

## **PETROLEUM RESERVOIRS**

### **GENERATION OF HYDROCARBONS:**

There are three requirements to meet before a petroleum reservoir can exist:

- 1- Hydrocarbon source rock**
- 2- Reservoir rock**
- 3- Hydrocarbon trap**

If any one of these does not exist, the presence of a hydrocarbon reservoir is not possible.

#### **1- Hydrocarbon source rock:**

\*Source rock: A sedimentary rock in which petroleum forms.

The primary theory accepted for the generation of hydrocarbons is that it is formed by organic evolution. Plants and animals complete their life cycles and die, with their organic debris being deposited on the earth's surface. The primary source of these organic depositions is microscopic plant and animal life and the smaller plants and animals within a water environment.

Significant organic sedimentation occurs primarily in a water environment. As this organic debris is deposited, other materials are also deposited which, through lithification, will lead to the formation of sedimentary rocks such as shale and limestone. With continuing sedimentation and increasing overburden pressures due to increasing weight, sediments containing the organic debris move deeper into the earth. With increasing depth, temperature increases, geologic time passes, and chemical action occurs, converting the organic debris into hydrocarbons.

The same four factors (pressure, temperature, time, and chemical action) which lead to lithification of the sediments forming solid rock are also converting organic materials into hydrocarbons. Source rock is defined as rock formed through lithification, from original sediments containing

organic debris. In most geologic situations, the resultant hydrocarbons formed have been forced out of the sediments during lithification. For example, shale is one of the dominant source rocks for hydrocarbon (behave as excellent seals), yet is seldom ever a rock from which hydrocarbon can be produced. Once lithification has been completed to form the shale, any hydrocarbons remaining will be trapped within the sedimentary bed and cannot be produced.

In order for hydrocarbons to be generated from organic deposition, temperatures must rise above 104°F (40°C) but not exceed 662°F (350°C). Higher temperatures than these will destroy any remaining organic materials or hydrocarbons already generated. This temperature range illustrated in (Figure 1) is called the hydrocarbon temperature window. In order for hydrocarbons to be generated, a proper sequence of geologic events and conditions must occur.

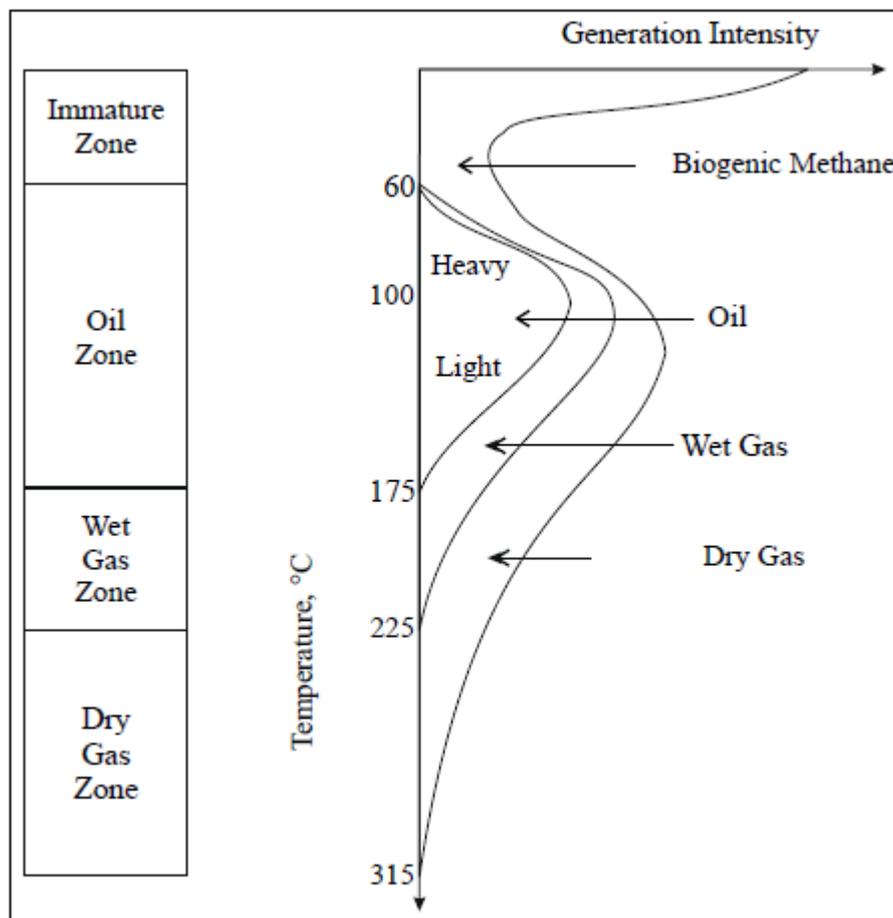


Figure (1) Temperature Window for Generating Hydrocarbons

Most major source rocks are shale's and biogenic limestone's. Coal may also be considered as a source rock, even though it is present in relatively

small quantities within the earth when compared to shale's and biogenic limestone's. Essentially all shale's and limestone's result from water deposition.

## **2- Reservoir Rock:**

The term "reservoir" implies storage. Reservoir rock is rock where hydrocarbons are stored and from which they can be produced. This reservoir rock may or may not be source rock. The fluids of the subsurface migrate according to density. The dominant fluids in hydrocarbon regions are hydrocarbon gas, hydrocarbon liquids, and salt water. Since hydrocarbons are the less dense of these fluids, they will tend to migrate upward, displacing the heavier salt water down elevation. Hydrocarbons may therefore be forced from their source rock during lithification, and migrate into the reservoir rock in which they are stored. The fluids present will separate according to density as migration occurs. In order for a rock to be a potential reservoir rock, two properties, porosity and permeability, must exist of sufficient magnitudes to justify economic development of the hydrocarbon reservoir.

The three sedimentary rock types most frequently encountered in oil fields are shales, sandstones, and carbonates will be discussed.

### **Shales –Source Rocks and seals:**

#### **Description:**

Dark brown to black in color, with smooth lateral surface (normal to depositional direction).

#### **Properties:**

- Composed of clay and silt sized particles.
- Clay particles are platy and oriented themselves normal to induced stress (overburden).
- Behave as excellent seals.
- Widely regarded to be the main source for hydrocarbons due the original composition being rich in organics.

## Sandstones and Sandstone Reservoirs:

### Description:

Composed of sand-sized particles, light beige to tan in color; can also be dark brown to rusty red.

### Properties:

- Sandstone porosity is on the range of 10-30%, (figure 2).
- Intergranular porosity is largely determined by sorting (primary porosity).
- Poorly indurated sandstones are referred to as fissile (easily disaggregated when scratched), whereas highly indurated sandstones can be very resistant to weathering and erosion.

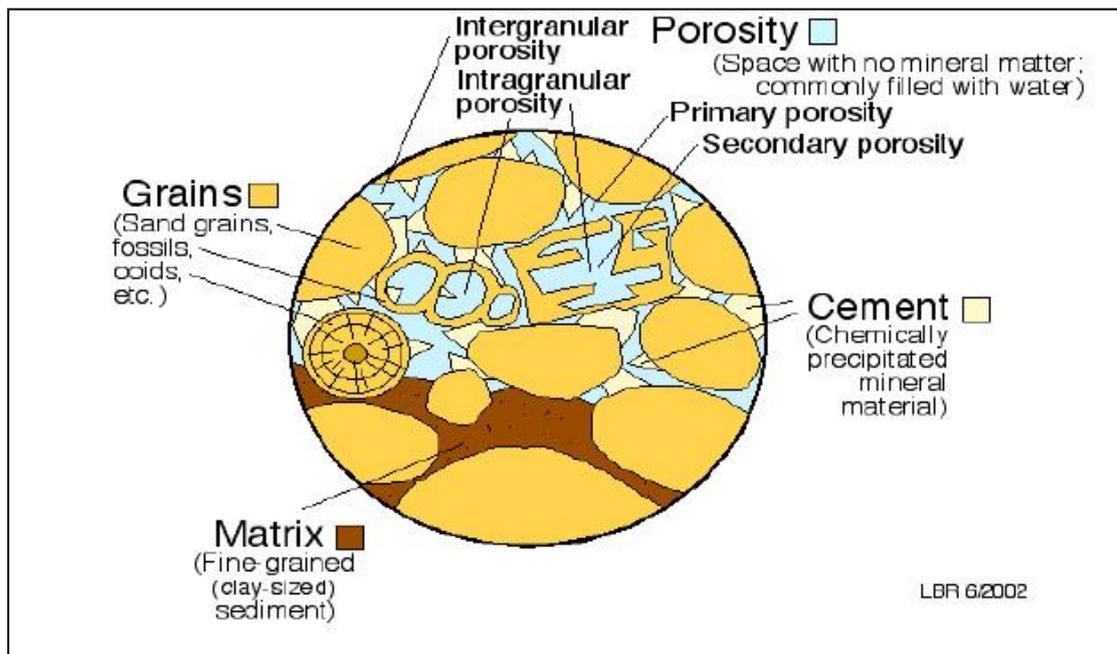
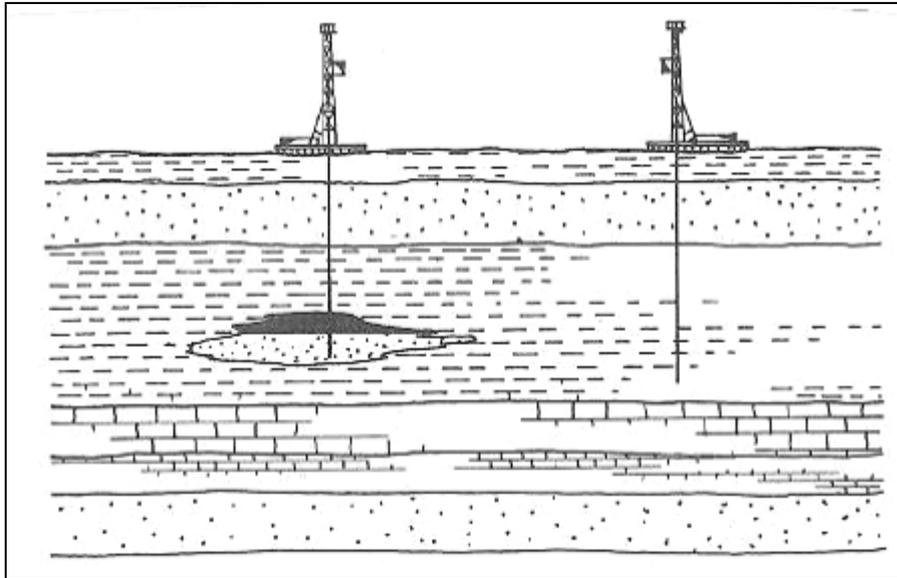


