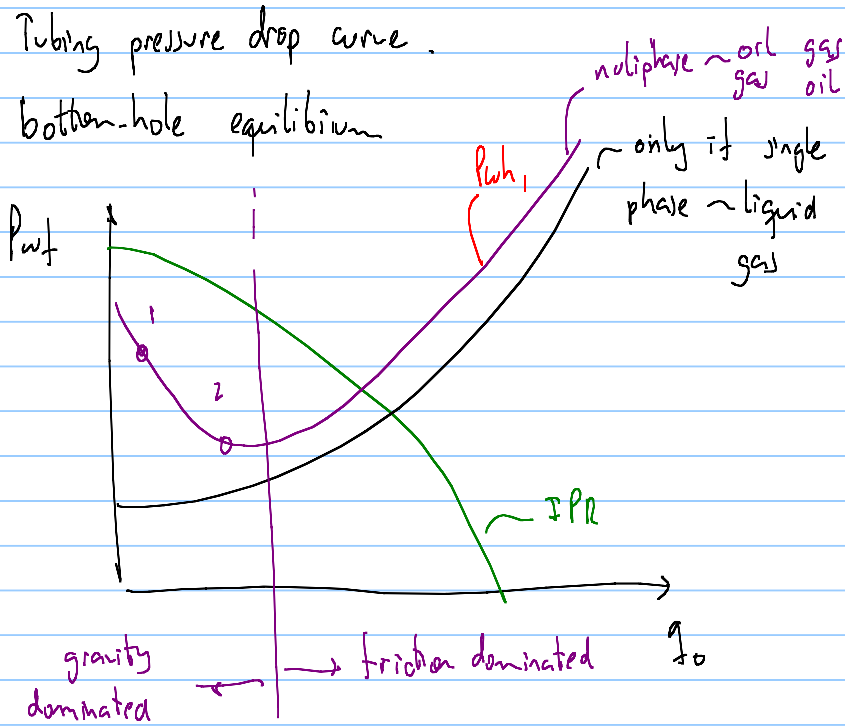
0 -> Stratified smooth
1 -> Stratified wavy
2 -> Annular
3 -> Slug flow
4 -> Bubble flow
5 -> Two-phase oil/water
6 -> Single phase gas
7 -> Single phase oil
8 -> Single phase water

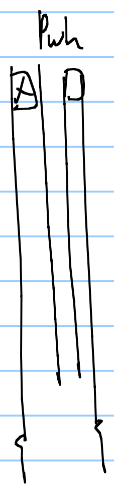


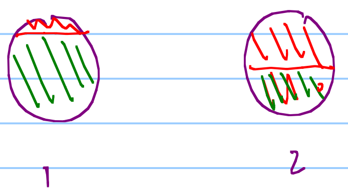

| | hness | Pipeline Length [m] | Pressure [Pa] | Superficial Gas Velocity [m/s] | Superficial Oil/Liquid Velocity [m/s] | Gas Density [kg/m3] | Oil/Liquid Density [kg/m3] | Gas Viscosity [N-s/m2] | Oil/Liquid Viscosity [N-s/m2] | Oil/Gas Surface Tension [N/m] |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 10 | 2000000 | 0.02 | 1.5 | 117 | 500 | 1E-05 | 0.001 | 0.008 |
| ▸* | | | | | | | | | | |

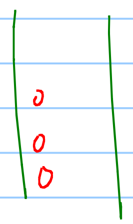
| | Case # | Volfraction, Total Liquid [-] | Pressure Gradient, Total [Pa/m] | Pressure Gradient, Frictional Part [Pa/m] | Total Pressure Drop [Pa] | Wall Shear Stress, Gas [Pa] | Wall Shear Stress, Oil Film [Pa] | Flow Regimes, Gas/Liquid | Pressure Gradient, Gravitational Part [Pa/m] | Volfraction, Total Gas [-] |
|---|---|---|---|---|---|---|---|---|---|---|
| ▸ | 1 | 0.987936636727... | -4949.11881968... | -89.4436500723... | 49491.18819685... | 0 | 2.683309502170... | 4 | -4859.67516961... | 0.012063363 |

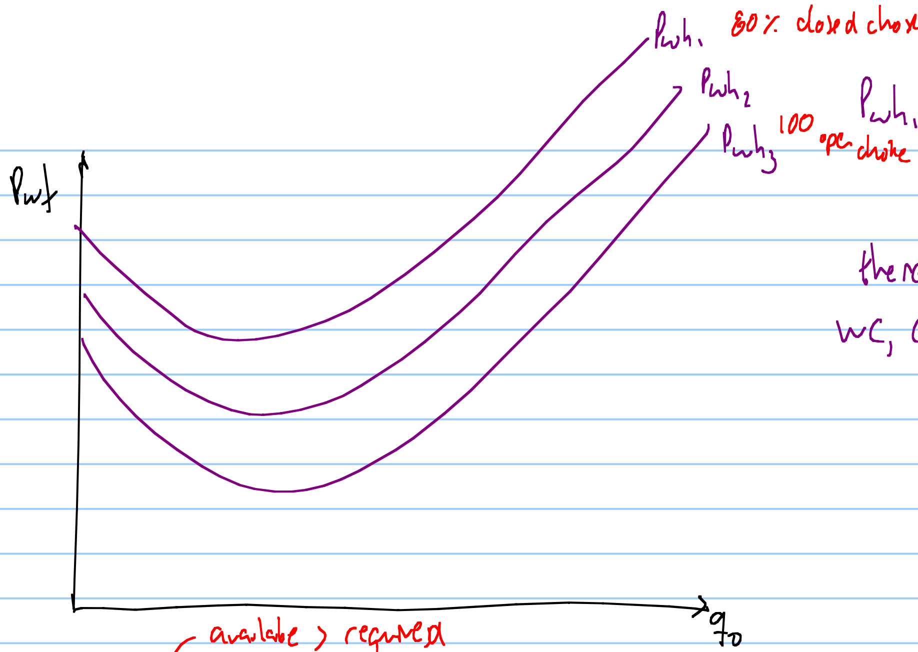
Tubing pressure drop curve.
bottom-hole equilibrium



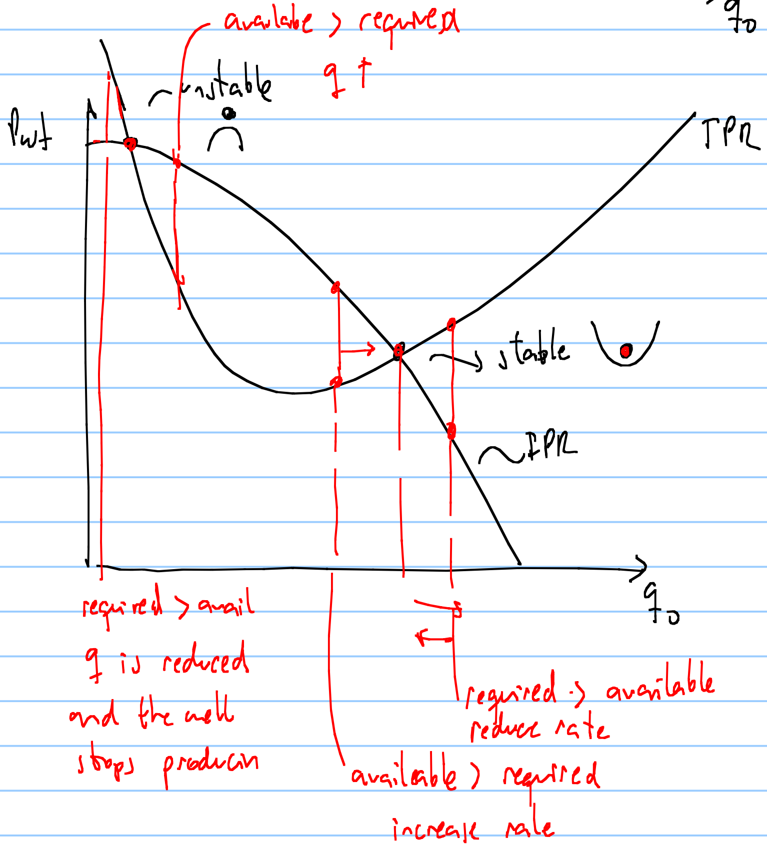



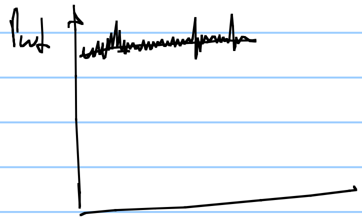






$P_{wh_1} > P_{wh_2} > P_{wh_3}$

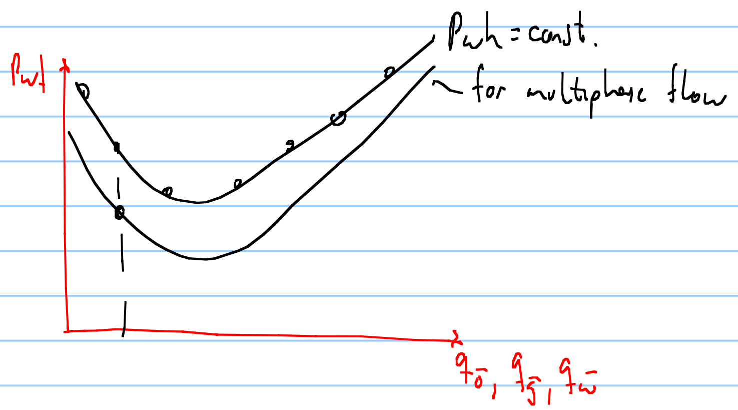
there is also a change with WC, GOR.



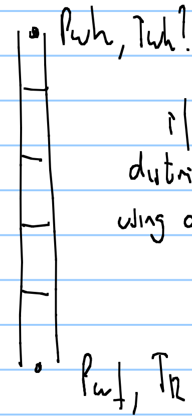



Comment about allocation: it is performed over a period of time!

↳ it involves integration of rates with time.




each point in the curve is calculated with a numerical integration (RK-4, explicit), stepwise calculation




if the temperature distribution is approximated using other method, is OK

<u>Tubing tables</u>: pre compute, for a large variation of $\bar{q_o}$, $P_{wh}$ the pressure drop in the tubing

$P_{wh} = P_{wh_1}$

| $\bar{q_o}$ | $\bar{q_g}$ | $\bar{q_w}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

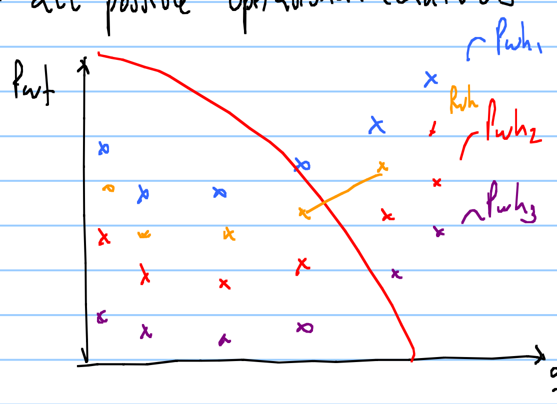
$P_{wh} = P_{wh_2}$

| $\bar{q_o}$ | $\bar{q_g}$ | $\bar{q_w}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 00 | | | | |
| 500 | | | | |

$P_{wh} = P_{wh_3}$

| $\bar{q_o}$ | $\bar{q_g}$ | $\bar{q_w}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 00 | | | | |
| 500 | | | | |

range chosen to cover all possible operational conditions



application case res. sim. outputs $P_{wf}$, $q_{\bar{o}}$ ~> compute $P_{wh}$

from res sim

$Sm^3/d$

$P_{wh} = P_{wh_1}$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh} = P_{wh_2}$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 00 | | | | |
| 500 | | | | |

$P_{wh} = P_{wh_3}$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 00 | | | | |
| 500 | | | | |

$P_{wf}^{*}$ ~ from res sim

bilinear interpolation to find $P_{wh}$

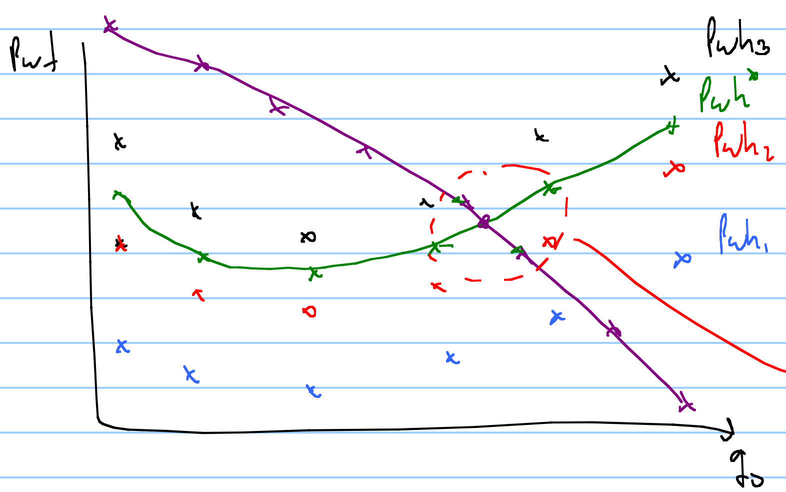
interpolation on the rate ①

② interpolation on $P_{wf}$

③ $P_{wh}$

| | | | |
|---|---|---|---|
| $q_1$ | $P_{wf_1}$ | $P_{wf_3}$ | $P_{wf_2}$ |
| $q_{f_3}$ | $P_{wh_3}$ | $\boxed{\phantom{x}}$ | $P_{wh}$ |
| $q_2$ | $P_{wf_1}$ | | $P_{wf_2}$ |

find equilibrium at fixed $P_{wh}$.

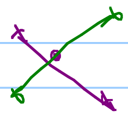



$P_{wh}$

it is very important when using tubing tables to use an appropriate number of points

compare result from interpolating on the table = performing the multiphase $\Delta p$ calculation

intersection of two straight lines



designing flow table (FT)

$P_{wh_1}$ $GOR_1$ $WC_1$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_2}$ $GOR_1$ $WC_1$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_3}$ $GOR_1$ $WC_1$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_1}$ $GOR_2$ $WC_1$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_2}$ $GOR_2$ $WC_1$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_3}$ $GOR_2$ $WC_1$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_1}$ $GOR_3$ $WC_1$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_2}$ $GOR_3$ $WC_1$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_3}$ $GOR_3$ $WC_1$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_1}$ $GOR_3$ $WC_2$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_2}$ $GOR_3$ $WC_2$

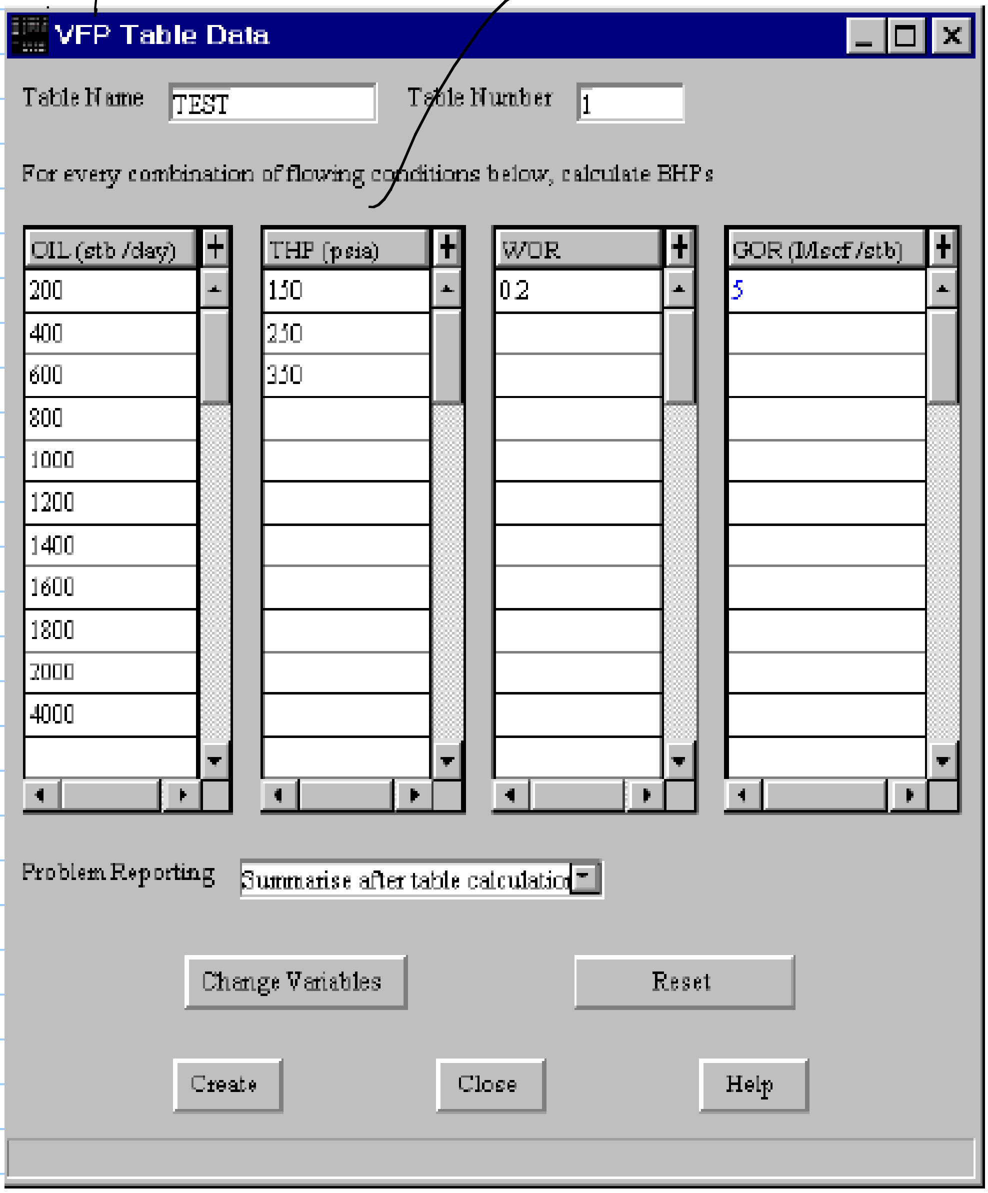
| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

$P_{wh_3}$ $GOR_3$ $WC_2$

| $q_{\bar{o}}$ | $q_{\bar{g}}$ | $q_{\bar{w}}$ | $P_{wf}$ | $T_{wh}$ |
|---|---|---|---|---|
| 0 | | | | |
| 50 | | | | |
| 100 | | | | |
| 200 | | | | |
| 500 | | | | |

vertical flow performance

from Sim launcher in eclipse




Push

should take into account changes with time

- tubing tables can be generated from production simulators
  - Pipesim
  - GAP
  - wellflow

- tubing tables can also include artificial lift equipment, $q_{g\,inj}$, $f_{esp}$
  - gas injection rate
  - esp frequency.

flow tables are used by: reservoir simulators
production simulators ~ (network simulators) GAP

flow tables are generated assuming:
- fluid properties don't change
- well layout/completion doesn't change.

main motivation to use flow tables: table interpolation much quicker than pressure drop calculations !

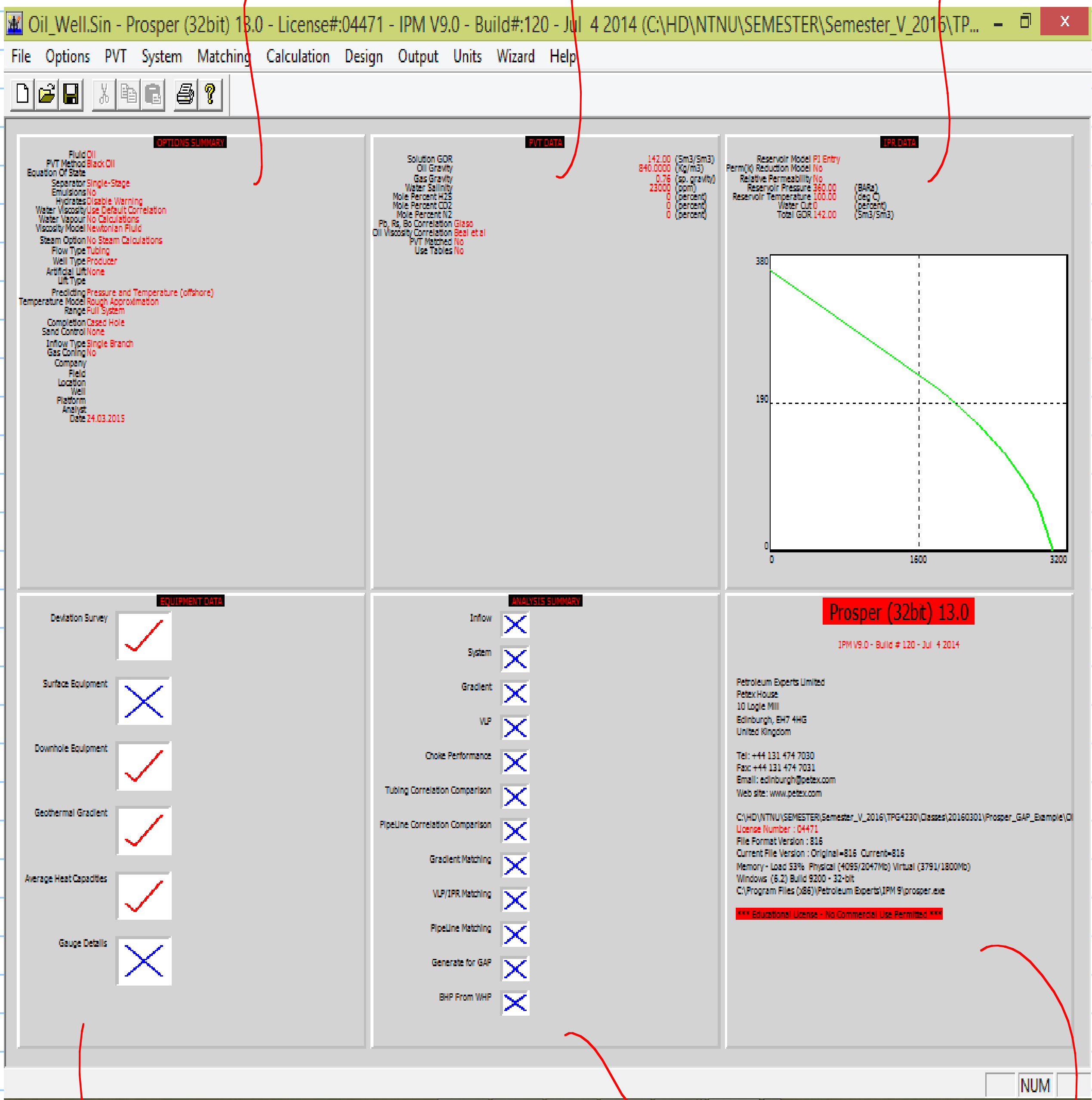
Prosper (PETEX, petroleum experts) → single well hydraulics

| | | |
|---|---|---|
| Oil_Well | Tpd | → tubing table in gap format |
| Oil_Well | Sin | → user input data |
| Oil_Well | Pvt | → fluid properties |
| Oil_Well | Out | → main file |
| Oil_Well | Anl | → analysis file: results of the simulations |

general info

fluid properties

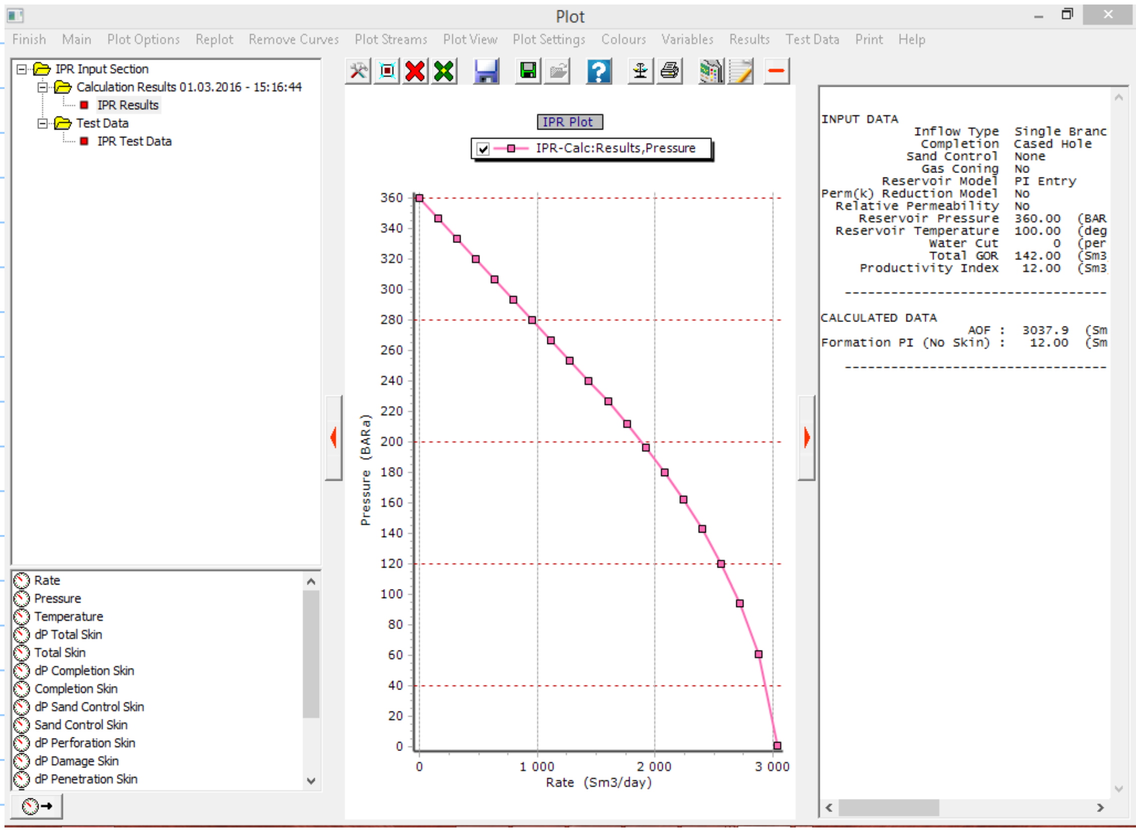
IPR

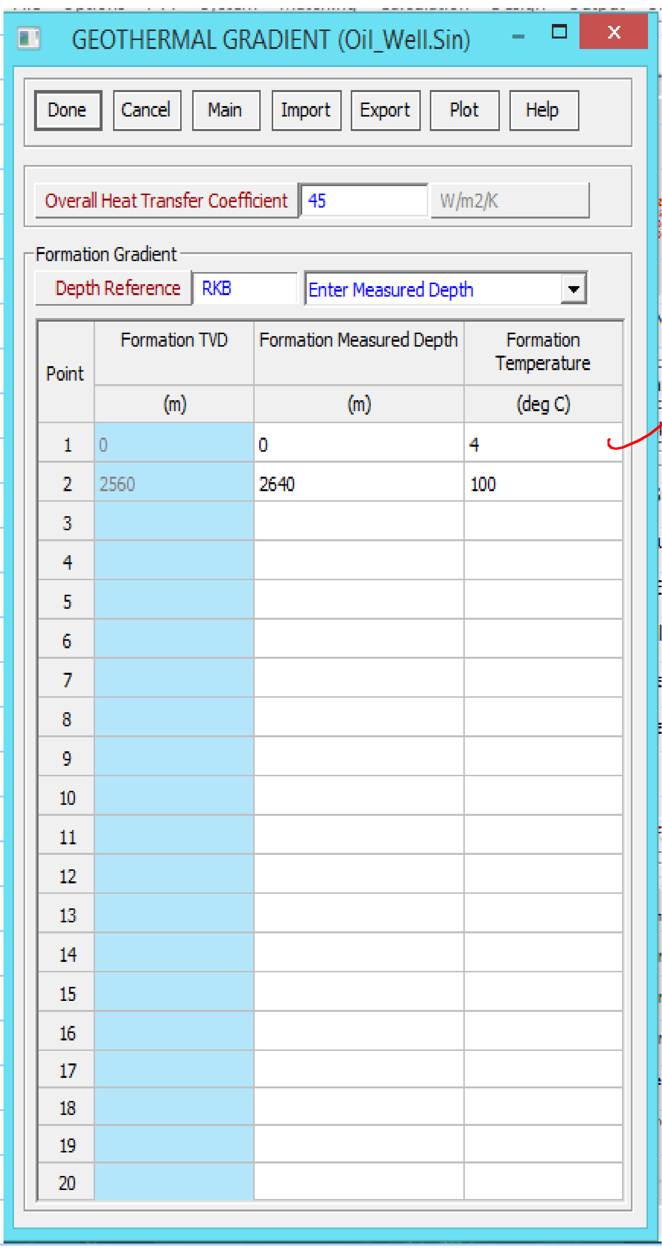


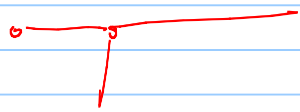

well layout and lifting equipment

analysis and calculations

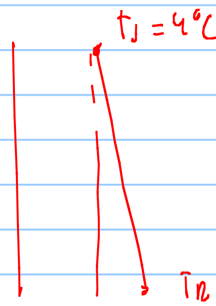
license info.



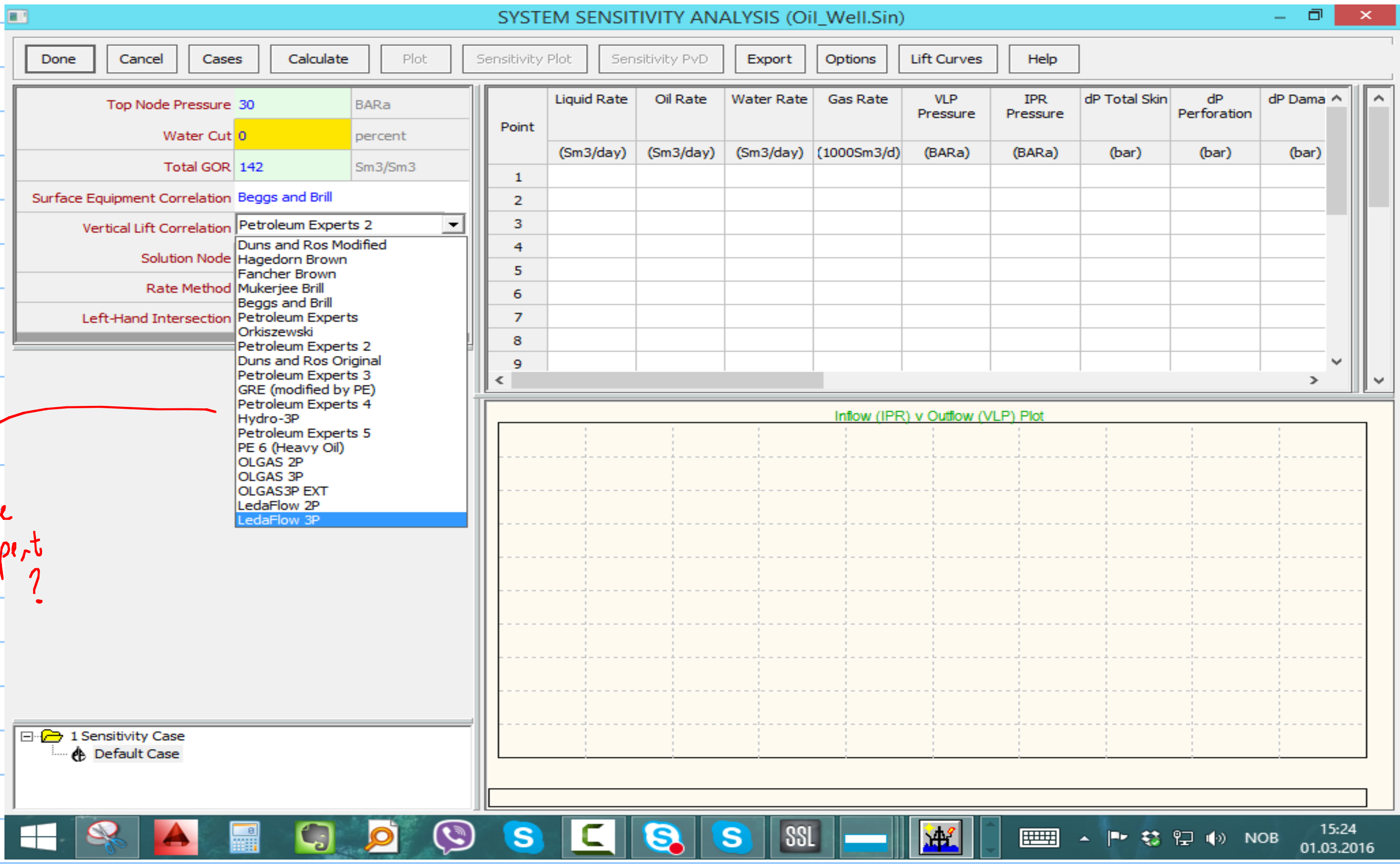



ambient temperature used for heat transfer calculations

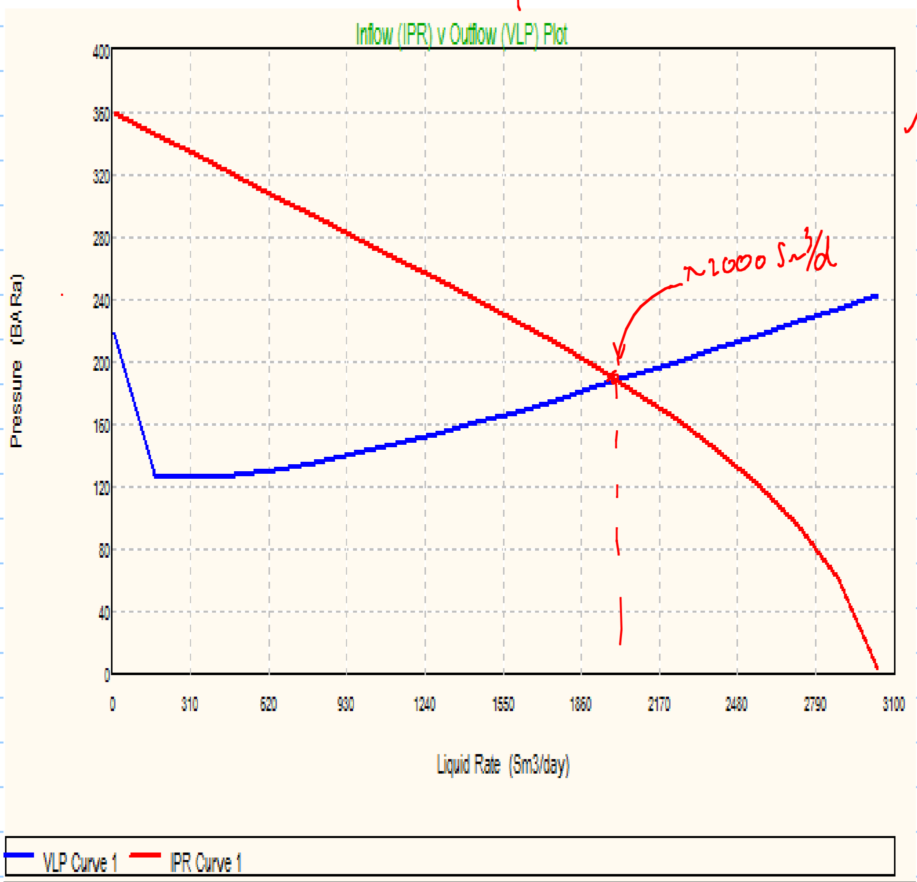



wich multiphase flow expert to use ?

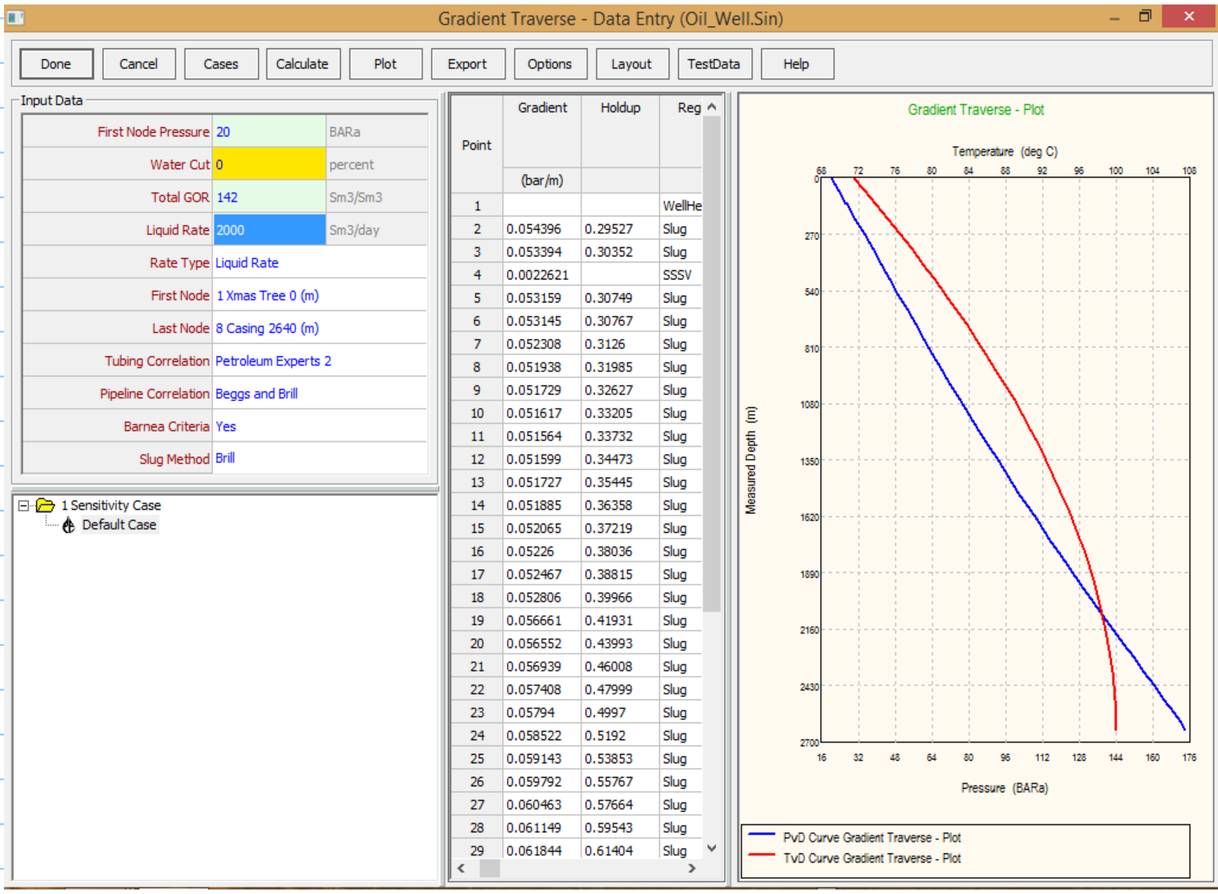



vertical lift performance

equilibrium at bottom-hole



"gradient"




$q = J(P_R - P_{wf})$

underaturated oil + water

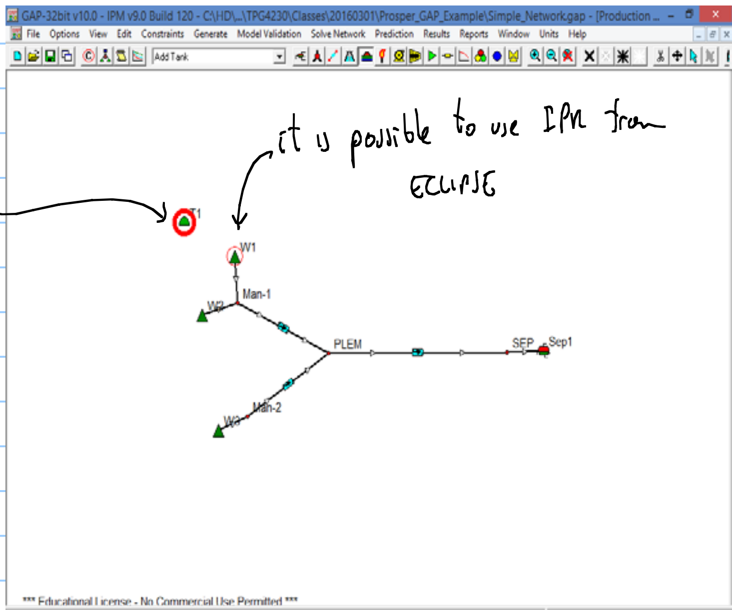
J is for total liquid.

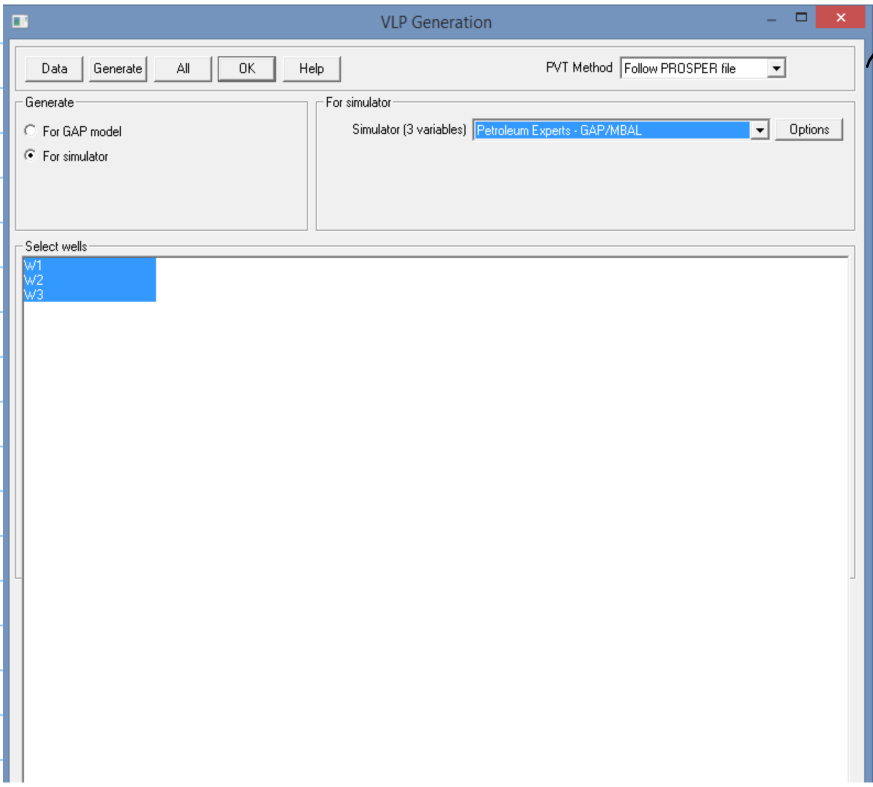
Simple_Network gap

tank model representing reservoir

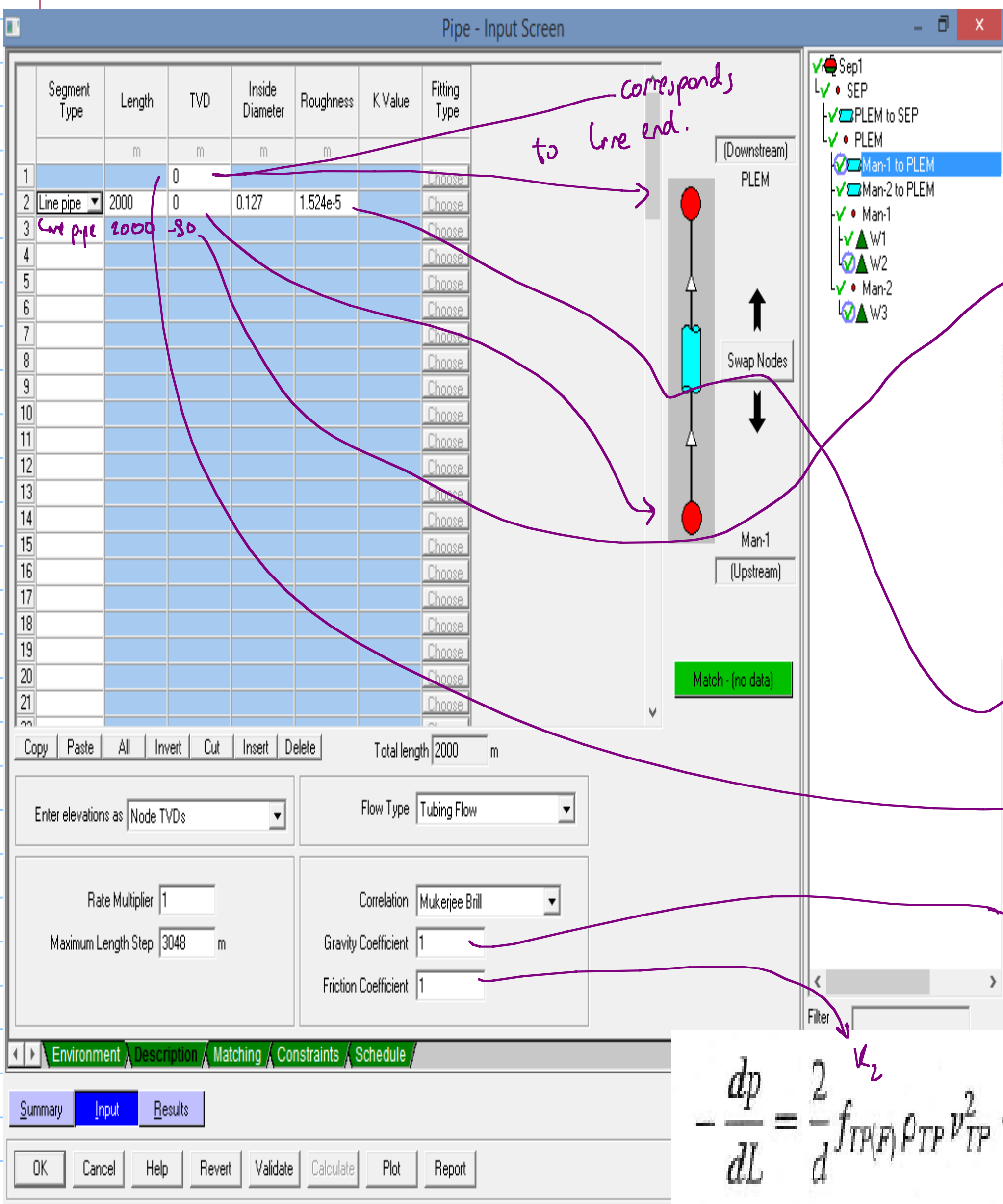
MBAL

it is possible to use IPM from ECLIPSE

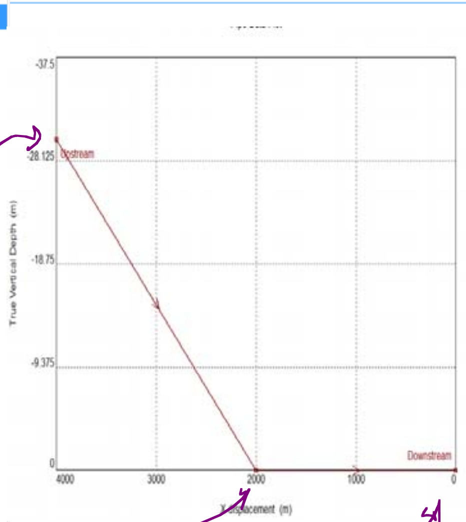




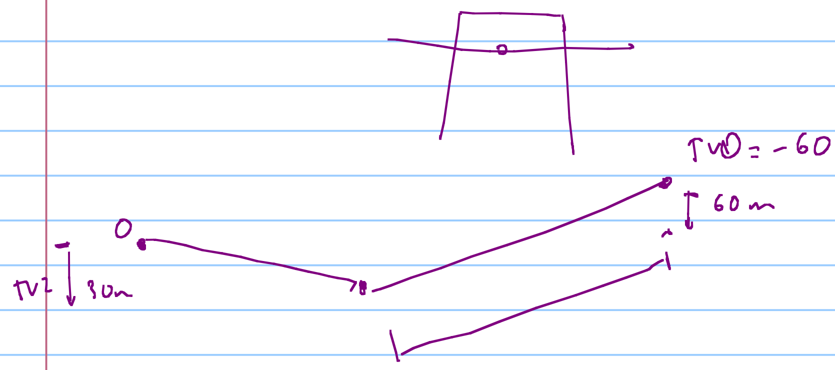

batch generation of tubing tables from GAP

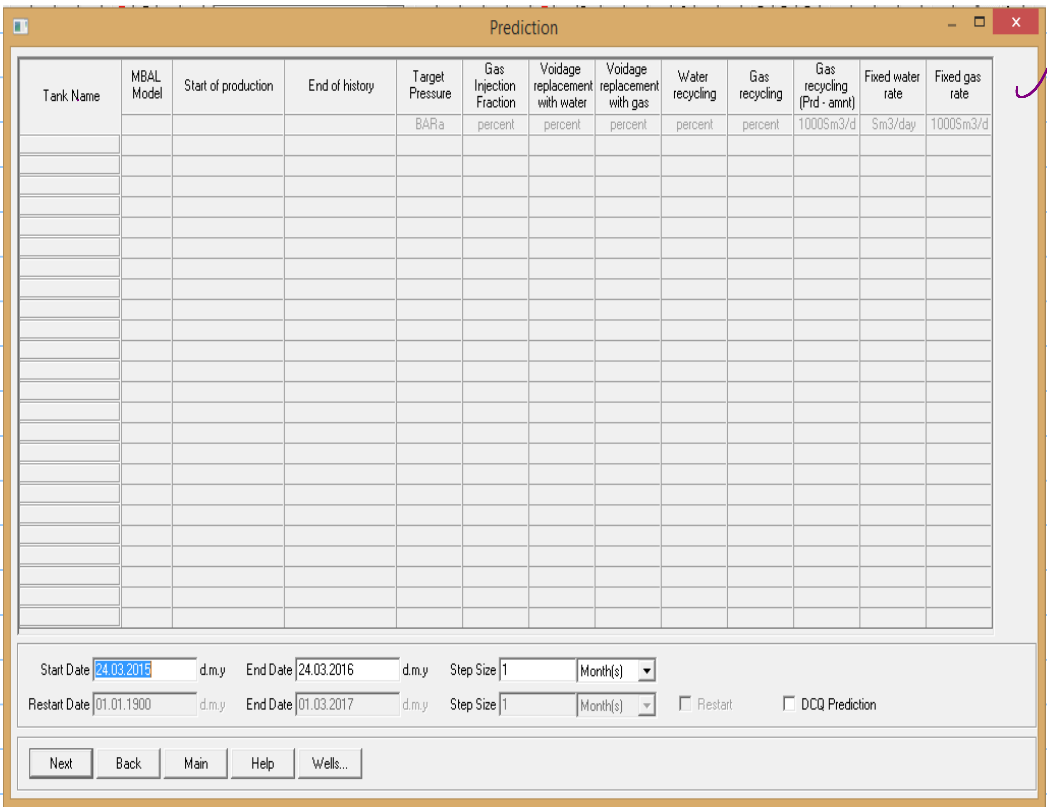



corresponds to line end.



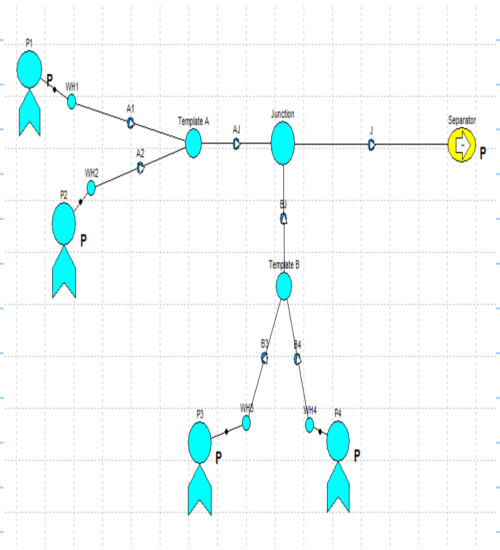

$$-\frac{dp}{dL} = \overset{K_2}{\frac{2}{d} f_{TP(F)} \rho_{TP} v_{TP}^2} + \overset{K_1}{\rho_{TP}\, g \sin\theta} + \rho_{TP} v_{TP} \frac{dv_{TP}}{dL},$$

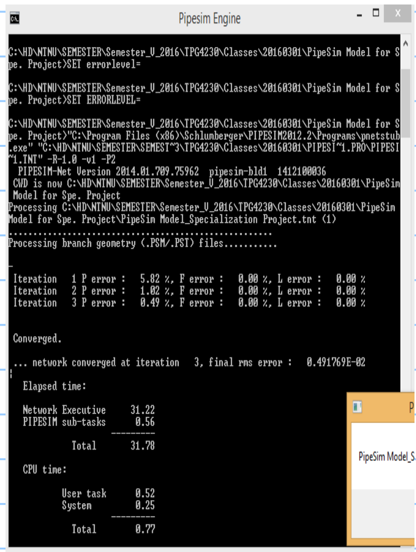



running GAP with MBAL: similar to what we have done in excel.

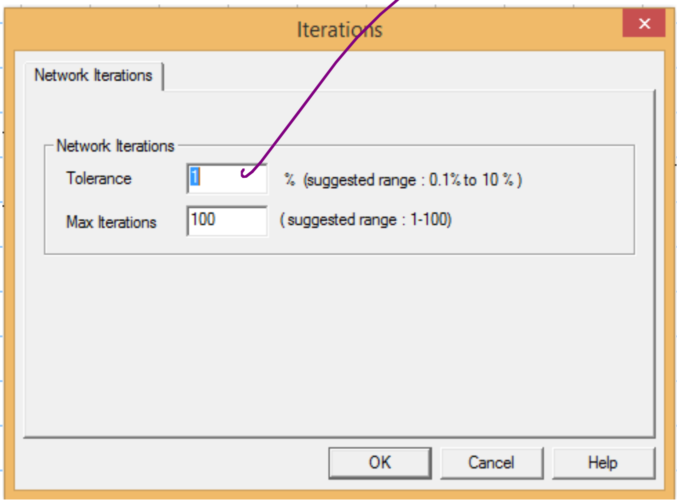
PipeSim Model_Specialization .. bpn



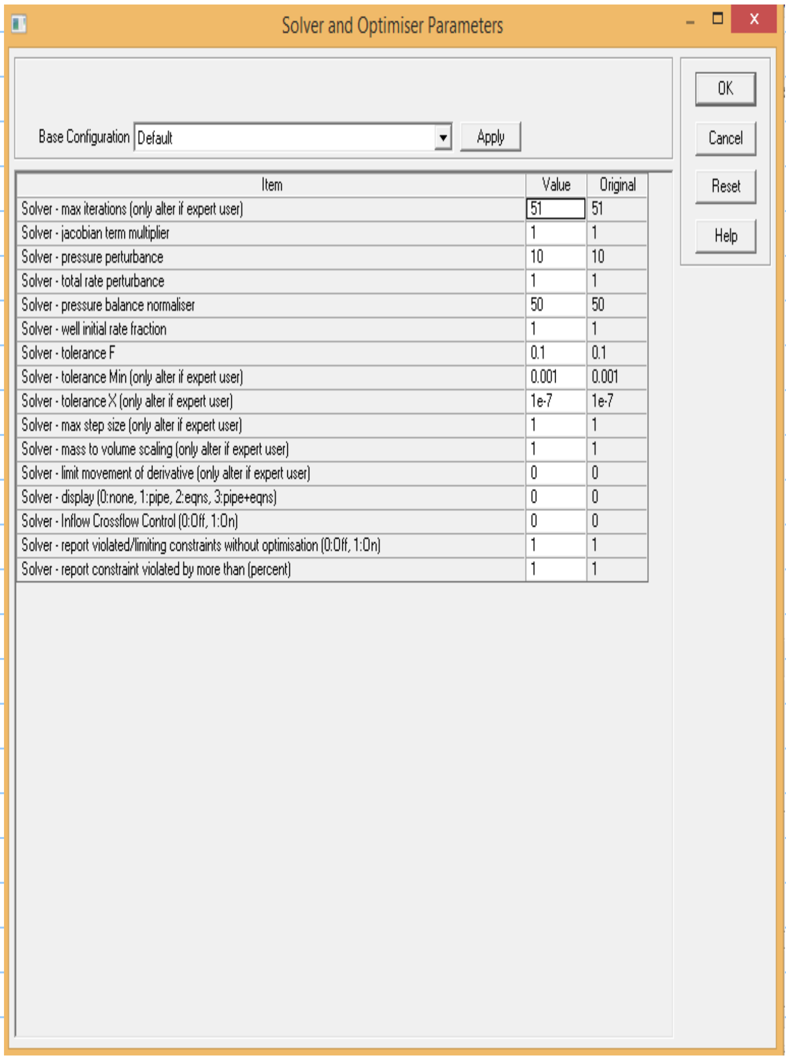

```
C:\HD\NTNU\SEMESTER\Semester_V_2016\TPG4230\Classes\20160301\PipeSim Model for S
pe. Project>SET errorlevel=

C:\HD\NTNU\SEMESTER\Semester_V_2016\TPG4230\Classes\20160301\PipeSim Model for S
pe. Project>SET ERRORLEVEL=

C:\HD\NTNU\SEMESTER\Semester_V_2016\TPG4230\Classes\20160301\PipeSim Model for S
pe. Project>"C:\Program Files (x86)\Schlumberger\PIPESIM2012.2\Programs\pnetstub
.exe" "C:\HD\NTNU\SEMESTER\SEMEST~3\TPG4230\Classes\20160301\PIPESI~1.PRO\PIPESI
~1.TNT" -R-1.0 -v1 -P2
 PIPESIM-Net Version 2014.01.709.75962  pipesim-bld1  1412100036
 CWD is now C:\HD\NTNU\SEMESTER\Semester_V_2016\TPG4230\Classes\20160301\PipeSim
 Model for Spe. Project
Processing C:\HD\NTNU\SEMESTER\Semester_V_2016\TPG4230\Classes\20160301\PipeSim
Model for Spe. Project\PipeSim Model_Specialization Project.tnt (1)
.......................................................
Processing branch geometry (.PSM/.PST) files...........

 Iteration   1 P error :   5.82 %, F error :   0.00 %, L error :   0.00 %
 Iteration   2 P error :   1.02 %, F error :   0.00 %, L error :   0.00 %
 Iteration   3 P error :   0.49 %, F error :   0.00 %, L error :   0.00 %

 Converged.

 ... network converged at iteration   3, final rms error :   0.491769E-02

   Elapsed time:

   Network Executive     31.22
   PIPESIM sub-tasks      0.56
                     ---------
             Total       31.78

   CPU time:

           User task      0.52
           System         0.25
                     ---------
             Total        0.77
```

tolerance — we use different tolerances until the results stop changing.




↓ TOL more iterations

↑ TOL less iterations


Solver and Optimiser Parameters

Base Configuration Default Apply

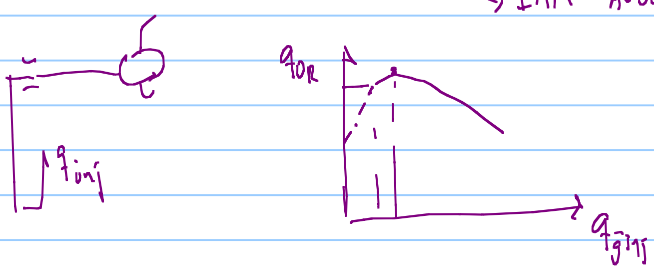
OK Cancel Reset Help

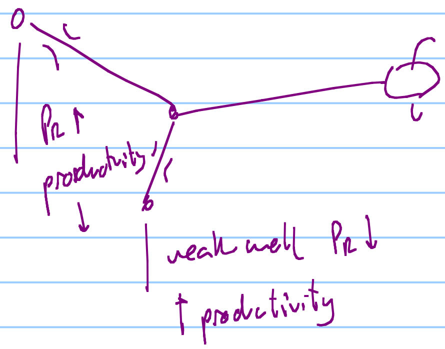
| Item | Value | Original |
|---|---|---|
| Solver - max iterations (only alter if expert user) | 51 | 51 |
| Solver - jacobian term multiplier | 1 | 1 |
| Solver - pressure perturbance | 10 | 10 |
| Solver - total rate perturbance | 1 | 1 |
| Solver - pressure balance normaliser | 50 | 50 |
| Solver - well initial rate fraction | 1 | 1 |
| Solver - tolerance F | 0.1 | 0.1 |
| Solver - tolerance Min (only alter if expert user) | 0.001 | 0.001 |
| Solver - tolerance X (only alter if expert user) | 1e-7 | 1e-7 |
| Solver - max step size (only alter if expert user) | 1 | 1 |
| Solver - mass to volume scaling (only alter if expert user) | 1 | 1 |
| Solver - limit movement of derivative (only alter if expert user) | 0 | 0 |
| Solver - display (0:none, 1:pipe, 2:eqns, 3:pipe+eqns) | 0 | 0 |
| Solver - Inflow Crossflow Control (0:Off, 1:On) | 0 | 0 |
| Solver - report violated/limiting constraints without optimisation (0:Off, 1:On) | 1 | 1 |
| Solver - report constraint violated by more than (percent) | 1 | 1 |

IAM integrated asset modeling

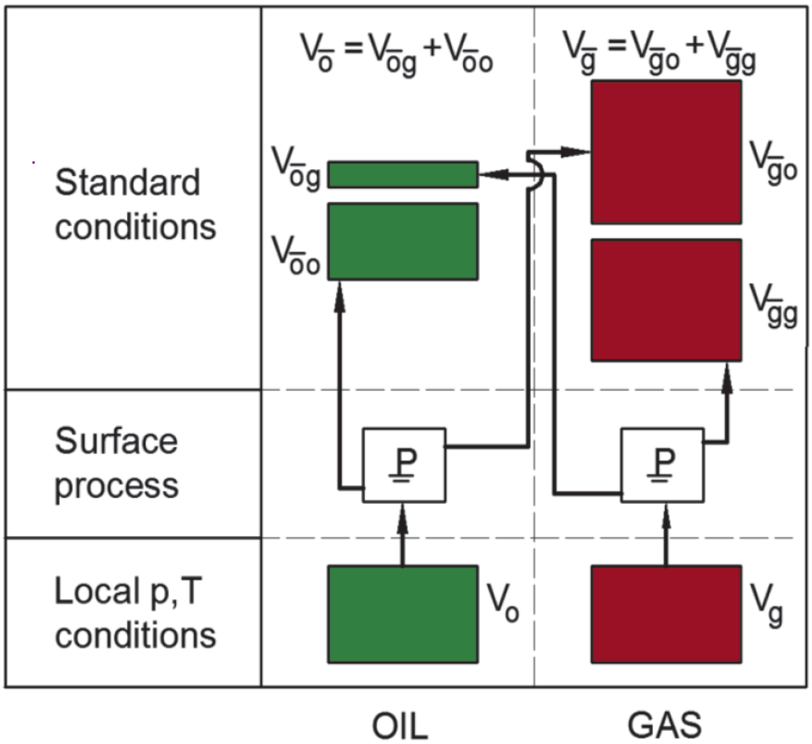
to integrate reservoir + production modes ⤳ Resolve (Petex)

↳ IAM Avocet (Schlumberger) eclipse. pipesim





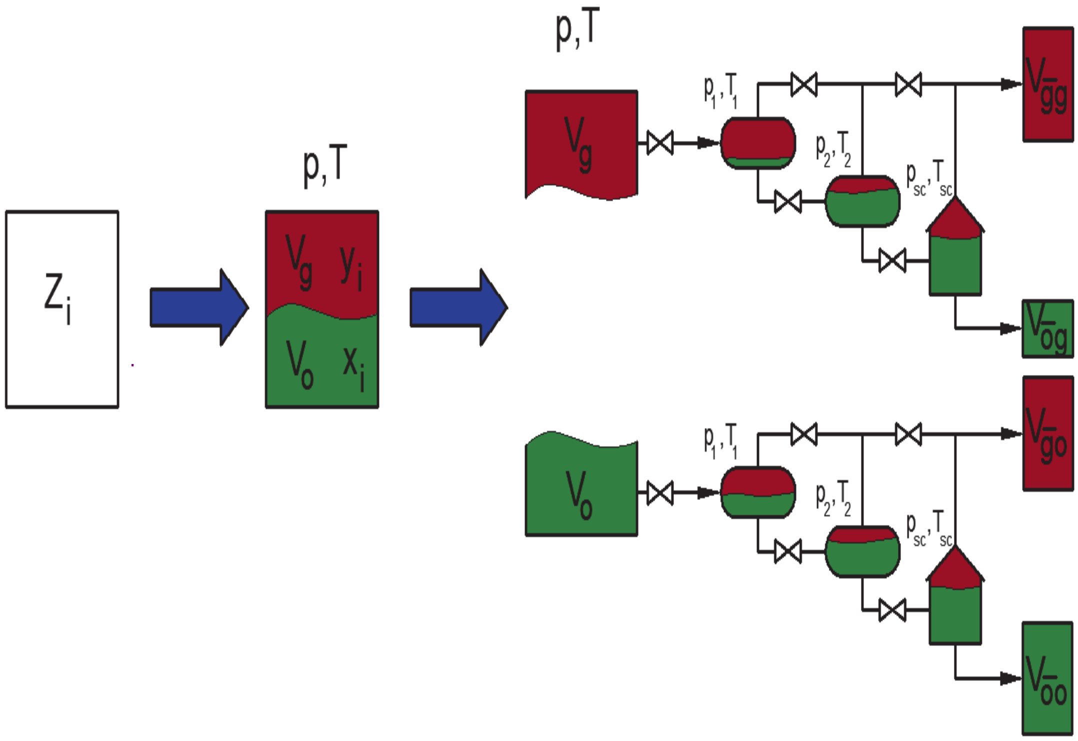

BO Approach: (2 components oil and gas)



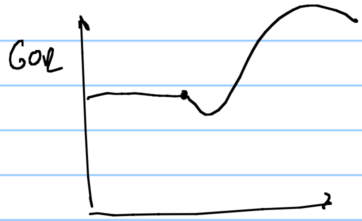

| BO Variable | Definition |
|---|---|
| Oil Volume Factor | $B_o(p,T) = \dfrac{V_o(p,T)}{V_{\bar{o}o}}$ |
| Gas Volume Factor | $B_g(p,T) = \dfrac{V_g(p,T)}{V_{\bar{g}g}}$ |
| Solution Gas Oil Ratio | $R_s(p,T) = \dfrac{V_{\bar{g}o}}{V_{\bar{o}o}}$ |
| Solution Oil Gas ratio | $r_s(p,T) = \dfrac{V_{\bar{o}g}}{V_{\bar{g}g}}$ |

where do i get these properties from?

