Rock Compressibility

- Reservoir rocks are subjected to the internal stress exerted by fluids contained in the pores, and to external stress which is in part exerted by the overlying rocks.

- The weight of the overburden simply applies a compressive force to the reservoir rock. Compressibility typically decreases with increasing porosity and effective overburden pressure.

- Porosity is a function of compaction. It is generally reduced by increase in compaction. Compaction is a function of depth of burial.
- Rock compressibility is the fractional change in Volume per unit change pressure

Expressed as:

$$C = \frac{1}{V}\left(\frac{\partial V}{\partial P}\right)_T$$

Types of Compressibility

Rock-matrix (grain) compressibility, Cr

Is defined as the fractional change in volume of the solid rock material (grains) with a unit change in pressure. Mathematically, the rock compressibility coefficient is given as;

$$c_r = -\frac{1}{V_r}\left(\frac{\partial V_r}{\partial p}\right)_T$$

where c_r = rock-matrix compressibility, psi^{-1}
V_r = volume of solids

Rock-bulk compressibility, Cb

Is defined as the fractional change in volume of the bulk volume of the rock with a unit change in pressure. The rock-bulk compressibility is defined mathematically by:

$$c_B = -\frac{1}{V_B}\left(\frac{\partial V_B}{\partial p}\right)_T$$

where c_B = rock-bulk compressibility coefficient, psi^{-1}
V_B = bulk volume

Pore-volume compressibility, Cp or Cf

The pore compressibility coefficient is defined as the fractional change in pore volume of the rock with a unit change in pressure and given by the following relationship:

$$c_p = \frac{-1}{V_p}\left(\frac{\partial V_p}{\partial p}\right)_T$$

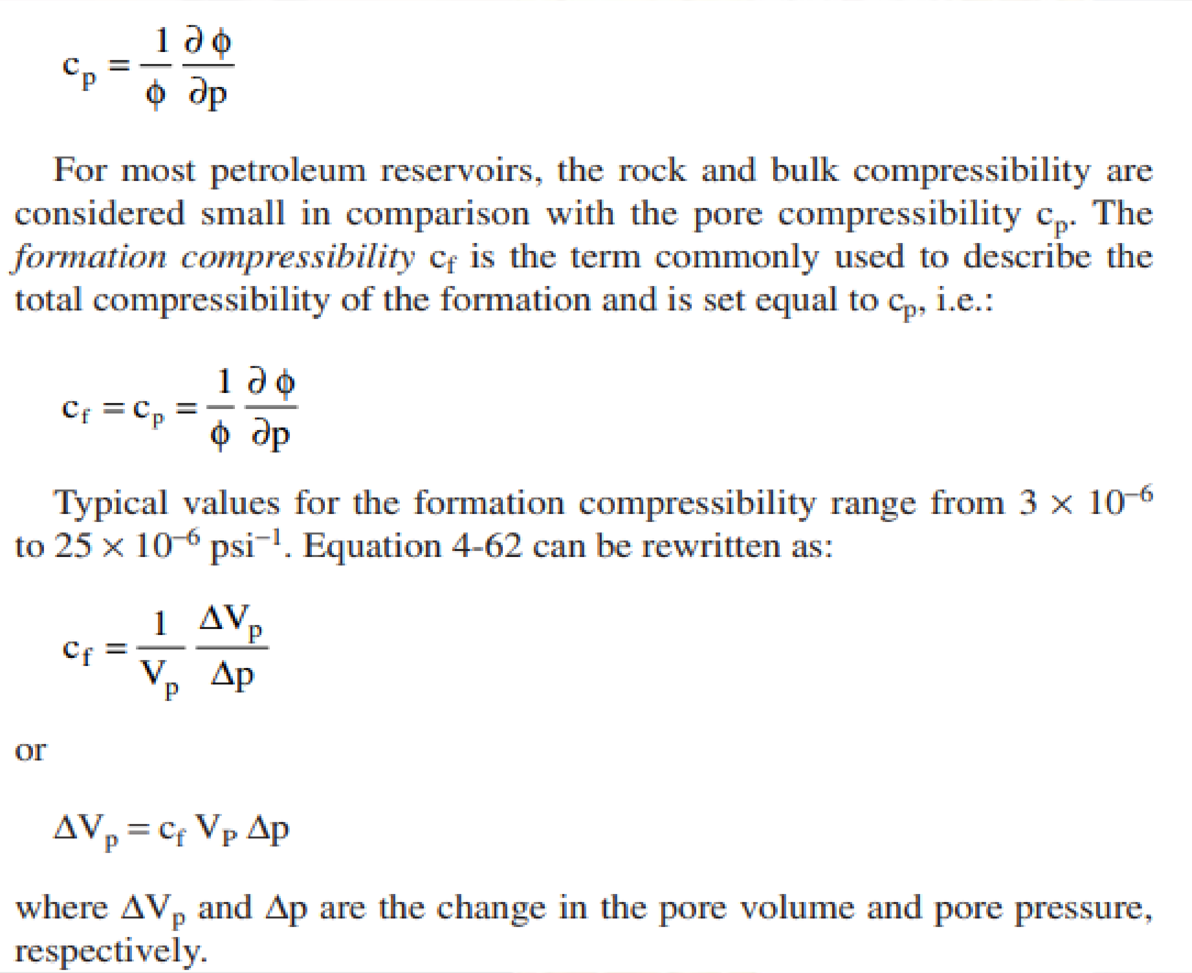
where p = pore pressure, psi
c_p = pore compressibility coefficient, psi^{-1}
V_p = pore volume

Porosity and compressibility relationship

Equation

$$C = \frac{1}{V}\left(\frac{\partial V}{\partial P}\right)_T$$

can be expressed in terms of the porosity φ $(\emptyset = V_P/V_b)$ *by noting that* φ *increases with the increase in the pore pressure; or:*



$$c_p = \frac{1}{\phi}\frac{\partial \phi}{\partial p}$$

For most petroleum reservoirs, the rock and bulk compressibility are considered small in comparison with the pore compressibility c_p. The *formation compressibility* c_f is the term commonly used to describe the total compressibility of the formation and is set equal to c_p, i.e.:

$$c_f = c_p = \frac{1}{\phi}\frac{\partial \phi}{\partial p}$$

Typical values for the formation compressibility range from 3×10^{-6} to 25×10^{-6} psi^{-1}. Equation 4-62 can be rewritten as:

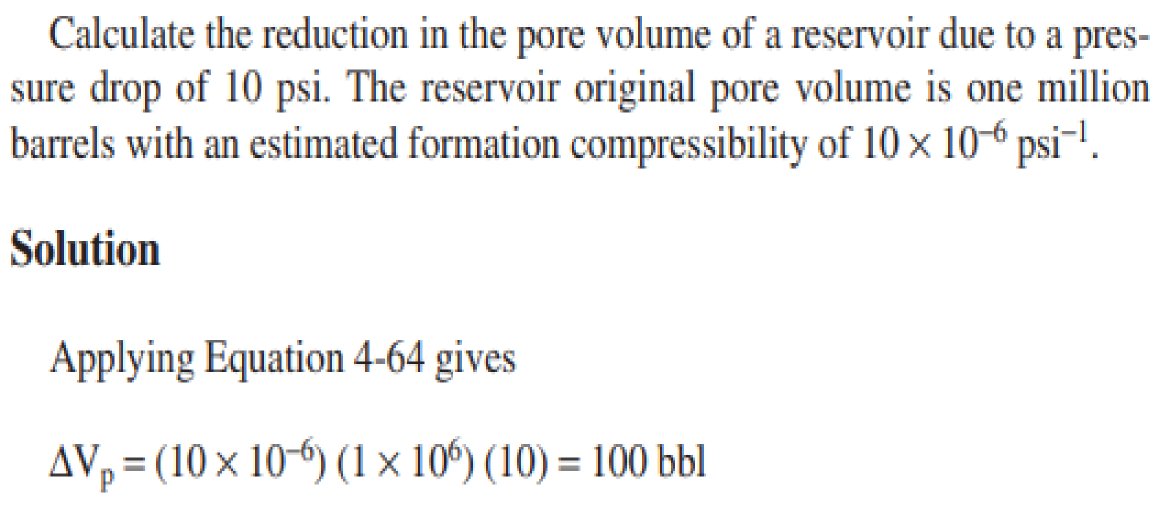
$$c_f = \frac{1}{V_p}\frac{\Delta V_p}{\Delta p}$$

or

$$\Delta V_p = c_f V_p \Delta p$$

where ΔV_p and Δp are the change in the pore volume and pore pressure, respectively.

Example:

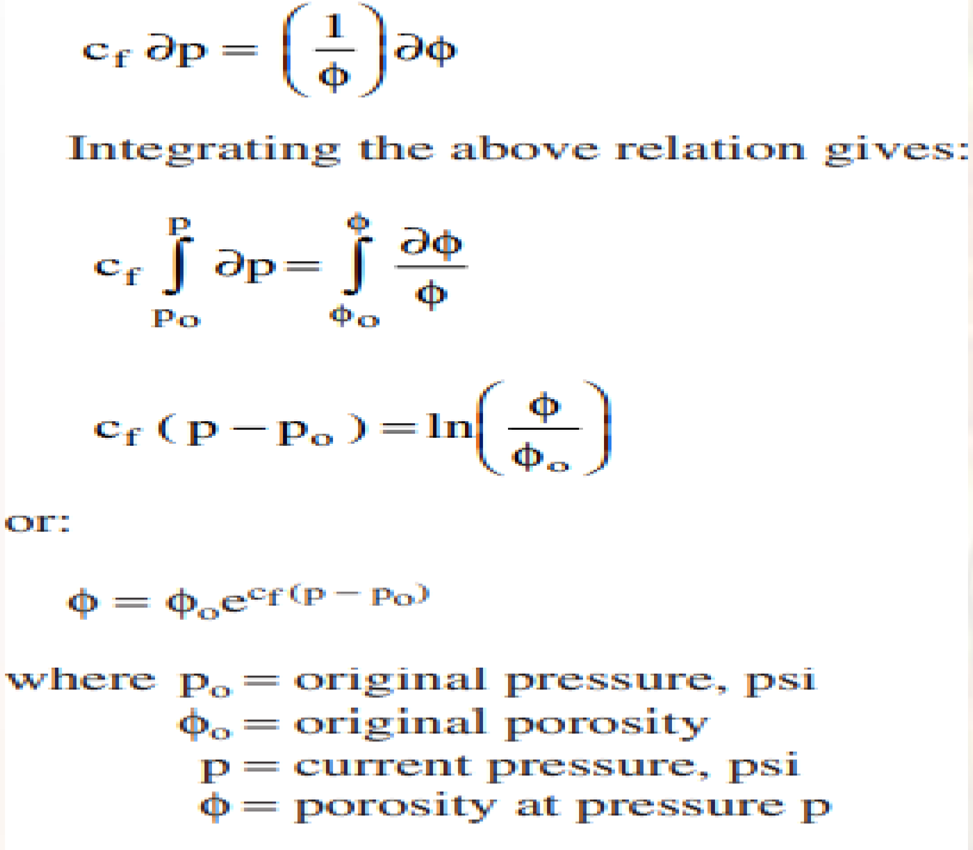


Calculate the reduction in the pore volume of a reservoir due to a pressure drop of 10 psi. The reservoir original pore volume is one million barrels with an estimated formation compressibility of 10×10^{-6} psi^{-1}.