Figure (2) illustrate the grains, matrix and porosity of sedimentary rocks

*Example of sandstone reservoir (Sallyards and Lamont, Southern Kansas, USA)*



Cross-section of the earth's crust showing a sandstone reservoir encrusted in a shale layer

### **Carbonates and Carbonate Reservoirs:**

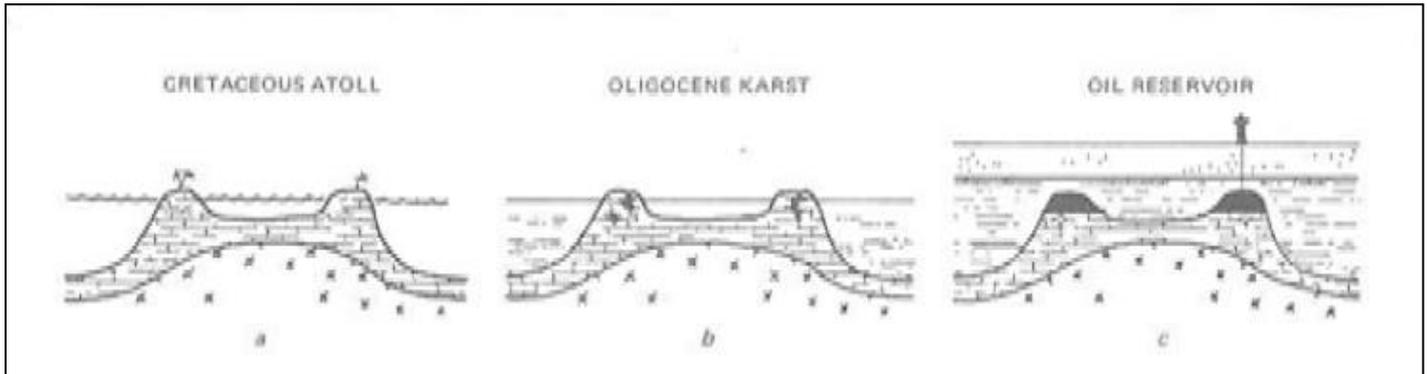
Description:

Grains are the skeletal or shell remains of shallow marine organisms, varying in size and shape, that either lived on the sea bottom (benthic) or floated in water column (neritic). Usually light or dark gray, vuggy (vugular) porosity.

Properties:

- Porosity is largely a result of dissolution and fracturing (secondary porosity).
- Carbonates such as coquina are nearly 100% fossil fragments (largely primary porosity).
- Are characteristically hard rocks, especially dolomite.
- Susceptible to dissolution weathering.

*Example of carbonate reservoir (Golden Lane oil field, Mexican city, Tuxpan)*



Cross-sections showing the formation of Golden Lane oil field (a) Deposition of a large Cretaceous atoll of limestone that is then buried in the subsurface; (b) Erosion of the overlying sediments during the Oligocene to expose the atoll and dissolve it; (c) the Golden Lane oil field with the oil in the karst limestone.

Reservoir rock (as early mentioned is a permeable subsurface rock that contains petroleum) must be both porous and permeable.

### **Porosity:**

Porosity is defined as the percentage of the total volume (bulk volume) of the rock that is void space. This volume is often referred to as the pore volume. Porosity is normally represented by the Greek letter  $\phi$  and is an indication of the potential storage space for hydrocarbons within the rock structure itself.

Assume that the a well which discovered a hydrocarbon reservoir was drilled vertically, and a vertical core was taken through the rock containing the hydrocarbons (the reservoir rock). A core is a rock cylinder, normally 4" to 6" in diameter, ideally taken through the entire thickness of the reservoir rock containing the hydrocarbons. This core is retrieved to the surface and transported to the core laboratory for analysis. It is determined from the core analysis of the core from the discovery well for Our Reservoir that the rock containing this hydrocarbon reservoir is a Permian Beach Sandstone with  $\phi = 22\%$ . This provides information indicating that this rock was originally deposited as a beach sand during the Permian Period of geologic time (approximately 200 to 235 million years ago) and, during the passage of time since its original deposition,

lithification occurred, changing the original beach sand sediment into sandstone.

Based on the core analysis, 22% of the total volume of this rock is void space. Note that this determination is made based on a core analysis from a single well. The porosity may not be uniform over the entire hydrocarbon reservoir.

Consider a cube of this beach sandstone  $10\text{ m} * 10\text{ m} * 10\text{ m}$ , as it exists naturally in the reservoir at reservoir conditions. Its total volume is  $1,000\text{ m}^3$  and, with  $\phi = 22\%$ , there will be  $220\text{ m}^3$  of void space within this cube. For a typical reservoir rock such as sandstone, these void spaces will be extremely small in size. It is common for sandstones to have porosities in the range of 20% to 30%.

### **Carbonate pore type classification:**

Pore systems in carbonates are much more complex than siliciclastics . This complexity is a result of the overwhelming biological origin of carbonate sediments and their chemical reactivity. In carbonate sediment the shape of the grains and the presence of intragrain porosity as well as sorting have a large effect on porosity.

Porosity reduction is complex and can involve cementation, compaction, or combinations of the two. Some studies show that porosity in carbonate reservoirs is reduced by a factor of 2 during burial to a depth of 1740 m.

**Jerry Lucia (1995)** classified the vuggy pore space to **interparticle pore space** alters the petrophysical characteristics by altering the manner in which the pore space is connected, all pore space being connected in some fashion. Separate vugs are defined as **pore space** that is interconnected only through interparticle pore space. Touching vugs are defined as pore space that forms an interconnected pore system independent of interparticle pore space (figure 3).

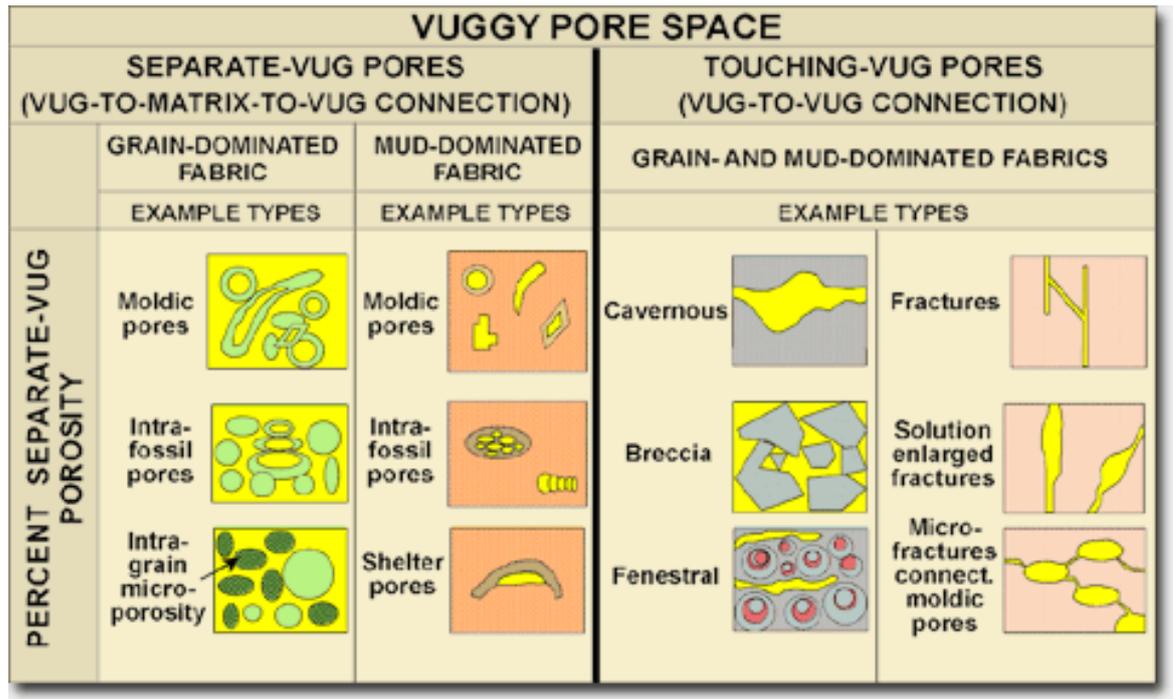
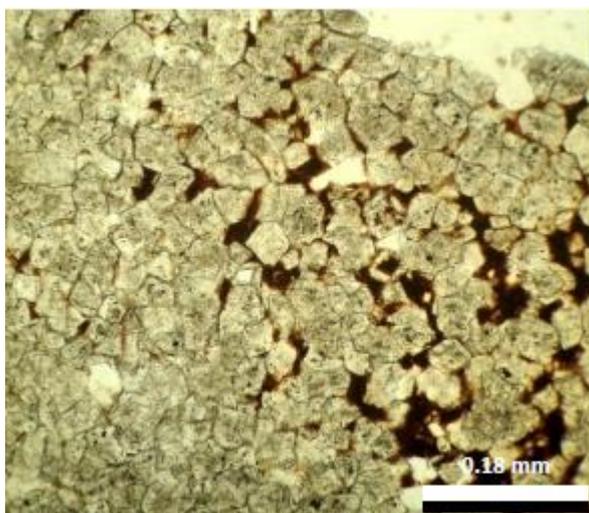


Figure (3) Geological/petrophysical classification of vuggy pore space based on vug interconnection (Lucia, 1995).

