Properties of Reservoir Rocks and Cap Rocks

(For Petroleum Engineering Students)

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- Reservoir pore space - porosity: Primary and Secondary porosity, Effective porosity, fracture porosity
- Permeability - effective and relative permeability
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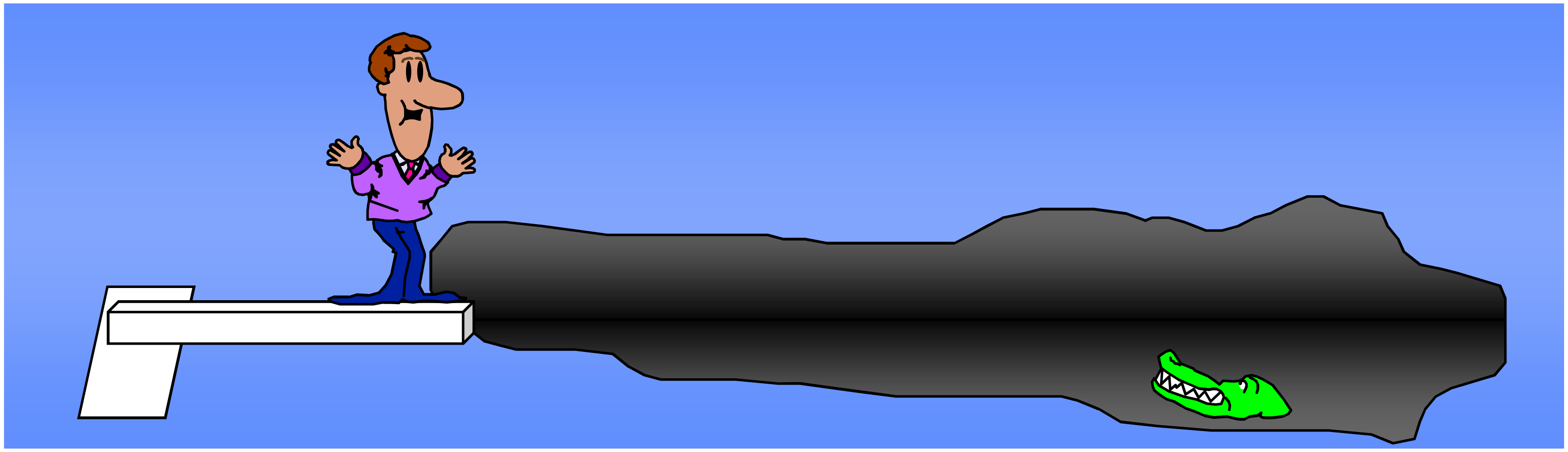
- Classification and origin of pore space
- Recrystallization - Dolomitization phenomenon
- Cementation and compaction
- Artificial or man made porosity and permeability.
- Cap Rocks: Definition and characteristics of ‘cap Rocks’.

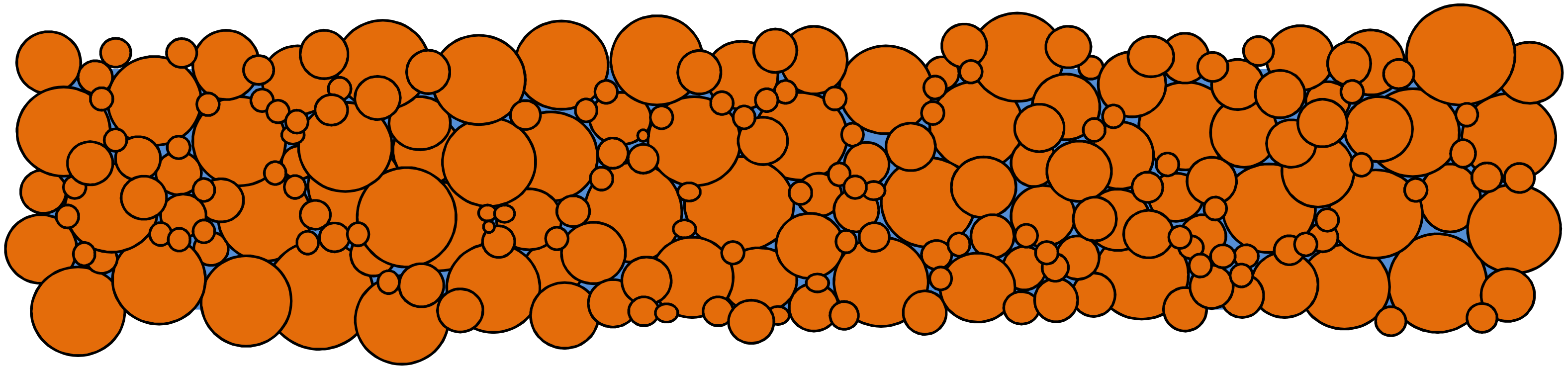
Where we can find Oil and Gas?

Where we can find Oil and Gas?

Some people think that oil is found in big pools underground…



Actually, most oil is trapped in the tiny pore spaces between grains of rock or sand. Most of these pores are too small to be seen with the naked eye.



Parameters required to Evaluate Reservoirs

(1) Water Saturation

(2) Hydrocarbon Saturation

(3) Reservoir Thickness and Area

(4) Porosity

(5) Permeability

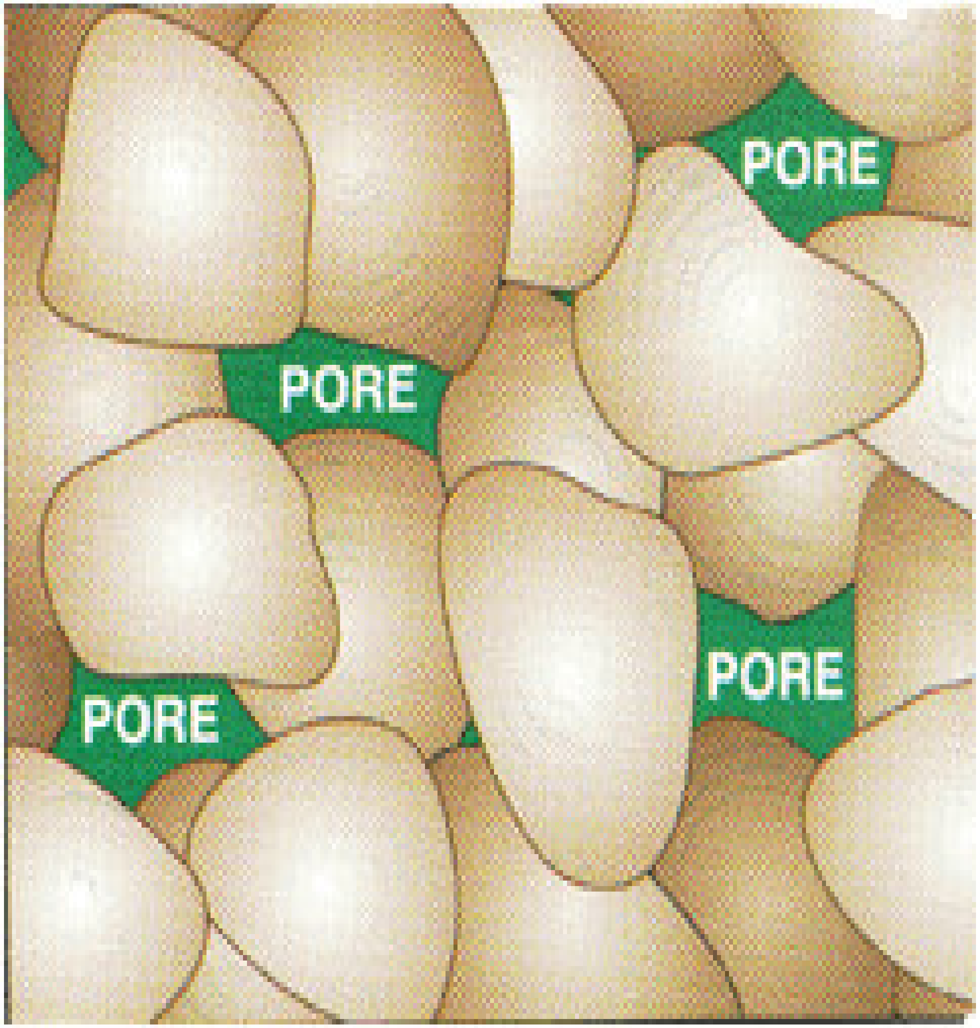
Porosity

For rock to contain petroleum and later allow petroleum to flow, it must have certain physical characteristics. Obviously, there must be some spaces in the rock in which the petroleum can be stored.

If rock has openings, voids, and spaces in which liquid and gas may be stored, It is said to be porous. For a given volume of rock, the ratio of the open space to the total volume of the rock is called porosity, the porosity may be expressed a decimal fraction but is most often expressed as a percentage. For example, if 100 cubic feet of rock contains many tiny pores and spaces which together have a volume of 10 cubic feet, the porosity of the rock is 10%.

Porosity

Pores



Porosity

Porosity is defined as the ratio of pore space to total volume of rock and is commonly expressed as a percentage. Porosity is an intensive property that describes the fluid storage capacity of rock.

Two measurements, **pore volume** and **bulk volume**, are required to obtain the percentage **porosity** from the following equation:

$$\text{Porosity} = (\text{Pore Volume} \; / \; \text{Bulk Volume}) \times 100$$

Porosity varies greatly within most reservoirs, both laterally and vertically.

If porosity is measured for each foot of core sample taken from the reservoir rock, as is the common practice, even some of the most uniform-appearing rocks show rapid marked changes in porosity.

Porosity

Porosity

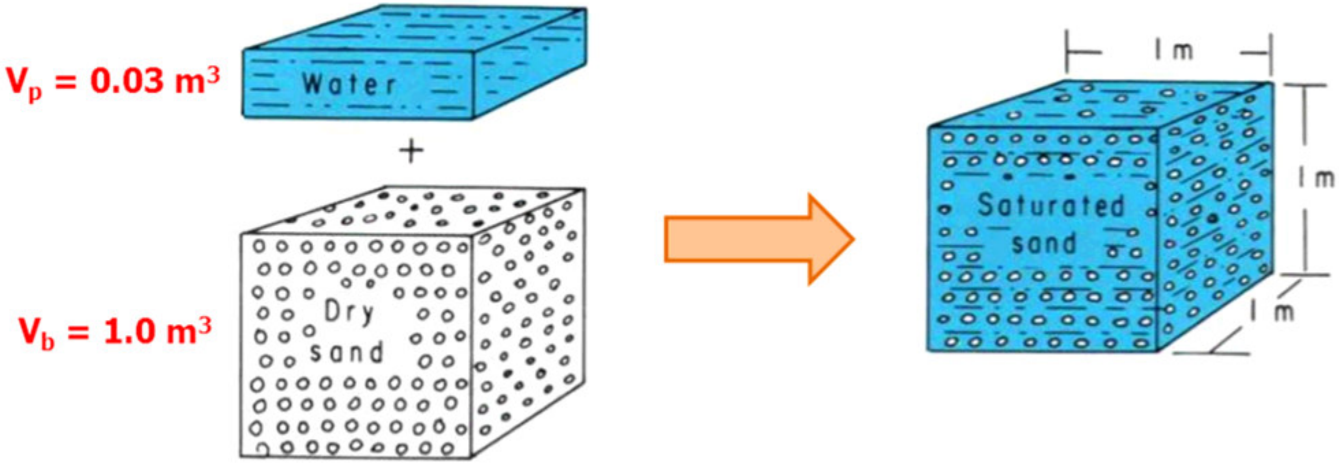
Porosity, conventionally denoted by the Greek letter "ϕ" (phi), can be measured by the following equation:

$$\phi = V_p / V_b \times 100$$

or, $$\phi = (V_b - V_g) / V_b \times 100$$

or, $$\phi = (V_b - V_{ma}) / (V_b) \times 100$$

Where, V_p = Pore Volume
V_b = Bulk Volume
V_g = Grain Volume
V_p = Matrix Volume



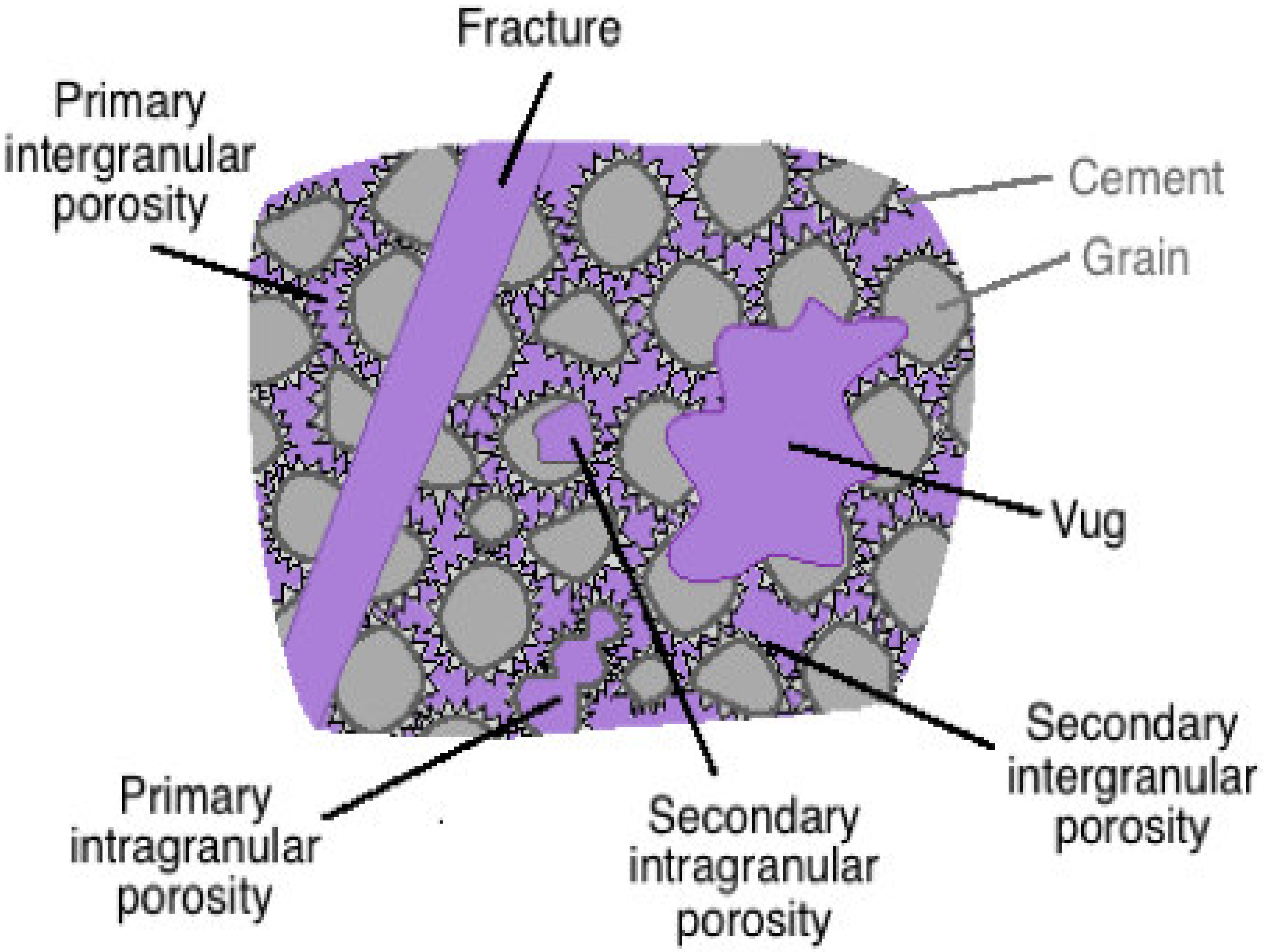
$$\text{Porosity } (\phi) = \frac{\text{Pore Volume } (V_p)}{\text{Bulk Volume } (V_b)} = \frac{0.03\ m^3}{1.0\ m^3} = 0.03 = 30\%$$

Porosity

Porosity Calculations: Uniform Spheres

- Bulk Volume = $(2r)^3 = 8r^3$
- Matrix Volume = $4 \pi r^3 / 3$
- Pore Volume = Bulk Volume - Matrix Volume

Porosity


Fracture
Primary intergranular porosity
Cement
Grain
Vug
Primary intragranular porosity
Secondary intragranular porosity
Secondary intergranular porosity

Porosity

Range of Porosity Values: For the common reservoir rock types under average operating conditions, porosity values may be viewed thus:

ϕ (%)	Qualitative Evaluation
0 – 5	Negligible
5 – 10	Poor
10 – 15	Fair
15 - 20	Good
20+	Very Good

Porosity

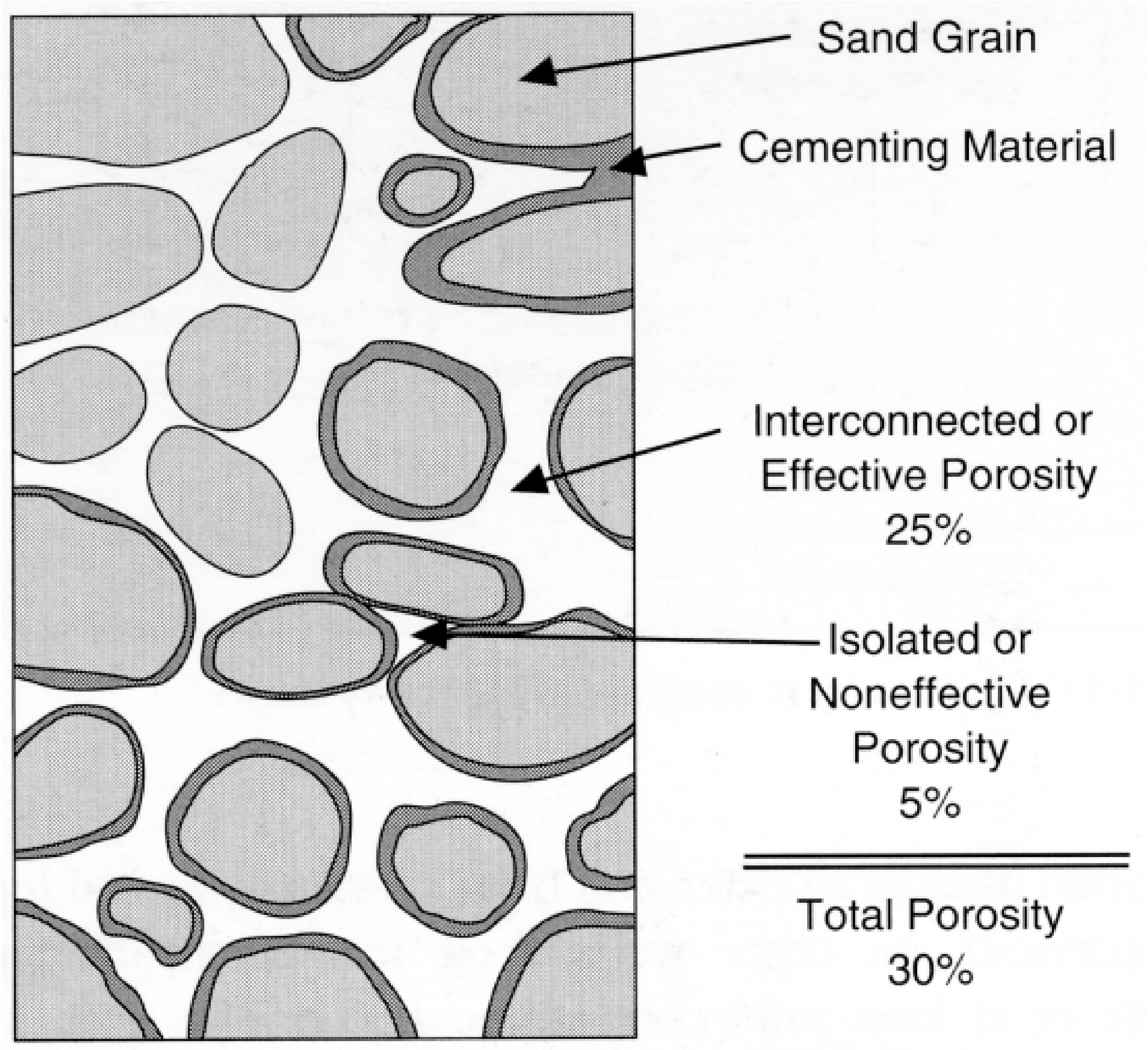
The ratio of total volume of pore space to total volume of rock is called the **absolute porosity** or **total porosity**. It includes all of the interstices or voids, whether interconnected or not.