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

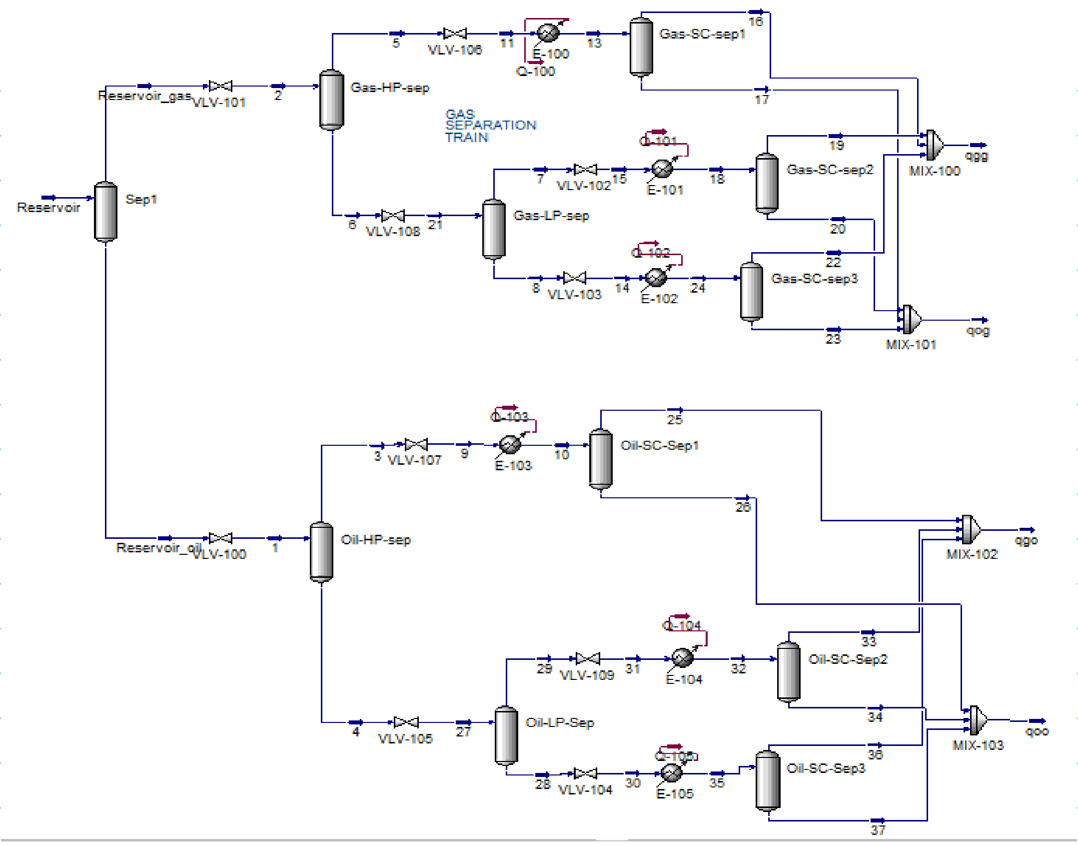



well GOR = f(t)




~> $z_i$ changes with time

if GOR changes then the composition changes




$T = T_1$

| $P$ | $B_o$ | $B_g$ | $R_s$ | $r_s$ |
|---|---|---|---|---|
| $P_1$ | $B_{o1}$ | $B_{g1}$ | $R_{s1}$ | $r_{s1}$ |
| $P_2$ | $B_{o2}$ | $B_{g2}$ | $R_{s2}$ | $r_{s2}$ |
| $P_3$ | $B_{o3}$ | $B_{g3}$ | $R_{s3}$ | $r_{s3}$ |
| $P_4$ | $B_{o4}$ | $B_{g4}$ | $R_{s4}$ | $r_{s4}$ |

| $\gamma_{os}$ | $M_o$ | $M_g$ |
|---|---|---|
| | | |

$T = T_2$

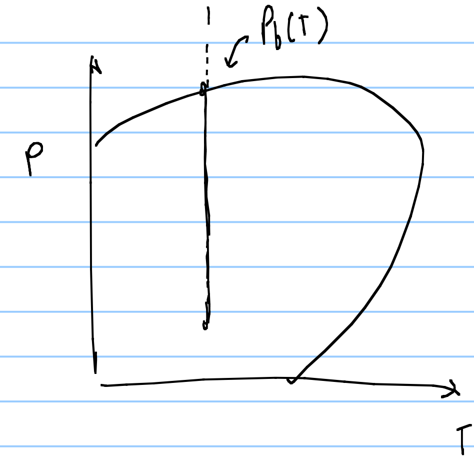
| $P$ | $B_o$ | $B_g$ | $R_s$ | $r_s$ |
|---|---|---|---|---|
| $P_1$ | $B_{o1}$ | $B_{g1}$ | $R_{s1}$ | $r_{s1}$ |
| $P_2$ | $B_{o2}$ | $B_{g2}$ | $R_{s2}$ | $r_{s2}$ |
| $P_3$ | $B_{o3}$ | $B_{g3}$ | $R_{s3}$ | $r_{s3}$ |
| $P_4$ | $B_{o4}$ | $B_{g4}$ | $R_{s4}$ | $r_{s4}$ |

$T = T_3$

| $P$ | $B_o$ | $B_g$ | $R_s$ | $r_s$ |
|---|---|---|---|---|
| $P_1$ | $B_{o1}$ | $B_{g1}$ | $R_{s1}$ | $r_{s1}$ |
| $P_2$ | $B_{o2}$ | $B_{g2}$ | $R_{s2}$ | $r_{s2}$ |
| $P_3$ | $B_{o3}$ | $B_{g3}$ | $R_{s3}$ | $r_{s3}$ |
| $P_4$ | $B_{o4}$ | $B_{g4}$ | $R_{s4}$ | $r_{s4}$ |

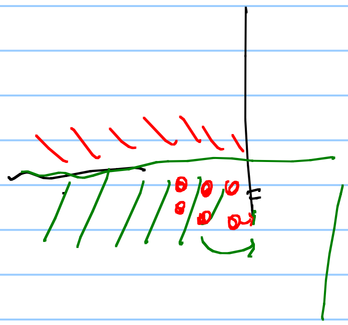
| | |
|---|---|
| $\begin{bmatrix} \rho_{\bar{g}} \\ \rho_{\bar{o}} \\ \rho_{\bar{w}} \end{bmatrix} = \begin{bmatrix} \dfrac{B_g}{1-r_s \cdot R_s} & \dfrac{-r_s \cdot B_o}{1-r_s \cdot R_s} & 0 \\ \dfrac{-R_s \cdot B_g}{1-r_s \cdot R_s} & \dfrac{B_o}{1-r_s \cdot R_s} & 0 \\ 0 & 0 & B_w \end{bmatrix}_{(p,T)} \cdot \begin{bmatrix} \rho_g \\ \rho_o \\ \rho_w \end{bmatrix}$ | $\begin{bmatrix} \rho_g \\ \rho_o \\ \rho_w \end{bmatrix} = \begin{bmatrix} \dfrac{1}{B_g} & \dfrac{r_s}{B_g} & 0 \\ \dfrac{R_s}{B_o} & \dfrac{1}{B_o} & 0 \\ 0 & 0 & \dfrac{1}{B_w} \end{bmatrix}_{(p,T)} \cdot \begin{bmatrix} \rho_{\bar{g}} \\ \rho_{\bar{o}} \\ \rho_{\bar{w}} \end{bmatrix}$ |
| Standard conditions calculated from local conditions | Local conditions calculated from standard conditions |

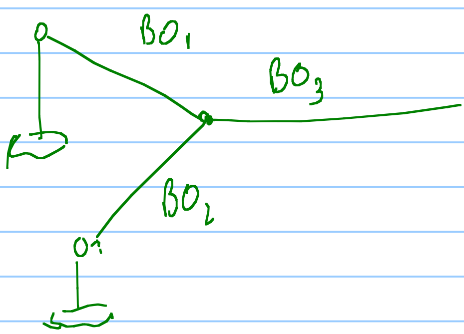
usually there is a change of trend in BO properties at the saturation pressure




Usually if changes in GOR are caused by changes of flow of reservoir oil and reservoir gas

I can use the same BO tables, just changing the saturation properties according to the GOR.





BO correlations

*Bubble Point Pressure* $\gamma_{\bar{o}}, \gamma_{\bar{g}}$

Standing

Glasø

$$P_b = 18.2\left[\left(R_s / S_g\right)^{0.83} (10)^a - 1.4\right]$$

where

| | |
|---|---|
| a | $= 0.00091T - 0.0125(API)$ |
| $P_b$ | = bubble point pressure, psia |
| $R_s$ | = solution gas to oil ratio SCF/STB |
| T | = Temperature, °F |

$$B_o = 0.9759 + \overset{K_1}{0.000120}\left[R_s\left(S_g / S_o\right)^{0.5} + 1.25T\right]^{1.2} \; K_2$$

07/03/2016

- Multiphase flow transportation
  ↓
  Flow assurance

- HYSYS usage
- Production enhacement techniques
  - ESP
  - Gas Lift
  - Multiphase boosting (wet gas compression)
  - increase number of wells
  - stimulation

before easter ↑

---

- Optimization of production systems
  - gas lift
  - ESP, routing

- Dynamics of marine structures

- Problem class with Prosper and GAP

---

<u>Multiphase flow transport</u>: if I have enough energy to produce the desired field rate

- longer transportation distances
- Low temperatures
- Accurate prediction of pressure and temperature drop in transportation pipelines

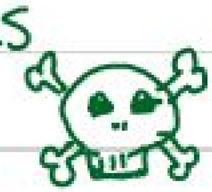
## Flow Assurance

Ensure a successful transportation of hydrocarbons from the reservoir to the processing facilities

## Main problem of transportation

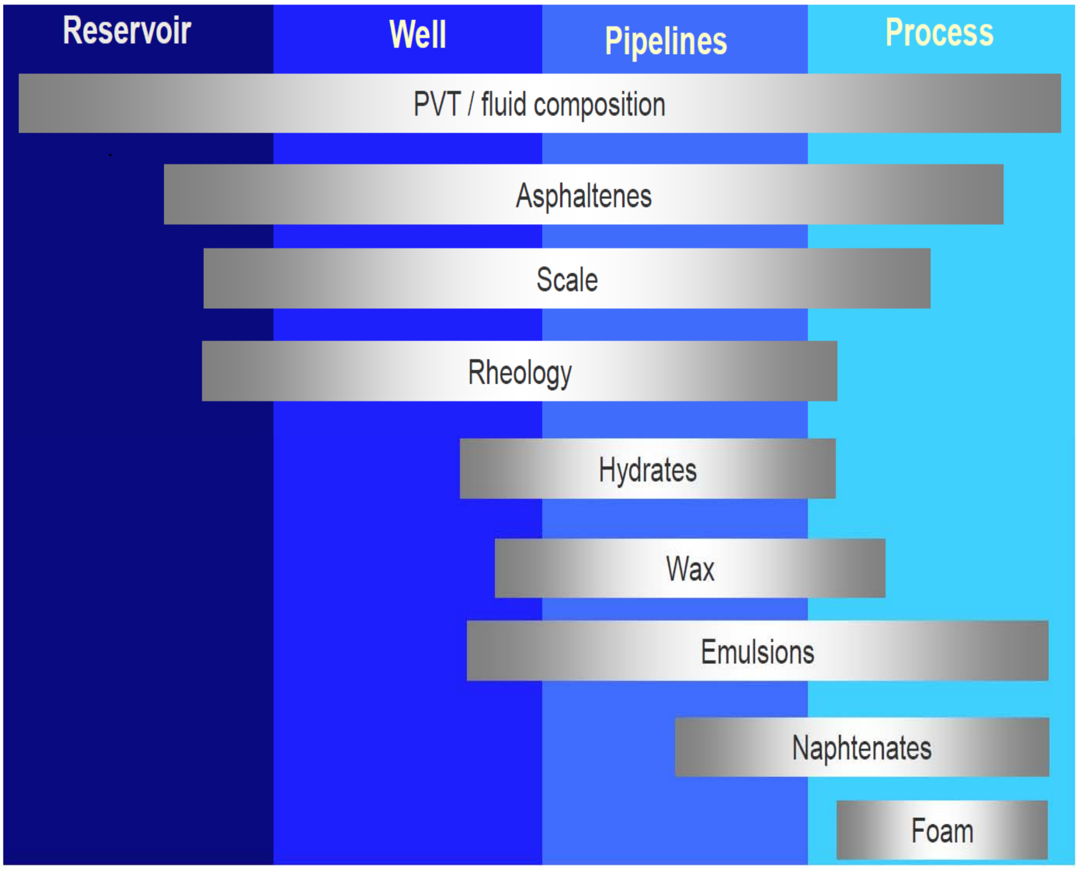
- pressure drop → gas liberation
  liquid condensation
  liq accumulation → extra press drop
  difficult to transport

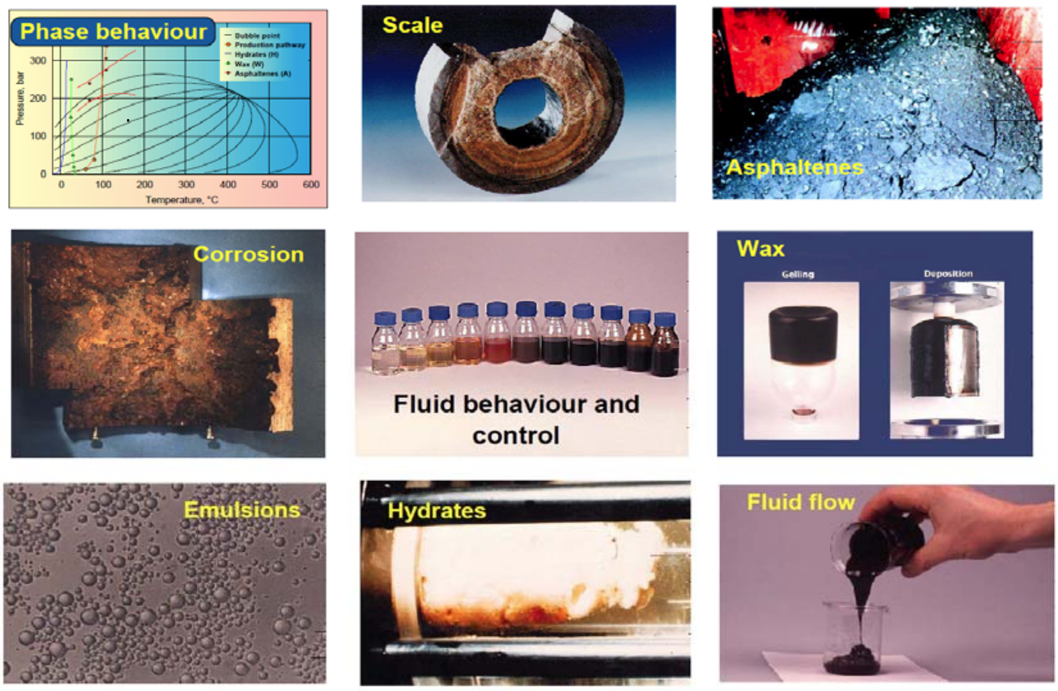
- Temperature drop → ↑ liq viscosity
  liq dropout of gas



- intermitent flow
  - processing facilities
  - structural damage: jumper, pipe conections, risers (flow induce vibration
  - Causes extra pressure drop

Usually for long transportation distances, multiphase flow we use transient multiphase simulators → OLGA, LEDA

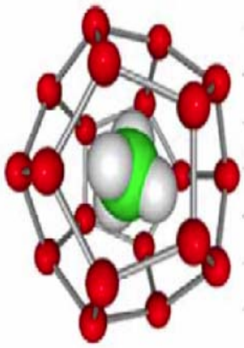


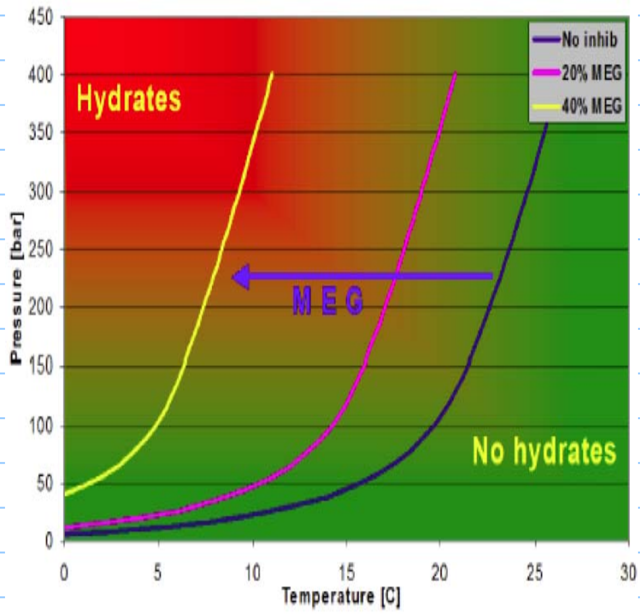
## Wax 'slug' in pig trap at Statfjord B

## Hydrates

- Hydrate is water in a solid structure with small gas molecules in cavities
  - Much like snow/ice
    - Water freeze at 0ºC, what about hydrates?
- Requirements for hydrate formation
  - Free water
  - Small gas molecules ($N_2$, $CO_2$, $CH_4$, $C_2$,$C_3$,...)
  - Low temperature
  - High pressure

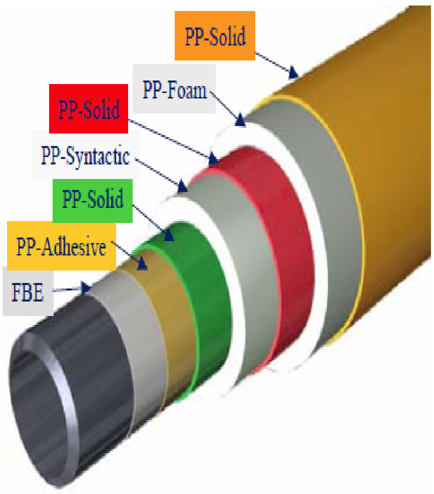


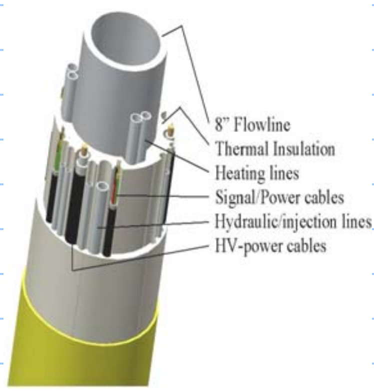
Inhibitors:Methanol, mono ethylene glycol




Hydrate equilibrium line: correlations, measurement, EOS equilibrium calculations

Injection of chemicals: costly!
Conserve heat, avoid high temperature drop




Wax: regular pigging

Anti slugging measures:
- gas lift in riser base
- choking at platform

How did I calculate molar flow to input in hysys?

$\dot{m}_g = q_{\bar{g}} \rho_{\bar{g}}$

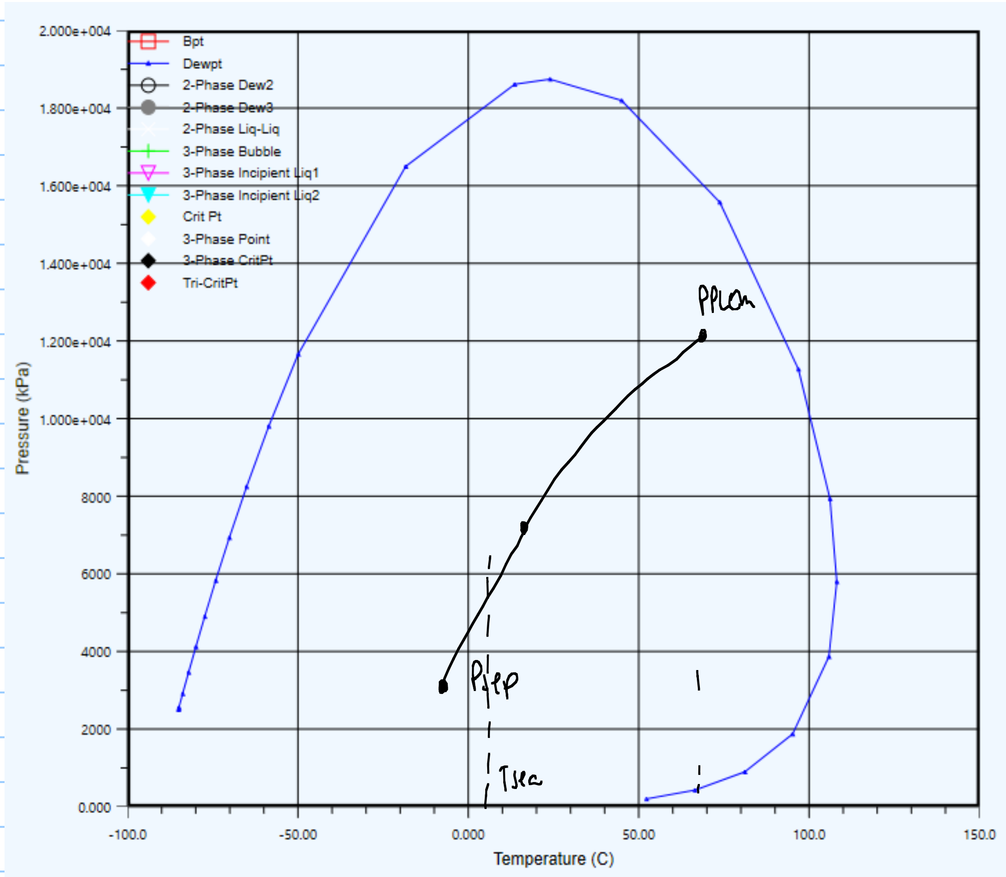
$\dot{m}_o = q_{\bar{o}} \rho_{\bar{o}}$

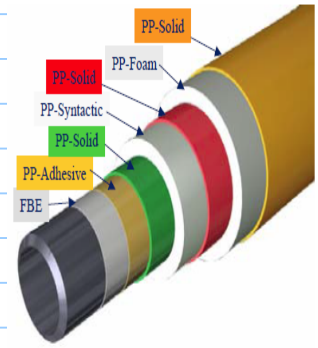
$\dot{m}_T = \dot{m}_g + \dot{m}_o$

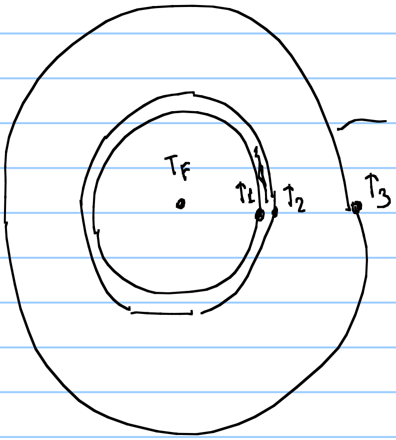
$\frac{\dot{m}}{MW} = \dot{n}$

$\uparrow$

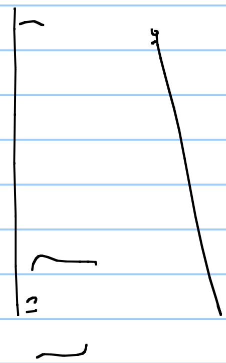
$MW = \sum x_i M_i$




Tamb



$\dot{Q}$ heat flowing from fluid to ambient.

heat transfer in solids conduction

heat transfer in fluids ~ convection → forced convection
→ natural convection

$$\left[\frac{W}{m^2 \cdot K}\right]$$

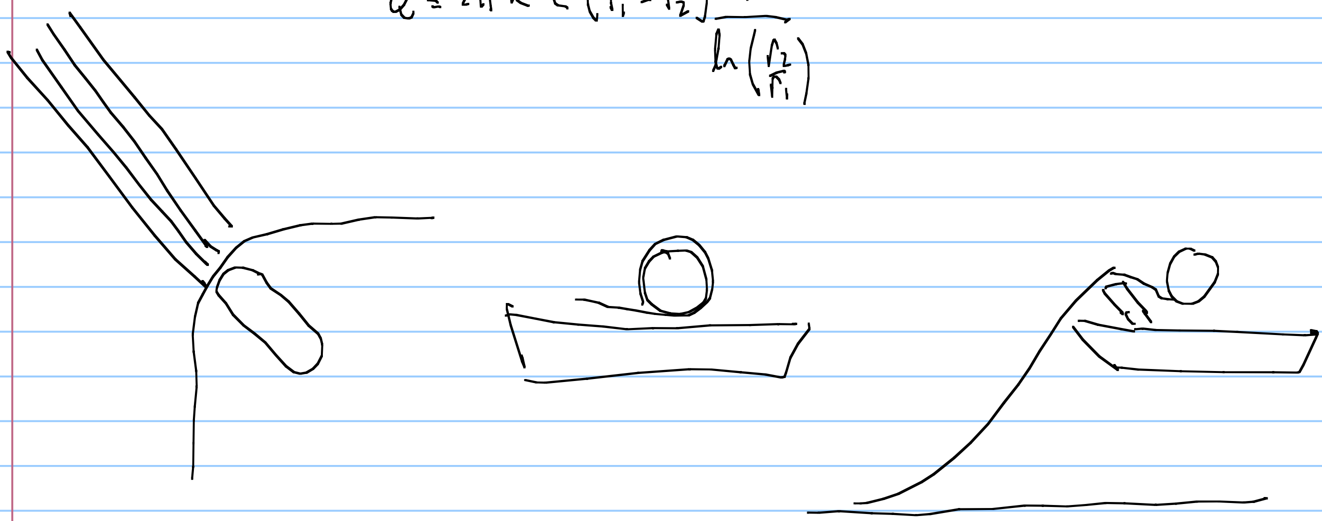
$$\dot{Q} = h_i \, A_i \, (T_f - T_1)$$

internal convection coefficient

$\pi D_1 . L$

conductivity

$$\dot{Q} = 2\pi K L (T_1 - T_2) \frac{1}{\ln\left(\frac{r_2}{r_1}\right)}$$



$$\dot{Q} = h_{out} A_{out} (T_3 - T_{amb})$$

Sum all the equations

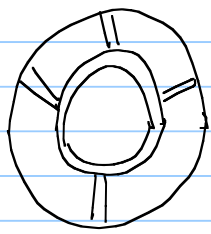
$$(T_f - T_{amb}) = \dot{Q} \left[ \frac{1}{h_i A_i} + \frac{1}{h_o A_o} + \frac{\ln(r_2/r_1)}{2\pi K_m L} + \frac{\ln(r_3/r_2)}{2\pi K_{insu} \cdot L} \right]$$

$$(T_f - T_{amb}) = \dot{Q} \frac{1}{U \cdot A_o}$$

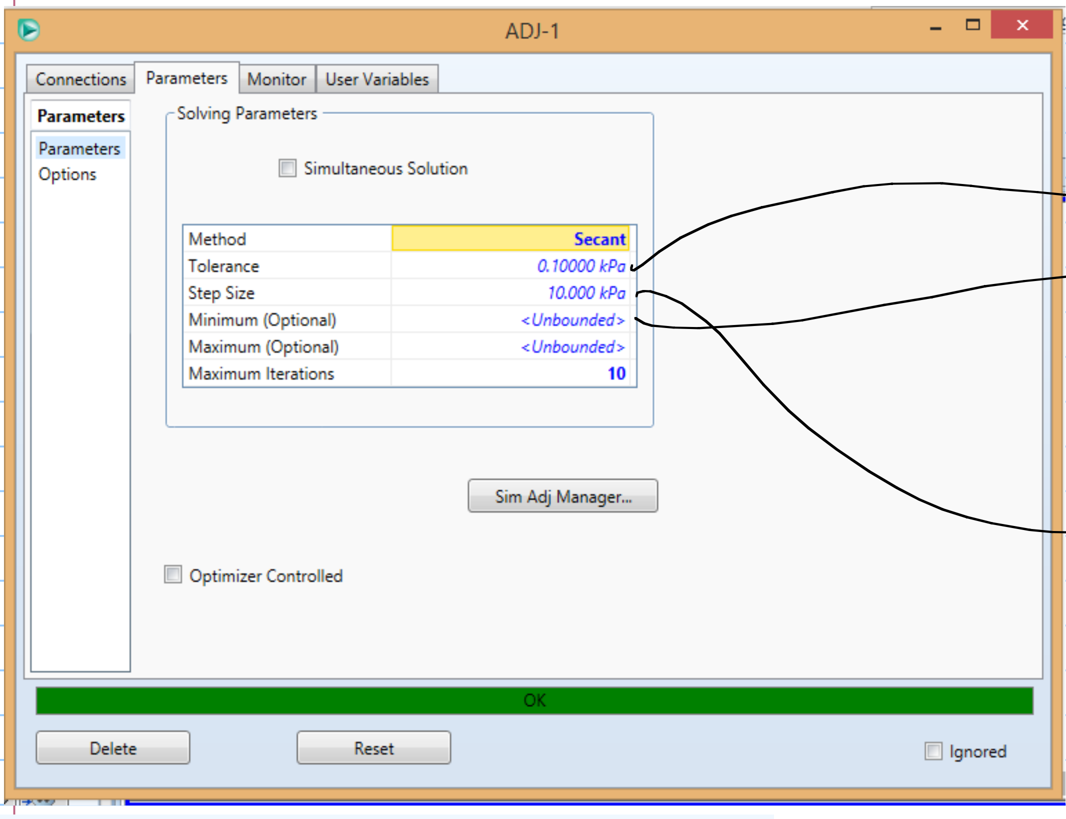
universal heat transfer coefficient

$$\frac{1}{U \cdot A_o} = \left[ \frac{1}{h_i A_i} + \frac{1}{h_o A_o} + \frac{\ln(r_2/r_1)}{2\pi K_m L} + \frac{\ln(r_3/r_2)}{2\pi K_{insu} \cdot L} \right]$$

$$U = A_o^{-1} \cdot \left[ \frac{1}{h_i A_i} + \frac{1}{h_o A_o} + \frac{\ln(r_2/r_1)}{2\pi K_m L} + \frac{\ln(r_3/r_2)}{2\pi K_{insu} \cdot L} \right]^{-1}$$



$h \neq f(x)$ $\quad x$ distance.



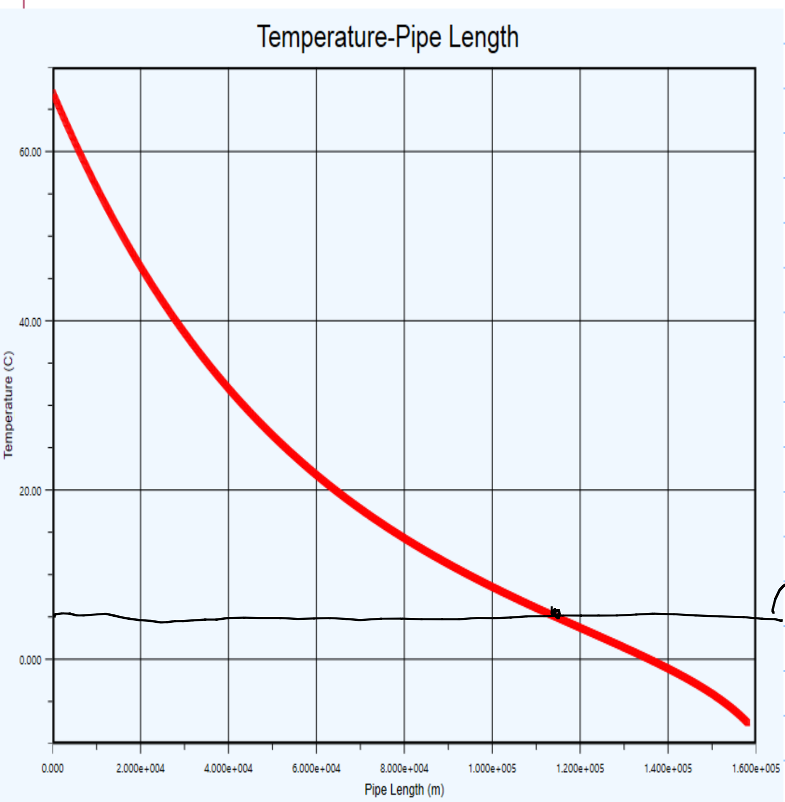

$p = 30$ bar $\pm$ 0.001 bar

$P_{plem}$ min

$P_{plem}$ max ~>

$P_{plem}$ 120 bar

120.01 bar

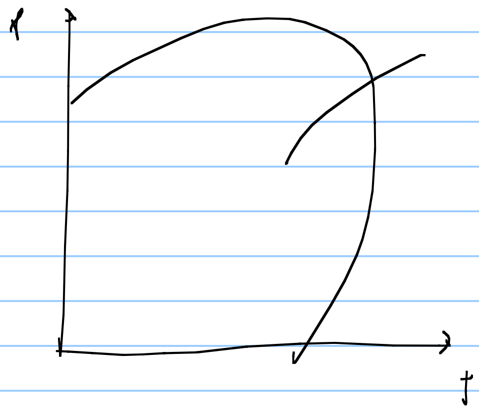



$T_{sea}$

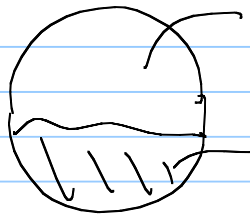
below sea temperature Joule-thompson effect

$\Delta p$ ~> $\Delta T$

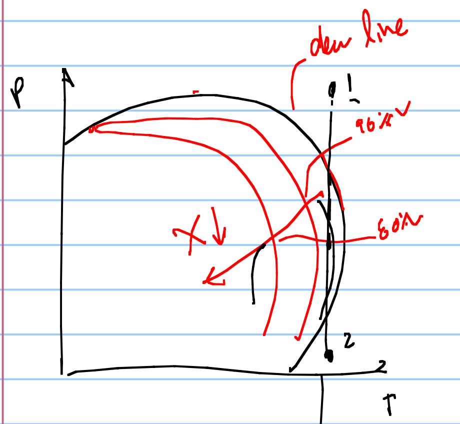
joule-thompson coefficient



$$\mu_{JT} = \left(\frac{\partial T}{\partial P}\right)_H$$



$$\frac{A_L}{A_T} = H_L$$





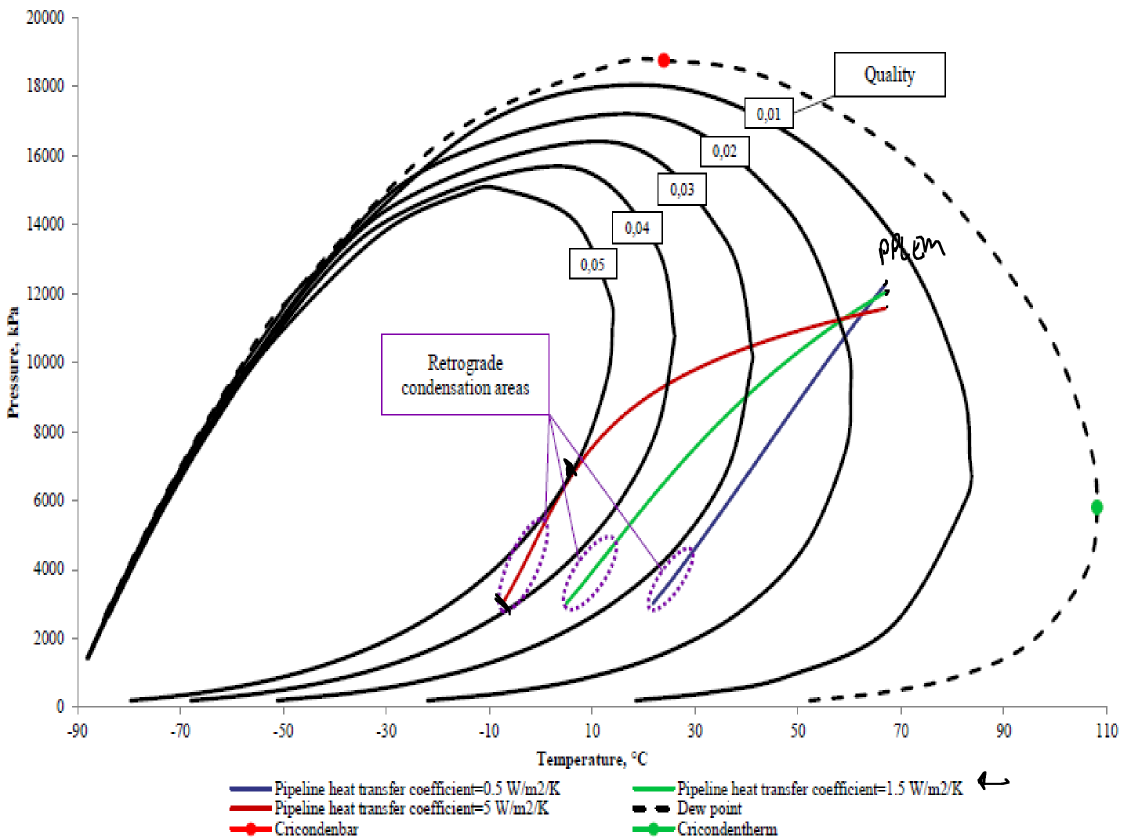
$$X = \frac{m_g}{m_L + m_g}$$

• condensation evaporation

retrograde condensation

• multiphase flow dynamics $V_L \downarrow$ $V_g \uparrow$

condensation → evaporation.

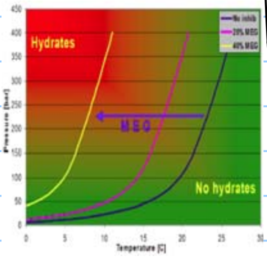
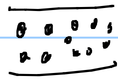
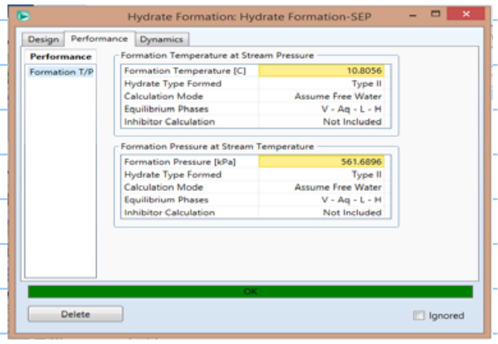
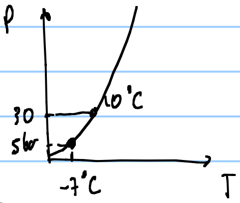
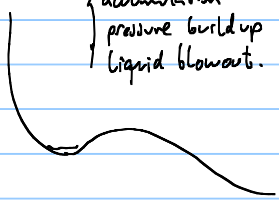
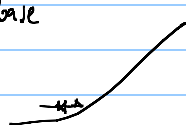
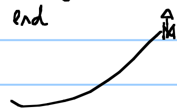
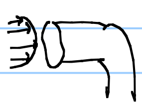



$$\Delta p = \Delta p_g + \Delta p_f$$

$\rho$ $\rho$

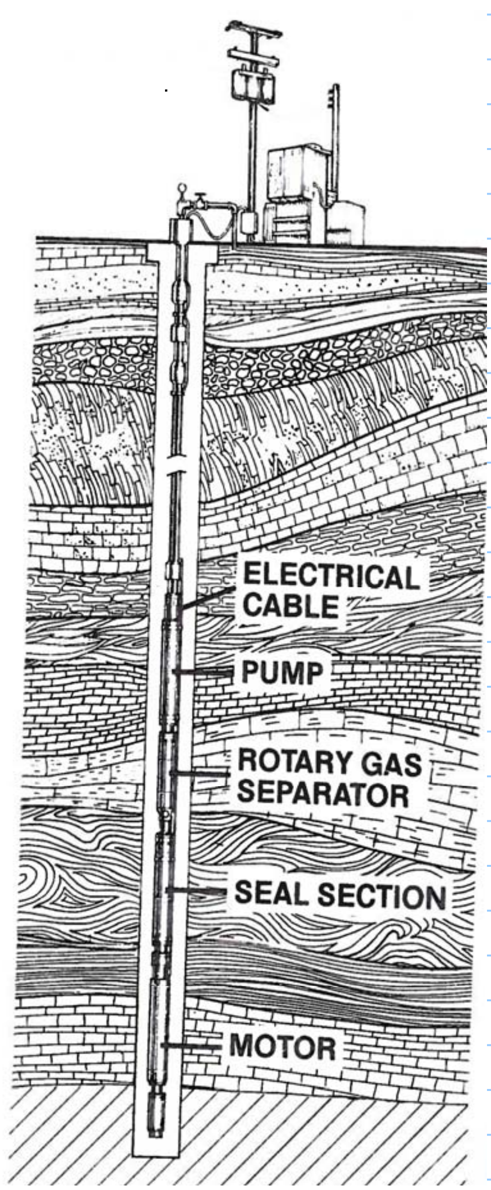
$$\rho = f(P, T)$$

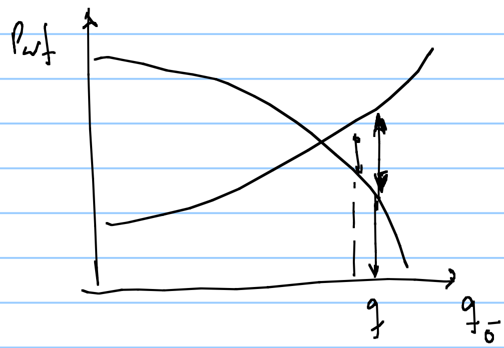
**Figure 10.** Phase envelope of the gas mixture and P-T distribution along the pipeline (zero-elevation case).

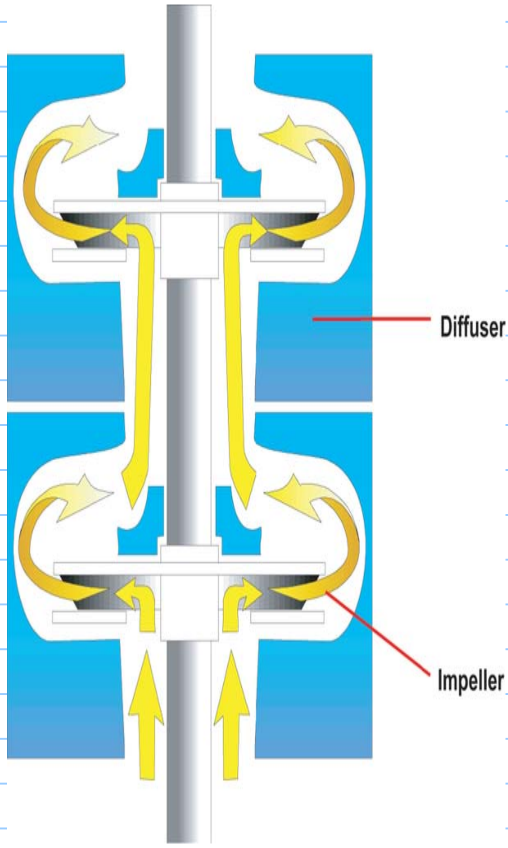
| Flow assurance issue | Cause | Consequences | industrial preventive measures | Tool to analyze |
| --- | --- | --- | --- | --- |
| Hydrates  | • water free water<br>• light HC molecules<br>• Begin to form at P, T according to hydrate equilibrium <br>• precipitation, agglomeration. | • blockage of pipe<br>production loss<br>• flowlines and pipelines | • pipe insulation<br>• electric heating<br>• hydrate inhibitor acting on the free water avoid inhibitor evaporation !! 150°C<br>• cold flow, SINTEF <br>• water separation<br>• pipe coating | • correlations<br>• compositional and multiphase simulators<br>Hydrate formation module in HYSYS   |
| Wax 'slug' in pig trap at Statfjord B  Wax | • precipitation of heavy chains as a solid phase.<br>• crudes with tendency to produce wax<br>• Begin to form at given P, T<br>• cold wall<br>• precipitation, agglomeration, deposition | ↑ pressure drop<br>• roughness ↑<br>• reduce cross section area of pipe<br>• gelling ↳ startup of pipe. | • pigging (3 months)<br>• stay away from wax region<br>- pipe insulation<br>- electrical heating<br>• chemical inhibitors<br>• chemical dissolvers<br>• pipe coating<br>• Cold flow | • laboratory experiments<br>tune to correlations or expressions<br>• deposition rates $\dot{m}$ vs T |
| Slugging intermittent flow  | • multiphase flow dynamics<br>• transients liquid accumulation<br>{ accumulation<br>pressure buildup<br>liquid blowout.  | • unstable operation<br>• added pressure drop<br>• vibration<br>↳ structural damage<br>↳ leaks | • gas lift in riser base <br>• choking at riser end <br>• subsea separation | • transient multiphase flow simulator (OLGA, LEDA)<br>slug frequency<br>slug length<br>↳ forces on structures<br>↳ riflex<br>↳ Fisana<br>↳ FEA Finite element analysis. |
| Scaling | Deposition of mineral from produced water<br>• Begin to deposit at P, T conditions<br>• mixing of incompatible waters<br>• occurs in well with associated water production. | • reduction of pipe cross section<br>• malfunctioning of well equipment.<br>SSSV | • chemical inhibitors<br>• chemical dissolvers<br>• mechanical removal<br>• pipe coating. | laboratory tests<br>deposition rates |
| erosion | • liquid droplets in the gas<br>• gas bubbles in liquid<br>• sand production | • structural problem<br>• leaks<br>• vibration | • high resistance pipe coating<br>• modify geometry<br>• reduce flow rate<br>• sand separation subsea | • Computational fluid dynamics (CFD),  |

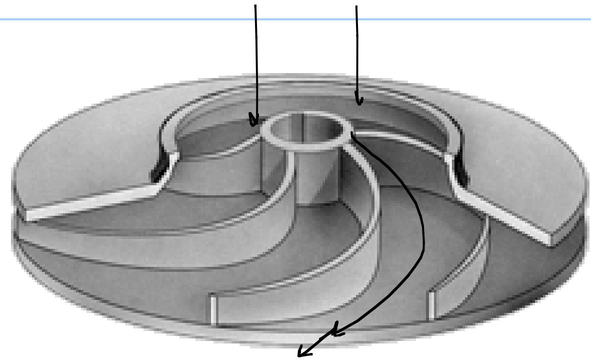

execute the analysis with fixed rate at a particular point in time
- design phase
- operational phase

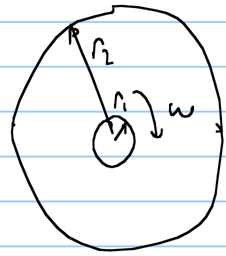
Production enhancement techniques: ESP: (Electric submersible pump).



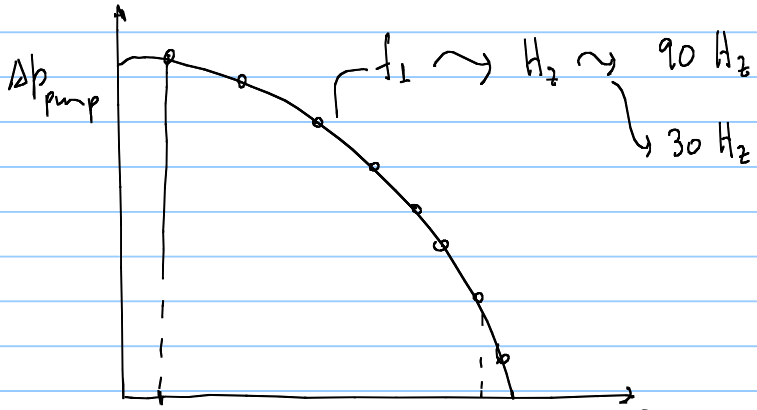




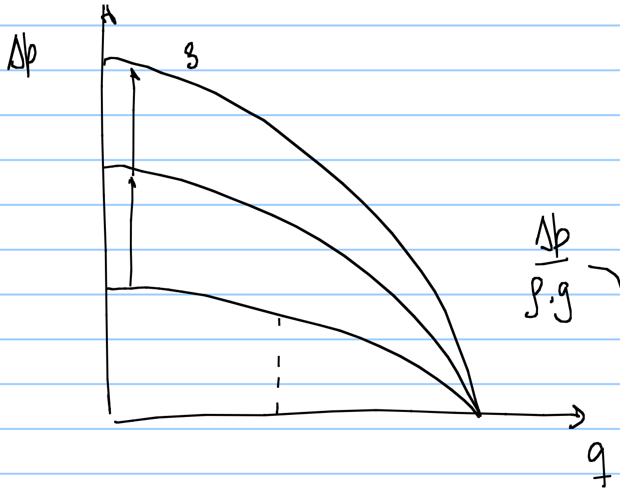

$U_1 = r_1 \vec{\omega}$

$U_2 = r_2 \vec{\omega}$

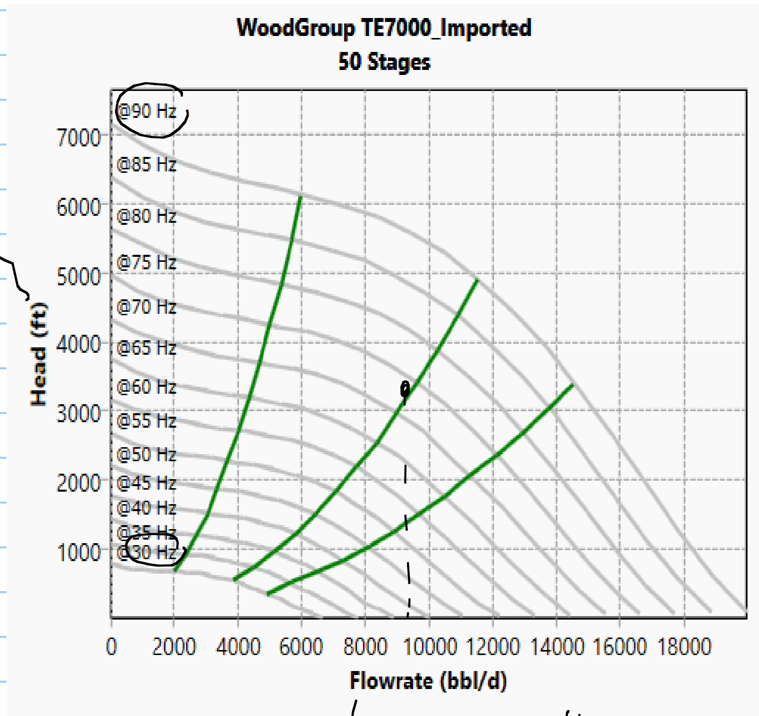
hydraulic performance of ESP = IPR



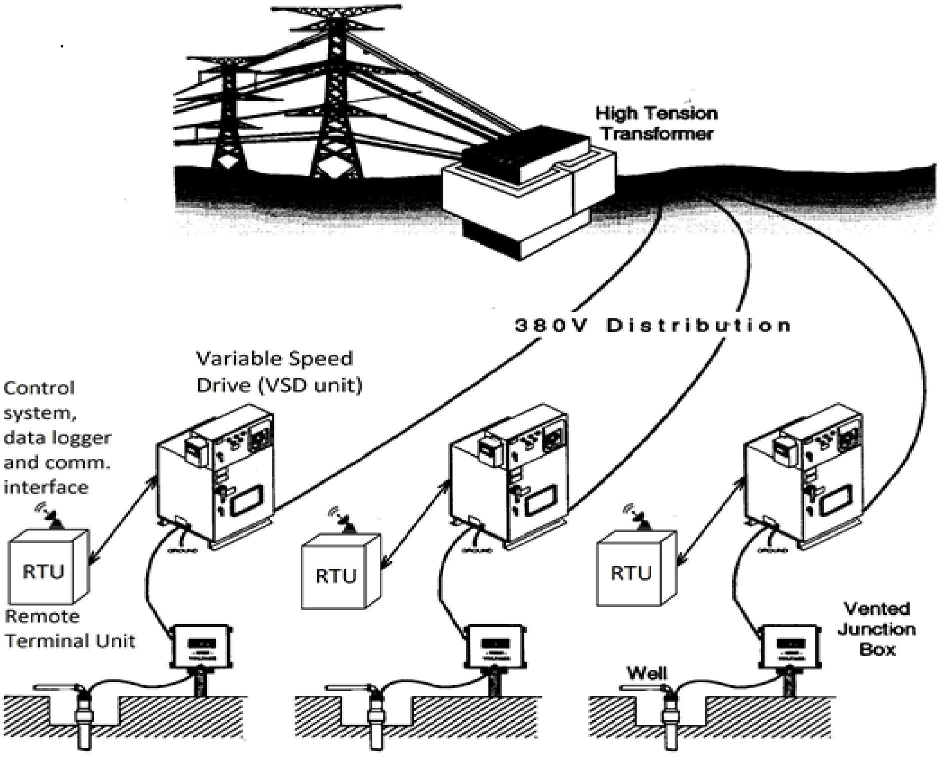

$q_{actual}$ liquid rate at pump outlet




$\frac{\Delta p}{\rho \cdot g}$



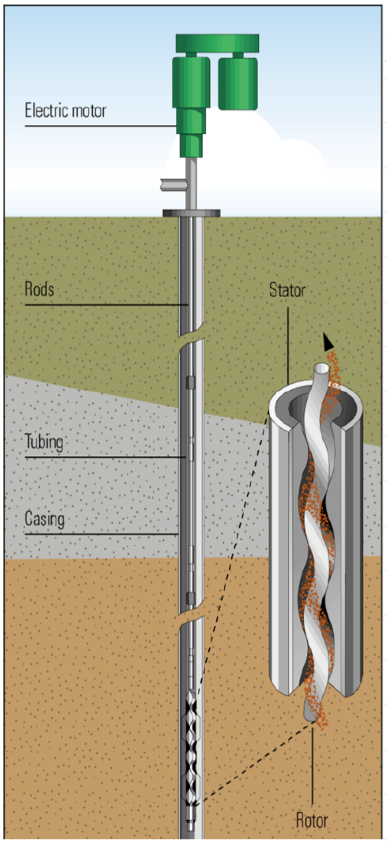

Local liquid flow rate



High Tension
Transformer
380V Distribution
Variable Speed
Drive (VSD unit)
Control
system,
data logger
and comm.
interface
RTU
Remote
Terminal Unit
RTU
RTU
Vented
Junction
Box
Well

Artificial lift methods:

- Gas lift
- Electric submersible pump (ESP)
- PCP progressive cavity pump $\rightsquigarrow M\uparrow$




- Rod pump $\downarrow q$

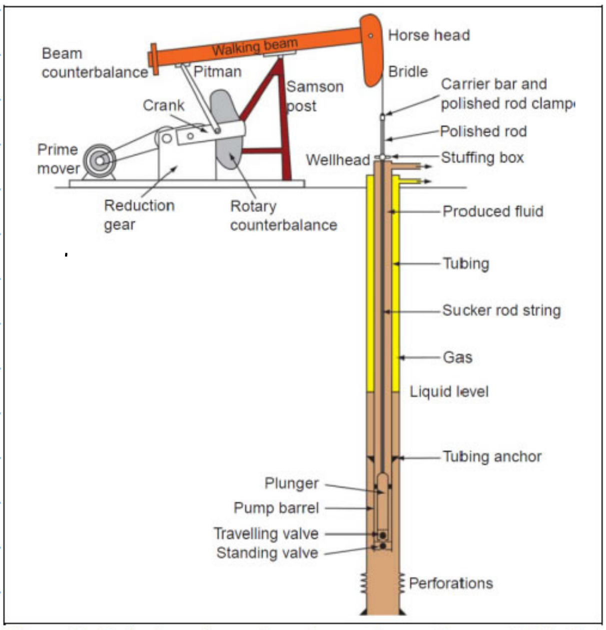
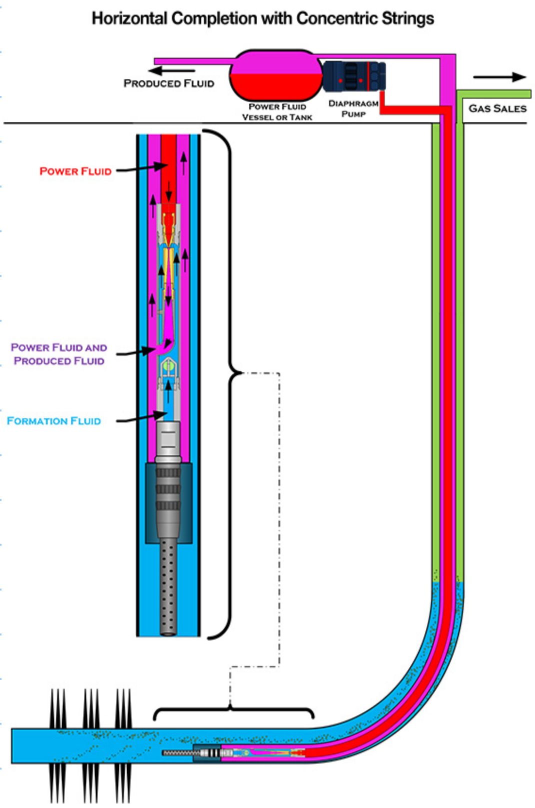
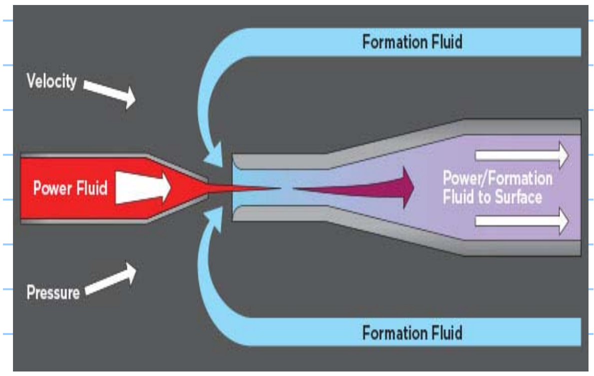