**Example:**

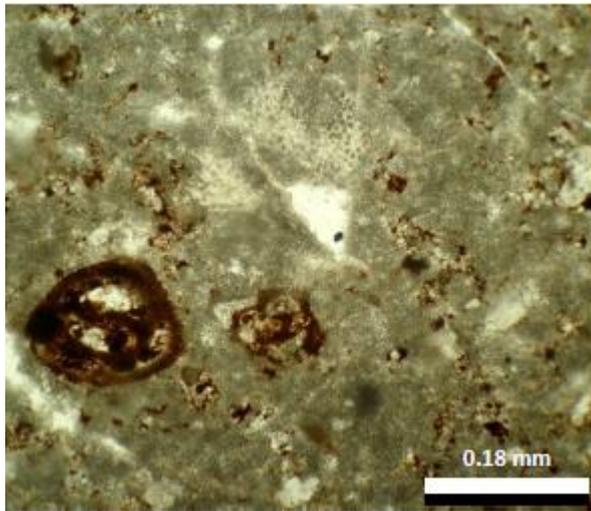
According to the classification models of (Lucia, 1995); AL-Zaidy, 2010 recognized the following types of porous system within the Qamchuqa Formation from NE, Iraq:

**1. Intercrystal porosity** is the porosity between crystals that may be secondary origin.

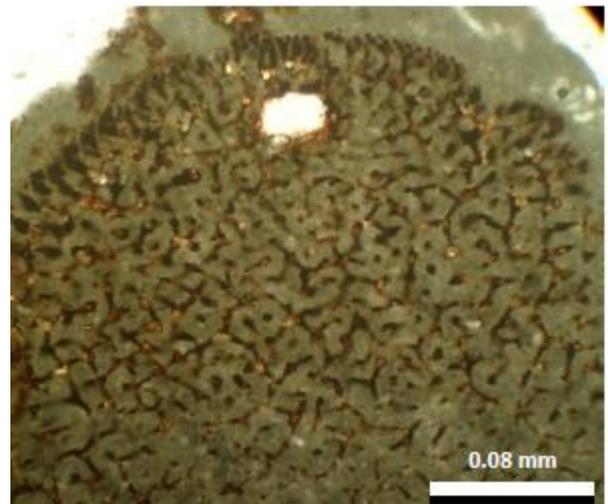


Intercrystalline pores in dolomite.

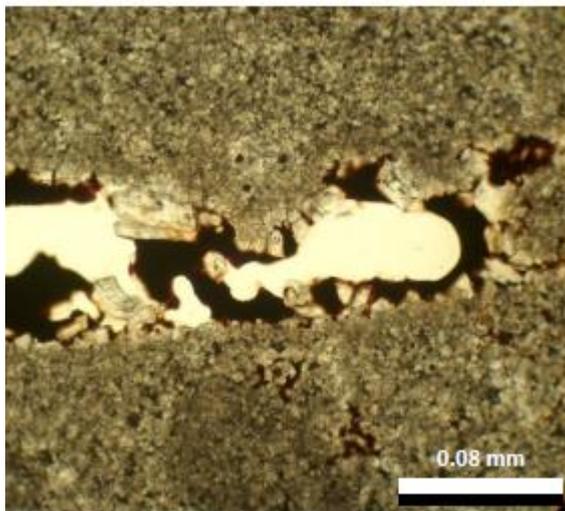
**2. Vuggy pores** are secondary solution pores that are touching-vug pore system, i.e. they are interconnected.



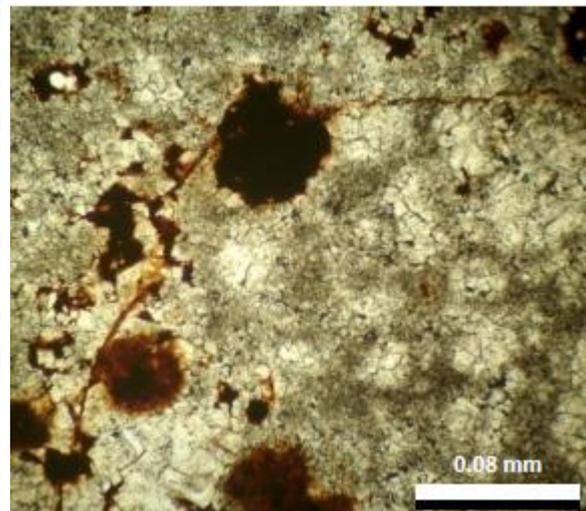
Separate vug pores, moldic type.



Separate vug pores, Intrafossils type.

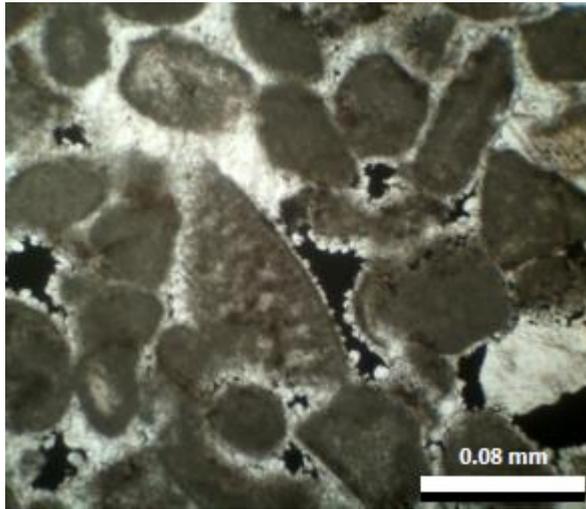


Touching vug pores, cavern type.



Touching vug pores, microfractures connecting moldic type.

**3. Interpartical pores** are pore spaces occurring within grains, either of primary origin or formed through the decay of organic material in carbonate skeletons.



Interpartical pores in grainstone.



Core sample showing vug pores.

Porosity in carbonate reservoirs ranges from 1-35 %; and can be obtained from logs such as **sonic log, density log or neutron log and resistivity log**. For all these devices, the tool response is affected by the formation porosity, fluid and matrix. If the fluid and matrix effects are known or can be determined, the tool response can be determined and related to porosity. Therefore, these devices are usually referred to as **porosity logs**.

### Density logs

Density is measured in grams per cubic centimeter,  $\text{g/cm}^3$  (or  $\text{Kg/m}^3$  or  $\text{Mg/m}^3$ ), and is indicated by the Greek letter  $\rho$  (rho). Two separate density values are used by the density log: **the bulk density** ( $P_b$  or RHOB) and the **matrix density** ( $P_{ma}$ ). The bulk density is the density of the entire formation (solid and fluid parts) as measured by the logging tool. The matrix density is the density of the solid framework of the rock. It may be thought of as the density of a particular rock type (e.g., limestone) that has no porosity.

Porosity is derived from the bulk density of clean liquid-filled formations when the matrix density  $P_{ma}$  and the density of the saturating fluids  $P_f$  are known.

$$\Phi_{\rho} = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_f)}$$

Where

$\Phi_{\rho}$  = Porosity by density log (Fig 4)

$\rho_b$  = formation bulk density (the log reading)

$\rho_f$  = fluid density (Salt water 1.16)

$\rho_{ma}$  = matrix density (Table 1)

The matrix density can be calculated by following equation

$$\rho_{ma} = \frac{\rho_b - \Phi_{n.d} * \rho_f}{1 - \Phi_{n.d}}$$

$\Phi_{n.d}$  = Neutron-density porosity

Table (1) Matrix densities values of common lithologies (Asquith and Krygowski, 2004).

