PGE385K

Lecture Presentation

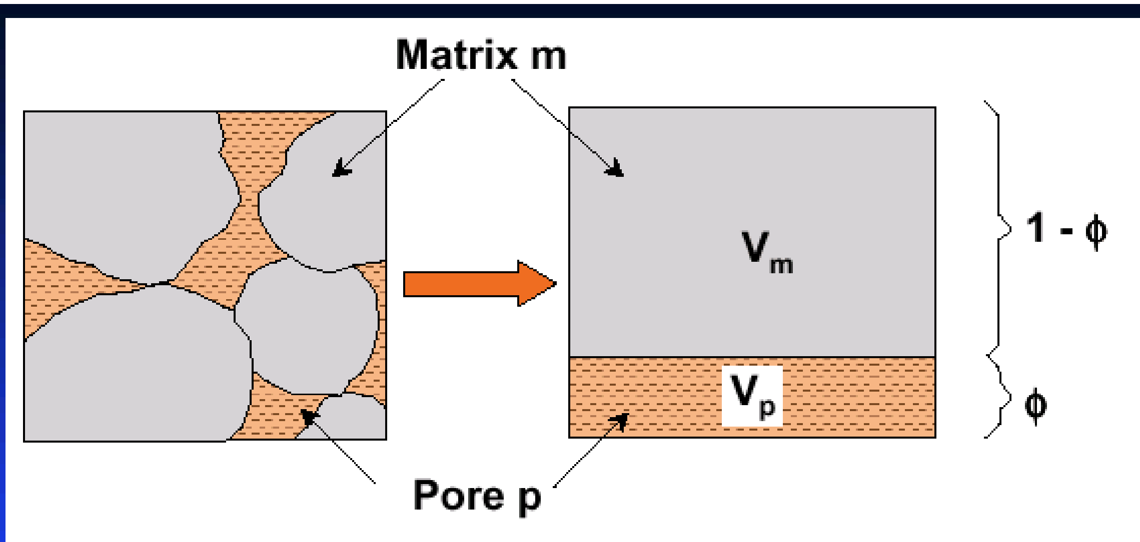
Permeability Estimation

Carlos Torres-Verdín, Ph.D.
Professor
Department of Petroleum and Geosystems Engineering
The University of Texas at Austin

Objectives:

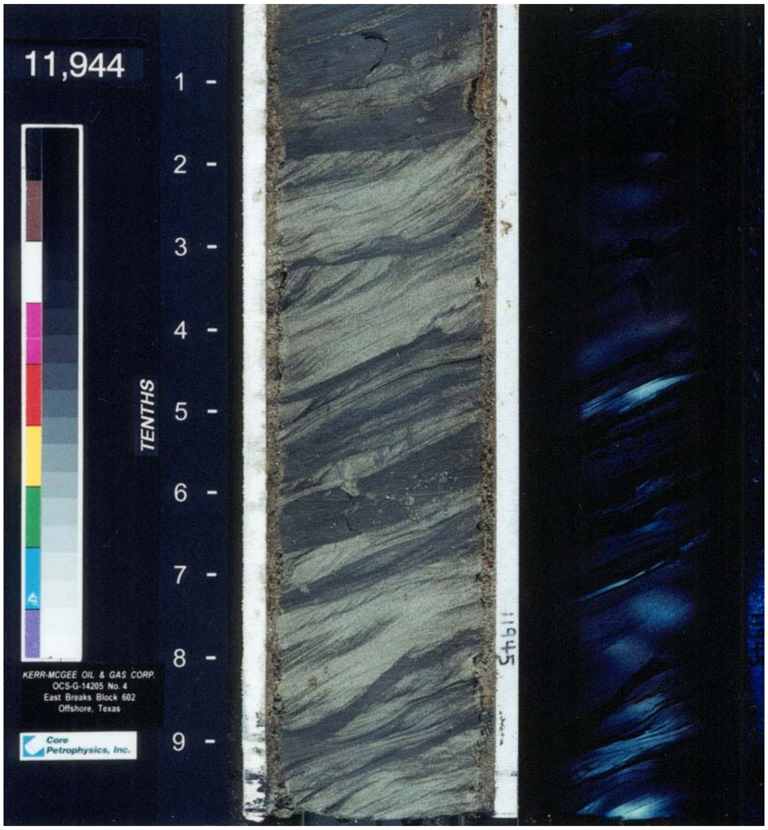
1. To introduce the concepts and assumptions used in the estimation of permeability from logs,
2. To introduce the various models used in the estimation of permeability from logs,
3. To introduce the methodology used to infer capillary pressure curves from logs, and
4. To exercise the estimation of permeability and capillary pressure based on well logs and rock-core measurements.

Review: Definition of Porosity



$$porosity = \frac{volume\ of\ pores}{total\ volume\ of\ sample} \qquad \phi = \frac{V_{pores}}{V_{sample}}$$

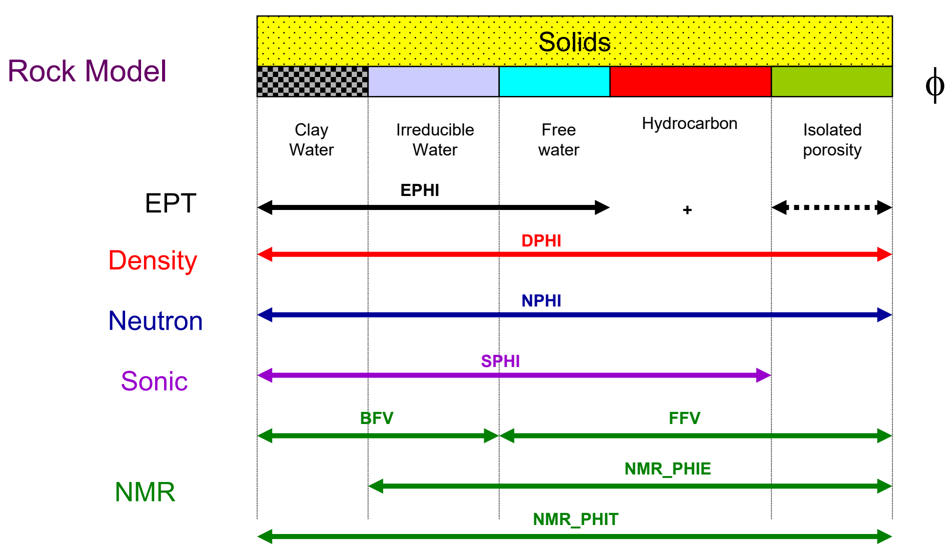
EXAMPLE: Fontainebleu Sandstone



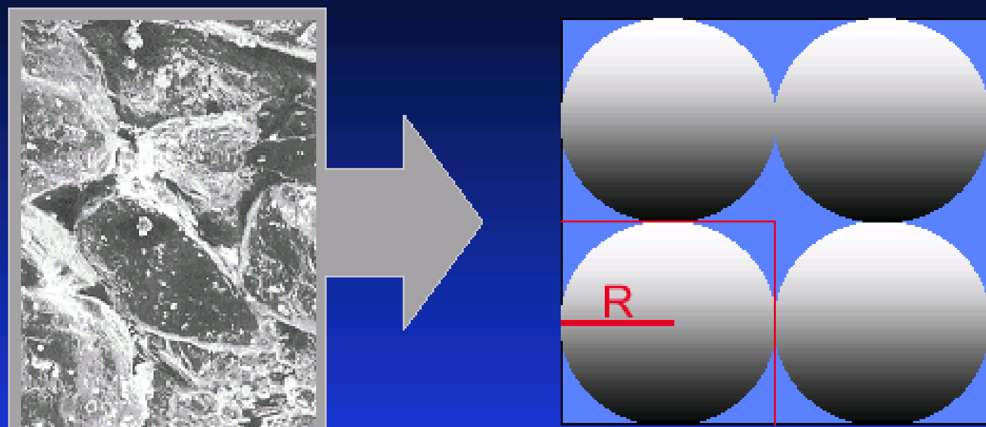
SCALE IS IMPORTANT

Sensitivity of Borehole Measurements to Porosity

Each tool responds in different ways to porosity. Combining them all helps to characterize complex porosity systems, as we found in carbonate rocks.



Porosity of a Sphere Packing

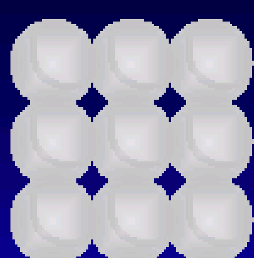


cubic packing

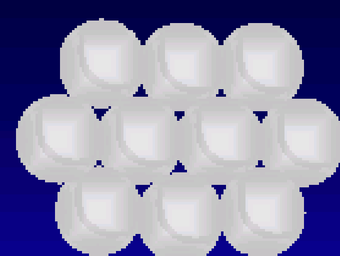
porosity $$\phi = \frac{(2 \cdot R)^3 - \frac{4}{3}\pi \cdot R^3}{(2 \cdot R)^3} = 1 - \frac{\pi}{6} \approx 0.48$$

number of contacts $K = 6$

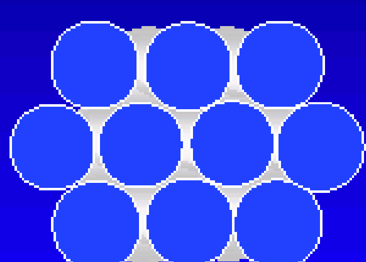
Types of Sphere Packing



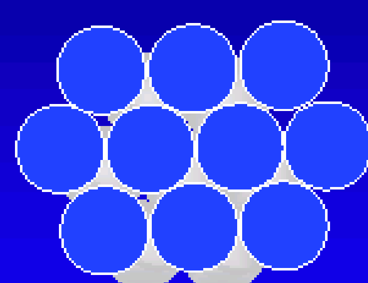
Cubic pack



Orthorhombic pack



Tetragonal spheroidal pack



Tetrarhombic pack

Porosity of Sphere Packings

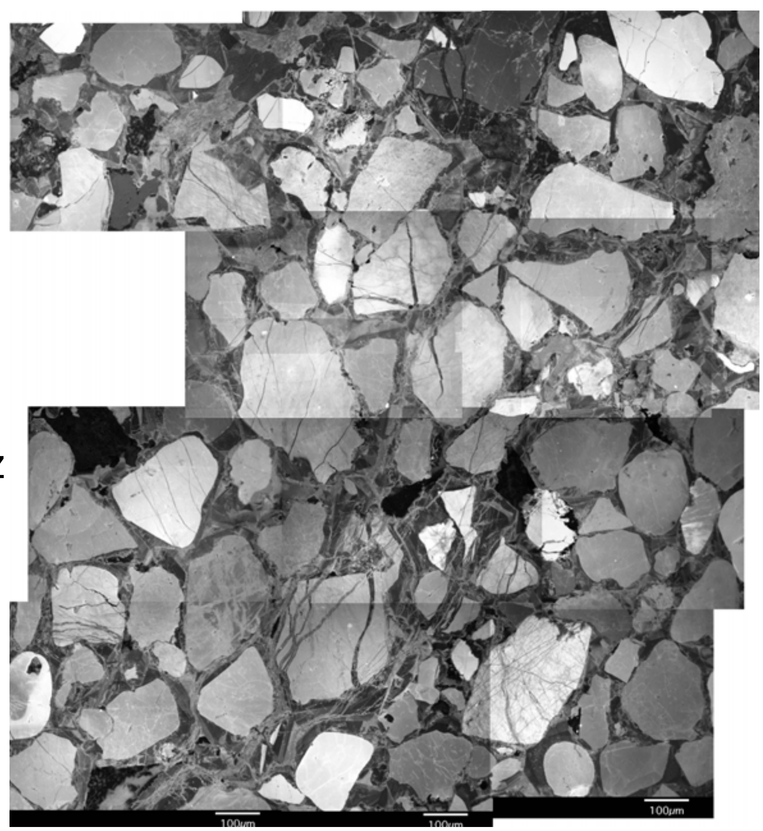
lattice	porosity	contacts
cubic	0.48	6
simple hexagonal	0.40	8
compact hexagonal, rhombohedral	0.26	12

Note:

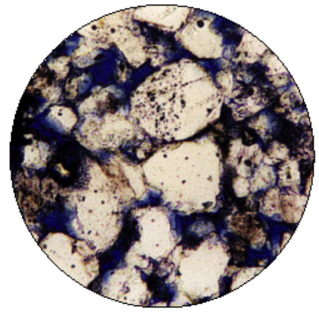
- only discrete porosity values
- porosity range between 0.26 (min) and 0.48 (max)
- porosity independent of sphere diameter

EXAMPLE

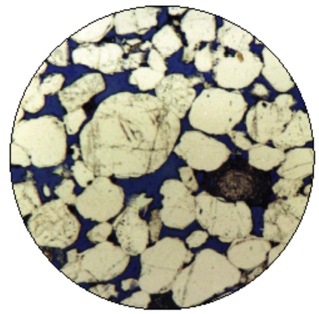
Large quartz grains showing quartz-filled fractures and porosity filling quartz (SEM-CL image).



PORE-SIZE DISTRIBUTIONS: SURFACE-TO-VOLUME RATIOS, PORE CONNECTIVITY, AND PERMEABILITY



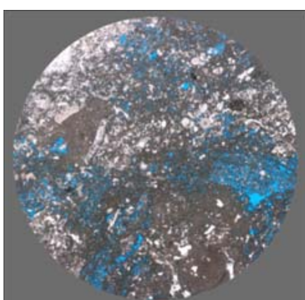
Porosity = 20%
Permeability = 7.5 md

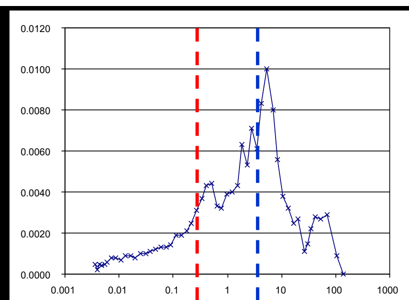


Porosity = 19.5%
Permeability = 279 md

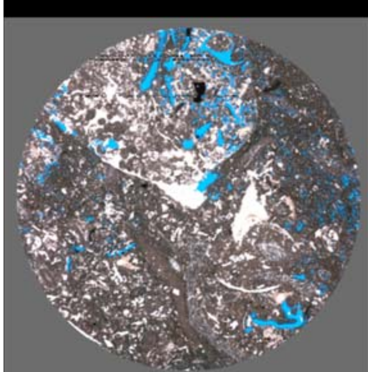
High Permeability Grainstone

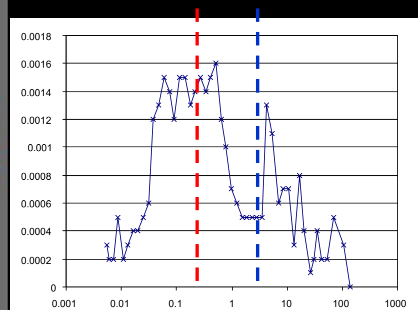
Low Permeability Wackestone





Sample 1 30 p.u. 97 md.

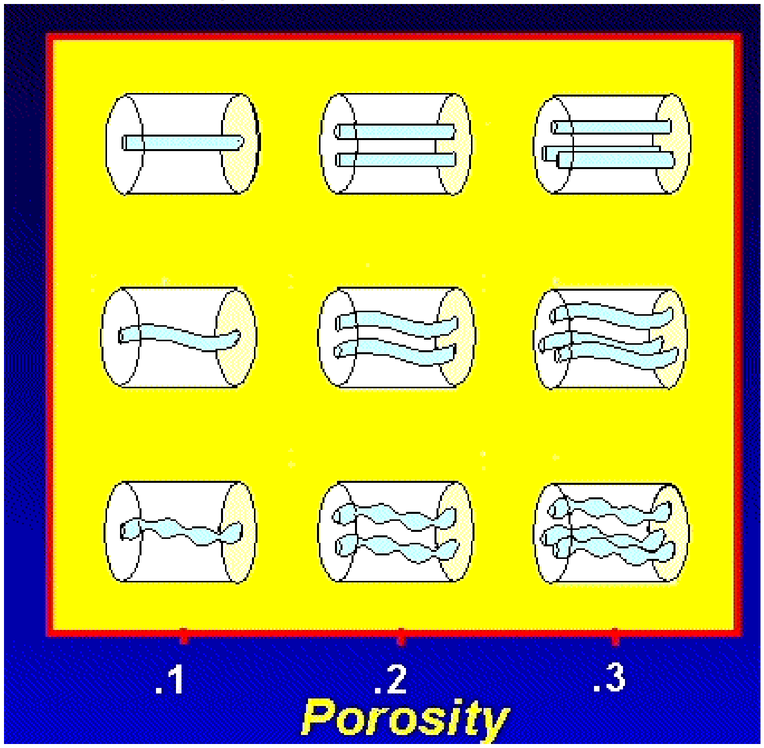




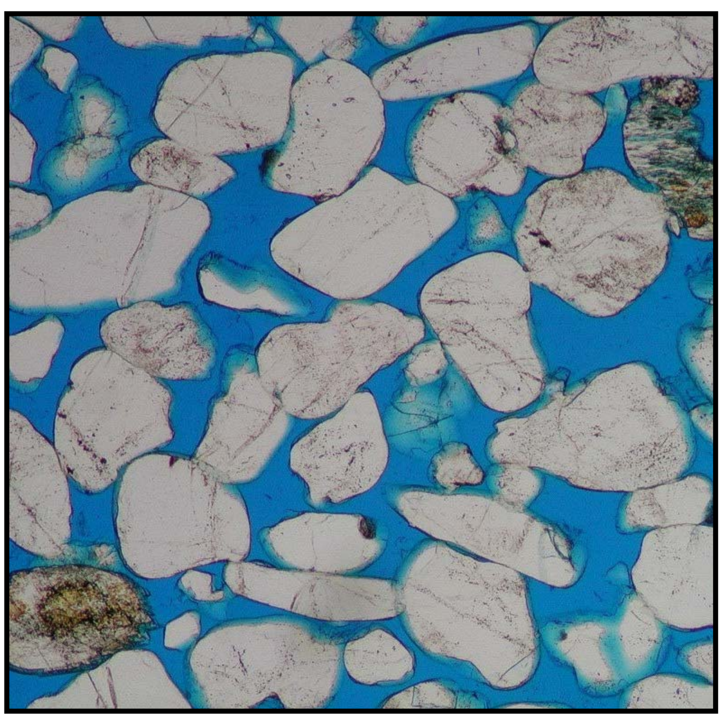
Sample 2 18 p.u. 2 md.

PORE-SIZE DISTRIBUTIONS: Surface-to-Volume Ratios, Pore Connectivity, and Permeability

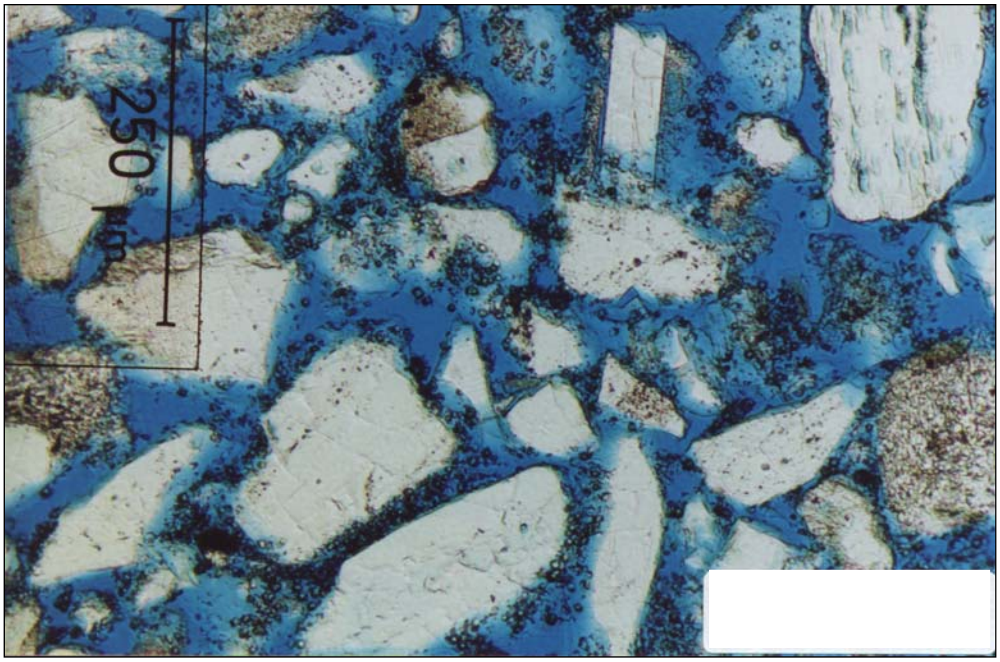
Porosity, Pore Connectivity, Tortuosity, and Permeability



Relationship between Grain Size, Grain Shape, Grain Packing, Pore Size, Throat Size, and Tortuosity: Influence on Permeability and Capillary Pressure



Relationship between Grain Size, Grain Shape, Grain Packing, Pore Size, Throat Size, and Tortuosity: Influence on Permeability and Capillary Pressure

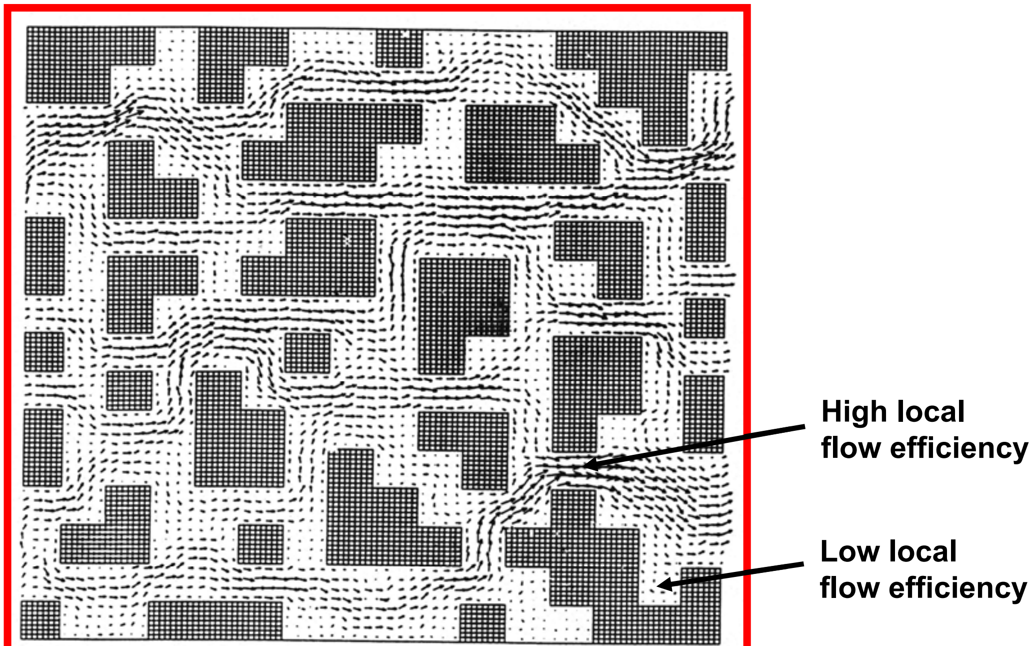


Analogy:
Permeability and Network Connectivity

Analogy: Permeability and Network Connectivity

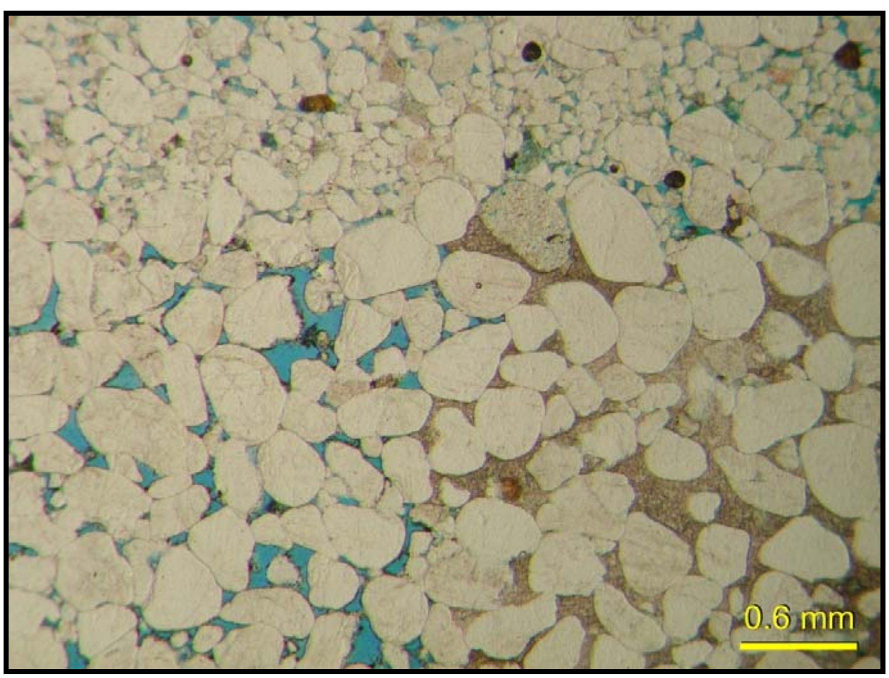
Analogy: Permeability and Network Connectivity

