भारतीय प्रौद्योगिकी संस्थान
(भारतीय खनि विद्यापीठ)
धनबाद

IIT ISM

INDIAN INSTITUTE OF TECHNOLOGY
(INDIAN SCHOOL OF MINES)
DHANBAD

GPC510 - Well logging

Semester - Winter 2025; Lecture - 7

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TEACHING OUTLINE

Week 4

Tutorial 10 – Water saturation, Archie’s equation

Tutorial 11 – Capillary pressure, water saturation

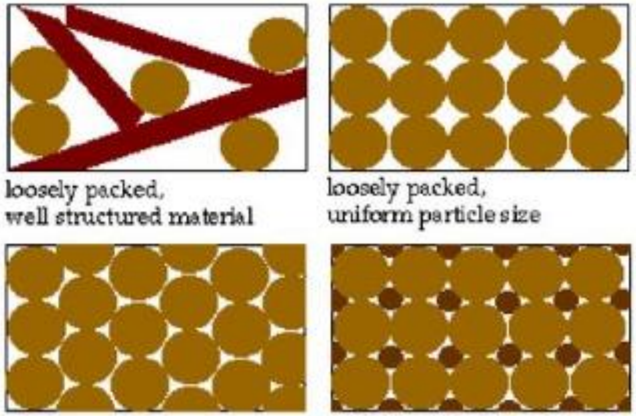
AGENDA

- Direct field method of permeability measurement
- Log-based technique of permeability estimation
- Water saturation (S_w)

POROSITY

Porosity of rock depends upon

- Shape and arrangement of grains
- Mixing of grain size
- Degree of cementing materials