Lithology/ Fluid	$\rho_{ma}$ or $\rho_{fl}$ g/cm <sup>3</sup> [Kg/m <sup>3</sup> ]
Sandstone	2.644 [2644]
Limestone	2.710 [2710]
Dolomite	2.877 [2877]
Anhydrite	2.960 [2960]
Salt	2.040 [2040]
Fresh water	1.0 [1000]
Salt water	1.15 [1150]

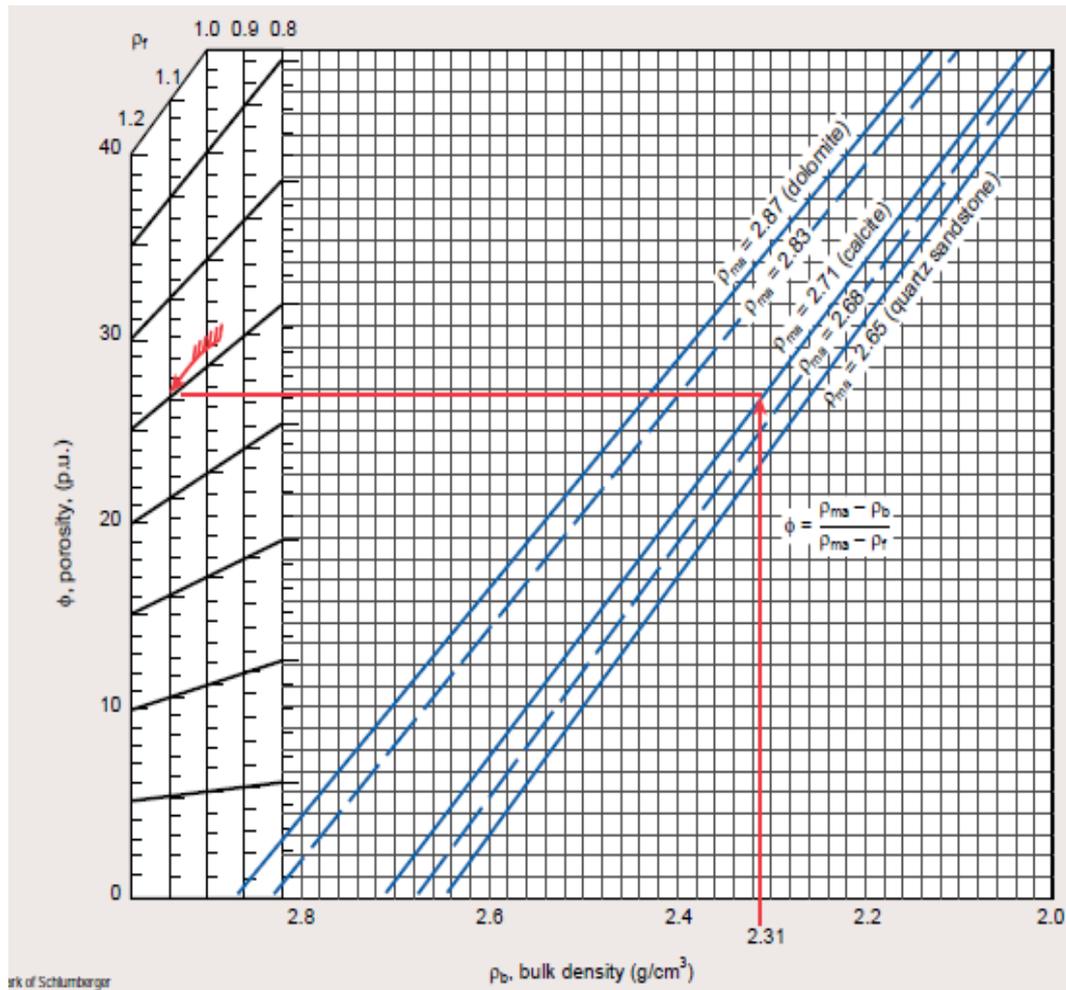


Figure (4) Chart for converting bulk density ( $P_b$ ) to density porosity ( $\phi \rho$ ).

note: p.u. means porosity unit (1 pu= 1%)

Bulk density,  $P_b$ , as recorded with the FDC (Compensated Formation Density or Litho-Density) logs, is converted to porosity with this chart. To use, enter bulk density, corrected for borehole size, in abscissa (X axis) ; go to the appropriate reservoir rock type and read porosity on the appropriate fluid density,  $\rho_f$ , scale in ordinate (Y axis). ( $\rho_f$  is the density of the fluid saturating the rock immediately surrounding the borehole—usually mud filtrate.)

**Example:**  $P_b = 2.31 \text{ g/cm}^3$  in limestone lithology

$\rho_{ma} = 2.71$  (calcite)

$\rho_f = 1.1$  (salt mud)

Therefore,  $\phi_D = 25 \text{ p.u.}$

### Sonic logs

The sonic tool measures the interval transit time (t) or the time in microseconds for an acoustic wave to travel through 1 foot (or 1 m) of a formation along a path parallel to the borehole. The interval transit time ( $\Delta t$ ) is dependent upon both lithology and porosity. Therefore, a formation's matrix interval transit time (Table 2) must be known to derive sonic porosity either by chart (Figure 5) or by the following formulas:

$$\Phi_s = \frac{\Delta t_{log} - \Delta t_{maa}}{\Delta t_{fl} - \Delta t_{maa}} \quad \text{(Wiley Time-average formula)}$$

$\Phi$  = sonic-derived porosity

$\Delta t_{log}$  = interval transit time in the formation

$\Delta t_{fl}$  = interval transit time in the fluid in the formation (freshwater mud = 189  $\mu$ sec/ft; saltwater mud= 185  $\mu$ sec/ft).

$\Delta t_{maa}$  = interval transit time in the formation, we can get the matrix velocity values by using the table (2) or by using the equation

$$\Delta t_{maa} = \frac{\Delta t_{log} - \Phi_{n.s} * \Delta t_{fl}}{1 - \Phi_{n.s}}$$

$\Phi_{n.s}$  = neutron-sonic crossplot porosity

Table (2) Sonic Velocities and Interval Transit Times for Different Matrixes. These constants are used in the sonic porosity formulas above (Schlumberger, 1972).

Lithology/ Fluid	Matrix velocity ft/sec	$\Delta t_{matrix}$ or $\Delta t_{fluid}$ (Wyllie) $\mu$ sec/ft [ $\mu$ sec/m]	$\Delta t_{matrix}$ (RHG) $\mu$ sec/ft [ $\mu$ sec/m]
Sandstone	18,000 to 19,500	55.5 to 51.0 [182 to 168]	56 [184]
Limestone	21,000 to 23,000	47.6 [156]	49 [161]
Dolomite	23,000 to 26,000	43.5 [143]	44 [144]
Anhydrite	20,000	50.0 [164]	
Salt	15,000	66.7 [219]	
Casing (iron)	17,500	57.0 [187]	
Freshwater mud filtrate	5,280	189 [620]	
Saltwater mud filtrate	5,980	185 [607]	

The interval transit time ( $\Delta t$ ) of a formation is increased due to the presence of hydrocarbons (i.e., hydrocarbon effect). If the effect of hydrocarbons is not corrected, the sonic-derived porosity is too high. Hilchie (1978) suggests the following empirical corrections for hydrocarbon effect:

$$\Phi = \Phi_s * 0.7 \text{ ————— } gas$$

$$\Phi = \Phi_s * 0.9 \text{ ————— } oil$$

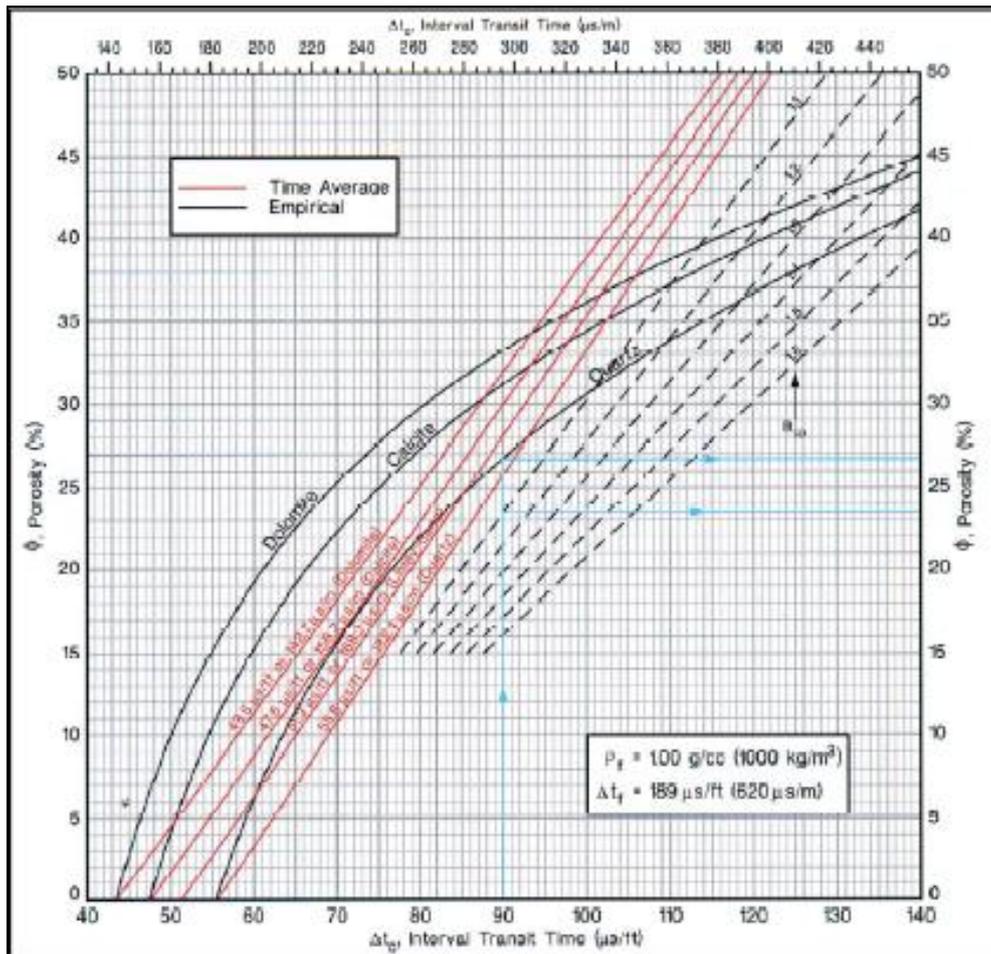


Figure (5) chart for converting interval transit time ( $\Delta t$ ) to sonic porosity ( $\phi_s$ ). Straight lines are corresponding to Wiley formula and curved lines are related to Rimmer equation

## Primary and secondary porosity

The neutron and density logs are responses to pores of all sizes. However, field observation over many years has shown that the sonic log is a measure of interparticle (intergranular and intercrystalline) porosity but is largely insensitive to either fractures or vugs (Doveton, 1999). When sonic porosities are compared with neutron and density porosities, the total porosity can be subdivided between **primary porosity** (interparticle porosity) recorded by the **sonic log** and **secondary porosity** (vugs and/or fractures) computed as the **difference between the sonic porosity and the neutron and/or density porosity** (Schlumberger, 1997). Typically, moderate values in secondary porosity are caused by vugs, because fracture porosity does not usually exceed 1 to 2% by volume (Doveton, 1999).