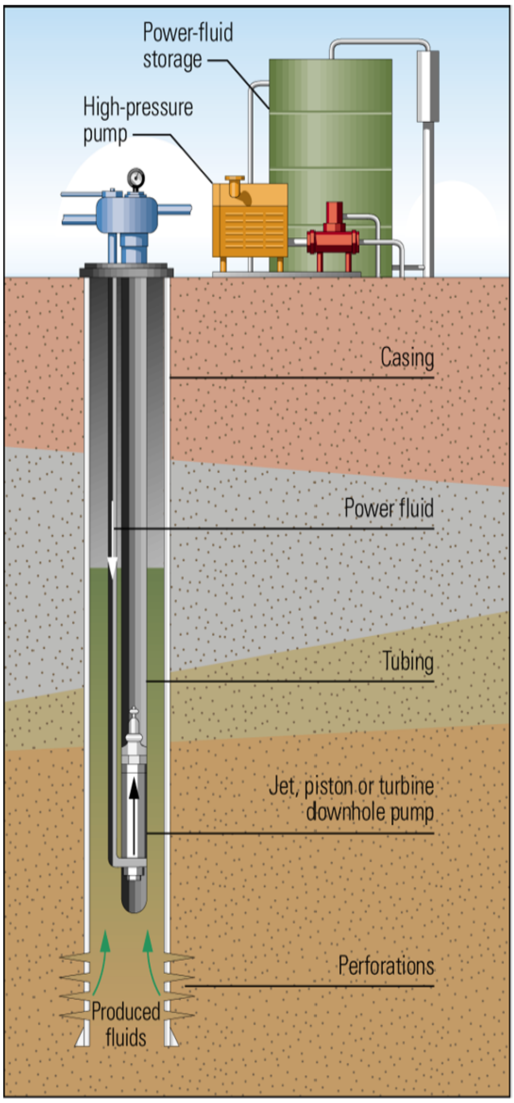

**Figure 2. Typical configuration of a sucker rod pump (Bellarby, 2009).**

← positive displacement principle

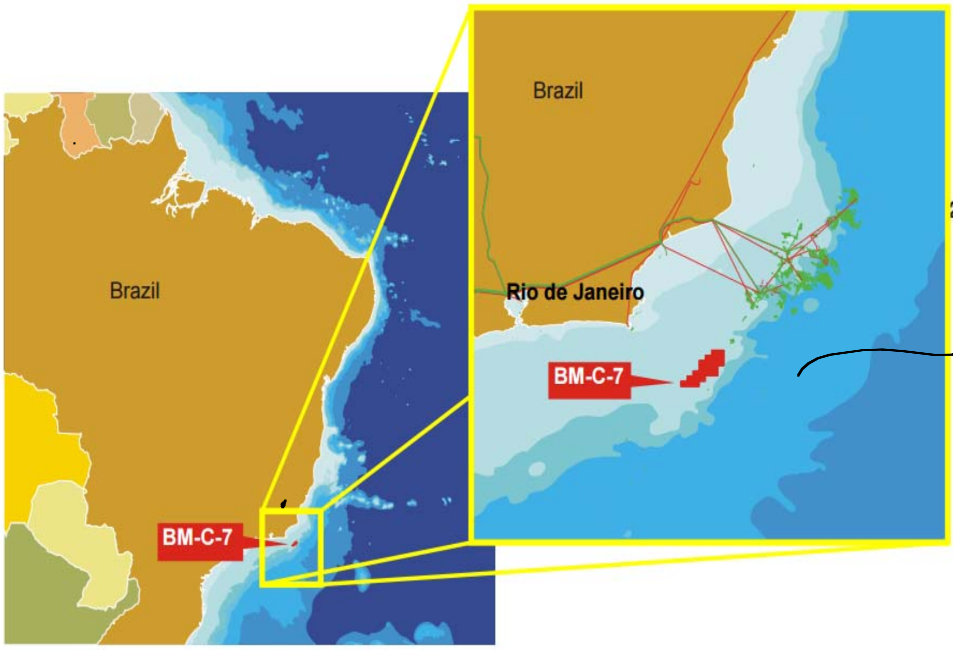
- Jet pump






Peregrino field



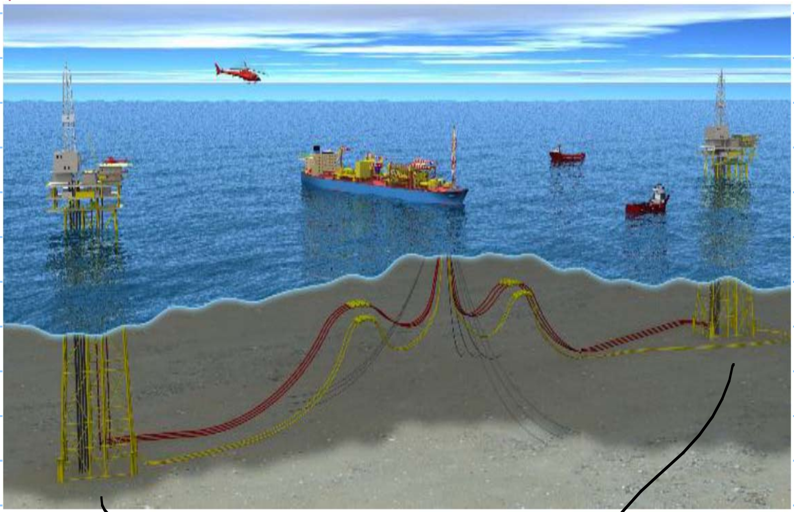

100 m

API : 14

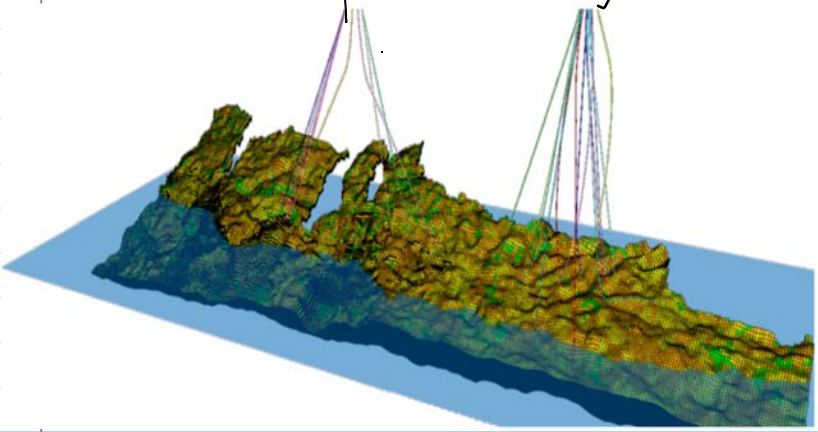
$\mu_o$ = 120 - 200 cp @ $T_R$

GOR ≈ 100 $Sm^3/Sm^3$

aquifer and water reinjection

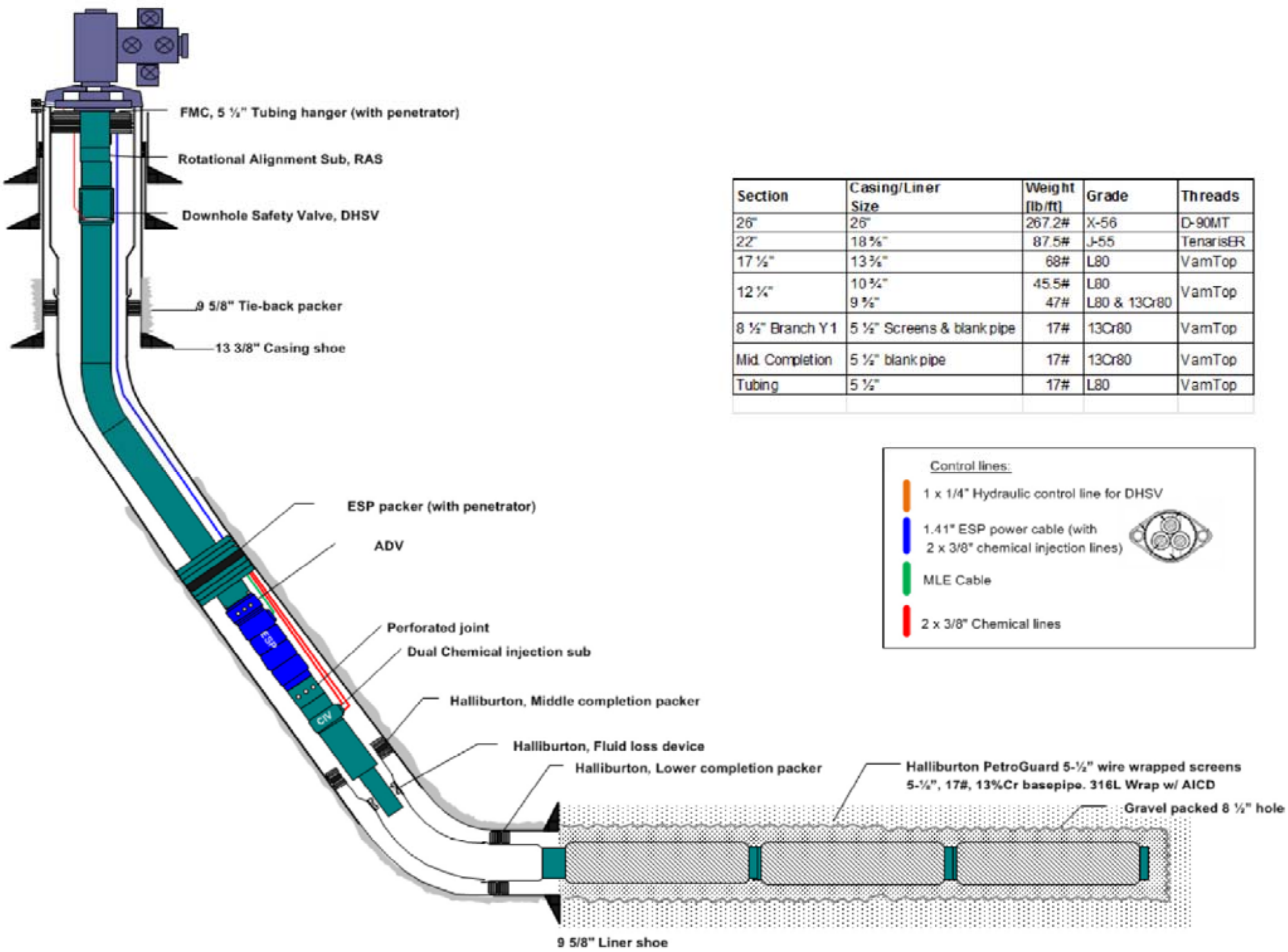


- LQ
- Drilling module
- Movable drill rig
- Electrical plant
- Wellheads
- Booster pumps
- Water Injection
- Uptime 99% bracket



typical life of ESP (5 years)
medium life (2 years – 1 year)

- frequent startups ~ shutdowns hurt the life of the pump.
- Sand production




| 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"<br>9 ⅝" | 45.5#<br>47# | L80<br>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

ESP lifted wells

liquid through tubing
gas through annulus

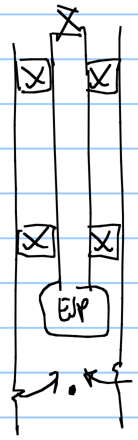
liquid and gas (if any) through tubing


pump submergence

ASV - Annular safety valve.

bubble point pressure

$P_{wf} < P_b$




gas affects negatively the performance of the pump

- performance
- vibration
- cooling
- frequent failures

$P_{suc} \geq F_s \cdot P_b$

$P_{suc} \geq 1.05\ P_b$

$\geq 1.05\ 30$ bar

GVF → gas volume fraction

$GVF = \dfrac{q_g}{q_L + q_g} \leq 0.3$ ← local

$q_L = J_L \cdot (P_R - P_{wf})$

initial

| 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 | | 78 |

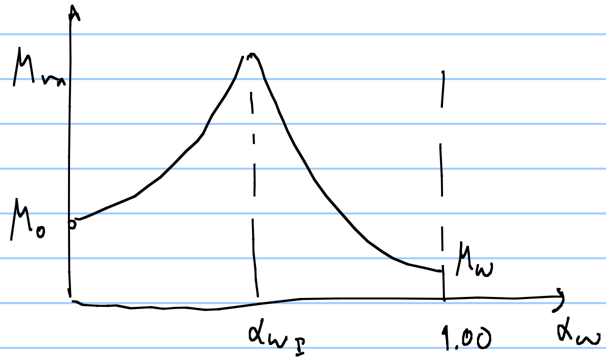
| | Water | Oil | |
|---|---|---|---|
| Fluid Density | 1025 | 897 | [kg/m^3] |
| Richardson Emul. exp. | 3.089 | 3.215 | |
| Viscosity | 1.00E-03 | 0.1 | [Pa s] |
| $\alpha_w$ cut off | 0.60 | | |
| Roughness tubing and lines | 0.00010 | m | |
| Bubble point pressure [bara] | 30 | [bara] | |

$h_1$ .. distance from sand phase to pump suction

$h_2$ .. distance from pump discharge to well head


| Wells | $p_R$ | WC | Average density | Effective viscosity | $q_{tot}$ | $p_{wf}$ | $q_o$ | $q_w$ | $p_{suc}$ | $p_{disc}$ | $\Delta p_{ESP}$ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| - | bara | [-] | kg/m^3 | Pa s | Sm^3/d | bara | Sm^3/d | Sm^3/d | bara | bara | bara |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |

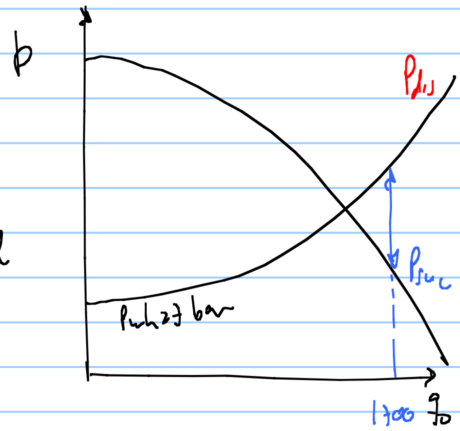
dispersion
mixture of oil and water




$q_{target} = 1700\ Sm^3/d$ oil


$\Delta p_{pump}\ (P_{dis} - P_{suc})$ @ $q_{\bar{o}} = 1700\ Sm^3/d$

$R_L$ $\quad q_{\bar{o}}$



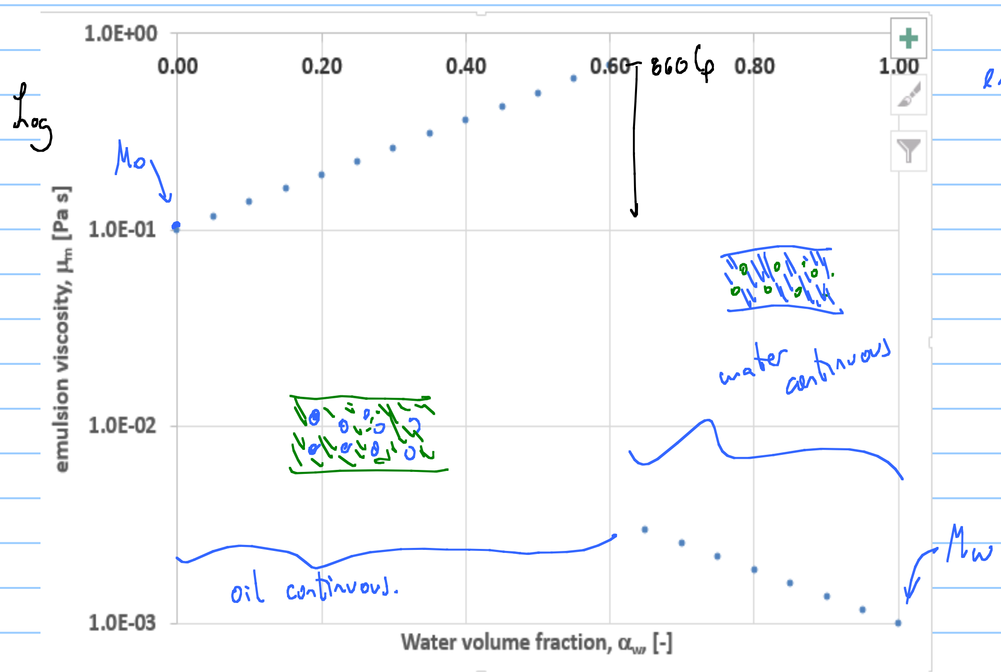

$$\rho_m = \rho_o(1-\alpha_w) + \rho_w(\alpha_w)$$

<u>assumption</u>

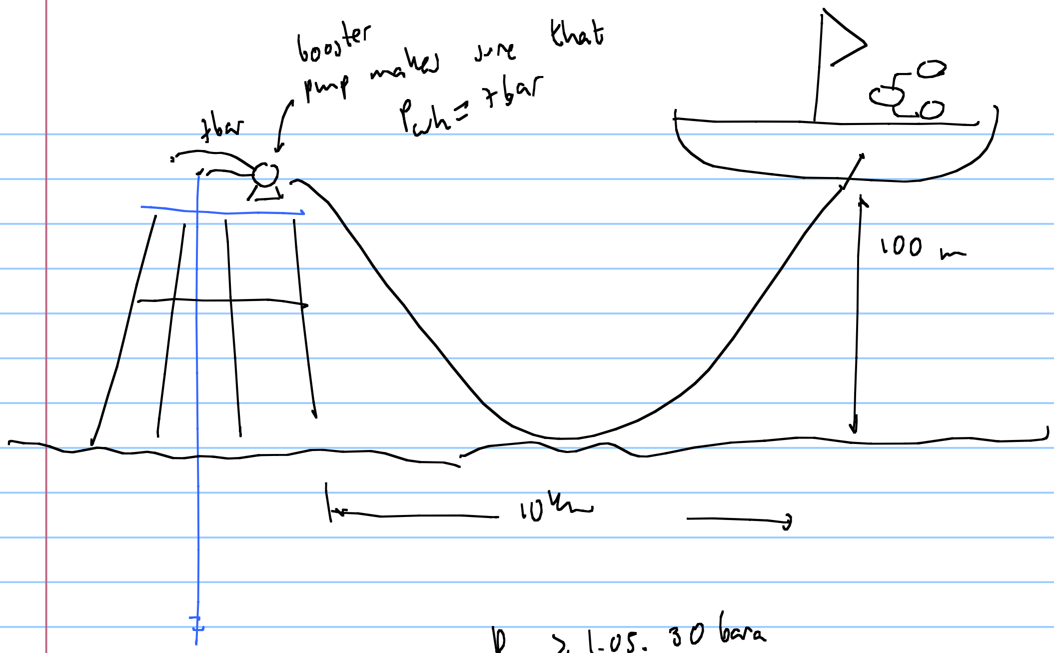
the oil and water are incompressible $\quad q_{\bar{o}} = q_o(P,T)$

$$q_{\bar{w}} = q_w(P,T)$$

$$\alpha_w(P,T) = wc$$




emulsion behavior.



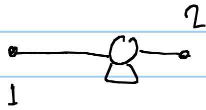

$P_{suc} \geq 1.05 \cdot 30$ bara

$P_{suc} \geq 31.5$ bara

Power capacity → casing size limits the maximum power capacity
→ $

300 hp → 1500 hp
minimum maximum

600 hp → comes from the expert




$$P_{Hydraulic} = \frac{(P_2 - P_1)\, q}{\eta_{eff}}$$

$\eta_{eff}$ → ? → 50% → 70%

→ assume 60%

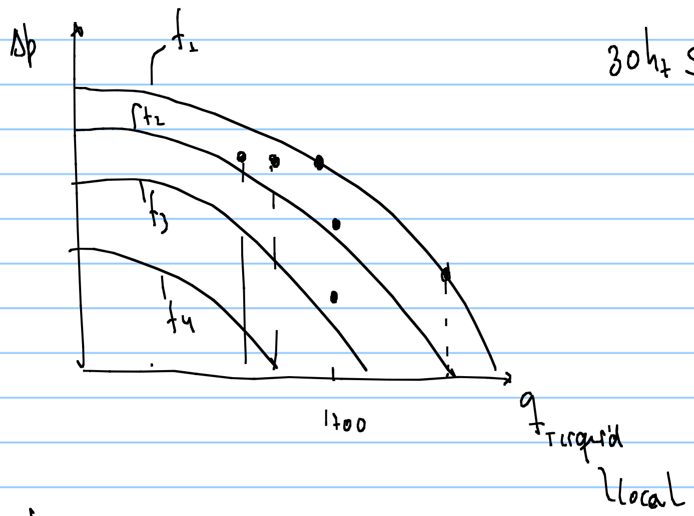
$$W = \frac{J}{s} = \frac{N \cdot m}{s} =$$

$$Pa \cdot m^3/s = \frac{N}{m^2} \frac{m^3}{s} = \frac{J}{s}$$

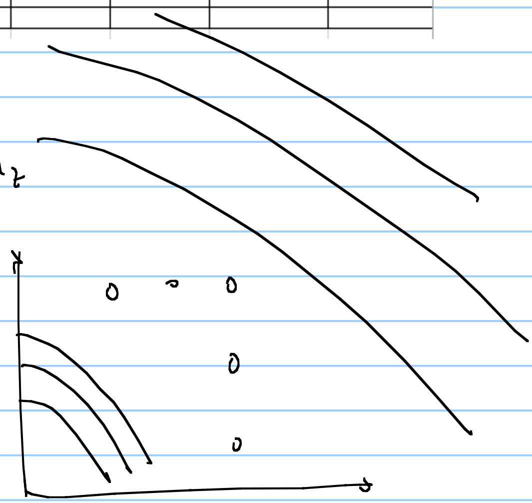
| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| - | bara | Sm^3/d/bar | m | m | m | m | - | - |
| 1 | 231 | 14 | 380 | 1960 | 0.24 | 0.14 | | 78 |

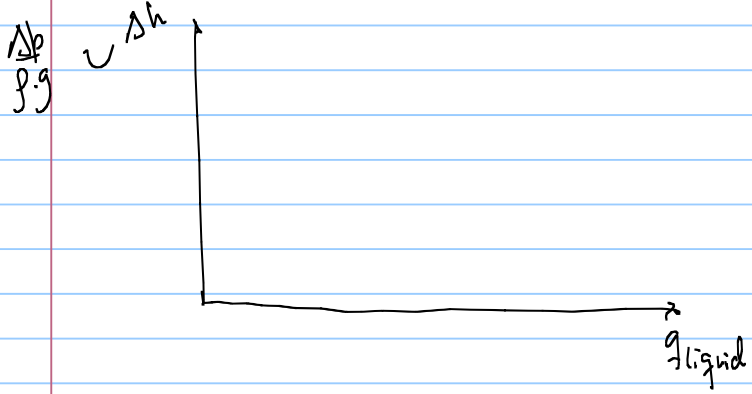
| | Water | Oil | |
|---|---|---|---|
| Fluid Density | 1025 | 897 | [kg/m^3] |
| Richardson Emul. exp. | 3.089 | 3.215 | |
| Viscosity | 1.00E-03 | 0.1 | [Pa s] |
| $\alpha_w$ cut off | 0.60 | | |
| Roughness tubing and lines | 0.00010 | m | |
| Bubble point pressure [bara] | 30 | [bara] | |

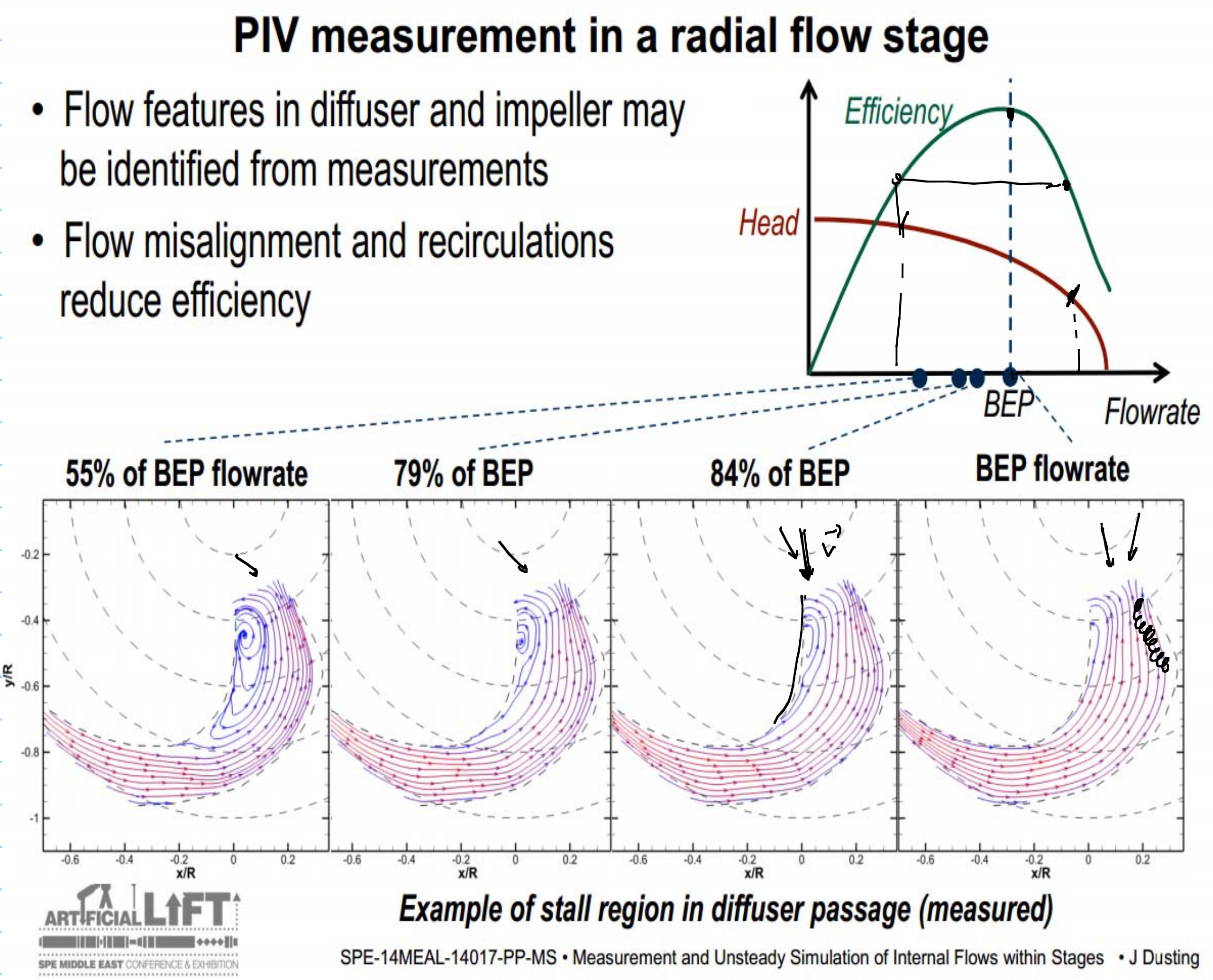
| Wells | $p_R$ | WC | Average density | Effective viscosity | $q_{tot}$ | $p_{wf}$ | $q_o$ | $q_w$ | $p_{suc}$ | $p_{disc}$ | $\Delta p_{ESP}$ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| - | bara | [-] | kg/m^3 | Pa s | Sm^3/d | bara | Sm^3/d | Sm^3/d | bara | bara | bara |
| | 231 | 0.00 | 897 | 0.100 | 1700 | 110 | 1700 | 0 | 76 | 185 | 10 |
| | 215 | 0.00 | 897 | 0.100 | 1700 | 94 | 1700 | 0 | 60 | 185 | 12 |
| | 200 | 0.00 | 897 | 0.100 | 1676 | 80 | 1676 | 0 | 47 | 185 | 13 |
| | 175 | 0.00 | 897 | 0.100 | 1527 | 66 | 1527 | 0 | 32 | 184 | 15 |
| | 150 | 0.00 | 897 | 0.100 | 1190 | 65 | 1190 | 0 | 31.5 | 183 | 15 |



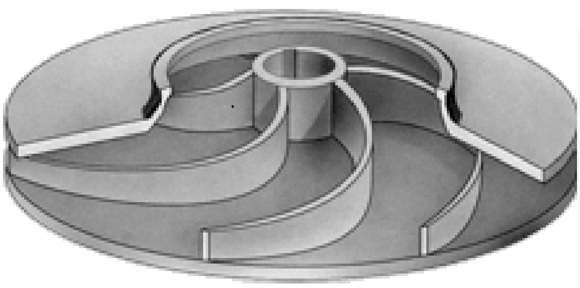

$30\,hz \le f \le 60\,hz$

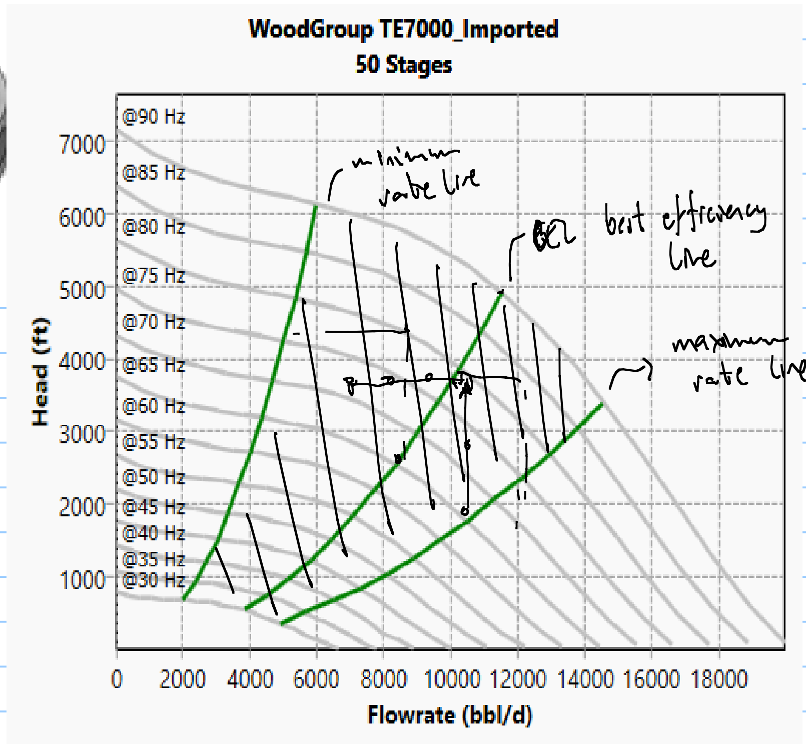


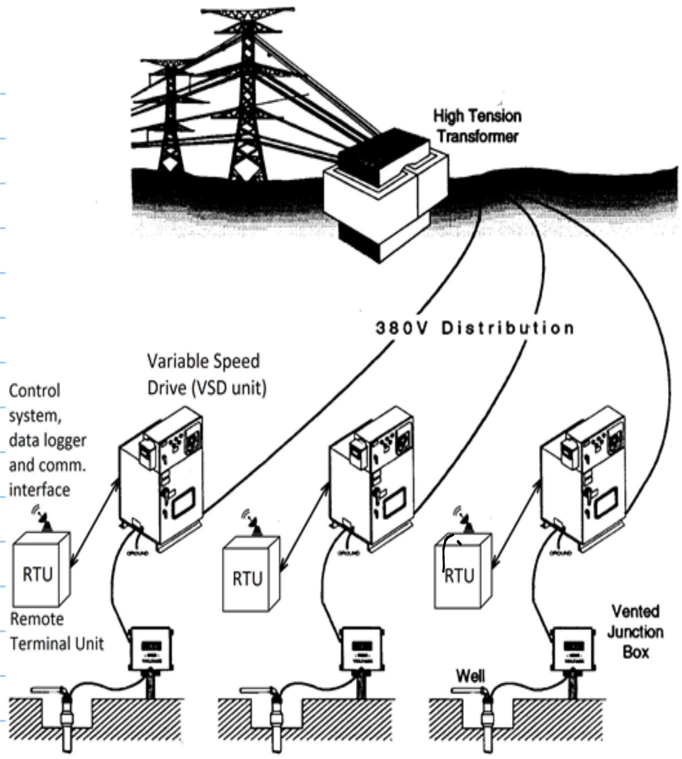





BEP when the flow is aligned with the vane angle






High Tension
Transformer
380V Distribution
Variable Speed
Drive (VSD unit)
Control
system,
data logger
and comm.
interface
RTU
RTU
RTU
Remote
Terminal Unit
Vented
Junction
Box
Well

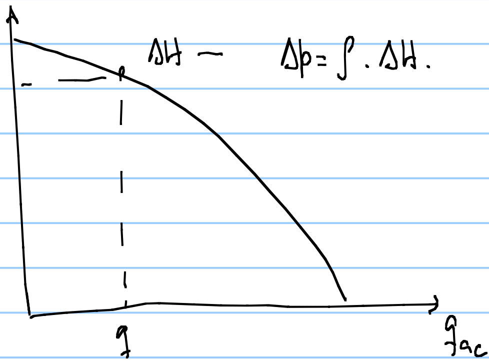
1700 [$m^3$/d

Note Title 15.03.2016

ESP { performance curve


head

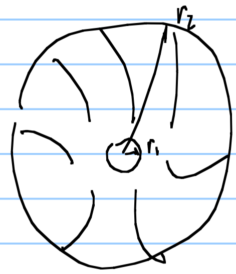
$\Delta H = \frac{\Delta p}{\rho \cdot g}$




$\Delta H$ — $\Delta p = \rho \cdot \Delta H.$

- water → $\Delta p / (\rho \cdot g)$
- single stage

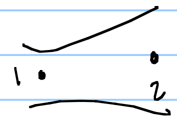
- impeller : increase the fluid energy by increasing the speed




$$\Delta H = \left(a_4 \cdot q^4 + a_3 \cdot q^3 + a_2 \cdot q^2 + a_1 \cdot q + a_0\right) N$$

2nd order → 5th order polynomial

- diffusor



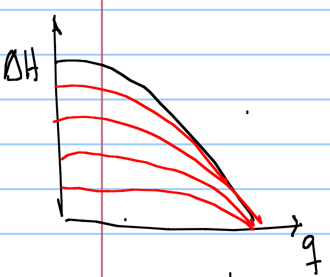

convert kinetic energy to potential energy

$$\frac{P_1}{\rho \cdot g} + \frac{v_1^2}{2g} = \frac{P_2}{\rho \cdot g} + \frac{v_2^2}{2g}$$

↑ ↑ ↑ ↑

modifications

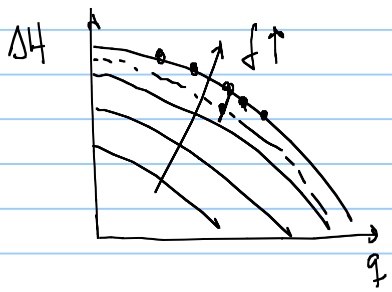
Number of stages




N number of stages

$\Delta H_{\text{single stage}} \cdot N = \Delta H_{ESP}$

changes with rotational speed
$f_{ref} = 60\ h_z$

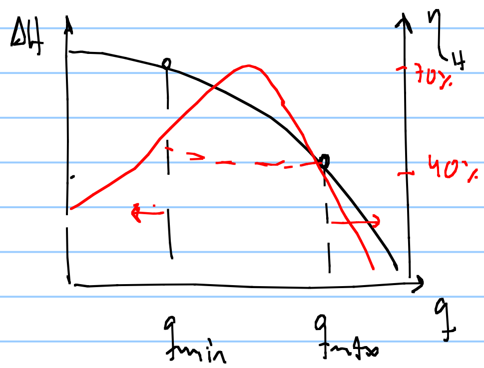



$f_{min} \leq f \leq f_{max}$

30-40 $h_z$

60-70 $h_z$

- operational limits

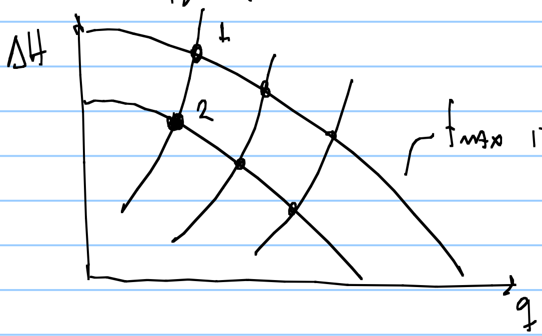



- upthrust
- downthrust

*

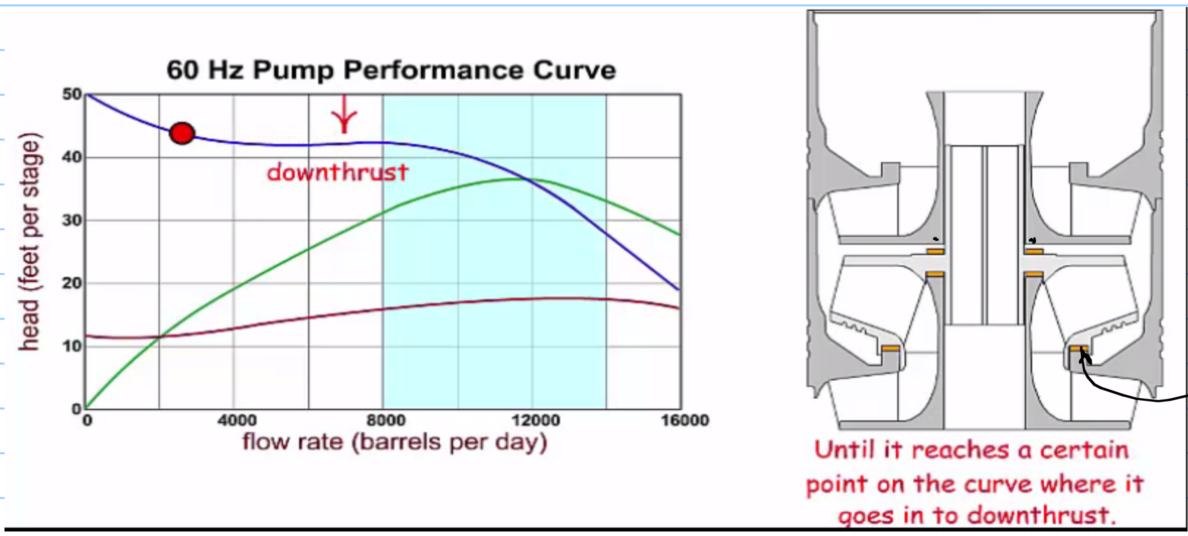
$$\frac{\Delta H_1}{\Delta H_2} = \left(\frac{f_1}{f_2}\right)^2$$

$$\frac{q_1}{q_2} = \left(\frac{f_1}{f_2}\right)$$




$f_{max}$ is given by the maximum power capacity of the motor

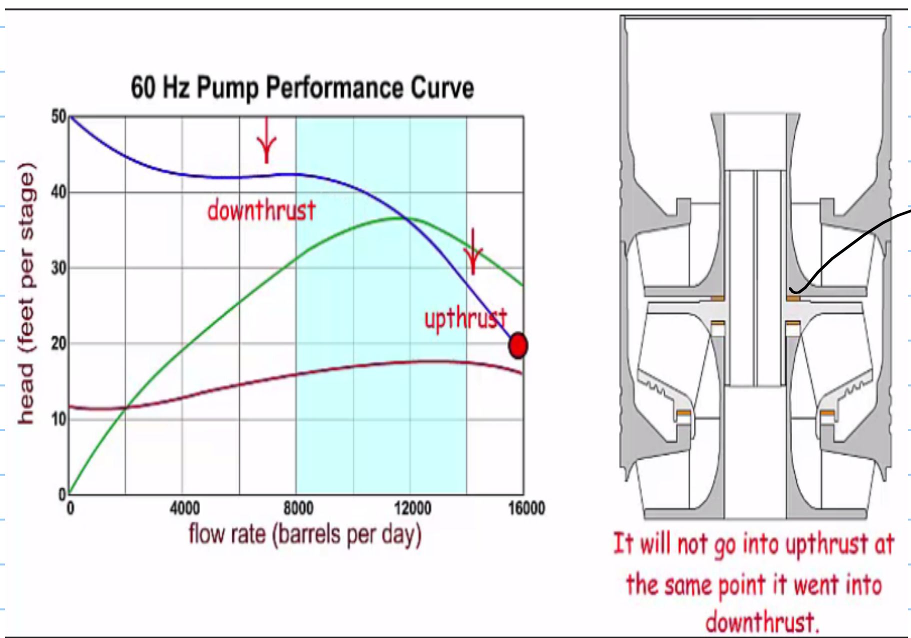
$$\Delta H = \left( a_4 \cdot \left(\frac{60\ hz}{f}\right)^4 \cdot q^4 + a_3 \cdot \left(\frac{60\ hz}{f}\right)^3 \cdot q^3 + a_2 \cdot \left(\frac{60\ hz}{f}\right)^2 \cdot q^2 + a_1 \cdot \left(\frac{60\ hz}{f}\right) \cdot q + a_0 \right) \cdot \left(\frac{f}{60\ hz}\right)^2 \cdot N_{stages}$$




downthrust

too much weight in the washer area

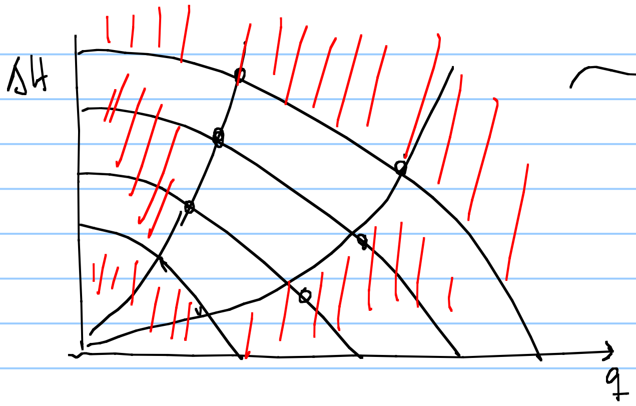
↳ failure



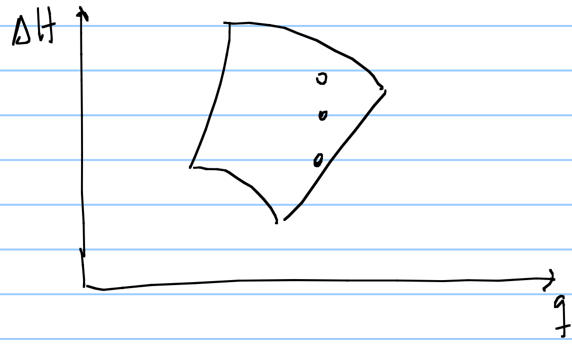

upthrust ~> wear, heating

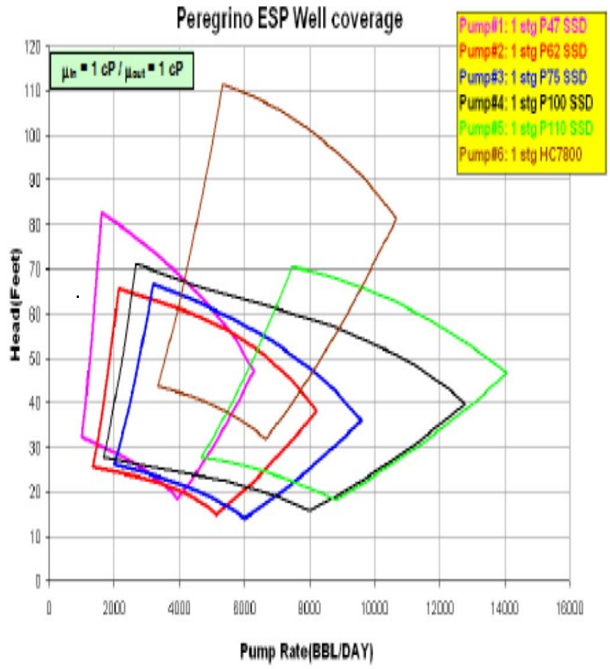
detrimental for the life of the ESP

$q_{min}$ and $q_{max}$ change with the rotational speed of the pump

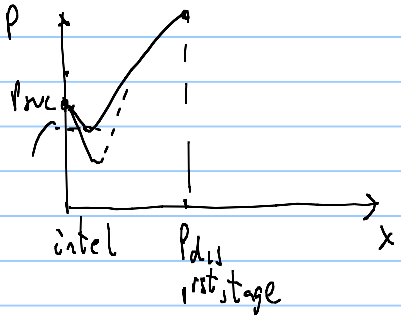



$$\frac{q_1}{q_2} = \frac{f_1}{f_2}$$



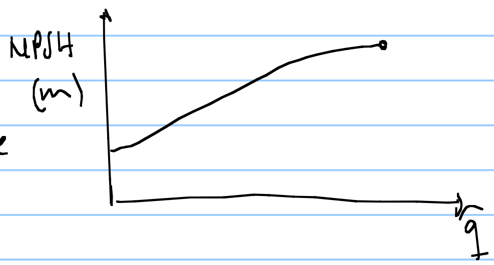

• $P_{suc} \geq P_{minimum}$ → avoid gas coming out of solution
→ avoid cavitation




x → fluid path along the pump

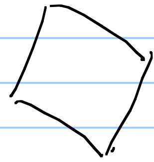
P has to be larger than $P_b$ of the fluid at that temperature

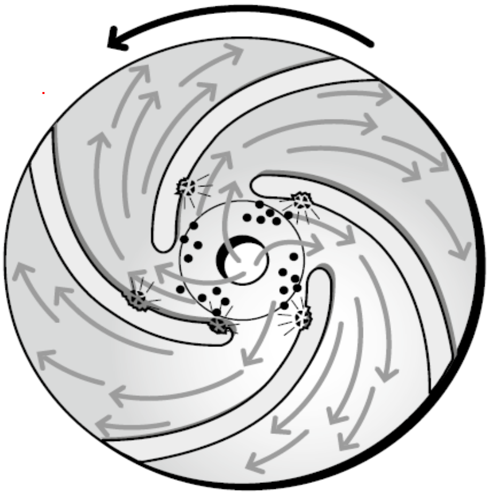
NPSH for each rate
(Net positive suction pressure



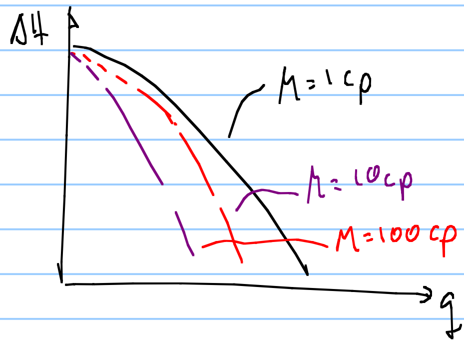
$$\left\{\begin{array}{l} q_{min}(t) \\ q_{max}(t) \\ f_{min} \\ f_{max} \\ P_{suc} \geq P_{min} \end{array}\right.$$

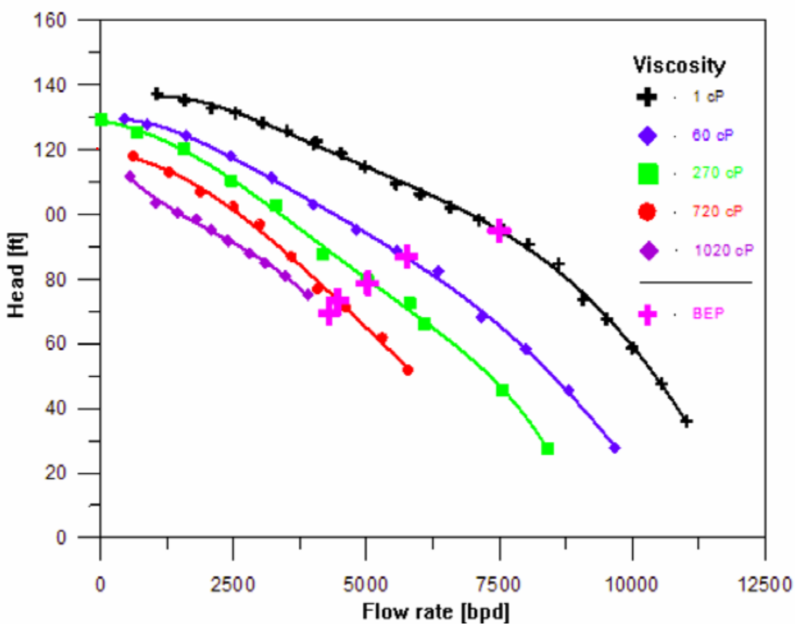
$P_{suc} \geq P_{min}$ { vaporization and cavitation





Performance of the pump for different viscosit






ANSI/HI 9.6.7-2010

American National Standard (Guideline) for

Effects of Liquid Viscosity on Rotodynamic (Centrifugal and Vertical) Pump Performance class examples → $P \leq 600\,hp$

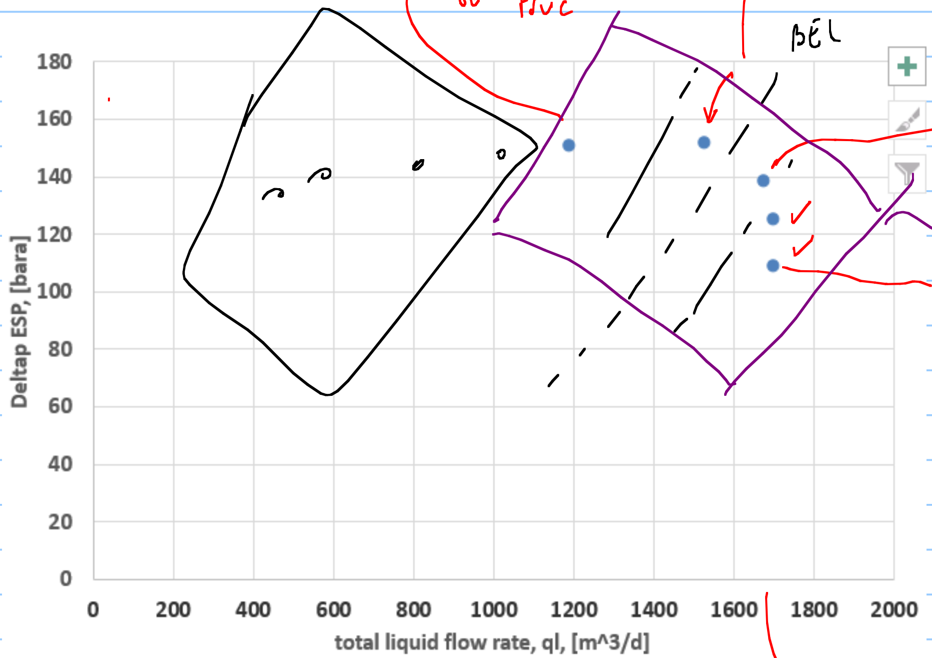
$P_{suc} \geq 31.5$ bara

rate reduction due to $P_{suc}$

rate reduction due to : power constraint
$P_{suc}$

rate reduction due to power constraint

BEL

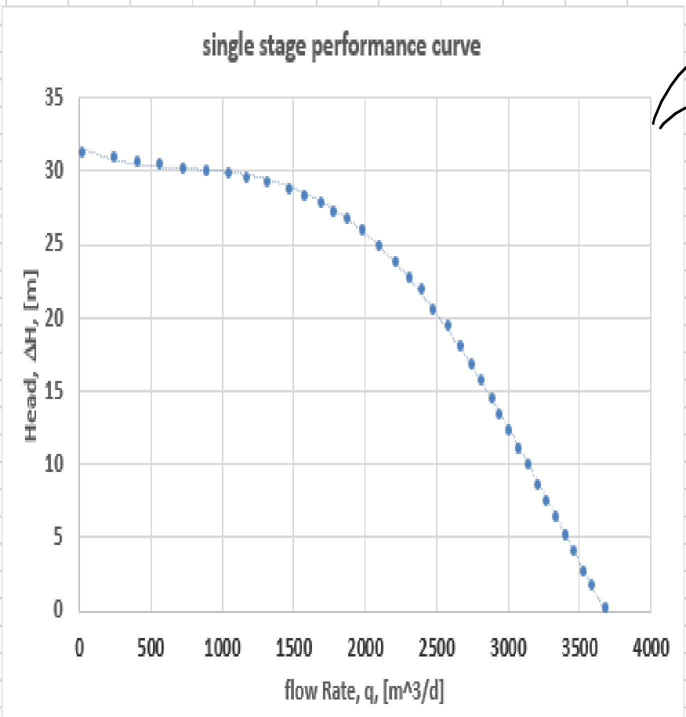



find a pump envelope such as all points fall inside the feasible area.

1700 m³/d

ESP model:

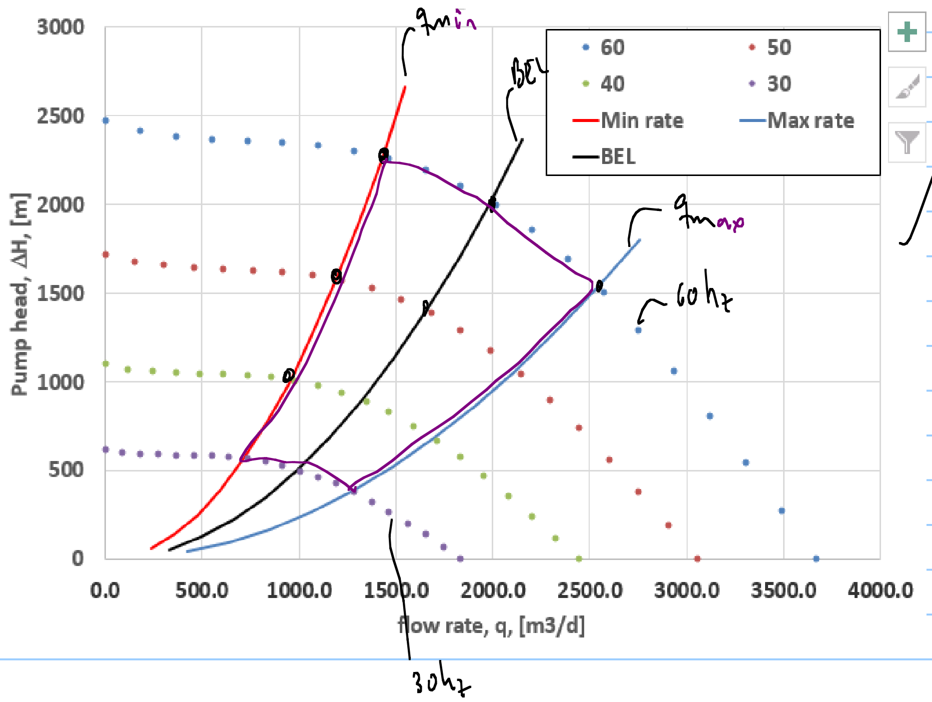
| flowrate [bbl/d] | flowrate [m^3/d] | head [ft] | head [m] |
|---|---|---|---|
| 107 | 17 | 103 | 31 |
| 1524 | 242 | 102 | 31 |
| 2566 | 408 | 101 | 31 |
| 3524 | 560 | 100 | 31 |
| 4524 | 719 | 99 | 30 |
| 5608 | 892 | 99 | 30 |
| 6545 | 1041 | 98 | 30 |
| 7358 | 1170 | 97 | 30 |
| 8254 | 1312 | 96 | 29 |
| 9213 | 1465 | 95 | 29 |
| 9921 | 1577 | 93 | 28 |
| 10630 | 1690 | 91 | 28 |
| 11193 | 1780 | 90 | 27 |
| 11756 | 1869 | 88 | 27 |
| 12464 | 1982 | 85 | 26 |
| 13194 | 2098 | 82 | 25 |
| 13903 | 2210 | 78 | 24 |
| 14529 | 2310 | 75 | 23 |
| 15050 | 2393 | 72 | 22 |
| 15572 | 2476 | 68 | 21 |
| 16197 | 2575 | 64 | 19 |
| 16761 | 2665 | 59 | 18 |
| 17220 | 2738 | 55 | 17 |
| 17679 | 2811 | 52 | 16 |
| 18138 | 2884 | 48 | 15 |
| 18492 | 2940 | 44 | 13 |
| 18910 | 3006 | 41 | 12 |
| 19327 | 3073 | 37 | 11 |
| 19744 | 3139 | 33 | 10 |
| 20183 | 3209 | 29 | 9 |
| 20537 | 3265 | 25 | 8 |
| 20934 | 3328 | 21 | 6 |
| 21351 | 3395 | 17 | 5 |
| 21727 | 3454 | 13 | 4 |
| [illegible] | [illegible] | [illegible] | [illegible] |



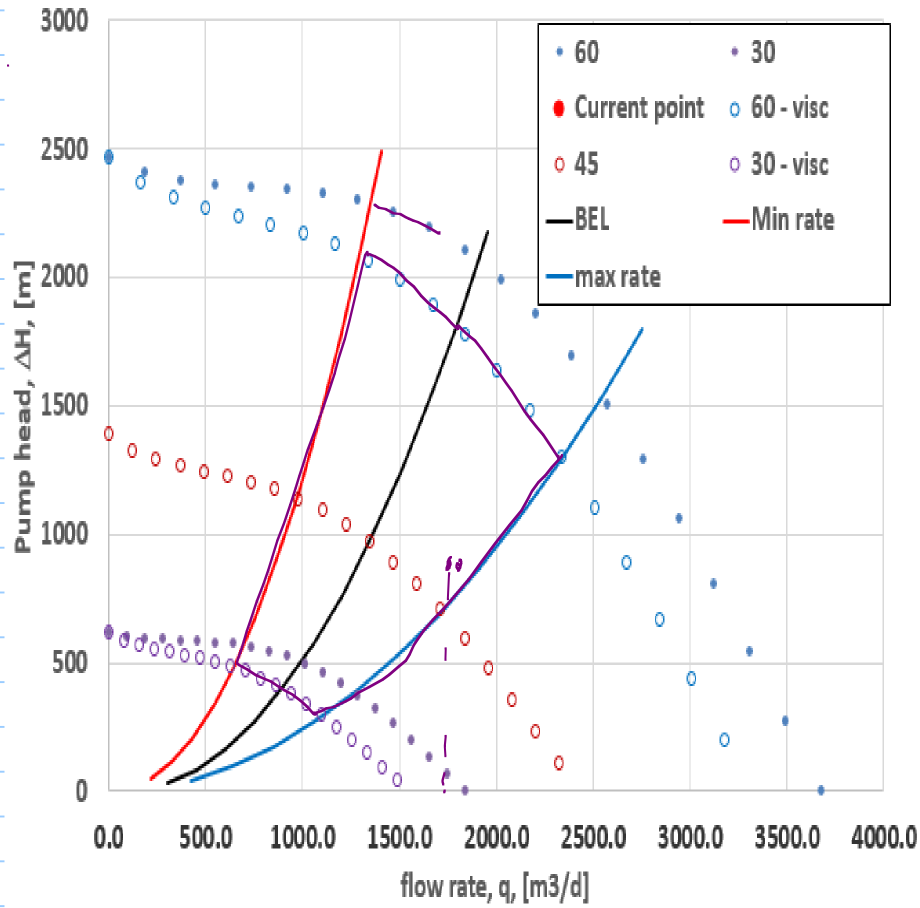

water
single stage.
$f = 60\,hz$

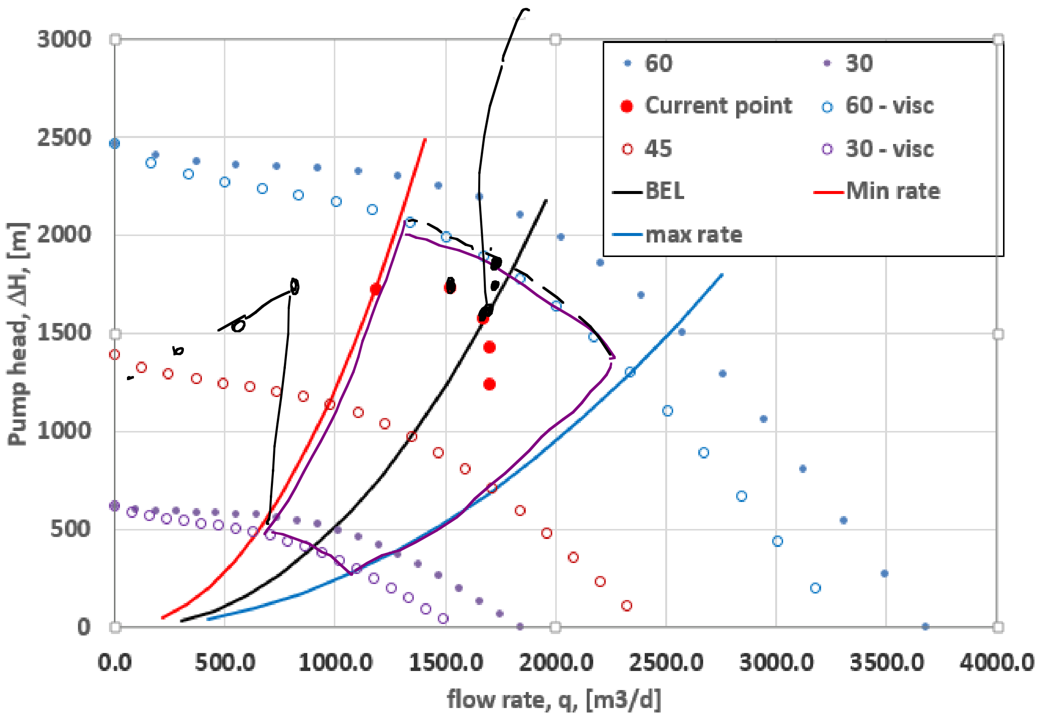
$$y = \underbrace{4.24658E\text{-}13}_{a_4}x^4 - \underbrace{3.62657E\text{-}09}_{a_3}x^3 + \underbrace{6.64204E\text{-}06}_{a_2}x^2 - \underbrace{5.13919E\text{-}03}_{a_1}x + \underbrace{3.16938E{+}01}_{a_0}$$

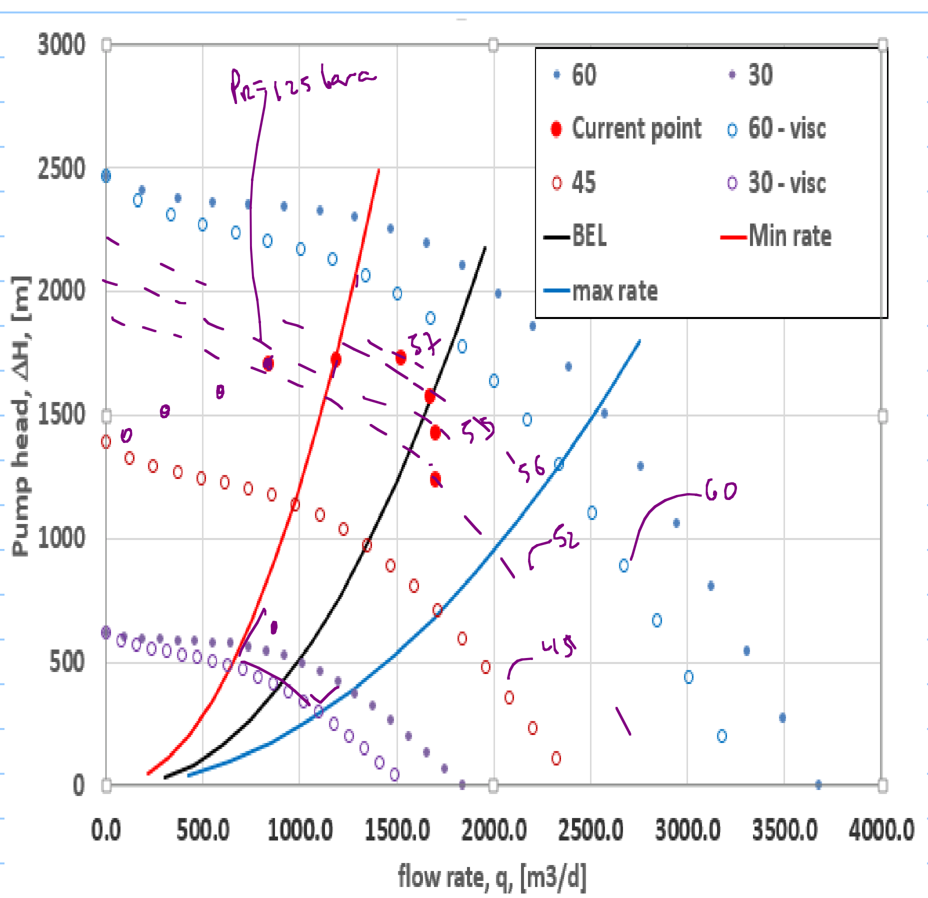
water, 38 stages

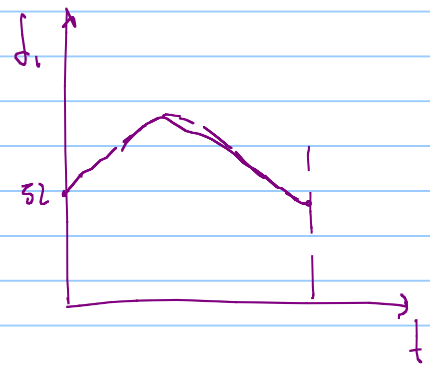



performance curves corrected by viscosity = 100 cp






NOTE: $P_{wh} \leq P_b$ probably gas coming out of solution at some position in the tubing. We are neglecting this gas !

