PETROFISICA INTEGRATA

Modulo 1 - 2 CFU
A.A. 2016-17

Corso di Insegnamento per
Laurea Magistrale in **Geoscienze**

curriculum
Geofisico – II° anno
Geologico Ambientale – I° anno – complementare
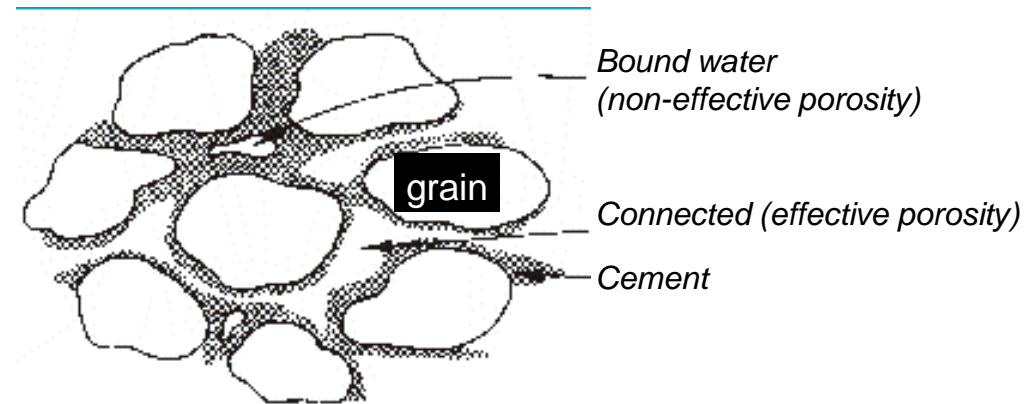
1b - CARATTERISTICHE FISICHE

POROSITY

La **porosità assoluta (φ)** della roccia è espressa dal volume percentuale dei pori rispetto al volume totale della roccia.

La **porosità effettiva (φe)**
(o porosità connessa) considera solo i vuoti interconnessi, potenzialmente attraversabili dai fluidi.

I vuoti non interconnessi sono occupati dalla *bound water*

φe è generalmente del 75-85%, ma può arrivare al 50% di φ

Bound water (non-effective porosity)

grain

Connected (effective porosity)

Cement

NMR = Risonanza Magnetca Nucleare

porosità NMR legata alle argille

porosità NMR associata ai fluidi non mobili

porosità NMR associata ai fluidi mobili

porosità totale da neutron log

porosità totale da density log

porosità da sonic log

porosità assoluta

volume associato alle argille

porosità effettiva

matrice	minerali argillosi	spazi intercristallini tra minerali argillosi	pori piccoli	pori grandi	pori isolati

acqua di struttura

acqua legata alle argille

acqua capillare

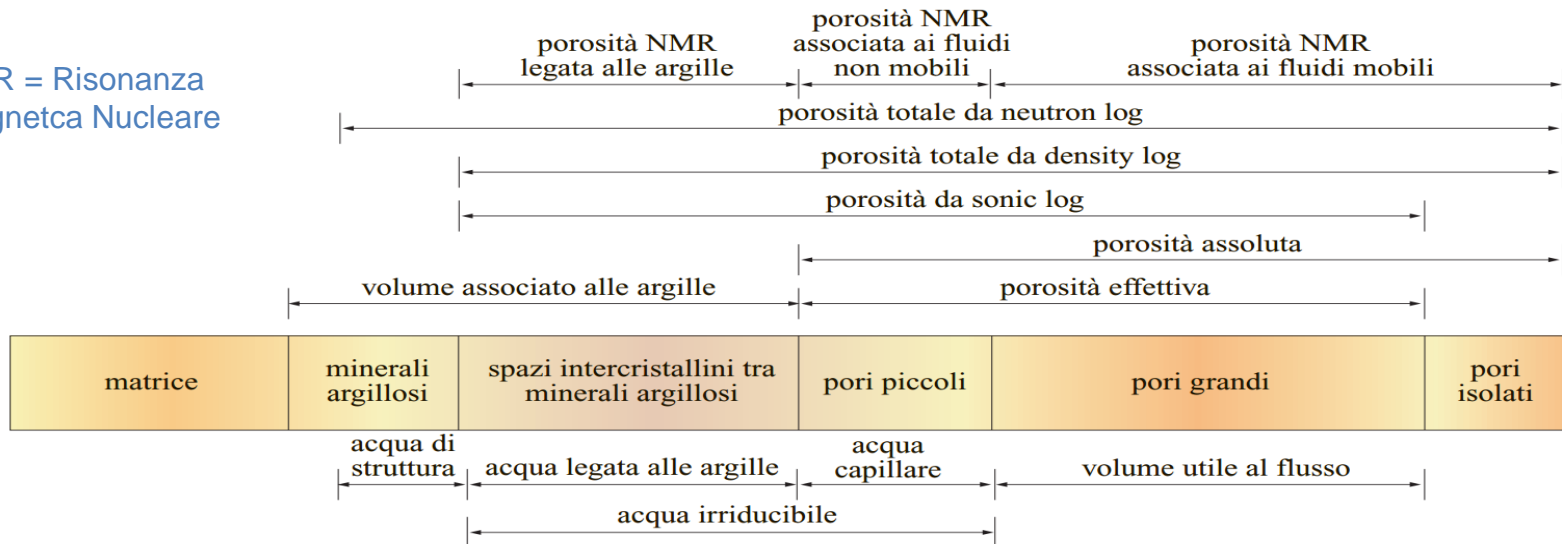volume utile al flusso

acqua irriducibile

fig. 5. Scala di indagine dei principali metodi di misura della porosità in formazioni contenenti frazioni argillose (Cosentino, 2001).

Con il diminuire della granulometria aumenta l'effetto della capillarità, quindi aumenta Sw.

Oltre alla **porosità della matrice**, si può avere la **porosità fessurale** (per micro-fratturazione), che generalmente ha valori molto più bassi, ma può incrementare ϕ.

Nelle **rocce detritiche** la porosità dipende non solo dalle **dimensioni** dei granuli, ma soprattutto dalla loro **forma**.

Per **microporosità** si intende la porosità data dai pori più piccoli (≤4 μ), che intrappolano e bloccano l'acqua per effetto della capillarità. Generalmente associata ad argille o gessi, spesso caratterizzati da alti valori percentuali di microporosità e porosità, ma bassa permeabilità. Si tratta quindi di **porosità non-effettiva**. Se non riconosciuta come tale può portare a valutazioni ottimistiche del potenziale *reservoir*:

L'acqua irriducibile (*bound water*) associata ad alta microporosità, può abbassare la resistività che viene letta nei *logs*, portando a stime pessimistiche della saturazione in acqua.

Spesso la valutazione di un campo (**quantità di idrocarburi in posto**) viene espressa in

$\phi_h = \phi_e \times h$ dove h è l'altezza del *reservoir*

Vuggy, oil-filled Tamabra debris flow (Poza Rica)
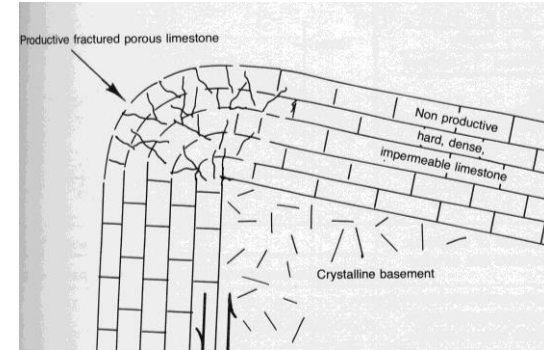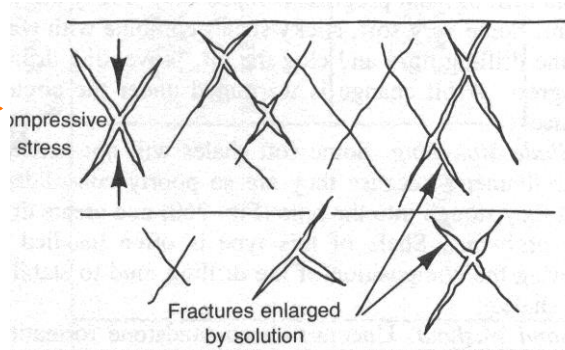
11-63.   CM
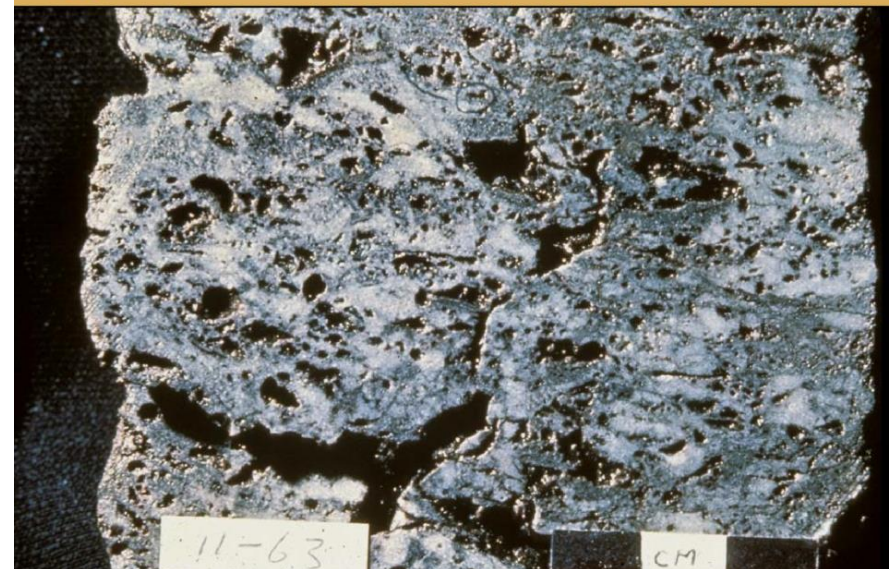
SECONDARY POROSITY

The secondary porosity is due to phenomena which <u>follow deposition </u>of sediments and are often active after their lithification. The main types of secondary porosity are due to:

- Fracturing

by structural failures of rocks under tension by tectonic activity.
Porosity by fractures in carbonate generally does not exceed 1%

- Dolomitization

during diagenesis or hydrothermal alteration
$2\ CaCO_3 + Mg^{2+} \rightarrow (CaMg)\ (CO_3)_2 + Ca^{2+}$
<u>13% volume reduction</u> (ionic vol. Mg < Ca)
Main setting: dry coastal areas

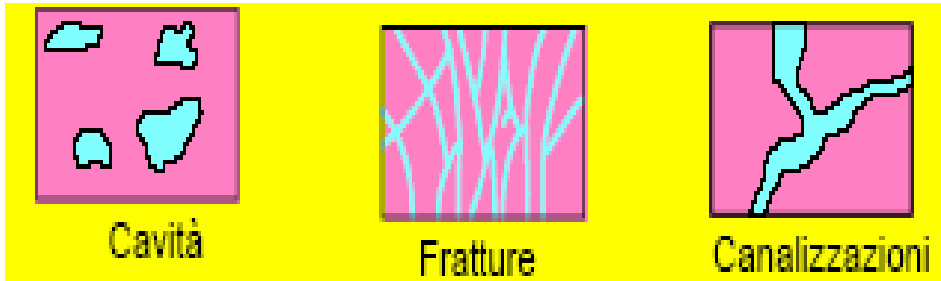## - Solution by circulating <u>warm or hot solutions</u>, opening caused by <u>weathering organisms </u>and enlarged by solution

Cavità   Fratture   Canalizzazioni
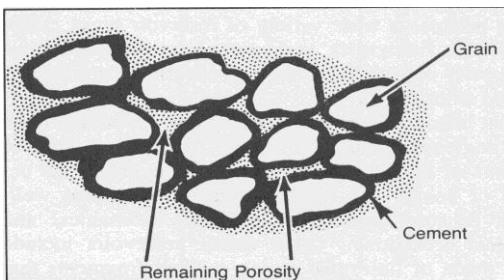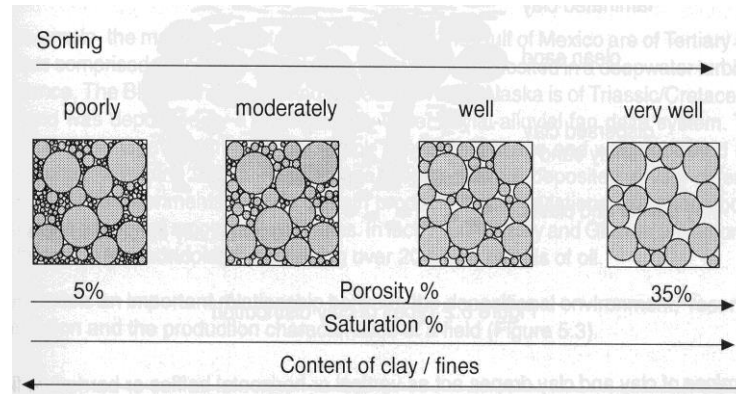
Calcite (pink)
Dolomitization
Atrim Fm., Michigan
Dolomite
2 mm
Permian, W. Texas
2 mm

Productive fractured porous limestone
Non productive hard, dense, impermeable limestone
Crystalline basement

compressive stress
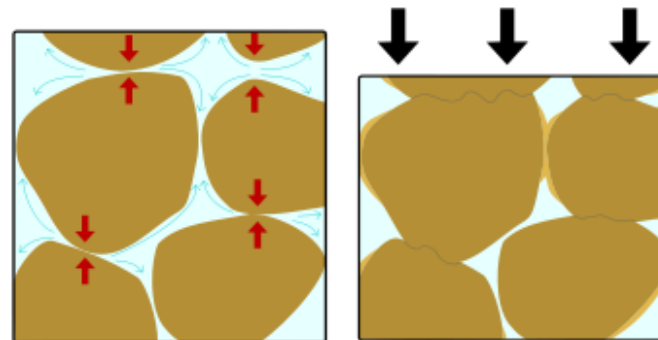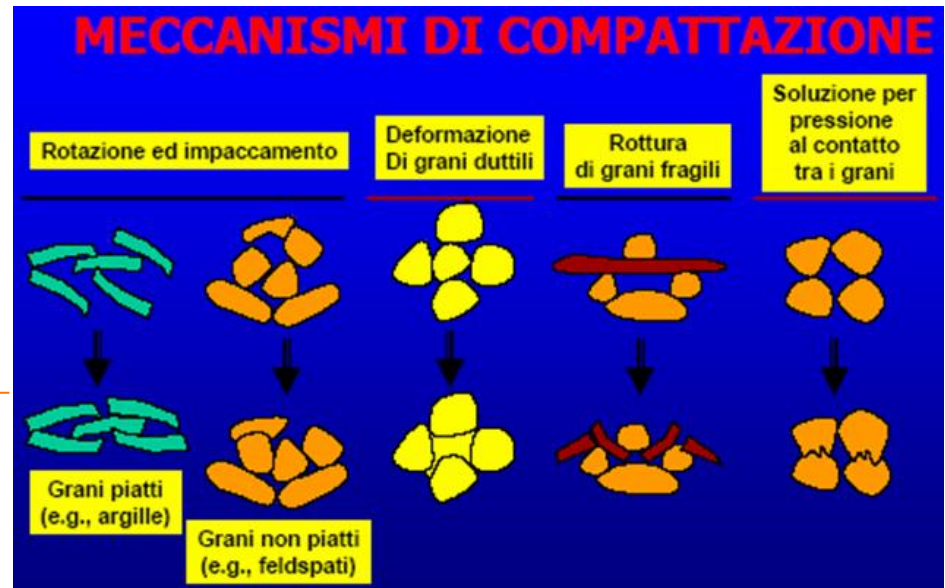Fractures enlarged by solution

FACTORS AFFECTING POROSITY

- **Grain sorting**

- **Grain disposition**

- Cementation

- Grain sizes

- Grain composition

- Compaction

- Pressure solution

Diversa distribuzione della dimensione dei grani

Molto ben classati | ben classati | Moderatam. classati | poco classati | Molto poco classati

POROSITA'

Sorting

poorly | moderately | well | very well

5% | Porosity % | 35%
Saturation %
Content of clay / fines

ORGANIZZAZIONE CUBICA DI SFERE
Porosità = 47,6%

ORGANIZZAZIONE ROMBICA DI SFERE
Porosità = 27 %

Grain

Cement

Remaining Porosity

FACTORS AFFECTING POROSITY

- Grain sorting

- Grain disposition

- **Cementation**

- **Grain sizes**

- **Grain composition**

- **Compaction**

- **Pressure solution**

Pressure solution, accommodating, compression/compaction in a clastic rock. Left box shows the situation before compaction. Light blue arrows indicate the flow of particles in solution. Red arrows indicate areas of maximum stress (= grain contacts). Right box shows the situation after compaction. In light coloured areas new mineral growth has reduced pore space

FACTORS AFFECTING POROSITY

- Grain sorting

- Grain disposition

- Cementation

- **Grain sizes**

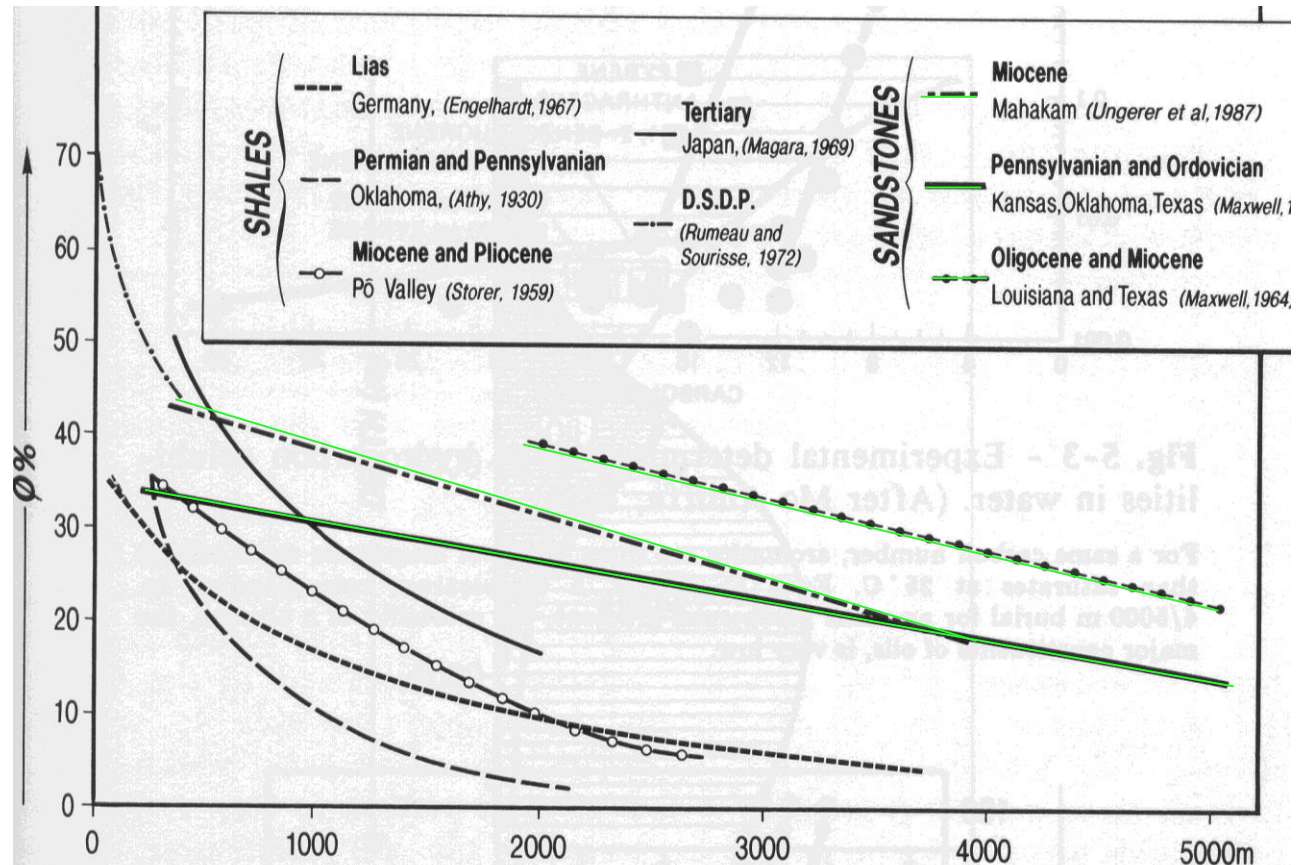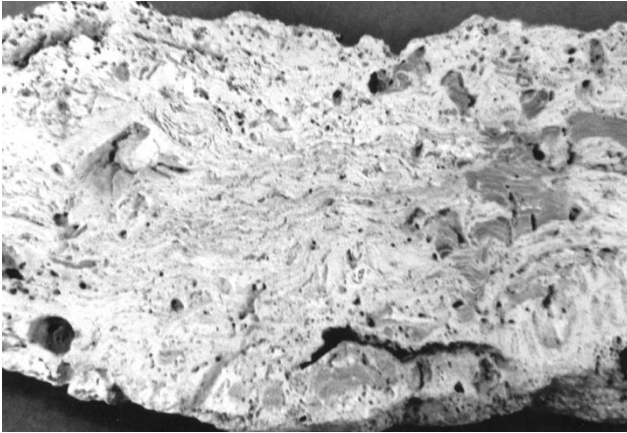- **Grain composition**

- **Compaction**
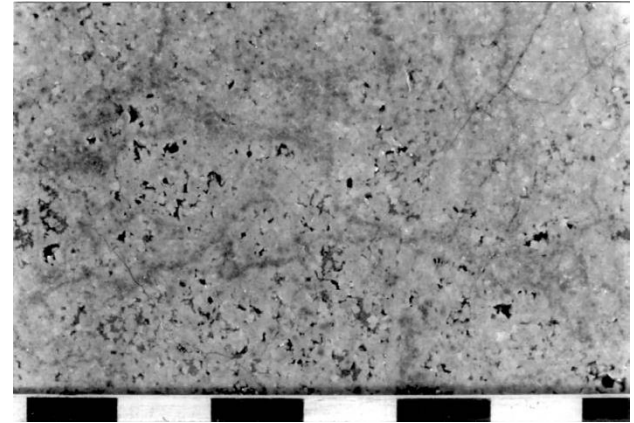
- Pressure solution

Fig. 5-2 – Decrease of porosity in shales and sandstones with increasing depth for selected basins.
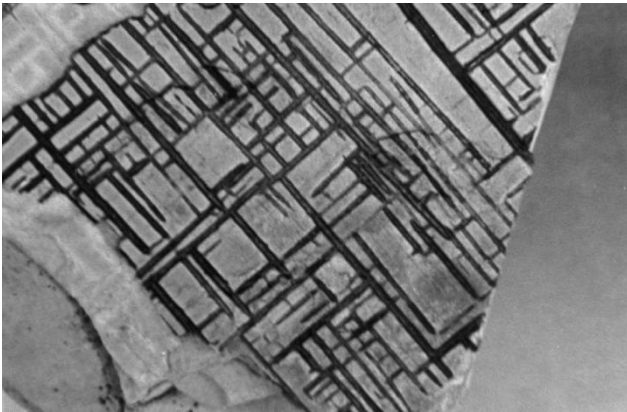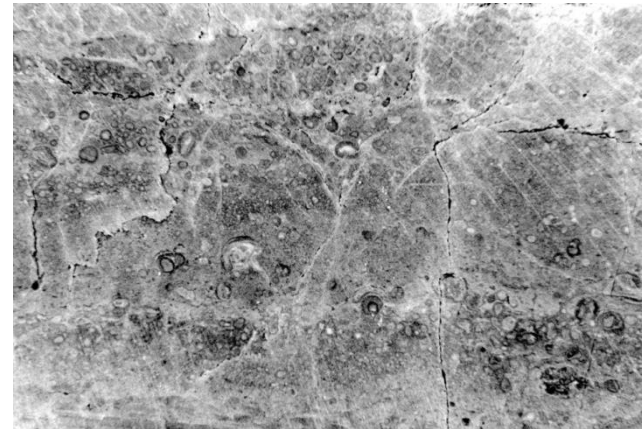
POROSITY

(Phillips, 2009)

An extremely porous limestone from a Bermuda coral reef, containing shell fragments and many interstices with scales of up to a centimeter or so, courtesy of Professor Hardie.

Pores in dolomite from the Latemar Massif in northern Italy. The blocks in the scale are 1 cm long. (Photograph courtesy of Dr. E. N. Wilson.)

A network of plane fractures provided pathways for the flow of fluid in a sandstone cleavage plane, which then diffused into the matrix blocks, courtesy of Professor L. Hardie.

In this calcite block, previous fractures have been filled with dolomite, while more recent fractures remain partially open.