To calculate the secondary porosity, we use the equation below by Schlumberger (1997):-

$$SPI = (\Phi_{n.d} - \Phi_s)$$

$SPI$  = Secondary porosity index

$\Phi_{n.d}$  = density and neutron porosities combination

$\Phi_s$  = sonic-derived porosity

## Resistivity Logs

Resistivity is, perhaps, the most fundamental of all measurements in logging. All materials possess some amount of resistance, or the inherent ability to resist the flow of an electrical current.

Resistivity (R) is the physical measurement of resistance, and is defined as the reciprocal of electrical conductivity (C).

$$R = \frac{1000}{C} .$$

C = conductivity in milliohm/m (= milliSiemens)

R = resistivity in ohm-m

Oil and gas are electrical insulators. They will not conduct the flow of an electrical current, and therefore their resistivity are said to be infinite.

Water, however, will conduct electricity depending upon its salinity. Salt water, with high concentrations of dissolved solids (e.g., NaCl, etc), will conduct electricity much more readily than will fresh water. Therefore, salt water has a much lower resistivity than does fresh water. In most instances, the water present in a formation will be saline, and will have a resistivity much lower than or similar to the resistivity of the fluid used to drill a well penetrating that formation (Halliburton, 2001). Thus resistivity logs are used to:

- determine hydrocarbon-bearing versus water bearing zones.
- indicate permeable zones.
- determine porosity.

### **Fluid Saturations:**

Within the earth there is no such condition as a perfect vacuum. Any void space in the rock will be 100% filled with fluids or other materials. Ideally, hydrocarbons dominate this pore volume within the rock. The fluids within these void spaces may include gases at low pressures, consequently with low densities.

Porosity is a rock property. **Properties indicating fluids or other materials present within that porosity, however, are not rock properties but *reservoir properties*.**

**Relative presence of fluids within the porosity is indicated by the fluid saturations.** Assume that in a reservoir the only fluids or materials present or potentially present within the porosity are hydrocarbon liquid, hydrocarbon gas, and water. This water is normally salt water, but since the salt is in solution within the water, it is not considered separately. The relative presence of these three fluids within the void spaces is given by:

- **Oil saturation,  $S_o$**  - the percentage of the void space containing liquid hydrocarbons at reservoir conditions.
- **Gas saturation,  $S_g$**  (implying hydrocarbon gas) – the percentage of the void space containing gaseous hydrocarbons at reservoir conditions.
- **Water saturation,  $S_w$**  - the percentage of the void space containing water at reservoir conditions.

There are two main methods to calculate **water saturation  $S_w$ , Archie method** and **Ratio Method**.

### 1. Archie method:

Archie (1942) showed that the resistivity of a water-filled formation ( $R_o$ ) could be related to the resistivity of the water ( $R_w$ ) filling the formation through a constant called the formation resistivity factor ( $F$ ):

$$R_o = F * R_w$$

Archie also revealed that the formation factor ( $F$ ) could be related to the porosity of the formation by the following formula:

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

By combining the two equations above, the water-saturation formula can be rewritten in the following form:

$$S_w = \left( \frac{a * R_w}{R_t * \Phi^m} \right)^{\frac{1}{n}}$$

Where:

$S_w$  = water saturation

$a$  = tortuosity factor ( $a = 1.0$ )

$m$  = cementation exponent ( $m = n = 2.0$ )

$n$  = saturation exponent

$R_w$  = resistivity of formation water ( $R_w = 0.065$  ohm-m)

$\Phi$  = porosity

$R_t$  = true formation resistivity as derived from a deep reading resistivity log.

This is the formula that is most commonly referred to as the Archie equation for water saturation ( $S_w$ ). All present methods of interpretation involving resistivity curves are derived from this equation (Asquith and Krygowski, 2004).

### Bulk volume water

The product of a formation's water saturation ( $S_w$ ) and its porosity ( $\phi$ ) is the bulk volume of water (BVW).

$$BVW = S_w * \Phi$$

Where:

$BVW$  = bulk volume water

$S_w$  = water saturation of uninvaded zone

$\Phi$  = porosity

If values for bulk volume water, calculated at several depths in a formation, are constant or very close to constant, they indicate that the zone is of a single rock type and at irreducible water saturation ( $S_{w \text{ irr}}$ ). When a zone is at irreducible water saturation, water in the uninvaded zone ( $S_w$ ) does not move because it is held on grains by capillary pressure. Therefore, hydrocarbon production from a zone at irreducible water saturation should be water free.

Because the amount of water, a formation can hold by capillary pressure increases with decreasing grain size, the bulk volume water also increases with decreasing grain size. Table (3) illustrates the relationship of bulk volume water values to decreasing grain size and lithology. The bulk volume water values for carbonates should be used only as a very general guide to different types of porosity.

Table (3) Bulk volume water (BVW) as a function of grain size and lithology.

Lithology	Grain Size (millimeters)	Bulk Volume Water (BVW)
<i>Clastics</i>		
Coarse	1.0 to 0.5	0.02 to 0.025
Medium	0.5 to 0.25	0.025 to 0.035
Fine	0.25 to 0.125	0.035 to 0.05
Very Fine	0.125 to 0.062	0.05 to 0.07
Silt	< 0.062	0.07 to 0.09
<i>Carbonates</i>		
Vuggy		0.005 to 0.015
Vuggy and intercrystalline (intergranular)		0.015 to 0.025
Intercrystalline		0.025 to 0.04
Chalky		0.05

### Measurement of Fluid Saturations:

In determining the fluid saturations from a core sample, two techniques are commonly employed; evaporation of the fluids in the pore space, known as the **retort method**, and the leaching of fluids in the pore space, known as the **Dean-Stark extraction method**.

In the retort technique the sample is sealed inside an aluminum cell and then heated in stages from 400 °F to 1100 °F. (Figure 6) is an illustration of conventional retort apparatus.



Figure (6) Picture of a conventional retort

The advantages to this method is the time for the experiment is short, typically less than 24 hours, and multiple samples can be run at same time. The disadvantages are heating process burns oil to the pore surfaces. This is known as the coking effect and thus results in oil recovery less than the initial amount in the sample. A correction factor (Figure 7) has been empirically developed to overcome this problem.

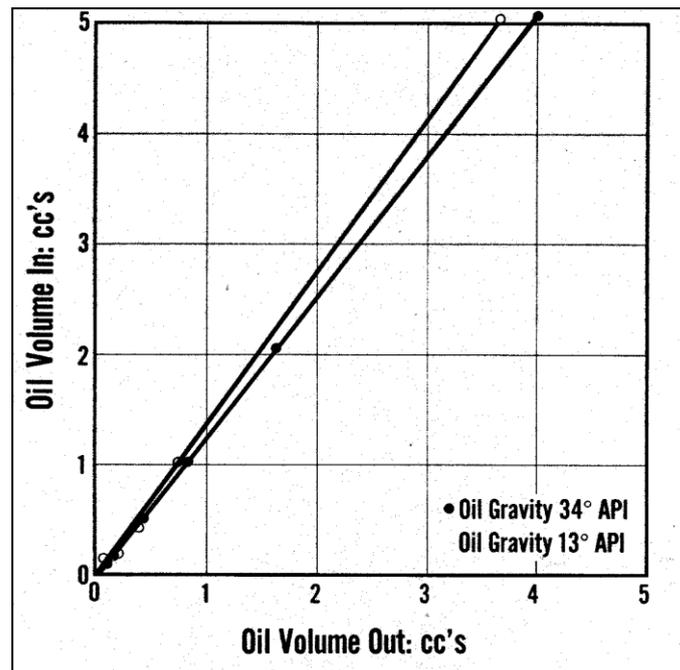


Figure (7) Retort oil correction curve

**API ( American Petroleum Institute)** API gravity, is a measure of how heavy or light a liquid is compared to water: if its API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier and sinks.

Note:

In the pores of oil or gas reservoirs, there always remains some water that was there before the hydrocarbon entrapment. At any time during the life of an oil or gas reservoir, the following relationship must hold true.

$$S_o + S_w + S_g = 1.0$$

$$S_o = \frac{\text{oil volume}}{\text{pore volume}} = \frac{V_o}{V_p}$$

$$S_w = \frac{\text{water volume}}{\text{pore volume}} = \frac{V_w}{V_p}$$

$$S_g = \frac{\text{gas volume}}{\text{pore volume}} = \frac{V_g}{V_p}$$

**Example:**

The corrected volumes of oil and water recovered from the retort method were 4.32 and 1.91 ml, respectively. Prior to this experiment, the bulk volume was measured to be 34.98 ml and the grain volume was 26.34 ml. Determine the saturations of this sample.

**Solution**

The following stepwise procedure is presented.

- The pore volume of the sample is,  $V_p = V_b - V_g = 8.64$  ml.
- The porosity of the sample is 24.7%.
- Applying equations, the oil and water saturations are:

$$S_o = \frac{V_{or}}{V_p} = \frac{4.32}{8.64} = 50\%$$

$$S_w = \frac{V_{wr}}{V_p} = \frac{1.91}{8.64} = 22\%$$

- The gas saturation cannot be measured and therefore is determined by the volume balance

$$S_g = 1 - S_o - S_w = 28\%$$

The Dean-Stark extraction method uses the vapor of a solvent to rise through the core and leach out the oil and water. The water condenses and is collected in a graduated cylinder. The solvent and oil continuously cycle through the extraction process. A typical solvent is toluene, miscible with the oil but not the water. (Figure 8) is an illustration of the apparatus.

