Reservoir Engineering Functions

Determine Hydrocarbon in place

Volumetric method
- Area
- Thickness
- Porosity
- Saturation

Material balance method
- Production data
- Fluid properties

Determine Reserves

Primary recovery phase
- Expansion
- Solution gas drive
- Gas cap drive
- Water drive
- Gravity drainage
- Combination

Supplemental recovery phase
- Secondary recovery
  - Water injection
  - Gas injection
- EOR
  - Miscible displacement
  - Thermal recovery
  - Chemical Injection

Determine Rates

Number of wells

Well potential
- Completion
- Reservoir permeability and thickness
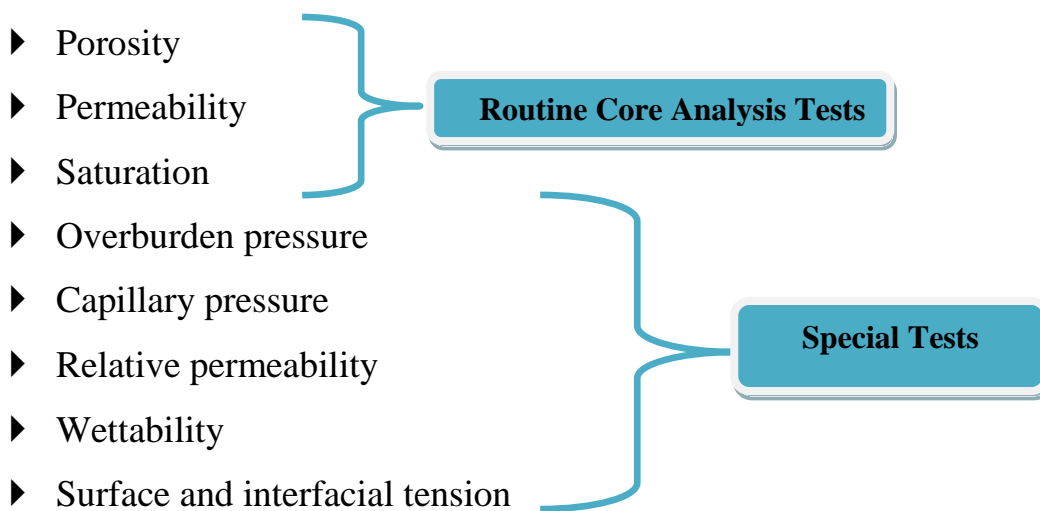- Reservoir homogeneity

Fundamentals of Rock Properties

The petroleum reservoir is that portion of the rock that contains the pool of petroleum. A reservoir consists of four essential elements, a) The reservoir rock b) reservoir pore space c) reservoir fluids and d) reservoir trap. The reservoir rock is that material in which oil and gas are found. Oil and gas are chiefly found in sand stones, lime stones and dolomites and are essentially sedimentary rocks. Out of all rocks lime stone and dolomites contain the most of the world petroleum. Maximum number of reservoirs is found in sand stones, however the total quantity of petroleum produced from carbonate reservoirs is more than that produced from sandstone reservoirs.

The material of which a petroleum reservoir rock may be composed can range from very loose and unconsolidated sand to a very hard and dense sandstone, limestone, or dolomite. The grains may be bonded together with a number of materials, the most common of which are silica, calcite, or clay. Knowledge of the physical properties of the rock and the existing interaction between the hydrocarbon system and the formation is essential in understanding and evaluating the performance of a given reservoir.

Rock properties are determined by performing laboratory analyses on cores from the reservoir to be evaluated. The cores are removed from the reservoir environment, with subsequent changes in the core bulk volume, pore volume, reservoir fluid saturations, and, sometimes, formation wettability. The effect of these changes on rock properties may range from negligible to substantial, depending on characteristics of the formation and property of interest, and should be evaluated in the testing program. There are many categories of core analysis tests that are performed on core samples regarding physical properties of reservoir rocks. These are:

▶ Porosity

▶ Permeability ────────┐

▶ Saturation   **Routine Core Analysis Tests**

▶ Overburden pressure

▶ Capillary pressure

▶ Relative permeability   **Special Tests**

▶ Wettability

▶ Surface and interfacial tension

The above rock property data are essential for reservoir engineering calculations as they directly affect both the quantity and the distribution of hydrocarbons and when combined with fluid properties, control the flow of the existing phases (i.e., gas, oil, and water) within the reservoir.

Reservoir Rock Characteristics:

❖ To form a commercial reservoir of hydrocarbons, any geological formation must exhibit two essential characteristics.

❖ These are capacity for storage and transmissibility to the fluids concerned.

❖ Storage capacity requires void spaces within the rock and the transmissibility requires that there should be continuity of those void spaces.

Porosity

The porosity of a rock is a measure of the storage capacity (pore volume) that is capable of holding fluids. Quantitatively, the porosity is the ratio of the pore volume to the total volume (bulk volume). This important rock property is determined mathematically by the following generalized relationship:

$$\emptyset = \frac{\textbf{Pore Volume}}{\textbf{Bulk Volume}} = \frac{V_P}{V_B} * \textbf{100}\% \text{ --- (1)}$$

Where:

$\emptyset$ = porosity

V_P = Pore volume

V_B = Bulk volume = $(V_P + V_G)$

As the sediments were deposited and the rocks were being formed during past geological times, some void spaces that developed became isolated from the other void spaces by excessive cementation. Thus, many of the void spaces are interconnected while some of the pore spaces are completely isolated. This leads to two distinct types of porosity, namely:

- Absolute porosity

- Effective porosity

Absolute Porosity

The absolute porosity is defined as the ratio of the total pore space in the rock to that of the bulk volume. A rock may have considerable absolute porosity and yet have no conductivity to fluid for lack of pore interconnection. The absolute porosity is generally expressed mathematically by the following relationships:

$$\emptyset_a = \frac{\text{Total Pore Volume}}{\text{Bulk Volume}} \text{ --- (2)}$$

$$\emptyset_a = \frac{\text{Bulk Volume} - \text{Grain Volume}}{\text{Bulk Volume}} \text{ --- (3)}$$

$$\emptyset_a = \frac{VB - VG}{VB} * 100\% \text{ --- (4)}$$

Where:

$\emptyset_a$ = Absolute porosity

V_G = Grain volume

Effective Porosity

The effective porosity is the percentage of interconnected pore space with respect to the bulk volume, or

$$\emptyset_e = \frac{\text{Interconnected Pore Volume}}{\text{Bulk Volume}} \text{ --- (5)}$$

Where: $\emptyset_e$ = Effective porosity

1. Clean sandstones: $\Phi_e = \Phi_t$

2. Carbonate, cemented sandstones: $\Phi_e < \Phi_t$

The effective porosity is the value that is used in all reservoir engineering calculations because it represents the interconnected pore space that contains the recoverable hydrocarbon fluids.
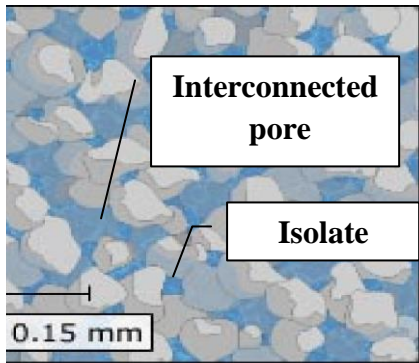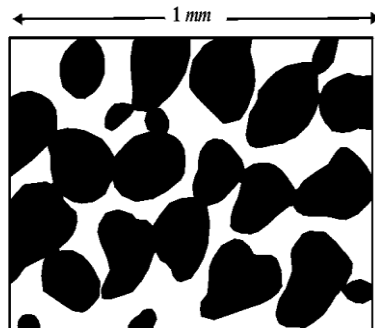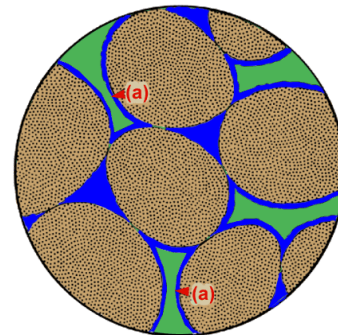

Fig. (1)

Fig. (2)

Fig. (3)

Porosity may be classified according to the mode of origin as original & induced. The original porosity is that developed in the deposition of the material, the intergranular porosity of sandstones and the intercrystalline and oolitic porosity of some limestones typify original porosity. While induced porosity is that developed by some geologic process subsequent to deposition of the rock. Induced porosity is typified by fracture development as found in shales and limestones and by the slugs or solution cavities commonly found in limestones. Rocks having original porosity are more uniform in their characteristics than those rocks in which a large part of the porosity is included.
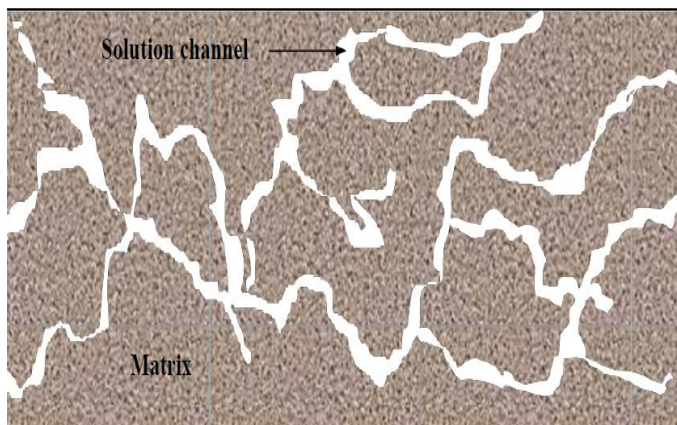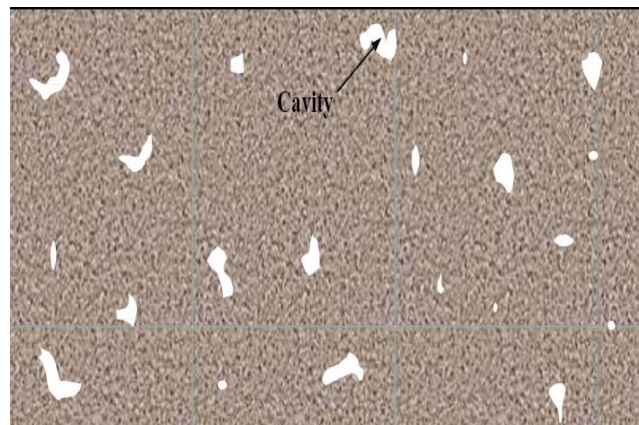

Fig.(4) Secondary porosity by solution

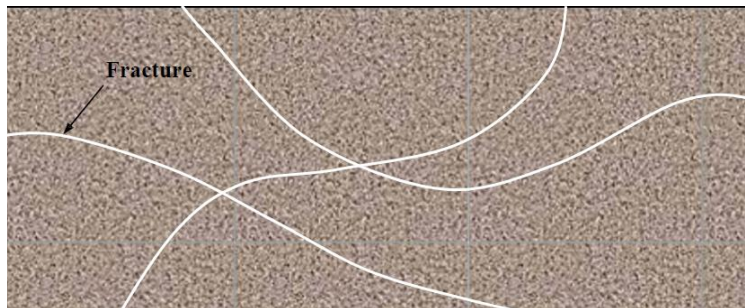**Fig. (5) Secondary porosity by dolomitization of calcite**

Fig. (6) Secondary porosity by fractures

Factors Effecting on Porosity

1) **Packing type**: there are two packing type of grains:

   a) Uniform packing: this type includes:

   i) Cubic packing of uniform spheres: Ө=90°

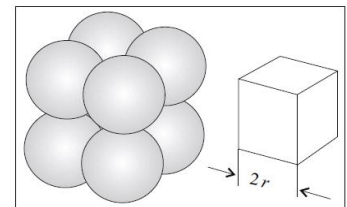$$V_b = (2r)^3 = 8r^3$$

$$V_m = 8(1/8 \text{ sphere}) = 1 \text{ sphere} = 4/3 \; \pi \; r^3$$

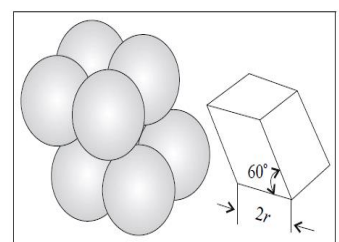$$\emptyset = \frac{V_b - V_m}{V_b} = \frac{8r^3 - (4/3)\pi r^3}{8r^3}$$

$$\emptyset = 1 - \pi/6 = 0.476 = 47.6\% \text{ max. value}$$

   r: sand grain radius
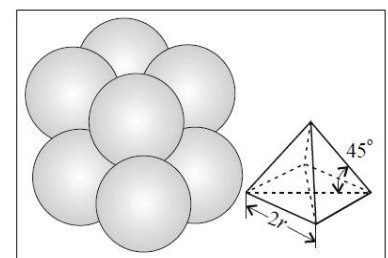
   ii) Hexagonal packing of uniform spheres: Ө=60°

   Ø=39.5%

   iii) Rhombohedral packing of uniform spheres: Ө=45°

   Ø=25.7%

   And other types as showed in the below

Packing Arrangement and porosity	
Packing Arrangement	**Porosity %**
Cubic	47.6
Rhombohedra	26
Orthorhombic	39.5
Tetragonal	30.2
Tetrahedral	26
Pyramidal	26
Hexagonal	39.5
Triclinic	26
Random	$\geq$39.5
Effect of different packing Arrangement	

It's obvious that the porosity decrease as the packing increase.

b) Random packing:

i) Linear approximation:

$$\bar{n} = 19 - 27.5\emptyset \quad \text{------ (6)}$$

Where, $\bar{n}$: no. of touch points* no. of spheres(N)

$$\bar{n} = \frac{\sum N*n}{\sum N} \quad \text{------ (7)}$$

ii) Smith relation:

$$\bar{n} = 6\left[\frac{1+1.828\bar{x}}{1+0.414\bar{x}}\right] \quad \text{------ (8)}$$

$$\bar{x} = \frac{0.476\emptyset}{0.217} \quad \text{------ (9)}$$

iii) Beverdges relation:

$$\bar{n} = 22.47 - 39.39\emptyset \quad \text{------ (10)}$$

2) Packing Arrangement

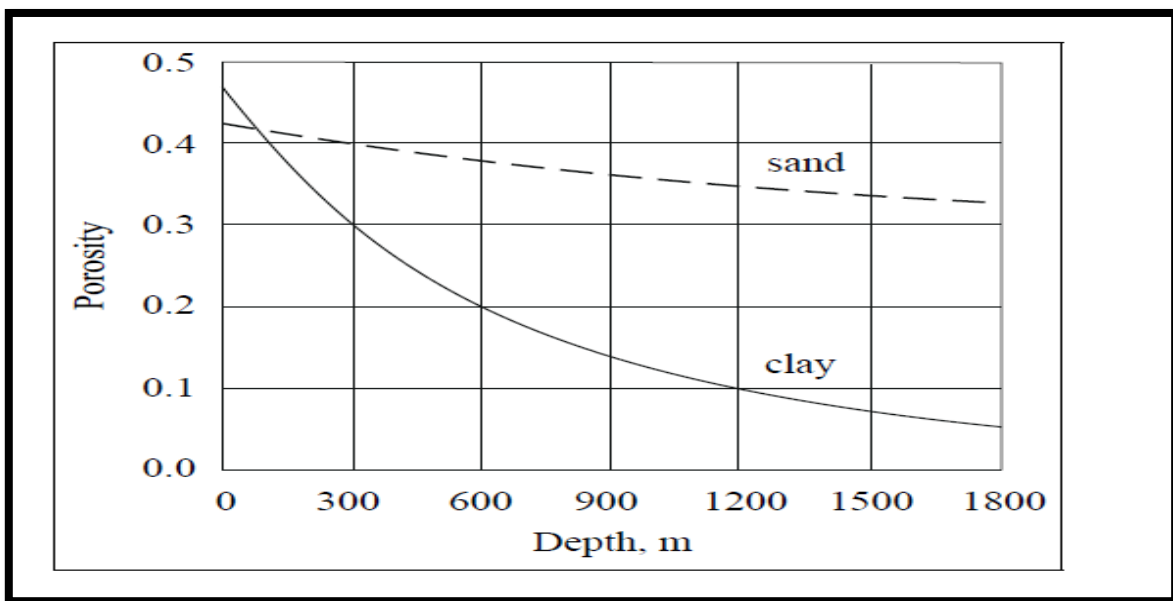Porosity decreases as compaction increases.

