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1. Introduction

While it is true that geologist study rocks, much applied geology is concerned with the study of holes within the rocks. The study of these holes or pores including their size, geometry, mode of occurrence and connectivity is termed as ***petrophysics***. This is of utmost vital importance to identify any sedimentary rock as a reservoir in search of oil and gas. A reservoir is a rock strata that has significant void space so as to hold liquid/gas and also connectivity between pores so that there is easy passage of fluid through them. However, mere presence of reservoir quality (porosity and permeability) is not a guarantee of getting oil or gas. Source rock and cap rock is also necessary for formation of a trap and physical presence of oil/gas.

A clastic sedimentary rock is composed of grains, matrix, cement and pores. The grains are the detrital particles which generally from the framework of a sediment. Matrix is the finer detritus, which occurs between the framework. There is no arbitrary size distinction between grains and matrix. Conglomerates generally have a matrix of silt and clay. Cement is post- depositional mineral growth, which occurs within the voids of sediment. Pores are the hollow spaces not occupied by grains, matrix or cement. The study of pore liquids and gases lies in the scope of both hydrology and petroleum engineering. Petrophysics, the study of physical properties of pores, lies on the boundary between these disciplines and sedimentary geology.

The ratio of volume of void spaces within a rock to the total bulk volume of that rock is commonly expressed as a percentage; i.e., all the collective void space is referred to as pore volume so that percent porosity is calculated as

$$\varphi = \text{pore volume} / \text{Total rock volume} \times 100$$

Where φ represents porosity

In practice, several descriptions of porosity exist, but the two most common are total porosity and effective porosity. Total porosity represents the ratio of total pore volume within a rock to the total bulk volume including voids as given in the previous equation. Effective porosity represents the ratio of the interconnected pore space to the total bulk volume.

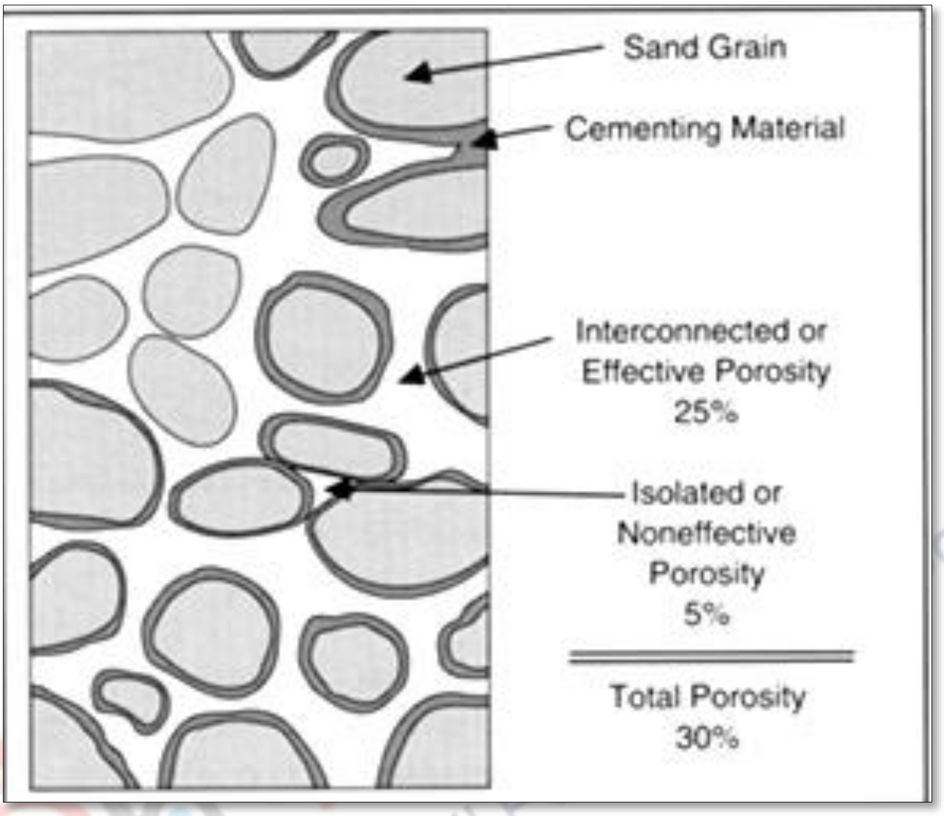

Fig. 1 Diagrammatic illustration of total, effective and non-effective porosity.

2. Pore Morphology

The pores themselves may be studied by a variety of methods ranging from examination of rough or polished rock surfaces by hand lens or stereoscopic microscope, through study of thin sections using a petrological microscope or by the use of scanning electron microscope. Another effective technique of studying pore fabric is to impregnate the rock with a suitable plastic resin and then dissolve the rock itself with an appropriate solvent. Examination of the residues gives some indication, not only of the size and shape of pores, but also of the throat passages, which connect pores. The minimum size of throats and the tortuosity of pore systems are closely related to the permeability of the rock.

