DANMARKS OG GRØNLANDS GEOLOGISKE UNDERSØGELSE RAPPORT 2009/15

Petroleum related core analysis techniques

A short course held for SPE Copenhagen, April 2009

Niels Springer

GEOLOGICAL SURVEY OF DENMARK AND GREENLAND
MINISTRY OF CLIMATE AND ENERGY

GEUS

DANMARKS OG GRØNLANDS GEOLOGISKE UNDERSØGELSE RAPPORT 2009/15

Petroleum related core analysis techniques

A short course held for SPE Copenhagen, April 2009

Niels Springer
GEUS Core Laboratory

GEOLOGICAL SURVEY OF DENMARK AND GREENLAND
MINISTRY OF CLIMATE AND ENERGY

GEUS

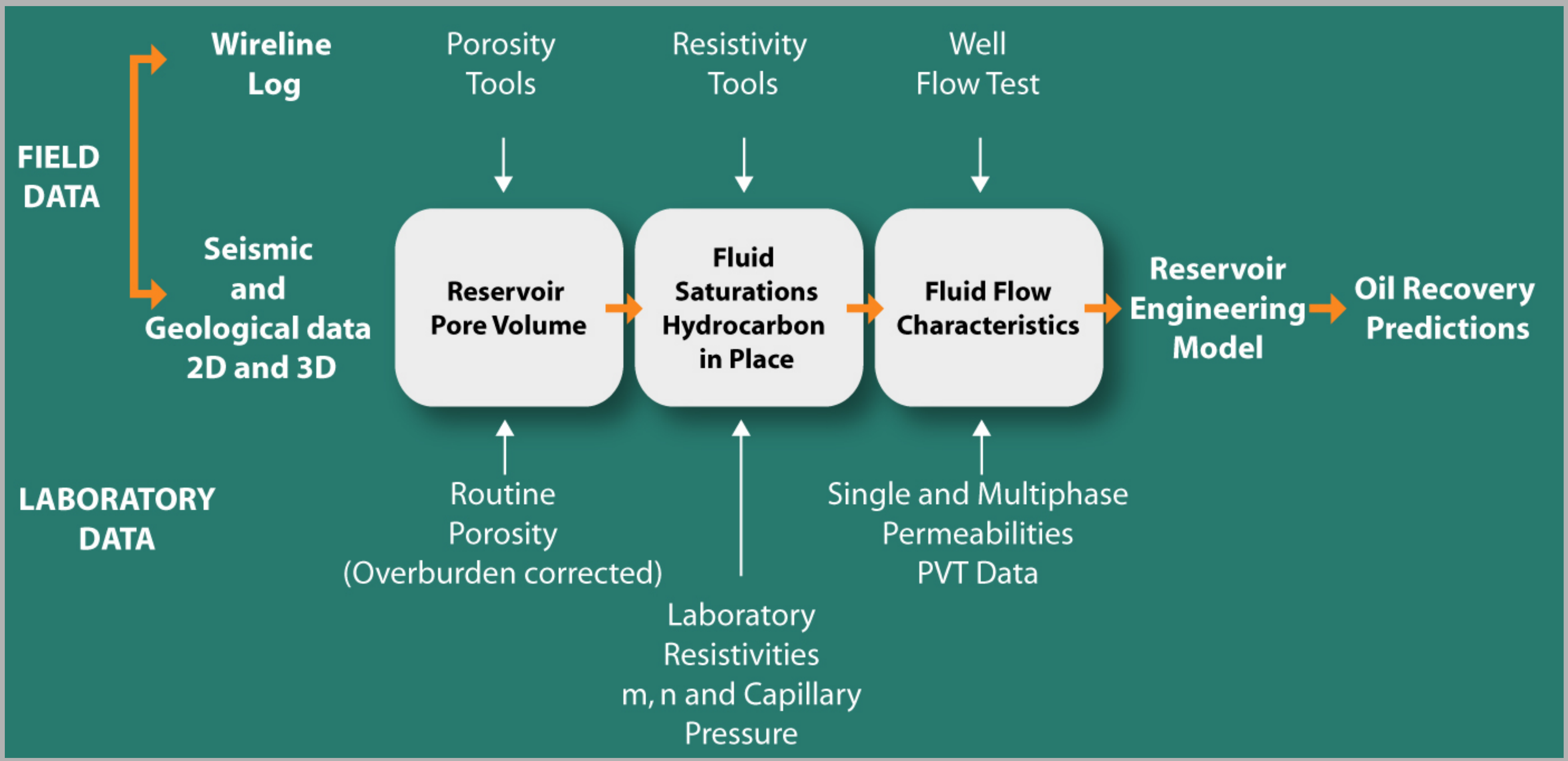
CORE ANALYSIS

Presented by

Niels Springer

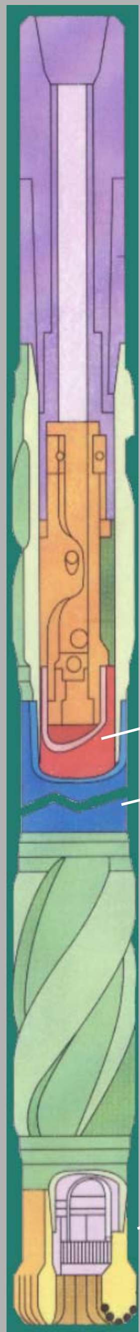
GEUS

Reservoir Engineering Data Sources



Coring

Coring has been with us for a century



Inner Tube

Outer Barrel

(Holland 1908)

Catcher Assembly (+stationary inner barrel, USA 1925-26)

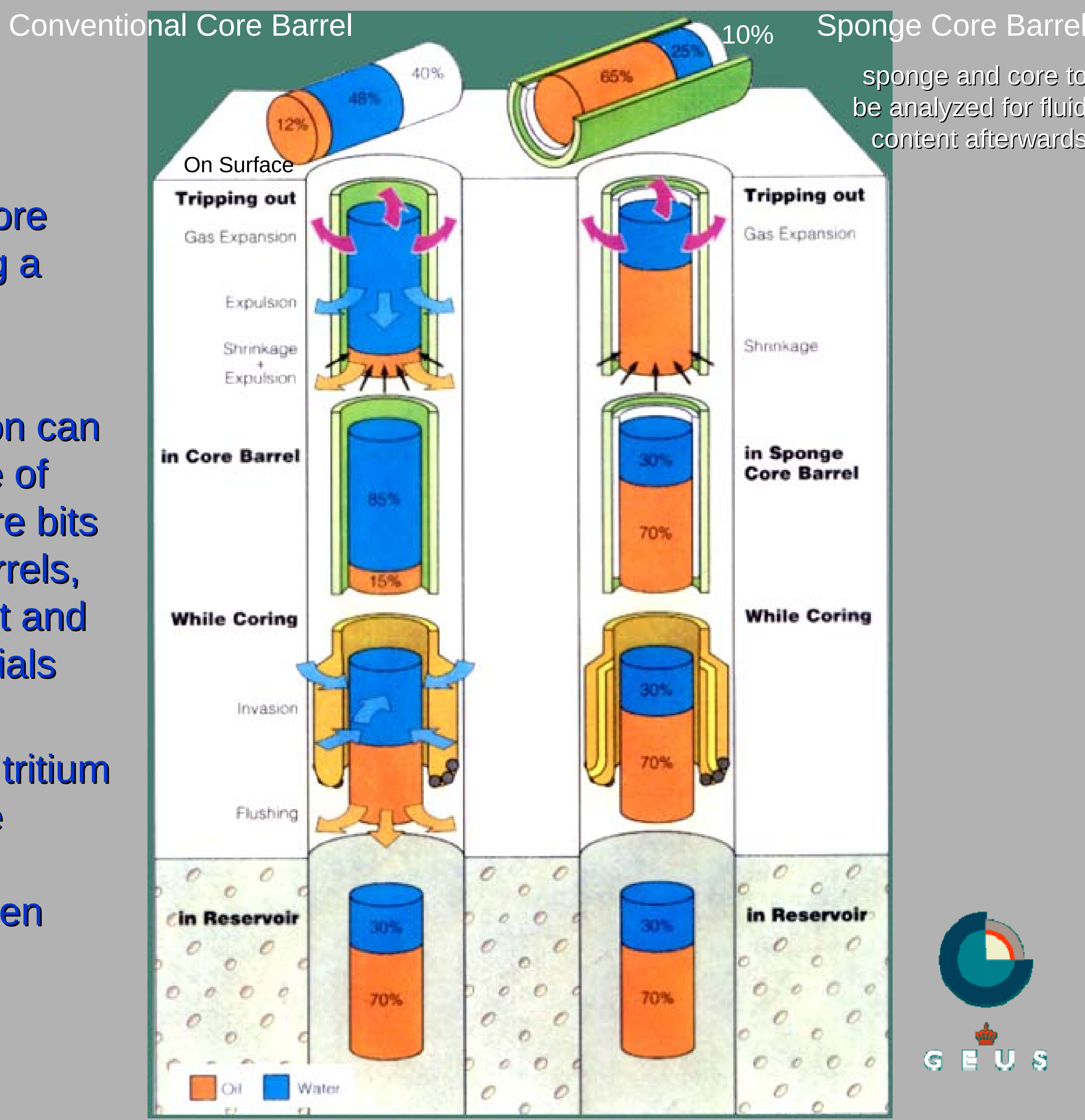
Core bit

Credits : Paaby-1, Harte 1936

Evolution of typical core fluid saturation during a coring operation

Flushing and invasion can be minimized by use of special designed core bits and sponge core barrels, available in waterwet and oilwet sponge materials

Tracers as D_2O and tritium may be added to the drilling fluid and pressurized core taken



Drilling mud contamination:

neutral to waterwet reservoir chalk are completely invaded by water-base mud:

Chemical Composition of Mud Filtrate and pore water, Nana-1X										
Sample	Depth m	pH	Cl mg/l	SO4 mg/l	HCO3 mg/l	Na mg/l	K mg/l	Ca mg/l	Mg mg/l	Sr mg/l
Mud filtrate		9.1	82855	1758	333	12496	65122	7.1	5.4	0.6
GEUS core 1		7.28	63953	1040		26214	19967	1074	472	144
GEUS core 4			69444	801		32075	19937	1484	309	205

Indicating that chalk may be preferentially waterwet

Table 1.2 Utsira Sand water samples extracted from core plugs; results in mg/l.

Plug No.	Porosity	Chloride	Bromide	Sulfate	Sodium	Potassium	Calcium	Magnesium
	%	Cl	Br	SO4	Na	K	Ca	Mg
A-23-1	42.5	43100	443	182	8200	36400	270	390
A-23-2	41.9	41200	423	153	7500	36200	250	390
A-23-3	40.71	46600	521	177	7700	50400	260	370
A-23-4	40.47	41700	406	146	8800	38000	310	480

Mud that contains oil components like Versavert or PEG can jeopardize source rock analysis

GEUS

Well-site services

- Some core analysis contractors offer well-site services:

- ”Hot-shot” poro-perm and fluid saturation
- Preservation of plugs and full core pieces for SCAL (Special Core AnaLysis) (onshore).

- Observe: - samples not (or improperly) cleaned
  - preservation technique could be unsuitable for certain core tests

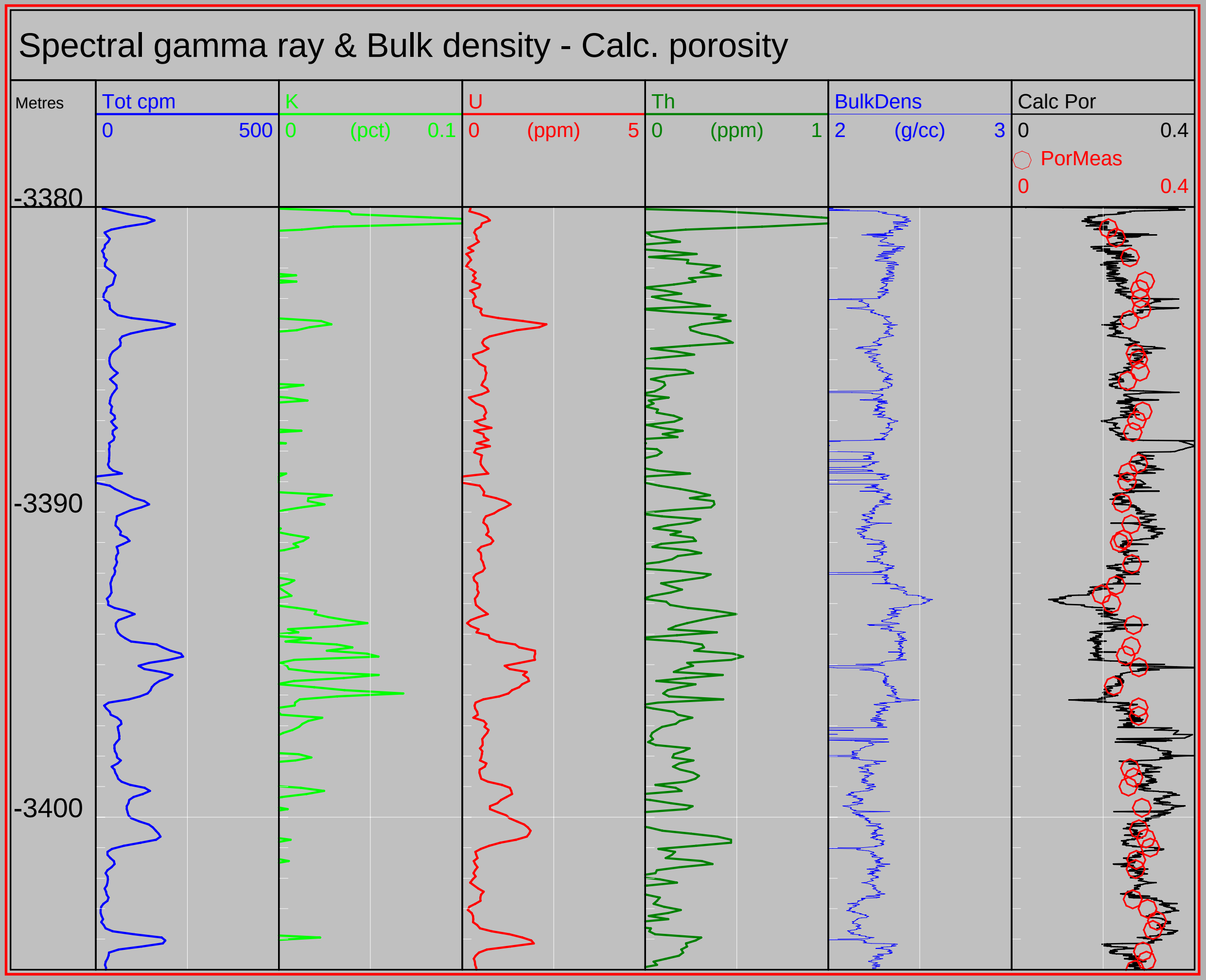
Conventional Core Analysis

- Core scanning
- Plugging
- Fluid saturation
- Cleaning
- porosity
- grain density
- gas permeability
- core photo

GEUS

Core gamma and density log :

- Used for lithological correlation and estimation of shale Vsh



- K is fixed in feldspar and certain clay minerals

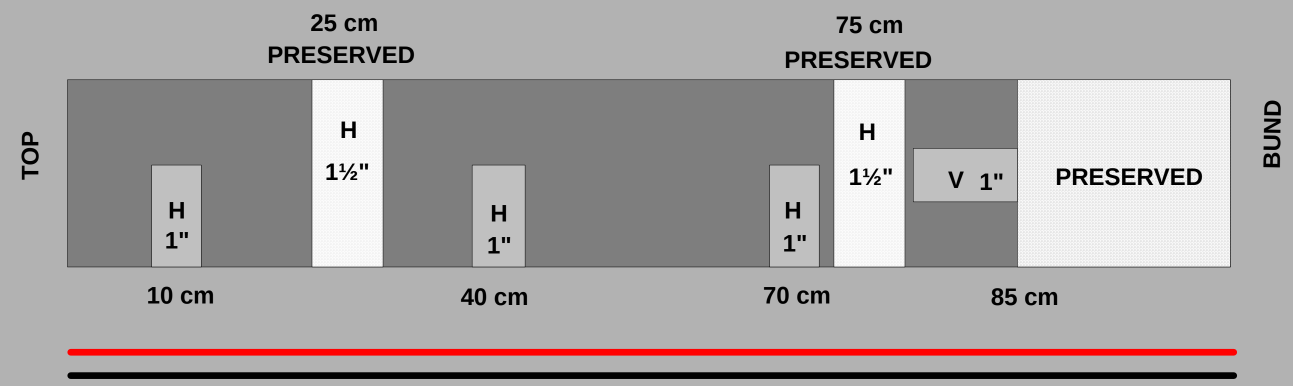
- Th is fixed in clay and some heavy minerals

- U is fixed in organic materials (coal, organic shales)

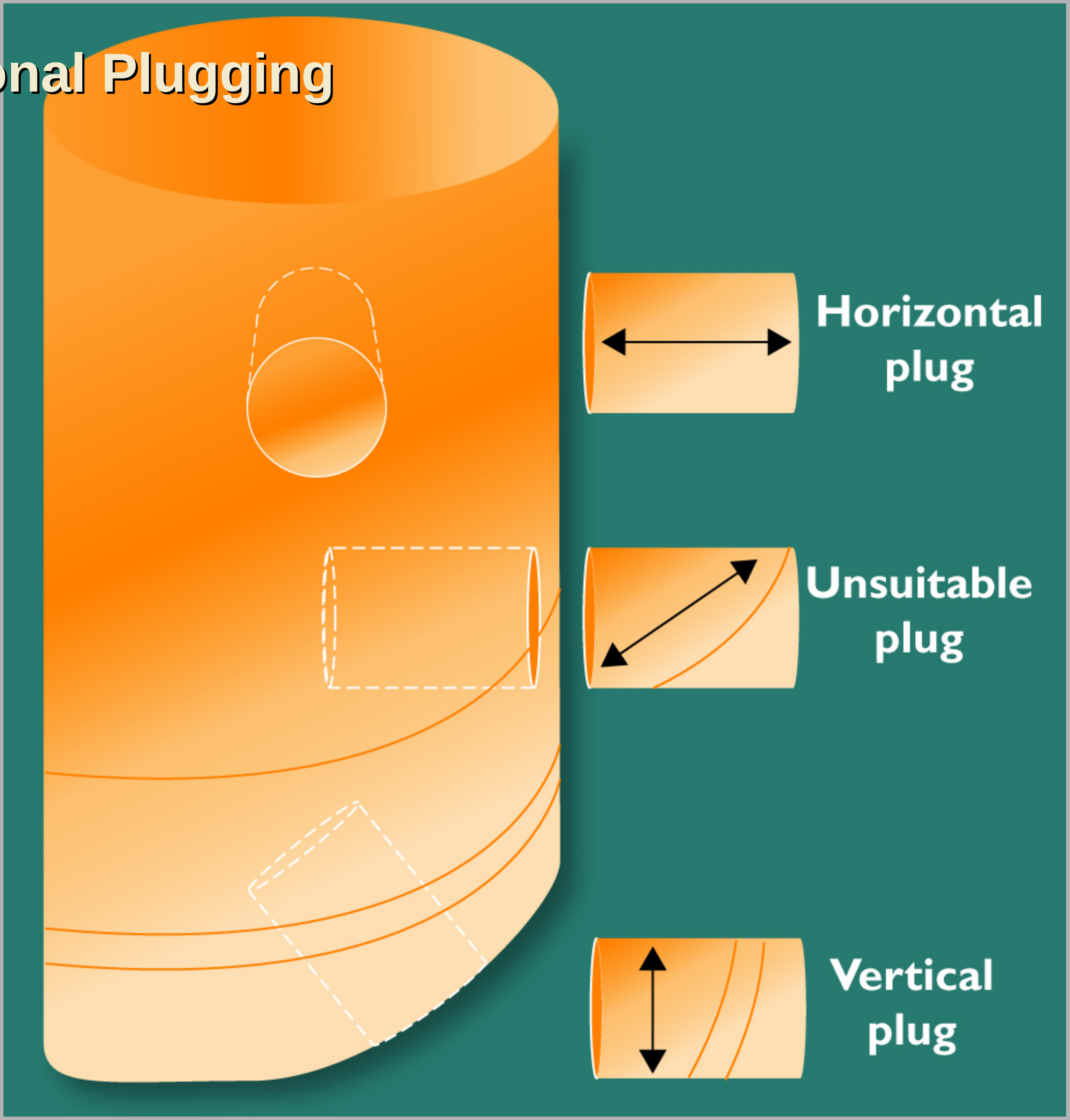
Designing a core analysis programme

- The core is cut into 1 m pieces and given a box no. starting from the top with Box # 1
- Routine plugs are taken at regular intervals along the length of the core, eg. 30 cm (1 foot)
- Preserved plugs are taken as required
- Finally the core is slabbed and photographed; a thin cut is resinated or glued to a tray and archived

STENLILLE-14 og 15



Directional Plugging



Determination of fluid saturation:

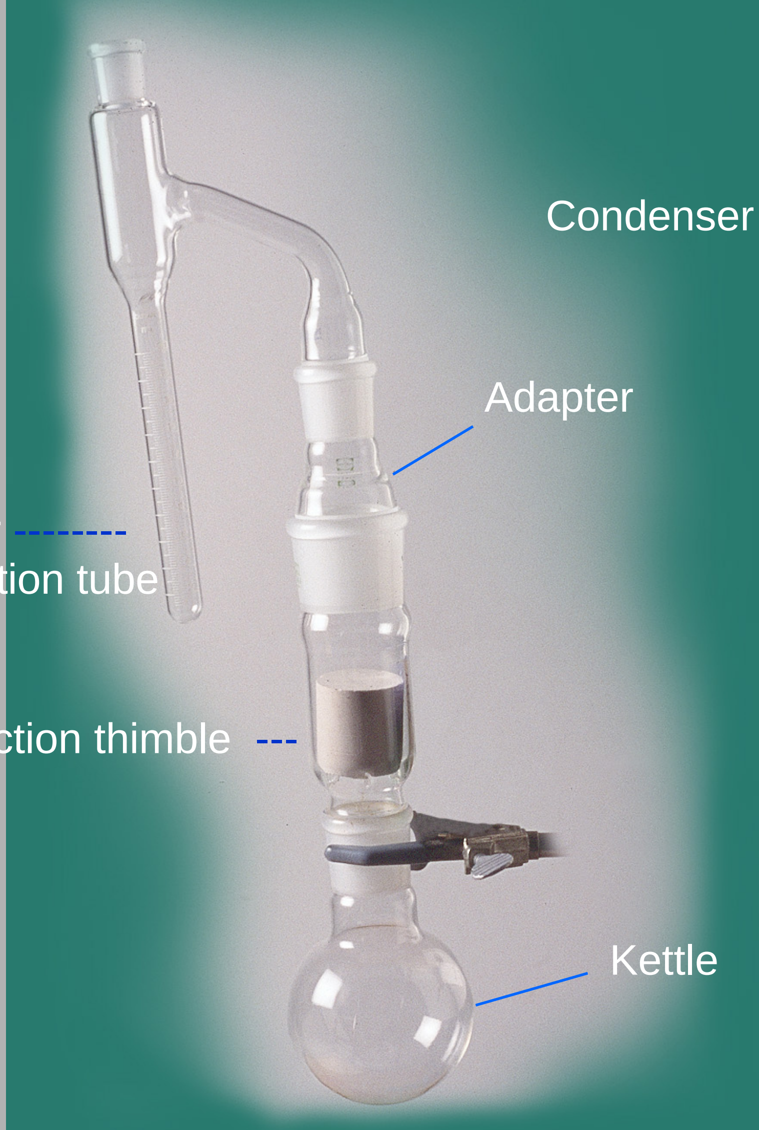
By definition : $S_w + S_o + S_g = 1$ (relative to the sample PV)

in principle simple, but errors can easily happen

- By retort (requires correction curves, gas saturation is derived from a second sample by mercury injection and porosity is derived from third sample)
- By Karl Fischer titration (based on Methanol as the working medium)
- By Dean Stark extraction (extraction using an organic solvent, eg. toluene)

GEUS

Dean-Stark Apparatus for volumetric determination of water




- Principle of determination:

wet weight – dry weight = extracted oil + water

Water is collected and read from the graduated tube, oil is then calculated from the assumed density

If the volume of water + oil is less than the pore volume, the excess must be gas saturation

GEUS

Errors in Dean Stark analysis:

• Leaks in glass fittings or poor (lost) circulation of cooling water may lead to an under estimation of water content (= false high oil saturation)

• Under humid conditions (summer in DK or in tropical places) water may condense from ambient air and be detected in the cold finger of the extractor (= false high water saturation)

• Unattended grain loss during the handling process of a sample is calculated as an oil content (= false high oil saturation)
(fragile samples needs special treatment, determination of BV before test and correction of weight data based on a volume correction factor)

• Oil gravity must be known or guessed

• Observe: The collected (destilled) water must be recalculated to a volume of brine, which requires the water salinity or density be known

GEUS

Dean Stark, accuracy (Tor +Ekofisk chalk samples) :

Swi (Dean Stark)	**Swi** (Flood down)
[%]	[%]
16	19
18	19
34	40
19	21
14	16
11	12
18	19
21	21
19	19
18	17
21	23
19	19
21	19
17	16
22	20
33	34
23	24
22	22
37	37

- Normally a very good agreement between Dean Stark data after test and flood down data observed during a SCAL test proves that the method is reliable
- Dean Stark on plugs from fresh core (water zone) yields

  S_w=90-100%

  (but few data only in our database)
- Fluid saturation data should be measured on fresh core asp , offshore or in the laboratory (oil zone data will be affected by expansion and shrinkage).

Cleaning and drying of plugs

- The main reason to clean core is to remove brine and dead oil from the core so that porosity, permeability and grain density can be measured.

    - Methods
    - Making the right choice
    - To clean or not to clean

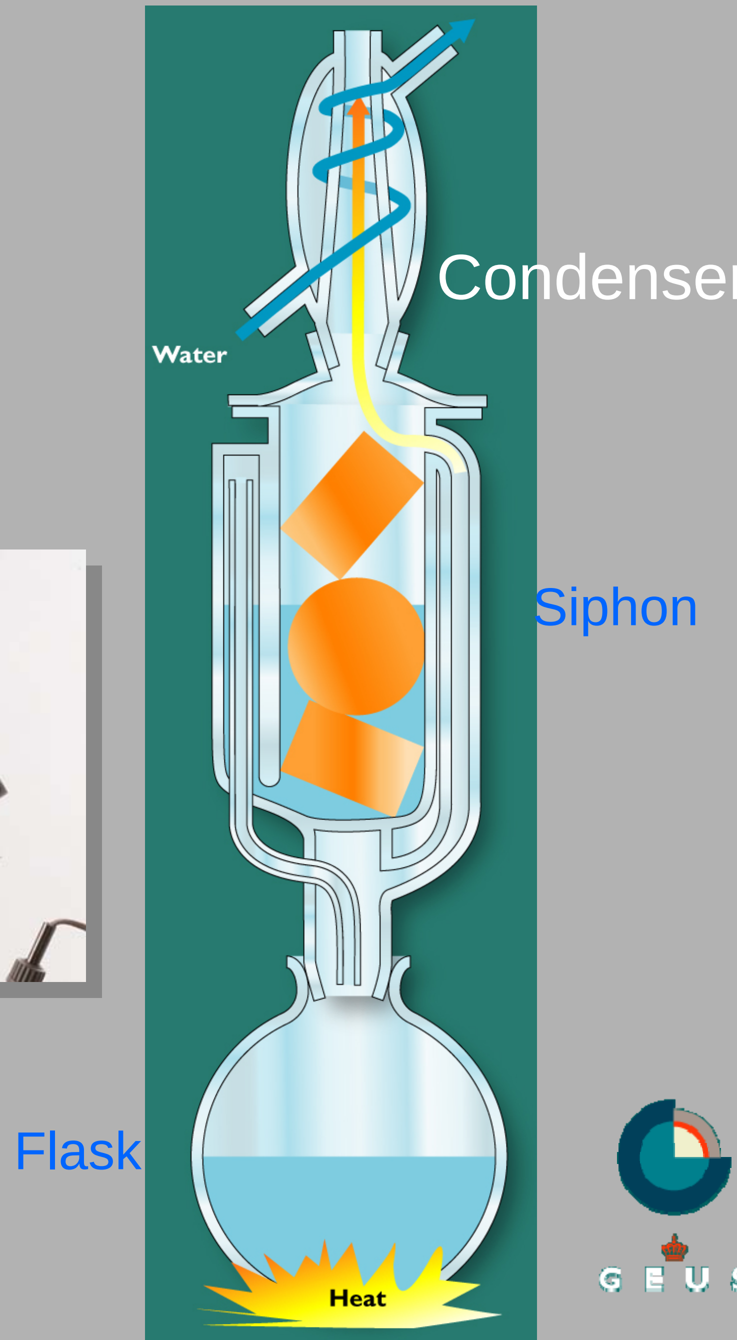
Cleaning methods and errors:

A number of cleaning liquids are used in core analysis depending on the complication of the cleaning job, but miscible cleaning using methanol and toluene are widely accepted

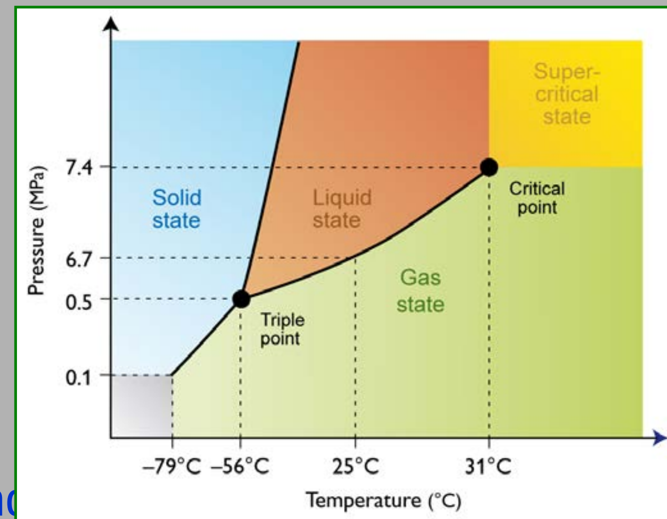
- Hot Soxhlet extraction :
  + Cheap, many samples at once
  - Clay damage, slow process
- Flow through dynamic displacement cleaning :
  + Fast and efficient
  - Expensive, limited sample capacity
- Centrifuge Flushing :
  + Fast
  - May fracture the sample, limited sample capacity
- Gas-Driven Solvent extraction (CO_2 + toluene @ 80 °C and pressure in separate core holders) :
  + Used for whole core cleaning and samples with very low permeability, fast and efficient
  - May fracture the sample

GEUS

Soxhlet Extraction



Drying methods and errors:



- A controlled temperature oven at 110^{o}C

+ Fast

- May damage clay

- A controlled temperature oven at 60^{o}C and

+ Preserves the clay structure (sometimes)

- Not 100 % dry samples

- Critical point drying using supercritical CO_2 (no surface tension and therefore no drag and distorsion of grains)

+ Preserve the clay structure at a temperature much below 100^{o}C

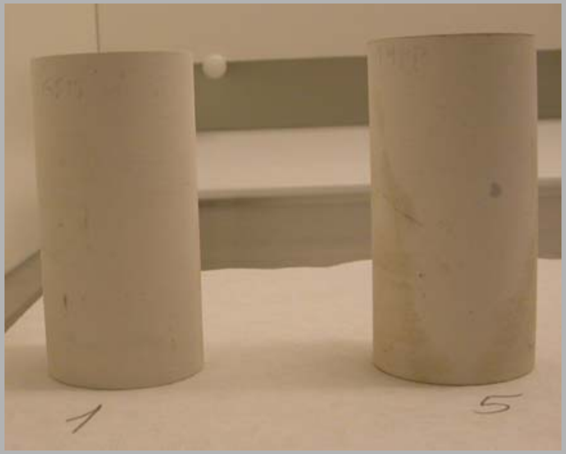
G E U S

Making the right choice:

- Influence of clay
- Time aspect
- Cleanness of the sample
- Fracturing of samples
- Wettability considerations (fresh core may be an option)

Example : Old core material

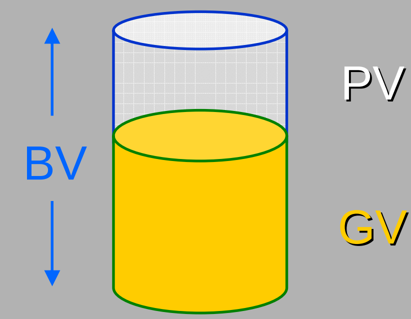
XRD analysis showed the white fines fraction to be non-crystalline, ie not chalk fines



- Core material, many years old, can still be used for most core analysis tests, but sometimes require special attention and treatment.
- In the 1980'ies oilbase drilling mud was used in a number of Tyra wells that later turned out to affect the core and be very difficut to clean out
- A special cleaning treatment can sometimes restore the core material, and SCAL experiments and rock mech testing have proved that this old core material can be safely used for advanced core testing

GEUS

Porosity and grain density:



$$\text{Porosity} = \frac{\text{Pore Volume}^{(1)} * 100}{\text{Grain Volume}^{(2)} + \text{Pore Volume}} \quad [\%]$$

$$\text{Bulk Volume} = \text{Grain Volume} + \text{Pore Volume} \quad [cc]$$

(1) Connected pores only

(2) Grains + Closed Pores

$$\text{Grain Density} = \frac{\text{Plug Weight}}{\text{Grain Volume}} \quad [g/cc]$$

Precision +/- 0.3 porosity-% for porosities > 1%,

better than +/- 0.01 [g/cc] for grain density

Porosity can be measured by different techniques:

- A simple wet vs dry weight and caliper of plug dimensions
- By Archimedes test if the grain density is known and the plug saturated completely with the test fluid
- By mercury porosimetry
- By helium porosimetry

(some other techniques are available eg. porosity from image analysis, but this is not routinely used in core analysis)

GEUS

Porosity by different techniques :

He-porosity and Archimedes porosity are widely used in CCAL and SCAL analysis respectively; how do they compare :

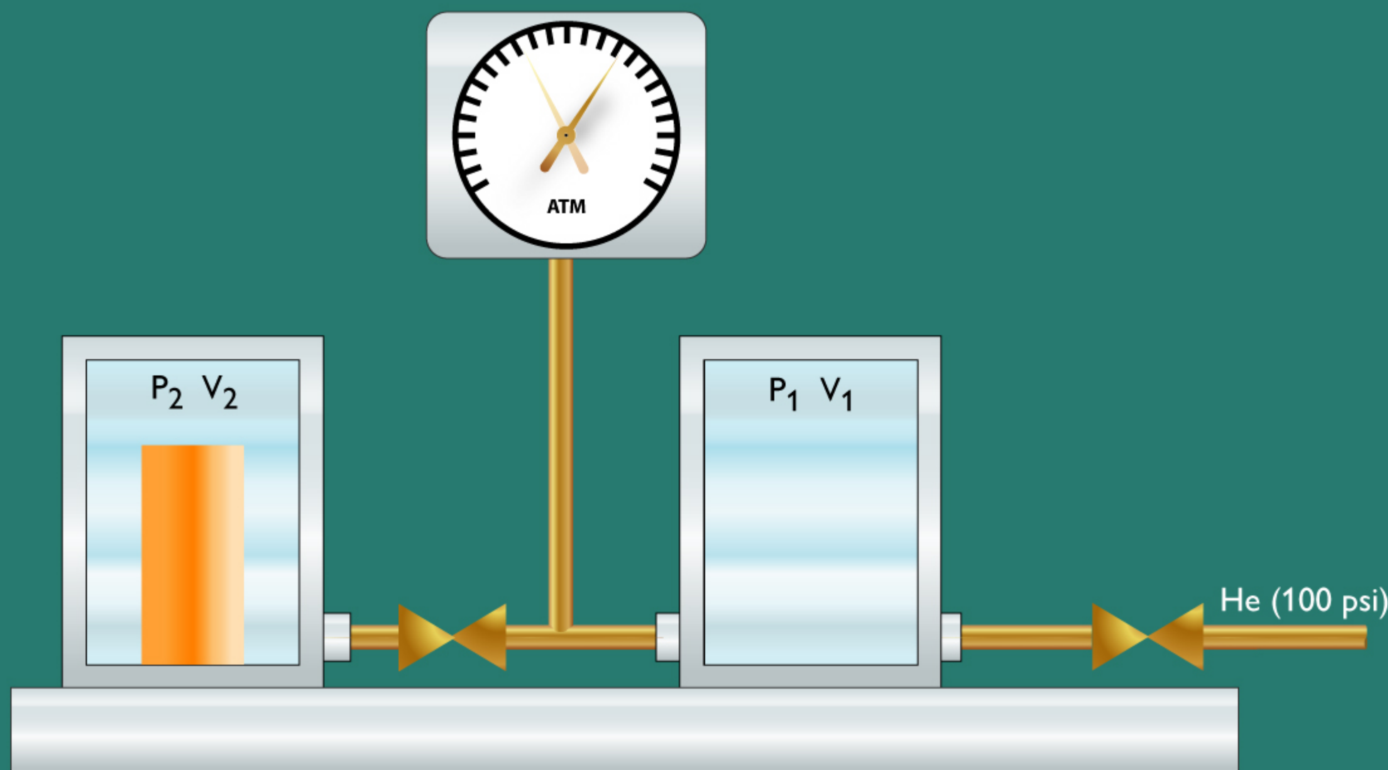
Data after plug trim and brine saturation (Greensand plugs)							
Plug ID	**Wet weight [g]**	**Imm. weight [g]**	**$BV_{(Arch)}$ [cc]**	**$PV_{(Arch)}$ [cc]**	**$Porosity_{(Arch)}$ %**	**$Porosity_{(He)}$ %**	**Por. Difference porosity-%**
H2	128.95	70.98	54.95	10.92	19.87	19.73	0.14
H8	134.40	75.22	56.09	9.43	16.81	16.70	0.11
H10	132.28	71.75	57.37	12.75	22.23	22.23	0.00
H14	131.92	71.89	56.90	12.16	21.38	21.34	0.04
H24	133.78	74.07	56.60	11.07	19.56	19.32	0.24
H32	133.46	74.12	56.25	10.38	18.45	18.34	0.11
H43	131.28	72.25	55.95	11.02	19.70	19.65	0.05
H49	129.91	71.20	55.65	11.26	20.23	20.29	-0.06
H51	130.93	71.88	55.97	11.35	20.28	20.23	0.05
H62	129.46	70.94	55.47	11.62	20.96	20.76	0.20
H82	131.64	72.03	56.50	11.76	20.82	20.82	0.00
H95	133.04	73.29	56.64	11.31	19.97	19.74	0.23
H97	133.35	73.46	56.77	11.14	19.62	19.55	0.07
H102	125.64	68.42	54.24	11.77	21.69	21.75	-0.06

Weakly consolidated core and some high porosity rocks may expand when saturated with a liquid

GEUS

Porosity: Boyles Law He-porosimeter

Calibration performed with a set of reference volume steel plugs



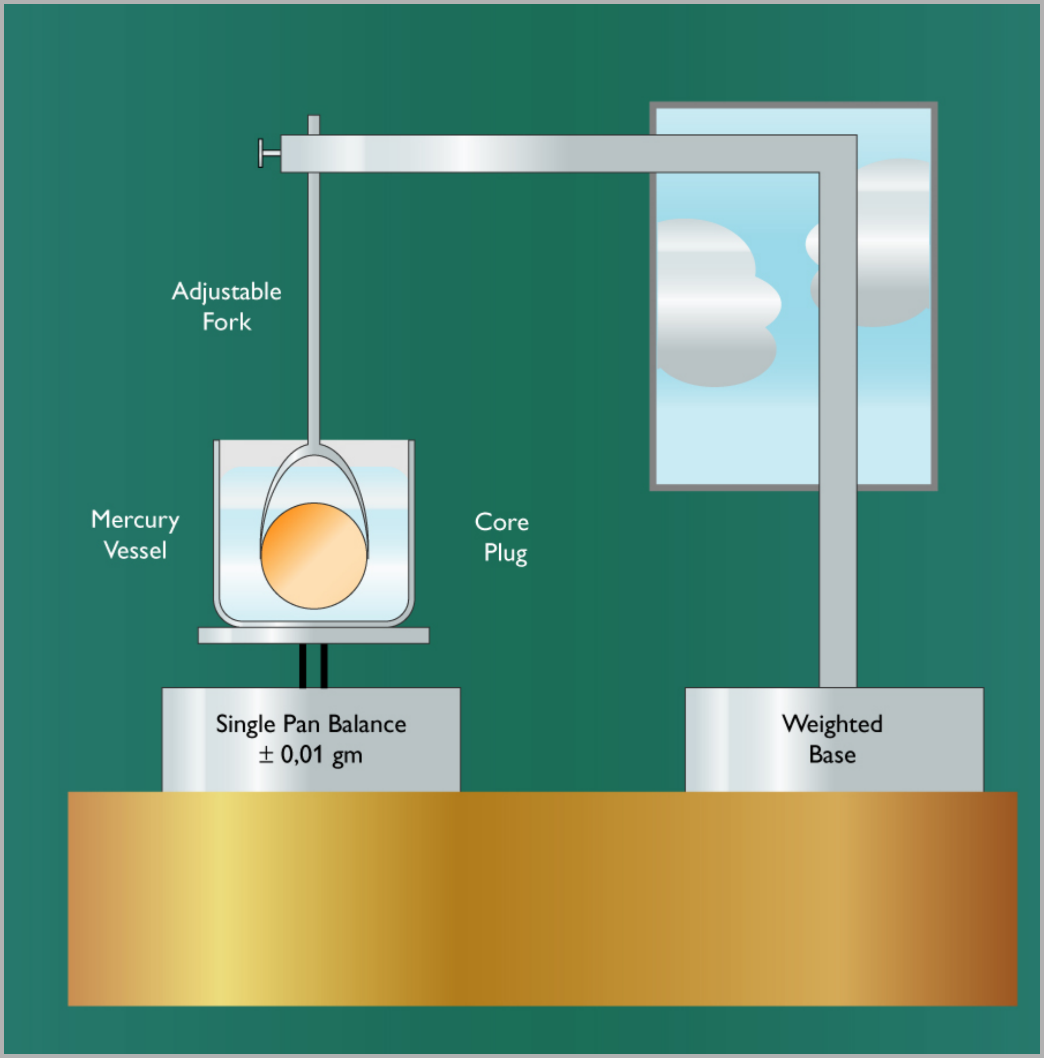
$$P_2 (V_2 - V_G) + (P_1 V_1)$$

$$P_3 (V_1 + V_2 - V_G)$$

PLOT V_G VERSUS P_3, (CONST P_1)

GEUS

Plug bulk volume measurement apparatus
(Archimedes principle)



Routine core analysis:

Typical grain density values [g/cc]	
Sandstone / Quartz	2.65
Limestone / Calcite	2.71
Dolomite	2.85 - 2.95
K-feldspar	2.58
Halite (salt)	2.17
Opal	2.1
Illite / Mica	2.6 – 2.9
Kaolinite	~ 2.60
Smectite	2 – 2.3
Gypsum	2.3
Anhydrite	2.9
Siderite	3.9
Pyrite	5.0
Barite	4.5

Carbonaceous material and salt reduces grain density for common sedimentary rocks; barite may be a contaminant from drilling mud.

