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GENERAL INTRODUCTION

Porous media as a source of fluids and vapours like water, oil, gas or as a depot for the storage or disposal of fluids or other materials is getting more and more attention. To describe the state of the pore content, it is necessary to specify the spatial characteristics of the pore space and the pressure, the composition and the energy contained in the pore filling material. To estimate the flow in porous media, in time and space, certain parameters must be specified. For flow considerations, the primary parameters are porosity and permeability. For the vertical dimensions of fluid zones the capillary pressures are of importance. The purpose of this chapter is to present data on these factors, combined with geological and reservoir technical relations.

4.1. POROSITY

4.1.1. HISTORICAL ASPECTS

Theoretical points of view of the transit of ground water in porous media went ahead of the developments in reservoir engineering, as needed in the oil industry. Slichter [1899] already showed that the porosity of uniformly sized spheres varied from about 47% for the cubic packing to a minimum of 26% for the rhomboedrical packing. However naturally occurring grain aggregates are heterogeneous and their measured porosities are above and below these limits. Fraser [1935] considered the following factors and their relative importance in determining the porosity of unconsolidated natural deposits:

- Absolute grain size
- Grain size distribution
- Sorting
- Grain shape
- Way of deposition
- Degree of compaction
- Consolidation

His work has been used for many attempts to create porosity relations. Slichter defined porosity simply as *“The percentage of open space to the whole space”* or *“as “that part of the rock where no matrix material is present”*. Later on the effective porosity was defined as *“the amount of interconnected pore space available for fluid transmission, expressed as a percentage of the total volume”*. In our professions can be stated that *“The effective porosity is the fraction of the total rock volume, which is filled with water, gas, or oil”*. The material of a porous rock may range from very loose unconsolidated sand to a very hard, dense sandstone, limestone or dolomite. Sand grains and particles of carbonate materials, that make up sandstone and limestone reservoirs, usually never fit together perfectly due to the high degree of irregularity in shape. The cement that fills the pores and binds the grains together may consist of silica, calcite or clay. This mixture of matrix material, cement, and pore filling clays create a large range of porosity values and porosity types.

4.1.2. POROSITY DEFINITION

The porosity is the amount of pore space expressed as a fraction of the total volume.

$$\phi = \frac{V_b - V_{ma}}{V_b} \dots or, \quad \phi = \frac{V_p}{V_b} \dots or, \quad \phi = \frac{V_p}{V_{ma} + V_p} \quad (\text{eq. 4.1,2 and 3})$$

where: ϕ : porosity V_p : pore volume V_b : bulk volume, V_{ma} : matrix volume

4.1.3. POROSITY VALUES AND SPATIAL CHARACTERISTICS

Porosity may range from 80 % in volcanic tuffs or 60% as found in diatomites in the Monterey formation in California - which do not, or hardly, produce any fluid - to a porosity value of 1% in fractured carbonate formations (Middle East). Here one well occasionally produces more oil than all productive oil wells in The Netherlands (on-shore). The factors governing the magnitude of porosity in clastic sediments are:

1. Spatial conditions of the grain shape and packing,
2. Grain size uniformity,
3. Consolidation and cementation
4. Pore space reduction during and after deposition
5. Grain size – pore size relation
6. Dual porosity.