Fig. (7) Effect of Natural Compaction on Porosity

3) Particle size distribution: the porosity increase as the arrangement of particle size increase. larger particles cannot pack together as tightly as smaller particles can, a rock made out of larger particles will usually be more porous than a rock made out of smaller particles. But rocks are not static; like everything, rocks change over time. When enough pressure, or force, is applied to a rock, the pressure can make the rock more efficiently pack its particles.. You can see how this process, known as compaction, makes the rock's porosity decrease with time.
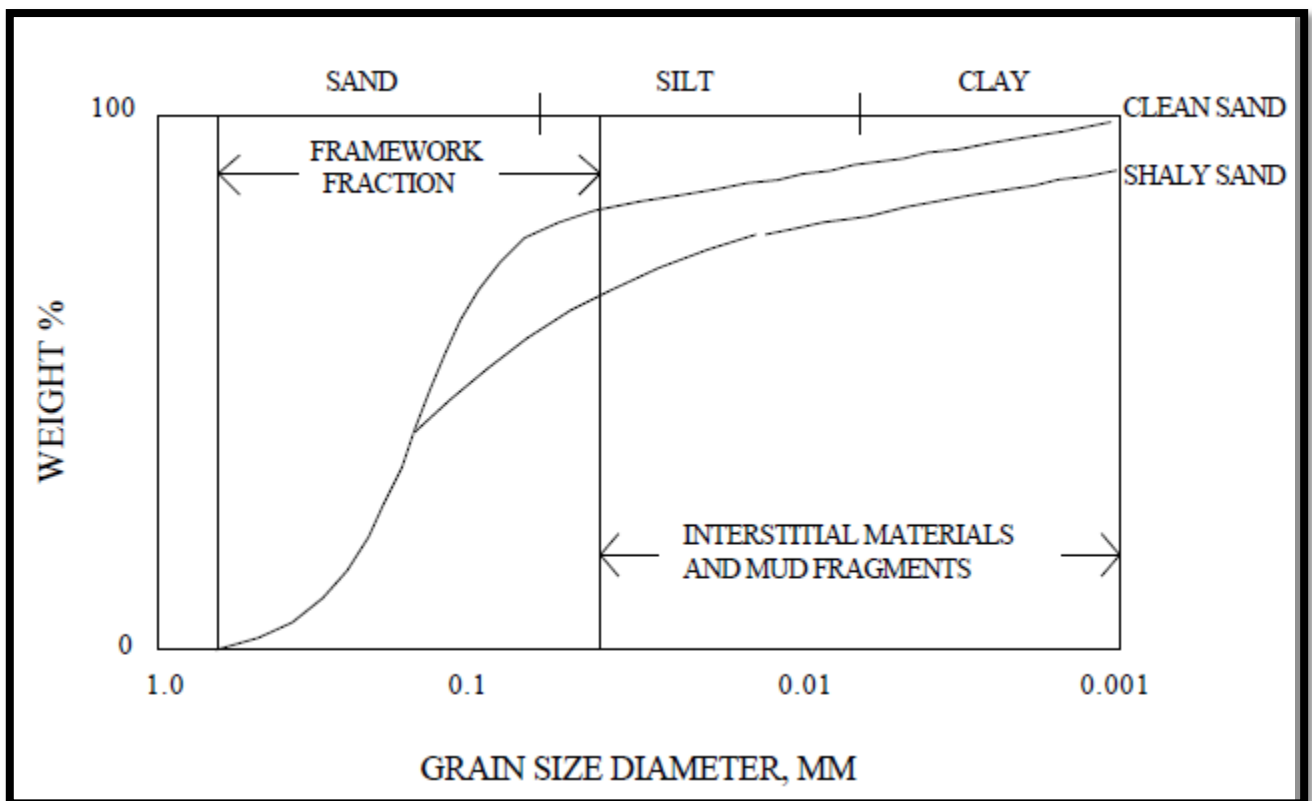
Fig(8) Particle shape and size: the porosity of irregular shape is greater than that of regular shape depending on packing and size distribution.
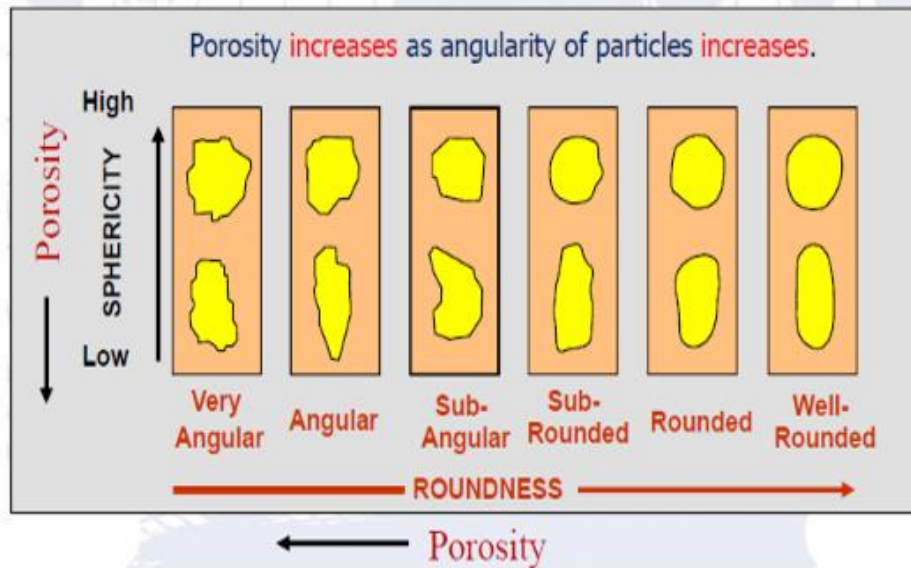
Fig(9) Particle shape and size: the porosity of irregular shape is greater than that of regular shape depending on packing and size distribution.

| Millimeters (mm)		Micrometers (µm)	Phi (f)	Wentworth size class		Rock type
	4096		-12.0	Boulder		
	256		-8.0	Cobble	Gravel	Conglomerate/ Breccia
	64		-6.0	Pebble		
	4		-2.0	Granule		
	2.00		-1.0	Very coarse sand		
	1.00		0.0	Coarse sand		
1/2	0.50	500	1.0	Medium sand	Sand	Sandstone
1/4	0.25	250	2.0	Fine sand		
1/8	0.125	125	3.0	Very fine sand		
1/16	0.0625	63	4.0	Coarse silt		
1/32	0.031	31	5.0	Medium silt	Silt	Siltstone
1/64	0.0156	15.6	6.0	Fine silt		
1/128	0.0078	7.8	7.0	Very fine silt		
1/256	0.0039	3.9	8.0	Clay	Mud	Claystone
	0.00006	0.06	14.0			

Fig(9) Wentworth scale

4) <u>Degree of cementation:</u>

   a) Porosity decrease as the amount of interstitial material increases.

   b) Porosity decrease as the amount of cemented material increase.

   c) Clean sand - little interstitial material.

   Shaly sand - has more interstitial material.(Fig. 8).

5) <u>Vugs, fractures</u>:

   a) Contribute substantially to the volume of pore space.

   b) Highly variable in size and distribution.

   c) There could be two or more systems of pore opining - extremely complex.

   d)
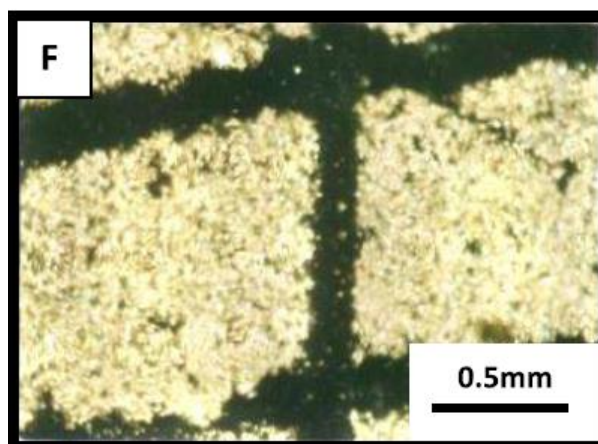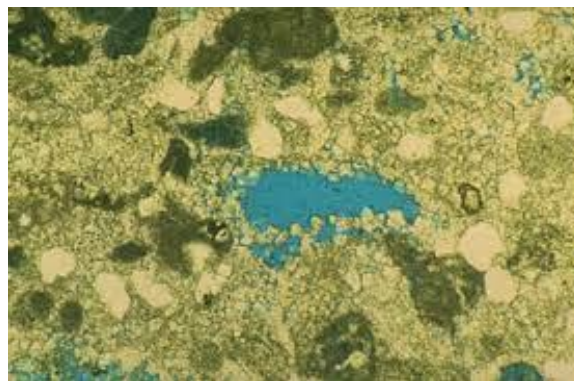
Some Real Values of Measured Porosity

1) Sand stone: Ø=(10-40)%

2) Limestone: Ø=(5-25)%

3) Clay: Ø=(20-45)%

All of these values depends on the depth and origin, also, other factors that affect the porosity which was discussed.

Measurement of Porosity

Estimates of reservoir porosity can be obtained from several sources both:

A) Direct methods in the laboratory.

B) Indirect methods by using well logs (Density log, Sonic (Acoustic) log, Nutrone log).

A) Laboratory measurement

Conventional core analysis is measure any two:

1) Bulk volume, V_b

2) Matrix volume, V_m

3) Pore volume, V_p

▶ **Bulk volume**

1) Calculate from dimensions

2) Displacement method

A) Volumetric (measure volume)
(1) Drop into liquid and observe volume charge of liquid
(2) Must prevent test liquid from entering pores space of sample
        (a) Coat with paraffin
        (b) Presaturate sample with test liquid
        (c) Use mercury as test liquid
B) Gravimetric (measure mass)

(1) Change in weight of immersed sample prevent test liquid from entering pore space

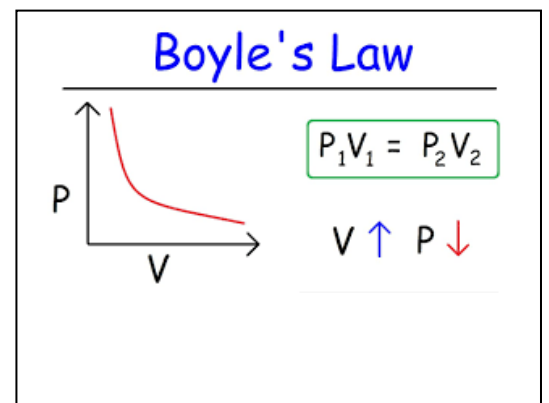(2) Change in weight of container and test fluid when sample is introduced.

▶ **Matrix Volume**

1) Assume grain density

$$V_m = \frac{\text{dry weight}}{\text{matrix density}} = \frac{m_s}{\rho_g}$$

2) Displacement method reduce sample to particle size, then

       a) Volumetric

       b) Gravimetric

3) Boyle's Law: $P_1V_1 = P_2V_2$
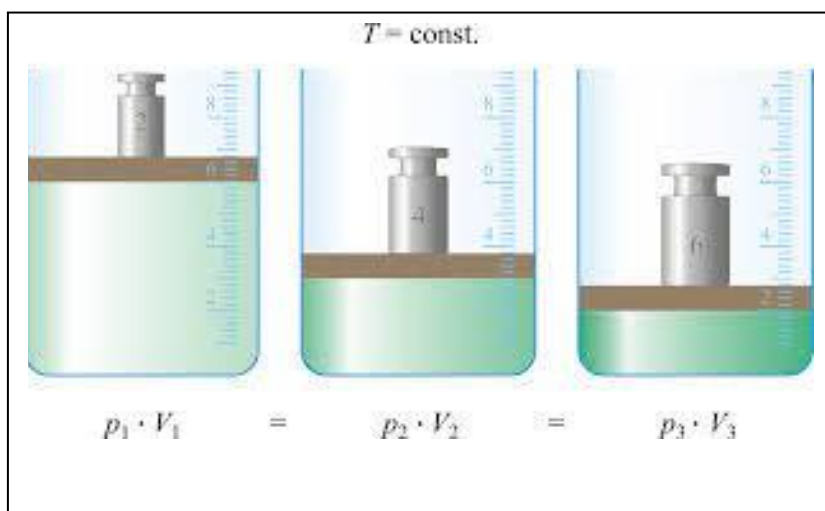
Boyle's law, also called Mariotte's law, a relation concerning the compression and expansion of a gas at constant temperature. This empirical relation, formulated by the physicist Robert Boyle in 1662, states that the pressure (p) of a given quantity of gas varies inversely with its volume (v) at constant temperature.

a)

VALVE CLOSED
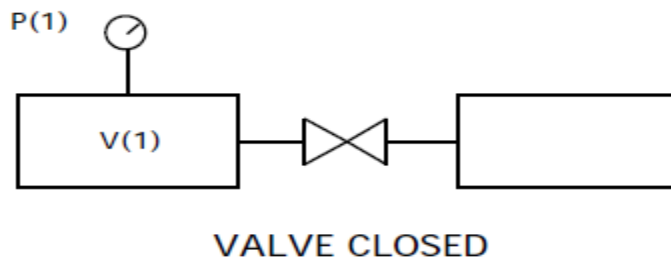
b) Put core in second chamber, evacuate
c) Open valve

VALVE OPEN
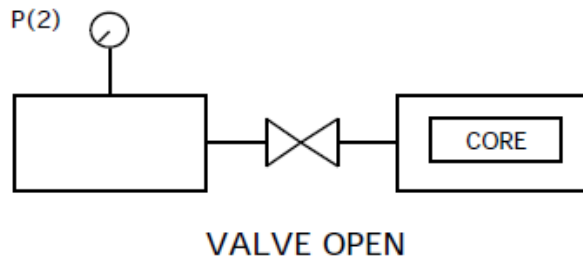
V_2 = volumetric of first chamber & volume of second chamber - matrix volume or core (calculated)

V_T = volume of first chamber + volume second chamber (known)

4) $V_m = V_T - V_2$

▸ **Pore Volume**
   1) Gravimetric

$$V_P = \frac{\text{satuarted weight} - \text{dry weight}}{\text{density of satuarted fluid}}$$

   2) Boyle's Law: $P_1 V_1 = P_2 V_2$
      a)

VALVE CLOSED
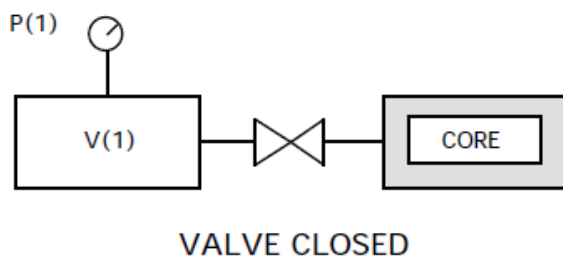
b) Put core in Hassler sleeve, evacuate

c) Open valve

VALVE OPEN
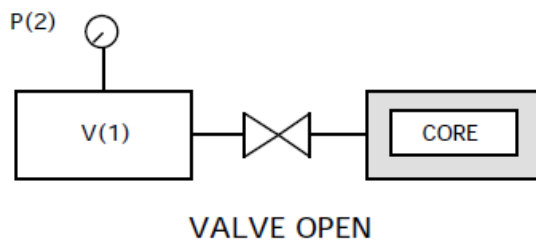
V_2 = Volume of first chamber + pore volume of core (calculated)

3) $V_P = V_2 - V_1$

Table (1) Matrix of densities

Name	Formula	Density (gm/cc)
Quartz	Sio_2	2.64
Calcite	$CaCo_3$	2.71
Dolomite	$CaCo_3MgCo_3$	2.85
Anhydrite	$CaSo_4$	2.98
Gypsum	$CaSo_4(H_2O)_2$	2.35

The reservoir rock may generally show large variations in porosity vertically but does not show very great variations in porosity parallel to the bedding planes. In this case, the arithmetic average porosity or the thickness-weighted average porosity is used to describe the average reservoir porosity. A change in sedimentation or depositional conditions,

however, can cause the porosity in one portion of the reservoir to be greatly different from that in another area. In such cases, the areal weighted average or the volume-weighted average porosity is used to characterize the average rock porosity. These averaging techniques are expressed mathematically in the following forms:

Arithmetic average $\emptyset = \dfrac{\sum \emptyset i}{n}$ --- **(11)**

Thickness-weighted average $\emptyset = \dfrac{\sum \emptyset i * hi}{\sum hi}$ -- **(12)**

Areal-weighted average $\emptyset = \dfrac{\sum \emptyset i * Ai}{\sum Ai}$ -- **(13)**

Volumetric-weighted average $\emptyset = \dfrac{\sum \emptyset i * Ai * hi}{\sum Ai * hi}$ -- **(14)**

Where: n = total number of core samples, h_i = thickness of core sample i, $\emptyset_i$ = porosity of core sample i, A_i = reservoir area i

Saturation

Saturation is defined as that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water). This property is expressed mathematically by the following relationship:

$$S = \frac{Vf}{Vp}$$

Applying the above mathematical concept of saturation to each reservoir fluid gives:

$$S_o = \frac{Vo}{Vp} \quad , \qquad\qquad S_w = \frac{Vw}{Vp} \qquad , \qquad\qquad S_g = \frac{Vg}{Vp}$$

Thus, all saturation values are based on pore volume and not on the gross reservoir volume. The saturation of each individual phase ranges between zero to 100 percent. By definition, the sum of the saturations is 100%, therefore

$$S_g + S_o + S_w = 1$$

The fluids in most reservoirs are believed to have reached a state of equilibrium and, therefore, will have become separated according to their density, i.e., oil overlain by gas and underlain by water. In addition to the bottom (or edge) water, there will be connate water distributed throughout the oil and gas zones. The water in these zones will have been reduced

to some irreducible minimum. The forces retaining the water in the oil and gas zones are referred to as capillary forces because they are important only in pore spaces of capillary size. Connate (interstitial) water saturation is important primarily because it reduces the amount of space available between oil and gas. It is generally not uniformly distributed throughout the reservoir but varies with permeability, lithology, and height above the free water level. Another particular phase saturation of interest is called the critical saturation and it is associated with each reservoir fluid.

- **Connate water**:

  Water trapped in the pores of a rock during formation of the rock. The chemistry of connate water can change in composition throughout the history of the rock. Connate water can be dense and saline compared with seawater. Formation water, or interstitial water, in contrast, is simply water found in the pore spaces of a rock, and might not have been present when the rock was formed. Connate water is also described as fossil water.

▶ **Critical oil saturation, S_{oc}**

For the oil phase to flow, the saturation of the oil must exceed a certain value which is termed critical oil saturation. At this particular saturation, the oil remains in the pores and, for all practical purposes, will not flow.

▶ **Residual oil saturation, S_{or}**

During the displacing process of the crude oil system from the porous media by water or gas injection (or encroachment) there will be some remaining oil left that is quantitatively characterized by a saturation value that is larger than the critical oil saturation. This saturation value is called the residual oil saturation, S_{or}. The term residual saturation is usually associated with the nonwetting phase when it is being displaced by a wetting phase.