The classification shown in Table 1 divides porosity types into two main varieties, which are commonly recognized. These are primary porosity fabrics, which were present during and immediately after deposition of sediment and secondary or post depositional fabrics, which formed after sedimentation by a variety of causes.

Table 1: Classification of Porosity Types.

	TYPE	ORIGIN
Primary or depositional	a) Intergranular or interparticle b) Intraparticle	Sedimentation
Secondary or post depositional	c) Intercrystalline d) Fenestral e) Mouldic f) Vuggy g) Fracture	Igneous rock, Dolomite Cementation Fabric-selective solution Fabric-inselective solution Tectonic movement compaction or dehydration

2.1 Primary or depositional porosity: Primary or depositional porosity is that which, by definition, forms when a sediment is laid down. Two main types of primary porosity may be recognized.

2.1.1 Intergranular porosity: Intergranular or interparticle porosity occurs in the spaces between the detrital grains which form the framework of sediments (Fig. 2a). This is very important porosity type in sedimentary rocks and is present initially in almost all sedimentary rocks. Intergranular porosity is generally progressively reduced by diagenesis in many carbonates, but it is dominant porosity type found in sandstones. Sediment grain size has no role on the volume of porosity in any clastic rock (sandstone or shale). A mass of spheres of uniform sorting and packing will have same porosity, regardless of size of the spheres. Porosity volume is dependent of grain packing (Cubic packing 48% porosity, Rhombohedral packing 26% porosity) (Fig. 2b). Grain shape also has a role.

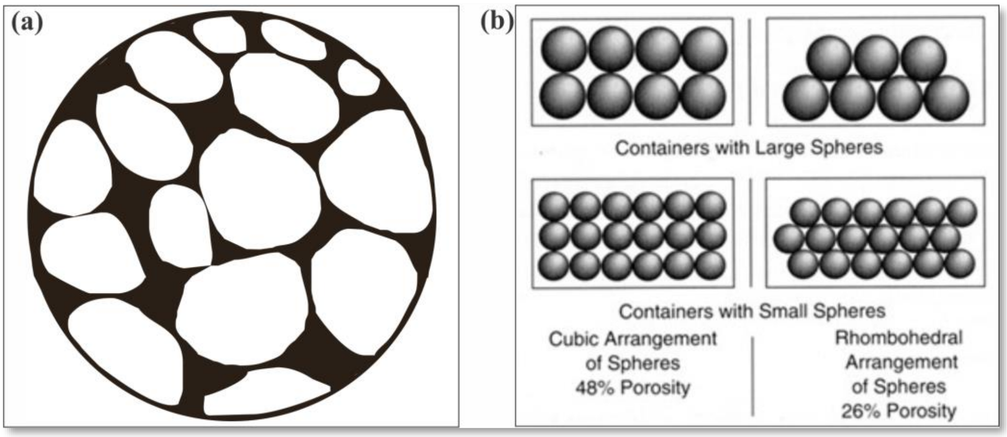

Fig. 2 (a) Interparticle porosity; (b) Illustration showing control of grain packing on porosity irrespective of grain size.

Intergranular porosity and permeability are greatly reduced by burial diagenesis. When deposited, initial porosities may be 35% to 40% and permeabilities of several darcies. Typical oil and gas reservoirs have porosities ranging from 10% to 25% and permeabilities of a few to a few hundred millidarcies.

2.1.2 Intraparticle porosity: In carbonate sands, particularly those of skeletal origin, primary porosity may be present within the detrital grains. For example, the cavities of molluscs, ammonites, corals, bryozoan and microfossils may be all classed as intraparticle primary porosity (Fig. 3).

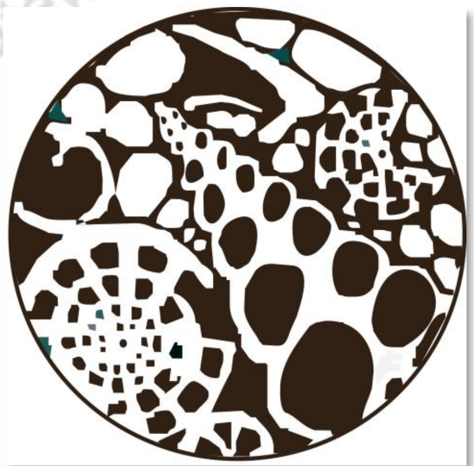

Fig. 3 Intraparticle porosity.

This kind of porosity is often diminished shortly after deposition by infiltrating micrite matrix. Furthermore, the chemical instability of the carbonate host grains often leads to their intraparticle pores being modified or obliterated by subsequent diagenetic history.

2.2 Effect of sorting and grain size on porosity and permeability: Porosity increases with increasing sorting (Fig. 4). In a poorly sorted sandstone, finer grains occupy the interstitial spaces between the larger grains and thereby decrease porosity of sandstone. In fact, finer grains block both pores and pore throat passages. Both grain shape and roundness affect porosity. Lower the roundness of grain higher will be the porosity. This is because packing of grains become tighter with higher sphericity of grains.