The porosity measurement ordinarily used in reservoir studies, however, is the ratio of the interconnected pore spaces to the total bulk volume of the rock, and is termed as **effective porosity**.

Effective porosity is a measure of the void space that is filled by recoverable oil or gas; the amount of pore space that is sufficiently interconnected to yield its oil and gas for recovery.

It lies commonly in the range of 40% to 75% of the total porosity, except in unconsolidated sediments.

Porosity


Sand Grain
Cementing Material
Interconnected or Effective Porosity 25%
Isolated or Noneffective Porosity 5%
Total Porosity 30%

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:

Porosity (ϕ) = Pore Volume (V_p) / Bulk Volume (V_b) … (1)

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

Total Porosity or Absolute Porosity

The total or 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 total / absolute porosity is generally expressed mathematically by the following relationships:

Total Porosity (ϕ_t) =
Total Pore Volume (V_{tp}) / Bulk Volume (V_b) … (2)

Or

Total Porosity (ϕ_t) =
[Bulk Volume (V_b) - Grain Volume (V_g)]/ Bulk Volume (V_b) … (3)

Effective Porosity

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

Effective Porosity (ϕ_e) =

Interconnected Pore Volume (V_{icp}) / Bulk Volume (V_b) … (4)

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.

Effective Porosity

Porosity may be classified according to the mode of origin as original induced. The original / primary porosity is that developed in the deposition of the material, while induced / secondary porosity is that developed by some geologic process subsequent to deposition of the rock.

The intergranular porosity of sandstones and the inter-crystalline and oolitic porosity of some limestones typify original porosity.

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.

Effective Porosity

For direct quantitative measurement of porosity, reliance must be placed on formation samples obtained by coring. Since effective porosity is the porosity value of interest to the petroleum engineer, particular attention should be paid to the methods used to determine porosity.

For example, if the porosity of a rock sample was determined by saturating the rock sample 100 percent with a fluid of known density and then determining, by weighing, the increased weight due to the saturating fluid, this would yield an effective porosity measurement because the saturating fluid could enter only the interconnected pore spaces.

On the other hand, if the rock sample were crushed with a mortar and pestle to determine the actual volume of the solids in the core sample, then an absolute porosity measurement would result because the identity of any isolated pores would be lost in the crushing process.

Effective Porosity

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. The total bulk volume of the reservoir can be determined from the following expressions:

Bulk volume = 43,560 Ah, ft^3 ... (5)

or

Bulk volume = 7,758 Ah, bbl ... (6)

where A = areal extent, acres
h = average thickness

Effective Porosity

The reservoir pore volume PV can then be determined by combining Equations 5 and 6 with 4.

Expressing the reservoir pore volume in cubic feet gives:

$PV = 43{,}560\ Ah\phi$, ft^3 … (7)

Expressing the reservoir pore volume in barrels gives:

$PV = 7{,}758\ Ah\phi$, bbl … (8)

Nature of Porosity

Porosity may be Primary (original) or Secondary.

Primary porosity is that which the rock possesses at the end of its depositional phase, on first burial; it is the void space that would be present if the grains has not been altered, fractured, or dissolved. Primary porosity depends on several factors:

(a) The degree of uniformity of grain size;

(b) The shapes of the grains;

(c) The method of deposition, and so manner of packing;

(d) The effect of compaction, during or after deposition

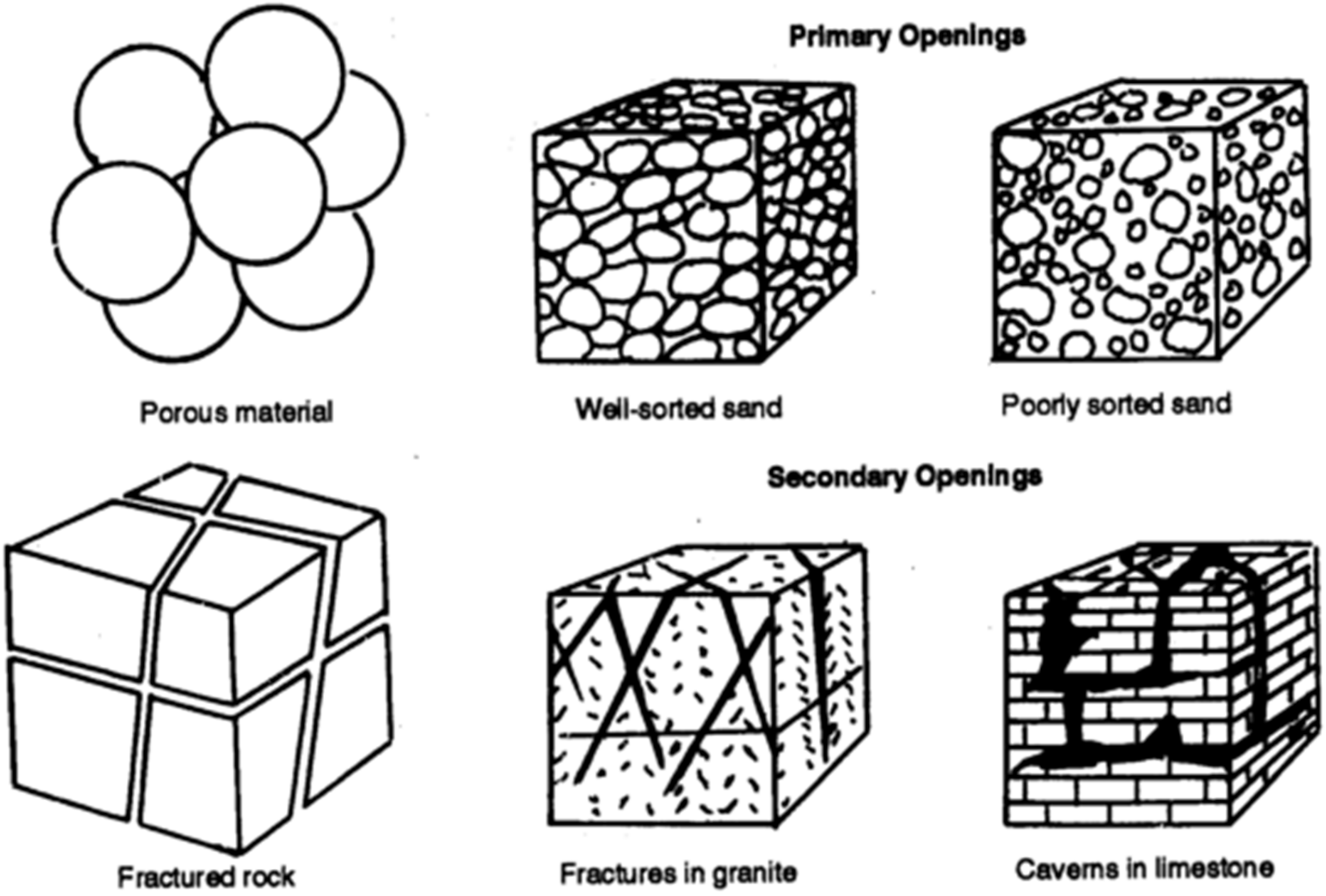
Nature of Porosity

Secondary porosity is additional void space due to post-depositional or diagenetic processes, but the total porosity may be much less than the original porosity.

In sandstone reservoirs, modifications of primary porosity are due principally to the interlocking of grains through compaction, contact-solution and re-deposition, and to cementation.

In carbonate reservoirs, the principal modifications are by solution, recrystallization (especially dolomitization), fracturing, and cementation.

Nature of Porosity



Principal Factors Controlling Porosity

The following factors control the porosity of any formation or reservoir:

1. **Grain or Particle Size**

2. **Grain and Particle Shape**

3. **Method of Deposition**

4. **Effects of Compaction**

Principal Factors Controlling Porosity

1. Grain or Particle Size

The actual particle size is theoretically immaterial. However, all ordinary depositional mechanisms are such that the coarser the average grain size the greater the average variety of sizes.

A rock may easily consist of very fine sand grains and little else; it will not long survive consisting of tennis-ball-sized cobbles and nothing else. Hence finer grained sediments in general have higher porosities than coarser grained sediments because there are invariably other factors in play.

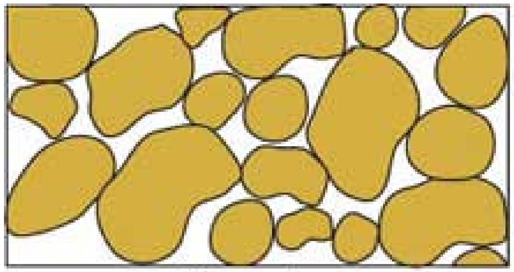
For example, freshly deposited clays have porosities of 50% to 85%. Fine sandy loam may attain 52%, and fine sand 48%, but coarse sand without cement is unlikely to exceed 40%.

In sandstones, the sizes of the pores and pore-throats commonly retain a close relation with particle size.

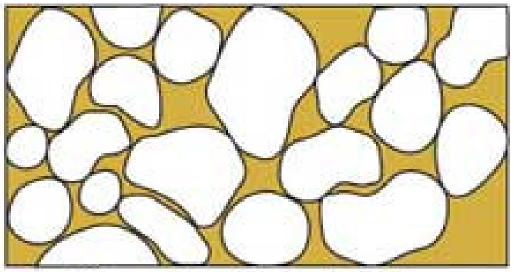
Principal Factors Controlling Porosity

In unaltered carbonates, there is also a general relation, the pore diameter (μ_p) being smaller than the grain diameter (μ_g); but carbonates undergo such a variety of modifications that the relation is commonly obscured or destroyed.

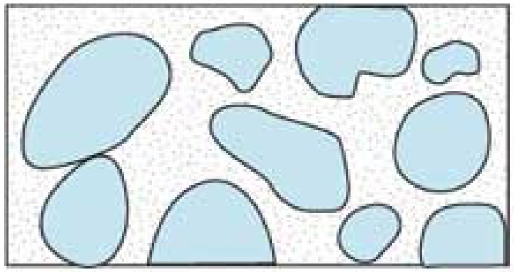
Grain-size Distributions



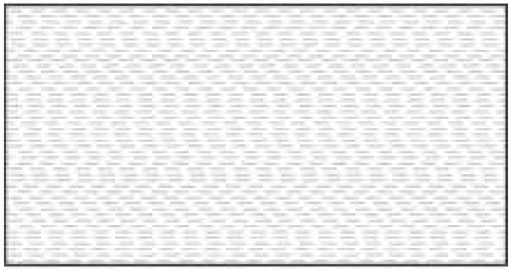
Gravel
well sorted, high porosity



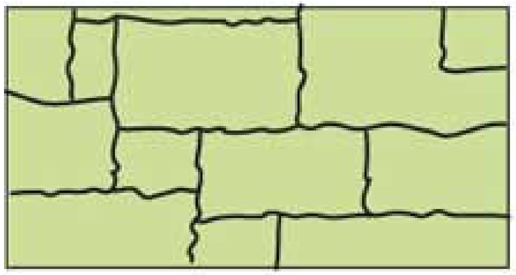
Gravel - Sand - Clay
poorly sorted, low porosity



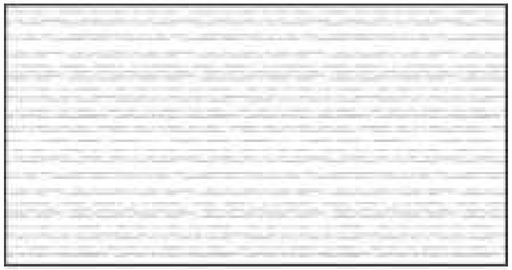
Cemented Sandstone
low porosity



Clay
high porosity



Limestone
low porosity



Shale
low porosity

Grain-size Distributions

Large than 355 µm

300-355 µm

250-300 µm

150-250 µm

Principal Factors Controlling Porosity

2. Grain or Particle Shape

In sandstones, the shapes of the pores are obviously strongly dependent on the shapes of the grains.

In carbonates, this is seldom the case unless complete dolomitization has occurred.

However, the amount of pore space is ambiguously related to grain shapes. The greatest porosity is theoretically possessed by a rock consisting of spherical grains of uniform size.

Cubic packing of uniform spherical grains results in porosity of 47.6%, orthorhombic packing of 39.5% and rhombohedral packing of about 26%.

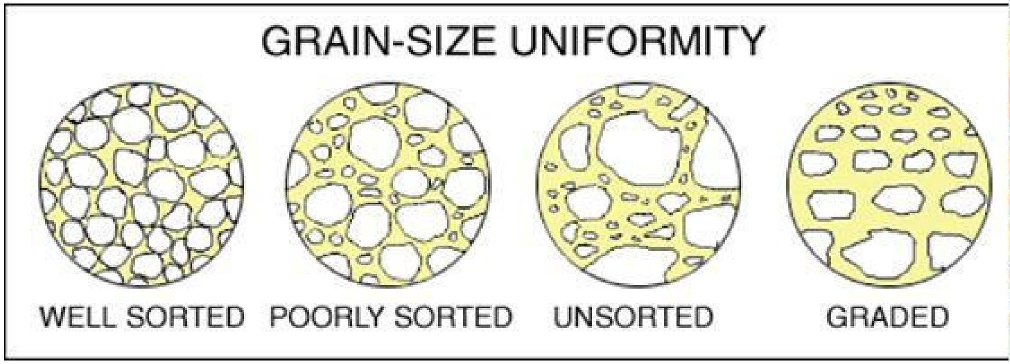
The lowest porosity is theoretically provided with unsorted angular grains.

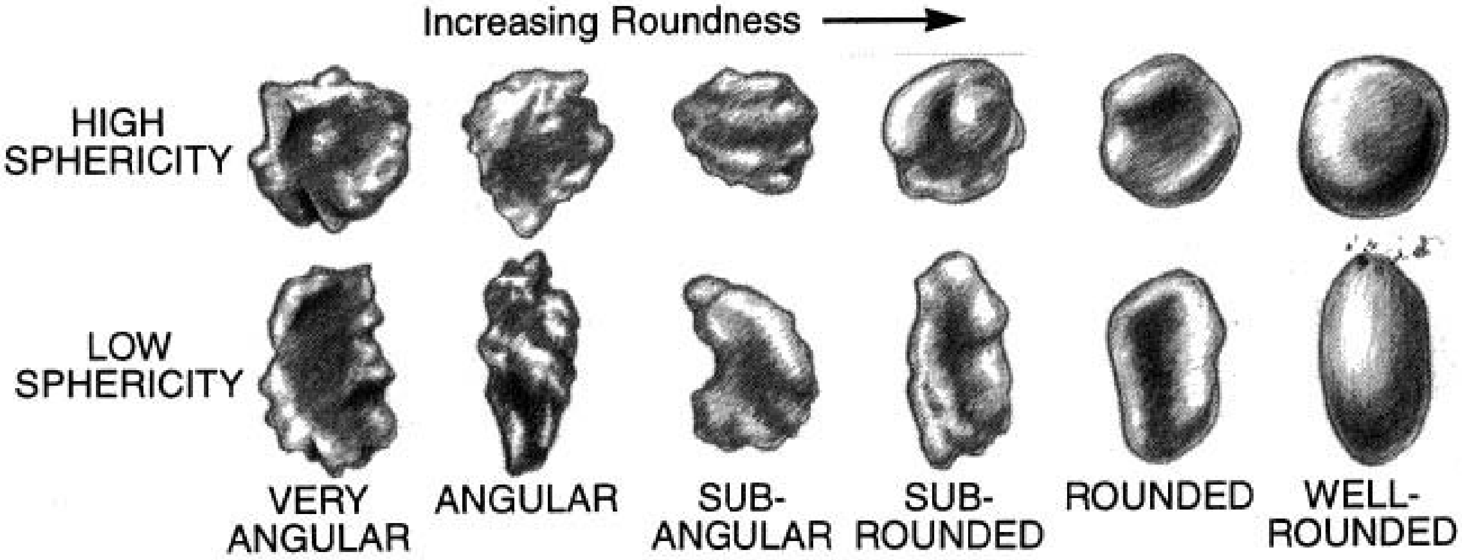
Principal Factors Controlling Porosity

In practice, grain shapes have unexpected effects. Grains of high sphericity tend to pack with minimum pore spaces; as absolute uniformity of grain size is never achieved, even in windblown sands or oolitic limestones, bimodal and polymodal size patterns lower the theoretical porosities.