▶ **Movable oil saturation, S_{om}**

Movable oil saturation S_{om} is another saturation of interest and is defined as the fraction of pore volume occupied by movable oil as expressed by the following equation:

$$S_{om} = 1 - S_{wc} - S_{oc}$$

▶ **Critical gas saturation, S_{gc}**

As the reservoir pressure declines below the bubble-point pressure, gas evolves from the oil phase and consequently the saturation of the gas increases as the reservoir pressure declines. The gas phase remains immobile until its saturation exceeds certain saturation, called critical gas saturation, above which gas begins to move.

▶ **Critical water saturation, S_{wc}**

The critical water saturation, connate water saturation, and irreducible water saturation are extensively used interchangeably to define the maximum water saturation at which the water phase will remain immobile.

▶ **Average saturation**

Proper averaging of saturation data requires that the saturation values be weighted by both the interval thickness h and interval porosity Ø. The average saturation of reservoir fluid is calculated from the following equation:

$$\mathbf{S_{avg.}} = \frac{\sum \emptyset_i * h_i * S_i}{\sum \emptyset_i * h_i} \quad \text{---} \quad \mathbf{(14)}$$

Schematic showing identical glasses filled with different fluids: (a) the glass is filled with 100% water, representing $S_w = 1$, (b) the glass is filled with 50% water and 50% oil, representing $S_w = 0.5$ and $S_o = 0.5$, and (c) the glass is filled with 50% water, 30% oil, and 20% air (gas), representing $S_w = 0.5$, $S_o = 0.3$, and $S_g = 0.2$.
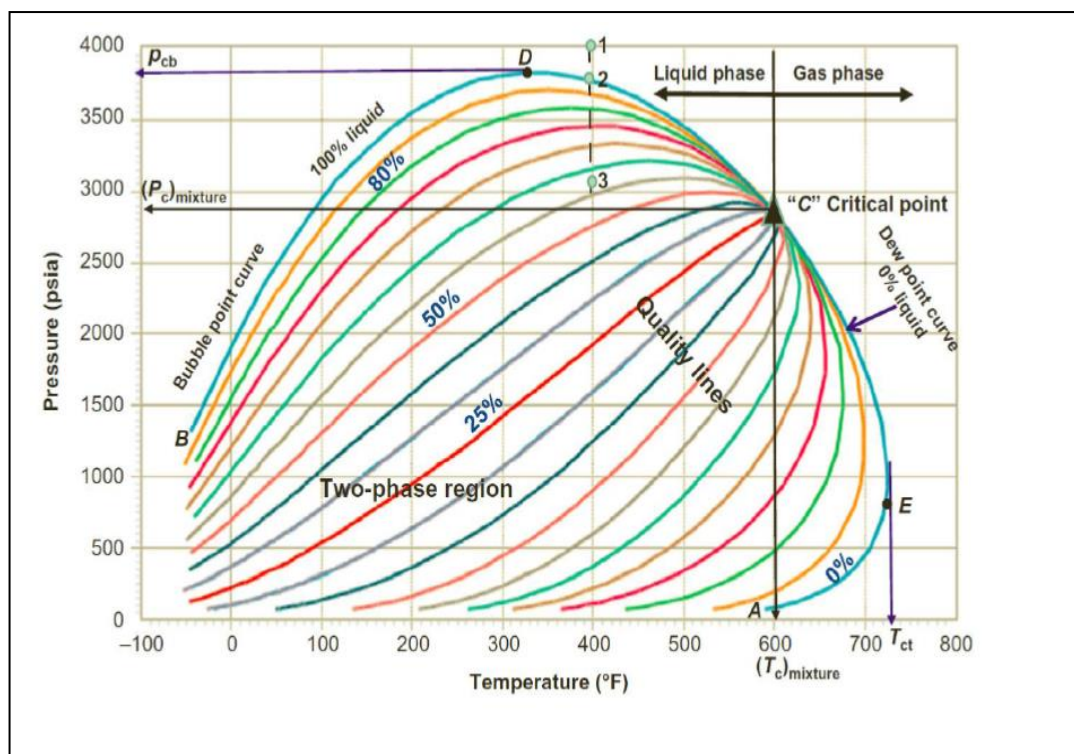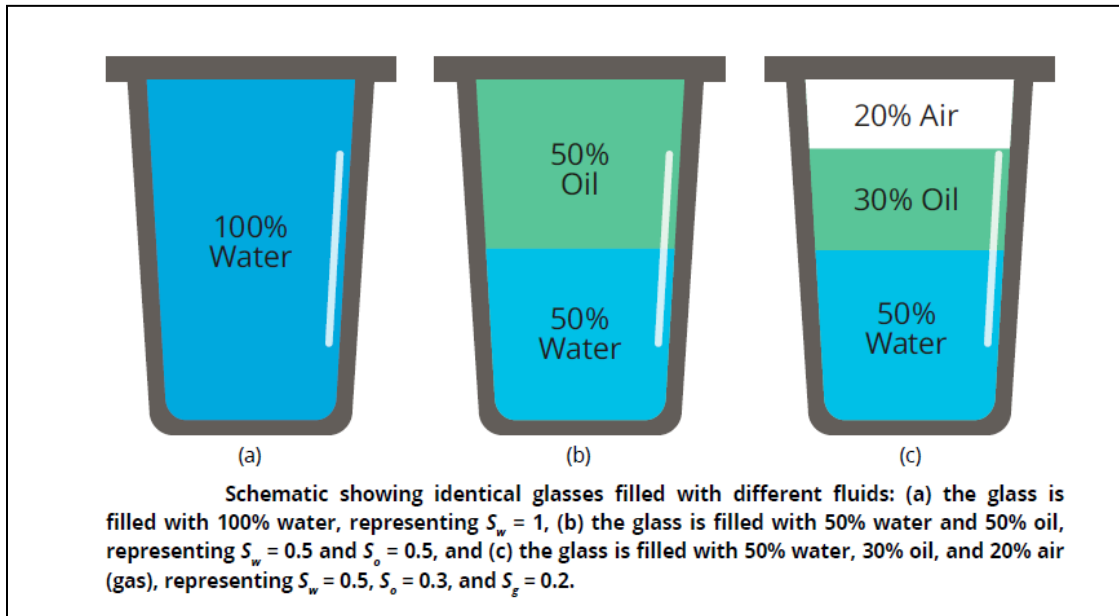
Calculating Original Oil and Gas in Place by the Volumetric Method

To better understand reserves estimation, a few important terms require definition. Original oil in place (OOIP) and original gas in place (OGIP) refer to the total volume of hydrocarbon stored in a reservoir prior to production. Reserves or recoverable reserves are the volume of hydrocarbons that can be profitably extracted from a reservoir using existing technology. Resources are reserves plus all other hydrocarbons that may eventually become producible; this includes known oil and gas deposits present that cannot be technologically or economically recovered (OOIP and OGIP) as well as other undiscovered potential reserves.

Estimating hydrocarbon reserves is a complex process that involves integrating geological and engineering data. Depending on the amount and quality of data available, one or more of the following methods may be used to estimate reserves:

A- Volumetric: OOIP, OGIP, recoverable reserves. Use early in life of field.

B- Material balance: OOIP, OGIP, assumes adequate production history available, recoverable reserves (assumes OOIP and OGIP known). Use in a mature field with abundant geological, petrophysical, and engineering data.

C- Production history: Recoverable reserves. Use after a moderate amount of production data is available.

D- Analogy: OOIP, OGIP, recoverable reserves. Use early in exploration and initial field development.

1- Calculating Original Oil in Place(OOIP) by the Volumetric Method

One important application of the effective porosity is its use in determining the original hydrocarbon volume in place. Consider a reservoir with an areal extent of **A** acres and an average thickness of **h** feet.

- Bulk volume

  - Area

  - Thickness
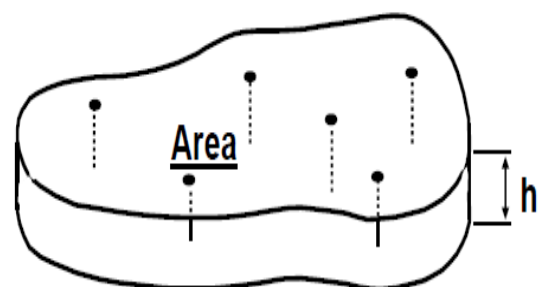
Reservoir Bulk Volume (BV) :

BV = Area * Thickness

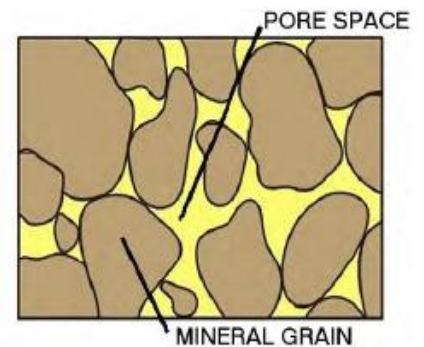**Bulk volume = 43,560 Ah, ft^3** --- **(15)**

or

Bulk volume = 7,758 Ah, bbl --- **(16)**

Where: A = areal extent, acres, h = average thickness, ft.

- Porosity
  - Pore space within the rock
  - Generally 5% to 30% of the bulk volume
- Fluid saturations
  - Water (usually 10% to 50% of pore space)
  - Oil
- Shrinkage (oil formation volume factor) (B_{oi})

The reservoir pore volume PV can then be determined by combining Equations above, Expressing the reservoir pore volume in cubic feet gives:

PV = 43,560 AhØ, ft^3 --- **(17)**

Expressing the reservoir pore volume in barrels gives:

PV = 7,758 AhØ, bbl -- **(18)**

OOIP (N or N_i) = PV* $(1-S_{wi})$ / B_{oi} --- **(19)**

OOIP (N or N_i) = 7,758*AhΦ$(1-S_{wi})$ / B_{oi} --- **(20)**

OOIP (N or N_i) = 7,758*AhΦ*(S_o) / B_{oi} --- **(21)**

Where:
OOIP (N or N_i) = original oil in place, STB
7,758 = factor converting acre-feet to barrels
A = reservoir area, acres
h = average reservoir thickness, feet
Φ = average reservoir porosity, fraction bulk volume
S_w = average water saturation, fraction pore volume
B_o = oil formation volume factor, RB/STB(defined as the ratio of the volume of oil (plus the gas in solution) at the reservoir temperature and pressure to the volume of oil at standard conditions.)
$S_o = V_o / V_p$ 1

V_o = So Vp 2

ϕ = V_p/V_b..........................3

Vp = ϕVb 4

V_o = $S_o\phi V_b$..........................5

Two notes can be considered:

1) Water saturation is usually measured by capillary pressure and resistivity logs and thus the oil saturation is replaced by 1- Sw for an oil/ water and gas/water reservoirs.

 2) V_o for the reservoir is referred to as OIP and thus the equation becomes:

OIP = ϕVb(1 − Sw) 6

The same process would go for gas/water reservoir for GIP and the equation becomes:

GIP = ϕVb(1 − Sw)..........................7

Net to Gross

There are other parameters that can be included in the OIP/GIP equations such as the net to gross (NTG), which is the ratio of the fraction of reservoir section to the total studied section (reservoir and non-reservoir sections). For example, in Figure 10.1, the total section includes both reservoir rocks and impermeable rocks. The fraction of the reservoir section to the total section in this case will be: NTG = h1 + h2 + h3 + h4/ h total.

If the NTG is known, then the OIP equation can be modified to obtain:

OIP = φAh$_{total}$ NTG (1 − Sw)

2- Calculating Original Gas in Place (OGIP) by the Volumetric Method

$$V_b = 43{,}560 * A * h$$

$$\text{OGIP (G or}G_i) = V_b*\Phi*(1\text{-}S_{wi})/B_{gi} \quad\text{-- (22)}$$

$$\text{OGIP (G or}G_i) = 43{,}560 * A * h *\Phi*(1\text{-}S_{wi}) \qquad \text{in ft}^3 \qquad \text{------------------------- (23)}$$

$$\text{OGIP (G or}G_i) = 43{,}560 * A * h *\Phi*(1\text{-}S_{wi}) /B_{gi} \quad \text{in MMSCF ------------------------- (24)}$$

Where:

B_{gi} = gas formation volume factor at initial reservoir pressure p_i, ft^3/SCF

Rock Compressibility

A reservoir thousands of feet underground is subjected to an overburden pressure caused by the weight of the overlying formations. Overburden pressures vary from area to area depending on factors such as **depth**, **nature of the structure**, **consolidation of the formation**, **and possibly the geologic age and history of the rocks**. Depth of the formation is the most important consideration, and a typical value of overburden pressure is approximately one psi per foot of depth.

The weight of the overburden simply applies a compressive force to the reservoir. The pressure in the rock pore spaces does not normally approach the overburden pressure. A typical pore pressure, commonly referred to as the reservoir pressure, is approximately 0.5 psi per foot of depth, assuming that the reservoir is sufficiently consolidated so the overburden pressure is not transmitted to the fluids in the pore spaces.

The pressure difference between overburden and internal pore pressure is referred to as the effective overburden pressure. During pressure depletion operations, the internal pore pressure **decreases** and, therefore, the effective overburden pressure **increases**. This increase causes the following effects:

❖ The bulk volume of the reservoir rock is reduced.

❖ Sand grains within the pore spaces expand.

These two volume changes tend to reduce the pore space and, therefore, the porosity of the rock. Often these data exhibit relationships with both porosity and the effective overburden pressure. Compressibility typically **decreases** with **increasing** porosity and effective overburden pressure.

The compressibility of a substance is defined as the shrinkage of a unit volume of the substance per unit increase in pressure.

There are three different types of compressibility that must be distinguished in rocks:

A) Rock matrix compressibility, C_r

Is defined as the fractional change in volume of the solid rock material (grains) with a unit change in pressure. Mathematically is given by:

$$C_r \text{ or } Cm = -\frac{1}{Vr \text{ or } Vm}\left(\frac{\partial Vr}{\partial P}\right)_T \text{ or } (dvr \text{ or } dvm /dp)_T \text{-------------------------------------- (25)}$$

Where:

C_r = rock-matrix compressibility, psi^{-1},

V_r = volume of solids.

The subscript **T** indicates that the derivative is taken at constant temperature.

B) Rock bulk compressibility,C_b

Is defined as the fractional change in volume of the bulk volume of the rock with a unit change in pressure. which defined mathematically by:

$$C_b = -\frac{1}{V_b}\left(\frac{\partial V_b}{\partial P}\right)_T or(dvb/dp)_T \text{---} (26)$$

Where:

C_b = rock-bulk compressibility coefficient, psi^{-1},

V_b = bulk volume.

c) Pore compressibility,C_p

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:

$$C_p = -\frac{1}{V_p}\left(\frac{\partial V_p}{\partial P}\right)_T \text{ or } (dvp/dp)_T \text{--} (27)$$

Where:

C_p = pore compressibility coefficient, psi^{-1}

V_p = pore volume.

The above equation can be expressed in terms of the porosity Φ by noting that Φ increases with the increase in the pore pressure; or:

$$C_p = \frac{1}{\emptyset}\left(\frac{\partial\emptyset}{\partial P}\right)_T \text{---} (28)$$

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.:

$$C_f = C_p = \frac{1}{\emptyset}\left(\frac{\partial\emptyset}{\partial P}\right)_T \text{---} (29)$$

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

$$C_t = S_oC_o + S_wC_w + S_gC_g + C_f \text{-- (30)}$$

Where:

S_o, S_w, S_g = oil, water, and gas saturation

C_o = oil compressibility, psi^{-1}

C_w = water compressibility, psi^{-1}

C_g = gas compressibility, psi^{-1}

C_t = total reservoir compressibility.