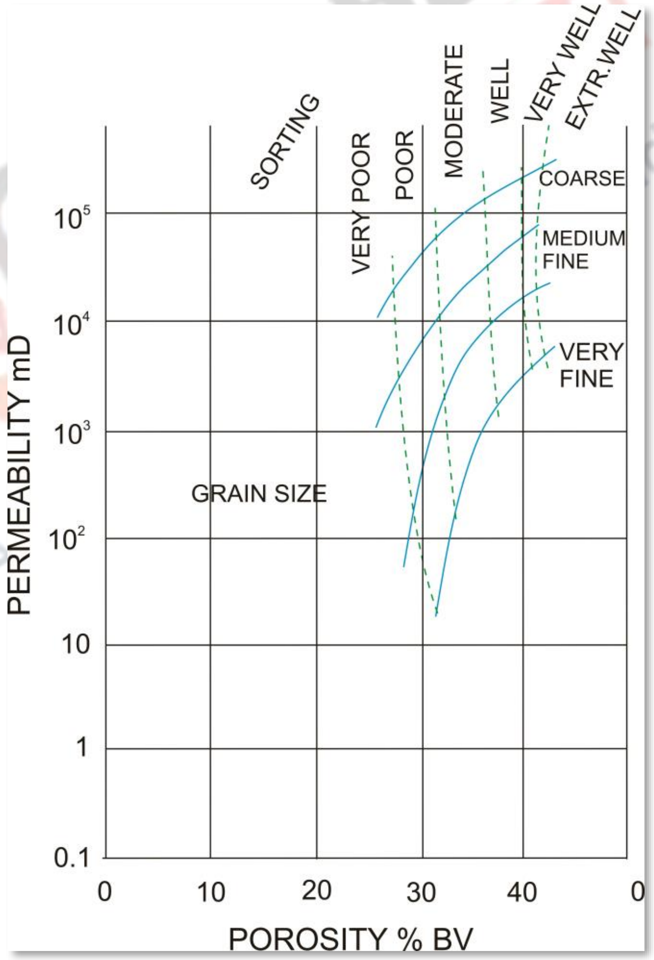

Fig. 4 Control of grain size and grain sorting on reservoir porosity and permeability (after Selley, 2000)

Table 2: Effect of rock properties on Porosity and Permeability.

Rock property texture	Effects on permeability and porosity
Grain size	Permeability decreases with grain size; porosity unchanged
Sorting	Permeability and porosity decrease as sorting becomes poorer
Packing	Although little data is available, tighter packing favors both lesser permeability and porosity
Grain fabric	In absence of lamination, controls anisotropy of permeability, permeability is maximum parallel to mean shape fabric
Cement	The more cement, less permeability and porosity

2.3 Secondary or Post depositional porosity: Secondary porosity is that which, by definition formed after sediment was deposited. Secondary porosity is more diverse in morphology and more complex in genesis than primary porosity. The following main types of secondary porosity are recognizable (Fig. 5).

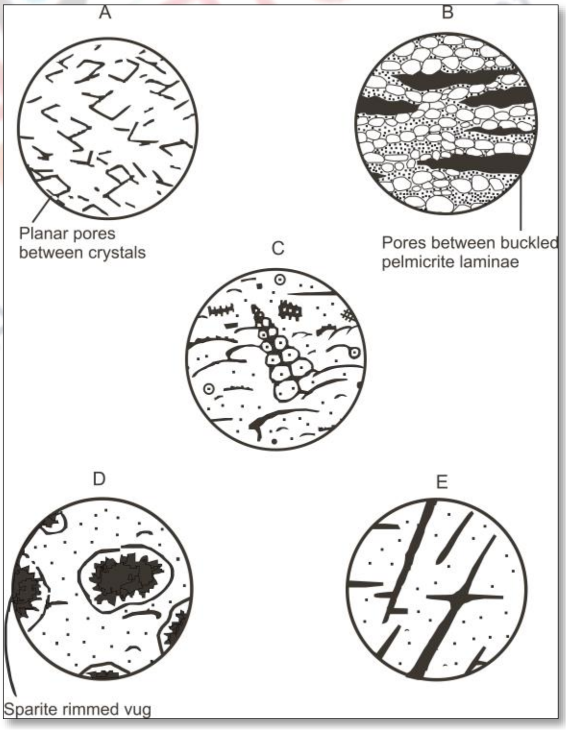

Fig. 5 Different types of secondary porosity a. Intercrystalline, b) Fenestral, c) Moldic, d) Vuggy and e) Fracture.