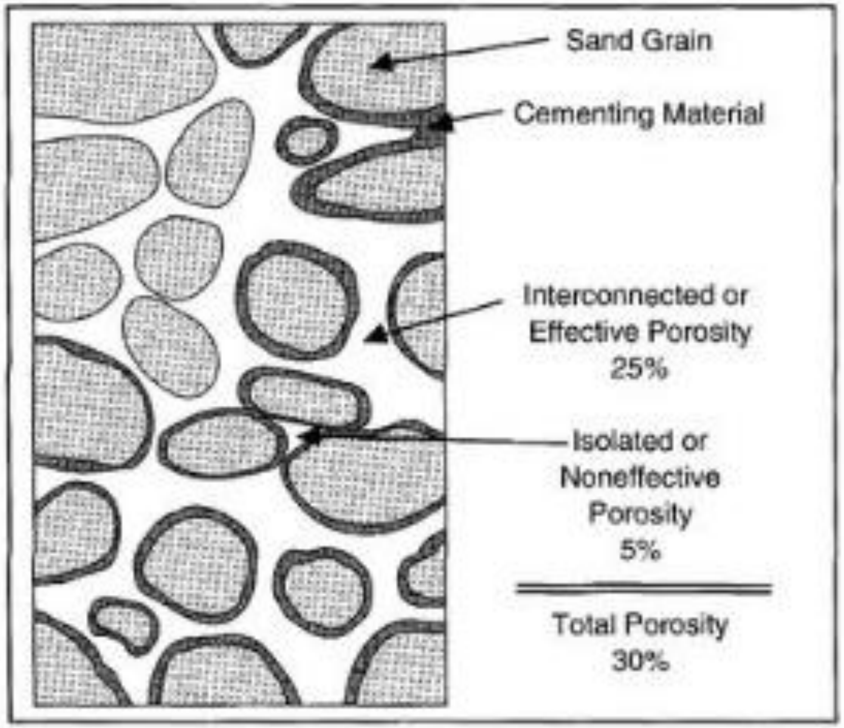


loosely packed, well structured material

loosely packed, uniform particle size

tightly packed, uniform particle size

tightly packed, mixed particle sizes

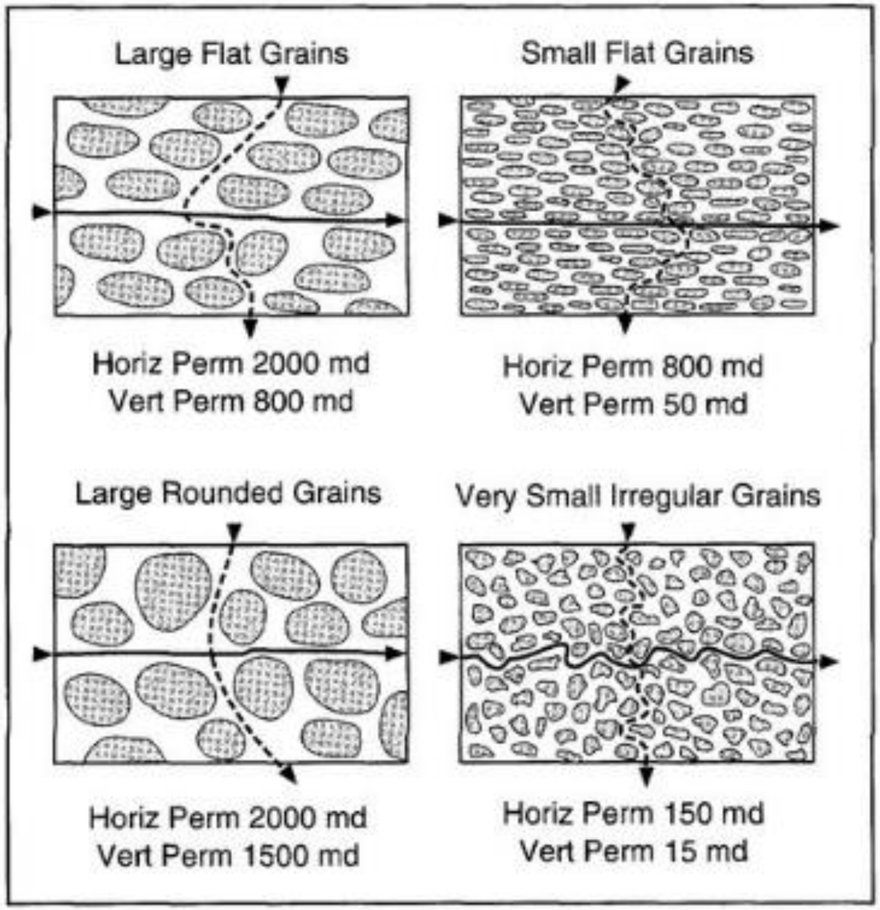


Total porosity (ϕ_t) = effective porosity (ϕ_e) + non-effective porosity)

PERMEABILITY

Permeability of rock depends upon

- Size of pore openings
- Degree and size of pore connectivity
- Degree and type of cement materials
- Permeability will be anisotropic in nature [direction dependent properties]



DIRECT MEASUREMENT

Permeability can be measured directly from field operation and laboratory tests

- Pressure build-up from drill-stem tests (DST)
- Pressure drawdown and build-up from wireline repeat formation tests (RFT)
- Core analysis

Method	**Radius of investigation (ft)**
DST	10^2 to 10^4
RFT buildup	10 to 10^2