Typical values for the formation compressibility range from 3×10^{-6} to 25×10^{-6} psi^{-1}. Equation **28** can be rewritten as:

$$C_f = \frac{1}{V_p}\frac{\Delta V_P}{\Delta p} \text{ --- (31)}$$

or

$$\Delta V_p = C_f V_p \Delta p \text{ --- (32)}$$

Where:

ΔV_p and Δp are the change in the pore volume and pore pressure, respectively.
Geertsma (1957) suggested that the bulk compressibility C_b is related to the pore compressibility C_p by the following expression.
$$C_b \cong C_p \emptyset \text{ -- (33)}$$

PERMEABILITY

Permeability is a property of the porous medium that measures the capacity and ability of the formation to transmit fluids. The rock permeability'' k'' is a very important rock property because it controls the directional movement and the flow rate of the reservoir fluids in the formation. This rock characterization was first defined mathematically by Henry Darcy in **1856**. In fact, the equation that defines permeability in terms of measurable

quantities is called Darcy's Law. Darcy developed a fluid flow equation that has since become one of the standard mathematical tools of the petroleum engineer.
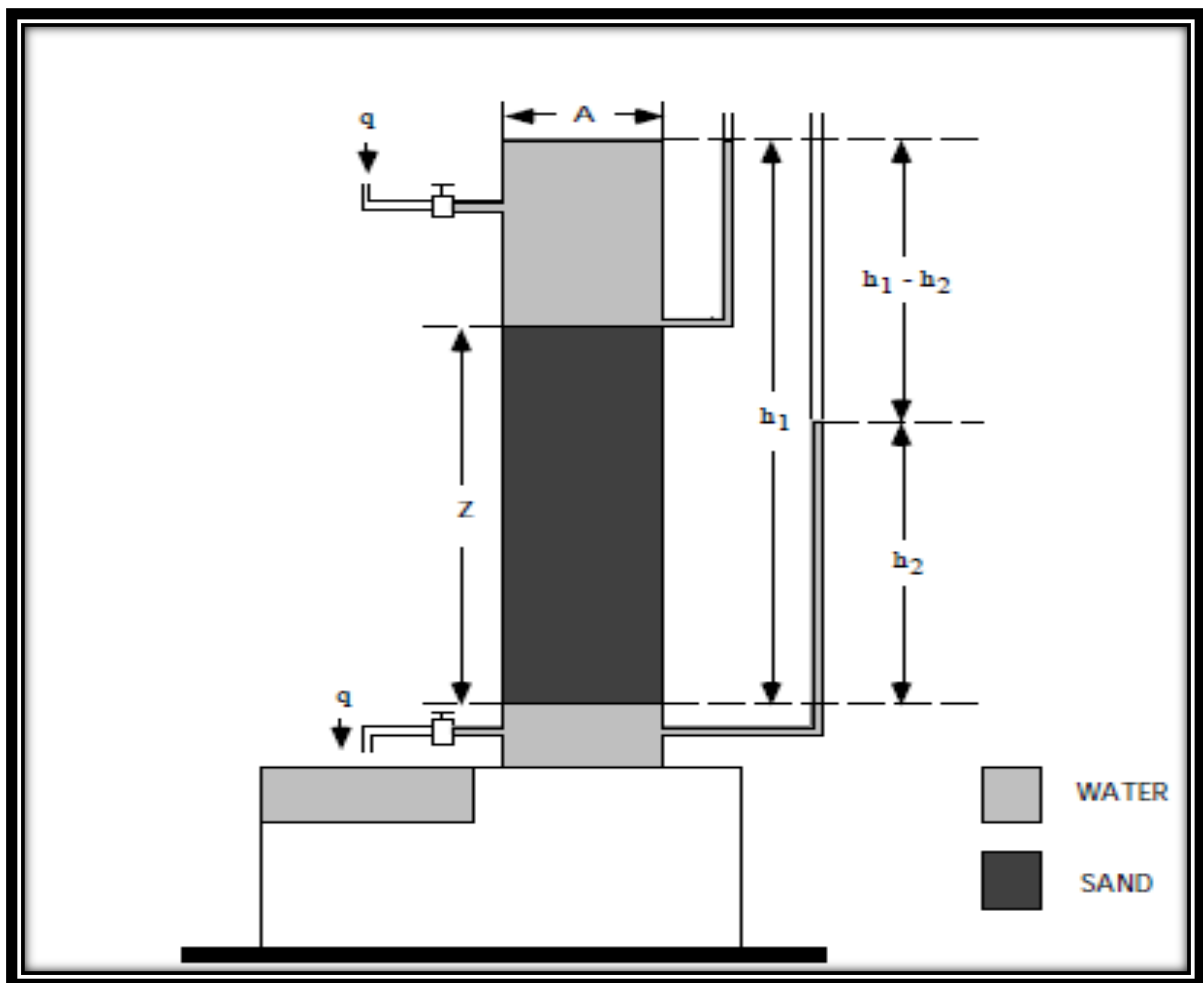

Fig. (8) Darcy's fountain.

$q = kA (h_1 - h_2) / \mu L$

Length of sand pack, $L = Z$

1. Constant of proportionality, k, characteristics of particular sand pack, not sample size
2. Darcy's work confined to sand packs that were 100% saturated with water

3. Equation extended to include other liquids using viscosity
Notes:

 A- In formations with large grains the permeability its high and the flow rate large

PERMEABILITY AND ROCKS
In formations with large grains, the permeability is
high and the flow rate larger.
The permeability in the horizontal direction is controlled by the
large grains.
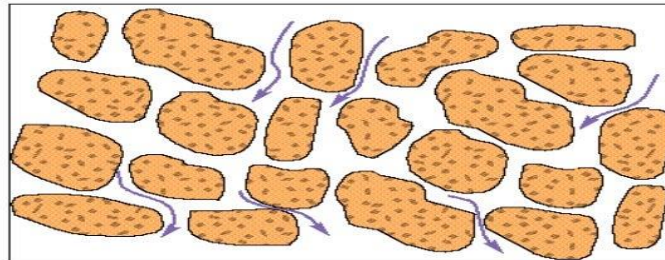
  B- In rocks, with small grains the permeability is less and the flow lower

In a rock with small grains the permeability is less and the flow lower.
The permeability in the vertical direction is controlled by the small grains
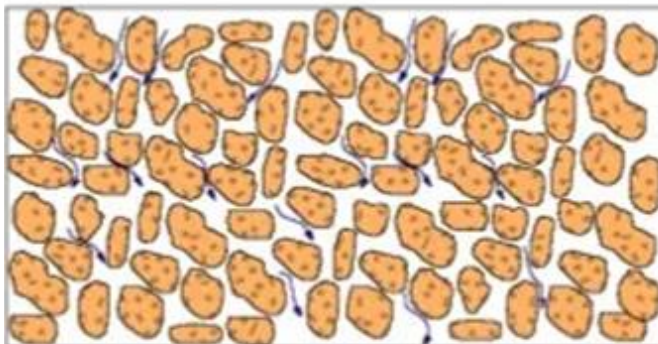
CLASSIFICATION OF PERMEABILITY

A) **Absolute Permeability (k):** Permeability of a rock to a fluid when the rock is 100% saturated with that fluid.

B) **Effective Permeability (ke):** defined as the apparent permeability to a particular phase (oil, gas or water) or saturation with more than one phase. The amount that flow is impeded depends upon the saturation of the fluids in the sand.

C) **Relative Permeability (kr):** is the ratio of effective permeability of a particular fluid at a particular saturation to absolute permeability of that fluid at total saturation. If a single fluid is present in a rock, its relative permeability is 1.0. Calculation of relative permeability allows comparison of the different abilities of fluids to flow in the presence of each other, since the presence of more than one fluid generally inhibits flow. The unit of effective permeability is the Darcy while the relative permeability is being a ratio, has no unit.
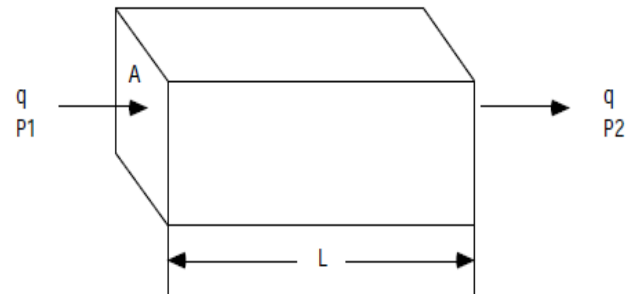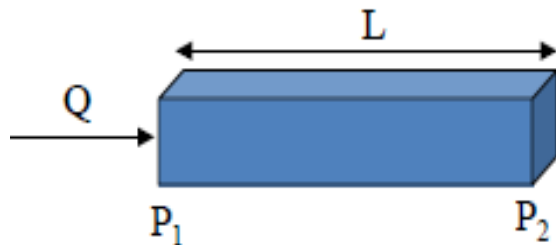
D) **Geometrical classification**

Permeability classification	Permeability (mD)
Very low	<0.01
Low	0.01–1
Average	1–100
High	100–10,000
Very high	>10,000

Darcy=1000 md,   1 md=$9.87*10^{-12}$ cm^2,   atm=$1.0133*10^6$ dyne/cm^2.

RESERVOIR SYSTEMS

1- Flow of incompressible liquid

A) Horizontal, linear flow system

Conditions:

1) Horizontal system, dz /ds= 0(pressure gradient)

2) Linear system, A = constant

3) Incompressible liquid, q = constant

4) Laminar flow, can use Darcy's equation

5) Non-reactive fluid, k = constant

6) 100% saturated with one fluid

7) Constant temperature, μ

Derivation of flow equation

$$V_s = -\frac{k}{\mu}\left[\frac{dp}{ds} - \frac{\rho g}{1.0133 \times 10^6}\frac{dz}{ds}\right]$$

$$V_s = \frac{q}{A} = -\frac{k}{\mu}\frac{dp}{ds}$$

$$q\int_0^L ds = -\frac{kA}{\mu}\int_{p_1}^{p_2} dp$$

$$q(L - 0) = -\frac{kA}{\mu}(p_2 - p_1)$$

$$\mathbf{q = \frac{kA}{\mu L}(p_1 - p_2)} \text{ -- (34)}$$

Or

$$\mathbf{q = \frac{kA\Delta p}{\mu L}} \qquad \text{For Lab. Unit -- (35)}$$

$$\mathbf{q = 1.127 * 10^{-3}\frac{kA\Delta p}{\mu L}} \qquad \text{For Field Unit -- (36)}$$

$$q_o = 1.127 * 10^{-3} \frac{k_o A \Delta p_o}{\mu_o L} \quad \text{For Field Unit} \text{------------------------------ (37)}$$

$$q_w = 1.127 * 10^{-3} \frac{k_w A \Delta p_w}{\mu_w L} \quad \text{For Field Unit} \text{------------------------------ (38)}$$

$$q_g = 1.127 * 10^{-3} \frac{k_g A \Delta p_g}{\mu_g L} \quad \text{For Field Unit} \text{------------------------------ (39)}$$

Note:

P_1 acts at $L = 0$

P_2 acts at $L = L$

q is + if flow is from $L = 0$ to $L = L$

The actual velocity is determined by dividing the apparent velocity by the porosity of the rock. If irreducible water saturation is present the actual velocity in a water wet reservoir is:

$$V_a = \frac{v}{\emptyset(1 - Swi)} \quad \text{--- (40)}$$

The following equation can be used to estimate the pressure at any point in a linear flow system:

$$P = (P_2 - P_1)\frac{x}{L} + P_1 \quad \text{--- (41)}$$

B) Non-horizontal (Inclined), linear system, the flow from bottom to top.

Conditions:
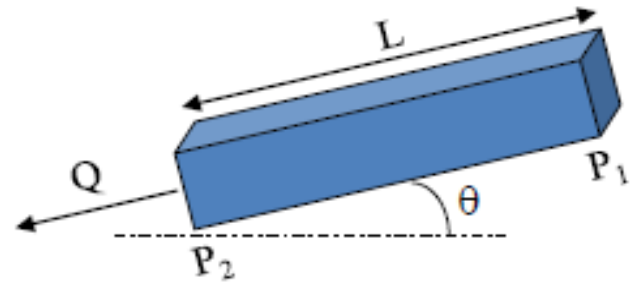
1) Non-horizontal system, dz / ds= sinθ = constant

2) Linear system, A = constant

3) Incompressible liquid, q = constant

4) Laminar flow, use Darcy equation

5) Non-reactive fluid, k = constant

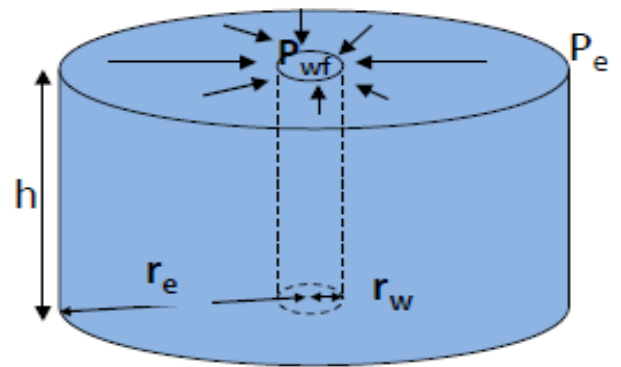6) 100% saturated with one fluid

7) Constant temperature μ, q
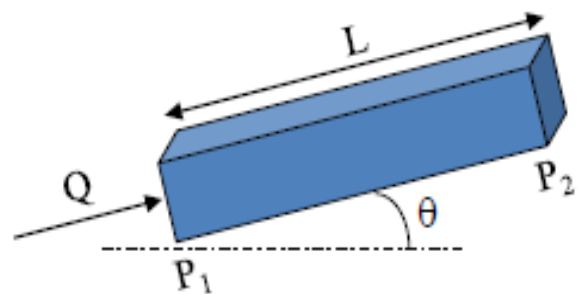
$$q = \frac{kA}{\mu}\left(\frac{p_1 - p_2}{L} - \rho g \sin \theta\right) \quad \text{-------------------------------------- (42)}$$

C) Non-horizontal (Inclined), linear system, the flow from top to bottom.

$$q = \frac{kA}{\mu}\left(\frac{p_1 - p_2}{L} + \rho g \sin \theta\right)$$ --- **(43)**

D) Horizontal radial flow

2- Flow of compressible liquid (Linear flow of gases)

The flow equation of gases differs from liquids because of that the gas expands as the pressure decline, however, the pressure gradient increase toward the downstream end, and consequently the flow rate is not constant, but is a function of pressure. Three equations can be used to describe the flow of gases expressed by field unit:

$$Q_2 = \frac{3.17 * 10^{-3} KA(P_1^2 - P_2^2)}{\mu_g L P_2}$$ --- **(44)**

$$\bar{Q} = \frac{6.33 * 10^{-3} KA(P_1 - P_2)}{\mu_g L}$$ --- **(45)**

$$Q_{sc} = \frac{0.122 KA(P_1^2 - P_2^2)}{\bar{z}\,\bar{T}\mu_g L}$$ --- **(46)**
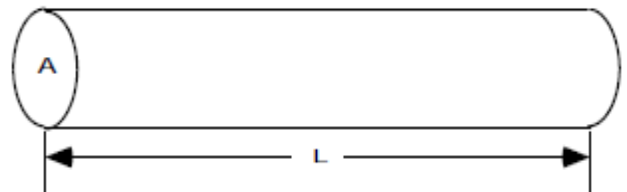
Where, $\bar{Q}$, Q_2 : ft³/day, Q_{sc} : scf/day, K:md, A : ft², L:ft, P: Psia, μ_g : cp.

The following equation can be used to estimate the pressure at any point in a linear flow system of gases:

$$P^2 = \left(P_2^2 - P_1^2\right)\frac{X}{L} + P_1^2 \qquad\qquad (47)$$

3- Flow through channels and fractures

A) Flow through constant diameter channel

1- Poiseuille's Equation for viscous flow through capillary tubes

$$q = \frac{\pi r^4}{8\mu L}(p_1 - p_2) \qquad\qquad (48)$$

$$A = \pi r^2 \text{ , therefore}$$

$$q = \frac{Ar^2}{8\mu L}(p_1 - p_2) \qquad\qquad (49)$$

2- Darcy's law for linear flow of liquids

$$q = \frac{kA}{\mu L}(p_1 - p_2) \qquad\qquad (50)$$

assuming these flow equations have consistent units

$$\frac{Ar^2}{8\mu L}(p_1 - p_2) = \frac{kA}{\mu L}(p_1 - p_2) \qquad\qquad (51)$$

$$k = \frac{r^2}{8} = \frac{d^2}{32}$$

Where:-

$$d = \text{inches,}$$
$$k = 20 \times 10^9 \ d^2 \ \text{md} \qquad\qquad (52)$$

B) Flow through fractures

$$v = \frac{q}{A} = \frac{h^2}{12\mu L}(p_1 - p_2) \text{ --- (53)}$$

$$v = \frac{b^2 A}{12\mu L}(p_1 - p_2) \text{ --- (54)}$$

Setting this flow equation equal to Darcys flow equation,

$$\frac{b^2 A}{12\mu L}(p_1 - p_2) = \frac{kA}{\mu L}(p_1 - p_2) \text{ --- (55)}$$

Solve for permeability of afracture:

$$k = \frac{b^2}{12} \text{ --- (56)}$$

$$k = 54 \times 10^9 b^2 \text{ -- (57)}$$

Where:-
 b = inches

Table (2) Conversion to Oilfield Units

Symbol	Darcy units	Oil field
q	cc/sec	bbl/d or cu ft/d
k	darcy	md
A	sq cm	sq ft
h	cm	ft
p	atm	psia
L	cm	ft
μ	cp	cp
ρ	gm/cc	lb/cu ft

Relative Permeability Concepts

Numerous laboratory studies have concluded that the effective permeability of any reservoir fluid is a function of the reservoir fluid saturation and the wetting characteristics of the formation. It becomes necessary, therefore, to specify the fluid saturation when stating the

effective permeability of any particular fluid in a given porous medium. Just as **k** is the accepted universal symbol for the absolute permeability, **k_o, k_g**, and **k_w** are the accepted symbols for the effective permeability to oil, gas, and water, respectively. The saturations, i.e., **S_o, S_g**, and **S_w**, must be specified to completely define the conditions at which a given effective permeability exists.

Effective permeabilities are normally measured directly in the laboratory on small core plugs. Owing to many possible combinations of saturation for a single medium, however, laboratory data are usually summarized and reported as relative permeability.

The absolute permeability is a property of the porous medium and is a measure of the capacity of the medium to transmit fluids. When two or more fluids flow at the same time, the relative permeability of each phase at a specific saturation **is the ratio of the effective permeability of the phase to the absolute permeability, or:**

$$k_{rw} = \frac{k_w}{k}$$

$$k_{ro} = \frac{k_o}{k}$$

$$k_{rg} = \frac{k_g}{k}$$

Where:

k_{ro} = relative permeability to oil

k_{rg} = relative permeability to gas

k_{rw} = relative permeability to water

k = absolute permeability

k_o = effective permeability to oil for a given oil saturation

k_g = effective permeability to gas for a given gas saturation

k_w = effective permeability to water at some given water saturation

For example, if the absolute permeability **k** of a rock is **200 md** and the effective permeability **k_o** of the rock at an oil saturation of **80%** is **60 md**, the relative permeability **k_{ro}** is **0.30** at $S_o = 0.80$.

Since the effective permeabilities may range from zero to **k**, the relative permeabilities may have any value between **zero** and **one**, or:

$$0 \leq k_{rw}, k_{ro}, k_{rg} \leq 1.0$$

It should be pointed out that when three phases are present the sum of the relative permeabilities ($k_{ro} + k_{rg} + k_{rw}$) is both variable and always less than or equal to unity.