Distribuzione della porosità nelle rocce sedimentarie

Le porosità delle formazioni in sottosuolo mostrano larghe variazioni:

- carbonati (calcari e dolomie):
  - da 0 a 45 %
- evaporiti (sale, anidrite, gesso, silvite, ecc.):
  - porosità praticamente nulla
- arenarie consolidate:
  - da 5 a 15 %
- sabbie inconsolidate:
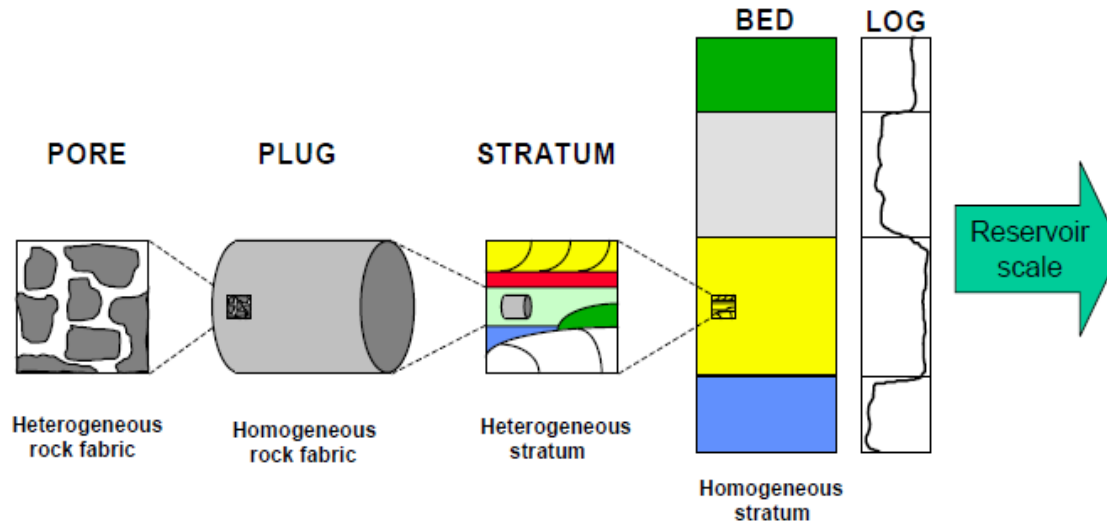 - 30% o più
- argille:
  - spesso più del 40 %

Distribuzione della porosità nelle rocce sedimentarie

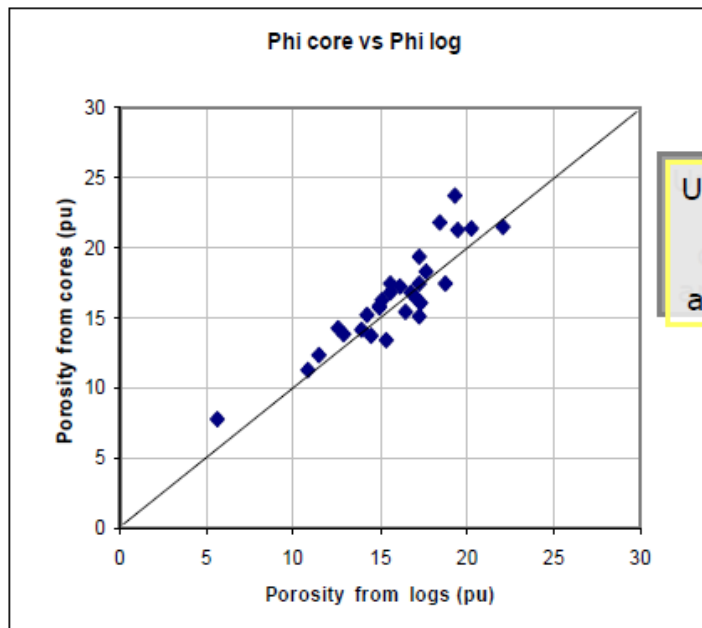| Field	Φ (%) min	Φ (%) max	Lithology
Nigeria	18	35	Clean Sands
Adriatic Sea	25	35	Clean Sands
Adriatic Sea (below 3500 m)	10	15	Clean Sands
Po Valley	20	30	Clean Sands
Persian Gulf (Nowrouz Fm.)	20	25	Clean Sands
Lybia (Bu Attifel)	12	15	Sandstones
Sicily (Gagliano Fm.)	2	6	Low porosity sandstones
Monte Alpi	0	4	Low porosity carbonates
Sicily (Gela Fm.)	0	5	Low porosity carbonates
Cavone	8	12	Oolitic limestones
Persian Gulf (Arab Fm.)	8	15	Limestones
Lybia (off shore)	10	15	Limestones
Lybia (off shore)	20	24	Dolostones
Persian Gulf	25	35	Chalky limestones
North Sea	30	45	Chalky limestones

Distribuzione della porosità in rocce serbatoio tipiche

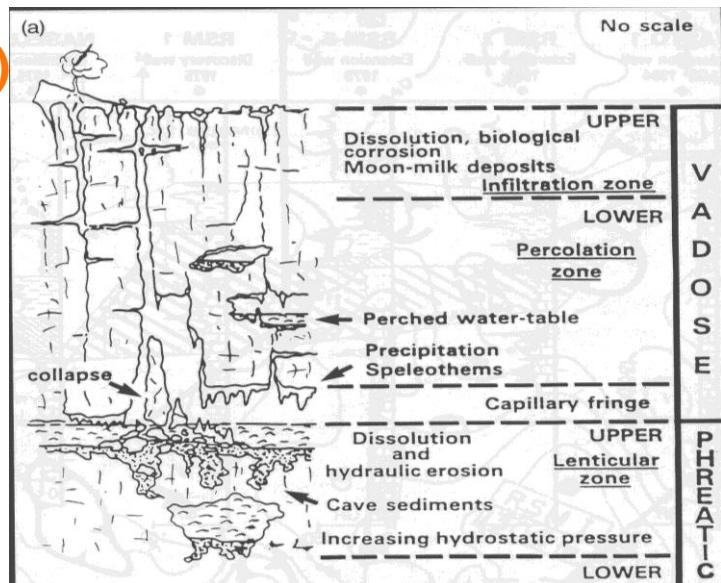da Gonfalini

Problemi relativi alle diverse scale di misura

PORE — Heterogeneous rock fabric

PLUG — Homogeneous rock fabric

STRATUM — Heterogeneous stratum

BED — Homogeneous stratum

LOG

Reservoir scale

Parametri petrofisici: porosità

Phi core vs Phi log

Porosity from cores (pu) vs Porosity from logs (pu)
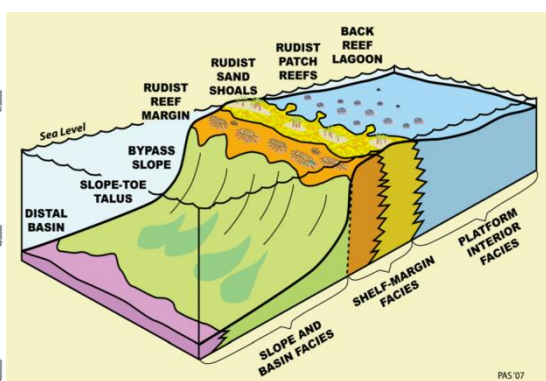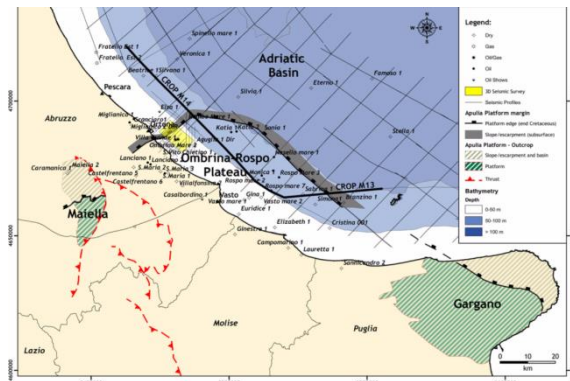
Un esempio di correlazione tra misure di porosità da log e da carote in un arenaria (Fossa Bradanica)
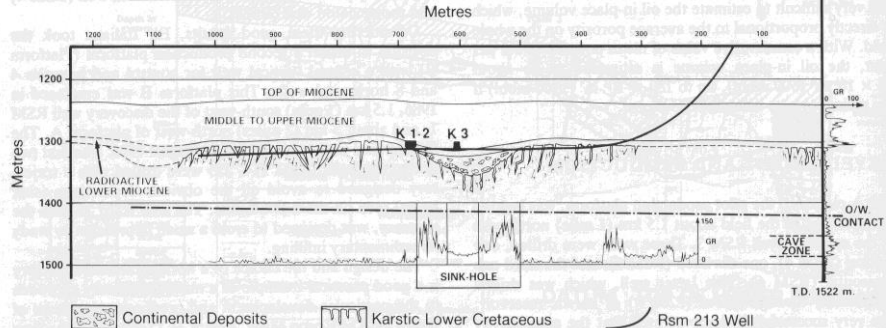
da Gonfalini

Esempio di porosità secondaria per soluzione (carsismo) nel campo di Rospo Mare (Adriatico)
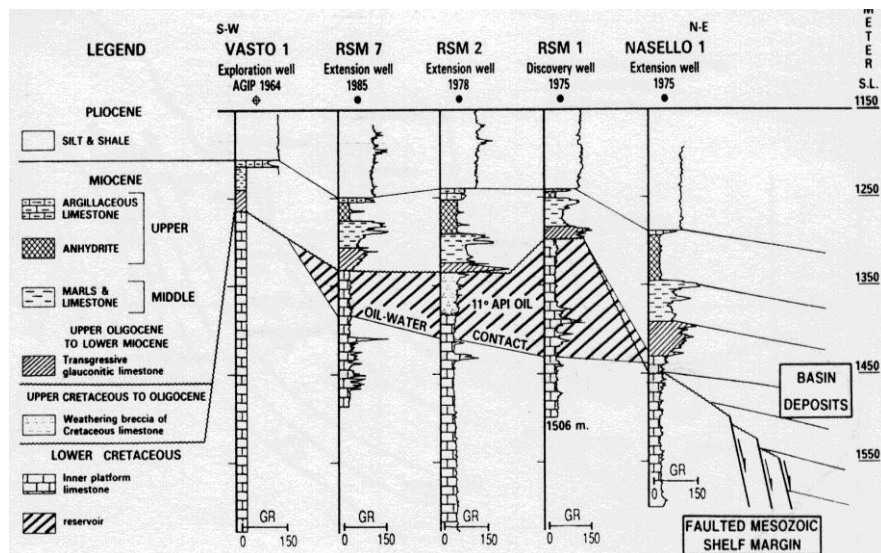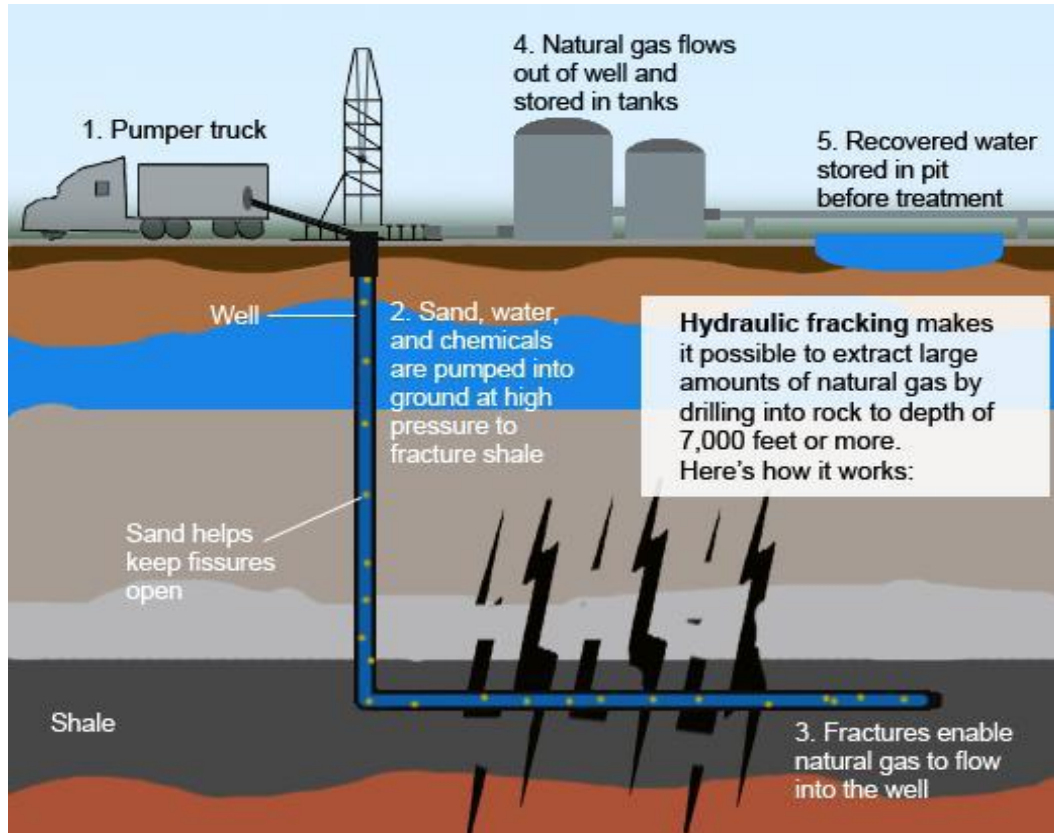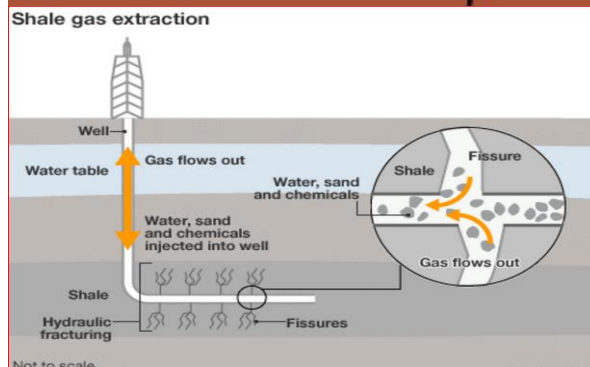

Origine del Carsismo

OWC tiltato per acquifero attivo

FRACKING
HYDRAULIC FRACTURING PROCEDURE

The new artificial secondary porosity that has changed the world economy

1. Pumper truck

4. Natural gas flows out of well and stored in tanks

5. Recovered water stored in pit before treatment

Well

2. Sand, water, and chemicals are pumped into ground at high pressure to fracture shale

Sand helps keep fissures open

Shale

3. Fractures enable natural gas to flow into the well

Hydraulic fracking makes it possible to extract large amounts of natural gas by drilling into rock to depth of 7,000 feet or more. Here's how it works:

Shale gas extraction

Well
Water table
Gas flows out
Water, sand and chemicals
Water, sand and chemicals injected into well
Shale
Fissure
Shale
Gas flows out
Shale
Hydraulic fracturing
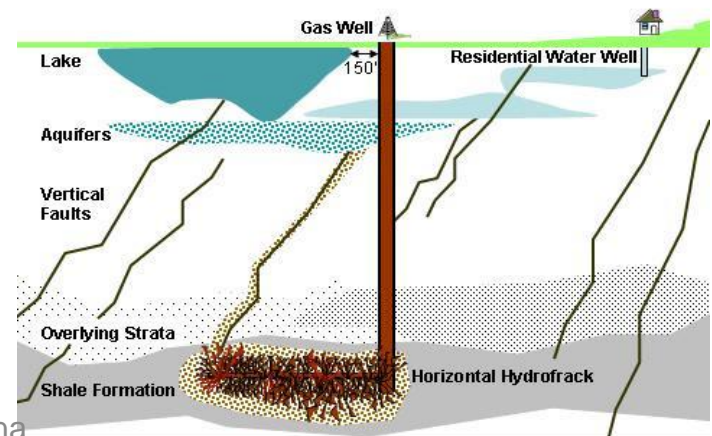Fissures
Not to scale

1. A well is drilled, set with steel casing, cemented, and punctured (perforated) along zones that contain gas;

2. Fracture fluid (water, sand, and chemical mixture) is injected at a very high pressure through the perforations. The high pressure causes the shale rock to crack (fracture), creating fissures for gas to flow through;

3. Sand acts as a proppant (propping agent) to keep fissures open to allow gas flow;

4. Injected fracking fluid pressure is released;

5. Most of the fracking fluid flow back into the wellbore, then pumped to the surface for storage;

6. The fracking equipment is removed; and a temporary wellhead is installed;

7. The well is cleared of water;

8. The natural gas in the shale formation is ready to be produced;

9. Gas can now flow freely into the wellbore; and the fluids containing dissolved natural gas are pumped back to the surface for refining.

Fault Pathway from Shale Gas to Aquifers

Gas Well
Lake
Residential Water Well
150'
Aquifers
Vertical Faults
Overlying Strata
Shale Formation
Horizontal Hydrofrack

Why is it controversial?
-fracking uses huge amounts of water
-potentially carcinogenic chemicals used may escape and contaminate groundwater
-can cause small earth tremors (?)
-is distracting from investing in renewable sources of energy, and encouraging continued reliance on fossil fuels.
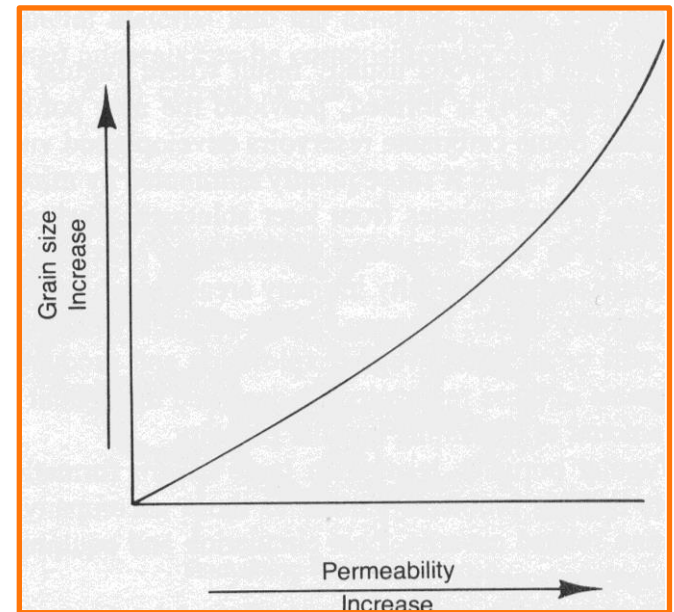
PERMEABILITY

In addition to being porous, a reservoir rock must allow petroleum fluids to flow through its pores. A porous medium allows fluids to move only if the pores are interconnected, in this case we can speak of **permeable rock**.
The permeability thus represents the <u>predisposition of a formation to be crossed by a fluid with a certain viscosity to pass through it</u>.

In figure, a first relation of permeability is with the <u>grain size</u>: greater the size, greater the pores in the rocks.
<u>Porosity</u> (% value) can remain the same, but probability of inter-connection between the pores is greater.

Granulometric composition of sandstones, grain size, pore size, specific surface area, irriducible fluid saturation and other variables, influences the relationship between porosity and permeability.

PERMEABILITY

Porosity/Size/Permeability relationships

Low porosity

High porosity
High permeability

High porosity
Low permeability
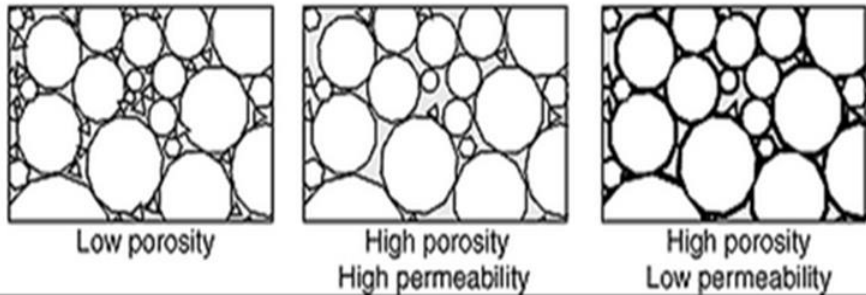
Relationship between permeability and porosity is qualitative, also if useful correlation can be found within one formation.

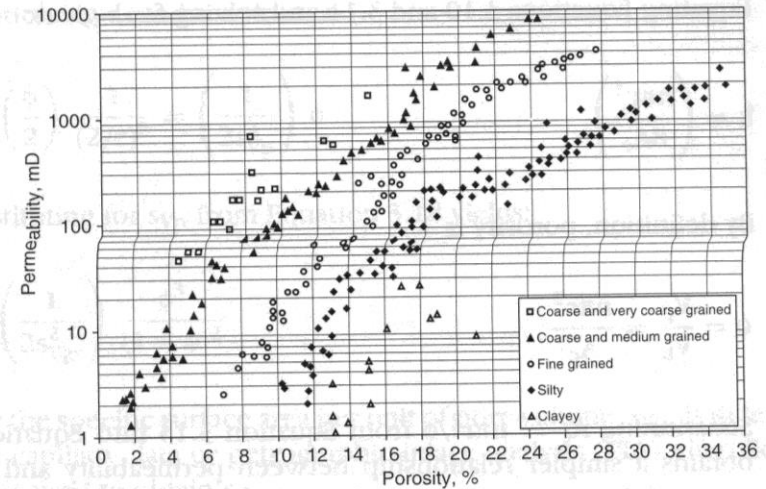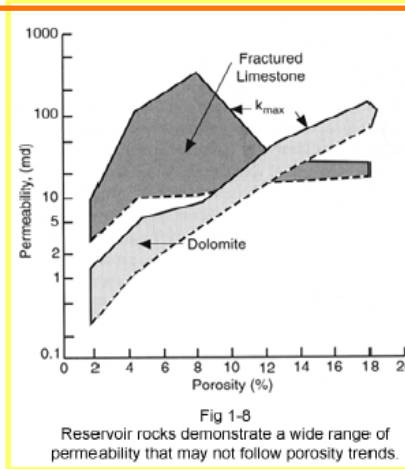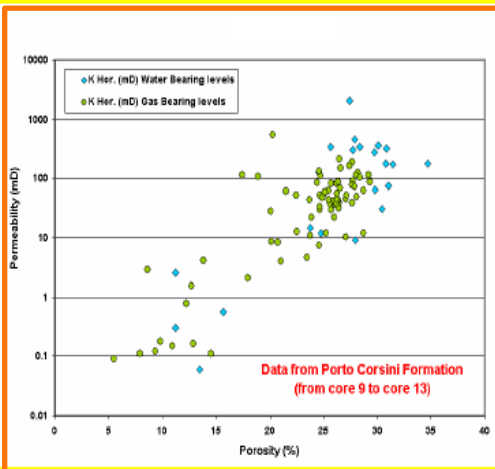**Figure 3.12.** *Influence of grain size on the relationship between permeability and porosity [14].*

Data from Porto Corsini Formation
(from core 9 to core 13)

Fig 1-8
Reservoir rocks demonstrate a wide range of permeability that may not follow porosity trends.
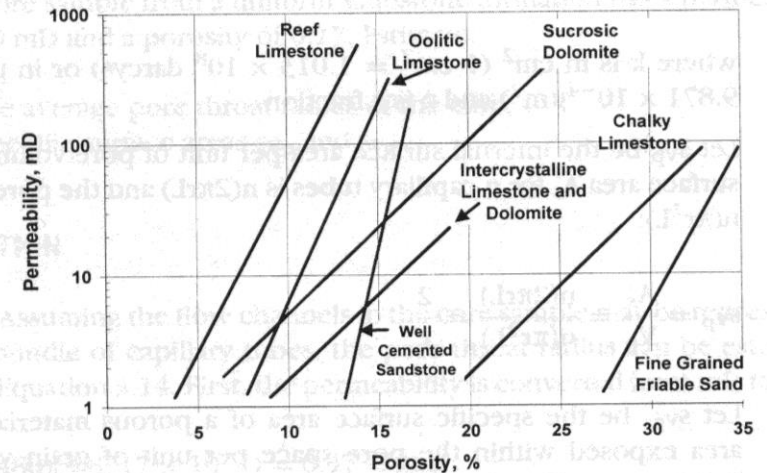
Figure 3.13. *Typical permeability-porosity relationship for various rock types (courtesy of Core Laboratories).*

PETROPHYSICS - Del Ben Anna

PERMEABILITY

Primary or matrix permeability originated at the time of deposition and lithification of the sedimentary rock.

Secondary permeability resulted from the alteration of the rock matrix by compaction, cementation, fracturing and solution.

Compaction and cementation generally reduce the permeability,
fracturing and solution tend to increase it.

Factors affecting the permeability
(often differently for K_H and K_V)
in sediments are:

- Shape and size of the sand grains

- Lamination

- Cementation

- Fracturing & solution
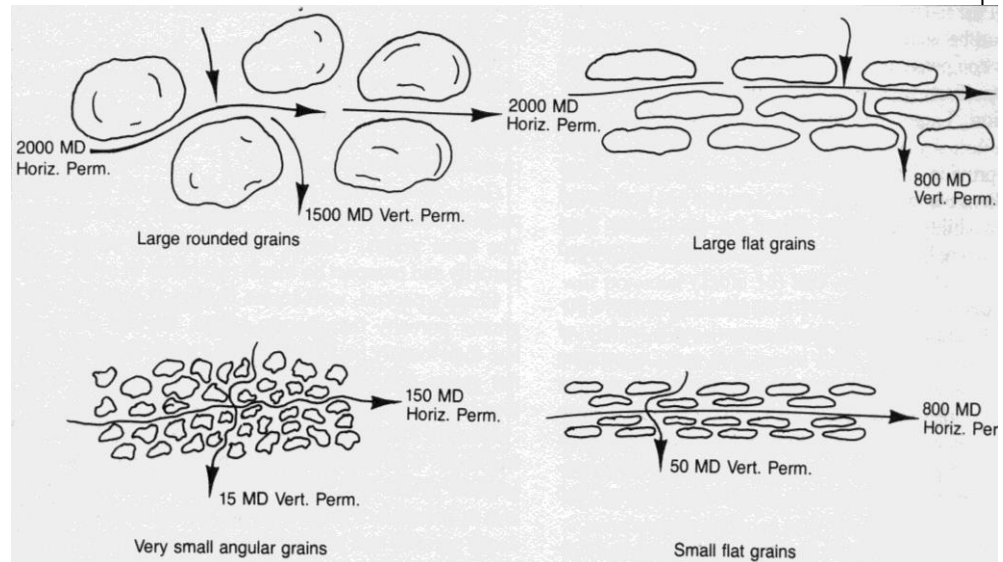
PERMEABILITY

The permeability is measured in Darcy ("D" or, better, in millidarcy "mD")

$$Q = K \frac{S}{\eta} \frac{dp}{dx}$$

where:

-Q is the **fluid velocity** through the rock in cm/s,
-S is the cross sectional area of the rock, in cm^2,
-dp / dx is the **pressure gradient** in the direction of the flow,
 in atm/cm,
-**η** is the **viscosity** of the fluid in centipoises (cP),
-K is the **permeability** expressed in Darcy,
 it depends on the size and sorting of the grains.