Illustration of Local Flow Efficiency

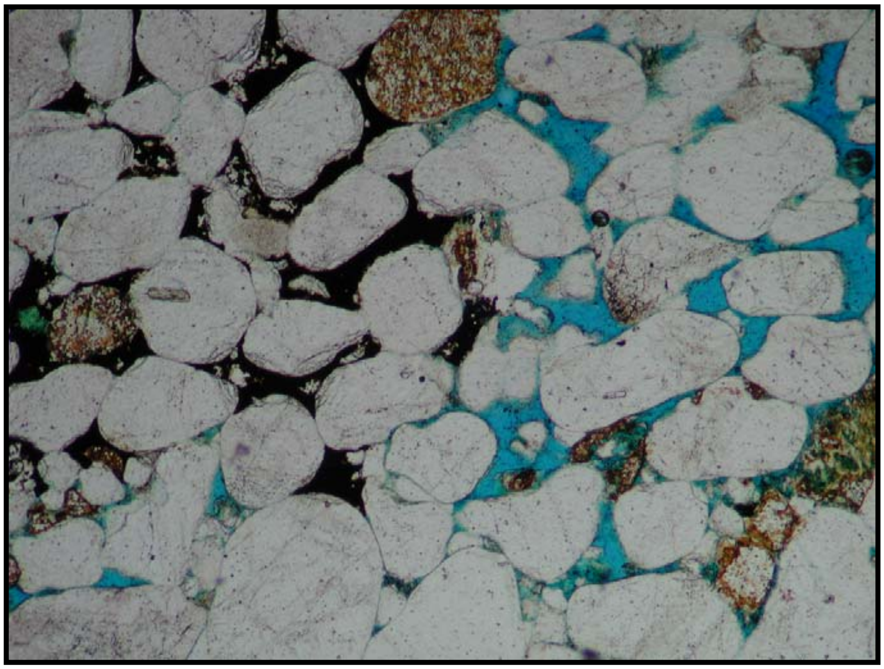


"....The majority of the flow follows just a few winding paths, while many areas are relatively stagnant...." (Rothman, 1988)

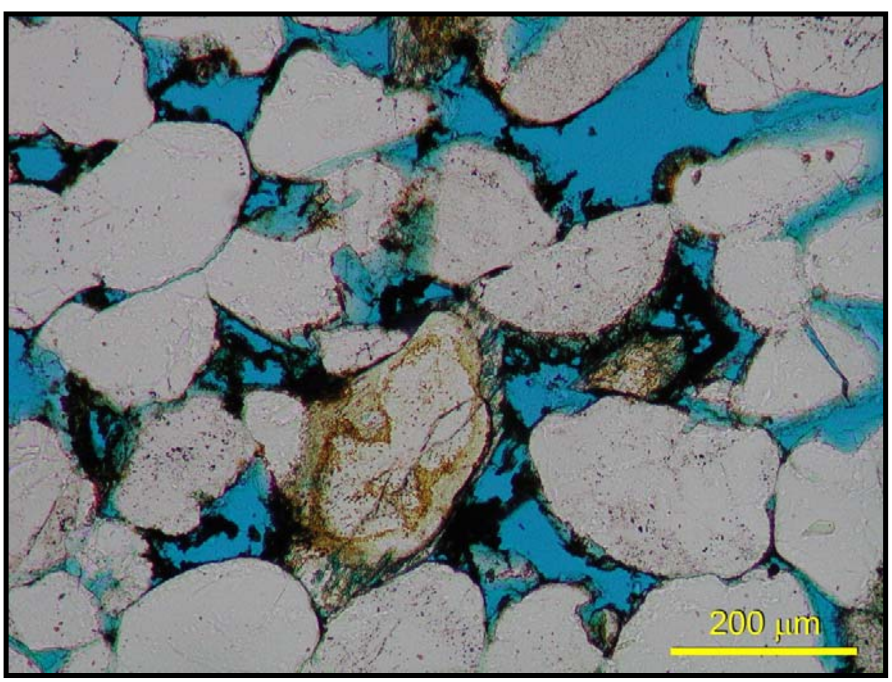
Relationship between Grain Size Distribution, Pore Size Distribution, Throat Size Distribution, and Tortuosity: Influence of Permeability and Capillary Pressure



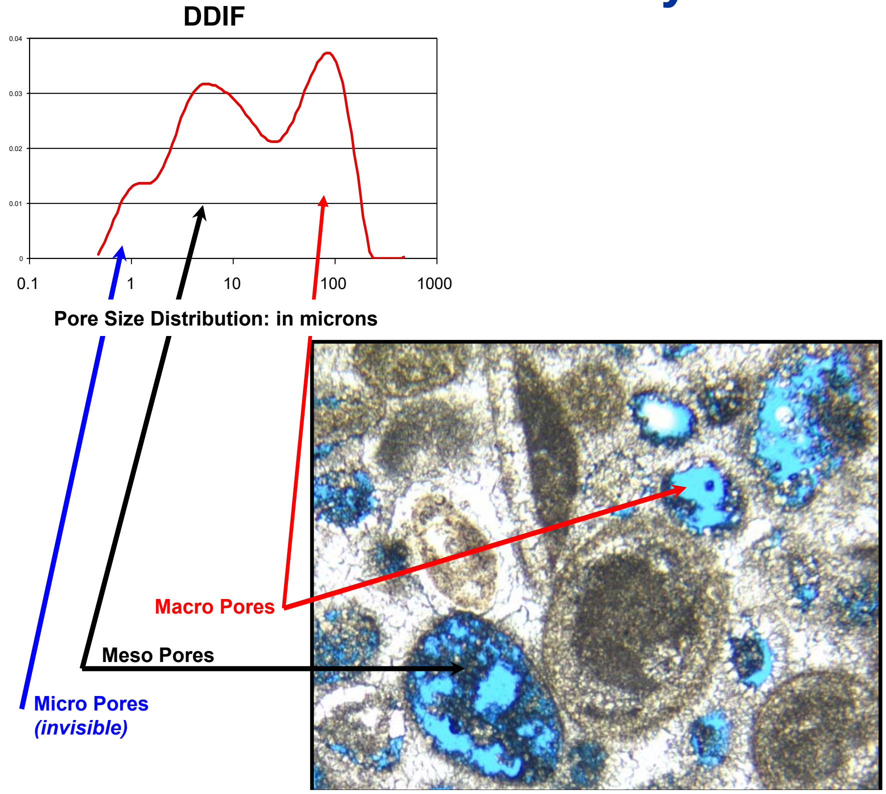
Relationship between Wettability, Throat Size Distribution, Fluid Distribution, and Tortuosity on Permeability, Relative Permeability, and Capillary Pressure



Relationship between Wettability, Throat Size Distribution, Fluid Distribution, and Tortuosity on Permeability, Relative Permeability, and Capillary Pressure

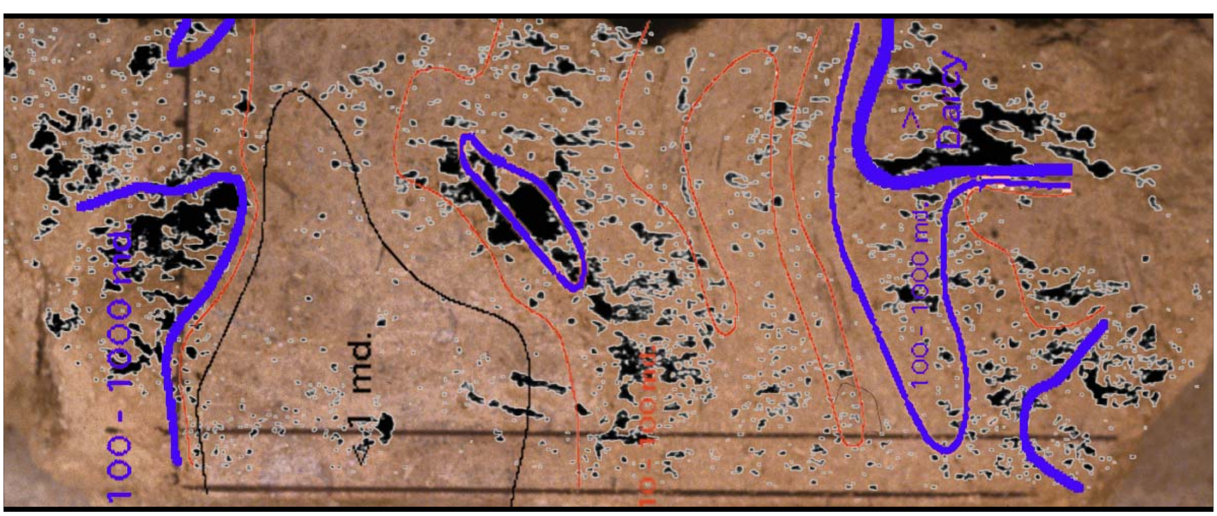


Pore Size Distribution and Pore Connectivity in Carbonates



Pore Size Distribution and Pore Connectivity in Carbonates

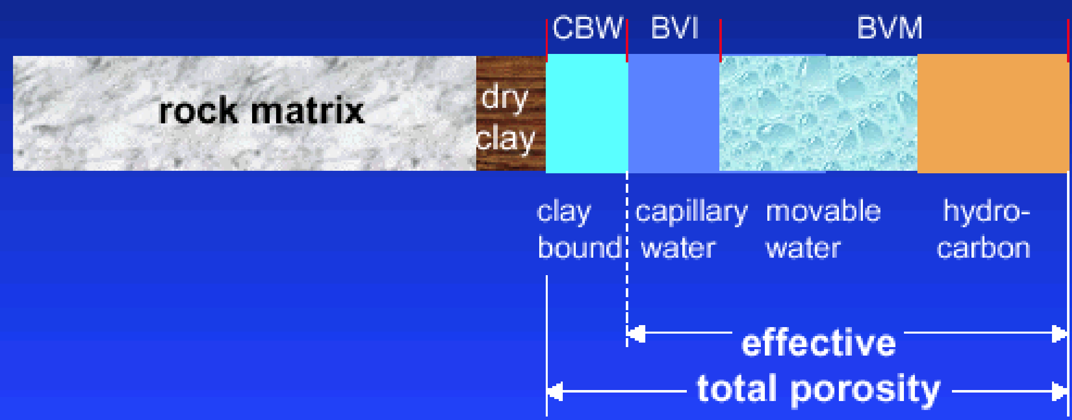
Combined Analysis of Dissolution Network



Fluids in the Pore Space

$$\text{saturation}_i = \frac{\text{volume fluid i}}{\text{pore volume}}$$

volumetric model



Fluids in the Pore Space

$$\text{saturation}_i = \frac{\text{volume fluid i}}{\text{pore volume}}$$

Bulk Volume Water **BVW**

- fraction of pore volume occupied by water

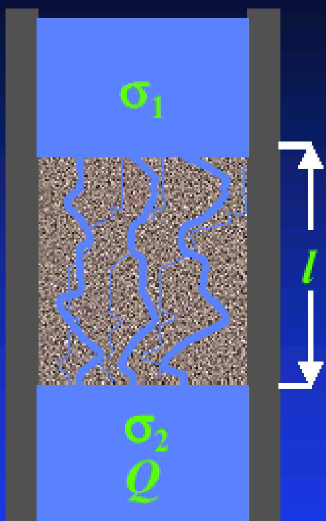
Bulk Volume Irreducible **BVI**

- fraction of pore volume occupied by immobile capillary-bound water

Clay Bound Water **CBW**

- water bound to negatively charged clay mineral surface

Permeability



Henry Darcy, 1856 - Laminar Flow

$$u = \frac{Q}{A \cdot t} = \frac{k}{\eta} \cdot \frac{\sigma_1 - \sigma_2}{l} = \frac{k}{\eta} \cdot \frac{\Delta\sigma}{l} = \frac{k}{\eta} \cdot grad\ \sigma$$

$$k = \eta \cdot \frac{u}{grad\ \sigma}$$

- k permeability
- u volume flow density
- V fluid volume
- t time
- A cross section
- η dynamic viscosity

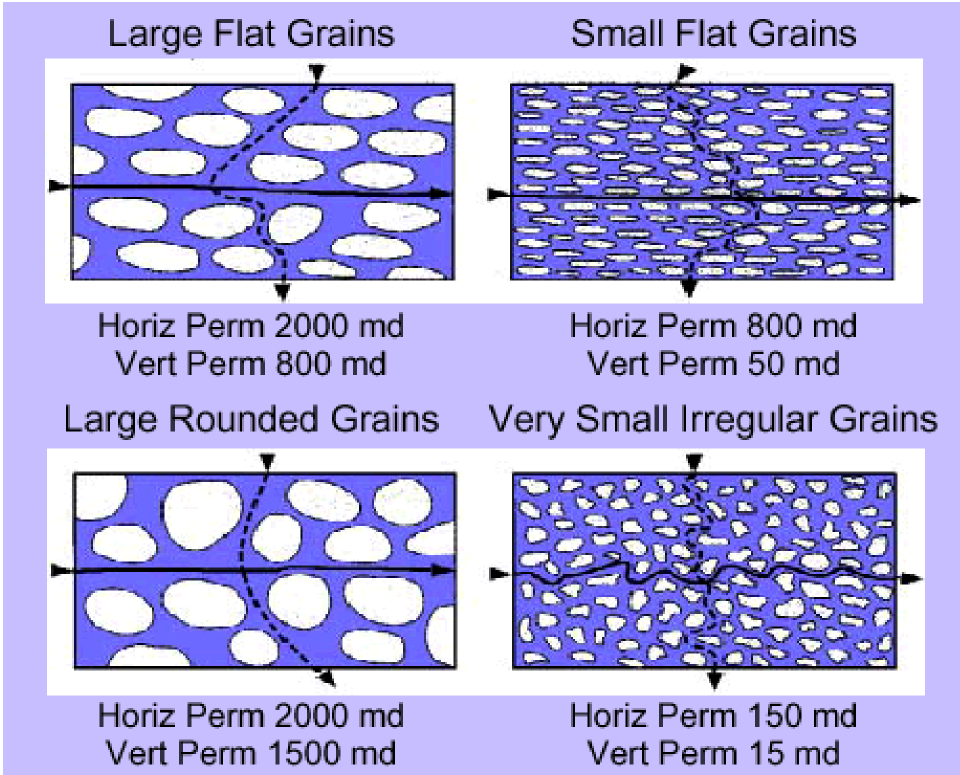
Units :

1 Darcy = 0.98 10^{-12} m^2 ≈ 1 μm^2

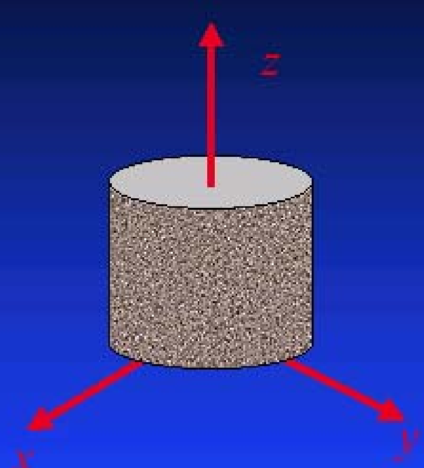
Methods Used for Measuring Permeability

- Well and drillstem tests
- Wireline formation testers
- Conventional cores
  - whole core
  - core plugs
  - probe permeameters
- Well and drillstem tests
- Sidewall cores
- Wireline logs
  - NMR
  - Stoneley waves

Effect of Grain Size and Shape on Permeability



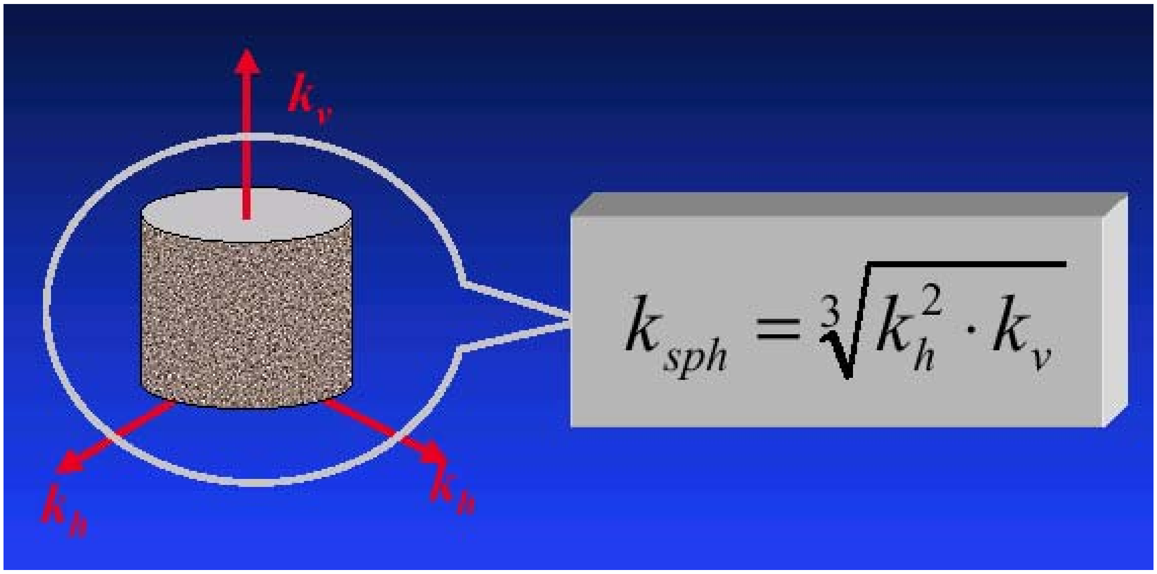
Permeability Tensor



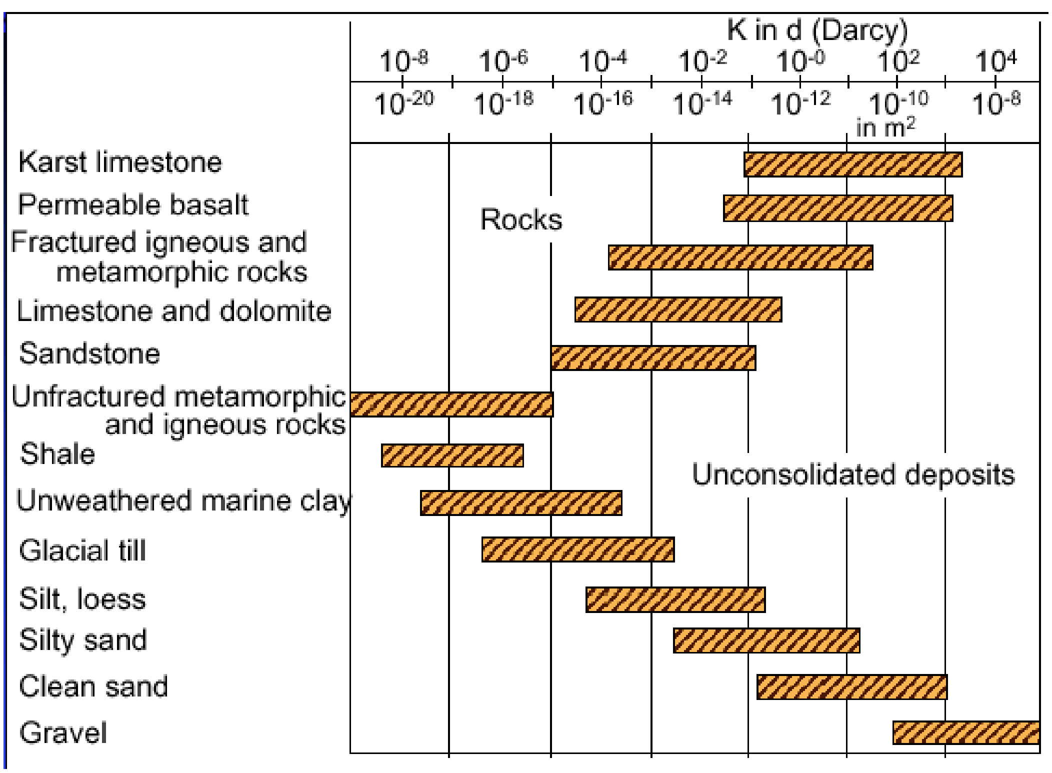
for a transversely isotropic rock (z-axis = axis of symmetry):

$$\mathbf{k} = \begin{pmatrix} k_h & 0 & 0 \\ 0 & k_h & 0 \\ 0 & 0 & k_v \end{pmatrix}$$