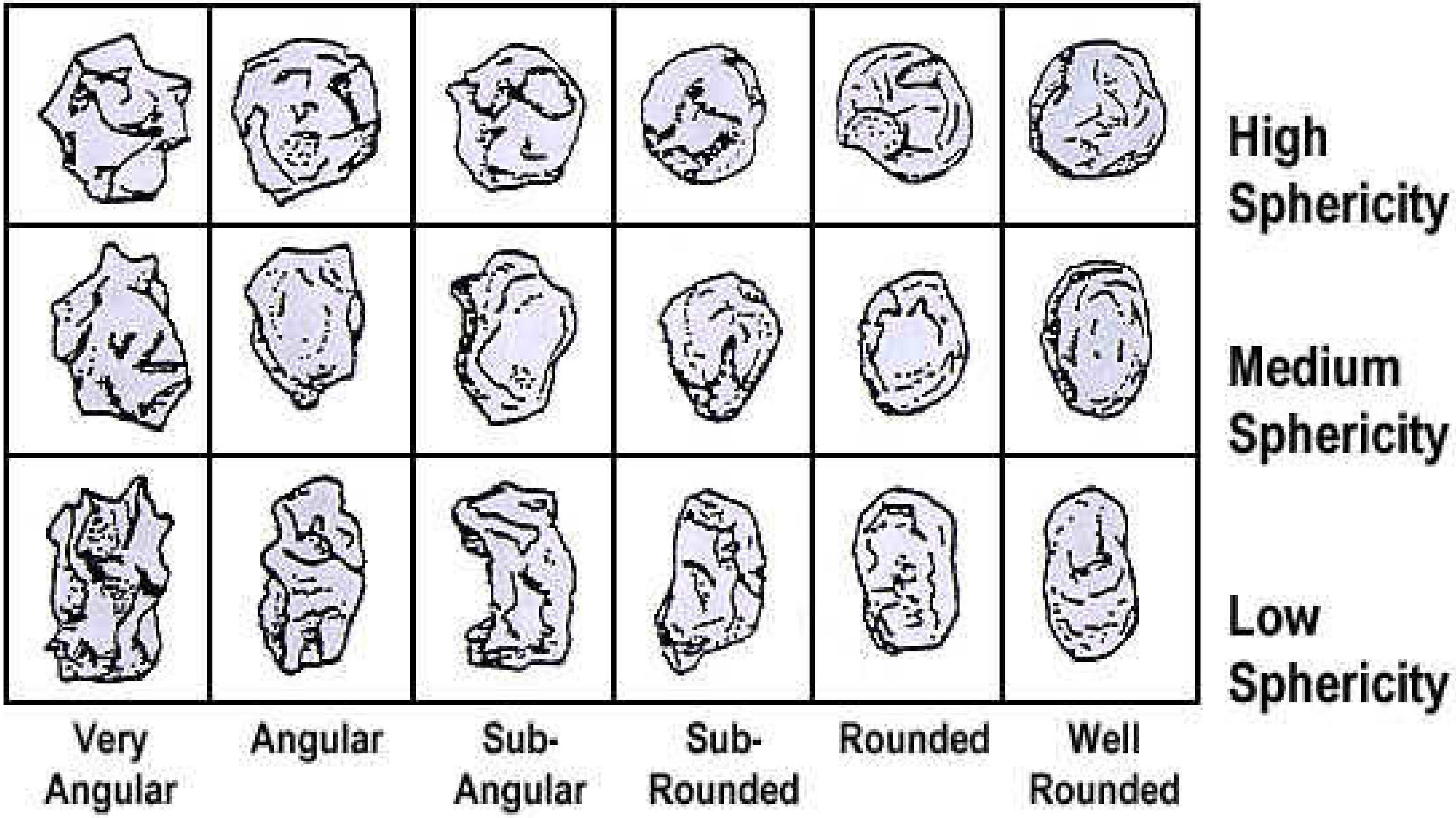
The best actual porosities are often found in rocks consisting of well sorted angular or subangular grains, as in many calcarenites.

Principal Factors Controlling Porosity

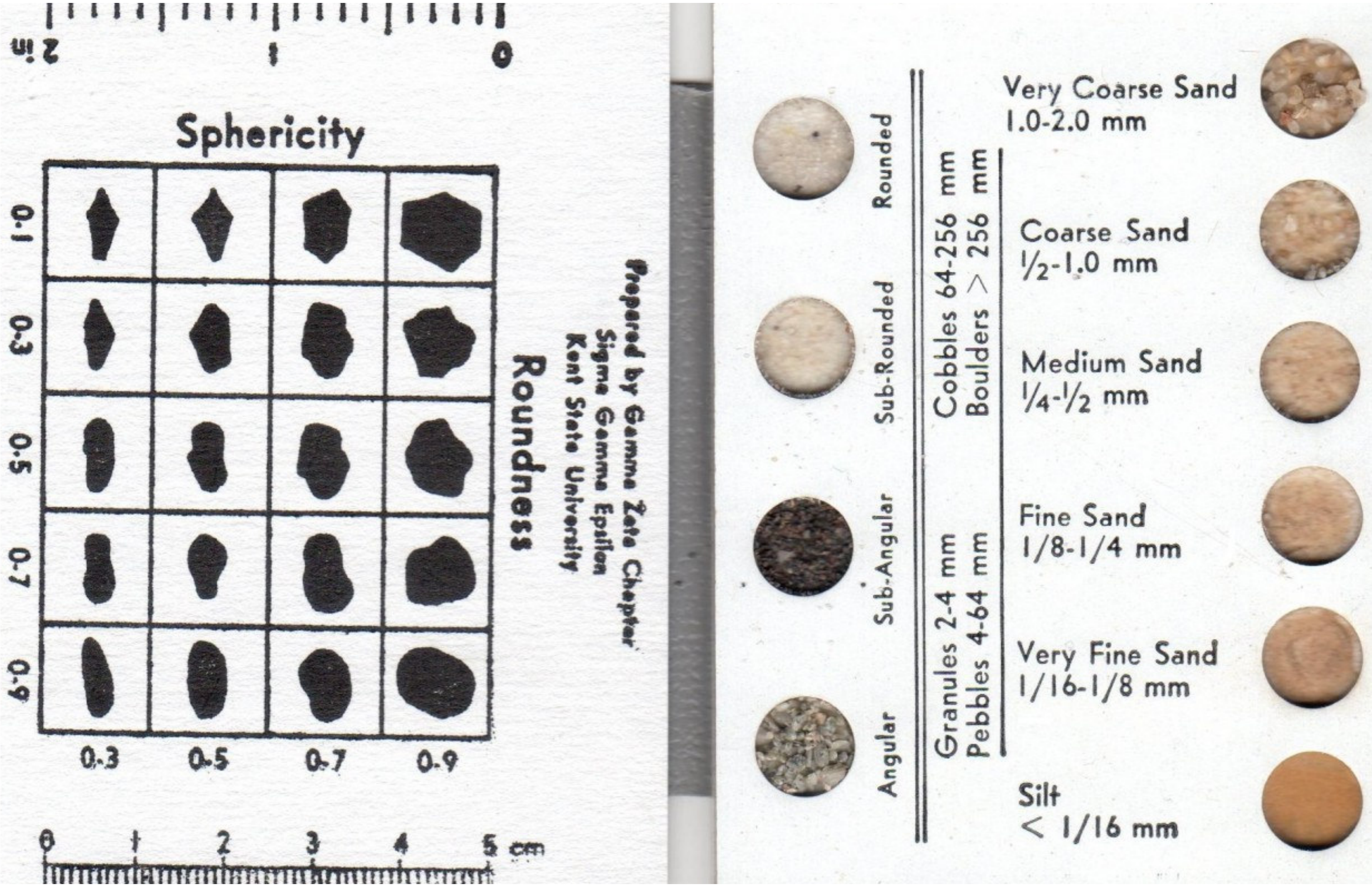




Principal Factors Controlling Porosity



Principal Factors Controlling Porosity



Principal Factors Controlling Porosity

3. Method of Deposition

Poorly sorted sediments are less porous than well sorted sediments; the ultimate porosity is highly dependent upon the degree of sorting.

Packing helps to sort the grains according to size, but it tends always to make the rock as tight as possible.

Depositional packing of course is continued by compaction under an increasing load of overlying sediments.

Principal Factors Controlling Porosity

4. Effects of Compaction

Compaction may be defined as the process by which porosity is reduced below the water-content boundary between the plastic and the semi-solid state (the so-called Atterberg Plastic Limit).

The process is induce by stress, the grains being deformed in a manner which is both inelastic and irreversible; they do not recover elastically when the load is removed.

Sands compacts only about 2% under 25 kPa (equivalent to about 1000 m of burial). As the reduction of porosity with burial is essentially exponential, it becomes exceedingly slow at greater depths, but the durations of burial are so great that sandstones of different ages can broadly discriminated by their porosities.

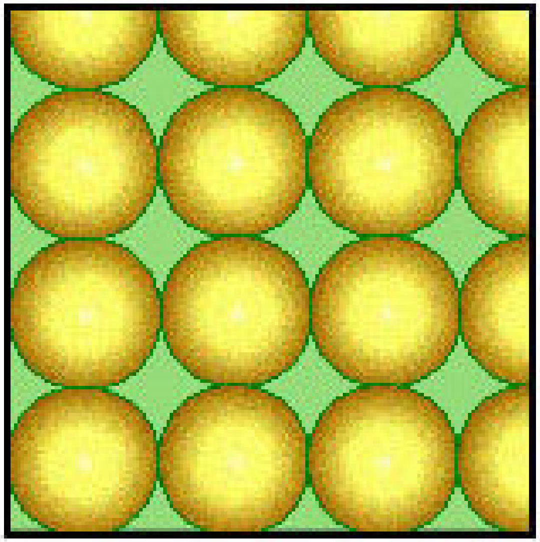
Principal Factors Controlling Porosity

For most ancient sandstones it is difficult to know what the original porosity was and how much of its reduction has been due to compaction.

For Tertiary sandstones, however, and especially for Neogene sandstones, this handicap is much less severe. Tertiary sandstones from the Great Valley of California, having initial porosities of 35% to 40%, lost 0.5% to 0.6% of their porosity per 100m of burial, regardless of their actual age. Gulf Coast sandstones lost 0.4% to 0.5% per 100m of burial.

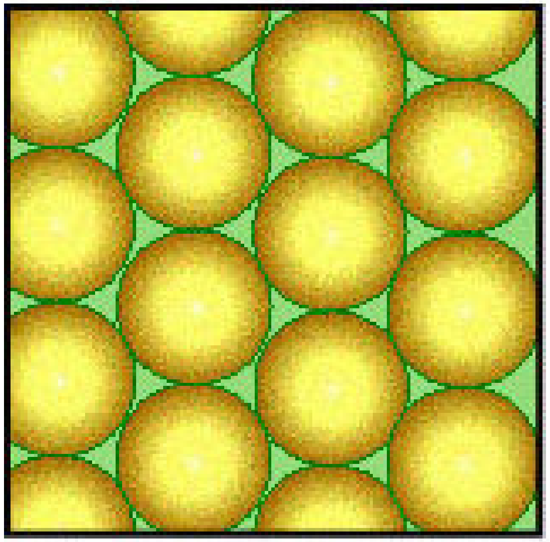
An allied factor influencing the rate of porosity loss with depth is the geothermal gradient. In clastic sequences, at least, higher geothermal gradients delays the rate of loss of both porosity and permeability.

Types of Pores Distribution



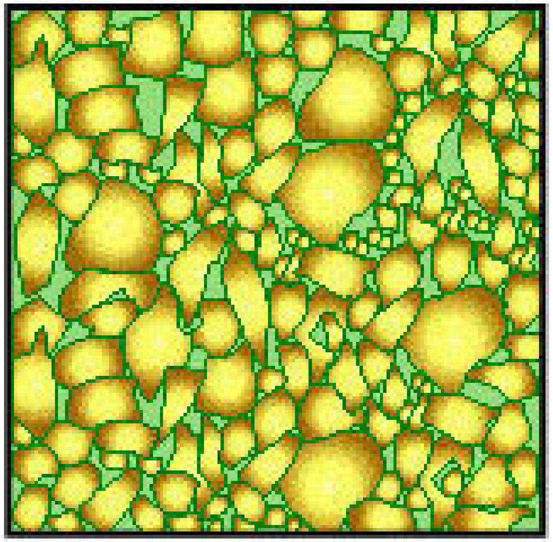
Uniform Spheres
with Cubic Packing

Porosity = 47.6%
(for any Sphere Radius)



Uniform Spheres with
Rhombohedral Packing

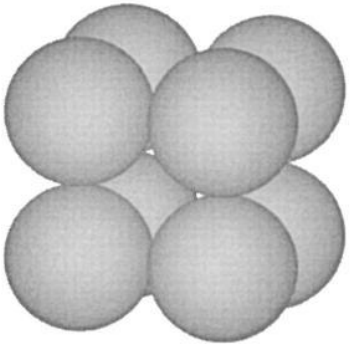
Porosity = 25.96%
(for any Sphere Radius)



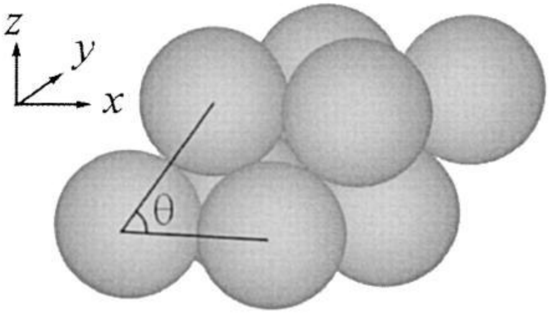
Non-Uniform Particles
with Non-Uniform Packing
of Typical Sandstone
Resrvoir Rock

Porosity ≈ 5-25%

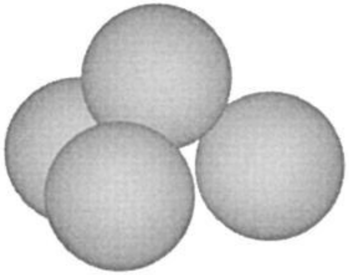
Packing of Sediments



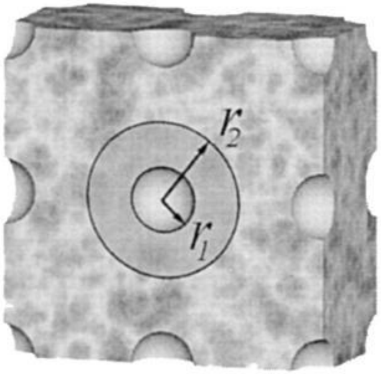
(a) Cubic



(b) Rhombic

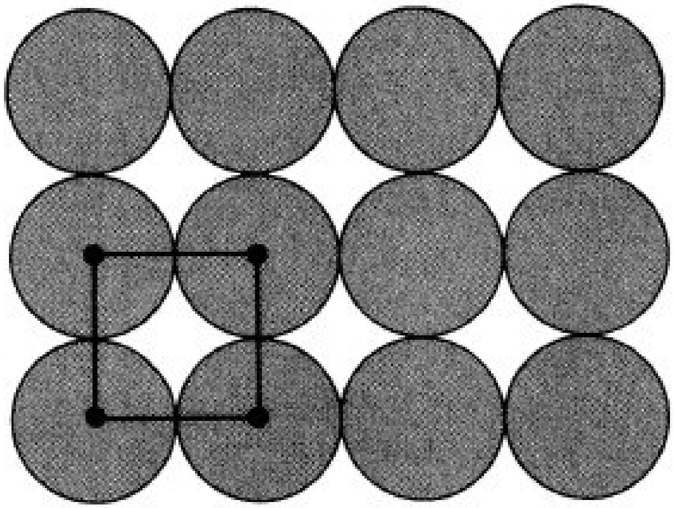


(c) Generalized Rhombohedral

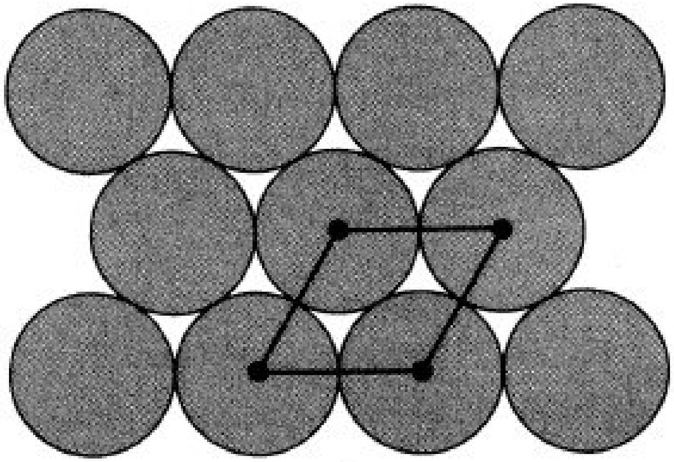


(d) Closed Pore Embedded in Matrix

Packing of Sediments



Cubic packing
(48% porosity)

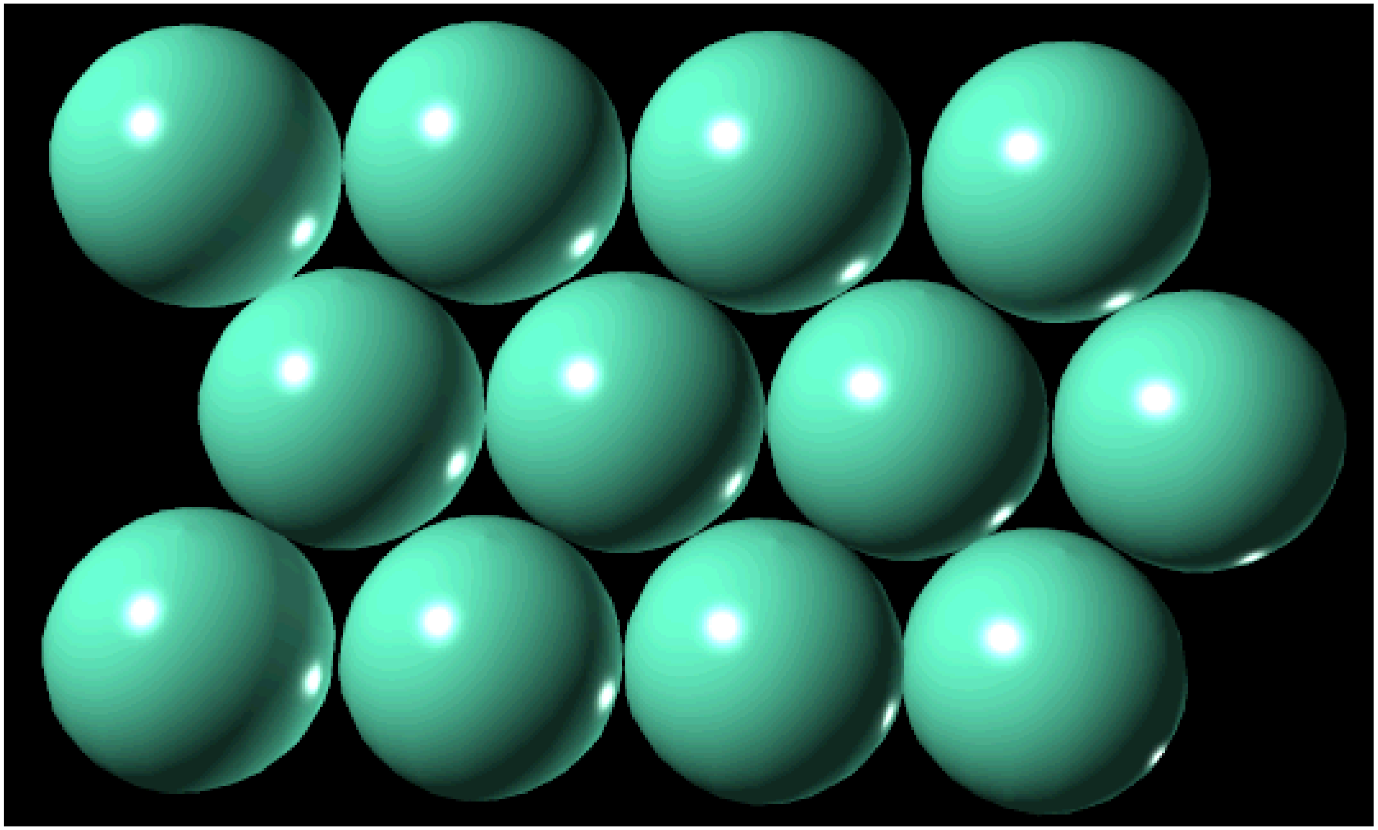


Rhombohedral packing
(26% porosity)