GEUS

Example : Flush cleaning vs Soxhlet cleaning

Geensand (glauconite), Danish North Sea :

Sample ID	GEUS Por %	Other Por %	GEUS Dens g/ccm	Other Dens g/ccm
64	31.39	29.9	2.783	2.74
67	31.76	31.2	2.777	2.76
75	34.12	33.0	2.749	2.73
76	34.23	32.7	2.774	2.73
83	34.24	32.8	2.775	2.74
84	34.03	32.6	2.764	2.73
87	34.53	33.0	2.734	2.70
88	33.99	32.8	2.733	2.70
101	33.95	32.6	2.726	2.70
141	35.47	34.7	2.738	2.73
Mean	33.8	32.5	2.755	2.73
SDEV	1.24	1.25	0.022	0.020

GEUS Core Laboratory performed SCAL test on 10 greensand plugs previously analyzed for CCAL by another lab. The plugs were cold flush cleaned in core holders and re-analyzed for He-porosity and grain density. The avg. porosity was found to increase 1.3% and grain densty +0.025 g/cc.

This difference is due to improper Soxhlet cleaning. If in doubt always check against your porosity/density log data.

Conclusion: Soxhlet cleaning rests on diffusion that may take very long time for tight rocks; regular checks using dynamic (flush) cleaning should always be performed

GEUS

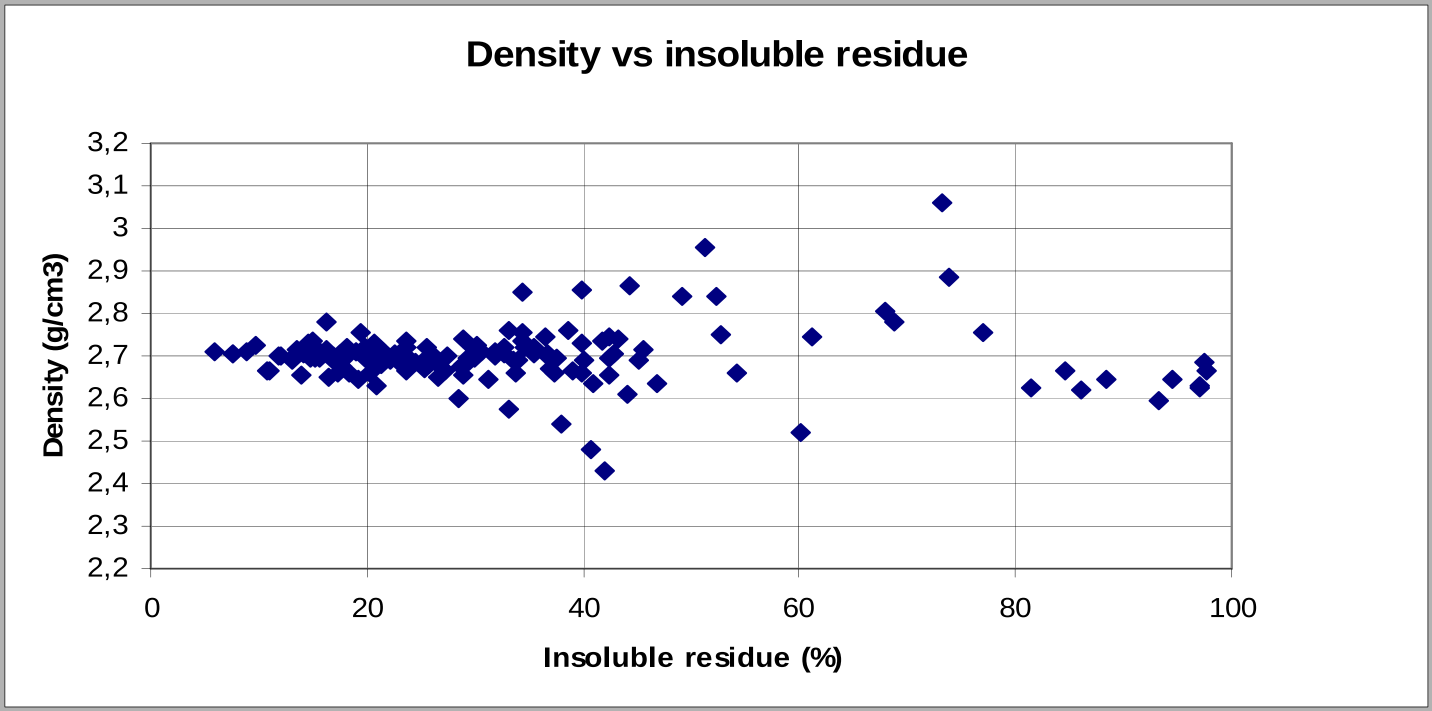
Example: Grain density

Conventional core analysis on a suite of chalk plugs from Lower Cretaceous gave a mean grain density of 2.71 g/cc

Conclusion by ”bright” petrophysicist: Nice chalk value, every thing is OK - the rock is even white as the white cliffs of Dover - - - I saw it with my own eyes - - - so lets get on !

But things are not OK unfortunately ! A scatter diagram shows:

Example: Grain density-insoluble residue trend for L. Cretaceous chalk (Tuxen-Sola Fm) :



Conclusion : A chalk model must consider the content of minerals other than calcite, eg. silica, clay and pyrite, and the effect that may have on grain density and porosity

Example: Porosity - grain density (Lower and Upper Cretaceous chalk) :

Minerals in ISR can be typed by XRD analysis :

Plug no.	Porosity, %	Grain dens., g/cc	ISR, wt-%	Qz, %
8	28.5	2.708	53	
10	23.1	2.707	62	
17	37.9	2.818	35	
21	29.3	2.709	40	
28	31.9	2.568	46	
30	23.7	2.513	69	
32	14.3	2.760	45	
A17.5	30.8	2.685	29	98

Exercise: Is it likely that plug A17.5 (Ekofisk chalk) contains ~ 30% quartz; base your QC on the measured grain density value.

Insoluble residue in chalk:

• Ekofisk Fm. chalk: 5-15% ISR consisting mainly of silica and kaolinite with some mixed-layer illite/smectite

• Tor Fm. chalk: 1-5% ISR consisting mainly of silica and mixed-layer illite/smectite with some illite as well

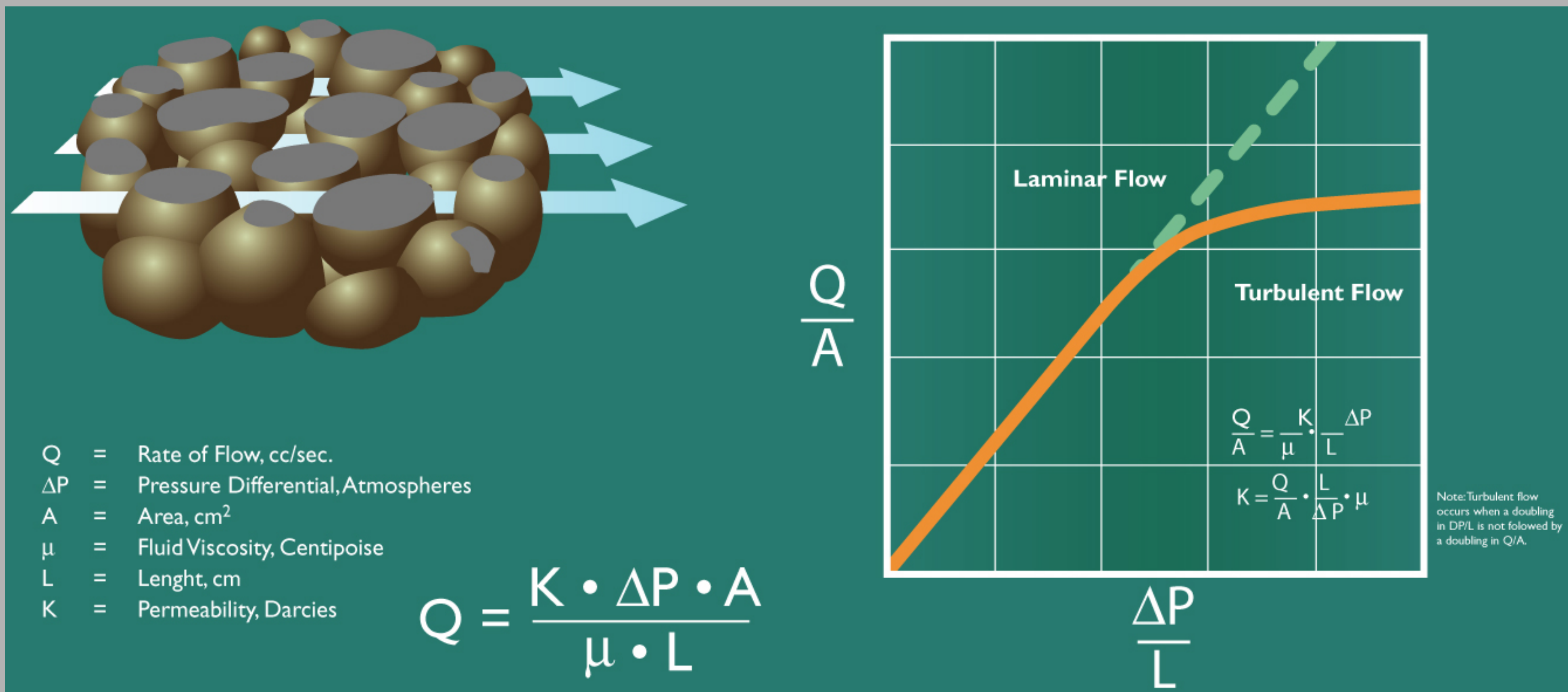
Permeability

- Gas permeability
- Klinkenberg permeability
- Liquid permeability

(in the petroleum industry gas permeability has been measured for a century contrary to the fact that oil permeability is the desired figure)

Permeability is the ability of a porous media to conduct a fluid; when a fluid flows through a porous media it experiences a certain resistance characteristic of the medium; the reciprocal of viscous resistivity is permeability

Effect of Turbulent Flow on Measured Permeability



Credits : Core Laboratories, 1984

Gas permeability:

The gas permeability is derived from Forchheimer's equation for isothermal, steady state flow of gas, that - at low flow velocities - simplifies to Darcy's equation (un-corrected for gas slippage):

$$\text{Gas } K_{[mD]} = (2000 * P_a * Q * \mu * L) / (P_u^2 - P_d^2) * A \qquad \text{unit length}^2$$

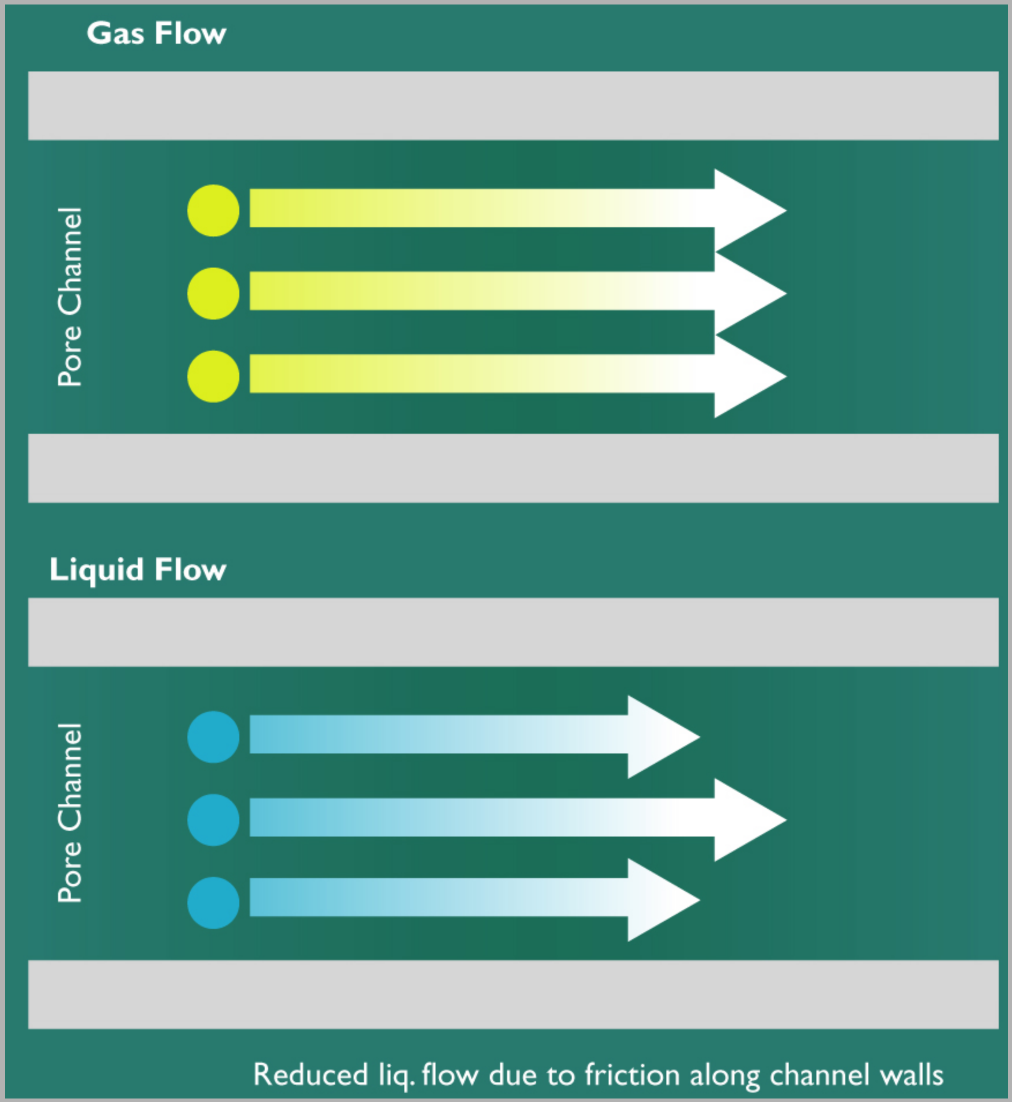
Where:

P_a = Atmospheric pressure [atm]
P_u = Upstream pressure [atm]
P_d = Downstream pressure [atm]
Q = Flowrate [cc/s]
μ = Gas viscosity [cP]
L = Sample length [cm]
A = Sample Area [cm^2]

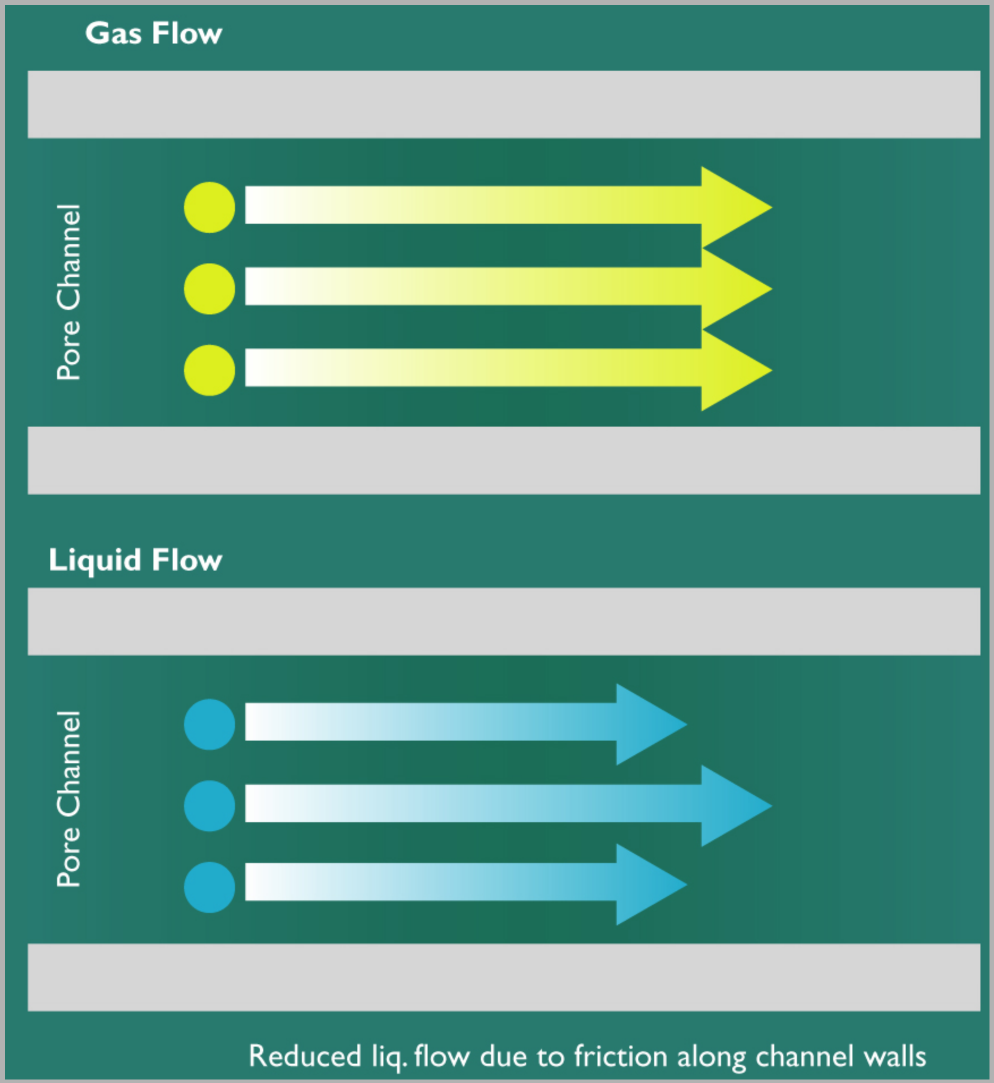
Traditionally gas permeability is expressed in Darcy or milli Darcy [mD]
The SI unit of permeability is [m^2], eg. 1 Darcy ~ 10^{-12} m^2

GEUS

Klinkenberg slip effect



Klinkenberg slip effect



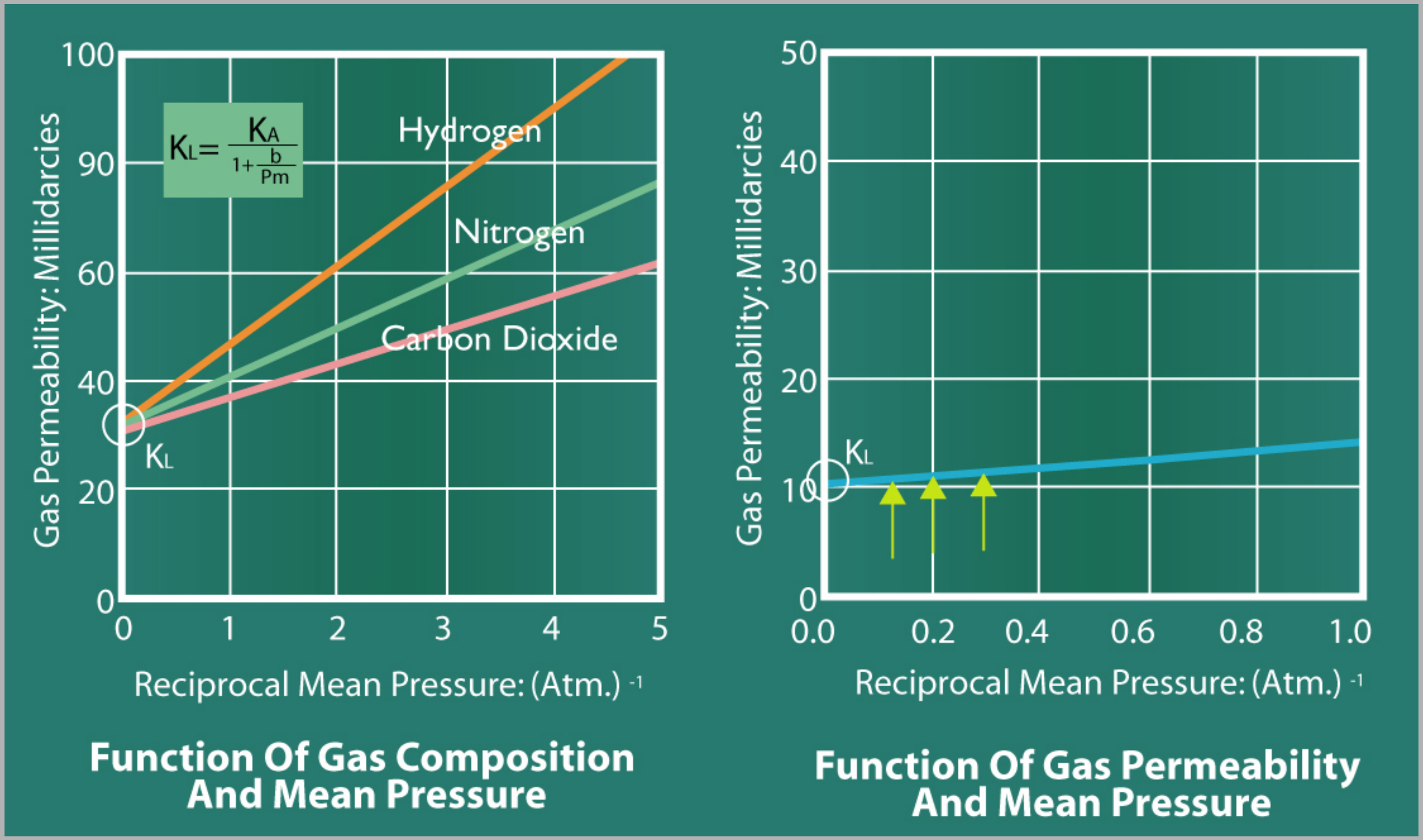
Klinkenberg slip effect:

$$k_g = k_{el} \times \left(1 + \frac{b}{p_m}\right)$$

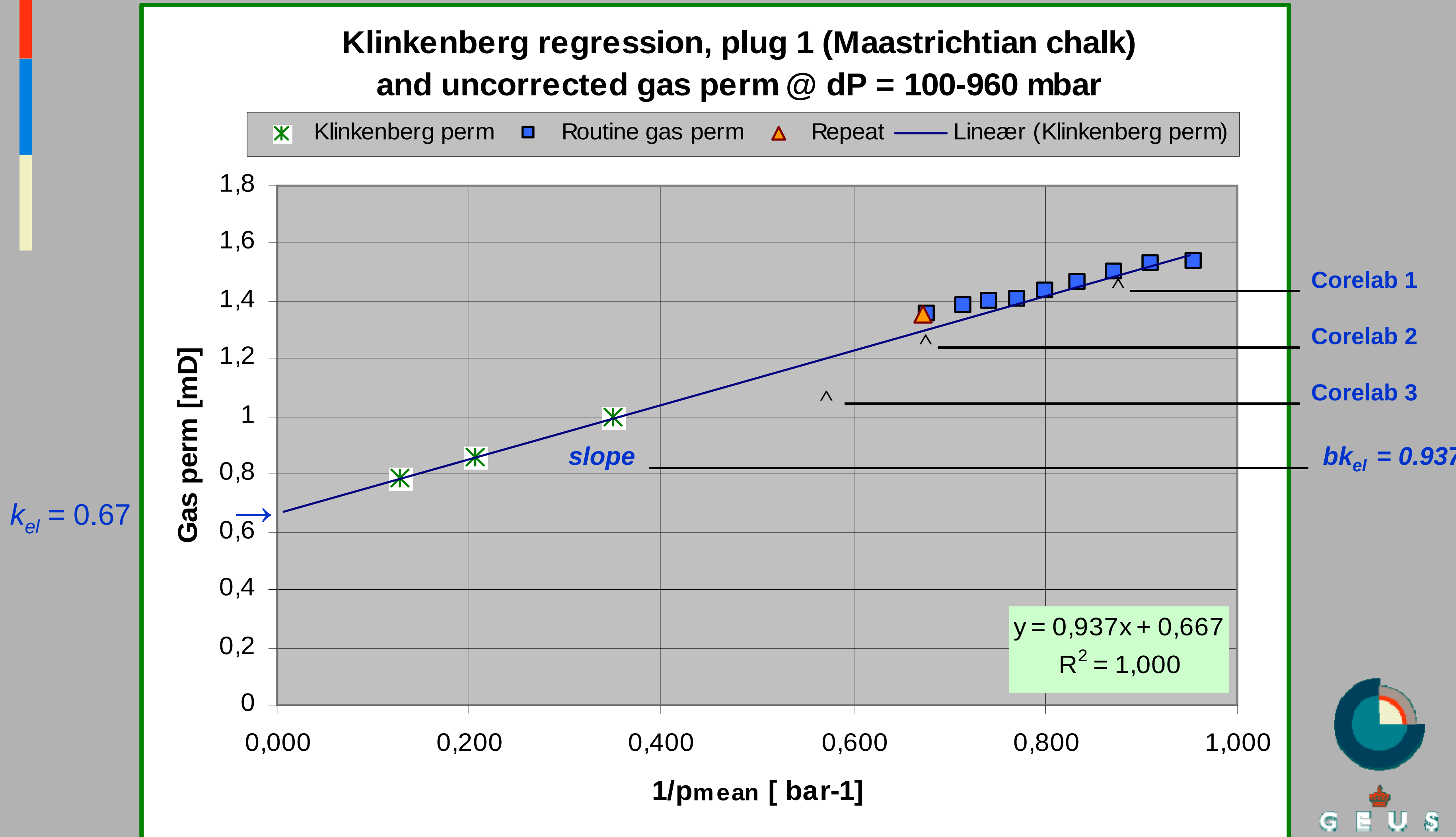
b is Klinkenberg's slip factor

p_m is the mean pressure :

Gas perm and Klinkenberg Gas Slippage Correction



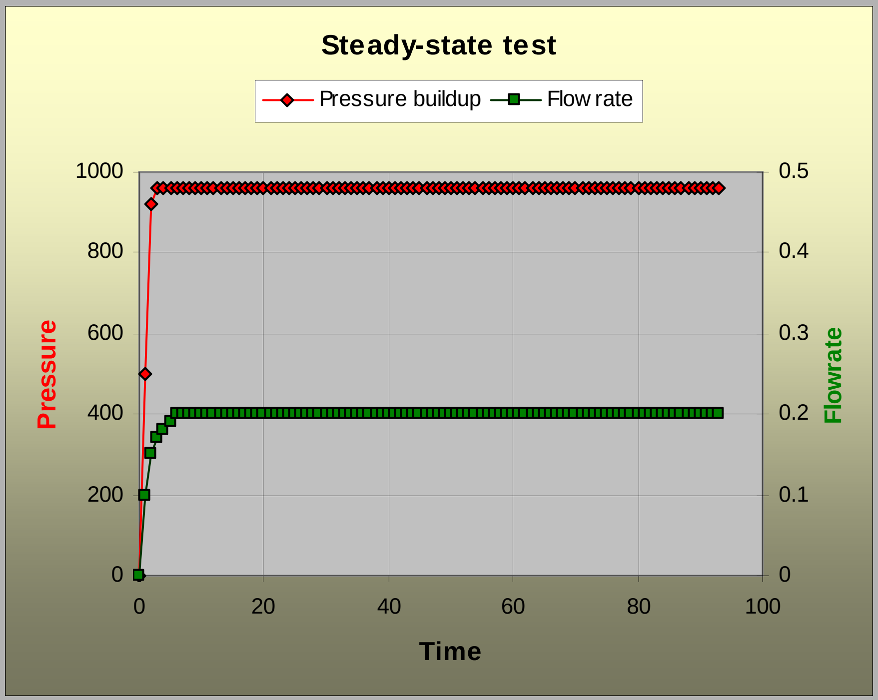
Klinkenberg or the slip corrected gas permeability, k_{el}

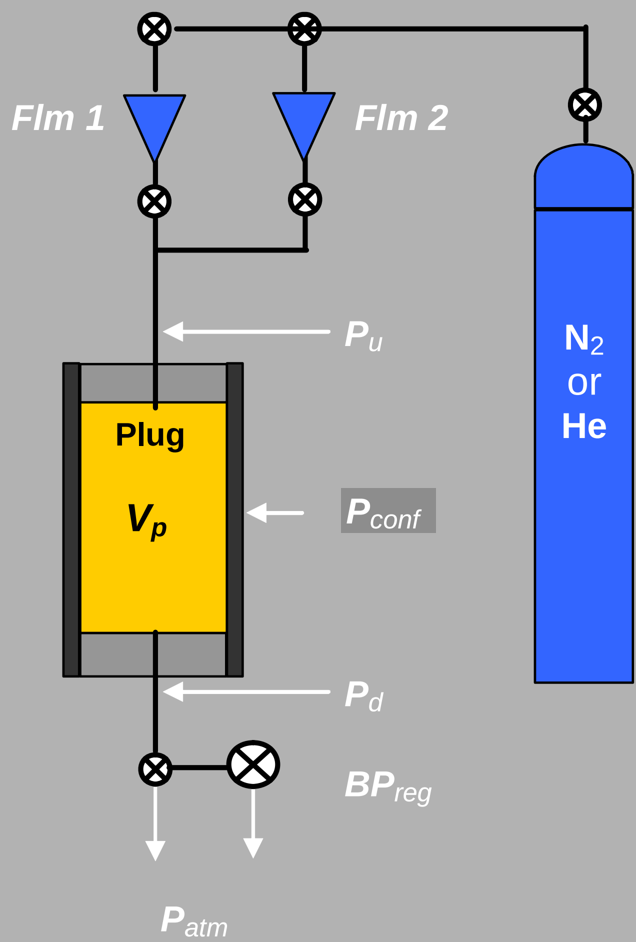


GEUS

Steady state gas permeameter :

Measures uncorrected gas permeability k_g, Klinkenberg corrected gas permeability k_{el} and slip factor *'b'* , but requires at least 4 measurements.

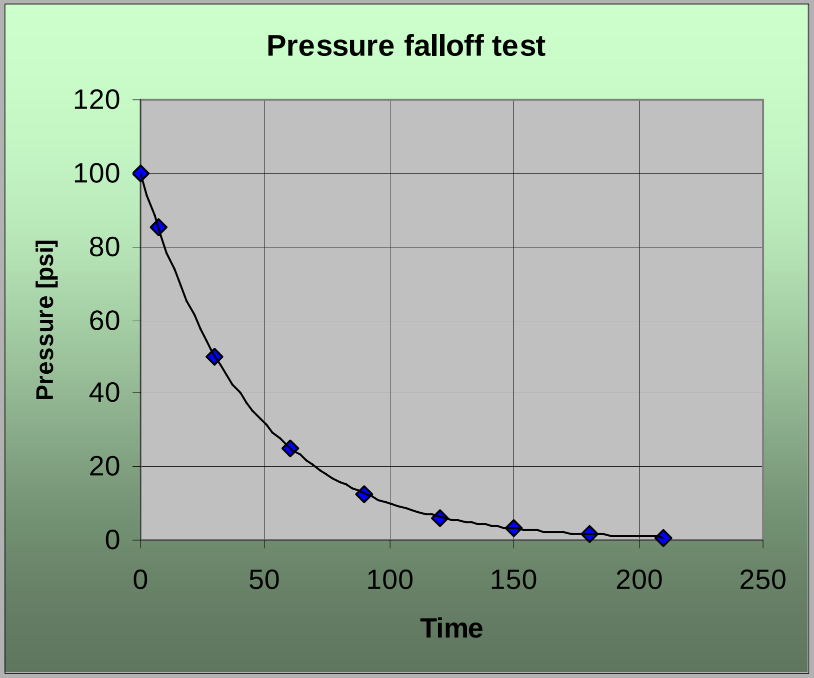


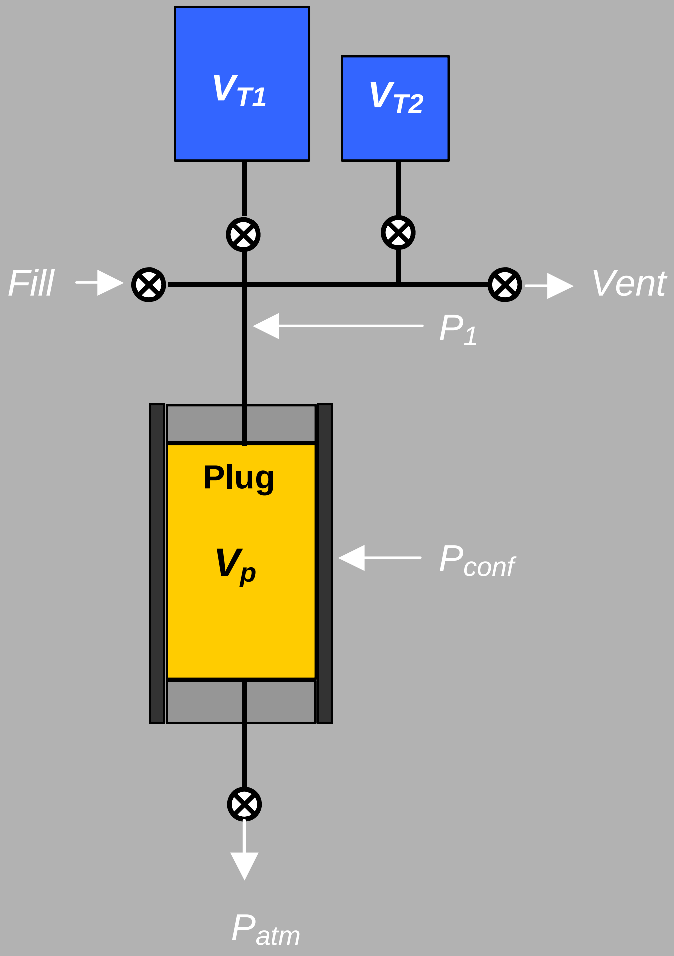


Un-steady state gas permeameter :

Measures k_{el} , Klinkenberg slip factor *'b'* and Forchheimer's inertial resistivity *'β'* in one single test.