Solution

Applying Equation 4-64 gives

$$\Delta V_p = (10 \times 10^{-6})(1 \times 10^{6})(10) = 100 \text{ bbl}$$



$$c_f\,\partial p = \left(\frac{1}{\phi}\right)\partial\phi$$

Integrating the above relation gives:

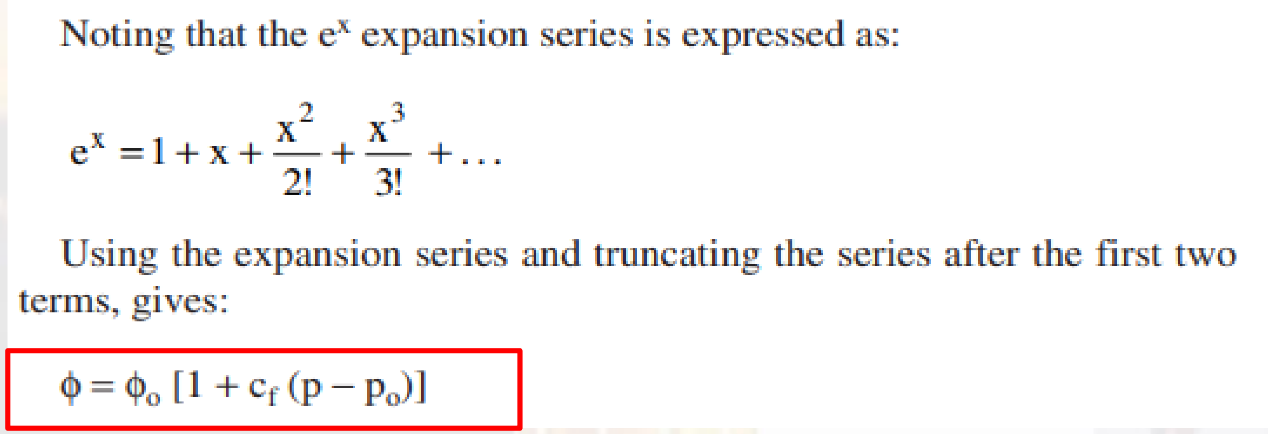
$$c_f \int_{p_o}^{p} \partial p = \int_{\phi_o}^{\phi} \frac{\partial\phi}{\phi}$$

$$c_f\,(p - p_o) = \ln\left(\frac{\phi}{\phi_o}\right)$$

or:

$$\phi = \phi_o e^{c_f (p - p_o)}$$

where p_o = original pressure, psi
ϕ_o = original porosity
p = current pressure, psi
ϕ = porosity at pressure p



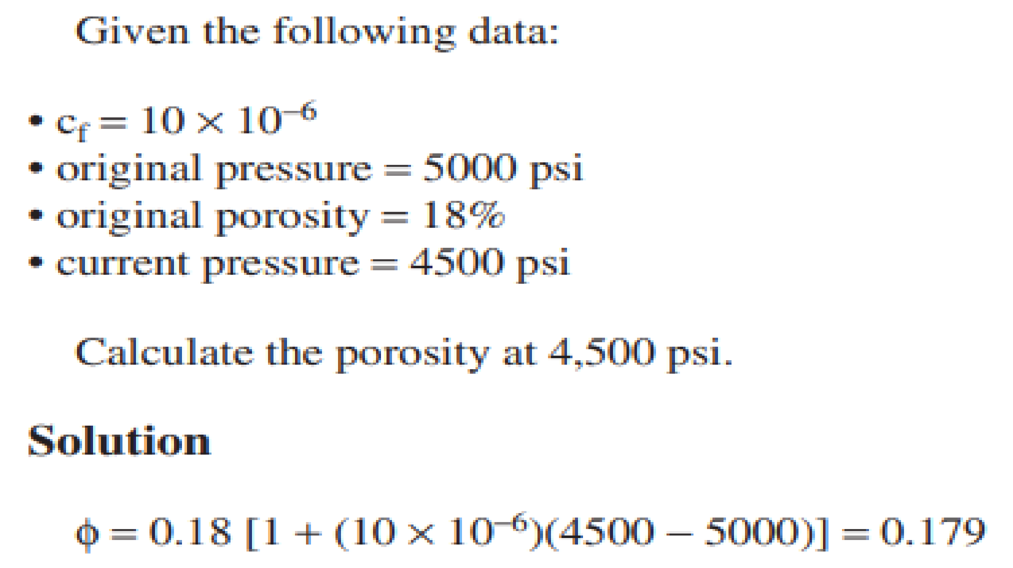
Noting that the e^x expansion series is expressed as:

$$e^x = 1 + x + \frac{x^2}{2!} + \frac{x^3}{3!} + \ldots$$

Using the expansion series and truncating the series after the first two terms, gives:

$$\boxed{\phi = \phi_o\,[1 + c_f\,(p - p_o)]}$$

Example :



Given the following data:

- $c_f = 10 \times 10^{-6}$
- original pressure = 5000 psi
- original porosity = 18%
- current pressure = 4500 psi

Calculate the porosity at 4,500 psi.

Solution

$$\phi = 0.18\,[1 + (10 \times 10^{-6})(4500 - 5000)] = 0.179$$

- Formation Compressibility is important to Reservoir engineers. It plays a role in depletion of fluid from pore spaces, internal rock stress changes which results in change in V_p, V_m, V_b

- Measurement

Halls correlation is generally acceptable for use with carbonates and consolidated sandstones and shows compressibility as a function of porosity. Also, Newman correlation for consolidated sandstones and limestones.

Halls correlation

$$c_f = (1.782/\phi^{0.438})\ 10^{-6}$$

Where: C_f = formation compressibility, psi^{-1}

φ = porosity, fraction

Newman correlation

$$c_f = \frac{a}{[1 + cb\phi]}$$

Where: a, b, c are variables depending on rock lithology

For consolidated sandstones

$a = 97.32 \times 10^{-6}$

$b = 0.699993$

$c = 79.8181$

For limestones

$a = 0.8535$

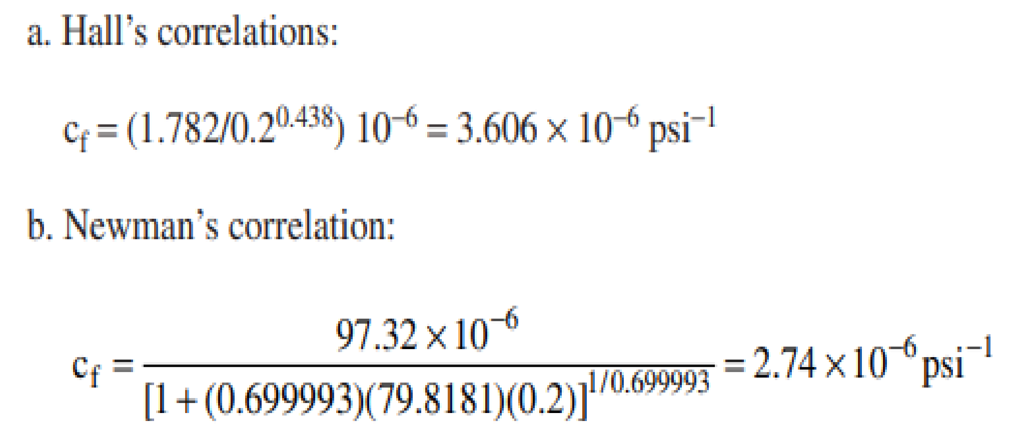
$b = 1.075$

$c = 2.202 \times 10^{6}$

Example:

Estimate the compressibility coefficient of a sandstone formation that is characterized by a porosity of 0.2, using: a. Hall's correlation b. Newman's correlation

Solution:



a. Hall's correlations:

$$c_f = (1.782/0.2^{0.438})\ 10^{-6} = 3.606 \times 10^{-6}\ \text{psi}^{-1}$$

b. Newman's correlation:

$$c_f = \frac{97.32 \times 10^{-6}}{[1 + (0.699993)(79.8181)(0.2)]^{1/0.699993}} = 2.74 \times 10^{-6}\ \text{psi}^{-1}$$

Note:

It should be pointed out that the total reservoir compressibility Ct is extensively used in the transient flow equation and the material balance equation as defined by the following expression:

$$C_t = S_oC_o + S_wC_w + S_gC_g + C_f$$

where : So, Sw, Sg = oil, water, and gas saturation

Co = oil compressibility, psi^{-1}

Cw = water compressibility, psi^{-1}

Cg = gas compressibility, psi^{-1}

Ct = total reservoir compressibility, psi^{-1}

Range of compressibility :

Cf is typically in the range 3×10^{-6} to $25 \times 10^{-6}\ \text{psi}^{-1}$

Cw = formation water compressibility 2×10^{-6} to $4 \times 10^{-6}\ \text{psi}^{-1}$

(depending on water salinity and dissolved gas in water)

Co = oil compressibility 5×10^{-6} to $30 \times 10^{-6}\ \text{psi}^{-1}$

Or (5 to $100 * 10^{-6}\ \text{psi}^{-1}$)

Cg = gas compressibility $500 \times 10^{-6}\ \text{psi}^{-1}$

Surface and Interfacial Tension

- Petroleum reservoirs commonly have 2 – 3 fluids (multiphase systems)