Permeability $K = \dfrac{Q \cdot \mu \cdot L}{A \cdot \Delta P}$

 1 Darcy is relatively high permeability => misure in md (milliDarcy)

This equation is derived from the originally empirically defined in 1856 by Darcy, a French engineer who first studied the fluid flow across porous media for the construction of the fountains of Dijon.
This equation is usually applied to granular or porous rocks with primary porosity widespread, and can not be used for fractured rocks in which the movement of the liquid follows different behaviors. For its full validity, reservoir rock must be completely saturated by a not compressible fluid, isotropic and resting on a waterproof substrate horizontal, having a constant cross section of area A and in which the fluid flows into the laminar regime.
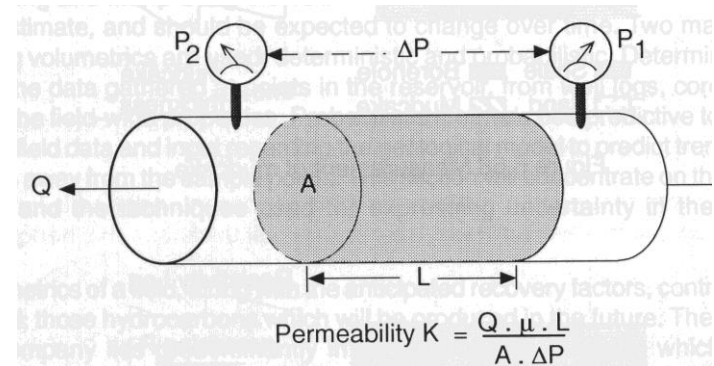
In describing Darcy's law, it has so far been assumed that the ABSOLUTE PERMEABILITY is a rock property which is a constant, irrespective of the nature of the fluid flowing through the pores.

PERMEABILITY

$$Q = K\frac{S}{\eta}\frac{dp}{dx}$$

The equation defines the **ABSOLUTE PERMEABILITY K**, valid if the rock is 100% saturated with a single fluid (or phase), such as oil, gas or water.

In some case the porous medium is saturated from <u>more immiscible phases</u> (<u>multiphase conditions</u>). These conditions are typical of hydrocarbon reservoirs, where the phases can be oil, gas, and water simultaneously. When the phases are in motion, you have the so-called <u>polyphasic motion</u>.

In presence of <u>more than one fluid</u>, we have to speak about **EFFECTIVE PERMEABILITY** (respectively K_o, K_g or K_w or, better, K_{eo}, K_{eg} or K_{ew}). Reservoir fluids interface with each other during their movement through the porous channels on the rocks; consequently the sum of the effective permeability of all the phases will be always less than the absolute permeability.

RELATIVE PERMEABILITY, is defined as :

$$K_{ro} = K_{eo}/K, \qquad K_{rg} = K_{eg}/K, \qquad K_{rw}, = K_{ew}/K$$

where K is the absolute permeability for that fluid with a saturation of 100%.

K_r are dimensionless, its value ranges between 0 and 1. The relative permeability may generate a slow and selective fluid migration (pass first, or only, the lighter components).
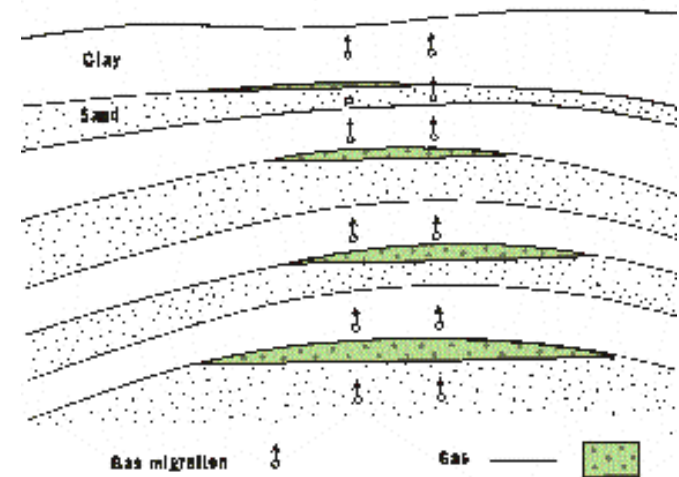

Fig. 67. — Vertical migration through shale seale (Neglia, 1979).

PERMEABILITY

Relative permeability values K_{ro}, K_{rg}, K_{rw}, are a function of:

- **rock chemical & physical properties**

- fluid disposition, related to the relative **wetting characteristics**

  and to the developing of their **saturation**

- **fluid velocity**   - **fluid viscosity**

It ranges between 0 and 1 and is represented in diagrams

where it is related to.

It is also sensitive to **temperature** because of the water-oil-rock

system becomes more water-wet as the temperature is increased.

Fluid Saturation/Permeability relationships
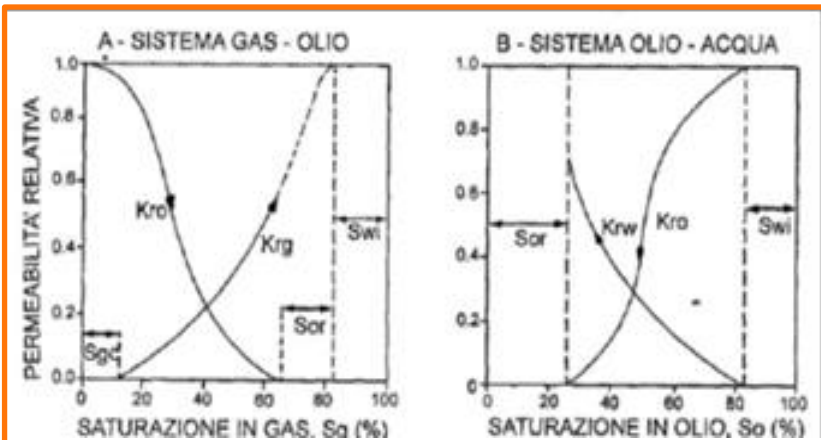
- drenaggio
(diminuzione di
saturazione della
fase bagnante)

-imbibizione
(aumento di
saturazione della
fase bagnante)
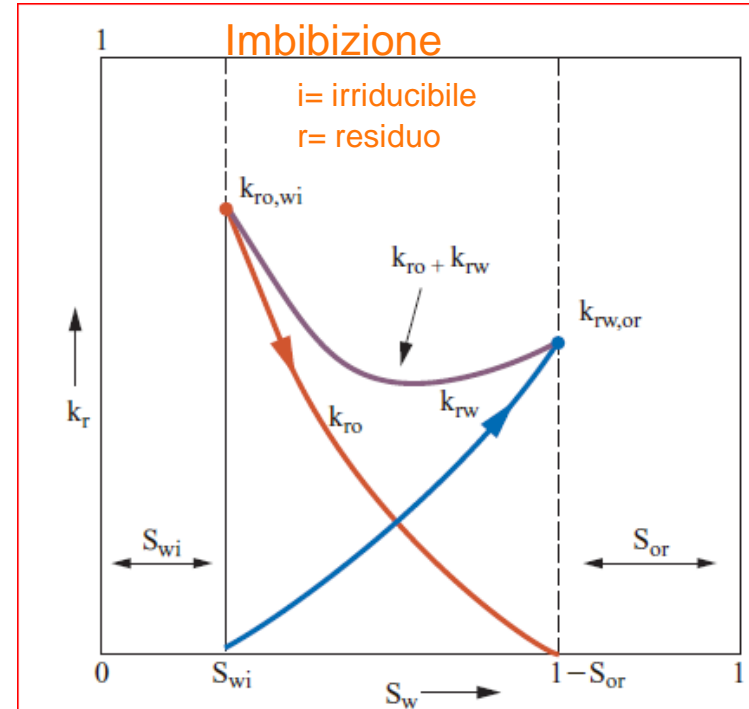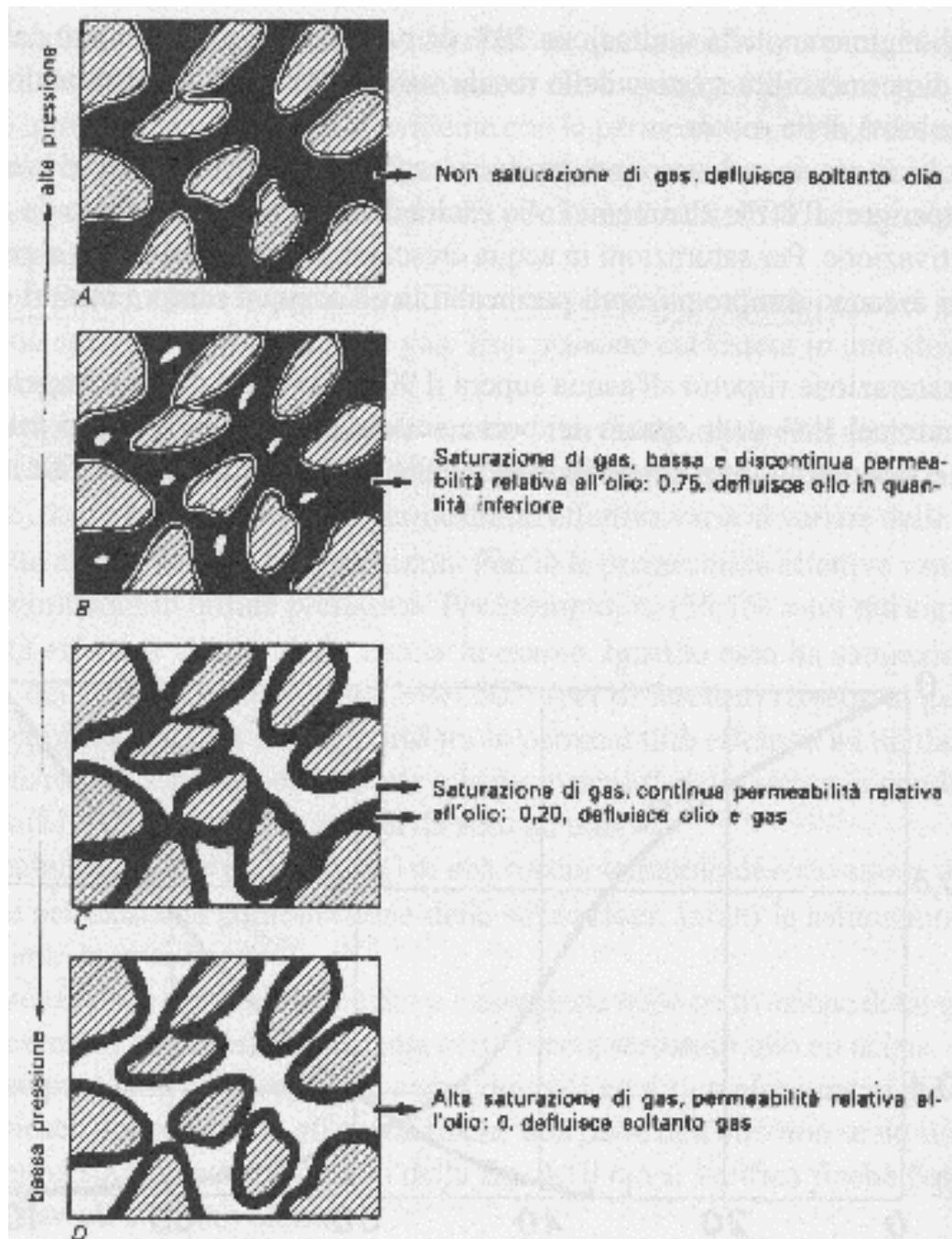
fig. 7. Curve di permeabilità relativa: S_{wi}, saturazione in acqua irriducibile; S_{or}, saturazione in olio residuo; $k_{ro,wi}$, permeabilità relativa all'olio in presenza di acqua irriducibile; $k_{rw,or}$, permeabilità relativa all'acqua in presenza di olio residuo. Si noti che la curva somma delle permeabilità relative all'olio e all'acqua ($k_{ro}+k_{rw}$) è sempre minore di 1.

Figure labels (left, top to bottom):

A — *alta pressione* — Non saturazione di gas. defluisce soltanto olio

B — Saturazione di gas, bassa e discontinua permeabilità relativa all'olio: 0.75, defluisce olio in quantità inferiore

C — Saturazione di gas. continua permeabilità relativa all'olio: 0,20, defluisce olio e gas

D — *bassa pressione* — Alta saturazione di gas, permeabilità relativa all'olio: 0, defluisce soltanto gas

The relative permeability do not depend only on the rock but also by the proportions of the different fluids contained. The different fluids are expulsed separately following their saturation in the porosity.

In the real case, a reservoir generally contains two or more fluids. A porous medium allows fluids contained in it to move only if the pores are interconnected, in this case we speak of rock which is permeable to that fluid.

The flow velocities of the fluids interfere and the sum of relative permeabilities is smaller than absolute.

← On the left:
Same solution of fluids at different pressure values gives different fluids saturation. Relative permeability of gas and oil will be strongly changing.

It is conventional to plot both permeabilities as functions of the water saturation alone since the oil saturation is $So = 1 - Sw$.

In an oil/water system the <u>relative permeability (K_o)</u> of the oil is max (approximates to 1), when the <u>saturation oil is maximum</u> (ca. 70-80%).

Considering the permeability curve for water, two points on this curve are known:

-if $Sw \leq Swc$ (Swc is the **critical water saturation**) connate or irreducible water saturation:
the <u>water will not flow</u> and $Kw = 0$

-$Sw = 1$ rock entirely saturated with water
→ $kw = kro$

For the curve of oil:

$Sw = 0 (So = 1)$ rock saturated with oil: $ko = k$

$Sw = 1 - Sor$ → $So = Sor$ (residual oil saturation)

not oil flow and $ko = 0$
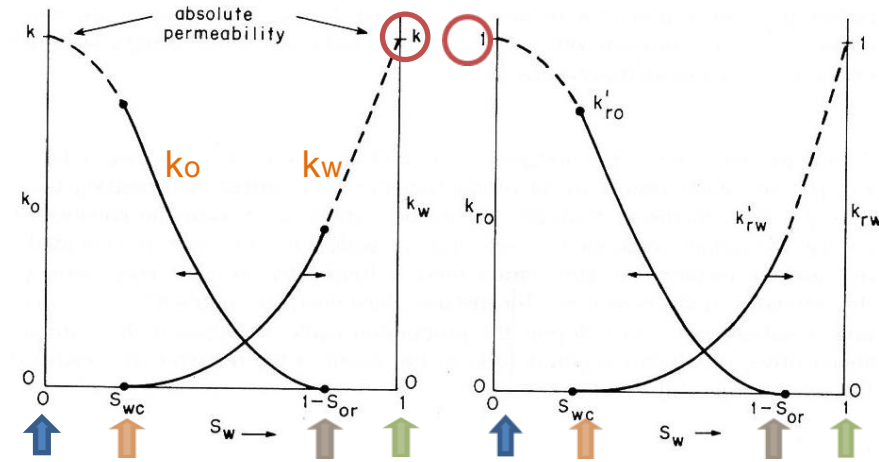

Effective *and* relative permeability plots:
they have the same shape, the only difference is the scale. Note the dashed lines

Figure below: the permeability of water initially is about zero, then (S_w=45-50%) it grows rapidly.   →
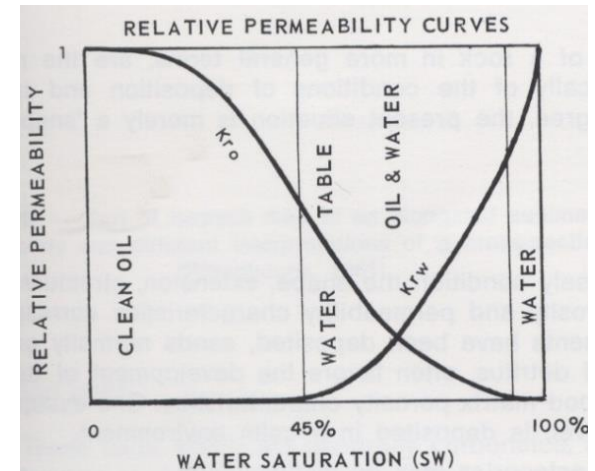The figure indicates that <u>the oil can be extracted up to a saturation of 50-55%,</u> after which it will be released a <u>mixture oil / water</u> with a fraction of water that goes to increase with Sw.

For Sw > 80-90% will be released <u>only water</u>.

The <u>wettability</u> has the main influence on the shapes of the curves, also if it is difficult to quantify.

RELATIVE PERMEABILITY CURVES

Classificazione della permeabilità

Permeabilità assoluta
permeabilità della roccia quando i pori sono riempiti da un solo fluido.

Permeabilità relativa
Permeabilità della roccia quando sono contemporaneamente presenti più fluidi; è il rapporto tra la permeabilità effettiva ad un fluido in presenza di un altro fluido e la permeabilità assoluta

Permeabilità effettiva
K_w = permeabilità eff. all'acqua
K_o = permeabilità eff. all'olio
K_g = permeabilità eff. al gas

Permeabilità relativa
$K_{rw} = K_w / K$ K rel. all'acqua
$K_{ro} = K_o / K$ K rel. all'olio
$K_{rg} = K_g / K$ K rel. al gas

Permeabilità orizzontale (Kh) e permeabilità verticale (Kv)
La permeabilità è una proprietà tensoriale e dipende dalla direzione di misura;

Kh e Kv in una roccia sedimentaria variano per la disposizione dei granuli e in rocce competenti per la presenza di fratture.

da Gonfalini

Horizontal Permeability (mD)

2000 - 4000	600 - 1000	200 - 400
1000 - 2000	400 - 600	100 - 200

50 - 100	1 - 10
10 - 50	Impermeable Shale Drapes

HYDROCARBON RESERVOIR

Oil accumulation in trap
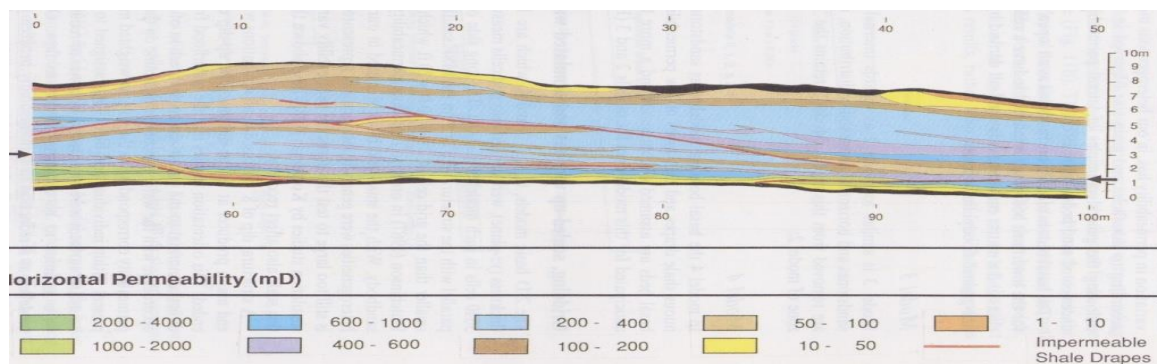
The hydrocarbon reservoir can be characterized by
one (**water with dissolved gas**)
two (**gas-water**, or **oil-water**)   fluid phases
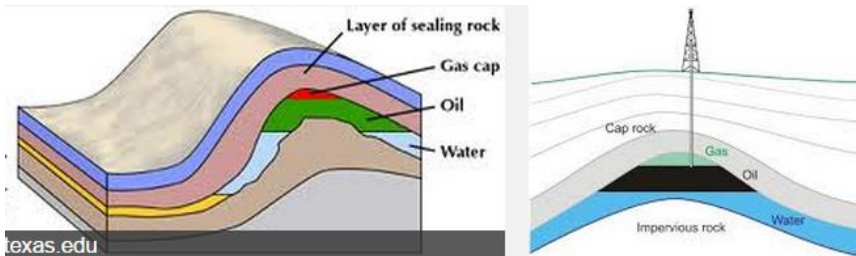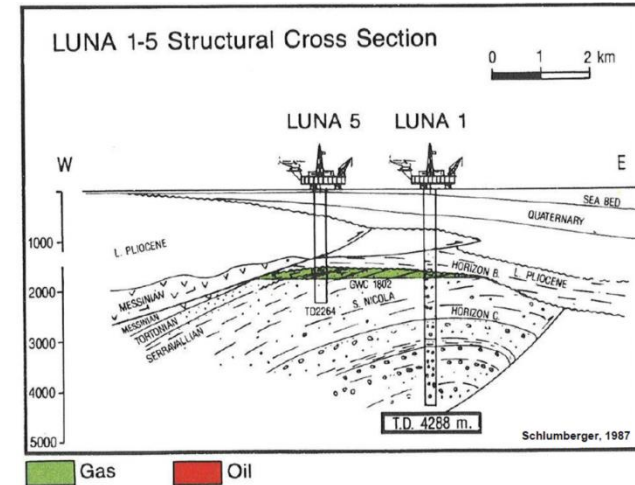three (**gas-oil-water**)

Free gas: the gas is present at the top of reservoir
                                    - above oil (GAS CAP)
                                    - above water (only gas reservoirs)

Solution gas: in all the oil reservoirs. Quantity of gas changes
with pression and temperature. When saturation point has
been reached, the extra gas produces the gas cap.

LUNA 1-5 Structural Cross Section
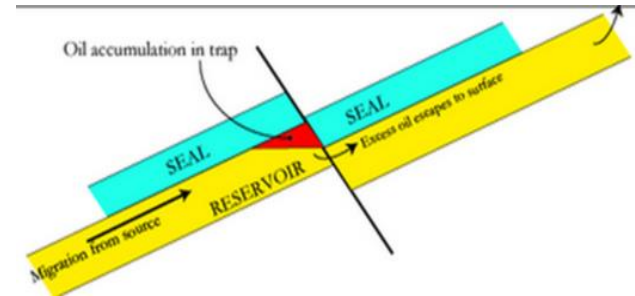
Different fluid phases are <u>separated by surfaces,
which are generally horizontal</u>, and are named:

- **GOC** (Gas Oil Contact, contatto gas-olio);
- **GWC** (Gas Water Contact, contatto gas-acqua);
- **OWC** (Oil Water Contact, contatto olio acqua);
- **WT** (Water Table, tavola d'acqua);

COMPORTAMENTO DEI **FLUIDI**

Si intende per **fase** ogni regione omogenea e fisicamente distinta, separata da altre regioni attraverso un limite netto. Negli idrocarburi le fasi più importanti sono <u>liquida</u> (acqua e olio), <u>gassosa</u> (o vapore) e, in misura minore, solida.

E' importante capire le condizioni dei fluidi nel giacimento di P e T per poter calcolare i volumi in superficie e le variazioni di fase durante l'estrazione.

Il modo più semplice è quello di considerare inizialmente un singolo componente (per es. l'acqua), osservando per ora le sole variabili P e T.

Un liquido che subisca aumento di T , partendo da A, attraversa la curva del punto di ebollizione nel "*boiling point*" or "*bubble point*", superato il quale si ha l'evaporazione. Se la temperatura diminuisce, il vapore da B raggiunge la curva del punto di rugiada nel "*dew point*".

Per un singolo componente i due punti, e le corrispondenti due curve, sono coincidenti. La curva si definisce
"*vapor pressure curve*".

Nel "**punto triplo**", caratteristico per ogni sostanza, le <u>tre fasi possono coesistere</u>.

Nel "**punto critico**", definito da Tc e Pc, diviene impossibile distinguere tra fase liquida e fase gassosa: il gas altamente compresso ha stessa densità e stesso aspetto di un liquido ad alta temperatura
⇒ **fluido supercritico**.

Durante lo sfruttamento di un giacimento si assume generalmente una "*isothermal depletion*" (da A ad A').

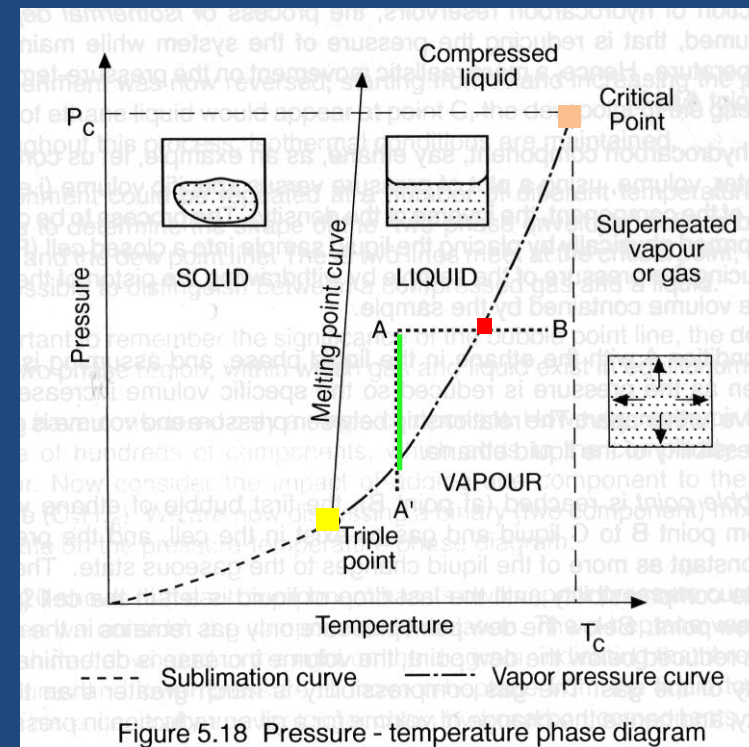Il grafico però, oltre a considerare un solo componente, <u>non tiene conto delle variazioni di volume</u> ...