2.3.1 **Intercrystalline porosity:** Intercrystalline porosity occurs between individual crystals of a crystalline rock. It is, therefore, the typical porosity type of igneous and high-grade metamorphic rocks and of some evaporates. Strictly speaking, such porosity is of primary origin. It is, however, most characteristics of carbonates, which have undergone crystallization, and is particularly important in recrystallized dolomites. The pores of crystalline rocks are essentially planar cavities, which intersect obliquely with one another with no constrictions of the boundaries or throats between adjacent pores.

2.3.2 **Fenestral porosity:** The term fenestral porosity was proposed for a primary or penecontempraneous gap in rock framework, larger than grain supported interstices. This porosity type is typical of fragmental carbonate sands, where it grades into primary porosity. It is most characteristic of pellet muds and homogeneous muds of lagoonal and intertidal origin. Pene-contemporaneous dehydration, cementation, and gas generation can cause depositional laminae to buckle and generate sub horizontal fenestral pores between the laminaes.

A variety of fenestral fabric has long been known as bird's eye. This refers to isolated eyes up to a centimeter across which occur in some lime mudstone. These structures have been attributed to organic burrows and to gas escape conduits. They are frequently infilled by crystalline calcite.

2.3.3 **Moldic porosity:** A third type of secondary porosity, generally formed later in the history of rock than fenestral is moldic porosity. Molds are pores formed by the solution of primary depositional grains generally subsequent to some cementation. Molds are fabric selective. That is to say, solution is confined to individual particles and does not cross cut cement matrix and framework. Typically, in any one rock it is all the grains of one particular type that are dissolved. Hence, one may talk of oomoldic, pelmoldic or biomoldic porosity where there has been selective solution of ooliths, pellets or skeletal debris. The geometry and effective porosity and permeability of moldic porosity can thus be extremely varied. In an oomoldic rock, pores will be subspherical and of similar size. In biomoldic rocks, by contrast, pores may be very variable in size and shape, ranging from minute to curved planar pores where shells have dissolved, and cylinders where echinoid spines have gone into solution.

2.3.4 **Vuggy porosity:** Vugs are a second type of pore formed by solution and like molds, they are typically found in carbonates. Vugs differ from molds though because they cross cut the primary depositional fabric of the rock. Vugs tends to be larger than molds. They are often lined by a selvedge of crystals. With increasing size, vugs grade into what is loosely termed cavernous porosity. The minimum dimension of a cavern is a pore which allows a man to enter or which, when drilled into, allows the drill string to drop by more than half a meter through the rotary table. Such cavernous porosity occurs in the Arab zone (upper Jurassic) of the abquaiq oil field in Saudi Arabia (Mc connel. 1951). Some of the largest cavernous oil reservoir on record occurs Texas, naturally where caverns up to five meters high were reported in the fusselman limestone of Dollarhide oil field.

2.3.5 **Fracture porosity:** The last main type of pore to be considered is that which occurs within fractures. Fracturing, in the sense of a breaking of depositional laminations can even occur pene-contemporaneous with sedimentation. This often takes the form of microfaulting caused by slumping, sliding and compaction. Fractures in plastic sediments are instantaneously sealed. In brittle rocks, however, fractures may remain open after formation, thus giving rise to fracture porosity. This porosity type characterizes rocks which are strongly lithified and is therefore, generally formed later in time than the other varieties of porosity.

It is important to note that fracture porosity is not only found in well-cemented sandstones and carbonates, but may also be present in shales and igneous and metamorphic rocks.

Fracture porosity can occur in a variety of ways and situations. Tectonic movements can form fracture porosity in two ways viz. tension over crests of compressional anticlines and shear failure.

Fracture porosity is also intimately associated with faulting and some oil fields show very close structural relation with individual fault system. Fracture porosity can also form from tectonic processes. It is often found immediately beneath unconformities. Here fractures, once formed by weathering, may have been enlarged by solution (especially in limestone) and get preserved without subsequent loss of porosity.

Recognition of the significance of fracture in producing fluids from high porosity low permeability formations has led to the development of artificial fracturing by explosive charges which simultaneously wedge the fractures open with sand, glass beads etc. similarly, the productivity of fractured carbonate reservoirs may be increased by the injection of acid to dissolve and enlarge the fractures.

Secondary porosity in sandstone: Secondary porosity is most common in carbonates. In case of sandstones, secondary porosity is common in some sandstones those have undergone long lasting burial diagenesis and have lost their primary porosity. Dissolution of carbonate cements results from decarboxylation of organic matter in strata during the course of burial and organic maturation. CO_2 and carbonic acid formed thereby cause dissolution of carbonate cement that might be present in sandstone and result in formation of secondary porosity.

3. Capillary Pressure Curves and Pore Morphology

Capillary pressure curves provides data to determine the size of the throats connecting the pores and the percentage of total pores effective at successive levels in a reservoir. Pore throat geometry is basically the key to hydrocarbon producing potential.

Fluid movement in a rock is a function of relative permeability, which in turn, for a given rock at a given time is a function of the fluid saturation in the rocks. Fluid saturations in turn are affected by pore geometry of the rock responding to reservoir pressures. Pressure is a function of height above oil – water contact, and with an increase in differential pressure, increasingly smaller pore throats are invaded by oil.