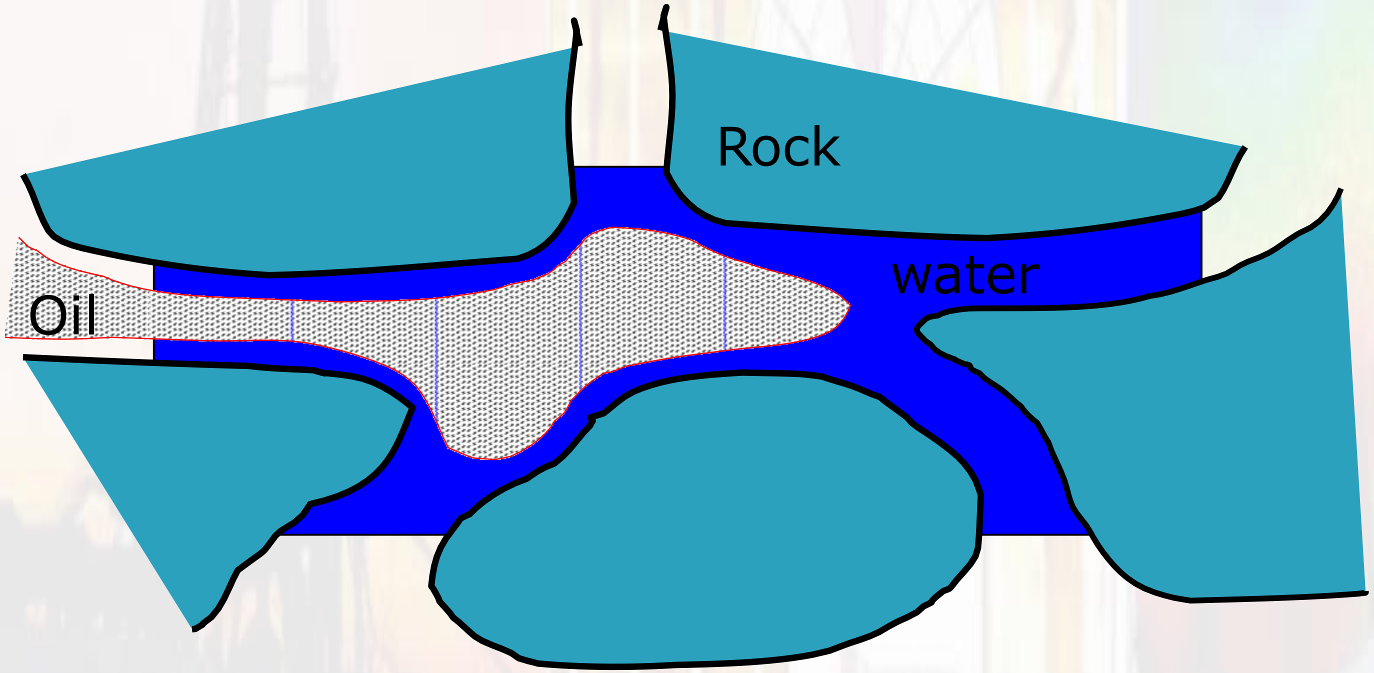
- It is necessary to consider the effect of the forces at the interface when two immiscible fluids are in contact.

- Any surface that is in the state of lateral tension, leads to the concept of surface tension.

- ***An interface*** is known as the boundary region between two adjacent bulk phases. The equilibrium bulk phases can be: Liquid-vapor (LV), Liquid-liquid (LL), Liquid-solid (LS), Solid-vapor (SV)

Surface and Interfacial Tension

- **Immiscible** fluids: when you bring them into contact they do not mix
- Two fluids are separated by an **interface**
- The molecules are attracted more to their own kind

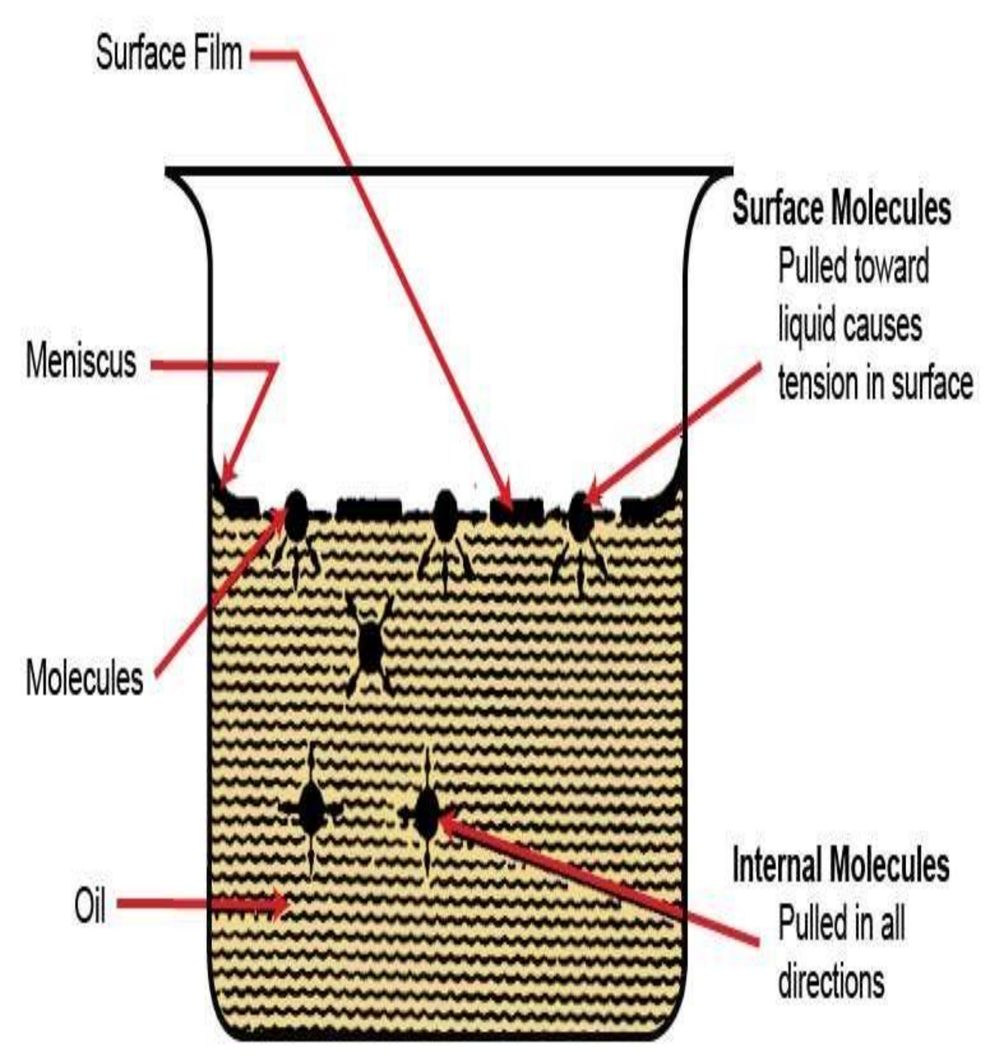


- **Attractive Force:**
- **Adhesion tension (if the force affect** Liquid-solid (LS))
- **Surface tension (if the force affect** Liquid-vapor (LV))
- **Interfacial tension (if the force affect** Liquid-Liquid (LL))

- The surface tension, denoted by σ, can be related to the work or energy required to establish the surface area.

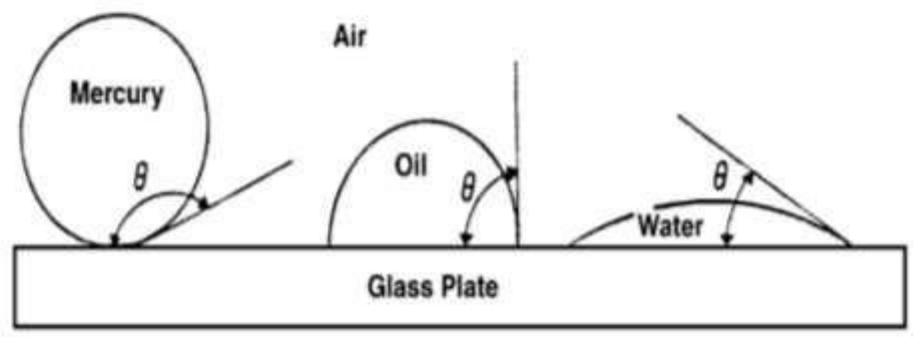
Interfacial Tension

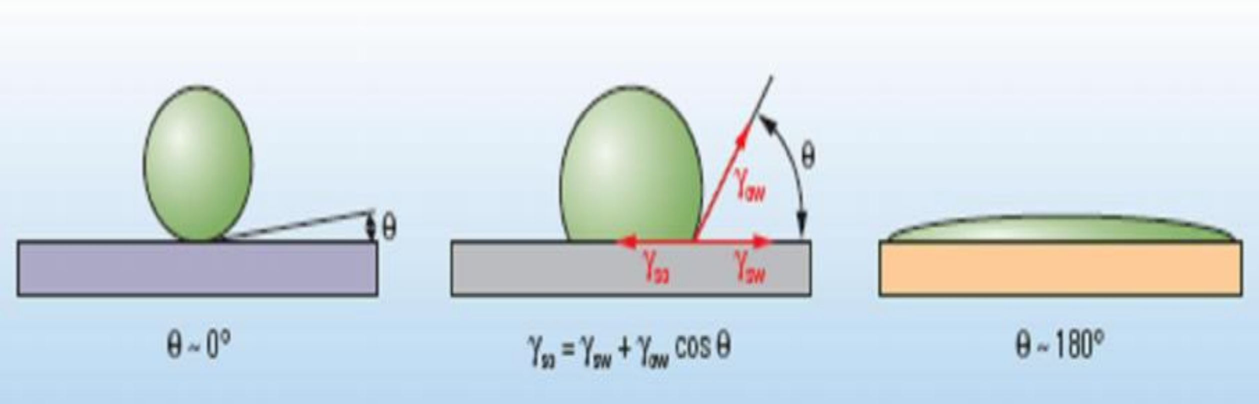
- Interfacial tension is a force at the interface that acts to decrease the area of the interface.
- A drop of water can hang down from the edge of a glass tube using the force at the interface.
- However, when the interfacial tension is weaker, only a smaller (lighter) drop can hang down from the edge of the glass.
- The interfacial tension can be measured using this phenomenon.
- At the surface, the attractive force works only from inside since there is no water on the outside (air side), so a water molecule on the surface is strongly attracted toward the inside.
- This force is called "surface tension". However, when something is adsorbed on the water surface, interactions between the adsorbed molecules themselves and also the adsorbed molecules and the water occur at the surface, so that the surface tension decreases.



WETTABILITY

- This is the tendency of a fluid to spread on or adhere to a solid surface in the presence of other immiscible fluid. The angles made by the fluid with the surface with which it is in contact is known as the "contact angle".