It has become a common practice to refer to the relative permeability curve for the nonwetting phase as **k_{nw}** and the relative permeability for the wetting phase as **k_w**.

There are two types curve of relative permeability

    1- Two - phase relative permeability.

2- Three - phase relative permeability.

TWO - PHASE RELATIVE PERMEABILITY

When a wetting and a nonwetting phase flow together in a reservoir rock, each phase follows separate and distinct paths. The distribution of the two phases according to their wetting characteristics results in characteristic wetting and nonwetting phase relative permeabilities. Since the wetting phase occupies the smaller pore openings at small saturations, and these pore openings do not contribute materially to flow, it follows that the presence of a small wetting phase saturation will affect the nonwetting phase permeability only to a limited extent. Since the nonwetting phase occupies the central or larger pore openings that contribute materially to fluid flow through the reservoir, however, a small nonwetting phase saturation will drastically reduce the wetting phase permeability.

Figure -9 presents a typical set of relative permeability curves for a water-oil system with the water being considered the wetting phase. **Figure -9** shows the following four distinct and significant points:
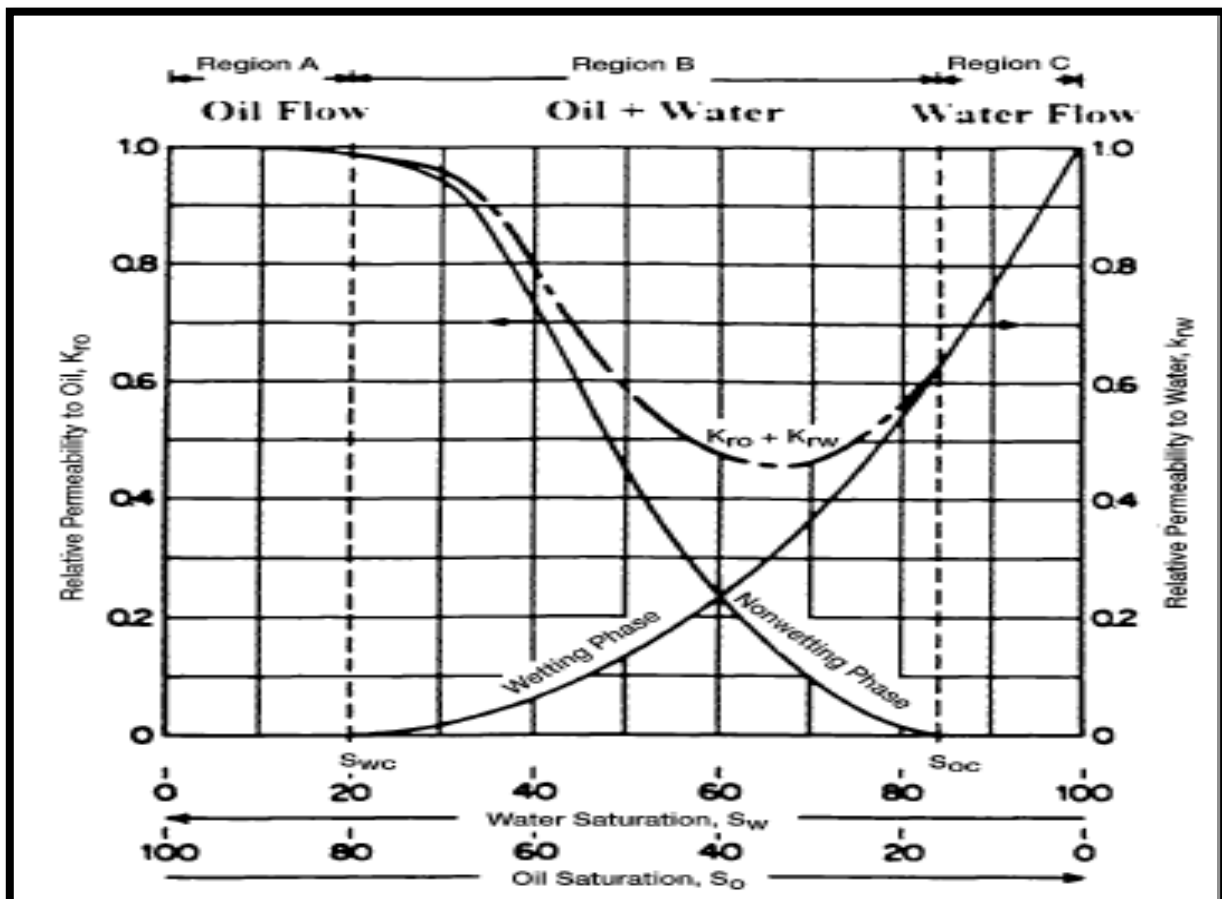

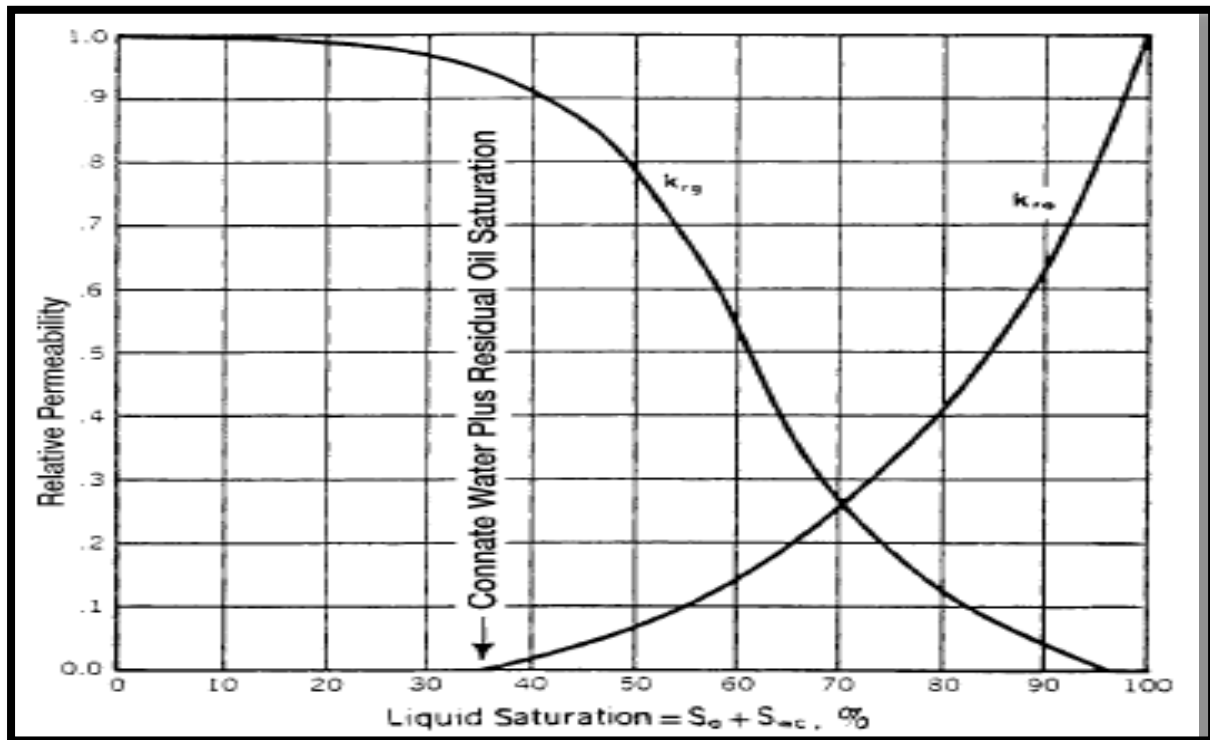**Fig.(9) Typical two-phase flow behavior. (Water-oil relative permeability curves).**

Fig.(10) Gas-oil relative permeability curves.

Wettability

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. The concept of wettability is illustrated in **Figure -11**. Small drops of three liquids mercury, oil, and water are placed on a clean glass plate. The three droplets are then observed from one side as illustrated in Figure -11. It is noted that the mercury retains a spherical shape, the oil droplet develops an approximately hemispherical shape, but the water tends to spread over the glass surface.

The tendency of a liquid to spread over the surface of a solid is an indication of the wetting characteristics of the liquid for the solid. This spreading tendency can be expressed more conveniently by measuring the angle of contact at the liquid-solid surface. This angle, which is always measured through the liquid to the solid, is called the contact angle Θ.

The contact angle Θ has achieved significance as a measure of wettability. As shown in Figure -11, as the contact angle decreases, the wetting characteristics of the liquid increase. Complete wettability would be evidenced by a zero contact angle, and complete nonwetting would be evidenced by a contact angle of **180°**. There have been various definitions of intermediate wettability but, in much of the published literature, contact angles of **60°** to **90°** will tend to repel the liquid. The wettability of reservoir rocks to the fluids is important in that the distribution of the fluids in the porous media is a function of wettability. Because of

the attractive forces, the wetting phase tends to occupy the smaller pores of the rock and the nonwetting phase occupies the more open channels.
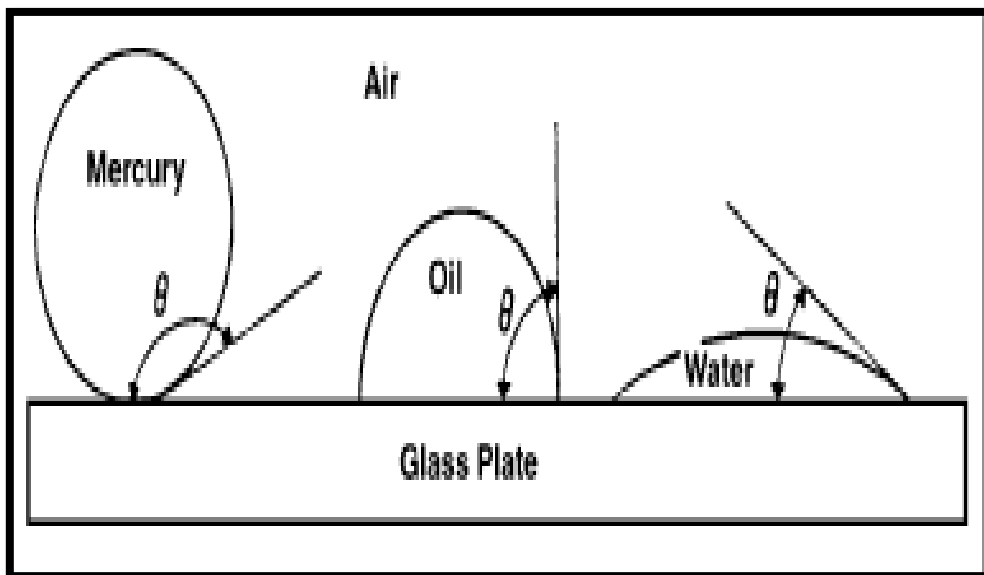

Fig. (11)Illustration of wettability.

Table (3): Relationship between wettability and contact angle.

value of contact angle (θ)	Wettability preference
0-30	Strongly Water wet
30-90	Preferentially water wet
90	Neutral wetability
90-150	Preferentially oil wet
150-180	Strongly oil wet

Surface and Interfacial Tension

In dealing with multiphase systems, it is necessary to consider the effect of the forces at the interface when two immiscible fluids are in contact. When these two fluids are liquid and gas, the term surface tension is used to describe the forces acting on the interface. When the interface is between two liquids, the acting forces are called **interfacial tension**. Consider the two immiscible fluids, air (or gas) and water (or oil) as shown schematically in Figure -12. A liquid molecule, which is remote from the interface, is surrounded by other liquid molecules, thus having a resulting net attractive force on the molecule of zero. A molecule at the interface, however, has force acting on it from the air (gas) molecules lying immediately above the interface and from liquid molecules lying below the interface. Resulting forces are unbalanced and give rise to surface tension. The unbalanced attraction

force between the molecules creates a membrane- like surface with a measurable tension, i.e., surface tension. The surface or interfacial tension has the units of force per unit of length, e.g., dynes/cm, and is usually denoted by the symbol σ. If a glass capillary tube is placed in a large open vessel containing water, the combination of surface tension and wettability of tube to water will cause water to rise in the tube above the water level in the container outside the tube as shown in Figure - 13.
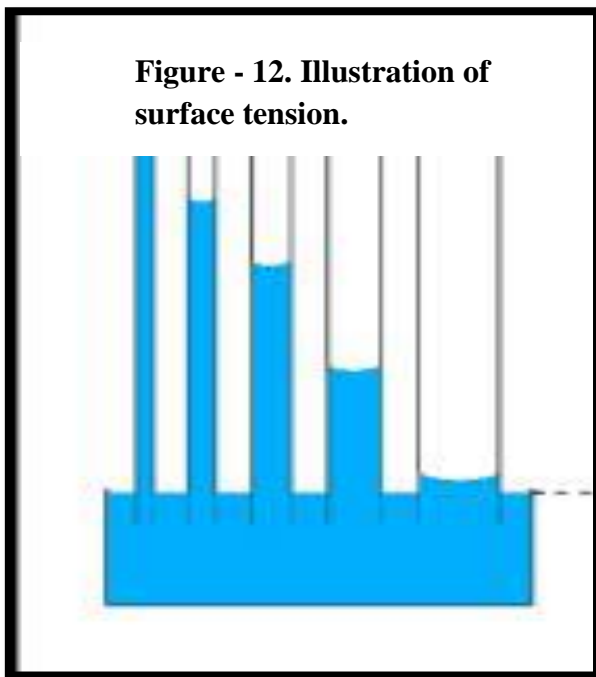
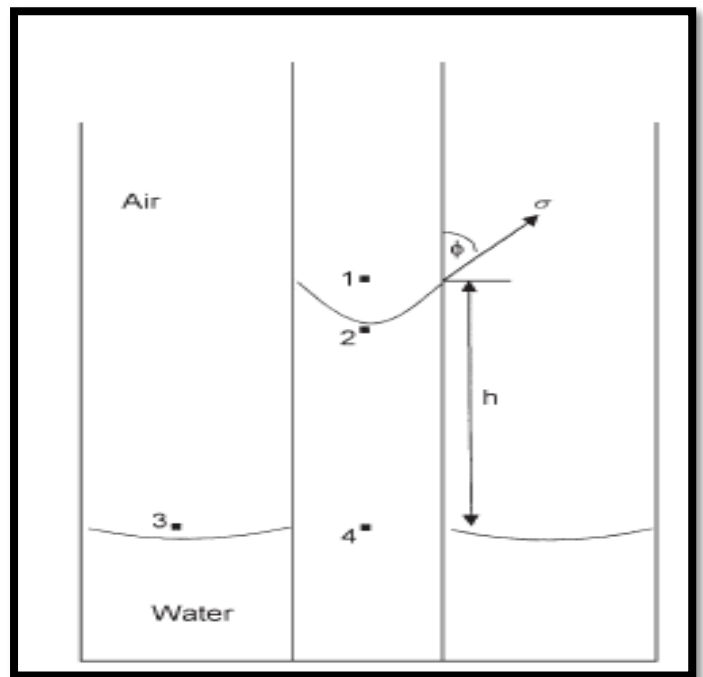**Figure - 12. Illustration of surface tension.**

Fig. (13) Pressure relation in capillary tube.

The water will rise in the tube until the total force acting to pull the liquid upward is balanced by the weight of the column of liquid being supported in the tube. Assuming the radius of the capillary tube is r, the total upward force F_{up}, which holds the liquid up, is equal to the force per unit length of surface times the total length of surface, or

$$F_{up} = (2\pi r)(\sigma_{gw})(\cos \theta) \text{ --- (58)}$$

Where:

σ_{gw} = surface tension between air (gas) and water (oil), dynes/cm

θ = contact angle

r = radius, cm

The upward force is counteracted by the weight of the water, which is equivalent to a downward force of mass times acceleration, or

$$F_{down} = \pi r^2 h(\rho_w - \rho_{air})g \text{ --- (59)}$$

Where:

h = height to which the liquid is held, cm

g = acceleration due to gravity, cm/sec^2

ρ_w = density of water, gm/cm^3

ρ_{air} = density of gas, gm/cm^3 parison with the density of water, Equation **59**

$$F_{down} = \pi r^2 \rho_w g \text{ --- (60)}$$

Equating Equation **58** with **60** and solving for the surface tension gives:

$$\sigma_{gw} = \frac{rh\rho_w\, g}{2\cos\theta} \text{ --- (61)}$$

The generality of Equations **58** through **61** will not be lost by applying them to the behavior of two liquids, i.e., water and oil. Because the density of oil is not negligible, Equation **61** becomes:

$$\sigma_{ow} = \frac{rhg(\rho_w-\rho_o)}{2\cos\theta} \text{ --- (62)}$$

Where:

ρ_o = density of oil, gm/cm^3

$\sigma_{o\omega}$ = interfacial tension between the oil and the water, dynes/cm.

Capillary Pressure

The capillary forces in a petroleum reservoir are the result of the combined effect of the surface and interfacial tensions of the rock and fluids, the pore size and geometry, and the wetting characteristics of the system.

Any curved surface between two immiscible fluids has the tendency to contract into the smallest possible area per unit volume. This is true whether the fluids are oil and water,

water and gas (even air), or oil and gas. When two immiscible fluids are in contact, a discontinuity in pressure exists between the two fluids, which depends upon the curvature of the interface separating the fluids. We call this pressure difference the **capillary pressure** and it is referred to by **pc**.

The displacement of one fluid by another in the pores of a porous medium is either aided or opposed by the surface forces of capillary pressure. As a consequence, in order to maintain a porous medium partially saturated with nonwetting fluid and while the medium is also exposed to wetting fluid, it is necessary to maintain the pressure of the nonwetting fluid at a value greater than that in the wetting fluid. Denoting the pressure in the wetting fluid by p_w and that in the nonwetting fluid by p_{nw}, the capillary pressure can be expressed as:

Capillary pressure = (pressure of the nonwetting phase) - (pressure of the wetting phase)

$p_c = p_{nw} - p_w$ --- **(62)**

That is, the pressure excess in the nonwetting fluid is the capillary pressure, and this quantity is a function of saturation. This is the defining equation for capillary pressure in a porous medium.