RFT drawdown	10^{-2} to 10
Log analysis	5 to 10^{-1}
Core analysis	8×10^{-2} to 3×10^{-1}

Ref: Bateman, 1985

WELL-LOG APPROACH

Several models are proposed to estimate permeability from wireline logging measurements above the transition zone (at hydrocarbon leg).

- Timur (1968) proposed permeability k is proportional to S^2_{wi} in general power law equation

$$k = 0.136 \frac{\emptyset^{4.4}}{S_{wi}^2}$$

where ϕ is porosity (%), k – permeability (mD), S_{wi} - irreducible water saturation in %

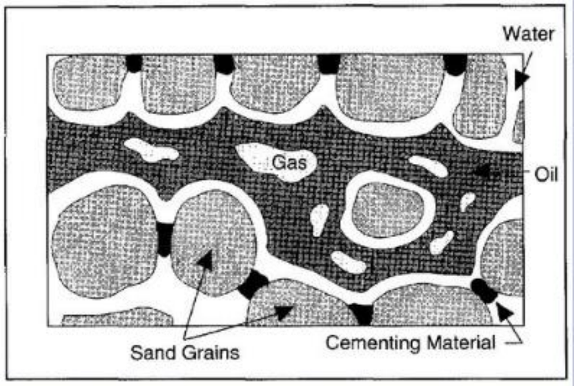
- Two methods for calculating log-derived permeability after Wyllie and Rose (1950)

$$k = \left[250\, x \left(\frac{\emptyset^3}{S_{wi}}\right)\right]^2$$ for oil

$$k = \left[79\, x \left(\frac{\emptyset^3}{S_{wi}}\right)\right]^2$$ for gas, again in k is in mD unit

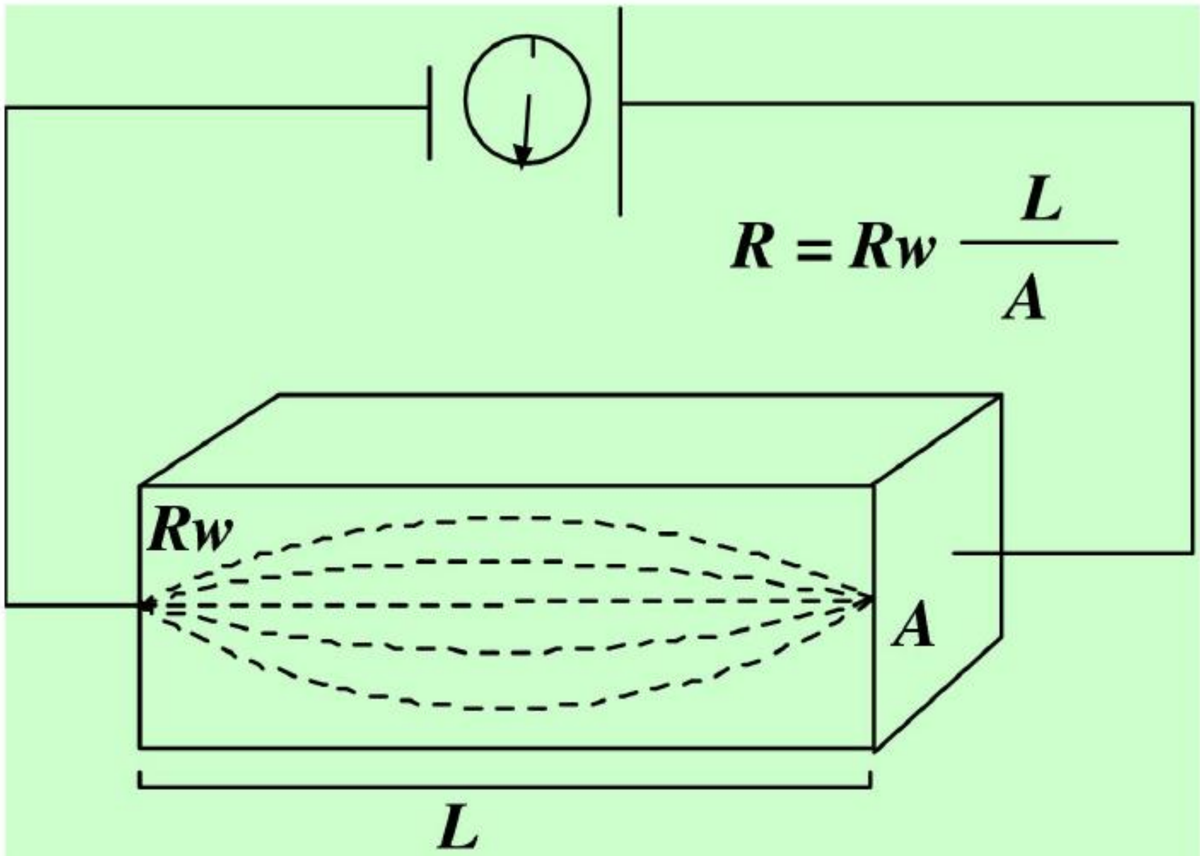
WATER SATURATION (S_W)