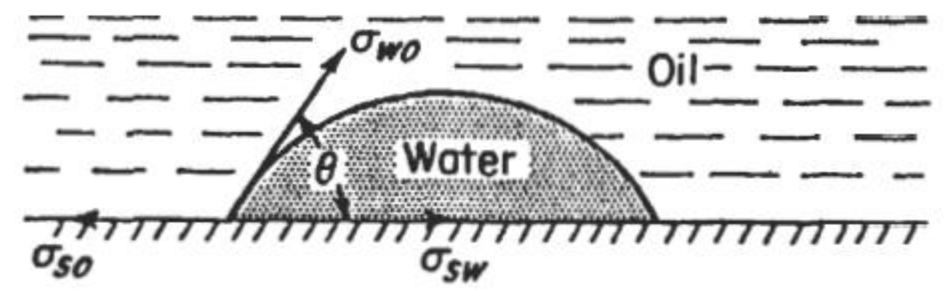




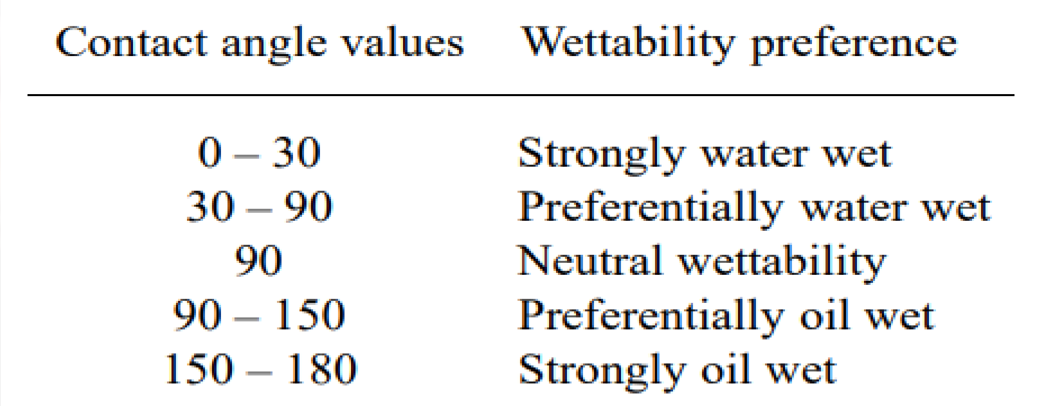
- Depending on the type of fluid in contact with a solid surface, a reservoir could be; water-wet or oil-wet. Because of the attractive force, the wetting phase tends to occupy the smaller pores of the rock and the nonwetting phase occupies the more channels.
- Contact angle : is the angle formed between the fluids interface and a flat solid surface. The contact angle (measured through the denser phase) is

$$\cos\theta = \frac{\sigma_{so} - \sigma_{sw}}{\sigma_{wo}} \qquad A_T = \sigma_{SO} - \sigma_{SW}$$

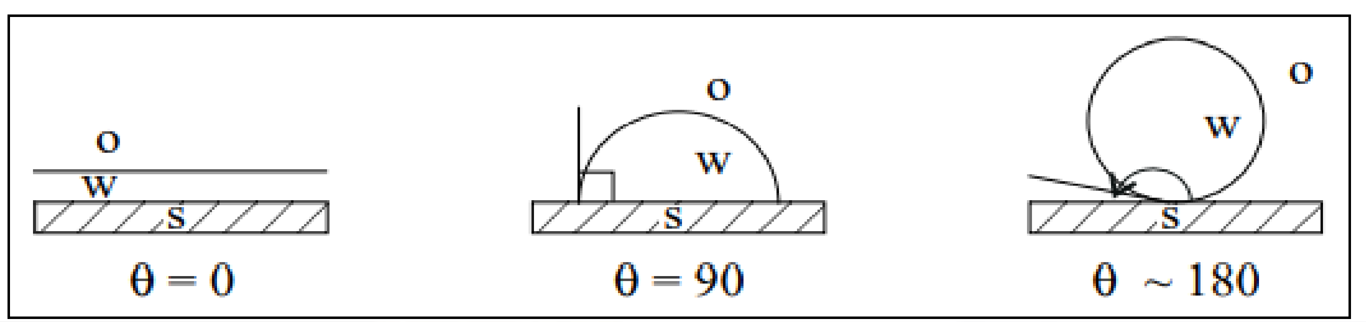
where: σso = interfacial tension between the solid and oil. σsw = interfacial tension between the solid and water. σwo = interfacial tension between water and oil.

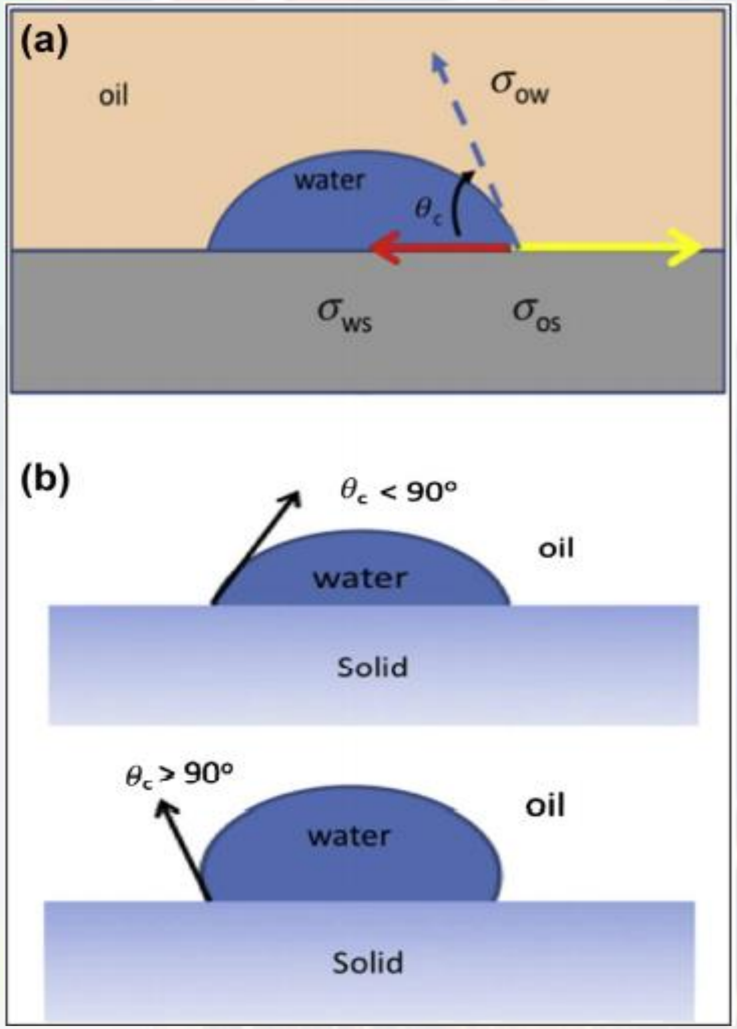


- The evaluation of reservoir wettability can be made through measurements of interfacial tensions, i.e., tensions acting at the fluid-fluid and rock-fluid interfaces, and the contact angle.
- The differences in contact angle somehow indicate different wettability preferences which can be illustrated by the following rule of thumb presented in Table

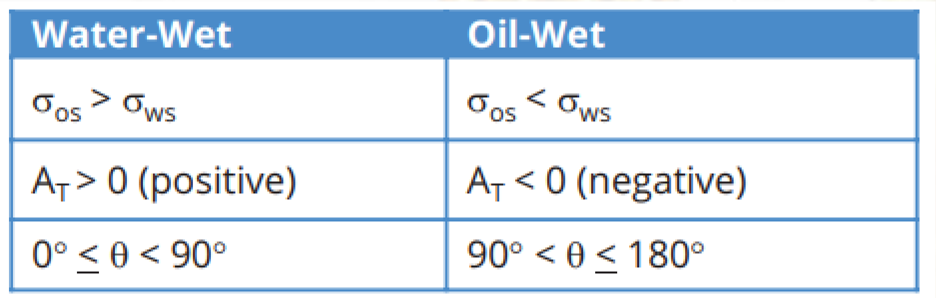


Contact angle values	Wettability preference
0 – 30	Strongly water wet
30 – 90	Preferentially water wet
90	Neutral wettability
90 – 150	Preferentially oil wet
150 – 180	Strongly oil wet





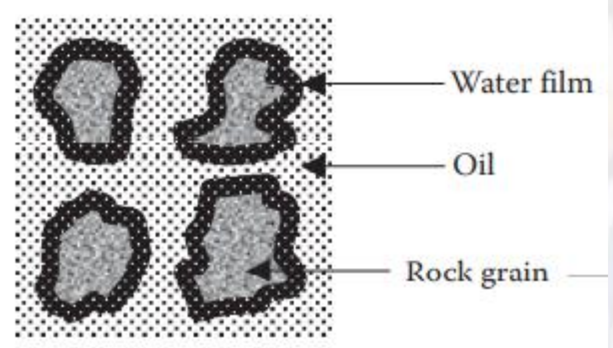
In general,



Water-Wet	Oil-Wet
$\sigma_{os} > \sigma_{ws}$	$\sigma_{os} < \sigma_{ws}$
$A_T > 0$ (positive)	$A_T < 0$ (negative)
$0° \leq \theta < 90°$	$90° < \theta \leq 180°$

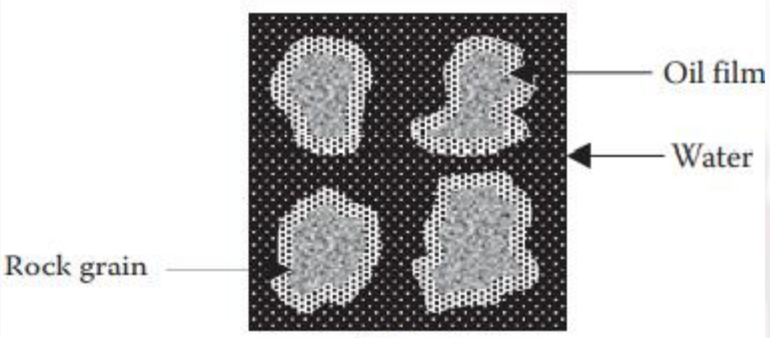
✓ CLASSIFICATION/TYPES OF WETTABILITY

Water Wet In this wettability state, all pore surfaces of the rock have preference for the water phase rather than the hydrocarbon phase, and as a result of this condition, the gas and oil are contained in the centers of the pores.



Water wet

Oil Wet This wettability state is exactly the opposite of the water-wet state, that is, the relative positions of the hydrocarbons and water are reversed. It is believed that surface active asphaltenic components of the oil phase cause this wetting state.



Oil wet

Intermediate Wet The definition of intermediate wettability state from a pore level standpoint is somewhat vague in that there is some tendency for both phases (oil and water) to have preference for the rock surface; however, if that tendency is equal, then this may be termed as neutral-wetting state or considered as a special category of intermediate wettability.