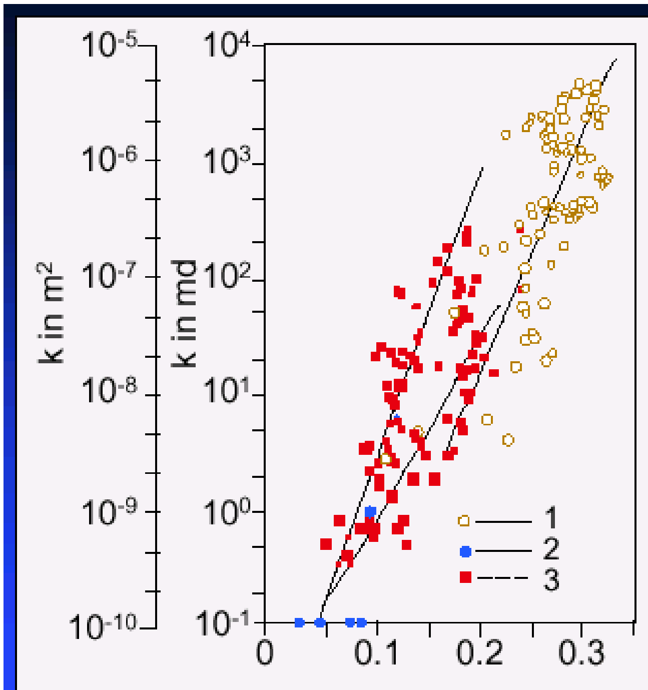
Spherical Permeability



Permeability Trends



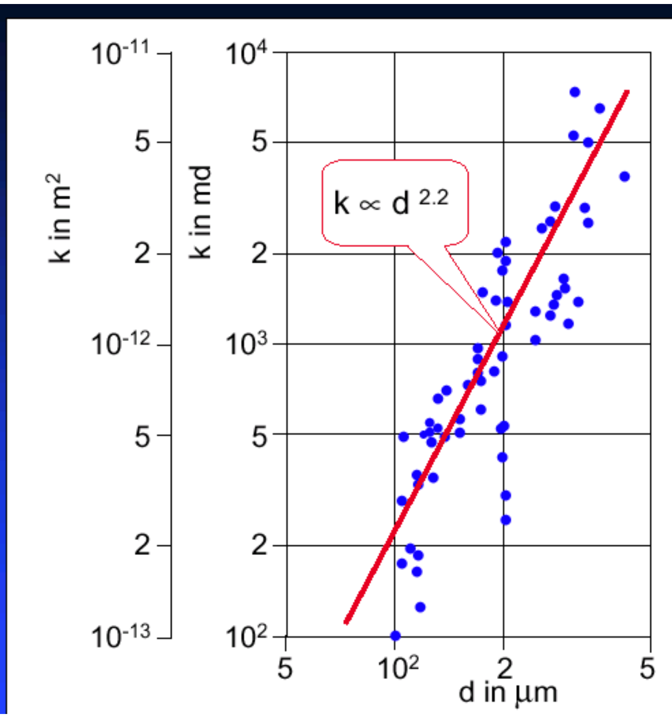
Permeability vs. Porosity



Core samples from three sandstone reservoirs,

from Timur 1968;
1. Gulf Coast Field
2. Colorado Field
3. California Field

Permeability vs Grain Size



Permeability κ vs. grain size d

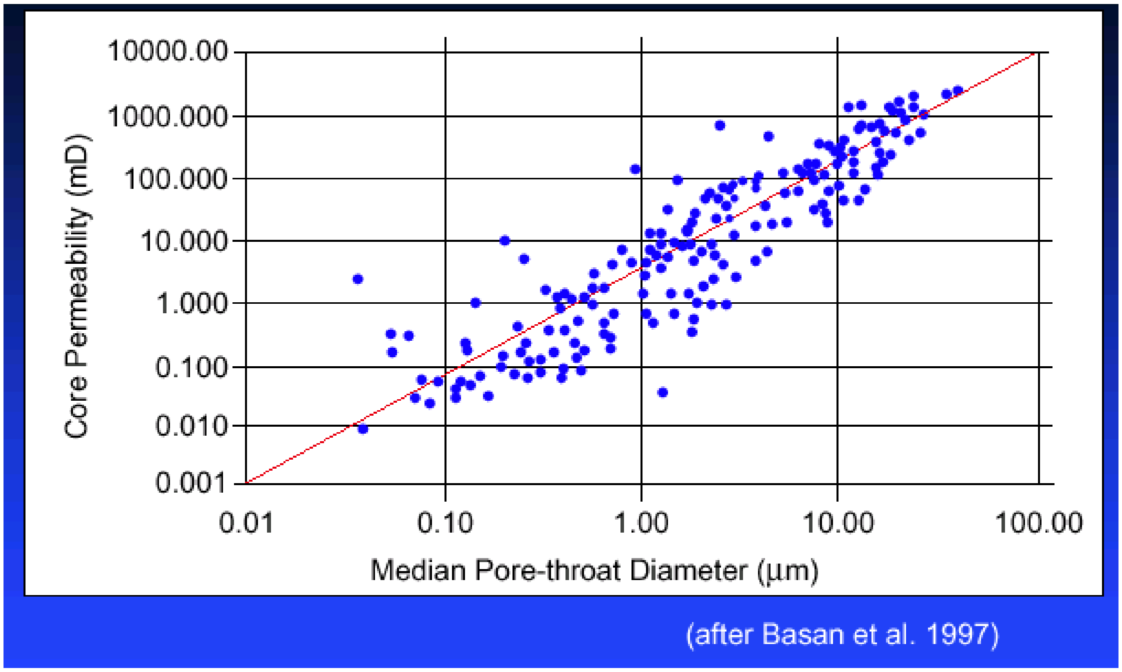
(Bentheim Sandstone, Scherhorn oilfield, Germany);

from Engelhardt 1960, Schopper 1982

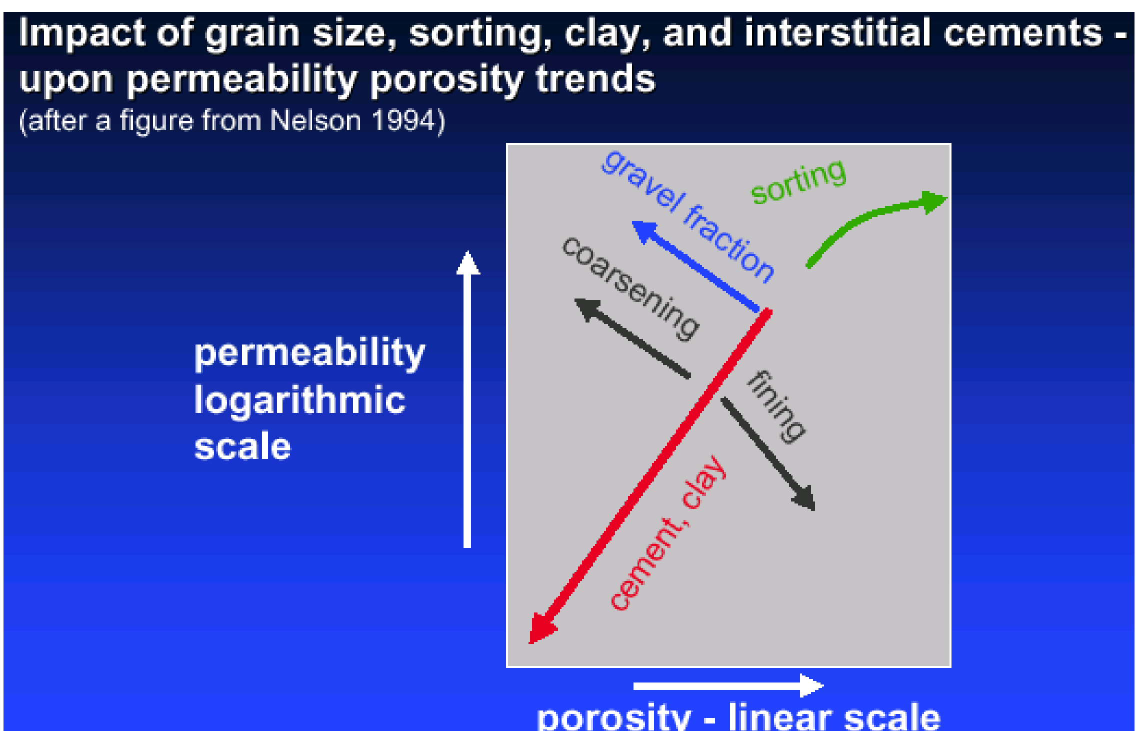
$\log k = 2.2 \log d - 2.101$

k in md d in µm

Permeability vs. Pore Size



Summary

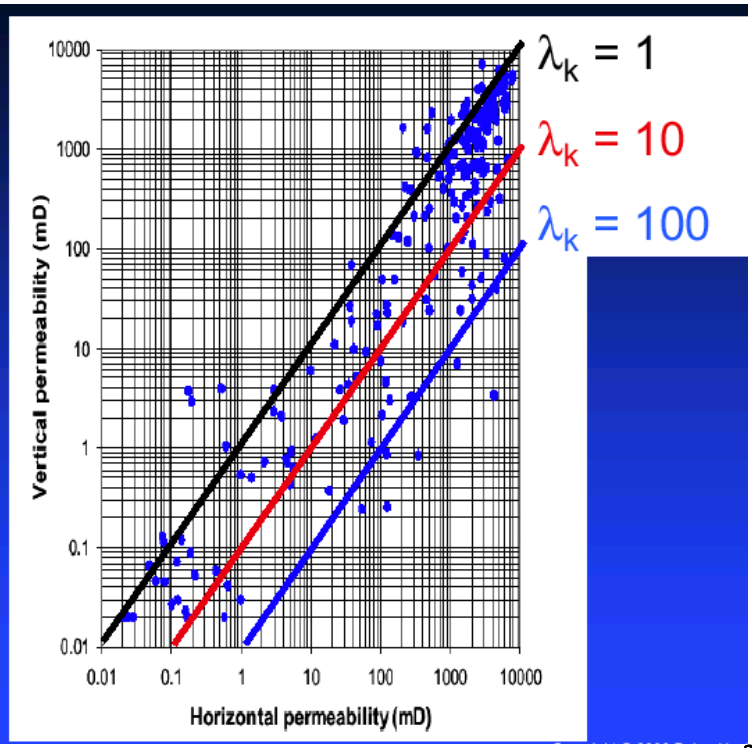


Permeability Anisotropy

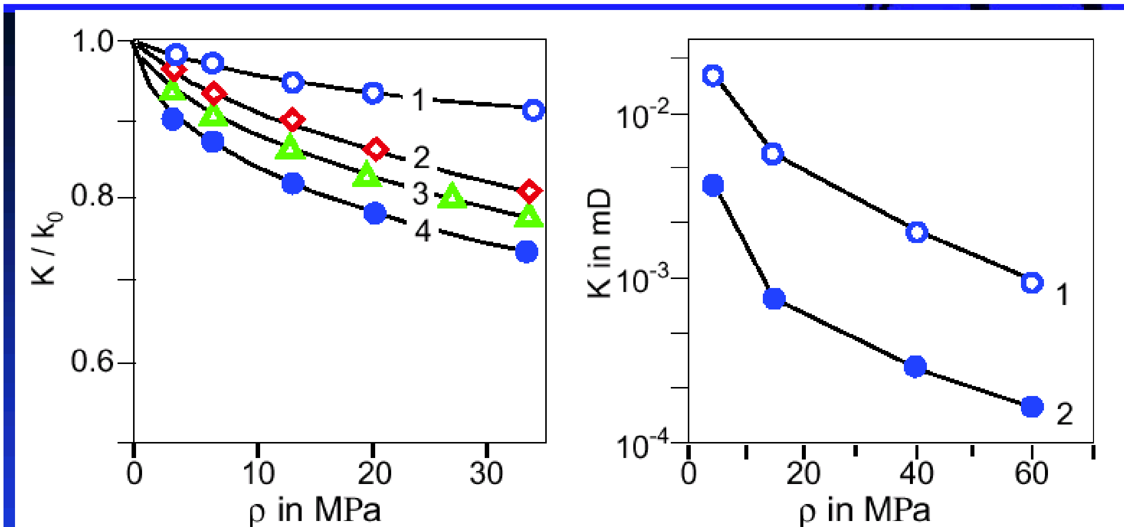
North Sea sediments, after Bang et al., 2000

$k_h > k_v$

$$\lambda_k = \frac{k_h}{k_v}$$



Pressure Dependence on Permeability



left - permeability κ (normalized with the value at pressure $P = 0$) as a function of the overburden pressure P; sandstone samples (Fatt 1953)

1: $\Phi = 15\%$ initial permeability 249 md; 2: $\Phi = 24\%$ initial permeability 163 md;
3: $\Phi = 25\%$ initial permeability 335 md; 4: $\Phi = 22\%$ initial permeability 110 md.

right - permeability k as a function of confining pressure, measured on a gneiss sample in two directions (after Nover et al.1989); 1 - axial, i.e. nearly parallel to the plane of foliation 2 - radial, inclined at an angle of 40°.

Absolute and Relative Permeability

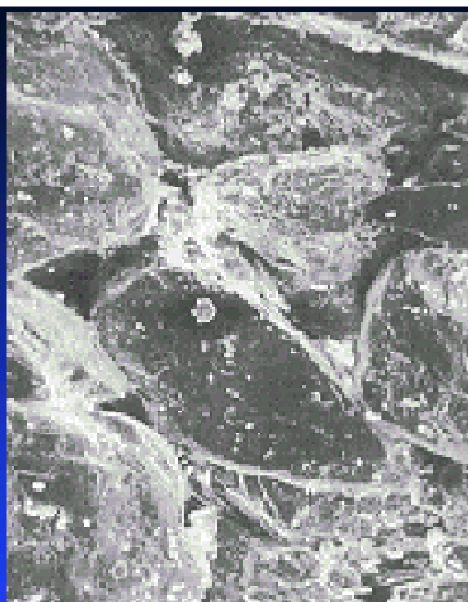
Permeability in Darcy's law is defined for a single fluid - this is the *absolute permeabilty*.

The reservoir can contain two or even three fluids (water, oil, gas) -- the flow of the individual fluids interfere and the *effective permeabilities* are less than the absolute permeability.

Thus, effective permeability describes the flow of a fluid through a rock in the presence of other pore fluids. It depends on the saturations.

Relative permeability is the ratio of effective permeability and absolute permeability; it varies between 0 and 1.

Specific Internal Surface



$$S_{total} = \frac{\text{Surface area of the pores}}{\text{Total volume}}$$

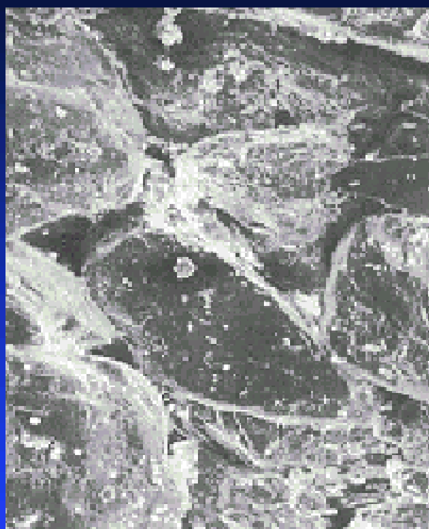
$$S_{por} = \frac{\text{Surface area of the pores}}{\text{Pore volume}}$$

$$S_{total} = S_{por} \cdot \phi$$

unit $m^2/m^3 = m^{-1}$ usually μm^{-1}

(related to mass --> m^2/g)

Specific Internal Surface



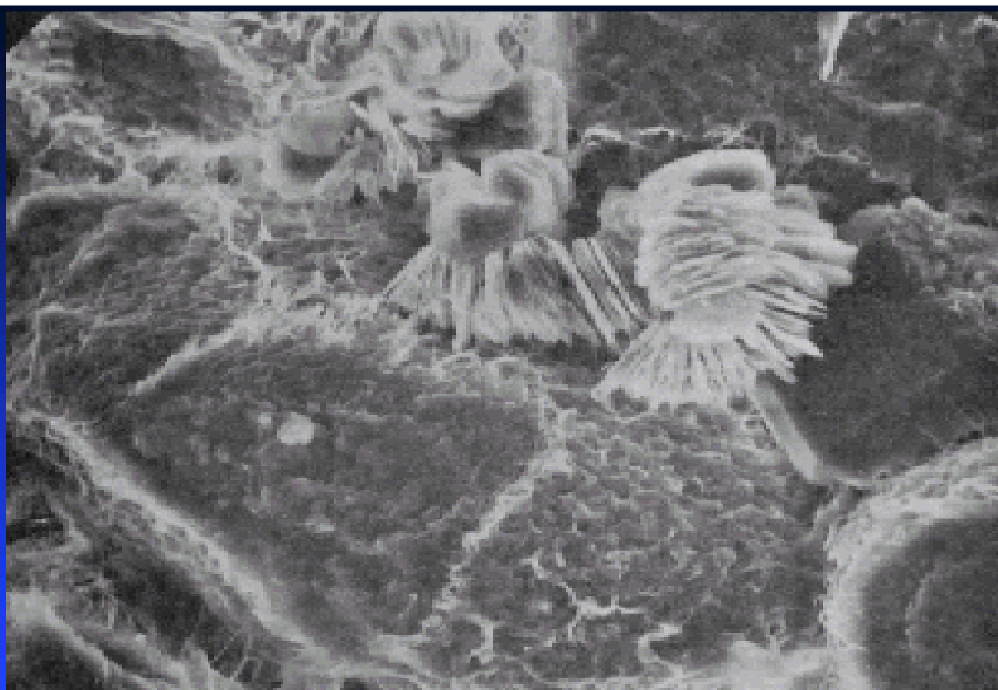
Depends on:

- size and shape of the pores
- microstructure and morphology of the interface matrix-pore

Related to such properties as:

- cation exchange capacity
- NMR signal T_2

Pore-Filling Kaolinite



Classical Kaolinite "booklets"

from Neasham 1977, SPE 6858

Surface Area of Common Rock Types

Material		[m2/g]
Pure Quartz Crystals		0.15•10-4
Quartz Spheres	60 μm	0.025
	30 μm	0.05
	2 μm	0.75
	1 μm	1.5
Crushed Quartz		3.1
Kaolinite		10- 40
Illite		30 - 70
Smectite		550 - 750
Limestone (Trenton & Caddo Form)		0.1 - 0.35
Gulf Coast Shaly Sands (Vc ~ 15 - 30%)		100 - 450

Source of Data

Zemanek, 1989

Carman, 1956

Brooks and Purcell, 1952

Almon and Davies, 1978

Surface-to-Volume Ratio

$$\frac{1}{T_2} \approx \rho \frac{S}{V} \propto \rho \frac{1}{length}$$

T_2 is proportional to pore size

Sphere

$$\frac{S}{V} = \frac{4\pi r^2}{\frac{4}{3}\pi r^3} = \frac{3}{r}$$

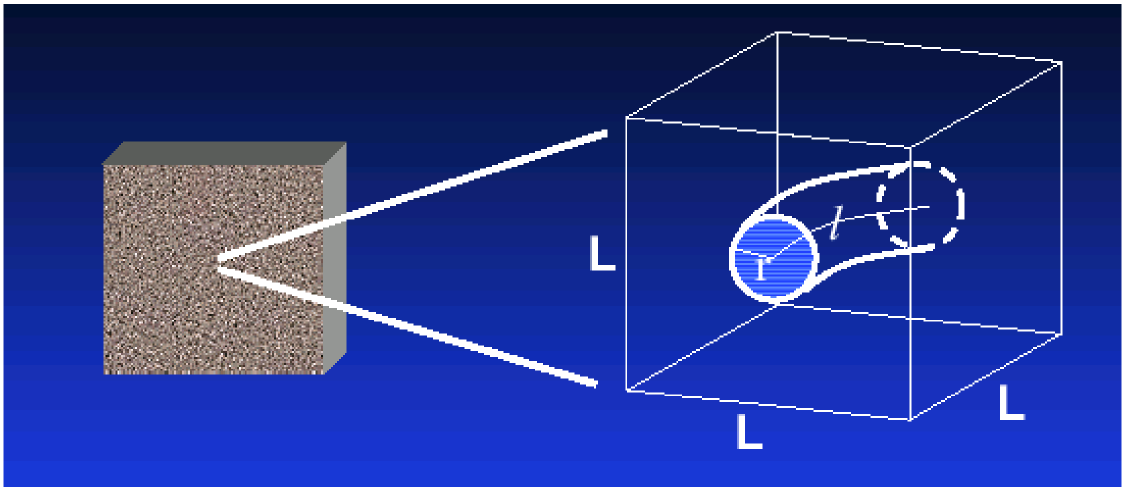
Cylinder

$$\frac{S}{V} = \frac{2\pi rh}{\pi r^2 h} = \frac{2}{r}$$

Fracture

$$\frac{S}{V} = \frac{2\,Ah}{Ah\,\delta} = \frac{2}{\delta}$$

Relationship Between Porosity, Specific Surface, and Tortuosity



$$\phi = \frac{\pi \cdot r^2 \cdot l}{L^3}$$

porosity

$$S_{por} = \frac{2 \cdot \pi \cdot r \cdot l}{\pi \cdot r^2 \cdot l} = \frac{2}{r}$$

specific surface

$$T = \frac{l}{L}$$

tortuosity

Relationship Between Porosity, Permeability, and Specific Surface-Based Models

Hagen-Poiseulle's law: flow rate for a tube

microscopic view

$$\frac{dV}{dt} = \pi \cdot \frac{r^4}{8 \cdot \eta} \cdot \frac{\Delta p}{l} = \pi \cdot \frac{r^4}{8 \cdot \eta} \cdot \frac{grad\, p}{T}$$

Darcy's law: flow density for a permeable material

macroscopic view

$$u = \frac{dV}{L^2 \cdot dt} = \frac{k}{\eta} \cdot grad \quad p$$

combination results in a relationship for permeability

$$k = \frac{1}{8} \cdot \frac{\phi}{T^2} \cdot r^2 = \frac{\phi}{2 \cdot T^2} \cdot \frac{1}{S_{por}^2} = \frac{\phi^3}{2 \cdot T^2} \cdot \frac{1}{S_{total}^2}$$

Model-Derived Equation Exhibits Similarity with Empirical Equations

For example, (Timur 1968; Coates & Dumanoir 1974) in this empirical type pore properties expressed in irreducible water saturation terms.

$$k = \left[100 \cdot \frac{\phi^{2.25}}{S_{w,irr}} \right]^2$$

Coates & Dumanoir - equation is one basis for permeability determination from NMR measurements.

$$k = \left[\frac{\phi}{C} \right]^4 \cdot \left[\frac{MBVM}{MBVI} \right]^2$$

MBVM - bulk volume moveable fluids

MBVI - bulk volume irreducible fluids

GENERALIZED COATES EQUATION

$$k = \left[\frac{\phi}{C} \right]^4 \cdot \left[\frac{MBVM}{MBVI} \right]^2$$

MBVM - bulk volume moveable fluids

MBVI - bulk volume irreducible fluids

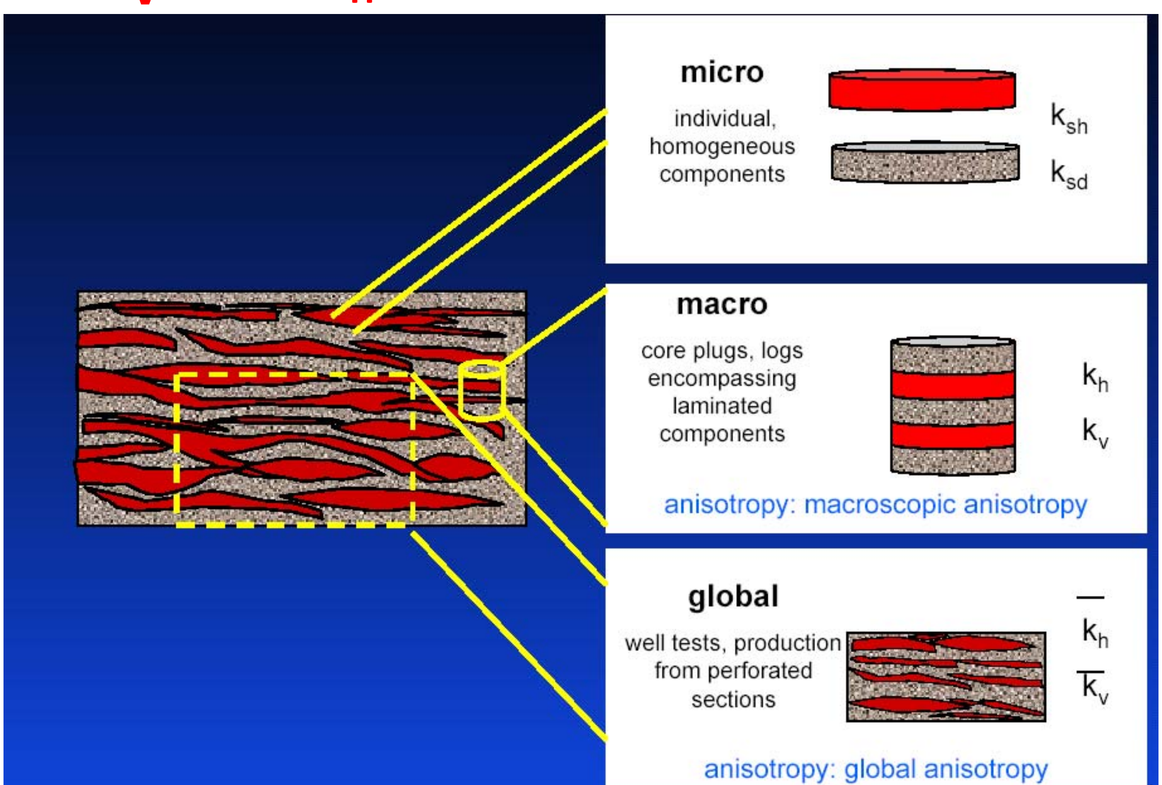
$$k = \left[\frac{\phi}{C} \right]^a \cdot \left[\frac{MBVM}{MBVI} \right]^b = \left[\frac{\phi}{C} \right]^a \cdot \left[\frac{\phi - MBVI}{MBVI} \right]^b$$