Uncorrected gas permeabilities k_g can be calculated for any mean pore pressure for comparison with existing conventional data





GEUS

Listing of CCAL data:

SAMPLE NO.	DEPTH FEET	PLUG TYPE	GAS PERM mD	1.5 P-M PERM mD	KLINK PERM mD	KLINK CORR. COEF.	POROSITY %	GRAIN DENS. G/CCM	WATER SATUR. %	OIL SATUR. %	GAS SATUR. %	COMMENT
34		HOR	0.664	0.657	0.249	1.000	31.92	2.707	73	21	5	
5X		HOR	1.08	1.07	0.421	0.997	36.19	2.706				
35		HOR	1.10	1.09	0.459	1.000	35.00	2.706	63	18	20	
36		HOR	0.443	0.432	0.180	1.000	27.37	2.708	67	17	16	
8V		VERT	1.54	1.50	0.654	1.000	38.80	2.708				
37		HOR	1.45	1.41	0.642	1.000	37.65	2.704	64	18	18	
38		HOR										Preserved
39		HOR	1.37	1.34	0.595	1.000	37.11	2.704	62	19	19	
40		HOR	1.47	1.42	0.616	1.000	37.99	2.701	65	19	16	
41		HOR	1.03	0.994	0.429	0.999	34.63	2.702	68	19	14	
9V		VERT	0.294	0.275	0.085	0.992	30.68	2.712				
42		HOR	0.485	0.449	0.189	0.999	30.00	2.700	82	7	11	
43		HOR	2.07	2.02	1.32	1.000	23.82	2.697	71	22	8	
6X		HOR	0.245	0.182	0.080	0.991	23.95	2.709				
44		HOR	0.678	0.649	0.290	1.000	30.11	2.705	64	22	14	
45		HOR	0.205				20.46	2.707	70	5	26	
10V		VERT	0.050				20.83	2.719				
46		HOR	0.206				22.39	2.683	82	1	17	
47		HOR	0.179				23.54	2.702	72	17	11	
48		HOR	0.808	0.795	0.321	1.000	34.00	2.704	59	19	22	
49		HOR	0.644	0.637	0.255	1.000	31.76	2.705	64	22	14	
50		HOR	1.00	0.989	0.426	1.000	35.57	2.701	58	32	11	

Credits : GEUS Core Lab

Gas permeability, conclusion :

• The vast majority of the worlds gas permeabilities are conventional, ie. steady state, uncorrected for slip and measured at 400 psi (2.8 MPa).

• Most oil companies keep core data bases with input from a number of different service companies having different gas permeameters operating at different instrumental settings.

• If uncorrected gas permeabilities are kept in a single data base it is necessary to normalize data to one common gas and mean gas pressure; eg. N_2 and 1.5 bara (bar absolute).

• A groving number of gas permeabilities are now being measured by the un-steady state method, a convenient way of obtaining both conventional and slip corrected (Klinkenberg) gas permeabilities in a single pressure fall-off test.

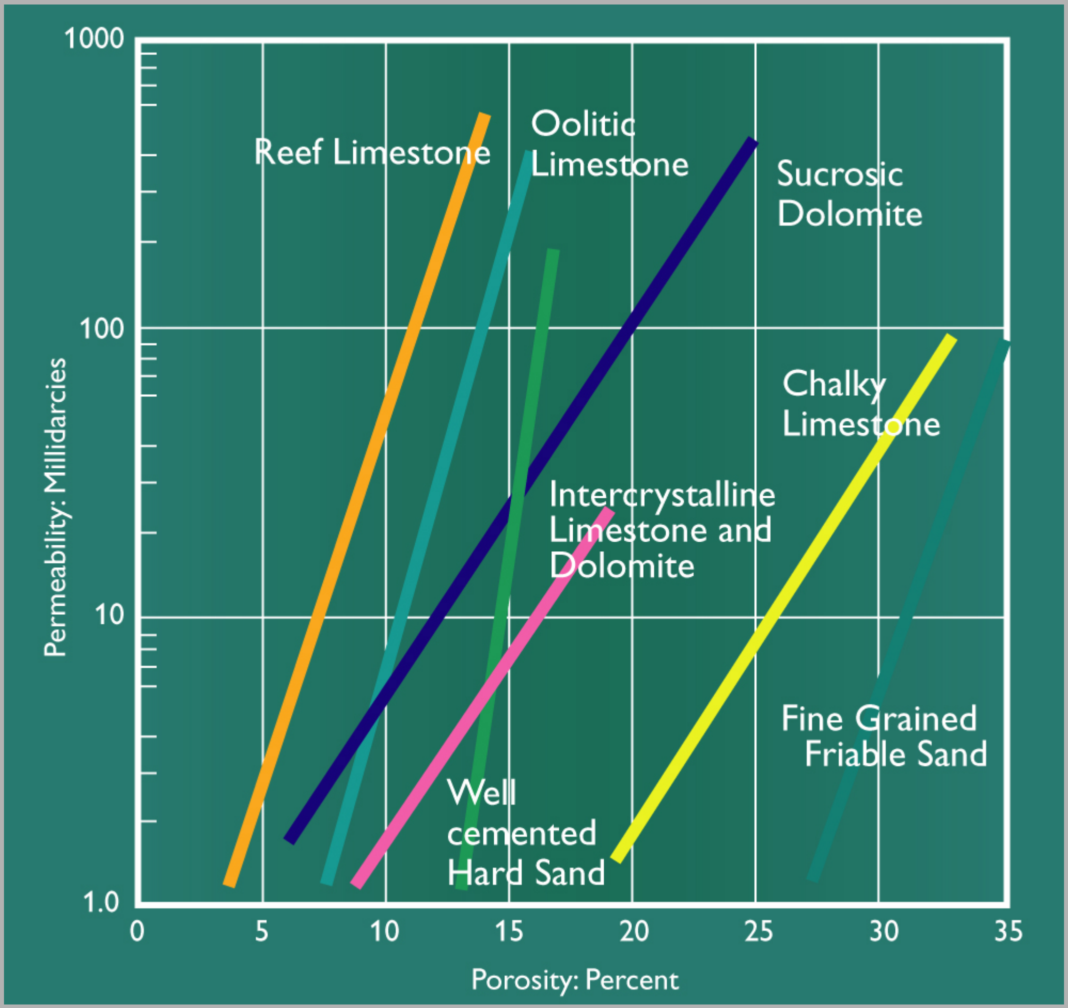
GEUS

Permeability and porosity trends for various rock types

Extreme CCAL data:

Diatomites (moclay) may have porosity ~70% (intra-particle porosity) while fresh granites and gneisses measure around ½-1%

Un-consolidated sand and coarse sandstones have very high permeabilities > 10 D, while fresh granites, marbles and shales may have permeabilities in the nD range



GEUS

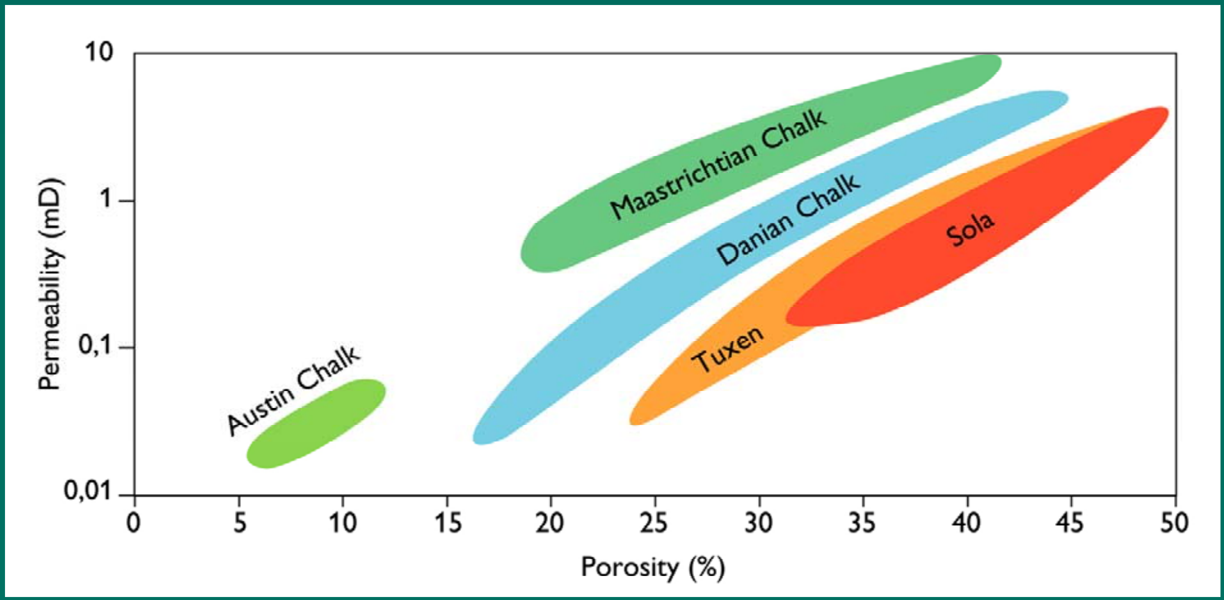
North Sea chalks, petrophysical properties: Porosity – Gas permeability trends

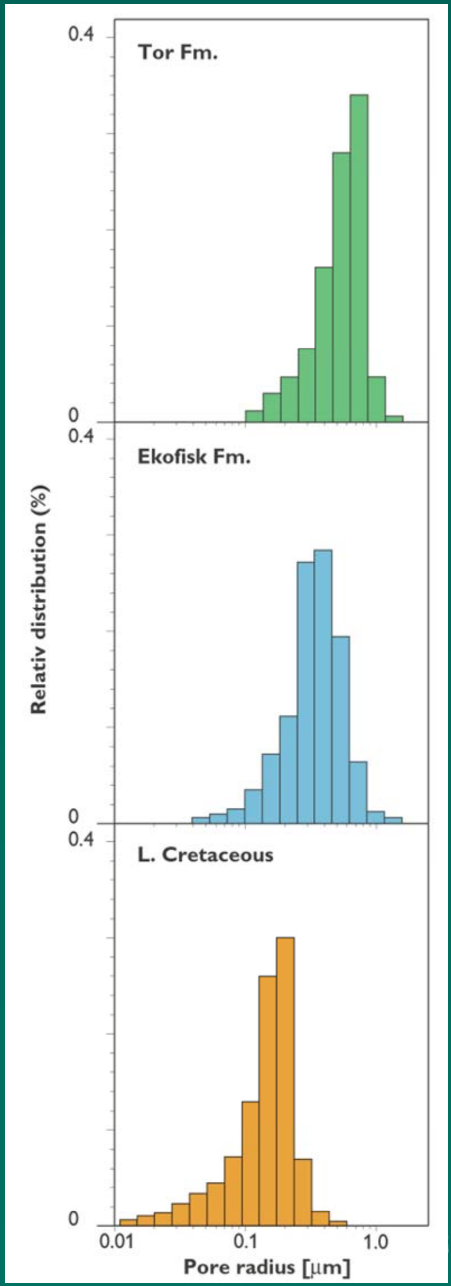
- Observe unimodal, left skewed Hg-injection pore size distribution due to ± silica, clay and small grains
- Tor (Maastrichtian) r_{50} ~ 0.6 µm

  Ekofisk (Danian) r_{50} ~ 0.4 µm

  L. Cretaceous r_{50} ~ 0.15 µm @ 35 - 40% porosity chalk

Partly after: Jakobsen et al., 2003 and Andersen, 1995





Permeability considerations:

- Sleeve pressure (400 psi, 800 psi or something else)
- Clay damage (liquid or gas)
- Fracture
- Flow rate
- QC - not easy to check permeability data by other means, core laboratory should measure standard reference steel plugs regularly and report data to Company

Copy of data listing from major core analysis company:

Sample	Depth (ft.)	Core	Gas Permeability @ 400 psig (mD)	Gas Permeability @ 2768 psig (mD)	Porosity @ Ambient (%)	Porosity @ 2768 psig (%)	Grain Density ($g.cc^{-1}$)	Sw (% of Pore Volume)	Comments
77	10656.05	2	7.65	7.56	36.7	35.5	2.70		White Chlak, firm, tr micpyr, tr dk mins, tr micpyr, frac, hi calc.
77V	10656.20	2	7.75	7.32	35.7	34.1	2.68	49.7	White Chalk, mod hrd, Frac, tr microfossils, cmted Frac, tr dk mins, hi calc.
78	10657.20	2	7.02	6.83	35.8	34.9	2.70		White Chalk, mod hrd, tr calc conc, tr dk mins, frac, hi calc.
80	10658.95	2	7.38	6.25	37.3	35.5	2.71		White Chalk, mod hrd, tr calc conc, tr dk mins, cmted frac, hi calc.
81	10660.15	2	5.45	5.39	35.5	34.1	2.71		White Chalk, mod hrd, tr micpyr, frac, tr calc conc, tr dk mins, styl, hi calc.
83V	10661.90	2	6.66	5.53	34.6	33.1	2.73	29.7	White Chalk, firm-mod hrd, cmted frac, lg calc conc, tr dk mins, hi calc.

Petrophysicist about to select samples for SCAL work is puzzled by the 2768 psi confining pressure used in porosity and permeability measurement

She compares with formation pressure data delivered from Company to the contracting core analysis company:

Total overburden P = 8300 psi

Reservoir pore P = 6400 psi

Net confining P = 1900 psi

which means that laboratory hydrostatic confining pressure should not exceed 1150 psi to prevent compaction !!

She is now looking elsewhere to find samples for SCAL work !

GEUS

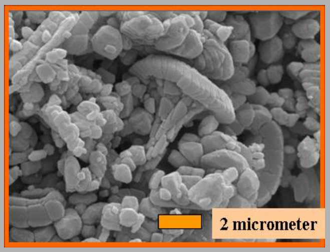
Core photo in white and UV light of slabbed core

- Supplements core description, sampling position and fluid saturation data

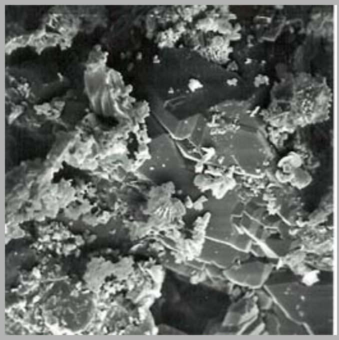
Rock properties

Fundamentals of rock properties 1: *Physical properties of rocks are controlled by texture, mineralogy and P,T conditions of formation*

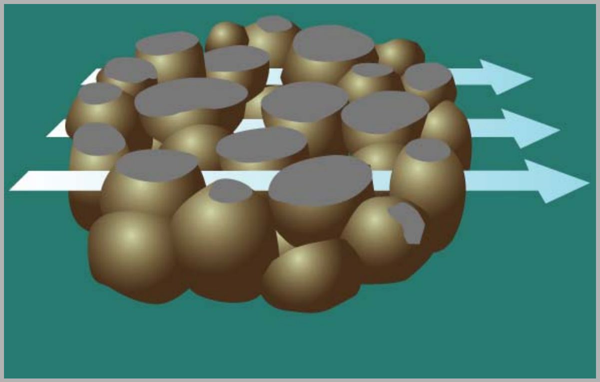
- The *fundamental rock properties* are:
  - Grain size distribution and packing of grains
  - Fractures
  - Compaction
  - Mineralogy (quartz and clay minerals)
  - Diagenesis

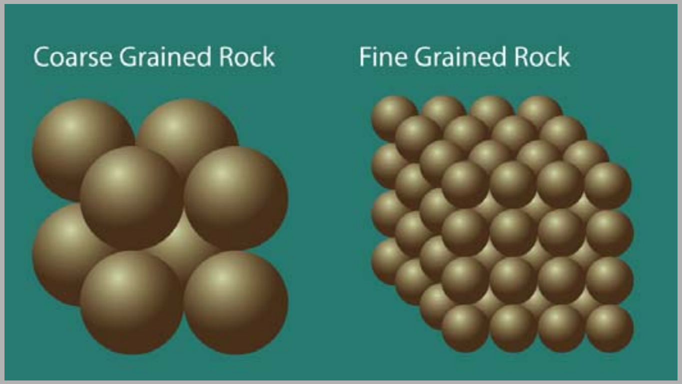


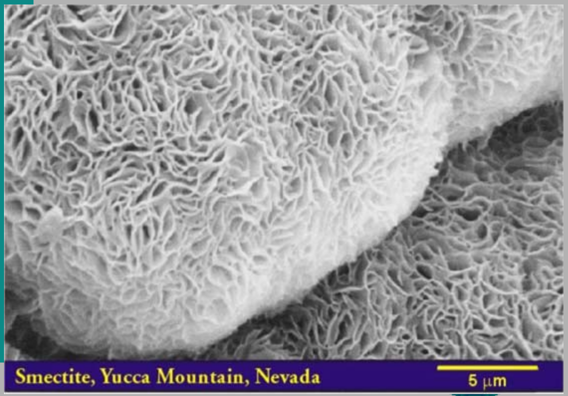
- They control the important *petrophysical properties*:
  - Porosity, pore size distribution, tortuosity and surface roughness, that determines
  - permeability, capillarity, electrical properties, sonic velocity and specific surface area



Fundamentals of rock properties 2 : *Grain size distribution and packing geometry of the grains defines pore size distribution in sedimentary rocks and thereby control permeability and capillary entry pressure. Packing geometry also affects the porosity.*



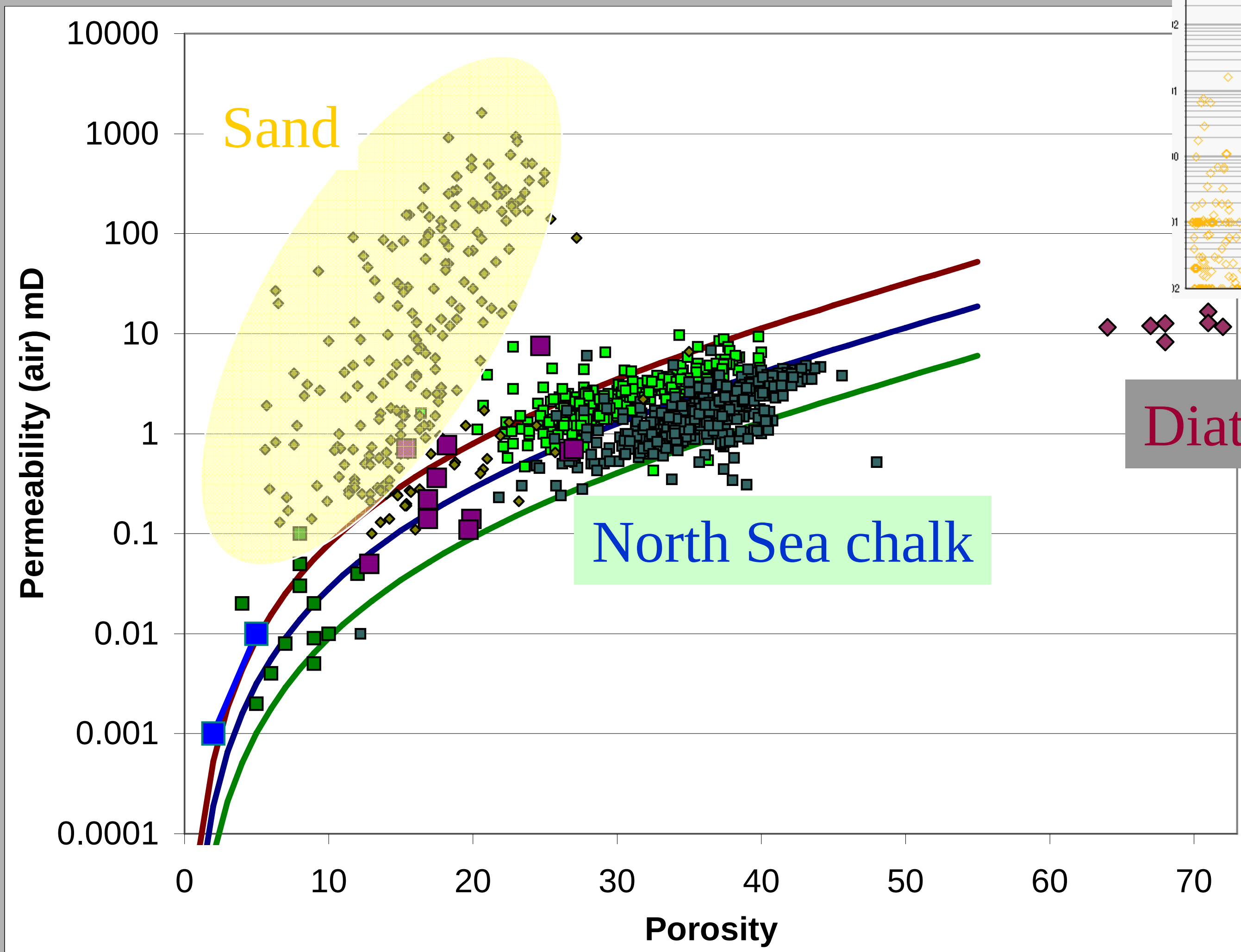


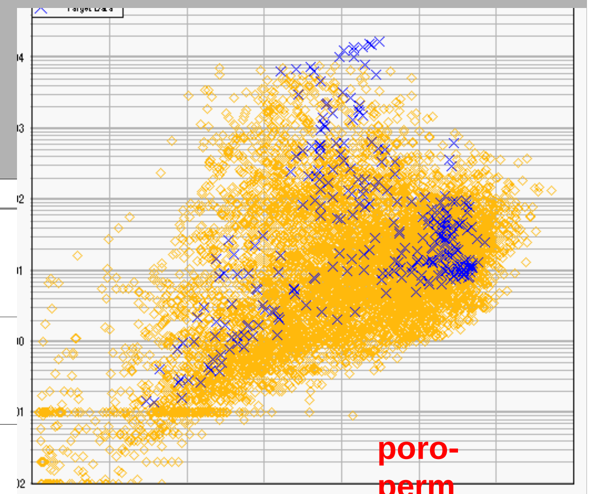


GEUS

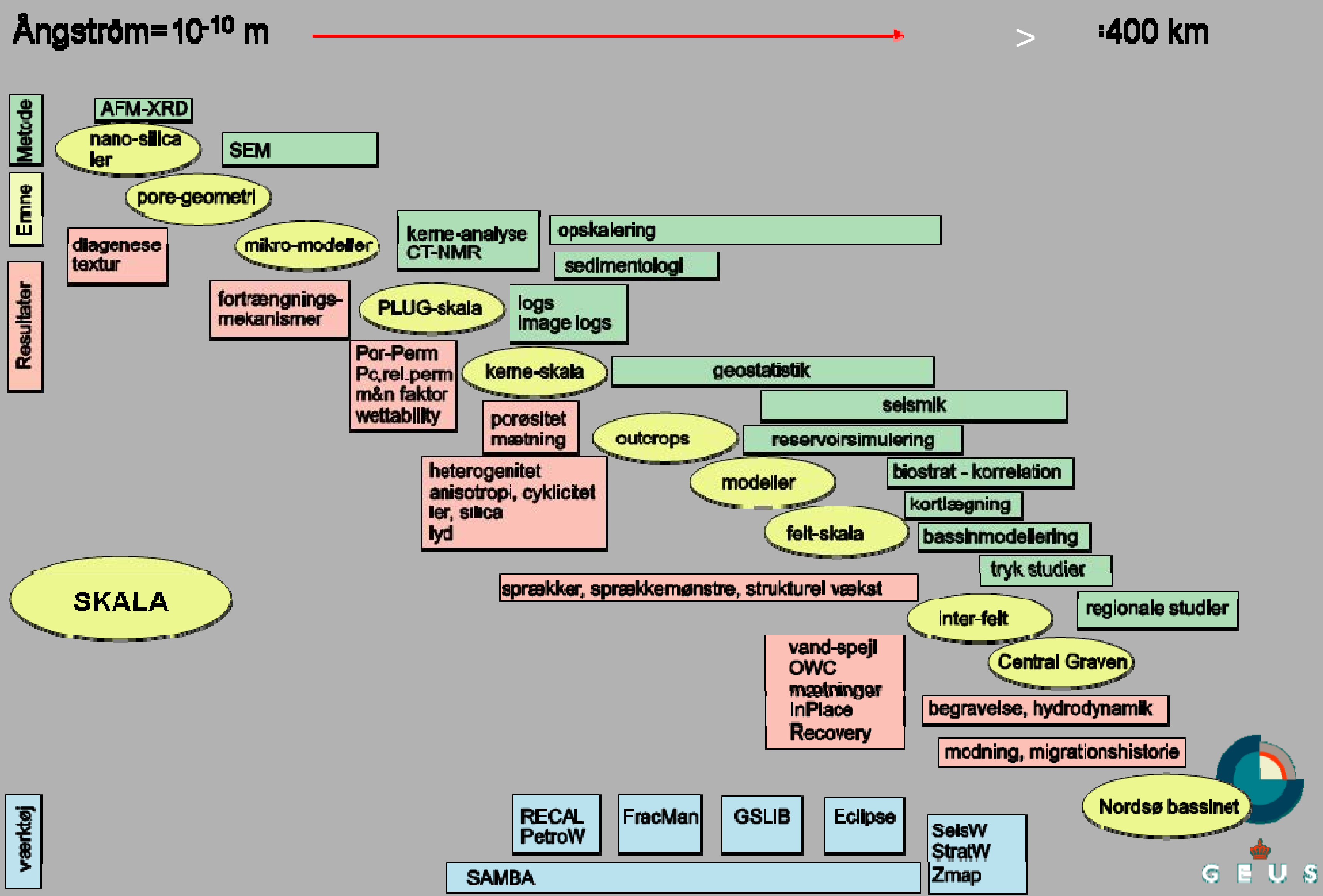
Credits : The Clay Minerals Soc.

Chalk family vs. Sand family and carbonates:





Fundamentals of rock properties 3 : *Scale effects in reservoir geology*



Credits : P. Frykman

Case stories

How to get high quality porosity data

- Order extended cleaning of plugs if core material is low perm (chalk) or contain clay minerals (greensand with glauconite) and allow the core lab to do a proper job – don’t rush final porosity measurements,
- With a few tricks you can always get the true porosity from ’Hot-shot’ measurements as fast as you like, you only need additional data that are not normally reported but measured by the laboratory anyway – ask for it !

Example: Correction of ”hot-shot” porosities (chalk)

If the grain density of the formation can be safely assumed, a good estimate of porosity can be obtained – ask the core laboratory to do the calculation:

Let X_c be the volume of contaminating fluid with density d_c that has not yet been cleaned off the plug. The fluid consist of oil and brine (salt) that is assumed to have a density close to 1 g/cc.

Plug	Gas Perm., mD	Porosity, %	Gr. Dens., g/cc
15X	2.40	29.77	2.566
16X	2.35	31.74	2.615
17X	1.91	24.06	2.673
18X	0.58	17.07	2.678

Data after re-cleaning and re-measurement:

Plug	Gas Perm., mD	Porosity, %	Gr. Dens., g/cc
15X	3.87	35.56	2.714
16X	3.31	35.41	2.708
17X	2.48	25.77	2.712
18X	0.73	18.58	2.711

From measured "Hot-shot" plug data Ø, BV and M_{plug} :

$$GD_{corr} = \frac{M_{plug} - X_c \times d_c}{GV - X_c} = 2.71$$

$$X_c = \frac{M_{plug} - 2.71 \times GV}{d_c - 2.71}$$

$Porosity_{corr}$ *	
15X	35.7
16X	35.5
17X	25.7
18X	18.6

GD = Grain density
GV = Grain volume
M_{plug} =. Plug dry weight

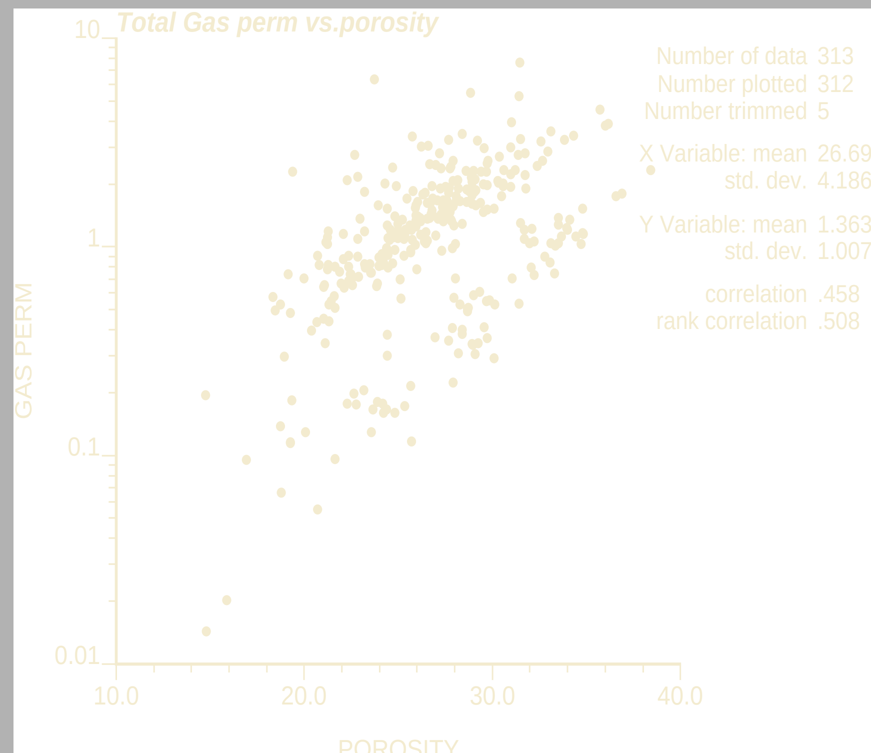
Sandstones (not too shaly) can be assumed to have a grain density of 2.65 g/cc

$$\text{* Porosity, corrected} = \frac{PV + X_c * 100 \quad [\%]}{BV}$$

GEUS

Case study: Porosity-permeability model for a North Sea chalk field

- Your chief petrophysicist asks you to update an old poro-perm model for a marginal field that is no longer as marginal (presumably). This is the set of data you get; what is the first thing you should do ?



- Different confining pressures have been used, 400 psi and 800 psi during gas perm measurement; what to do about it ?

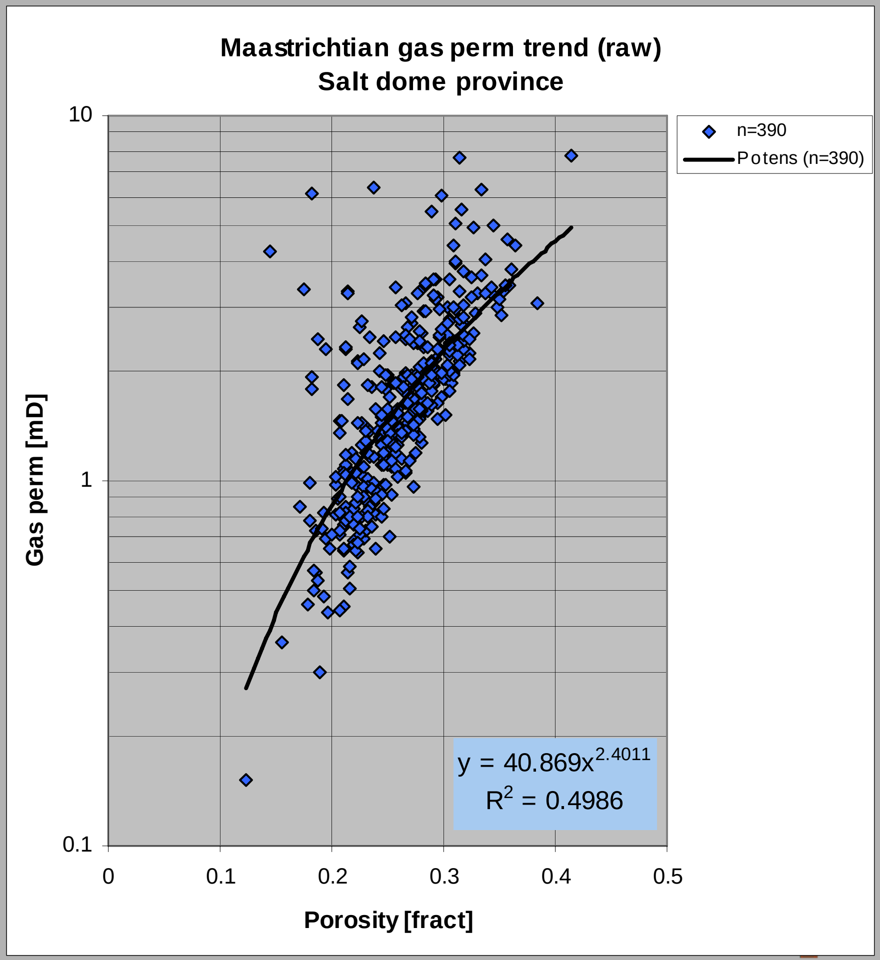
- and next ?

GEUS

Case study: Porosity-permeability model for a North Sea chalk field

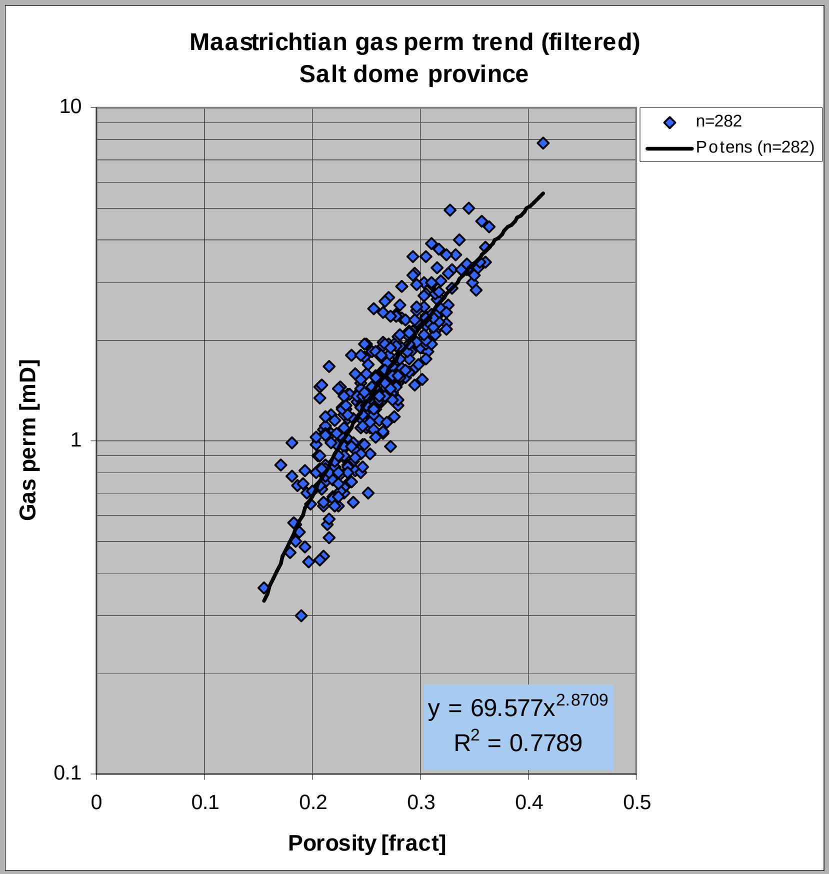
- You find that the data set you got contain Danian and Maastrichtian samples in the same file; you decide to split data and go on with the Maastrichtian samples. Are you (and your chief petrophysicist) happy with the model ?

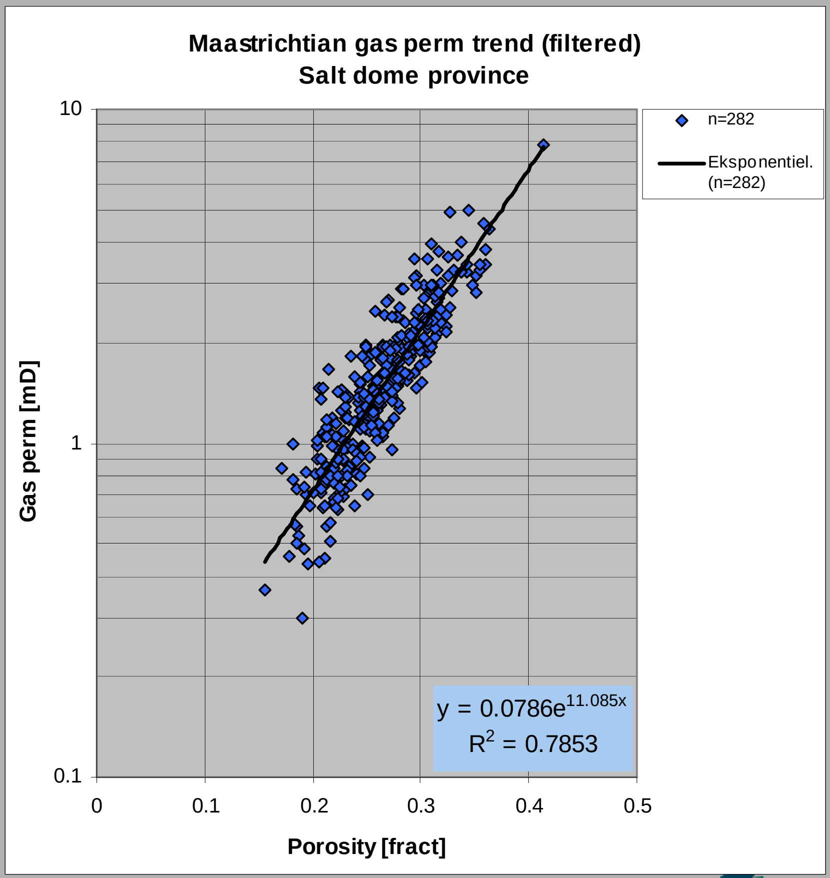
- What to do about it ?