Packing of Sediments

Rhombic Packing of Sphere

Porosity = 27 %



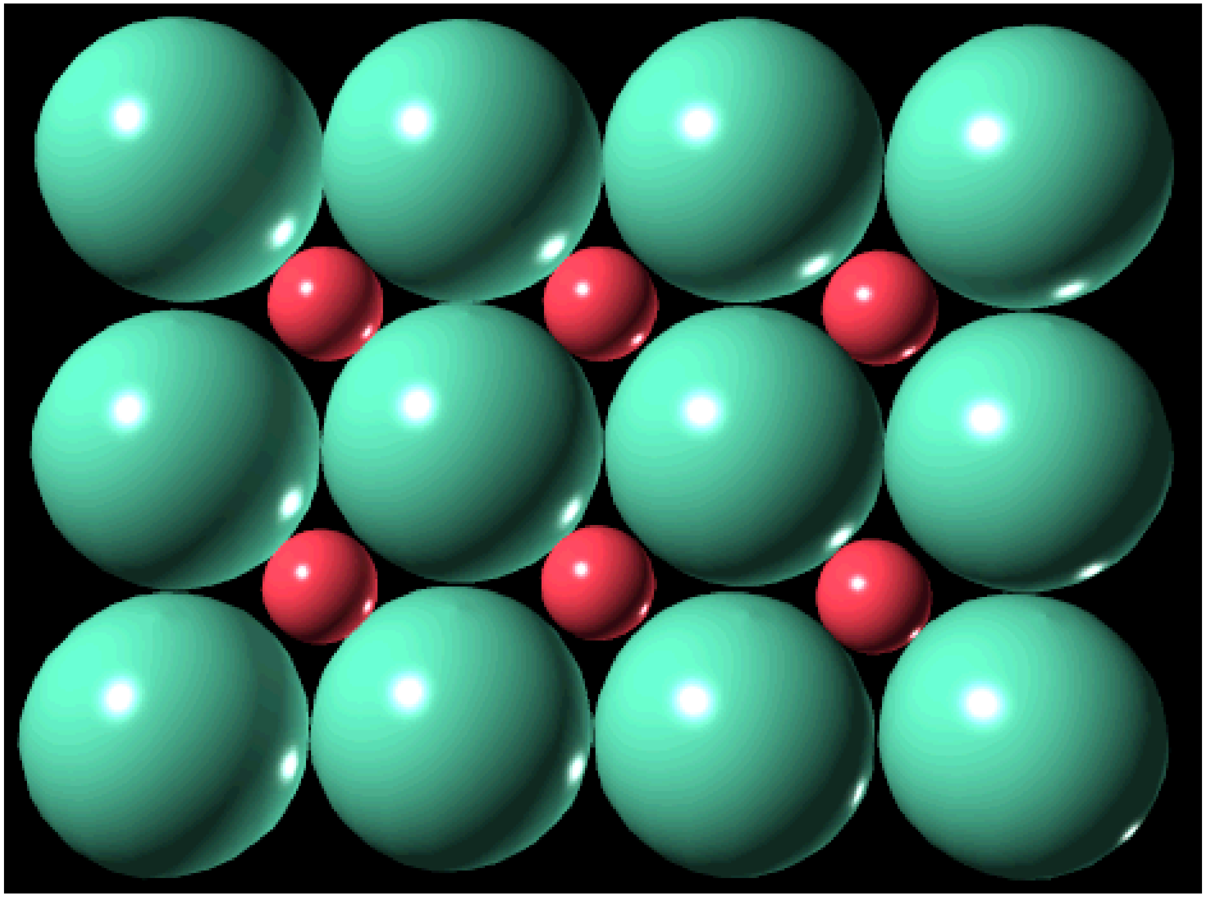
Packing of Sediments

Rhombic Packing of Sphere

Packing of Sediments

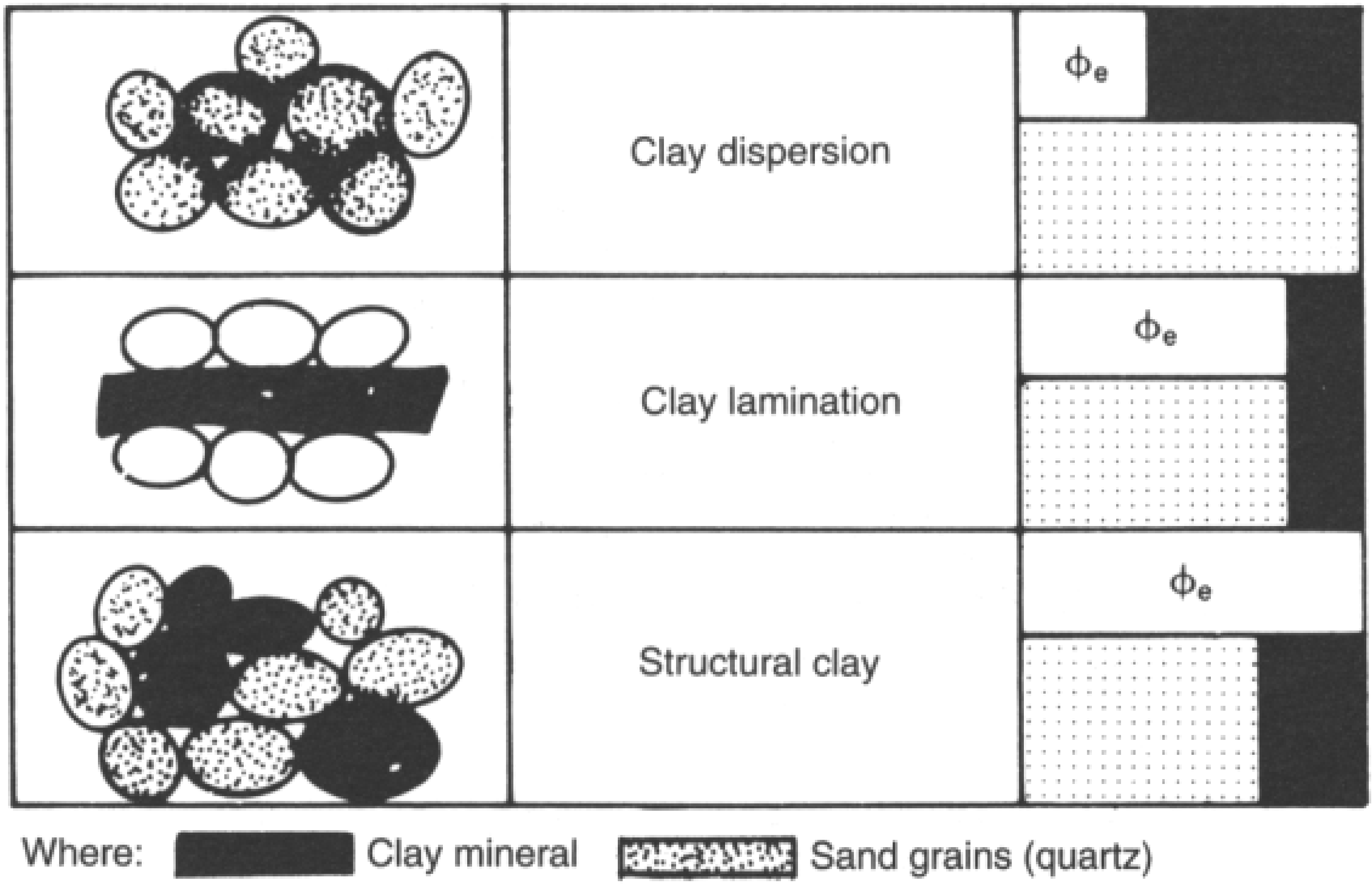
Packing of Two Sizes of Sphere

Porosity = 14%



Packing of Sediments

Clay Packing



Typical Porosity of Some Materials

Unconsolidated Deposits	
Gravel	25% - 40%
Sand	25% - 50%
Silt	35% - 50%
Clay	40% - 70%

Rocks	
Fractured Basalt	5% - 50%
Karst Limestone	5% - 50%
Sandstone	5% - 30%
Limestone, Dolomite	0% - 20%
Shale	0% - 10%
Fractured Crystalline Rock	0% - 10%
Dense Crystalline Rock	0% - 5%

Application of Porosity

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. The total bulk volume of the reservoir can be determined from the following expressions:

Bulk volume = 43,560 Ah, ft3

or

Bulk volume = 7,758 Ah, bbl

where A = areal extent, acres

h = average thickness

Compaction and Porosities of Shales

The behavior of clay rocks under compaction is quite different from that of sandstones. There are two inter-dependent reasons for the difference. The first is the high intrinsic (inherent) porosity of freshly deposited clays; only about 50% of their total initial volume actually consists of solids. Clay minerals are phyllosilicates. They tend to acquire parallel deposition of their platelets under compactions, bur initially the high water content causes the platelets to adopt a “house of cards” arrangement, with weak parallelism. The second reason for the compactibility of clay rocks is that not all their initial water content is held in the pore spaces.

We simply observed that some clays as originally deposited contain high proportion of expandable clay, especially smectite, and these clays contain “bound” water, between the layers of their crystals lattices, in addition to the water in their pores.

Compaction and Porosities of Shales

As both portions of the water content of expandable clays are expelled under increasing burial, the clay minerals change to other, non-expandable species having much lower intrinsic porosity.

According to James Momper, the diameters of typical clayrock pores ranges from 1nm to 3nm. Pores of these sizes do not have much space to lose any compaction, but 10% to 30% of total clay porosity consists of very much larger pores, from 0.05µm to 20 µm in diameter. It is these larger pores that hold most of the initial fluid content of the mud, and they must eventually undergo most of the volume and fluid loss under compaction.

Compaction and Porosities of Carbonates

The carbonates also undergo compaction when buried, but the process quite different from that in clastic sediments. Compaction may reduce the thickness of a carbonate formation by as much as 20% if the rock contains sufficient non-skeletal materials (especially lime mud and pellets). Wholly skeletal limestones undergo much less compaction, reefs hardly any.

The act of compaction, however, instigates pressure solution, which is much more important in limestones than in clastic sediments and quickly becomes dominant over simple mechanical compaction.

It takes place especially around fossils, flints, and other objects interrupting the bedding. As it progresses, layers of insoluble residue, including organic matter, are concentrated into seams. Familiar cases are stylolite seams and the nodular, castellated segregations called “false breccia”. Advanced pressure solution can eliminate whole beds of limesone.

Macropores and Micropores

We have seen that pore sizes are commonly bimodal of polymodal, especially in sandstones. We shall further see that, the water-wet environment of nearly all water-laid sedimentary rocks, capillarity ensures that water normally occupies the finer pore space even if oil or gas fills all the coarse porosity.

The coarse porosity may yield water-free oil, but pores smaller than 0.005mm to 0.010mm (5µm to 10µm) are almost certain to contain water both through capillarity and through imbibition.

Larger pores cannot hold water by capillarity. This high irreducible water saturation in the finer pores means that effective porosity in invariably lower than total porosity.

The reduction of effective porosity below the measured total porosity is brought about by the partitioning of the larger pores by authigenic clay – mineral cements.

Micro-pores and Macro-pores

The ration of fine pore space to coarse pore space consequently commonly increases during diagenesis. The critical dimension of the finer pores is not their volume but their smallest linear dimension; the pores themselves may be equant, planar, tubular, or any variant of these shapes.

If we define micro-porosity (ϕ_m) as the percentage of apertures with radius less than 0.5µm, and macro-porosity (ϕ_M) as the percentage of apertures larger than that, then high permeability, low water saturation, and good reservoir performance are likely only if ϕ_M is substantially higher than ϕ_m.

If the two are about equal, only the macro-pores will yield hydrocarbons, and measurements of total porosity will exaggerate the effective porosity by as much as 50%.

Micro-pores and Macro-pores

If ϕ_M is much less than ϕ_m, low permeability and high irreducible water saturation will result in poor reservoir performance.

Macro-porosity may be converted to micro-porosity by mechanisms other than clay-mineral partitioning.

Other types of cementation are equally possible. Various replacement reactions, such as those converting micas to clays, may lead to cracks (either of shrinkage or of expansion) and so to micro-pores.

The effect of compaction, deformation, solution, and grain corrosion may also contribute to the conversion.

Determination of Reservoir Porosity

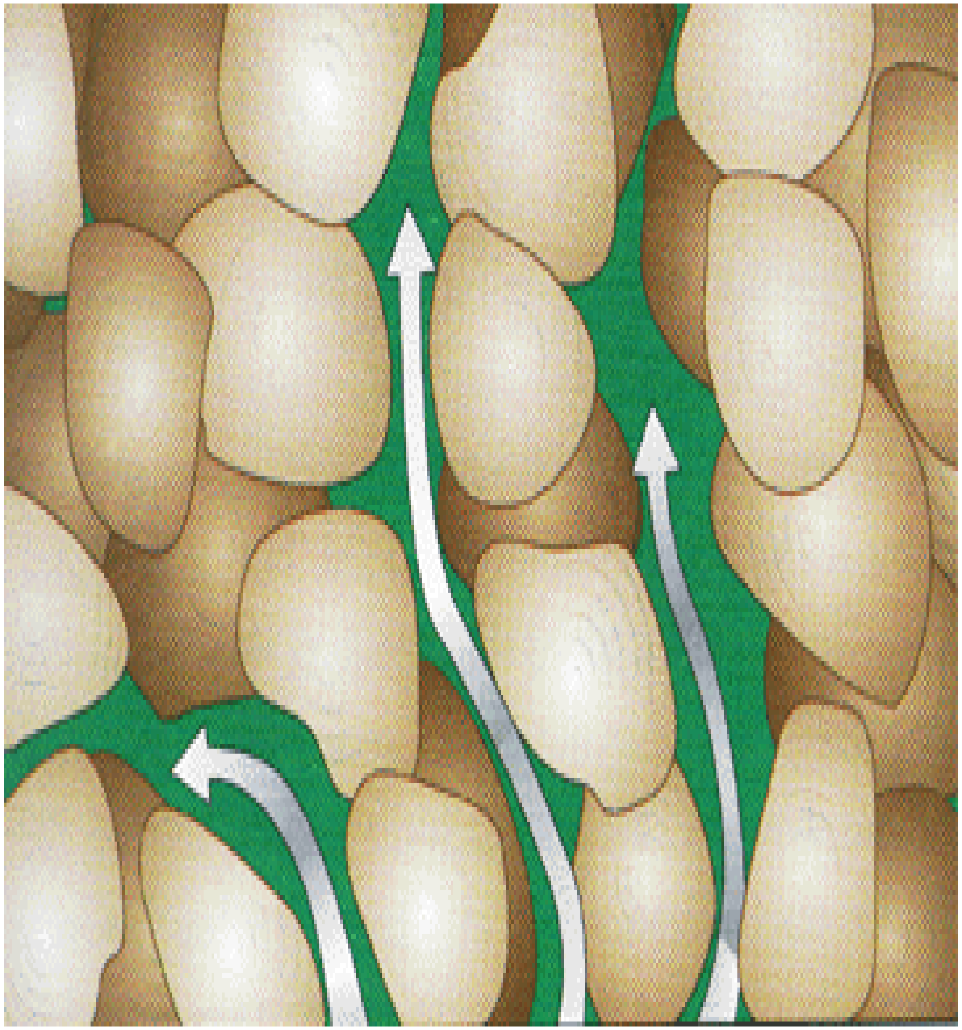
There are number of techniques for measuring the porosity of a reservoir rock. The common basis is the withdrawal of air from the pore spaces under vacuum, and the measurement of the volume of displaced air at atmospheric pressure.

For clastic reservoirs, the measurements are commonly made on small-diameter core "plugs".

For carbonate reservoirs, the nature of the porosity is insufficiently homogeneous or predictable for such a small sample to be adequate; in particular, a small plug may completely miss the large pores like vugs (cavities). Carbonate porosity is therefore better determined by full core analysis.

Permeability

Permeability



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.

Permeability

If a horizontal linear flow of an incompressible fluid is established through a core sample of length L and a cross-section of area A, then the governing fluid flow equation is defined as

$$v = -(k/\mu)(dp/dL) \quad \dots (1)$$

Where v = apparent fluid flowing velocity, cm/sec
k = proportionality constant, or permeability, Darcys
dp/dL = pressure drop pet unit length, atm/cm

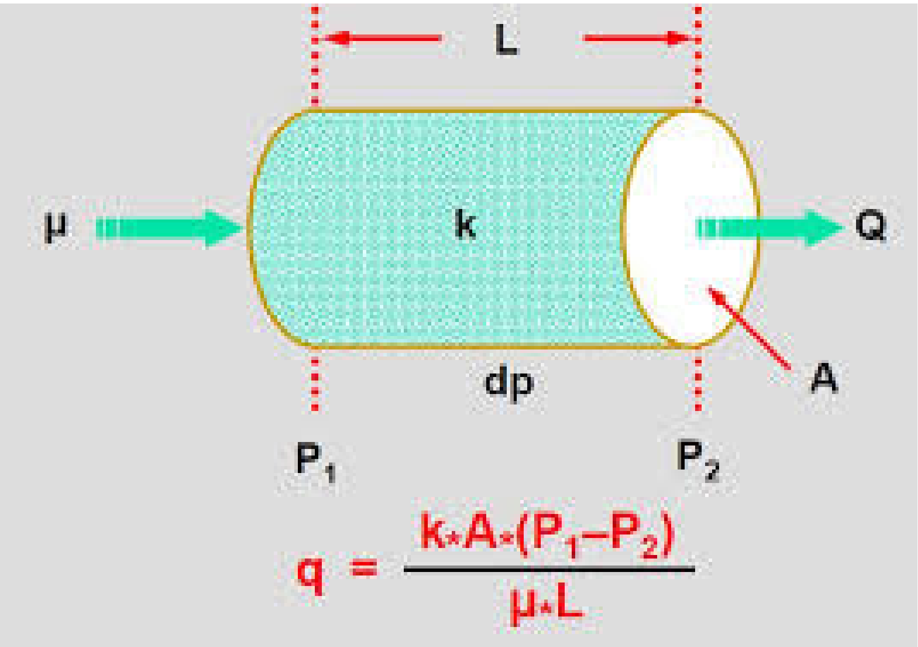
The velocity, v, in Equation 1 is not the actual velocity of the flowing fluid but is the apparent velocity determined by dividing the flow rate by the cross-sectional area across which fluid is flowing.