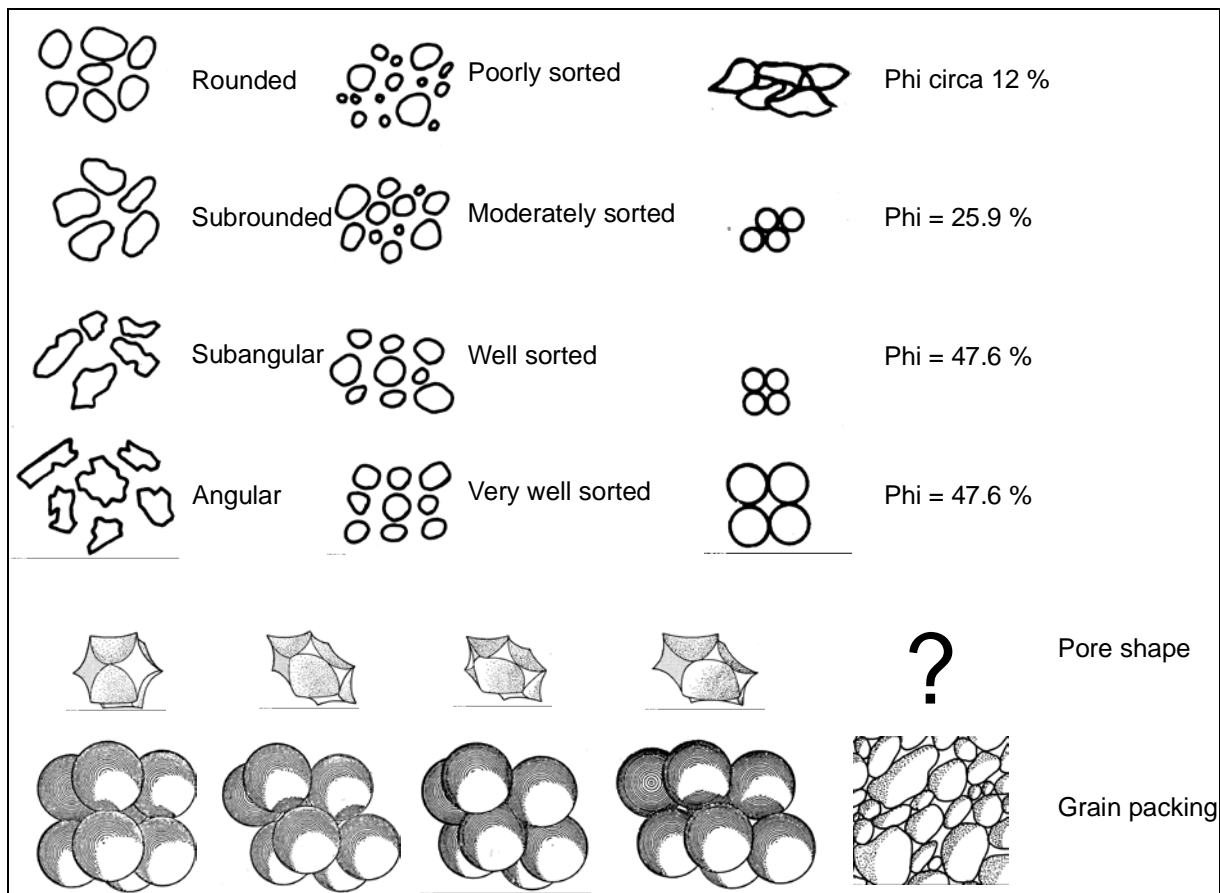


Figure 4.1: Grain shapes and grain packing as major spatial characteristics for the amount of pore space.

4.1.3.1. SPATIAL CONDITIONS OF THE GRAIN SHAPE AND PACKING

The arrangement of uniform spheres already shows that different packing create different porosities. A cubic, or wide-packed system, has a porosity of 47.6%, orthorhombic 39.5% porosity, a rhombohedral, or close-packed system, 25.9% and tetragonal a porosity of 30.2%.

Cubic packing is formed when the centres of spheres in the second square layer projected on the plane of the first layer coincide with the centres of the first layer. Orthorhombic packing is formed when the centres of spheres in the second square layer are in line with those of the first layer but are offset by a distance equal to radius R. Rhombohedral packing is formed when the centres of spheres in the second square layer are offset by half the distance between centres of diagonal spheres in the first layer. Tetragonal packing is formed when the centres of spheres in a second rhombic layer are in

line with those of the first rhombic layer but are offset by a distance equal to radius R. When all spheres are identical the porosity is only a function of the packing and independent of the sphere size. *Note that the porosity for such a system is independent of the sphere diameter.* Though, in case of a mixture of smaller spheres among larger spheres, the ratio of pore space to the solid framework becomes lower and porosity reduces. The porosities of reservoirs range from < 5 % to > 40 %. Normally the porosity values are in between 10 - 20 volume percent.