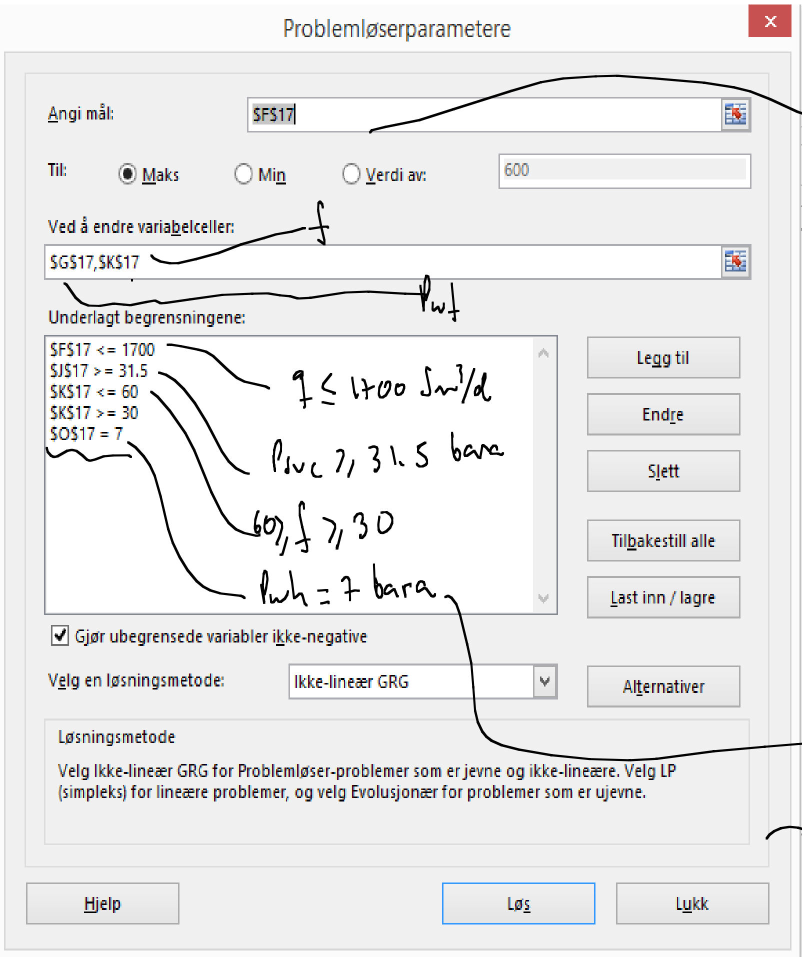
$2^{nd}$ approach : include the pump model in my hydraulic calculator

Calculation proposal co-current from bottom-hole to wellhead

check is $P_{wh,cal} = 7$ bara? if not → try new rate

if yes → stop calculation

Case 1 : finding f to get a certain rate and honouring operational constraints




max liquid rate

f

$P_{wf}$

$q \leq 1700\ Sm^3/d$

$P_{svc} \geq 31.5$ bara

$60 \geq f \geq 30$

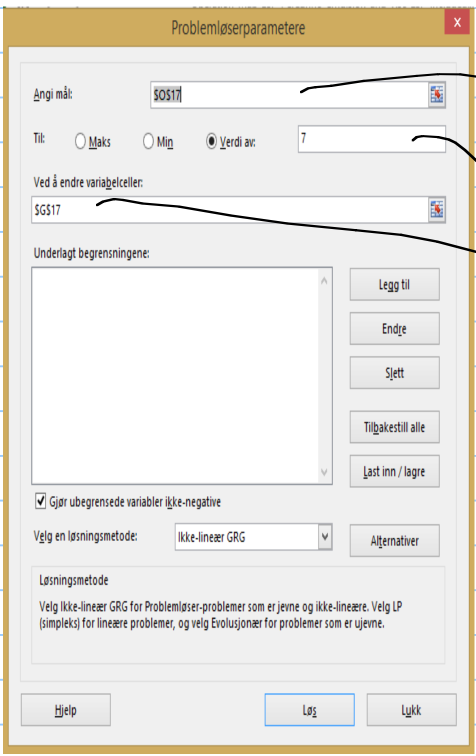
$P_{wh} = 7$ bara

closes the hydraulic equilibrium

solving the hydraulic equilibrium.

$\eta = a_4 q^4 + a_3 q^3$


Case 2 fixing f, find equilibrium rate




$P_{wh}$

7 bara

$P_{wf}$

Summarizing

1: approach : without pump ESP out of the system.

$q_L$ given by reservoir engineer

calculated $P_{DIS}$, $P_{SUC}$

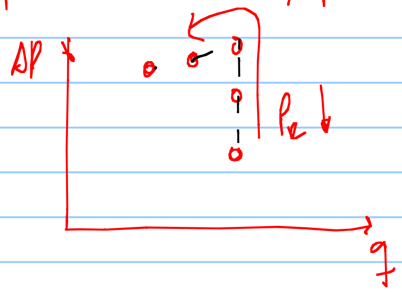
$$\left\lbrace \begin{array}{l} \dfrac{q \cdot \Delta P}{\eta} \leq P_{max} \\ P_{suc} \geq P_b \cdot F_s \end{array} \right.$$

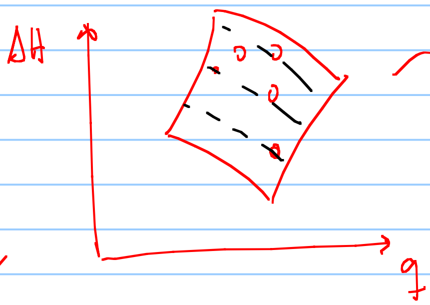
power

cavitation

OBS! we made a mistake, P should have been a bit higher than 600 hp

found that rate had to be reduced due to power limitations, $P_{suc}$ limitations




pump plot given by ESP specialist

↳ correction by Nstages

by frequency

by viscosity

the pump can provide the operational conditions that were estimated ✓ !!

2nd approach: there is an ESP model built in in the production simulator.

find f such as $P_{wf}$ →

$$\left\lbrace \begin{array}{l} q = 1700 \; Sm^3/d \\ P_{suc} \geq 31.5 \text{ bara} \\ P_{wh} = 7 \text{ bara} \\ q_{min} \leq q \leq q_{max} \\ 30 \leq f \leq 60 \text{ hz} \end{array} \right\rbrace$$

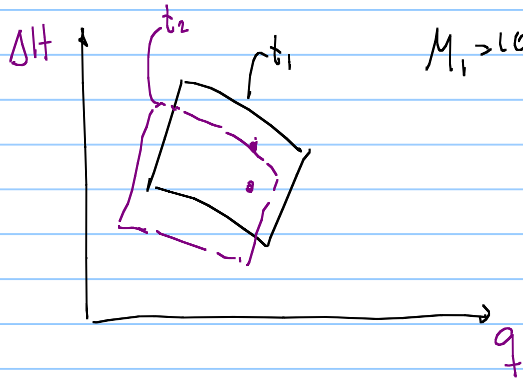
we have to use the solver

| Operational limits | |
|---|---|
| Frequency [Hz] | 60 |
| Min rate [m3/d] | 1302 |
| Max rate [m3/d] | 2314 |

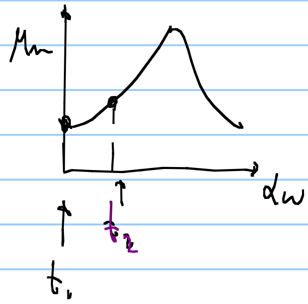
for a $\mu = 100\,cp$

$$\frac{q_{min@f}}{1302} = \frac{f}{60} \qquad q_{max@f} = \left(\frac{f}{60\,Hz}\right) \cdot 2314$$

Problems with the graphical method : pump operational envelope changes with viscosity




$\mu_1 > 100\,cp$

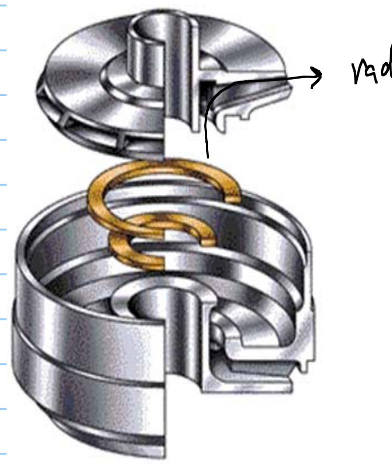


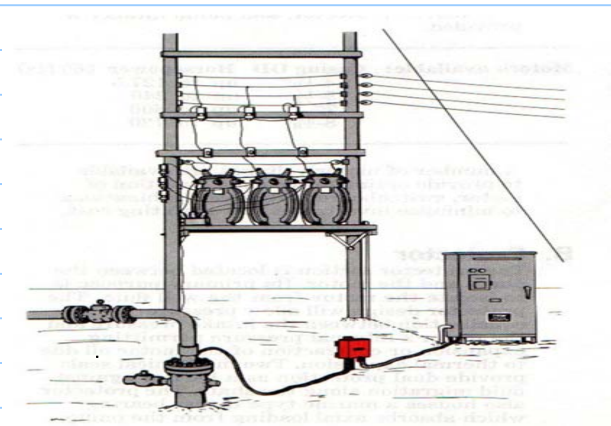

Problem with the analytical methods : it might be difficult for solver to find a feasible solution with all the constraints

//

mixed impeller
axial and radial

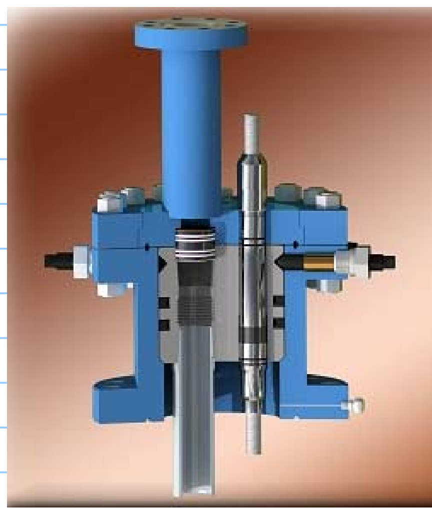
radial





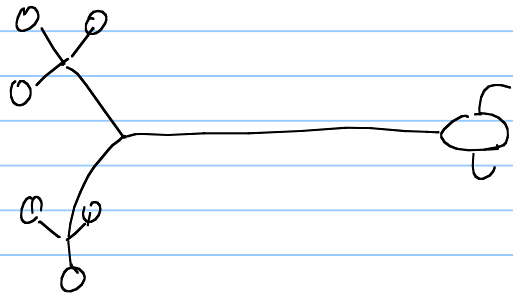
high GVF application
GVF $\lesssim 30\%$

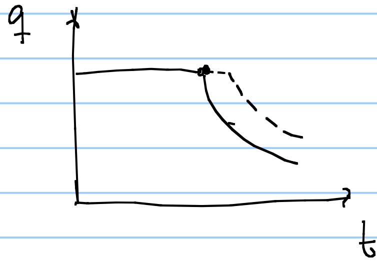
low GVF application
GVF $\lesssim 10\%$



ways to prolong plateau :

- increase the available pressure. ⇝ $P_{wh}$ (use methods)
- decrease the required pressure ⇝ $P_{wh}$






methods to increase the available pressure :

- Pressure support methods : maintain reservoir pressure
  - injection of water \$
  - injection of gas \$
- Improve reservoir deliverability ⇝
  - acidizing
  - injecting chemical to improve permeability of near wellbore region

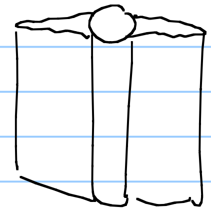
\$

$$q = J\,(P_R - P_{wf})$$

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

increase $J, C_R$

• fracturing



$

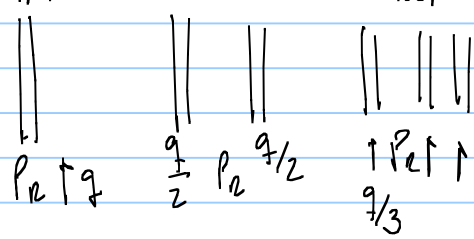
• well completion, • multilateral well
• ICV
• ICD

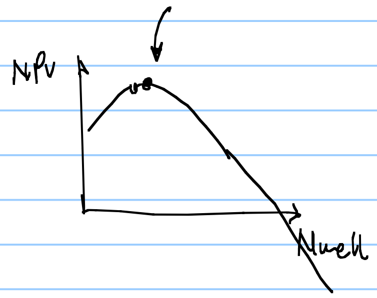
• tubing : increase the size of the tubing

install artificial lift : ESP, foam sticks,
gas lift, plunger lift,
rod pump,
jet pump,
PCP,

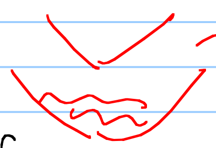
• inject diluent ⇝ High API crude to reduce the viscosity of the formation oil.

• increase the number of wells ⇝



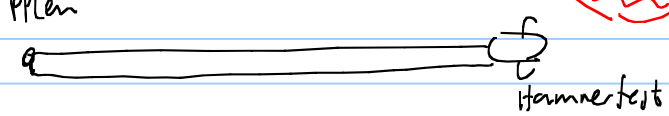




• seabed: bigger flowlines and pipelines
parallel flowline and pipeline
OBS ∇ gas and liquid production, if I increase the diameter of flowline

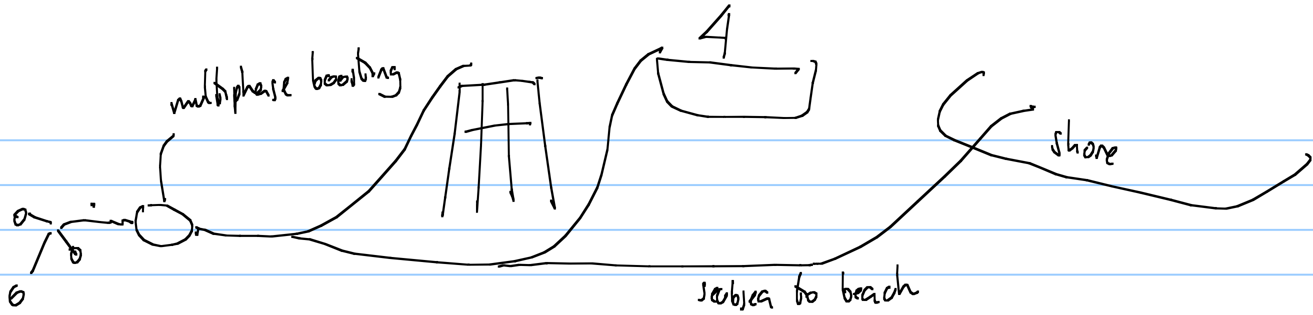


— bigger pipe ⇝ less gas velocity
↳ accumulation of liquid

P↓
$q_g$↑
$V_g$↑ — friction ↑ ⇝ Δp friction ↑

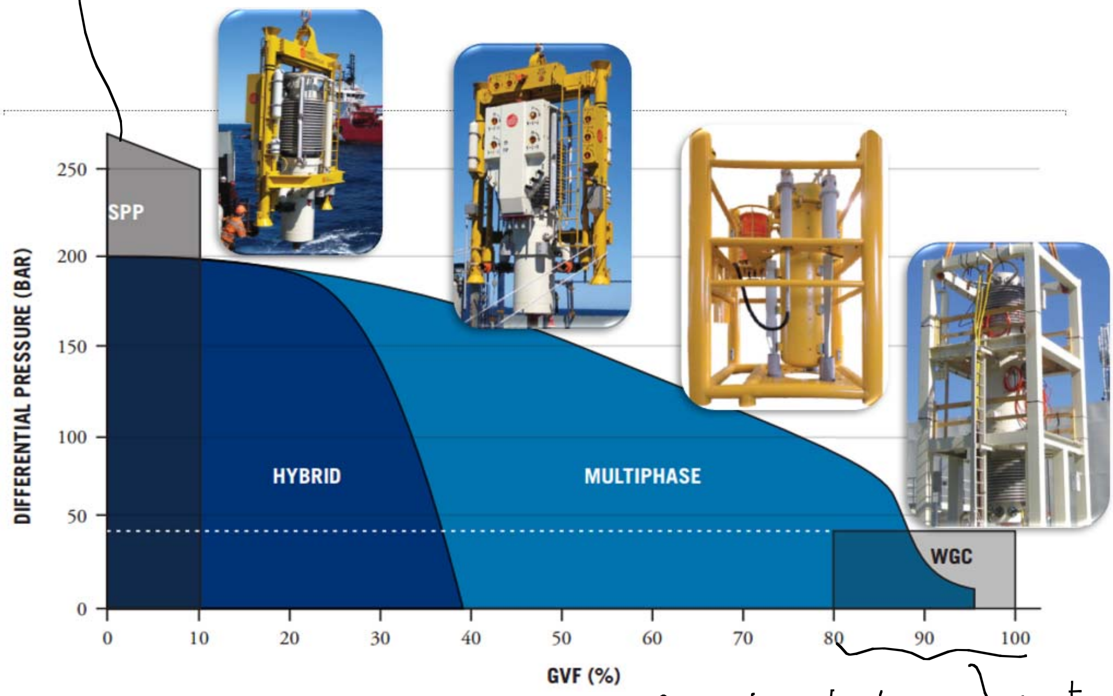



• subsea boosting and compression




one limitation is power transportation.

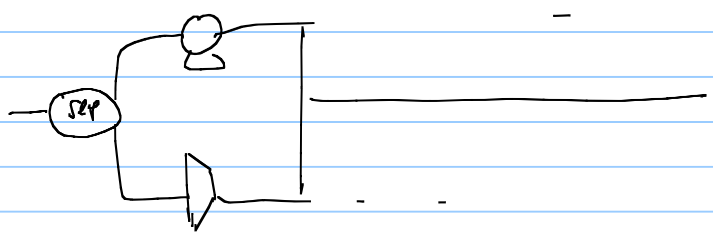
single phase pumps




Gas volume fraction

wet gas compression

subsea separation + single phase boosting.



Note Title 04.04.2016

Short session 04.04.2016 :

Cont. Production enhancement techniques :

↳ Subsea processing ⟶ perform processing
- ↳ sep oil, gas, water subsea
- ↳ water processing disposal
- ↳ gas treatment and reinjection
- ↳ more....

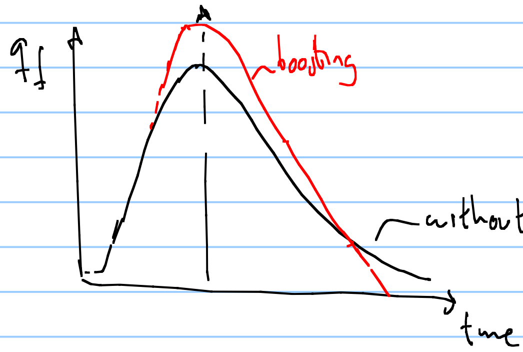
advantages
- mitigate flow assurance
- reduce or eliminate unnecessary transportation of fluids (water) reduces back-pressure.
- allows to implement single phase boosting ⟶ liquid
  ↳ gas

↳

→ reduce separator pressure (First stage high pressure separator)

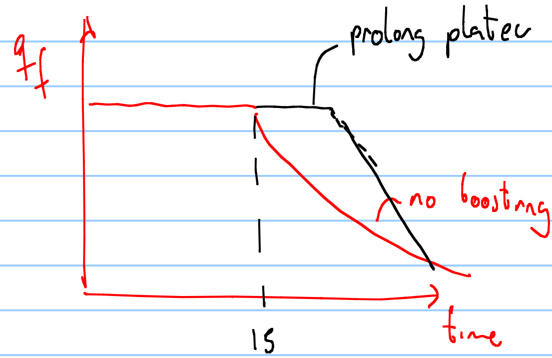
Lower sep pressure
Snøhvit 2020

Prod mode B




include booster in the field design phase

Prod mode A

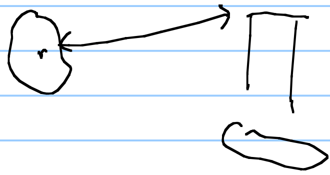



booster engineering and logistics can be delayed in time.

↳

Subsea boosting → advantages:

↳ compressors



- Increase production / maintain
- increase tie-back distances
- multiphase boosting: no need for pre-separation of fluids
- real state is cheap subsea than topside.
- low cost compared with other production enhancement alternatives.

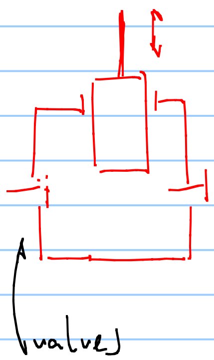
disadvantages

- cost of units, deployment, modification of existing production system
- maintenance (accessibility, cost ↑, reliability)
- multiphase: uncertainty on the performance

in general, there are two boosting principles:

**positive displacement**

formation of cavities that carry the fluid from inlet to outlet




twin-screw pumping

**rotordynamic** (hydrodynamic booster)

it is constituted by a stage

- impeller
- diffuser

Sequence:

1: accelerate the fluid in the impeller → increase $E_K$ kinetic energy

2: Change kinetic energy $E_K$ to potential energy (pressure)

$\circ_1$ $\circ_2$ $P_2 > P_1$ $V_2 < V_1$

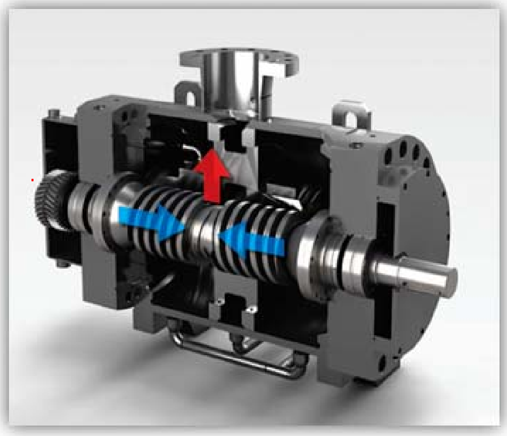
- low rates than hydrodynamic pumps
- $\Delta p$ higher than hydrodynamic pump
- slightly affected by $\mu$
- needs some liquid for cooling (not goog for high GVFs)
- doesn't tolerate solids (sand)

GVF

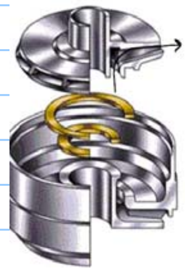
0 pure liquid

1 pure gas

90%

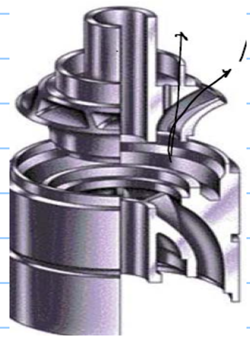


radial impeller



GVF < 10%

mixed flow impeller



GVF < 30%

axial impeller

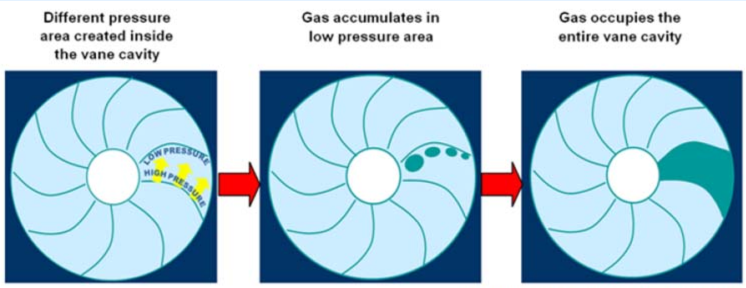
0 < GVF < 1

$\Delta p_{axial} << \Delta p_{radial}$, $\Delta p_{mixed}$

GVF

0

1



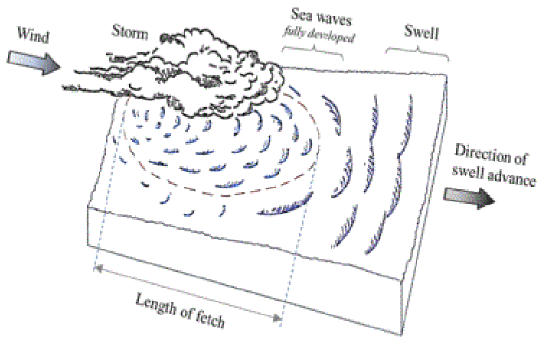
(Courtesy of Schlumberger)

(a) Impeller

(b) Diffuser

multiphase pumping: helico-axial pump

HAP




# Introduction to Offshore Structures with focus on Marine Dynamics

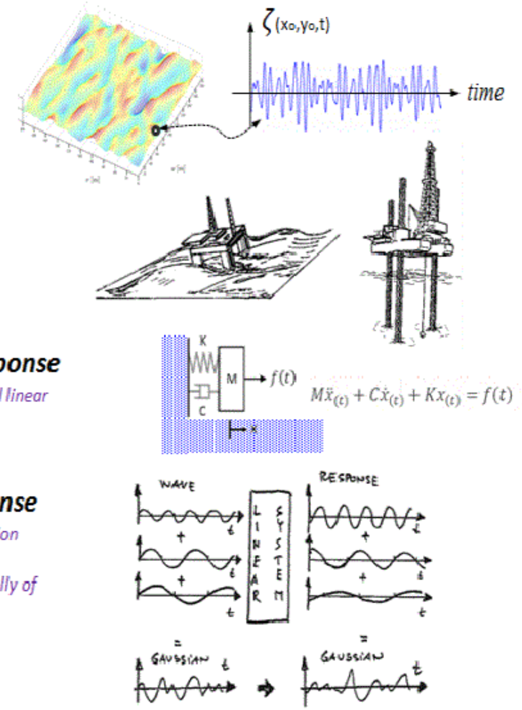
Jesus De Andrade
April, 2016

**Statistics of waves**
Wave surface elevation
Wave spectrum (Hs, Tp)

**Calculation of hydrodynamic loads**
Fluid-structure interaction

**Dynamic analysis response**
For practical purposes considered linear

**Statistics of the response**
Verification of design and operation according to rules
Ordinary gravity wave-wind usually of interest (period 4-24s)

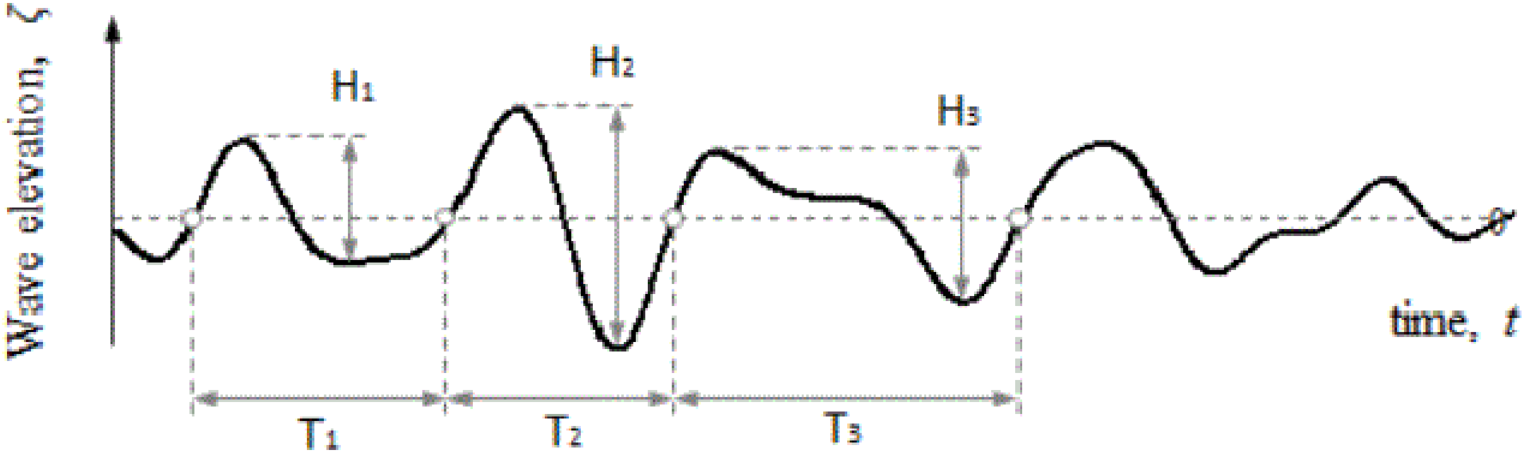


# Cases that show how not to do it

The Mars TLP after the hurricane Katrina

Typhoon upside down after hurricane Rita

# Waves statistics / Short-term




○ Zero-upcrossings

$H_1, H_2, H_3$ ...individual wave heights

$T_1, T_2, T_3$ ...corresponding zero-upcrossings periods

$$T_z = \frac{1}{N}\,(T_1 + T_2 + T_3 + \cdots + T_N) \tag{9}$$

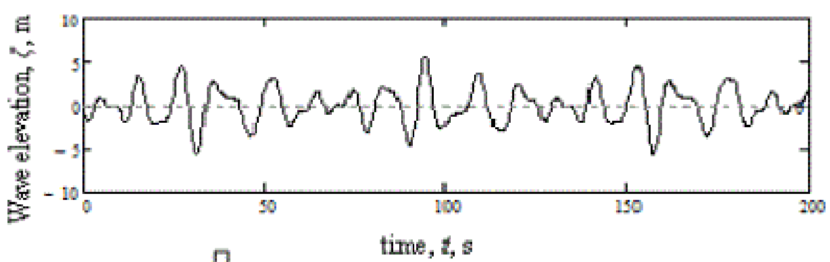
$$H_{mean} = \frac{1}{N}\,(H_1 + H_2 + H_3 + \cdots + H_N) \tag{10}$$

# Waves statistics / Short-term

- Distribution of wave surface elevation

$$T_z = \frac{1}{N}\,(T_1 + T_2 + T_3 + \cdots + T_N) \tag{9}$$

$$H_{mean} = \frac{1}{N}\,(H_1 + H_2 + H_3 + \cdots + H_N) \tag{10}$$

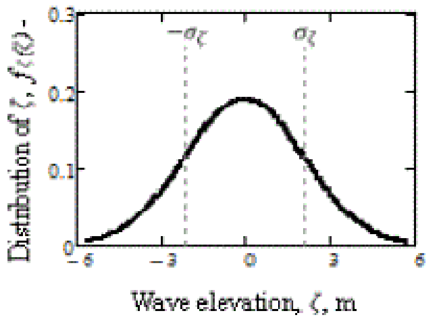



$$\zeta(t) = \sum_{i=1}^{N} \zeta_{ai} \sin(\omega_i t + \varepsilon_i)$$

Mean: $\mu = \dfrac{\int_0^{t_{final}} \zeta(t)dt}{t_{final}} = \dfrac{1}{N}\sum_{i=1}^{N} \zeta_i \approx 0$

Variance: $\sigma_\zeta{}^2 = \dfrac{1}{N}\sum_{i=1}^{N}(\zeta_i - \mu)^2 = \dfrac{1}{2}\sum_{i=1}^{N}(\zeta_{ai})^2$

$\sigma_\zeta$... standard deviation




Probability density function of wave elevation (Gaussian):

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

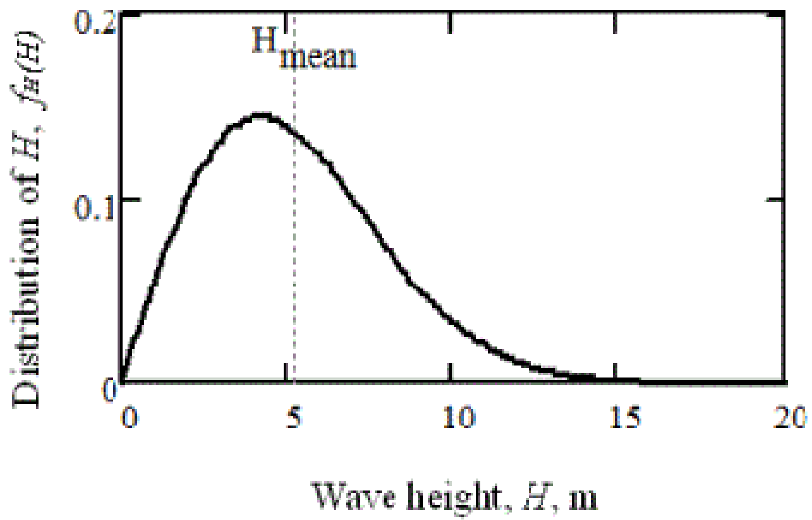
**Fig. 8.** Wave surface elevation normally distributed (Gaussian).

# Waves statistics / Short-term

- Distribution of Wave Height

**Rayleigh distribution**, which can be written as:

$$f_H(H) = \frac{H}{4\sigma_\zeta{}^2} exp\left[-\left(\frac{H}{\sigma_\zeta\sqrt{8}}\right)^2\right] \tag{11}$$




The mean and variance of wave height can now be expressed as follow:

$$H_{mean} = \frac{\int_0^\infty H\, f_H(H)\, dH}{\int_0^\infty f_H(H)\, dH} = \int_0^\infty H\, f_H(H)\, dH$$

$$\sigma_H{}^2 = \int_0^\infty (H - H_{mean})\, f_H(H)\, dH$$

# Waves statistics / Short-term

- Distribution of Wave Height

From statistics, the probability for the stochastic variable wave height $H$ is lower that certain value $H'$ is given by:

$$P(H < H') = \int_0^{H'} f_H(H)\,dH = F_H(H') = 1 - exp\left[-\left(\frac{H'}{\sigma_\zeta\sqrt{8}}\right)^2\right] \qquad (14)$$

Where $F_H(H)$ is the **cumulative distribution function** (cdf) for the wave height. Fig. 10 provides an example of probability density function $f_H$ and cumulative distribution function $F_H$ for the wave height of the wave record in Fig. 8. For example, in the figure it can be seen that less than 75% of the waves will have wave heights lower than approximately 7m, or one could say that the probability of exceeding 7m wave height is 25%.

# Waves statistics / Short-term

- Distribution of Wave Height

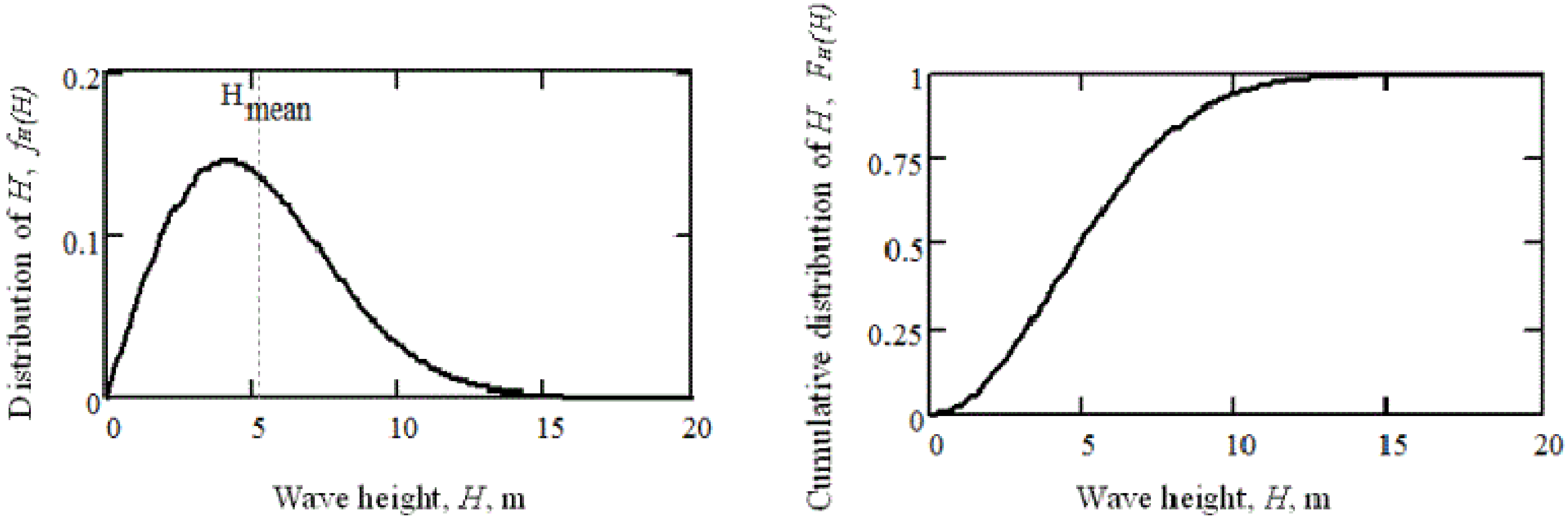



**Fig. 10.** Probability density function $f_H$ (Rayleigh distribution) and cumulative distribution function $F_H$ for the wave height of certain sea state.

# Waves statistics / Short-term

- Distribution of Wave Height

At this instant, it is also convenient to bring up the definition of **significant wave height**, $H_s$, $H_{m0}$ or $H_{1/3}$, which is defined as the average of the highest 1/3 of the waves in the record. Hence, according to Fig. 11, the $H_s$ is provided by:

$$H_s = \frac{\int_{h_{1/3}}^{\infty} H f_H(H)\, dH}{\int_{h_{1/3}}^{\infty} f_H(H)\, dH} = \frac{\int_{h_{1/3}}^{\infty} H \frac{H}{4\sigma_\zeta^2} exp\left[-\left(\frac{H}{\sigma_\zeta\sqrt{8}}\right)^2\right] dH}{1/3} \tag{15}$$

$$h_{1/3} = 4\,\sigma_\zeta \sqrt{\frac{\ln(3)}{2}} \tag{16}$$

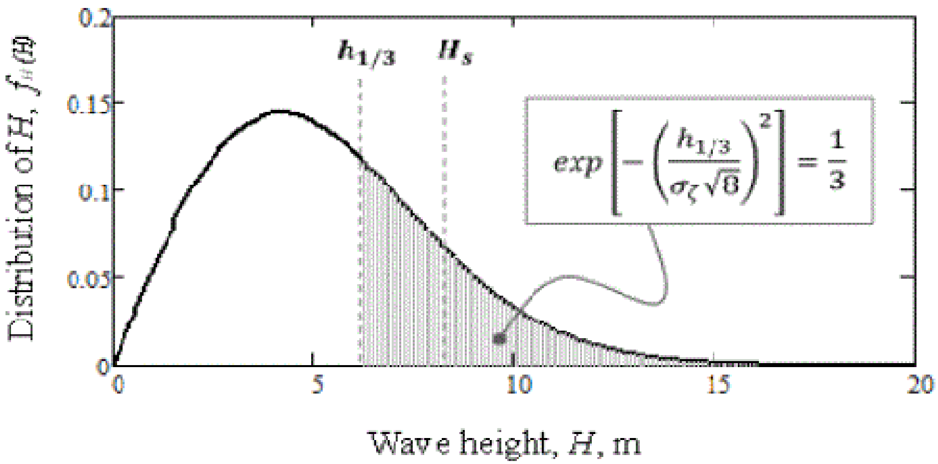


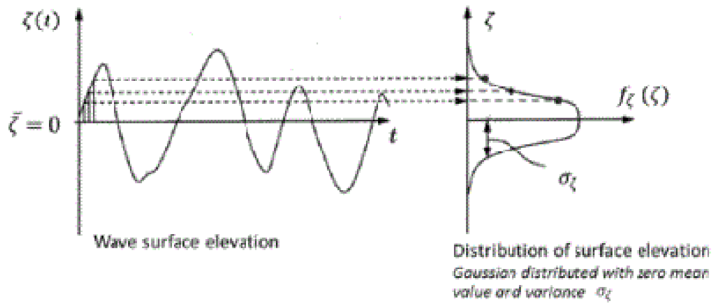

**Fig. 11.** Probability density function $f_H$ (Rayleigh distribution) and significant wave height of a certain sea state.

- **Exercise**

Short-term statistics

**Ex. 2 Wave energy spectrum and time domain wave record**

The total surface elevations in the previous Ex 1 is assumed to be Gaussian distributed, which means that the expected mean value will be zero and the variance equal to $\sigma_\zeta^2$, and they are considered to be constant during the whole time interval. This is illustrated in the figure below.




Tasks:
Using the data of wave surface elevation for time steps from 0,1,2…300s, find:

- Statistical calculations:
  1. The mean value of wave surface elevation, $\bar{\zeta}$
  2. The variance of the surface elevation, $\sigma^2{}_\zeta$
  3. The limit of the highest 1/3 of wave heights, $h_{1/3}$
  4. The significant wave height, $H_s$

- Distributions:
  1. Probability density function of wave elevations, $f_\zeta(\zeta)$ (Gaussian distribution)
  2. Probability density function of wave heights, $f_H(H)$ (Rayleigh distribution)
  3. Cumulative distribution function of wave heights, $F_H(H)$

Useful equations:

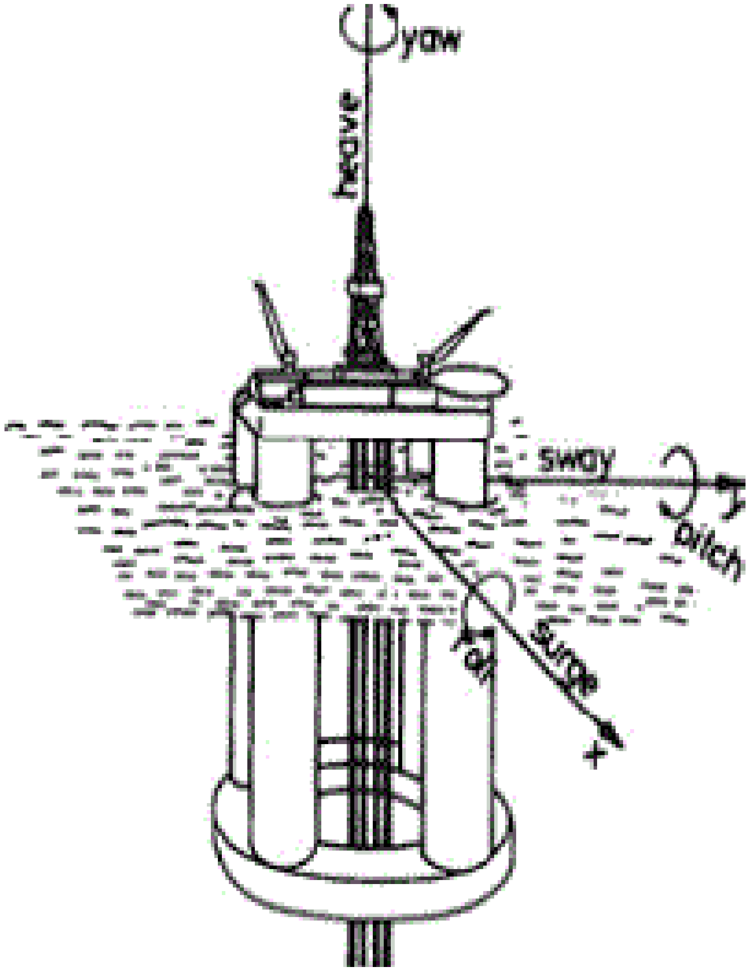
$$H_s = 4\,\sigma_\zeta \qquad h_{1/3} = 4\,\sigma_\zeta\sqrt{\frac{\ln(3)}{2}}$$

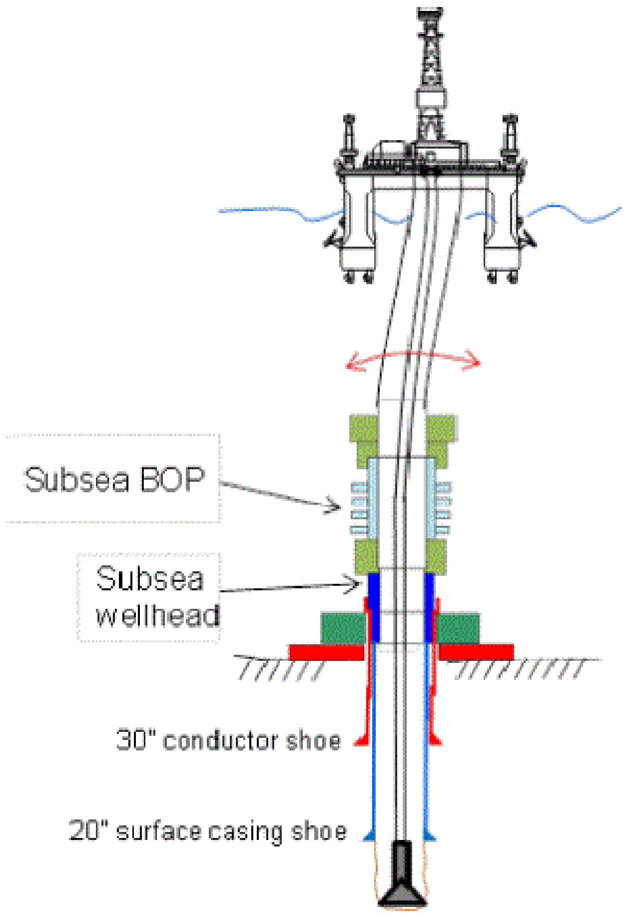
$$f_\zeta(\zeta) = \frac{1}{\sigma_\zeta\sqrt{2\pi}}exp\left[-\left(\frac{\zeta}{\sigma_\zeta\sqrt{2}}\right)^2\right]$$

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

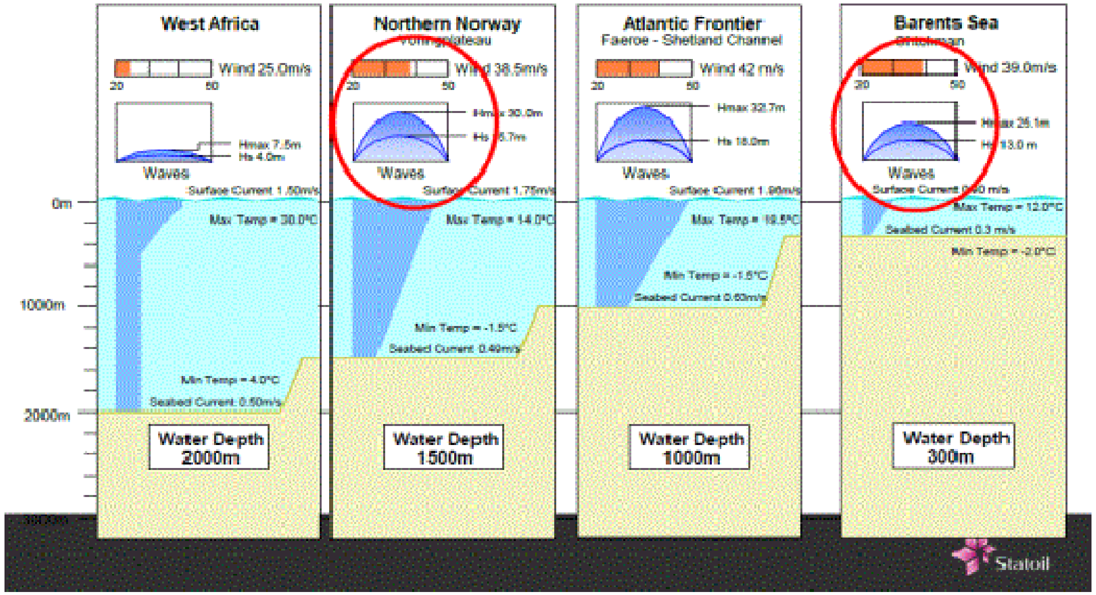
$$F_H(H) = 1 - exp\left[-\left(\frac{H}{\sigma_\zeta\sqrt{8}}\right)^2\right]$$

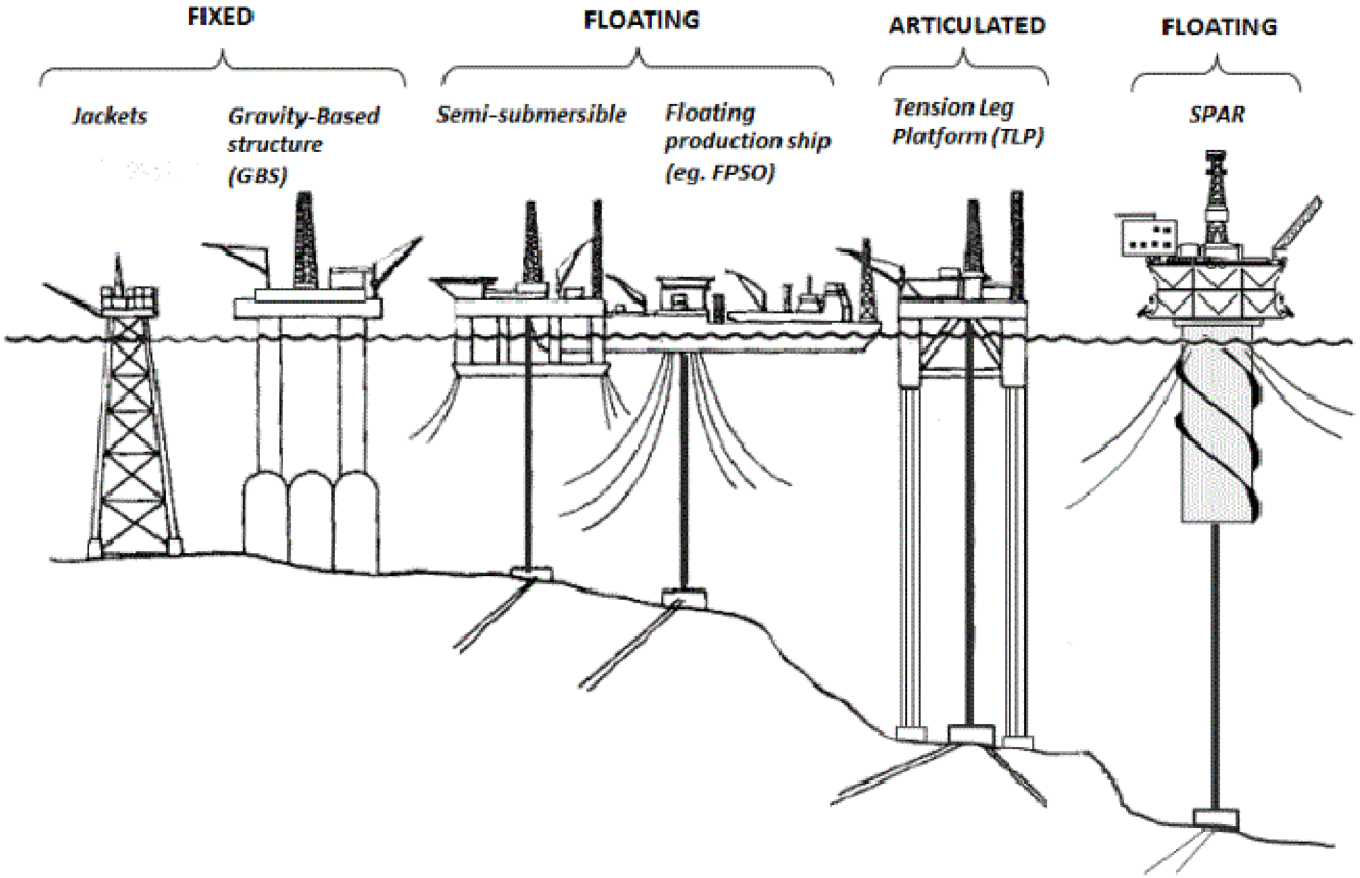
# Motion of marine structures



# Waves, wind and current comparable with Norway




FIXED
FLOATING
ARTICULATED
FLOATING
Jackets
Gravity-Based structure (GBS)
Semi-submersible
Floating production ship (eg. FPSO)
Tension Leg Platform (TLP)
SPAR

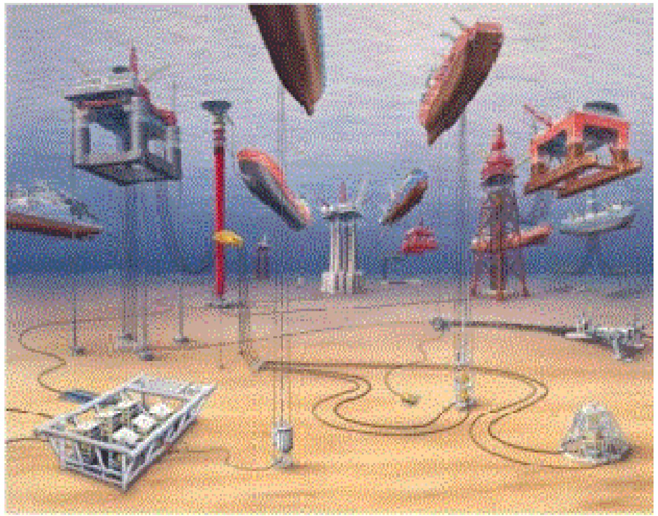
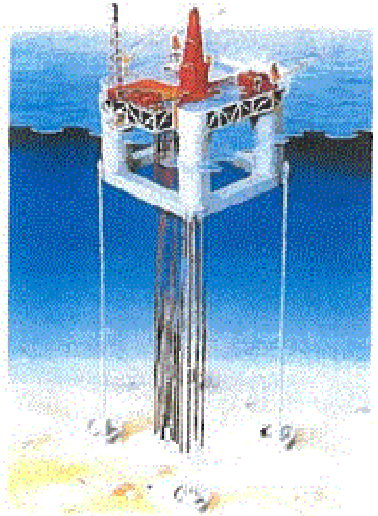
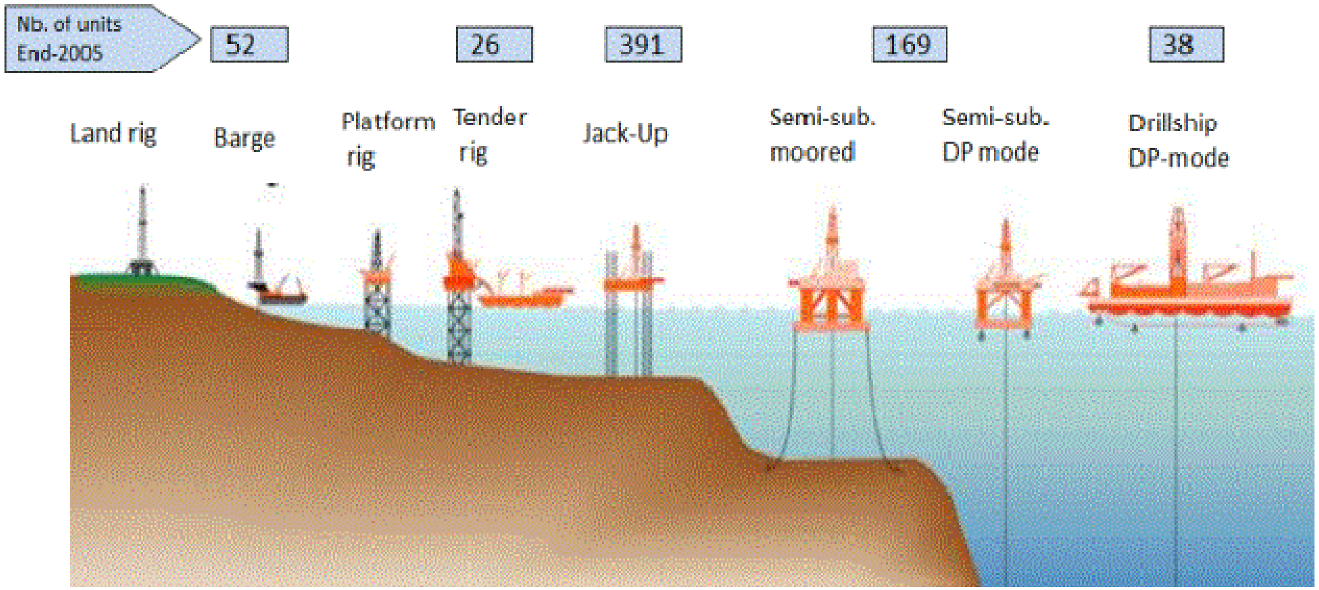




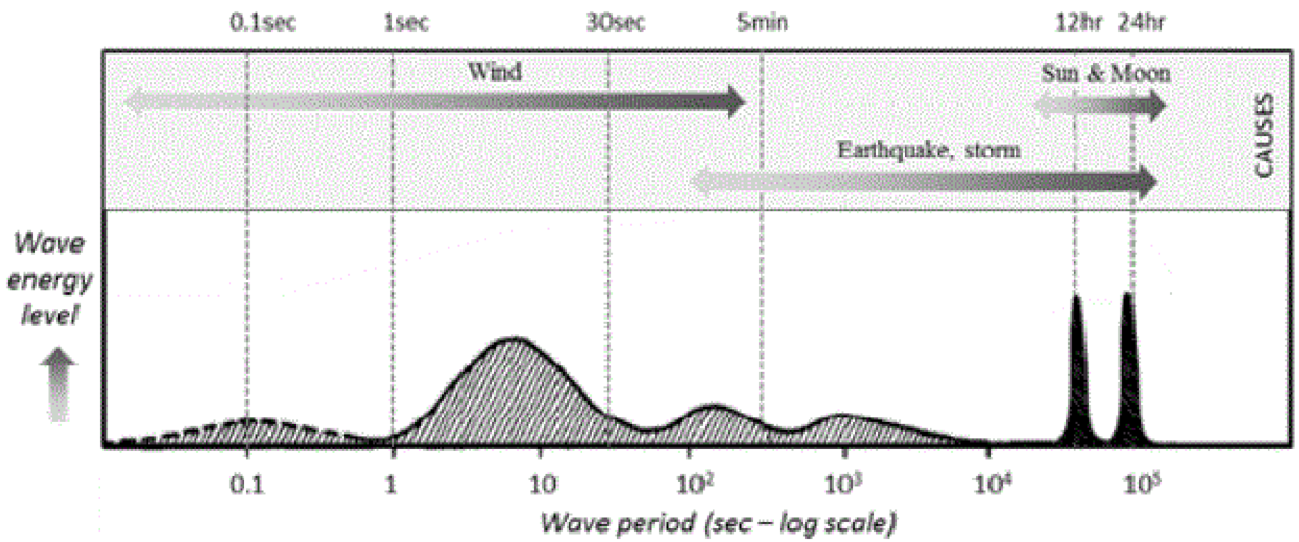
**Table 1.** Examples of offshore structures in the NCS for different water depths.