- Water saturation is defined as ratio of water volume in the pore space (V_w) to the total pore volume $S_w = V_w/V_p$, if there is no other fluid is present inside pore space, then $S_w = 1$
- When hydrocarbon (V_{hy}) is present along with water, $V_{hy} = V_p – V_w$ therefore $S_w = (V_p – V_{hy})/V_p = V_w/V_p$
- Saturation is a dimensional property expressed in fraction ($0 < S_w < 1$) or percentage ($0 < S_w < 100\%$)



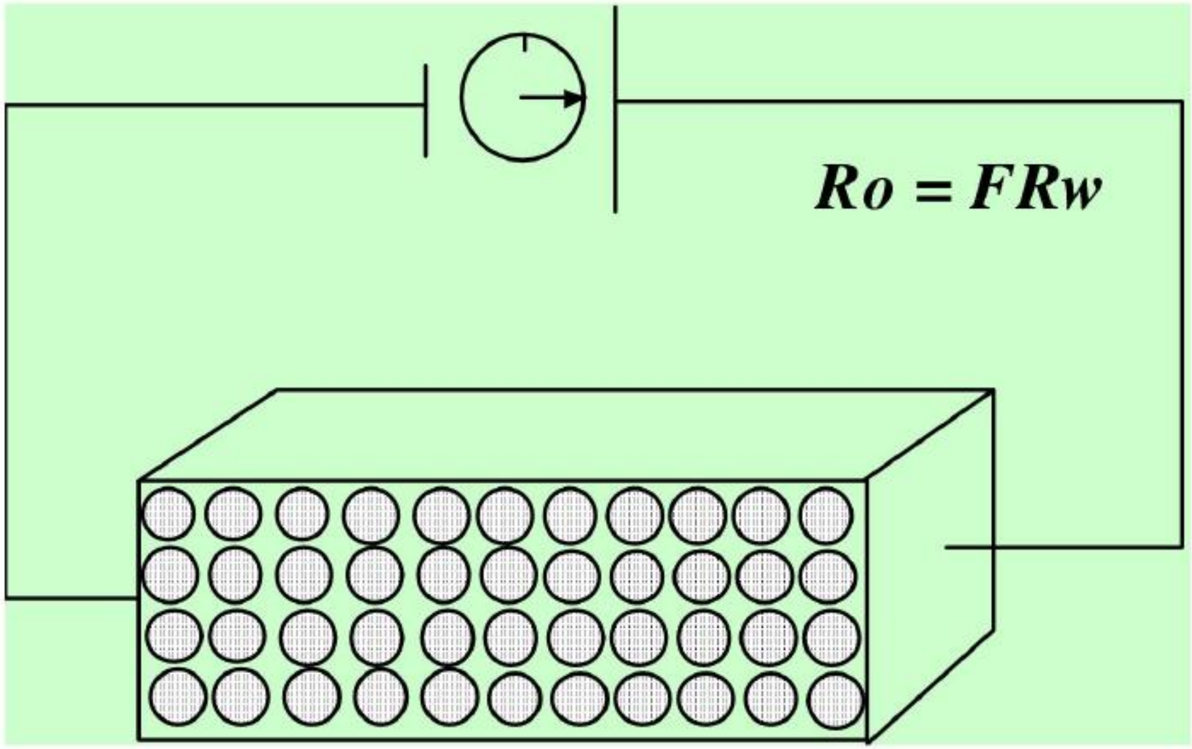
$S_w + S_o + S_g = 100\%$

ARCHIE'S CONCEPT



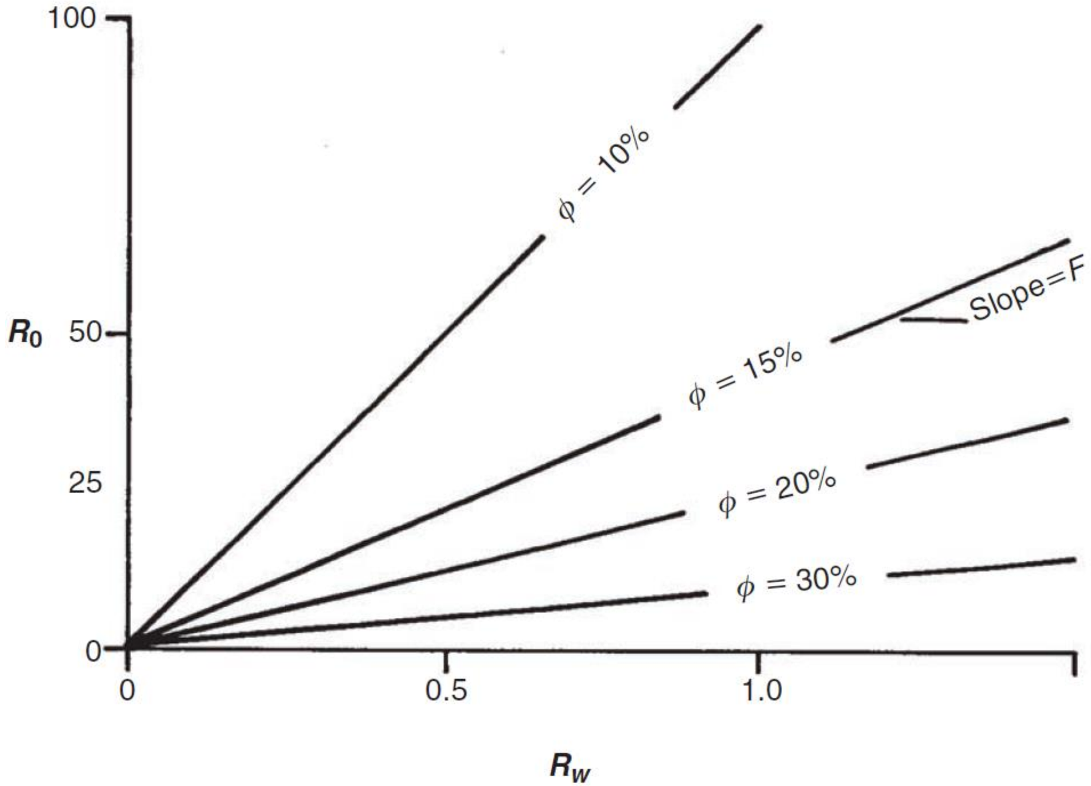
Fluid flow through a rock and the flow of electrical current through the same rock have several similarities. R = resistivity of the rock system filled with water of resistivity R_w.

ARCHIE'S CONCEPT



A rock cube is consisting of several cylindrical tubes drilled through it. R_0= resistivity of a rock 100% saturated with water. F = electrical formation factor

ELECTRICAL FORMATION FACTOR



R_0= resistivity of a rock 100% saturated with water of resistivity R_w.

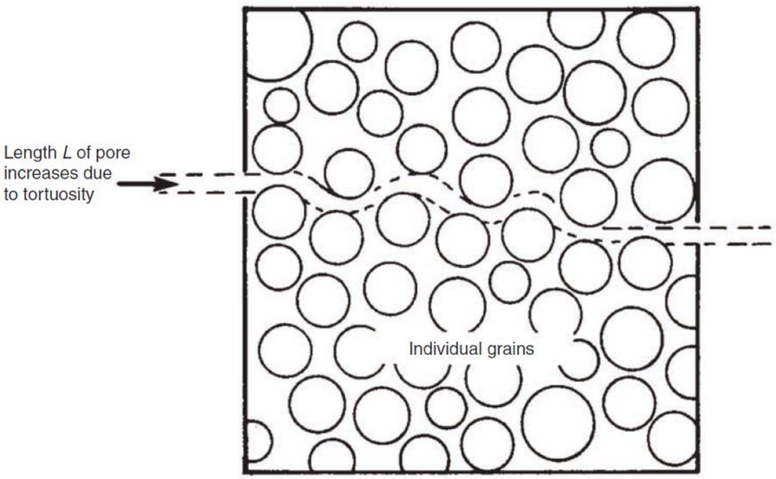
Ref: Bateman, 2012

IRREDUCIBLE WATER SATURATION

- The fraction of the pore volume occupied by water in a reservoir at maximum hydrocarbon saturation. It represents water that has not been displaced by hydrocarbons because it is trapped by adhering to rock surfaces, trapped in small pore spaces and narrow interstices, etc. Irreducible water saturation is an equilibrium situation [**SEG WIKI**]
- The lowest water saturation, S_{wi}, that can be achieved in a core plug by displacing the water by oil or gas. The state is usually achieved by flowing oil or gas through a water-saturated sample or spinning it in a centrifuge to displace the water with oil or gas. The term is somewhat imprecise because the irreducible water saturation is dependent on the final drive pressure (when flowing oil or gas) or the maximum speed of rotation (in a centrifuge). The related term connate water saturation is the lowest water saturation found in situ. [**SLB glossary**]

FORMATION FACTOR: F

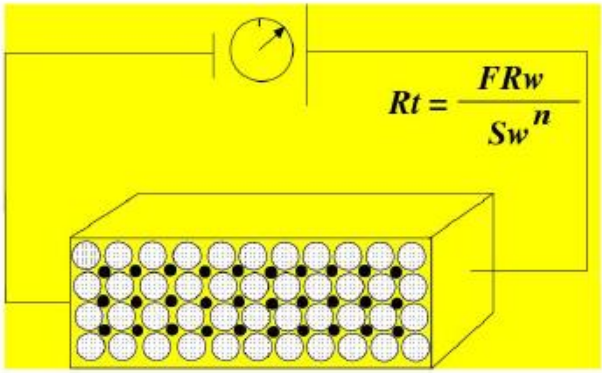
- Archie first introduced the concept of electrical formation factor F from laboratory test as the resistivity of the clean fully water saturated formation to the resistivity of formation water (brine) as F = R_0/R_w
- Later he established that F could be related to porosity of the rock as $\mathrm{F} = \frac{a}{\emptyset^m}$ where "a" is tortuosity factor and "m" is the cement exponent