4.1.3.2.: GRAIN SIZE UNIFORMITY

Uniformity or sorting is the gradation of grain sizes in a collection of grains. For example; when silt or clay particles are mixed with sand, the intercommunicating porosity will be notably reduced (fig. 4.1). Sorting depends on four significant factors:

1. size range of the grains,
2. kind of deposition,
3. nature of the transporting current, and
4. the time span of the sedimentary process.,

There are many definitions for sorting of which the Trask sorting is the most commonly used. This parameter makes use of the cumulative weight percentage in a sieve analysis and is defined as:

$$S_0 = \sqrt{\frac{S_{25}}{S_{75}}} \quad (\text{eq. 4.4})$$

S_{25} is the grain size at 25% cumulative weight percentage. This means that 75% of the weight of the rock has larger sizes than this 25% grain size value. S_{75} as the grain size at 75% cumulative weight percent. This is also illustrated in the figures 4.2. and 4.3.

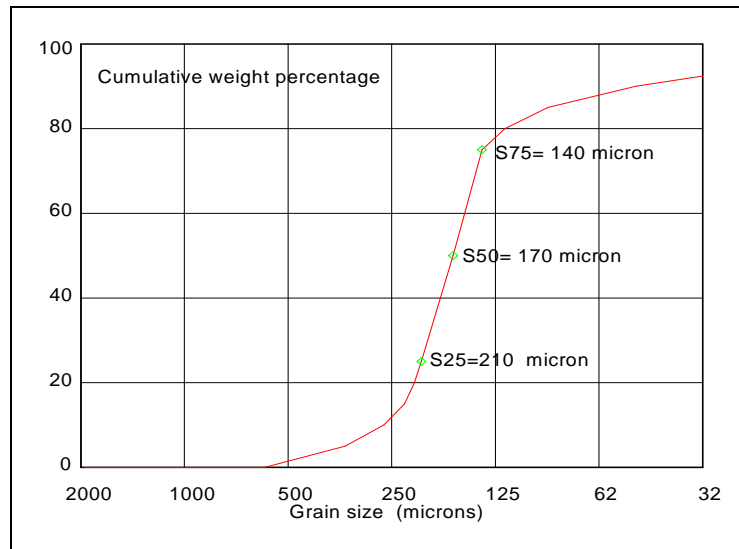


Figure 4.2: Grain size distribution with a Trask sorting of $S_0=1.22$

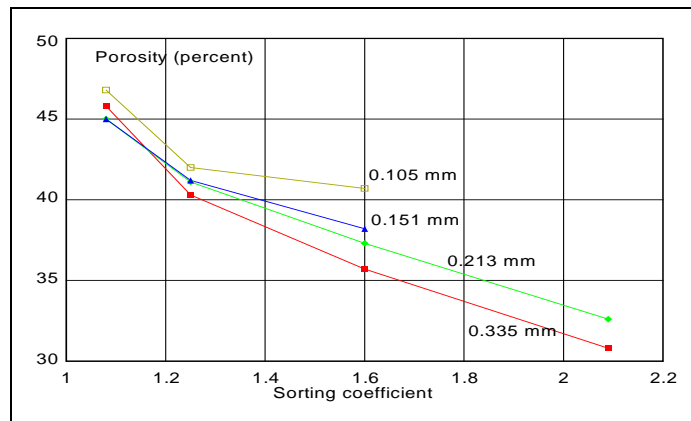
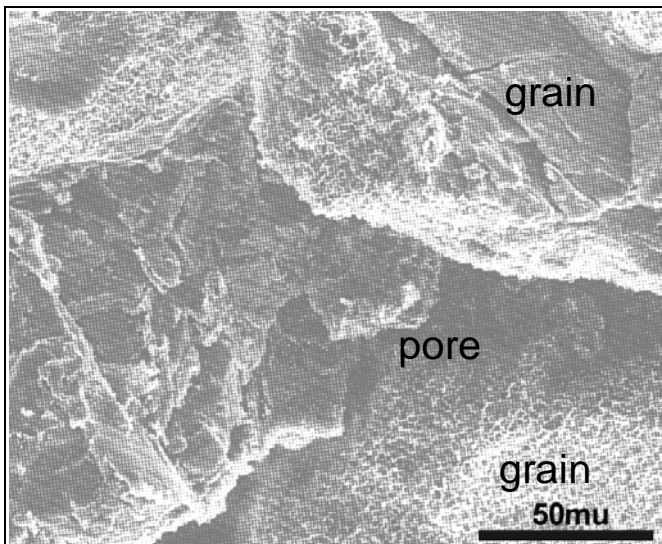