GEUS

Case study: Porosity-permeability model for a North Sea chalk field

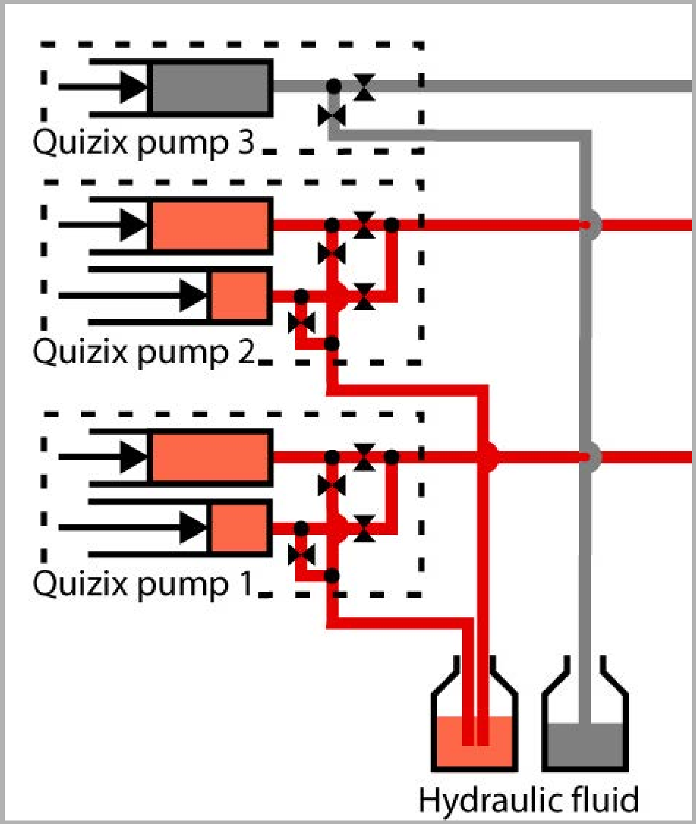




- You fit 2 different models to the screened data set; observe that the power curve may underestimate the high permeability range while the exponential fit may overestimate the low permeability range (a polynominal fit may be a better solution)

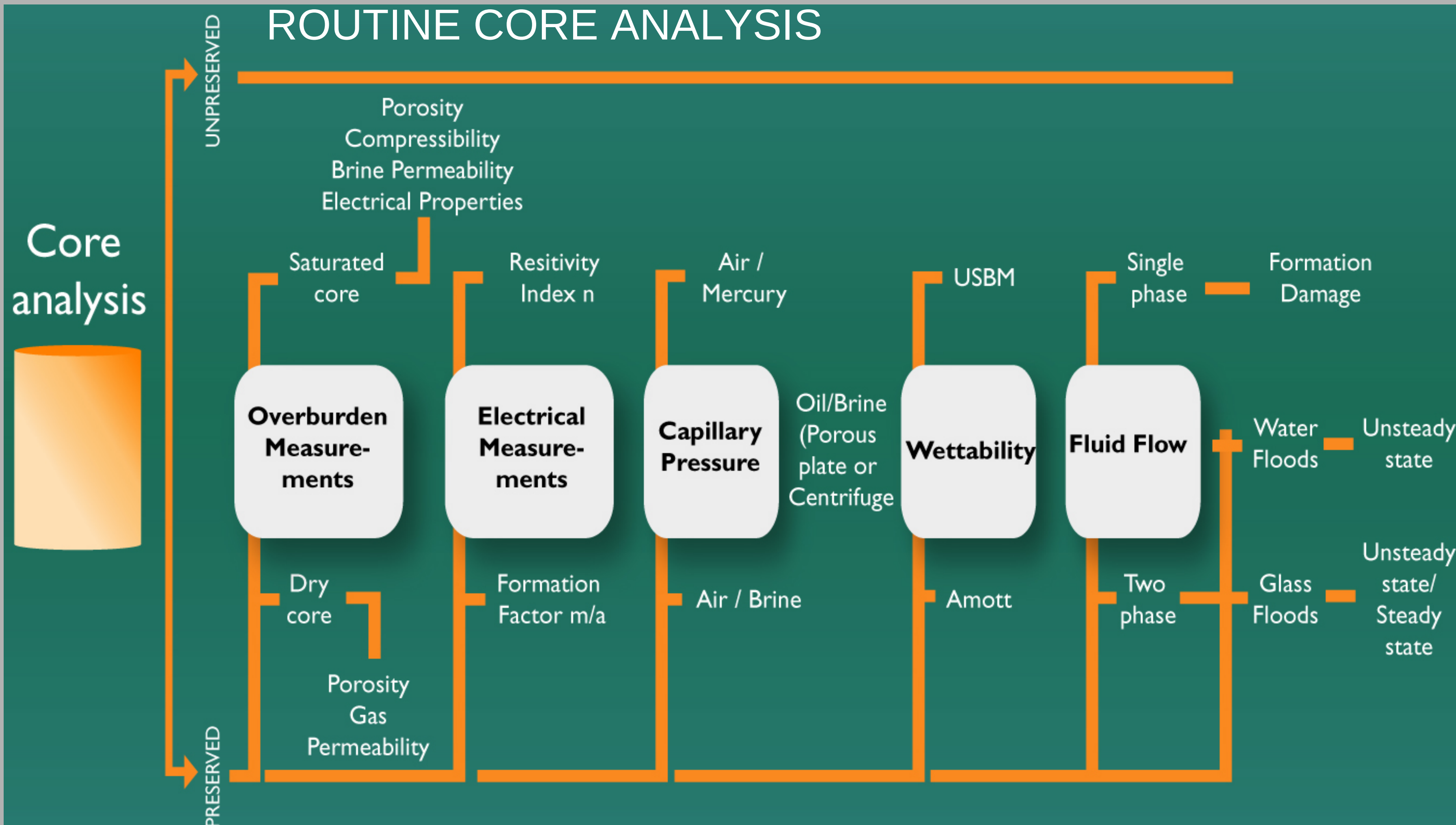
SPECIAL CORE ANALYSIS

GEUS



Presented by

Niels Springer



SPECIAL CORE ANALYSIS

Screening samples for SCAL work :

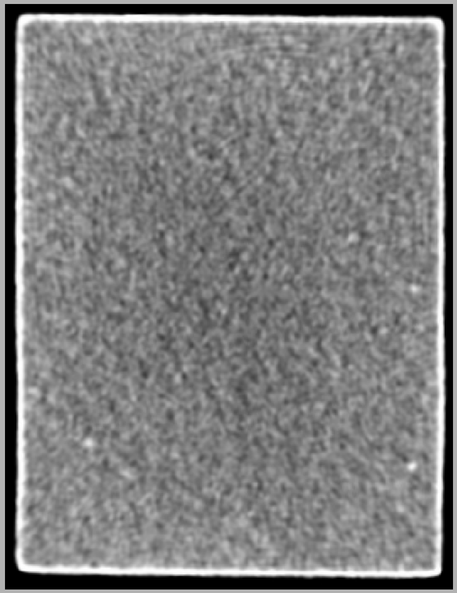
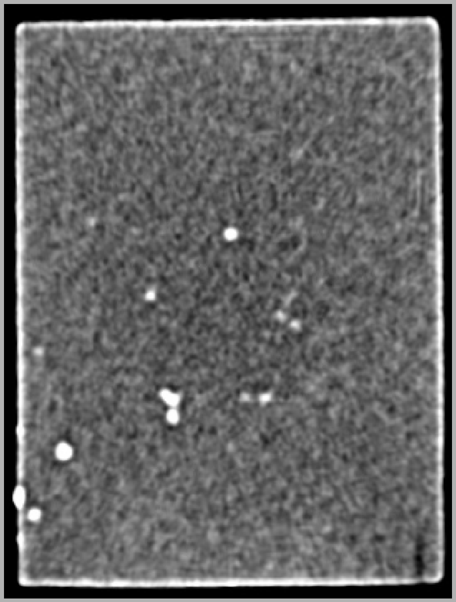
- Plug samples for core analysis are subject to scaling effects that do not affect borehole logging tools, eg. small scale fractures, healed hairlines, irregular cementation, large vugs, patchy pyrite or pyrite nodules, bioturbation and fossil shells.
- Such cm-scale textures disappear from a borehole log that covers a much larger volume of rock.
- It is therefore mandatory to screen plug samples for special core analysis and rock mechanics testing by X-ray CT-scanning to reveal any unwanted textures before initiating an often costly analytical programme.

- 2 longitudinal and/or transverse cuts through the plug will normally be sufficient to characterize the plug texture. The attenuation of X-rays is expressed in Hounsfield units or gray tones:
- Grey tone -1000 = air (100% porosity) appear black
- Grey tone 0 = water
- Grey tone +3000 = solid mater (0% porosity) appear white

GEUS

Screening samples for SCAL work : Green sand from the Siri area, Danish North Sea

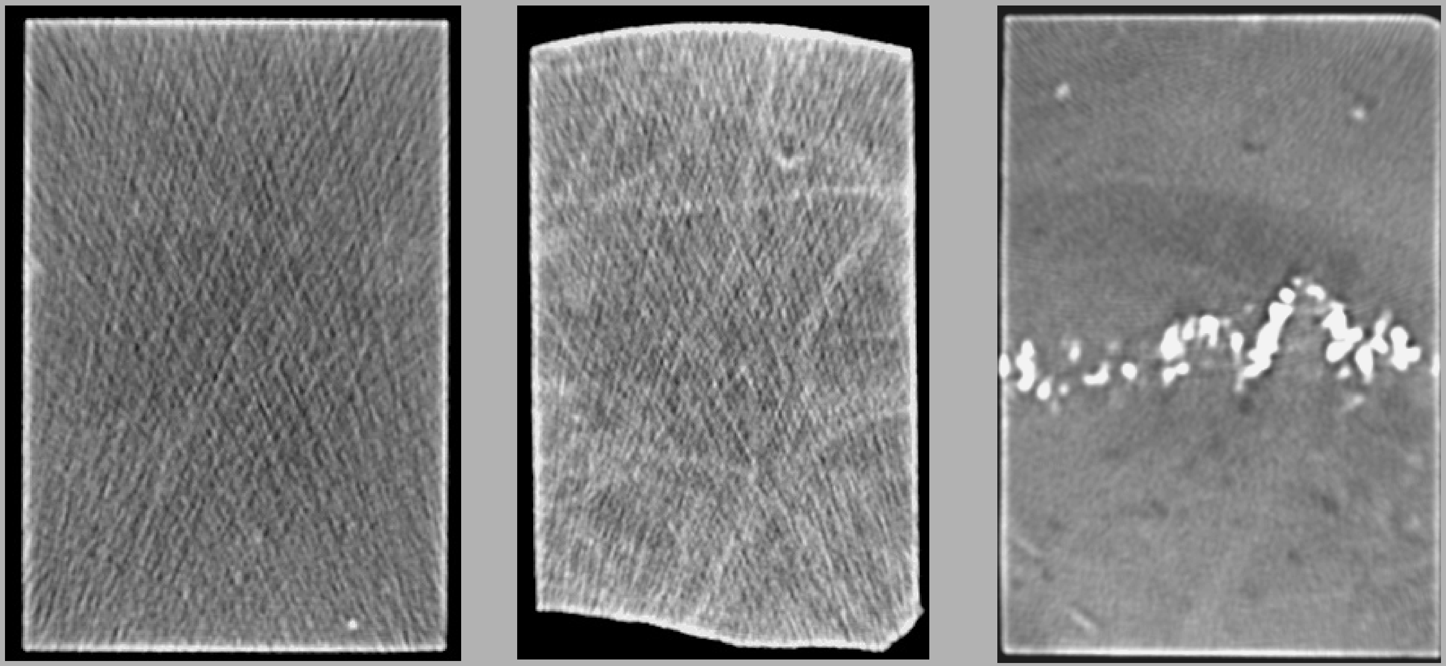
Pyrite and coal fragments ?


Typical sandstones have gray tone values of 1000-1800

Screening samples for SCAL work : Chalk from the Dan and South Arne area, Danish North Sea

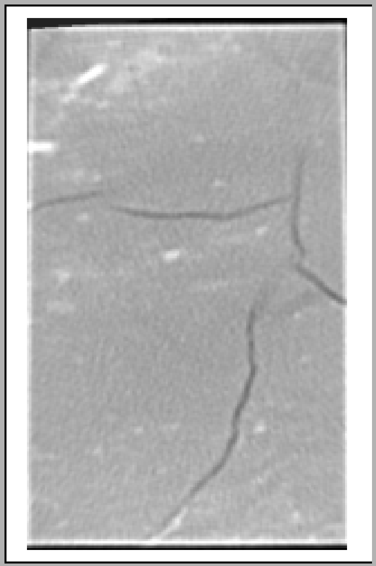
Healed hairlines and stylolite lined with pyrite

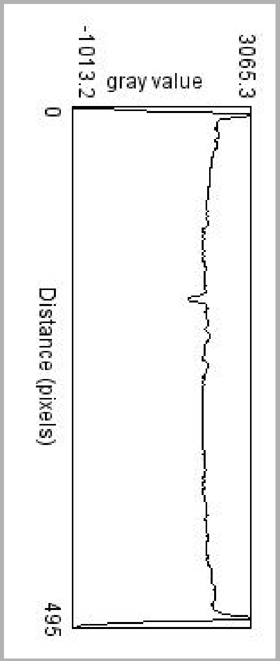


Typical carbonates and North Sea chalks have gray tone values of 1700-2500

Screening samples for SCAL work : Image analysis using dedicated software

- The normal delivery from a service company is a jpg-image in a rather poor quality.
- However, raw images in high resolution is always recorded and saved as ima and img file formats
- Special imaging software can handle these file formats and image analysis, viz. profile scans, average gray values and scatter figures can help evaluate the homogeneity of the plug (scatter in porosity)





Plug 9V
Depth: 626.70 [m]

Avg. gray value: 2092
Sdev: 126
Porosity: 11.5 [%]

Overburden measurements:

• Are conducted to establish the dynamics of a reservoir, pore volume reduction during pressure depletion (pore volume compressibility in material balance calculations)

• Are conducted to establish permeability, capillary and electrical properties at downhole conditions, or to correlate ambient data to downhole conditions

• Are performed in a hydrostatic loading cell (core holder) in most core laboratories and that requires correction of the effective stress

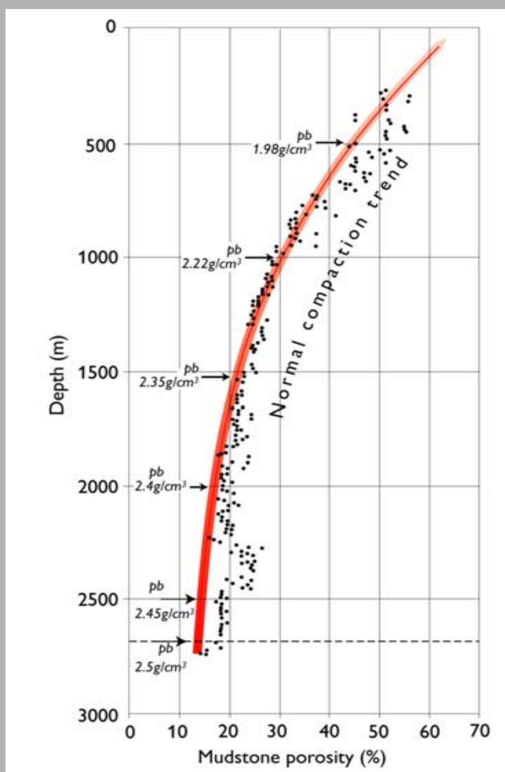
•Translates into reservoir condition measurements when live fluids require temperature and pressure identical to reservoir pressures

GEUS

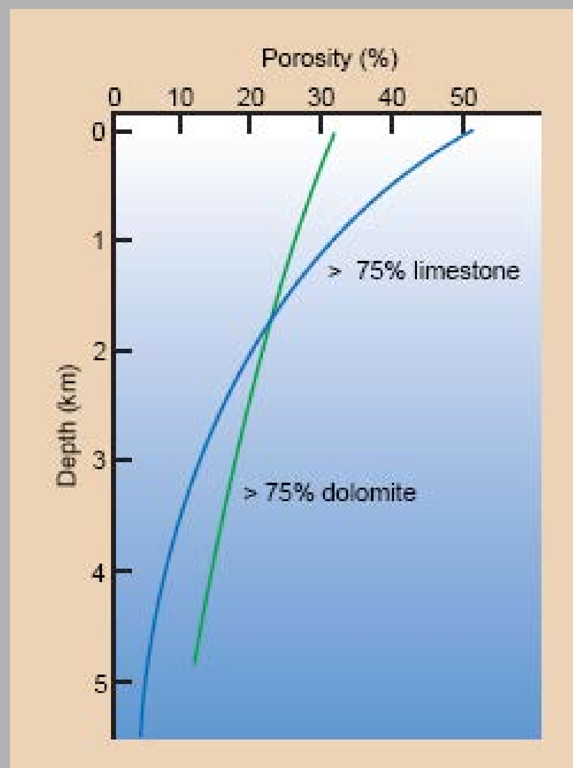
Compaction vs burial:

Sediments undergoes compaction (reduction of porosity) during burial due to the load of the overlying column of bulk rock

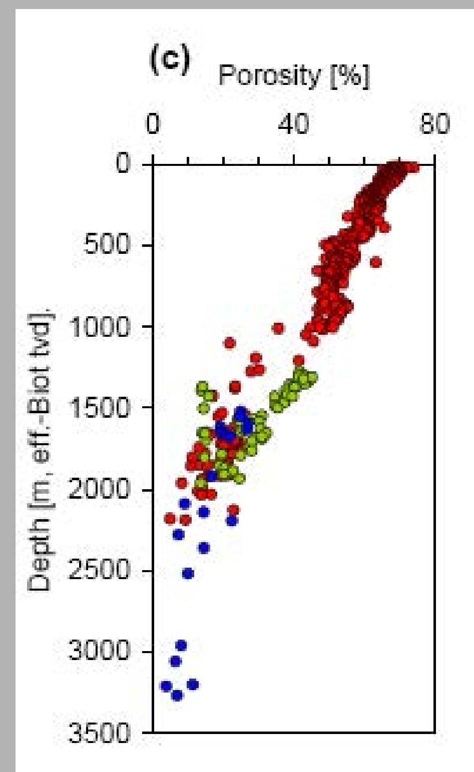
Sandstones, mudstones :



Carbonates :

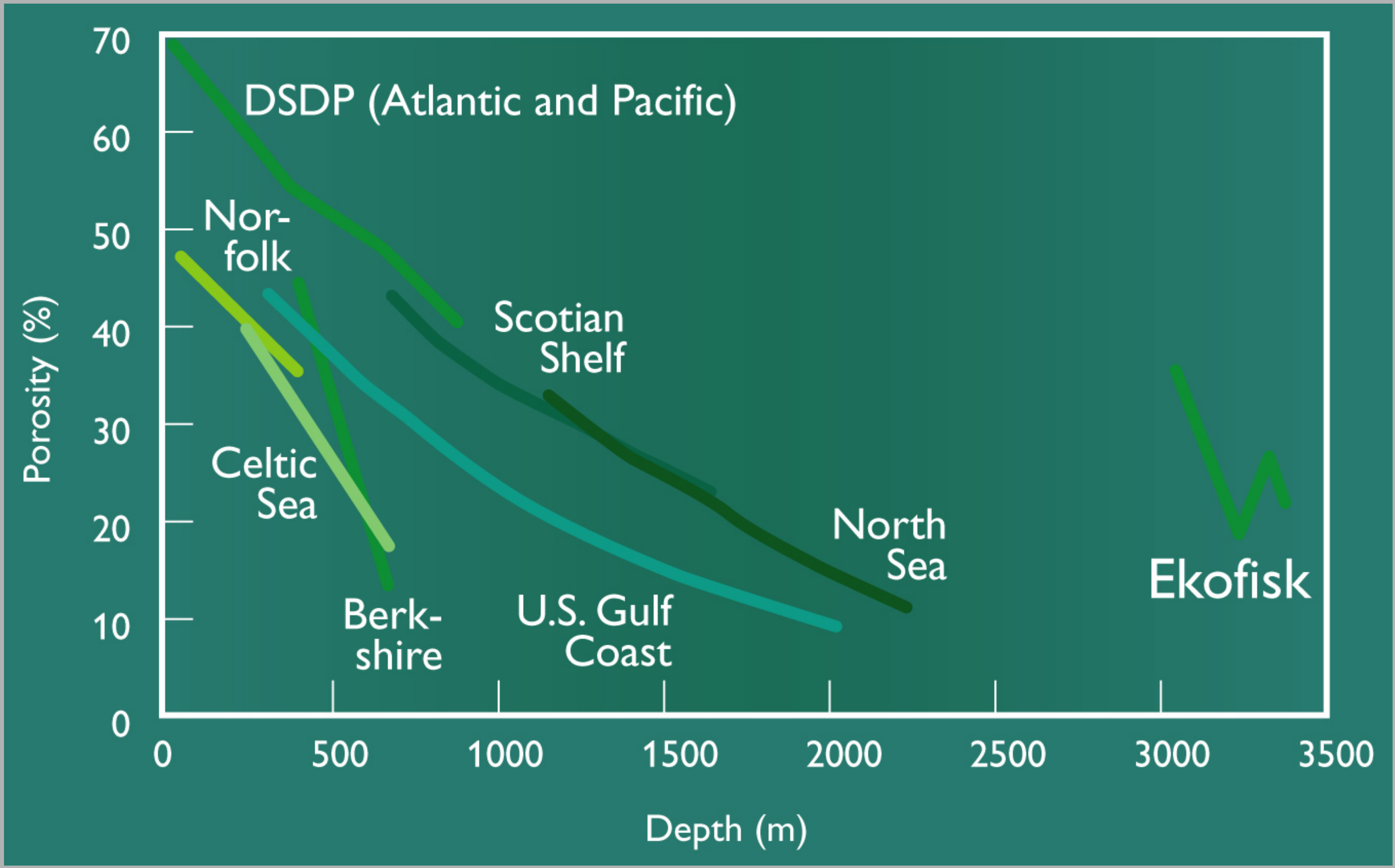


North Sea chalk :



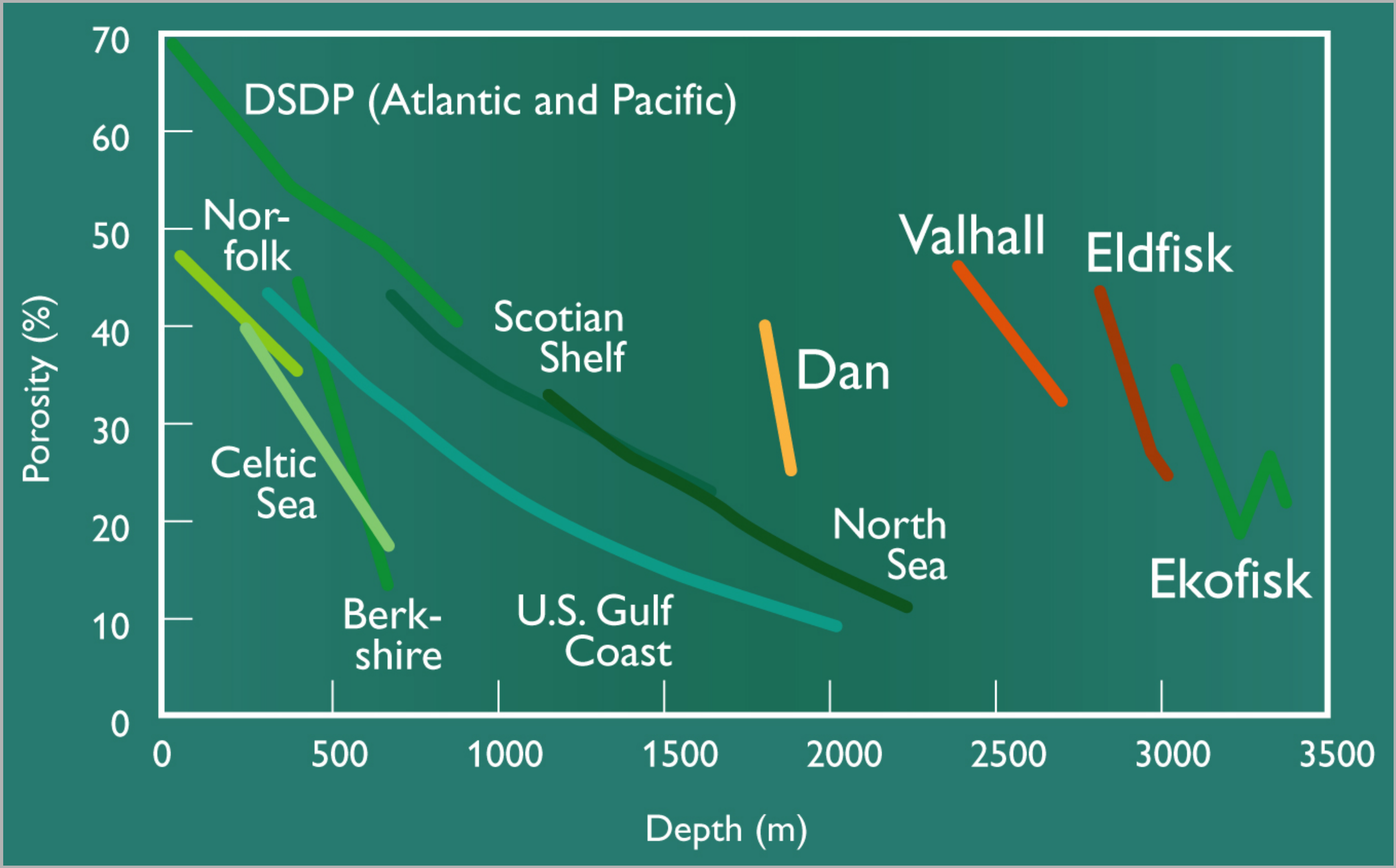
Credits : Magara (1968), SPE 37771 (2000) and Fabricius (2008)

Porosity reduces during burial:



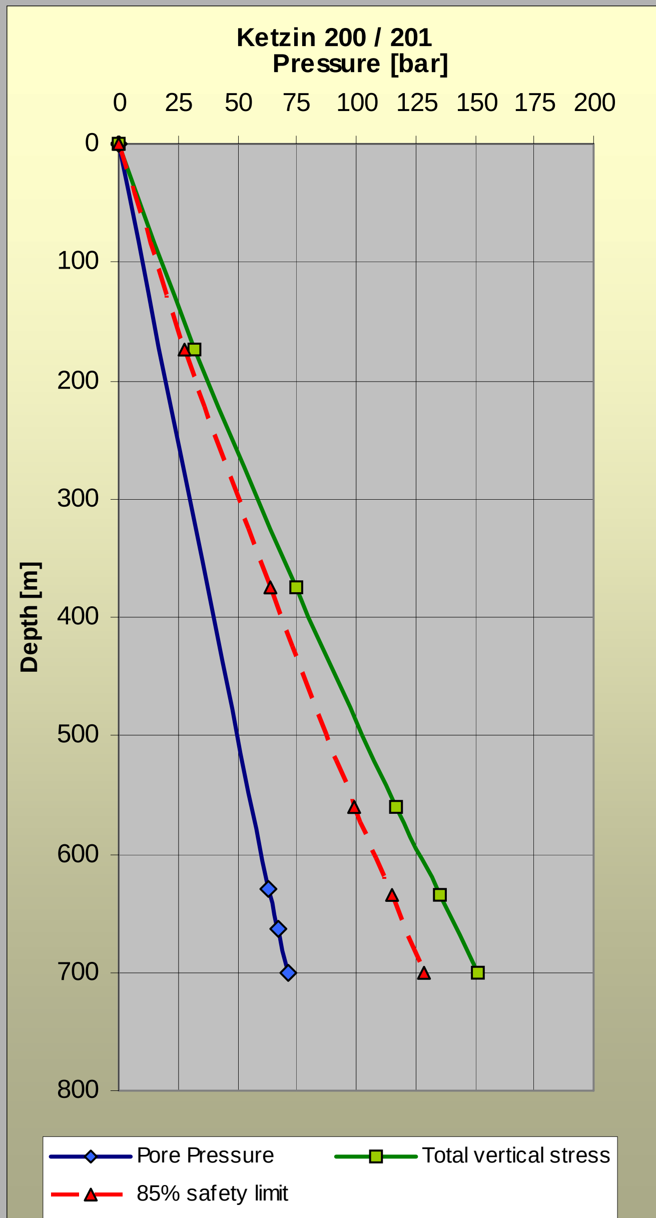
Ref.: Scholle, 1977

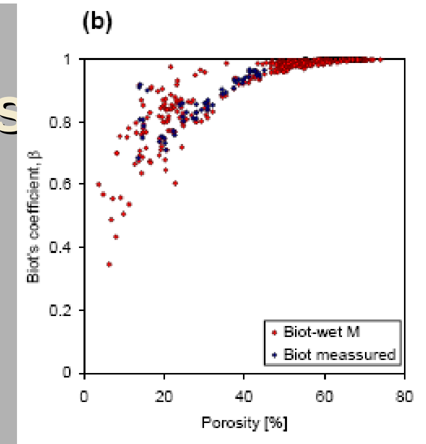
.. but is preserved in many hydrocarbon fields:



Ref.: Scholle, 1977

Reservoir loading : Stress vs depth trends





Credits : Springer & Garnett, 2007

Fabricius, 2008

- The net loading on a volume of rock in a certain depth depends on the total weight of the overlying column of bulk rock and the weight of the hydrostatic column of pore fluid (the effective stress concept by Terzaghi, 1943):

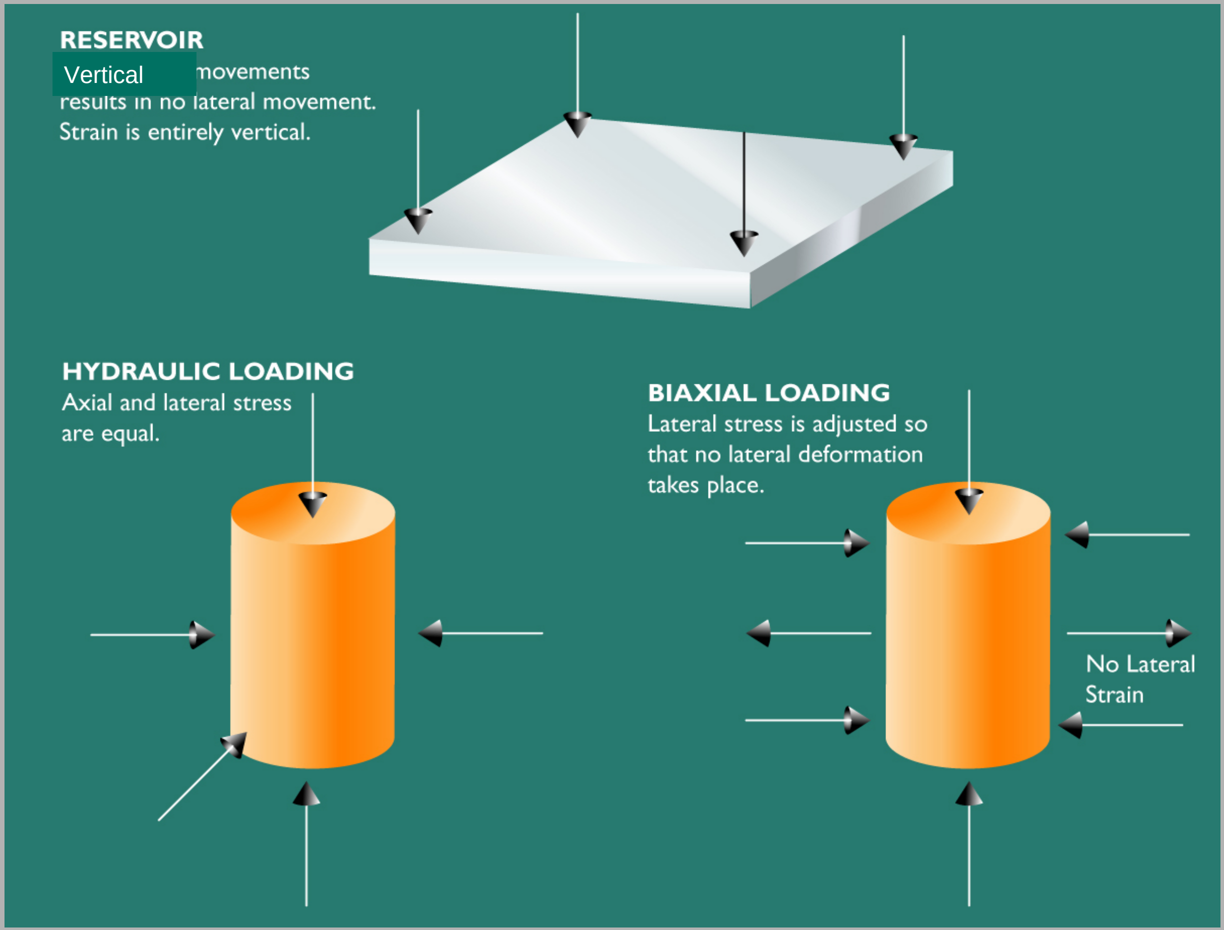
$$\sigma_{eff} = \sigma_b - \beta p_f$$

σ_b – bulk stress [Pa] from density log, but usually ~ 1 [psi/foot], 0.23 [bar/m]

p_f – fluid pore pressure [Pa] from chemical analysis or conductivity,but usually ~ 0.5 [psi/foot], 0.11 [bar/m]

β – Biot factor [$\leq$ 1], ~1 for un-consolidated rock and <1 for chalk

Laboratory test loading may differ from reservoir loading :



Stress is entirely vertical in the reservoir, but hydrostatic loading in lab testing affects both length and diameter of the sample under test; this causes excessive deformation that must be correced for.