Figure 5.18 Pressure - temperature phase diagram

Analizzando ora **un solo idrocarburo**, per es. etano, e considerando il parametro "volume", utilizziamo un grafico P / volume specifico. Il processo può essere descritto ponendo il fluido in una "cella PVT" a temperatura costante e riducendo la pressione del campione con un arretramento del pistone (immagini a sinistra).

Al variare da A ad A' si avrà una diminuzione di P ed un aumento di volume specifico (Vs) in funzione della compressibilità del fluido. Al punto B la curva (isotermica) raggiunge il *bubble point* B e la prima bolla di etano vapore si forma. Da B a C coesistono le due fasi, liquida e gassosa, la P rimane costante (ma Vs aumenta) fintanto che tutta la fase liquida è trasformata in fase vapore nel *dew point* C.

Da C si ha solo fase gassosa, la cui compressibilità è molto maggiore rispetto alla fase liquida, quindi la variazione di Vs a parità di variazione di P sarà maggiore.
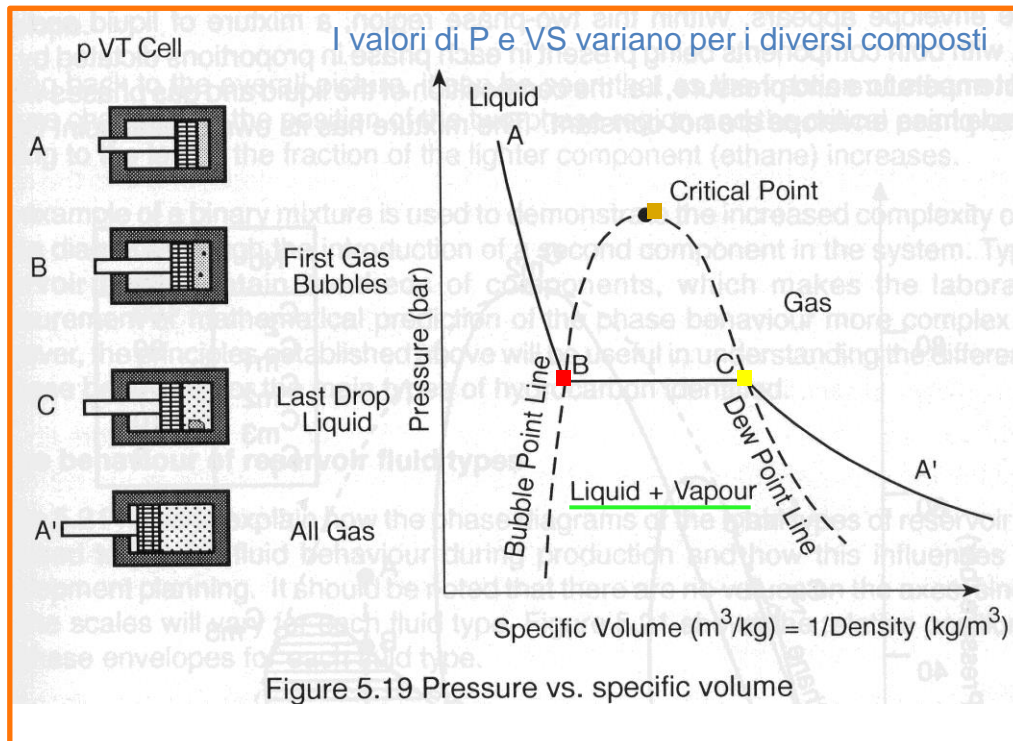
Misurando i punti B e C per diverse T si ottengono le curve (- - - - in fig.) di
Bubble point
e di
Dew   point
Le due curve si incontrano nel
punto   critico
dove liquido e gas compresso sono indistinti.
Le due curve inoltre delimitano il
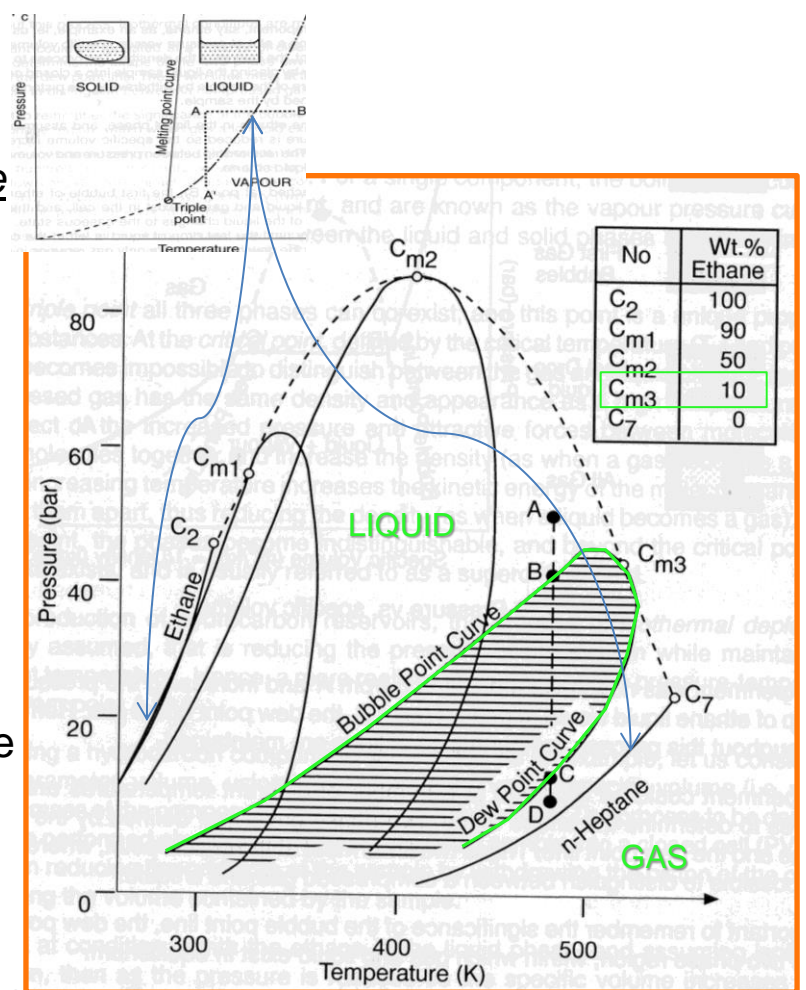*two-phase envelope*
dove   coesistono le due fasi.
…
stiamo però considerando ancora un solo componente …

I valori di P e VS variano per i diversi composti

Figure 5.19 Pressure vs. specific volume

Specific Volume (m^3/kg) = 1/Density (kg/m^3)

Consideriamo ora un **composto binario**, dato da etano (C_2H_6) e n-eptano (C_7H_{16}), sul grafico PT. Ogni singolo componente ha una sua *vapor pressure curve*, più bassa e più a destra per il n-eptano, ad indicare la maggior difficoltà per il passaggio di fase del composto a catena più lunga.

Se consideriamo una miscela (qui al 10% di etano e 90% di n-eptano) le due curve del *Bubble Point* e del *Dew Point* non coincidono, si ha quindi l'area a due fasi: ogni componente sarà presente nelle due fasi in proporzioni diverse in funzione di PT, quindi la composizione sarà variabile.

Se consideriamo un **andamento isotermico** a partire da A (fase interamente liquida), in B si formerà la prima bolla di gas (etano, più leggero), via via si formerà anche gas n-eptano e le fasi avranno composizioni variabili. In C l'ultima goccia di fase liquida (n-eptano) evapora e si avrà solo fase gassosa.

Le diverse *two-phase envelope* (da qui per brevità 2-PE) dovute alla diversa proprzione iniziale Tra C2 e C7, insieme andranno a descrivere la <u>curva dei punti critici</u> (CP).
Questo esempio di composto binario ci suggerisce la complessità del comportamento di un fluido nel *reservoir*, generalmente dato dalla miscela di centinaia di diversi idrocarburi. Ciò rende alquanto complesse le misure e le previsioni matematiche dei comportamenti di fase. Comunque i principi stabiliti sopra saranno utili per capire i diversi comportamenti .

When P of an oil (**volatile or black**) is greater than the *bubble point pressure*, that **oil** is **unsaturated**.

P of the *bubble point is of a*
          saturated oil
because if we would add gas,
it is not dissolved in the oil.

$\Rightarrow$**P** in the *bubble point* is
the saturation pression of that fluid
in the reservoir.
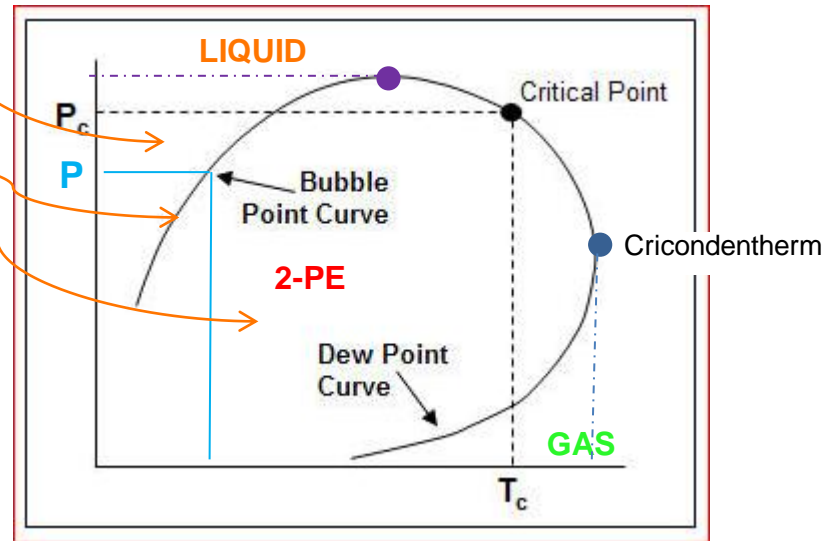
Oil with a *gas cap: pressure of the gas-oil contact* (GOC) is, for definition, the P of the *bubble point.*

Gas of the *gas cap* is called *free gas*,
gas in solution inner oil is called *solution gas*.

Cricondenbar is the maximum pressure above which no gas can be formed regardless of the temperature.
Cricondentherm is the maximum temperature above which liquid can not be formed regardless of the pressure.

In figura si vede la posizione delle Two *Phase Envelopes* *(2*-PE) per le principali tipologie di olii considerando le diverse condizioni in giacimento in funzione dei valori di P e T.

Si distinguono:

-Dry gas: il campo di esistenza contemporanea delle due fasi è molto ridotto, con temperature e pressioni decisamente basse , si noti inoltre la posizione della cricondoterma   => in giacimento solo fase gassosa

-Wet gas ....
-Gas condensate ....
-Volatile oil ....

-Black oil: la posizione del 2-PE più in alto e più a destra corrisponde a miscele contenenti maggior quantità di composti più pesanti. P e T della 2-PE descrivono una curva molto ampia che racchiude Un range molto ampio di condizioni del giacimento al suo interno => in giacimento fasi liquida e gassosa

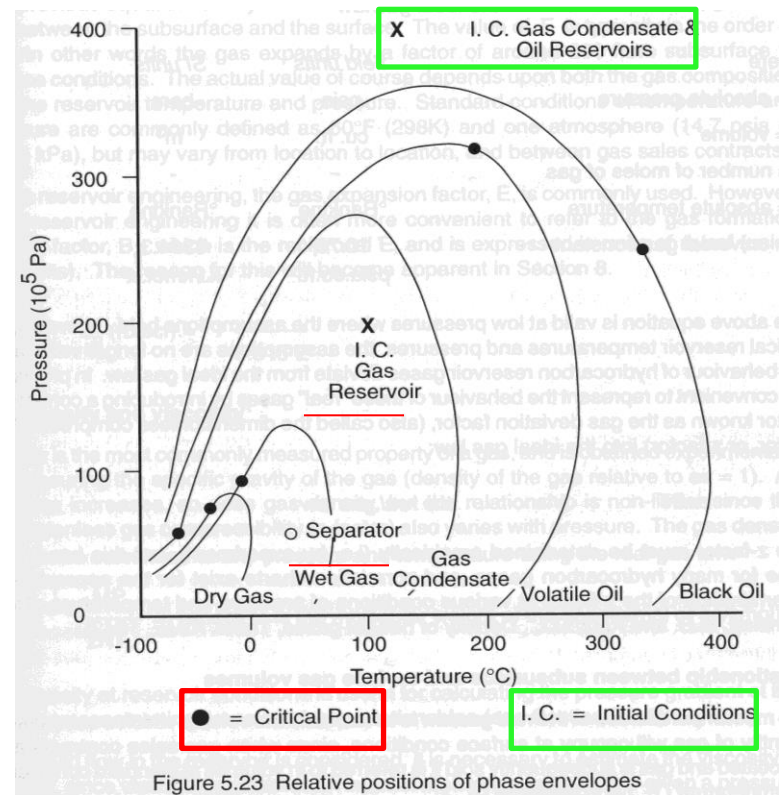Le condizioni tipiche al separatore sono 50 bar e 15°C.

Figure 5.23 Relative positions of phase envelopes

Characteristic	Oils			Gases	
	Heavy Oils and Tars	Black Oils	Volatile Oils	Gas Condensates	Wet and Dry Gases
Initial fluid molecular weight	210+	70 to 210	40 to 70	23 to 40	<23
Stock-tank-oil color	black	brown to light green	greenish to orange	orange to clear	clear
Stock-tank oil-gravity, °API	5 to 15	15 to 45	42 to 55	45 to 60	45+
C_7-plus fraction, mol%	>50	35 to 50	10 to 30	1 to 6	0 to 1
Initial dissolved GOR, scf/STB	0 to 200	200 to 900	900 to 3,500	3,500 to 30,000	30,000+
Initial FVF, B_{oi}, RB/STB	1.0 to 1.1	1.1 to 1.5	1.5 to 3.0	3.0 to 20.0	20.0+
Typical reservoir temperature, °F	90 to 200	100 to 200	150 to 300	150 to 300	150 to 300
Typical saturation pressure, psia	0 to 500	300 to 5,000	3,000 to 7,500	1,500 to 9,000	—
Volatile-oil/gas ratio, STB/MMscf*	0	0 to 10	10 to 200	50 to 300	0 to 50
Maximum vol% liquid during CCE**	100	100	100	0 to 45	0
OOIP, STB/acre-ft (bulk)	1,130 to 1,240	850 to 1,130	400 to 850	60 to 400	0 to 60
OGIP, Mscf/acre-ft (bulk)	0 to 200	200 to 700	300 to 1,000	500 to 2,000	1,000 to 2,200

*At bubblepoint pressure. **Constant composition expansion of reservoir fluid.

Dry gas: le condizioni iniziali sono fuori della 2-PE e a destra del CP. Composizione e fase (gassosa) del fluido rimangono costanti anche in superficie.

Wet gas: contiene una maggior proporzione di C_2-C_6 . Nel *reservoir* sempre fase gassosa, al separatore anche fase liquida dei componenti più pesanti => alto valore commerciale + dry C_1.

Gas Condensate: la T iniziale nel giacimento sta tra il CP e la cricondoterma (Tmax di 2-PE): con l'estrazione e conseguente diminuzione di P si raggiunge il *dew point* e conseguente ridotta condensazione => non saturazione del liquido (alto valore commerciale); si noti come al diminuire di P il volume del liquido inizialmente aumenta sotto il *dew point* => *retrograde gas condensate.* Questo incentiva il mantenimento di alte P nel reservoir.

Figure 5.21 Pressure temperature phase envelopes for main hydrocarbon types

Volatile Oil: T nel reservoir sotto il CP => fase liquida in giacimento. Con la diminuzione di P si raggiunge il *bubble point* con formazione di fase gassosa contenente più componenti volatili rispetto al fluido iniziale. Importante trasformazione in fase gassosa (parte nei pozzi, parte nel *gas cap*) anche per ridotte diminuzioni di P. Al separatore in superficie si hanno condizioni interne al 2-PE, con conseguente liberazione di gas.

Black Oil: con porzione minore di componente volatile rispetto precedenti, richiedono maggior caduta di P per volumi significativi di gas (curve vicine alla linea dei *dew point*)
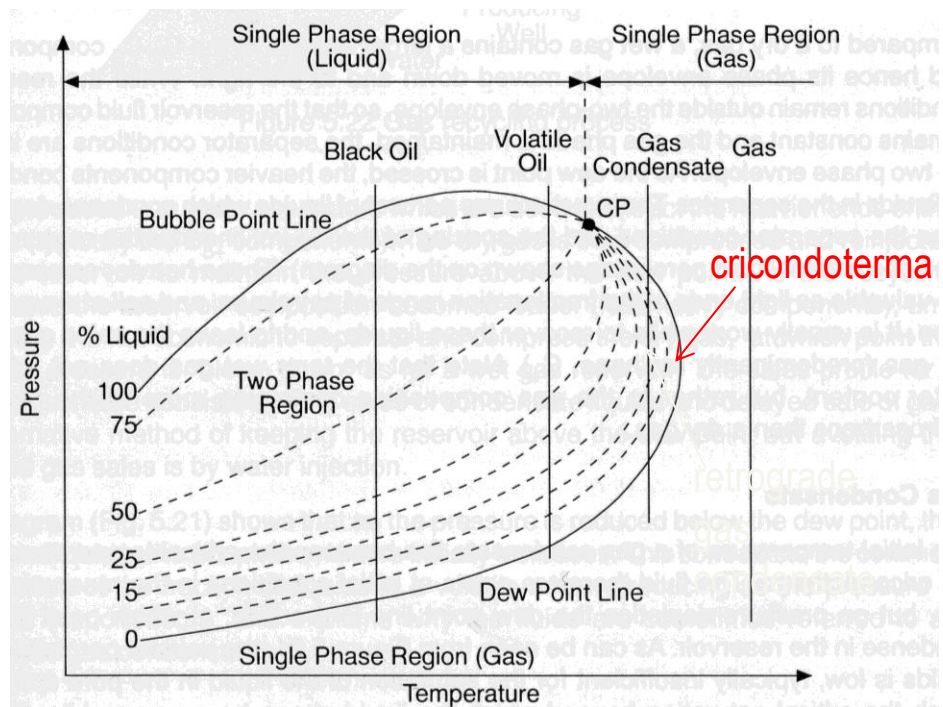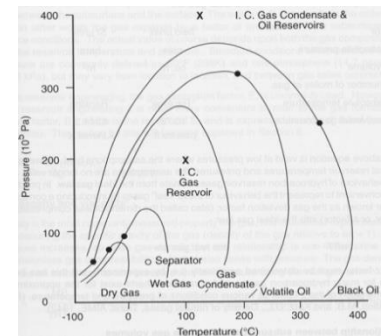
ALCUNE CARATTERISTICHE FISICHE DI OLIO E GAS

<u>DENSITA' OLIO</u>: riflette la composizione chimica, varia con la temperatura. A condizioni ambientali sono meno densi dell'acqua (nei pori acqua salata, densità 1.0-1.2 gr/cm³), in sottosuolo la densità dell'olio (**0.5-0.9 gr/cm³**) è condizionata dai gas disciolti.

<u>DENSITA' GAS</u>: a condizioni ambientali per il metano è 0.0003 gr/cm³, a 3-4000 m di profondità è di **0.2-0.4 gr/cm³**.

<u>In sottosuolo, quindi, le densità di olio e gas sono dello stesso ordine di grandezza</u>

PESO SPECIFICO (relativo) o *SPECIFIC GRAVITY*:

-per i <u>liquidi rispetto all'acqua distillata</u>, calcolato a 4°C

-per i <u>gas rispetto all'aria</u>, calcolato a 0°C (generalmente 0,6-0,9   ma anche oltre 1)

$$\gamma = \frac{P}{V} = \frac{mg}{V} = \rho g$$

Densità dell'olio: misura in GRADI API

$$°API = \frac{141,5}{PS} - 131,5 \qquad PS = \frac{141,5}{°API + 131,5}$$

Il petrolio (*crude oil*)

Definizione: miscela di idrocarburi che si trovano alla fase liquida nel sottosuolo e che rimangono liquidi una volta in superficie.

°API = [141.5 / (specific gravity 60/60°F)] – 131.5

dove 60/60°F è il peso specifico dell'olio a 60°F in rapporto a quello dell'acqua alla stessa temperatura

Un fluido con peso specifico 1 g/cm³ ha 10°API.

Idrocarburi pesanti: <20°API (peso specifico >0.93)

Idrocarburi "normali": 20-40°API (p.s. 0.83-0.93)

Idrocarburi leggeri: >40°API (p.s. <0.83)

Generalmente, la viscosità è inversamente proporzionale ai gradi API

API

American
Petroleum
Institute

Conversione
°Farehnait/Centigradi
°C= (°F-32) x 5/9

°API	PS	
0	1,076	oli pesanti (ricchi in nafteni)
10	1,00	
20	0,934	
22		oli medi
30	0,876	
40	0,825	oli leggeri
50	0,780	
60	0,739	

PROPERTIES OF GAS

The properties of gases are simple, because related by the single <u>equation of state for an ideal gas</u>

$$PV = nRT \qquad \text{ideal gas law} \qquad \text{valid at } \underline{\text{low pressures}}$$

Where: P & T are absolute pressure & temperature, n=number of moles of gas, R= universal gas constant.

For typical T and P in reservoir, the assumptions are no longer valid
→ an empirical correction factor   Z (gas deviation factor or dimensionless compressibility factor)

$$PV = znRT \qquad \text{real gas law}$$

The most important use of the real gas law is to <u>calculate the volume which a subsurface quantity of gas will occupy at surface</u> (sales conditions)
<u>(res = reservoir condition)</u>
(st = standard condition)

$$V_{st} = V_{res} \; \times \; (P_{res}/P_{st}) \; \times \; (T_{st}/T_{res})$$

This equation is valid as long as there is <u>no compositional change</u> of gas between subsurface and surface.

The ratio Vst / Vres   is the <u>gas expansion factor E</u>
It is depending upon both the gas composition and the reservoir (P&T) conditions.

The reciprocal gas formation volume factor FFVg Vres / Vst is more convenient in the
oil reservoir engineering

"st conditions" are tipically defined as
T=60°F (298°K, 15,5 °C)
P=1atm,
but may vary from location

PROPERTIES OF GAS

Gas density: is the most common measured property of a gas, obtained experimentally by measuring the specific gravity of the gas (density relative to air=1). It <u>increases as pressure increases</u>, but the <u>relationship is non-linear </u>because of <u>also z-factor varies with pressure</u>.

Gas density allows to calculate the <u>pressure gradient of the gas </u>when constructing pressure-depth relationship   → $(\Delta P / \Delta depth) = \rho \times g$

Gas viscosity (complex measures) in the reservoir typically is 0.01-0.05 cP (centiPoise) (by comparison water viscosity is 0.5-1.0 cP).

Lower viscosities imply that gas moves fast relatively to oil and water.

<u>Gas viscosity increases as pressure increases and as temperature increases </u>(the molecules move closer together and collide more frequently).

PROPERTIES OF OIL

Compressibility of oil is a <u>function of the amount of dissolved gas</u>. The pressure depletion in the reservoir can be assumed to be isothermal, such that

<u>isothermal compressibility is</u> $c = -1/V \cdot dV/dP$

Reservoir containing low compressibility oil (=>small amounts of dissolved gas) will suffer of large pressure drops after only limited production → reservoir abandonment conditions will be reached very soon.

Oil viscosity: determinant for the <u>fluid velocity</u> under a given pressure drop.
Oil viscosity is significantly greater than that of gas.
<u>Like gas viscosity, oil viscosity increases as pressure increases</u>, at least <u>above the bubble point</u>: below, the light components of oil transfer to the gas phase.
<u>Unlike gas viscosity, oil viscosity decreases as temperature increases</u>.

Oil density: commonly quoted in °API.
°API measures are affected by temperature:
thermal expansion of oil is significant,
especially for more volatile oils.
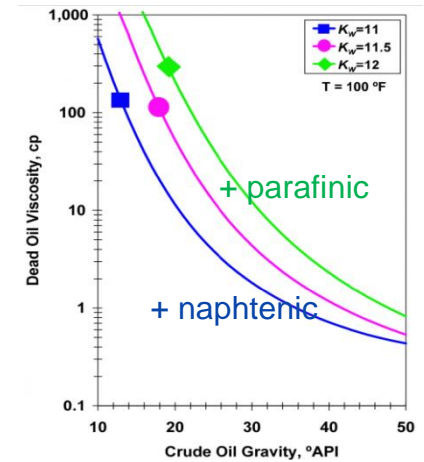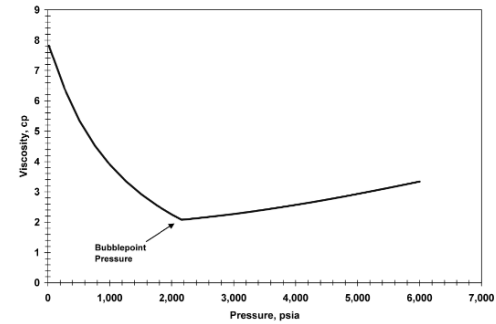Generally standard condition (T_{st}) should be used for this measure.

$$°API = \frac{141,5}{PS} - 131,5$$

Specific volume $V_S = 1 / \rho$

Determinare il **volume di gas disciolto** in un giacimento di petrolio è fondamentale per il suo **sfruttamento**. Questo valore è stabilito dal **rapporto di soluzione gas-olio** (G.O.R. Gas Oil Ratio) alle **condizioni** di **temperatura** e **pressione** del giacimento: esso tenderà pertanto a **variare** durante la **coltivazione** a causa delle **variazioni di pressione** che intervengono.