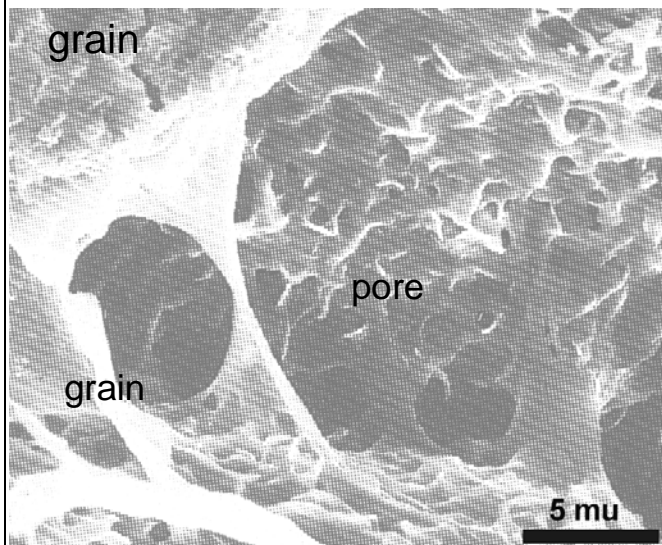
Figure 4.4: Relationship between porosity and sorting of sands with various median sizes. (After Rogers and Head 1961).

unconsolidated sands	35 - 45 %
more consolidated sandstone	20 - 35 %
tight/well cemented sandstone	10 - 20 %
limestone (e.g. Middle East)	5 - 20 %
dolomite (e.g. Middle East)	5 - 20 %
chalk (e.g. North Sea)	5 - 20 %

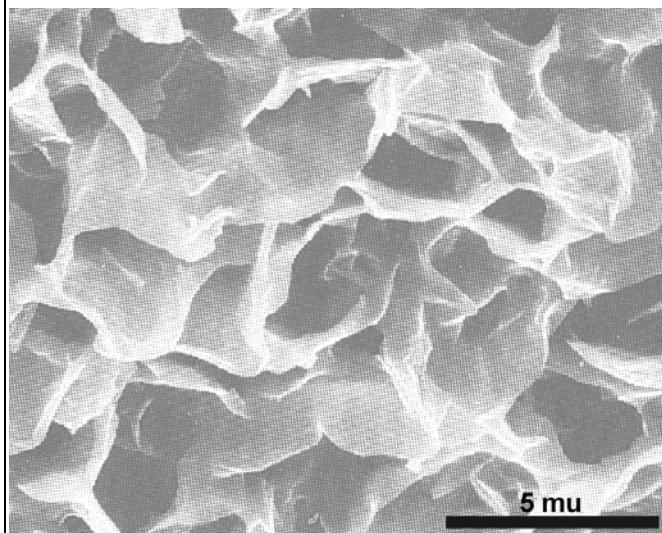
Table 4.1: Wentworth system for grain size analysis of siliciclastics



Pore lining chlorite and smectite clays



Pore bridging chlorite and smectite clays



Pore filling chlorite and smectite clays

Photo 4.1: Clay minerals filling pore space during diagenesis.