Uniaxial compressibility is ~ 62% of the figure measured in the lab under hydrostatic loading conditions

Teeuw's correction for hydrostatic stress loading:

Terzhagi's eq : $\sigma_{eff} = \sigma_{tot} - P_{pore}\ (\beta)$ (effective vert. stress testing)

($\beta \sim 1$ unless otherwise given)

Teeuw's simplified eq for uniaxial ε_z vs. bulk strain ε_b :

$$\varepsilon_z = \frac{1}{3}\left(\frac{1 + \upsilon}{1 - \upsilon}\right)\varepsilon_b \qquad (2)$$

Teeuw demonstrated that for most rocks Poisson's ratio ν falls in the range 0.25 - 0.35. Assuming a constant value of 0.3, equation (2) reduces to:

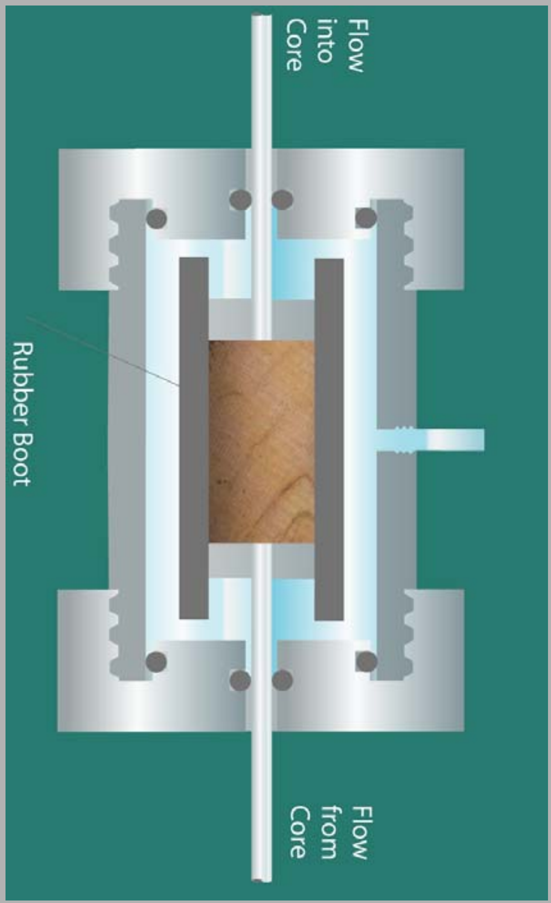
$$\varepsilon_z = 0.62\ \varepsilon_b$$

For the same loading, laboratory hydrostatic stress σ_{lab} should be reduced accordingly:

$$\sigma_{lab} = 0.62\ \sigma_{eff}$$

GEUS

Teeuw's correction for hydrostatic stress loading, example :

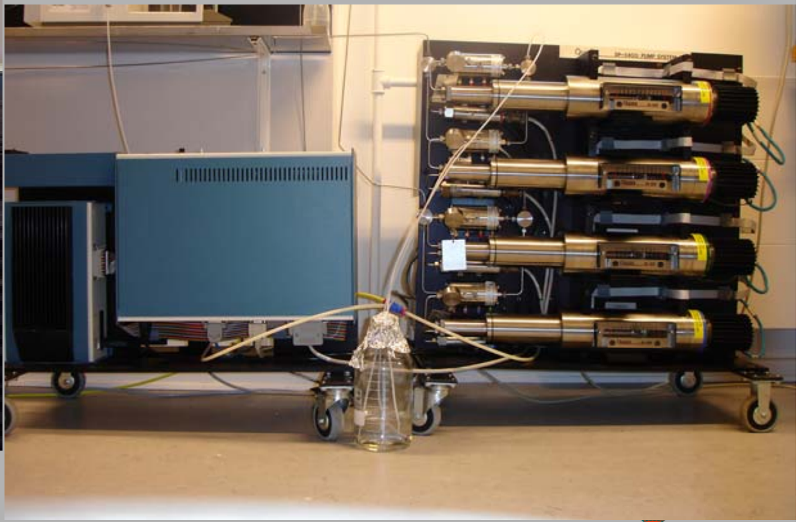


- Calculation of effective and laboratory hydrostatic stress :

- Total (bulk) stress : 8000 psi
- Initial pore pressure : 6000 psi
- Effective stress : 2000 psi
- Translates to laboratory testing: 2000 psi * 0.62 ~ 1200 psi

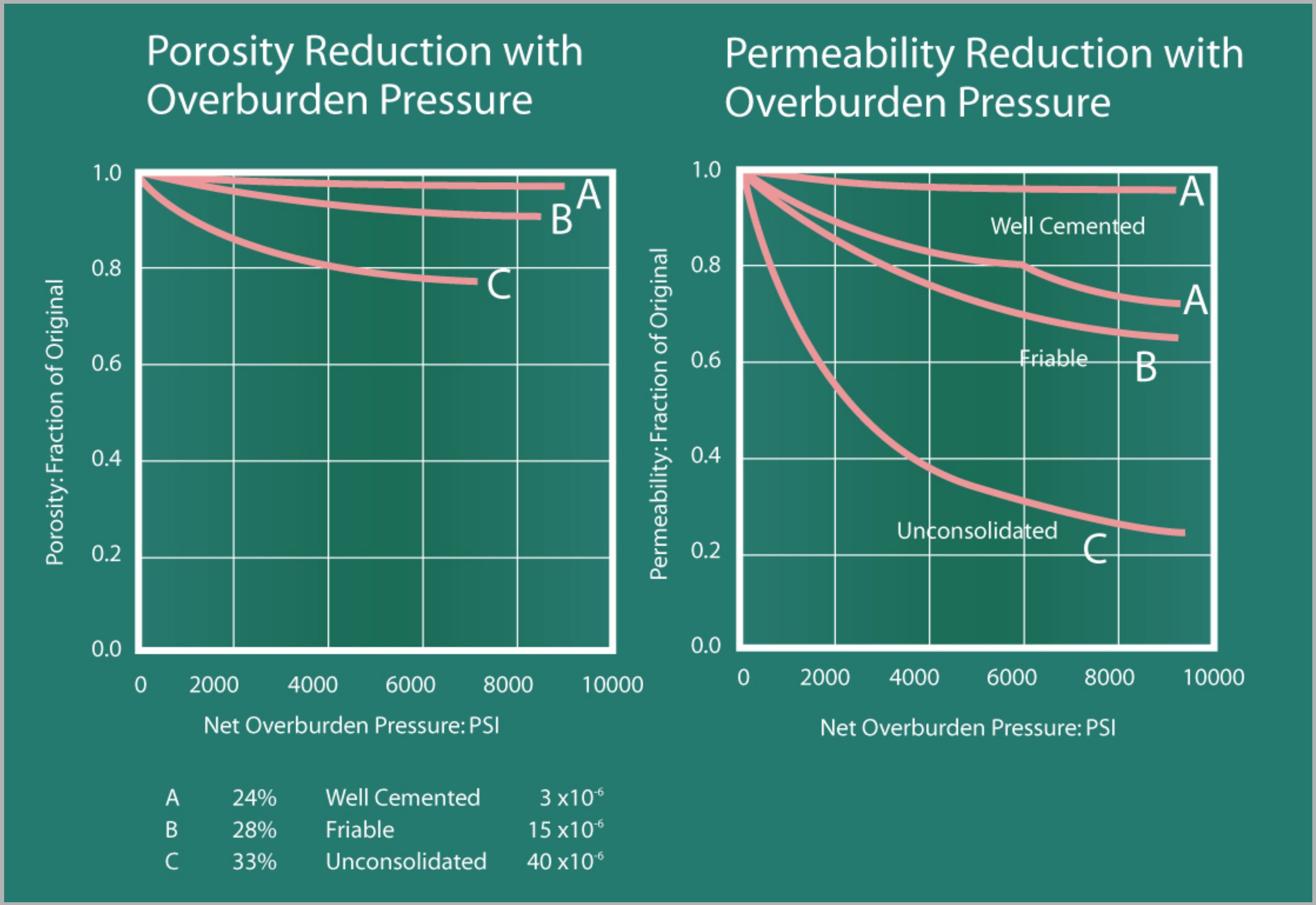
  (confining stress in hydrostatic core holder and ambient pore pressure)

Overburden Rig for core tests



GEUS

Reduction with Overburden Pressure

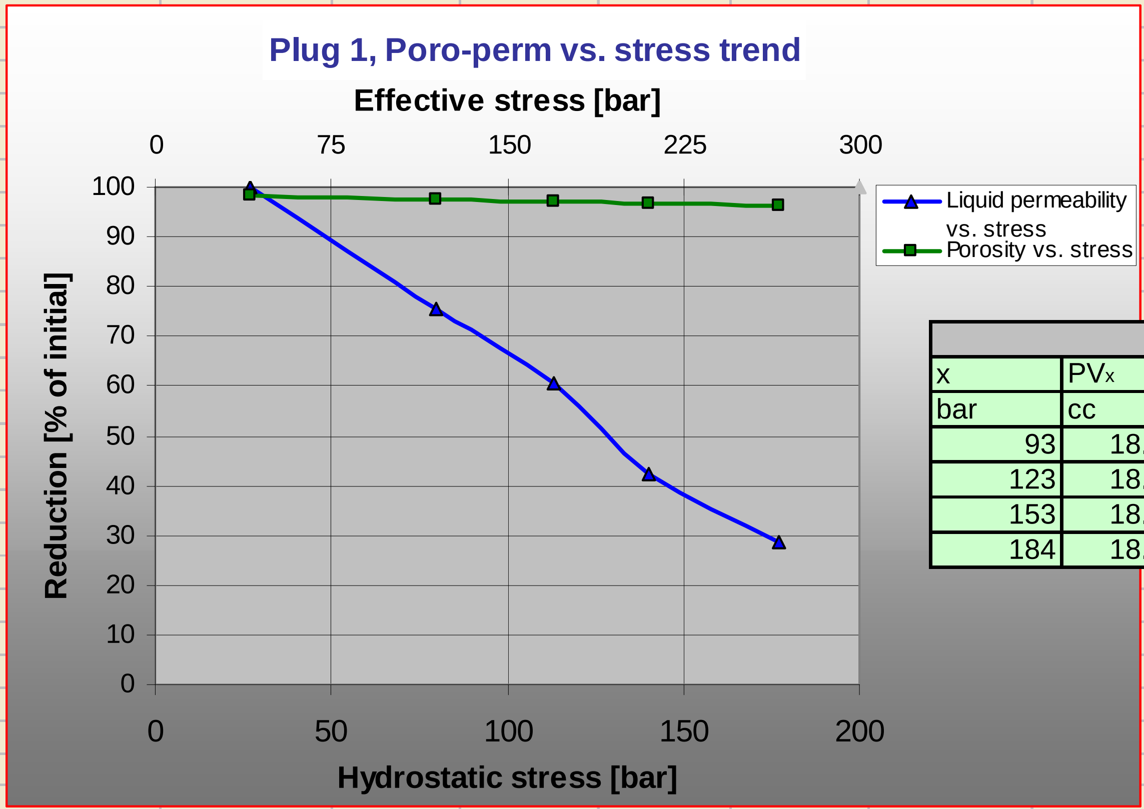


Plug no :	1	Conventional	
Depth [m] :	1880	Kg [mD] :	371
Formation :	Frigg	He-∅ [%] :	34,2

Confining pressure [bar]		Reduction in				Cp	F
hydrostatic	uniaxial *	Kl [mD]	% of initial	He-∅ [%]	% of initial	[bar^{-1}]	
27	43,5	323	100	33,60	98,3	4,83E-04	9,05
80	129,0	244	76	33,31	97,5	2,29E-04	9,29
113	182,3	196	61	33,12	96,9	1,65E-04	9,35
140	225,8	136	42	32,99	96,5	1,68E-04	9,40
177	285,5	92	28	32,86	96,1	2,57E-04	9,49

* corrected according to Teeuw (1971)

Siri area, glauconite sandstone

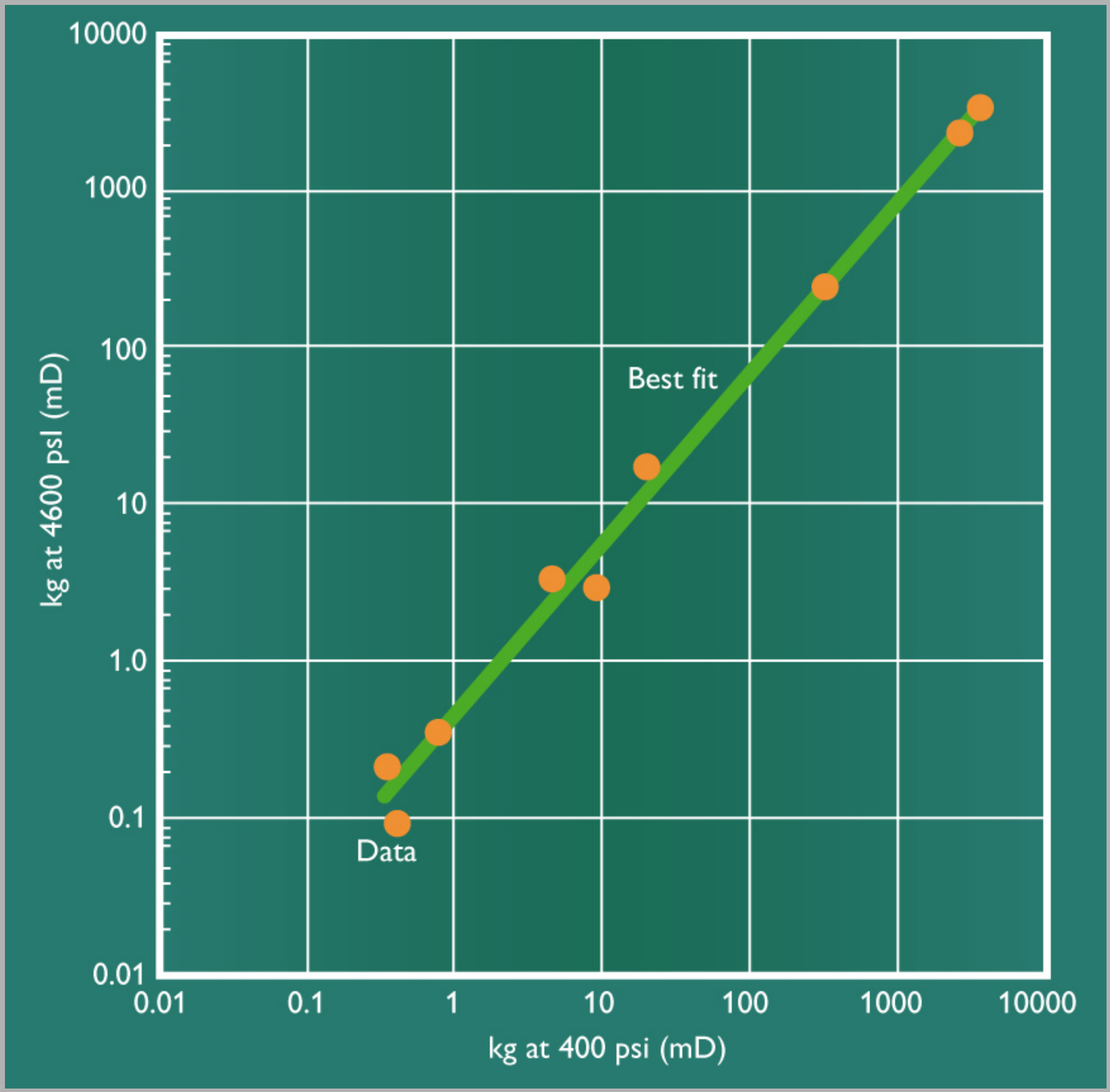


Observe unconsolidated behaviour

Plug 14P2			
x	PV_x	C_p	C_p x E-6
bar	cc	vol/vol/bar	vol/vol/psi
93	18.79	3.82E-04	26.3
123	18.59	3.02E-04	20.8
153	18.45	2.20E-04	15.2
184	18.35	1.34E-04	9.2

G E U S

Core Overburden Correction Transform, 400 psi > 4600 psi



SPE short course: exercise in net overburden calculation

The following info is given for a shallow reservoir :

Sea depth = 81 m
Core depth (BOD) = 784 m (BOD = below ocean datum)
Salinity = 3.5%
Average temperature of brine column = 20 °C
Average brine density = 1.025 kg/m^3 @ 20 °C
Average overlying formation density from geophysical logs = 1.900 kg/m^3

Calculate :

1. **Total vertical stress**
2. **Reservoir pore pressure (assuming hydrostatic column, ie. no over pressure)**
3. **Effective vertical stress**

Re-calculate #3 to laboratory hydrostatic conditions (use Teeuw's correction and assume Poisson's ratio 0.3)

Give results in MPa

Given: Force is measured in Newton : 1 N = 1 kgm/s^2
Pressure = force/area is measured in Pascal : 1 N/m^2 = 1 kg/ms^2 = 1 Pa
Acceleration of gravity = 9.81 m/s^2

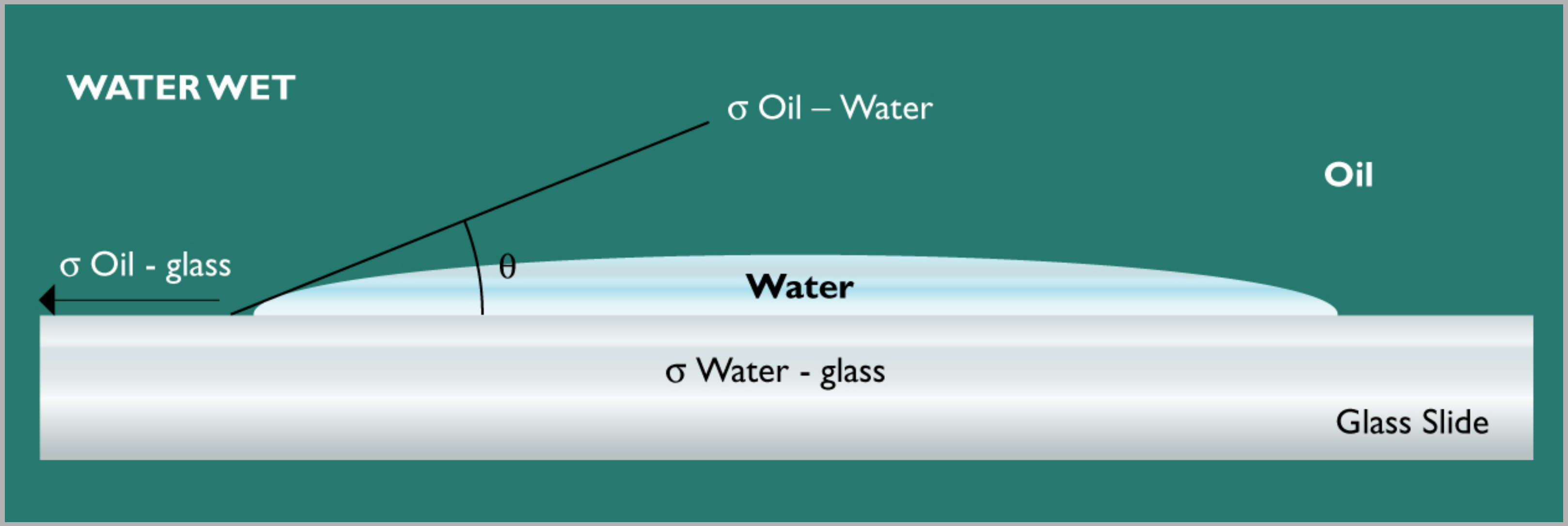
NS/11.2005

GEUS

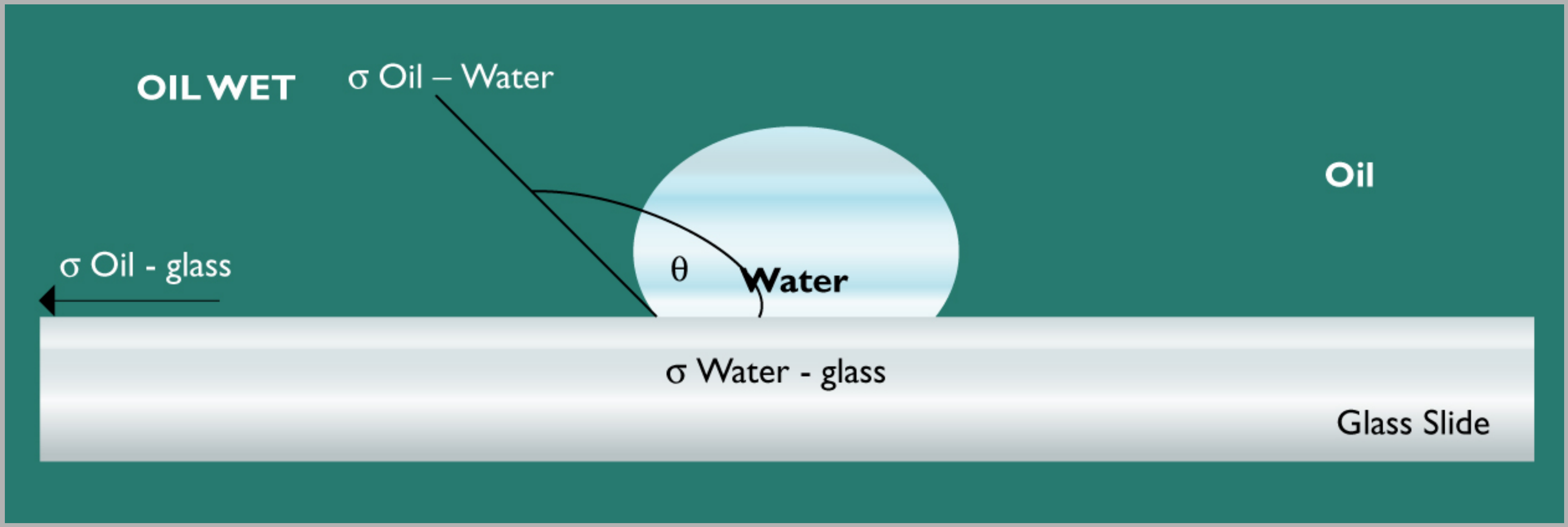
Wettability measurements:

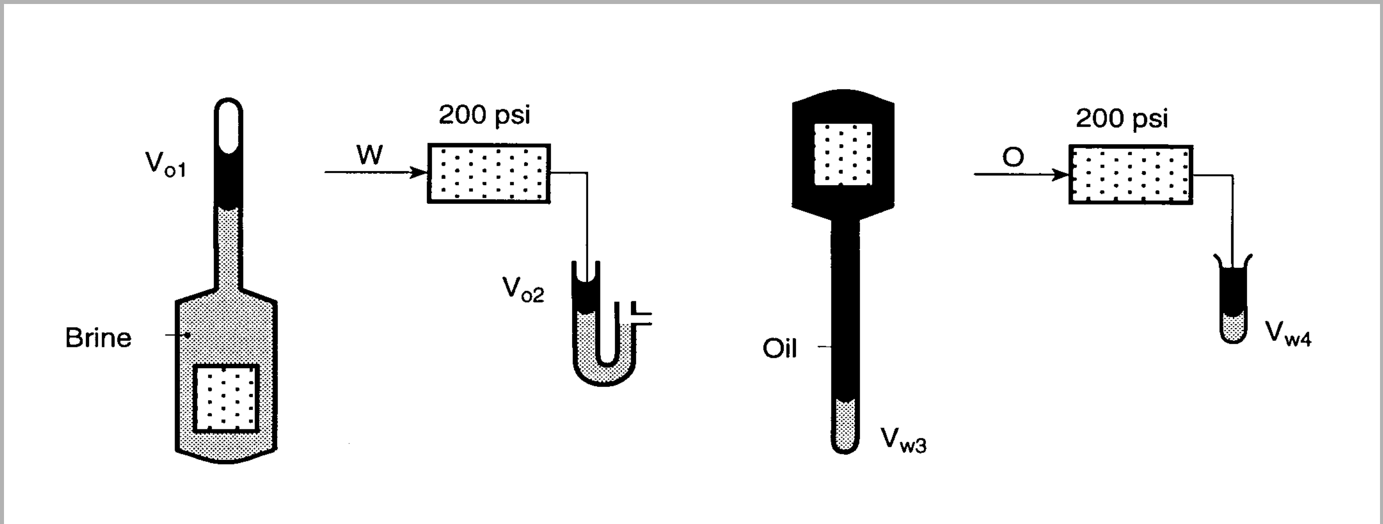
- Contact angle method
- Amott method
- USBM method

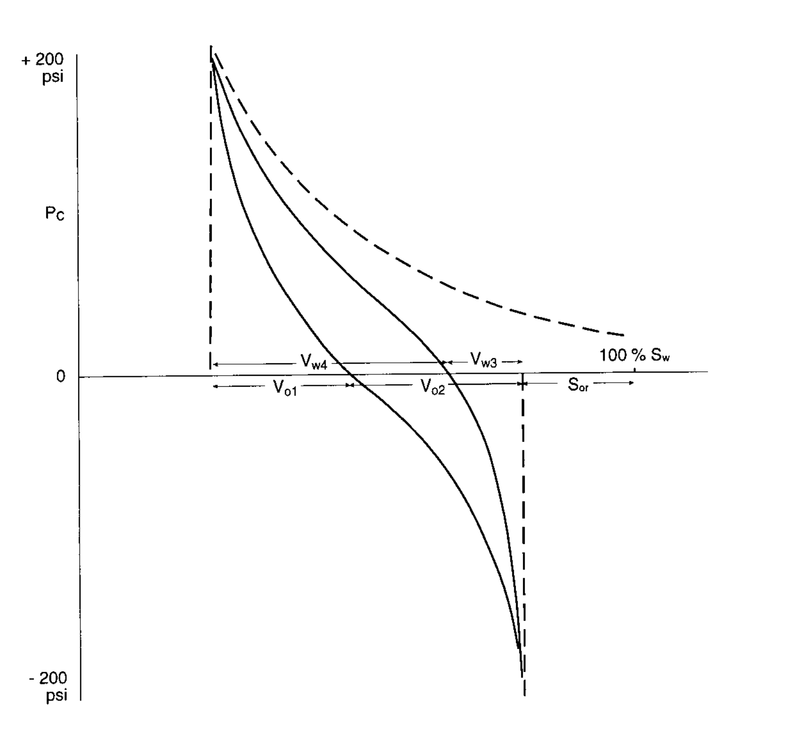
Contact angle



Wettability Concepts :







Mixed wet system

Amott's wettability test and the hysteresis loop

$I_w = V_{o1}/(V_{o1}+V_{o2})$

$I_o = V_{w3}/(V_{w3}+V_{w4})$

$I_{AH} = I_w - I_o$

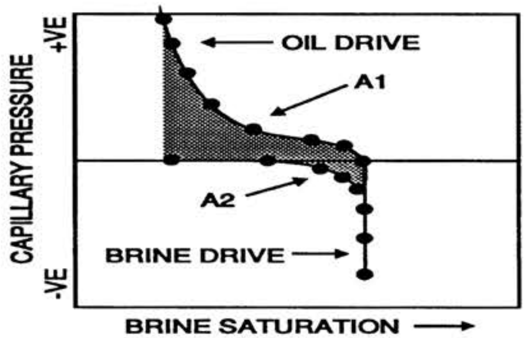
[+1, +0.3] : waterwet

[+0.3, -0.3] : mixed wet

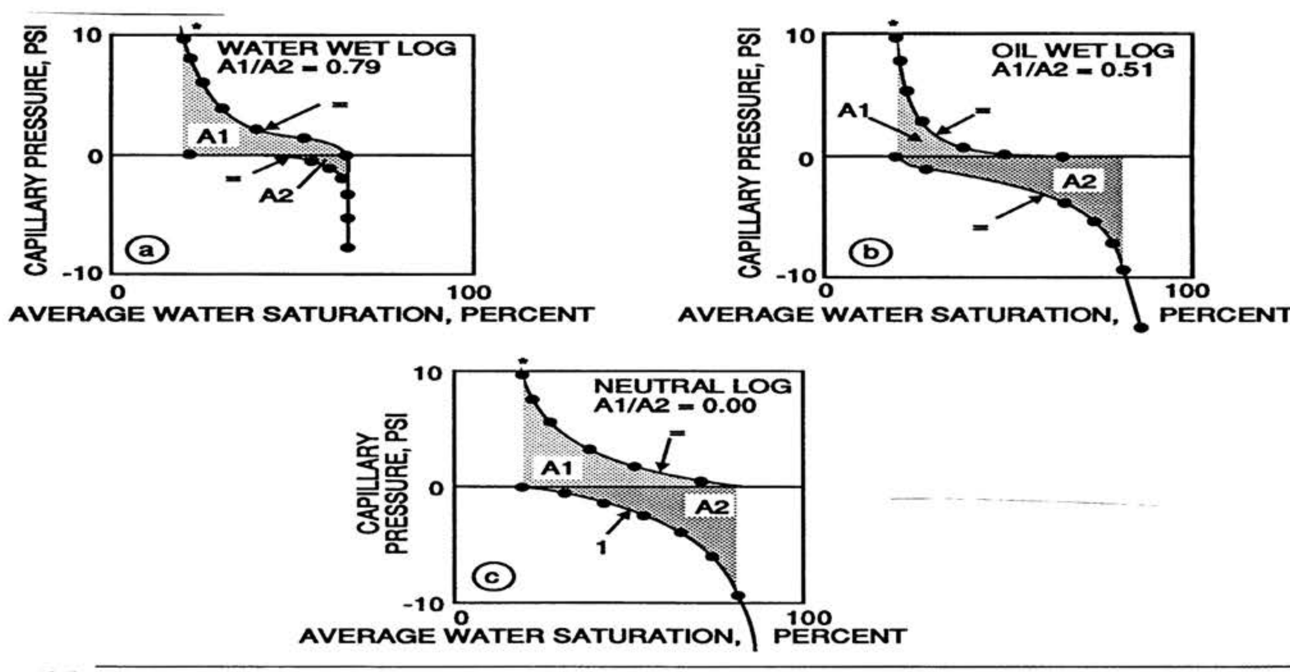
[-0.3, -1] : oilwet

GEUS

USBM Wettability Method



USBM Wettability States



Example: Problems in wettability measurement - S_{wi} and invasion.

Basis data:			Initial step		Brine imbibition				Oil imbibition				Amott calculations		
Plug	Ø	Dean Stark S_w	S_{wi}	K_o @S_{wi}	S_{w1}	S_{w2}	S_{or}	K_w @ S_{or}	S_{w3}	S_{w4}	S_{wf}	K_o @ S_{wf}	I_w	I_o	I_{AH}
no.	pct	pct	pct	mD	pct	pct	pct	mD	pct	pct	pct	mD			
4	37,05	51.1	19	0,5	64	68	32	0,09			68		0,93		
18	32,46	58.3	18	0,36	61	62	38	0,07	62	24	24	0,30	0,98	0,00	0,98
38	30,65	63.8	27	0,09	56	56	44	0,01			56		0,97		
117	24,52	74.9	35	0,03	60	60	40	<0,00			60		1,00		
118	35,71	36.0	5	1,62	41	72	28	0,42	72	17	17	1,20	0,54	0,00	0,54
134	24,57	58.1	21	0,18	54	54	46	0,02	54	18	18	0,14	1,00	0,00	1,00
153	18,22	71.6	44	$0,73^+$	62	62	38	$0,05^+$			62		1,00		

Table 1

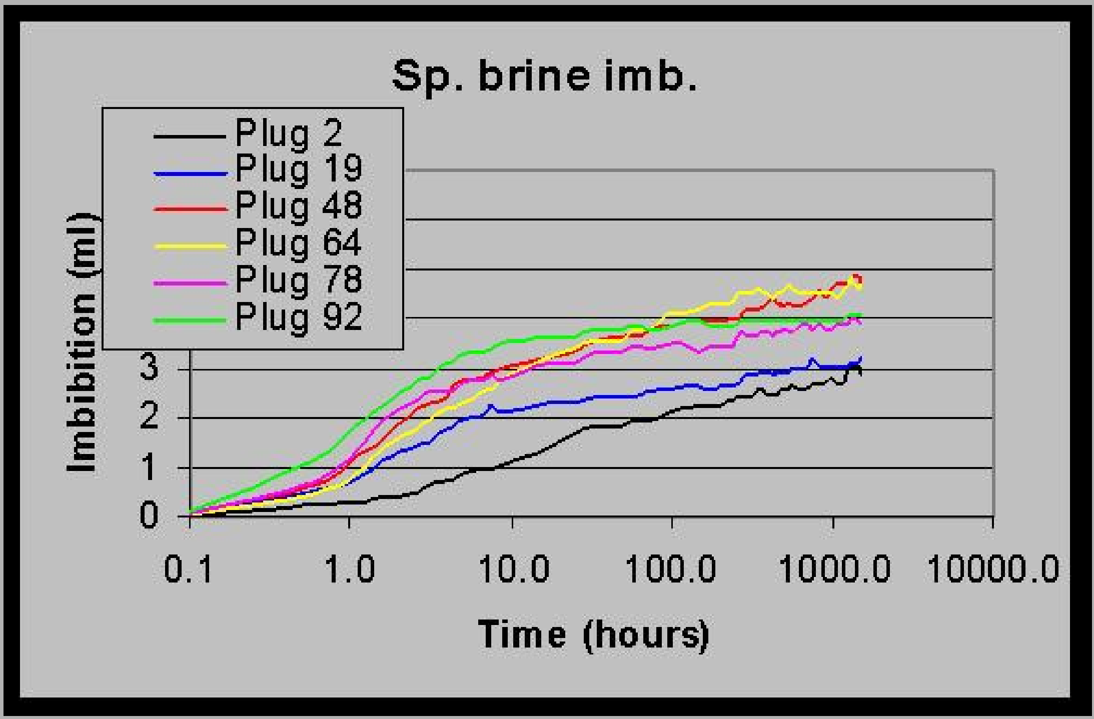
Chemical Composition of Mud Filtrate and pore water, Nana-1X

Sample	Depth m	pH	Cl mg/l	SO4 mg/l	HCO3 mg/l	Na mg/l	K mg/l	Ca mg/l	Mg mg/l	Sr mg/l
Mud filtrate		9.1	82855	1758	333	12496	65122	7.1	5.4	0.6
GEUS core 1		7.28	63953	1040		26214	19967	1074	472	144
GEUS core 4			69444	801		32075	19937	1484	309	205

GEUS

Maastrichtian chalk (Saltdome Province) : Wettability data and the S_{wi} problem

Initial flood down data		Brine imbibition data				Oil imbibition data				Brine volumes		Oil volumes		Amott Index		
Swi	Ko@Swi	Sw1	Sw2	Sor	Kw@Sor	Sw3	Sw4	Swf (Dean Stark)	Ko@Swf	Vws1	Vwf2	Vos3	Vof4	Iw	Io	IAH
pct	mD	pct	pct	pct	mD	pct	pct	pct	mD	ml	ml	ml	ml			
15	1,36	40	74	26	0,23	74	17	17	1,02	2,87	3,82	0	6,5	0,43	0	0,43
22	0,38	51	61	39	0,05	61	20	19	0,35	3,26	1,17	0	4,52	0,74	0	0,74
13	1,33	51	75	25	0,29			74		4,69	3,00			0,61	#####	#####
15	0,77	63	67	33	0,08	64	17	17	0,63	4,73	0,39	0,22	4,6	0,92	0,05	0,88
20	0,24	60	60	40	0,03			57		3,88	0,00			1,00	#####	#####
7	0,17	55	56	44	0,01			53		4,07	0,08			0,98	#####	#####



Target S_{wi} * %	Obtained S_{wi} %
4	15
5	22
3	13
4	15
6	20
8	7

Credits . GEUS Core Lab

GEUS

Wettability measurement

- Remember estimation of Swi for fresh samples
- Take a plug trim and determine fluid saturations > Sw for the test plugs
- Estimate Swi from resistivity logs and/or saturation-height models
- Flood/spin the test plugs down to the predicted Swi figure before installing them in the imbibiometer.

Wettability observations:

Very few overburden and extremely few reservoir condition experiments have been done

The ”classic” room condition tests also supply endpoint permeabilities, but require entensive handling of samples and material balance calculation and grain loss correction is essential for obtaining precision data

In theory the USBM - centrifuge technique allows true reservoir condition tests and at the same time circumvents the frequent handling normally associated with Amott’s test. This makes the centrifuge the most promising tool in wettability testing, but uncertainty still prevail about the effect of the uneven saturation distribution generated during spinning.

GEUS

Capillary pressure

Capillary pressure measurements are carried out to :

- Help establish saturation – height model(s) for a reservoir
- Determine connate water saturation
- Determine capillary entry (or threshold) pressure
- Determine pore throat size and distribution
- Support modeling of relative permeability data measured on small core plugs

Capillary pressure

- A capillary pressure P_c is generated when 2 immiscible fluid phases co-exists in a porous matarial; the conditions can be described by Purcell's eq.:

$$P_c = \frac{2\sigma \times \cos\theta}{r}$$

$$r = \frac{2\sigma \times \cos\theta}{P_c}$$

r is the pore throat radius [m], σ is the interfacial tension [N/m] and θ the contact angle [deg]. If a mismatch of american and cgs units are used, eg. P_c [psi], σ [dyn/cm] and r [μm] a multiplier C = 0.145 should be used on the right hand side of the equation

$$P_{c(res)} = P_{c(lab)} \times \frac{(2\sigma \times \cos\theta)_{(res)}}{(2\sigma \times \cos\theta)_{(lab)}}$$

Laboratory measured capillary pressures can be converted to reservoir conditions if σ and θ is known for both systems

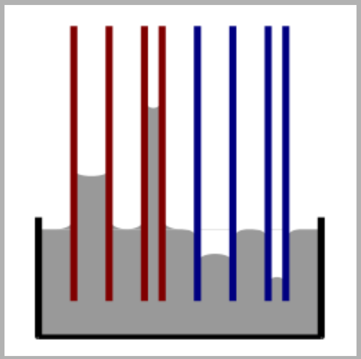


Illustration of capillary rise. Red=contact angle less than 90°; blue=contact angle greater than 90°

G E U S

Capillary pressure : Useful parameters derived from capillary pressure data

$$H_{FWL} = \frac{P_{c\,(res)}}{(\rho_w - \rho_{nw})}$$

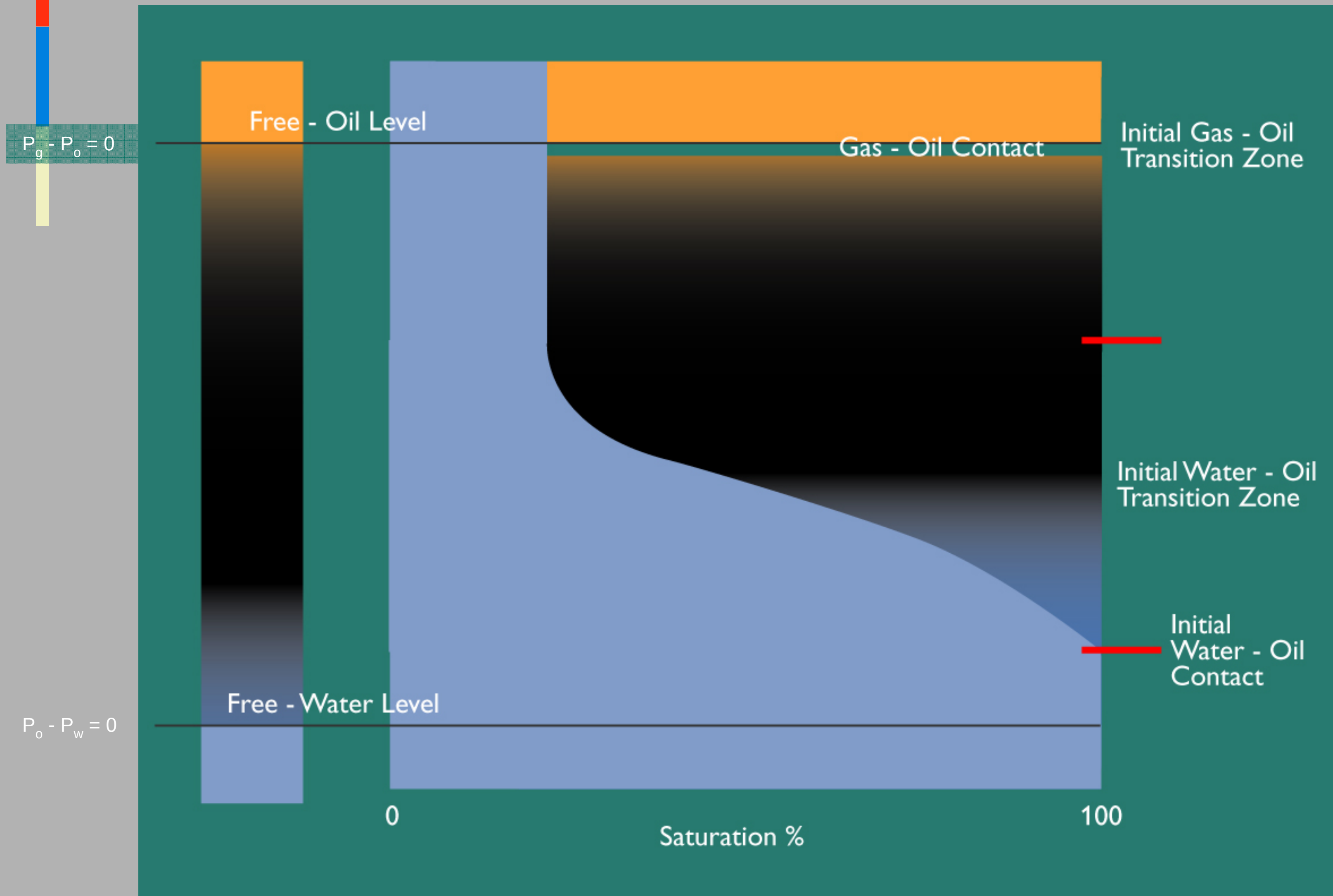
Convert laboratory measured capillary pressure to reservoir conditions and calculate the height above free water levet H_{FWL}. ρ_w and ρ_{nw} is the density gradient of the wetting and non-wetting phase (oil) respectively. For water 0.44 [psi/ft] and for oil 0.33 [psi/ft] traditionally

$$J = \frac{P_c \sqrt{\frac{k}{Ø}}}{\sigma \times \cos\theta} \times C$$

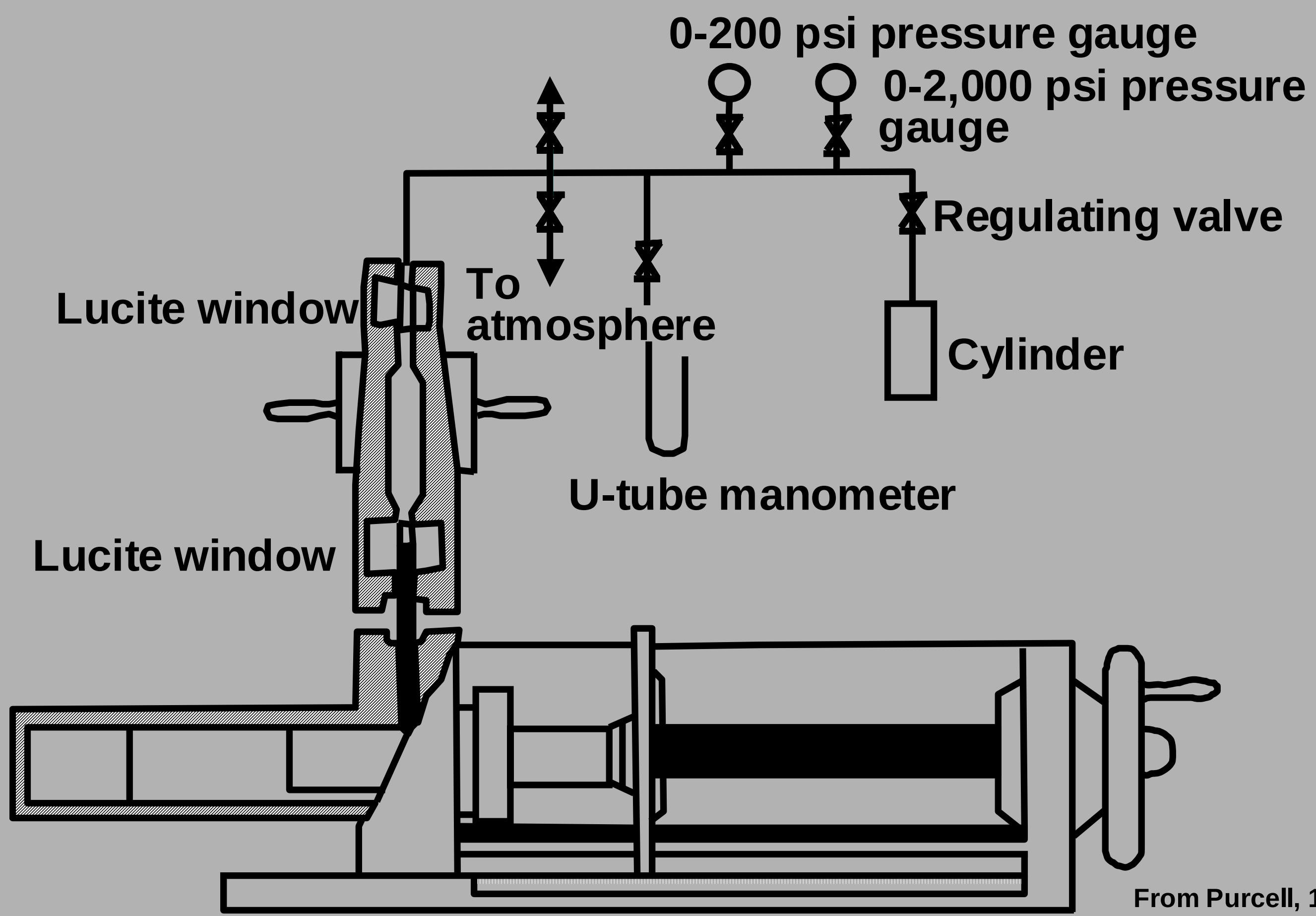
Leverett J-function can be used to correlate and normalize laboratory measured capillary pressure data from samples having similar pore structure, and reach the same low S_{wi} at high capillary pressures. C is a conversion constant = 0.217 if P_c is given in [psi] or = 3.162 if P_c is given in [bar]. Permeability k [mD], porosity Ø [fraction], σ [dyn/cm] and θ [deg].