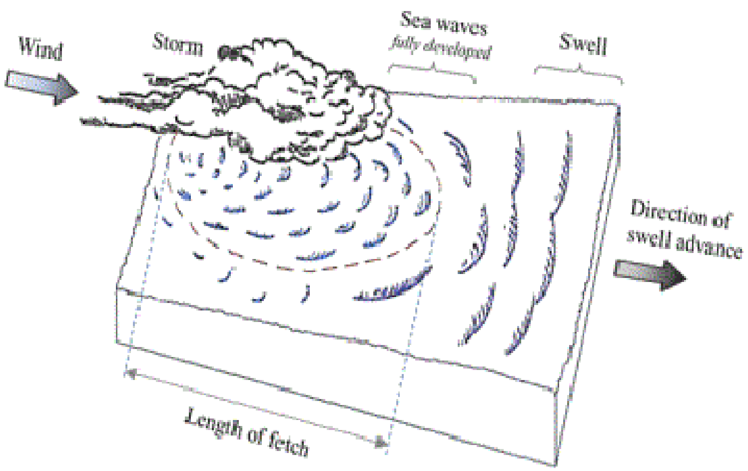
| Water depth | Field | Offshore structure |
|---|---|---|
| 70-75 mts | Ekofisk | Jackets |
| 120-130 mts | Balder | FPSO |
| 130-250 mts | Gullfaks | Concrete fixed facilities and steel topside |
| 300 mts | Troll | Concrete fixed facilities and steel topside |
| 300 mts | Åsgard B | Semi-submersible platform |
| 300-350 mts | Snorre | TLP steel platform |
| 370 mts | Kristin | Semi-submersible platform |
| 1300 mts | Luva* | Spar platform |

**Future field development*

## RIG TYPES


Nb. of units
End-2005
52
26
391
169
38
Land rig
Barge
Platform rig
Tender rig
Jack-Up
Semi-sub. moored
Semi-sub. DP mode
Drillship DP-mode



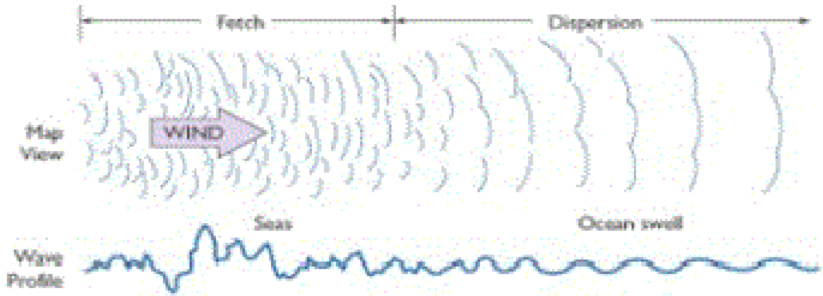
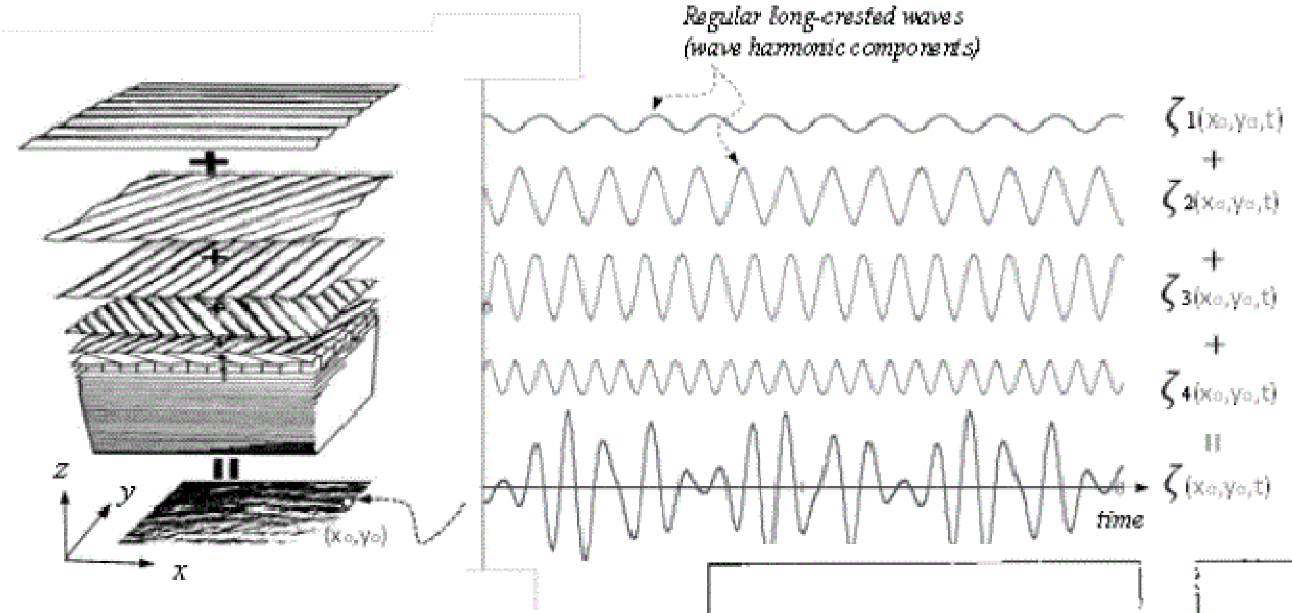
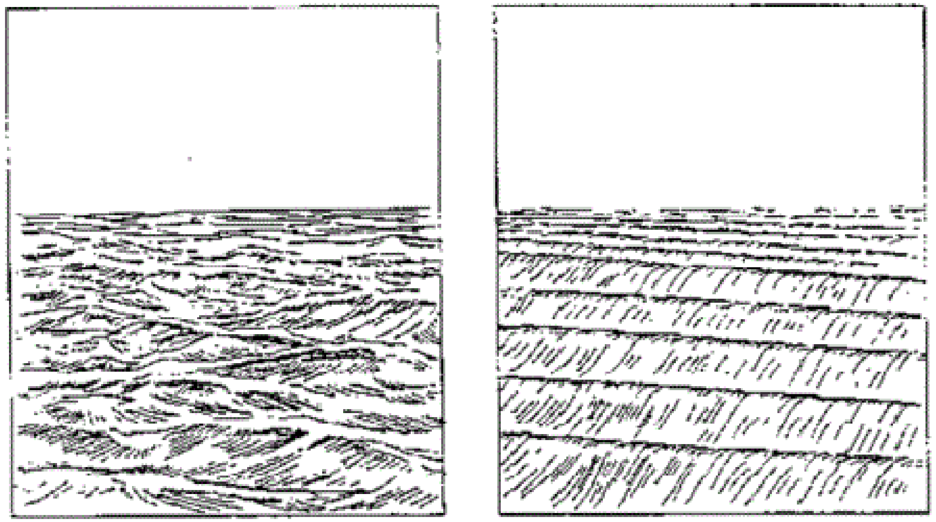
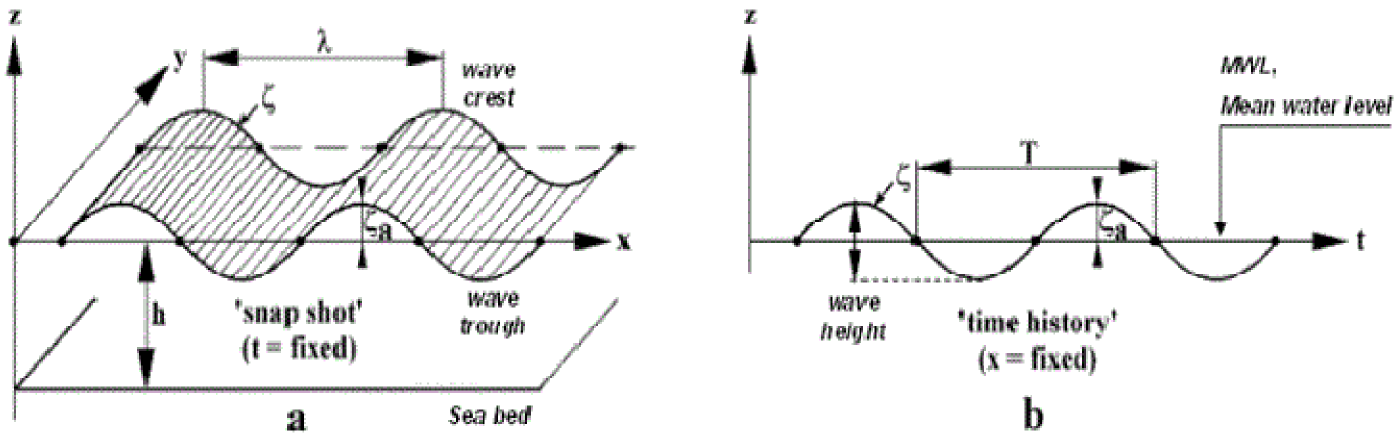
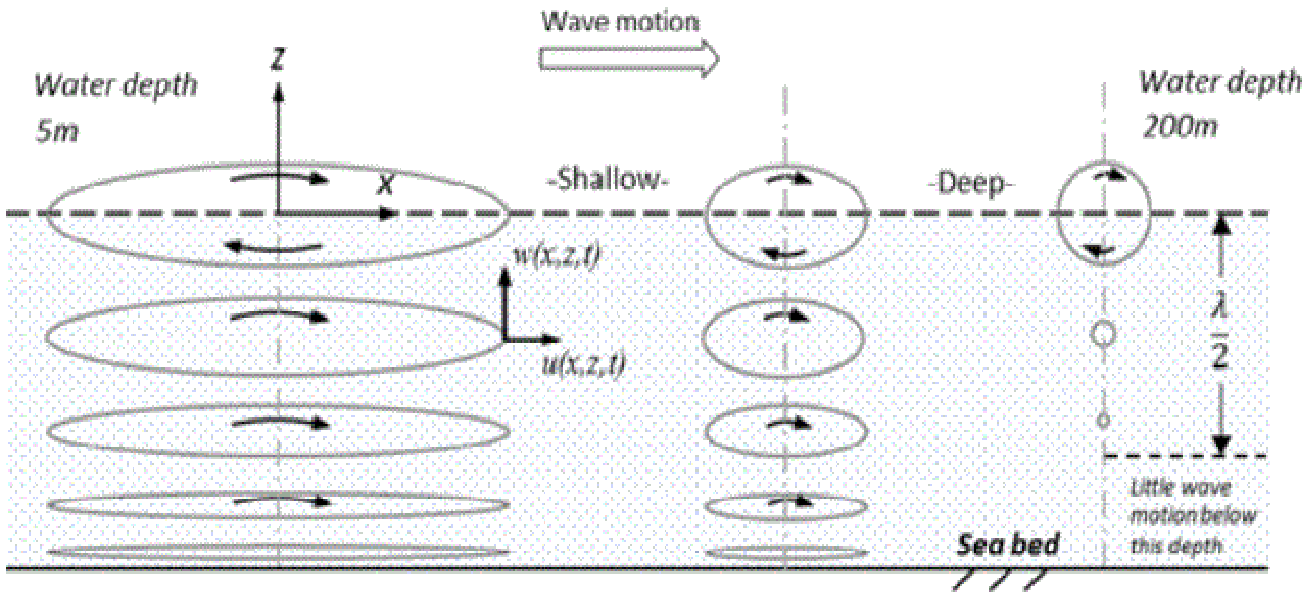




**Fig. 4.** Illustration of sea waves and swell generation.





ACTUAL SEAS "DESIGN" SEAS


z
y
λ
wave
crest
ζ
ζa
x
h
'snap shot'
(t = fixed)
wave
trough
Sea bed
a
z
MWL,
Mean water level
T
ζ
ζa
t
wave
height
'time history'
(x = fixed)
b

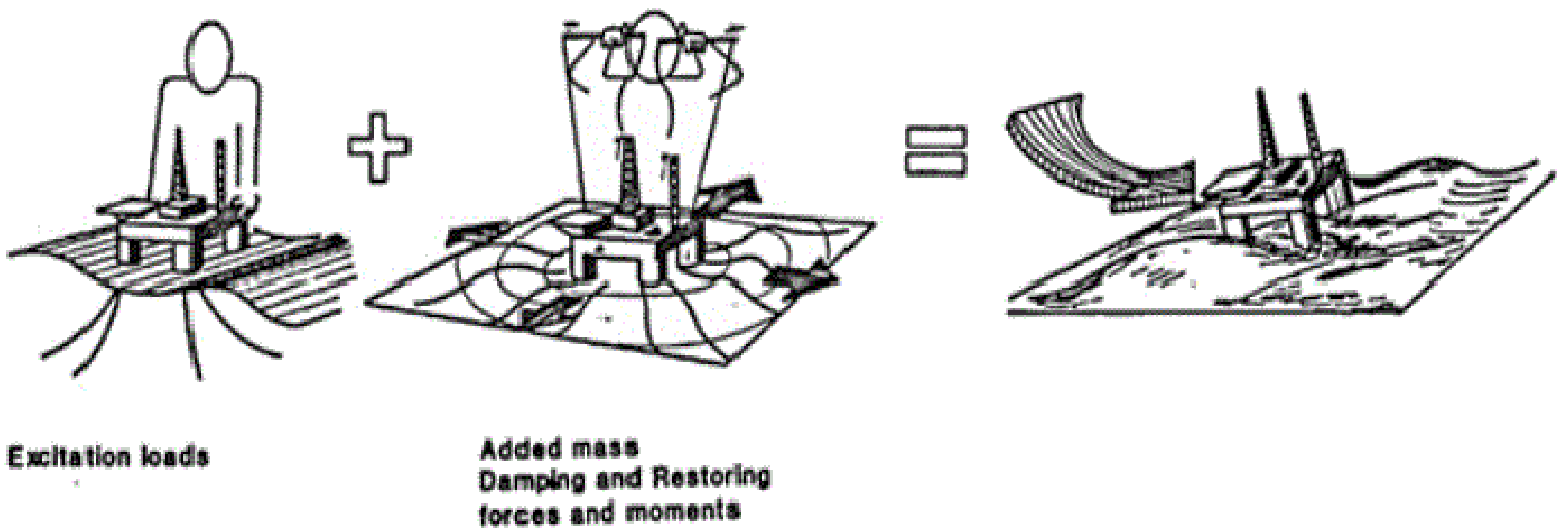

Wave motion
Water depth
5m
z
x
-Shallow-
-Deep-
Water depth
200m
w(x,z,t)
u(x,z,t)
λ
2
Little wave
motion below
this depth
Sea bed

## Properties of Ocean Waves

- A fully developed sea is a sea state where the waves generated by the wind are as large as they can be under current conditions of wind velocity.

- Significant wave height is the average of the highest 1/3 of the waves present.
  - Good indicator of potential for wave damage to marine structures

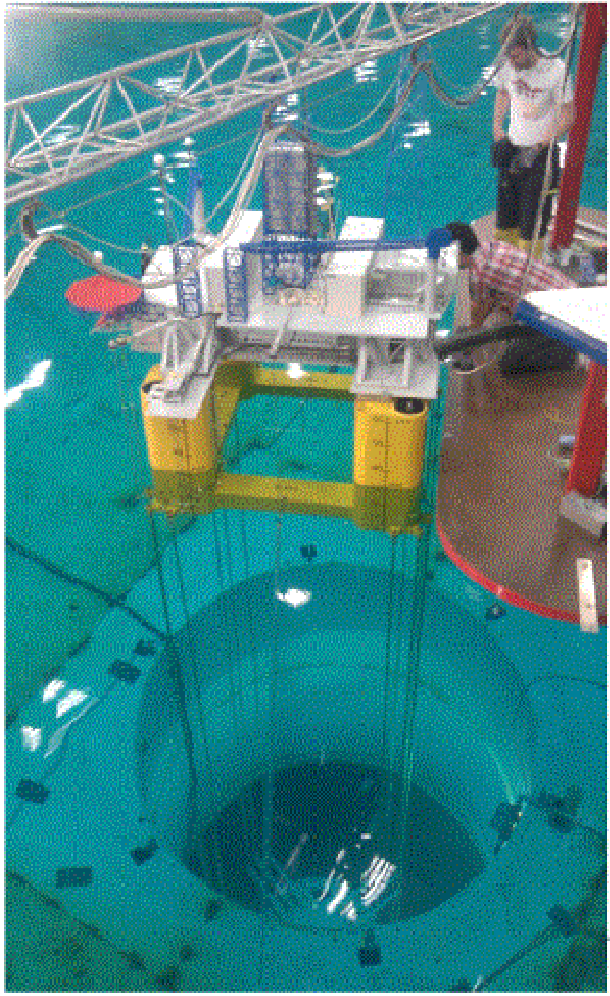
# Motion of marine structures

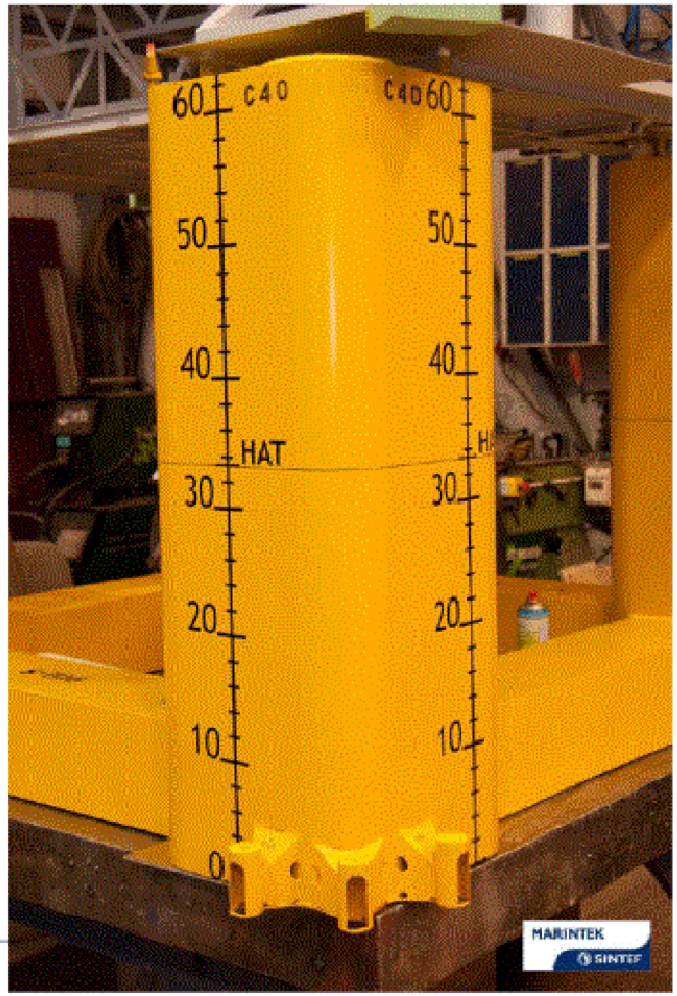



Superposition of wave excitation, added mass, damping and restoring loads.

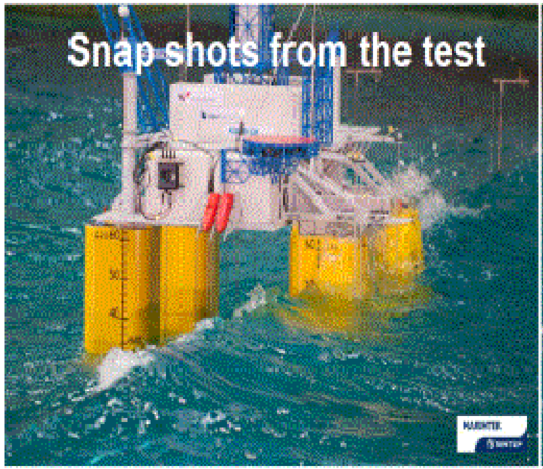
- Semi-analytical
- Numerical Model
- Experimental testing

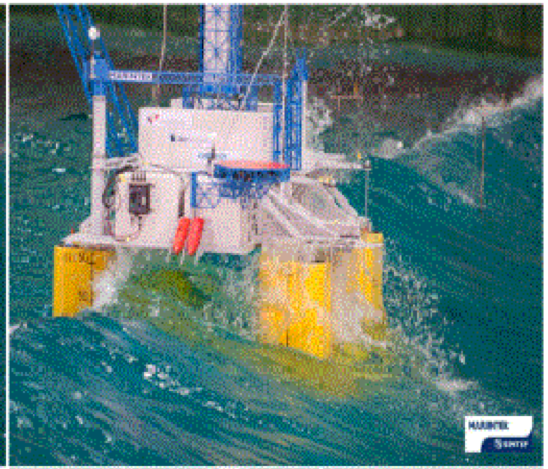
# Scaled-down Exp. Tests





# Scaled-down Exp. Tests



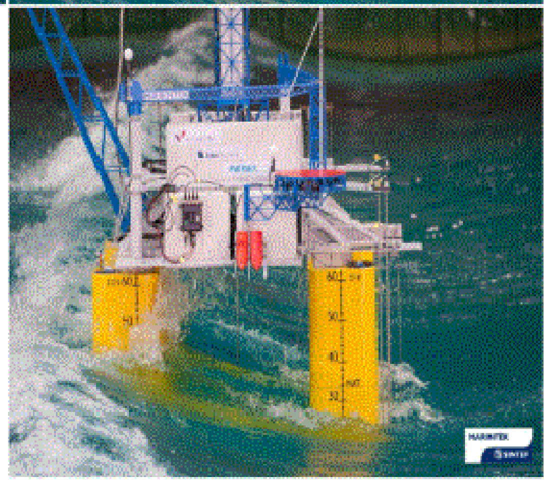



10,000 year cyclonic max wave

Beam sea

Hs = 20.7 m, Tp = 16.8 s

Wind 44.0 m/s, Current 2.2 m/s



# Motion of marine structures

## Response amplitude operator, RAO

it establishes a relation between the motion and wave amplitude in the frequency domain

**heave motion of semi-submersible platforms**

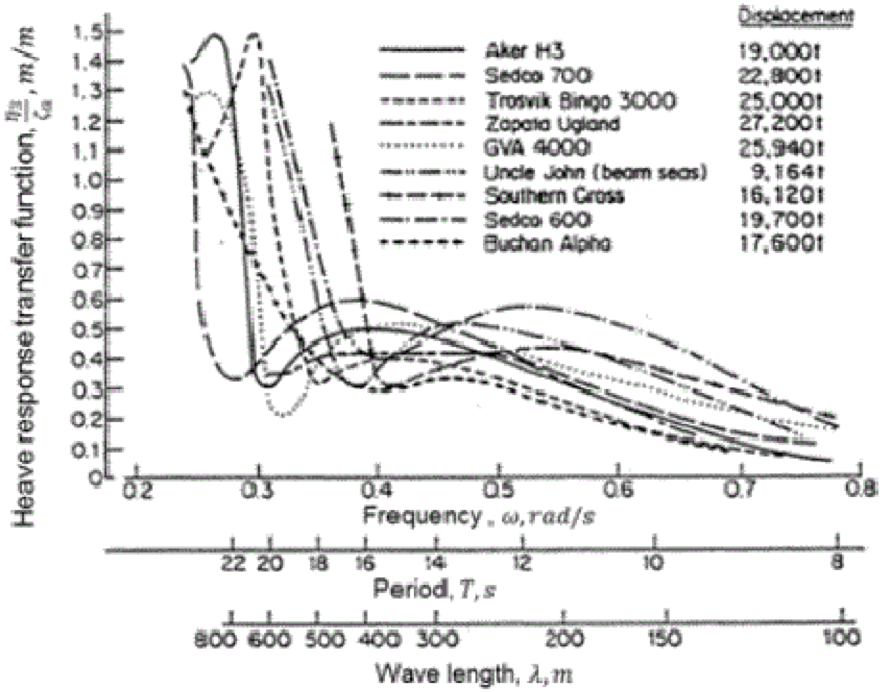



**Fig. 24.** Representative heave response transfer functions for different semi-submersibles.

# Motion of marine structures

**Surge (horizontal) motion of TLP platforms**

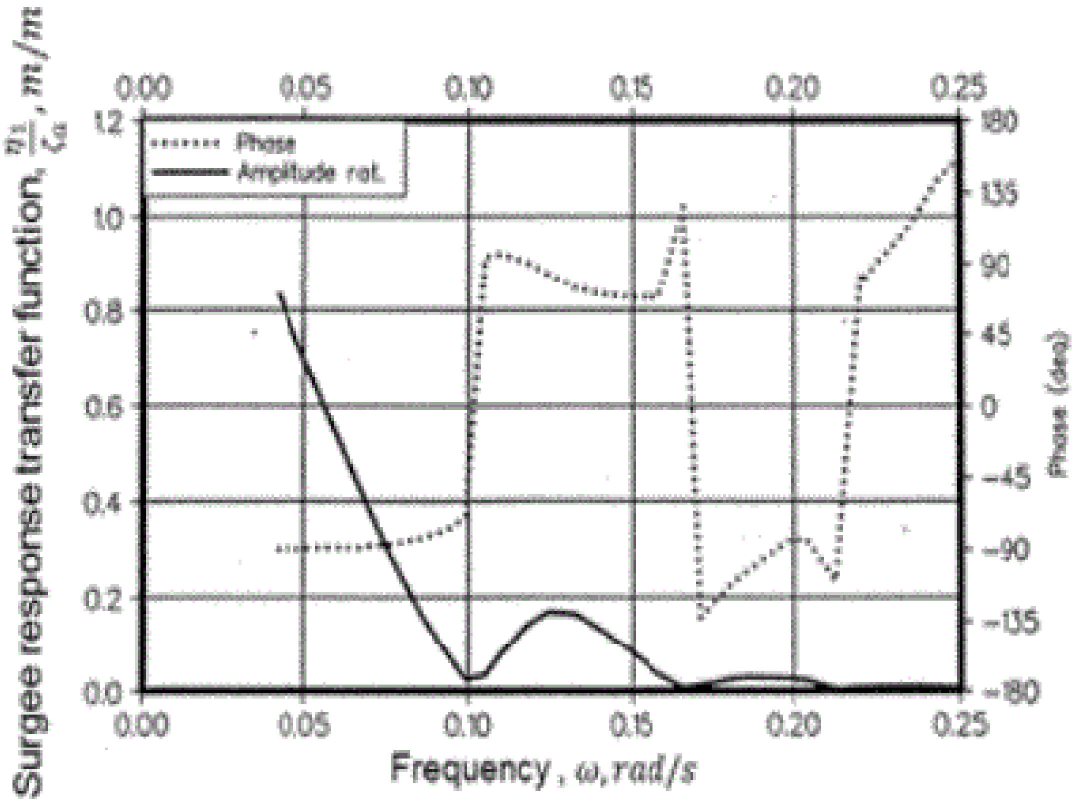
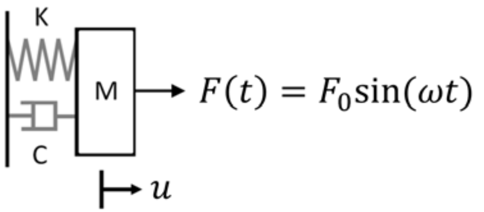
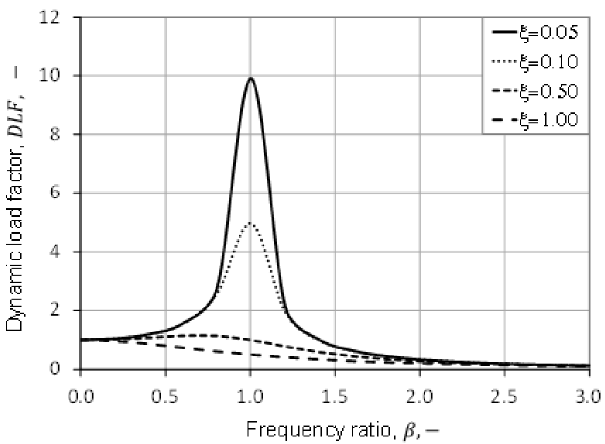



Fig. 25. Surge response transfer function of TLP.

# Motion of marine structures



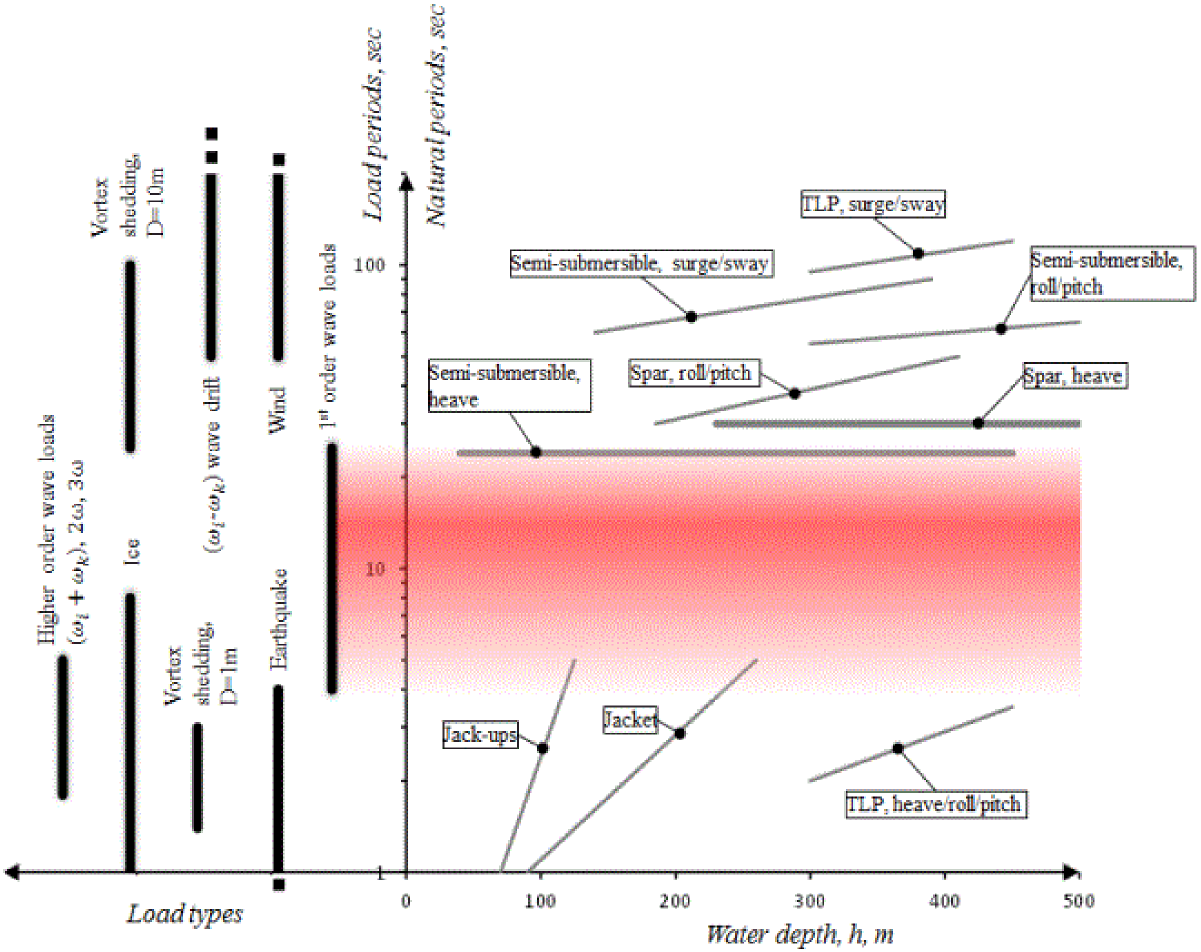




Illustration of largest natural period versus depth for some platform concepts, and periods for important environmental loads.

# Motion of marine structures

## Which natural periods ($=2\pi/\omega_0$) do we phase for offshore structures?

- **Fixed platforms:**
  Jackets and GBS's: About: 1s for depth < 100m, 3-5s for 200-250m depth

  Jack-ups: About: 4-5s for depth of about 90 150m (depending on foundation solution).

- **Floating platforms:**

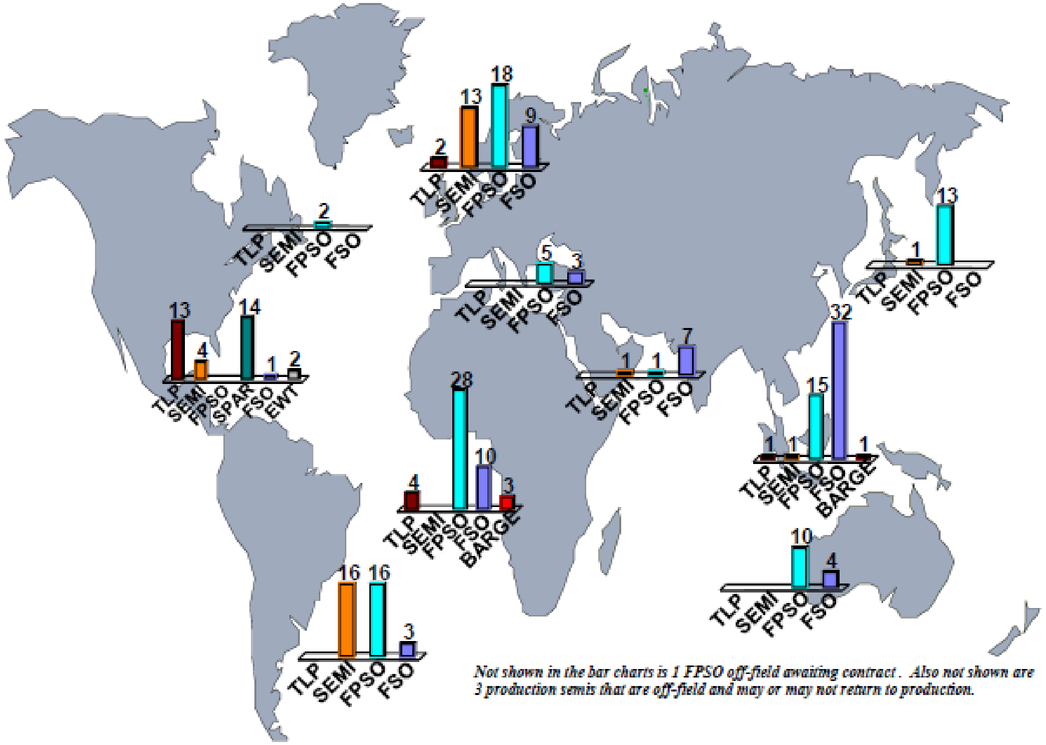
| | |
|---|---|
| Heave semi-submersible: | 23 – 26s |
| Surge/sway of catenary moored semi submerisble: | 60 – 90s |
| Pitch/Roll of semi submersible: | 30 – 60s |
| Heave of Cell spar platform (see next page): | 25 – 35s |
| Surge/sway of taut moored spar: | 2 – 3 min. |
| Roll – pitch of spar: | about 1 min |

- **Articulated platforms**

| | |
|---|---|
| Heave TLP | 2 – 3s |
| Surge/sway of TLP (300 – 400m depth): | 1 – 2 min. |
| Roll/Pitch of TLP: | 2 – 3.5s |

StatoilHydro

# Current world fleet of floating systems




**<u>256 Floating Production Units worldwide (Aug 2011, ref. Petroleum Insights)</u>**

62% are floating production, storage, offloading (FPSO) vessels;

17% are production semisubmersibles (Semi);

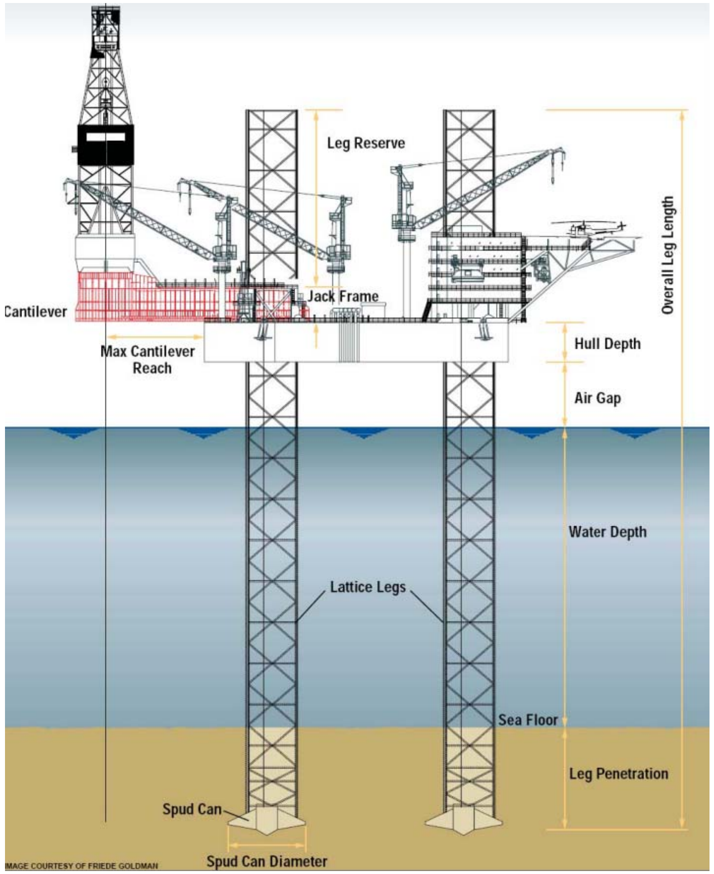
9% are tension leg platforms (TLP);

7% are production spars;

and the remaining 5% are production barges and floating storage and regasification units (FSRUs).

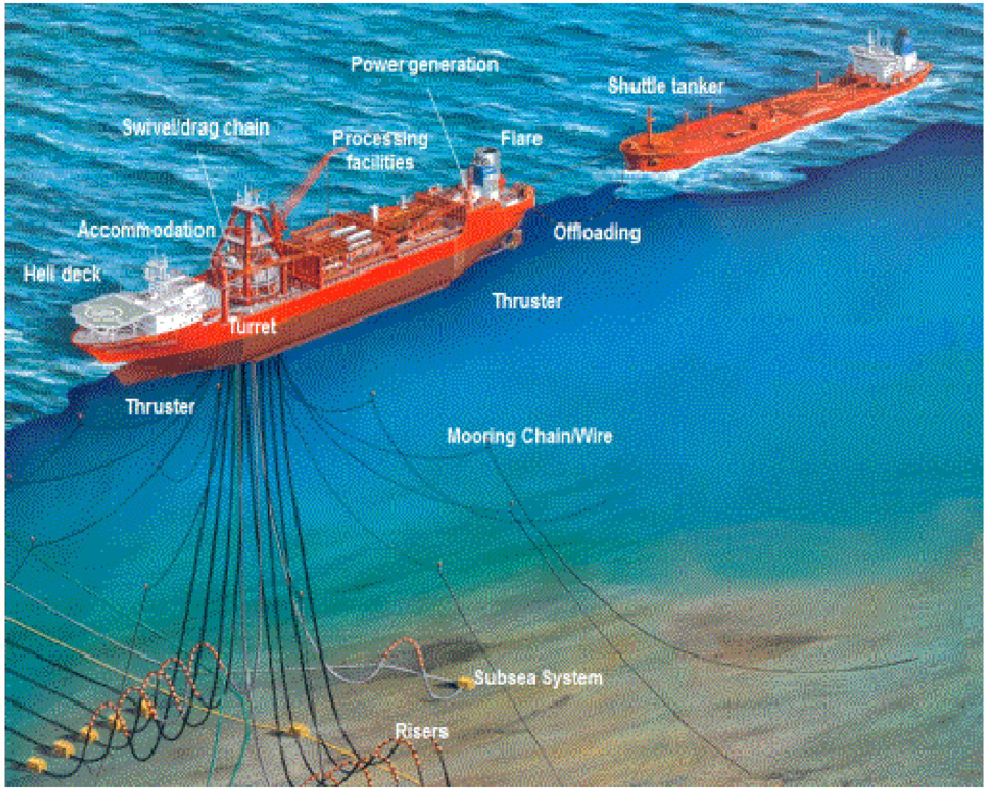
AkerSolutions


Plataforma Troll A


Leg Reserve
Overall Leg Length
Jack Frame
Cantilever
Max Cantilever Reach
Hull Depth
Air Gap
Water Depth
Lattice Legs
Sea Floor
Leg Penetration
Spud Can
Spud Can Diameter
IMAGE COURTESY OF FRIEDE GOLDMAN

# FPSO (Floating Production Storage and Offloading)

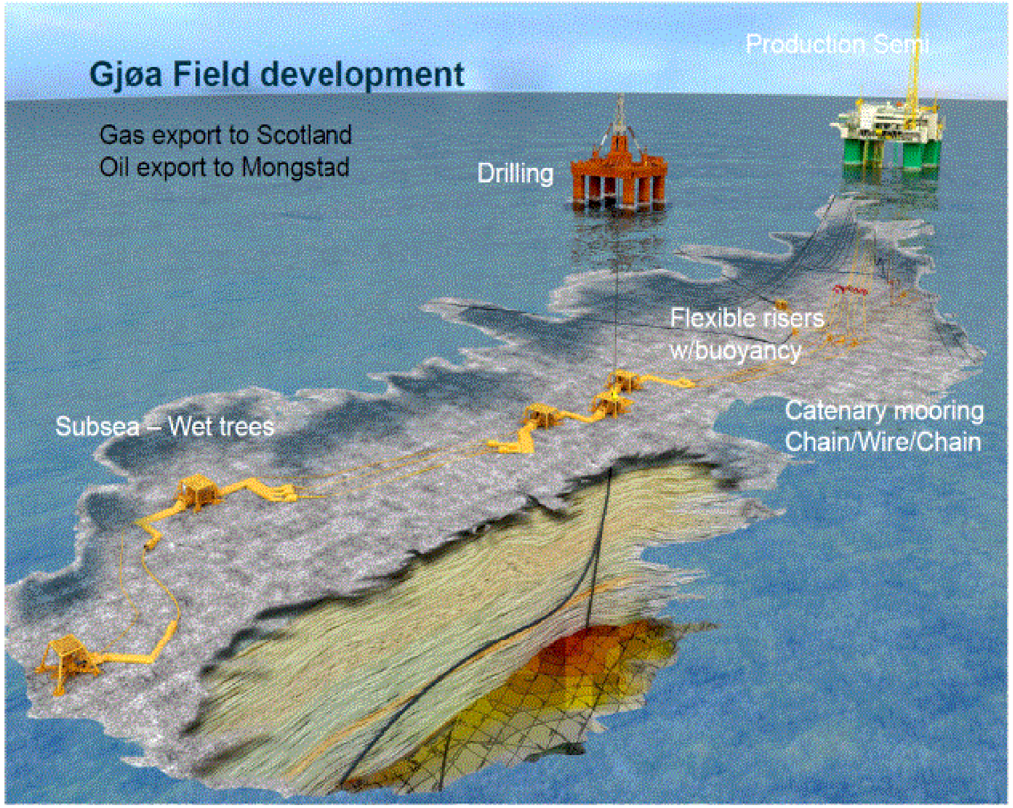
- Ship shaped or circular
- **Large storage capacity**
- Large topside capacity
- Good separation between hazardous and non-hazardous areas
- Fair motions
- Flexible risers and turret
- Integration and commissioning inshore



# Semi-Submersible (Semi)

- Flexible concept with large (unlimited) capacity, topside weight and area
- Column stabilized
- **No water depth limit**
- Good motions
- Feasible with Steel Catenary Risers (SCRs) in deep water
- No (limited) storage
- Integration and commissioning inshore

Ultra-Deepwater
Semi-submersible

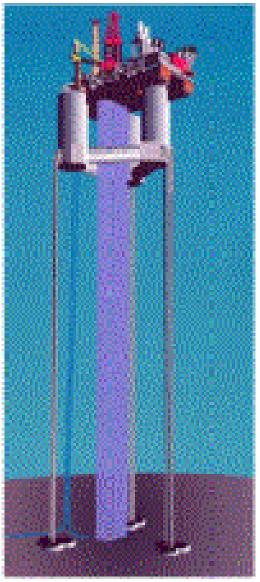


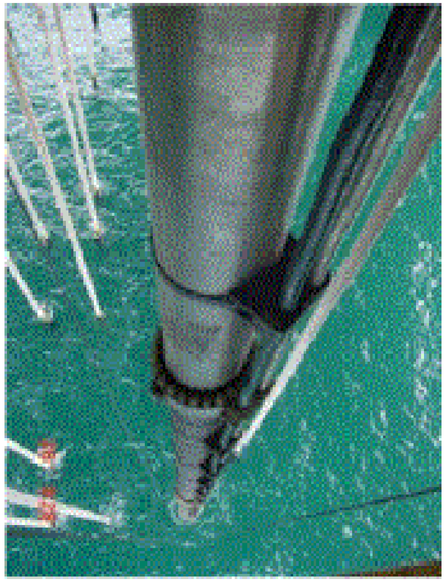
# Main Platform Elements - Gjøa

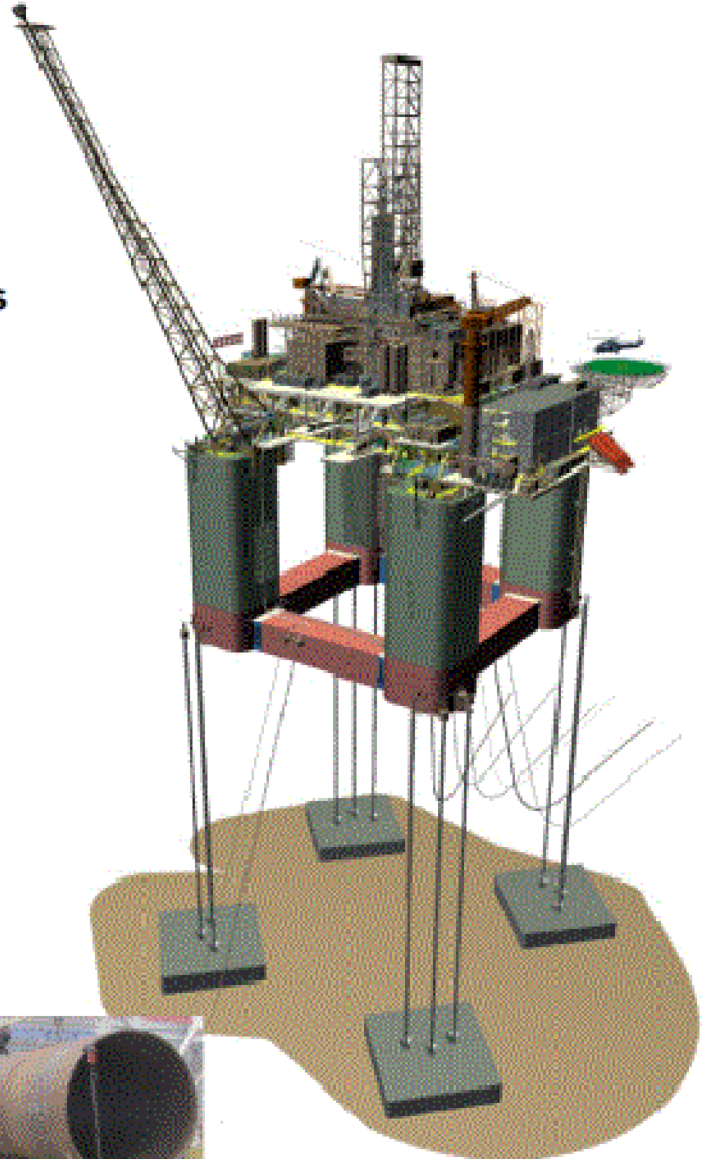

AkerSolutions

# TLP (Tension Leg Platform)

- Station keeping and stability by tethers
- **Excellent motions**
  - **Top Tensioned Risers (TTRs) and dry trees**
- Large capacity, limited by tethers
- No storage
- Integration and commissioning inshore







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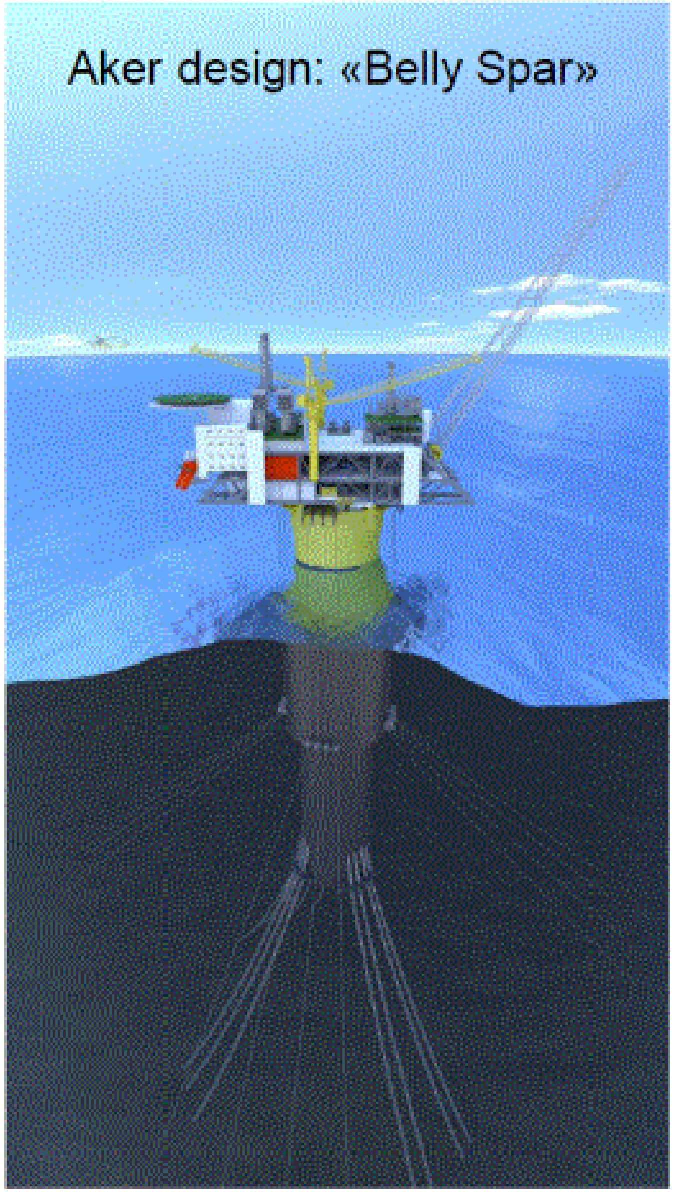
# Spar Platforms

- Weight stable (by counter weight)
- Limited capacity, limited footprint
- **Excellent motions**
  - **Top Tensioned Risers possible**
- Storage (limited)
- Integration and commissioning offshore or inshore in deep fjord (> 200 m WD)

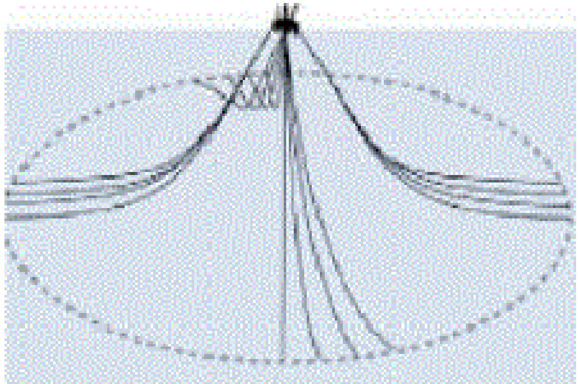



AkerSolutions

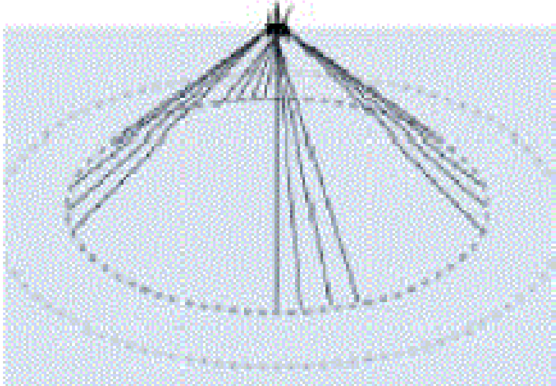
## Mooring Systems

- Purpose of mooring is to keep platform on location

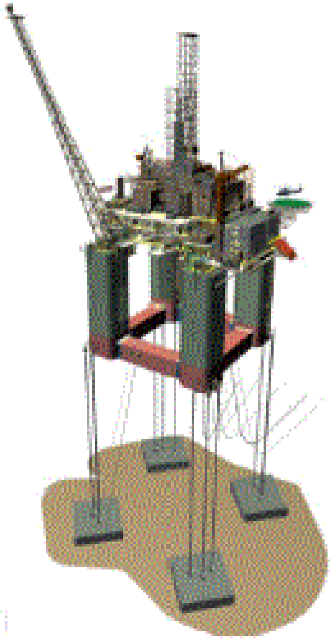
Catenary mooring (traditional)



Taut mooring



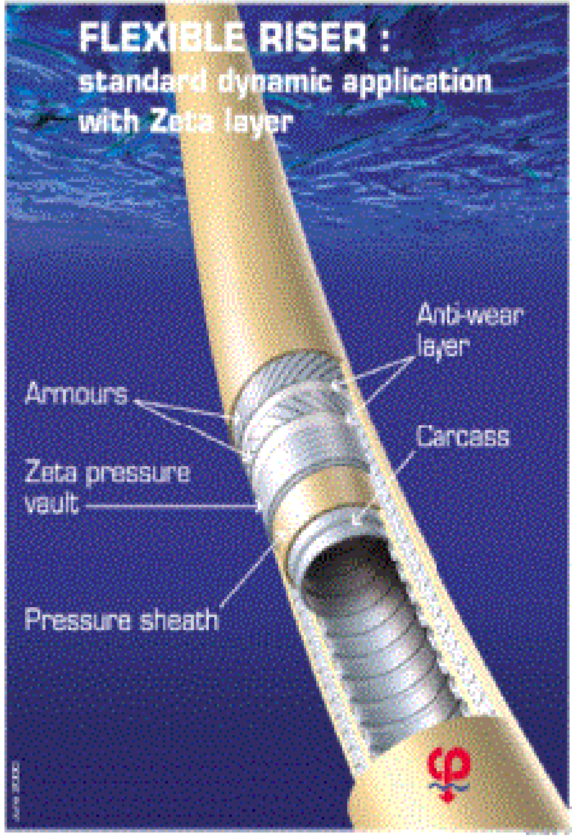
Tethers (steel pipe)



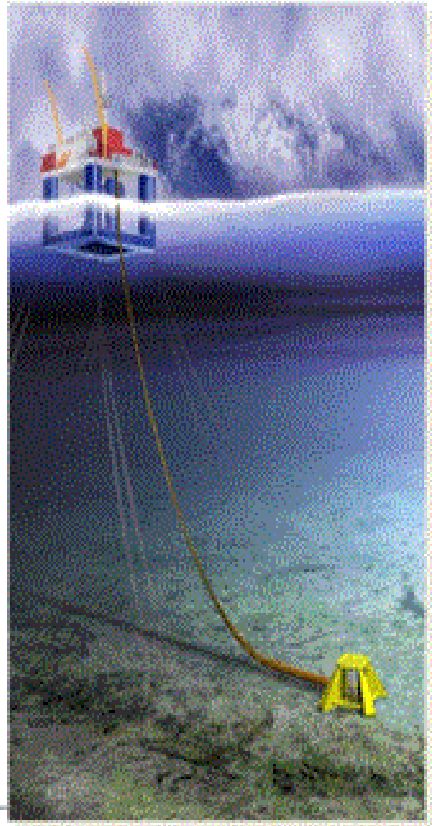
# Risers

- The tube that connect the platform to the well head. Purpose is to transport hydrocarbons from the well to the platform or to export hydrocarbons from the platform to pipeline/shuttle tanker

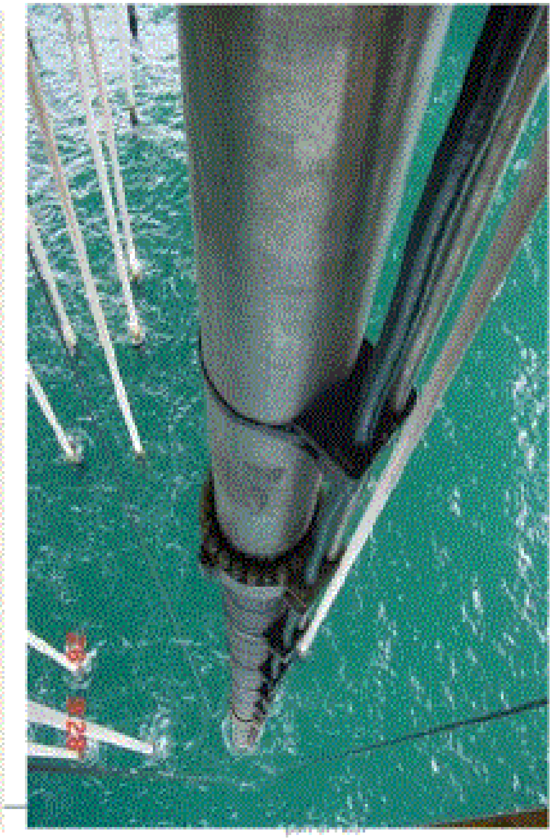
Flexible Risers



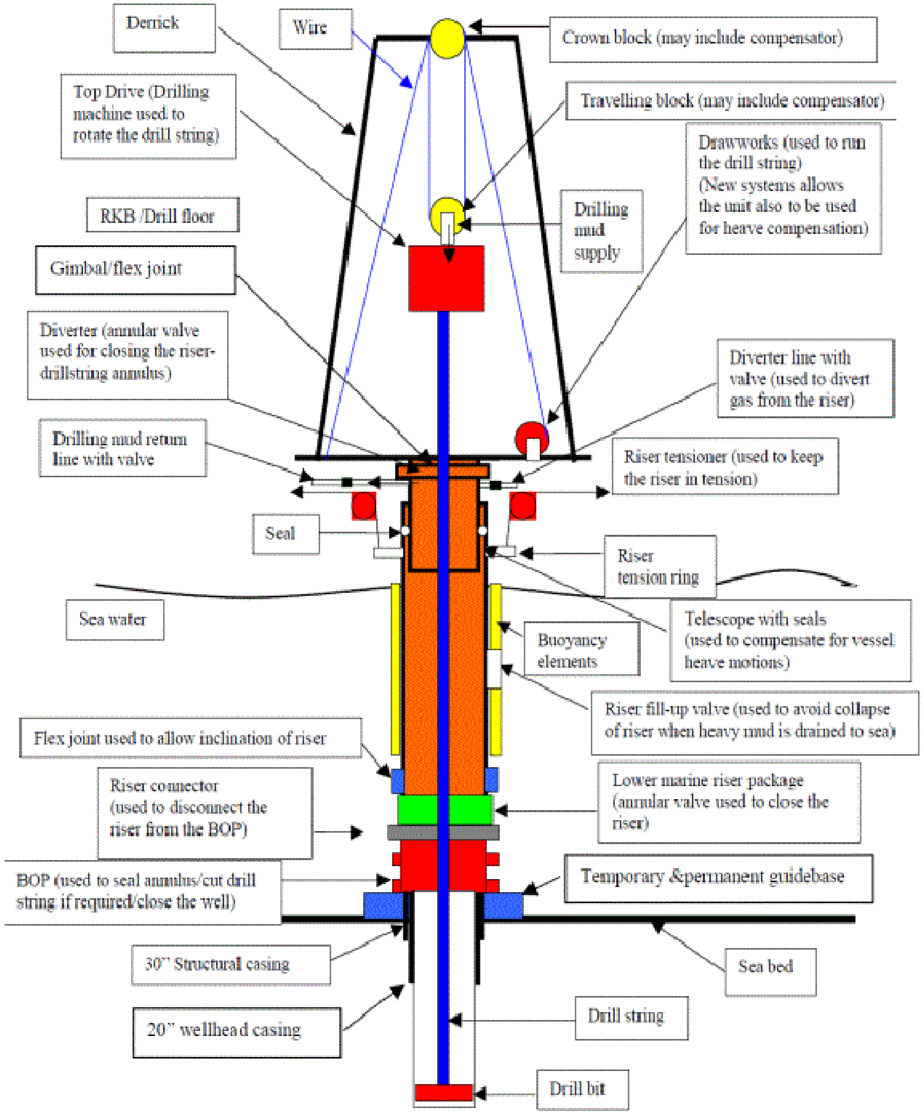

Steel Catenary Risers (SCR)



Top Tensioned Risers (TTR)



# Riser tensioner




(a) Wire-line. (b) N-line.

The different riser tensioner systems (National Oilwell Varco, 2007*b*).

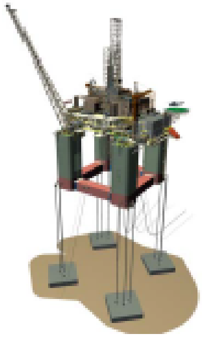
Figure 5.3: Production riser tensioner system at the TLP Jolliet (National Oilwell Varco, 2007*b*).

# Principal Selection Criteria

- Storage or pipeline?
  - FPSO
    - Mild weather: No turret
      - West Africa
      - SE Asia
      - Conversions

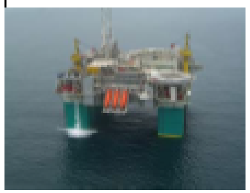
    - Severe weather: Turret
      - Aasgard A
      - Norne
      - Skarv

  - Drilling capabilities or independent drilling
    - Dry trees or Wet trees
      - TLP / Spar
        - Snorre A
        - Diana
        - Shenzi
        - Tahiti



      - Semi w. drill
        - Njord
        - Snorre B
        - Thunder Horse

    - Semi / mini TLP / Spar
      - Blind Faith
      - Gjøa
      - Typhoon
      - Red Hawk



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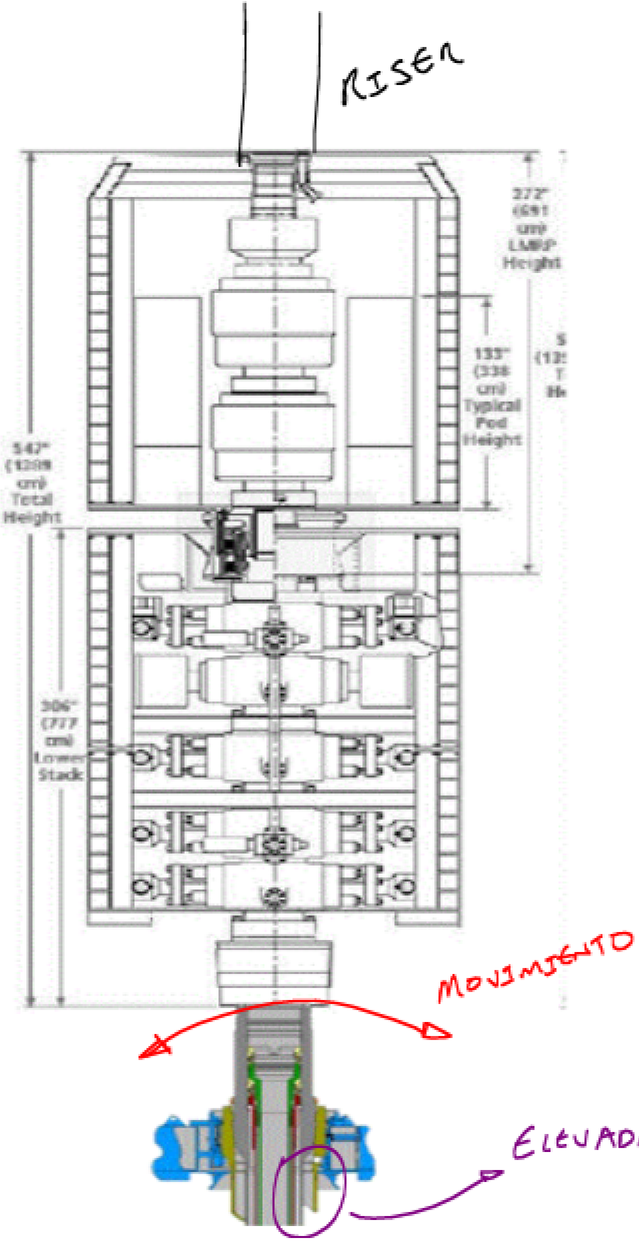
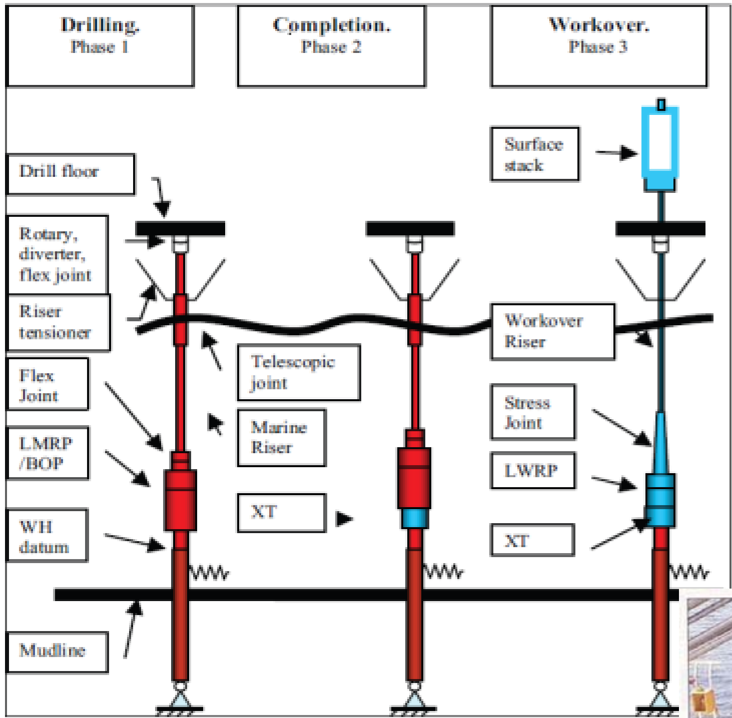
# WH Fatigue

## Background

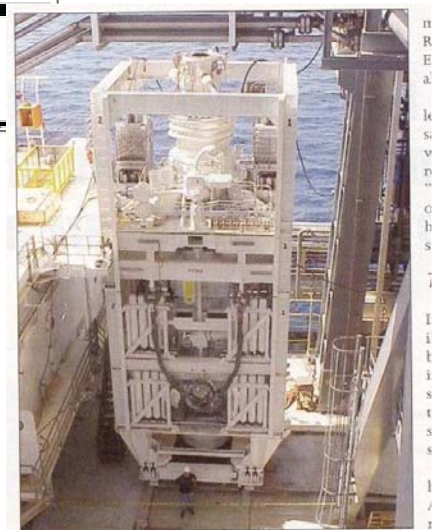
- Increased re-entry on existing wells on the Norwegian continental shelf.
- Complex well designs and operations including multilateral- and smart wells increases drilling time. Increased amount on intervention and work-over operations on sub sea wells.
- Life time extension of wells, Specified total drilling time for new complex wells can be up to 300 days
- Increased size of drilling rigs and weight of BOP's, on new rigs up to 400 ton




ELEVADAS CARGAS : • AXIAL
• FLEXION } → FATIGA




Weight : 250 T in ai



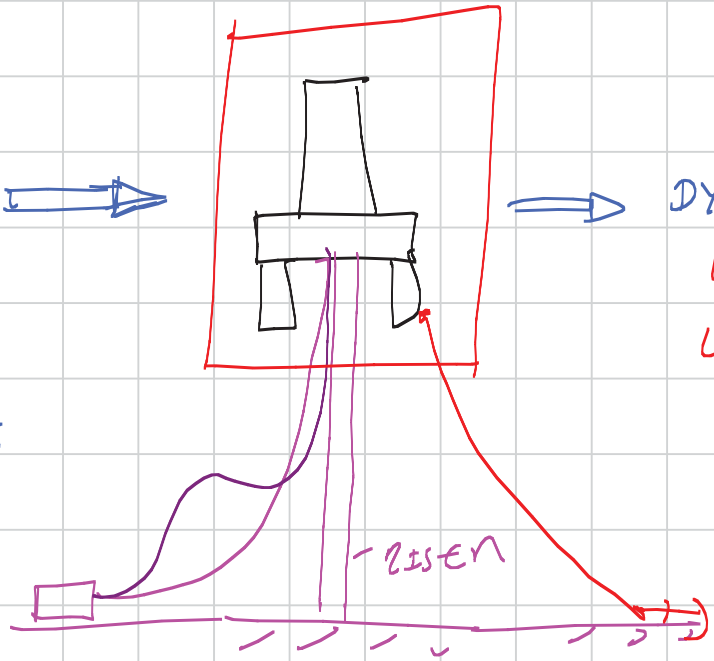
Hydril will supply two BOP control stacks and a multiplex pressure control system similar to this for the Ocean Endeavor (Fig. 3; image from Hydril Co.