If relative permeability to oil and water is also determined from a core sample, in addition to the capillary pressure curve, a quite accurate picture can be constructed of fluid behavior in a reservoir composed of this rock. A typical relationship between relative porosity and permeability and capillary pressure, as well as the effect of the two parameters on productibility is illustrated in Fig. 6. Most reservoir rocks are naturally water wet. As oil enters within the reservoir initially it occupies the coarser pore spaces driving water out into smaller and finer pore spaces where capillary pressure is high. This is the time reservoir only yields water. Only when the replacement of water by oil reaches 20% reservoir starts yielding water plus some oil. With time reservoir turns into oil-wet from water-wet and relative permeability of reservoir with respect to water becomes zero. The reservoir now produces oil without water. The permeability relative to oil rises rapidly and the capillary pressure increases abruptly to the maximum. At this stage, oil replaces water in almost all pore spaces except fine/very fine ones where it is held by high capillary pressure. This water is referred as irreducible water and in present case, it is 30%.

The degree of sorting and skewness, which the pore system exhibits, is of more than academic interest. It should be apparent that, if a rock exhibits markedly fine skewness, excessive heights above oil water contact are required before it is capable of holding oil. Thus, even though rock may be porous, it may be incapable of holding oil. Even though rock may be porous, it may be incapable of holding oil if the closure of the potential trap is less than the required height above oil-water contact.

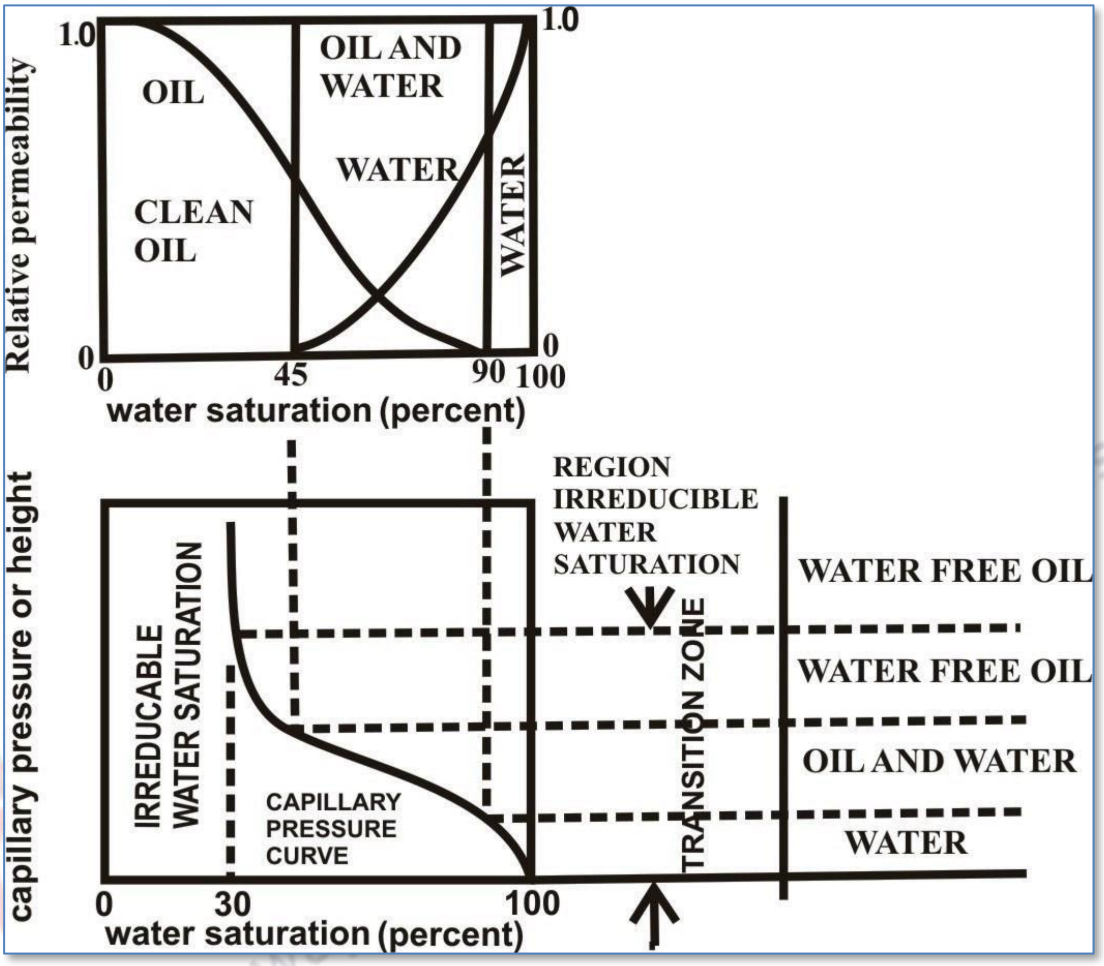

Fig. 6 Rock productibility as determined from capillary pressure and relative permeability curves. Smallest pore throat effective at any pressure level shown on scale to right of capillary pressure curve.