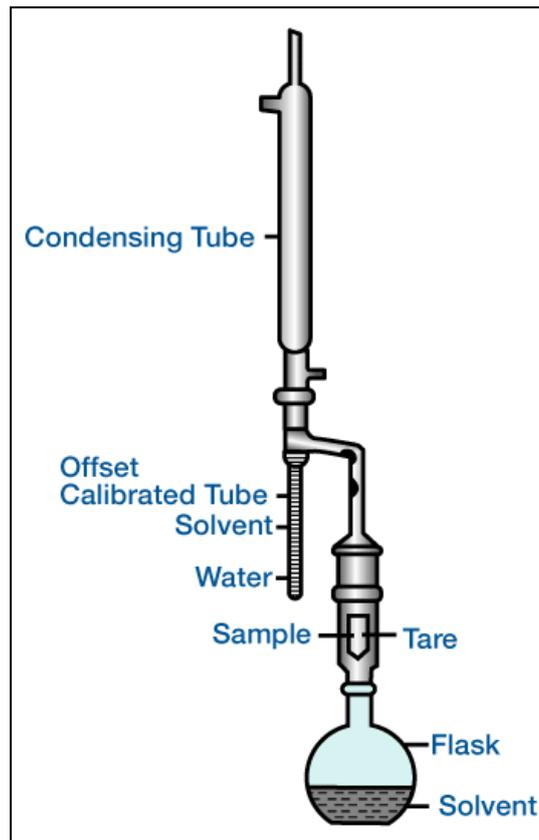


Figure (8) Dean-Stark Apparatus

The volume of the water collected relative to the pore volume provides an estimate of the water saturation. The oil saturation is determined by,

$$S_o = \frac{W_{\text{wet}} - W_{\text{dry}} - W_{\text{wtr}}}{V_p \cdot \rho_o}$$

that is, by the weight loss not accounted for by the water. Equation above requires:

- the weight of the core prior to the test (not cleaned!)
- the weight of the core after the test, cleaned and dried
- the pore volume from other methods
- an estimation of the oil density

**Example**

The following procedure illustrates the usefulness of the extraction method.

- a. Obtain the mass of the saturated sample = 57 gms.
- b. Determine the bulk volume by nondestructive means = 25 cc
- c. Determine the oil density = 0.88 gm/cc
- d. Place the sample in the extraction apparatus and heat the solvent. Record the volume of water collected and when the reading becomes constant – stop.  $V_w = 1.4$  ml
- e. After cooling, remove the core and dry, obtain dry weight = 53 gms.
- f. Using the saturation method, resaturate the sample with fresh water ( $P = 1.00$  gm/cc) and weigh. 58 gms.
- g. Calculate the pore volume and porosity,

$$V_p = \frac{58 - 53}{1.00} = 5 \text{ cc}$$

$$\phi = \frac{5}{25} = 20\%$$

- h. Calculate the water saturation

$$S_w = \frac{1.4}{5} = 28\%$$

- i. Calculate the oil saturation

$$S_o = \frac{57 - 53 - 1.4 * 1.00}{5 * 0.88} = 59\%$$

- j. Calculate the gas saturation

$$S_g = 1 - 0.28 - 0.59 = 13\%$$

## Permeability from logs

Permeability is the property that permits the passage of a fluid through the interconnected pores of a rock. There are three type of permeability:-

1- **Absolute Permeability (Ka)**:- Permeability calculated with only one fluid present in the pores of a formation.

2- **Effective Permeability (Ke)**:- The ability of a rock to conduct one fluid in the presence of another, considering that both fluids are immiscible (e.g., oil and water). Effective permeability depends not only on the permeability of the rock itself, but also on the relative amounts of the different types of fluid present.

3- **Relative Permeability (Kr)**:- The ratio of a fluid's effective permeability to the formation's absolute permeability (100% saturated with that fluid). Permeability is measured in darcies.

The permeabilities of average reservoir rocks generally range between 5 and 1000 millidarcys. A reservoir rock whose permeability is 5 md or less is called tight sand or dense limestone, according to composition. A field appraisal of reservoir permeabilities is:

Fair	1-10 md
Good	10-100 md
Very good	100-1,000 md

Log-derived permeability formulas are only valid for estimating permeability in formations at irreducible water saturation. Before calculating the permeability, we must first determine whether or not a formation is at irreducible water saturation. Whether or not a formation is at irreducible water saturation depends upon bulk volume water values ( $BVW = S_w - \Phi$ ).

When the bulk volume water values of a formation are constant, the zone is at irreducible water saturation. If the values are not constant, a zone is not at irreducible water saturation (Figures 9), and the estimates of permeability are suspect.

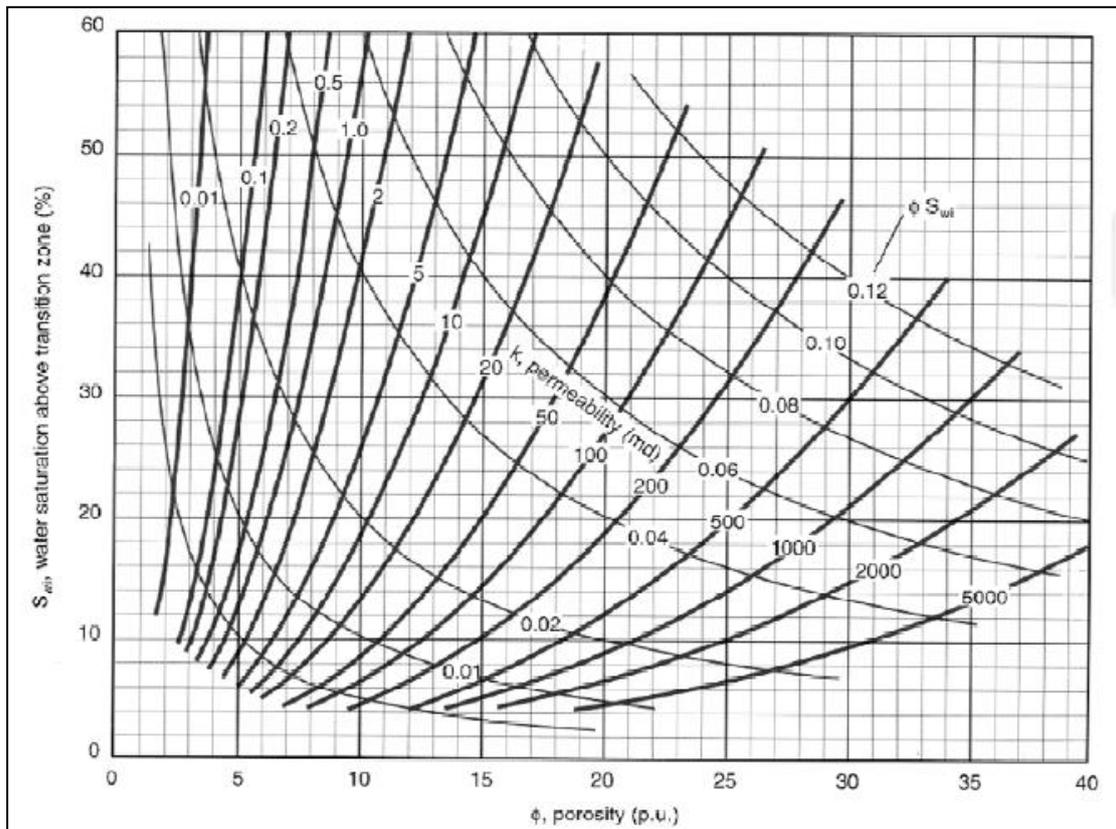


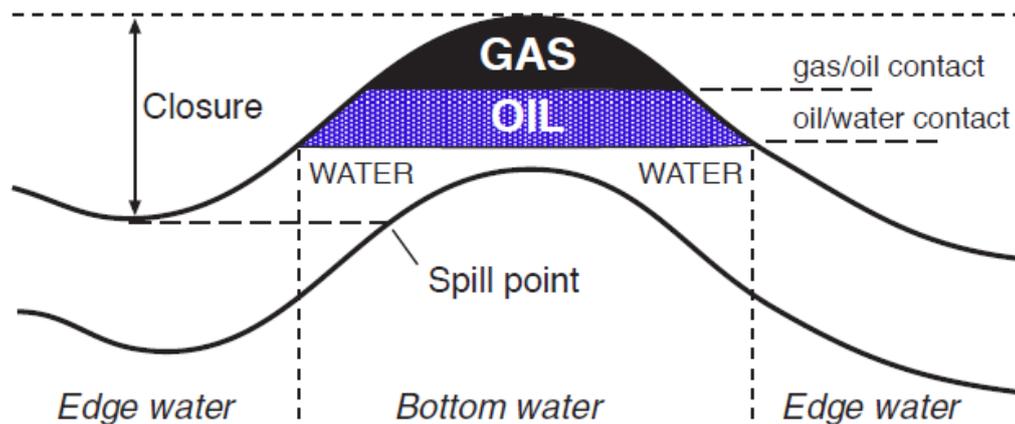
Figure (9) Chart of porosity ( $\phi$ ) versus irreducible water saturation ( $S_{wirr}$ ) for estimating permeability and determining bulk volume water.

### 3- Hydrocarbon trap:

**Trap:** is a geometric arrangement of permeable (reservoir) and less-permeable (seal) rocks which, when combined with the physical and chemical properties of subsurface fluids, can allow hydrocarbons to accumulate.