# INTRODUCTION TO OFFSHORE STRUCTURES - FOCUS ON MARINE ASPECTS

Note Title 05.04.2016

JESUS DE ANDRADE - email: jesus.andrade@ntnu.no

HYDRODYNAMIC LOADS
- WAVES
- CURRENT
- WIND



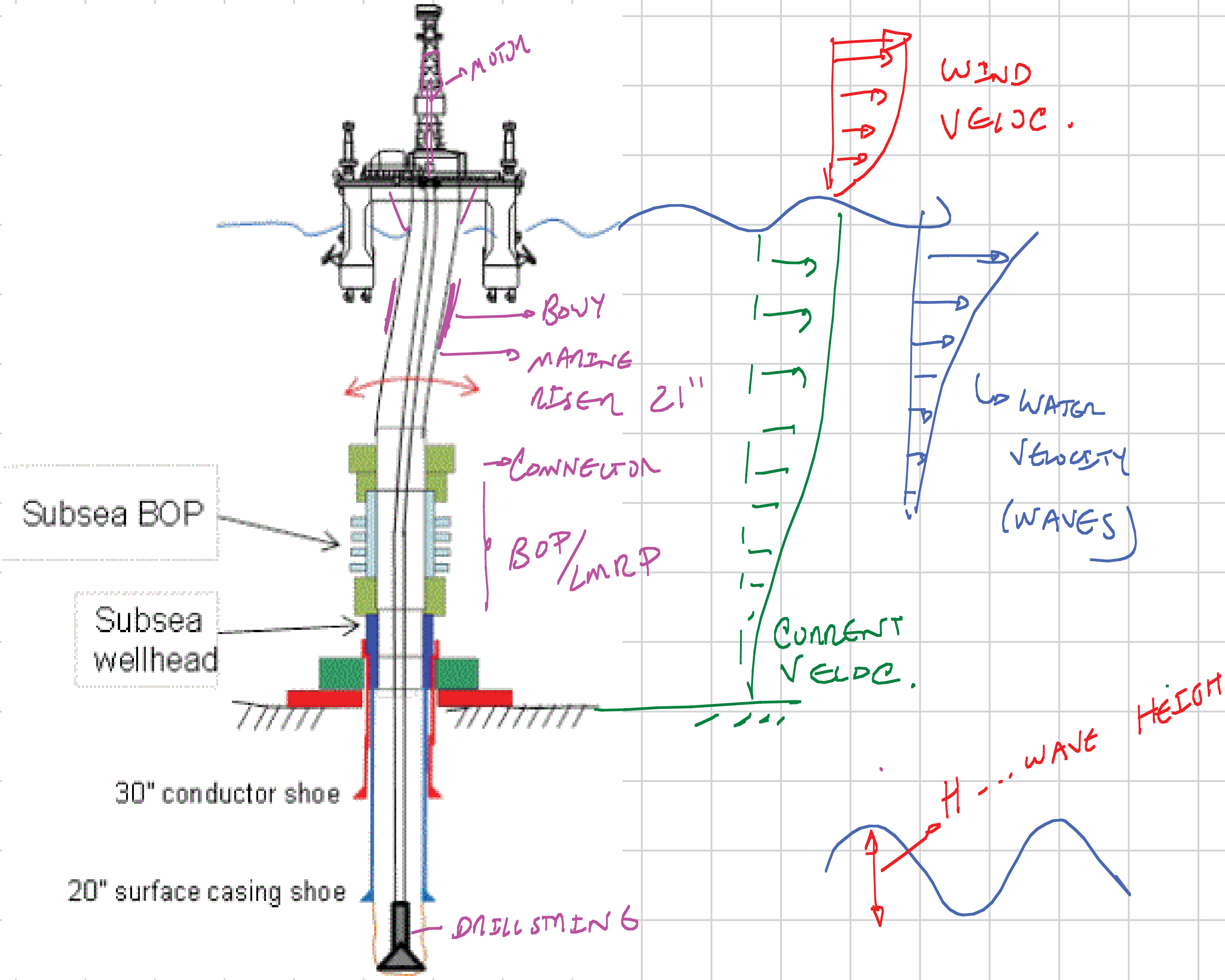

DYNAMIC RESPONSE
- MARINE STRUCTURE
- CONNECTION TO THE SEABED
  - RISERS
  - MOORING SYSTEM

## Cases that show how not to do it

The Mars TLP after the hurricane Katrina

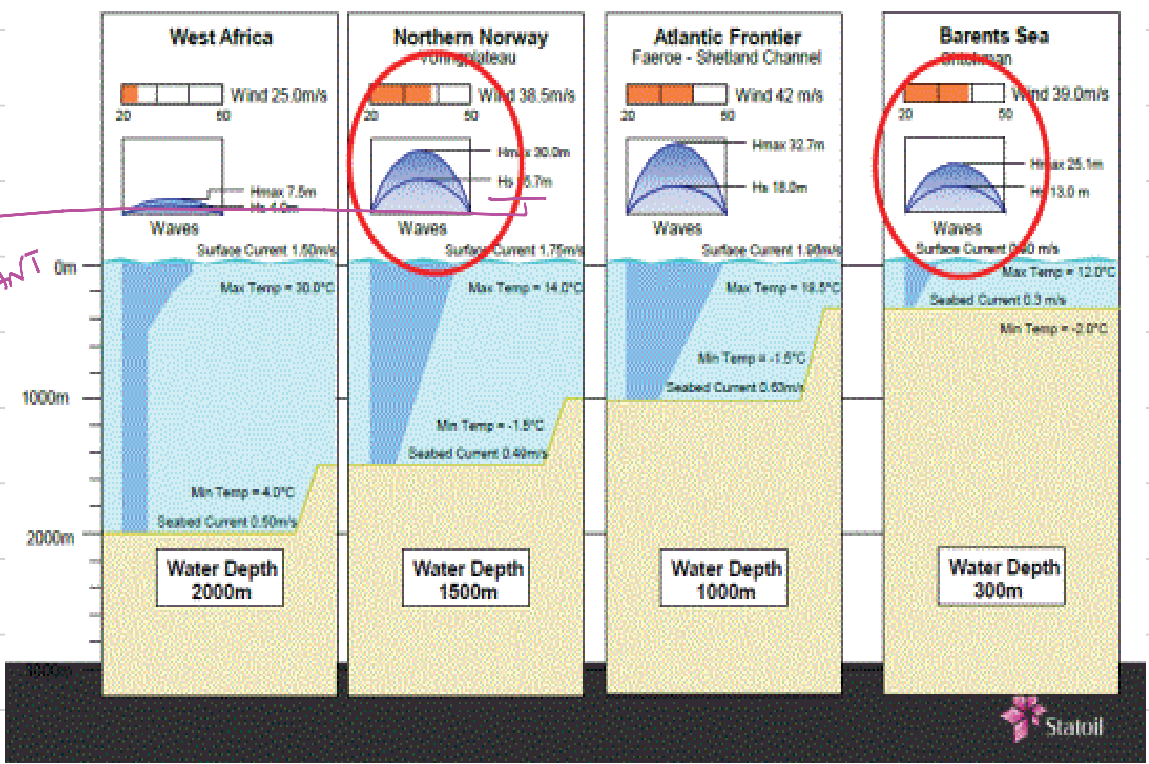
Typhoon upside down after hurricane Rita

# ENVIRONMENTAL LOADS




## Waves, wind and current comparable with Norway

Hs
↓
SIGNIFICANT WAVE HEIGHT



"NCS"

- CURRENT ≈ 1 m/s CONSTAT ⇒ DESIGN
  - ↳ 2 m/s COULD BE REACHEDD.

- WAVES:
  - ↳ $H_{max} \approx 30$ mts
  - ↳ $H_S \approx 18$ mTs ⇒ DESIGN
    - SIGNIFICANT WAVE HEIGHT
    - ↳ MEAN VALUE OF THE HIGHEST 1/3 OF THE WAVES

  TIME - SCALE
  - AVERAGE CHARACT (1 TO 4 hr)
  - RAPID FLUCTUATION (4 TO 24 s)

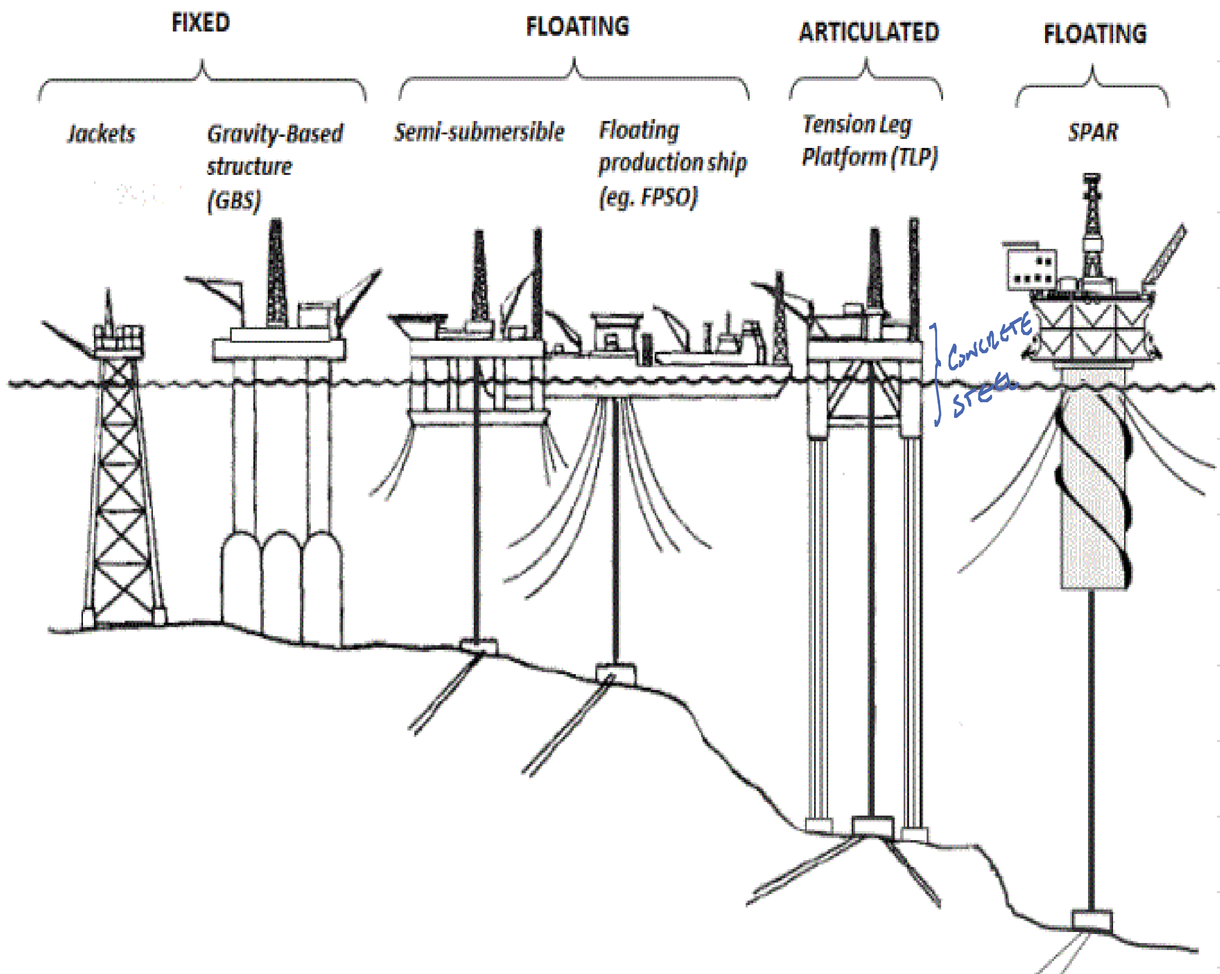
- WIND | TWO SCALES
  - SLOW - VARYING MEAN CHARACTERISTICS (1 TO 3 min)
  - RAPID FLUCTUATIONS,

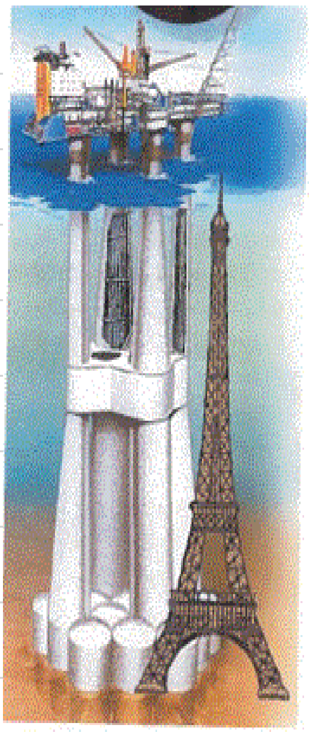
  ↳ 150 km/hr IN NCS MAY BE REACHED.

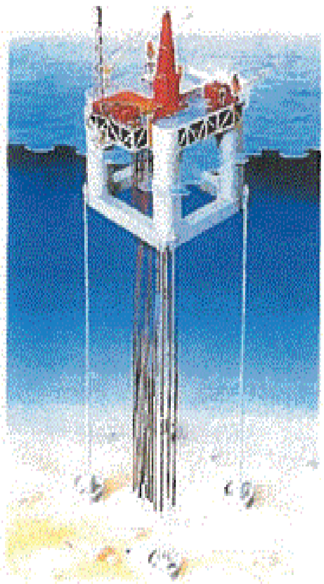
CONVENTIONALLY DIFFERENT STRUCTURES ← WATER DEPTH.

↳ MOVE VERY DIFFERENT

↳ HORIZONTAL AND VERT. MOTION





# MARINE STRUCTURES

- WATER DEPTH
- HYDRODYNAMIC LOADS,
- FOUNDATION SUPPORT (SEA BED)
- DYNAMIC RESPONSE OF THE STRUCTURE

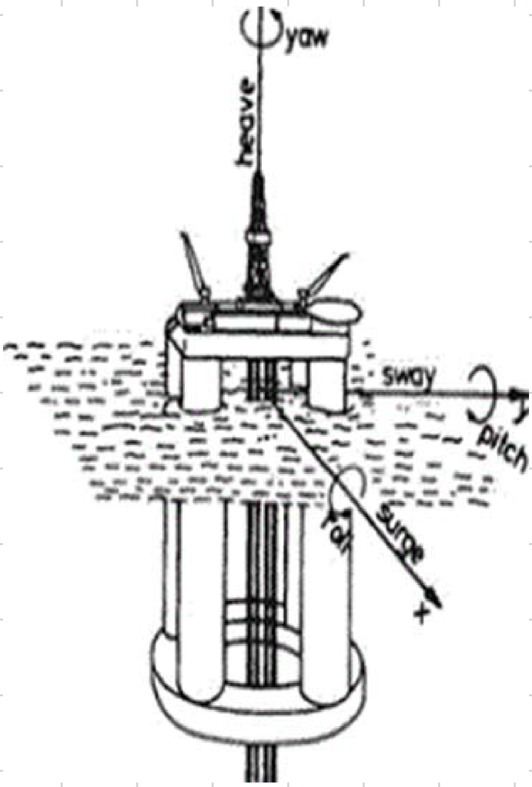
( • RESERVOIR
• SUBSEA TECH. )

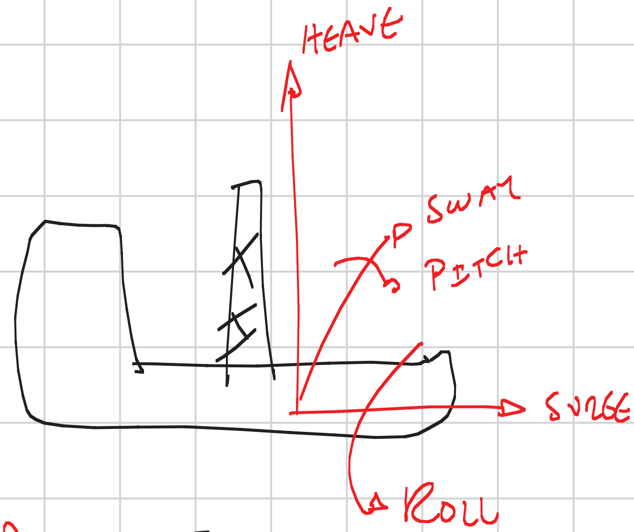
**Table 1.** Examples of offshore structures in the NCS for different water depths.

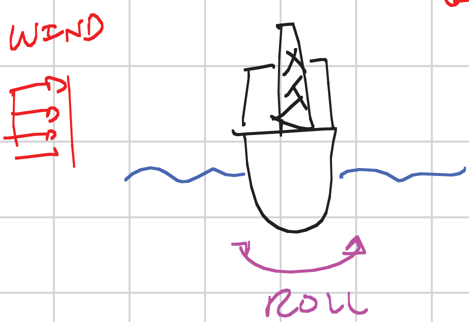
| Water depth | Field | Offshore structure |
|---|---|---|
| 70-75 mts | Ekofisk | Jackets |
| 120-130 mts | Balder | FPSO |
| 130-250 mts | Gullfaks | Concrete fixed facilities and steel topside |
| 300 mts | Troll | Concrete fixed facilities and steel topside |
| 300 mts | Åsgard B | Semi-submersible platform |
| 300-350 mts | Snorre | TLP steel platform |
| 370 mts | Kristin | Semi-submersible platform |
| 1300 mts | Luva* | Spar platform |

**Future field development*

- MOTION UNDER OCEAN WAVES LOADS:



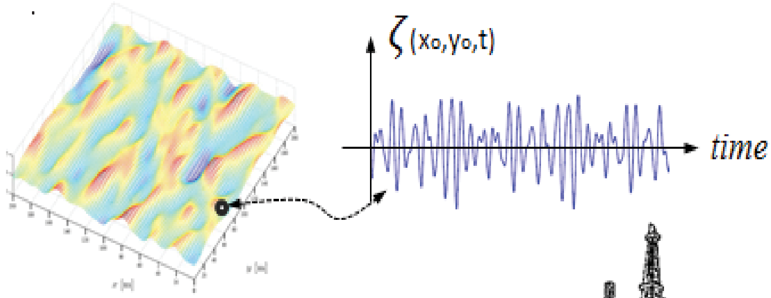
- STOCHASTIC ANALYSIS OF OFFSHORE STRUCTURES (WAVE LOADS)

WAVES ARE VERY RANDOM → (STATISTICAL APPROACH)

**Statistics of waves**

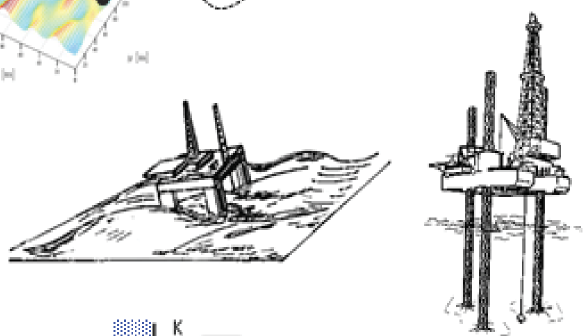
Wave surface elevation

Wave spectrum (Hs, Tp)



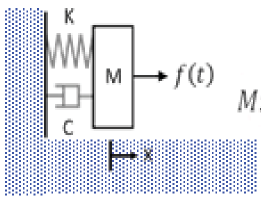

**Calculation of hydrodynamic loads**

Fluid-structure interaction



**Dynamic analysis response**

For practical purposes considered linear

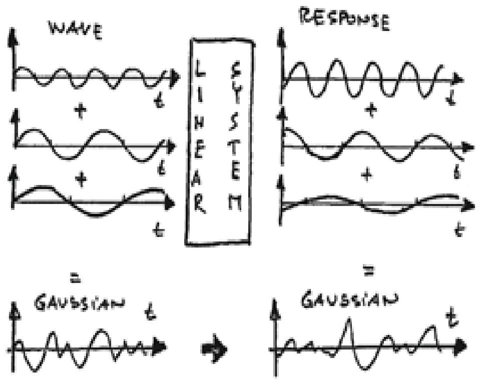



$$M\ddot{x}_{(t)} + C\dot{x}_{(t)} + Kx_{(t)} = f(t)$$

**Statistics of the response**

Verification of design and operation according to rules

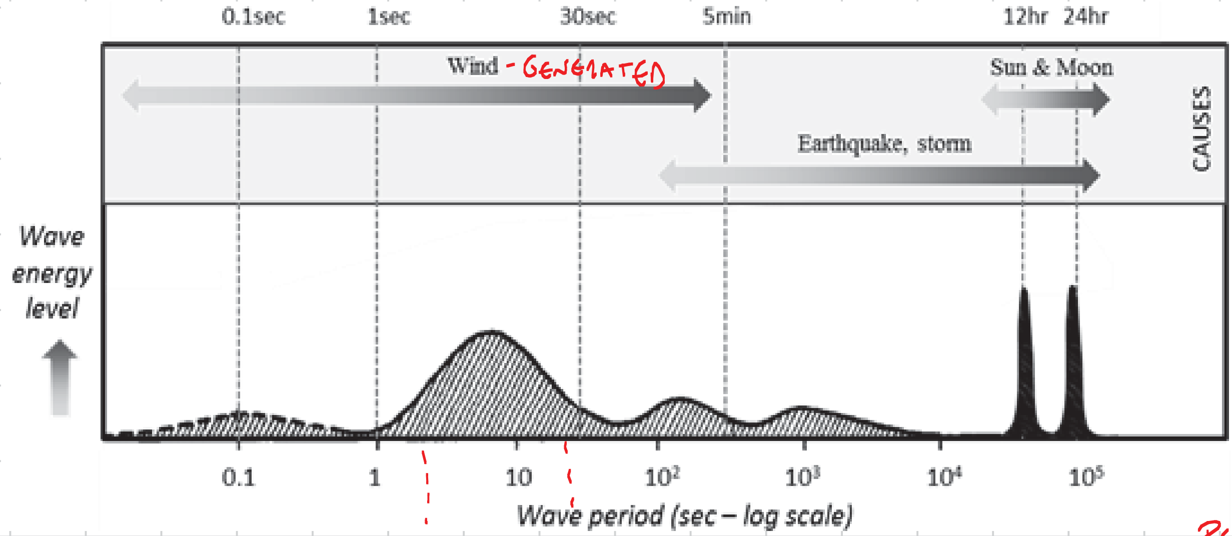
Ordinary gravity wave-wind usually of interest (period 4-24s)




WHAT'S GOING TO HAPPEN AFTER 100 YEARS?

# WAVES AND WAVES STATISTICS

- GENERATION OF WAVES DEPENDENT ON SITE AND WATER DEPTH




OIL AND GAS

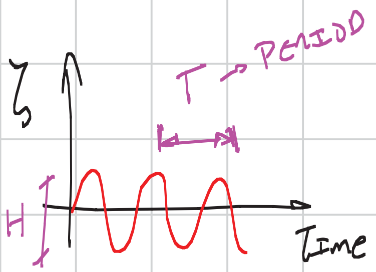
↳ OFFSHORE STRUC.

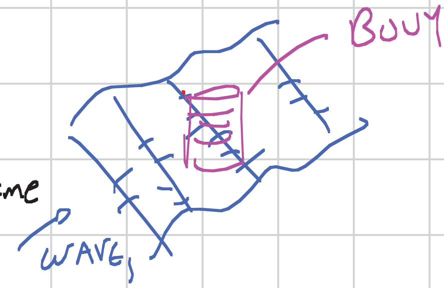
4 - 24 s

PERIOD:

NCS → 13

(SEVERE) TO 15 s



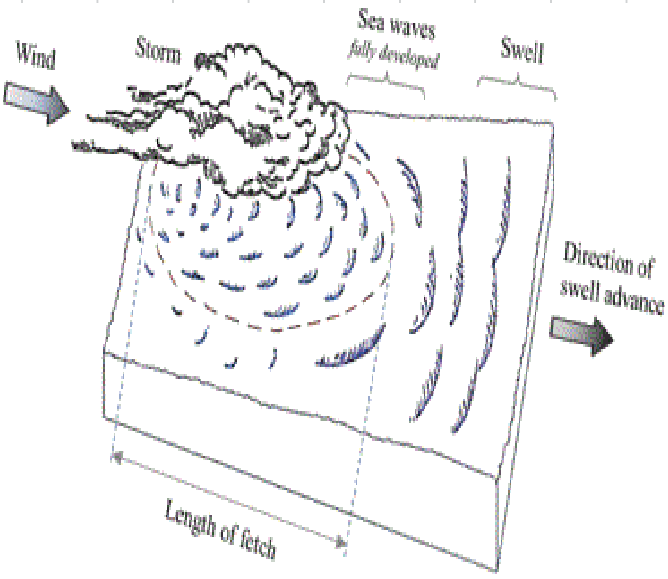
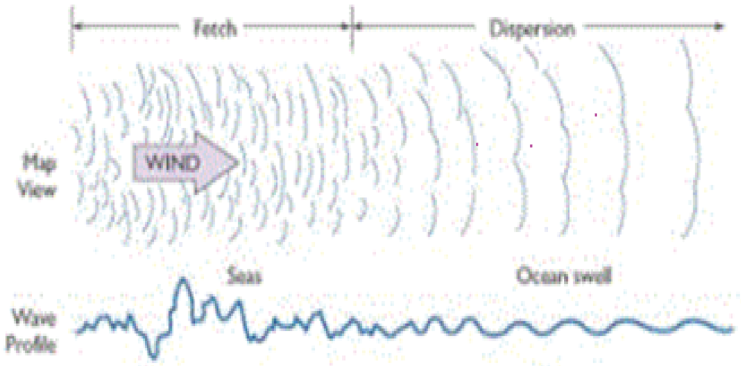



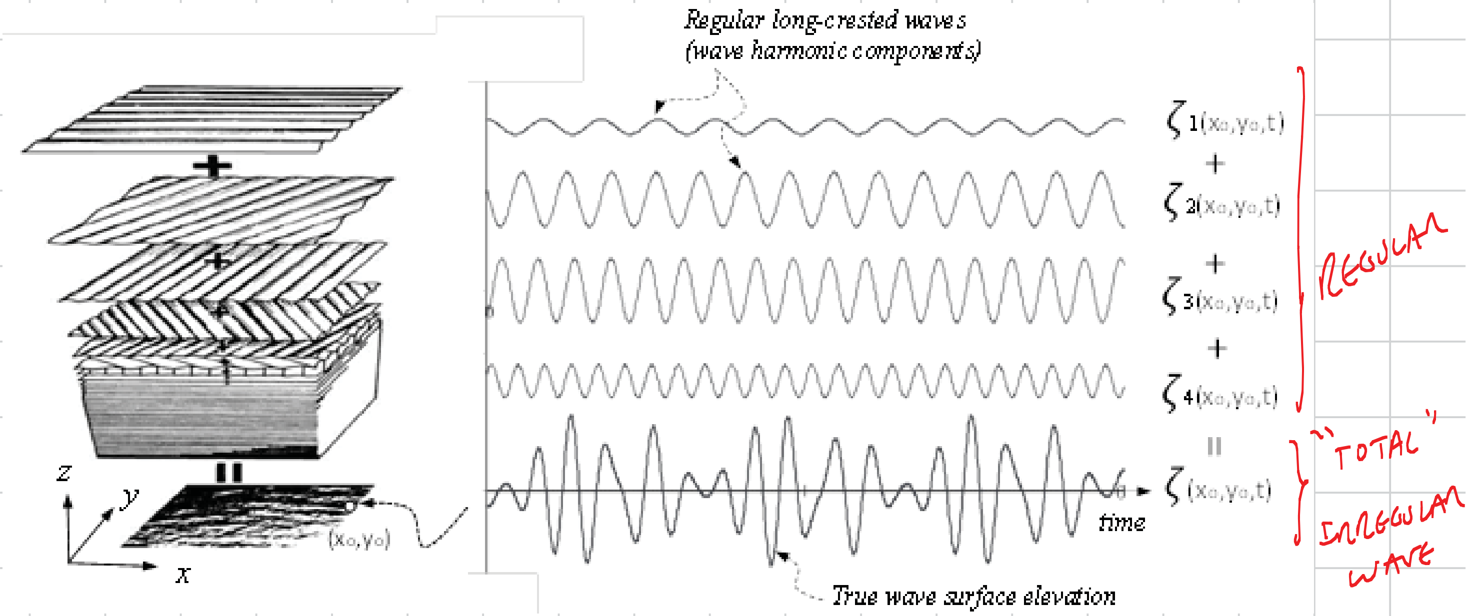

**Fig. 4.** Illustration of sea waves and swell generation.

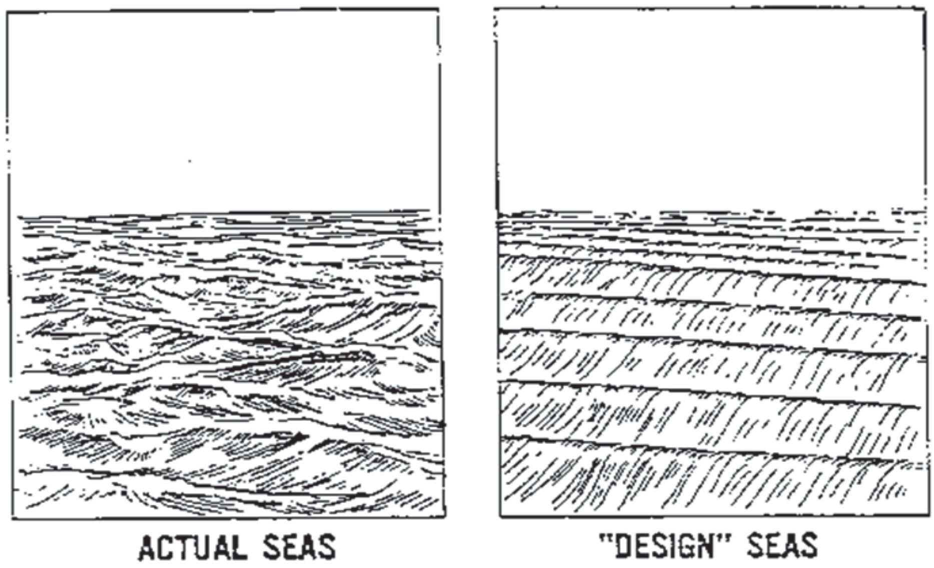



IRREGULAR WAVES

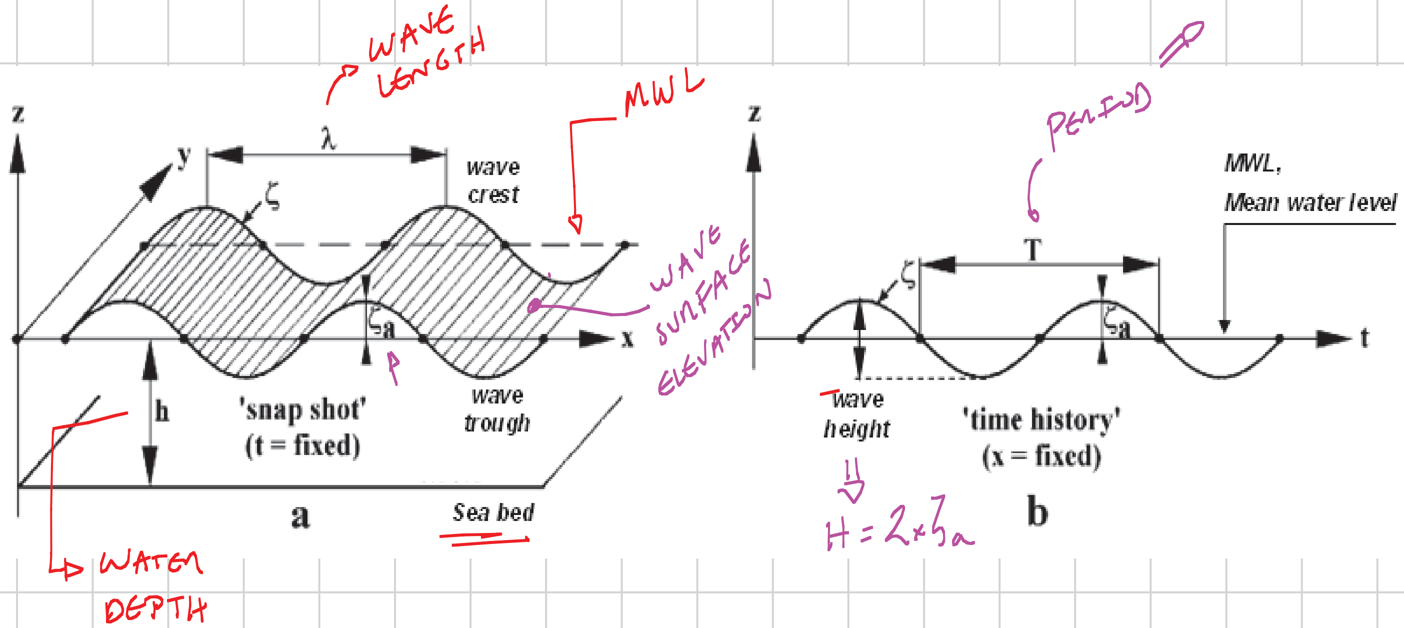
REGULAR WAVES

Wind-generated waves present irregularity motion that in time and space cannot be exactly predicted. Therefore, it is a common practice to represent the elevation of the sea surface with sum of many sinusoidal waves with different direction, amplitudes, frequencies, and phases




$\omega = \frac{2\pi}{T}$ [rad/s]



EQ. FOR THE IRREGULAR WAVE:

$$\zeta(x,t)=\sum_{i=1}^{N}\zeta_{a_i}\cdot \sin(\omega_i\cdot t - k_i\cdot t - \varepsilon_i)$$

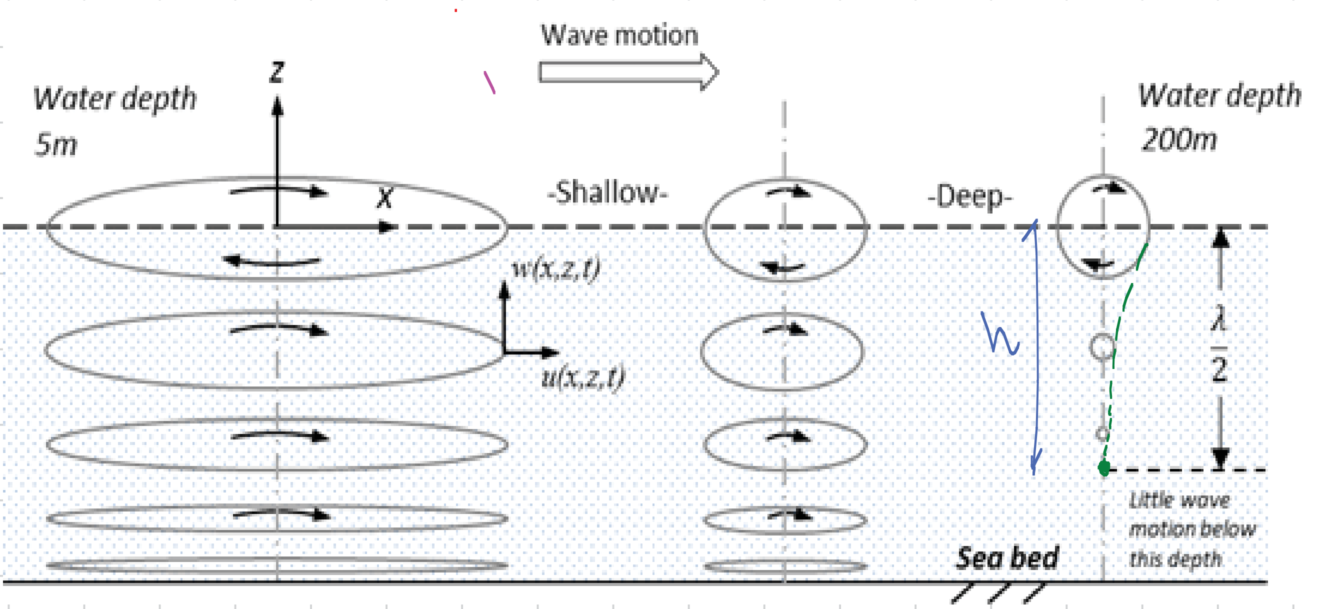
→ FREQ.

→ WAVE NUMBER: $k_i=\dfrac{2\pi}{\lambda_i}$

↳ WAVE "i" ELEVATION AMPLITUDE

↳ PHASE AMONG WAVES (0 - 2π)

- SHALLOW VS DEEP WATER:




- FOR DEEP WATER (EX.)

- $T = 12$ sec. → WAVE LENGTH ⇒ $\lambda = \dfrac{g\cdot T^2}{2\pi}$

  ↑ PERIOD IP NCS

$$\lambda = \frac{(10\ m/s^2)\times(12\ s)^2}{2\pi} = \underline{229\ mts}$$

- WATER DEPTH → $h = \dfrac{\lambda}{2} = \underline{115\ m}$

- MAX. WAVE HEIGHT

  Hmax

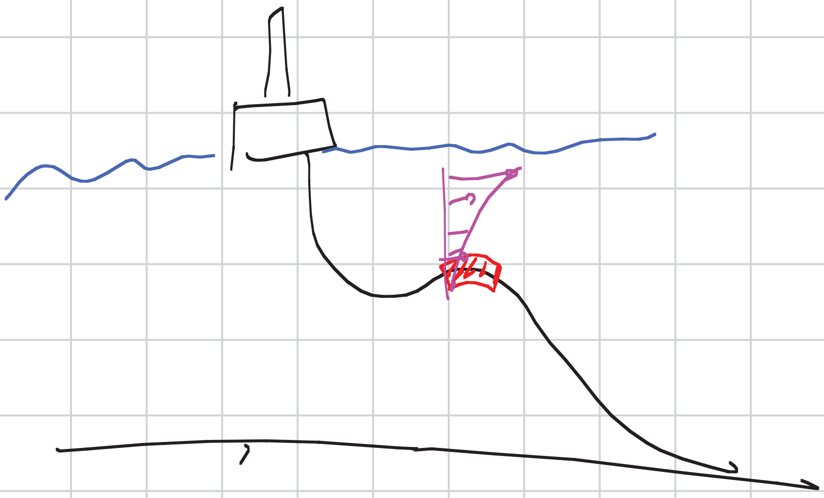
  NCC → Hmax = 30m ←

  SIMPLE THEORY (CONSERVATIVE)

  $H_{max} = \lambda/7 = 229/7 = \underline{32\ m}$

- Horizontal veloc of the wave


$$u = \omega \cdot \zeta_a \cdot e^{kz}$$



$$u_{(z=-150)} = \frac{2\pi}{\underset{120}{T}} \times \frac{\overset{32m}{H_{max}}}{2} \times e^{\left(\frac{2\pi}{\underset{229}{\lambda}}\right)\left(\overset{-150}{z}\right)}$$

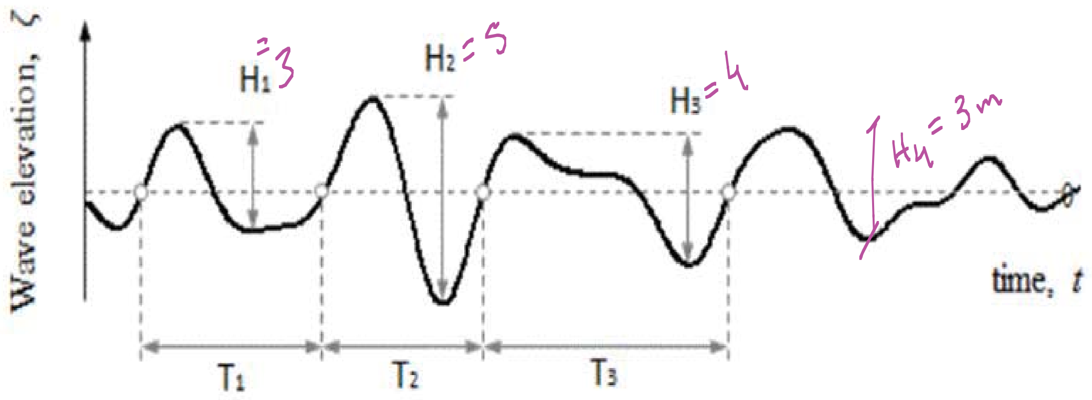
$$u_{(z=-150)} = 0.14 \ m/s$$

$$u_{(z=-15m)} = 5.6 \ m/s$$

Significant wave height: ($H_s$)

→ The ave. of the highest 1/3 waves present

↳ Good indicator for potential damage due to the wave




○ Zero-upcrossings

$H_1, H_2, H_3$ ...individual wave heights

$T_1, T_2, T_3$ ...corresponding zero-upcrossings periods

$$T_z = \frac{1}{N}(T_1 + T_2 + T_3 + \cdots + T_N) \tag{9}$$

$$H_{mean} = \frac{1}{N}(H_1 + H_2 + H_3 + \cdots + H_N) \tag{10}$$

WAVE HEIGH RECORD

$\int \rightarrow$ INTEGRATION

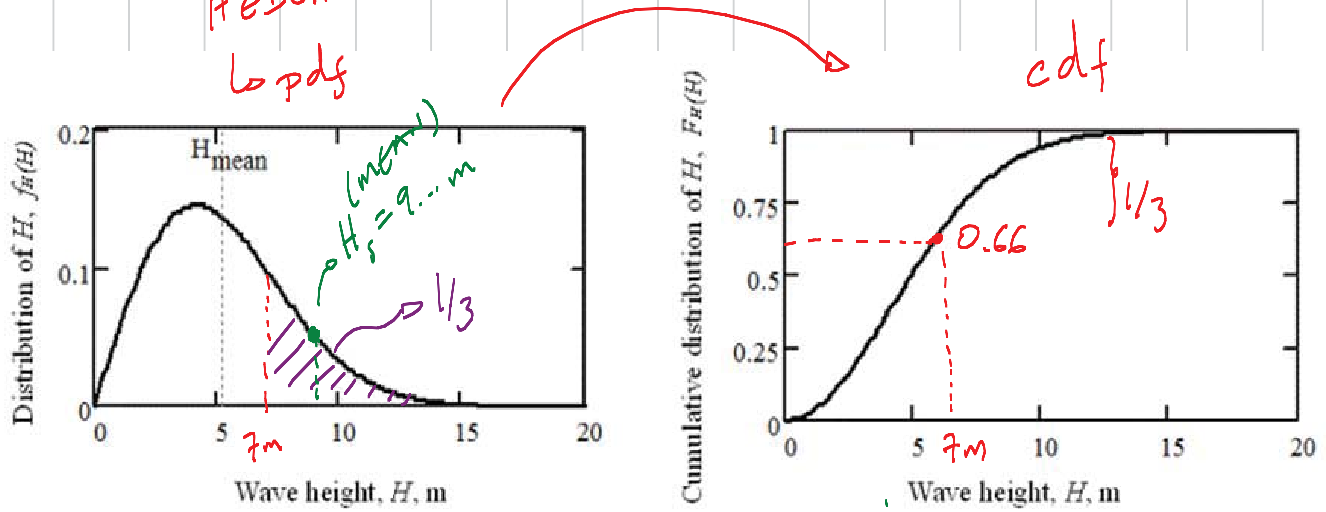
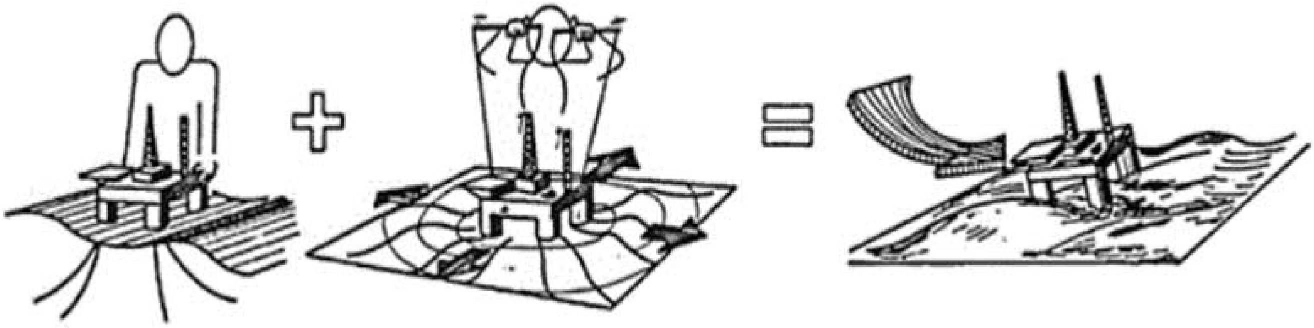



**Fig. 10.** Probability density function $f_H$ (Rayleigh distribution) and cumulative distribution function $F_H$ for the wave height of certain sea state.

# Motion of marine structures

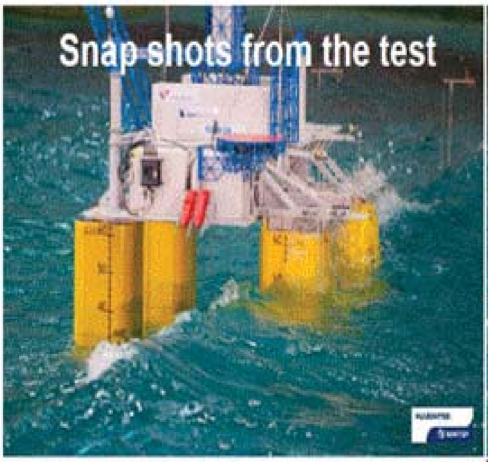


Excitation loads

Added mass
Damping and Restoring
forces and moments

Superposition of wave excitation, added mass, damping and restoring loads.

- Semi-analytical
- Numerical Model
- Experimental testing




10,000 year cyclonic max wave

Beam sea

Hs = 20.7 m, Tp = 16.8 s

Wind 44.0 m/s, Current 2.2 m/s

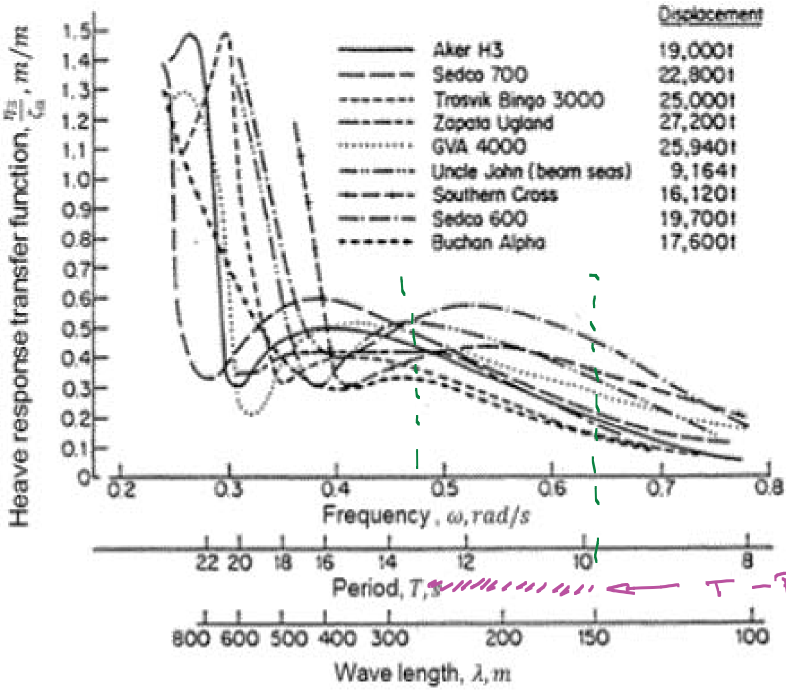
- Purpose
  - Verification of mooring system
  - Verification of deck level
  - Global motions
  - ⋮

# Response amplitude operator, RAO

it establishes a relation between the motion and wave amplitude in the frequency domain

## heave motion of semi-submersible platforms

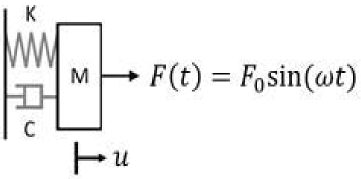
HEAVE AMPLITUDE ← $\frac{\eta_3}{\zeta_a}$ ← WAVE AMPLITUDE

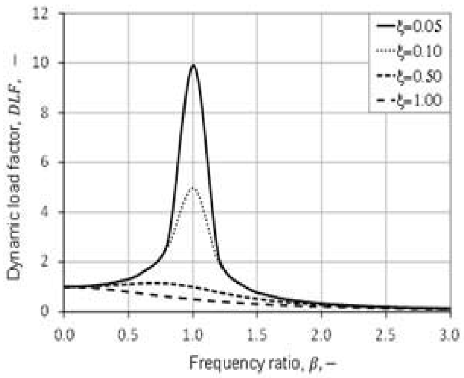



WAVE T - PERIOD

**Fig. 24.** Representative heave response transfer functions for different semi-submersibles.

IF T= 12 s → SEMIS WILL MOVE UP AND DOWN (HEAVE) 20 TO 50% OF THE WAVE AMPLITUDE



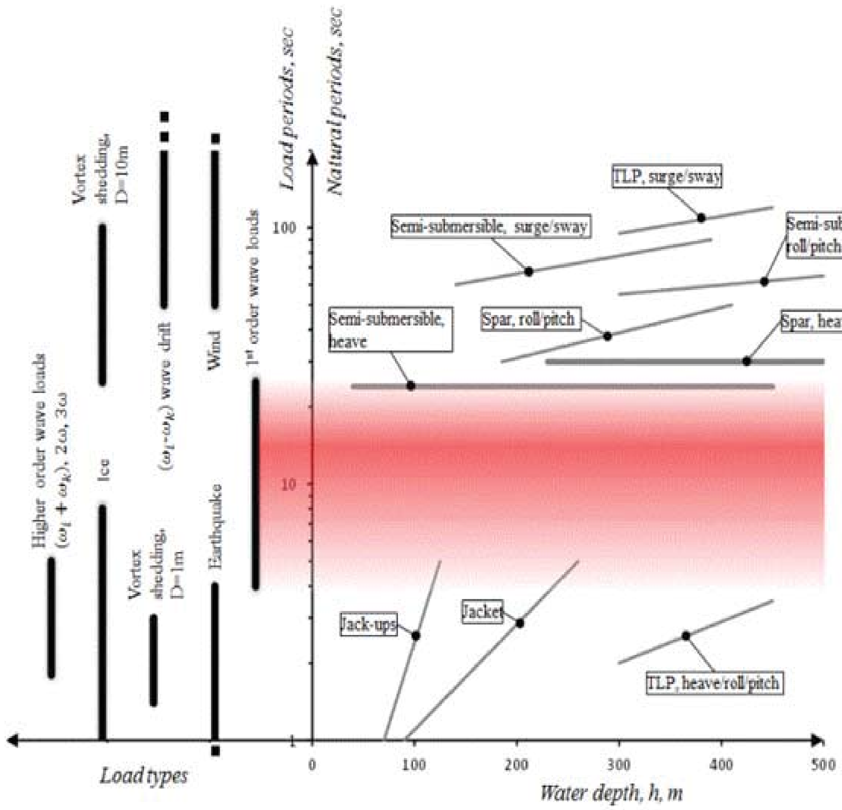
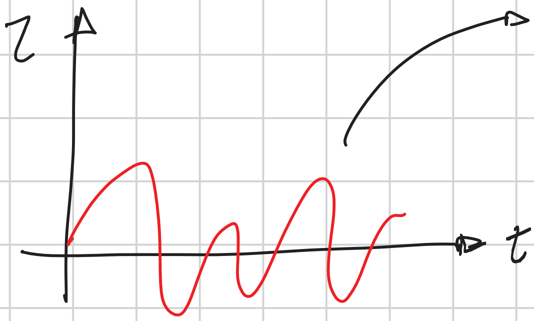




Illustration of largest natural period versus depth for some platform concepts, and periods for important environmental loads.

- WAVE SPECTRUM :



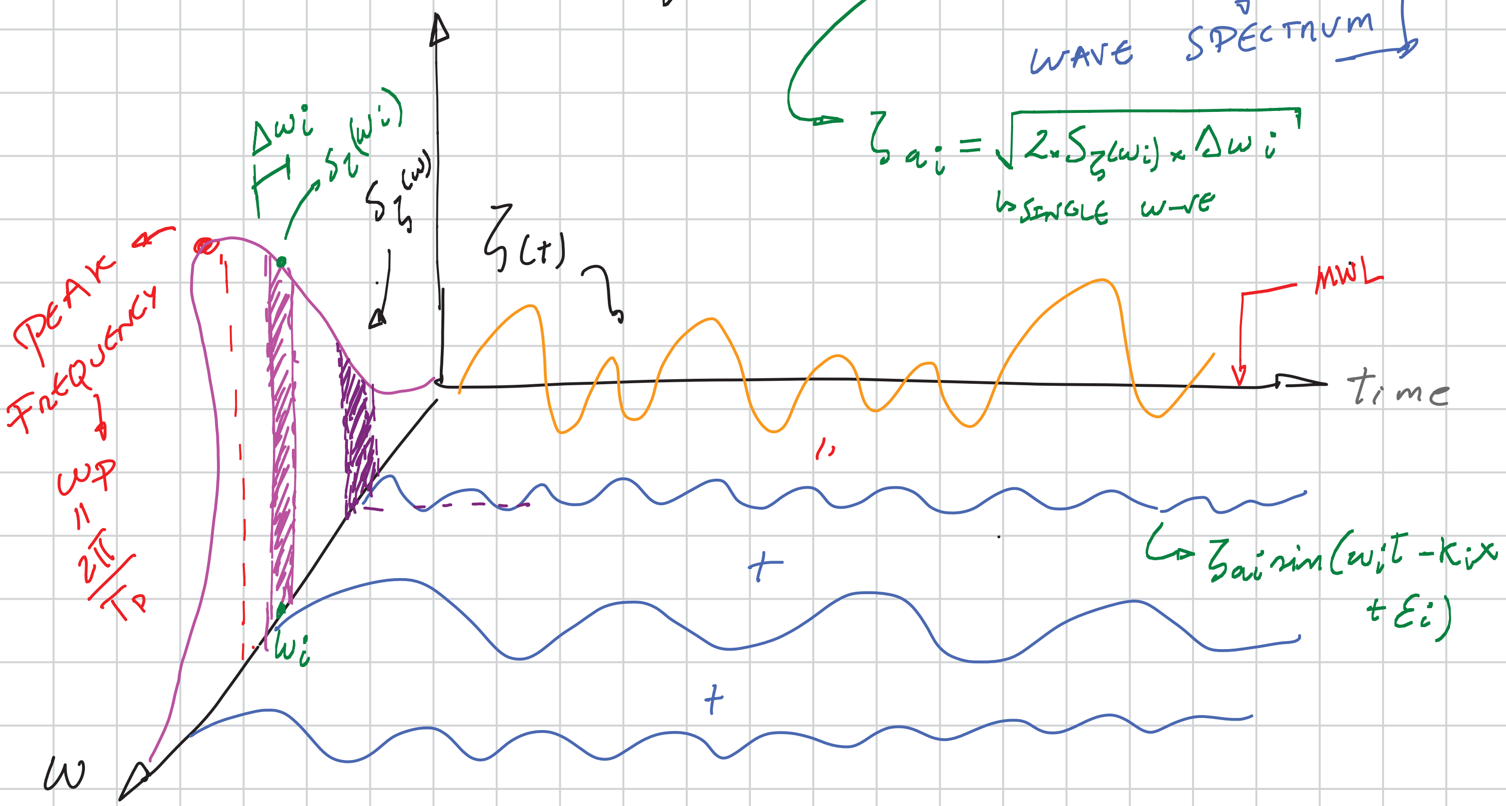

$$\frac{E}{\rho g} = \sum_{i=1}^{N} \frac{1}{2} \zeta_{a_i}^2(\omega_i)$$

SPECTRUM OF ENERGY :

$$\text{Energy}\left\{\frac{E}{\rho g} = \sum_{i=1}^{N} \frac{1}{2} \zeta_{a_i}^2(\omega_i) \triangleq \sum_{i=1}^{N} \underbrace{S_\zeta(\omega_i)}_{\text{WAVE SPECTRUM}} \times \Delta\omega_i\right.$$

$$\zeta_{a_i} = \sqrt{2 \times S_\zeta(\omega_i) \times \Delta\omega_i}$$

↳ SINGLE WAVE




SPECTRUM ⟹ STATISTICAL INFORMATION

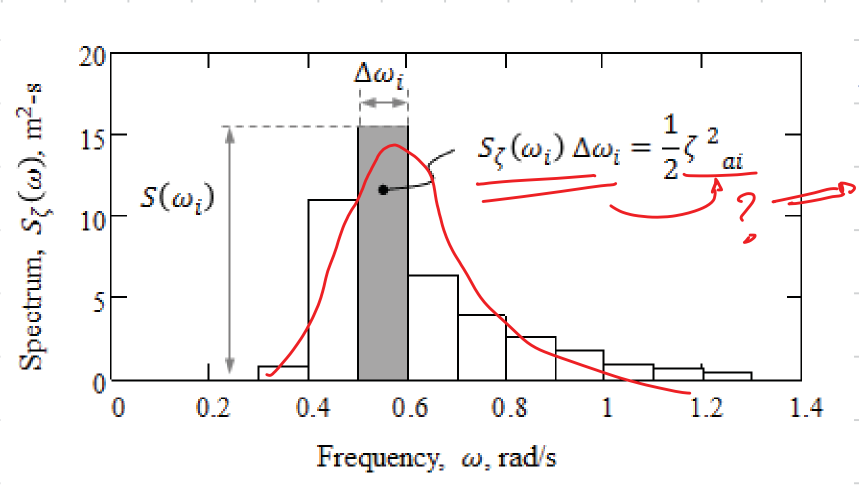
↳ PERIOD

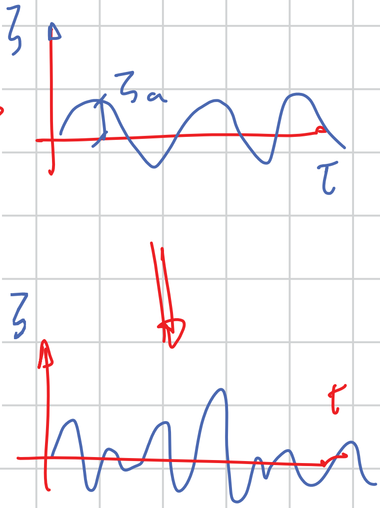
↳ $H_s$ (SIGNIFICANT WAVE HEIGHT)

$T_P$ (PEAK PERIOD) $= 2\pi / \omega_P$

$$\int_0^\infty S_\zeta(\omega)\, d\omega = \sigma_\zeta^2 \Rightarrow \sigma_\zeta \rightarrow \text{STD. DEVIATION OF THE WAVE SURF. ELEVATION}$$

$H_S = 4\sigma_\zeta$




USUALLY, THERE ARE CORRELATIONS.

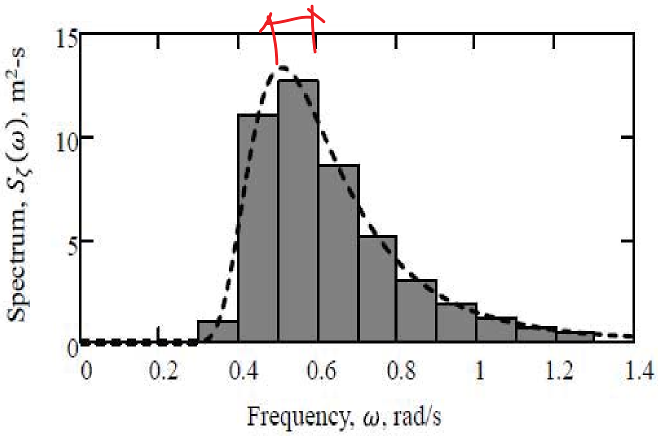
$T_{WAVES}$, $H_S$ ⇒ SPECTRUM

↳ HOW THE WAVES LOOK LIKE

## Ex. 1 Wave energy spectrum and time domain wave record

A wave energy spectrum obtained from 20 min sample of instrumentally recorded wave data in the Troll field (position 60° 45' 21.12" N 3° 38' 22.98" E) is given in the figure below. The spectrum has been simplified to a column type diagram with frequency steps of $\Delta\omega_i$=0.1 rad/s, and the values are given in the table. This sea state is formed by long crested deep-water waves.

$\Delta\omega_i = 0.1\ rad/s$




| ω | $S_\zeta$ |
|---|---|
| rad/s | $m^2$-s |
| 0.35 | 1.1 |
| 0.45 | 11.1 |
| 0.55 | 12.6 |
| 0.65 | 8.6 |
| 0.75 | 5.2 |
| 0.85 | 3.1 |
| 0.95 | 1.9 |
| 1.05 | 1.2 |
| 1.15 | 0.8 |
| 1.25 | 0.5 |

**Tasks:**

1. Find the wave surface elevation amplitude for each wave component
2. Find and plot the wave elevation function corresponding to the first, fourth and eighth wave component (0.35, 0.65 and1.05 rad/s).
3. Then, find and plot the resulting wave surface elevation by adding the contribution of all the harmonic wave components for time steps such as: 0,1,2 … 300s.
   - Generate random values for the phase angle $\varepsilon_i$ among all wave components. To do so, it is possible to use excel functions as follow: =RAND()*2*Pi()

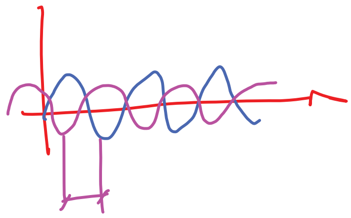
Useful equations:

Wave surface elevation for an *"i"* harmonic component: $\zeta_i(x,t) = \zeta_{ai}\, sin(\omega_i * t + \varepsilon_i)$

Total wave surface elevation: $\zeta(x,t) = \sum_{i=1}^{N} \zeta_{ai}\, sin(\omega_i * t + \varepsilon_i)$

Wave energy spectrum: $\frac{1}{2}\zeta^2{}_{ai}(\omega_i) \triangleq S_\zeta(\omega_i)\,\Delta\omega_i$

$$\frac{E}{\rho g} = \sum_{i=1}^{N} \frac{1}{2}\zeta^2{}_{ai}(\omega_i) \triangleq \sum_{i=1}^{N} S_\zeta(\omega_i)\,\Delta\omega_i$$



$\varepsilon \rightarrow$ USE RANDOM FUNCTION

# Multiphase boosting.

radial impeller | mixed flow | axial flow

GVF

0 ———————————— 1

0 pure liquid

0.96 – 1 radial pure gas

0.3: radial

0.7: mixed flow

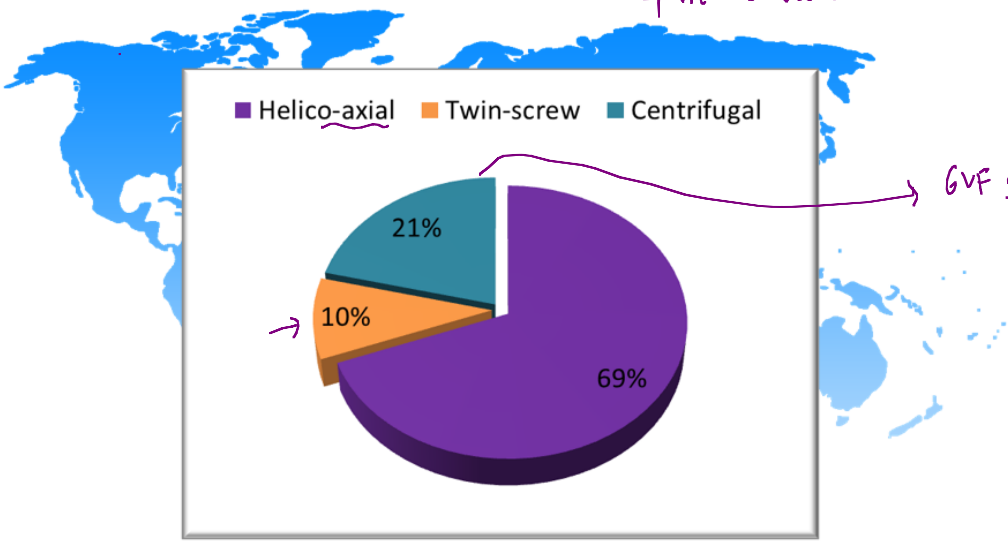
can get ↑Δp with few stages

axial impeller: get less Δp ⟶ increase the number of stages

**Subsea multiphase boosting around the world**

52 subsea pumps in 23 locations in the World

~ pumps in parallel
~ spare boosters




GVF ≤ 0.67

From http://www.offshore-mag.com/

helico-axial pump

(a) Impeller (b) Diffuser

GVF >, .95 wet gas compressor.

Counter rotating blades (Rotors).