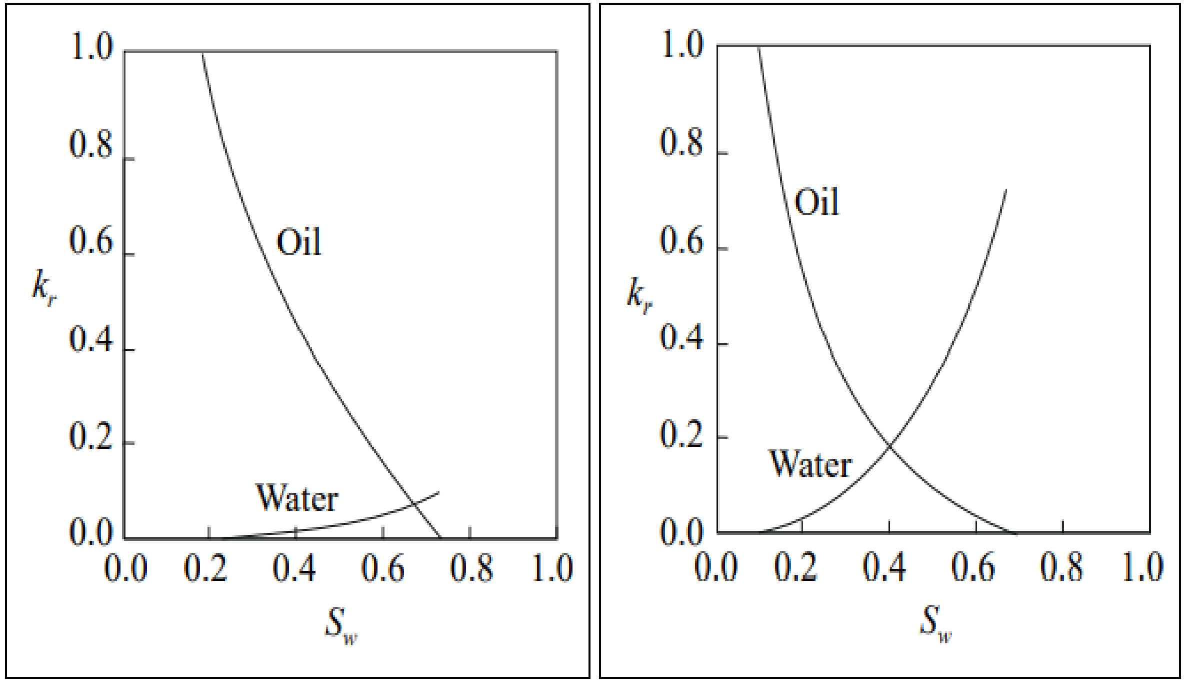
MEASUREMENT OF RESERVOIR ROCK WETTABILITY

Reservoir wettability can be evaluated by two different groups of methods: **qualitative** and **quantitative**.

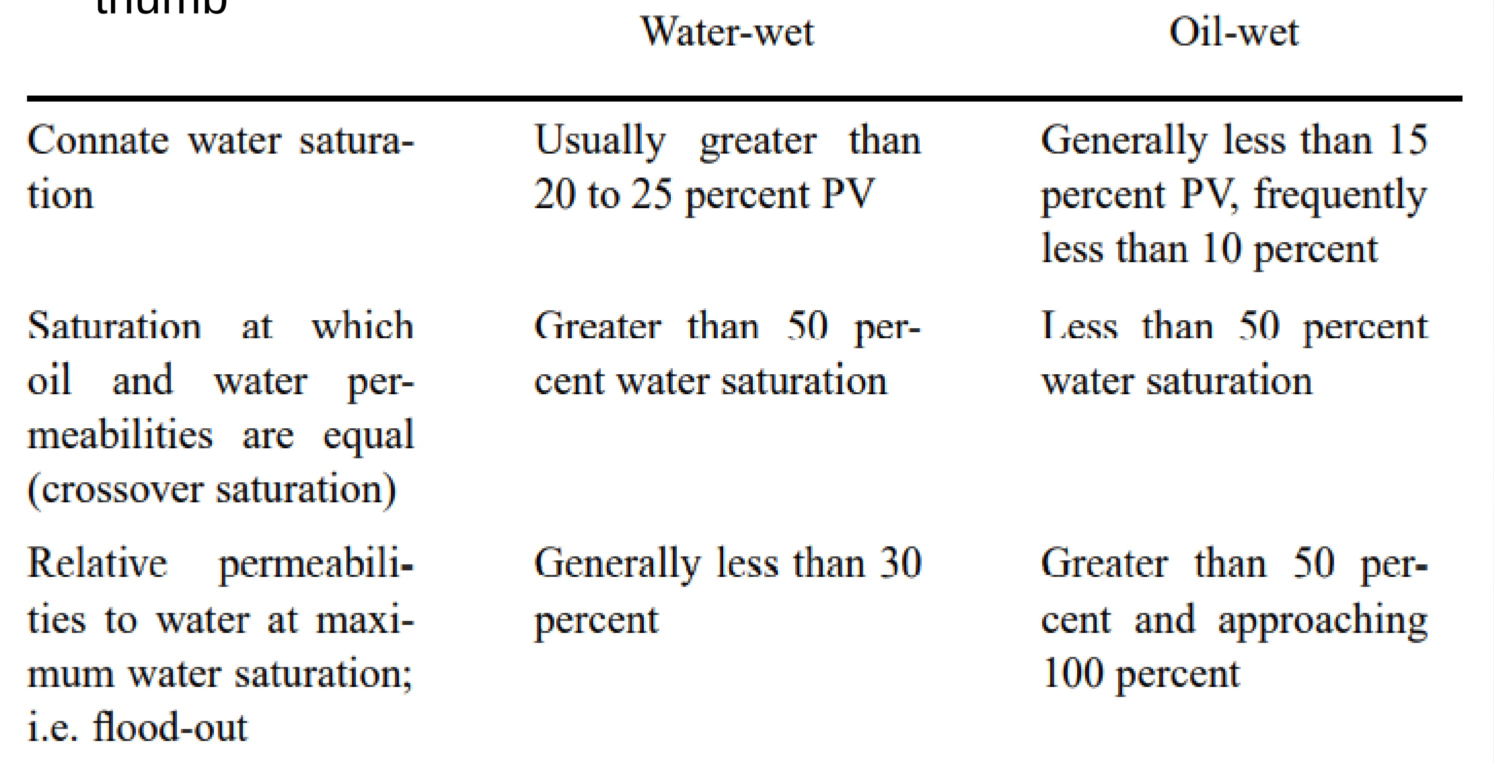
- In **qualitative methods**, wettability is indirectly inferred from other measurements, such as capillary pressure curves or relative permeability curves.
- **Quantitative methods** are direct measurement methods, where the wettability is measured on actual rock samples using reservoir fluid samples .The direct quantitative methods include **contact angle measurement**, the **Amott test**, and the **U.S. Bureau of Mines (USBM)** wettability method.

- Note: the best **qualitative method to evaluate wettability is** relative permeability curves as a function to water saturation. Typical water-oil relative permeabilities are presented for strongly water-wet and oil-wet formations as shown in fig.
- Assumed oil – water system, where:
- Oil is nonwetting phase and water is wetting phase
- Then the relative permeability curve wil be a shown:

Figure shows Characteristics of typical relative permeability for a two phase flow, where Sw is the wetting phase and Sn is the non-wetting phase (left: a water-wet formation and right: an oil-wet formations).



- The difference in the flow properties that indicates different wettability preferences can be illustrated by the following rule of thumb



	Water-wet	Oil-wet
Connate water saturation	Usually greater than 20 to 25 percent PV	Generally less than 15 percent PV, frequently less than 10 percent
Saturation at which oil and water permeabilities are equal (crossover saturation)	Greater than 50 percent water saturation	Less than 50 percent water saturation
Relative permeabilities to water at maximum water saturation; i.e. flood-out	Generally less than 30 percent	Greater than 50 percent and approaching 100 percent

Wettability depends on:

1- rock material and pore geometry
2- Geological mechanism (accumulation and migration)
3- composition and amount of oil and brine.
4- physical condition (temperature and pressure)
5- mechanism occurring during production (change in saturation, pressure , and composition)

Hysteresis

The history of the porous rock (in terms of the history of the phases water ,oil or gas that have occupied the pore space) will have a strong effect on its wettability; this is known as “hysteresis.”

Imbibition and Drainage

Imbibition is the phenomenon of increasing wetting-phase occupation of pore space, while ***drainage*** is a decrease in the wetting phase present.

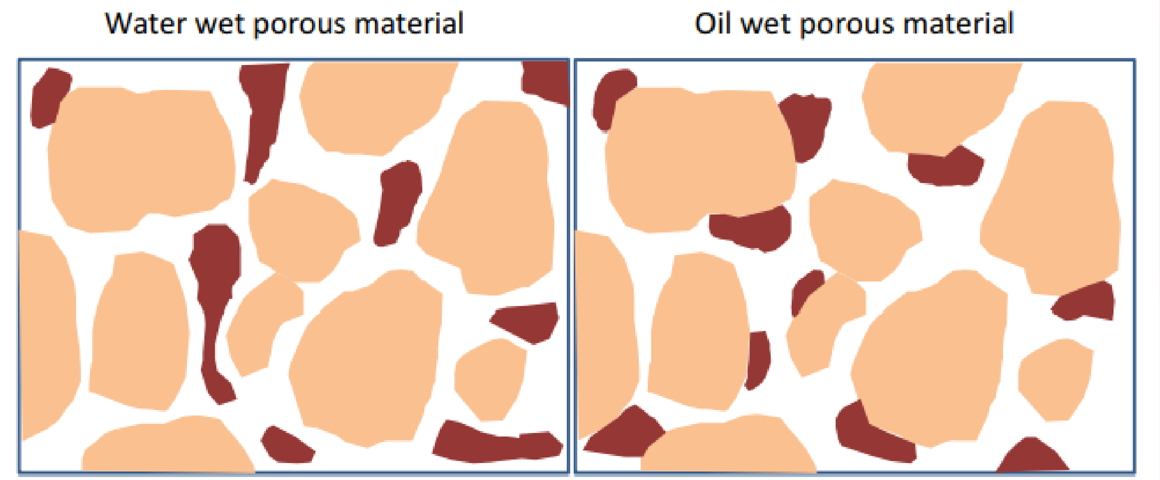
Note:

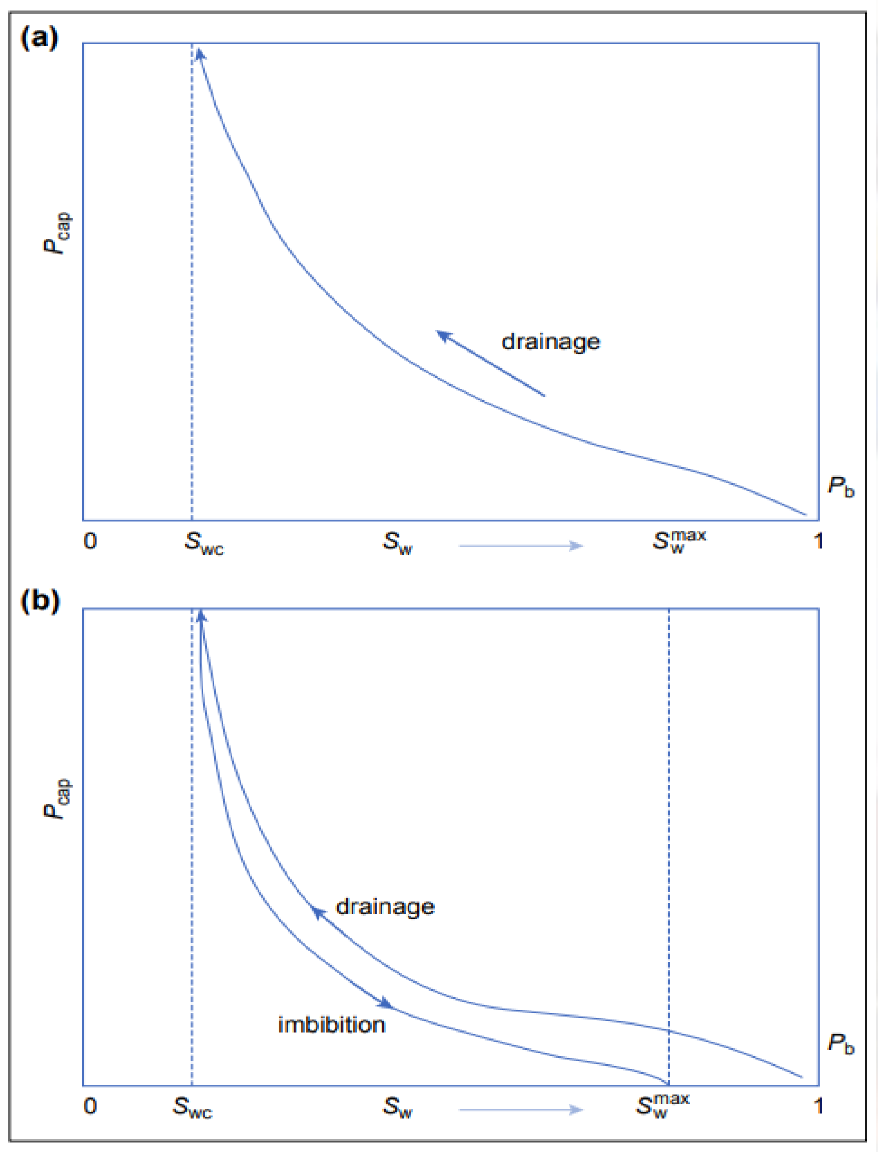
–***Drainage Process***

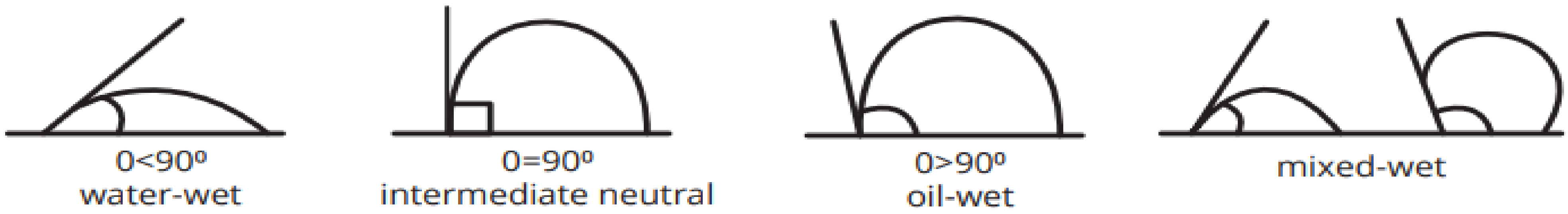
Wetting phase decreasing Initial conditions in reservoir

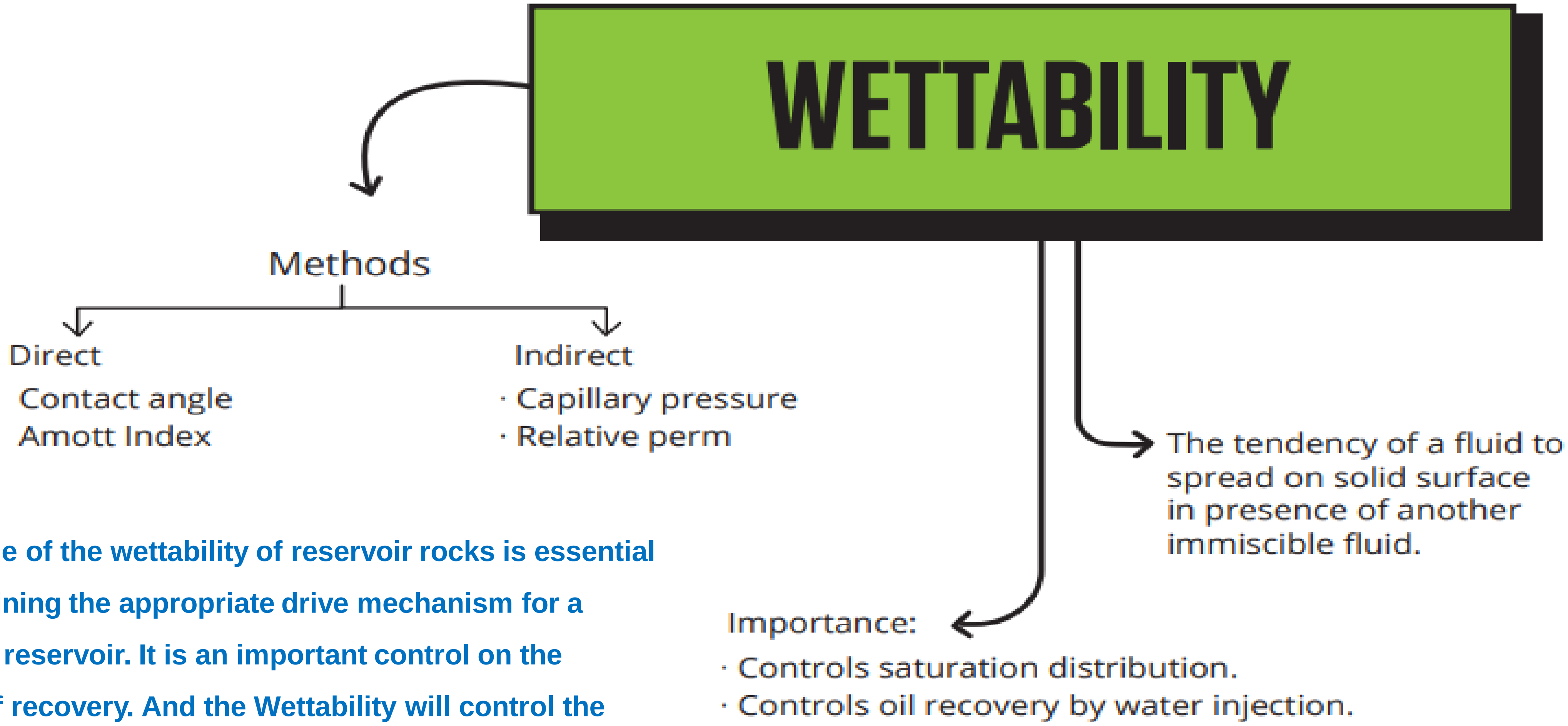
–***Imbibition Process***

Wetting phase increasing Water displacing oil in reservoir









WETTABILITY

The tendency of a fluid to spread on solid surface in presence of another immiscible fluid.

Methods

Direct

Contact angle
Amott Index

Indirect

- Capillary pressure
- Relative perm

Importance:

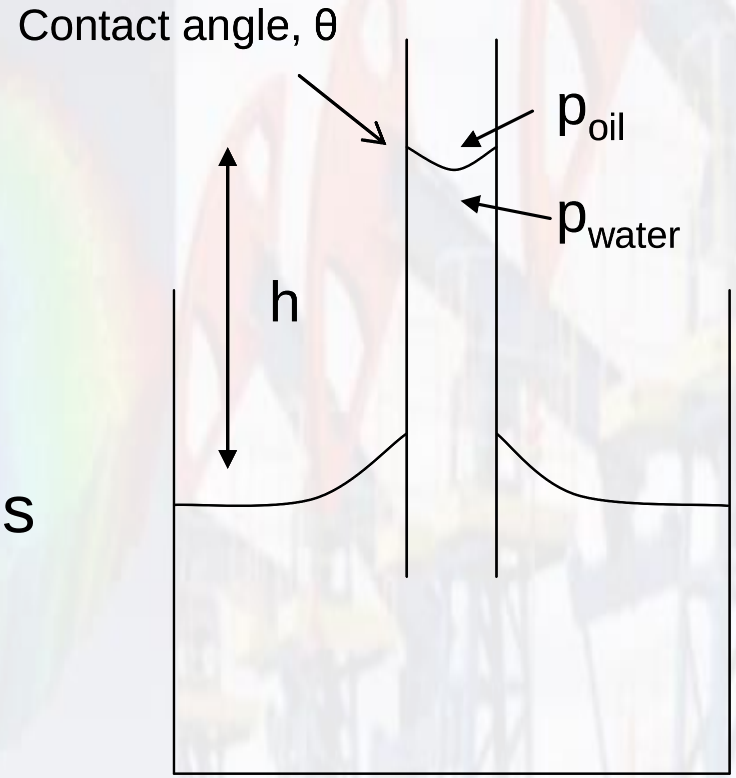
- Controls saturation distribution.
- Controls oil recovery by water injection.

- **Knowledge of the wettability of reservoir rocks is essential in determining the appropriate drive mechanism for a particular reservoir. It is an important control on the amount of recovery. And the Wettability will control the distribution of oil and water in the pore space**

Capillary Pressure

- Capillary pressure is defined as the pressure difference existing across the interface separating two immiscible fluids (i.e. the pressure difference between the two immiscible fluids at the interface.
- It is defined as the difference between the pressures in the non-wetting and wetting phases. That is:

$$P_c = P_{nw} - P_w$$



- For an oil-water system (water wet): $P_c = P_o - P_w$
- For a gas-oil system (oil-wet): $P_c = P_g - P_w$

where:
Pc = capillary pressure [Pa]
Pnw = pressure of the non-wetting phase [Pa]
Pw = pressure of the wetting phase [Pa]

Capillary Pressure

- When two immiscible fluids are in contact, a discontinuity in pressure exits between the two fluids, which depends upon the curvature of the interface separating the fluids. We call this pressure difference the capillary pressure, Pc.