GEUS

Capillary pressure: Initial Distribution of Fluids within a Uniform Sand Reservoir:



Mercury injection to establish cap. curve and pore size distribution:



From Purcell, 1949

Cap pressure by Hg-injection: How is it carried out

- Hg-injection is performed unconfined on small chips (~4-7 cc) or on plug size samples (1” or even 1½” diameter).

- The test run starts from high vacuum and pressure is then continous or stepwise increased to 2000 psi or 30-60,000 psi in the auto-pore meters, ie. the smallest pore throats invaded by Hg is 4-2 nm by radius

- Most tests are performed under constant injection rate conditions; this is a fast and cost effective service, but with some limitations.

- Hg-injection is available for plug size samples under confining P (in core holder); this can run as constant injection rate or constant pressure

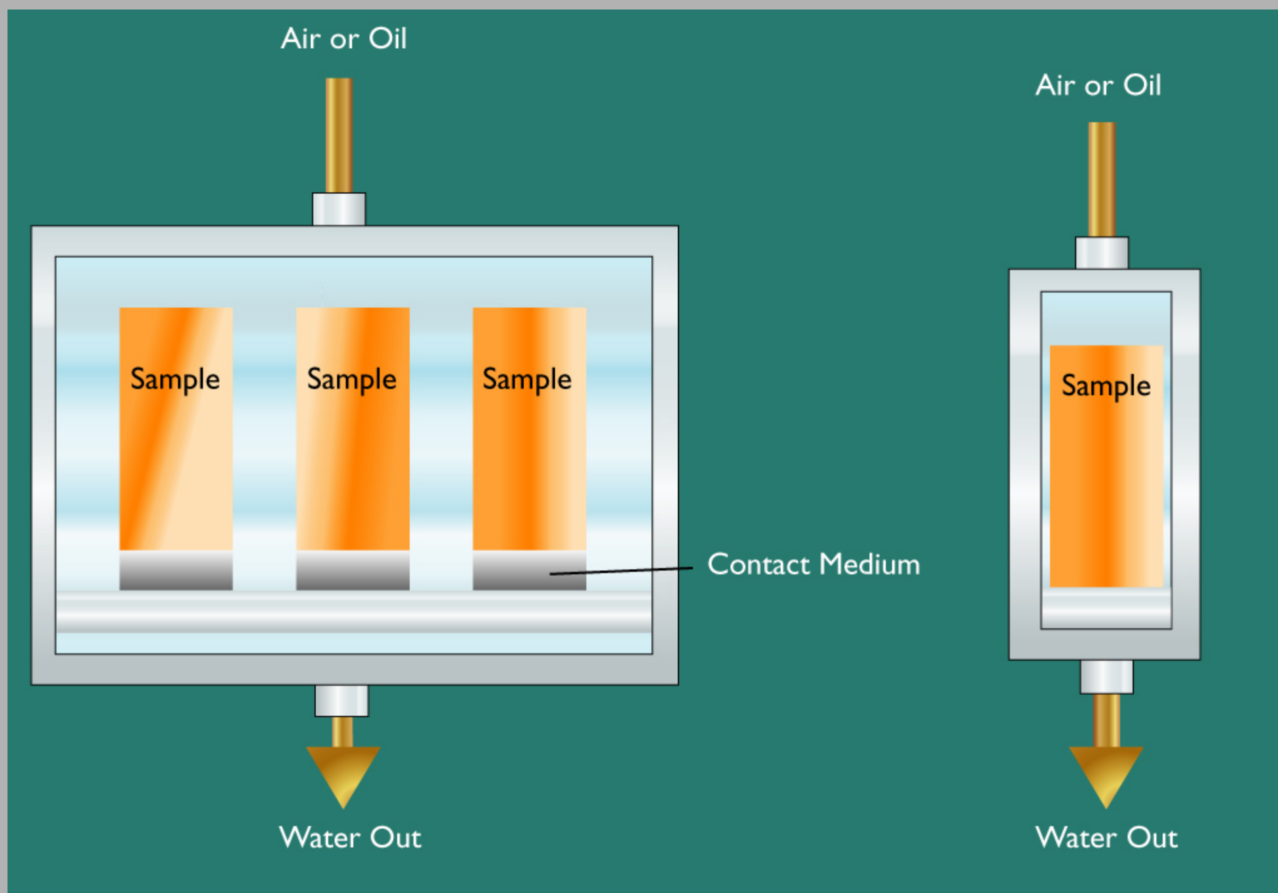
- Constant pressure has the advantage of giving a usable imbibition curve, but at a high cost.

- The test is destructive, the sample must be discarded after test.

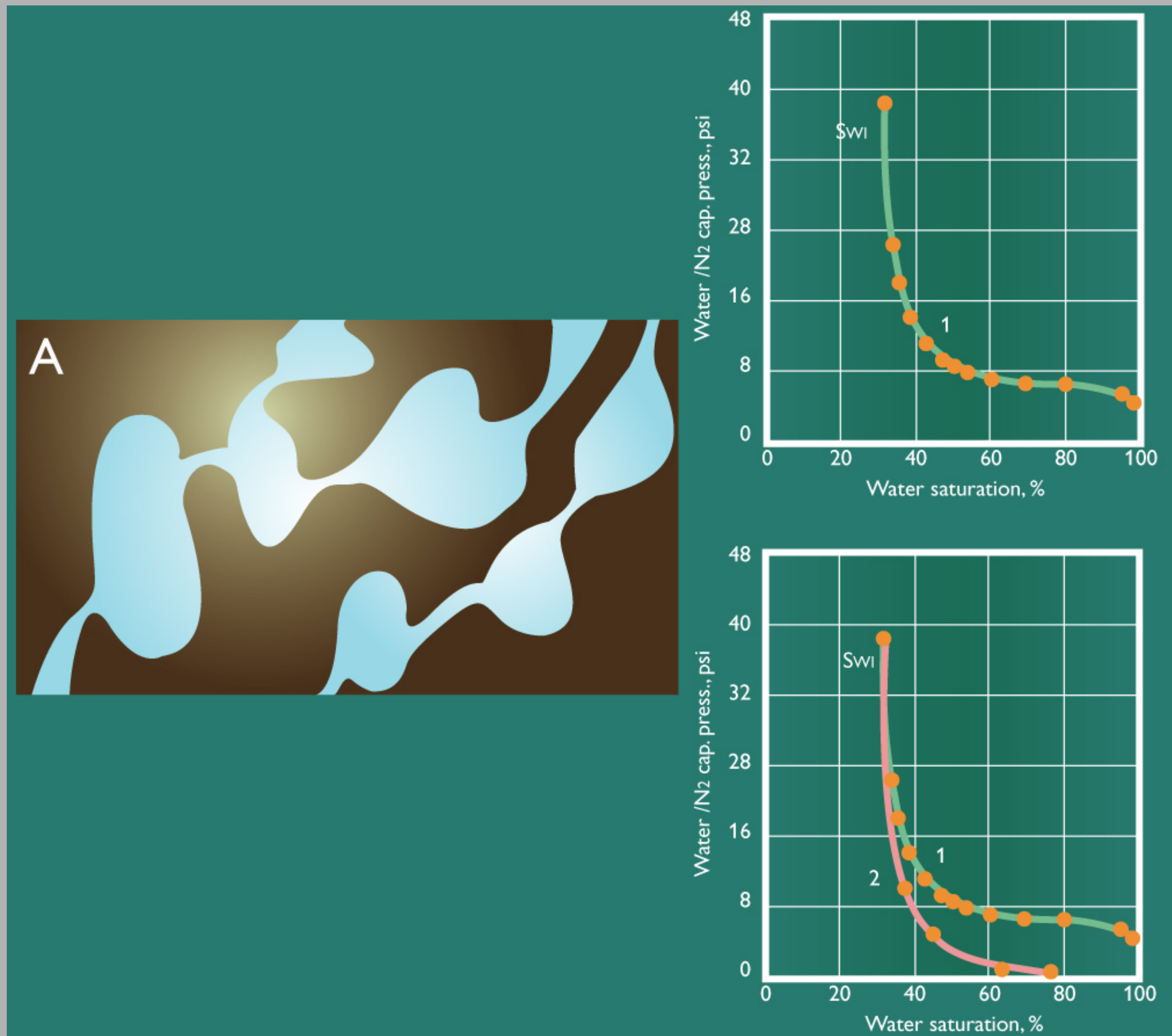
G E U S

Porous Plate drainage (and imbibition) cap. curves

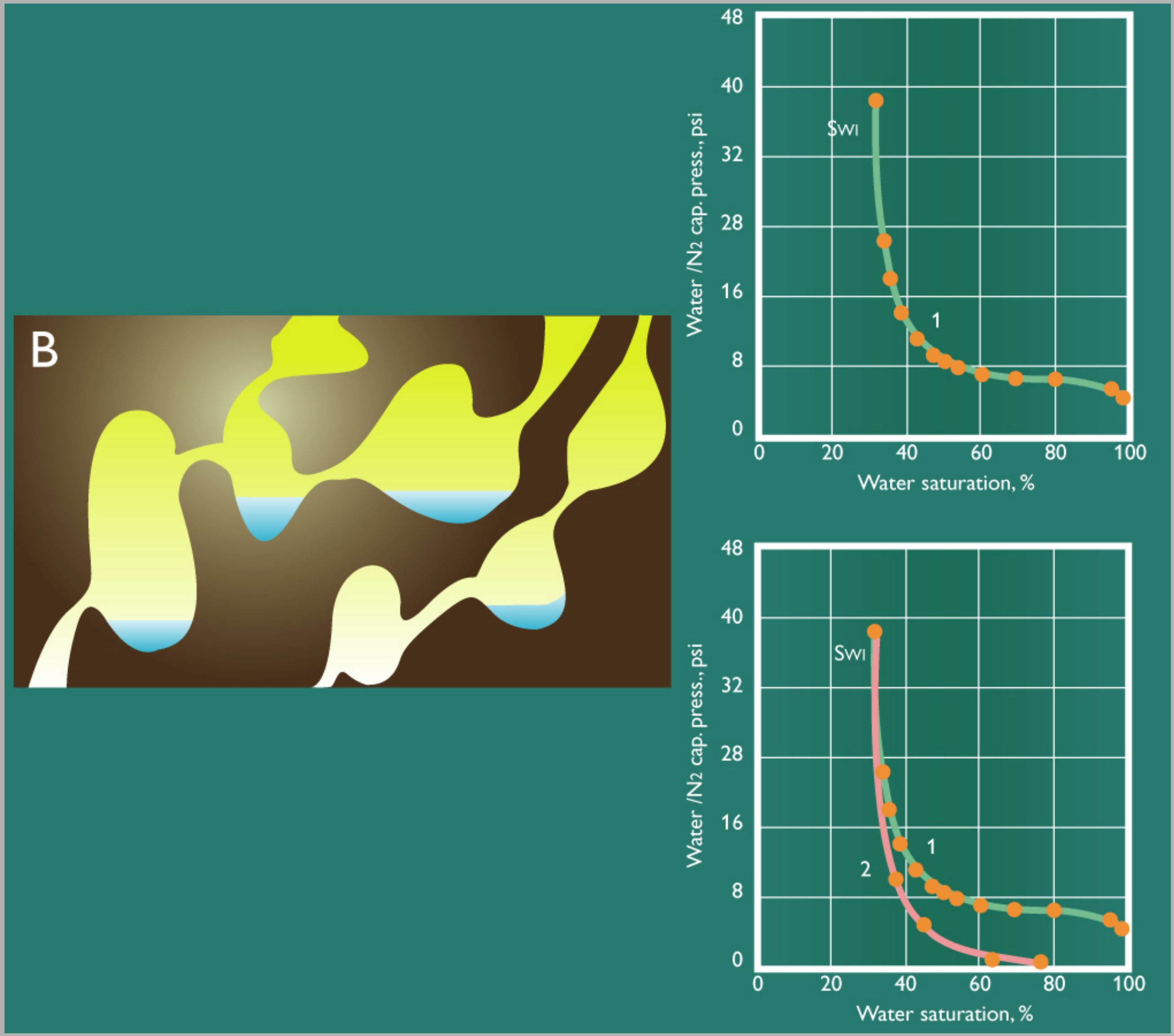
- Performed in multi sample pressure pot or in single sample cells, initial 100 % S_w plugs are drained by non-wetting gas or oil through a waterwet ceramic plate or micro-pore filter.



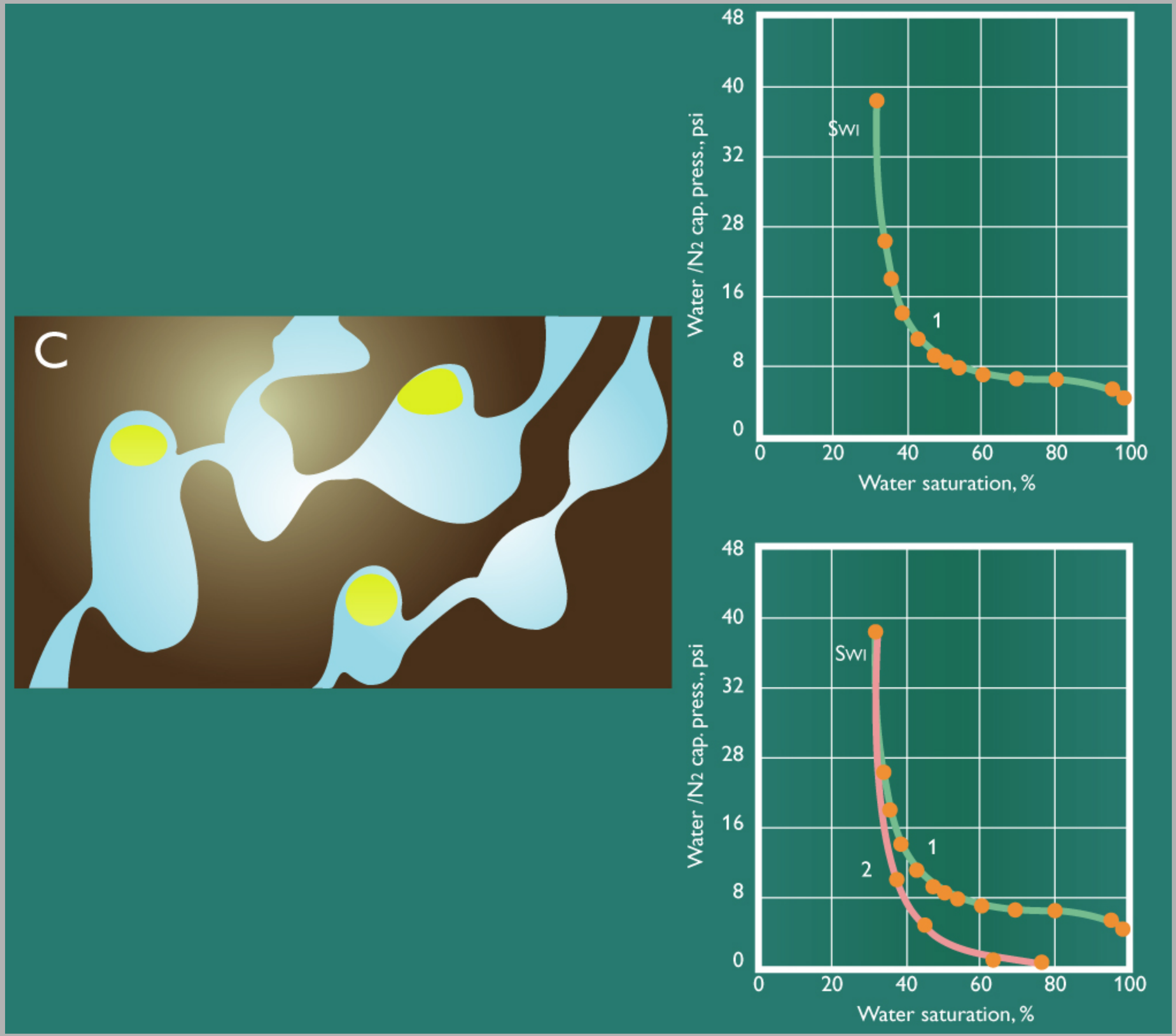
Drainage Proces



Drainage Proces



Imbibition Proces:



Cap pressure by porous plate: How is it carried out

- This is the classical technique to measure capillary pressure in core analysis, it uses real fluids (water/brine, oil and gas) and can even work at reservoir conditions.

- Plug size samples are required, but the method works for weakly consolidated (jacketed) samples as well. Un-confined and overburden measurements are possible as required.

- The test is carried out under constant, but stepwise increasing pressure, but is limited to lower pressures than both Hg-injection and centrifuge tests; 5-8 pressure steps are normally recorded.

- Porous plate measurements takes a long time for equilibration, especially for low permeable materials (chalk), and are therefore expensive.

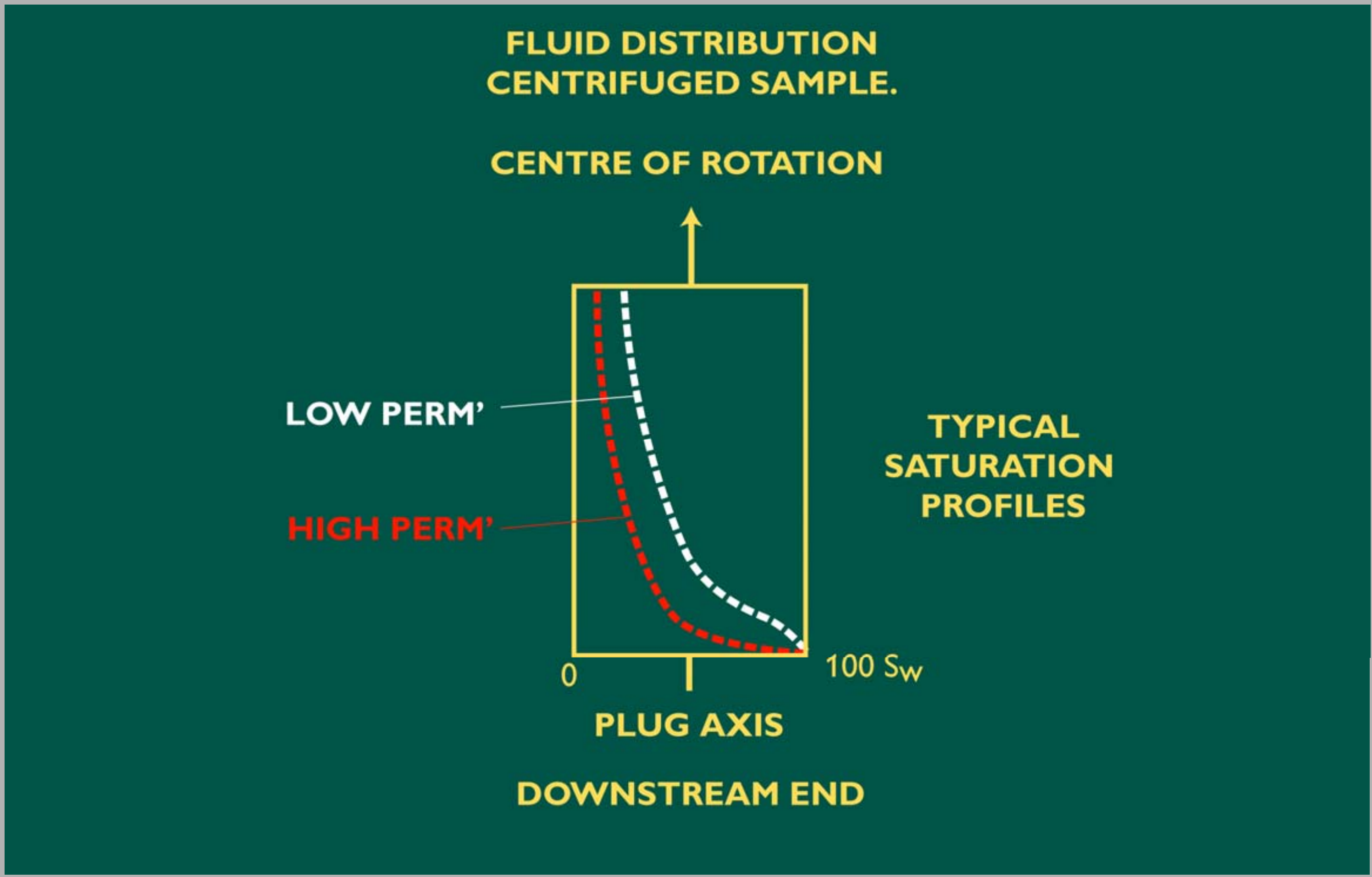
- The test is non-destructive, the sample may be re-used for other tests.

-Grain loss can cause errors in water saturation determination in multi sample pressure pot experiments. The effect is false low S_w figures

- The final S_w should be checked against a Dean Stark fluid saturation determination

GEUS

Capillary pressure by centrifuge measurement : Distribution of two immiscible fluids in centrifugation



Cap pressure by centrifugation: How is it carried out

- 4-8 plugs are placed in the rotor and the centrifuge spun to high rpm's; the capillary pressure in this system is proportional to √ rpm and 6-8 data points are normally recorded using a stroboscope technique.

-The centrifuge is the only technique able to record the full capillary pressure curve – both the positive and negative part.

- Plug size samples are required, but the method works for weakly consolidated (jacketed) samples as well. The test runs un-confined, very few instruments are available for overburden measurements.

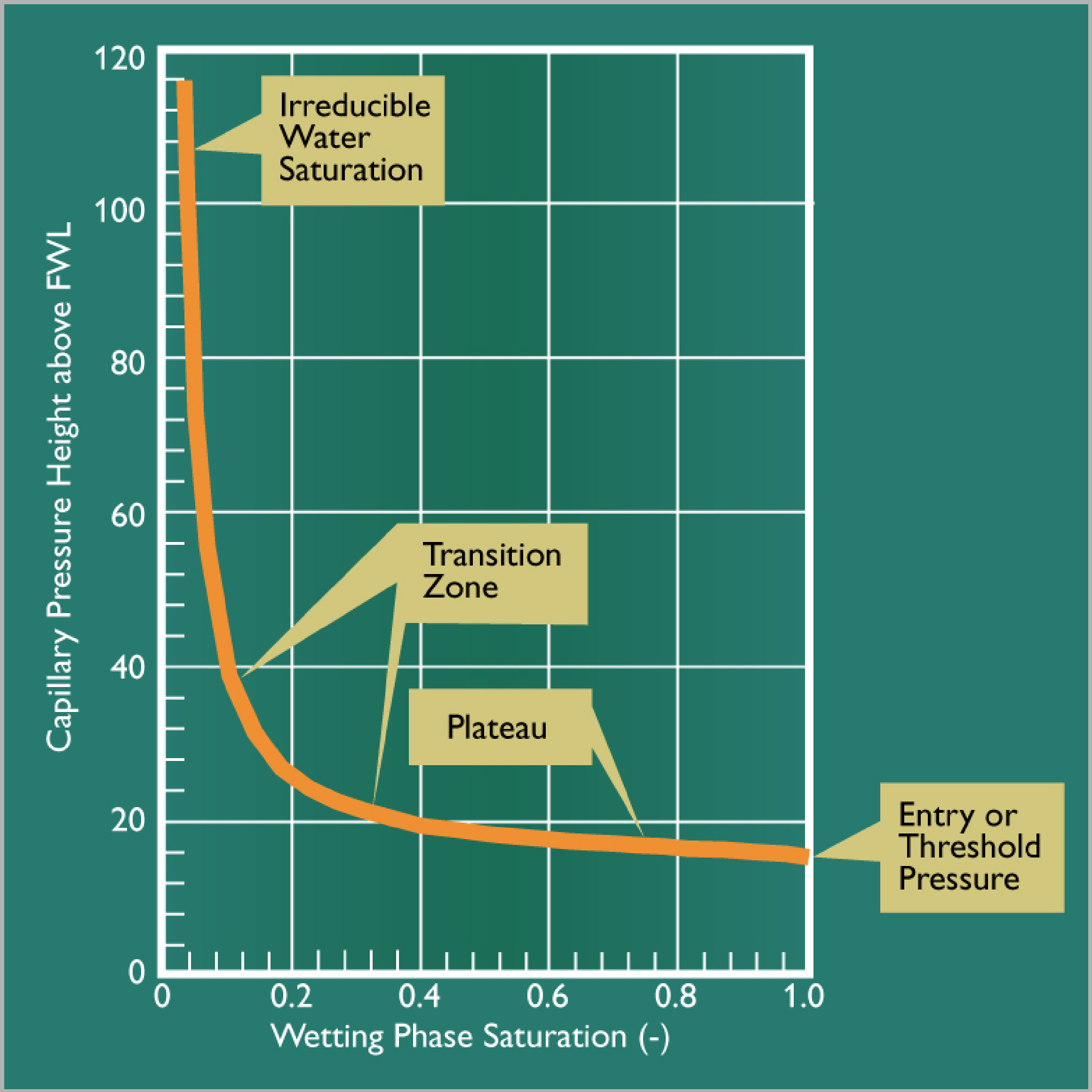
- The test is non-destructive, the sample may be re-used for other tests; some fragile samples may not stand high rpm's

- The test is affected by capillary end effects and data reduction is complicated.

- Spinning time alotted for the experiment may be inadequate to reach equlibrium (cost of the experiment)

GEUS

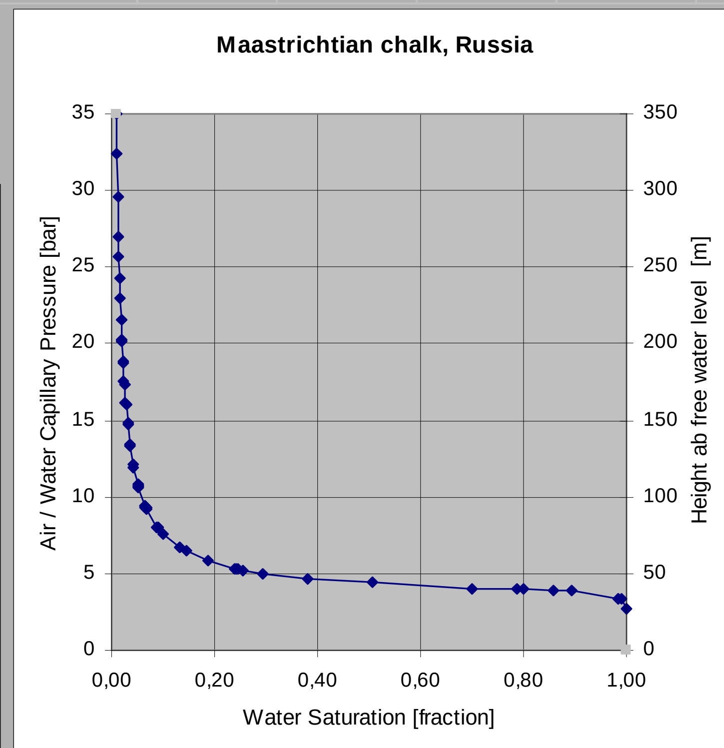
Capillary Pressure Curves: Key Features

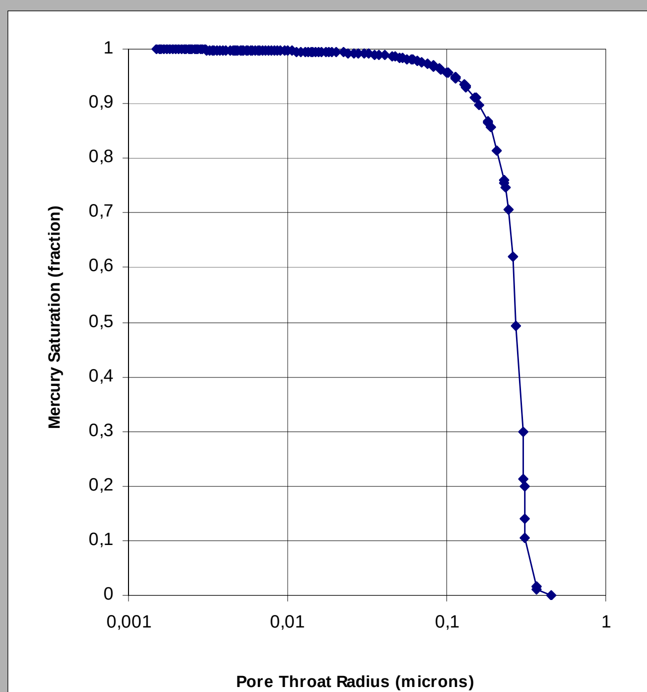


The y-axis is normally given in a pressure unit, [psi], [bar], [MPa] or here as a hight above the free water level

Output from Hg-injection test :

Injection Pressure	Mercury Saturation	Water Saturation	Pore Throat Radius	Normalized PSD	Equivalent Injection Pressure (psia)			Height Above Free Water	Height Above Free Water	Normalized Permeability Dist	J Function
(psia)	(fraction)	(fraction)	(micron)		A/B (Lab)	O/B (Lab)	O/B (Res)	A/B(feet)	O/B(feet)		
197,19	0,000	1,000	0,459	0,000	38,6	22,3	13,9	87,9	126,7	1,000	#VÆRDI!
245,13	0,011	0,989	0,369	0,030	48,0	27,7	17,3	109,2	157,5	0,977	#VÆRDI!
246,42	0,016	0,984	0,367	0,071	48,3	27,9	17,4	109,8	158,3	0,967	#VÆRDI!
247,16	0,017	0,983	0,366	0,086	48,4	27,9	17,5	110,1	158,8	0,965	#VÆRDI!
290,29	0,106	0,894	0,312	0,412	56,8	32,8	20,5	129,3	186,5	0,834	#VÆRDI!

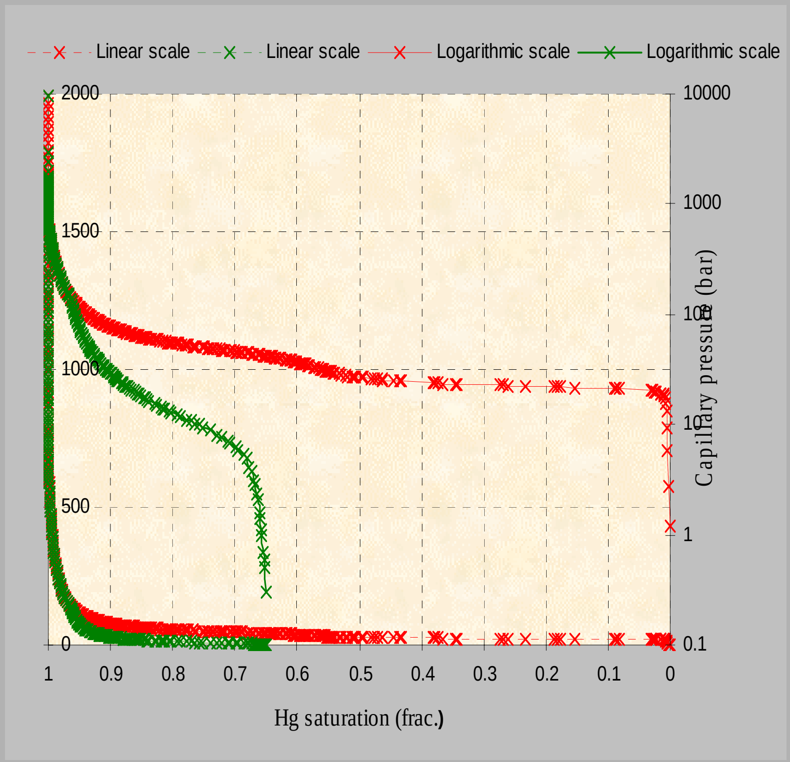


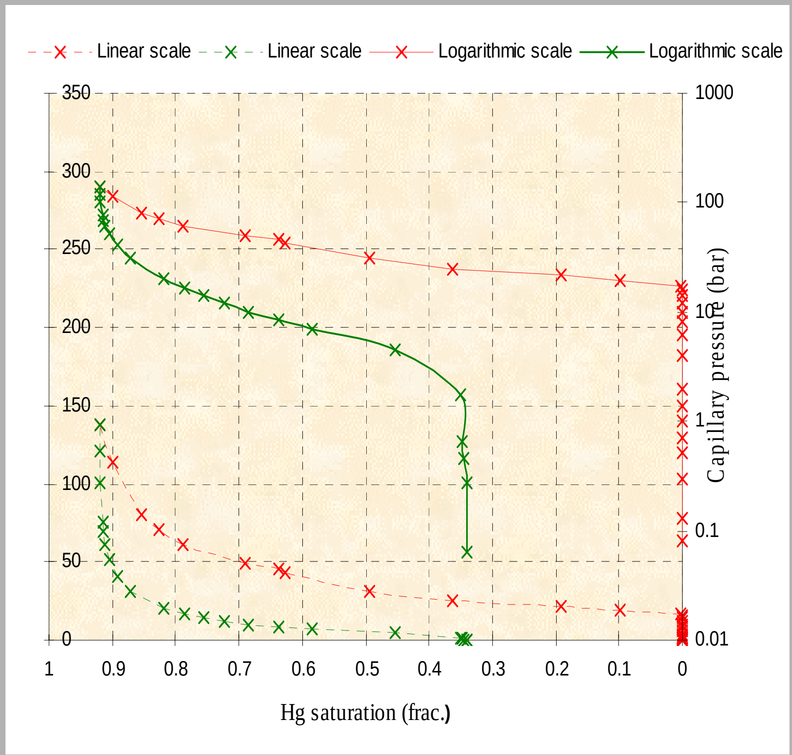


GEUS

Case study: Mercury constant injection and withdrawal rate (left) and constant pressure right

Why Hg-injection tests are only ½ the truth: cost and time !