SUMMARY OF PERMEABILITY FORMULAS

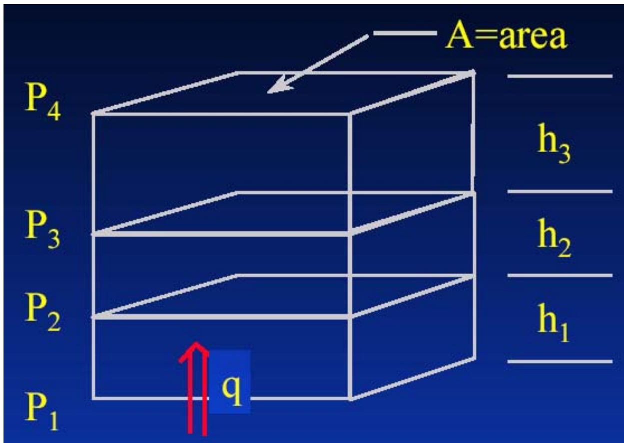
Authors (year)	Permeability Correlations	
Kozeny (1927) Carman (1938)	$k = \phi^3 / \left[5A_g^2\,(1-\phi)^2\right]$	A_g-grain area
Berg (1970)	$k = 0.0053\,\phi^3\,D_g^2$	D_g-grain diameter
Timur (1968)	$k = 0.136\,\dfrac{\phi^{4.4}}{S_{wir}^2}$	S_{wir}- irreducible water saturation
Coates (1974)	$\sqrt{k} = 100\,\phi_e^2\,\dfrac{(1-S_{wir})}{S_{wir}}$	
Coates (1981)	$S_{wir} = 1 - \left[(1-S_w)^{2.1}/k_{rh}\right]^{0.5}$	

(Yao and Holditch, 1993)

K_V and K_H: Dependence on Scale



PERMEABILITY: Beds in Series



$$q = \frac{kA}{\mu}\frac{dP}{dx}$$

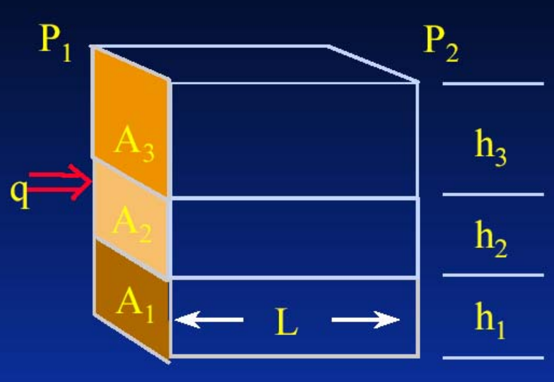
$$(P_4 - P_1) = (P_4 - P_3) + (P_3 - P_2) + (P_2 - P_1)$$

$$\frac{h_{total}}{k_{ave}} = \frac{h_1}{k_1} + \frac{h_2}{k_2} + \frac{h_3}{k_3};$$

$$\boxed{k_{ave} = \frac{\sum h_i}{\sum h_i / k_i}}$$

Harmonic

PERMEABILITY: Beds in Parallel



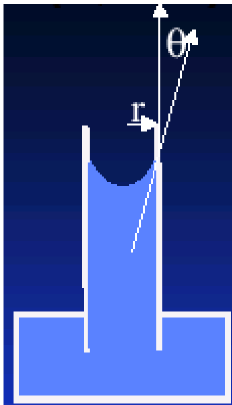
$$q = \frac{kA}{\mu}\frac{dP}{dx}$$

$$q_{total} = q_1 + q_2 + q_3; \qquad q_{total} = \frac{k_{ave} A_{total}}{\mu}\frac{P_2 - P_1}{L},$$

$$q_{total} = (k_1 A_1 + k_2 A_2 + k_3 A_3)\frac{P_2 - P_1}{L}; \qquad \boxed{k_{ave} = \frac{\sum k_i h_i}{\sum h_i}}.$$

Arithmetic

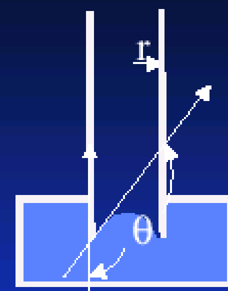
Fundamentals of Capillary Pressure



Water wet

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

$$S_w = f(P_c)$$



Oil wet

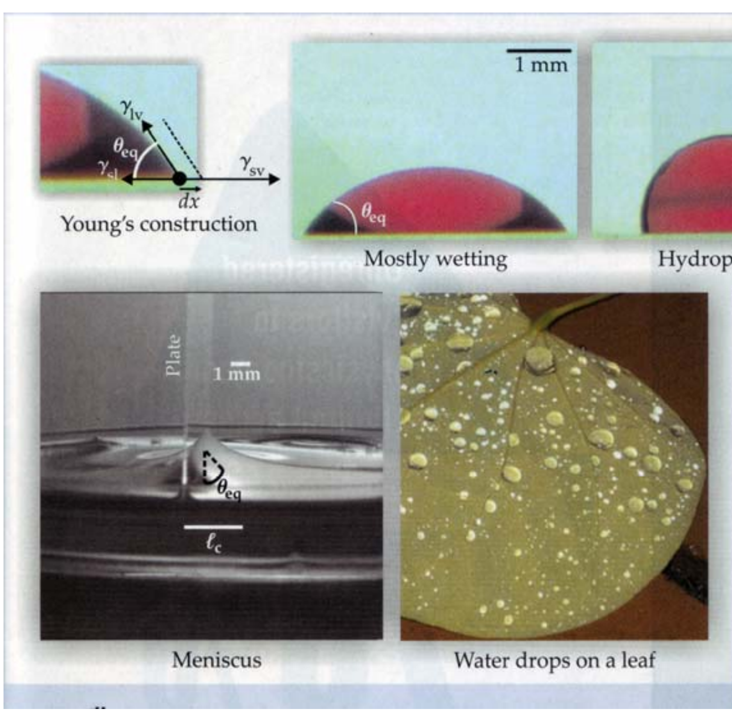
σ	θ	r_p
Fluid property Interfacial tension	Rock-fluid property Contact angle	Rock property Capillary radius

P_c controlled by rock-fluid system

IFT = molecular force to minimize the surface area

Wetting Phenomena

(Taken from Physics Today)



Wetting phenomena. The way a liquid makes contact with a surface is characterized by the equilibrium contact angle θ_{eq}. As described in the text, Young's construction considers a small displacement dx of the contact line (seen edge-on as a filled circle) and determines the angle. A water drop deposited on different substrates can exhibit various wetting behaviors: It mostly wets a hydrophilic glass plate, poorly wets a hydrophobic flat surface, and displays super-hydrophobicity when surface roughness is enhanced, as on some leaves. A meniscus is observed when a glass plate is dipped into water; the deformation vanishes over a length scale $\ell_c = \sqrt{\gamma/\rho g}$, determined by balancing surface and gravitational forces.

Capillarity and Throat Radius

In a pore tube - at liquid-solid interface, surface tension acts and water rises in the tube.

Capillary pressure (LAPLACE equation):

$$P_c = 2 \cdot \sigma \cdot \frac{\cos\Theta}{r}$$

σ - interfacial tension

Θ - meniscus contact angle

r - radius of the tube

In equilibrium, capillary pressure = water column weight

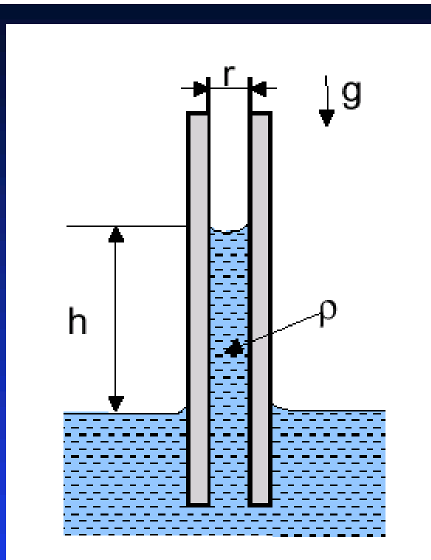
$$h \cdot g \cdot \rho$$

h - height of column

ρ - water density

g - gravity acceleration

Capillarity and Throat Radius



$$h = 2 \cdot \sigma \cdot \frac{\cos\Theta}{r \cdot \rho \cdot g}$$

σ - interfacial tension

Θ - meniscus contact angle

r - radius of the tube

ρ - density of water

g - gravity acceleration

The finer the capillary tube, the higher the water will rise.

Capillary Pressure Curves

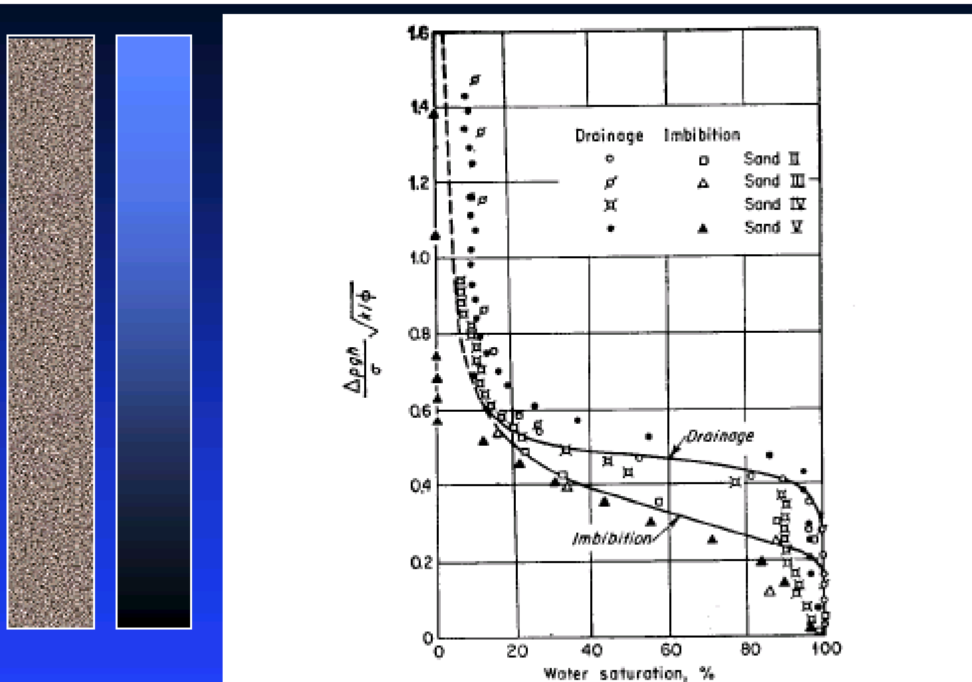
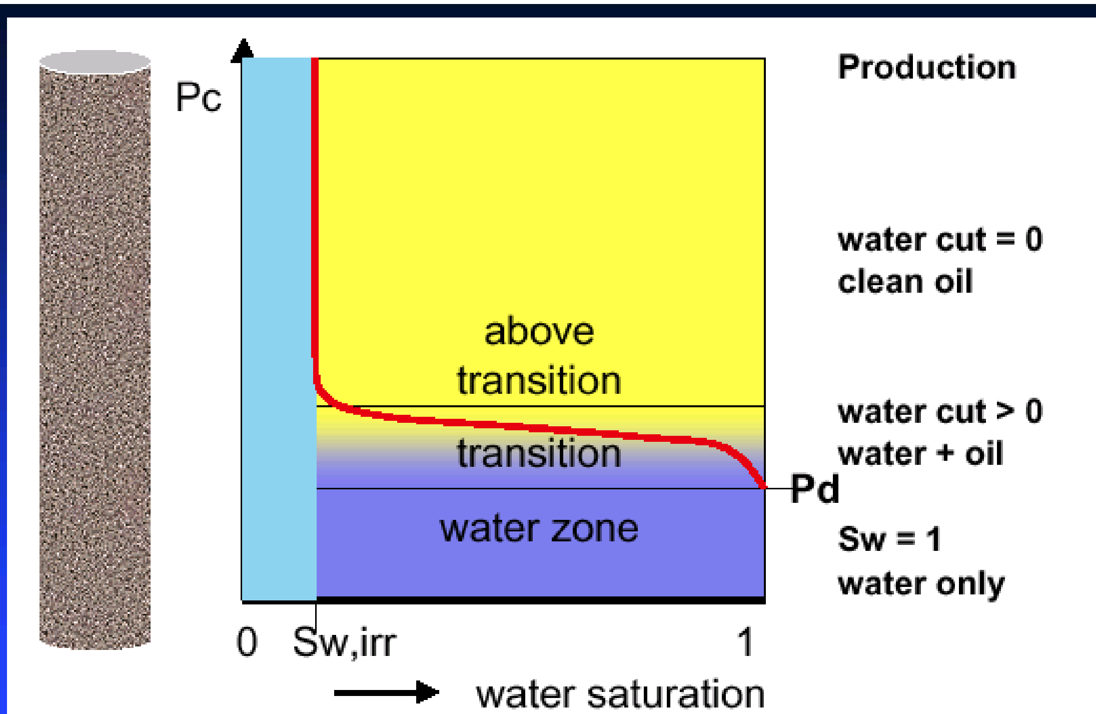


FIG. 3-10. Correlation of data from height-saturation experiments on clean unconsolidated sands. (*From Leverett.*[5])

Capillary Pressure Curves



Capillary Pressure: Summary

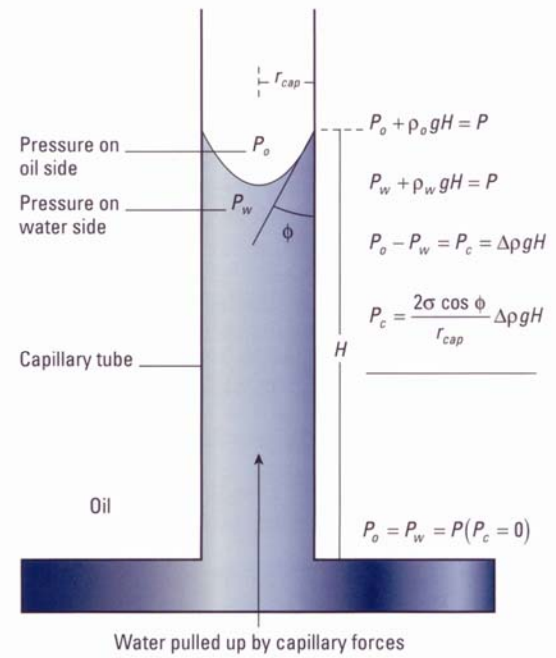


Figure 17. Capillary pressure in a reservoir filled with oil and water.

Taken from ***Fundamentals of Formation Testing***, Schlumberger

Capillary Pressure and Throat-Size Distribution

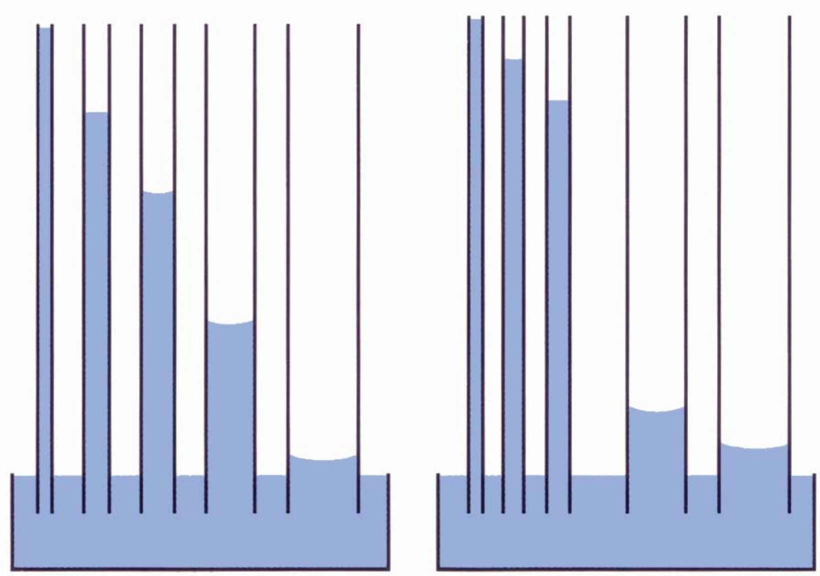


Figure 18. Capillary tubes analogy to reservoir pore throats.

Taken from ***Fundamentals of Formation Testing***, Schlumberger

Capillary Transition Zone

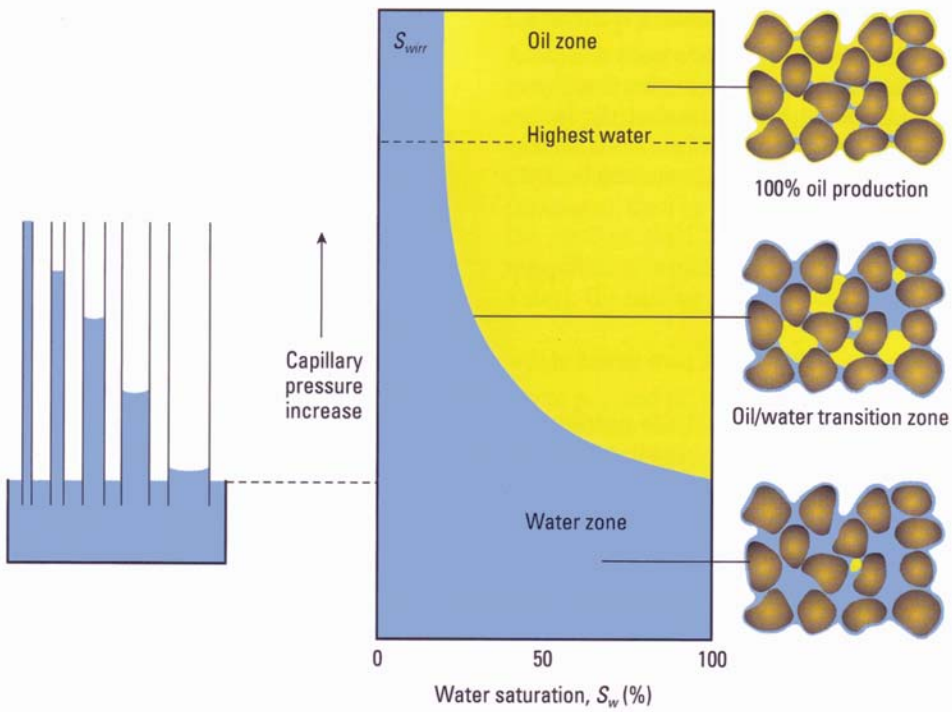


Figure 19. Saturation profile across a transition zone.

Taken from *Fundamentals of Formation Testing*, Schlumberger

Irreducible Water Saturation and Capillary Pressure

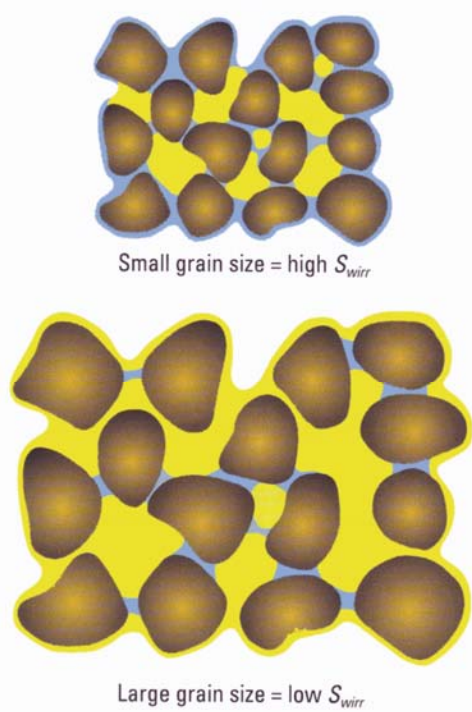
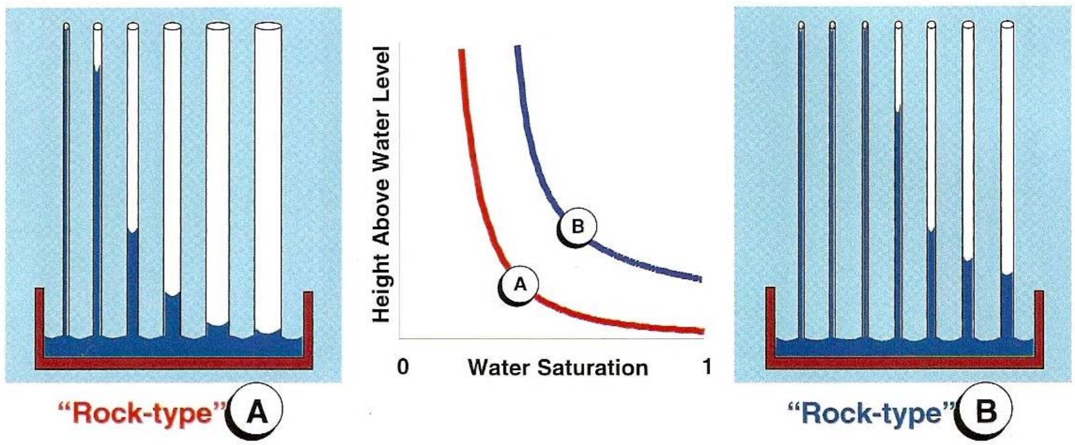


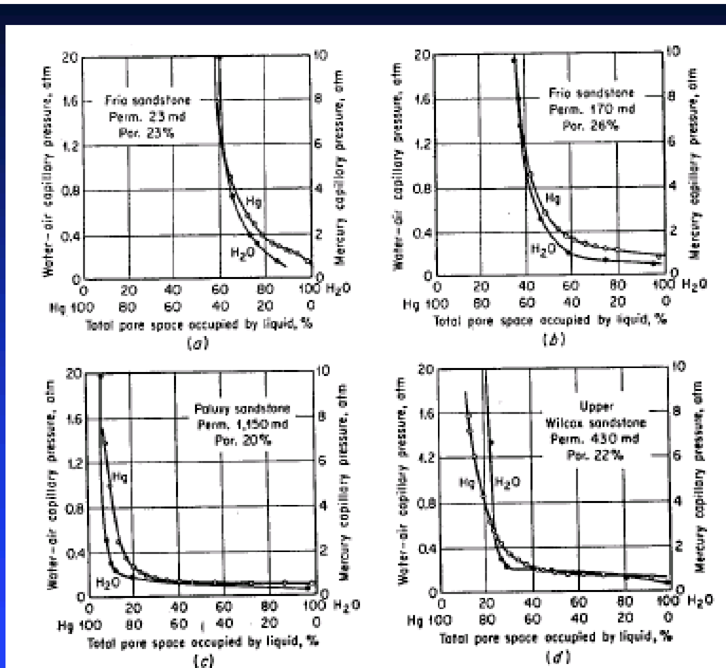
Figure 20. Effect of grain size on irreducible water saturation.