There are three types of capillary pressure:

1) Water-oil capillary pressure (denoted as P_{cwo})
2) Gas-oil capillary pressure (denoted as P_{cgo})
3) Gas-water capillary pressure (denoted as P_{cgw})

Applying the mathematical definition of the capillary pressure as expressed by Equation **62**, the three types of the capillary pressure can be written as:

$p_{cwo} = p_o - p_w$ --- **(63)**

$p_{cgo} = p_g - p_o$ --- **(64)**

$p_{cgw} = p_g - p_w$ --- **(65)**

Where:

p_g, p_o, and p_w represent the pressure of gas, oil, and water, respectively.

If all the three phases are continuous, then:

$p_{cgw} = p_{cgo} + p_{cwo}$ --- **(76)**

Referring to **Figure -13**, the pressure difference across the interface between Points **1** and **2** is essentially the capillary pressure, i.e.:

$p_c = p_1 - p_2$ -- **(67)**

The pressure of the water phase at Point **2** is equal to the pressure at point **4** minus the head of the water, or:

$p_2 = p_4 - gh\rho_w$ --- **(68)**

The pressure just above the interface at Point **1** represents the pressure of the air and is given by:

$$P_1 = p_3 - gh\rho_{air} \hspace{2cm} (69)$$

It should be noted that the pressure at Point **4** within the capillary tube is the same as that at Point **3** outside the tube. Subtracting Equation **68** from **69** gives:

$$P_c = gh\,(\rho_w - \rho_{air}) = gh\Delta\rho \hspace{2cm} (70)$$

Where $\Delta\rho$ is the density difference between the wetting and nonwetting phase. The density of the air (gas) is negligible in comparison with the water density.

In practical units, Equation **70** can be expressed as:

$$P_c = \left(\frac{h}{144}\right)\Delta\rho \hspace{2cm} (71)$$

Where:

p_c = capillary pressure, psi

h = capillary rise, ft

$\Delta\rho$ = density difference, lb/ft^3.

In the case of an oil-water system, Equation **70** can be written as:

$$P_c = gh\,(\rho_w - \rho_o) = gh\Delta\rho \hspace{2cm} (72)$$

and in practical units

$$P_c = \left(\frac{h}{144}\right)\Delta\rho \hspace{2cm} (73)$$

$$P_c = \left(\frac{h}{144}\right)(\rho_w - \rho_o) \hspace{2cm} (74)$$

The capillary pressure equation can be expressed in terms of the surface and interfacial tension by combining Equations **70** and **72** with Equations **61** and **62** to give:

▸ **Gas-liquid system**

$$P_c = \frac{2\sigma_{gw}(\cos\theta)}{r} \hspace{2cm} (75)$$

And

$$h = \frac{2\sigma_{gw}(\cos\theta)}{rg(\rho_o - \rho_g)} \hspace{2cm} (76)$$

Where:

ρ_w = water density, gm/cm^3

σ_{gw} = gas-water surface tension, dynes/cm

r = capillary radius, cm

θ = contact angle

h = capillary rise, cm

g = acceleration due to gravity, cm/sec^2

p_c = capillary pressure, dynes/cm^2

▸ **Oil-water system**

$$P_c = \frac{2\sigma_{ow}(\cos\theta)}{r} \quad\text{---} \quad (77)$$

And

$$h = \frac{2\sigma_{ow}(\cos\theta)}{rg(\rho_w - \rho_o)} \quad\text{--} \quad (78)$$

Where:

σ_{wo} = is the water-oil interfacial tension.

Capillary Hysteresis

It is generally agreed that the pore spaces of reservoir rocks were originally filled with water, after which oil moved into the reservoir, displacing some of the water and reducing the water to some residual saturation.

When discovered, the reservoir pore spaces are filled with a connatewater saturation and an oil saturation. designed to duplicate the saturation history of the reservoir. The process of generating the capillary pressure curve by displacing the wetting phase, i.e., water, with the nonwetting phase (such as with gas or oil), is called the **drainage process**. This drainage process establishes the fluid saturations, which are found when the reservoir is discovered. The other principal flow process of interest involves reversing the drainage process by displacing the nonwetting phase (such as with oil) with the wetting phase, (e.g., water). This displacing process is termed the **imbibition process** and the resulting curve is termed the **capillary pressure imbibition curve**. The process of **saturating** and **desaturating** a core with the nonwetting phase is called **capillary hysteresis**. **Figure-14**shows typical drainage and imbibition capillary pressure curves. The two capillary pressure-saturation curves are not the same.
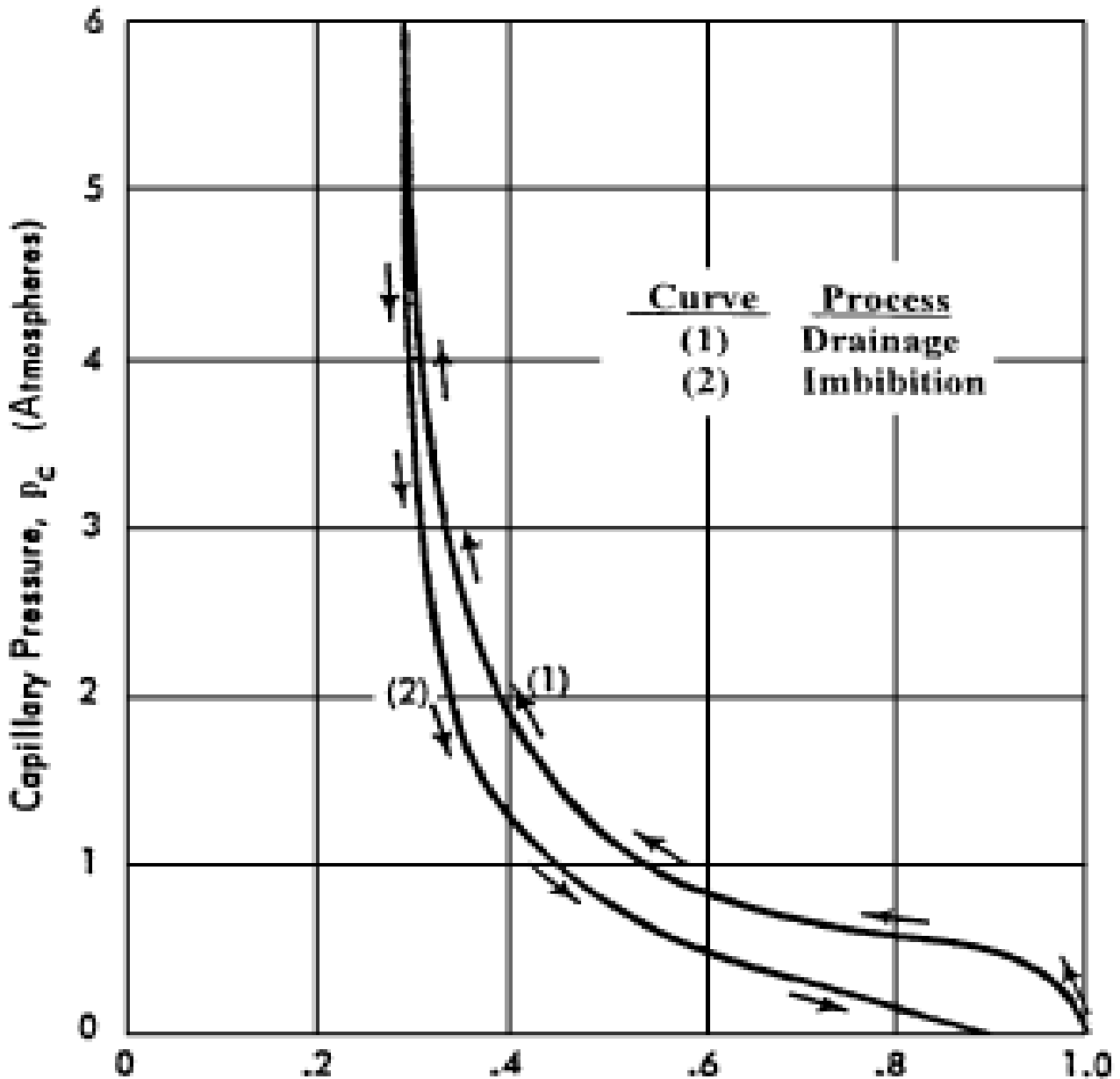
Fig. (14) Capillary pressure hysteresis.

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 by arranging Equation of capillary pressure and solving for the height h above the free- water level.

$$h = \frac{144 P_c}{\Delta \rho} \ \text{---} \quad (79)$$

Figure **15** 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)

It should be noted that there is a difference between the free water level (FWL) and the depth
at which 100% water saturation exists. From a reservoir engineering standpoint, the free
water level is defined by zero capillary pressure. Obviously, if the largest pore is so large that
there is no capillary rise in this size pore, then the free water level and 100% water saturation
level, i.e., WOC, will be the same. This concept can be expressed mathematically by the
following relationship:

$$\text{FWL} = \text{WOC} + \frac{144P_d}{\Delta\rho} \text{ -- (80)}$$
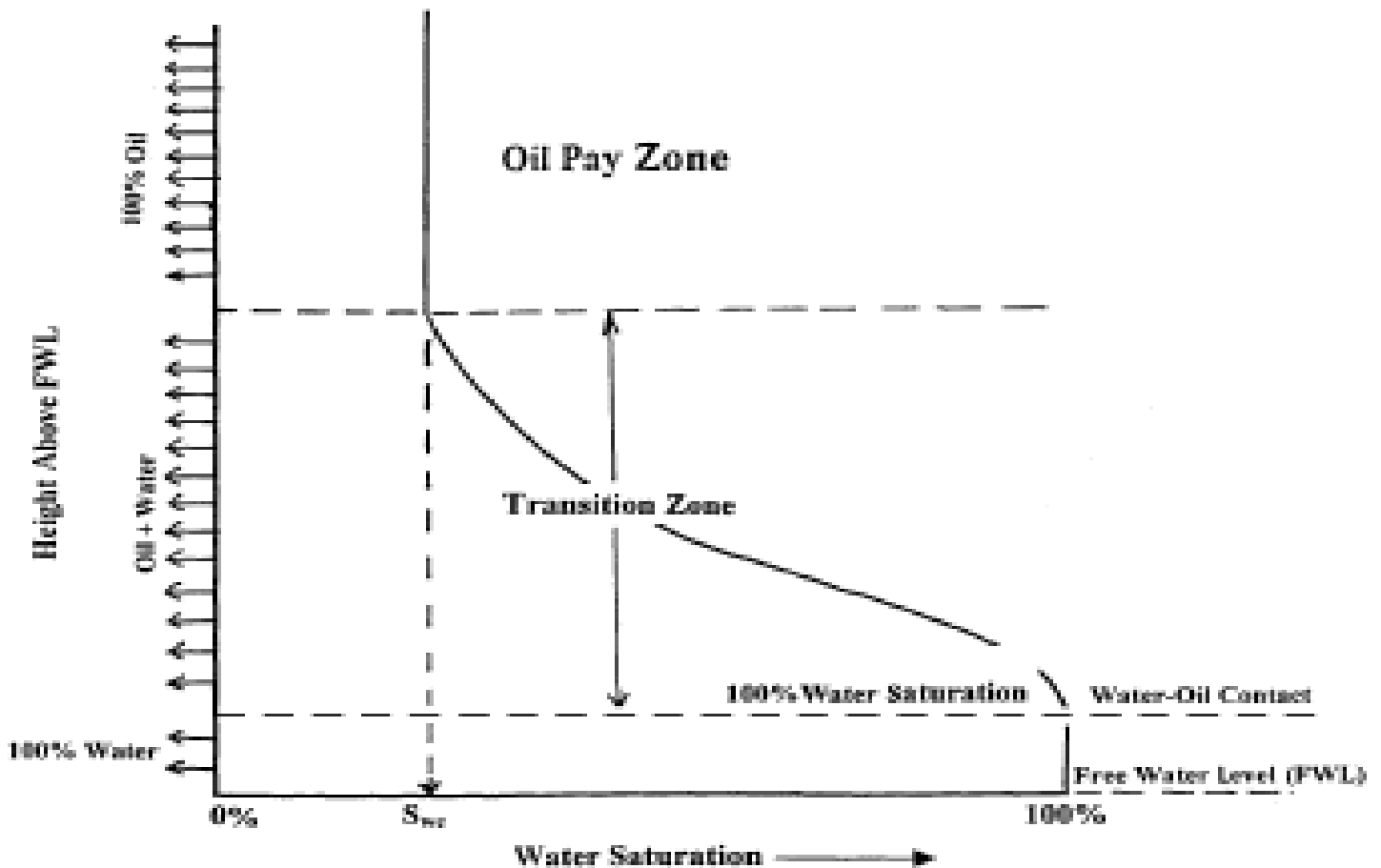
Fig.(15) Water saturation profile.
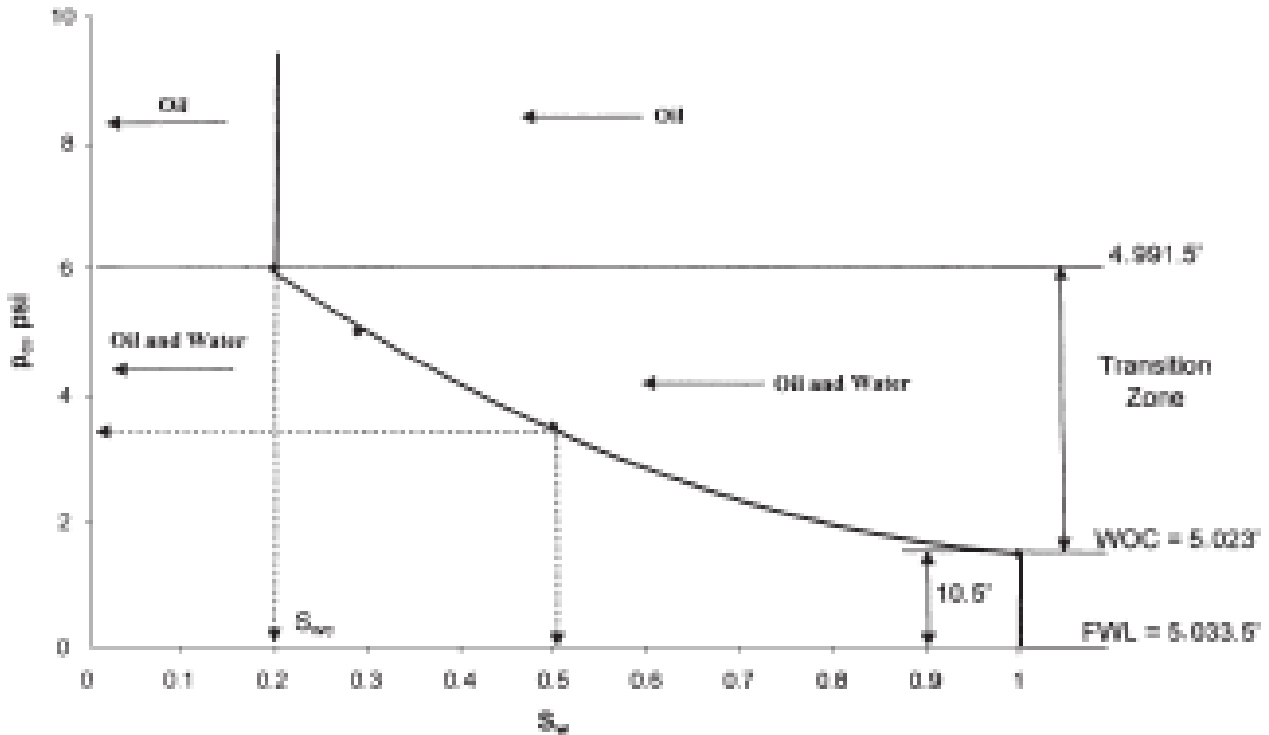
Fig.(16) Capillary pressure saturation data.

Converting Laboratory Capillary Pressure Data

For experimental convenience, it is common in the laboratory determination of capillary pressure to use air-mercury or air-brine systems, rather than the actual water-oil system characteristic of the reservoir. Since the laboratory fluid system does not have the same surface tension as the reservoir system, it becomes necessary to convert laboratory capillary pressure to reservoir capillary pressure. We can calculate reservoir capillary pressure as show below.

$$(Pc)res. = (Pc)lab \frac{\delta res}{\delta lab}$$ -- **(81)**

 Even after the laboratory capillary pressure has been corrected for surface tension, it may be necessary to make further corrections for permeability and porosity. The reason for this is that the core sample that was used in performing the laboratory capillary pressure test may not be representative of the average reservoir permeability and porosity. The reservoir capillary pressure can be expressed as:

$$(Pc)res. = (Pc)lab \frac{\delta res}{\delta lab} \sqrt{(\emptyset res\ Kcore)/(\emptyset core\ Kres)}$$ --------------------------------- **(82)**

Reservoir Temperature and Pressure:

Hydrocarbon accumulations occur in partially sealed structures where the upward migration of oil and gas from the source beds is blocked by an impermeable barrier. Unless subsequent tectonic movements completely seal the reservoir, the underlying waters are contiguous and pressures in the aquifer will approximate to some local or regional hydrostatic gradient. In a water column, the pressure at any depth is approximated to;

$$P = G_w * h$$

Where: h is the depth and Gw is the water pressure gradient.