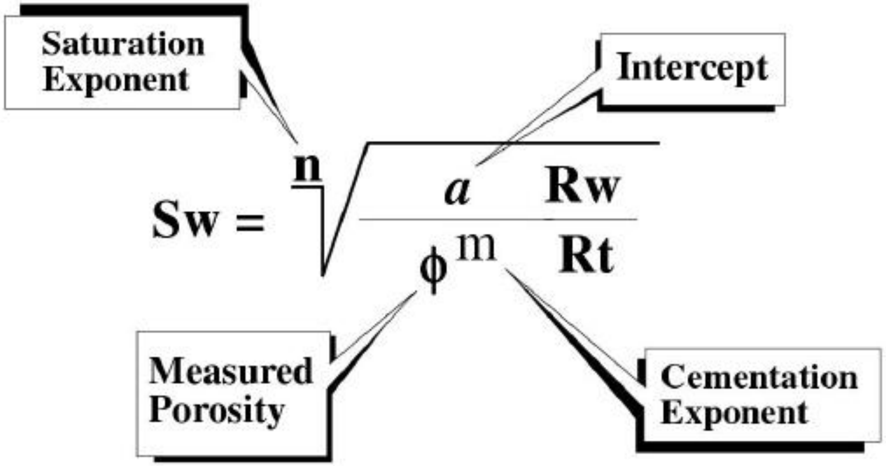


DETERMINATION OF S_W – CLEAN FORMATION

- Archie (1942) proposed water saturation of clean reservoir formation following large number of laboratory measurements as below (known as Archie's equation)