3.1 Permeability: Permeability measures ease of flow of a fluid through a porous media. Porosity controls volume of hydrocarbons in a reservoir, permeability controls productivity rates. The pore network is considered as a bundle of tortuous circular capillary tubes of constant diameter. Darcy’s law demonstrate flow through this network

$$Q = k\ A/\mu\ dP/dL$$

Where Q is flow in Cm3/sec, k is permeability in darcy, A is cross-sectional area, μ is viscosity of fluid in centipoises, dP/dL is pressure gradient (Fig. 7).

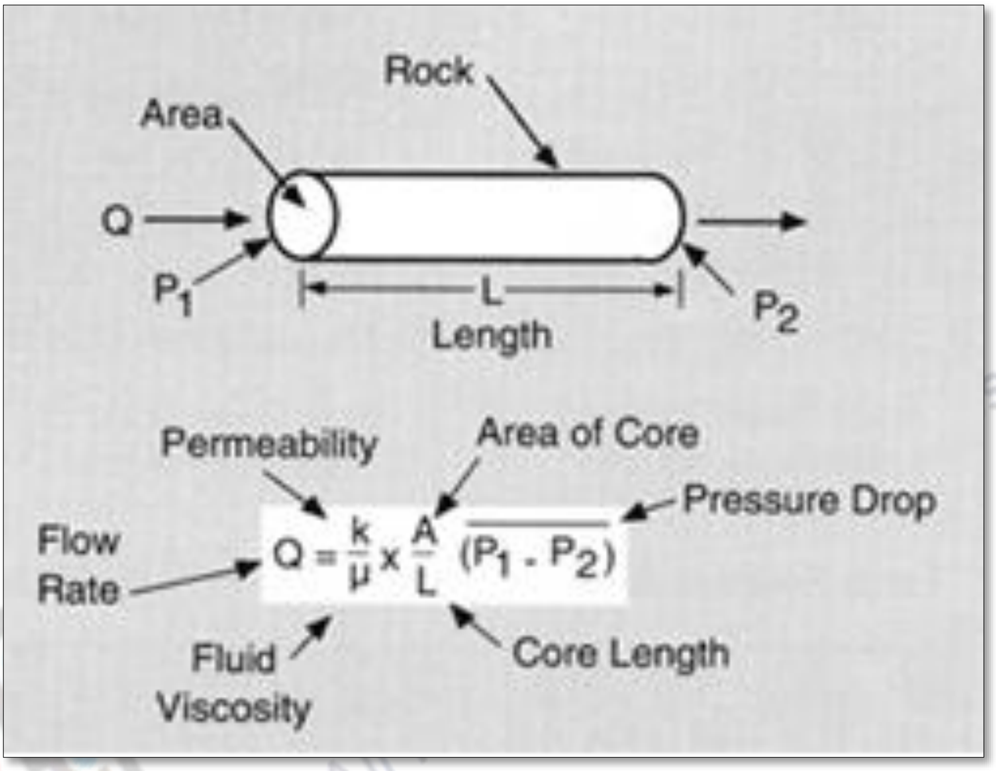

Fig. 7 Definition of permeability from a core sample.

Permeability depends largely on –

- Size of pore openings
- Degree and size of pore connectivity
- Degree and type of cementing material between rock grains

3.2 Absolute, Effective and Relative permeability: Darcy's Law is valid under the following conditions:

- Entire pore spaces are filled by a single fluid i.e. saturation is 100%
- Fluid must be a Newtonian fluid i.e. viscosity is independent of flow rate
- Flow must be in the viscous, laminar region

When these three conditions are met, the permeability is considered as absolute or specific permeability i.e. permeability of one phase in a single-phase system.

When there is multi-fluid system, permeability of one particular fluid is its effective permeability. The effective permeability may vary from zero to 100% of absolute permeability. It depends on relative saturation of different phases, capillary pressure and surface tension and wettability of reservoir rocks.

Relative permeability is effective permeability divided by absolute permeability. Thus, relative permeability expresses the fraction of the total or absolute permeability, which a particular fluid is utilizing.

Horizontal permeability is generally accepted as the rock's permeability in a more-or-less horizontal direction, while vertical permeability is generally accepted as the component perpendicular to horizontal permeability (Fig. 8). Vertical permeability (k_v) is usually somewhat less than horizontal permeability because of the layering effect of sedimentation; i.e., clay laminae, platy minerals, etc. Horizontal permeability (k_h), measured parallel to bedding, is the major contributor of fluid flow into a typical wellbore. The ratio of k_h / k_v generally ranges from 1.5 to 3.0 but might exceed 10.0 in some reservoirs.