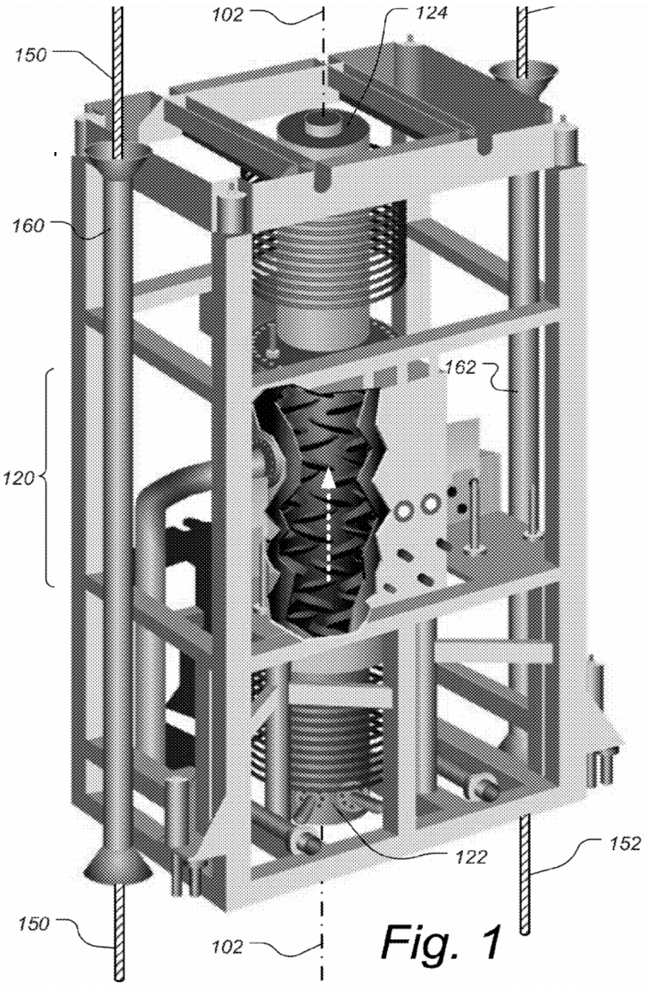



Fig. 1

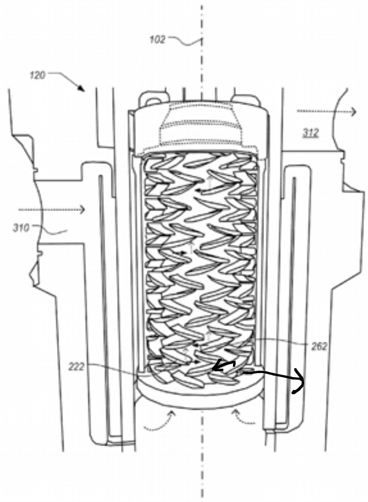
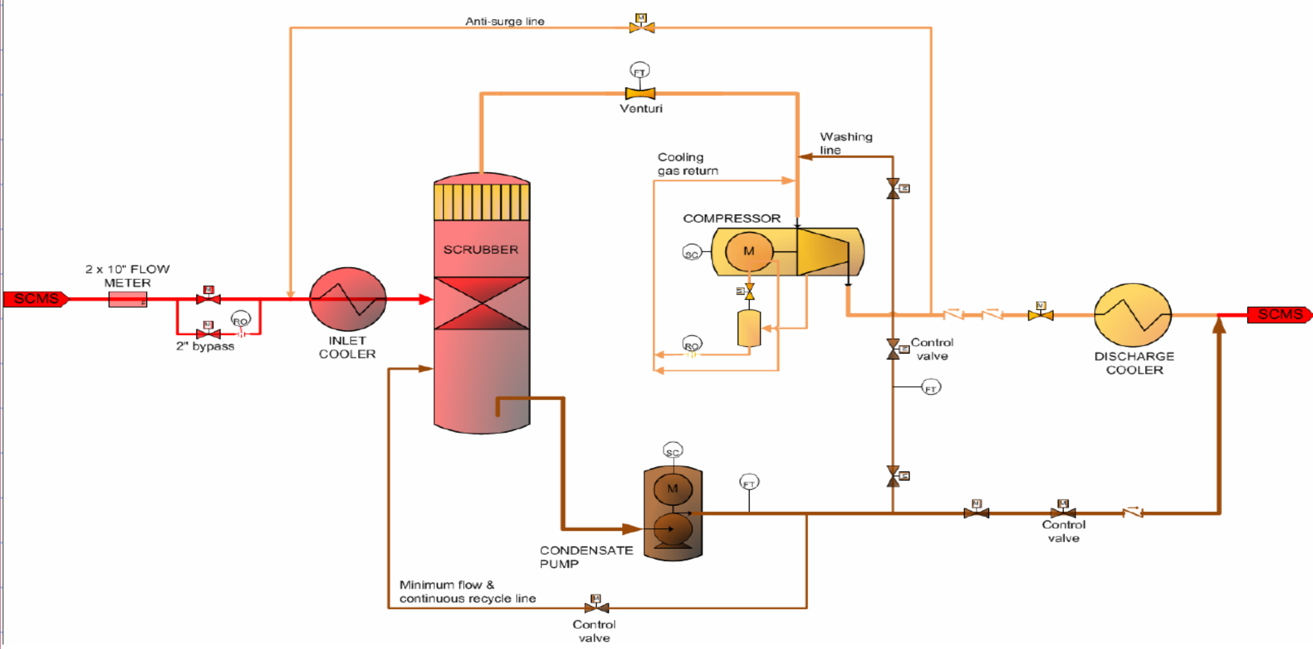


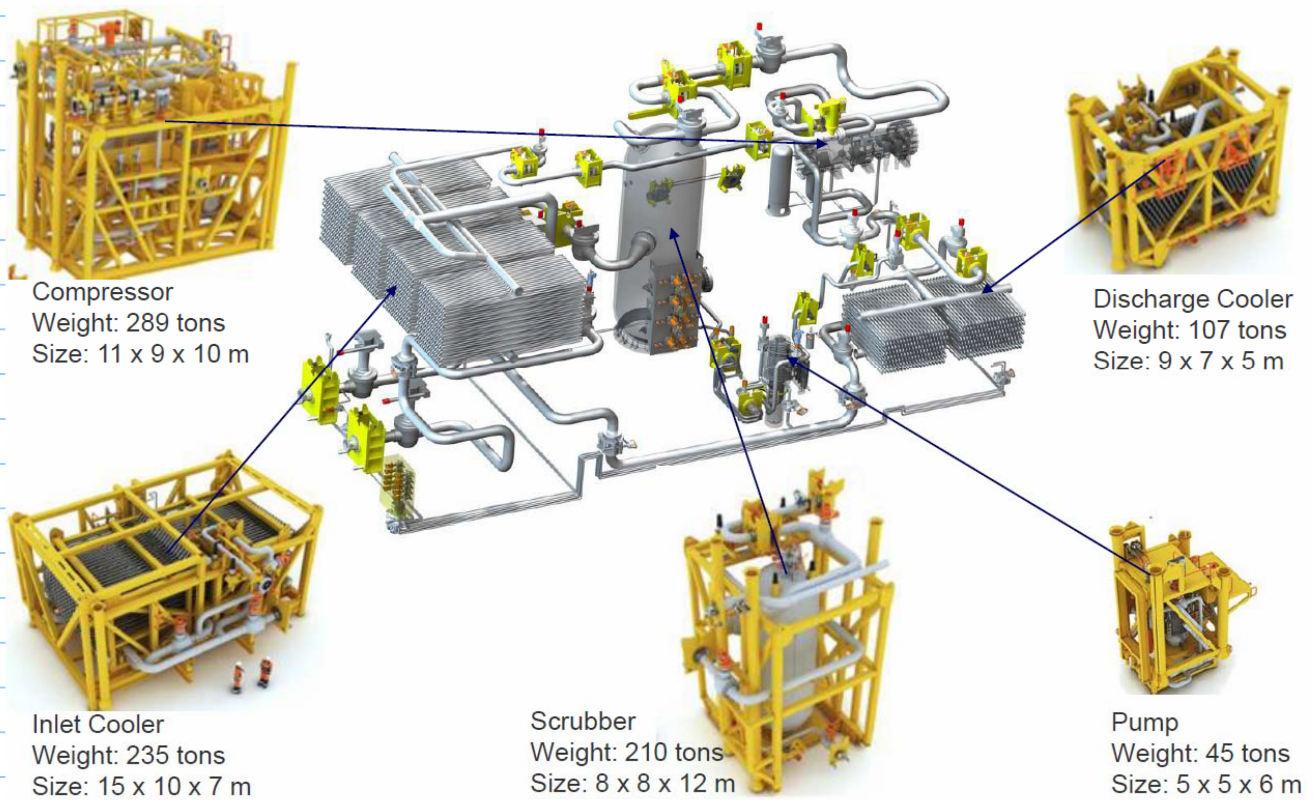

Fig. 3A

Aasgard dry gas compressor with separation before

# Process Flow Diagram

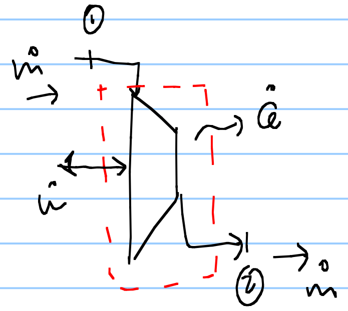



# Process Modules- Sizes and Dry Weights




dry gas compression

First law of thermodynamic for steady state open systems




$$\dot Q - \dot W = \dot m \left[ e_2 - e_1 \right]$$

$$\underbrace{e}_{\text{thermal, kinetic, potential}} = h + \cancel{\frac{v^2}{2}} + \cancel{z}\cdot g \approx h$$

$$\underbrace{\cancel{\dot Q}}_{0} - \dot W = \dot m (h_2 - h_1)$$

$$\dot W = \dot m (h_1 - h_2)$$ specific enthalpy

$$h = u + p\cdot v = u + \frac{p}{\rho}$$

$$\dot W = \dot m \left( \cancel{u_2} + P_2 v_2 - u_1 + P_1 \cdot v_1 \right)$$

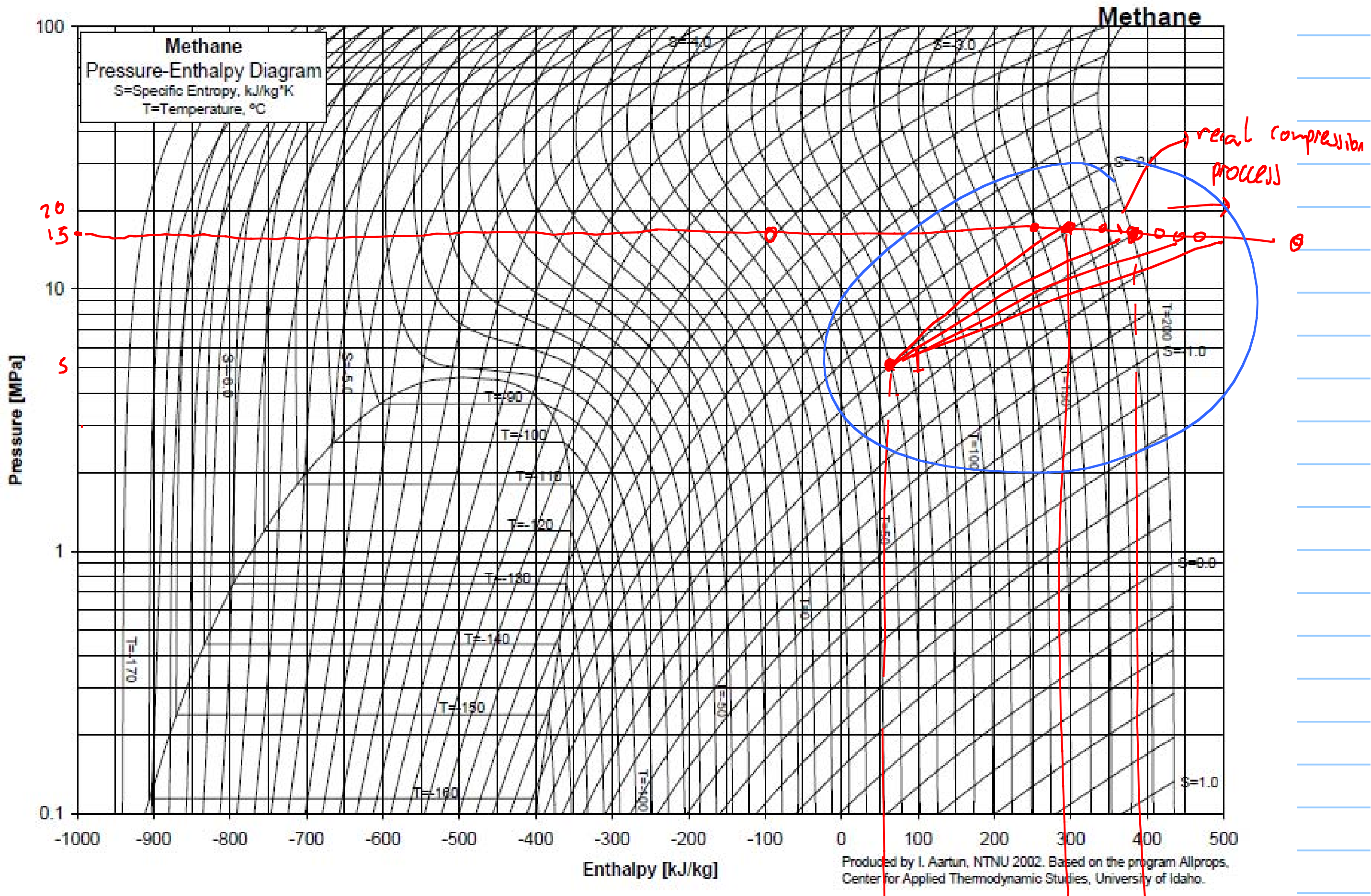
$f(T)$

$P = \Delta P \cdot q$

assumption $v_1 \approx v_2$

$u_1, u_2 << P_2 v_1$

$$\dot W = \frac{\dot m}{\rho} \cdot (P_2 - P_1) = q (P_2 - P_2)$$




ideal compressor $\Delta h$

$T_{inlet} = 70°C$

$P_{inlet} = 50$ bara

$P_{outlet} = 150$ bara

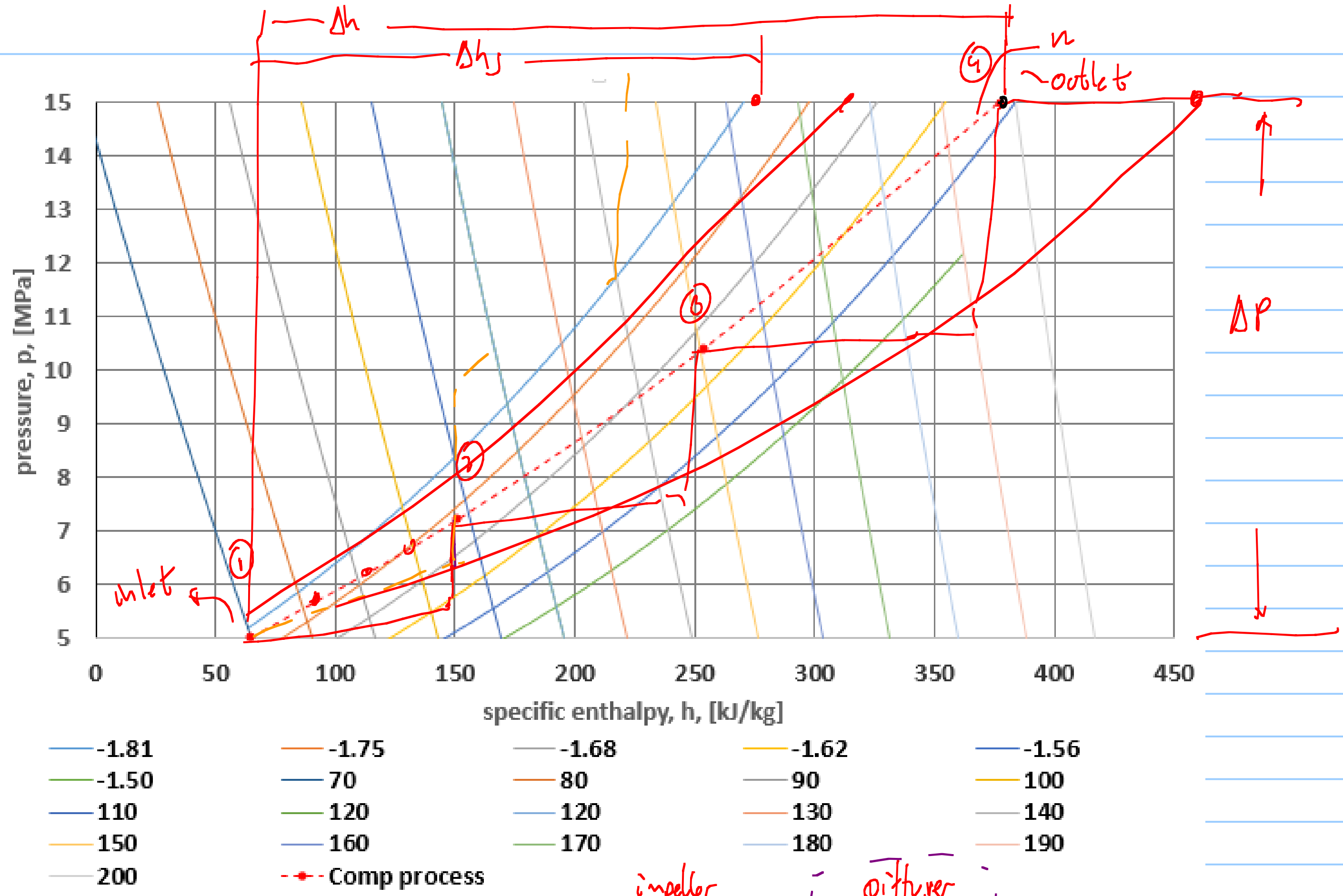
$\eta_{compressor} = \dfrac{\text{ideal compressor work}}{\text{real compressor work}}$

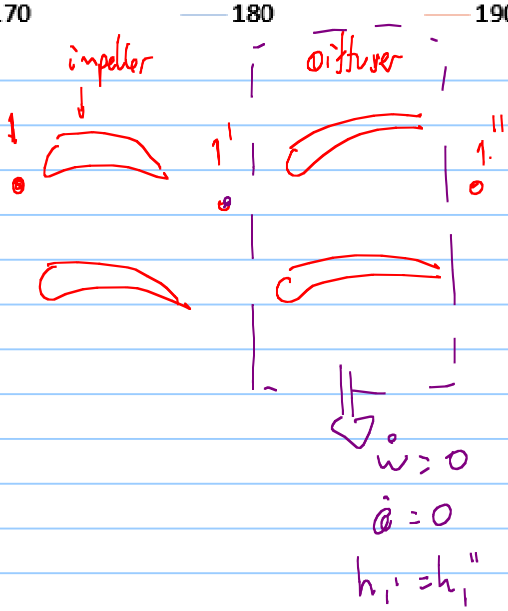
↳ adiabatic efficiency

$$\eta_{com} = \frac{\Delta h_s}{\Delta h_r}$$

$$\eta_{adia} = \frac{h_{2s} - h_1}{h_2 - h_1}$$

$pv^n = \text{const.}$ — $n$: polytropic coefficient




$r_p$ = constant

$$\frac{P_{stage\,1}}{P_{int}} = \frac{P_{stage\,2}}{P_{stage\,1}} = \frac{P_{outlet}}{P_{stage\,2}} = r_p$$

when I have a multiphase mixture?

$$h_i = \sum x_i h_i$$ mass fraction of component $i$

$$h_i = x h_g + (1-x) h_f$$

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}}$$ for a polytropic process

$\frac{n-1}{n}$ → efficiency

1 inlet compressor

2 outlet compressor

$\sim P_2, T_1 \sim$

Constraints on the compressor operation

simplified analysis i need an representative efficiency

$n \quad f(\eta_p) \quad \eta_p = 0.70$

$0.80$

detailed analysis

- $P_{suc}$
- minimum flow $\sim$ surge
- maximum flow $\rightarrow$ choked flow / sonic flow in the machine
- frequency
- Required power
- $T_{outlet}$

integrity of downstream piping

$T \lesssim 150°C$

integrity seals

$T \lesssim 180°C$

hydrate inhibitors:

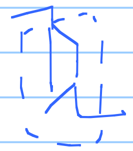
to avoid evaporation

$T_{out} \lesssim 140°C$

Note Title 12.04.2016

Compression process

$\dot{W} = \dot{m}(h_2 - h_1)$ $\quad P_1 \rightarrow P_2$



$\frac{\dot{W}}{\dot{m}} = w \sim$ specific work

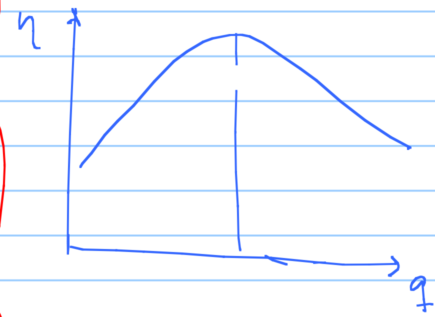
$(h_{2s} - h_1) \rightarrow$ smallest specific work required to compress from 1 to 2

$T_{2s}$ is the smallest outlet temperature that i can get when compressing from 1 to 2

is difficult to relate it with $q, \Delta p$

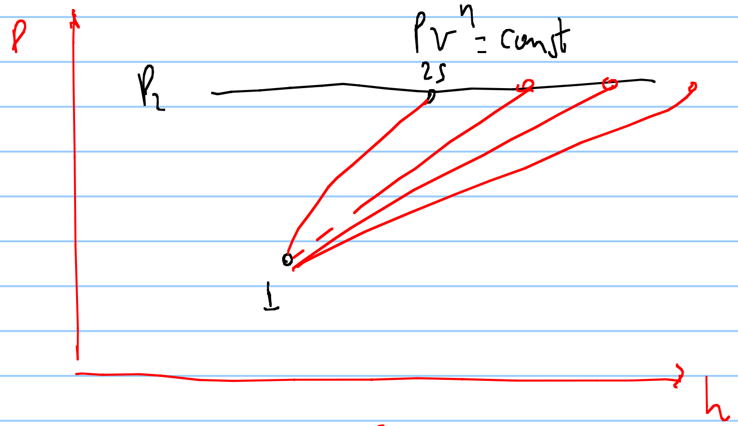
$$\eta_{adiabatic} = \frac{\Delta h_s}{\Delta h_{real}}$$

example for pump





assume polytropic process





$$\left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} = \frac{T_2}{T_1} \rightarrow \eta_p \text{ polytropic efficiency} \rightarrow f(n)$$

$$r_p^{\frac{n-1}{n}} = \frac{T_2}{T_1}$$

$$r_p = \frac{P_2}{P_1}$$

resembles a bit for liquids

$\Delta h \simeq C_p(\Delta T)$

if a polytropic process : $\Delta h_p = T_1 \, Z_{av} \, R \, \frac{n}{n-1} \left( r_p^{\frac{n-1}{n}} - 1 \right)$

$\Delta h_p$: calculated assuming a politropic process

$Z_{av}$: $\frac{Z_1 + Z_2}{2}$

$R$: $\frac{\bar{R}_u}{M_g} \sim$ molecular weight of the gas

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

$$\eta_p = \frac{\Delta h_s}{\Delta h_p}$$

$$\Delta h_s = Z_{av} \cdot T_1 \, R \cdot \frac{k}{k-1}\left[r_p^{\frac{k-1}{k}} - 1\right] \qquad k = \frac{C_v(T)}{C_p(T)}$$

adiabatic coefficient, exponent

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

polytropic efficiency

polytropic exponent

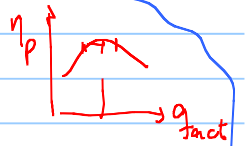
$k = 1.3 - 0.31(\gamma_g - 0.55)$

HC

$\eta_p$ for radial compressors $\{$ 0.6 – 0.77

$\eta_p$ for axial compressors $\{$ 0.8 – 0.85

we are going to use for class exercise $\eta_p = 0.73$

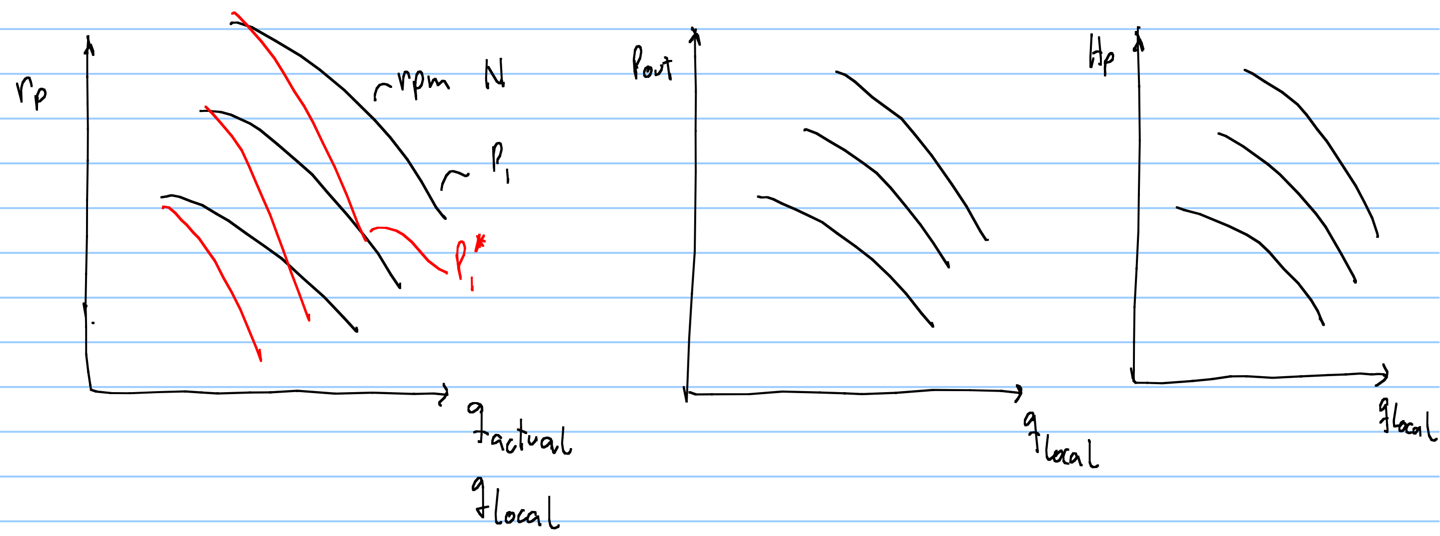



$q_{sc} \cdot \rho_{sc}$ , $q_{act} \cdot \rho_{act}$

$P = \dot{m}\,\Delta h_p$

polytropic head $H_p = \dfrac{\Delta h_p}{g} \rightsquigarrow [m]$ $\qquad \dfrac{\Delta P}{\rho} = h\,[m]$

Performance curves $\quad f(P_1, T_1, \gamma_g, k)$

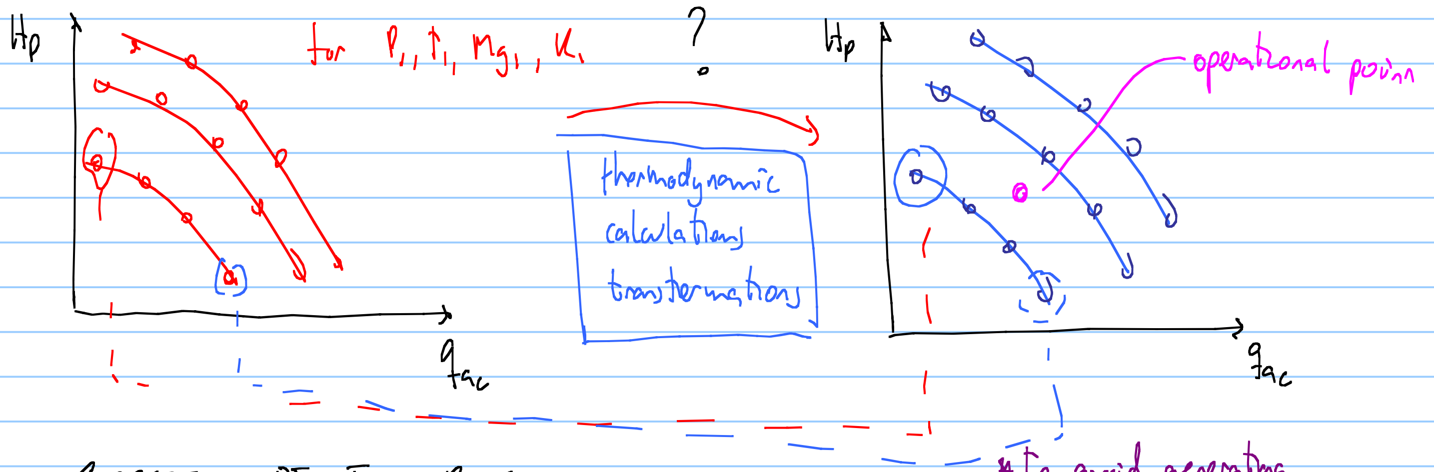


Usually compressor performance curves are measured for a specif set of inlet conditions $P_1, T_1$ → use a particular fluid $Mg, K$

$P_1$ = 1.01325 bara, $T_1$ = 15.6 °C

only for the exercise. *

$P_1^*, T_1^*, Mg_1^*, K_1^*$




* to avoid generating performance map for every year.

- CORRECTION OF FLOW RATE :

$$\phi = \frac{\dot m}{\rho_{01} a_{01} D^2} \Rightarrow \underset{(TEST)}{\phi_T} = \underset{(ACTUAL)}{\phi_a} \Rightarrow \frac{\dot m_T}{\rho_T a_T \cancel{D^2}} = \frac{\dot m_a}{\rho_a a_a \cancel{D^2}}$$

$$\Rightarrow \frac{q_T \cdot \cancel{\rho_T}}{\cancel{\rho_T}\, a_T} = \frac{q_a \cancel{\rho_a}}{\cancel{\rho_a}\, a_a} \Rightarrow q_a = q_{TEST} \times \frac{\sqrt{k_a R_a T_a}}{\sqrt{K_{TEST} R_{TEST} T_{TEST}}}$$

$$\Rightarrow \boxed{q_{ACTUAL} = q_{TEST} \sqrt{\frac{K_a}{K_{TEST}}} \times \sqrt{\frac{M_{TEST}}{M_a}} \times \sqrt{\frac{T_a}{T_{TEST}}}}$$

- CORRECTION OF PRESSURE RATIO :

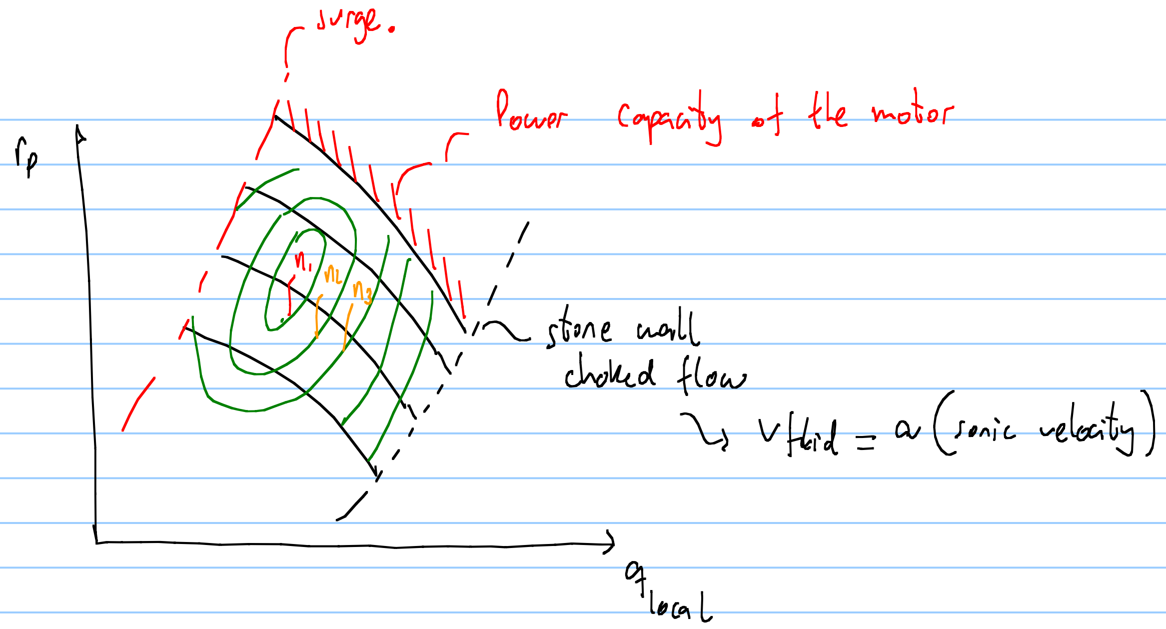
THE POLYTROPIC HEAD REMAINS THE SAME…

$$\boxed{H_{P_{TEST}} = H_{P_A}}$$

$$\left[ R T_1 Z_1 \frac{n}{n-1} \left[ r_p^{\frac{n-1}{n}} - 1 \right] \right]_{TEST} = \left[ R T_1 Z_1 \frac{n}{n-1} \left[ r_p^{\frac{n-1}{n}} - 1 \right] \right]_{ACTUAL}$$

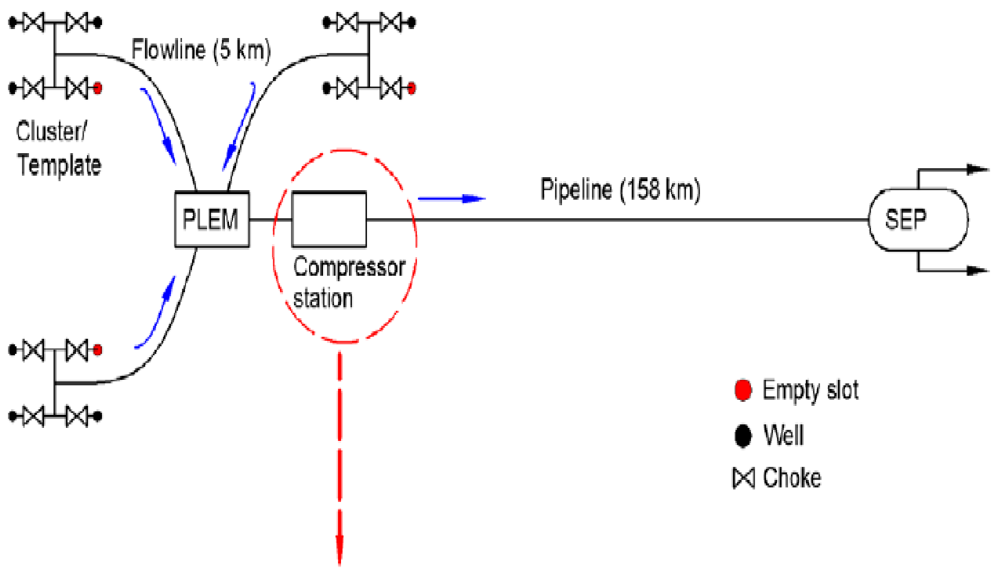
$$\frac{n-1}{n} = \frac{k-1}{k \cdot \eta_p}$$

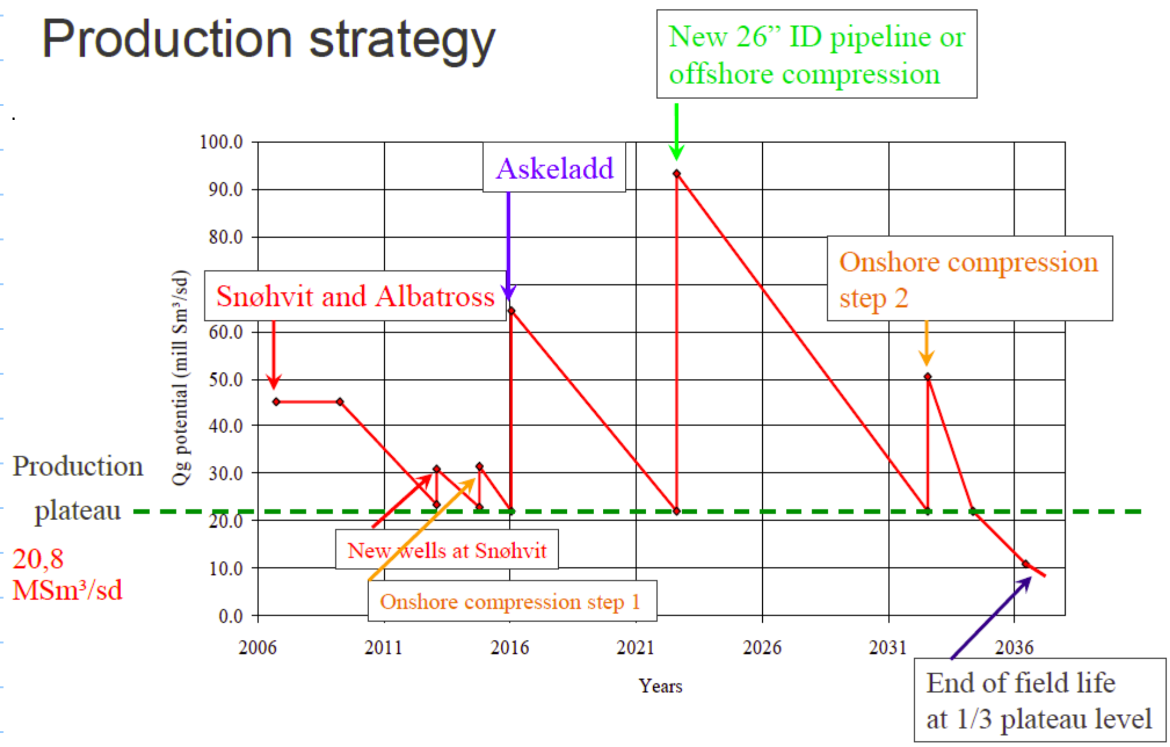
THEN …
$$\boxed{r_{p_a} = \left[ \frac{M_a}{M_T} \frac{T_T}{T_a} \frac{Z_a}{Z_T} \frac{\frac{n_T}{n_T - 1}}{\frac{n_a}{n_a - 1}} \left[ r_{p_T}^{\frac{n_T - 1}{n_T}} - 1 \right] + 1 \right]^{\frac{n_a}{n_a - 1}}}$$



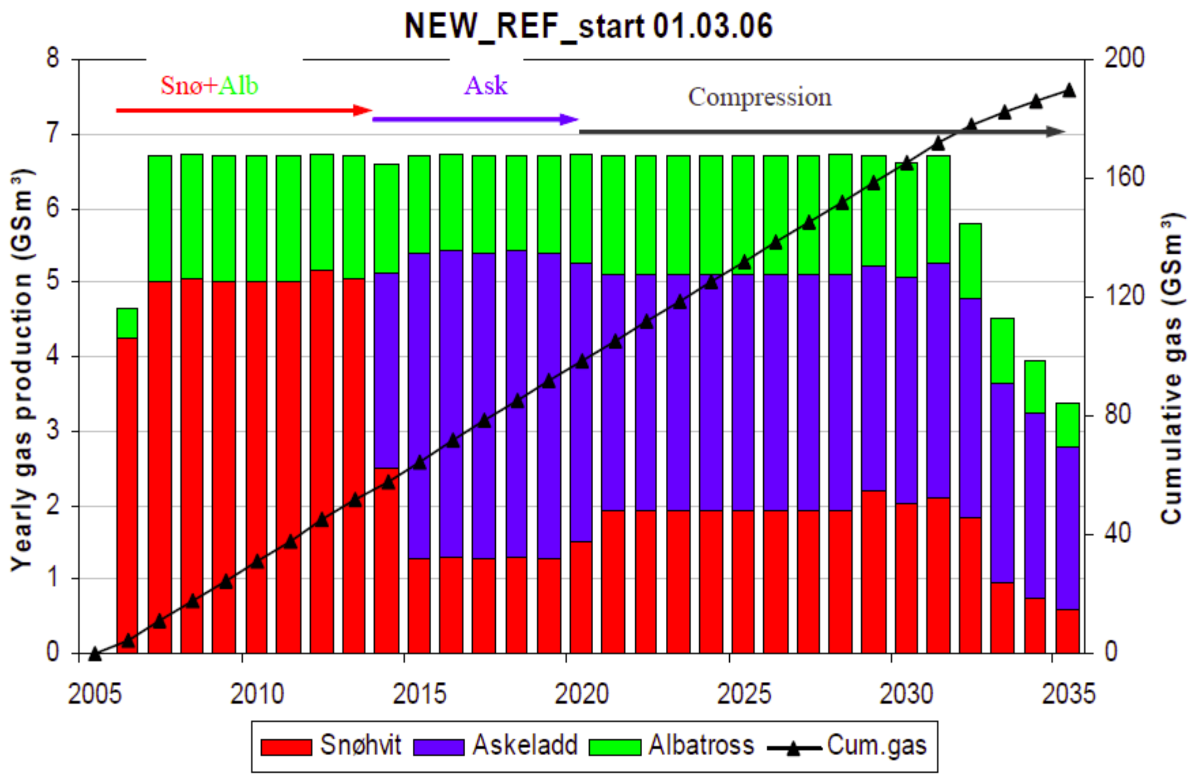

Class exercise

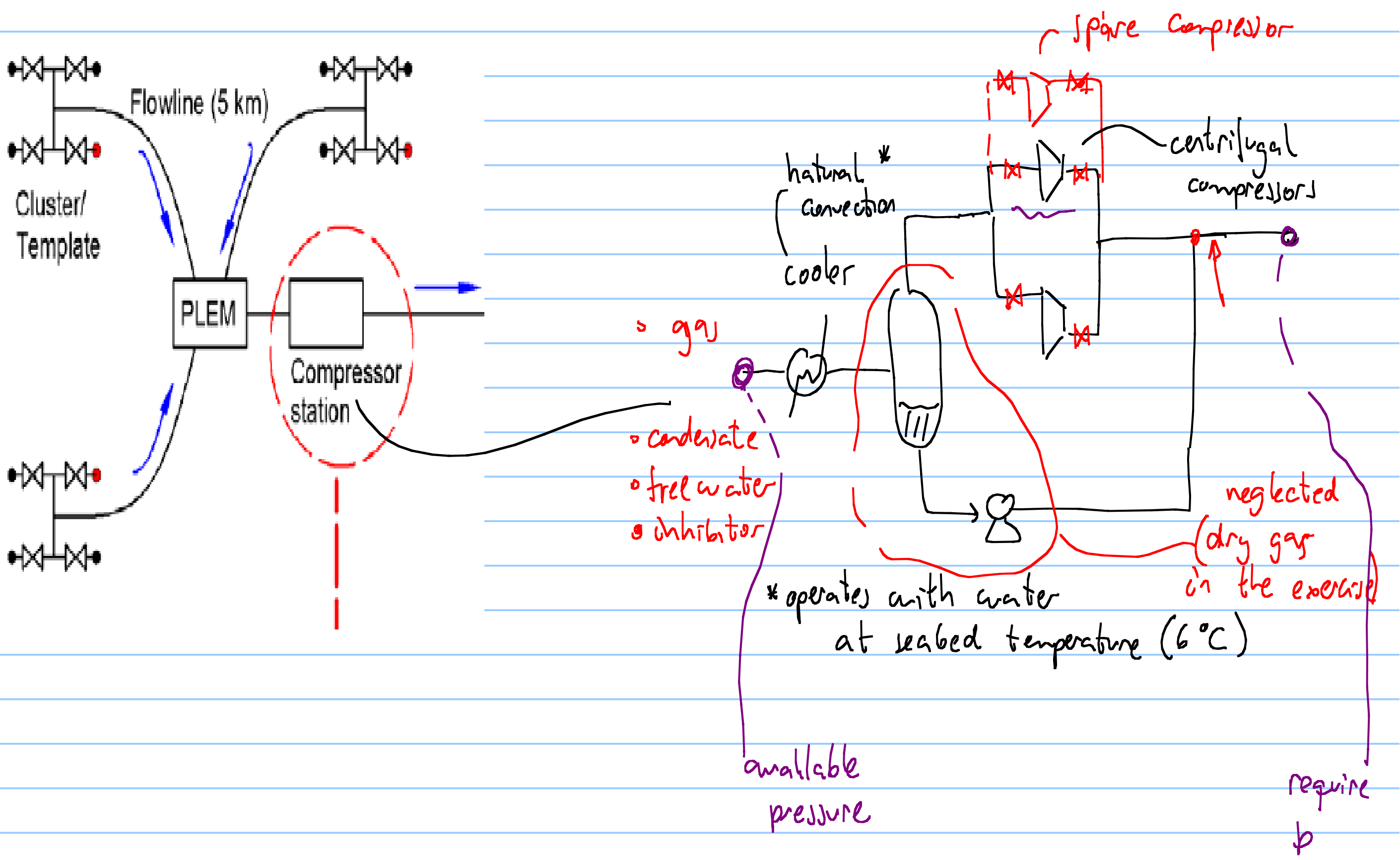
Snøhvit



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



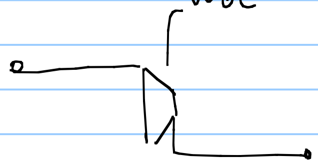



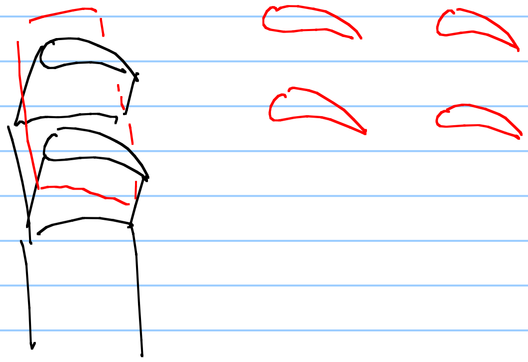

$\Delta p$ needed is high

a) a side note: other option for boosting

WGC wet gas compressor

$\Delta p \leq 40$ bara





assumptions / requirements for the exercise:

- $\eta_p = \text{const} = 0.7$
- $T_{discharge} \leq 150°C$ { seals integrity; avoid vaporization of inhibitor; to avoid structural problems in discharge pipeline } operational constraints / general compressor constraints → later: specific compressor constraints with the performance curve.
- $T_{inlet} = 67°C$ compressor station
- Cooler is operating with $T_{amb} = 6°C$ $\qquad \Delta T_{MAX} = 27°C$
- Power of each compressor unit: 11 MW. $\qquad$ Max total = 22 MW.
- $P_{suc} \geq 20$ bara

$$r_p^{\frac{n-1}{n}} = \frac{T_2}{T_1} \qquad T_2 = T_1 \, r_p^{\frac{n-1}{n}} \; ✓ \; ?$$

T in absolute units K, °R

$$B_g(P,T) = \frac{q_{g\,local}}{q_{\bar{g}}}$$

$$q_{g\,local} = q_{\bar{g}} \cdot B_g(P,T)$$

for this class $z_{av} \approx z_1$

$q_{sc} \cdot \rho_{sc}$

$\frac{m^3}{d} \quad \frac{kg}{m^3} \quad \frac{kg}{d} \quad \frac{1\,d}{(24\,h} \quad \frac{1\,h}{3600\,s)}$

$J = \frac{W}{s}$

$\Delta h = \frac{kJ}{}$

$P = \Delta h_p \cdot \dot{m}$

$\frac{kJ}{kg} \cdot \quad kg/s \qquad \frac{kJ}{s} \quad \frac{kW}{1000} = [MW]$

Debugging:

$\Delta h_p = \underset{\sim}{T_1 Z_{av}} R \frac{n}{n-1}\left(r_p^{\frac{n-1}{n}} - 1\right)$

? [K] $\frac{kJ}{kg\,K}$ $= \frac{kJ}{kg}$

$\bar{R} = 8314 \frac{J}{kgmol\,K}$

$8.314 \frac{kJ}{kgmol\,K}$

max = 22 MW

$P_{comp_1} + P_{comp_2}$

$T_{dis} \leq 150°C$

$P \geq 20$ bar

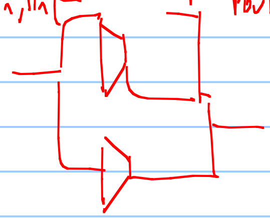
| year | $P_{suc}$ (bara) | Pplem req | Tsuc | rp | deltap | np | n | Tdis | zsuc | zdisc | Bg @suc | qg_local | Δhp | m | Power | Hp test | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | [bara] | [C] | [-] | [bar] | [-] | [-] | [C] | | | [m^3/Sm^: | [m^3/d] | [J/kg] | [kg/s] | [MW] | [m] | [m |
| 21 | 76.6 | 78.6 | 67 | 1.03 | 1.94 | 0.70 | 1.49 | 69.81 | 0.93 | 0.93 | 14.5E-3 | 289.3E+3 | 4126.15 | 156.0 | 643.6E-3 | 219.4E+0 | |
| 22 | 67.1 | 78.6 | 67 | 1.17 | 11.43 | 0.70 | 1.49 | 85.05 | 0.94 | 0.94 | 16.7E-3 | 332.7E+3 | 26754.95 | 156.0 | 4.2E+0 | 49.2E+0 | |
| 23 | 57.1 | 78.6 | 67 | 1.38 | 21.45 | 0.70 | 1.49 | 104.60 | 0.94 | 0.95 | 19.8E-3 | 394.5E+3 | 56384.84 | 156.0 | 8.8E+0 | 562.3E+0 | |
| 24 | 45.8 | 78.6 | 67 | 1.71 | 32.75 | 0.70 | 1.49 | 133.02 | 0.95 | 0.97 | 24.9E-3 | 497.1E+3 | 100283.54 | 156.0 | 15.6E+0 | 3.0E+3 | |
| 25 | 31.9 | 78.6 | 67 | 2.46 | 46.68 | 0.70 | 1.49 | 184.44 | 0.97 | 0.99 | 36.3E-3 | 724.1E+3 | 181242.31 | 156.0 | 28.3E+0 | 12.0E+3 | |
| 26 | 3.9 | 78.6 | 67 | 20.06 | 74.65 | 0.70 | 1.49 | 638.81 | 1.00 | 1.02 | 304.1E-3 | 6.1E+6 | 908936.00 | 156.0 | 141.8E+0 | 60.3E+9 | |
| | #VALUE! | 78.6 | 67 | #VALUE! | #VALUE! | 0.70 | 1.49 | #VALUE! | #VALUE! | #VALUE! | #VALUE! | #VALUE! | #VALUE! | 156.0 | #VALUE! | #VALUE! | # |
| | #VALUE! | 78.6 | 67 | #VALUE! | #VALUE! | 0.70 | 1.49 | #VALUE! | #VALUE! | #VALUE! | #VALUE! | #VALUE! | #VALUE! | 156.0 | #VALUE! | #VALUE! | # |

year 25

$\dot{m}_T \Delta h_p$

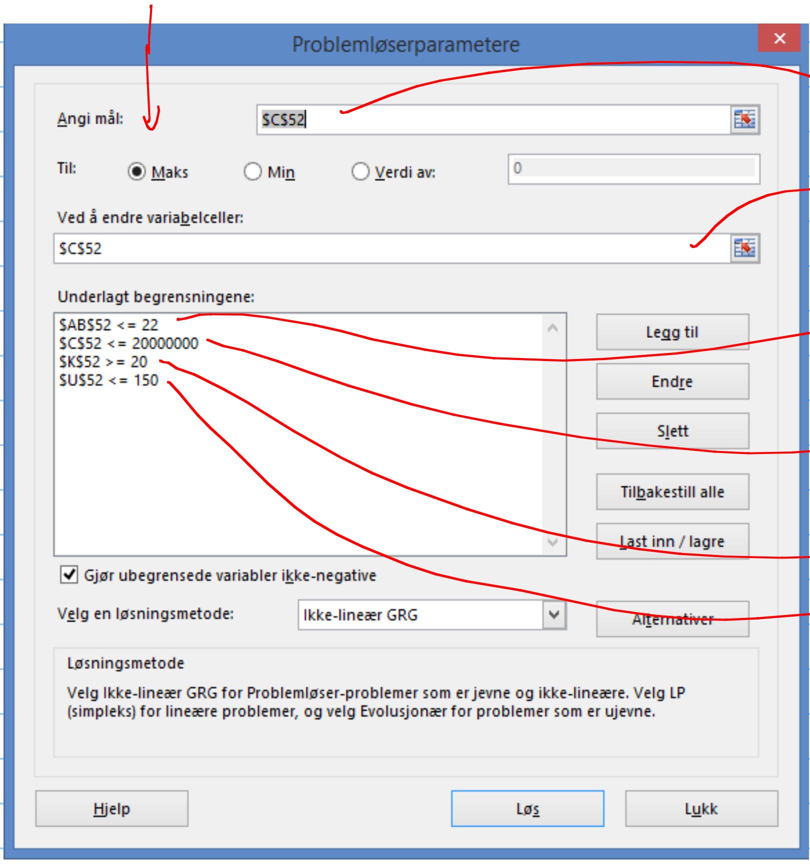
$\sqrt{\ } \quad \Delta h_p \cdot \dot{m}$

$P_{in}, T_{in}$ $\quad \Delta h_p \quad$ $P_{out}\ T_{out}$



$\frac{\dot{m}_T}{2} \cdot \Delta h_p + \frac{\dot{m}_T}{2} \Delta h_p$

Instead of reducing manually the field rate, I set up the solver to modify it automatically while honouring all operational constraints.



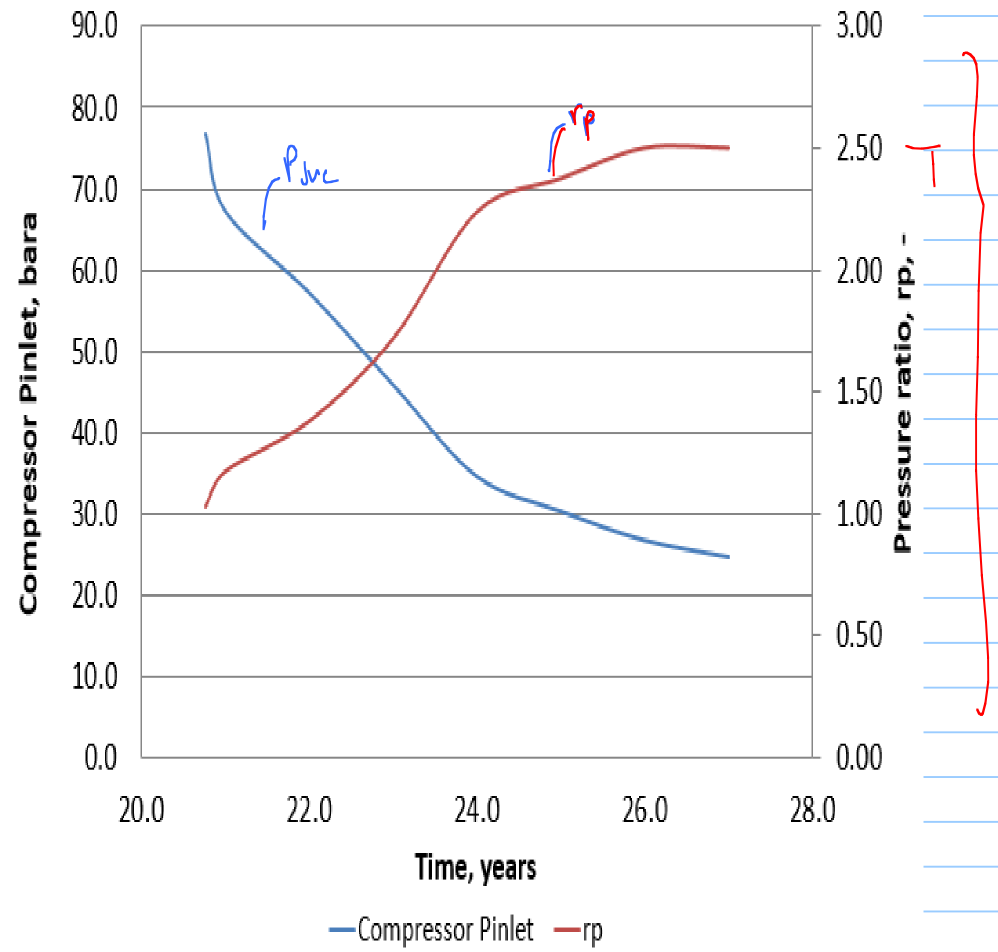

field rate

total power $\leq 22$ MW

$q_f \leq 20E6$ $Sm^3/d$

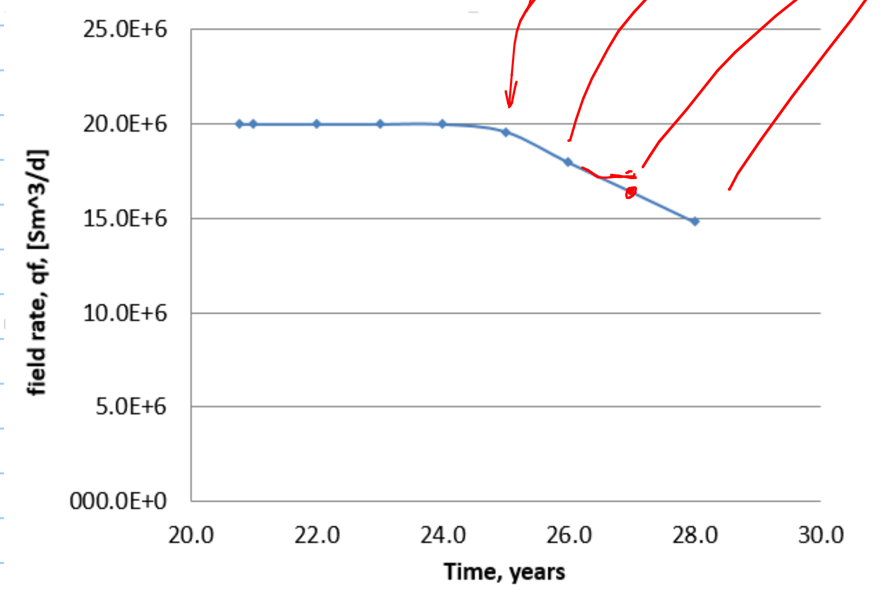
$P_{suc} \geq 20$ bara

$T_{dis} \leq 150°C$

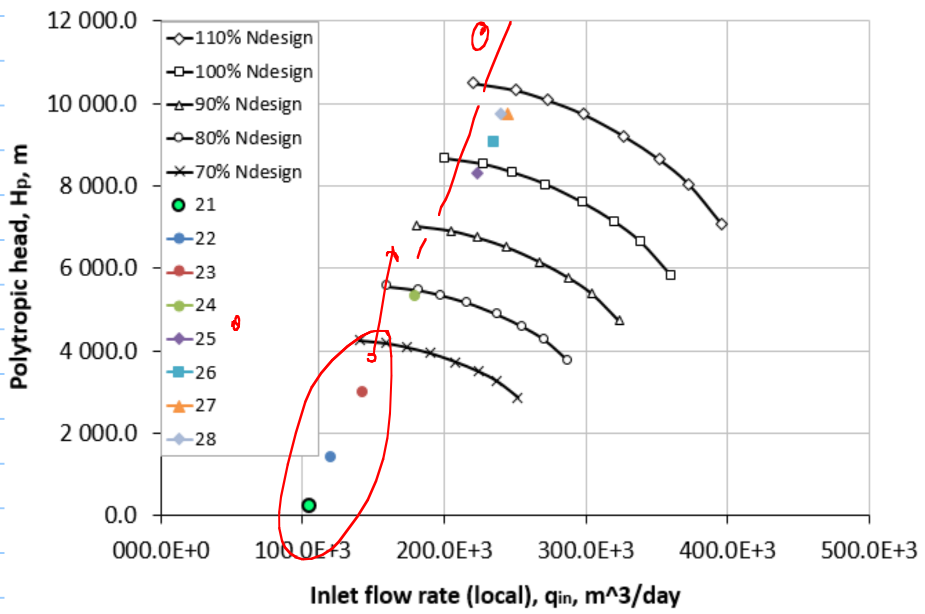


-3 years with plateau, no issues
-year 4 activate cooling to avoid excesive outlet temperature, compressor operating at maximum power, not possible to deliver plateau rate
-Year 5 , compressor operating at maximum power, not possible to deliver plateau rate
-years 6 and 7, reduce further the rate to avoid excessive outlet temperature, compressor operating at power less than maximum

activate cooling
$P = 22\,MW$ $P = 22\,MW$ $T_{dis} = 150°C$ $P \leq 22\,MW$




In the last two years outlet temperature is th limiting condition. I could produce more gas but then the cooler efficiency has to be improved.



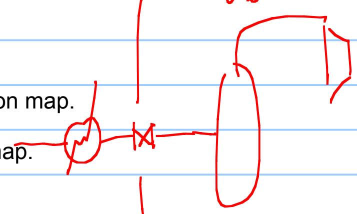

I have to move the points in the first 3 years inside the compressor map.

One solution is to choke at the inlet of the compressor.

In that way the compresor rp increases, i.e. the point goes up in the compression map.