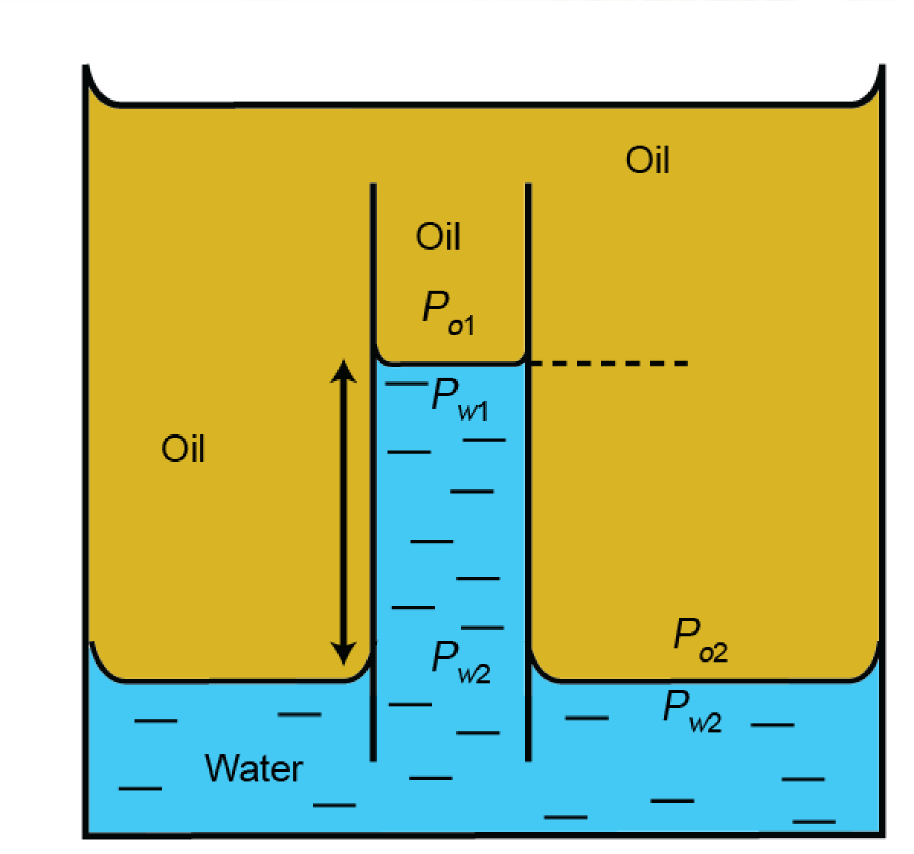
- ***Measurement***

Core Analysis
1.The porous plate (restored state core) method
2.The centrifuge method
3.Mercury injection method.

- ***Application***

Assists in determining saturation values for calculations of hydrocarbons in place.

Oil-water system.



$$P_{a2}=P_{w2}$$

$$P_{w2}=P_{w1}+h\rho_w g$$

$$P_{o2}=P_{o1}+h\rho_o g$$

Since, $P_{w2}=P_{o2}$

Then, $P_{w1}+h\rho_w g=P_{o1}+h\rho_o g$ Therefore, $P_{o1}-P_{w1}=(\rho_w-\rho_0)hg$ That is, $P_c=(\rho_w-\rho_o)hg$

$Pc=(\rho_w-\rho_o)gh$

$\rho_{w,o}$ = fluid density

g = gravity

h = height of water column

$$P_c=g(\rho_w-\rho_o)h=\frac{2\sigma_{ow}\cos\theta}{r}$$

- ☐ In the capillary tube capillary pressure can be defined as:

$$Pc=\frac{2\sigma_{wo}\cos\theta}{r}$$

Or

$$h=\frac{2\sigma(\cos\phi)}{rg\Delta\rho}$$

σ_{ow} = interfacial tension between oil and water

θ = contact angle

r = radius of tube

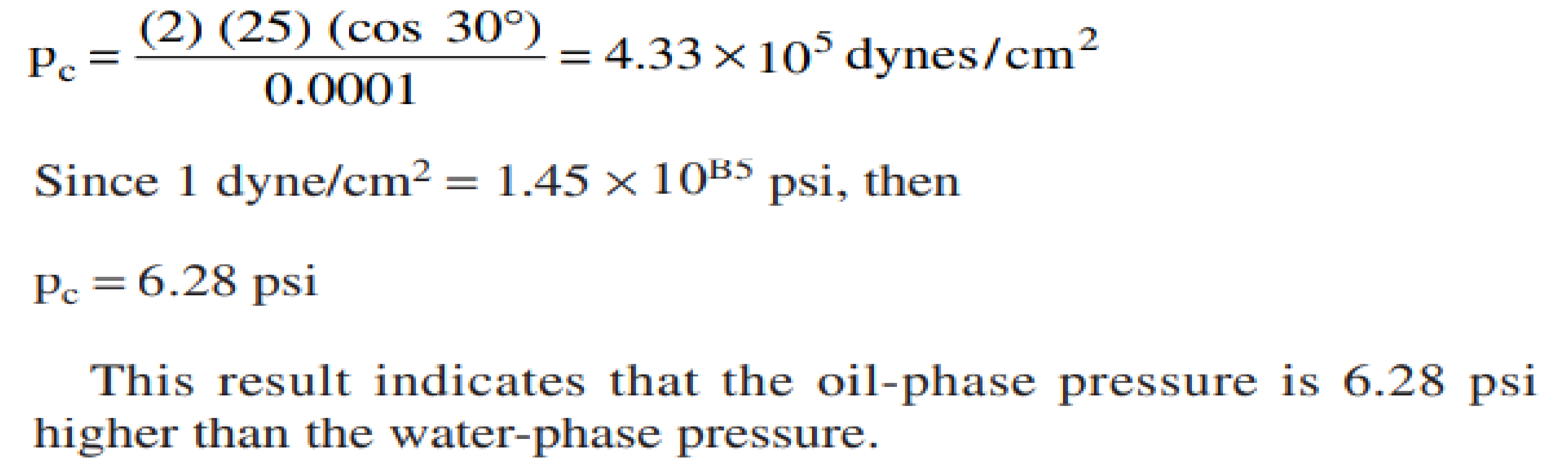
1 dyne/ cm² =1.45*10⁻⁵ psi

Example

Calculate the pressure difference, i.e., capillary pressure, and capillary rise in an oil-water system from the following data: $\theta = 30°$ $\rho w = 1.0$ gm/cm³ $\rho o = 0.75$ gm/cm³ ; $r = 10^{-4}$cm ; $\sigma ow =$ 25 dynes/cm

Solution:

Step 1. Apply Equation $$Pc = \frac{2\sigma_{wo}\,Cos\theta}{r}$$



$$p_c = \frac{(2)\,(25)\,(\cos\ 30°)}{0.0001} = 4.33 \times 10^5 \text{ dynes/cm}^2$$

Since 1 dyne/cm² = 1.45×10^{B5} psi, then

$$p_c = 6.28 \text{ psi}$$

This result indicates that the oil-phase pressure is 6.28 psi higher than the water-phase pressure.

Step 2. Calculate the capillary rise by applying $$h = \frac{2\sigma\,(\cos\phi)}{rg\Delta\rho}$$

$$h = \frac{(2)\,(25)\,(\cos\ 30°)}{(0.0001)\,(980.7)\,(1.0 - 0.75)} = 1766 \text{ cm} = 75.9 \text{ ft}$$

Initial Saturation Distribution in a Reservoir

- An important application of the concept of capillary pressures pertains to the fluid distribution in a reservoir prior to its exploitation.
- The capillary pressure-saturation data can be converted into height-saturation data and solving for the height h above the free water level (FWL).

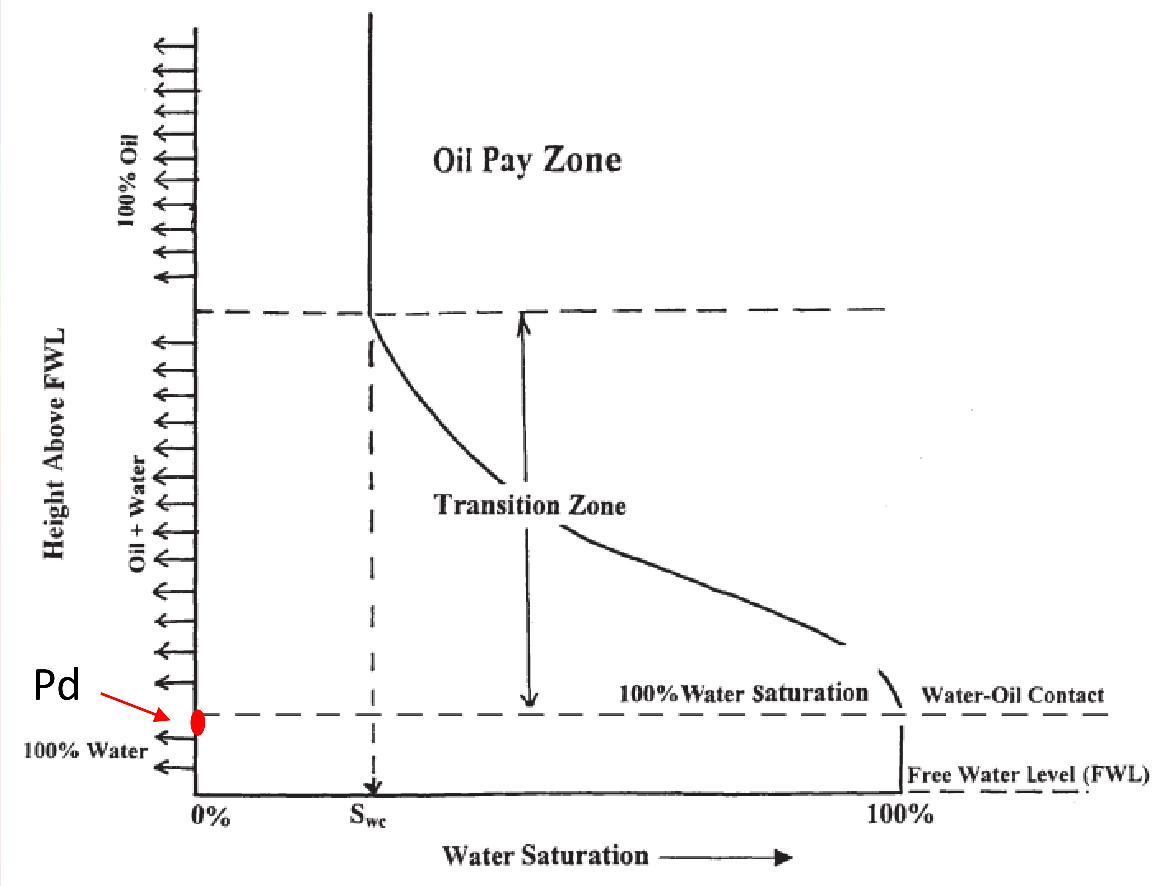
$$h = \frac{144\, p_c}{\Delta \rho}$$

where pc = capillary pressure, psia ; Δρ = density difference between the wetting and nonwetting phase, lb/ft^3;
H = height above the free-water level, ft

Figure shows a plot of the water saturation distribution as a function of distance from the free-water level in an oil-water system. It is essential at this point to introduce and define four important concepts:

- Transition zone
- Water-oil contact (WOC)
- Gas-oil contact (GOC)
- Free water level (FWL)