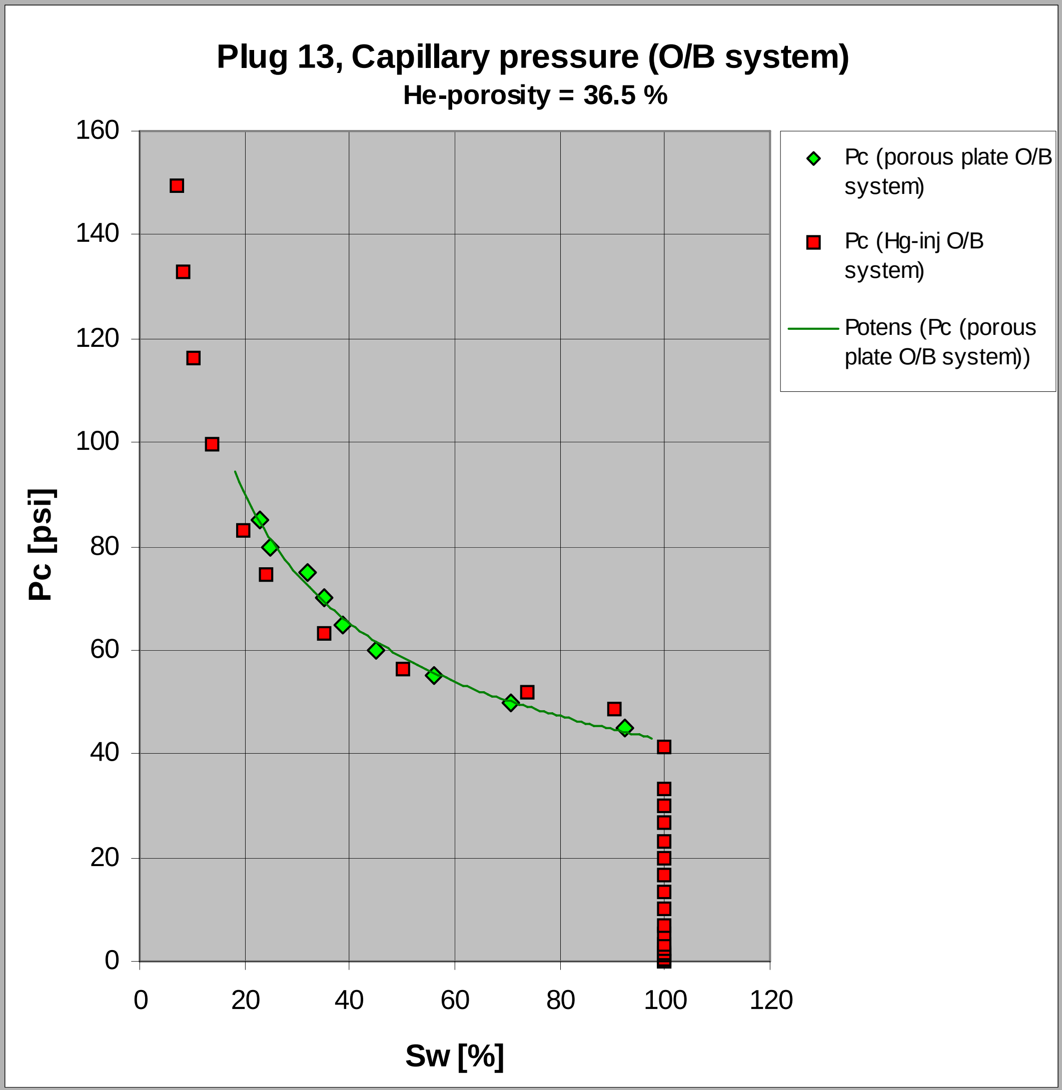


Auto pore intrument to 30,000 psi (~ 2 kbar), analytical time 1 hour

Step driven Hg-pump to 2,000 psi (~ 140 bar), analytical time 3-4 days

GEUS

Case study: North Sea chalk capillary pressure curve



Igor, Danian chalk

Capillary pressure curves measured by different techniques on nearby plugs having identical He-porosity:

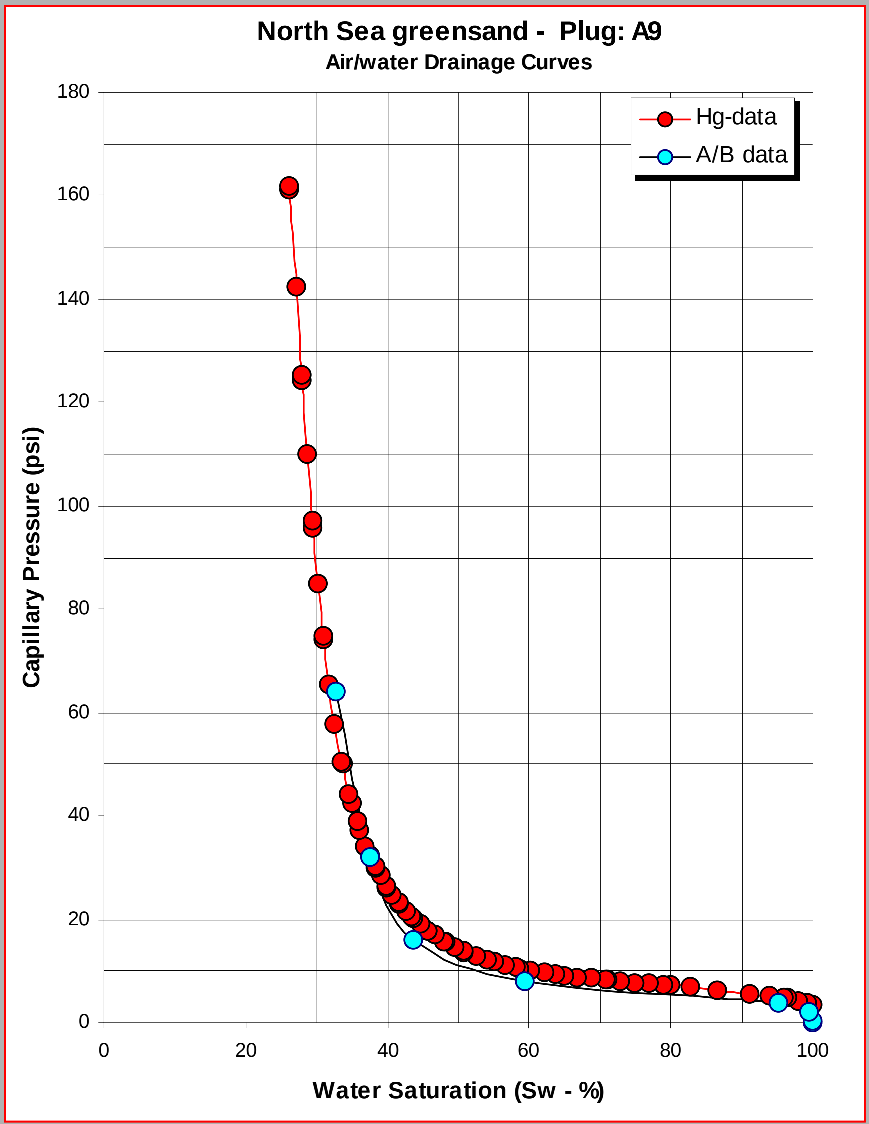
1. Porous plate oil-brine system in single core holder @ 800 psi conf. P;
exp. time = ½ year

2. Hg-injection in single core holder @ 800 psi conf. P, recalculated to an oil-brine system
exp. time = 3-4 days

Credits : GEUS Core Lab + ResLab N

GEUS

Case study: North Sea greensand capillary pressure curve



Paleocene greensand

Capillary pressure curves measured by different techniques on identical plug and trim:

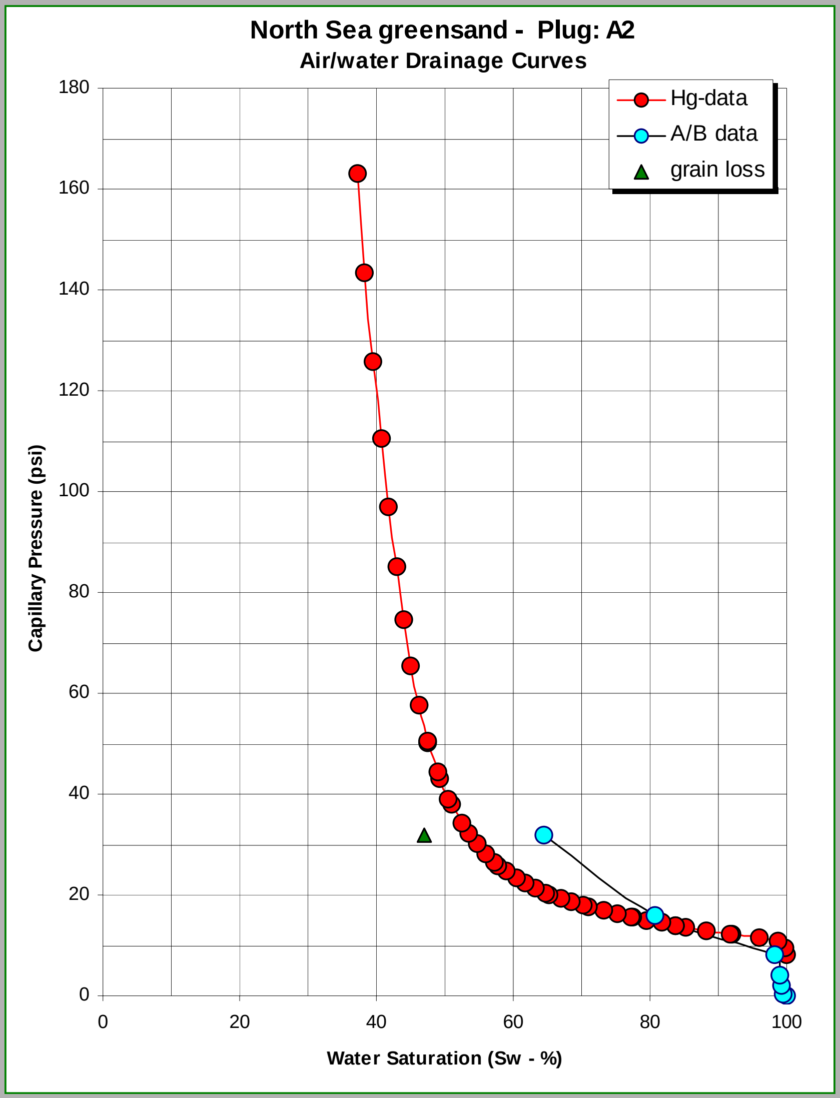
1. Porous plate air-brine system in multiple sample pressure pot unconfined
exp. time = ~ 5 months

2. Hg-injection in auto pore instrument unconfined, recalculated to an air-brine system

Credits : GEUS Core Lab

GEUS

Porous plate pitfalls: loss of capillary contact and grain loss from weakly consolidated plugs



Simultaneous measurement of porous plate and Hg-injection data on plug and plug trim could form a very good check on data quality

GEUS

Capillary pressure conclusions :

Good results can be obtained with the porous plate and centrifuge method if adequate time is allowed to reach equilibrium at each pressure step

Grain loss and loss of capillary contact may be a problem in the multi sample pressure pot method

Some reservation exist in the litterature against using air-mercury capillary pressure curves to define saturation-height models

Experience from the North Sea chalk and geeensand reservoirs show that air-mercury injection data can be used with confidence in setting up saturation-height models

This is an important observation because mercury injection data can be obtained at low cost and in a short time, ie. a large database of capillary pressure data can be established for these reservoirs quickly.

GEUS

Electrical methods: Formation Resistivity Factor F, Resistivity Index RI, Archie m and n:

- Porous rocks consealed below the ground water zone are saturated with salty water (brine) that conducts electricity.

- Rock matrix, oil and gas are normally non conductive

- Archie parameters F, RI, m and n are used to predict porosity and water saturation (hydrocarbon saturation) from logged downhole formations, and it is therefore very important to determine these parameters correctly

-Archie parameters are determined in the laboratory by analyzing the conductivity (resistivity) of small core samples saturated (or partly saturated) with formation water

-Results may be affected by scaling effects

G E U S

Formation Resistivity Factor, F

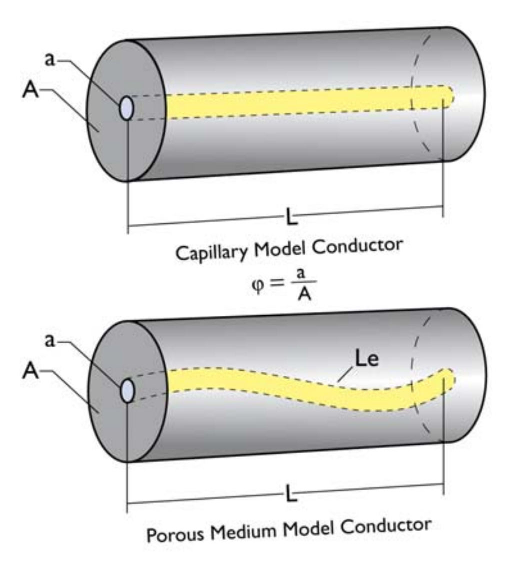
- F is defined as the ratio between the resistivity R_o of the fully brine saturated rock and the resistivity R_w of the saturating brine

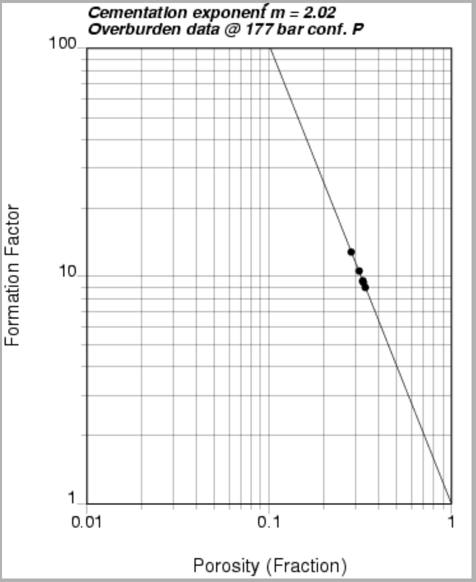
- R_o is proportional to R_w , to the rock tortuosity L_e/L and inverse proportional to the porosity Ø (the total brine content):

- F is therefore a function of porosity and pore geometry of the rock. 'm' is called the cementation exponent (slope of the regression line), and the constant 'a' (intercept) often assumed or measured to be close ~1

$$F = \frac{R_0}{R_w} = \frac{\left(\frac{L_e}{L}\right)^2}{Ø} \cong \frac{a}{Ø^m}$$

$$log(F) = -m\ log(Ø) + log(a)$$

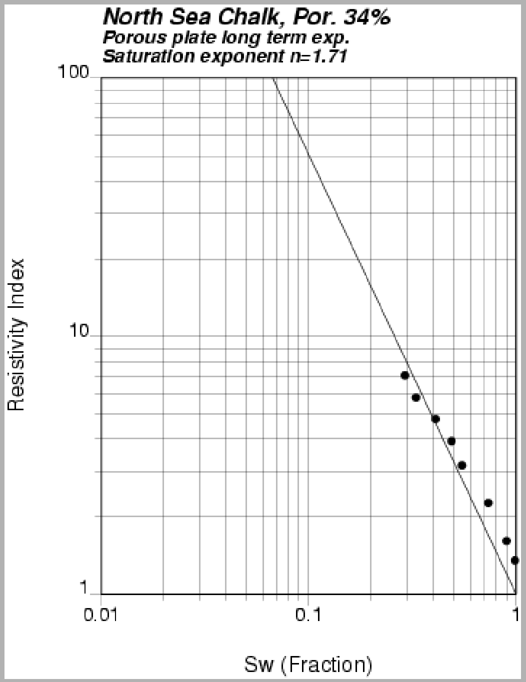




Resistivity Index RI

- RI is defined as the ratio between the true resistivity R_t of a rock partially saturated with non conducting oil or gas and the resistivity R_o of the fully brine saturated rock

- RI is then a function of water saturation (hydrocarbon saturation), but is also a function of pore geometry of the rock. 'n' is called the saturation exponent (slope of the regression line)

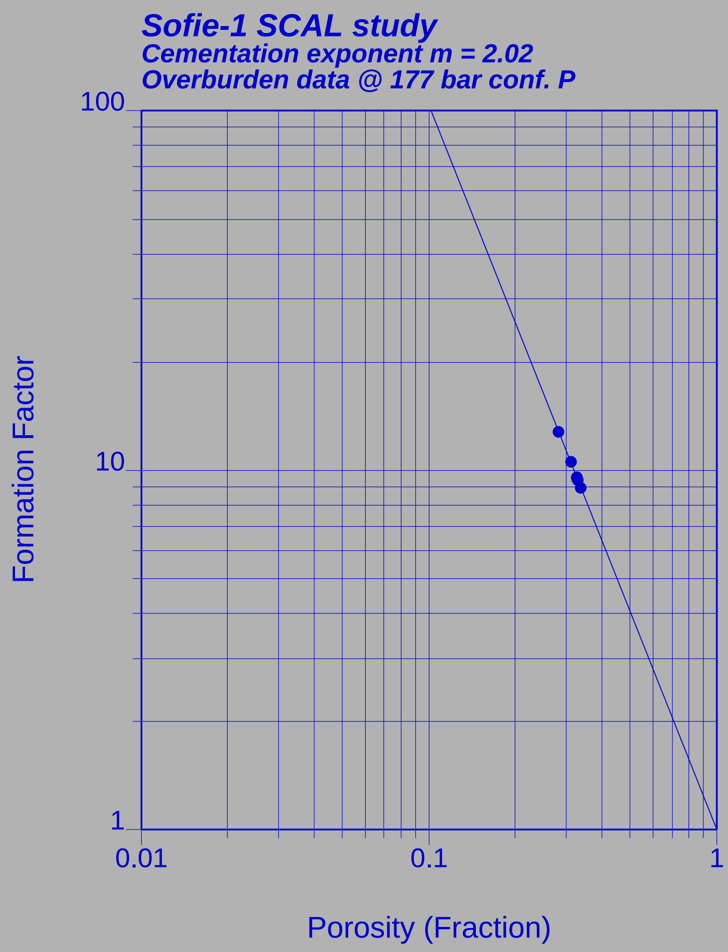


$$S_w^{\ n} = \frac{1}{RI},\ RI = \frac{R_t}{R_o} \quad \Rightarrow \quad RI = S_w^{\ -n}$$

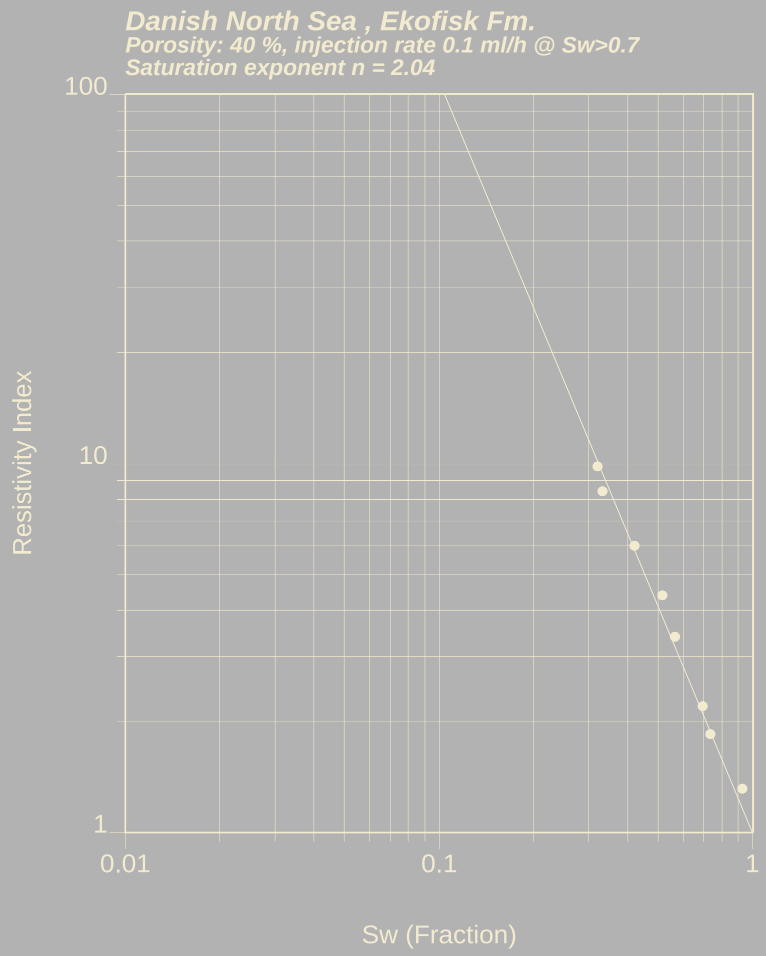
$$\log(RI) = -n\ \log(S_w)$$

Electrical methods: Archie FRF diagram for Ø correlation
Archie RI diagram for Sw correlation

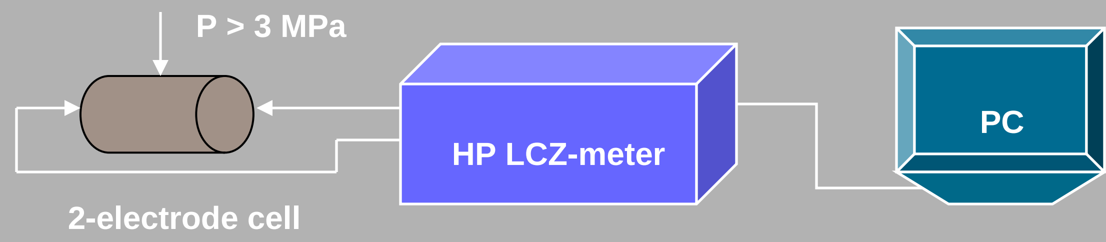
Suite of samples data: full range in porosity



Single sample data: large spread in S_w



GEUS



Measurement of Archie parameters:

The plug is installed in a resistivity core holder at overburden pressure, saturated with formation water and the resistivity determined as the impedance to an AC signal of typically 1 – 20 kHz

The resistivity of the formation water R_w is measured in a conductivity meter (the reciprocal of resistivity is conductivity). The laboratory measured figure should be checked against tables or computer codes

Electrical resistivity is measured in [ohm-m]; The resistivity of a formation in ohm-m is the resistance in ohms of a one meter cube measured between opposite faces of the cube

GEUS

Resistivity measurements: observations 1

- Different analytical methods produces different results for Archie parameters
- Methods:
  - Room condition simultaneous with Pc experiment
  - ”Dynamic” displacement at overburden condition using air or oil as the non-wetting fluid.
  - ”Static” displacement with porous plate at over-burden condition using air or oil as the non-wetting fluid.
  - Centrifuge desaturation using air or oil as the non-wetting fluid.
  - Continous injection (RICI) with oil as non-wetting fluid

Danish North Sea chalk fields: Ekofisk Fm (Danian chalk)
’shot-gun’ distribution of ’m’ and ’n’ data

Observations 2 : This unfortunate state of affairs are due to lacking care in all stages of laboratory resistivity measurement. It has not been generally recognized :

When is Archie's eq. for m and n valid ?

1. At uniform core saturation
2. At non-conducting matrix conditions

- When is the core saturation uniform ?

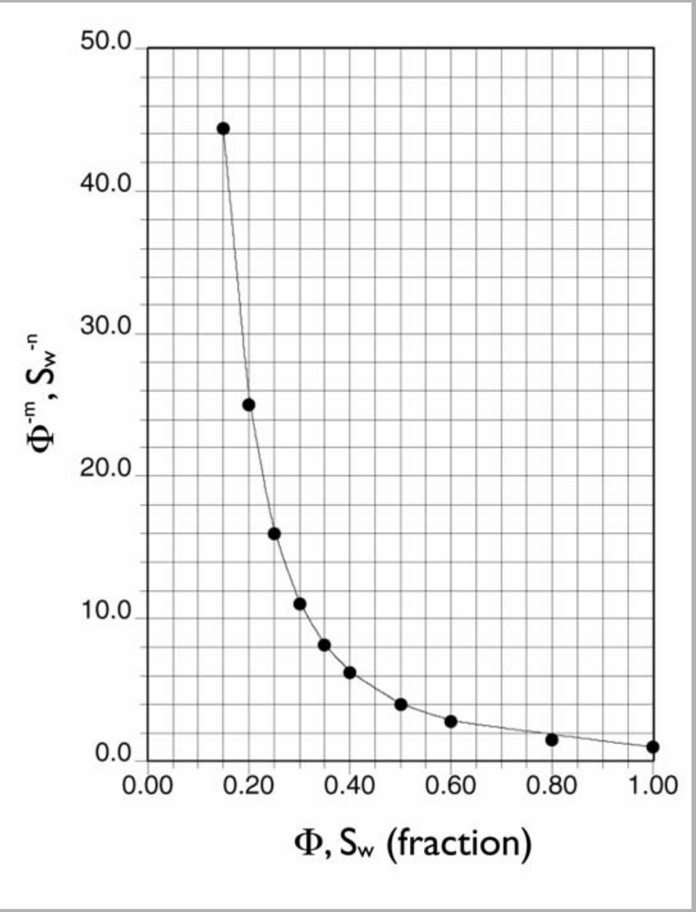
1. At drainage equilibrium (no end-effects)
2. At uniform core porosity

- A non-uniform saturation experiment, a conductive matrix or dual-porosity materials will produce curved lines in a resistivity plot.
- <u>Eletrical measurement of small core plugs therefore requires careful geological and X-ray CT-screening in advance if quality data is called for and scaling effects should be minimized</u>

GEUS

Observations 3 : How can it be understood ?

Archie's equations are convex functions, and any deviation from uniformity will cause erroneous high figures in the recorded RI (for the most widely used measurement techniques), as we shall see in the next slide



$$F = \text{Ø}^{-m}$$

$$RI = S_w^{-n}$$

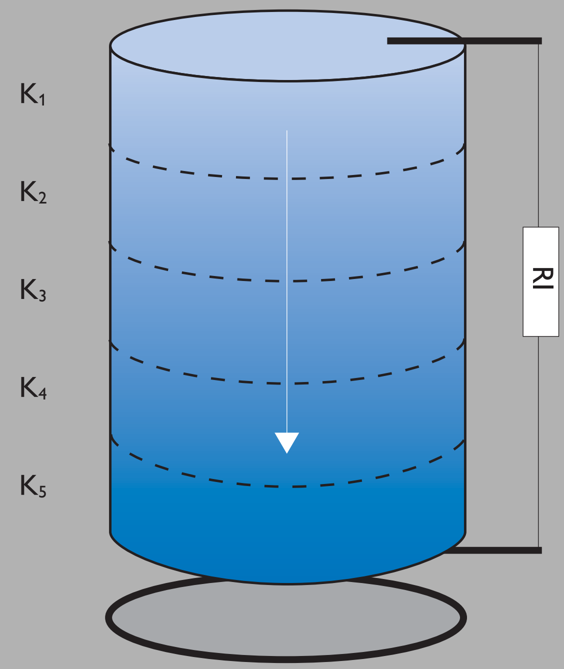
Eg. assume n=2, this would give $S_w^{-n} = 16$ for $S_w = 0.25$

Sensitivity of the resistivity index to non-uniform saturation distributions: Model calculations showing effect on measured bulk RI value

(based on Lyle & Mills, 1989)

SCA 2003-38

Subinterval	S_{wk} distribution		
	ex. 1	ex. 2	ex. 3
k_1	0.25	0.19	0.10
k_2	0.25	0.21	0.15
k_3	0.25	0.23	0.20
k_4	0.25	0.25	0.30
k_5	0.25	0.37	0.50
RI	**16.0**	**18.5**	**36.9**

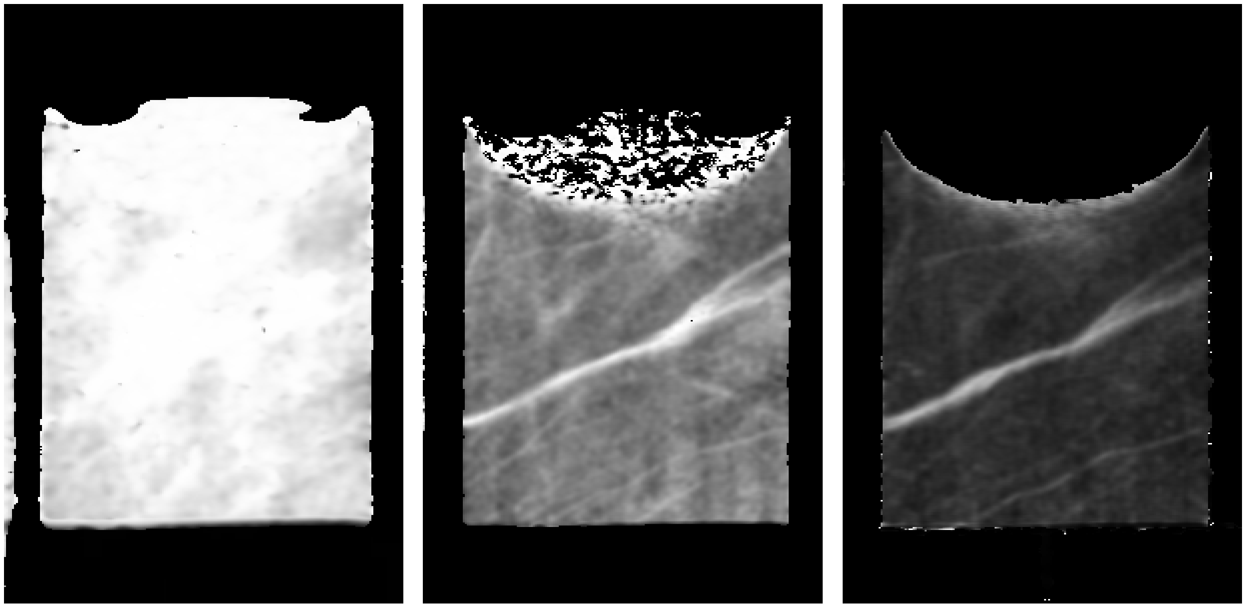


GEUS

Electrical methods in core analysis, observations 4: Equilibrium drainage using a porous plate; t_{exp} ~ 3 years.

A uniform saturation distribution may be a hypothetical phenomenon in chalk plugs.

GEUS Core Lab.

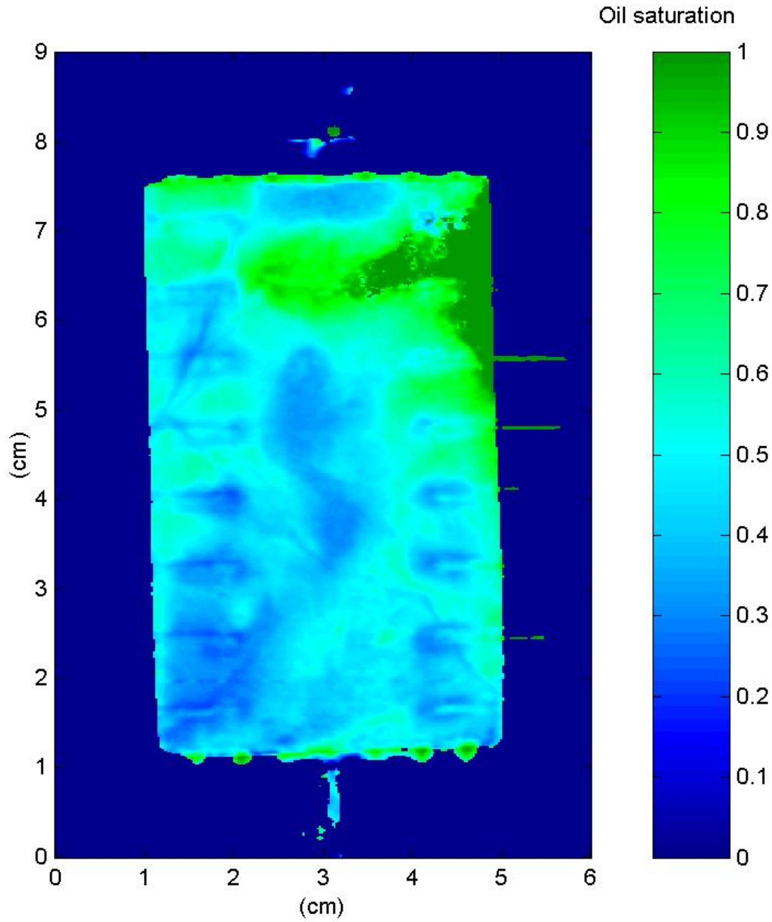


P_C (bar)	2.0	2.5	3.5
Bulk $S_{W,PROD}$	0.890	0.543	0.266
Mean $S_{W,IMAGE}$	0.929	0.507	0.211

Fig. 2.13. Quantitative water distribution in sample M16H during porous plate experiment determined by CSI NMR. Grey tone scale indicates water saturation: white: S_W = 1.0, black: S_W = 0.0. The porous plate is situated at the top of the sample, but is not visible in the figure. In the upper fifth of the sample the porous plate destroys the NMR signal, resulting in an elongate area with spurious data values. Field of view is 4.7 x 7.0 cm.

GEUS

NMR imaging of an oil-water 2 phase flow experiment in a multiple electrode core holder



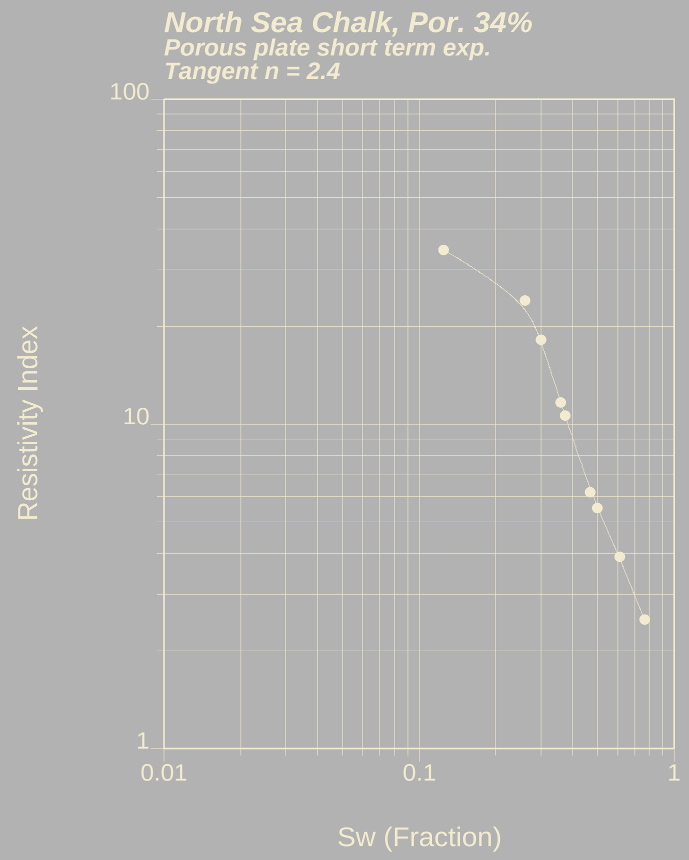
Case story: Static displacement at overburden conditions in an oil-water system using 15 bar porous plate: Disequilibrium even after 6 months drainage. Measurements at low capillary pressures (high water saturations) may be skipped.