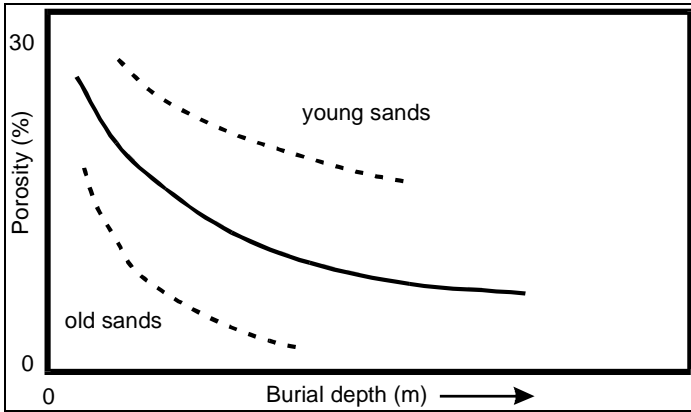


Figure 4.5: Porosity reduction as a function of depth.

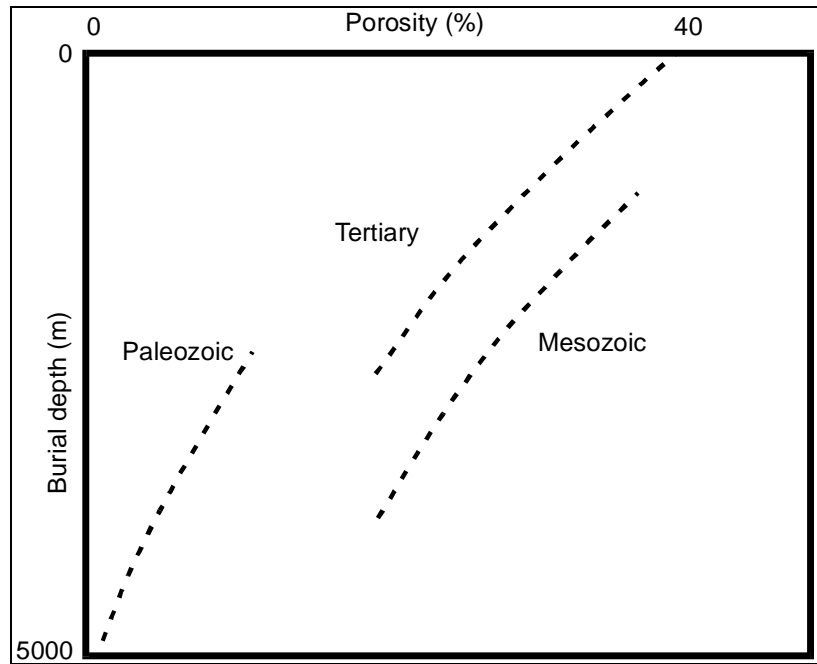


Figure 4.6: Porosity reduction with depth of different generations of porous rock.

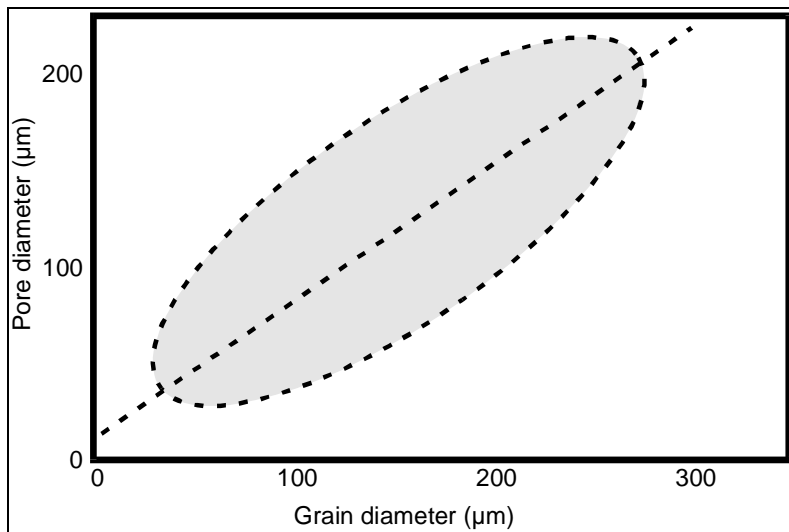


Figure 4.7: Relation between grain size and size of pore diameter.