Il gas si può trovare **disciolto** anche **nell'acqua** (solubilità del **6%** rispetto a quella nell'olio), in quantità **minori** con l'**aumentare** della **salinità** dell'acqua.

→It is a function of

- Pressure (= depth)   If there is a gas cap and the pressure increases
- Solubility   GOR and volume of oil increases till the bubble point.
- Temperature   If T decreases, solubility decreases

GAS and OIL **FORMATION VOLUME FACTOR**   FFV or FVF

$$V_{res} = FFV \, V_{st}$$

The FFV at initial reservoir conditions (FFVi) depends upon the fluid type and the initial reservoir conditions.
It is used to convert the volumes of oil, calculated to stock tank conditions.

GAS   gas expansion factor $V_{st} / V_{res} = E$

gas formation volume factor $\underline{FFV_g}$ (o B_g) = $1/E = V_{res} / V_{st}$

$$FFVg = B_g = \frac{V_{res}}{V_{st}} = \frac{c}{c_{st}} \frac{P_{st}}{P} \frac{T}{T_{st}} = 0{,}034636 \; \frac{cT}{P}$$

where c is the compressibility ($c_{st} = 1$)

OIL

Above the bubble point (P_b), only one phase of unsaturated oil exists in the reservoir.

Below the bubble point, gas (solution gas) is liberated from the oil, and the

remaining oil occupies a smaller volume.

The **solution gas oil ratio (Rs o GOR)**, is a rate between volumes; it is constant above the Pb (Rsi),

decreases below the Pb. The oil shrinks, and volume of gas liberated, is Rsi-Rs.

If the pressure in reservoir drops below the Pb, then the gas will be liberated in the reservoir: it could flow

towards the producing well or could migrate upward to form a secondary gas cap. Consequently the gas oil
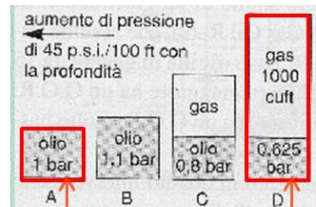
ratio will differ from Rsi.
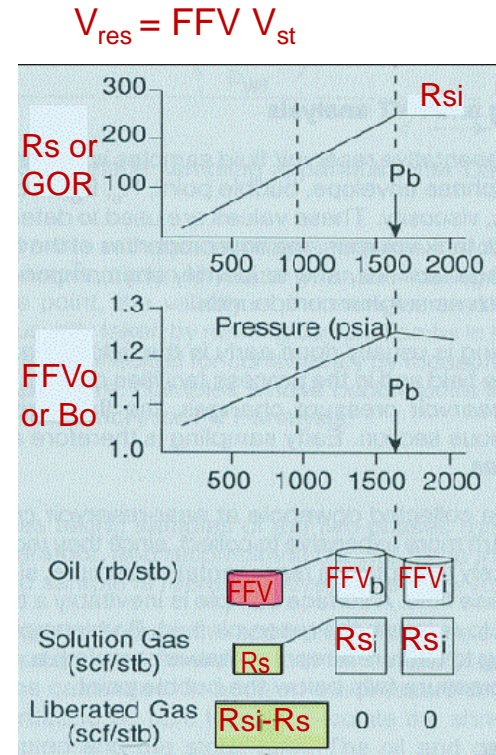
PVT analysis

Typical table resulting by PVT analysis →
-Initial reservoir pressure is 6000 psia
-Bubble point pressure is 980 psia.
-Bo and Bg are respectively the formation
Volume factors of oil and of gas;
-Rs is the solution gas / oil ratio;
μo and μg are
respectively the
Viscosities of oil
and of gas.

es : FFVm³ → 1m³

Pressure (psia)	FFV Bo (rb/stb)	FFV Bg (rb/Mscf)	GOR Rs (scf/stb)	μo (cP)	μg (cP)
6500	1.142	0.580	213	1.41	0.0333
6000	1.144	0.609	213	1.32	0.0317
5000	1.150	0.670	213	1.18	0.0282
4000	1.158	0.768	213	1.08	0.0248
3000	1.169	0.987	213	0.99	0.0215
2000	1.177	1.302	213	0.93	0.0180
1200	1.189	2.610	213	0.85	0.0144
980 *	1.191	3.205	213	0.83	0.0138
500	1.147	6.607	130	1.03	0.0125
100	1.015	33.893	44	1.07	0.0120

VR decreases due to compresion

Unsatured oil

VR decreases due to gas escape

Gas cap

Note: in an oil reservoir Bg is referred to the volume that the gas dissolved in the oil would occupy as gas free at the reservoir condition PT.

The collection of representative reservoir fluid samples is important in order to establish the PVT properties (phase envelope, bubble point, volume factors, composition, density, viscosity). These values are used to determine the initial volumes of fluid in place and in standard conditions and the flow properties of the fluid, both in the reservoir and through the surface facilities and to determine any components which can require special treatment (i.e. sulphur compounds).

Fluids may be collected:

• Downhole at near-reservoir conditions: more expensive, but also more representative; the hole pressure should preferably be above the bubble point pressure of the fluid to avoid phase segregation. If P is lower than the Pb, validity of sample remains doubtful.

• At surface: more easy to do; gas and liquid phase have to be sampled, with measures of P, T and flow rate, and appropriately recombined.

HYDROCARBON SOLUBILITY

All hydrocarbons are mutually soluble. Solubility decreases with the increase of the number of Carbon athoms. Lighter the oil, greater is the solubility of gas.

-The heavy fraction and the solid phase are dissolved in light hydrocarbons
-Liquid fractions dissolve in the gas
-Gas are dissolved in large quantities in liquid fractions. The solubility of gases in liquid hydrocarbons is much greater than the solubility between oils. Gas solubility in oils decreases with increase of temperature (about 4% /1°C).

GOR (*Gas/Oil Ratio*) in m³/ton or in %, increases with P and decreases if oil density increases.

Solubility decreases with increasing salinity of water.

Methane solubility is relatively high (5-10 g/dm³ per T=25°),
It increase with P until about 70 bar > hydrate methane.

The *Bubble Point* is the maximum GOR at a fixed temperature. Distillation is a separation of these mixtures of hydrocarbons for gaseous, liquid and solid present in complex combinations.

Solubility in water: oil has a small solubility in water; it is higher for gas, where it increases with P and decreases with salinity.
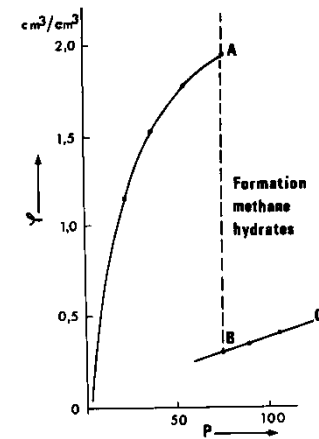
Methane solubility versus P

PETROPHYSICS - Del Ben Anna
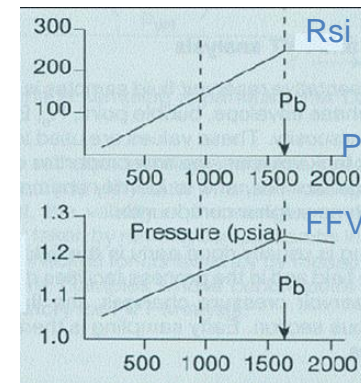
ACQUA DEL GIACIMENTO

L'**acqua** (più o meno salata) è l'unico fluido **sempre presente** nei giacimenti di petrolio e prende il nome di **acqua di strato**. In base alla sua origine si distingue in **connata**, **meteorica e mista**.

ACQUA CONNATA: rappresenta l'acqua associata ai sedimenti durante la loro **deposizione**, per tale motivo viene anche detta **singenetica** o **fossile**.

Ha **salinità variabile** (concentrazione dei sali superiore a quella del mare), ma **composizione** molto simile a quella delle **acque marine** attuali.

L'**aumento di concentrazione** è stato interpretato in modi diversi:

- **evaporazione** all'interno di bacini chiusi (evaporiti);
- **apporto** successivo di **sali** dall'esterno (circolazione delle acque);
- **assorbimento** delle acque da parte dell'argilla;
- **calo di pressione** (espansione del gas libero, parziale evaporazione dell'acqua);
- **costipamento** dei sedimenti (disidratazione delle argille).

Contiene una grande quantità di **cloruro di sodio**, percentuali variabili di iodio, ammoniaca, acido metasilicico, tracce di acido fosforico e naftenico, ma è quasi priva di **solfati** presenti invece nel mare.

L'assenza di solfati potrebbe dipendere da azioni di batteri anaerobi.
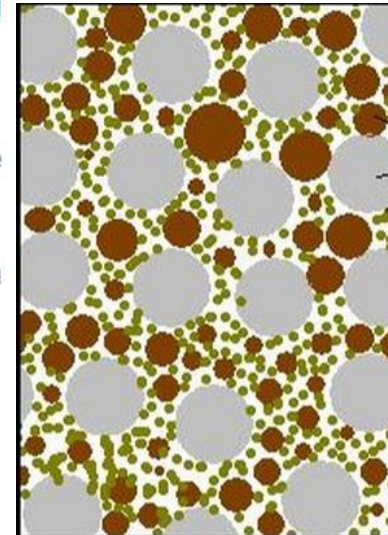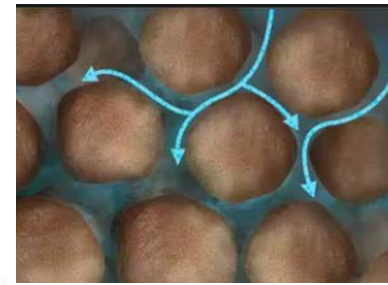
PROPERTIES OF **FORMATION WATER**

Water is the only fluid which is always associated with petroleum reservoir;
its properties affect the expansion and movement which can contribute
significantly to the drive mechanism in the reservoir;
assessing the size and flow properties of the aquifer are essential
in predicting the pressure support which may be provided.
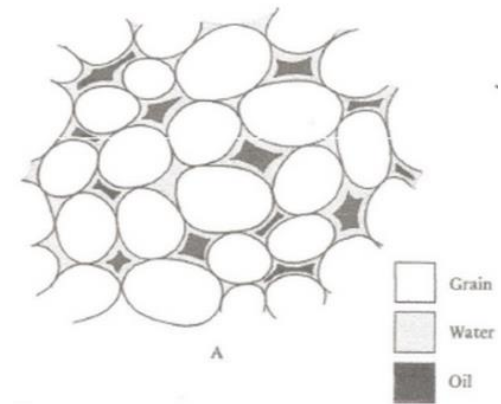
Formation water **density** is a function of :
-its salinity,
-amount of dissolved gas (small amount of gas, typically CO_2, are dissolved
in water),
-variation of P: density increases as pressure increases (but the
 compressibility is small, typically 2-4 x 10-6 psi-1)
-variation of T: density increases as temperature decreases (expansion)
        → opposing effects of P & T

Formation Volume Factor (Bw o FFV$_w$) is close to 1, typically between 1.0 and 1.07, depending
on amount of dissolved gas and on reservoir conditions.

Viscosity, as for liquids in general, reduces as temperature increases;
usually lower than that of oil (0.5-1.0 cP).

Solubility in oil is small; it increases with the increase of T and
decrease of the oil density.
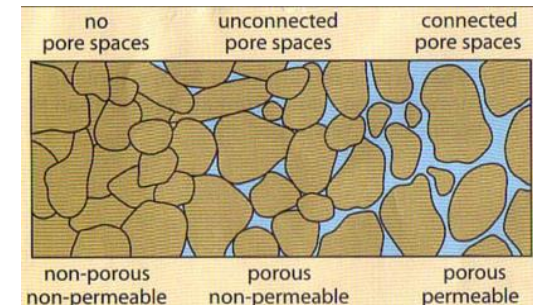
PRESSURE-DEPTH   RELATIONSHIPS

The relationship between reservoir fluid pressure and depth may be used to define the interface between fluids or to confirm the observations made directly by wireline logs.
If different pressure regimes   →   lack of reservoir continuity (important for development planning).

Normal pressure regimes follow a **hydrostatic fluid gradient** from surface and are approximately linear. In a normal pressure regime, pressure balances the overburden pressure due to the weight of the rock (matrix) and fluid. With production, fluid pressure decreases, the grains of rock crush together so providing a (compaction) drive energy to the production and eventual reduction of reservoir thickness (subsidence, i.e. Groningen field in Netherland and Ekofisk field in North Sea).

$P_w = (\Delta P / \Delta depth)_w \times depth$

$(\Delta P / \Delta depth)_w = \rho_w \times g$ Water pressure gradient is water density x acceleration due to gravity

So the pressure gradient can be calculated starting from the density of the fluid. Clearly, this is valid for all different fluids (water, oil, gas)

Gradient intercept technique   →

The densities of water, oil and gas are so different that they show significantly different gradient on a pressure-depth plot and this could be useful to determine the interface between fluids. In figure, the intercept between gas and oil gradients indicates the gas-oil contact

Figure 5.26 The gradient intercept technique
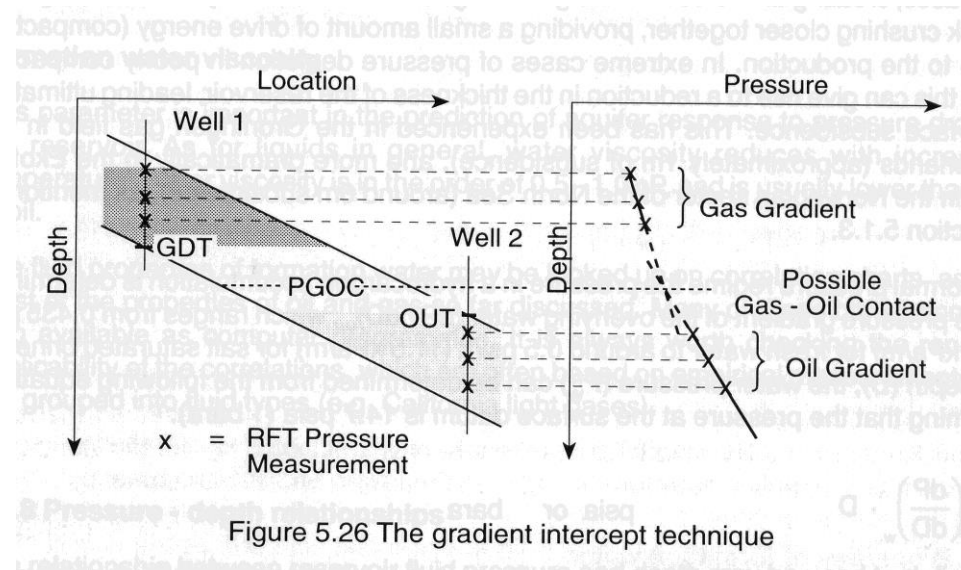
Abnormal pressures (pressure different than hydrostatic: overpressured or underpressured fluids) represent a discontinuity and require special care.
In figure the pressure-depth relationship is interrupted by a sealing layer. Value by which the extrapolated pressure exceeds or is minor than 1 atm at the datum level, defines the level of overpressured or underpressured fluid.
In hydrocarbon reservoirs the common presence of a seal at the crest of the accumulation represents a potential for abnormal pressure regimes.

The most common causes of abnormally pressured reservoirs are:

-Reservoir encapsulated by seal sequence, successively uplifted or buried or rotated;

-Thermal effect in an encapsulated system

-Rapid burial of permeable and impermeable sediments → no escape of fluid (overpressure)

-Depletion due to production of the reservoir or to production of an adjacent reservoir connected via a common aquifer

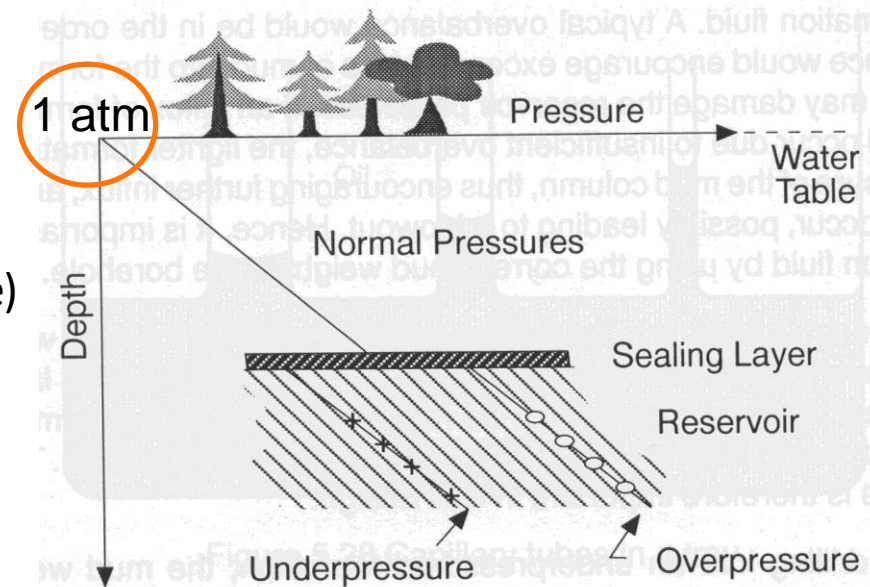-Phase change (i.e. anhydrite into gypsum or alteration of clay mineralogy)

Figure 5.27 Normal and abnormal pressure regimes

CAPILLARY

An equilibrium exists between gravity forces and capillary forces.

When two or more phases are present in a reservoir, buoyancy and capillary forces determine the distribution of fluids and hence the volume of fluid in place.

We have seen as we can establish the gas/oil contact (GOC) by the intercept between gas and oil gradients and the free water level (FWL) by the intercept between oil and water gradients.
But the capillary force rises the water level so that FWL is not coincident with the OWC.

We usually see the capillary effect when we have a number of glass tubes of varying diameter placed into a tray of water.

The capillary effect is a result of an interaction of attractive forces between molecules in the two liquids (surface tension) and between the fluids and the solid surface (wettability/bagnabilità)
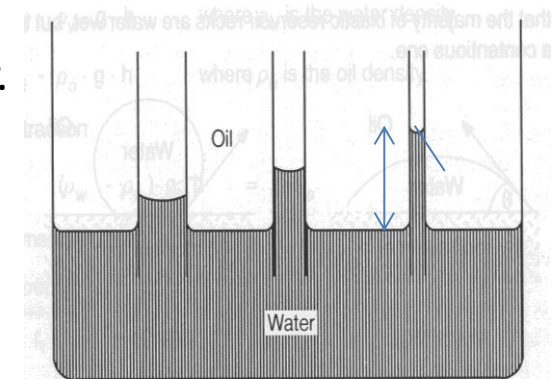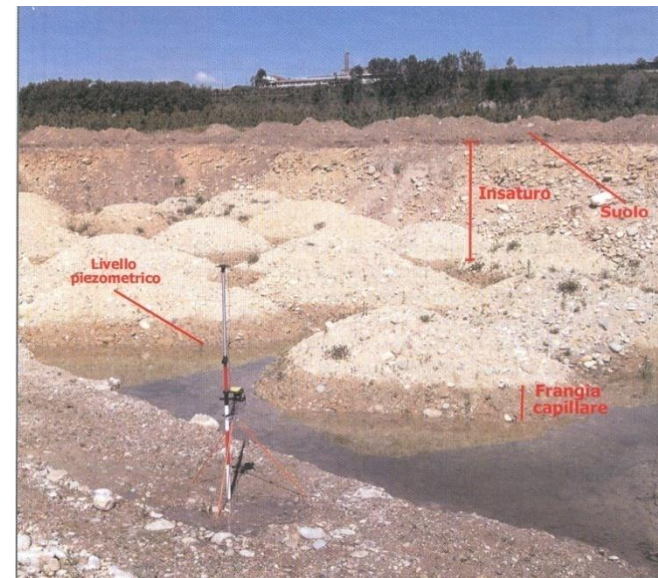
Figure 5.28 Capillary tubes in a tray

SURFACE TENSION and WETTABILITY

INTERFACIAL/ or SURFACE TENSION (σ) : arises at a fluid to fluid interface as a result of the unequal attraction between molecules of a fluid and the adjacent fluid; for example water in a

surrounded by air has a larger attraction to each other than to the adjacent air molecules → a surface tension exists at the interface between water and air and a pressure differential exists between the water phase and the air → water creates a spherical droplet, because of the imbalance of forces creates an inward pull which minimizes the surface area of the droplet.

Figure 5.29 Water droplet with attractive forces
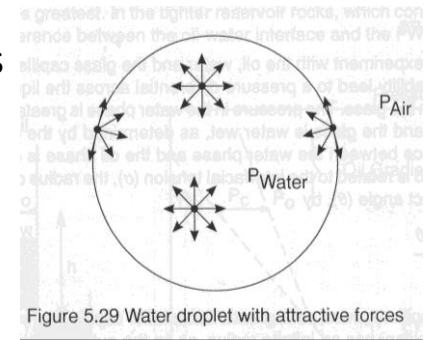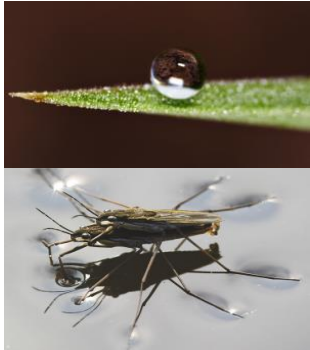
The relationship between the pressure drop across the interface (ΔP), the interfacial tension (σ), and the radius of the droplet (r), is: $\Delta P = 2\sigma / r$

WETTABILITY describes the relationship between the contact of two fluids and a solid. The type of contact is characterized by the contact angle Θ between the surface which separates two fluids and the solid surface, and is measured by convention through the denser liquid (water in figure): if it is lesser than 90°, the surface is said to be wetting to that fluid.

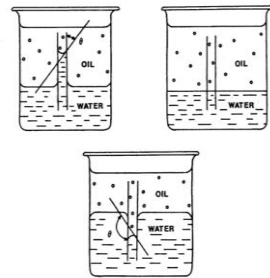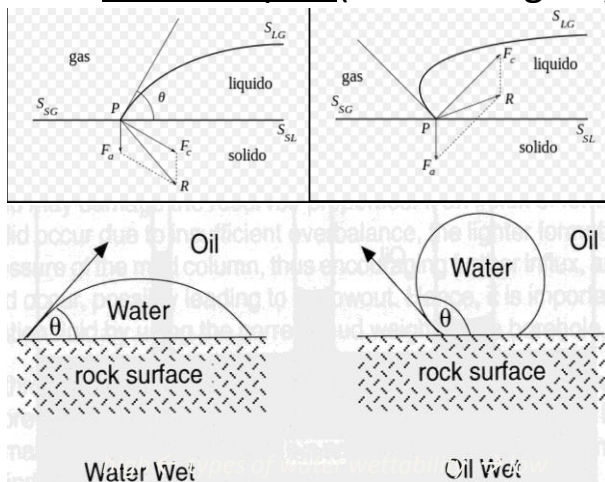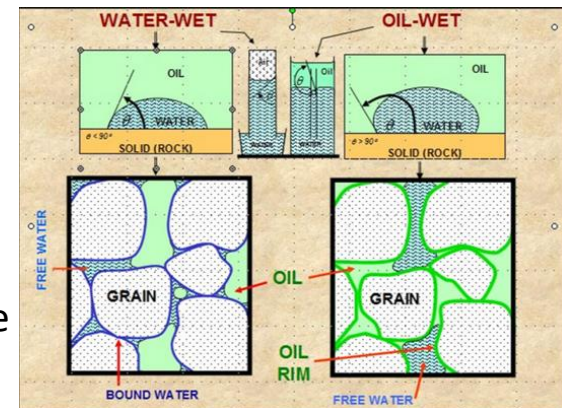The measure of wettability at reservoir conditions is very difficult, since the property is affected by the drilling and recovery of the samples.

The majority of clastic reservoir rocks are water wet.

igure 5.5. Menisci of capillaries having different wettabilities.

CAPILLARY PRESSURE

If we reconsider the glass capillaries with oil and water, the <u>interfacial tension and wettability</u> lead to
-a pressure differential across the liquid interface and
-a contact angle with the glass.

The CAPILLARY PRESSURE Pc is defined as the <u>pressure difference</u> between the non-wetting (nw) and wetting (w) phases:
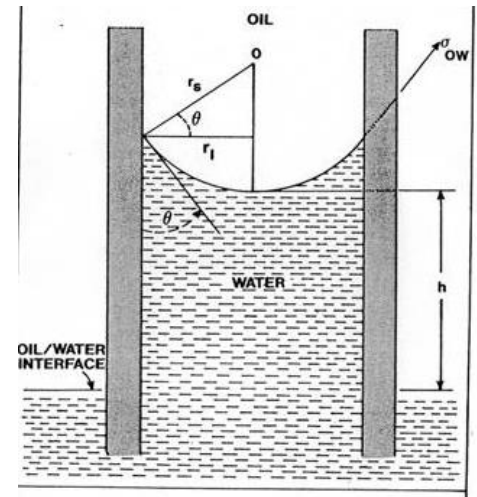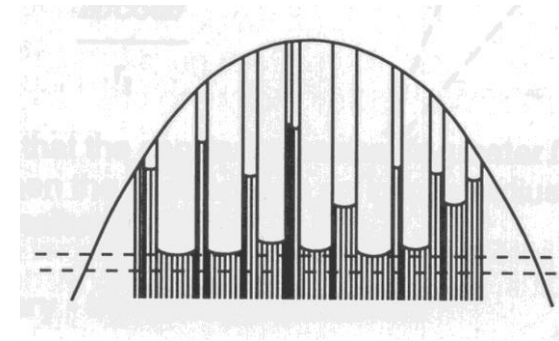
$$P_c = P_{nw} - P_w \qquad \text{more frequently} \quad Pc = Po - Pw$$

<u>Generally the pressure in the water phase is greater than in the oil</u> phase, and the glass is water wet, as determined by the contact angle Θ.