Although ground waters are saline, temperatures increasing with depth tend to reduce the water density and a common "normal" value of G_w is 0.433 psi/ft (0.1 kg/cm^2/m), which is approximately a fresh water gradient. Gradients within the range 0.43 to 0.5 psi/ft are considered normal. Pressures at the top of a hydrocarbon bearing structure are expected to be higher than the hydrostatic gradient extrapolated from the hydrocarbon/water contact, because of the lower density of hydrocarbon compared with water. Even in thick gas bearing zones, this situation does not usually lead to dangerously abnormal pressures.

Abnormal pressures can occur when some part of the overburden load is transmitted to the formation fluids. Abnormal pressures corresponding to gradients of 0.8 to 0.9 psi/ft and approaching the geostatic gradient (generally taken as approximately equivalent to 1.0 psi/ft) may occasionally be encountered and can be considered dangerously high.
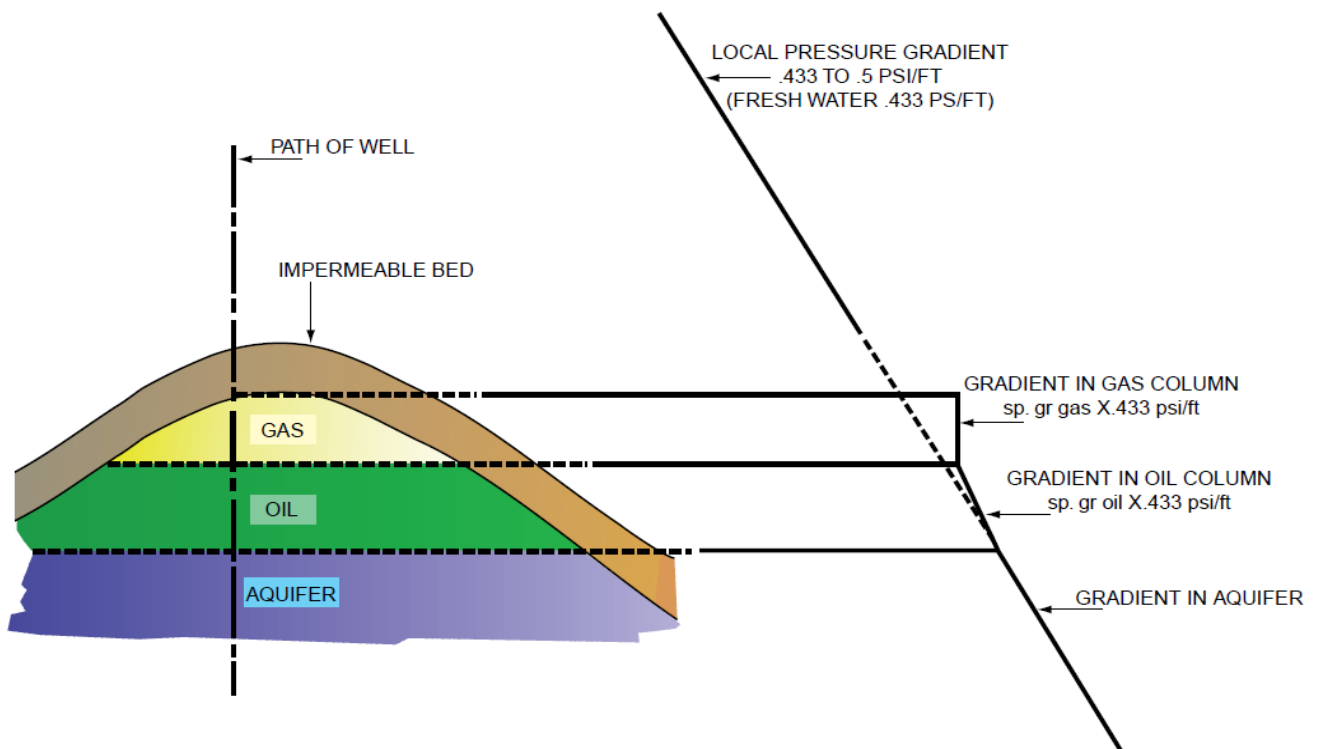
Typical "normal" pressure gradients for the water, oil and gas phases are:

Gw = **0.45** psi/ft,   Go = **0.35** psi/ft,   Gg = **0.08** psi/ft .

The pressure calculated by multiplying the gradient by depth,

The reservoir pressure can then be corrected relative to the hydrostatic pressure by using a constant (C) in the above pressure equations. The constant C accounts for the fact that the reservoir pressure is not in hydrostatic equilibrium, where the pressure in the reservoir is somewhat higher or lower than otherwise expected. Where C is positive when over-pressure is observed and negative for a under-pressured reservoir. In order to evaluate the pressure distribution in a reservoir, let us consider the reservoir which cross-section, as shown in Figure below;
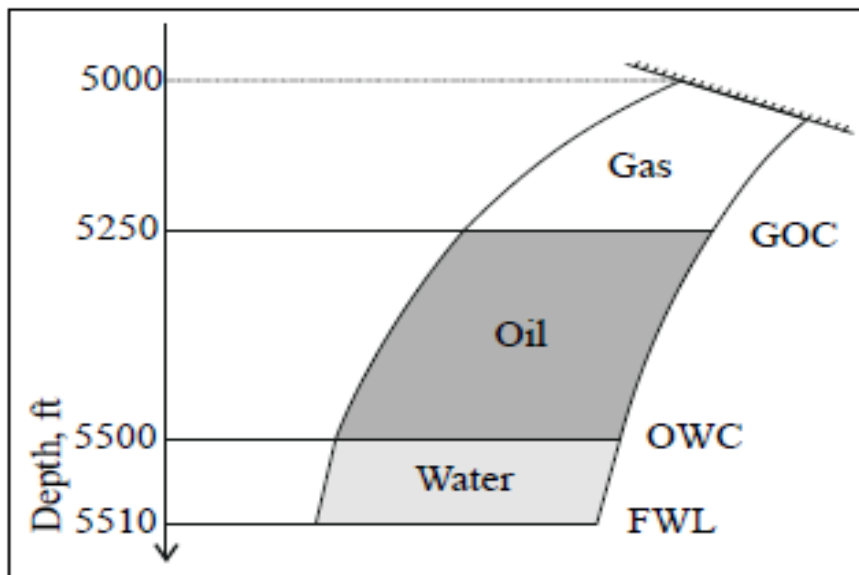
Assuming normal pressure condition, we can evaluate the fluid-phase pressures at the different reservoir levels.

• **Water phase:**

$(P_w)FWL = 0.45 \cdot 5510 + 14.7 = 2494.2$ psia

$(P_w)OWC = 0.45 \cdot 5500 + 14.7 = 2489.7$ psia

$(P_w)GOC = 0.45 \cdot 5250 + 14.7 = 2377.2$ psia

$(P_w)top = 0.45 \cdot 5000 + 14.7 = 2264.7$ psia

• **Oil phase:**

(P_o)FWL $= 0.35 \cdot 5510 + C_o = 2494.2$psia

Which gives: $C_o = 565.7$psia

$\qquad (P_o)$OWC $= 0.35 \cdot 5500 + 565.7 = 2490.7$psia

$\qquad (P_o)$GOC $= 0.35 \cdot 5250 + 565.7 = 2403.2$psia

$\qquad (P_o)$top $= 0.35 \cdot 5000 + 565.7 = 2315.7$psia

• **Gas phase:**

$\qquad (P_g)$GOC $= 0.08 \cdot 5250 + C_g = 2403.2$psia

Which gives: $C_g = 1983.2$psia

(P_g)top $= 0.08 \cdot 5000 + 1983.2 = 2383.2$ psia

The different phase pressures (water, oil and gas) are derived from a common reference which normally is the FWL pressure, (P_w)FWL. At this level there is no pressure difference between water and oil and the two pressures are identical, i.e., (P_w)FWL $= (P_o)$FWL.
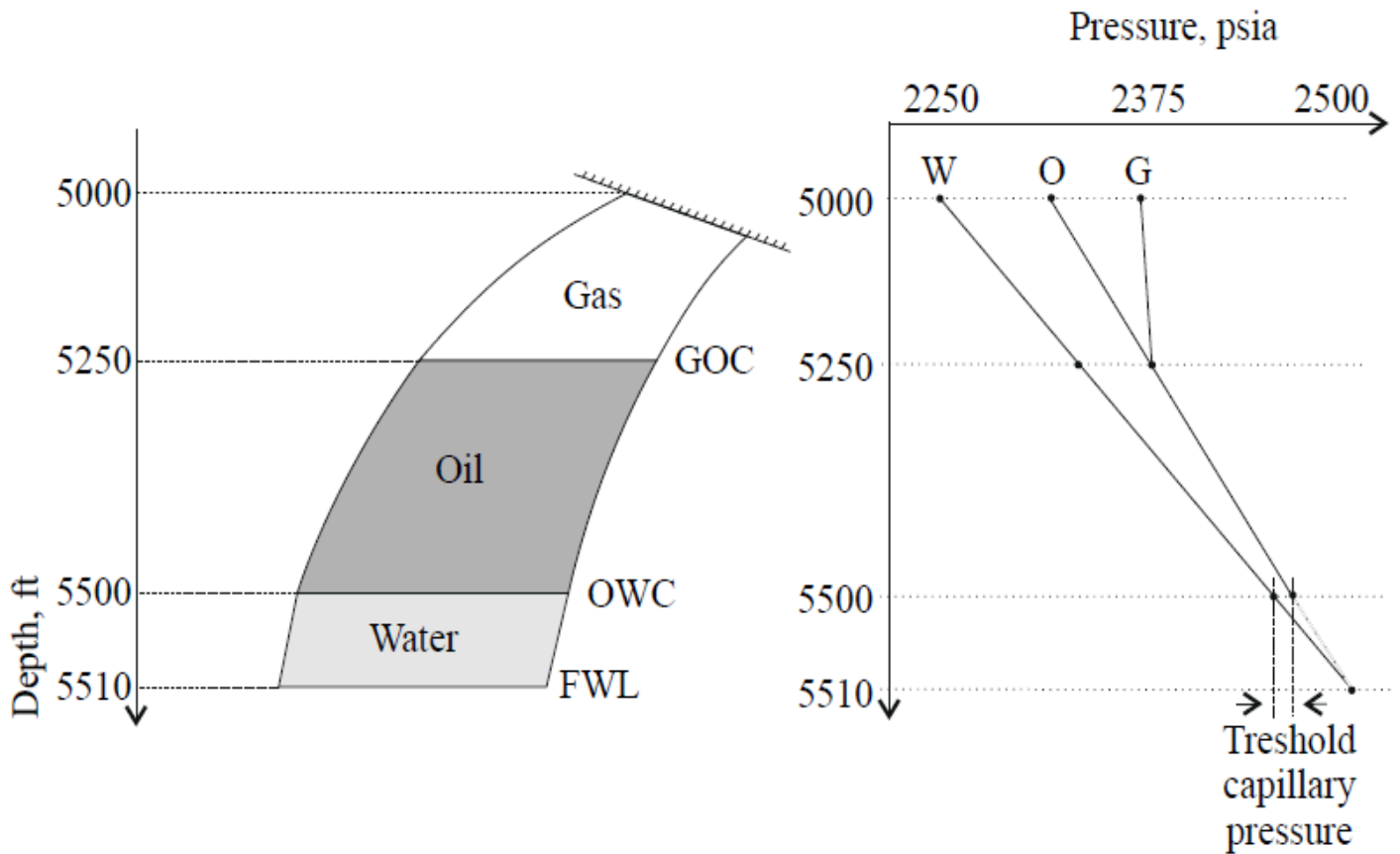
The capillary pressure at the top of the reservoir, shown in Figure above; can be evaluated as follows:

$$(P_c)_{ow}^{top} = (p_o)_{top} - (p_w)_{topt} = 2315.7 - 2264.7 = 51.0 \text{ psi(a)}$$
$$(P_c)_{go}^{top} = (p_g)_{top} - (p_o)_{top} = 2383.2 - 2315.7 = 67.5 \text{ psi(a)}$$
$$(P_c)_{gw}^{top} = (p_g)_{top} - (p_w)_{top} = 2383.2 - 2264.7 = 118.5 \text{ psi(a)}$$

Reservoir temperatures will conform to the regional or local geothermal gradient, a normal value being 1.6 °F/100ft. Because of the large thermal capacity of the rock matrix, which comprises about 80% of the bulk reservoir volume, and the very large area for heat transfer, conditions within the reservoir may be considered isothermal in most cases.
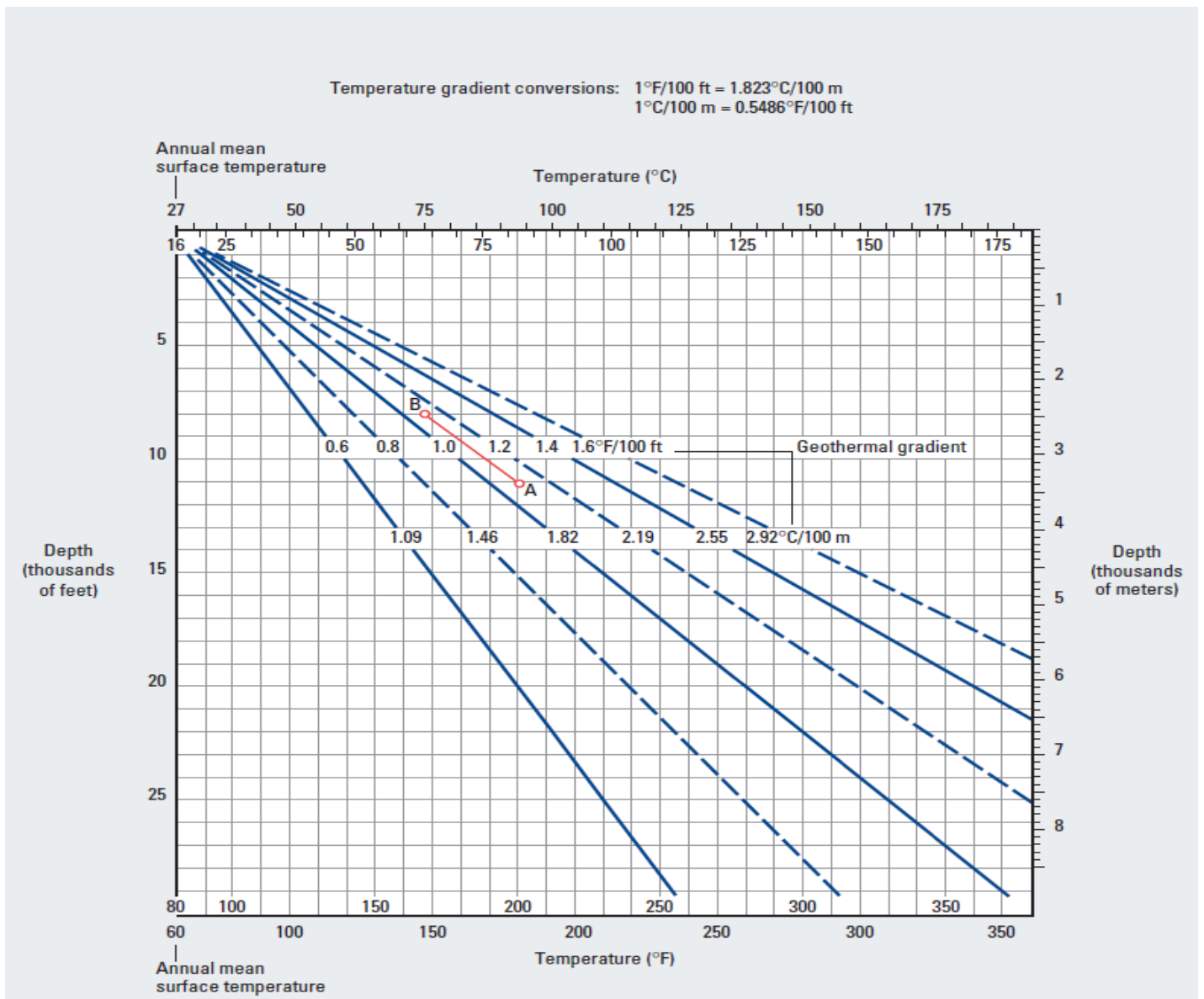
Type of Reservoirs

1-   Oil Reservoir.
  - Contain mainly oil with or without free gas (gas cap).
  - Can be divided into two:
    - Under saturated Oil Reservoir ($P_{res} > P_b$) - no free gas exists until the reservoir pressure falls below the bubble point pressure.
    - Saturated Oil Reservoir ($P_{res} < P_b$) – free gas (gas cap) exists in the reservoir.

2-   Gas Reservoir

Drive Mechanism

The natural energy of the reservoir used to transport hydrocarbons towards and out of the production wells. There are five important drive mechanisms (or combinations).

1) Solution Gas Drive.
2) Gas Cap Drive.
3) Water Drive.
4) Gravity Drainage.
5) Combination or Mixed Drive

A combination or mixed drive occurs when any of the first three drives operate together or when any of the first three drives operate with the aid of gravity drainage.