$$Sw^n = \frac{Ro}{Rt} = \frac{F \times Rw}{Rt} = \frac{aRw}{\phi^m Rt}$$



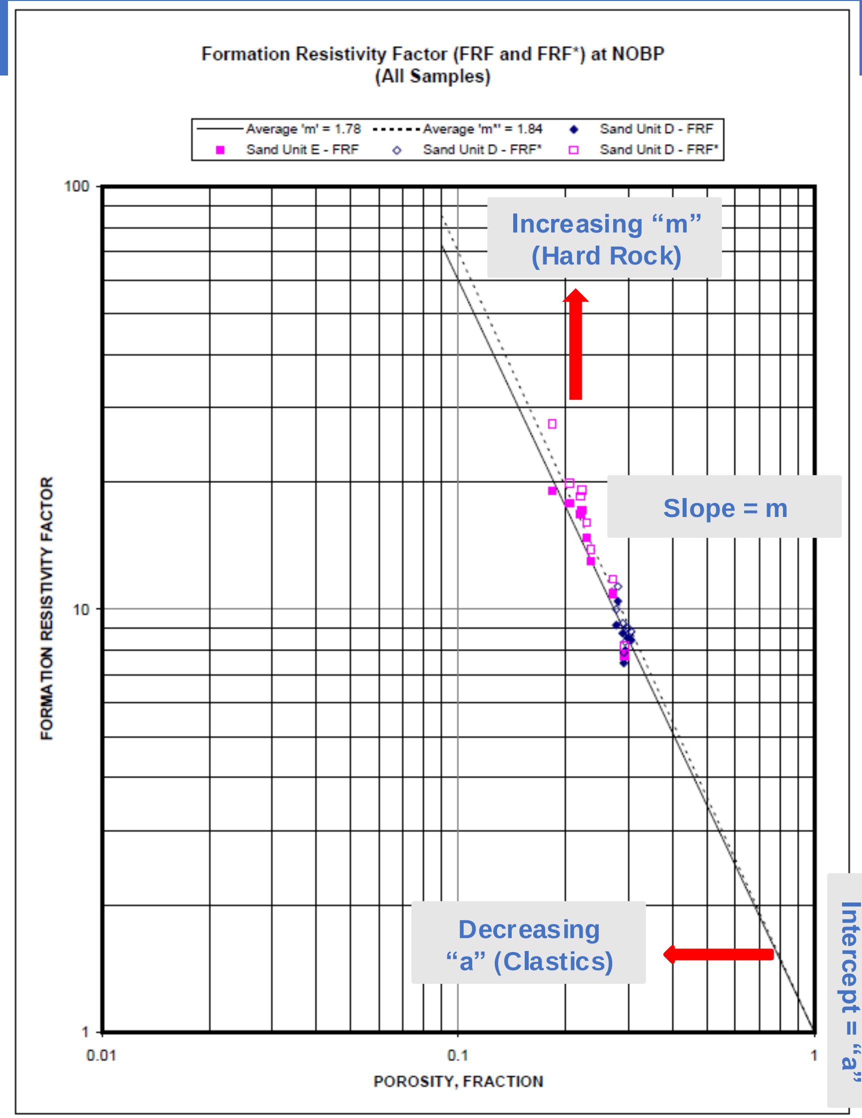


DETERMINATION OF COEFFICIENTS

$$F = \frac{a}{\emptyset^m}$$

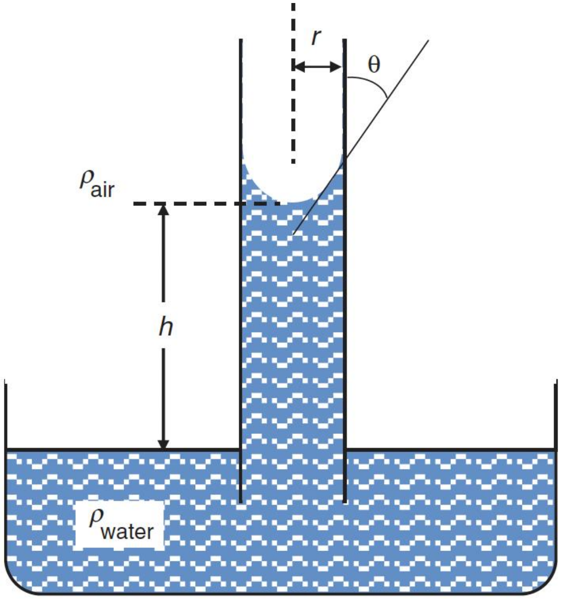
$$\log F = a - m \log \emptyset$$

- The conventional approach of determination of two coefficients a and m from Archie's equation. The log-log plot of formation factor versus porosity can provide required coefficients.
- $F = \frac{1}{\emptyset^2}$ (Carbonates)
- $F = \frac{0.62}{\emptyset^{2.15}}$ (Soft formations – Humble formula)
- $F = \frac{0.81}{\emptyset^2}$ (Sandstones)



FLUID DISTRIBUTION IN RESERVOIR

- The concept of capillary pressure (P_c) comes into play when multiple fluids are present in a given reservoir (Gas, Oil, and Water) and need to predict length of transition zone
- To understand the shape of the water-saturation curve in the transition zone, consider the case of a small glass tube held in a beaker of water, as shown in Figure.
- A capillary tube of radius r will support a column of water of height h. If the density of air is ρ_a and the density of water is ρ_w, the pressure differential at the air/water contact is simply $(\rho_w - \rho_a)$ h.

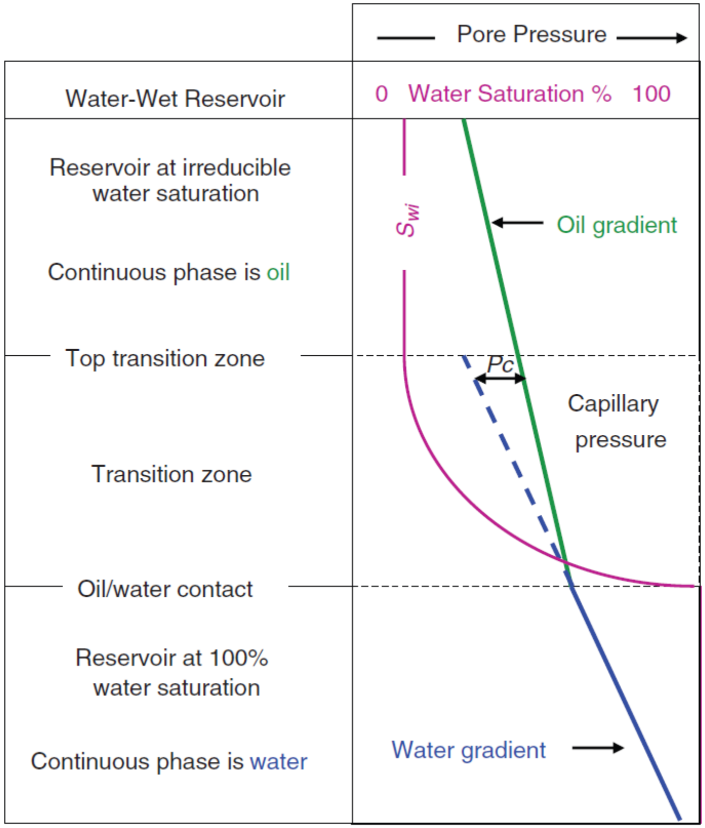


FLUID DISTRIBUTION IN RESERVOIR

- The pressure differential (ρ_w - ρ_a)*h at air/water contact counterbalanced by surface tension T, of the water film acting around the circumference of the capillary tube, at equilibrium

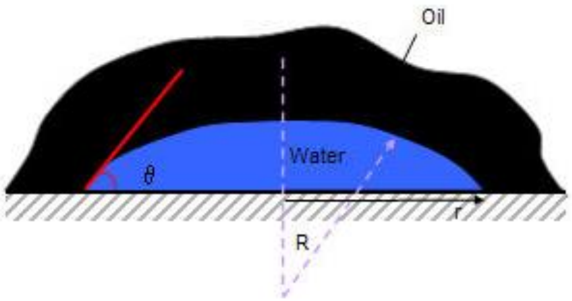
$2\pi r T \cos\theta = (\rho_w - \rho_a)gh \, * \, \pi r^2$, simplifying this

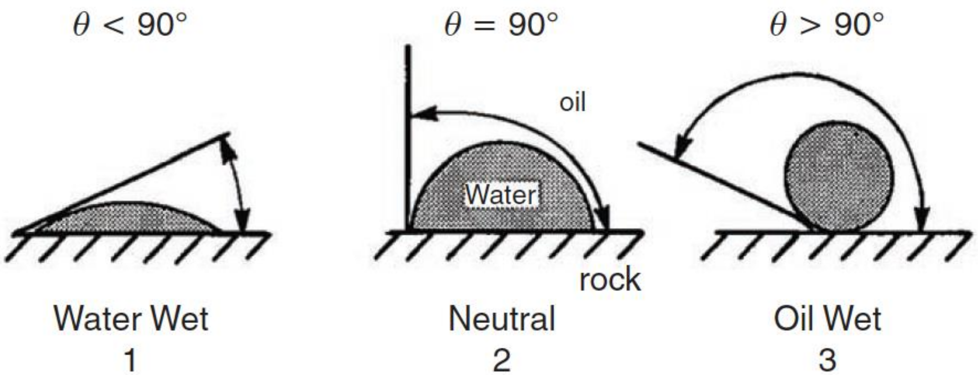
$h = \dfrac{2T\cos\theta}{rg(\rho_w - \rho_a)}$ i.e., smaller the *r* value, larger the *h* value