The **capillary pressure Pc** is related to the interfacial tension σ and to the contact angle Θ by:

$$Pc = \frac{2\ \sigma\ cos\Theta}{R}$$

σ = surface tension
Θ = contact angle (wettabilty)
R = ray of capillary tube

The capillary pressure is greater for smaller capillaries.
When the capillary has an infinite radius, Pc is zero.

e 5.3. *Capillary rise of water in a water-wet capillary tube.*

CAPILLARY – BUOYANCY EQUILIBRIUM

Now we consider the pressure profile in just one of the capillaries.

Inside the tube, the capillary pressure Pc is the pressure difference between the oil phase pressure Po and the water phase pressure Pw at the interface between the oil and the water

$$P_c = P_o - P_w$$

The capillary pressure can be related to the height of the interface above the level at which the capillary pressure is zero (FWL) by using the hydrostatic pressure equation.
Assuming the pressure at the FWL is Pi, the hydrostatic pressure is:

$$P_w = P_i - \rho_w\, g\, h \qquad\qquad P_o = P_i - \rho_o\, g\, h$$

by subtraction:

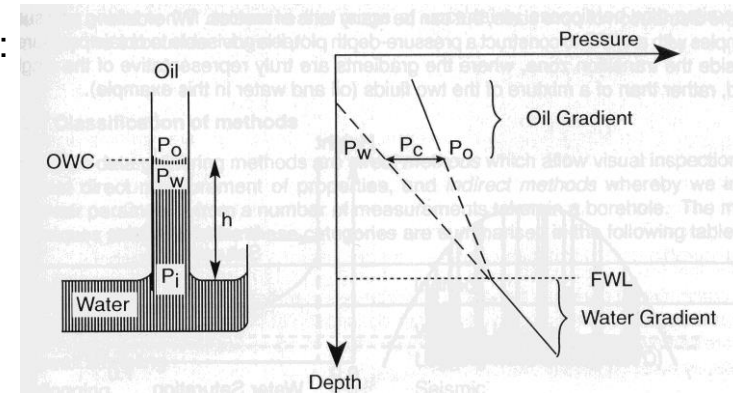$$P_c = P_o - P_w = (\rho_w - \rho_o)\, g\, h_c = \Delta\rho\, g\, h_c$$

$$\text{also:} \quad P_c = \frac{2\, \sigma\, \cos\Theta}{R}$$

$$\rightarrow \qquad h_c = \frac{2\, \sigma\, \cos\Theta}{\Delta\rho g R}$$

The largest difference between oil-water interface OWC and the FWL occurs for narrowest capillaries.

If pressure is measured inside the capillary, a discontinuity on the pressure gradient would be apparent at the FWL

The OWC is at the depth where $\qquad P_o - P_w = P_c$

For the purpose of calculating oil in place in the reservoir, it is the **OWC, not the FWL,** which should be used to define to what depth oil has accumulated.

Using the FWL would overestimate the oil in place, and could lead to a significant error in tight reservoir

The difference between OWC and FWL is greater in fine grain reservoir

Sediment	Grain Diameter (cm)	Pore Radius (cm)	Capillary Rise (cm)
Fine silt	0.0008	0.0002	750
Coarse silt	0.0025	0.0005	300
Very fine sand	0.0075	0.0015	100
Fine sand	0.0150	0.003	50
Medium sand	0.03	0.006	25
Coarse sand	0.05	0.010	15
Very coarse sand	0.20	0.040	4
Fine gravel	0.50	0.100	1.5

In the gas reservoirs a difference between gas-water contact **GWC** and **FWL** exists for the same reasons, but it is smaller and is often neglected.

It is common to have an approximately constant pressure gradient over the thickness of an oil reservoir among all wells that are hydraulically continuous.

Similarly, water gradients are usually even more constant.
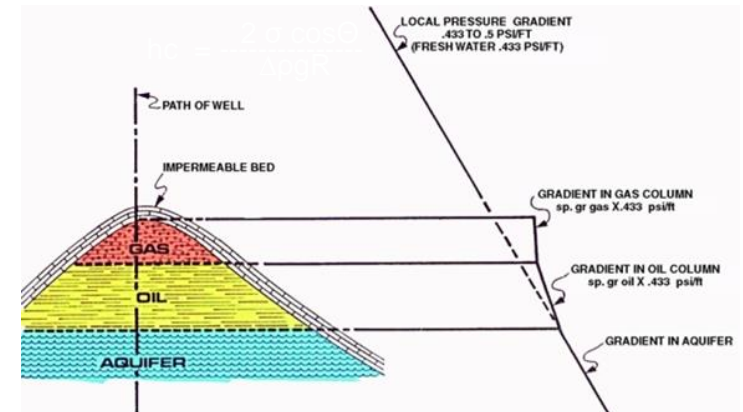
In a reservoir that is hydrostatic, the pressures in the continuous phases vary by depth based on the density of the fluid in the continuous phase. The oil density is primarily a function of the gravity of the oil, the amount of dissolved gas and the pressure. Compositional variations in oil density and dissolved gas are common over large areas and in very thick reservoirs. It is possible to detect varying density (compositional grading) from a depth vs. pressure plot.

SATURATION-HEIGHT RELATIONSHIPS

Above OWC, only hydrocarbon and **irreducible water** (typically 10-40%) .
Below OWC (below the largest capillaries) only water: **water saturation is 100%** .
Between the two points there is a gradual change in the water saturation

→ **TRANSITION ZONE**

<u>Wells completed within transition zone will produce</u> <u>hydrocarbon and water</u>.

If we take some measures to construct the pressure-depth plot, we have to measure outside the transition zone, where gradients represent a mixture of the two fluids.
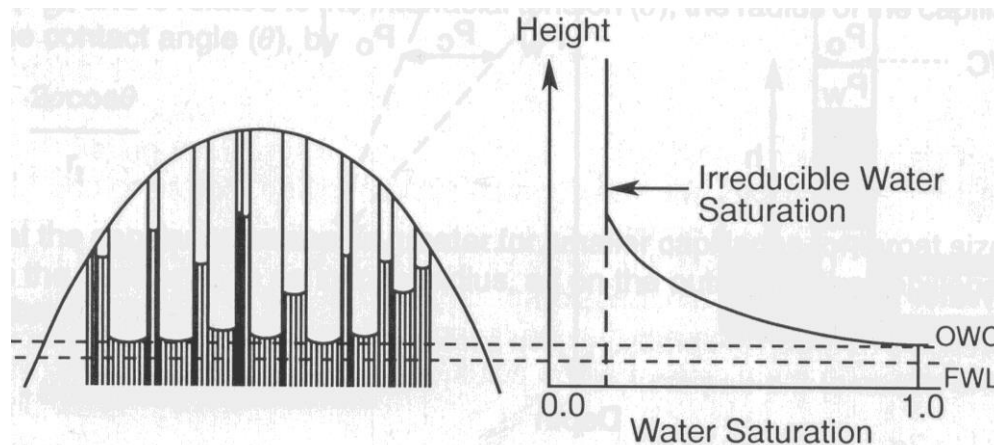

Figure 5.32 Saturation-height with capillaries

Irriducible water saturation (or critical water saturation) defines the maximum Sw that a formation can retain without producing water. This water is held in place by capillary forces and will not flow. Critical Sw is usually determined through special core analysis.
If the in-place Sw does not exceed the critical value, then the well will produce only hydrocarbons.
These saturation comparisons are particularly important in low permeability reservoirs, where critical water saturation can exceed 60% while still producing only hydrocarbons.


Importance of *bound water in hydrocarbon movement*

In figure, systems of pores in resevoir, where the same volume of pores, same volume of oil and different proportion of irriducible water

a) *no bound water*: the oil concentration is not sufficient to give continuity to fluid => the capillary force keeps the oil which is not able to move through the interconnected pores.

b) The same quantity of oil as in a), but the presence of *bound water* make the oil occupy the free volume of the pores due to the capillary force: expulsion can occur.

c) all the pore water is "bound": the same volume of oil as a) and b) origins continue filaments, relative permeability to oil is high and it could be expulsed from the main part
→ (*high expulsion efficiency*)

PETROPHYSICS - Del Ben Anna
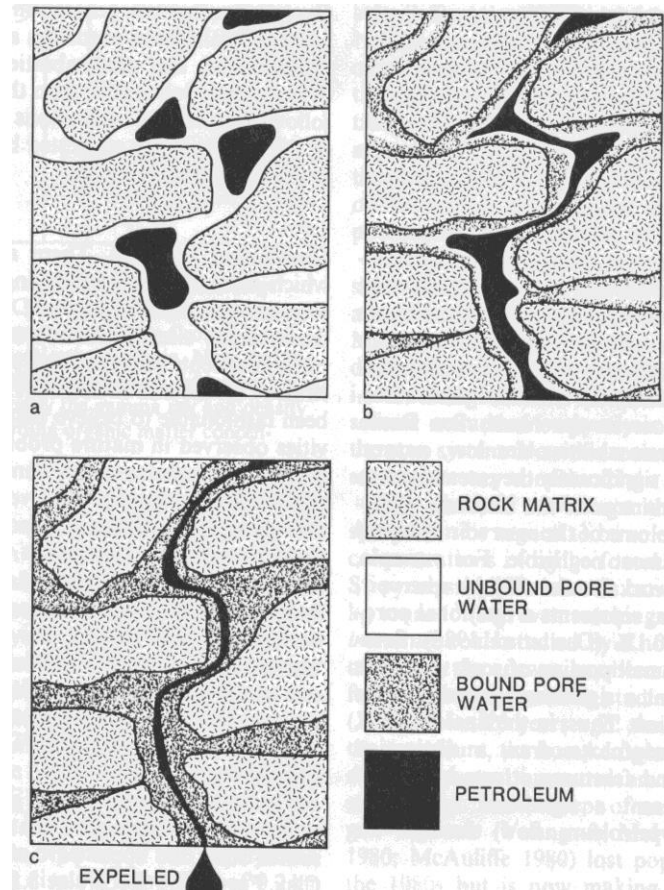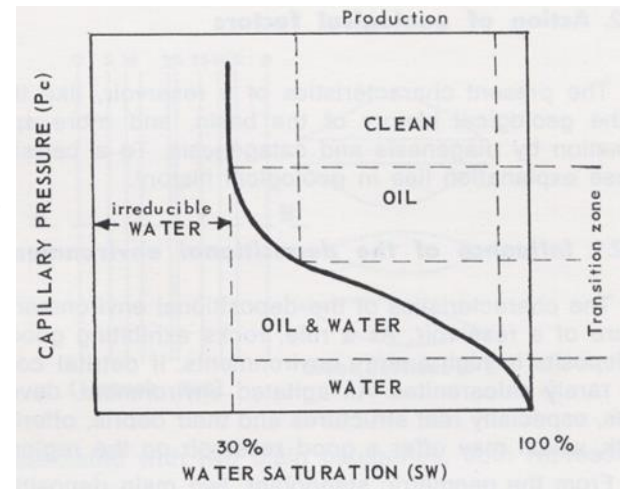
FLUID SATURATION

The porosity is very important to give a measure of the ability of that rock to store fluids (water, oil, gas).

Equally important is the relative extent to which the pores of the rock are filled with specific fluids

→ **FLUID SATURATION**, expressed as the fraction or percent of the total pore volume occupied by the fluid

If Vo = Volume of oil in the rock & Vp = Total pore volume of

Fluid saturation (%) $$Sw = V_w/V_p \quad (\cdot 100)$$

$So = Vo/Vp \quad (\cdot 100)$ Connate water, trapped during deposition,

$Sg = Vg/Vp \quad (\cdot 100)$ however, is always found.

$Sh = So + Sg = (Vo+Vg)/Vp \ (\cdot 100)$

→ $So + Sg + Sw = 1 \ (100)$

→ $Vo + Vg + Vw = Vp$

Hydrocarbon saturation is major criterion for expulsion (**primary migration**)
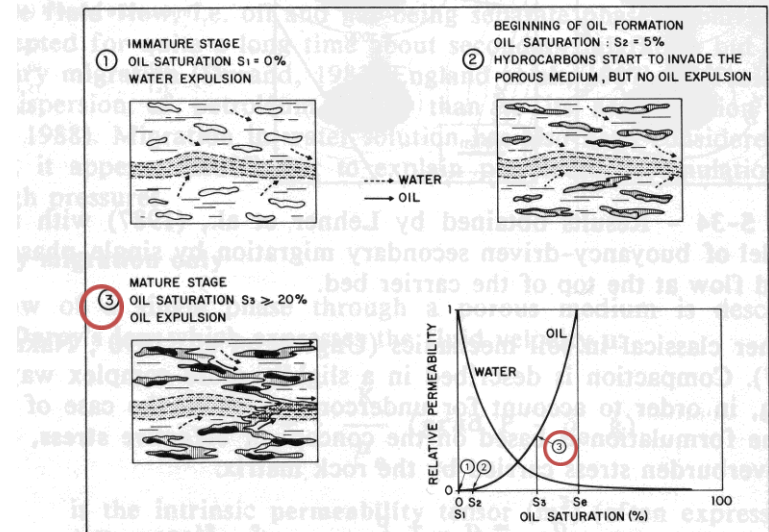<u>Poor source rock expels hydrocarbons <u>later</u> than rich source rocks</u>.
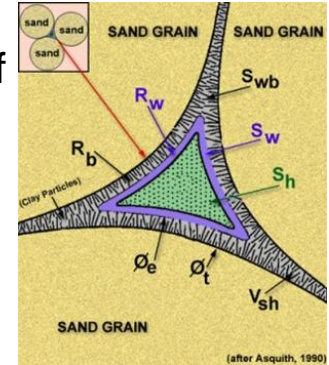

Fig. 5-35 – Theoretical scheme of primary migration at three successive stages and corresponding position on relative permeability curves in model.

In the extraction of gas condensates the low portion of the liquefied product does not allow its saturation of the pores in the reservoir rock: generally characterized by high commercial value, it results to be not mobile. There is therefore a strong incentive to avoid this condensation, through the maintenance of P above the dew point → It carries with it the "recycling" of the gas, which is commonly adopted for this type of deposits.
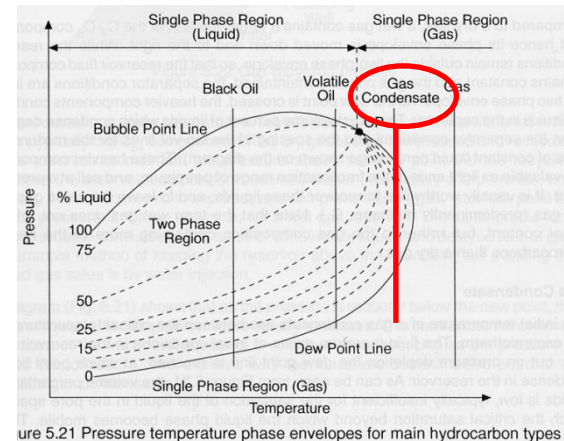
The dry gas produced in the separator surface after extraction of the heavier terms (typically C5+ components), is then compressed and re-injected into the reservoir to maintain high P. As it proceeds exploitation, the contents of the reservoir becomes lighter. At a certain point, there is no more economic convenience to separate and compress the dry gas. The profile for sale for an outline of recycling consists

Figure 5.21 Pressure temperature phase envelopes for main hydrocarbon types

Figure 5.22 Gas recycling process

of an initial sale of condensed liquids and a subsequent sale of gas.

In alternatively you can pump water.
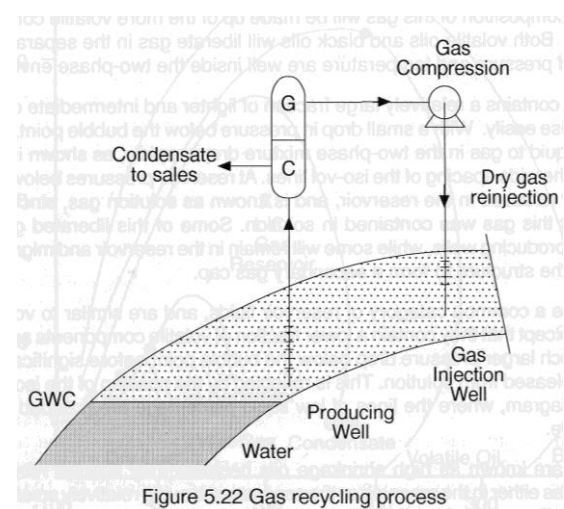
PETROPHYSICS PARAMETERS:
WATER SATURATION

- Water saturation (S_w) is generally evaluated by the <u>relation between resistivity and porosity</u> of the reservoir rock.

- In clean formations this relation is defined by the **formulas of Archie**.

- S_w can change between 100% and theoretical value of 4-5%: in real conditions, a quantity of bounded water (acqua connata o irriducibile - Swirr) in any case can not be removed.

Field	Swirr (%) min	Swirr (%) max	Lithology
Nigeria	5	7	Clean Sands
Po Valley	15	25	Clean Sands
Adriatic Sea	25	30	Clean Sands
Sicily (Gagliano Fm.)	10	20	Low porosity sandstones
North Sea	5	7	Chalky Limestones
Adriatic Sea	30	40	Fractured low porosity limestones
Persian Gulf (Arab Fm.)	50	60	Dolostones
Arabia (Mishrif Fm.)	60	70	Chalky Limestones

da Confalini

Saturazione in acqua minima (Swirr) in rocce serbatoio tipiche

Conduzione elettrica delle rocce

La corrente elettrica può passare attraverso la roccia soprattutto per la presenza di ioni disciolti nell'acqua di formazione (conduzione elettrolitica).

Più raramente la conduzione elettrica può essere di tipo metallico (movimento di elettroni) in presenza di minerali conduttivi (es. pirite) o cementi ferriferi (es. sideritici).
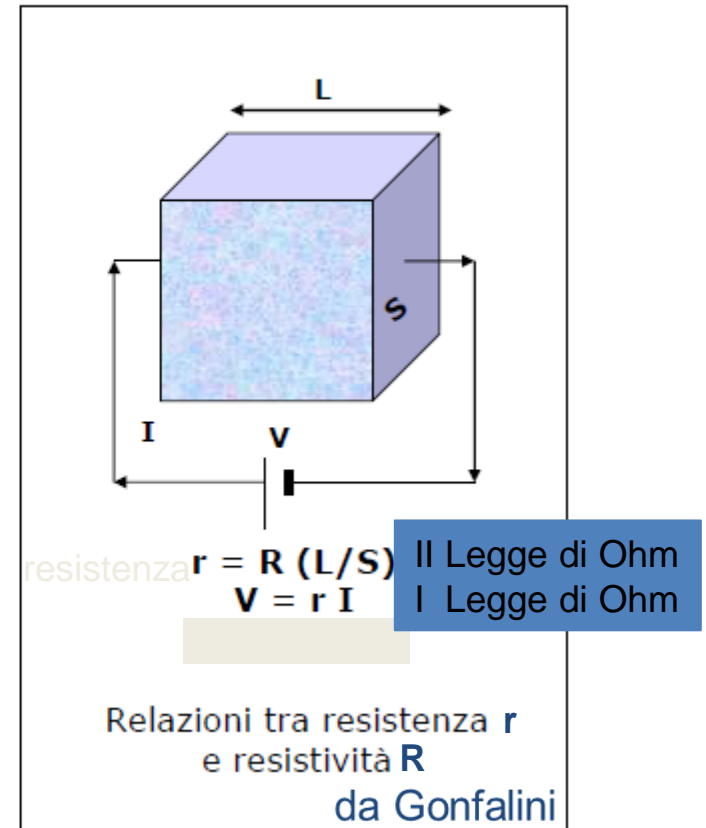
In presenza di argille la conduttività ionica avviene sulla superficie delle argille (conduttività di superficie) influenzando la conduttività della roccia.

Nel processo di *well logging* la proprietà che viene più usata è la resistività che, in mezzi isotropi, è l'inverso della conduttività.

L'unità di misura della resistività è ohm*m.

L'unità di misura della conduttività è S/m. (Siemens/metro)

resistenza $r = R (L/S)$ II Legge di Ohm

$V = r I$ I Legge di Ohm

Relazioni tra resistenza **r** e resistività **R**

da Gonfalini

Sedimentary formations are generally very poor conductors if they are entirely dry.

This is true also for pure water: only the interstitial and absorbed water with salts in solution are capable of transmitting an electric current. The greater the salt concentration (ions as Na^+, Ca^{2+}, Cl^-, SO_4^-, etc) the greater the **conductivity C** of connate water.

The **electrical resistivity R** of a fluid saturated rock is its ability to impede the flow of electric current through that rock.

The **resistance r** of a brine in a container of length L and section A to the flow of electricity is measured applying a differential potential V (in Volt) across the liquid and recording the amount of current I (in amperes), that will flow.

According to the First Ohm's law $I = V / r$

→ $r_w = V / I_w$

The resistance r could be also defined starting from some physics and geometric characteristic of the conductor, as **resistivity R**, length L and section A:
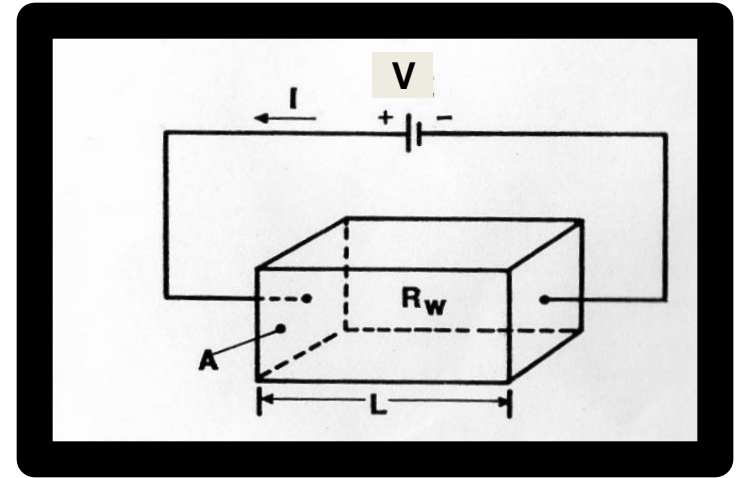
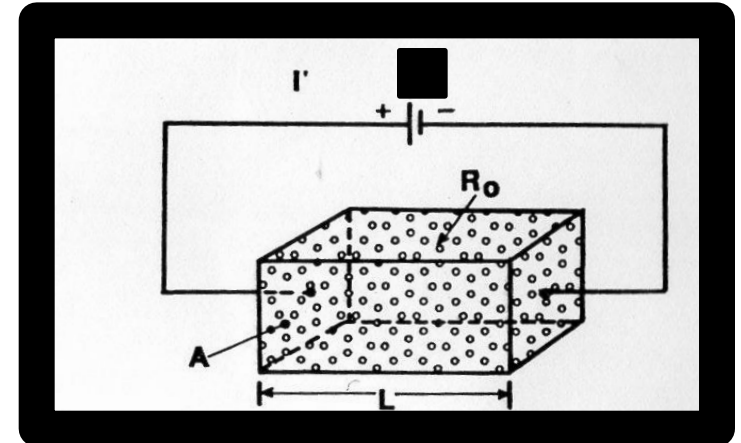According to the Second Ohm's law:

$r_w = R_w \cdot L / A$

→ $R_w = r_w \cdot A / L = V / I_w \cdot A / L$

If we consider a block of a porous rock (clean sand) of dimension A and L , with Sw = 100% (the same brine), resistivity of this porous rock will be:

→ $R_o = r_o \cdot A / L = V / I_o \cdot A / L$

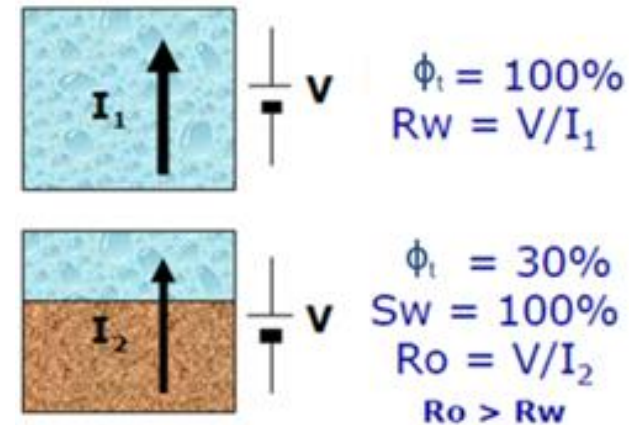*A volume A x L of brine (Rw) is crossed by a current I originated by V*

A volume A x L of rock (Sw=100%) is crossed by a current I originated by V (Ro)

$$Rw = rw \cdot A / L = V/Iw \cdot A / L$$

$$R_0 = r_0 \cdot A / L = V/I_0 \cdot A / L$$

→ $\quad \mathbf{R_0 / R_w} = (V/I_0 \cdot A / L) / (V/I_w \cdot A / L) = \mathbf{I_w / I_0}$

$\phi_t = 100\%$
$Rw = V/I_1$

$\phi_t = 30\%$
$Sw = 100\%$
$Ro = V/I_2$
$Ro > Rw$

Archie defined $\mathbf{R_0 / R_w}$ as **"formation resistivity factor - FR or F$_R$ or F"**

FR = Ro/Rw $\quad$ **is** $\quad$ **the First formula of Archie**

FR is the ratio of the resistivity of the medium when completely saturated with a conducting fluid, to the resistivity of the saturating fluid.