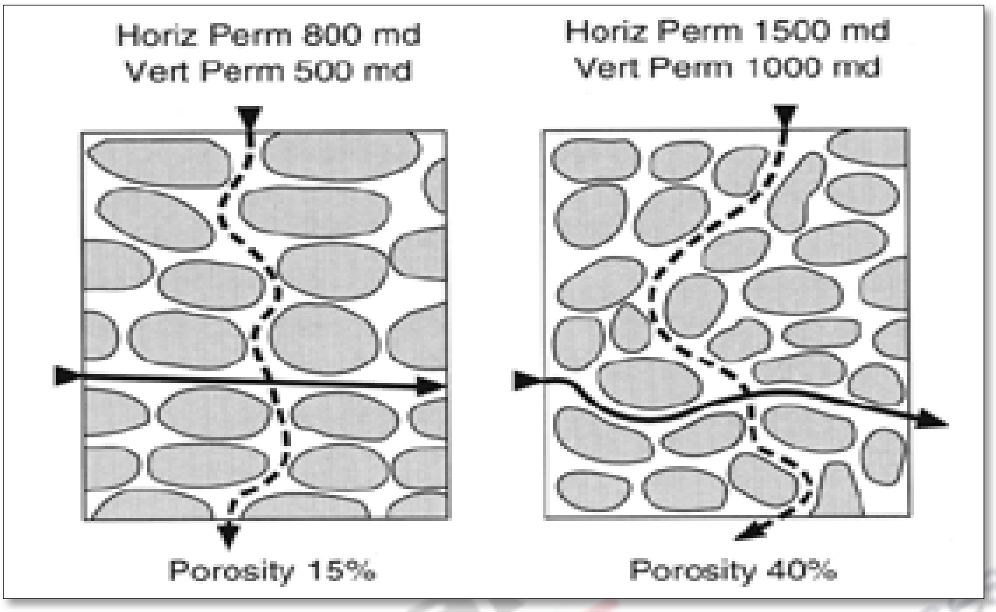

Fig. 8 Illustration of horizontal and vertical permeability.

3.3 Effect of sedimentary structures of horizontal and vertical permeability:

Parting lineation	Maximum permeability most probably Parallels fabric in plane of bedding.
Cross bedding	Scant available data suggests that horizontal Permeability parallels direction of inclination And that more dip of the foreset, weaker horizontal vector of permeability.
Ripple marks	Little data, but fine grain and more laminations combine to cause low permeability and hence ripple zones are commonly barriers to flow.
Grooves and flutes	As judged by fabric, permeability should parallel long dimension.
Slump structures	No data, but probably always greatly reduce horizontal permeability.
Biogenic structures	Destroy depositional fabric and bedding and Thus, drastically reduce permeability and cause minimal, if any, horizontal anisotropy of permeability. Effect on porosity is unknown but may be negligible.

3.4 Relationship between porosity and permeability: Even though theoretical equations may indicate a relationship between permeability and porosity, from a physical point of view such a relationship does not exist. Grain size, sorting and diagenetic products have a great effect on permeability. Fig.9 provides a general idea on possible relationship of porosity and permeability in different types of reservoir. Whereas in an ideal clastic reservoir there may a crude relationship, between the two; in a carbonate reservoir there can be very high porosity with a low permeability and in a fractured reservoir, high permeability can be recorded with low porosity.