Taken from *Fundamentals of Formation Testing*, Schlumberger

Capillary Pressure Curves



Capillary Pressure Curves vs. Permeability



large pore diameter

- high permeability
- low cap. pressure

small pore diameter

- low permeability
- high cap. pressure

Directions of Saturation Change

Drainage — nonwetting saturation increases

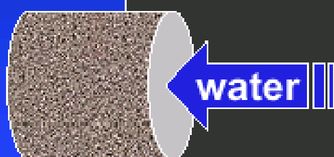
wetting saturation decreases

example: water wet sandstone, decrease of water saturation

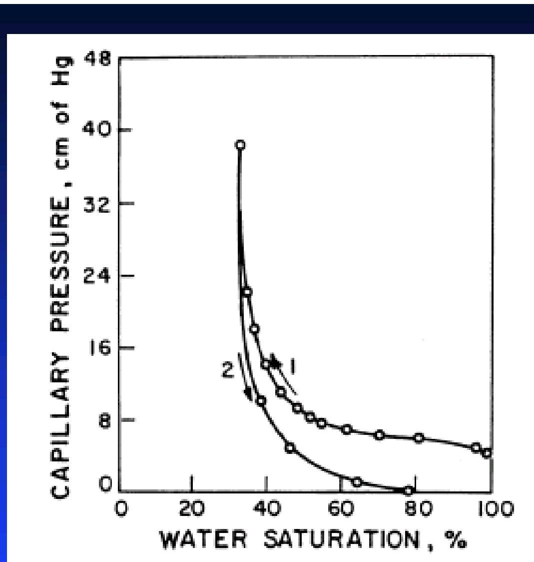
Imbibition — wetting saturation increases

nonwetting saturation decreases

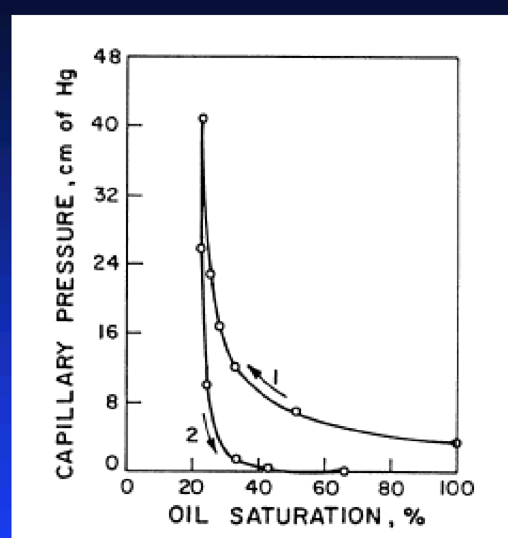
example: water wet sandstone, increase of water saturation



Capillary Pressure Curves: Water-Wet and Oil-Wet



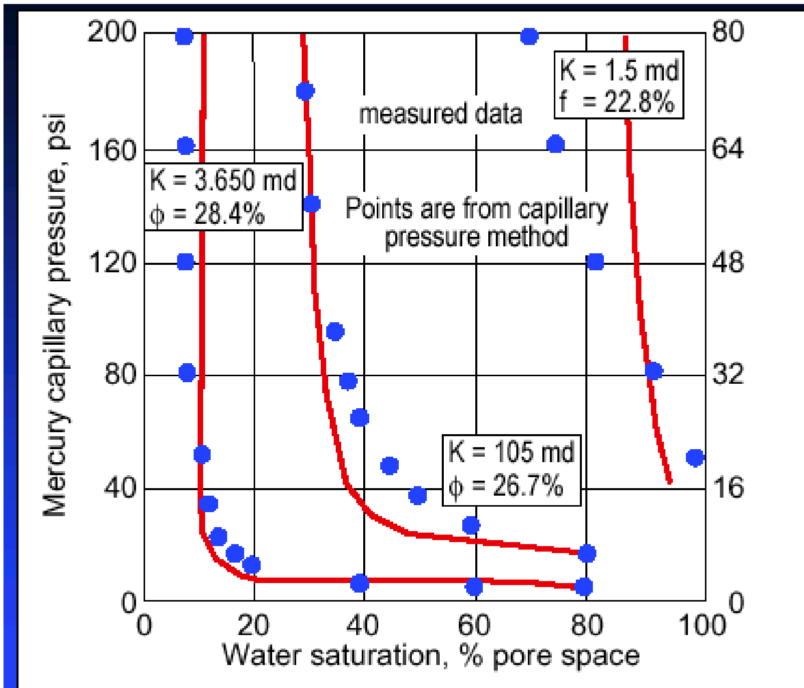
water-wet rock
(Vernango core)



oil-wet rock
(Tensleep sandstone)

after Killins et al. 1953, Dullien 1992

Capillary Pressure Curves

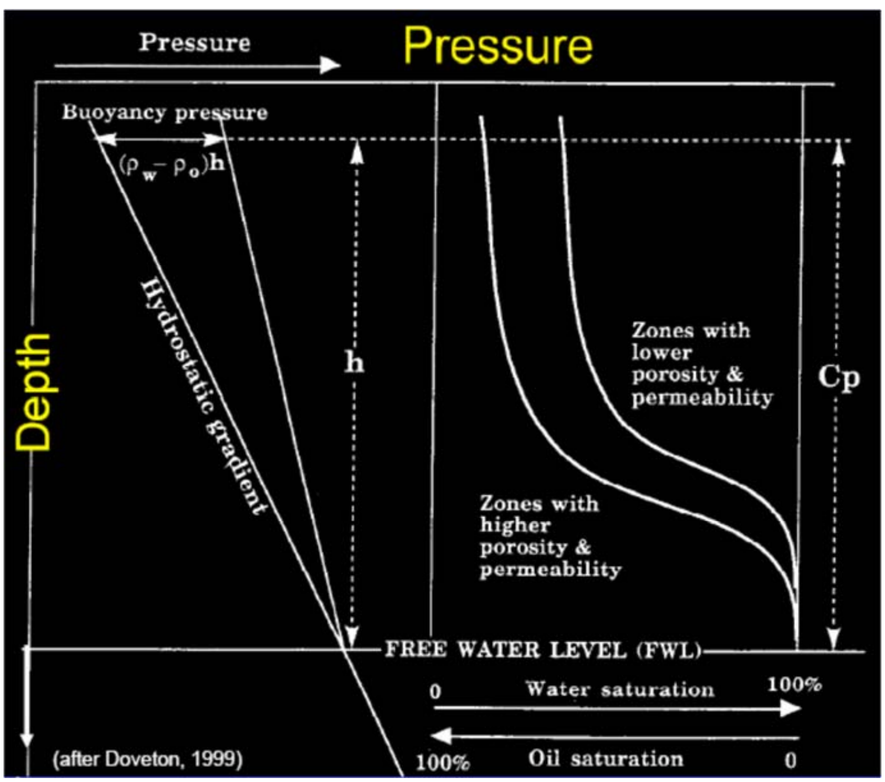


Capillary pressure curves

example for the influence of pore geometry (permeability)

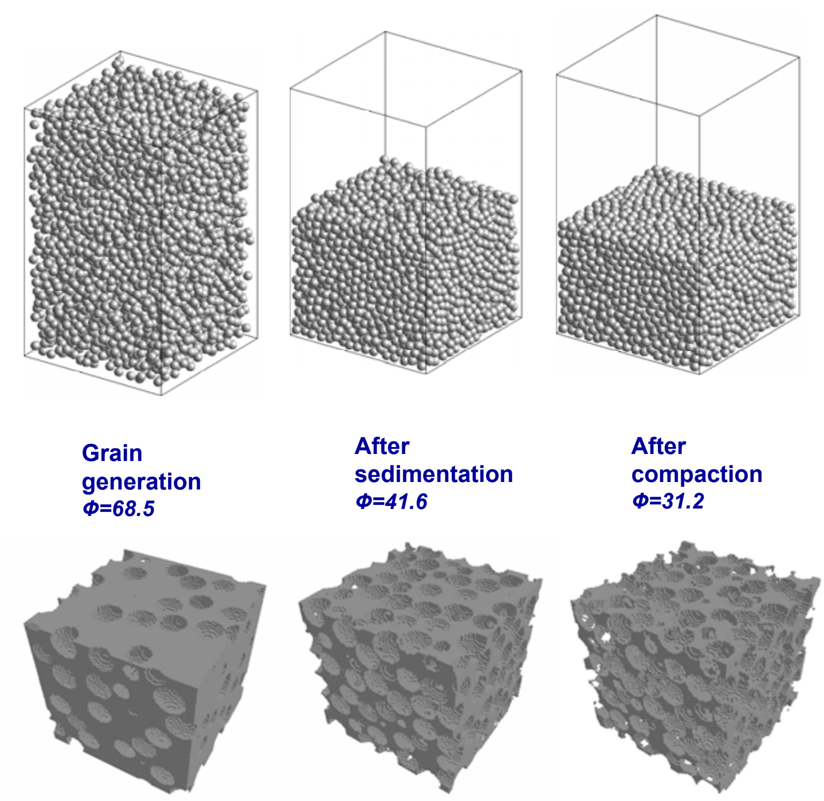
Hawkins et. al. 1993

Capillary Pressure and Vertical Location



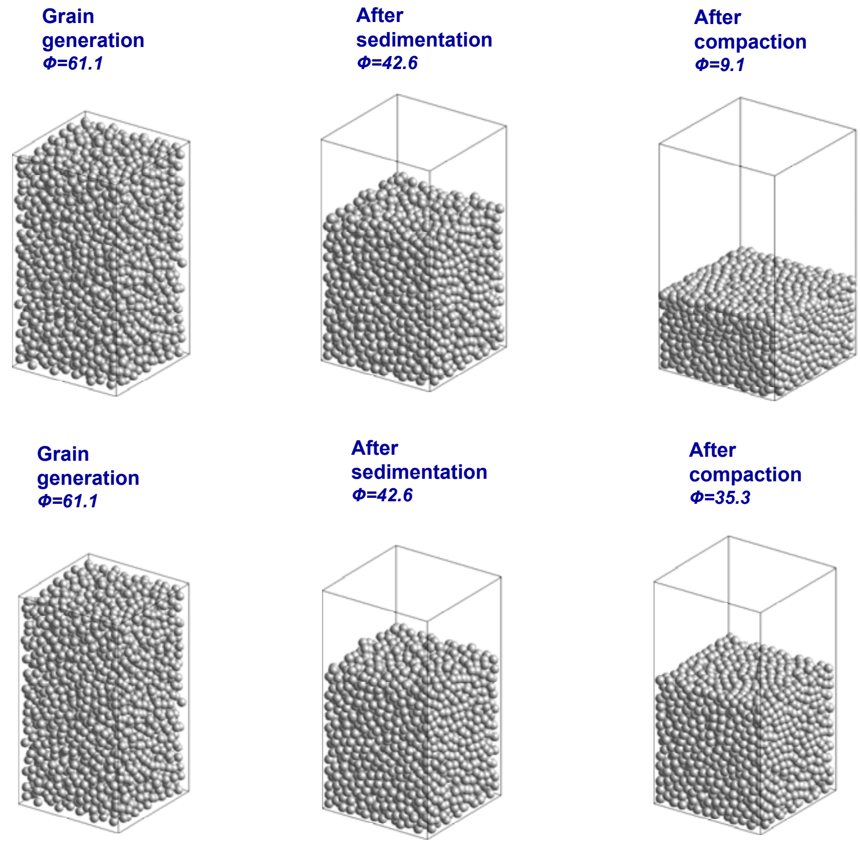
PORE-LEVEL STUDIES

Sedimentation and Compaction

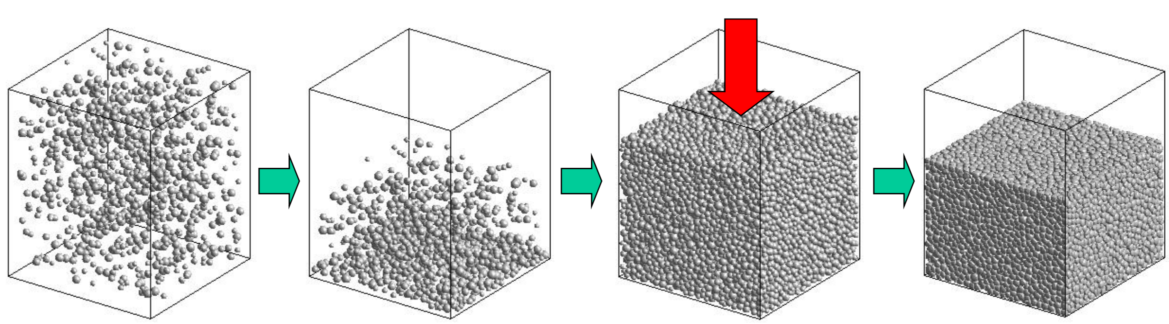


Pore space view from inside of the pack

Sedimentation and Compaction



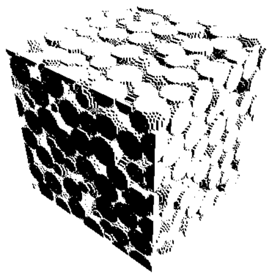
Dynamic Depositional Model



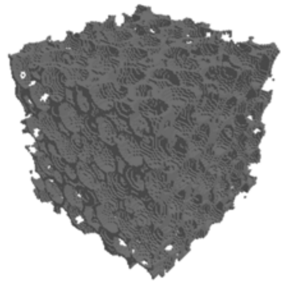
- Compact in **any** direction
- **Translate, rotate, and rebound**

Cementation

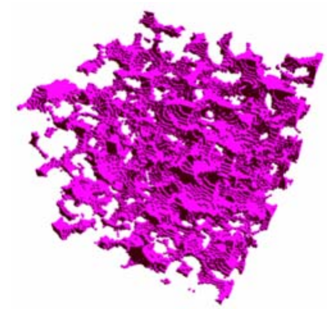
Grains
(68.8% of total volume)



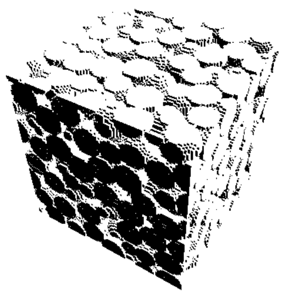
Cement
(23.1% of total volume)



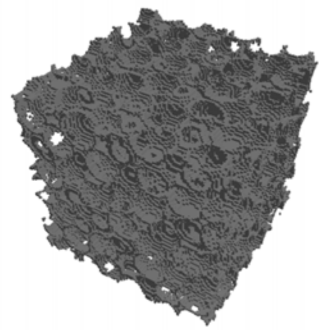
Pore space
(8.1% of total volume)



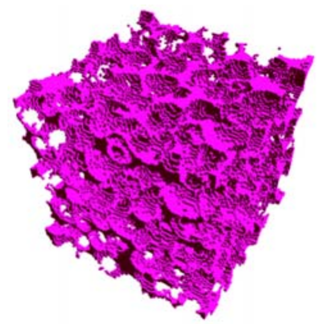
Grains
(68.8% of total volume)



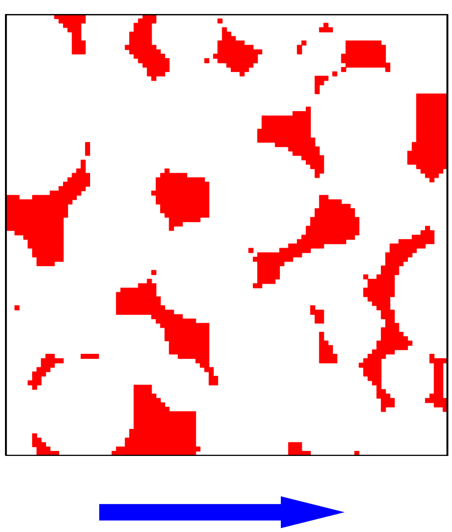
Cement
(16.0% of total volume)



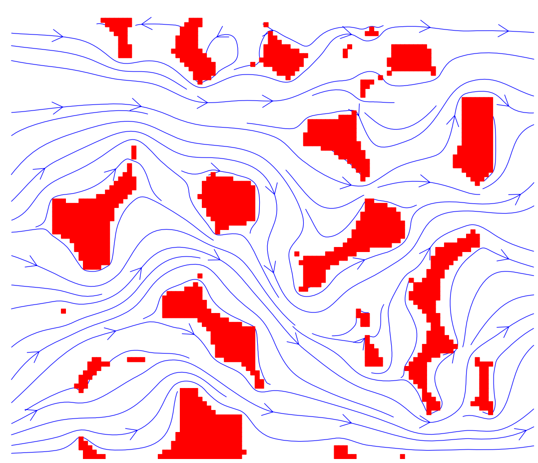
Pore space
(15.2% of total volume)



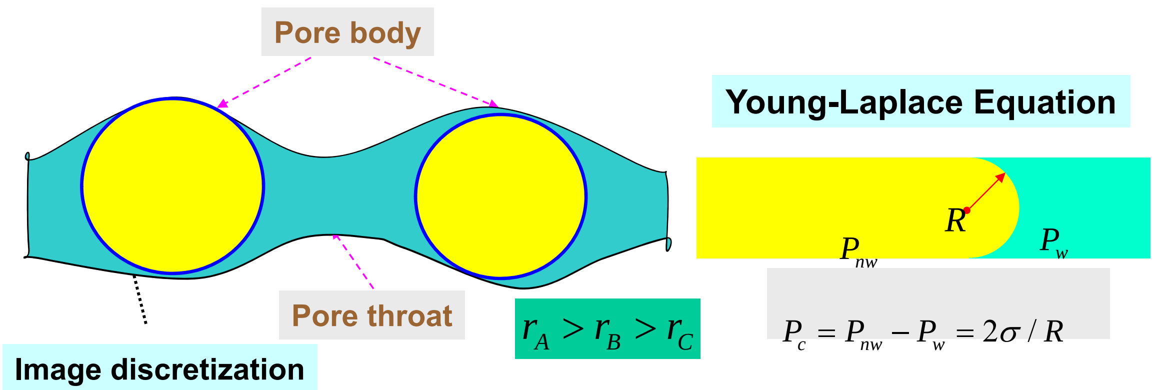
Lattice-Boltzmann Flow Simulator

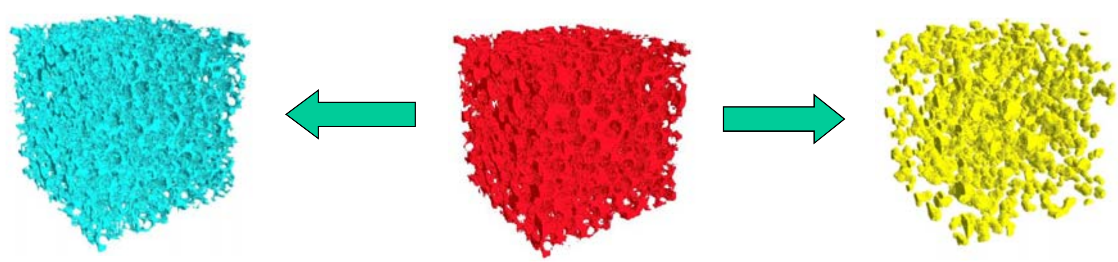


Flow direction

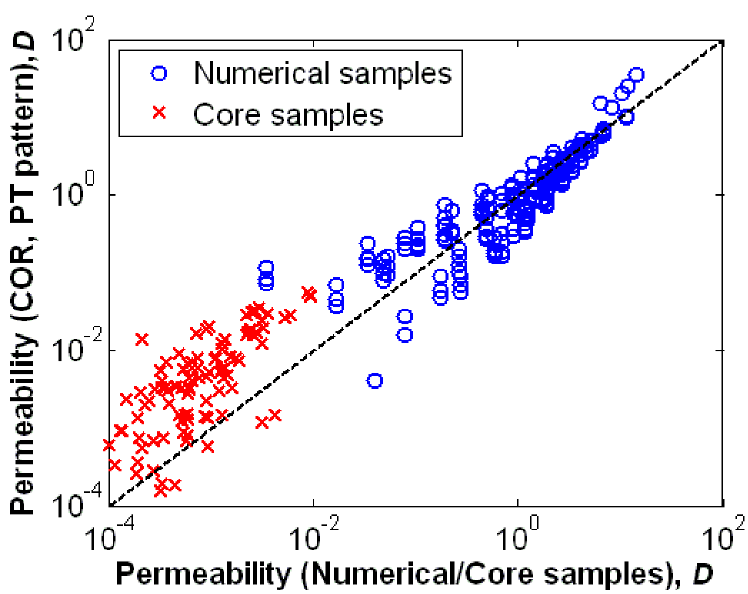


Fluid Distribution Simulator

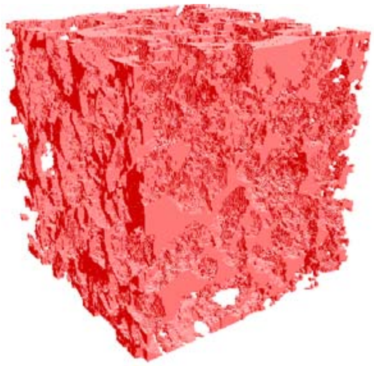


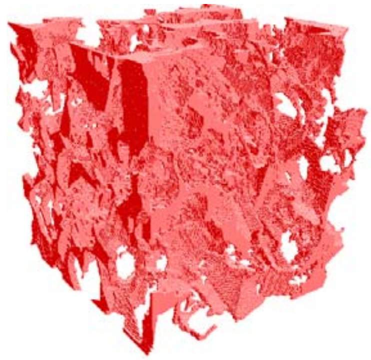


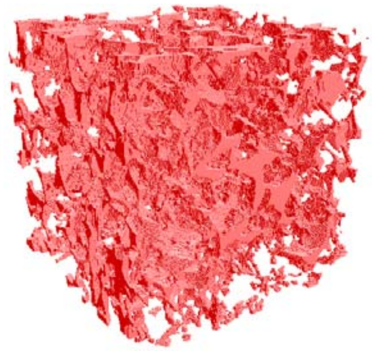
Comparison Against Experimental Data



CT Images



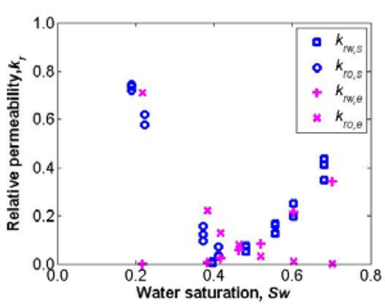


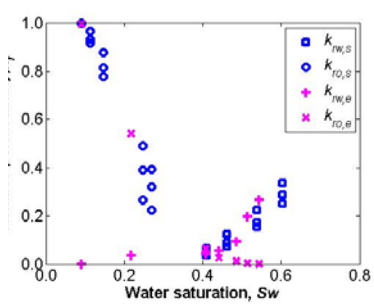


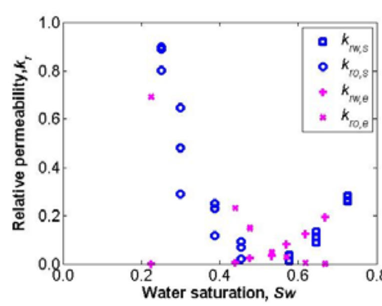
Sample A	Sample B	Sample C
ϕ_{core} = 20.3%	ϕ_{core} = 15.4%	ϕ_{core} = 12.1%
ϕ_{CT} = 21.1%	ϕ_{CT} = 14.5%	ϕ_{CT} = 10.4%