The concept of formation resistivity factor is one of the most important in petrophysical analysis.

For a given value of V → I_w is greater than I_o and

$\quad\quad$ R_o is greater than R_w $\quad\quad$ → $\quad\quad$ F$_R$ is always > 1

Definizioni

Roccia "pulita" (clean rock)

Roccia che non contiene una quantità apprezzabile di argilla.
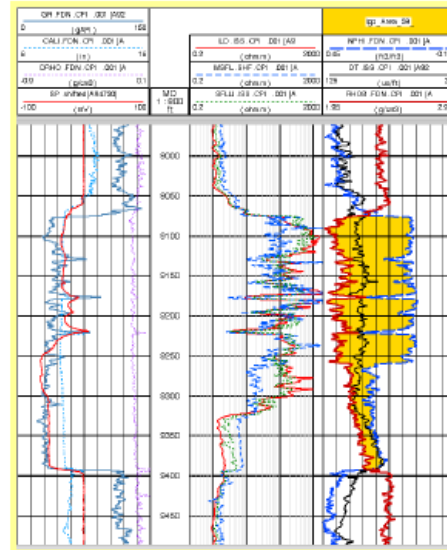
Il termine è riferito a sabbie, arenarie e carbonati.

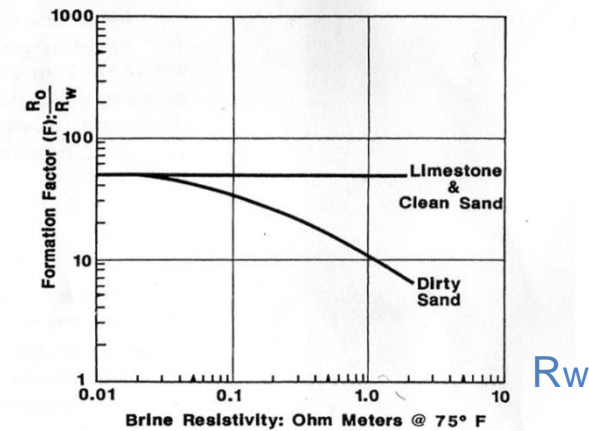### Roccia "sporca" o argillosa (shaly rock)

Roccia che contiene una quantità apprezzabile di argilla.

Questo materiale fa diminuire la permeabilità e la porosità efficace della roccia.

Tutti i log di pozzo sono influenzati dalla presenza dei minerali delle argille

Principi di interpretazione

1. individuare i livelli di sabbie dove il volume di argilla è minimo
2. individuare i livelli mineralizzati ed i livelli ad acqua
3. determinare la resistività in corrispondenza dei livelli mineralizzati (Rt)
4. determinare la resistività in corrispondenza di livelli sicuramente ad acqua
5. determinare il valore di porosità in corrispondenza del livello ad acqua
6. valutare Rw
7. determinare il valore di porosità in corrispondenza del livello mineralizzato
8. calcolare Sw
9. determinare lo spessore dei livelli potenzialmente produttivi
10. determinare i valori medi di porosità e Saturazione in acqua dei livelli produttivi

$$FR = R_o / R_w = I_w / I_o$$

For a clean sand FR is constant also with variable R_w because also R_o changes proportionally.

For a dirty (shaly) sand the clay in the water acts as a conductor (variably, depending on composition) → I_o increase more (not proportionally) than I_w and FR decreases with an increase of R_o
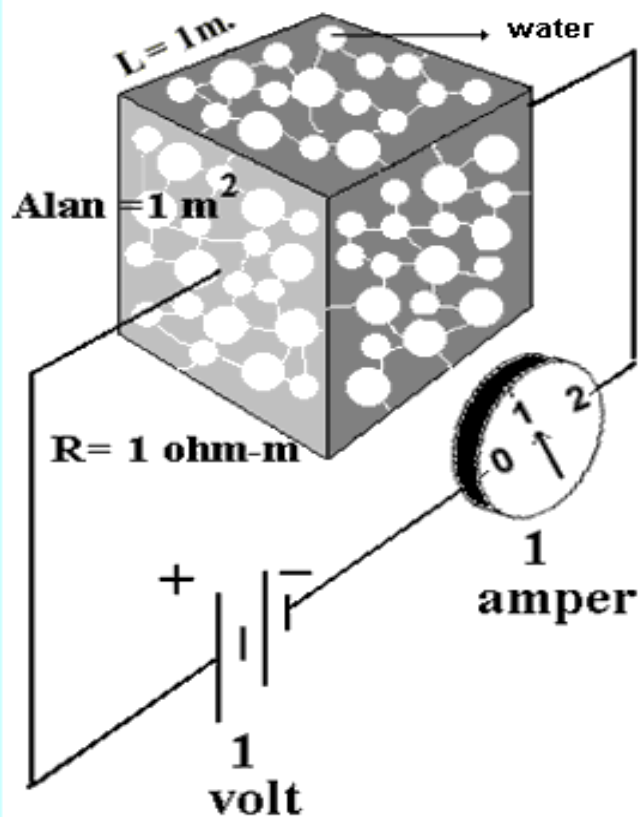
| Factors that effect the resistivity of formations.	
Effects that cause high resistivity	**Effects that cause low resistivity**
Unpearmeable zones, grains, cement, tourtousity, fresh water, hematite, limonite, blende, coal.	Clay, salty water, fractures with salt water graphite, pyrite, chalcoprite, pyrhotite, galena.

Measuring the resistivity of a core saturated with water.
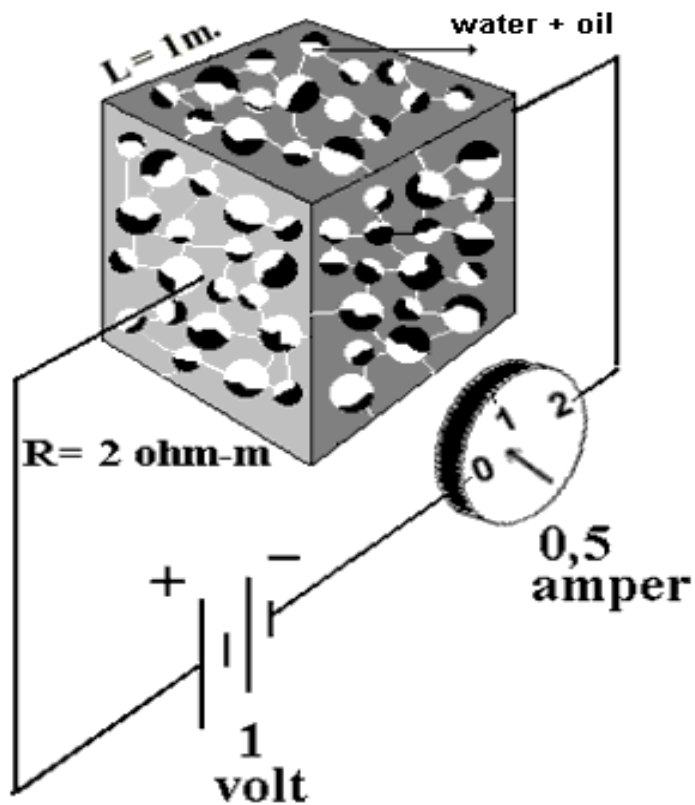
Measuring the resistivityof a core sample saturated with oil & water

Relazioni di Archie in formazioni "pulite"

In rocce saturate completamente in acqua con Sw=100%
(Prima relazione di Archie)

$$Ro = (F * Rw)$$

dove
$$F = (a / \phi^m),$$

Ro	= Resistività della roccia saturata in acqua
Rw	= Resistività dell'acqua di formazione
F	= Fattore di Resistività della Formazione
ϕ_t	= porosità totale
a	= coefficiente litologico or tortuosity factor
m	= esponente di cementazione

by Gonfalini,
(where F is for F_R)

A number of observations suggested to Archie that the conductivity (Co) of a water bearing formation sample is dependent primarily upon pore water conductivity (Cw) and porosity (φ) distribution

$$Co = \phi^m Cw$$

Φ describes the volume fraction of pore space, while the shape of the pore space is described by

m   →   cementation exponent

$Ro = (F*Rw)$
$F = (a / \phi^m)$,

$\Phi = 20\%$

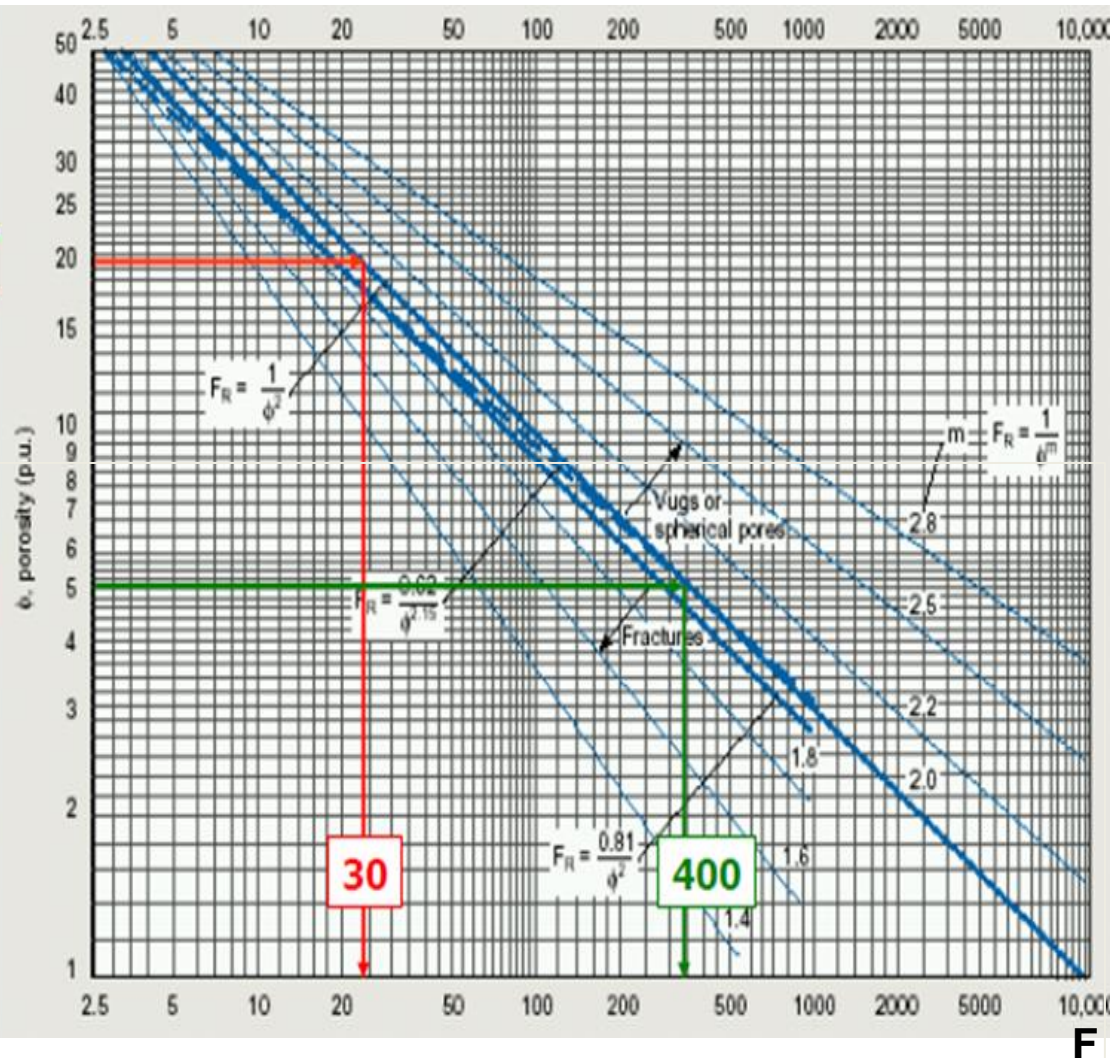**cementation exponent (m)**

$\Phi = 5\%$

«m» describes the complexity of the pore system, i.e. how difficult is for an electrical current to find a path through the rock.

If the pore network is modelled as a set of parallel capillary tubes (optimum condition for the current flow), a cross-section area average of the rock's resistivity would yield porosity dependence equivalent to a cementation exponent of 1.

However, tortuosity of the rock increases m to a higher value than 1. In a large range of reservoirs the cementation exponent can be taken as **m=2.**

by Gonfalini,
(where F is for F_R)

Pay attention: bigger m is, the bigger is F !!

θ. porosity (p.u.)

$F_R = \frac{1}{\phi^2}$

$m \quad F_R = \frac{1}{\phi^m}$

Vugs or spherical pores

Fractures

$F_R = \frac{0.62}{\phi^{2.15}}$

$F_R = \frac{0.81}{\phi^2}$

30

400

2.8
2.5
2.2
2.0
1.8
1.6
1.4

F

Ro vs PHI
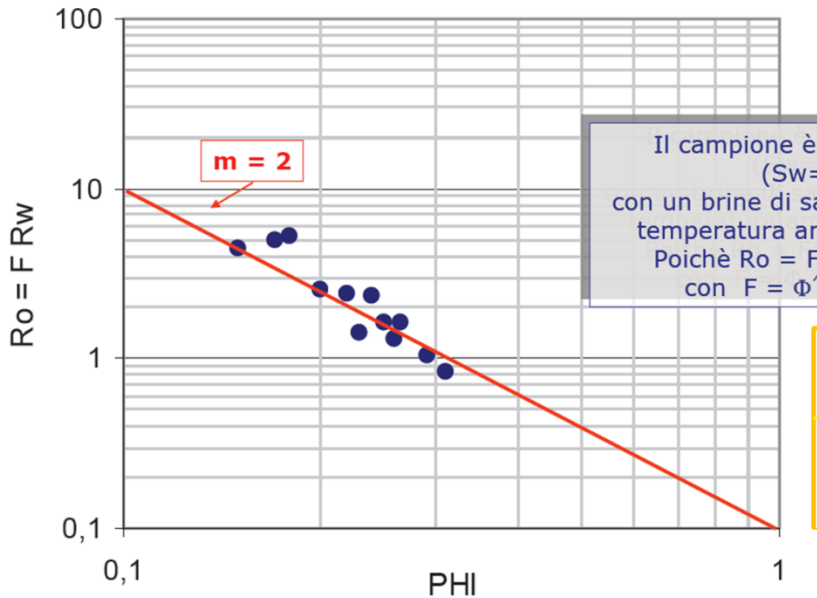
Determinazione di "m"
per mezzo di misure su carote

m = 2

Il campione è saturato in acqua
(Sw= 100 %)
con un brine di salinità conosciuta @ a
temperatura ambiente conosciuta.
Poichè Ro = F*Rw,   F=Ro/Rw
con F = Φ^{-m} (F=1/ Φ^m)

(Prima relazione di Archie)
Ro = (F*Rw)
F = (a / ϕ^m),

(Seconda relazione di Archie)
Rt = (F*Rw / Sw^n),
F = (a / ϕ^m),
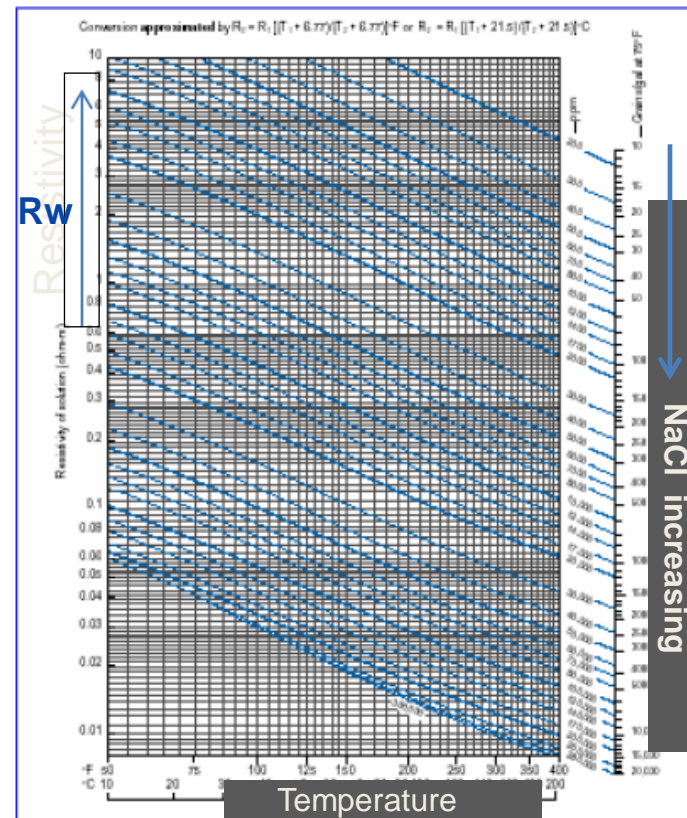Sw = ((a/ ϕ^m)*(Rw /Rt))$^{1/n}$

da Gonfalini

Resistivity of NaCl Solutions

Rw

Resistivity

NaCl increasing

Temperature

S_w 100%,
R_w, salinity and temperature are known,
R_o has measured → we can calculate F,
PHI (density) measured by sample

→ **m** can be calculated

*Resistivity R_w decreases as
the salinity and the
temperature increase*

Relazioni di Archie in formazioni "pulite"

In rocce saturate parzialmente in acqua e con Sw < 100%
(Seconda relazione di Archie)

$$R_t = (F * R_w / S_w^n),$$

dove

$$F = (a / \phi^m),$$

quindi

$$S_w = (a / \phi^m) * (R_w / R_t))^{1/n}$$

|	
Rt	= resistività vera della formazione
Rw	= resistività dell'acqua di formazione
Sw	= saturazione in acqua della formazione
Sh	= saturazione in idrocarburi (Sh = 1- Sw)
F	= Fattore di resistività della formazione
ϕ_t	= porosità totale
m	= esponente di cementazione
n	= esponente di saturazione

by Gonfalini,
(where F is for F_R)

Archie observed that as water is displaced by (non- conductive) oil in the pore system (Sw reduces), the conductivity (Ct) of an oil bearing reservoir sample decreases, such that:

$$C_t = S_w^n \, \phi^m \, C_w$$

Formation resistivity factor is an excellent parameter for the detection of hydrocarbon zones.
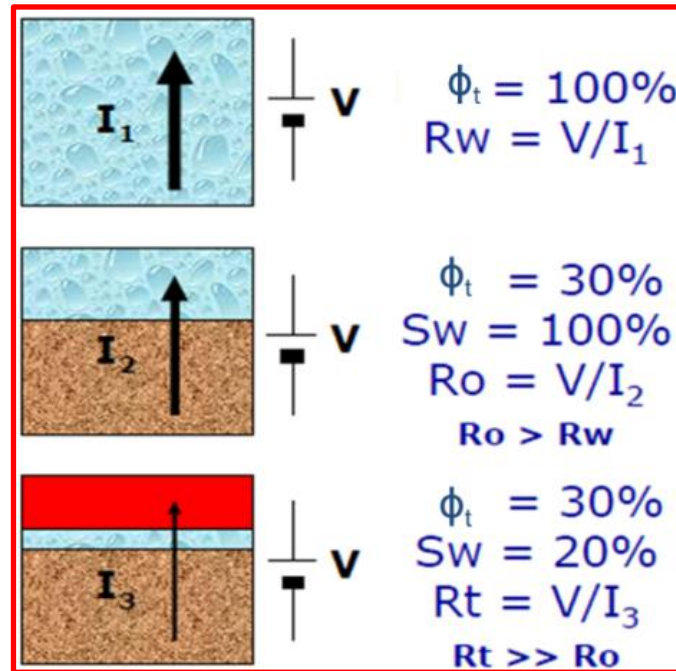
Formulas of Archie highlight the relationship between some important physics parameters.
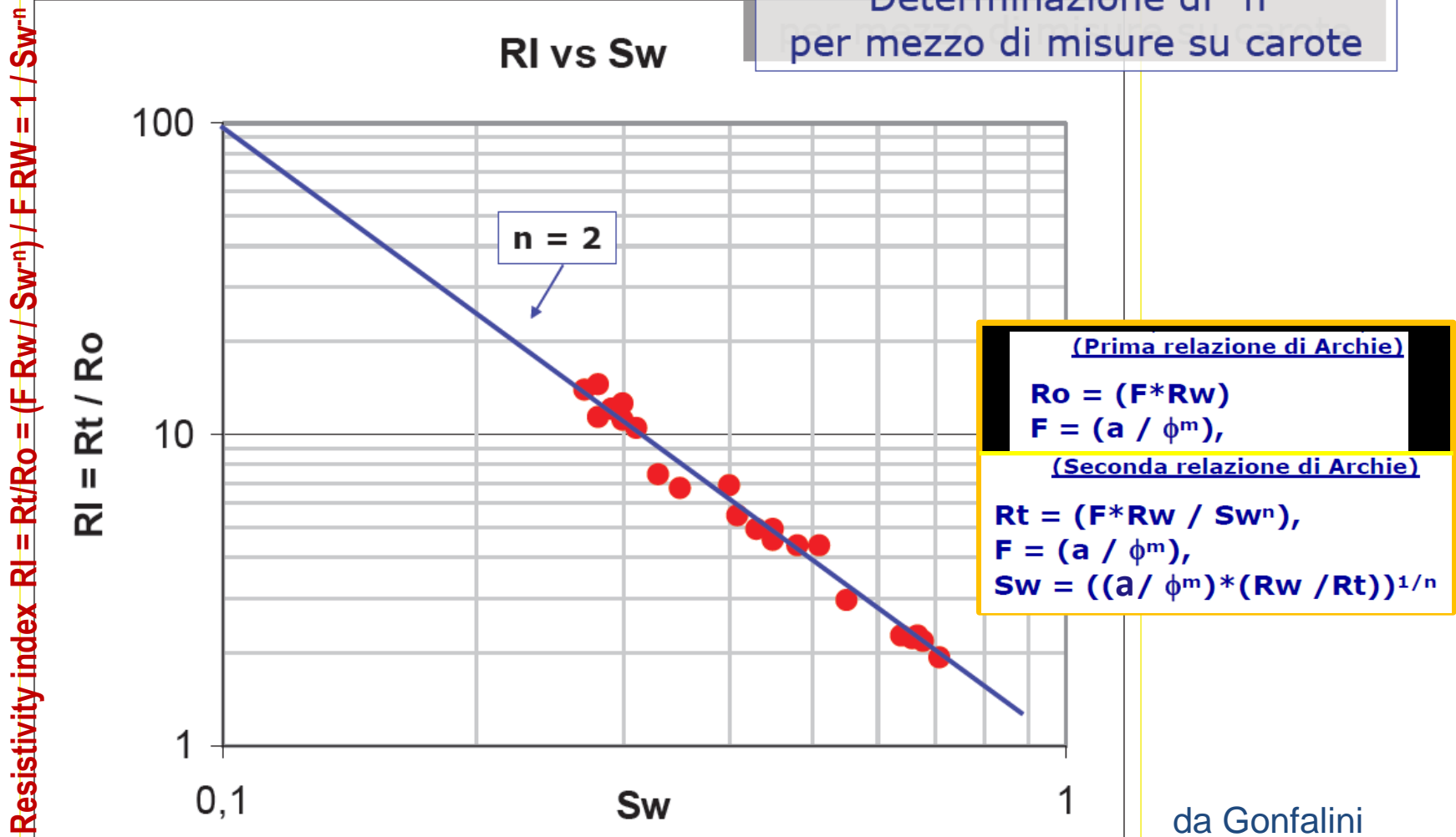
The main purpose of their application is the measure of the **saturations**.

The greater the S_{wirr}, the lower the formation resistivity R_o

Further than saturations, resistivity measure is also important for the formation producibility :
R close to the wellbore (flushed zone) where mud filtrate has invaded the formation is compared with R of a virgin portion of the formation (true resistivity, R_t).

Esponente di saturazione «n»

Determinazione di "n" per mezzo di misure su carote

y-axis (left, vertical): Resistivity index $RI = Rt/Ro = (F \cdot Rw / Sw^n) / F \cdot RW = 1 / Sw^n$

RI vs Sw

$RI = Rt / Ro$

n = 2

(Prima relazione di Archie)

$Ro = (F \cdot Rw)$
$F = (a / \phi^m),$

(Seconda relazione di Archie)

$Rt = (F \cdot Rw / Sw^n),$
$F = (a / \phi^m),$
$Sw = ((a / \phi^m) \cdot (Rw / Rt))^{1/n}$

da Gonfalini

Saturation exponent n, usually fixed to values close to 2, models the dependency on the presence of non-conductive fluid (hydrocarbons) in the pore-space, and is related to the wettability of the rock.
Water-wet rocks will, for low water saturation values, maintain a continuous film along the pore walls making the rock conductive.
Oil-wet rocks will have discontinuous droplets of water within the pore space, making the rock less conductive.