FLUID DISTRIBUTION IN RESERVOIR

- Wettability is another important concept to know contact angle therefore fluid distribution
- Pore-size distribution (distribution of pore throat radii and their actual size plays a crucial role)



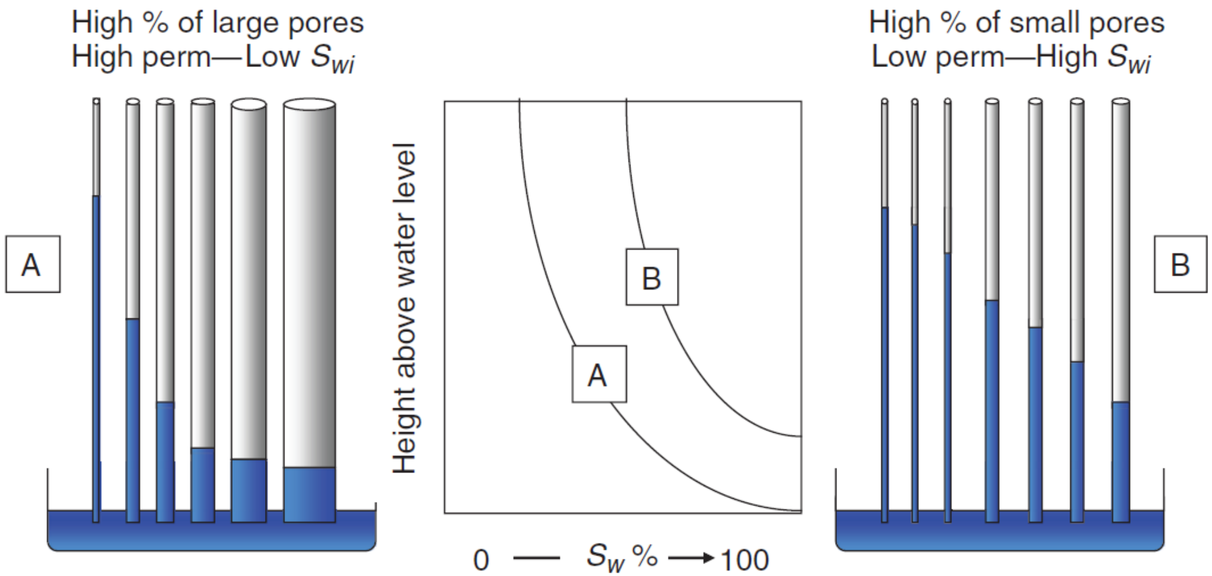


INTERFACIAL TENSION

- Rocks are, in most cases, water-wet, which means that water occupies the angular corners of the pores and exists as a film covering the solid particles. Oil-wet **rocks** do exist but are rare, and oil is usually not in direct contact with the rock. When considering the height to which water will rise in a zone impregnated with oil, we must modify the equation of water-air situation to include the interfacial tension of the two immiscible liquid and the density of two liquids
- To a good approximation, the interfacial tension is equal to the difference between the surface tension of i.e., T = T1- T2
- $h = \frac{2(T1 - T2)\cos\theta}{rg(\rho_w - \rho_o)}$

Ref: Serra, 1985

CAPILLARY PRESSURE EFFECTS



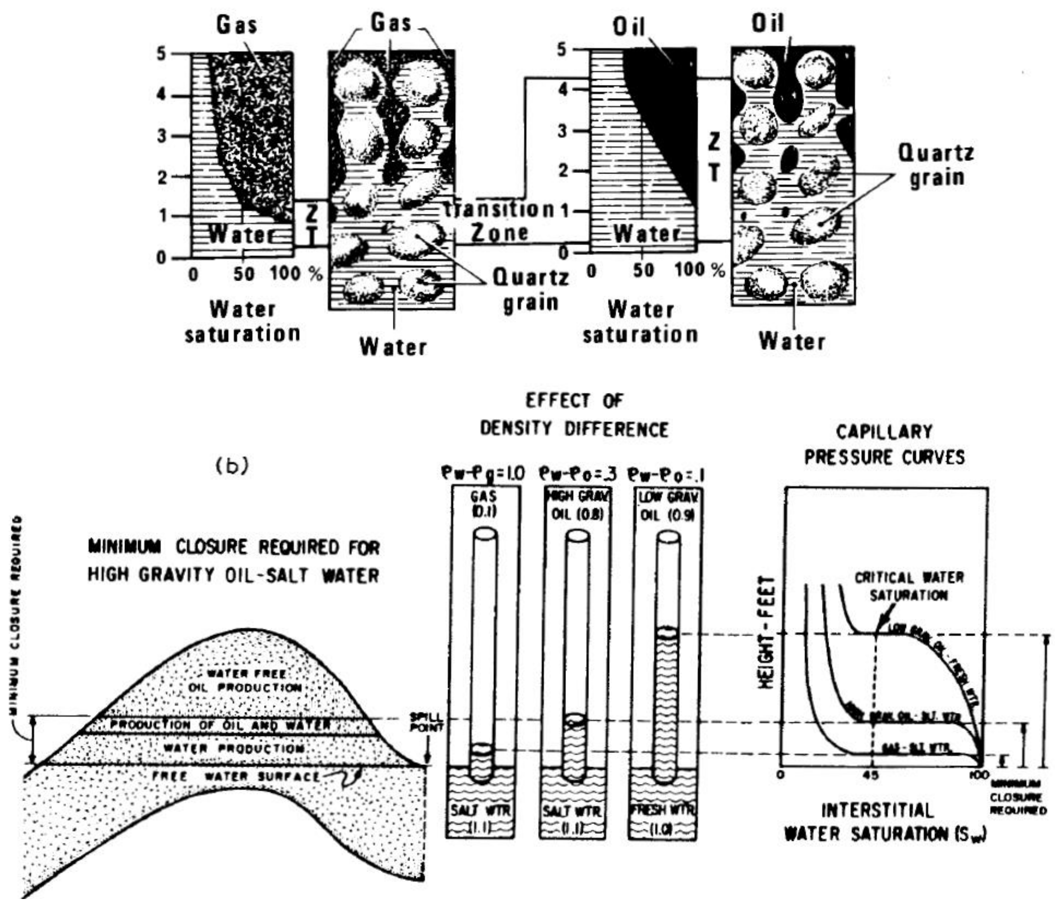
- A pore system is made up of a variety of pore sizes and shapes. As a result, no single value of r can be assigned to a particular reservoir. Therefore, depending on the distribution of the pore throat radii, as well as their actual size, either many or few of the available pore channels will raise water above the free-water level.