Image size 300X300X300 and voxel size 4.5 microns

Relative Permeability







Sample A

Sample B

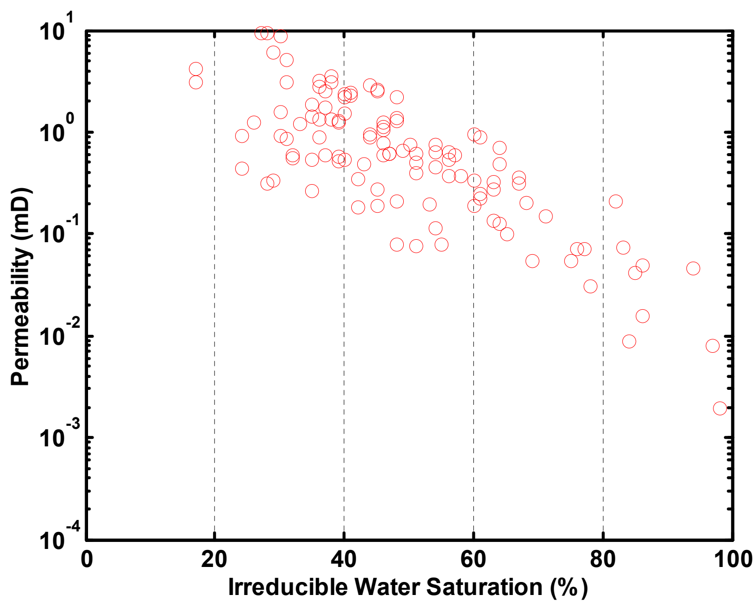
Sample C

Summary: Permeability Calculation

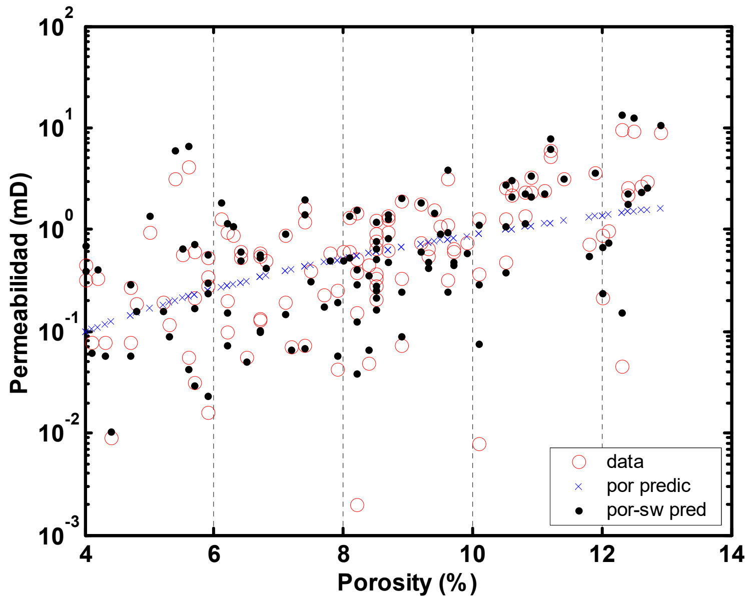
$$k = a\,\Phi^{\alpha}$$

$$k = a\,\frac{\Phi^{\alpha}}{S_{wi}^{\beta}}$$

Example: Permeability and Irreducible Water Saturation



Permeability Calculation: Comparison



$$k = a\,\frac{\Phi^{\alpha}}{S_{wi}^{\beta}}$$

$a = 1.01 \bullet 10^{9}$

$\beta = 3.03$

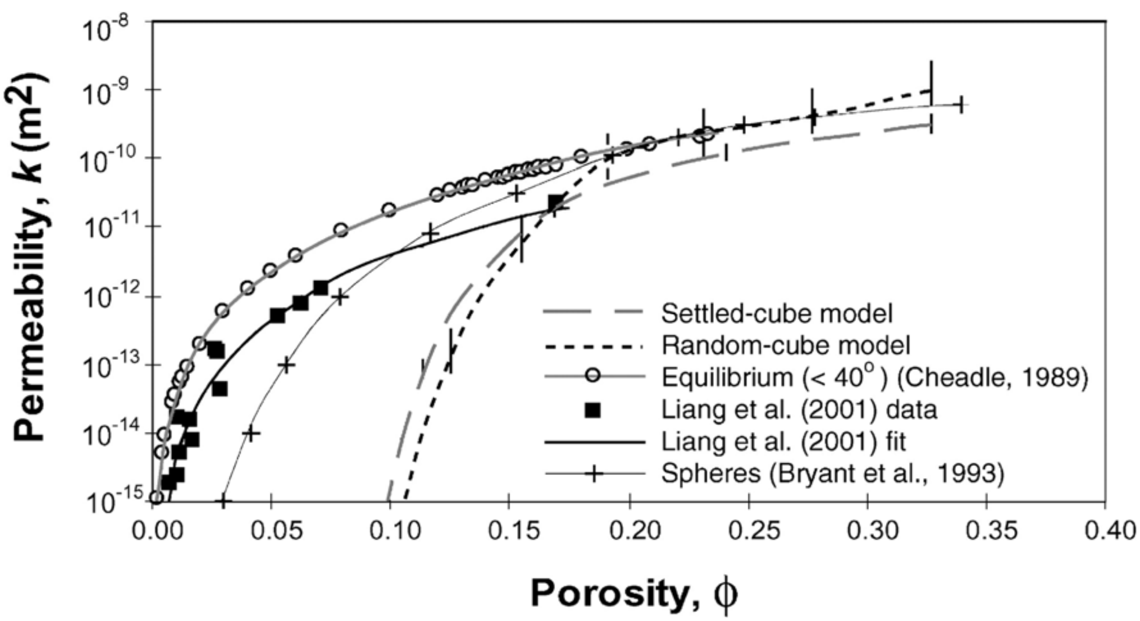
$\gamma = 3.59$

$\Phi[\,fraction], S_{wi}[\%], k[mD]$

2nd EXAMPLE OF METHODOLOGY

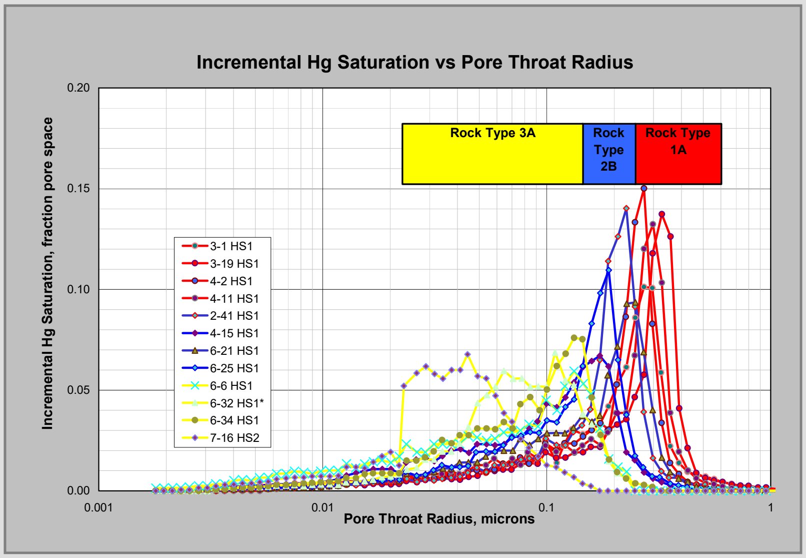
EXAMPLE: Fontainebleu Sandstone

Experimental Porosity-Permeability Relationship:
Fontainebleu Sandstone



Rock Classification Based on Capillary Pressure Data

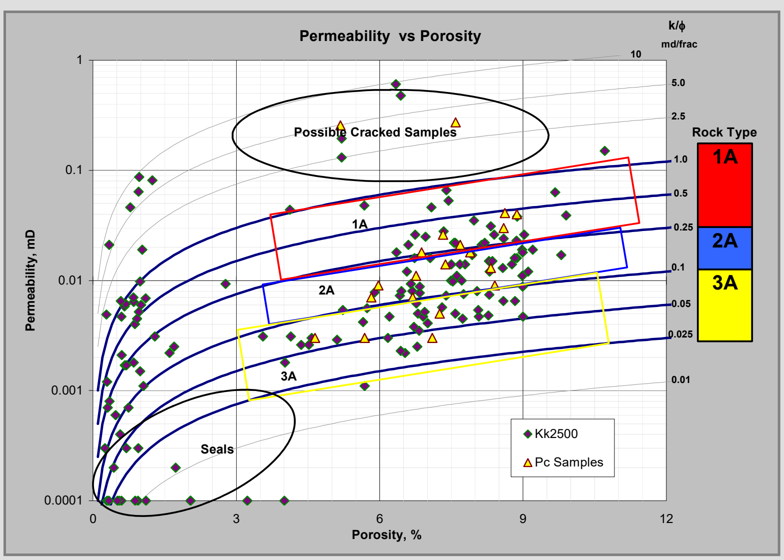
Pore Throat Radius Distribution



Three pore throat radius ranges were observed, therefore, three rock types are identified

ROCK TYPING

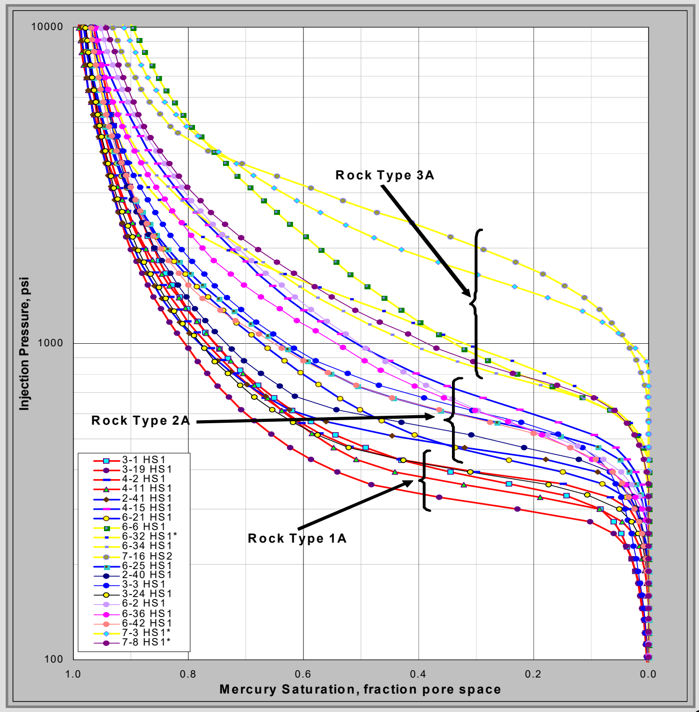
Porosity-Permeability



k/ϕ parametric curves clearly define three rock types

ROCK TYPING

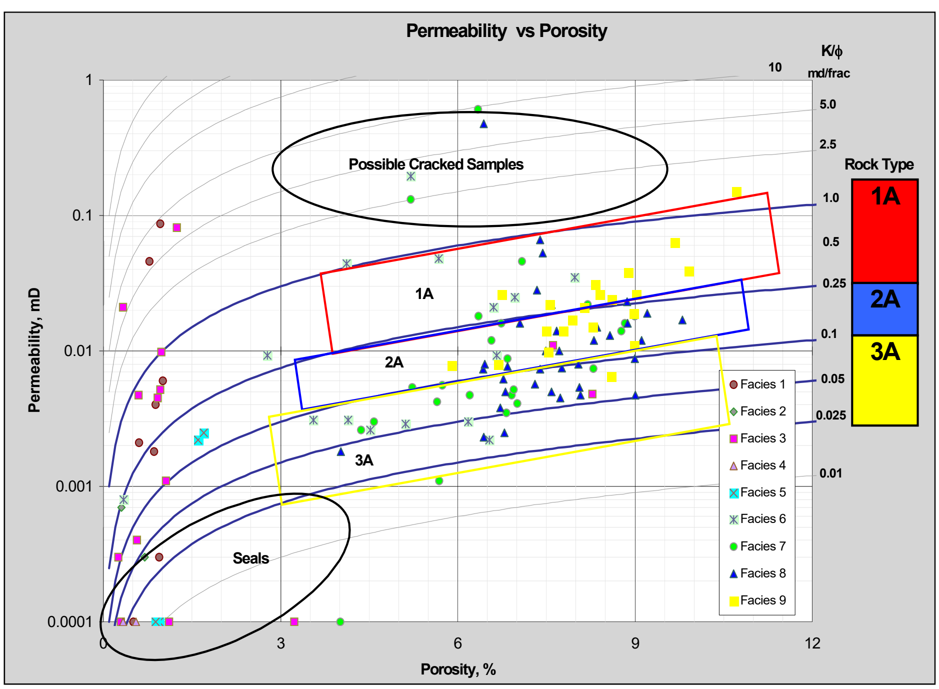
HPMI Capillary Pressure



Rocks 1A, 2A are considered reservoir rocks, 3A has very poor porosity and permeability and sometimes it can act as vertical flow barriers or seals

ROCK TYPING

Litho-facies vs petro-facies



WINLAND'S METHOD:
Calculation Details I

$$\text{Log}(R_{35}) = .732 + .588\text{Log}(K) - .864\text{Log}(\Phi)$$

Where:

R_{35} = Pore throat radius corresponding to the 35th percentile mercury saturation, microns.

K = Air permeability ambient conditions, md.

Φ = Porosity ambient conditions, %.

WINLAND'S METHOD:
Calculation Details II

$$\text{Winland Log}(R_{35}) = .732 + .588\text{Log}(K) - .864\text{Log}(\phi)$$
$$\text{Pittman Log}(R_{10}) = .459 + .500\text{Log}(K) - .385\text{Log}(\phi)$$
$$\text{Pittman Log}(R_{20}) = .218 + .519\text{Log}(K) - .303\text{Log}(\phi)$$
$$\text{Pittman Log}(R_{30}) = .215 + .547\text{Log}(K) - .420\text{Log}(\phi)$$
$$\text{Pittman Log}(R_{35}) = .255 + .565\text{Log}(K) - .523\text{Log}(\phi)$$
$$\text{Pittman Log}(R_{40}) = .360 + .582\text{Log}(K) - .680\text{Log}(\phi)$$
$$\text{Pittman Log}(R_{50}) = .778 + .626\text{Log}(K) - 1.205\text{Log}(\phi)$$

Please note Porosity must be entered as a percentage

WINLAND'S METHOD

Absolute Permeability

Based on Winland's pore throat radius model, a linear three-variable regression was performed, unlike Winland's model, this equation assumes *k* as the dependent variable :

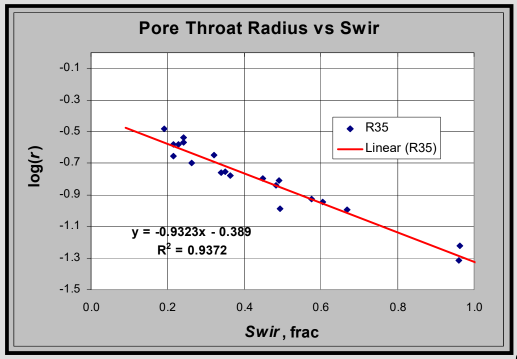
$$\log k = \log b + c \log r + d \log \phi$$

Klinkenberg corrected permeability @ 2500 psi is obtained :

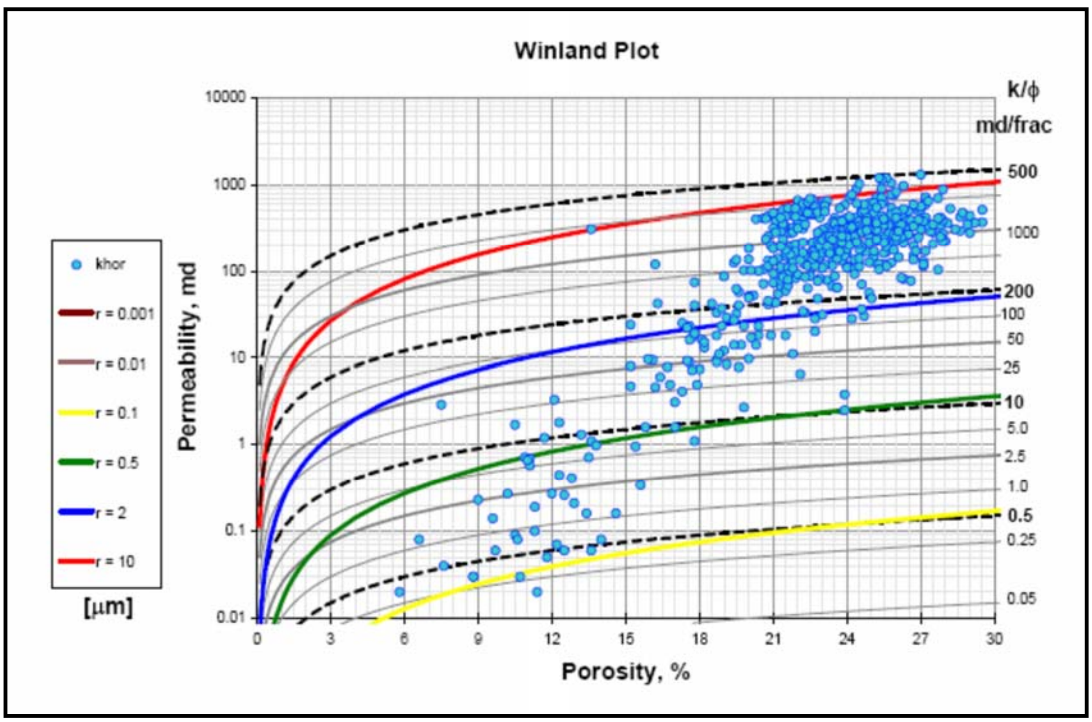
$$k = 1.2 \times 10^{-3} r^{0.858} \phi^{1.93}, \quad R^2 = 0.75$$

Pore throat radius, *r*, it is then estimated from irreducible water saturation by using the assumed equation:

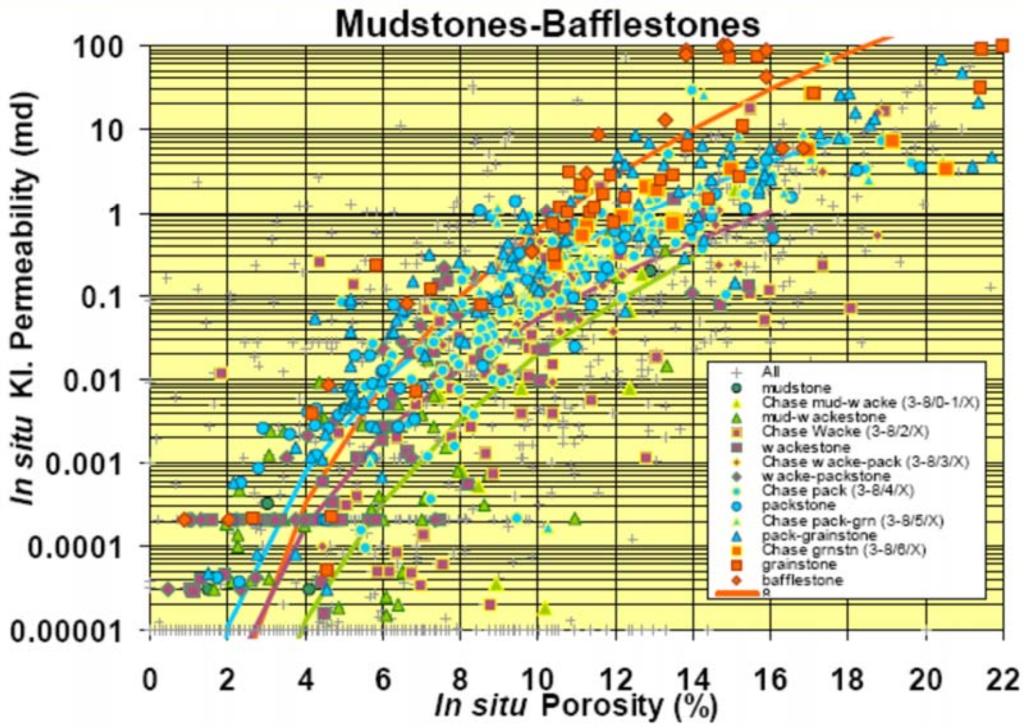
$$r = 0.41 \times 10^{-0.9323 S_w}, \quad R^2 = 0.94$$



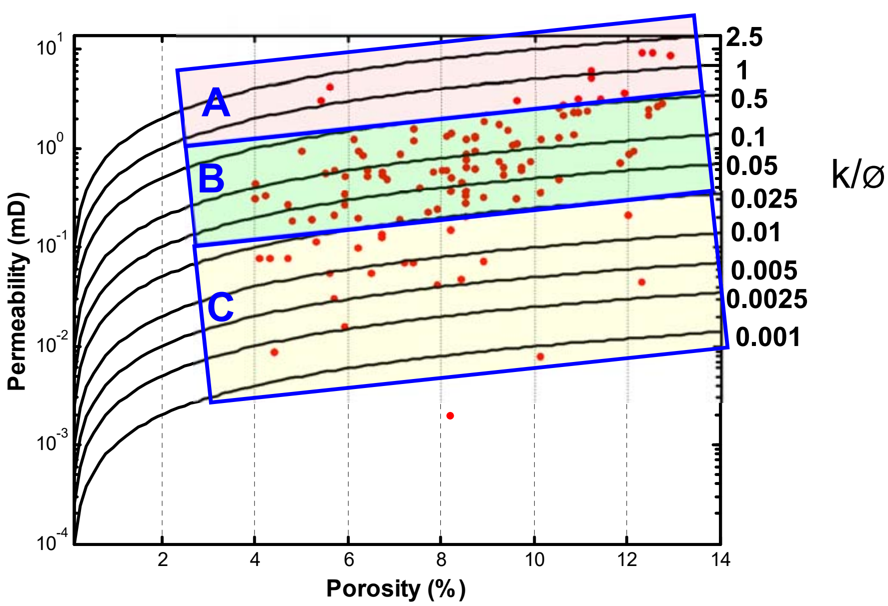
EXAMPLE OF WINLAND'S METHOD



Hugoton Carbonates



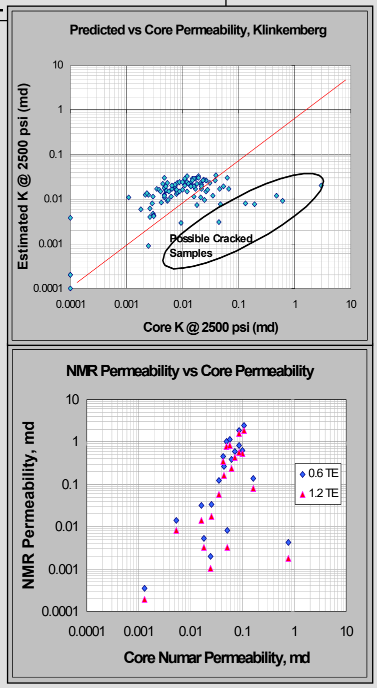
Example

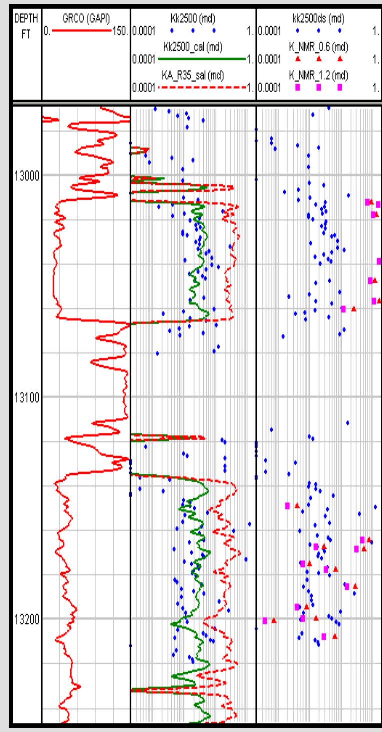


CALIBRATION

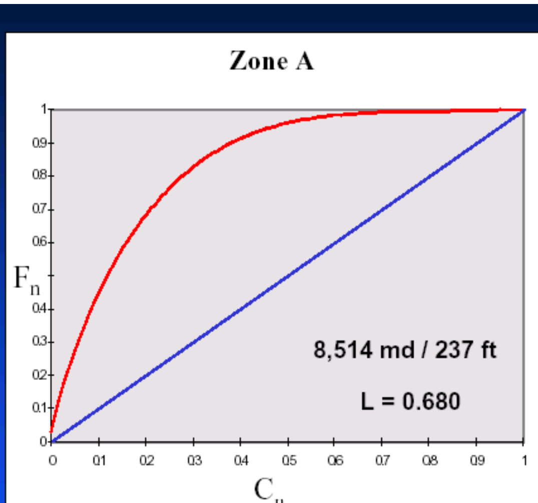
Absolute Permeability

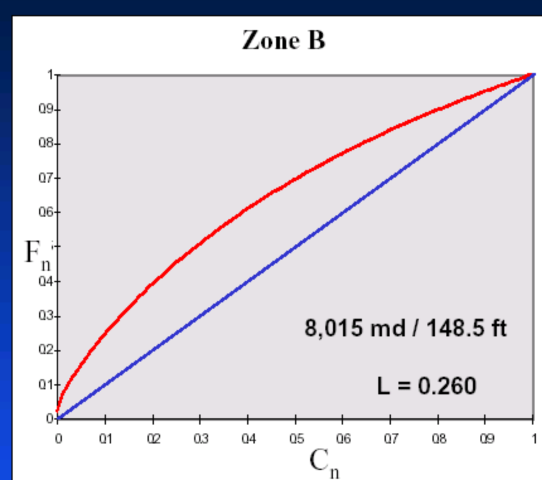
Correlations between core vs estimated and NMR permeability:





DEFINITION OF LORENZ COEFFICIENTS



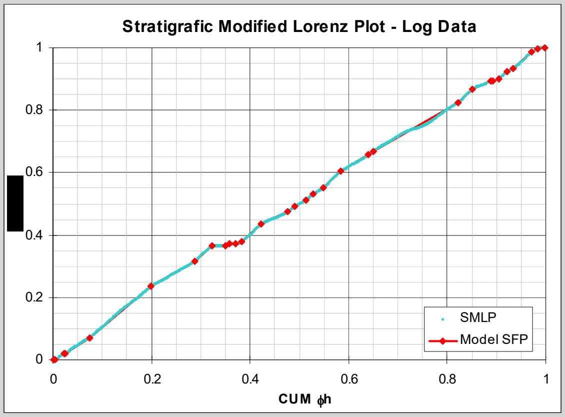


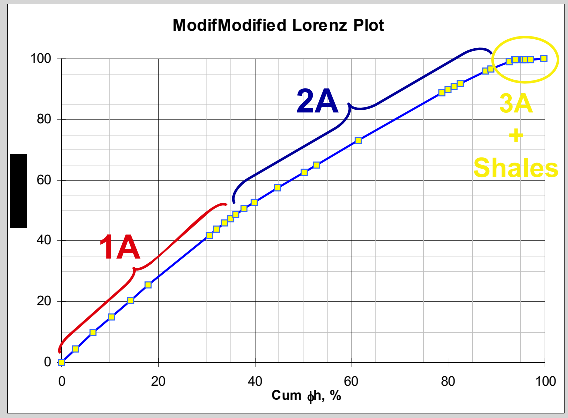
$$F_n = \sum_{l=1}^{n} \frac{k_l h_l}{H_t \bar{k}}$$

$$C_n = \sum_{l=1}^{n} \frac{\phi_l h_l}{H_t \bar{\phi}}$$

DEFINITION OF FLOW UNITS

Lorenz Plots to define flow units





Most Flow Units are Rock Type 2A and 1A

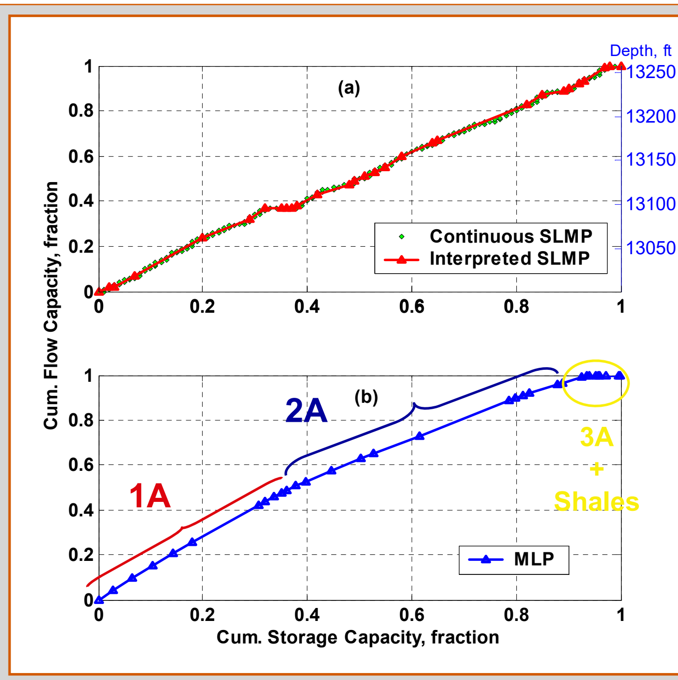
DEFINITION OF FLOW UNITS

Lorenz Plots to define flow units

$$stor.cap. = cum(h \cdot \phi)$$

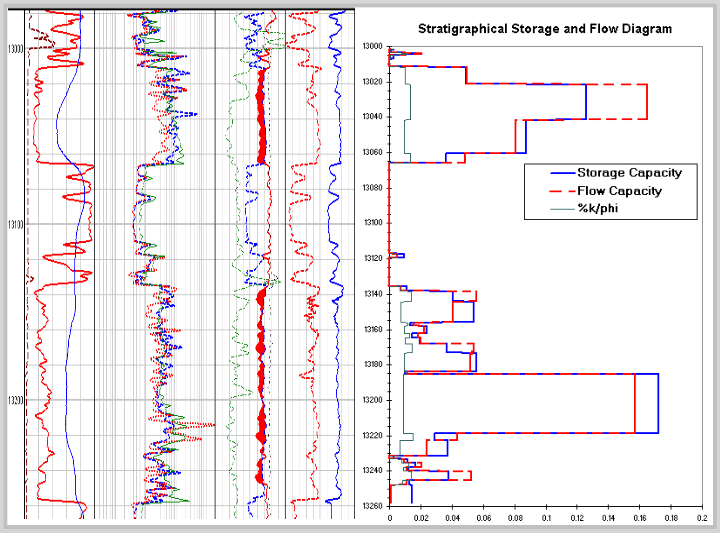
$$flow.cap. = cum(h \cdot k)$$

Most Flow Units are Rock Type 2A and 1A



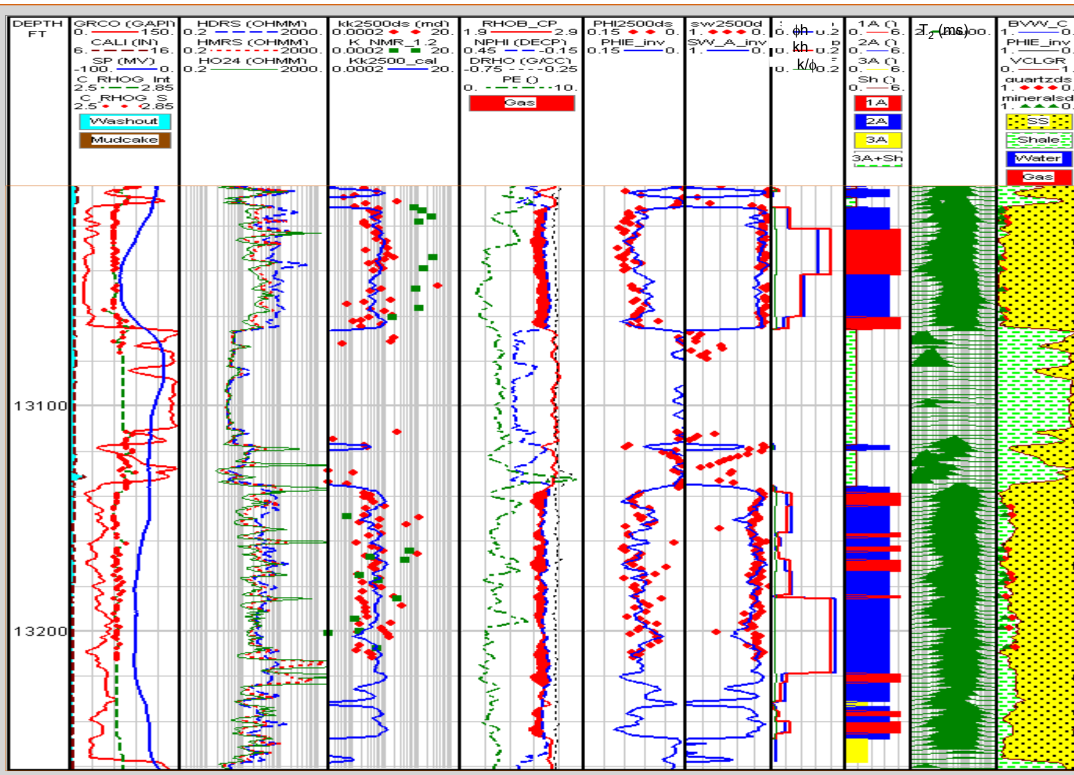
ASSESSMENT OF FLOW UNITS

Stratigraphical Flow Profile



Vertical representation of defined flow units

RESULTS

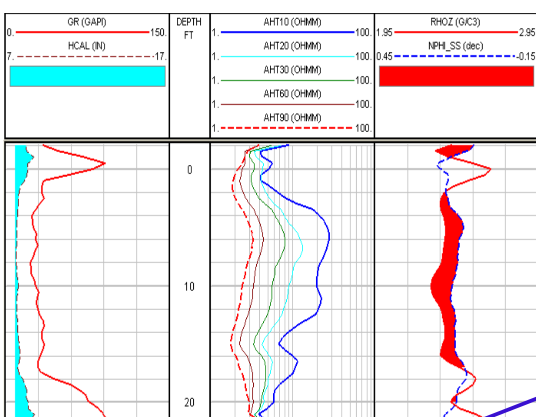


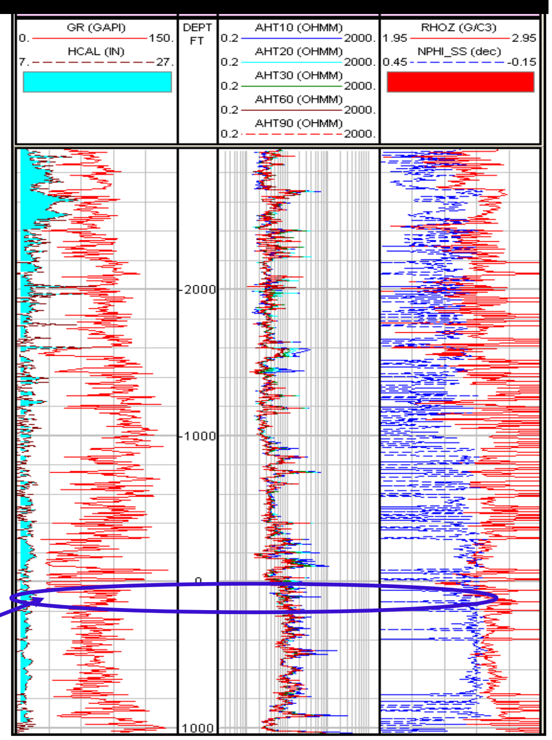
3rd EXAMPLE OF METHODOLOGY

Case Study

North Louisiana low-permeability, tight-gas sand reservoir.

Amalgamated clastic sequences in the Hosston formation .





Interval analyzed

Formation Evaluation

Effective Porosity

Dual-fluid, dual-mineral model:

$$\min_{(\phi_i)} \sum (\rho_{bi} - \hat{\rho}_{bi})^2, \qquad \phi \in [0,1]$$

$$\hat{\rho}_b = \phi\left[\sqrt[n]{\frac{R_{wxo}a}{\phi^m R_{xo}}}(\rho_1 - \rho_2) + \rho_2\right] + (1 - \phi - C_{sh})\rho_{ma} + C_{sh}\rho_{sh}$$

$$\phi_o = \sqrt{\frac{1}{2}\left[(\phi_N{}^{sh})^2 + (\phi_D{}^{sh})^2\right]}$$

Water Saturation

Archie's equation:

$$\boxed{S_w{}^n = \frac{R_w}{R_t}\frac{a}{\phi^m}}$$

Formation Evaluation

Absolute Permeability – initial model

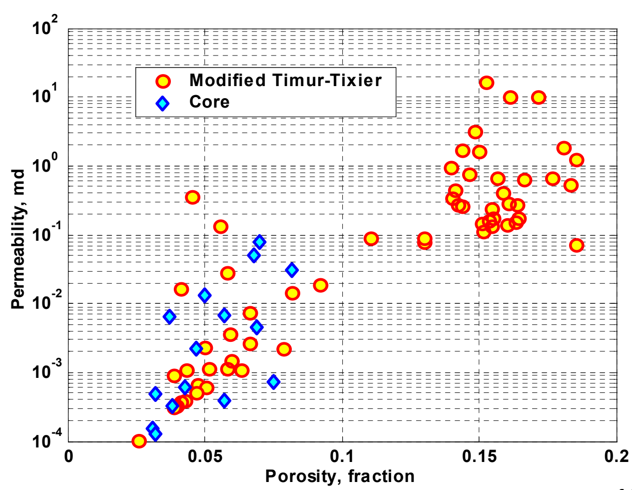
Linear 3-variable regression based on Timur-Tixier model:

$$\log k = \log A + B\log\phi - C\log S_{wir}$$

$$k = 0.04\frac{\phi^{1.83}}{S_{wir}{}^{2.3}}, \quad R^2 = 0.60$$

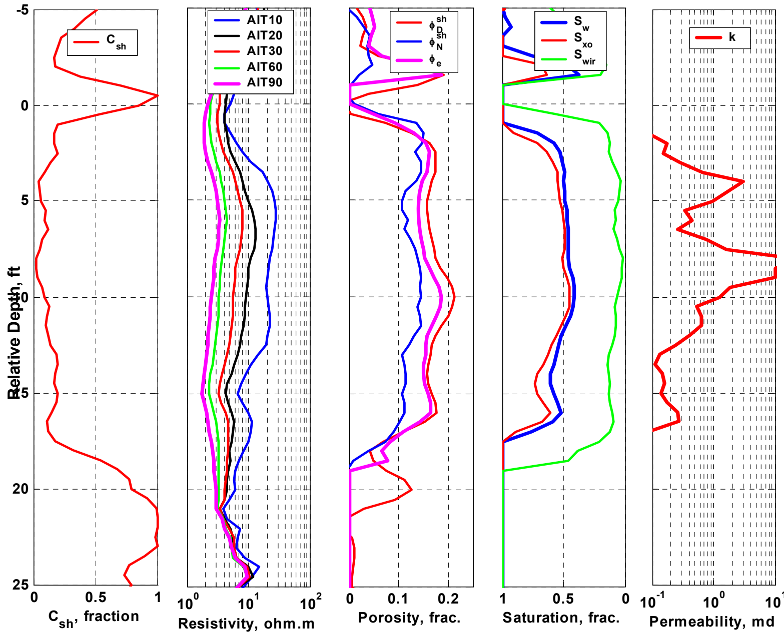
where,

$$S_{wir} = C_{sh}\frac{\phi_{tsh}}{\phi_t}$$



Formation Evaluation

Petrophysical Assessment - results



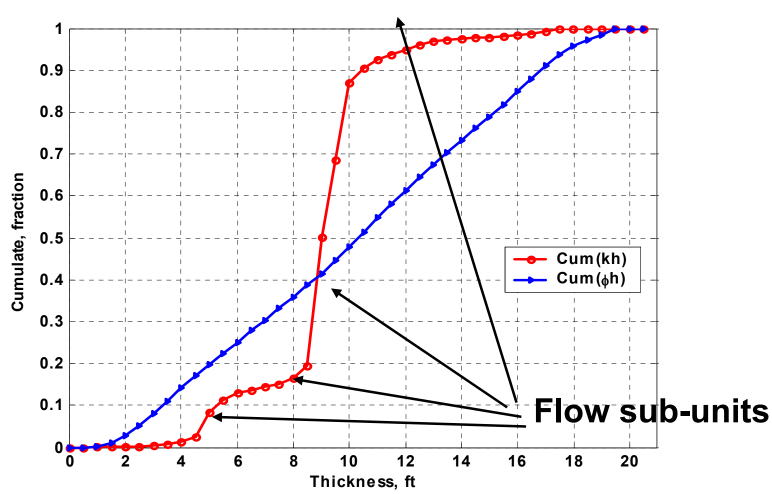
Flow Units

Lorenz Plots define flow units

$$\mathrm{Cum}(\phi h) = \frac{\int_0^h \phi dz}{\int_0^h dz}$$

$$\mathrm{Cum}(kh) = \frac{\int_0^h k dz}{\int_0^h dz}$$

$$\boxed{\begin{aligned} stor.cap. &= cum(h \cdot \phi) \\ flow.cap. &= cum(h \cdot k) \end{aligned}}$$

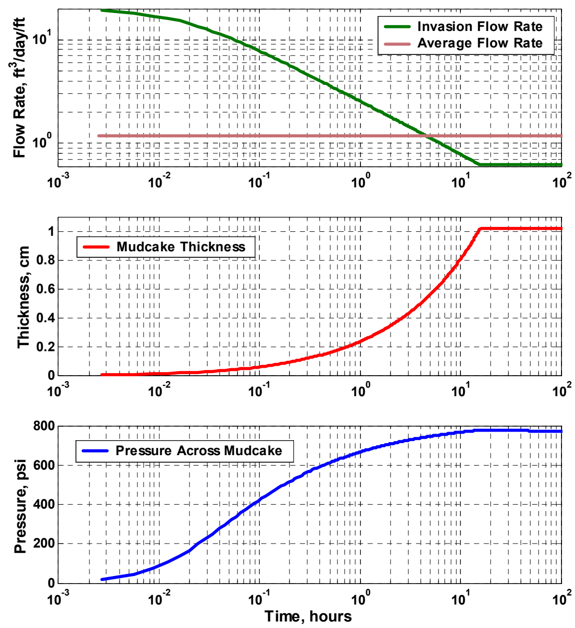


Flow Rate of Mud-Filtrate Invasion

UTCHEM-INVADE

Two-dimensional chemical flow simulator which includes the effect of salt mixing between mud filtrate and connate water

Flow rate is averaged in time, then used as an input to simulate array induction resistivity



INVADE results after 5 days of invasion

Resistivity Simulation

Resistivity

Water and formation resistivity spatial distributions are computed,

$$R_w(\mathbf{r},t) = \left(0.0123 + \frac{3647.5}{C_w^{\,0.955}(\mathbf{r},t)}\right)\left(\frac{81.77}{T+6.77}\right)$$

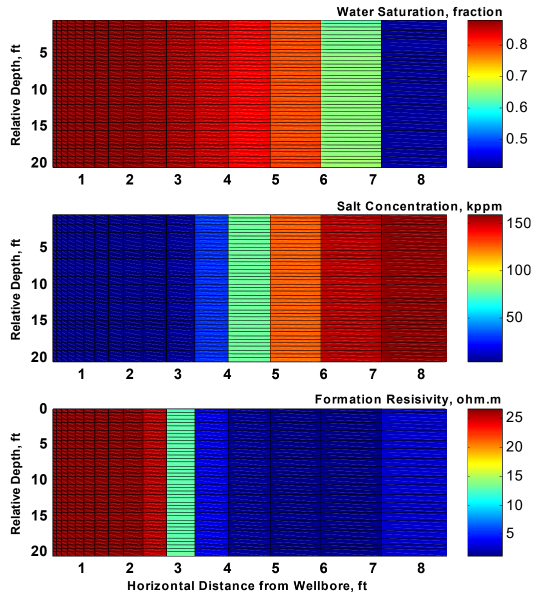
$$R_t(\mathbf{r},t) = \frac{R_w(\mathbf{r},t)}{S_w^{\,n}(\mathbf{r},t)} \frac{a}{\phi^m(\mathbf{r})}$$

Array induction resistivity (AIT™) measurements are simulated using Schlumberger's **SLDMINV**.