(additional examples in Sprunt et al., 1991 and Maas et al., 2000)

Springer et al. in SCA 2003-38

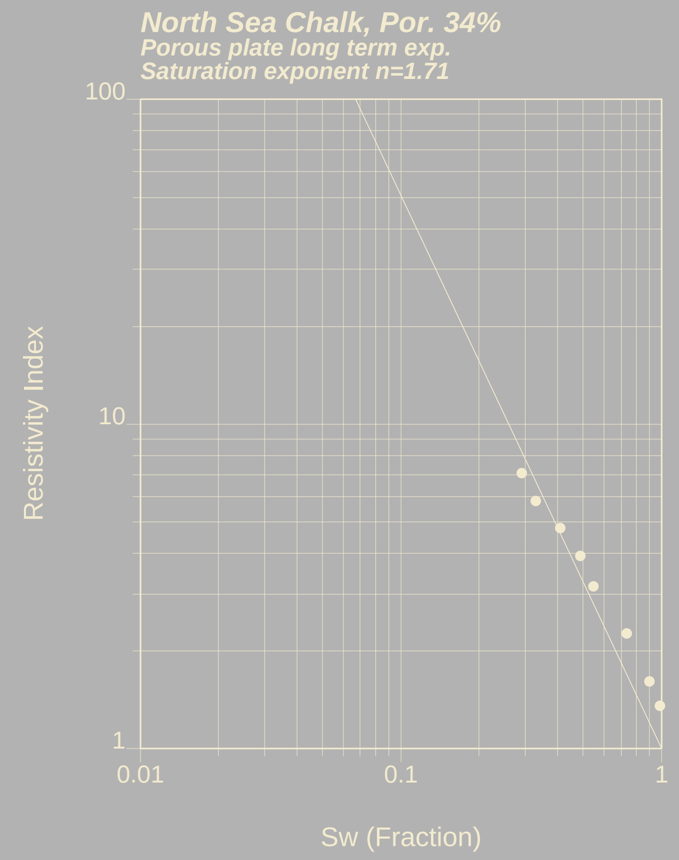
Tor Fm., 1 month exp. time

k_g ~ 3 mD **h = 44 mm**



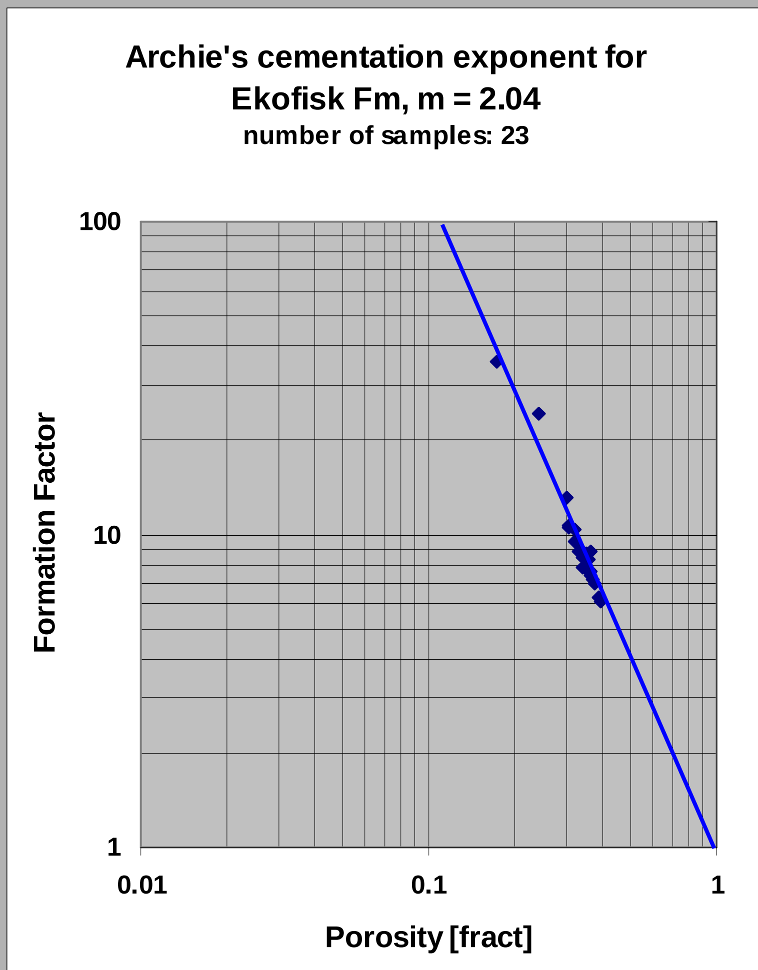
Ekofisk Fm., 6 month exp. time

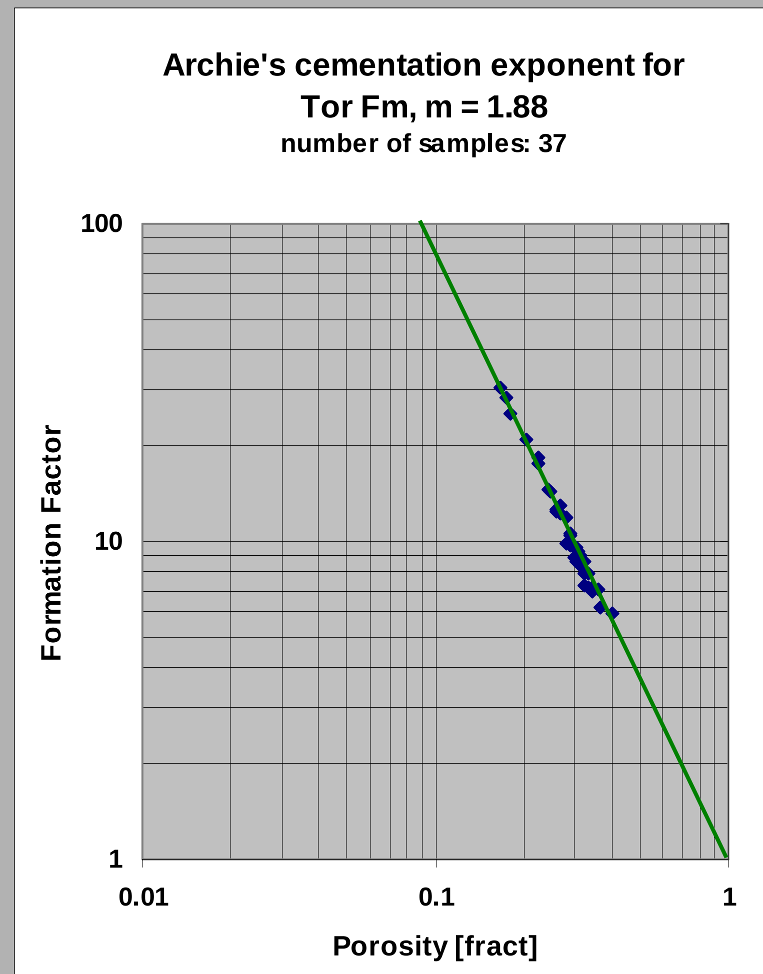
k_g ~ 1 mD **h = 32 mm**



GEUS

North Sea chalk fields: The electrical facies concept for the Saltdome province (chalk is electrical homogeneous and simple on a regional scale, inline with other observations).





Overburden data @ 800 - 1100 psi

North Sea chalks, petrophysical properties:
Upper Cretaceous Chalk is an Archie rock

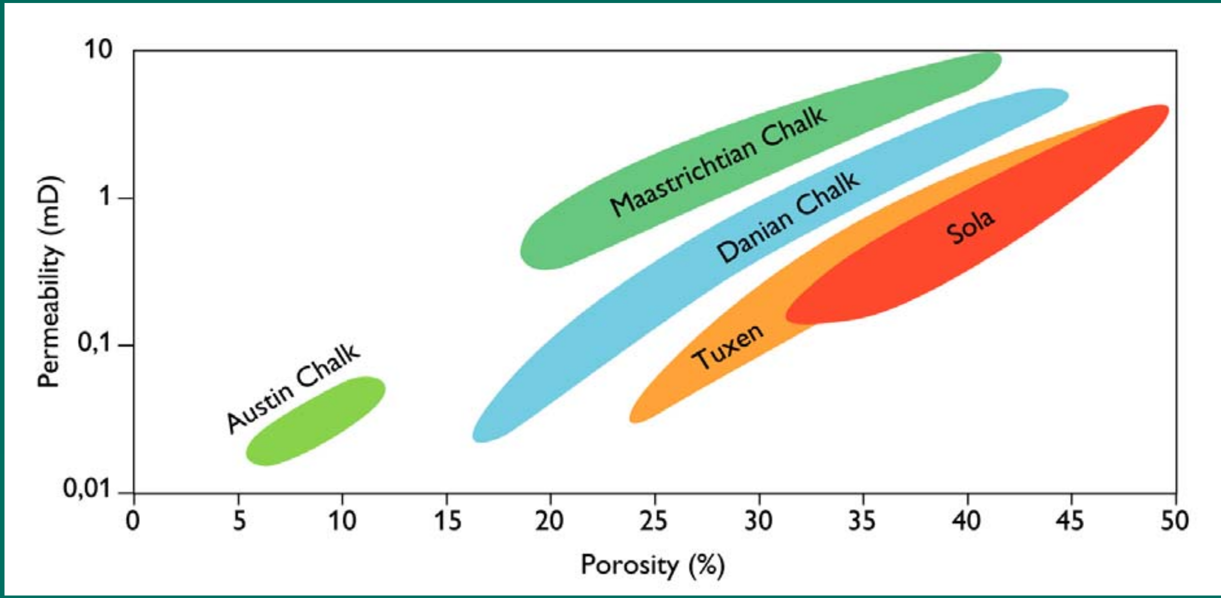
SCA 2003-38

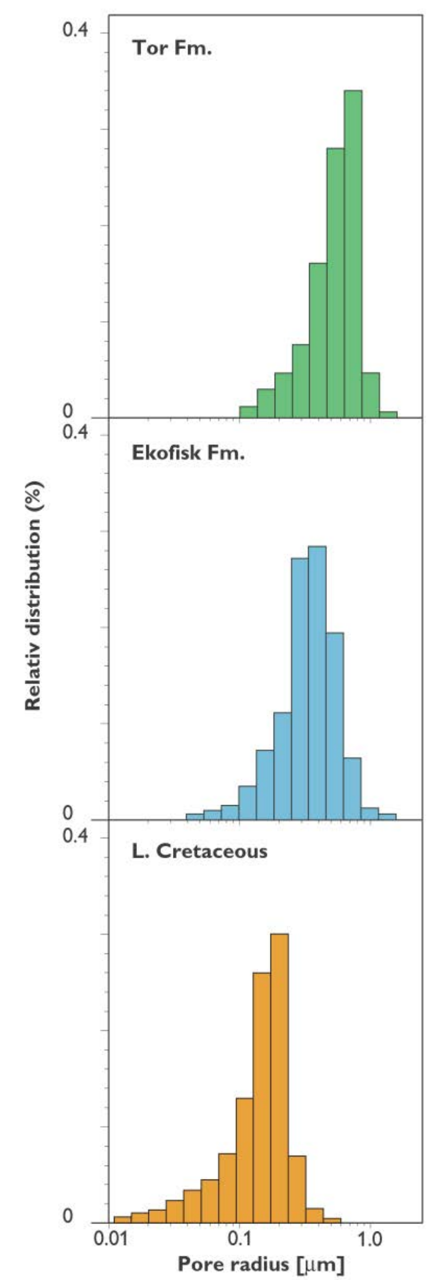
- Observe unimodal, left skewed Hg-injection pore size distribution due to ± silica, clay and small grains
- Tor (Maastrichtian) r_{50} ~ 0.6 μm

  Ekofisk (Danian) r_{50} ~ 0.4 μm

  L. Cretaceous r_{50} ~ 0.15 μm @ 35 - 40% porosity chalk

Partly after: Jakobsen et al., 2003 and Andersen, 1995





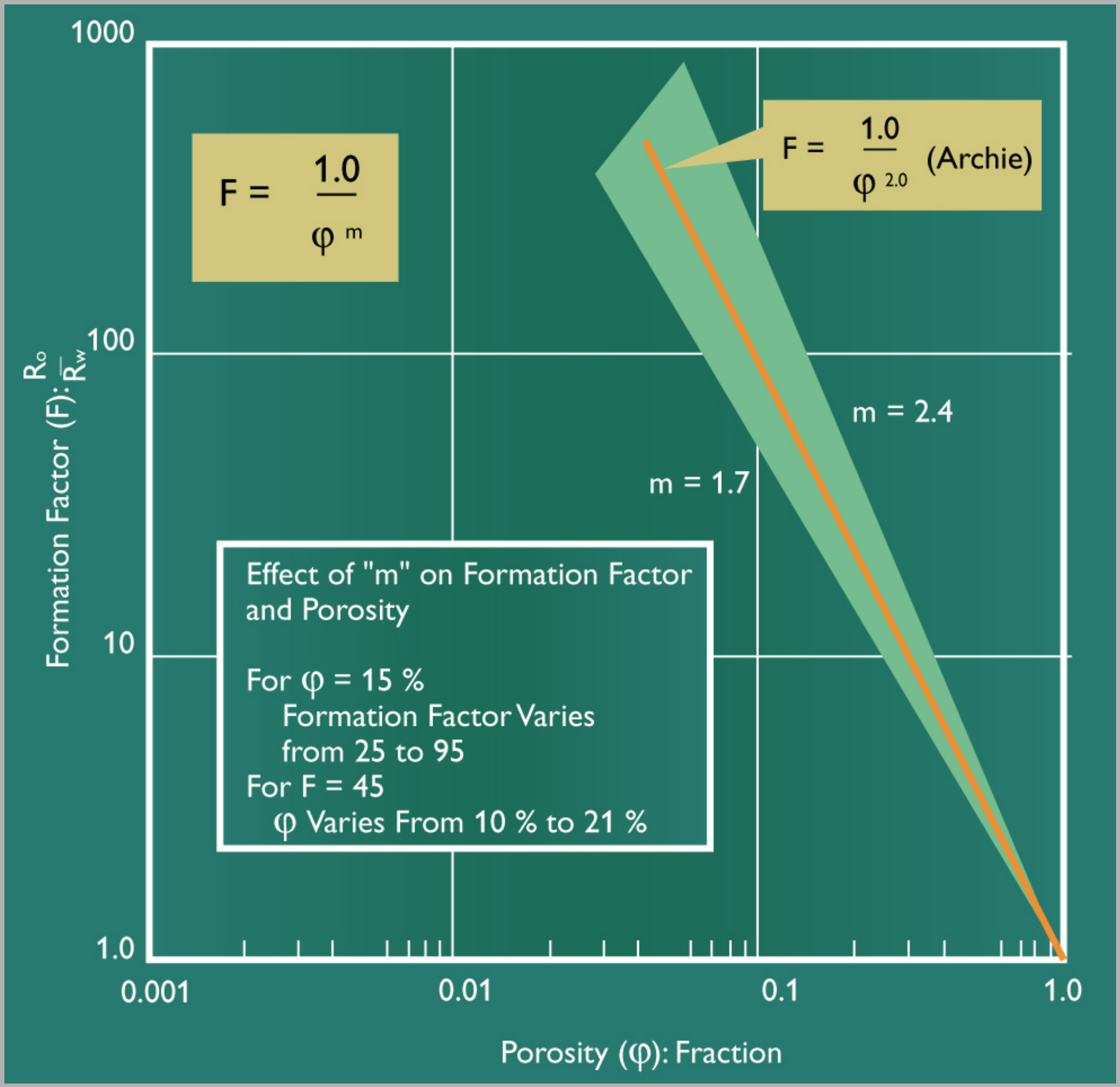
Electrical methods in core analysis: Does it matter to care about electrical parameters ?

Sensitivity of calculated water saturation to saturation exponent ”n”

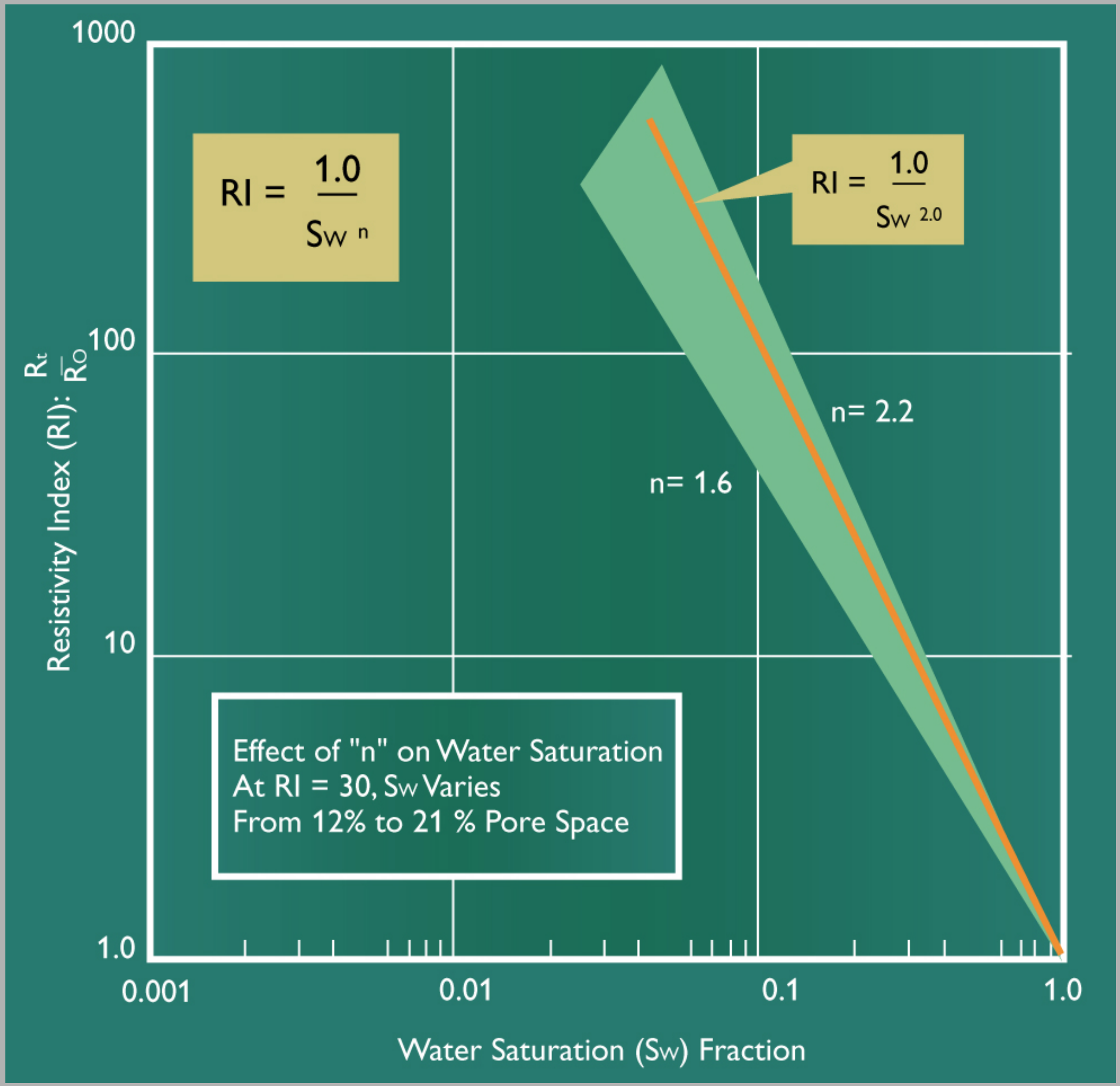
RI = R_t/R_o	Calculated water saturation S_w % n = 1.6	n = 2.2	ΔS_w
100	6	12	6
30	12	21	9
10	24	35	11
4	40	53	13
3	50	61	11
2	65	73	8
1	100	100	0

GEUS

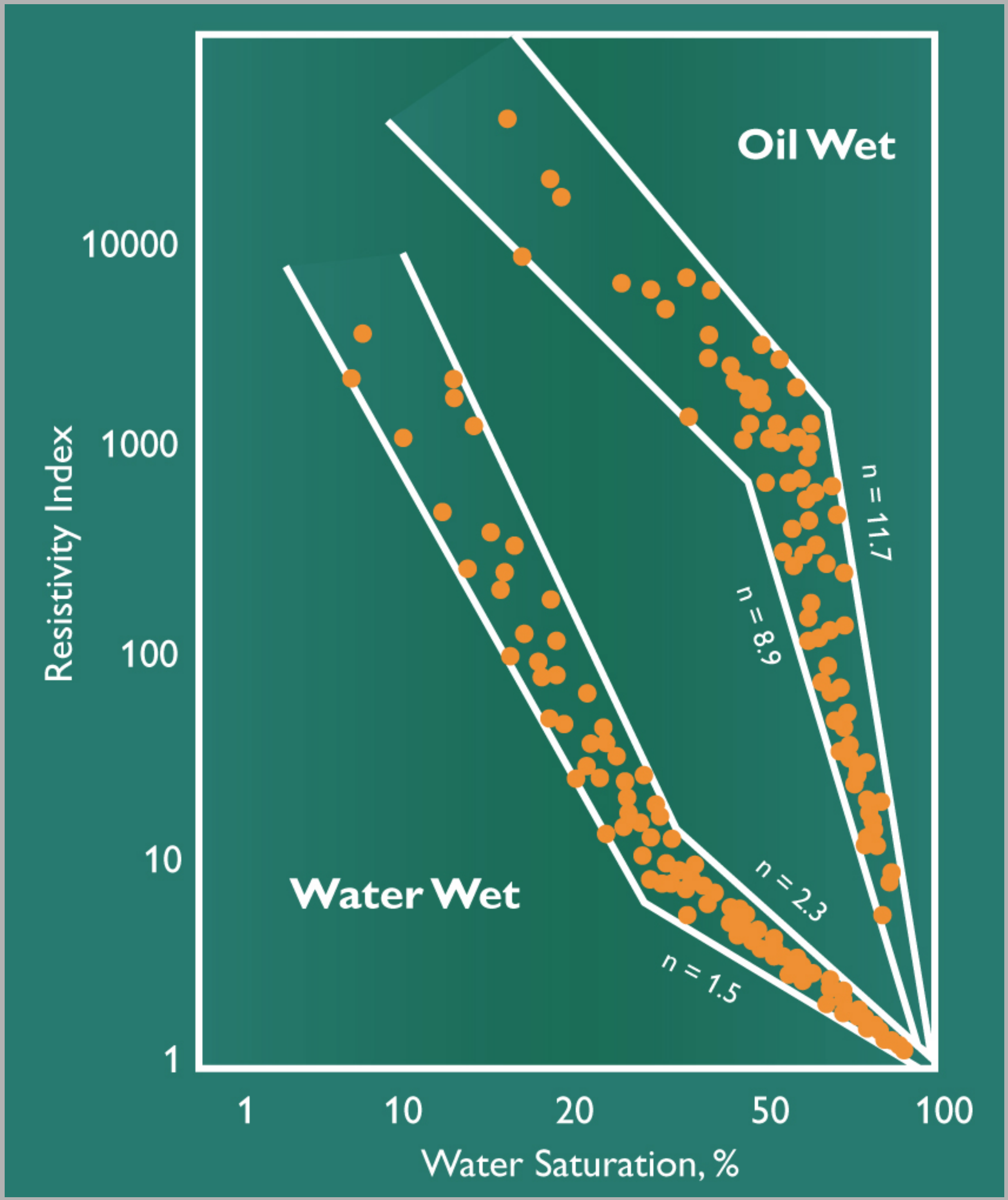
Formation Factor vs Porosity for a range of measured cementation factor's



Resistivity Index vs water saturation for a range of measured saturation exponents



Effects of Wettability on Saturation Exponents

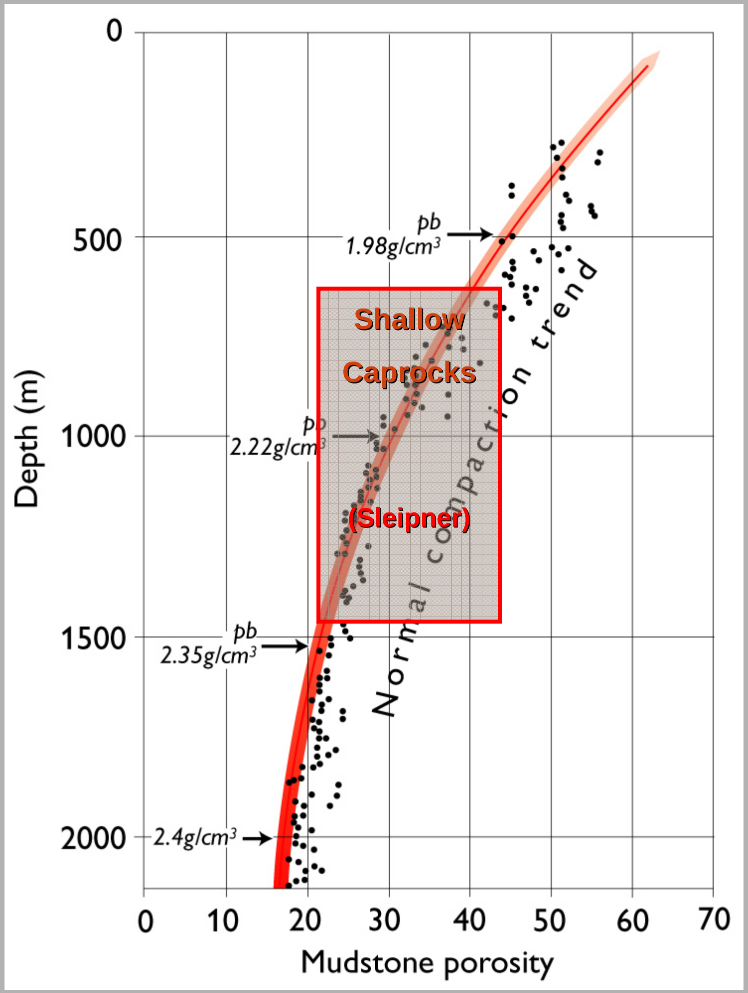


Caprock reseach:

- Observations relating to the sealing properties of cap rocks (ref. Dewhurst, Yang & Aplin 1999):

- **”Mudstone permeability vary by 10 orders of magnitude, and by 3 orders of magnitude at a single porosity”**
- ”None of the existing (poro-perm) models are ideal and need to be adjusted and validated through the aquisition of a much larger permeability database of well characterized mudstones”
- **Much of the range (in permeability) at a given porosity can be explained by differences in grain size and compaction”**
- ”The extent to which microfractures enhance mudstone permeability, both instantaneously and over longer periods of geological time, is poorly constrained”
- **”--- there are extremely few reliable permeability data for well-characterized mudstones (most published data are calculated from the different models).**

The majority of caprocks are shales



(After Magara, 1968 – Compaction of Neogene mudstones)

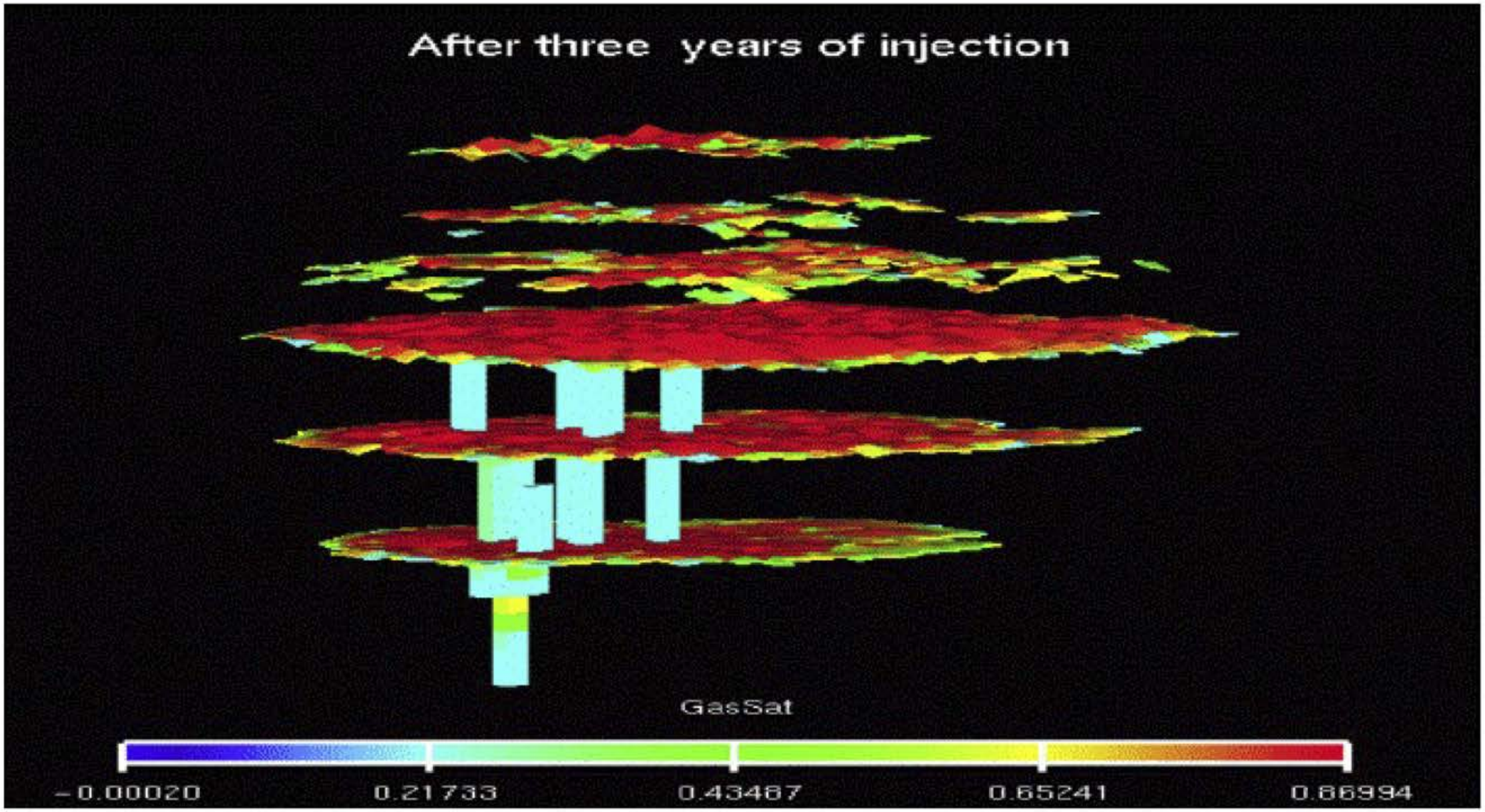
- Most data on caprocks originates from work on petroleum reservoirs or from caprocks that have been buried to greater depths
- Quality caprocks have:
  Permeability < 10 nD (< 10E-20 m^2)
  Entry pressure > 5 MPa
  They remain ”tight” for My
- Shallow caprocks < 1500 m can be attractive from a storage economic point of view (gas, CO2)

Caprock seal integrety

- **Gas, liquid or $scCO_2$ may invade a sealing caprock by different means:**

1. **Exceeding the capillary entry pressure**
2. **Fracturing the rock**
3. **Diffusion in the liquid phase along grain boundaries**
   (not treated here)

SACS Results: Seismic Monitoring Works !



Simulated picture of CO_2 after three years.
Largest bubble 800 m wide and the total 200 m high.

Ref: SINTEF Petroleum 2001

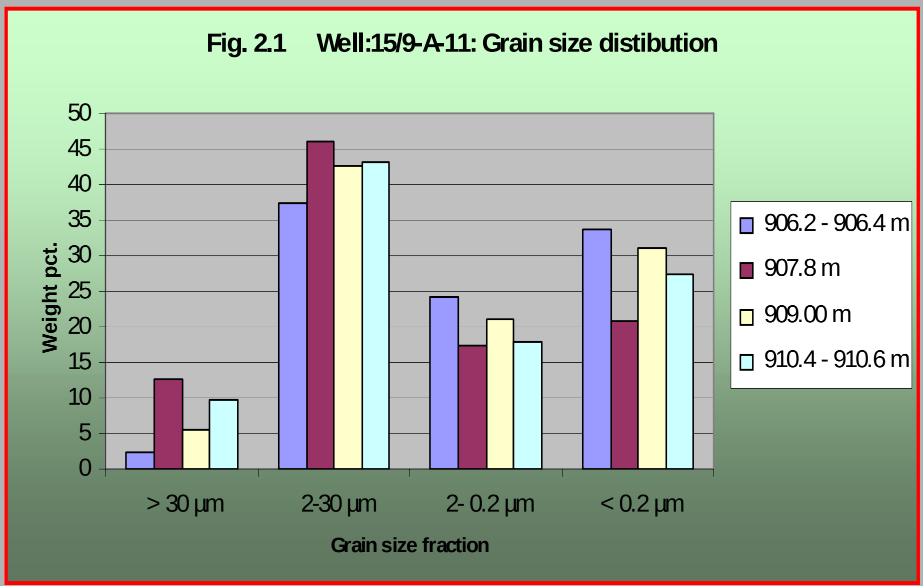
Cap rock properties

- Experimental data preferred for a caprock seal capacity test:

- Mineralogical composition (quantitative)
- Grain size / pore size distribution
- Specific surface area / CEC / TOC
- Porosity and permeability (relative perm.)
- Compaction - effective stress
- Capillary and threshold pressure rel to CO_2

Grain size and specific surface area:

- Important data for characterization of caprocks
- Fast and inexpensive to obtain
- May replace the conventional caprock test, that is difficult, slow and expensive ?

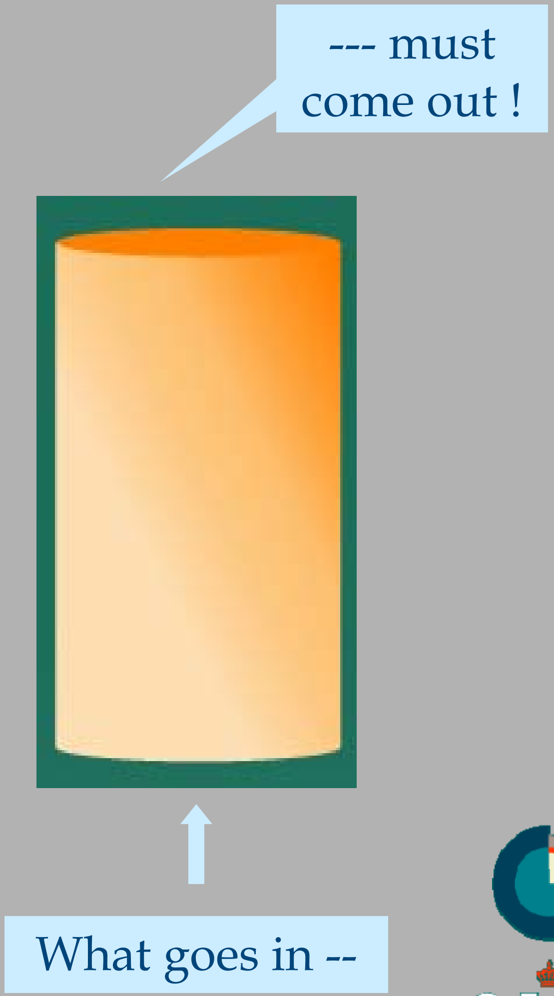


Clay fraction <2µm [wt-%]	N_{2BET} spec surface area [m^2/g]
58	25
38	17
52	24
45	22

Testing caprock seal properties:

- A liquid or gas pressure is applied to the upstream end of the sample, and pressures as well as injected and produced liquid is monitored.

- Diffucult due to creep (slow adjustment to effective confining pressure caused by very low permeability)
- Takes long time
- Requires leak tight precision equipment and temperature control.
- Using CO_2 is demanding due to corrosion problems and high mobility of CO_2



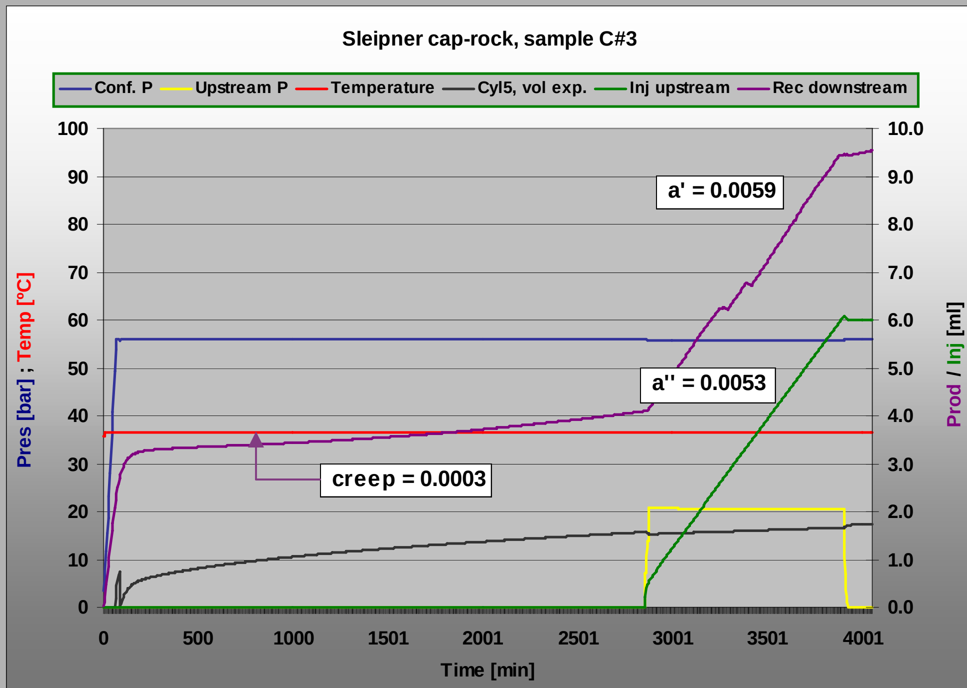
GEUS

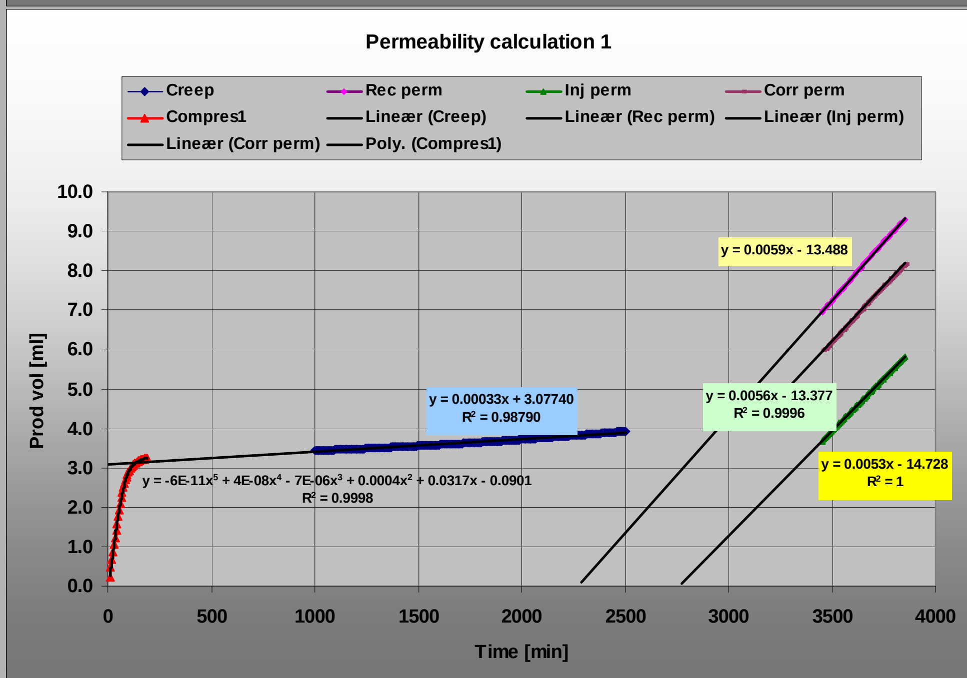
Equipment used for caprock testing:

Reservoir condition rig for measuring liquid permeability and threshold pressure of caprocks, down to ~ 1 nD ~ 10^{-21} m^2

max. P ~ 700 bar, min. dV ~ 1nl

GEUS





Example: Determination of caprock creep and corrected permeability; check on upstream and downstream liquid input/output

Permeability determined from pump reading ~ 865 nD

Permeability determined from balance reading ~ 910 nD

Entry pressure to $scCO_2$ estimated from pump stepping at 1.7 MPa

GEUS

CORE ANALYSIS LABORATORY

GEUS