Permeability

Substituting the relationship, q/A, in place of n in Equation 1 and solving for q results in

$$q = (kA/\mu)\,(dp/dL) \;\ldots\; (2)$$

Where
q = flow rate through the porous medium, cm^3/sec
A = cross-sectional area across which flow occurs, cm^2



Permeability

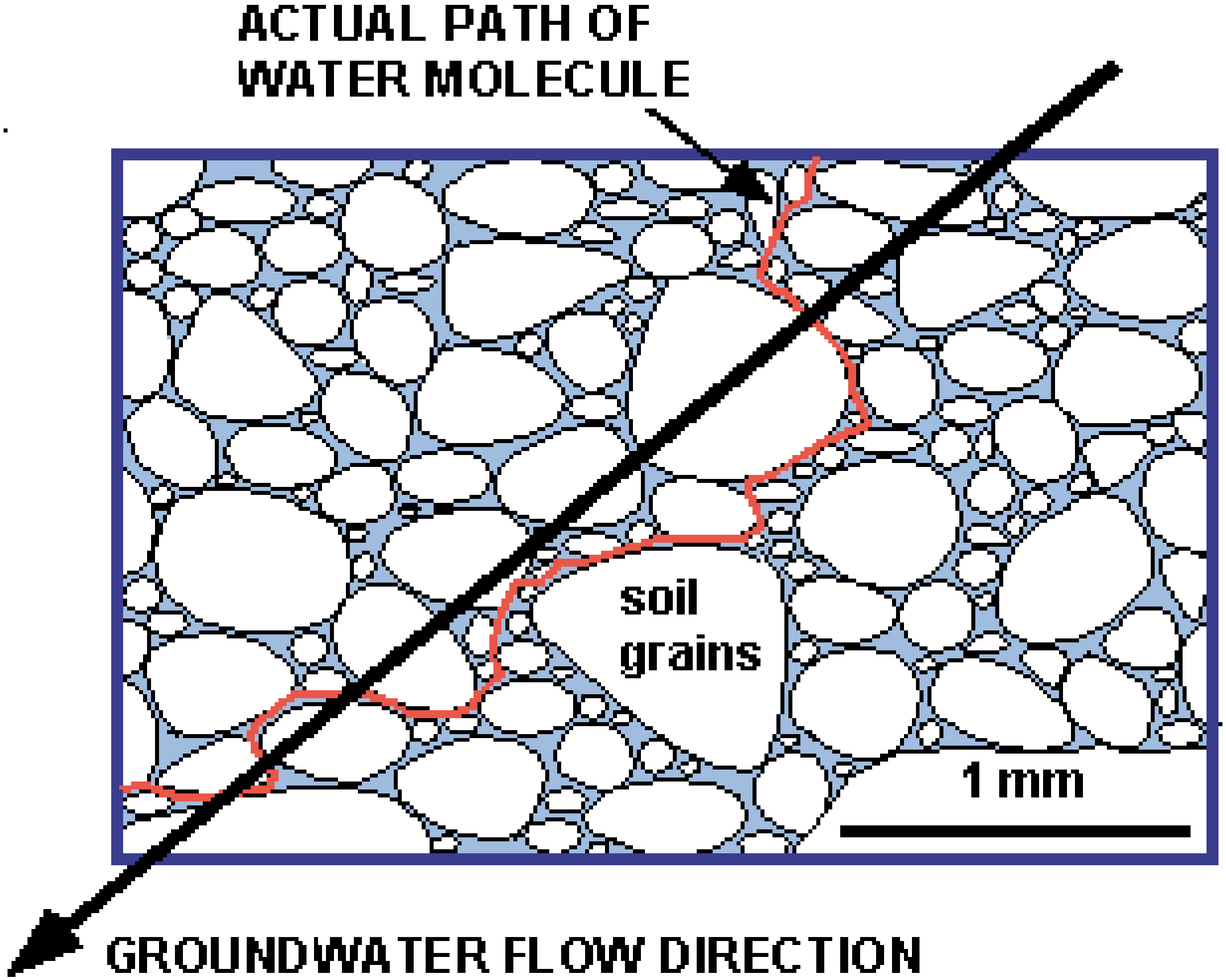
With a flow rate of one cubic centimeter per second across a cross-sectional area of one square centimeter with a fluid of one centipoise viscosity and a pressure gradient at one atmosphere per centimeter of length, it is obvious that k is unity.

For the units described above, k has been arbitrarily assigned a unit called Darcy in honor of the man responsible for the development of the theory of flow through porous media. Thus, when all other parts of Equation 2 have values of unity, k has a value of one Darcy.

One Darcy is a relatively high permeability as the permeabilities of most reservoir rocks are less than one Darcy.

In order to avoid the use off ractions in describing permeabilities, the term millidarcy is used. As the term indicates, one millidarcy, i.e., 1 md, is equal to one-thousandth of one Darcy or 1 Darcy = 1000 md

Permeability



Absolute Permeability

Effective Permeability

Relative Permeability

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.

Relative Permeability

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 to the absolute permeability, or:

$$k_{ro} = k_o/k$$
$$k_{rg} = k_g/k$$
$$k_{rw} = k_w/k$$

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

Relative Permeability

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

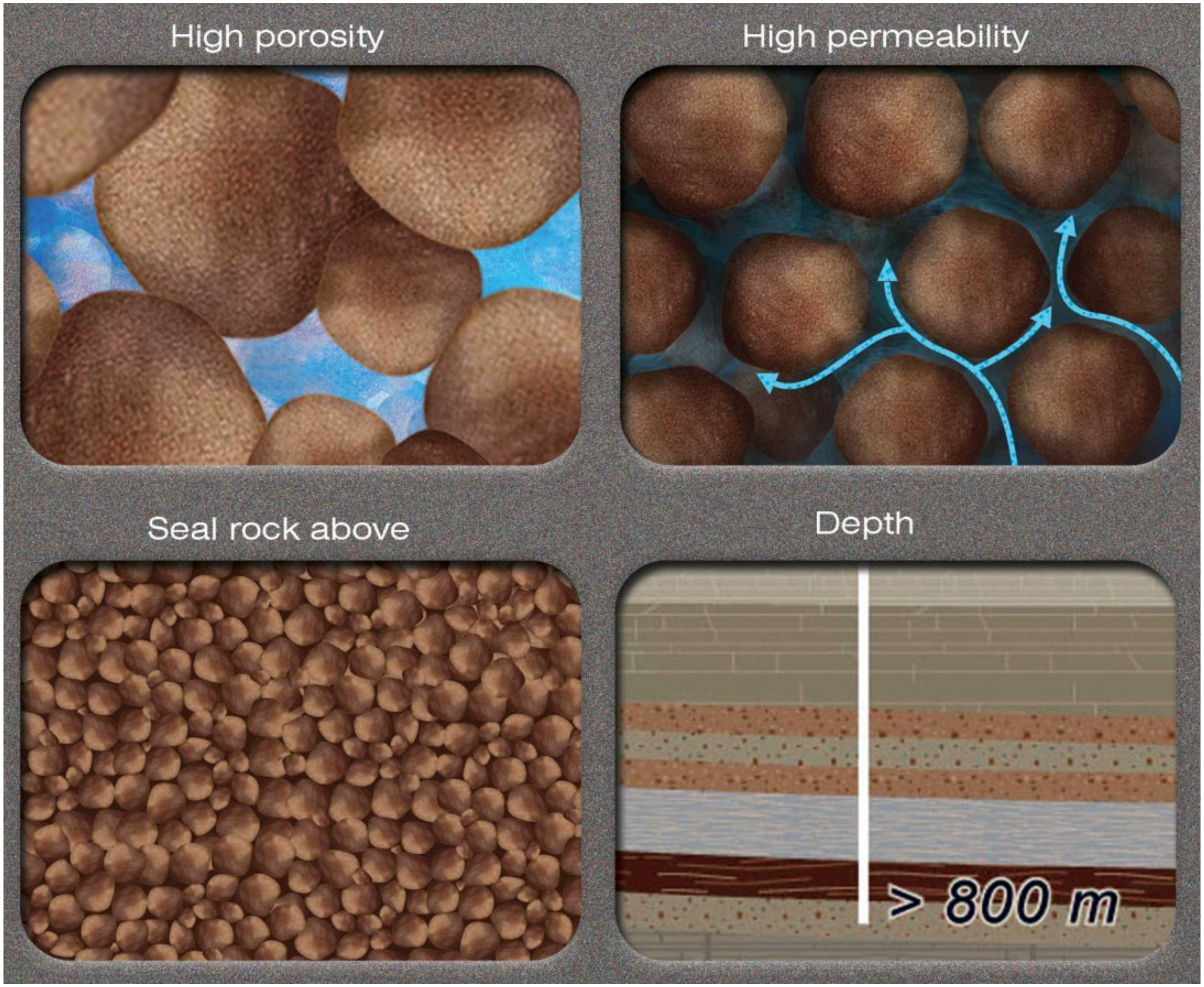
Since the effective permeabilities may range from zero to k, the relative permeabilities may have any value between zero and one, or: $0 \leqq k_{rw}, k_{ro}, k_{rg} \leqq 1.0$

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.

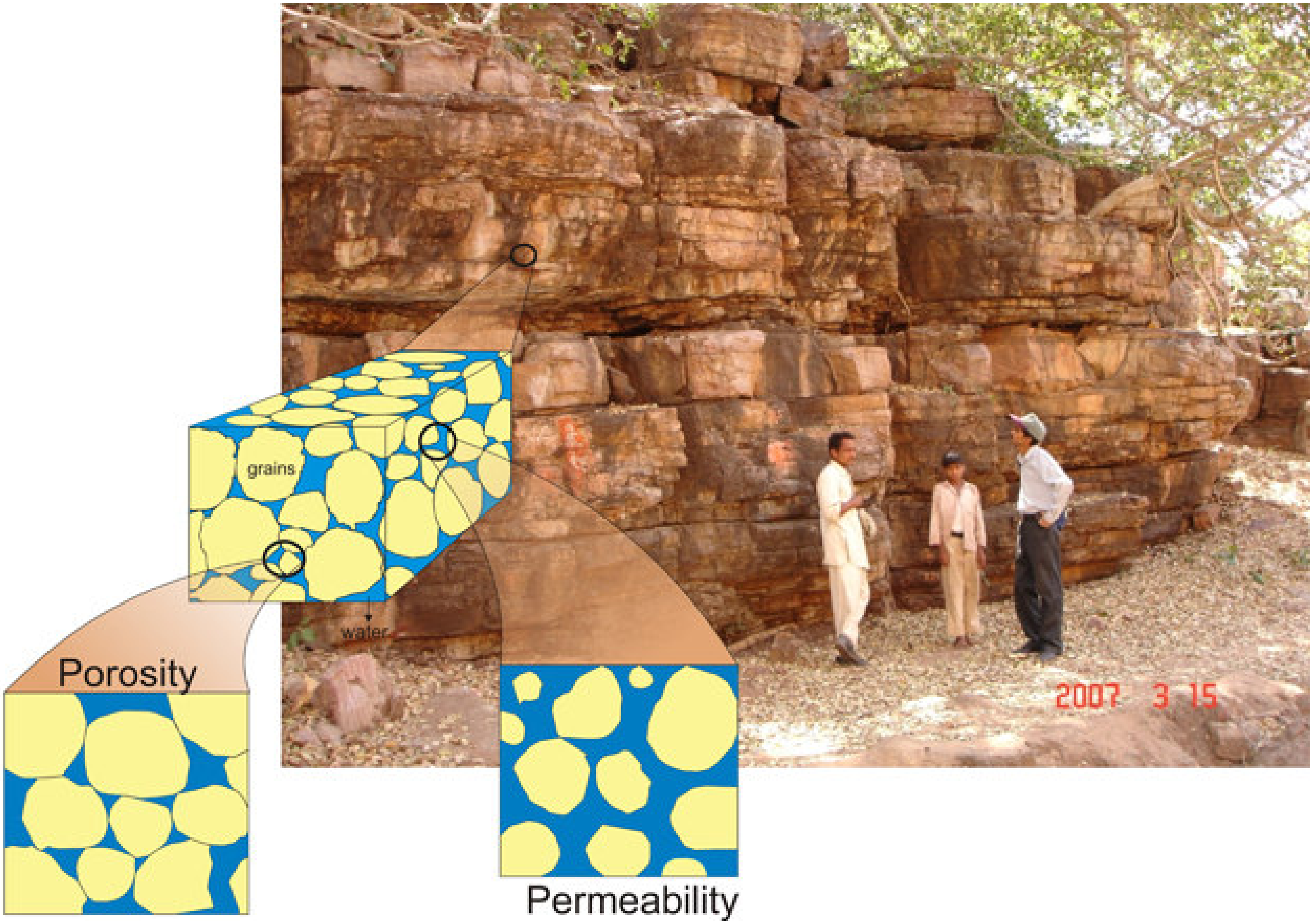
An appreciation of this observation and of its physical causes is a prerequisite to a more detailed discussion of two and three-phase relative permeability relationships.

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

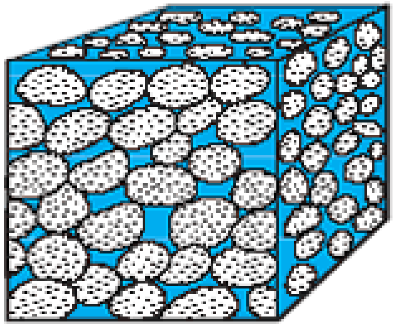
Difference between Porosity and Permeability

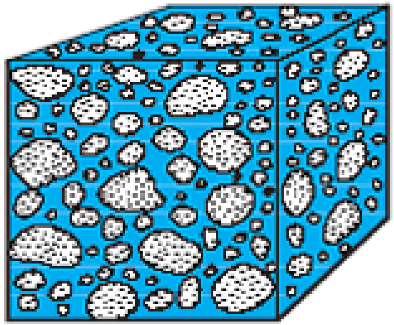


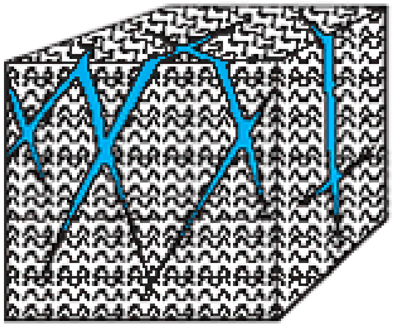
Difference between Porosity and Permeability

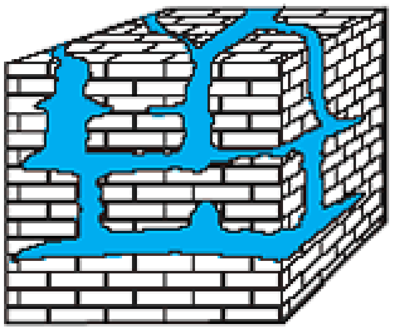


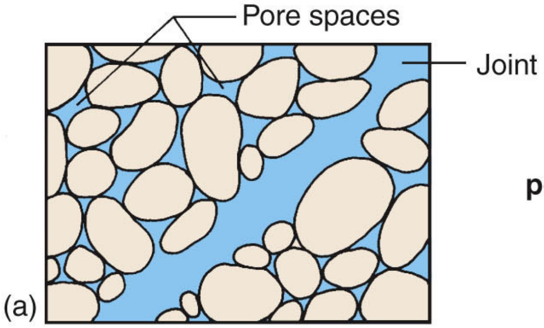
Difference between Porosity and Permeability


Well-sorted sand

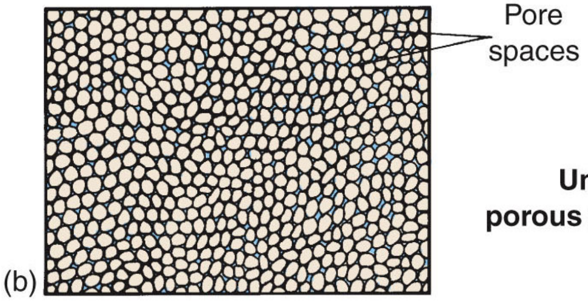

Poorly sorted sand


Fractures in granite

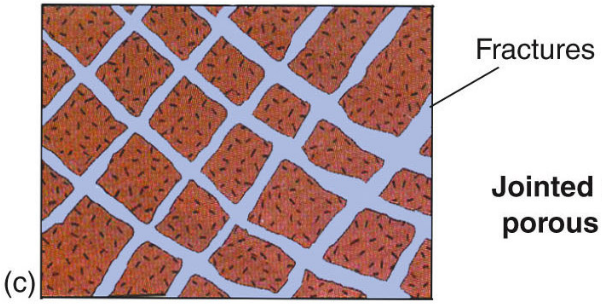

Caverns in limestone



Jointed sandstone porous and permeable



Unjointed clay porous and impermeable



Jointed nonporous rock porous and permeable

Definition of Texture

Porosity, Permeability and Texture: Relationship

Texture is a description of the shape, size, sorting and fabric of sedimentary rocks. All of these variable influence porosity and permeability, although there are no clear correlations between the variables.

There is little theory, and empirical evidence in equivocal.

(1) **Grain Shape:** Porosity (and possibly permeability) may decrease with sphericity and rounded grains.

(2) **Grain Size:** Porosity is theoretically independent of grain size, but there is a general empirical correlation between porosity and permeability. May be caused by increased cementation or because of poorer sorting.

Permeability decreases with decreasing grain size because pore throats are smaller and the capillary pressure goes up.