"a" "m" & "n" in serbatoi carbonatici
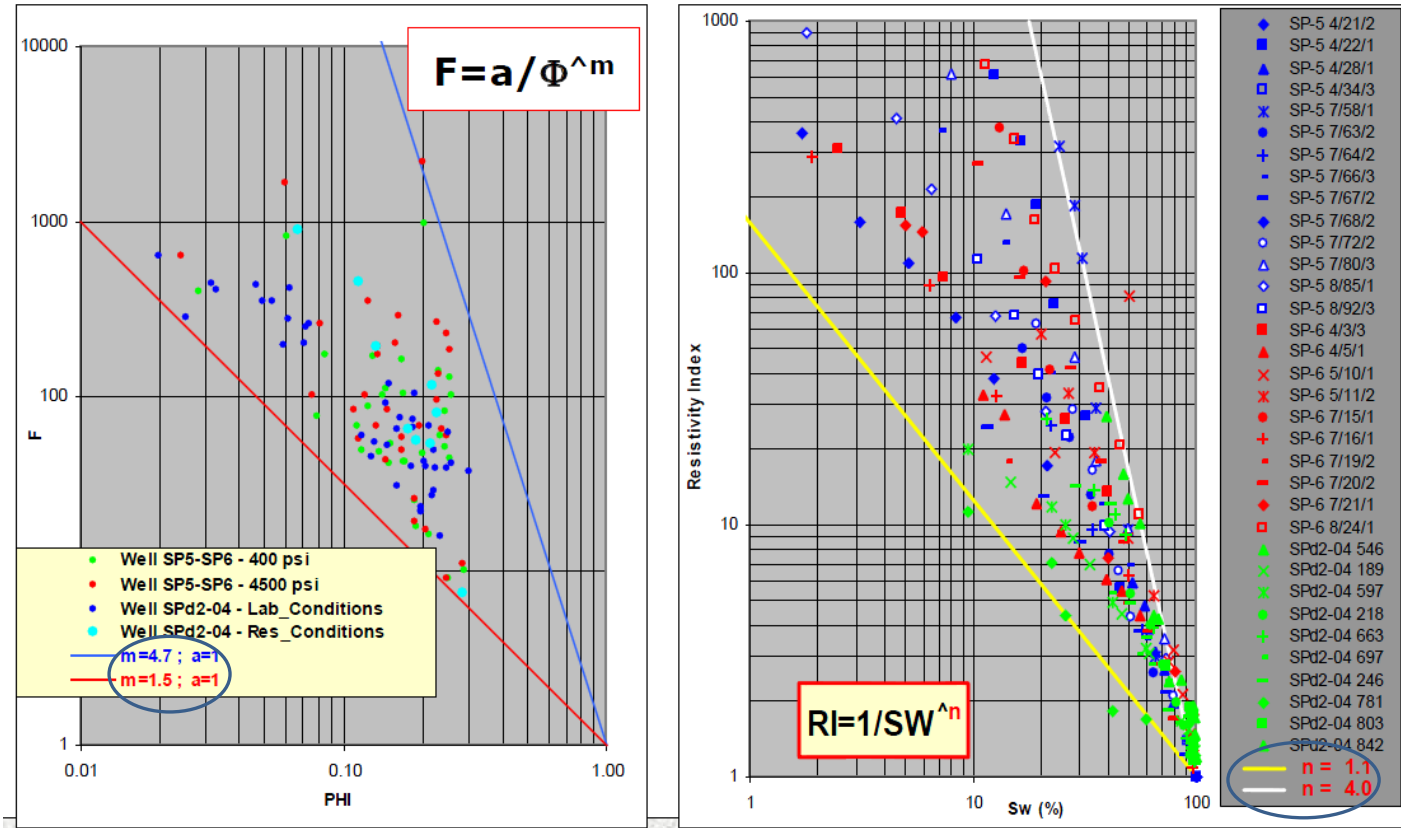
No methods are available for the direct measurement of the constant "**a**", called *tortuosity factor*, *cementation intercept*, *lithology factor* or *lithology coefficient*.

It is defined either as an <u>average elongation of fluid paths</u> or as a <u>retardation factor</u> that measures the <u>resistance of a porous medium to the flow</u>. It is affected by compaction, pore structure and grain size.

(Prima relazione di Archie)

$$Ro = (F*Rw)$$
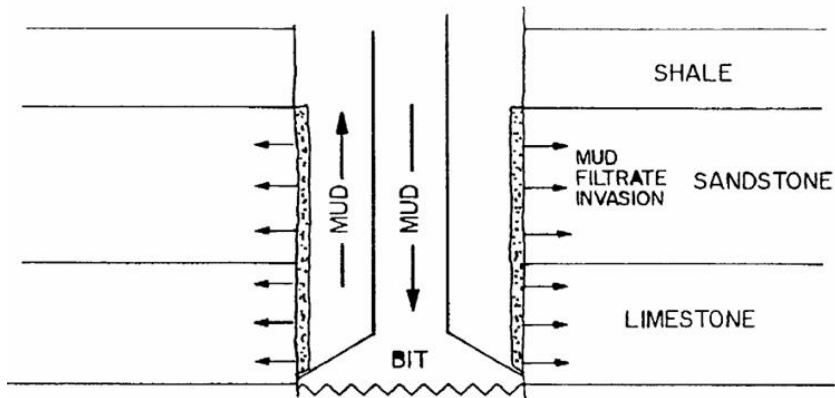$$F = (a / \phi^m),$$

(Seconda relazione di Archie)

$$Rt = (F*Rw / Sw^n),$$
$$F = (a / \phi^m),$$
$$Sw = ((a / \phi^m)*(Rw / Rt))^{1/n}$$

When acquiring downhole data, the mud filtrate contaminates, with varying degree, the newly penetrated formation.
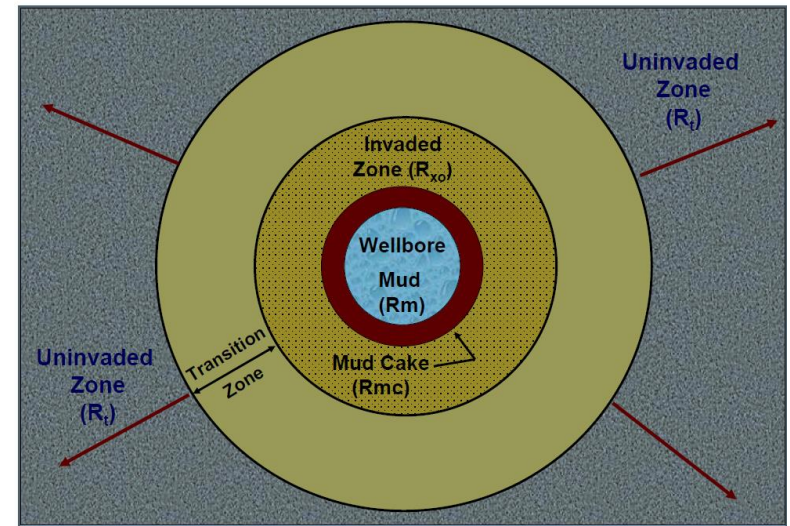
Effects of Drilling Mud and Mud Filtrate Invasion

Drilling Disturbs Formation
Washouts and Filtrate Invasion

- Drilling and rock crushing
  - Damage Zone
- Mud systems and invasion
  - Oil-based Mud
    - Small conductivity mud.
    - Shallow invasion.
    - Thin cake.
  - Water-based Mud
    - Moderate to very conductive mud.
    - Shallow to deep invasion.
    - Thin to thick cake.
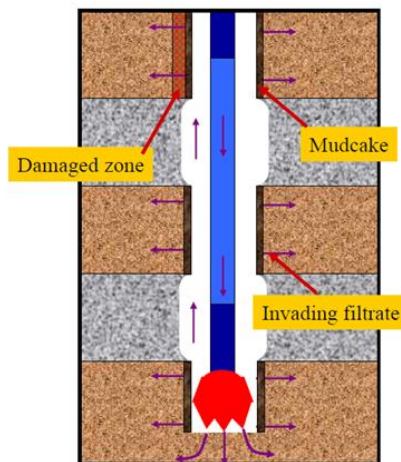
Mud Filtrate Invasion

In a <u>highly permeable</u> formation a large quantity of fluid will initially enter the pores. As a result, the clay platelets suspended in the mud will quickly accumulate around the borehole wall.

The formation effectively filters the penetrating fluid forming a **mud cake** around the borehole wall which in turn will <u>prevent further invasion</u>.

In a <u>less permeable formation</u>, invasion will take more time and will therefore <u>penetrate deeper</u> into the formation.

The main task of electrical logs is to measure the **true resistivity (Rt)** of a formation not contaminated by drilling mud, and the **resistivity Rxo** of the area completely crowded out of the mud, in the immediate vicinity of the wall of the hole.

These measures are used to calculate the water saturation in the virgin area and in the flushed zone using the formulas of Archie.

Several methods have been developed with the aim to determine the resistivity **Rw**, which could be widely variable also inner the same reservoir.

(Prima relazione di Archie)

$Ro = (F*Rw)$
$F = (a / \phi^m),$

(Seconda relazione di Archie)

$Rt = (F*Rw / Sw^n),$
$F = (a / \phi^m),$
$Sw = ((a / \phi^m)*(Rw / Rt))^{1/n}$

d_{xo} = Flushed zone diameter

d_i = İnvasion diameter

Common Terminology

Borehole

R_m = Borehole mud resistivity
R_{mc} = Mud cake resistivity

Invaded zone

R_{mf} = Mud filtrate resistivity
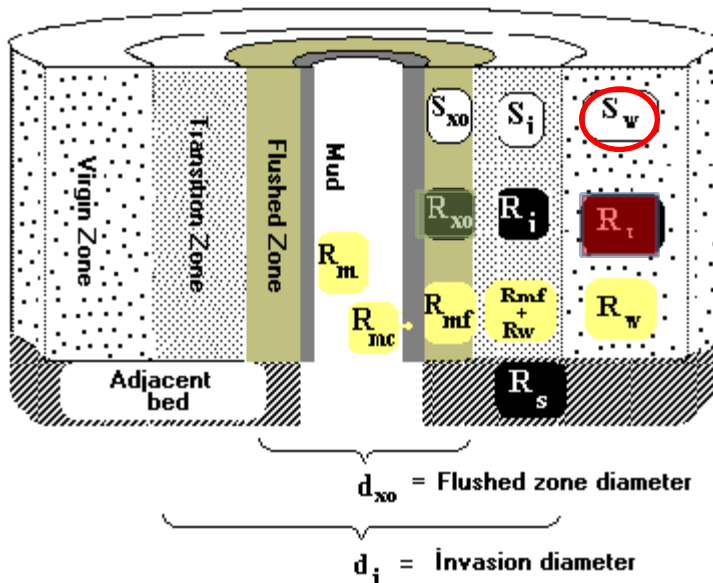R_{xo} = Invaded zone resistivity
S_{xo} = Invaded zone water saturation

Uninvaded zone

R_w = Interstitial water resistivity
R_t = Uninvaded zone resistivity
S_w = Uninvaded zone water saturation

# Effect of Mud Filtrate Invasion on Fluid Saturation (2/2)

	Original Conditions		After Invasion
1.00	Residual Oil	30% S_{xo} = 70%	Residual Oil
0.70	Moveable Oil	$(S_{xo} - S_w)$= 40%	Mud Filtrate
0.30	Connate Water	S_w = 30%	Mud Filtrate
0.0			

Filtrate Invasion Effects:
- Invasion of mud filtrate causes a change in pore fluid saturations.
- A difference in S_{xo} and S_w indicates movable hydrocarbon saturation.

From Halliburton, EL 1007)

Effect of Mud Filtrate Invasion on Fluid Saturation (1/2)
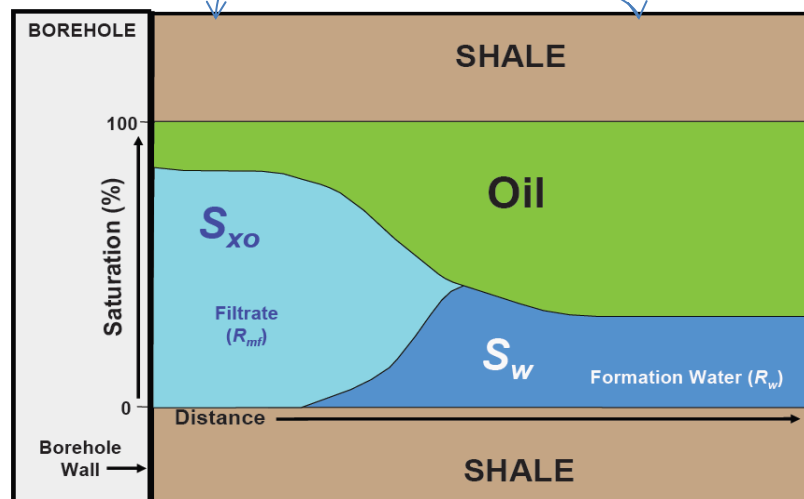
Difference between S_{xo} and S_w indicates movable hydrocarbons

Example of a formation with oil

Sw: uninvaded zone water saturation (30%).

After mud filtrate invasion:
Sxo: invaded zone water saturation (70%)

In the invaded zone: mud filtrate with resistivity Rmf

→Residual oil: 30%

In the transition zone:
formation water (Sw, resistivity Rw) increases with the distance from the borehole wall;
water, mud filtrate and oil are present in different ratio: it depends by distance from the borehole wall.

In the uninvaded zone:
Sw and So as before invasion (respectively 30% and 70%)

Calcolo di Sw: metodo diretto (Archie)

da Gonfalini
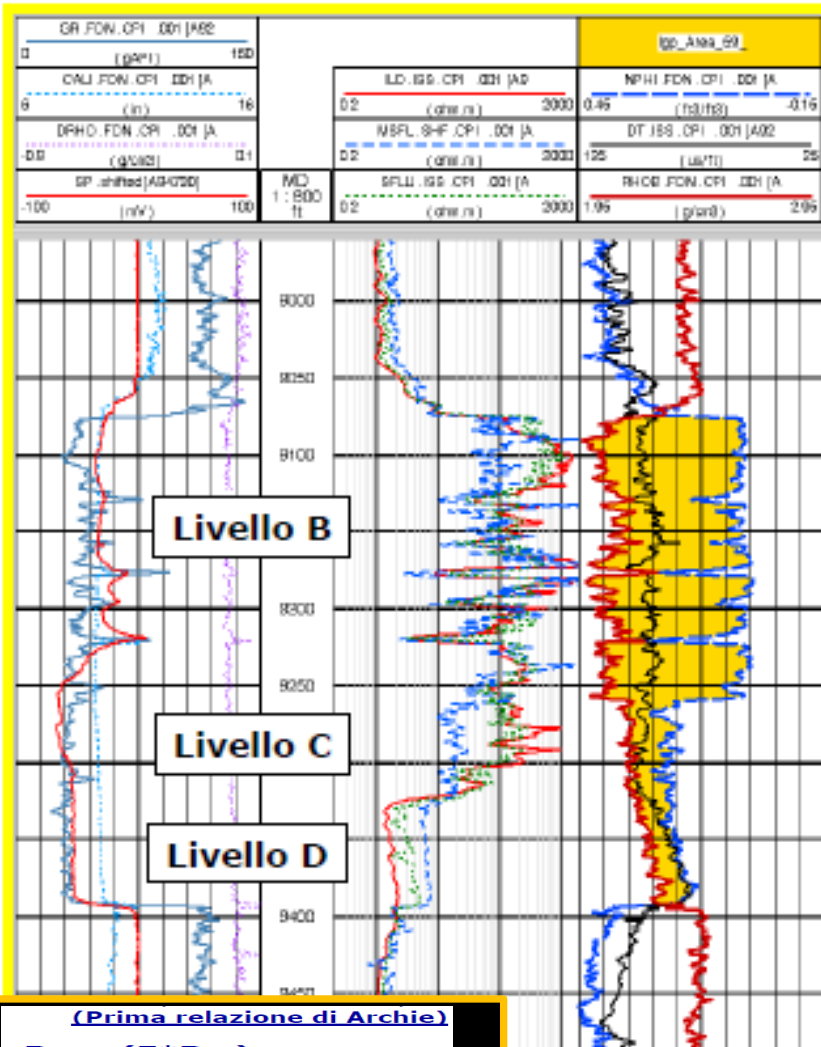
Calcolo di Sw

Il livello D è acquifero (Sw = 100 %).

In corrispondenza di questo punto possiamo calcolare Rw.

Per valutare Rw usiamo la prima relazione di Archie (Sw = 100%):

$$Rw = Ro/F = (Ro*\Phi^m)/a)$$

	Rt	PHIDN	a	m	n	Rw	Sw
Livello D	1,4	0,28	1	2	2	0,11	1,00

Per calcolare la Sw nei livelli B e C usiamo la seconda relazione di Archie:

$$Sw = (F*Rw/Rt)^{1/n} = ((a/\Phi^m)(Rw/Rt))^{1/n}$$

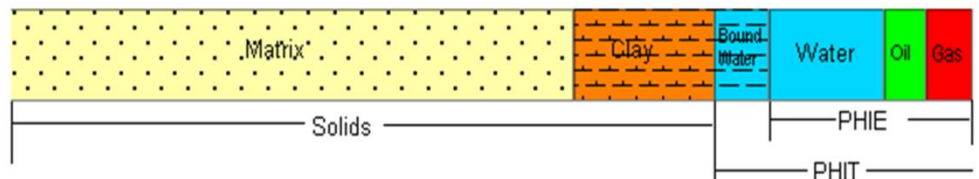|	Rt	PHIDN	a	m	n	Rw	Sw	Sw (%)
Livello B	1000	0,25	1	2	2	0,11	0,042	4,2
Livello C	220	0,27	1	2	2	0,11	0,083	8,3

Figure shows the distribution of fluids and solids in a formation:

PHI = porosity.

PHIE = proportion of fluids in the matrix.

PHIT = PHIE + VBW   (VBW= volume of bound water)

The matrix can be a clean sand of known density or a mixture of solids (Sand + Heavy Minerals or carbonate cements) or other.
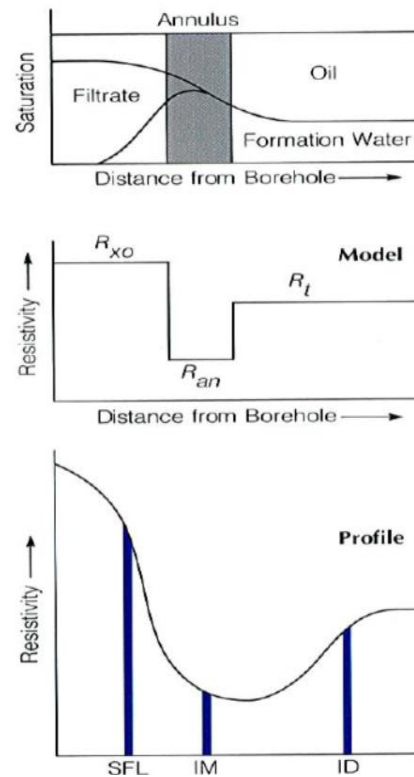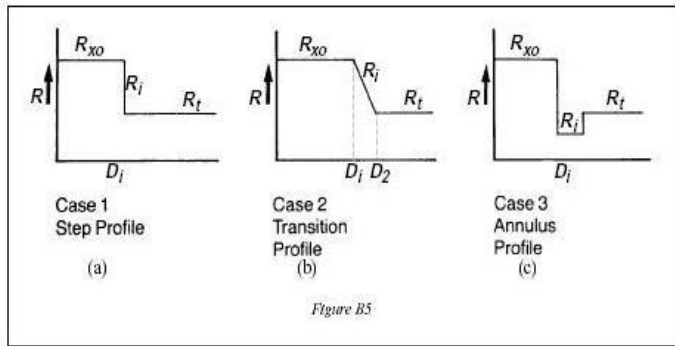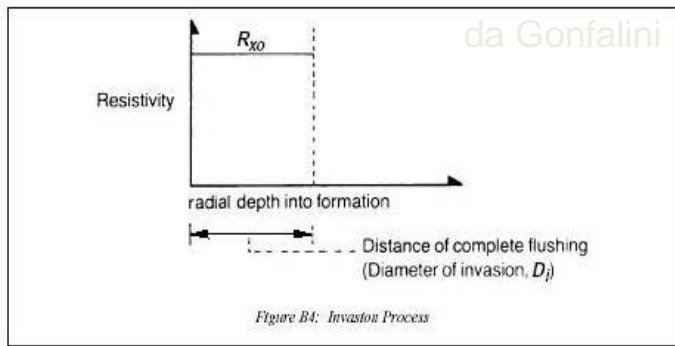
(Prima relazione di Archie)

$$Ro = (F*Rw)$$
$$F = (a / \phi^m),$$

(Seconda relazione di Archie)

$$Rt = (F*Rw / Sw^n),$$
$$F = (a / \phi^m),$$
$$Sw = ((a/ \phi^m)*(Rw /Rt))^{1/n}$$

da Gonfalini

Resistivity

R_{xo}

radial depth into formation

Distance of complete flushing
(Diameter of invasion, D_i)

Figure B4: Invasion Process

R | R_{xo} R_i R_t | R | R_{xo} R_i R_t | R | R_{xo} R_i R_t
D_i | D_i D_2 | D_i

Case 1 Step Profile (a) | Case 2 Transition Profile (b) | Case 3 Annulus Profile (c)

Figure B5

Saturation

Annulus

Oil

Filtrate

Formation Water

Distance from Borehole →

R_{xo} Model

R_t

R_{an}

Distance from Borehole →

Resistivity

Profile

SFL   IM   ID

Sw = Sxo = 100%
Ro= F Rw = $(1/\Phi^m)$ Rw
Rxo= F Rmf = $(1/\Phi^m)$ Rmf
Sw < 100%, Sxo <100%
Rt =$(1/\Phi^m)(Rw/Sw^n)$
Rxo=$(1/\Phi^m)(Rmf)/Sxo^n$

Virgin Zone | Transition Zone | Flushed Zone | Mud | S_{xo} S_i S_w | R_m R_{xo} R_i R_t | R_{mc} R_{mf} $\frac{Rmf}{+Rw}$ R_w | R_s

Adjacent bed

d_{xo} = Flushed zone diameter

d_i = Invasion diameter

Generally, mud filtrate displaces formation water and any hydrocarbon to some distance away from the borehole wall. The invaded zone surrounding the borehole becomes saturated with mud filtrate and has resistivity **Rxo**. The virgin formation beyond has resistivity **Rt**. This so-called **step profile** forms the basis for estimating R_t, R_{xo} and the diameter of invasion. In reality invasion is a lot more complex. It's physically implausible, for example, that an invaded formation can suddenly give way to virgin formation, but a gradual change gives rise to the so-called **ramp invasion**. Most of the time the three resistivity measurements lie in sequence between R_{xo} and R_t.

Water-wet formations have much higher relative permeability to oil than to water. In this case the mud filtrate displaces hydrocarbon more easily than the formation water: the zone immediately surrounding the borehole gets filled with mud filtrate, but there is a zone forming an **annulus** around the well that is filled with some filtrate, a lot of formation water (not displaced very easily) and little hydrocarbon (easily displaced). Beyond will be virgin formation. The annulus resistivity (R_i or R_{an}) depends on whether filtrate resistivity is greater or less than formation water resistivity. In the more common case, it is greater and R_{an} will be less than R_{xo}, but also than R_t because the zone has lost hydrocarbon while retaining formation water.

Figure 5.53 The Formation Resistivity Log
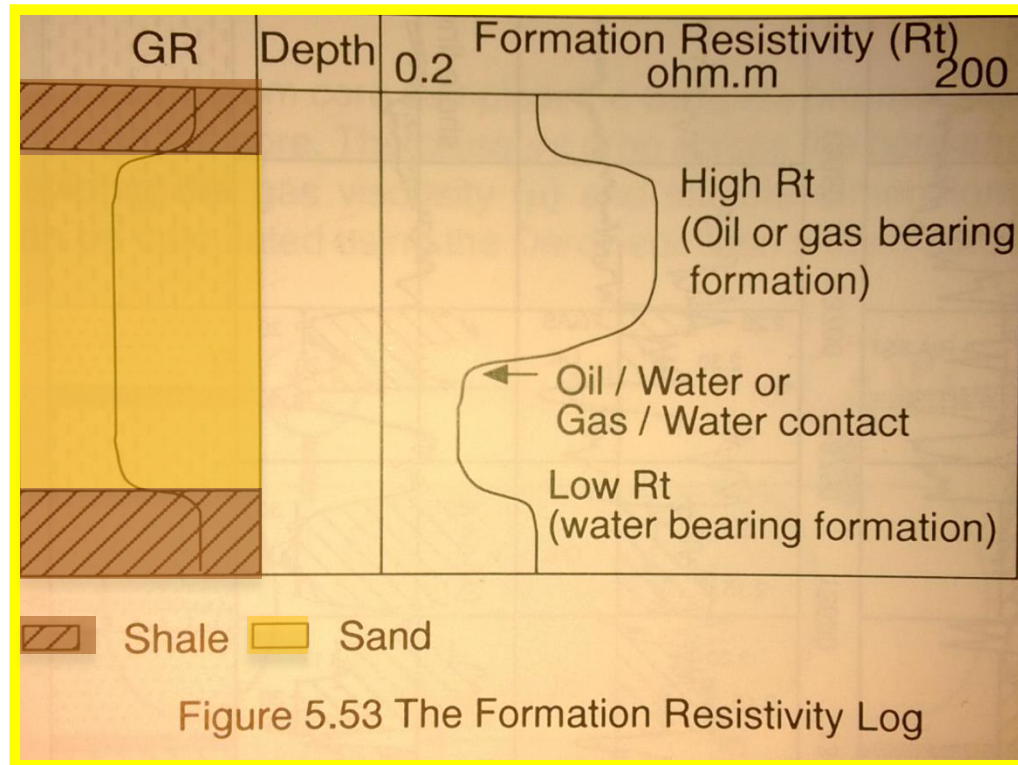
The resistivity log can also be used to define oil/water or gas/water contacts: the fluid contact can be defined as the point at which the resistivity begins to increase in the reservoir interval, inferring the presence of hydrocarbons above that point.

$$Rt = (F * Rw / Sw^n),$$
$$F = (a / \phi^m),$$
$$Sw = ((a / \phi^m) * (Rw / Rt))^{1/n}$$