▶ **Solution Gas Drive**

This mechanism (also known as depletion drive) depends on the associated gas of the oil. The virgin reservoir may be entirely liquid, but will be expected to have gaseous hydrocarbons in solution due to the pressure.
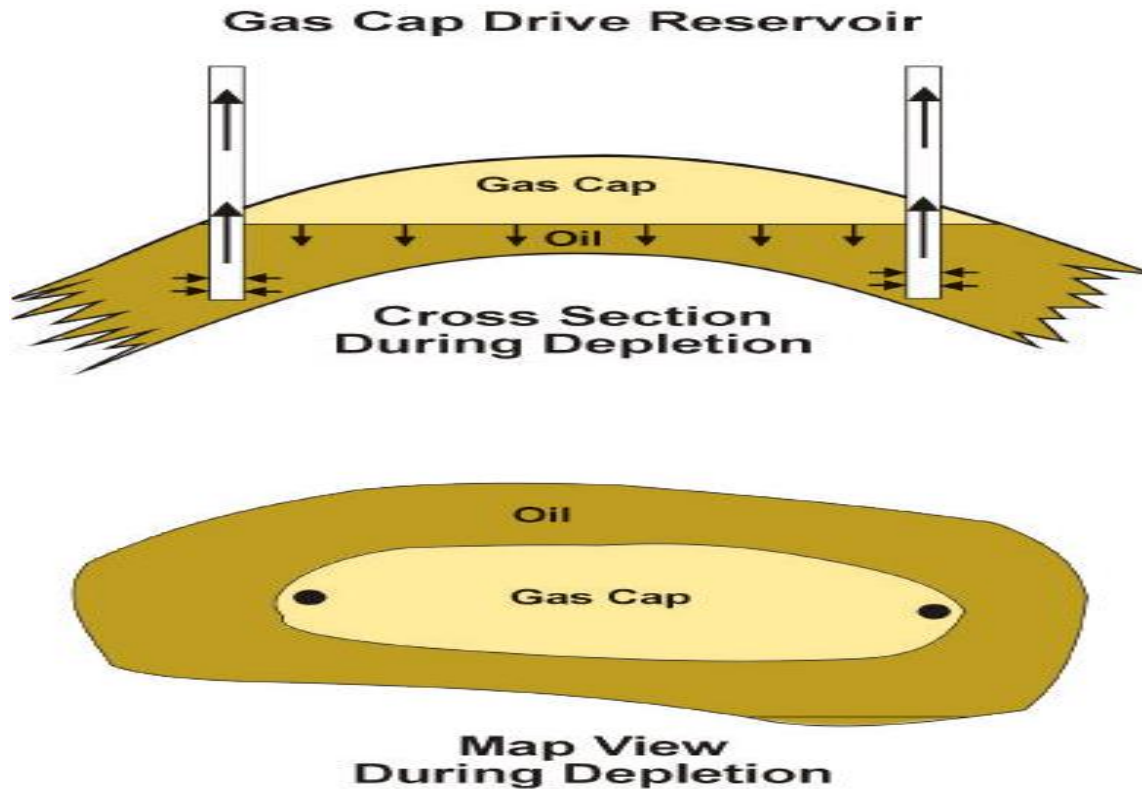
As the reservoir depletes (due to production), the pressure falls below the bubble point, and the gas comes out of solution to form a gas cap at the top. This gas cap pushes down on the liquid helping to maintain pressure.

The exsolution and expansion of the dissolved gases in the oil and water provide most of the reservoirs drive energy.

## Solution Gas Drive Reservoir
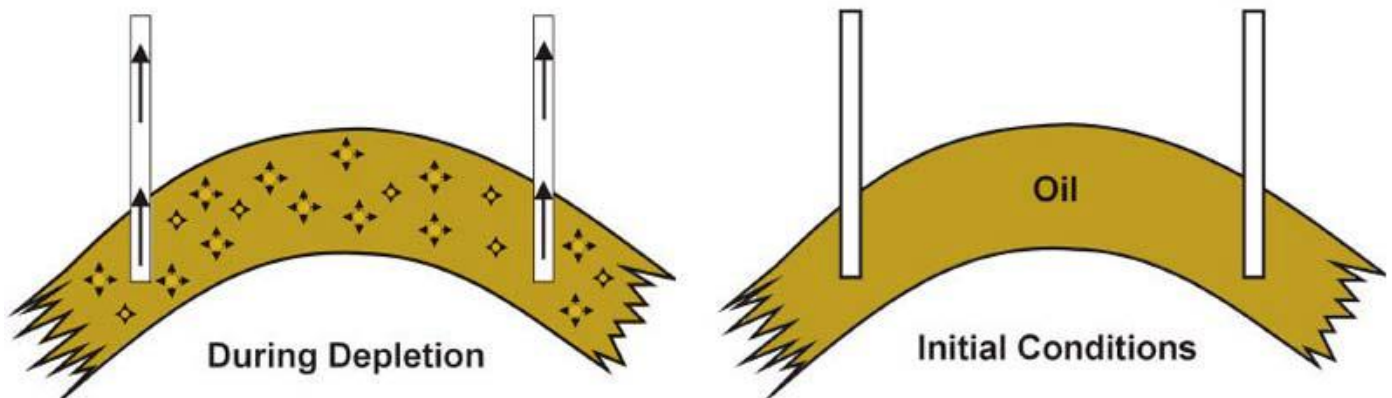
‣ Gas Cap Drive

In reservoirs already having a gas cap (the virgin pressure is already below bubble point), the gas cap expands with the depletion of the reservoir, pushing down on the liquid sections applying extra pressure. The presence of the expanding gas cap limits the pressure decrease experienced by the reservoir during production.

Gas Cap Drive Reservoir

Gas Cap

↓ Oil ↓

**Cross Section
During Depletion**

Oil

Gas Cap

**Map View
During Depletion**

▸ **Water Drive**

The drive energy is provided by an aquifer that interfaces with the oil in the reservoir at the oil-water contact (OWC).

As the hydrocarbons depleted (production continues), and oil is extracted from the reservoir, the aquifer expands slightly. If the aquifer is large enough, this will translate into a large increase in volume, which will push up on the hydrocarbons, and thus maintaining the reservoir pressure. Two types of water drive are commonly recognised: Bottom water drive and Edge water drive.

Water Drive

Bottom Water Drive

Edge Water Drive
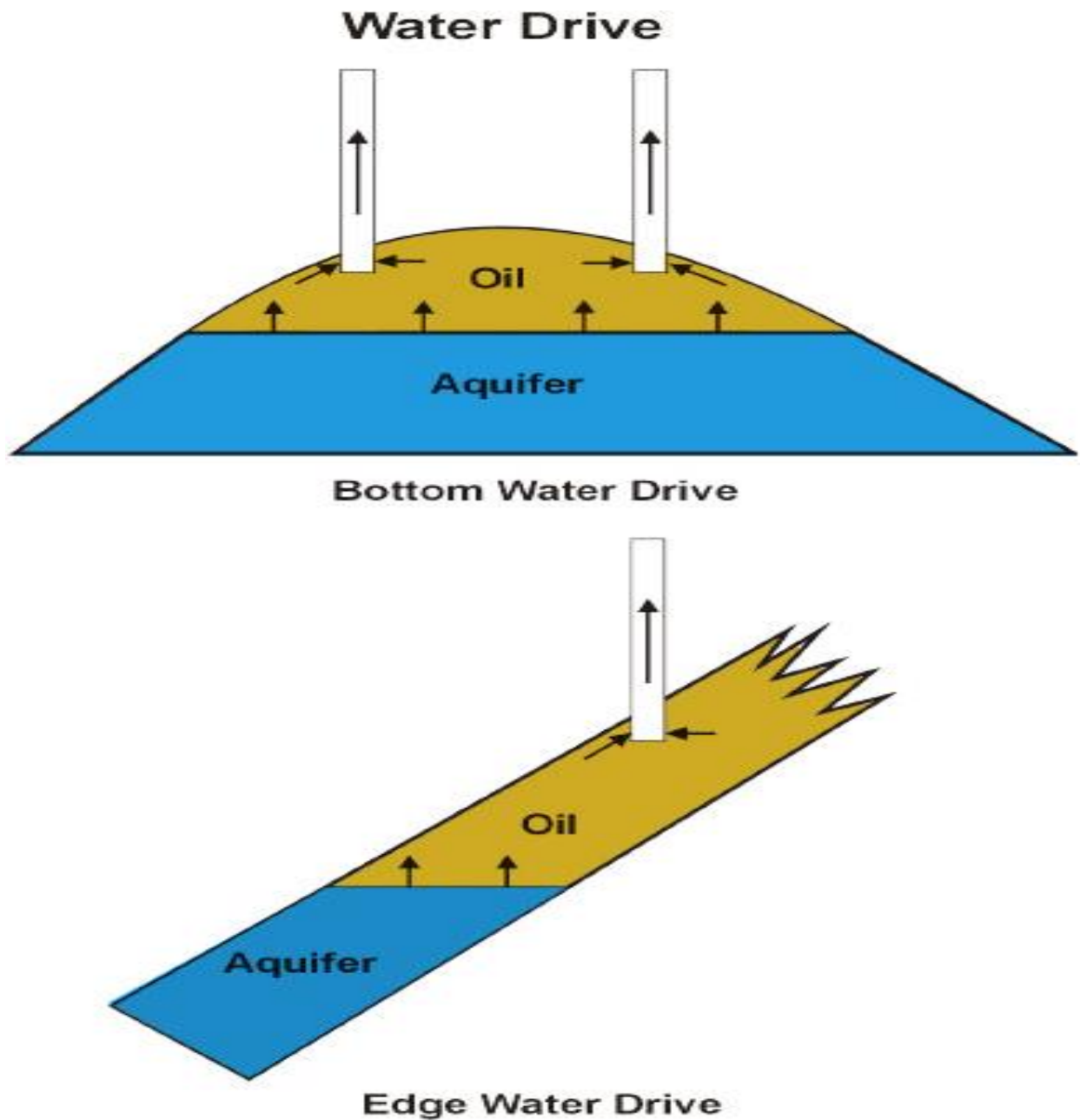
▸ **Gravity Drainage**

The density differences between oil and gas and water result in their natural segregation in the reservoir. This process can be used as a drive mechanism, but is relatively weak, and in practice is only used in combination with other drive mechanisms.
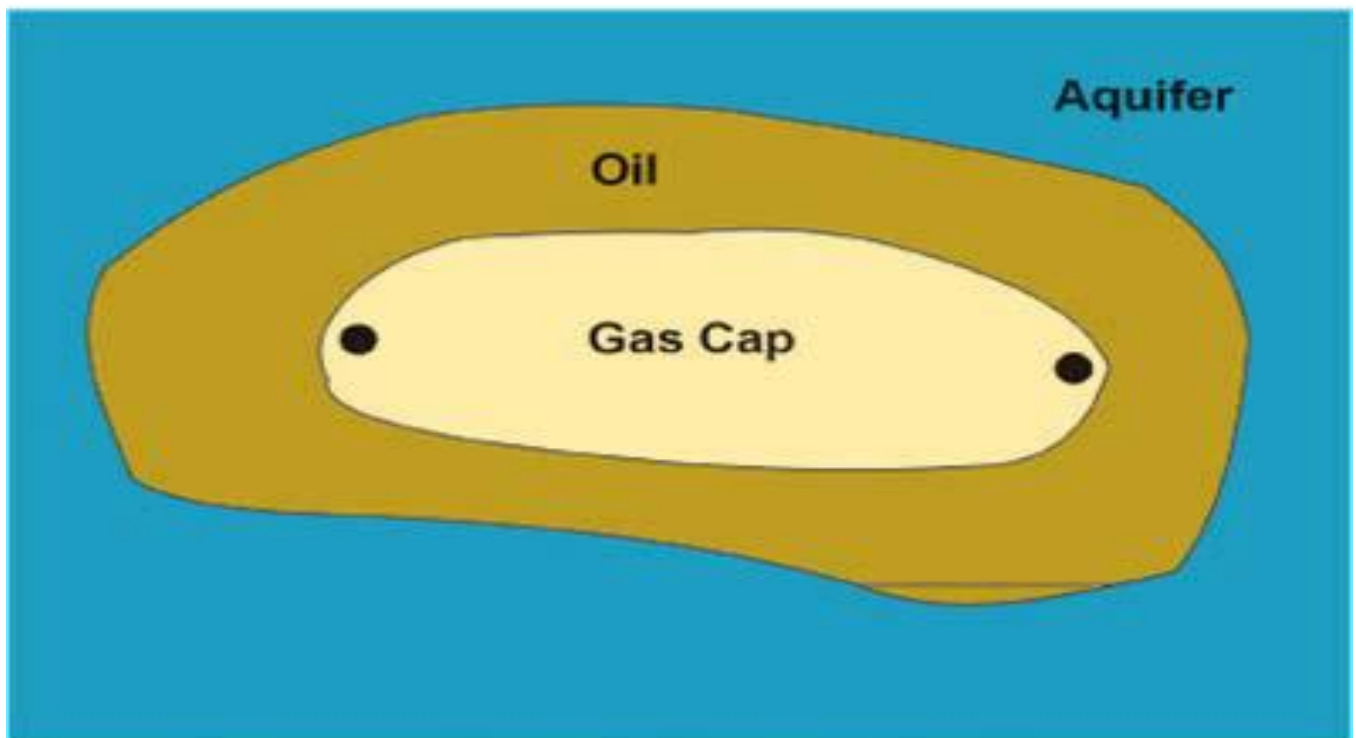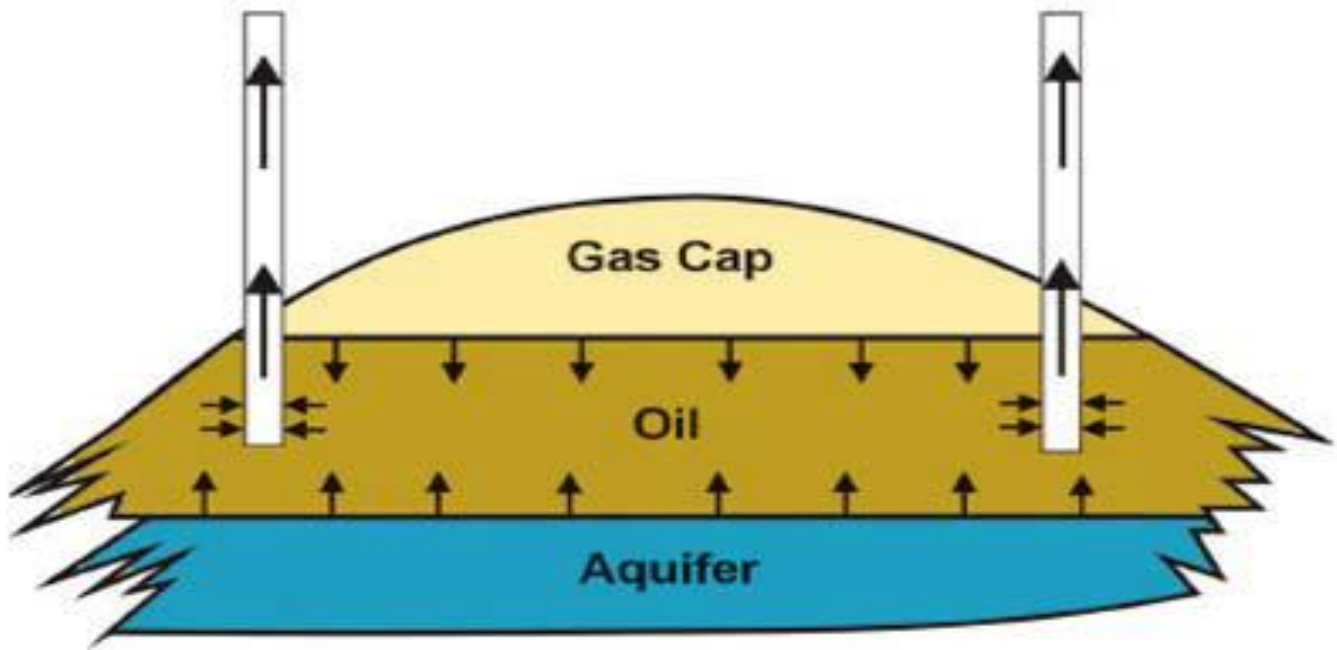
Gravity Drainage
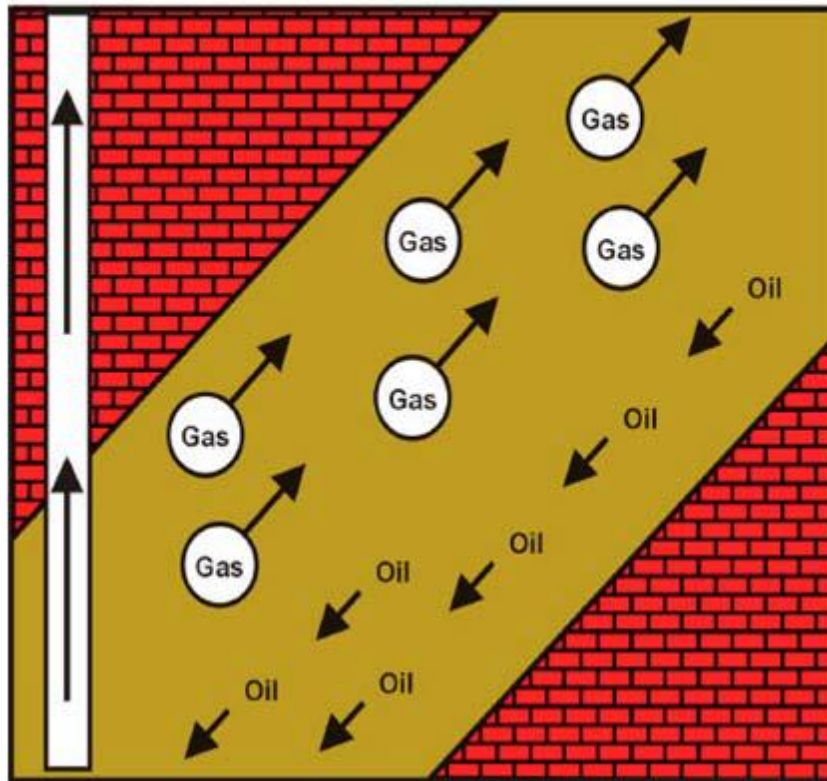
▶ **Combination**

In practice a reservoir usually incorporates at least two main drive mechanisms.

Mixed Drive Reservoir

Map View During Depletion