The fluids of the subsurface migrate according to density. As previously discussed, the dominant fluids present or potentially present are hydrocarbon gas, hydrocarbon liquid, and salt water. Since the hydrocarbons are less dense than the salt water, they will tend to migrate upward to the surface, displacing the heavier water down elevation. These fluids will continue to migrate until they encounter impermeable rock, which will serve as a reservoir “seal” or “trap.” These impermeable rocks serving as reservoir seals, of which shale’s are among the most common, are referred to as confining beds or cap rocks. Traps exist because of

variations in characteristics of rocks of the subsurface. If impermeable rock does not exist, the hydrocarbons will migrate to the surface and dissipate into the environment. In order for a hydrocarbon reservoir to exist, a proper sequence of events must have occurred in geologic time.



- **Spill point** - lowest elevation at which hydrocarbons can be contained in trap.
- **Closure** - highest elevation at which the trap is sealed.
- **Bottom water** - water directly beneath oil, below OWC.
- **Edge Water** - formation water in lowest strata.

Four types of hydrocarbon traps will be discussed. Most traps encountered by a petroleum geologist will be a combination or variation of these five types.

- 1• **Anticlinal traps**
- 2• **Fault traps**
- 3• **Salt dome traps**
- 4• **Stratigraphic unconformity traps**

## 1· Anticlinal traps:

This trap may exist as a simple fold or as an anticlinal dome. Sedimentary beds are generally deposited in horizontal parallel planes over a geographic region, so that many of these sediments will be of essentially uniform thickness over that region. If geologic activity should occur, resulting in the folding of these sediments, the result may be the formation of hydrocarbon reservoirs in anticlinal traps.

The high part of the fold is the anticline, and the low part of the fold is the syncline. Since the hydrocarbons are the less dense of the subsurface fluids, they will tend to migrate to the high part of the fold (figure 11).

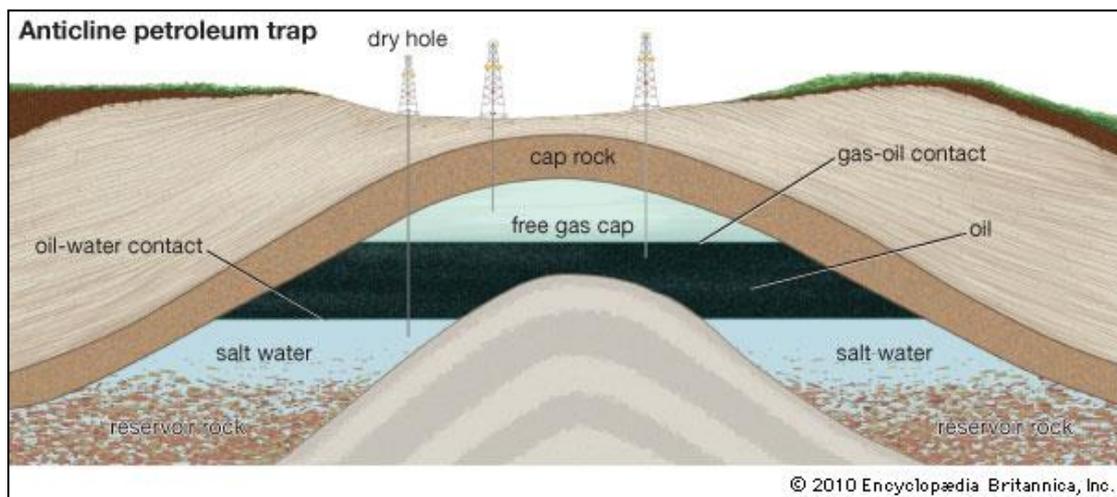


Figure (11) Anticlinal trap

Imagine a possible sequence of geologic events leading to the formation of this hydrocarbon reservoir. Sedimentary beds are deposited in a water environment, as indicated by the presence of limestone's and shale's. During or after lithification, geologic activity causes folding of the sediments. After folding and lithification, the sandstone has a 100% connate water saturation. Millions of years later, hydrocarbon generated in source rock down elevation from this anticlinal fold is forced from its source rock into the water-saturated, permeable sandstone. Since hydrocarbon is less dense than the water, it begins to migrate up elevation, displacing the heavier water down elevation.

From this point upward, gas is being released from the hydrocarbon. Since the gas is so much less dense than the oil or the water, it will migrate more rapidly toward the top of the anticlinal trap. This process of migration and fluid separation according to density may continue over

millions of years in geologic time, until finally, equilibrium is achieved as the hydrocarbon fluids accumulate within the trap formed by the impermeable shale cap rock.

## 2. Fault Traps:

Fault implies fracturing of rock and relative motion across the fracture surface. Consider a possible sequence of geologic events that, in geologic time, could lead to the formation of the hydrocarbon reservoir, as illustrated in (Figure 12).

Sedimentary beds are deposited in a water environment, as indicated by the presence of shale and limestone. During or after lithification, geologic events result in uplift of these original horizontal sediments, and fracturing and tilting above sea level, so that the surface rocks are exposed to erosion. During uplift, the rocks are fractured and slippage occurs along the fault plane. This brings the shale across the fault so that it seals the tilted sandstone below the fault. Millions of years later, hydrocarbon generated in its source rock down elevation from the fault is forced into the connate water-saturated sandstone.

Since the hydrocarbon is less dense than the water, it will migrate up elevation, displacing the heavier water down elevation. This upward migration will continue until it reaches the fault and is trapped by the impermeable shale. If the faulting had not occurred, the hydrocarbon would have continued to migrate upward until it was dissipated at the surface into the environment. Since faulting occurred, the shale provides the necessary seal, resulting in the existence of the hydrocarbon reservoir.

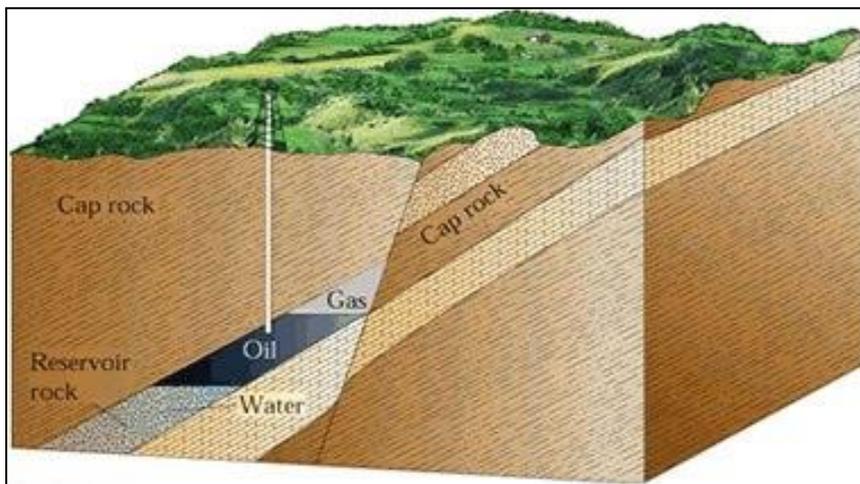


Figure (12)  
illustrate  
Fault trap

### 3. Salt Dome Traps:

Consider the salt dome geologic system illustrated in (Figure 13) and a possible sequence of geologic events that could lead to the formation of this salt dome environment. A major portion of a continental plate was below sea level at a point in geologic history. Due to geologic events, this region rose above sea level, trapping inland a salt water sea. As geologic time passed, the climate changed to a desert environment. This event could have resulted from movement of the continental plate near to the equator. In this arid desert environment, water evaporated from the salt water sea, leaving the salt residue on the dry sea bed. As millions of years passed in the desert environment, sand blew over the salt to cover and protect the salt sediment.

Later geologic events resulted in the sinking of the region below sea level, followed by tens of millions of years of sedimentation in the resulting water environment. As time passed, lithification occurred. The desert sand became sandstone, and the salt became rock salt (sedimentary salt).

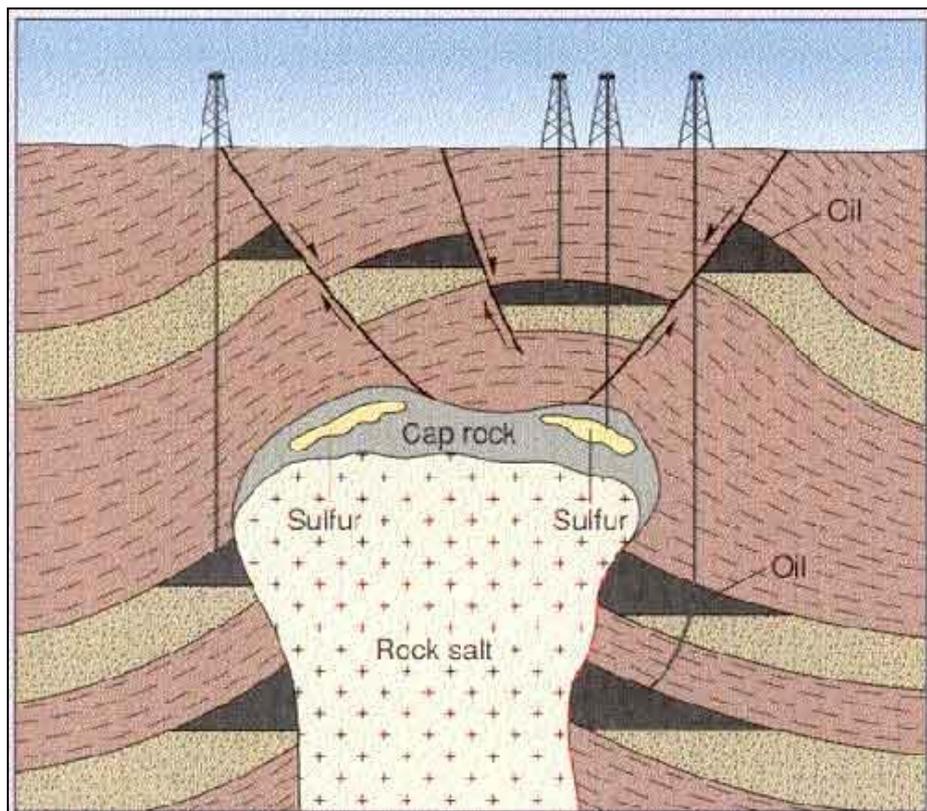


Figure (13) illustrate salt dome and fault traps

properties significantly different from typical shale, sandstone or limestone:

- It was less dense, with a measurably smaller specific weight.
- At subsurface overburden pressures and subsurface temperatures, the rock salt was a plastic solid (it was highly deformable).