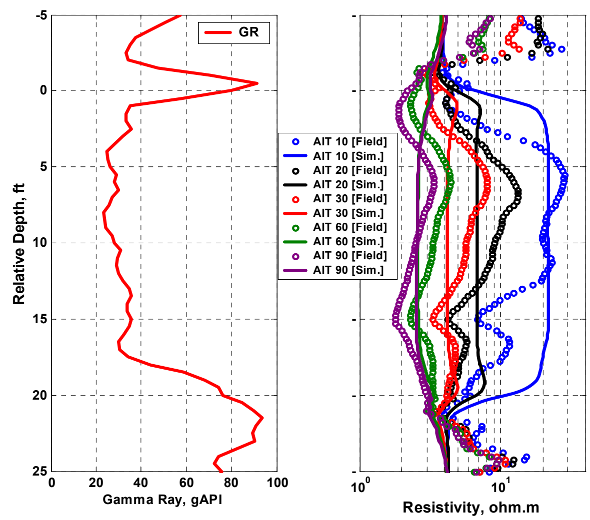
Field Example: Base Case

Resistivity Simulation Results

Cross-sections



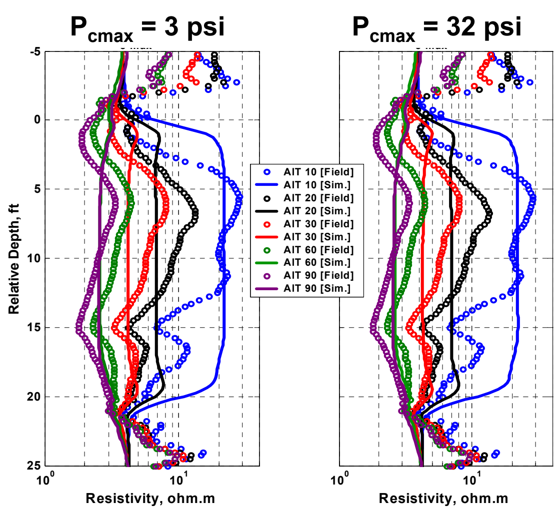
Array induction resistivity



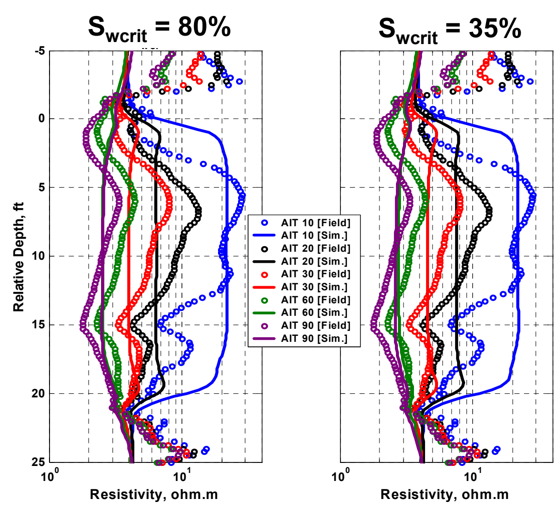
Field Example: Base Case

Resistivity Simulation: Sensitivity Analysis

Capillary Pressure



Relative Permeability

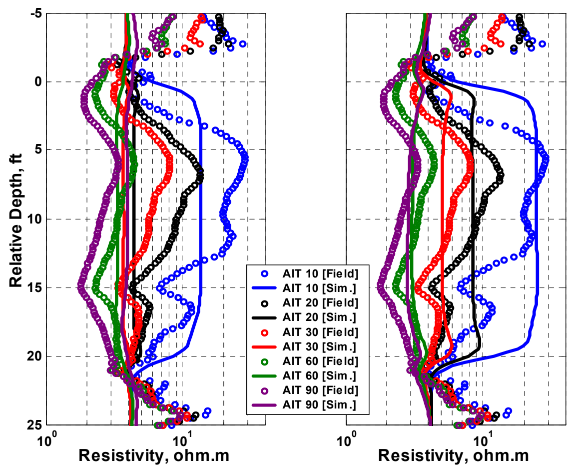


Field Example: Base Case

Permeability Inversion

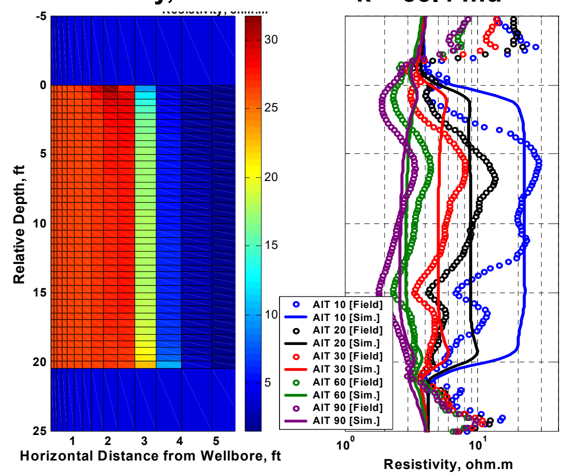
Manual resistivity matching

k = 0.15 md **k = 150 md**



Automatic inversion

Resistivity, ohm.m **k = 55.4 md**

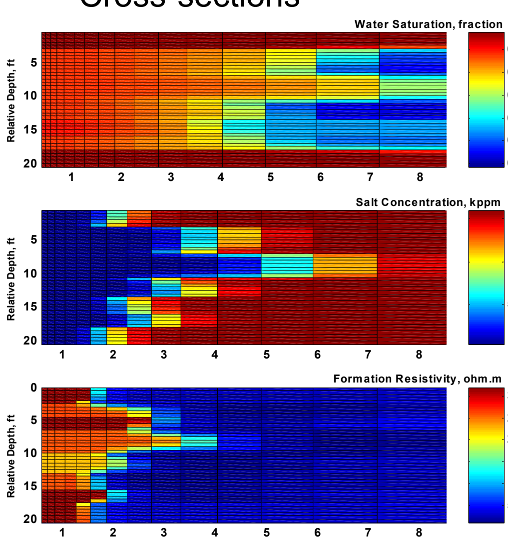


After 5 Gauss-Newton iterations

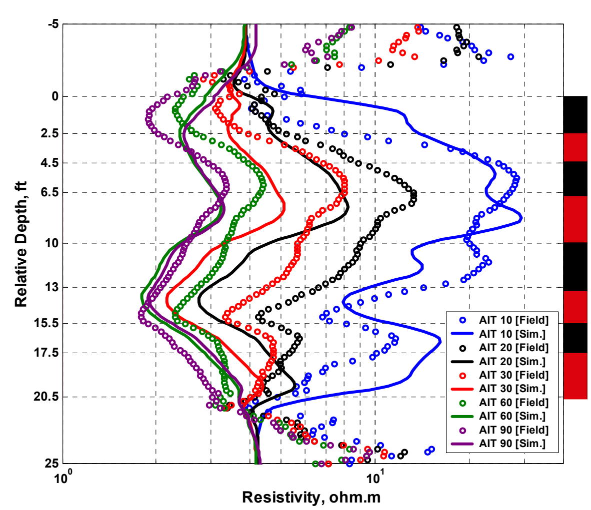
Field Example: Heterogeneous Flow Unit

Resistivity Simulation Results with Initial Guess of *k*

Cross-sections



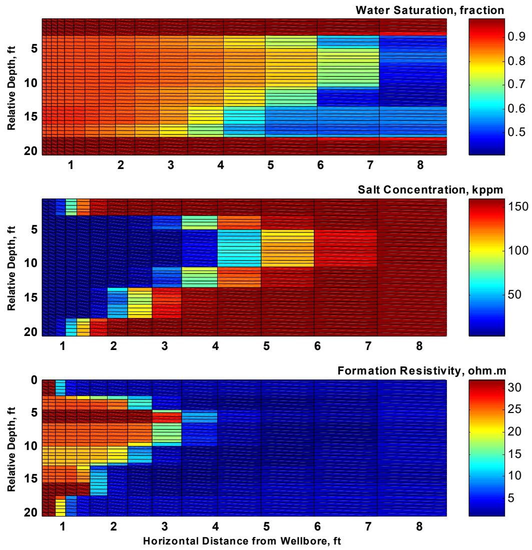
Array induction resistivity

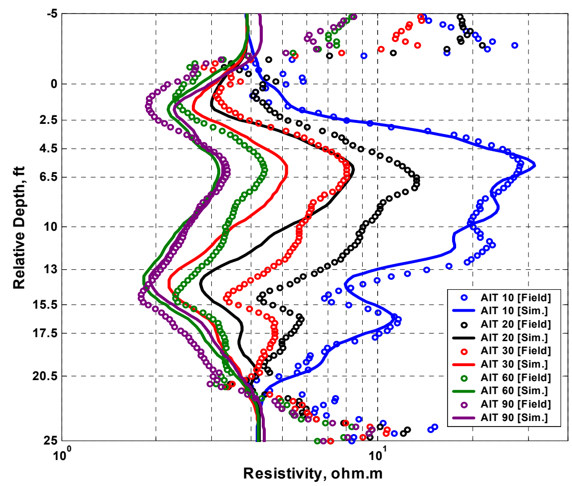


Field Example: Heterogeneous Flow Unit

Permeability Inversion

Manual resistivity matching

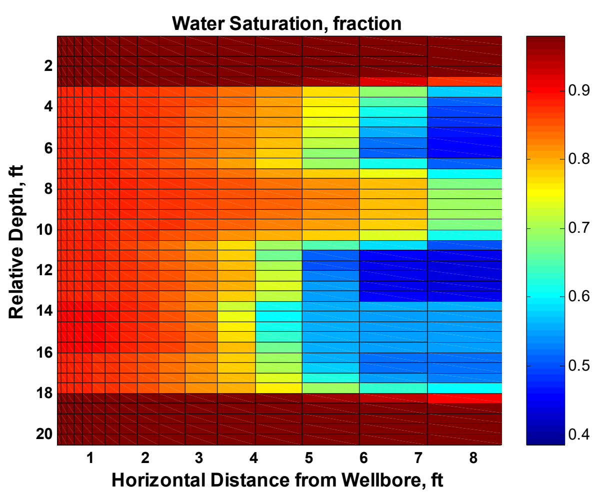


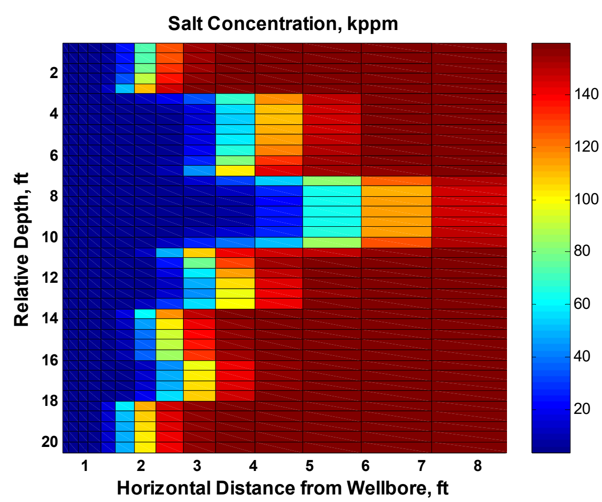


Field Example: Heterogeneous Flow Unit

Permeability inversion

Automatic inversion

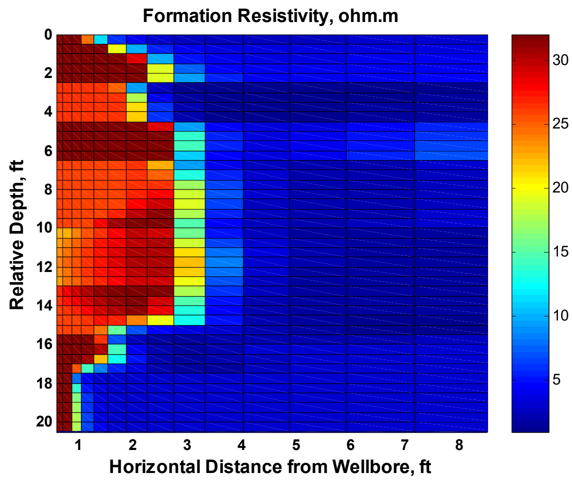


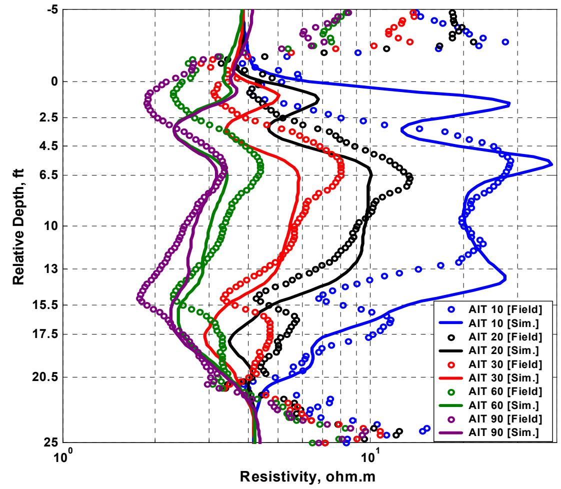


Field Example: Heterogeneous Flow Unit

Permeability inversion

Automatic inversion





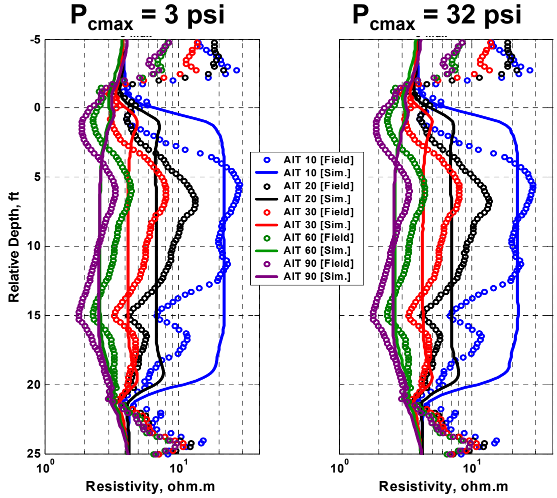
After 7 Gauss-Newton iterations

Field Example: Base Case

Resistivity Simulation: Sensitivity Analysis

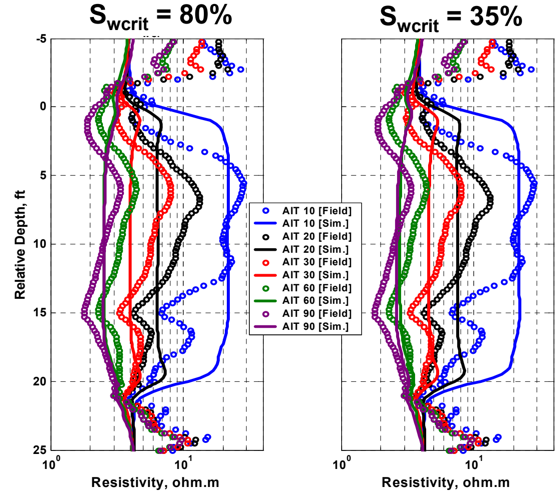
Capillary Pressure

P_{cmax} = 3 psi **P_{cmax} = 32 psi**



Relative Permeability

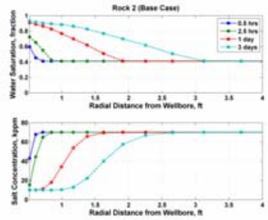
S_{wcrit} = 80% **S_{wcrit} = 35%**



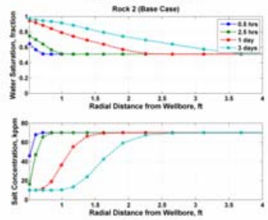
Los Molles SM
Intermedio (top)

Sensitivity Analysis

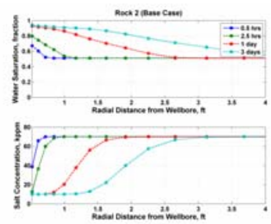
$S_{wini} = 0.4$



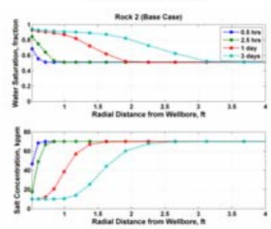
$S_{gr} = 0.01$

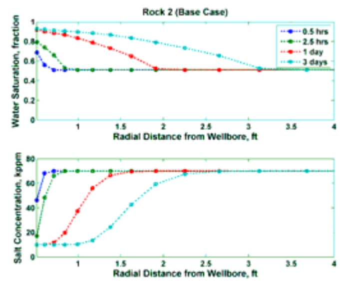


$\phi = 0.06$



$k = 0.01md$



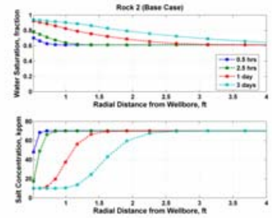


Base Case

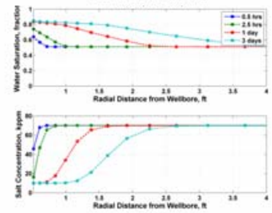
S_{wini} = 51% (Archie)
S_{gr} = 5%
ϕ = 9%
k = 0.1 md
Cmf = 10,000 ppm (changed)
Cw = 70,000 ppm (changed)

Hydrocarbon = CH_4

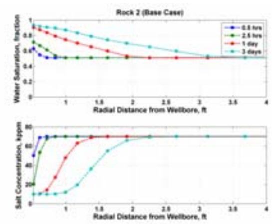
$S_{wini} = 0.6$



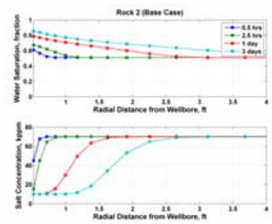
$S_{gr} = 0.15$



$\phi = 0.12$



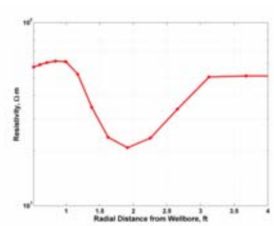
$k = 1md$



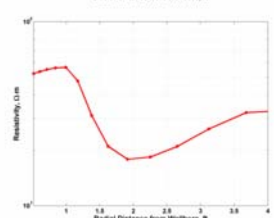
Los Molles SM
Intermedio (top)

Sensitivity Analysis

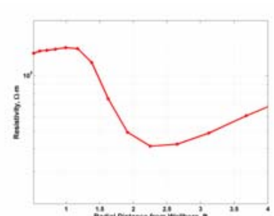
$S_{wini} = 0.4$



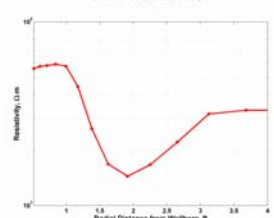
$S_{gr} = 0.01$

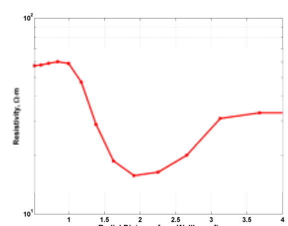


$\phi = 0.06$



$k = 0.01md$



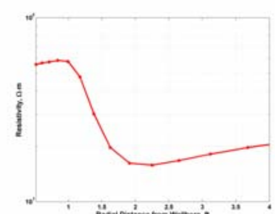


Base Case

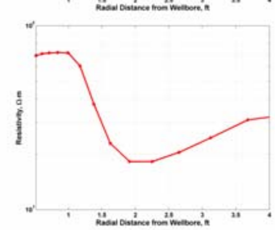
S_{wini} = 51% (Archie)
S_{gr} = 5%
ϕ = 9%
k = 0.1 md
Cmf = 10,000 ppm (changed)
Cw = 70,000 ppm (changed)

Hydrocarbon = CH_4

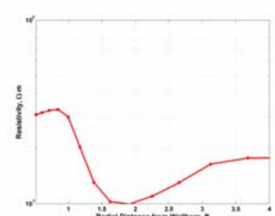
$S_{wini} = 0.6$



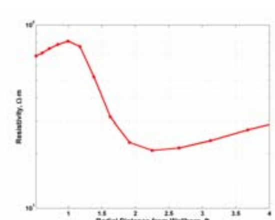
$S_{gr} = 0.15$



$\phi = 0.12$



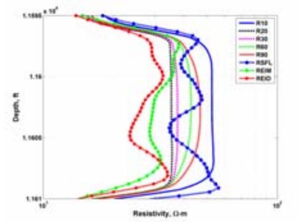
$k = 1md$



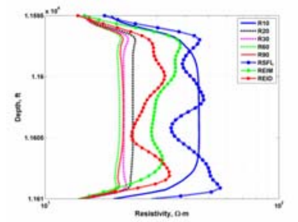
Los Molles SM
Intermedio (top)

Sensitivity Analysis

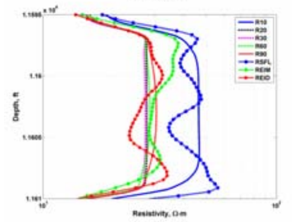
$S_{wini} = 0.4$

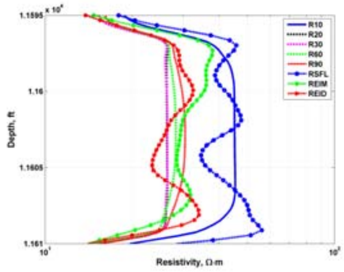


$S_{wini} = 0.6$

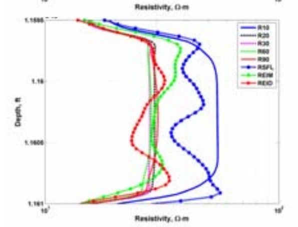


$S_{gr} = 0.01$

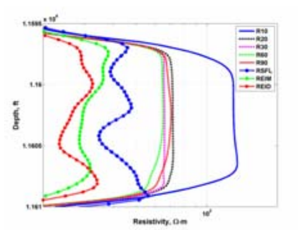




$S_{gr} = 0.15$



$\phi = 0.06$

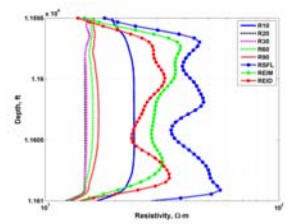


Base Case

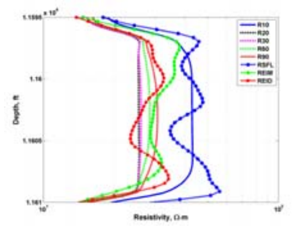
S_{wini} = 51% (Archie)
S_{gr} = 5%
ϕ = 9%
k = 0.1 md
Cmf = 10,000 ppm (changed)
Cw = 70,000 ppm (changed)

Hydrocarbon = CH_4

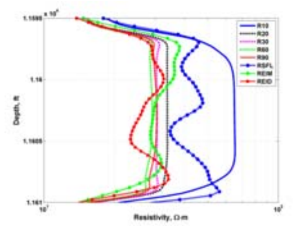
$\phi = 0.12$



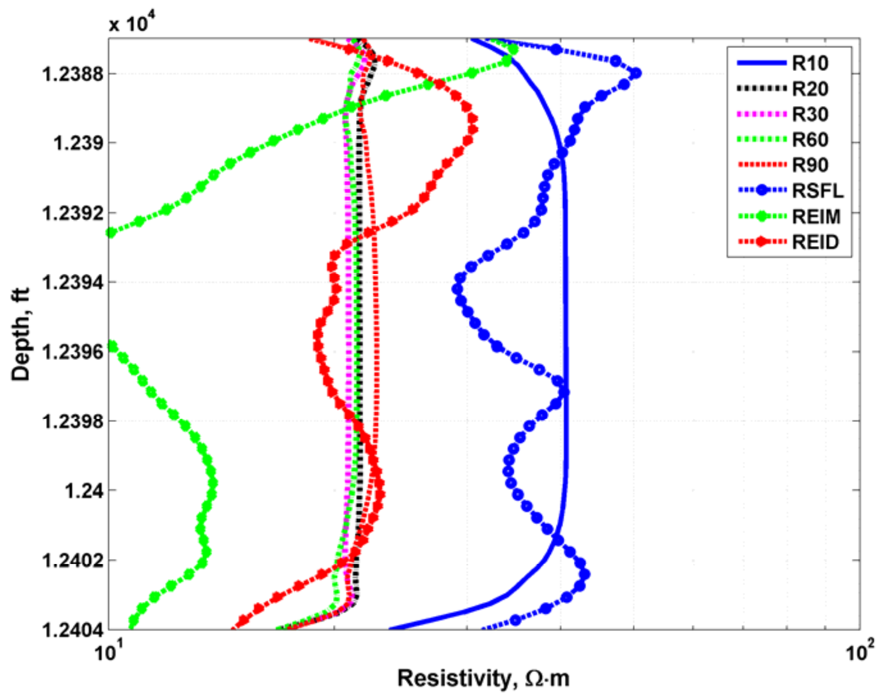
k = 0.01md



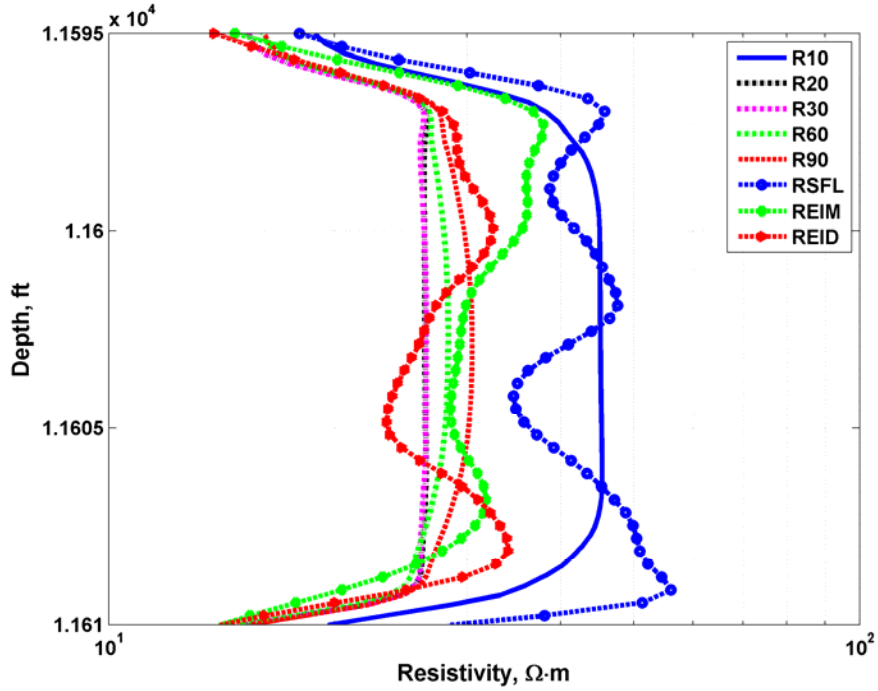
k = 1md



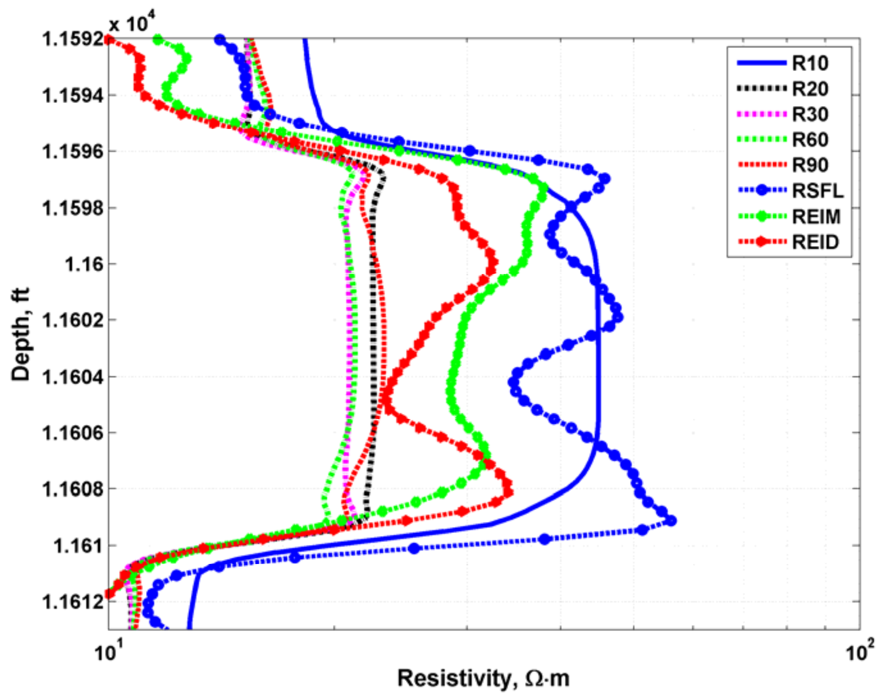
Los Molles SM Basal (Bottom)



Los Molles SM Intermedio (top)



Los Molles SM Intermedio (Top) Gas
1/8 of the capillary pressure (case 6B)



Summary

Porosity, permeability, and specific internal surface are most important pore space parameters.

- They show a more or less strong correlation, but express different physical properties:
  - Porosity characterizes the volume of pore space; it is a scalar property.
  - Specific internal surface characterizes the surface of pore space; it is a scalar property.
- Permeability expresses the ability of fluid flow and is a tensorial property.

Summary

- Porosity shows a strong correlation to density (and other properties measured by nuclear, acoustic, or electrical methods).
- Permeability correlates with porosity, but is strongly influenced by pore diameter (or grain size) - this circumstance causes the difficulties in permeability determination.
- Specific internal surface links porosity and permeability - therefore "surface - sensitive" properties, such as $S_{w,irr}$ or NMR, give a possibility of permeability derivation.