Porosity, Permeability and Texture: Relationship

(3) **Packing:** Porosity (and permeability) will decrease with tighter packing.

Most reservoirs are buried and altered, so packing is generally not an issue- the rocks are already packed.

(4) **Deposition Process:** No clear relationship, too many other variables.

(5) **Grain Orientation:** controlled primarily by layering in the beds.

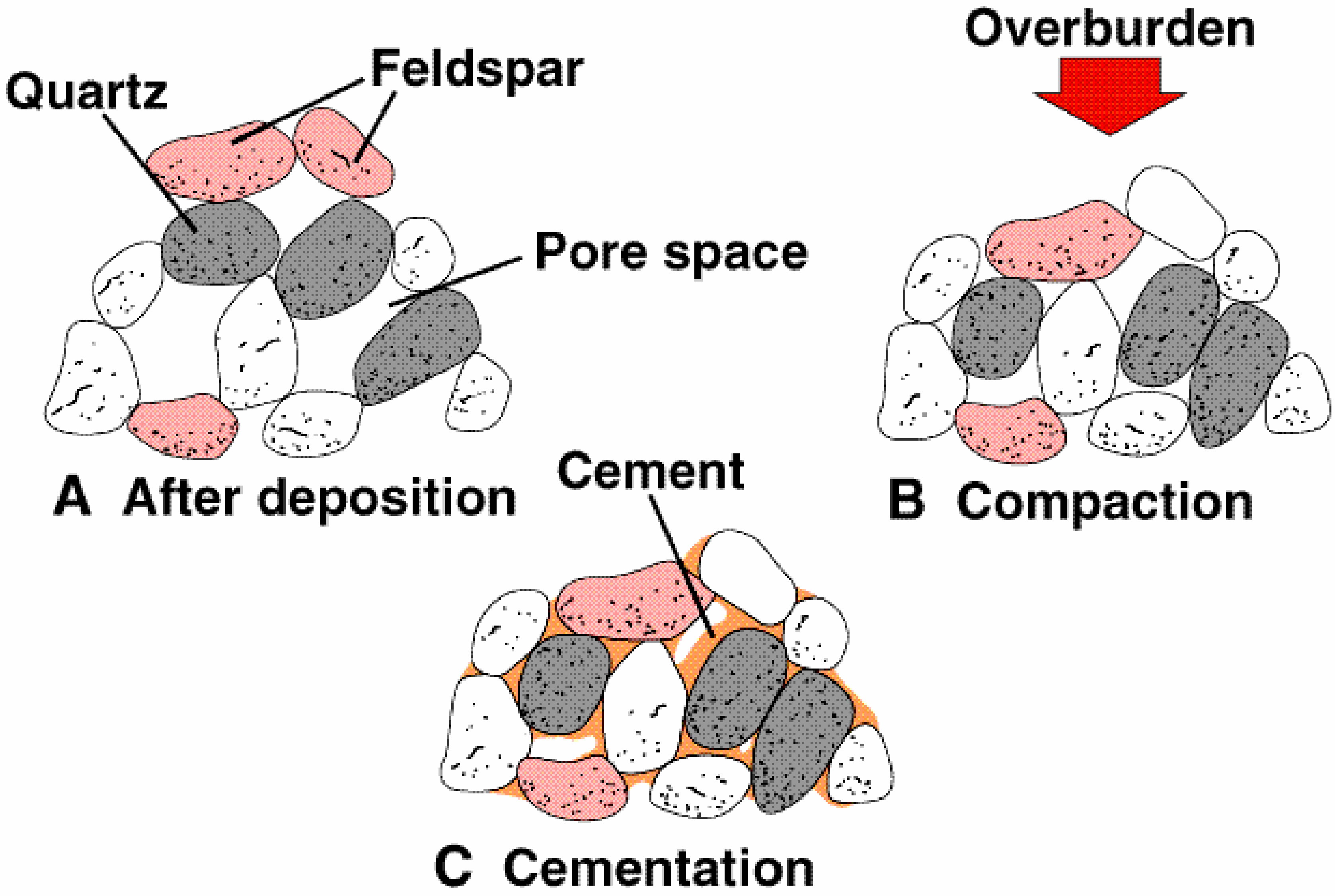
Recrystallization

Recrystallization is a metamorphic process that occurs under intense temperature and pressure, where grains, atoms and molecules of a rock or mineral are packed close together, creating a new crystal structure.

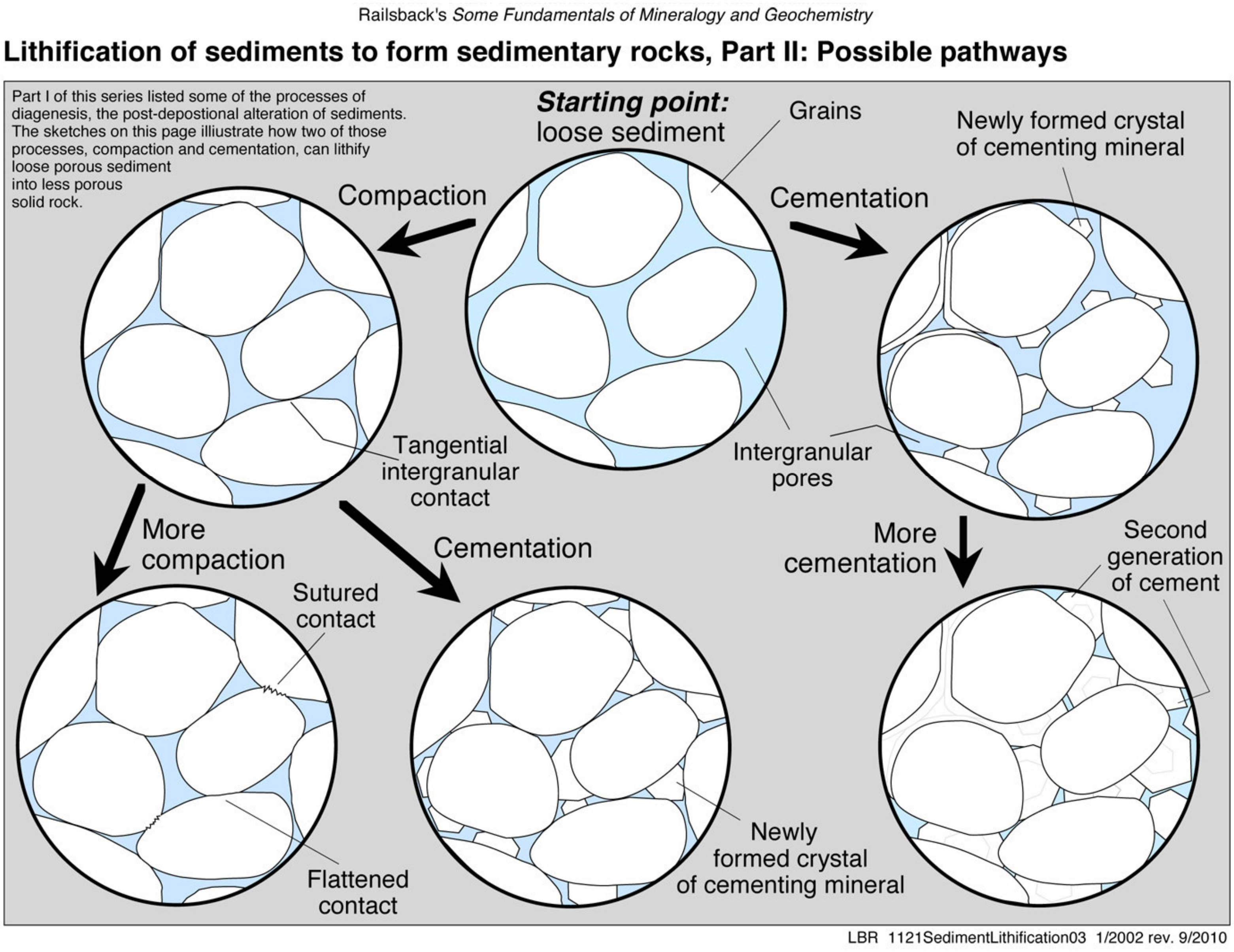
The basic composition remains the same. The process can be illustrated by observing how snow recrystallizes to ice without melting.

Dolomitization

Lithification



Lithification



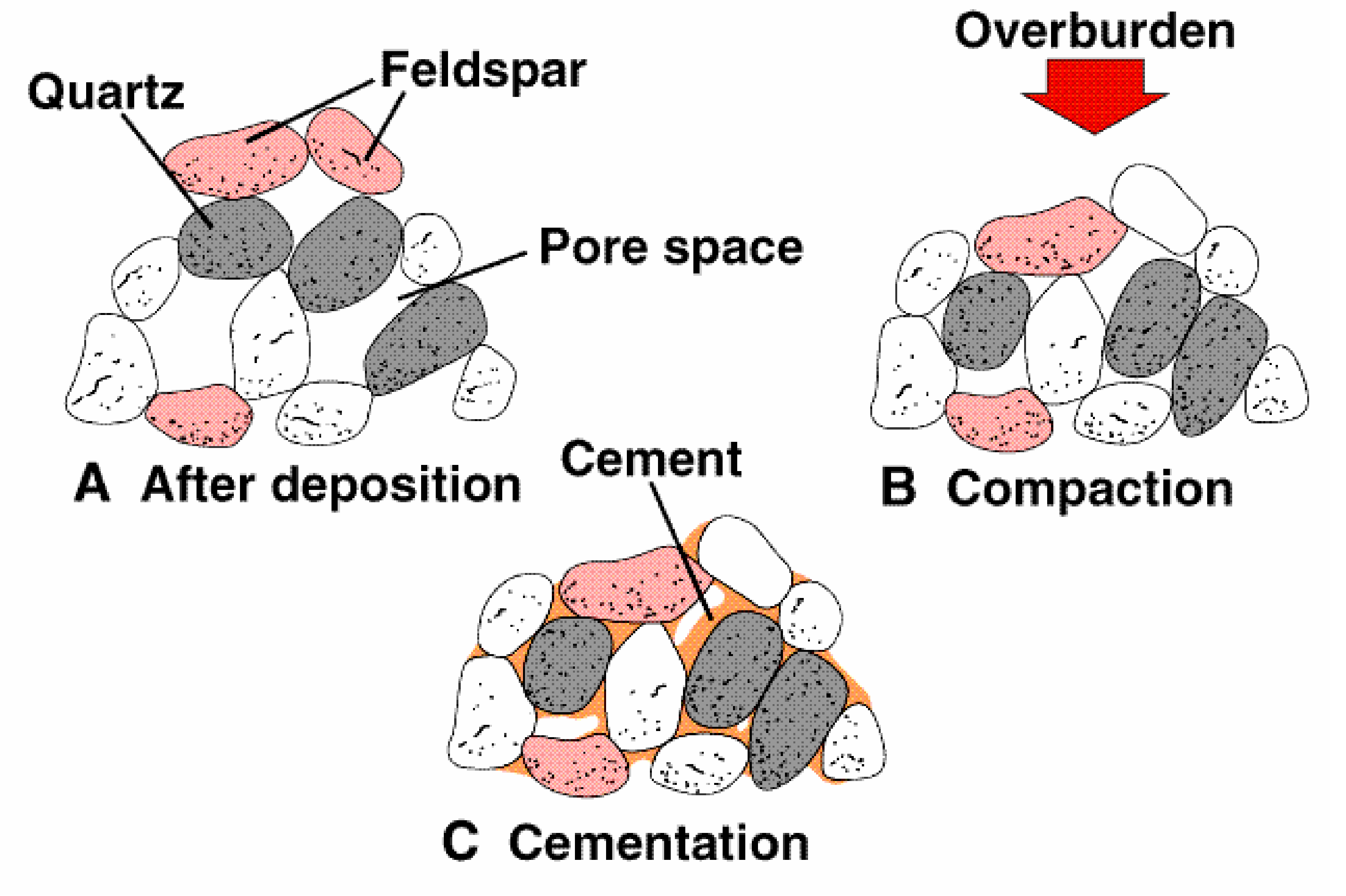
Railsback's *Some Fundamentals of Mineralogy and Geochemistry*

Lithification of sediments to form sedimentary rocks, Part II: Possible pathways

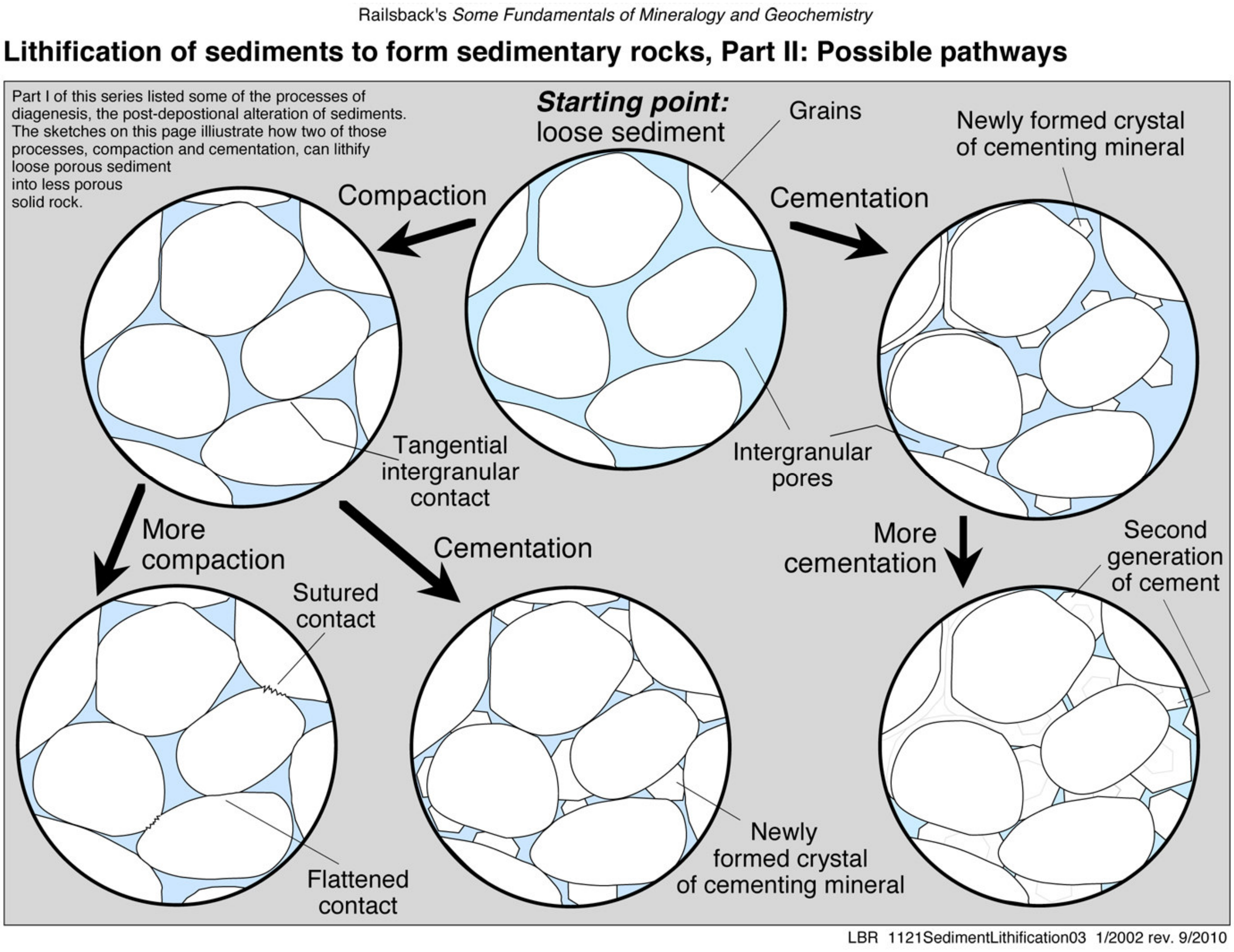
Part I of this series listed some of the processes of diagenesis, the post-depostional alteration of sediments. The sketches on this page illiustrate how two of those processes, compaction and cementation, can lithify loose porous sediment into less porous solid rock.