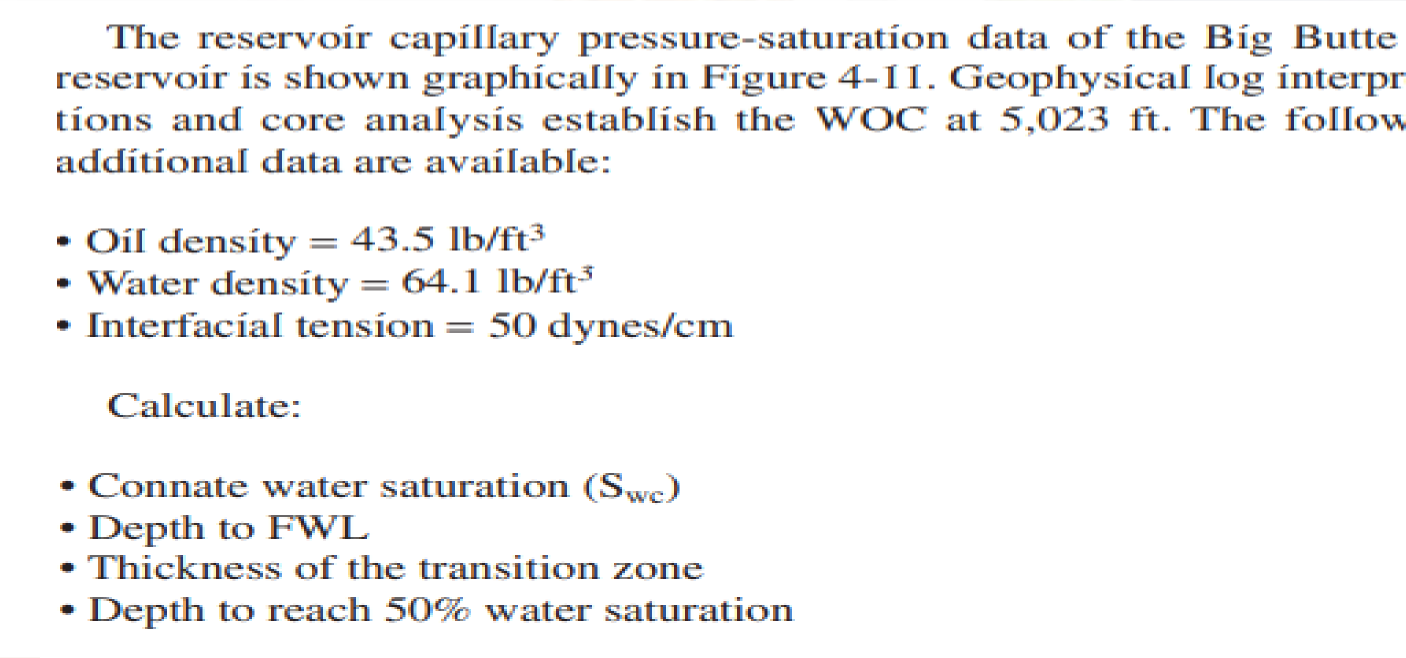
$$\boxed{FWL = WOC + \frac{144\, p_d}{\Delta \rho}}$$



Note:

- ***Pd*** is displacement pressure (threshold pressure)
- FWL can be estimated from Core, logs and DST test.

Example:

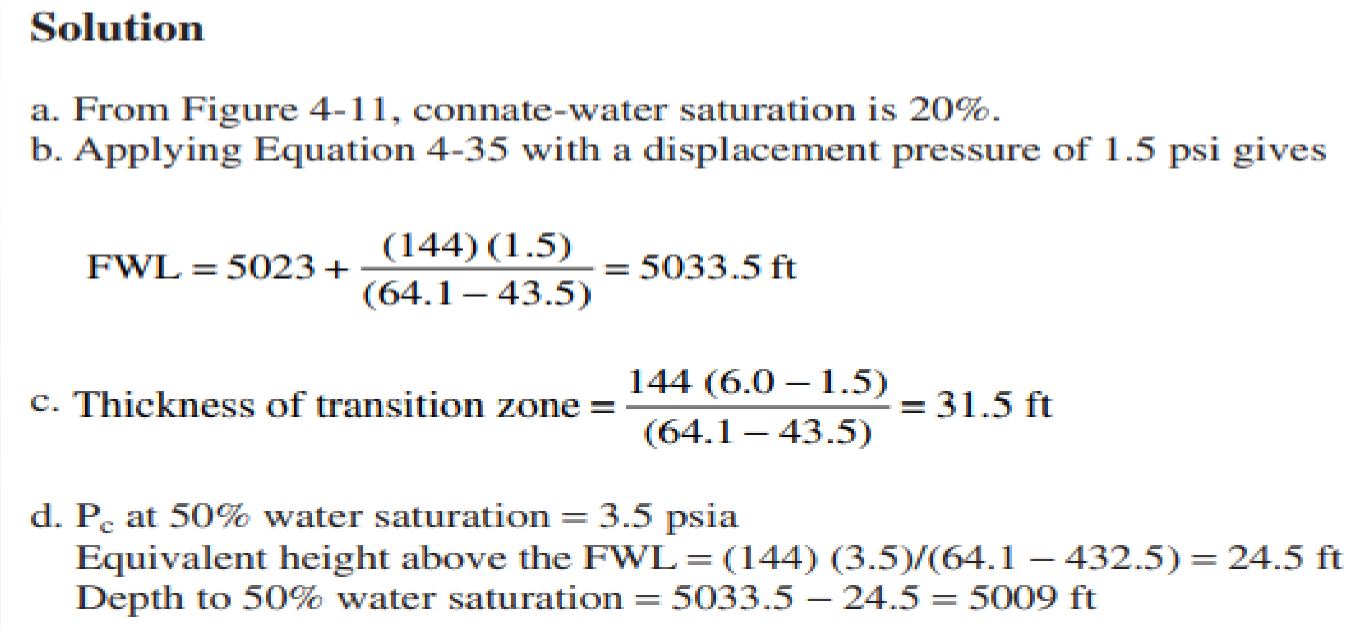


The reservoir capillary pressure-saturation data of the Big Butte Oil reservoir is shown graphically in Figure 4-11. Geophysical log interpretations and core analysis establish the WOC at 5,023 ft. The following additional data are available:

- Oil density = 43.5 lb/ft^3
- Water density = 64.1 lb/ft^3
- Interfacial tension = 50 dynes/cm

Calculate:

- Connate water saturation (S_{wc})
- Depth to FWL
- Thickness of the transition zone
- Depth to reach 50% water saturation



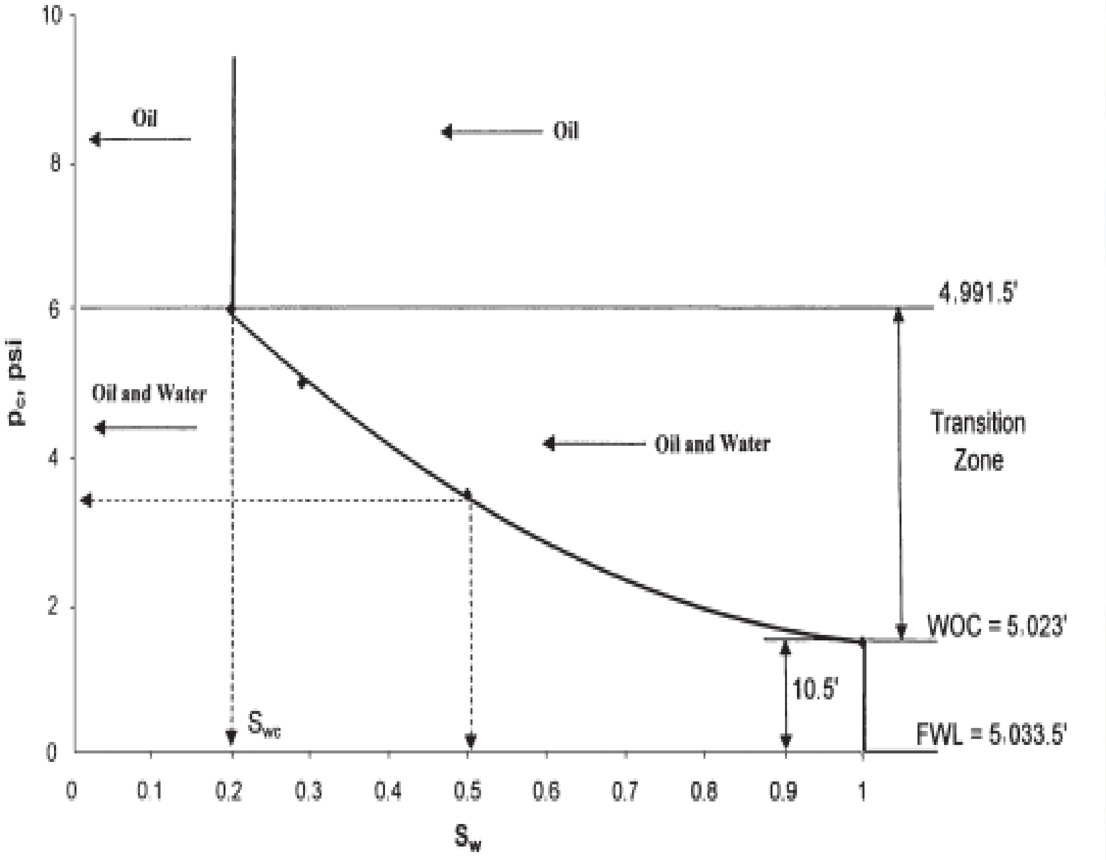
Solution

a. From Figure 4-11, connate-water saturation is 20%.
b. Applying Equation 4-35 with a displacement pressure of 1.5 psi gives

$$\text{FWL} = 5023 + \frac{(144)\,(1.5)}{(64.1 - 43.5)} = 5033.5 \text{ ft}$$

c. Thickness of transition zone $= \dfrac{144\,(6.0 - 1.5)}{(64.1 - 43.5)} = 31.5$ ft

d. P_c at 50% water saturation = 3.5 psia
Equivalent height above the FWL = (144) (3.5)/(64.1 – 432.5) = 24.5 ft
Depth to 50% water saturation = 5033.5 – 24.5 = 5009 ft



CAPILLARY PRESSURE

Imbibition:
The increase of wetting phase saturation.

Drainage:
The decrease of wetting phase saturation.

The difference between the non-wetting phase & the wetting phase pressures across interface.

Importance:
Drainage capillary pressure is used to determine fluid distribution in reservoir (initial condition) above the free water level

Methods

Porous Plate	Centrifuge	Mercury Injection
⊕ Most accurate	⊕ Fast	⊕ Fastest
⊕ Uses reservoir fluids	⊕ Uses reservoir fluid.	⊖ Does not use reservoir fluid
⊖ Very slow	⊖ Requires calculation of pressure and sat	⊖ Least accurate
	⊖ Less accurate	⊖ Requires interpretation