I want to choke as less as possible, just to get the points inside the operation map.

additional valve choke

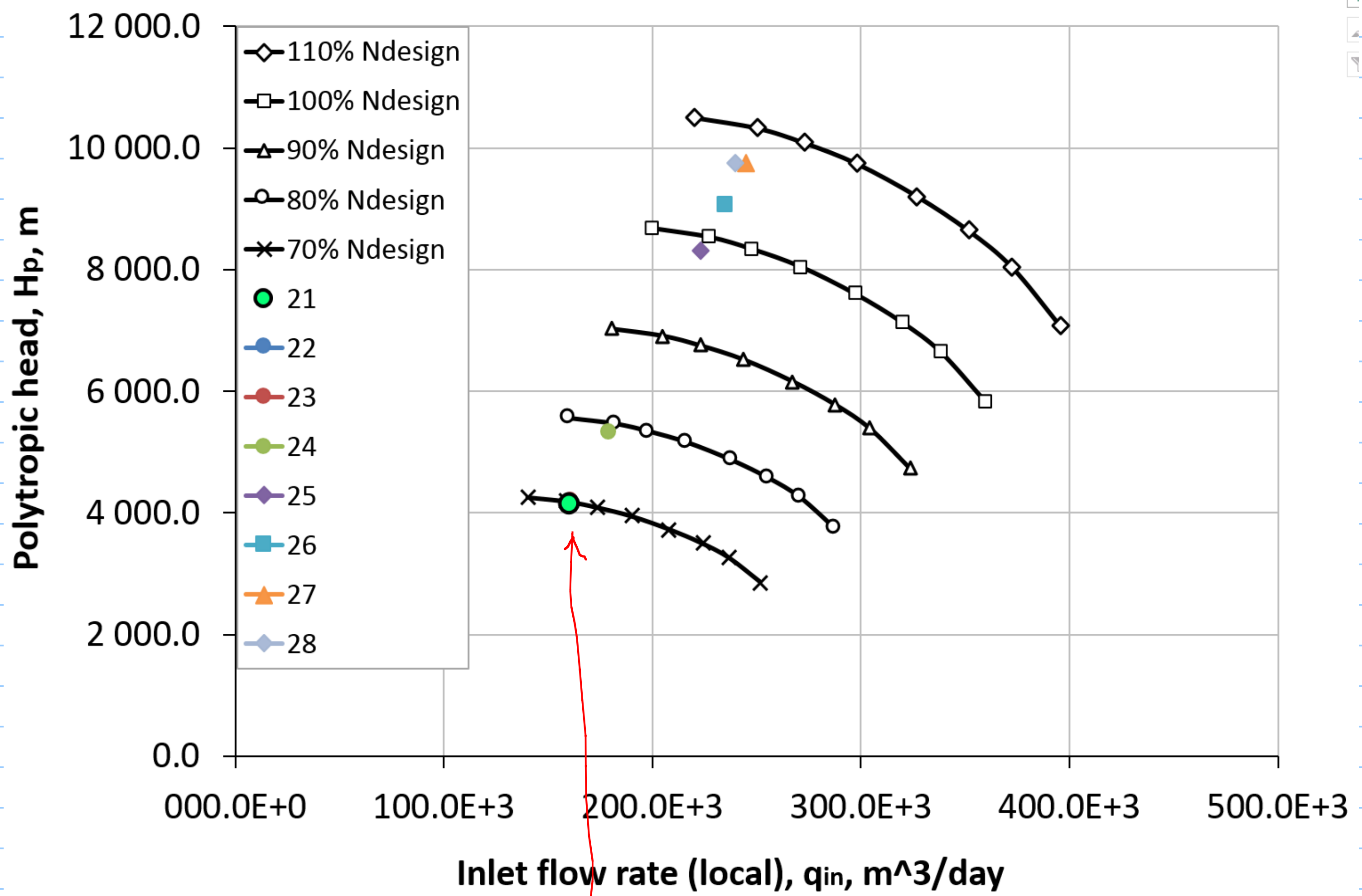


additional pressure drop to increase rp
$\Delta p_{comp}$

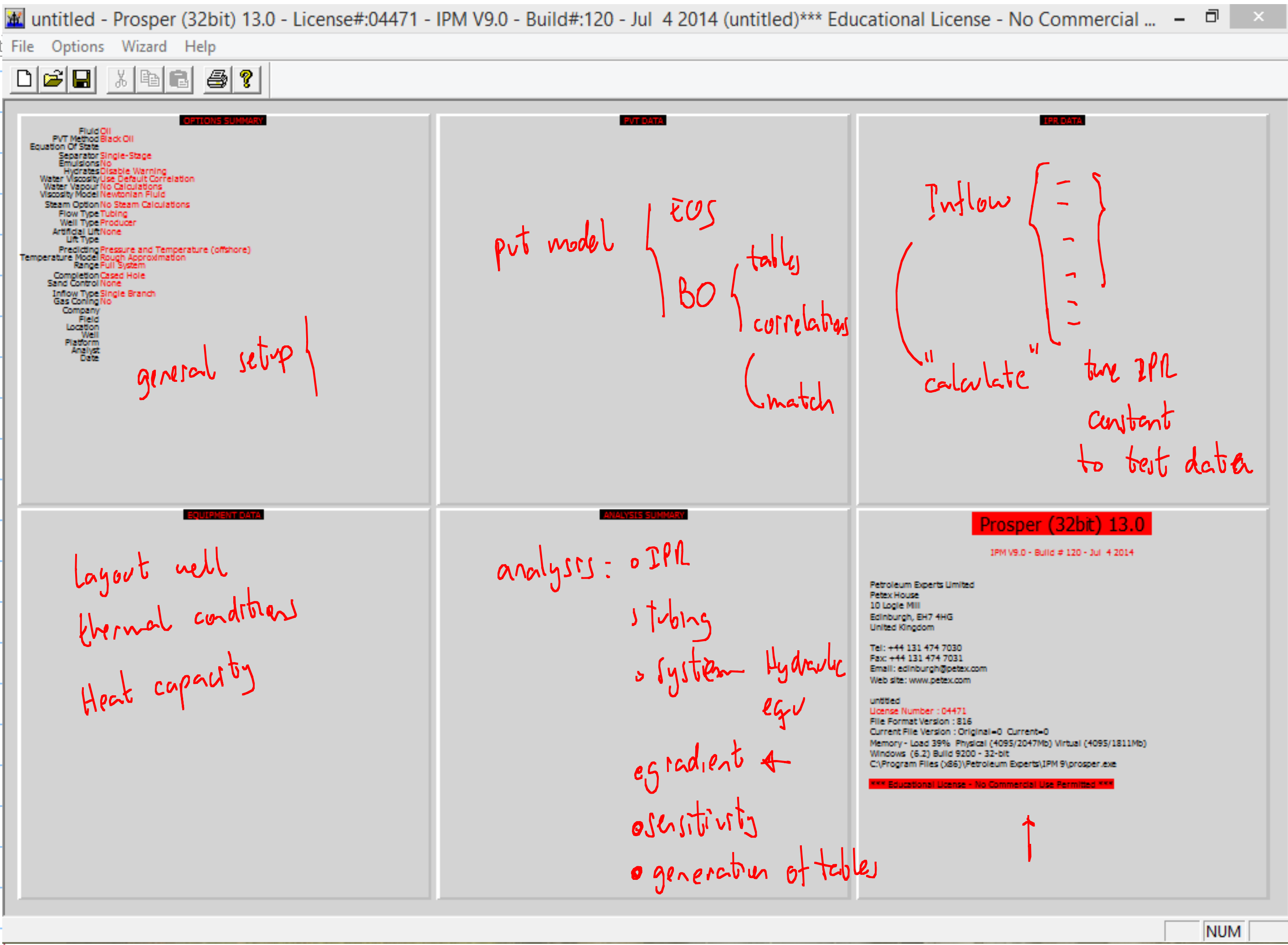
Modification of the excel sheet:

| 6 / 0 | Pplem req | deltap comp choke | psuc | Tsuc | rp | deltap | np | n | Tdis | zsuc | zdisc | Bg @suc | qg_local | Δhp | m | Power | Hp test | qact test | qact test single comp |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | [bara] | [bar] | [bara] | [C] | [-] | [bar] | [-] | [-] | [C] | | | [m^3/Sm^3] | [m^3/d] | [J/kg] | [kg/s] | [MW] | [m] | [m^3/d] | [m^3/d] |
| | 78.6 | 25.5 | 51.1 | 67 | 1.54 | 27.44 | 0.70 | 1.49 | 118.63 | 0.95 | 0.96 | 22.2E-3 | 443.2E+3 | 77954.84 | 156.0 | 12.2E+0 | 4.1E+3 | 320147.2 | 160073.6 |
| | 78.6 | 16 | 51.1 | 67 | 1.54 | 27.43 | 0.70 | 1.49 | 118.59 | 0.95 | 0.96 | 22.2E-3 | 443.1E+3 | 77893.47 | 156.0 | 12.1E+0 | 4.1E+3 | 320043.8 | 160021.9 |
| | 78.6 | 6.3 | 50.8 | 67 | 1.55 | 27.75 | 0.70 | 1.49 | 119.40 | 0.95 | 0.96 | 22.3E-3 | 446.0E+3 | 79145.59 | 156.0 | 12.3E+0 | 4.2E+3 | 322156.9 | 161078.4 |
| | 78.6 | 0 | 45.8 | 67 | 1.71 | 32.75 | 0.70 | 1.49 | 133.02 | 0.95 | 0.97 | 24.9E-3 | 497.1E+3 | 100283.54 | 156.0 | 15.6E+0 | 5.3E+3 | 359050.0 | 179525.0 |
| | 77.2 | 0 | 34.6 | 40 | 2.24 | 42.69 | 0.70 | 1.49 | 134.84 | 0.95 | 0.97 | 30.3E-3 | 592.6E+3 | 143884.32 | 152.9 | 22.0E+0 | 8.3E+3 | 446143.4 | 223071.7 |
| | 71.8 | 0 | 30.3 | 40 | 2.37 | 41.55 | 0.70 | 1.49 | 142.88 | 0.96 | 0.98 | 34.8E-3 | 624.0E+3 | 156933.95 | 140.2 | 22.0E+0 | 9.1E+3 | 469712.2 | 234856.1 |
| | 66.7 | 0 | 26.7 | 40 | 2.50 | 40.02 | 0.70 | 1.49 | 150.00 | 0.96 | 0.98 | 39.6E-3 | 649.3E+3 | 168531.01 | 128.1 | 21.6E+0 | 9.7E+3 | 488769.3 | 244384.6 |
| | 61.6 | 0 | 24.7 | 40 | 2.50 | 36.96 | 0.70 | 1.49 | 150.00 | 0.96 | 0.98 | 43.0E-3 | 636.9E+3 | 168880.65 | 115.7 | 19.5E+0 | 9.8E+3 | 479422.0 | 239711.0 |

The deltap of the inlet choke is changed manually for the first three years until all three points are inside the operational compressor map:




All points overlapping one on top of the other.




general setup

pvt model { EOS / BO { tables / correlations / (match

Inflow { "calculate" / tune IPR content to test data

layout well

thermal conditions

Heat capacity

analysis: o IPR

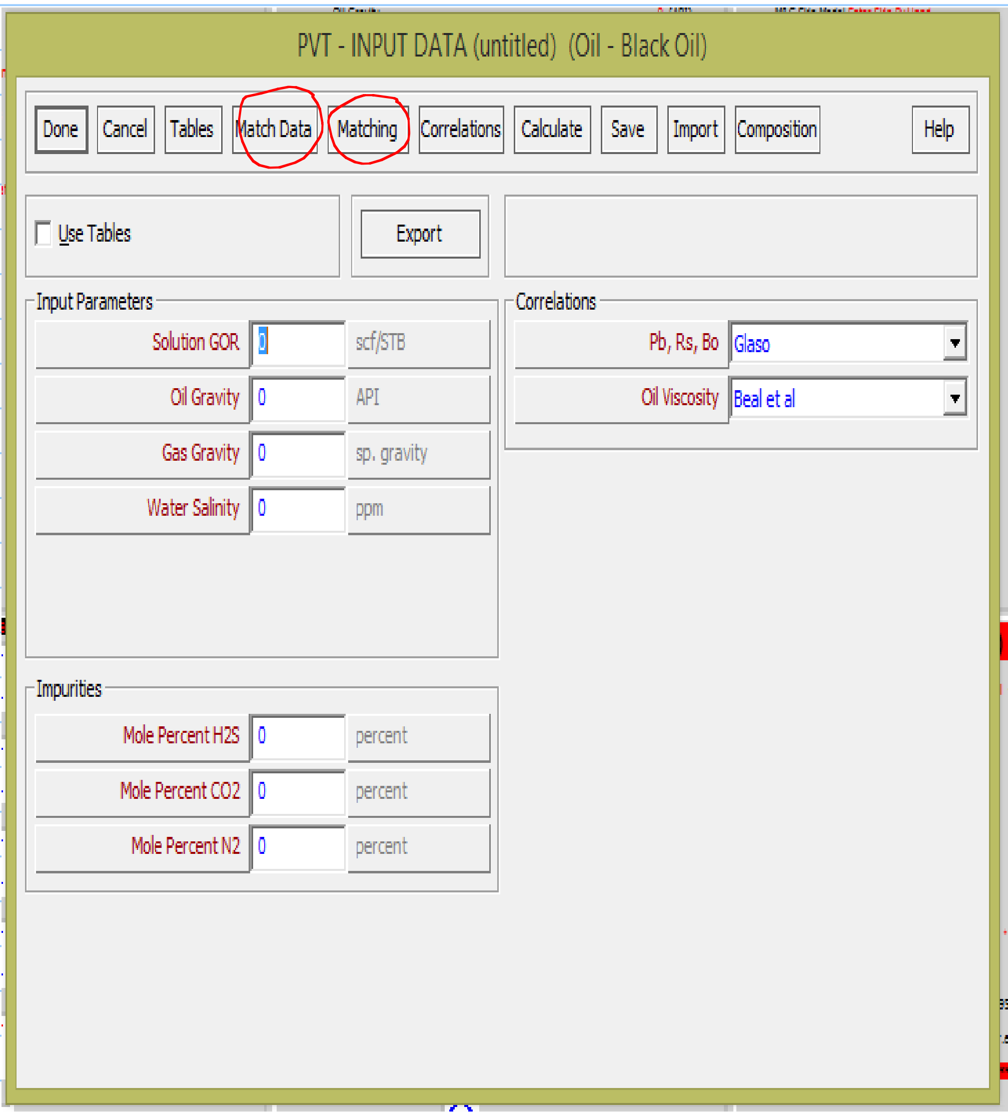
tubing

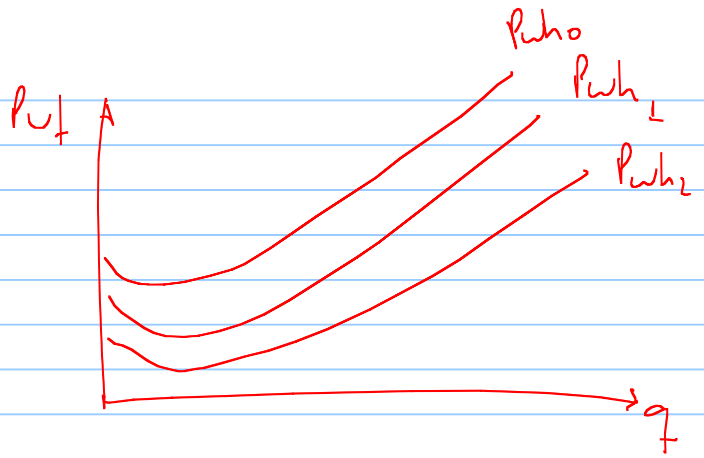
o system Hydraulic equ

o gradient ←

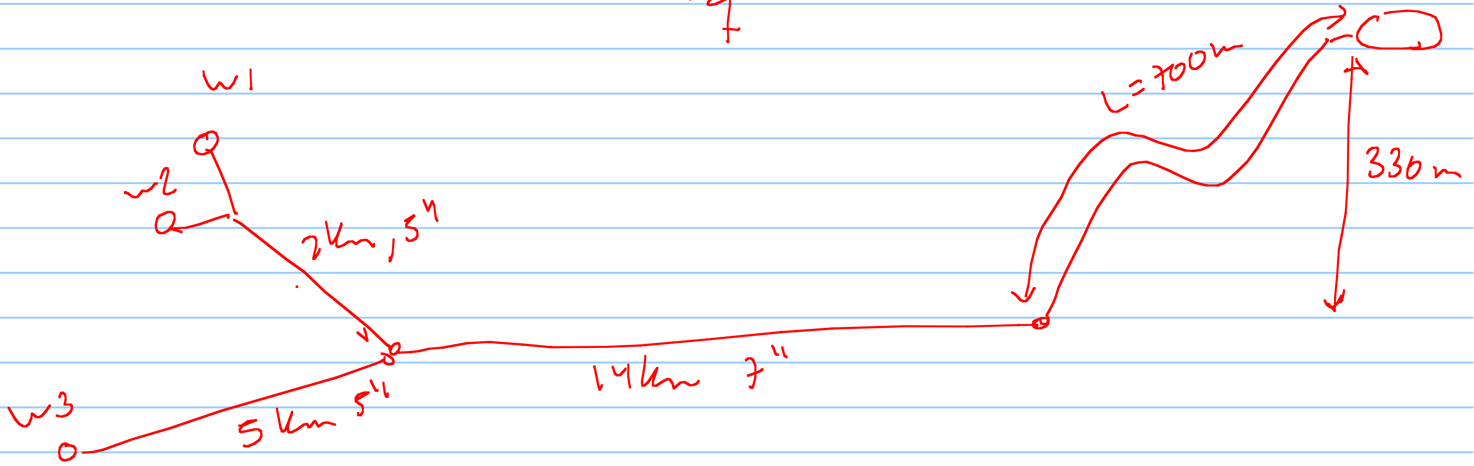
o sensitivity

o generation of tables






$P_{wh0} < P_{wh2} < P_{wh1} <$




| | | | | | |
|---|---|---|---|---|---|
| Oil_Well | Pvt | 55 729 | 18.04.2016 | 15:58 | -a- |
| Oil_Well | Sin | 179 346 | 18.04.2016 | 15:58 | -a- |
| Simple_Network | gap | 193 667 | 24.03.2015 | 10:47 | -a- |
| Simple_Network | gaplgs | 231 | 24.03.2015 | 10:47 | -a- |
| Oil_Well | vlp | 33 183 | 24.03.2015 | 09:57 | -a- |
| Oil_Well | Anl | 541 608 | 24.03.2015 | 09:38 | -a- |
| Oil_Well | Out | 619 439 | 24.03.2015 | 09:38 | -a- |
| Oil_Well | Tpd | 9 973 | 24.03.2015 | 09:37 | -a- |

Pvt → fluid properties

Sin → simulation interface

vlp → gap

Anl → analysis

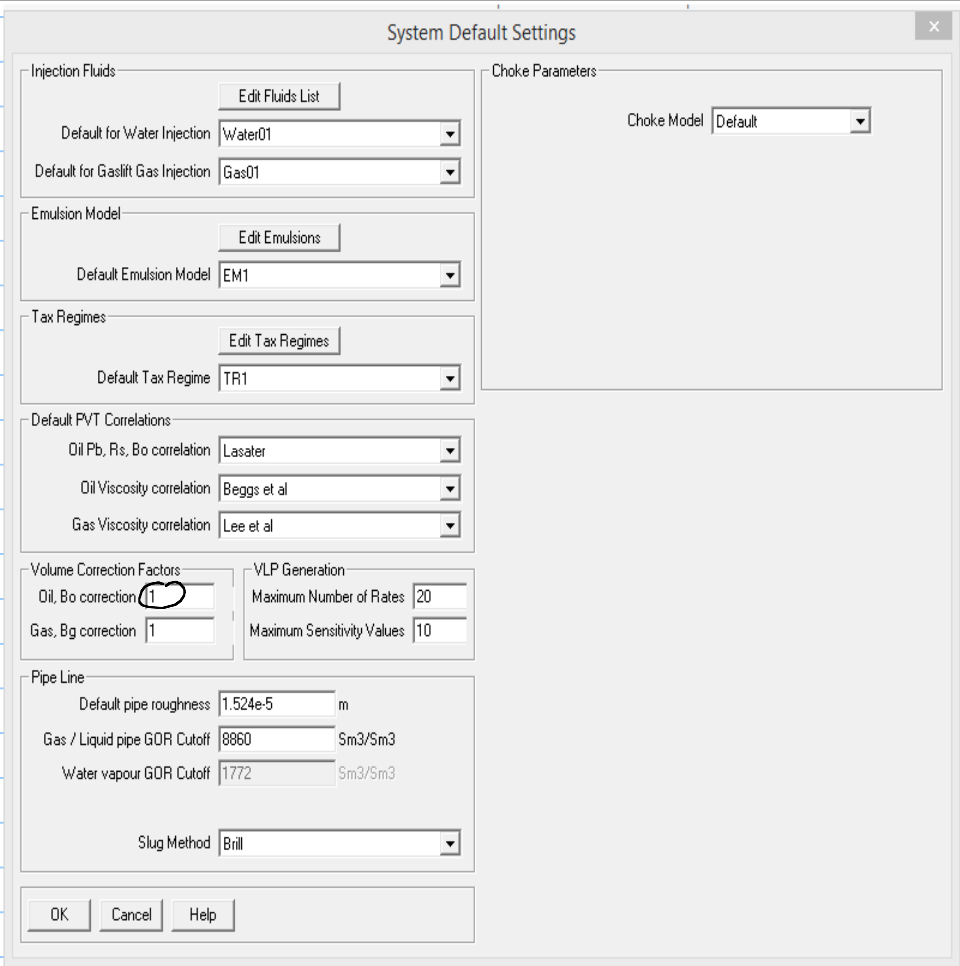
Out → main proper file

Tpd → exporting VLP

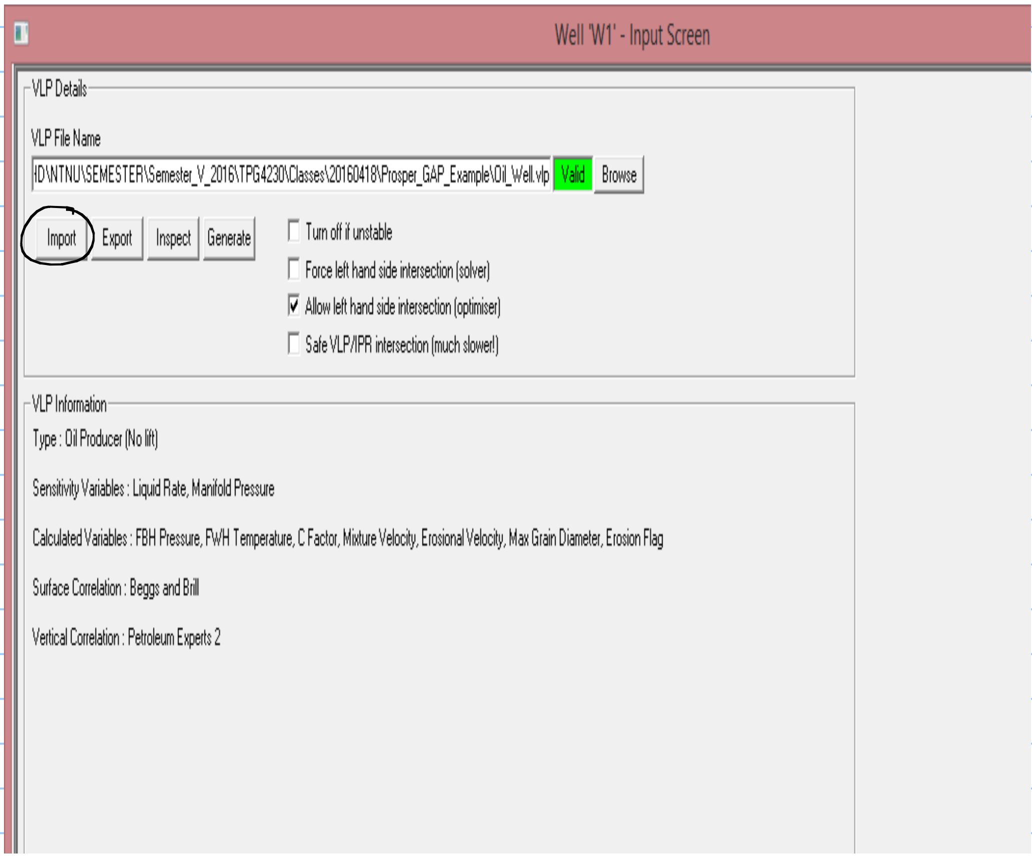
Out → for wells with similar layout but different properties, duplicate this file

In GAP

BO model settings




- link prosper file to well in GAP (summary window).
-




import tpd generated from prosper

generate automatic

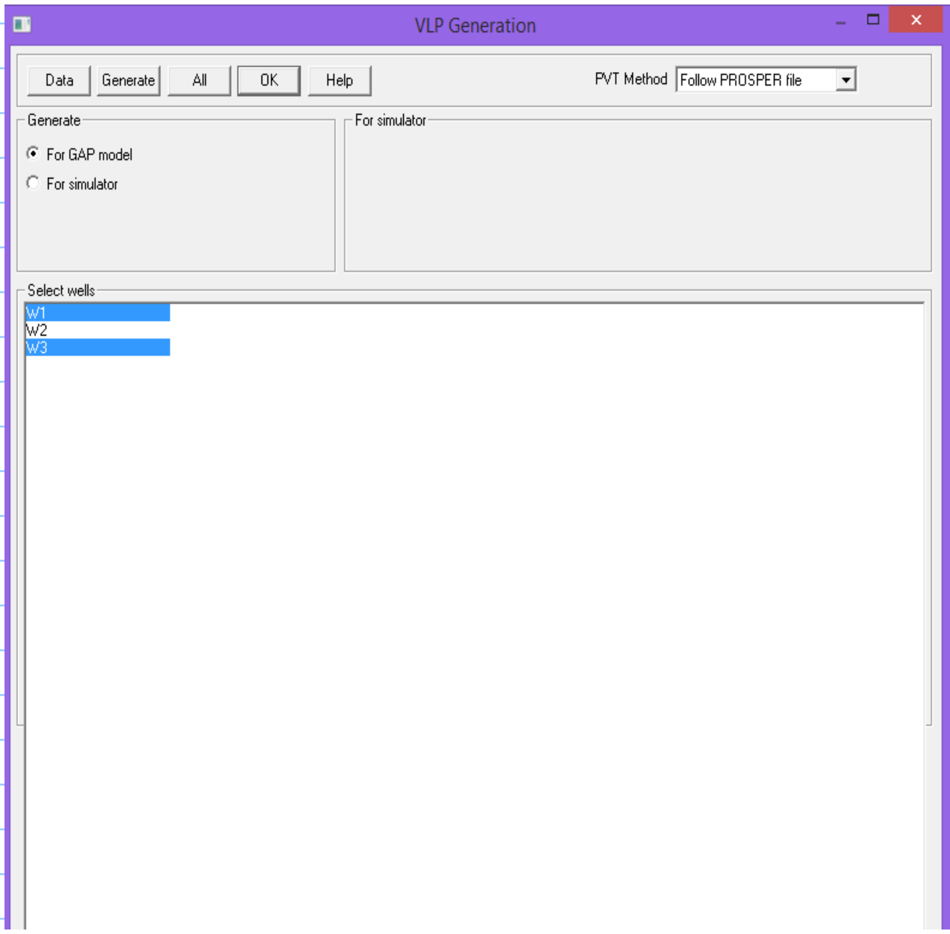
.vlp

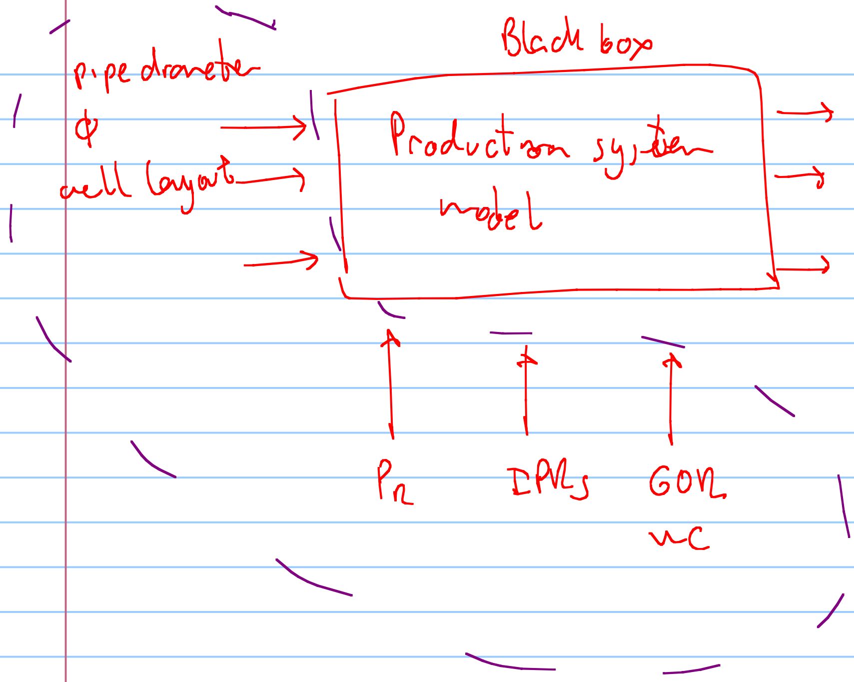
• Generate well IPR

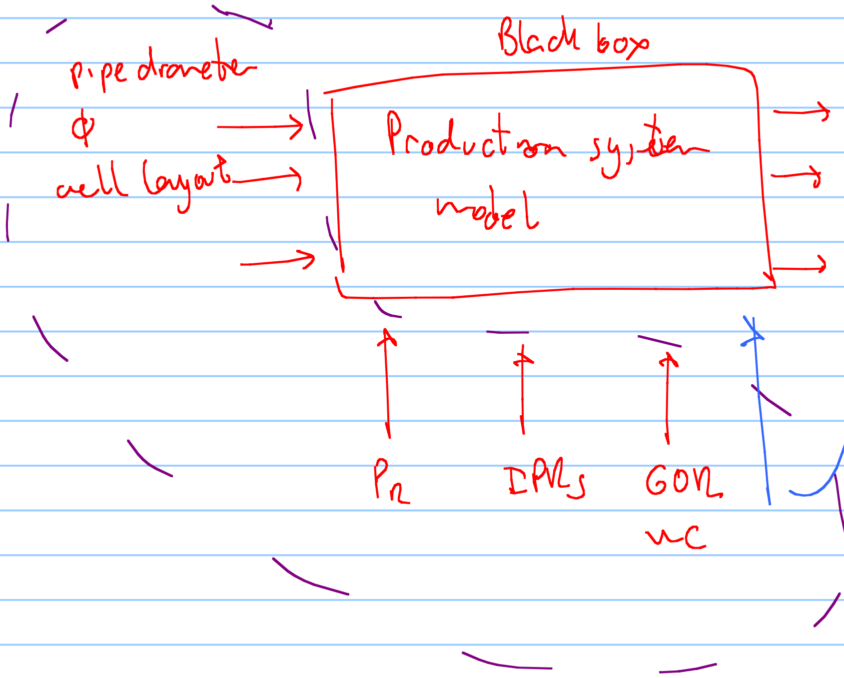
└ OBS ! this process might give error "process terminated"

└ typically is because well type in prosper ≠ well type in GAP

Batch generation of VLP curves.






adjustable variables
- choke opening
- gas lift injection rate
- esp frequency
- valve routing.
-

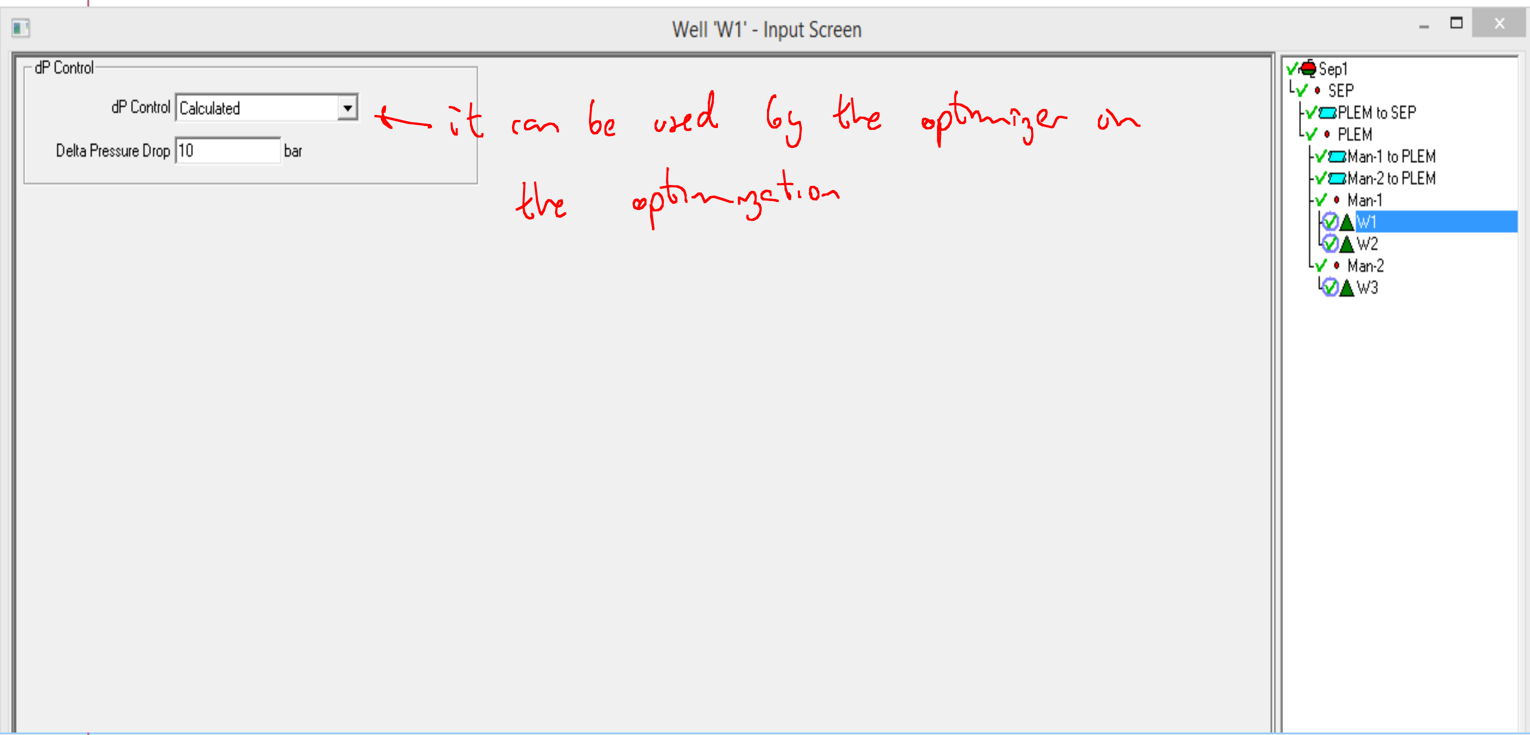
GAP is designed as an optimization software of production systems

objective { optimize → max oil (if gas

variables → by changing → adjustable element

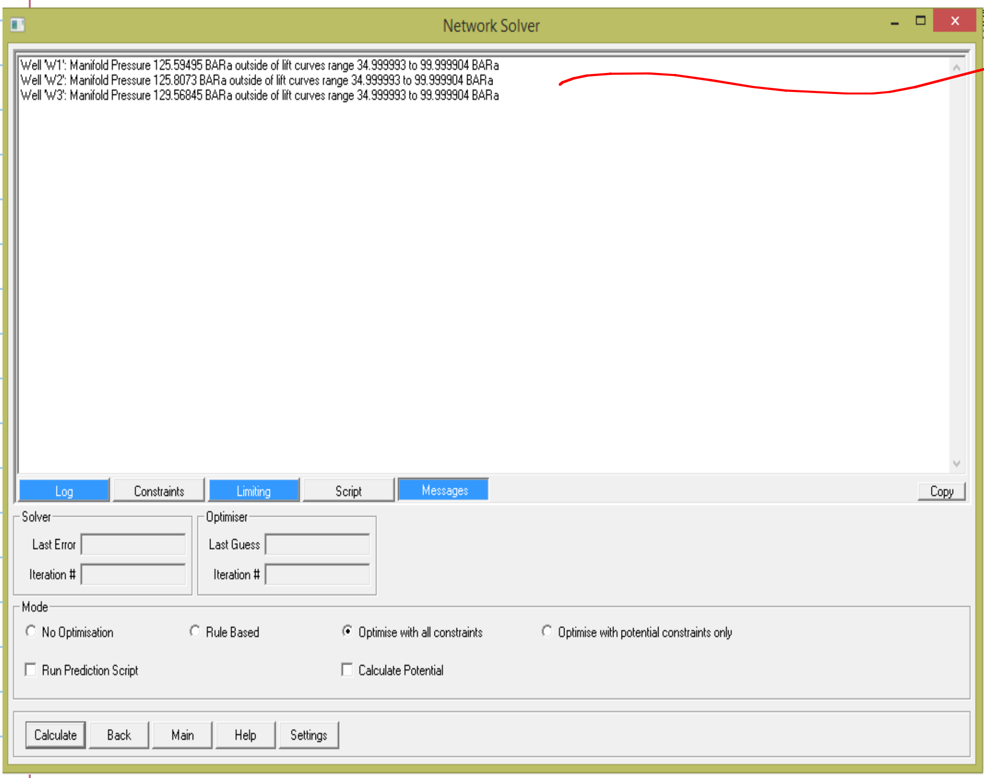
constraints. → by honoring → operational constraints } water prod, power capacity

→ GAP cannot make simulations with fixed well rate.

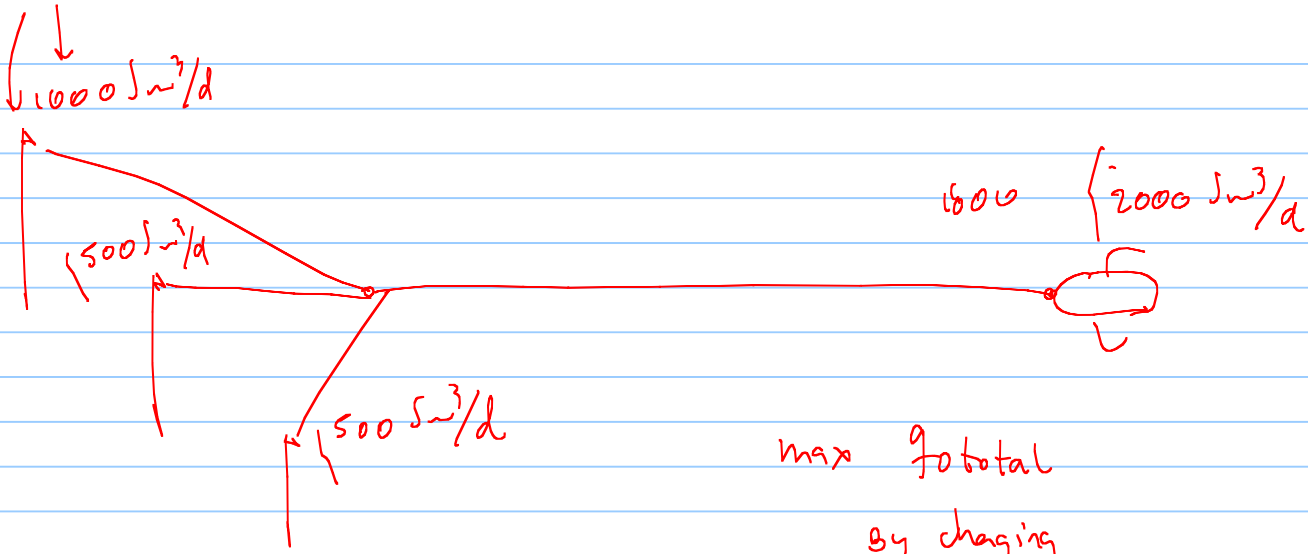



← it can be used by the optimizer on the optimization

optimization to get fixed rate is more expensive computationally than the method used in class




be aware of the warning messages of GAP




max $q_{total}$

by changing

$$\underbrace{q_1 + q_2 + q_3}\; = \underbrace{2000 \ Sm^3/d}$$

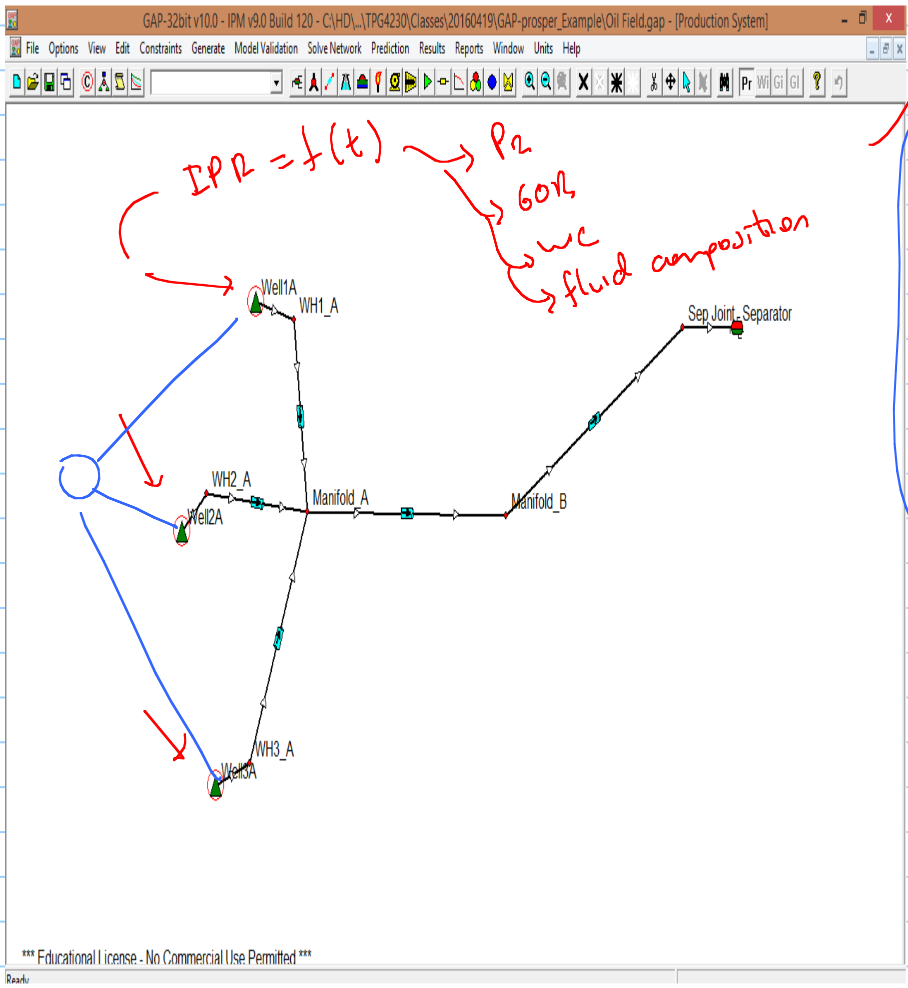
1 eq
3 unknowns
} multiple solutions

$q_1 =$ —

$q_2 =$ —

time analysis :

coupling can be done in GAP




→ Petroleum experts

MBAL material balance simulator

$P_R$ vs $N_p$

Reveal → reservoir simulator by PETEX.

Eclipse → commercial reservoir model

→ Resolve

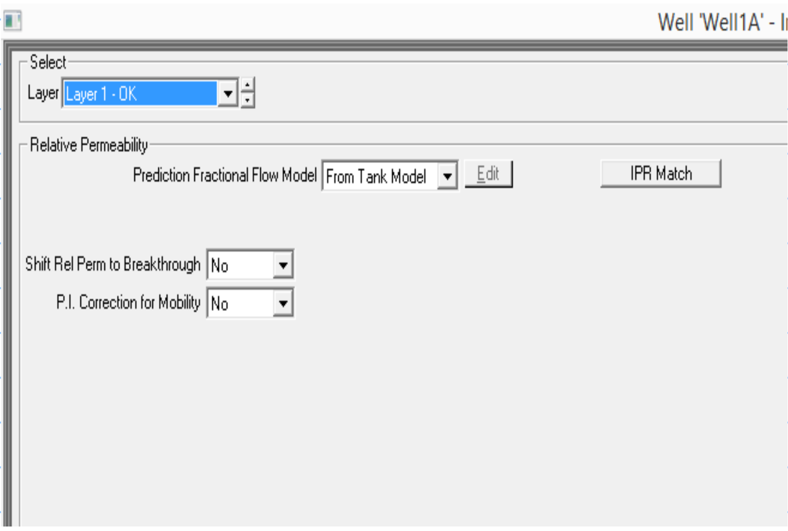
Material balance : big volume with average properties

$S_o, S_g, S_w, P_R$ vs $(N_p, G_p)$

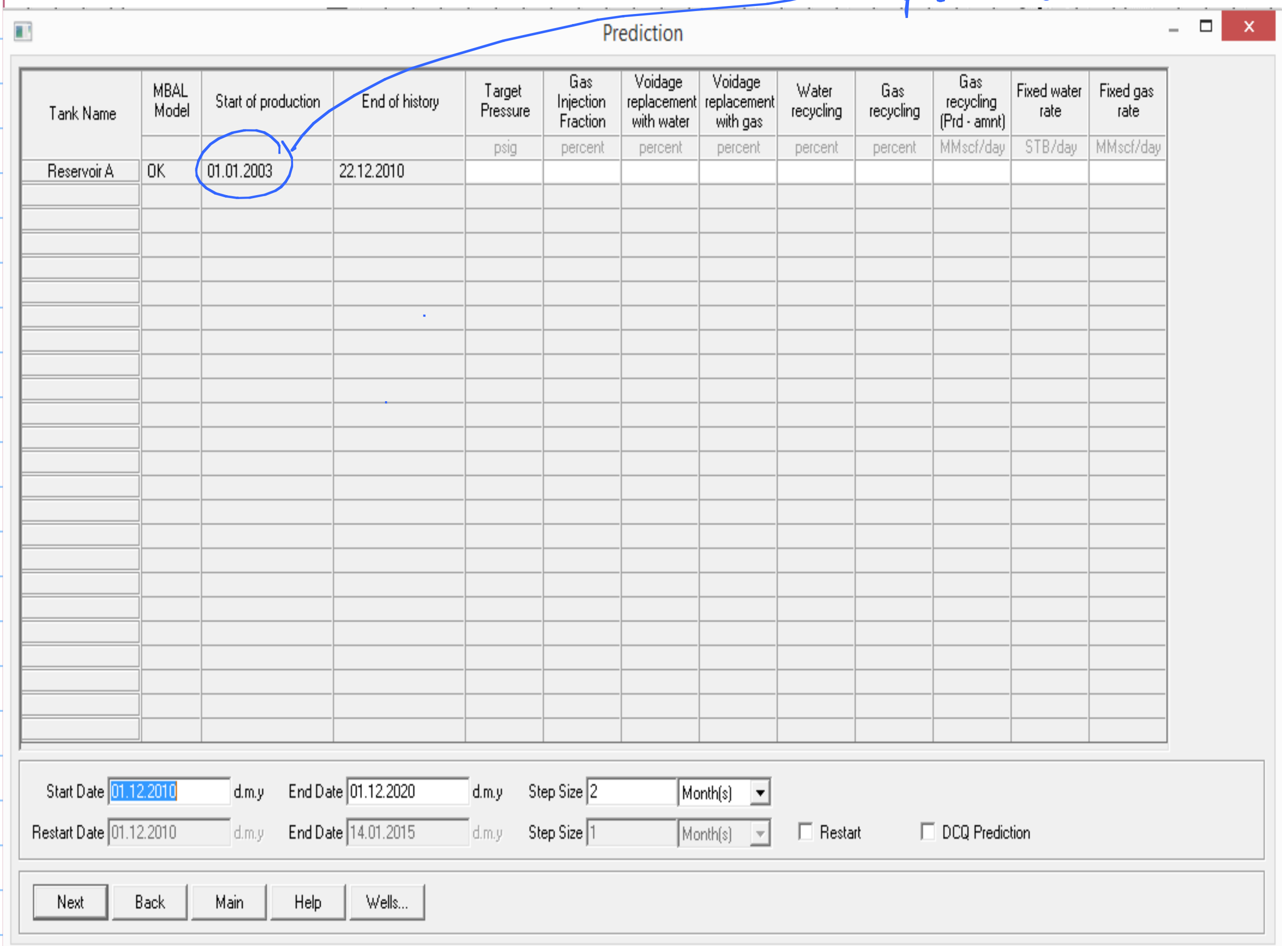
→ GOR vs $N_p, G_p$
WC vs $N_p, G_p$

BLACK-OIL PVT FORMULATIONS from prof. Whitson monograph: "phase behavior"

↳ $R_p$ (GOR) $= f \begin{cases} k_{ro} \\ k_{rg}, \mu_o, R_s, B_o, B_g, \end{cases}$




input in the MBAL.



COMMENTS OBS:

In exercise 1 of set 5, the pump map changes with $\mu$ and $\rho$

→ a map has to be generated any time the WC changes.

→ a template excel file will be provided for problems 2 and 3.

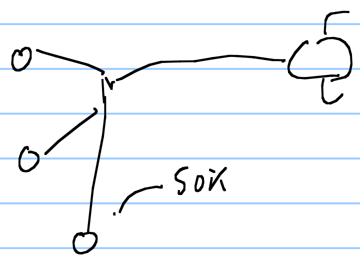
## Optimization of production systems

↳ effectivization: make thing better than the way they are now

- maintenance logistics
- predictive maintenance
- trouble shooting { find the cause of an underlying problem. e.g. sand production, scale deposition, wrongly sized ESP.
- Data analysis. { visualize, examine, analyze production data to find improvements, better operational conditions, solutions to problems. room for improvement.

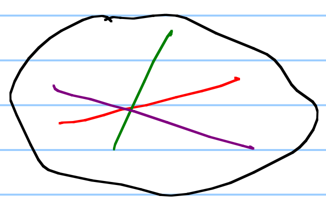
Schlumberger: oil field manager OFM, Spotfire

grouping ↳ cluster
↳ geographical location
↳ same separator.




- Sensitivity analysis with software { spider chart, tornado plots

↳ well placement



mathematical optimization
- computerized and automated process to find the best operating conditions
- model ↔ good representation of the production system

→ advise on the settings that I have to implement to operate under the best conditions
  - well placement
  - choke opening
  - gas lift rate
  - diameter of the pipeline
  - etc.

Element needed in an optimization

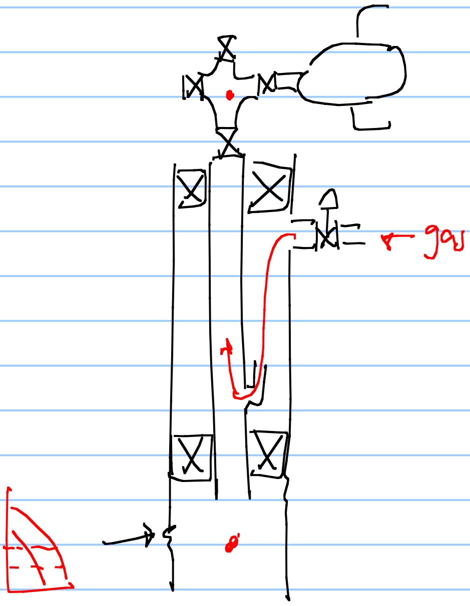
- Search maximum or minimum of an objective function
  - oil production, gas production, condensate prod, plateau length, cost, NPV, Recovery factor
- By changing adjustable parameters, variables in the system
  - well placement, number of wells, choke opening gas lift injection rate, ESP frequency,
- Honor constraints
  - water handling capacity, maximum well length, Power capacity, equipment operational conditions

the definition of obj, var, cons. depends on which phase in the life of the asset you are

uncertainty

there are typically two scales
- field life scale → development, EOR evaluation of
- operational time scale (weekly, daily, monthly)

Example: gas lift optimization




$P_{wh} = const$

$$\Delta p_{tubing} = \overbrace{\Delta p_{hydrostatic}}^{term\ 1} + \overbrace{\Delta p_{friction}}^{term\ 2}$$

$\hookrightarrow \rho_m \cdot g \cdot h$ $\qquad$ $\hookrightarrow f \frac{L}{\phi} \frac{v^2}{2g}$

$\uparrow$

$\rho_m \downarrow$ $\qquad$ $v \uparrow$

to generate this curve

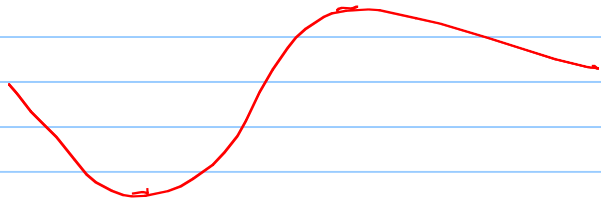
we test the well

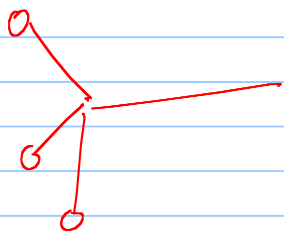
↳ model

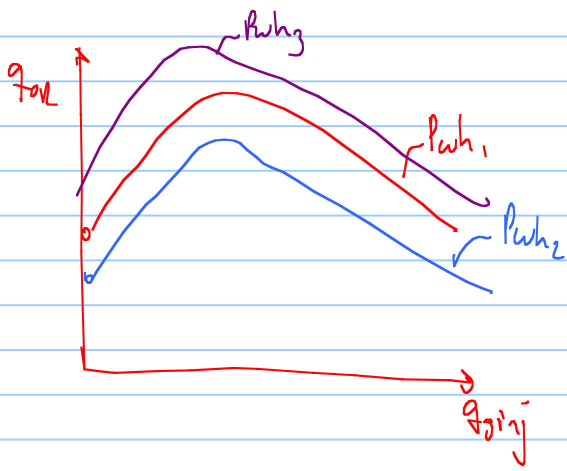

the reduction in term ① is more important than the increase on term ②

the increase in term ② is more important than the reduction in ①

$$\frac{d\, q_{oR}}{d\, q_{ginj}} = 0$$



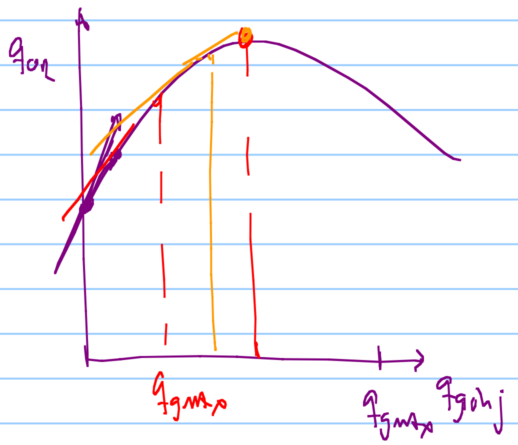




find $q_{ginj}^{*}$ where $q_{or}$ max $\rightsquigarrow$ $\left\{ \begin{array}{l} \dfrac{d q_{or}}{d q_{ginj}} = 0 \\ \dfrac{d^2 q_{or}}{d q_{ginj}^2} < 0 \end{array} \right\}$

$q_{or} = f(q_{ginj})$

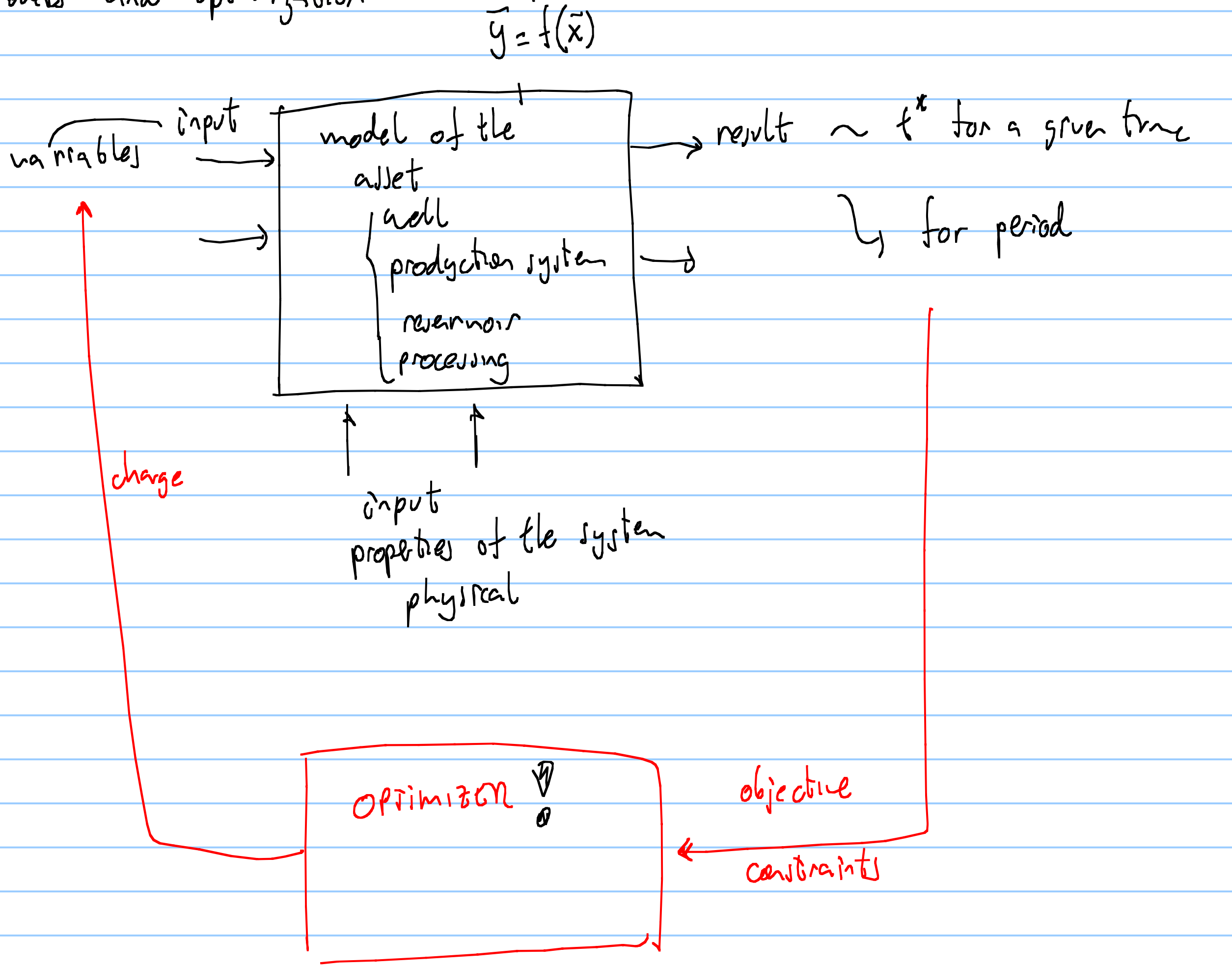
my model




$q_{ginj\,avl} < q_{gmax}$

impact of the constraint

models and optimization




when choosing variables, make sure that they affect the objective and constraints

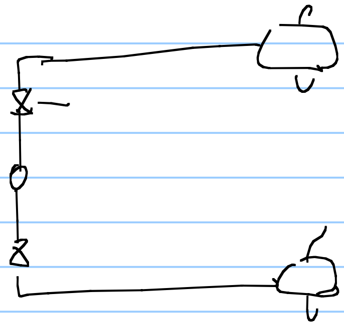
- Optimization types:

Constrained unconstrained

Continuous or integer 0 – 1

0.06

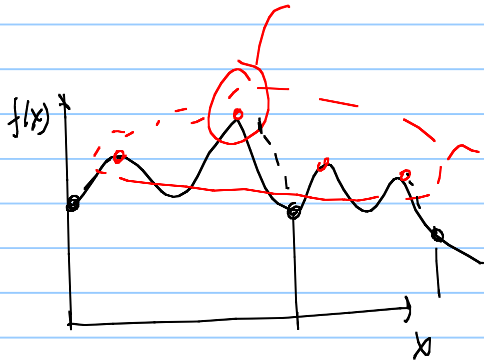
↳ nature of the opt. variable.



- non-linear / linear problems

local and global }

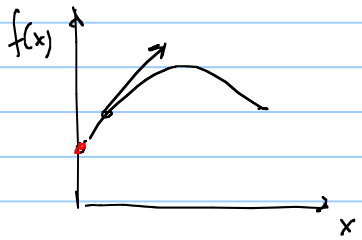
↳ method to solve this issue is multi-start



local maxima

## Optimization methods

- Gradient-based ~ determine a search direction using gradients (derivatives)



↳ very efficient for continuous problems

$\frac{\partial f}{\partial x}$ } analytical equation

$\frac{\partial \text{ fcn}}{\partial \text{ eqn}}$ { Black box model?

estimate numerically the derivative.

↳ time consuming for big models and for large number of variables

x → B.B → f(x)

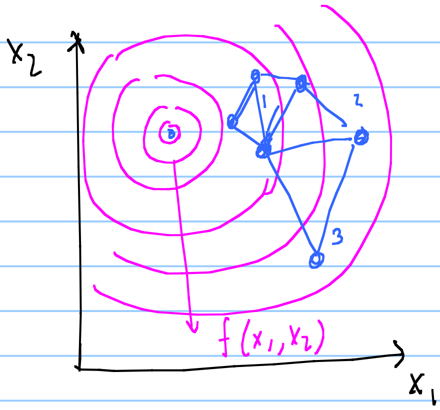
$x_1$ $f(x_1)$

$x_2$ $f(x_2)$

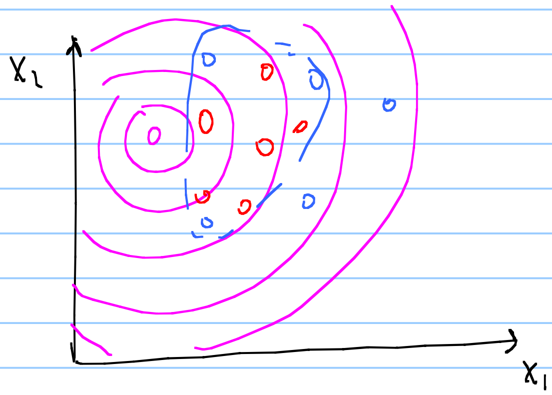
$$\frac{d f(x)}{d x} = \frac{f(x_2) - f(x_1)}{x_2 - x_1}$$

• heuristic methods: start with a collection of points and progress using penalization logic

nelder Mead




• Stochastic methods · random variables, evolutionary algorith, genetic algorith




it 1

it 2

o combinatorial techniques $\rightsquigarrow$ integer problems

Sometimes constraints that are not on the variables are included as part of the objective function

$q_{ginj} < q_{max}$

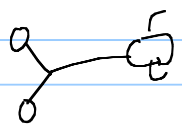
$q_{wat} < q_{max}$

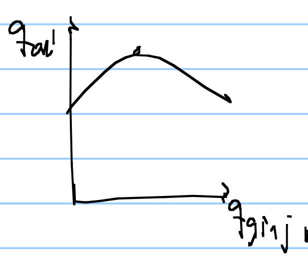
$$\max \left( q_{on} - \underbrace{f \cdot 0.2\, q_{wat}}_{\text{weight factor}} \right) \sim \text{compound objective function}$$

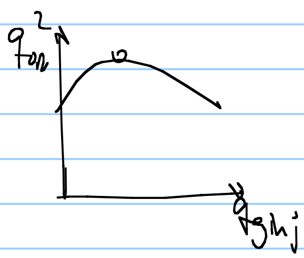
$$\frac{d q_{on}}{d q_g} \qquad \frac{\partial (q_{on} - q_w)}{d q_g}$$

System of two standalone gas lifted wells

$q_{max}$





$$q_{on} = \alpha_1 (2 - e^{-\beta_1 q_{ginj}}) - \alpha_2 e^{\beta_2 q_{ginj}}$$

• with the collection of points find the constants in the equation

| $q_{ginj\,1}$ | $q_{on_1}$ | $q_{ginj\,2}$ | $q_{on_2}$ | $q_{oT}$ |
|---|---|---|---|---|
| change | | change | | $q_{on_1} + q_{on_2}$ |

$$q_p = \tilde{\alpha}_1 (2 - e^{-\tilde{\beta}_1 q_i}) - \tilde{\alpha}_2 e^{\tilde{\beta}_2 q_i}$$

constants tuned with field data

Note Title 25.04.2016

* class exercise

** home exercise

Oil and gas field

Life cycle (timeframe)

- design and development
  - Architecture (Layout) **
    - marine dynamics of offshore structures **
    - drilling
    - well lower completion **
      - ICD
      - ICV
      - AICV
  - simplistic probabilistic reserve estimation
    - monte Carlo **
  - production scheduling
    - fundamentals
    - production potential *, **
    - choking
    - boosting
    - compression **, *
    - Artificial lift **, *
  - project management
    - decision tree
      - costs
      - revenue
  - economic calculations
    - NPV **
  - sensitivity studies
    - spider plot **
    - tornado chart **
- operations
  - allocation **
  - flow assurance
    - hydrate ** and liquid accumulation
  - flow performance **
  - effectivization and optimization
    - methods
    - basics
    - gas lift * 1.5
    - opt **
  - IAM
    - Prosper, GAP *
    - HYSYS **, *
    - Excel **, *

field, network, well reservoir flow performance **, *

q, P, T, vs (t)

- single phase liquid flow *, **
  - conduits
- single phase gas flow **, *
- multiphase flow
  - gas-oil **, *
  - oil-water emulsion **, *
  - tubing tables
- heat transfer
- PVT fluid behavior **, *
  - BO tables
  - BO correlation
  - compositional
- boosting design
  - multiphase boosters
  - pumps **, *
  - compressor **, *

engineering skills

solving problems

- numerical models
- simulators
- solving system of equations

Exam 06.06.2016 Kl. 09:00 4 hrs.

Content:

- Topics covered in class
- mandatory exercises, class exercises
- additional material
  - Haldorsen
  - Ch 01 field cycle
  - video lecture from Statoil about field development of the Åsta Hansteen field
- guest lectures

---

Exam:

- Hand calculations
- Some questions the performance curves will be provided (available and required).
- Build the layout of your excel sheet
- All relevant equations will be given
- theory question
  - simple
  - more detailed

- no printed information is allowed
- sketch (layout, behavior of curves)

check $\Longrightarrow$ quiz

on Itslearning $\hookrightarrow$ last years resitting examination