The combination of this lesser density and plasticity resulted in a buoyant effect if flow possibilities existed. Geologic events caused fracturing of overlying confining rocks. The salt, forced upward by the overburden pressures, began to flow plastically back to the surface, intruding into the overlying rock structures to lift, deform, and fracture them. The intruding salt was solid, yet geologically deformable. It might intrude at an average rate of only 1 inch per 100 years, yet on a geologic time basis, such deformation is highly significant. This rate would result in 10 inches in 1,000 years, or 10,000 inches (833 ft) in 1 million years. In a geologic time period of only 10 million years, this salt dome could intrude to a height of over 1.5 miles into the overlying structures. Obviously, a vertical subsurface structure 1.5 miles high is geologically significant.

Since the salt is impermeable, the region around the perimeter of the salt dome is an ideal geologic environment for hydrocarbon traps. The tendency of the intruding salt to uplift the rocks as it intrudes enhances the separation of the less dense oil from the more dense salt water by reducing the area of the oil-water contact.

The fracturing of surrounding rocks due to the intruding salt and the lifting of the rocks above the salt dome also provide an environment for the existence of fault traps and anticlinal traps in addition to the salt dome traps around the perimeter of the dome. A salt dome region, therefore, is an excellent geologic environment for all three types of traps discussed so far.

#### **4· Stratigraphic unconformity traps**

Consider the sequence of geologic events summarized in (Figure 14). Sedimentation occurs over millions of years in a water environment, resulting in horizontal, parallel, sedimentary beds.

Lithification occurs, followed by uplift and tilting above sea level. As a result of being uplifted above sea level, erosion occurs over millions of years, removing rocks down to an erosional surface, or unconformity. Following erosion, the region subsides again below sea level and is

followed by millions of years of sedimentation in a water environment. After lithification, the first sediment on top of the unconformity is impermeable shale. The unconformity represents a discontinuity in the geologic system, because there is a geologic time discontinuity between the rocks above the unconformity and those below it.

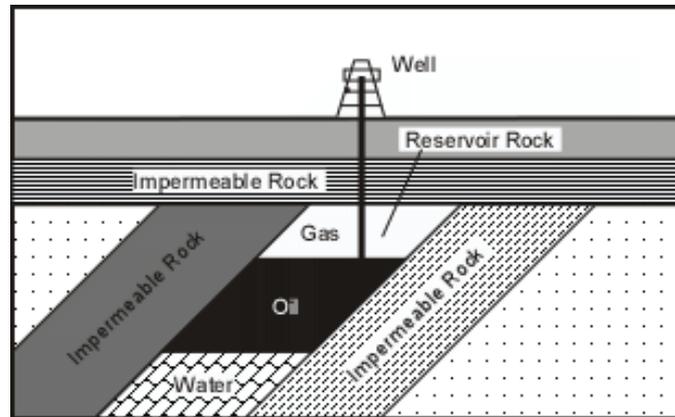


Figure (14) illustrate stratigraphic trap

Millions of years after this sequence of events, hydrocarbon that is generated in source rock at lower elevations is forced into the connate water-saturated sandstone. Due to its lesser density, it migrates upward through the permeable sandstone, displacing the heavier water down elevation. When the hydrocarbon reaches the unconformity, it is trapped. This trap is a stratigraphic trap, and this particular type of stratigraphic trap is referred to as an unconformity, or “truncation.” The specific type of unconformity illustrated here is an angular unconformity.

### Types of Reservoirs:

Three types of hydrocarbon reservoirs will be considered. Variations of these types might exist in specific geologic situations. In order for any reservoir to exist, however, source rock must have been present for the hydrocarbon to have been generated, reservoir rock must exist for storage of the hydrocarbon, and a trap must exist to trap the hydrocarbon. The three major types of hydrocarbon reservoirs are:

- 1· Oil reservoir (no gas cap).
- 2· Oil reservoir (with gas cap).
- 3· Gas reservoir.

**1· Oil reservoir (no gas cap):**

An oil reservoir with no gas cap implies that the reservoir fluid pressure is higher than the bubble point pressure of the hydrocarbon present, so gas is not expected to exist initially within the reservoir. The oil zone of this reservoir will probably have 10% to 20% irreducible water saturation and is probably water-wet. Dependent upon the development plan and therefore the production history of the reservoir, a gas cap may come to exist during its productive life. The advantage of this type of reservoir is the relative ease of maintaining the flowing bottomhole pressures of the producing wells above the bubble point pressure, for a longer period during the productive life of the reservoir.

**2· Oil reservoir (with gas cap):**

A second type of hydrocarbon reservoir is the oil reservoir with a gas cap. Since the gas cap exists naturally, the reservoir fluid pressure in the natural state must be less than the bubble point pressure of the original hydrocarbon combination (before hydrocarbon molecules were released from solution to form the gas). If a gas cap exists, the gas-oil contact will be essentially a distinct plane, compared to the oil-water contact, which will be a transition zone. The oil zone of this reservoir will probably have 10% to 20% irreducible water saturation.

**3· Gas reservoir.**

The third major type of hydrocarbon reservoir is the gas reservoir. The gas volume at reservoir conditions is extremely large, compared to any hydrocarbon liquid volume. The reservoir is essentially a gas zone above a water zone. A gas water contact could exist.

From the original reservoir fluid sample, collected at datum depth using the bottomhole sampler, the P-V-T analysis will provide a P-T (Pressure-Temperature) Diagram. This P-T diagram is more commonly known as a "Phase Diagram." Based on the Phase Diagram for the particular hydrocarbon reservoir fluid and its initial pressure-temperature conditions, the reservoir can be categorized as a particular type reservoir. (Figure 15) is the Phase Diagram for the hydrocarbon of a reservoir. Liquid, gas, and two-phase regions are identified.

This diagram can be used to predict changing conditions within the reservoir over its productive life. For most reservoirs, the production process is a constant temperature (isothermal) process, so that a vertical line on the Phase Diagram will predict reservoir history during production, dependent upon factors within the reservoir development plan (such as artificial maintenance of reservoir fluid pressures by fluid injection). Also, an exception to this isothermal process might exist due to application of thermal techniques for enhanced recovery during the productive life of the reservoir. As seen from this Phase Diagram, a reservoir identified by P-T conditions at (point A) would be an oil reservoir with an initial gas cap, (point B) identifies an oil reservoir without a gas cap, and (point C) identifies a gas reservoir. A reservoir containing a particular hydrocarbon combination with this Phase Diagram, representing the hydrocarbon present, could be any of these types of reservoirs, dependent upon its original natural pressure-temperature condition. In summary, the Phase Diagram for the reservoir hydrocarbon and the pressure-temperature condition at which it exists will determine the classification of the hydrocarbon reservoir.

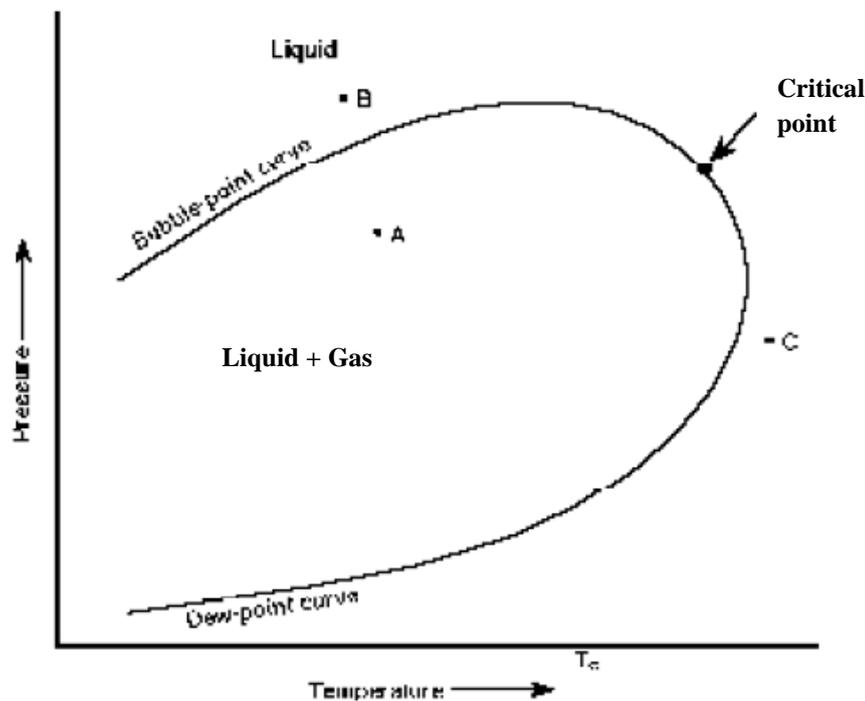


Figure (15) Phase Diagram for Our Reservoir (P-T Diagram)