LBR 1121SedimentLithification03 1/2002 rev. 9/2010

Compaction


Quartz
Feldspar
Pore space
A After deposition
Overburden
B Compaction
Cement
C Cementation

Compaction



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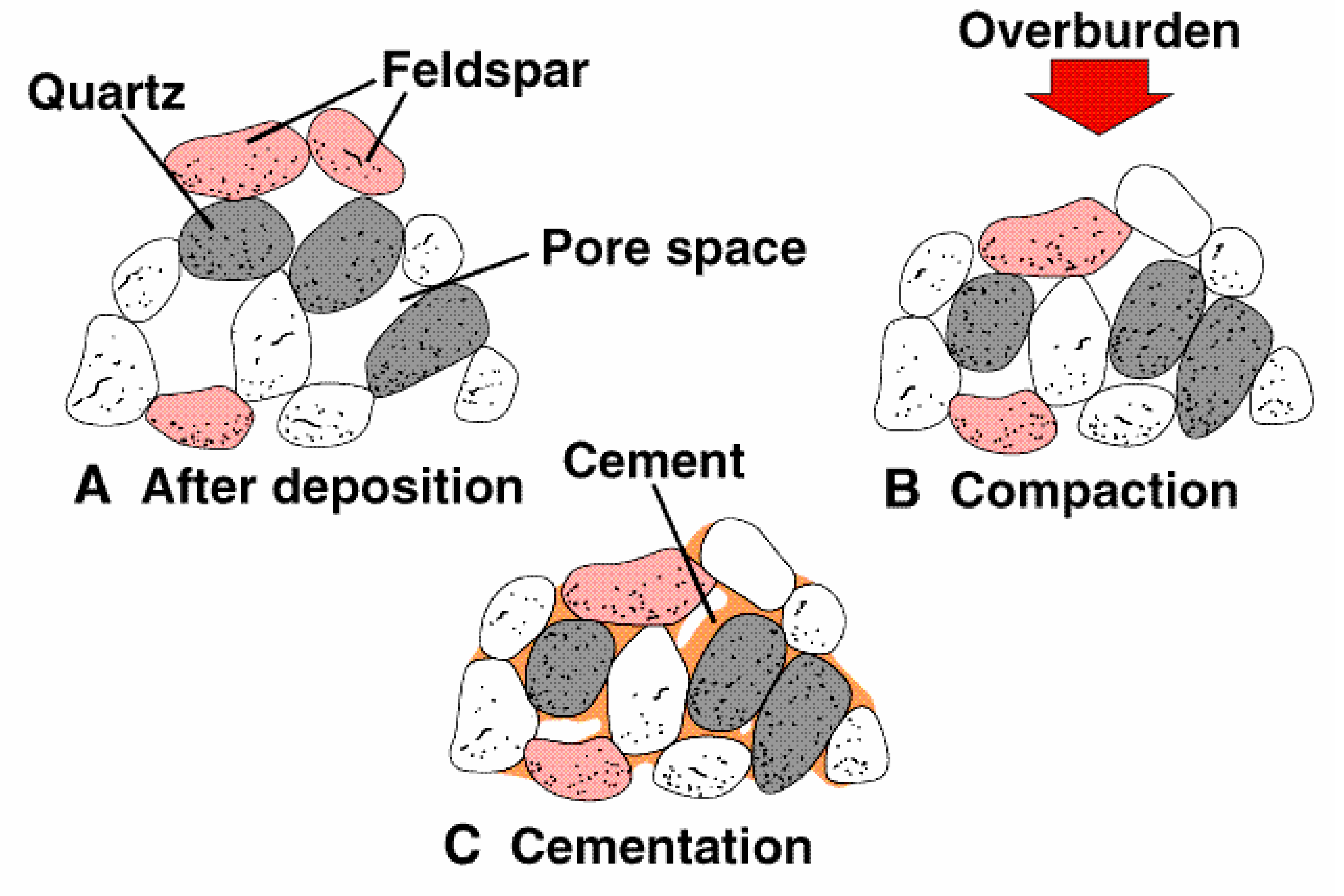
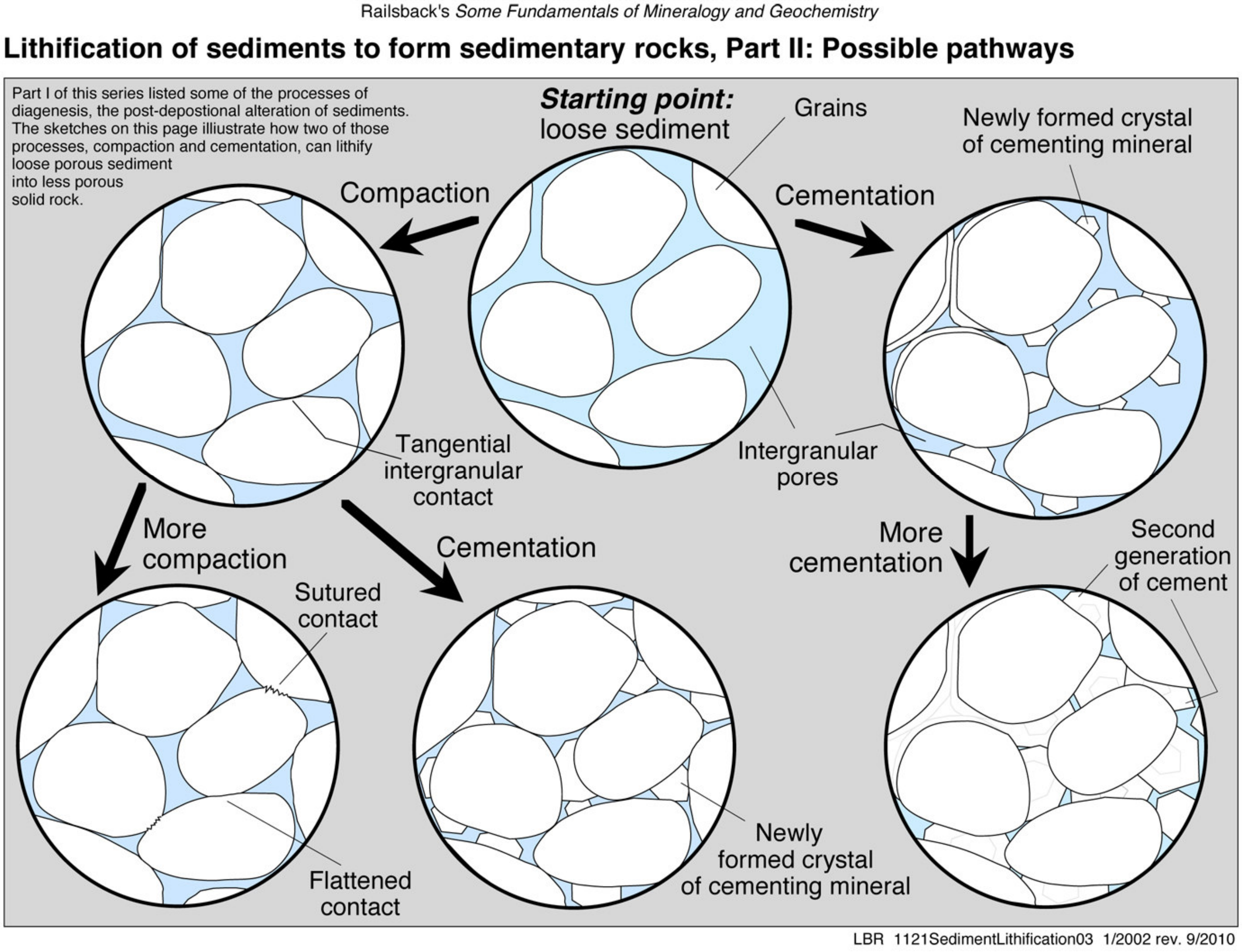
Cementation



Cementation



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Artificial or Man made Porosity and Permeability

After the well is perforated, it may produce naturally if the reservoir is excellent.

Most of the time it is required to fracture the reservoir to produce.

During the fracturing process, large amounts of fluids (such as water, carbon dioxide, or diesel oil) and other materials (such as sand or man-made proppant) are forced down the hole (in a procedure known as a *frac job*), thru the perforations, and into the producing zone.

This combination of high pressure and material fill fractures the rock, creating spaces of artificial porosity and permeability.

Roof Rocks, Wall Rocks and Cap Rocks

A reservoir rock of sufficient porosity and permeability to contain hydrocarbons and release them for production is an integral part of any trapping mechanism.

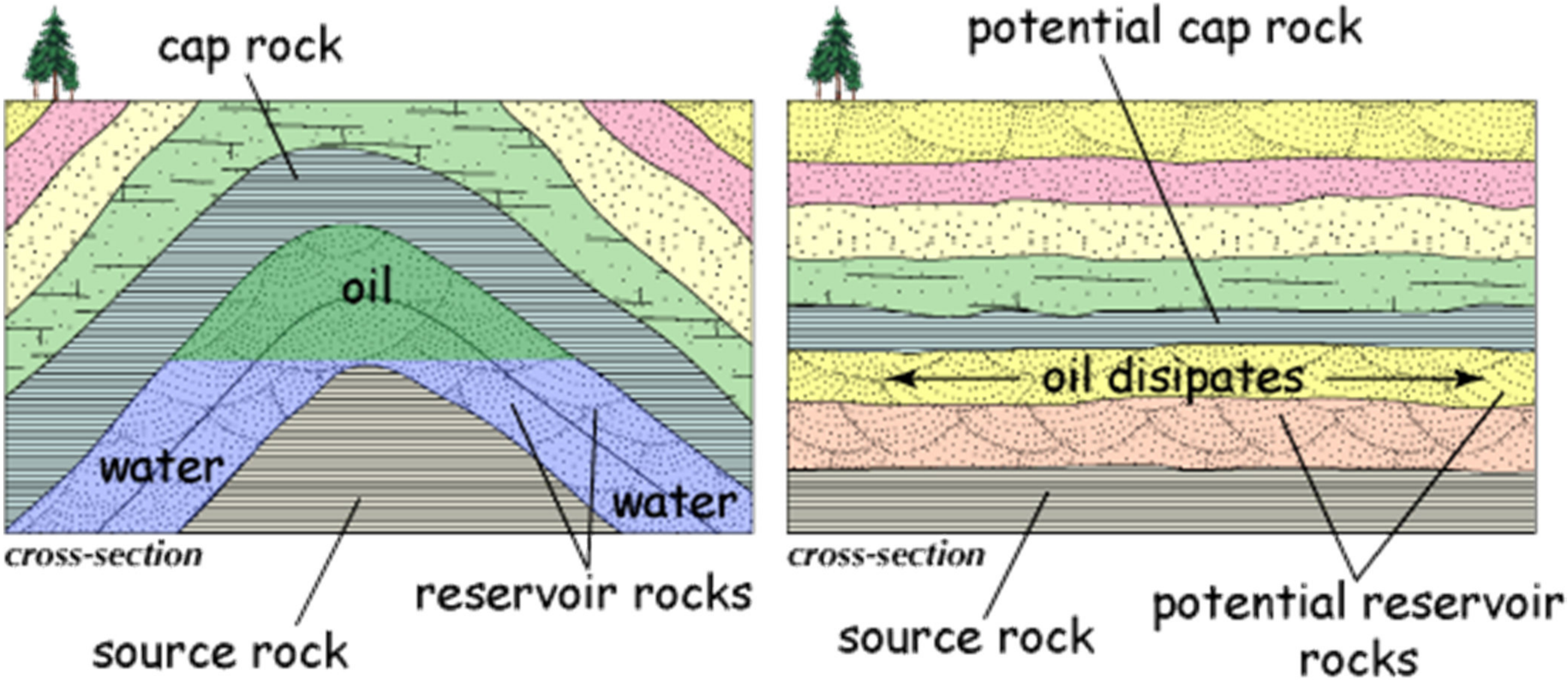
Equally integral is a rock of sufficiently low porosity and permeability that, under the pressure gradient in operation, it prevents the hydrocarbons from moving any further.

As the tendency of the hydrocarbons in otherwise water-bearing rocks is to move upwards, the barrier rock normally lies above the reservoir rock and is called the roof rock or seal.

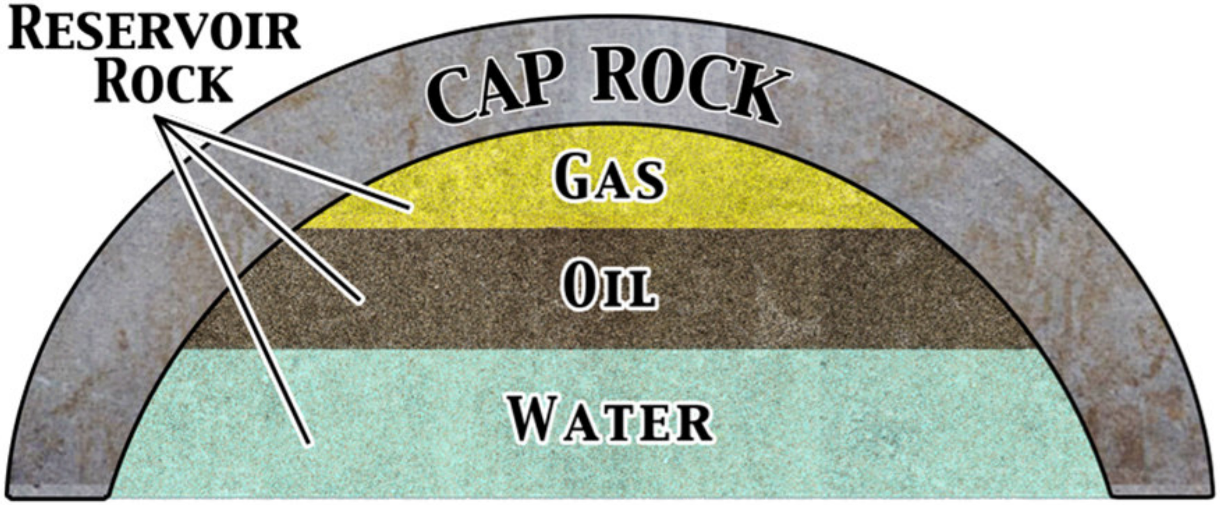
If the deposition of the strata is such as to facilitate lateral movement of the fluids, the lateral barrier necessary to make a trap may be called wall rock.

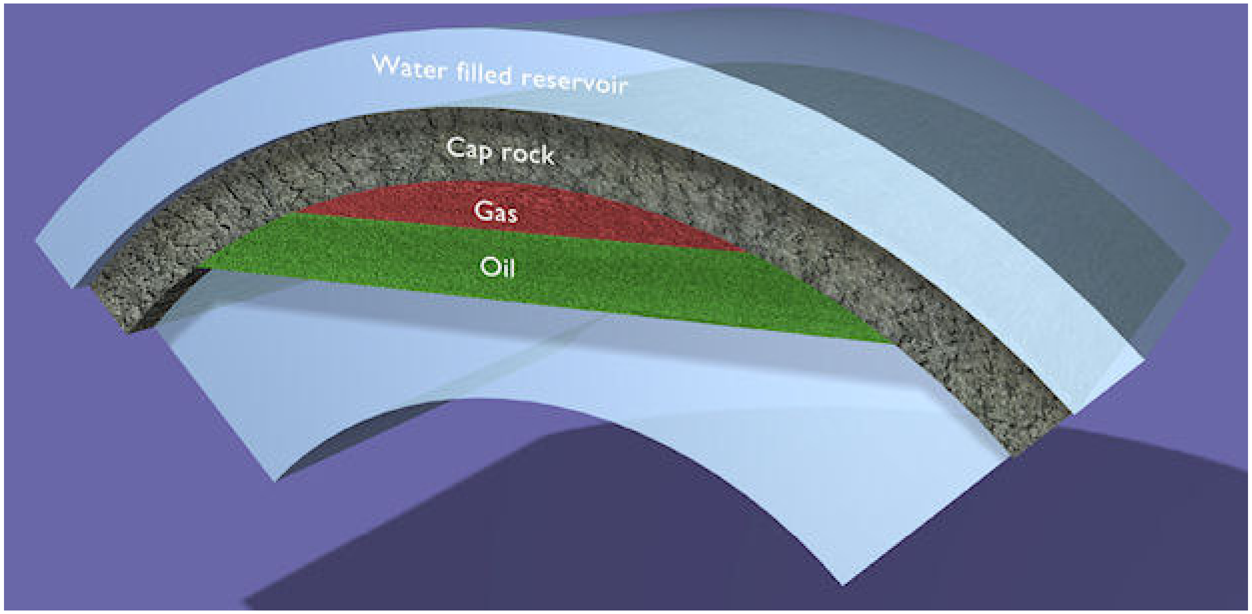
Many petroleum geologists continue to call roof rock (and even wall rock) as cap rock.

Roof Rocks, Wall Rocks and Cap Rocks



Roof Rocks, Wall Rocks and Cap Rocks





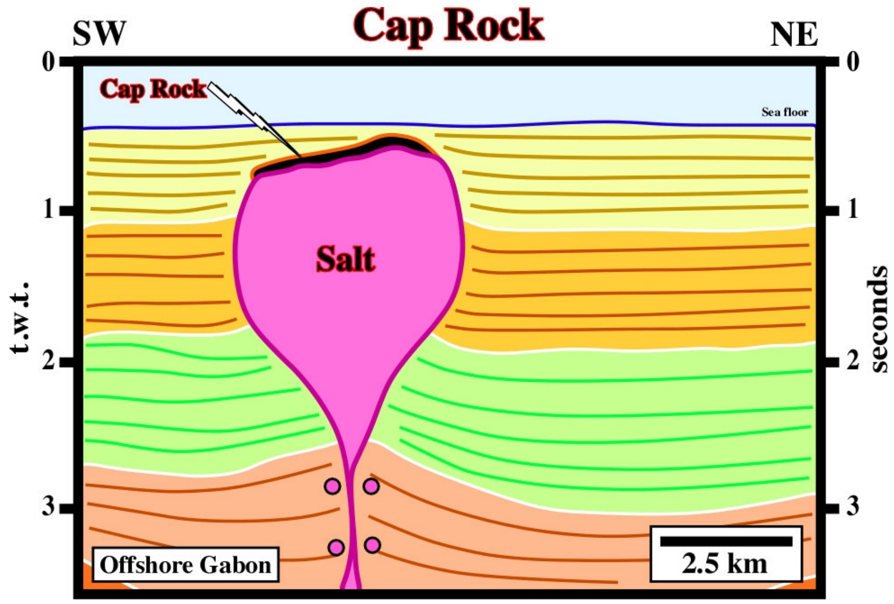
Roof Rocks, Wall Rocks and Cap Rocks

Use of this term should be restricted to the secondary sheath around the tops of salt domes.

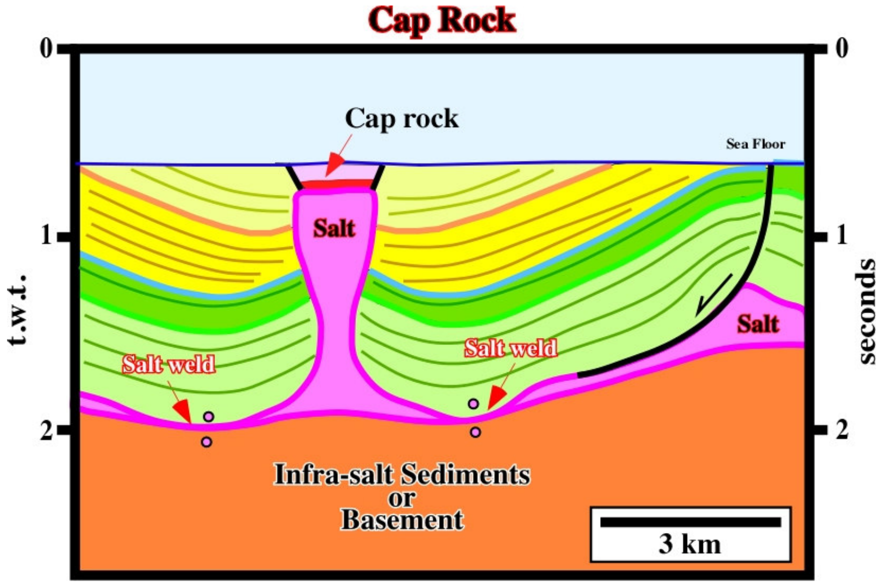
No sedimentary rock is totally impermeable, but most roof rocks have measurable permeabilities less than 10^{-4} darcies. A roof rock may be permeable to water, but if it is, the fluid potential in the roof rock must be higher than it is in the adjacent aquifer. The rock below the accumulation ned not be impervious so long as it is water-bearing.

The best seals are formed by ductile sedimentary rocks. Clays and shales are most common in the transgressive legs of depositional cycles and form the roof rocks for most sandstone reservoirs. More than 60% of known giant oilfields have shale roof rocks.