- Reservoirs with large pore throat and high permeability have short transition zones than smaller pore throat and small permeability

Ref: Bateman, 2012

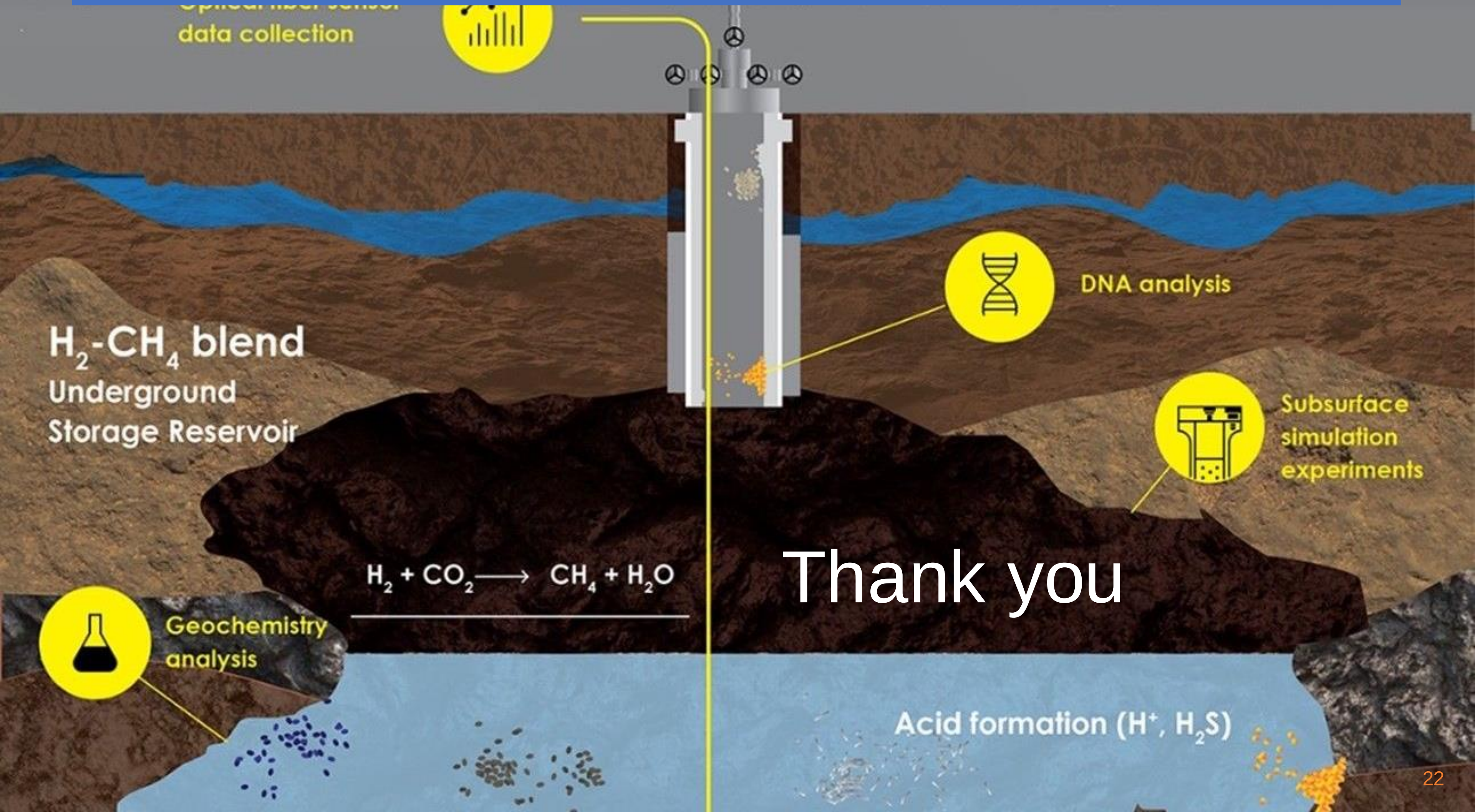
TRANSITION ZONES

- The distribution of water and gas or oil in a transition zone. For a given set of conditions, the smaller the difference between the densities of the fluids in contact, the higher the transition zone.
- Influence of density difference on the transition zone and capillary pressure curves (from **Arps,** 1964).



Ref: Serra, 1985

END OF LECTURE



Thank you