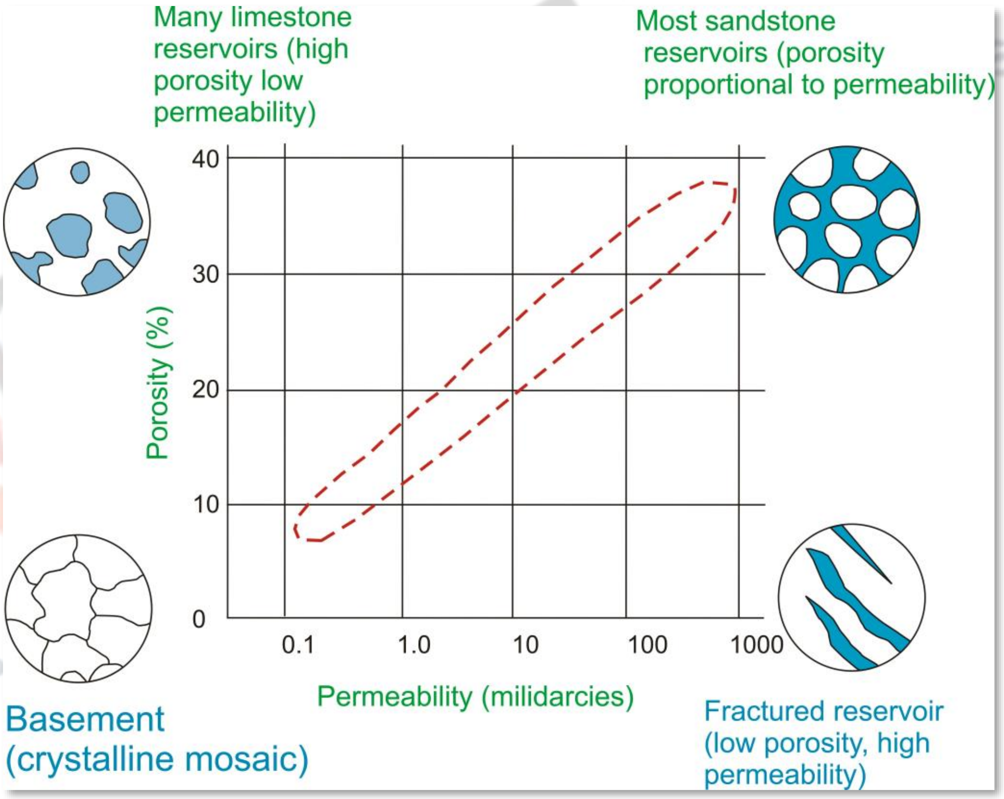

Fig. 9 Porosity-Permeability cross-plot for different varieties of reservoirs.

Table 3: Comparison of porosity in sandstone and carbonate.

ASPECT	SANDSTONE	CARBONATE
Amount of primary porosity In sediment	Commonly 25-40%	Commonly 40-70%
Amount of ultimate porosity of rocks	Commonly half or more of initial porosity, 15-30% common	Commonly none or only small Fraction of initial porosity, 5-10% common in reservoir facies.
Types of primary	Almost exclusively interparticle	Interparticle commonly predominates, but intraparticle is also important.
Types of ultimate porosity	Almost exclusively primary interparticle.	Widely varied because of post depositional modifications.
Size of pores	Diameters and throat sizes closely related to sedimentary particle size and sorting.	Diameters and throat sizes commonly show little relation to sedimentary particle size or sorting
Shapes of pores	Strong dependence on particle shape – a negative of particle	Greatly varied, ranges from strongly dependent positive or negative of particles to form complete independent of depositional or diagenetic components.
Uniformity of size, shape and distribution	Commonly fairly uniform within homogenous body	Variable ranging from fairly uniform to extremely heterogeneous . Even within body made up of single rock type.
Influence of diagenesis	Usually minor reduction of primary porosity by compaction and cementation.	Major influence; can create/ obliterate or modify porosity.
Influence of fracturing	Generally not of major importance in reservoir properties	Of major importance in reservoir properties if present.
Visual evaluation of porosity and permeability	Semi quantitative visual estimates commonly relative easy.	Variable, semi quantitative visual estimates range from easy to virtually impossible
Adequacy of core analysis for reservoir evaluation.	Core plugs of 1” diameter commonly adequate for matrix porosity.	Core plugs commonly inadequate, even whole cores (3”dia) may be inadequate for large pores.
Permeability and porosity interrelations	Relative consistent, commonly dependent on particle size and sorting	Greatly varied, commonly independent of particle size and sorting.

4. Summary

Reservoir petrophysics deals with two major properties viz. porosity and permeability that makes the rock strata a possible site for fluid accumulation. The total void space present in a rock viz. sandstone, carbonate etc. is referred as porosity and the interconnected porosity that allows flow of fluid through the network of pores is called effective porosity or permeability. Whereas porosity does not have any unit and expressed as percentage, the unit of permeability is 'Darcy'. Porosity does not depend on grain size but depend on grain shape, roundness and packing. Permeability depends on grain sorting. Better the sorting of grain, higher will be permeability. Porosity is broadly classified as primary and secondary. Porosities those form during and immediately after deposition are called primary and porosity formed after deposition/ lithification is referred as secondary porosity. A number of varieties of primary and secondary porosity types are discussed that help a rock strata to get reservoir quality. Capillary pressure curves help in determining size of throats connecting the pores and percentage of total pores operative as interconnected and effective.

Frequently Asked Questions-

Q1. Define porosity. Discuss different types of porosity commonly found in rock strata with illustrative figures?

Q2. Define permeability taking help of Darcy's Law. What do you understand by absolute, effective and relative permeability of a reservoir?

Q3. Enumerate fundamental differences between a sandstone and carbonate reservoir keeping in view their porosity and permeability character?

Q4. What do you understand by horizontal and vertical permeability of a reservoir? How can you account for differential permeability in a reservoir?

Multiple Choice Questions-

1. Porosity depends on

(a) Grain size
(b) Grain packing
(c) Grain packing and grain roundness
(d) Grain fabric

2. In a fractured reservoir we may get

(a) High porosity and permeability
(b) Low porosity and permeability
(c) High porosity and Low permeability
(d) Low porosity and high permeability

3. The following secondary porosity is fabric-selective

(a) Intercrystalline
(b) Mouldic
(c) Cavernous
(d) Fenestral

4. The unit of porosity is

(a) percentage
(b) darcy
(c) cm^3
(d) there is no unit for porosity

Suggested Readings:

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