Roof Rocks, Wall Rocks and Cap Rocks

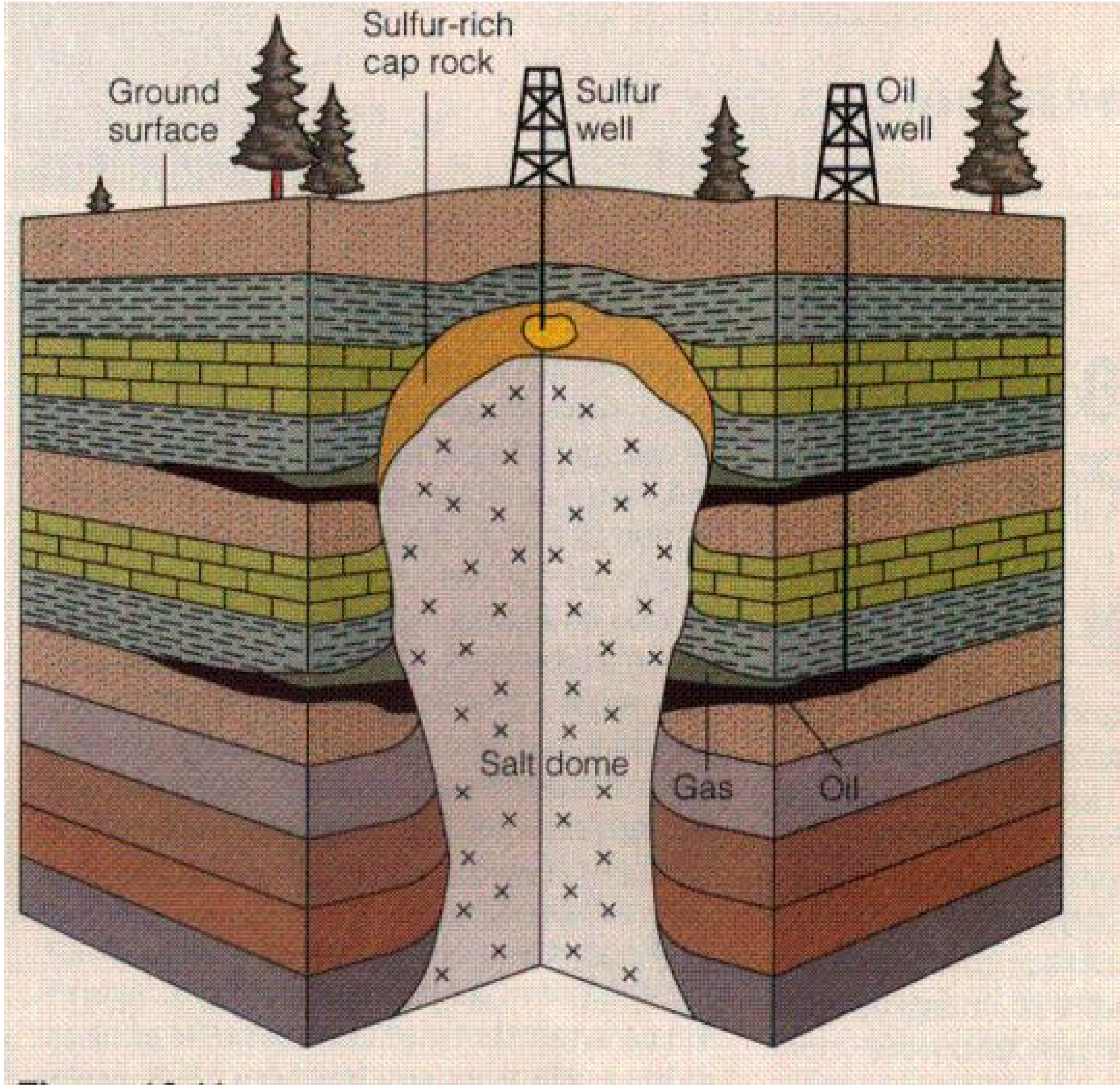


Cap Rock



Cap Rock

Roof Rocks, Wall Rocks and Cap Rocks



Roof Rocks, Wall Rocks and Cap Rocks

Evaporites, the ideal roof rocks, are common in regressive legs of cycles and are especially favorable where the reservoir rocks are carbonates. At least 25% of giant gas fields are capped by evaporites of Permian and Triassic ages alone.

Evaporites play havoc with conventional well logs unless great care is taken with the drilling mud. Anhydrite can usually be identified on density logs, its relative density being almost 3. Potash salts are easily picked out on radioactive logs.

A third common type of roof rock or wall rock is simply a more closely cemented or more argillaceous version of reservoir rock, creating a permeability pinch out. This is more common in clastic sediments than in carbonates; only a minority of limestone reservoirs have dense carbonate roof of wall rocks.

Any normally porous sedimentary rock can be converted to seal by diagenesis before, during, or after complete burial.

Roof Rocks, Wall Rocks and Cap Rocks

Cementation by clay minerals, cementation by the introduction of soluble salts percolating downwards from overlying evaporites, recrystallization, pressure solution and re-deposition, deformation of ductile grains, or the dehydration of the hydrocarbons themselves, forming asphalts or "tar" seals, are all familiar means of converting reservoir rocks into seals.

The opposite process is also important, though less common and obvious. A seal may be rendered ineffective not only by such routine geological processes as fracturing or recrystallization, but also by a change in the pressure regime.

Even a dense rock is a seal only if pressure conditions permit it to be. If those conditions change sufficiently to overcome the sealing rock's entry pressure, the seal becomes a sieve, in Gilman Hill's phrase, and the hydrocarbon accumulation below or behind it is lost or greatly reduced.

Roof Rocks, Wall Rocks and Cap Rocks

The efficiency of a seal, measured by the thickness of the oil or gas column it can retain below or behind it, is a function of pore size, the “integrity” of the rock (its lack of open fractures), its continuity, and its thickness. The thickness, continuity and integrity estimated.

Evaporites and permafrost have very high integrity because they have the capacity of self-healing of fractures.

Evaporite is a name for a water-soluble mineral sediment that results from concentration and crystallization by evaporation from an aqueous solution. There are two types of evaporate deposits: marine, which can also be described as ocean deposits, and non-marine, which are found in standing bodies of water such as lakes. Evaporites are considered sedimentary rocks.

In geology, **permafrost** or **cryotic soil** is soil at or below the freezing point of water 0°C (32°F) for two or more years. Most permafrost is located in high latitudes (i.e. land close to the North and South poles), but alpine permafrost may exist at high altitudes in much lower latitudes.

Roof Rocks, Wall Rocks and Cap Rocks

To calculate the seal capacity, however, the geologist needs also to know the pore size and the parameters permitting the fluids to pass through pores of that size: the fluid densities, the interfacial tension (γ) between the fluids, and the wettability.

The seals are a function not only of the stratigraphic regime but of the structural style in addition; their efficiency depends partly on the trapping mechanism.

Simple anticlinal traps may provide sequential sealing surfaces because many inter-bedded units may be involved in them. Failure of one seal may merely cause the hydrocarbons to ascend to a higher reservoir capped by a seal which is still intact.

In a non-convex, pinchout trap, in contrast, an adjacent seal may depend on a single rock stratum and its failure may cause the loss of the accumulation.

Roof Rocks, Wall Rocks and Cap Rocks

In thrust belts, the lithologic seals may be destroyed but the thrust surfaces themselves may create high-pressure, tectonic seals. Oil in thrust-belt fields are typically very light and volatile.

Furthermore, thrust planes are preferentially located within ductile strata like clay-shales or evaporites, which provide fault gathering zones and lead to *décollements*. These fault favoring strata add to the seal capacity of the thrust surfaces.

Regional Cap Rock or Top Seal

The existence of a petroleum play depends on the presence of an effective regional cap rock or top seal.

- **Any rock may act as a seal as long as it is impermeable.**

- **Seal will commonly be porous, may be petroleum saturated, but they must not permit vertical migration of petroleum from trap.**

- **Shales: Commonest seals - commonly porous but impermeable.**

- **Evaporites: Most effective seal.**

Mechanisms of Sealing

The basic physical principles governing the effectiveness of petroleum cap rocks are the same as those controlling secondary migration.

Forces that control secondary migration are:

(i) **Buoyancy:** Main driving force which act in favor

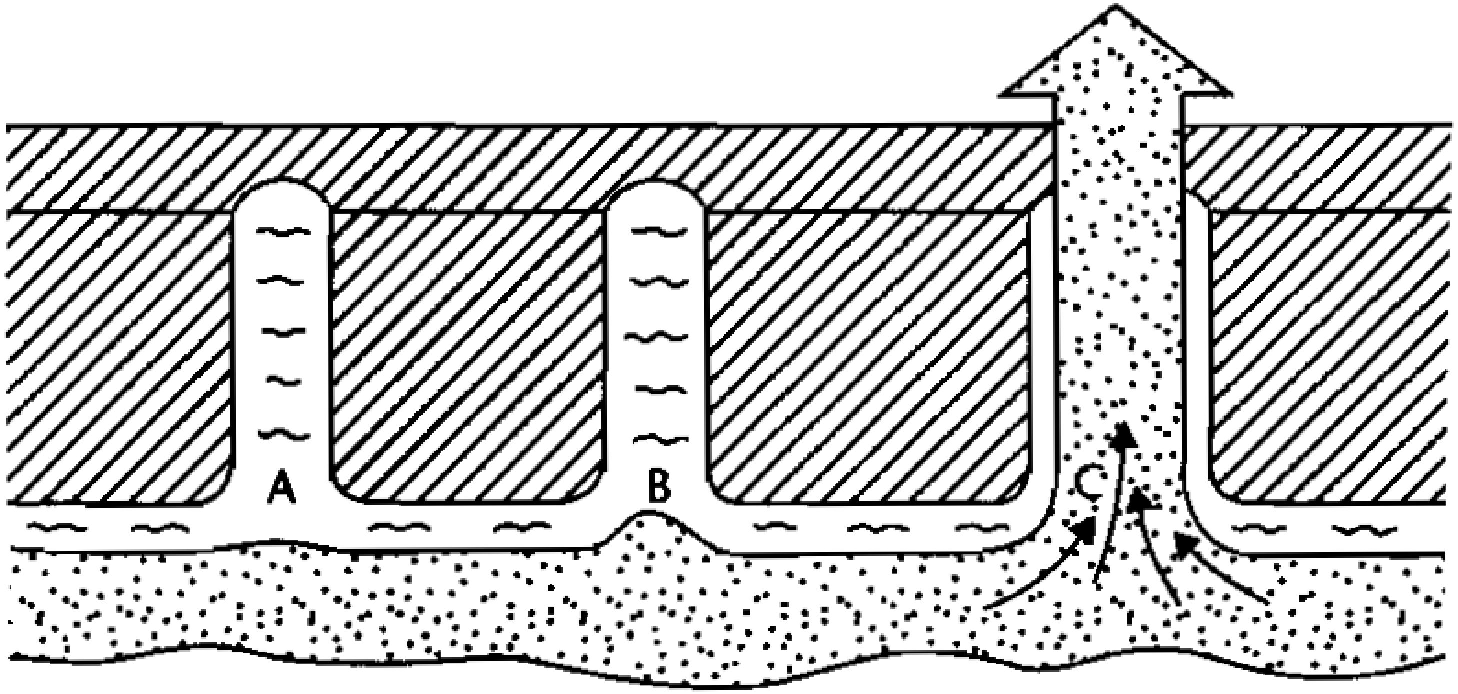
(ii) **Capillary or Displacement Pressure:** It is the main restricting force to this movement. This mainly depends on the size (i.e. radius) of pore throats.

A rock will seal an underlying petroleum accumulation if: Capillary or displacement pressure of its largest pore throat ≥ the upward buoyancy pressure of the petroleum column.

Ineffective Seal

SEAL INEFFECTIVE

(Largest pore throat determines seal capability)



A, B: Capillary displacement pressure exceeds hydrocarbon buoyancy pressure.

C: Large pore throat has insufficient displacement pressure to retain hydrocarbons – seal is ineffective.

Factors affecting effectiveness of Cap Rock

The effectiveness of cap rocks may be worldwide examined in terms of their

- **(i) Lithology**
- **(ii) Ductility**
- **(iii) Thickness**
- **(iv) Lateral Continuity**
- **(v) Burial Depth**

Factors affecting effectiveness of Cap Rock

(i) Lithology

Nederlof and Mohler (1981), in a statistical analysis of 160 reservoirs / seals, found that cap rock lithology was of considerable importance in influencing seal capacity.

- Cap rocks need small pore sizes. Hence vast majority of cap rocks are :

(i) Fine grained siliciclastic: Clays, Shales
(ii) Evaporites : Anhydrite, Gypsum, Halite
(iii) Organic rich rocks

Other lithologies such as argillaceous limestones, tight sandstones and conglomerates, cherts and volcanics may also seal, but they are globally far less important, are frequently of poor quality, and geographically of limited extent.

Factors affecting effectiveness of Cap Rock

Grunau (1987) compiled information on the cap rock lithologies of he world's 25 largest oil and 25 largest gas fields. There was a roughly equal split between shales (13) and evaporites (12) foe the 25 oil fields. For gas fields, shales (16) predominated over evaporites (9).

For Oil Fields:

Evaporites: Cap 40% of ultimately recoverable oil reserves from worlds giant oil fields (examples: Oil fields of Middle East & N Africa

Shales: Cap 60% (examples: In Alaska, Western Canada, California, Gulf of Maxico, Soviet Union, Indonesia & Brunei)

For Gas Fields:

Evaporites: Cap 34%

Shales: Cap 60%

Factors affecting effectiveness of Cap Rock

(ii) Ductility

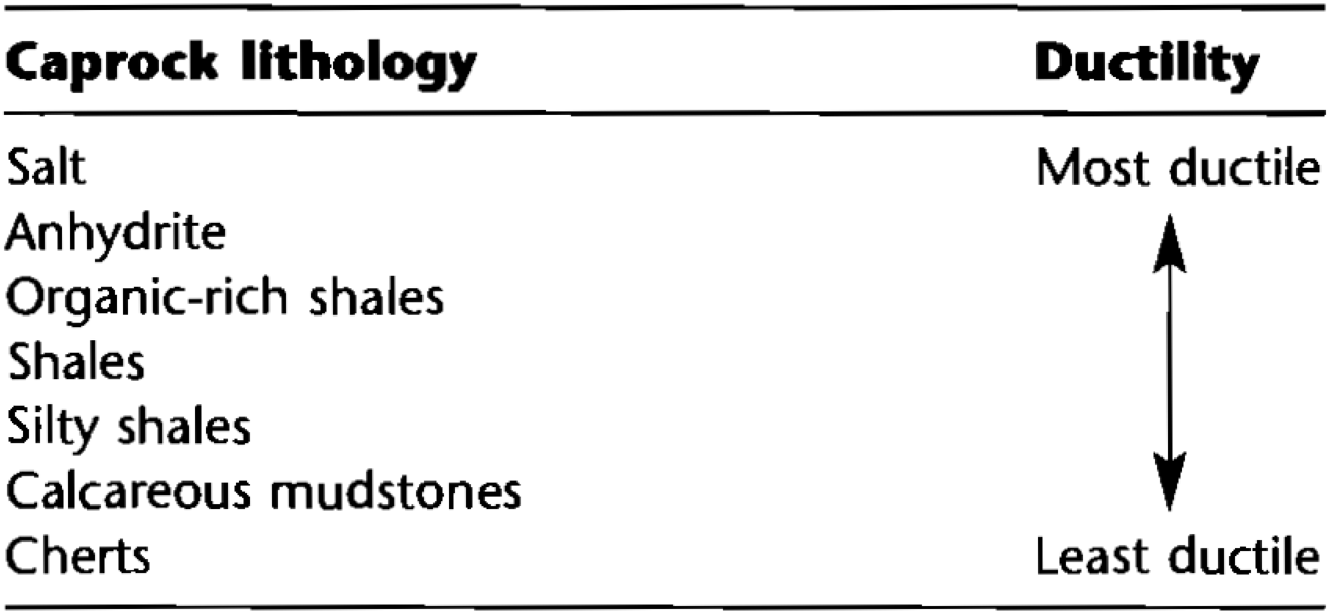
Ductile cap rock lithologies are less prone to faulting and fracturing than brittle lithologies.

Cap rocks are places under substantial stress during periods of structural deformation, including the deformation responsible for trap formation.

During the formation of a simple anticline, for example, tensional fractures may occur in brittle cap rocks in the crestal parts of the fold.

Ductility is, therefore, a particularly important requirement od cap rocks in strongly deformed areas such as fold and thrust belts.

Factors affecting effectiveness of Cap Rock



Caprock lithology	Ductility
Salt	Most ductile
Anhydrite	↑
Organic-rich shales	
Shales	
Silty shales	
Calcareous mudstones	↓
Cherts	Least ductile

The most ductile lithologies are evaporites, and the least ductile are cherts. This may explain the extraordinary success of evaporites as cap rocks. A high kerogen content appears to enhance the ductility of shale cap rocks. Many source rocks, therefore, also serve as seals. Ductility is also a function of temperature and pressure. Evaporites may be brittle at shallow depths, but very ductile at depths of over 1 km.

Factors affecting effectiveness of Cap Rock

(iii) Thickness

A small thickness of fine grained cap rock may have sufficient displacement pressure to support a large hydrocarbon column.

Thin cap rocks, however, tend to be laterally impersistent; thus a thick cap rock substantially improves the chances of maintaining a seal over the entire prospect, or even over the entire play fairway or basin.

Typical cap rock thicknesses range from 10s of m to 100s of m (Grunau 1987). Very large volume of petroleum may be sealed by relatively modest thickness of cap rock.

Factors affecting effectiveness of Cap Rock

(iv) Lateral Continuity

In order to provide good regional seals, cap rocks need to maintain stable lithological character (and hence capillary pressure and ductility characteristics) and thickness over broad areas.

Most prolific petroleum provinces contain at least one of these regional seals. The search for petroleum in these basins may be focused on the base of the regional seal, rather than on any particular reservoir horizon. The lateral variability of the regional seal may be studied using wireline log information and seismo-stratigraphic analysis.

Factors affecting effectiveness of Cap Rock

(v) Burial Depth of Cap

Almost half of the ultimately recoverable reservoirs of oil occurs in 1000-2000m depth range and 31% in 2000-3000m depth range. But these totals are strongly influenced by deposits of Middle East.

However, many important regional variations:
In N-America: > half of the giant oil fields < 1000m depth range
In Australia: 72%, >3000m depth range,.

Deep gas are much more abundant in nature. This indicates seals may be effective at all depths. Requirement is that a unit of high displacement pressure and ductility is present over wide areas.

Many shallow oil accumulations occur in structures that have undergone significant uplift, bringing well compacted cap rock close to the surface.

Questions

1. Explain the term porosity. What do you mean by primary porosity, secondary porosity and effective porosity?
2. Describe permeability. How it is measured? Explain relative permeability.
3. Explain the relation between porosity, permeability and texture.
4. Explain artificial or man made porosity.

Thank You !!!