4.1.3.3. CONSOLIDATION AND CEMENTATION

Unconsolidated rocks or fresh sediments do have high porosities, while cemented sandstones usually do have very low porosities. Cementation occurs during lithification and due to alterations by groundwater. Then pores are filled with minerals. The major present cementing materials are: calcium-, magnesium-, and iron carbonates, iron sulphides, limonite, hematite, dolomite, calcium sulphate and clay minerals. As an example we show Scanning Electron Microphotographs of secondary clays, grown during diagenesis (photo 4.1: a, b and c)

4.1.3.4. PORE SPACE REDUCTION DURING AND AFTER DEPOSITION

Compaction squeezes fluid out of pores and brings the grains closer to each other, closing pore space. In particular the finer-grained sedimentary rocks are subject to this phenomenon. Compaction is a major lithifying process in claystones, shales, and fine-grained carbonate rocks. However, in packed sandstones or conglomerates it is neglectible. As shown in the figures 4.4 and 4.5, porosity is lower in deeper, older rocks, but exceptions to this basic trend are known. With an increasing overburden pressure, poorly sorted angular sand grains show a progressive change from random packing to a closer packing. Some crushing and plastic deformation of the sand particles is a part of the process.

Category	Median grain size in μm
GRAVEL	2000
VERY COARSE	1000
COARSE	500
MEDIUM	250
FINE	125
VERY FINE	62
COARSE SILT	16
FINE SILT	8

Table 4. 2: average porosities of several porous rock types

4.1.3.5. GRAIN SIZE - PORE SIZE RELATION

It is already mentioned that reduction of grain size normally indicates a reduction in pore size. This is shown in figure 4.6: Pore size increases with grain diameter and the grain size appears to be bigger than the pore size. For this reason the grain size distribution for siliclastics, as defined by Wentworth (table 4.1 and 4.2), also gives an indication on the maximum pore sizes.

4.1.3.6. DUAL POROSITY

The heterogeneity of grain compositions also produces heterogeneity in pore sizes. This distribution of pore sizes can be random or uniform. Hence a zonation of different pore size areas is not possible. However, in case of layering/lamination or grouping, different areas with different pore spaces are defined. Here we speak of a dual porosity system. Examples are:

- Turbidites with a stratification of coarse and fine grains.
- Coal with highly large porous cleats and fractures and a very fine porous matrix of coal macerals.

4.1.4. POROSITY CLASSIFICATION OF CARBONATES BY ARCHIE, 1952

In carbonates there are several basic porosity types such as oolitic, vuggy, fracture or intercrystalline porosity. The Archie system divides carbonates in a descriptive way (table 4.3). The classification consists of two parts:

1. The texture of the matrix. This fulfils in part the lithological description and also gives information on the minute pore structure between the crystals, granules or fossils.
2. The character of the visible pore structure. A skeleton classification with symbols is used and co-ordinated with petrophysical data.

Example: A carbonate rock of type III F-B is defined as a finely sucrosic carbonate with matrix porosity Φ_{ma} of 10%, visible porosity about 10% with pores smaller than 0.1 mm, resulting in a total porosity Φ_{total} of 20%.

Class	Crystal size	Top val. size (μ)	Appearance	ϕ_{ma} (%)	Visible porosity			ϕ_{total}
					Size of pores in (mm)			
				A	B <0.1	C 0.1-2.0	D >2.0	
I	Course	1000	Resinous	2	e.g. 10	e.g.15		27
Compact Cryst.	Medium	500						
	Fine	250						
	Very Fine	125	to					
	XF	62						
	SL	20						
	Li	4	vitreous	5	e.g.10	e.g.15		30
II	SL	20	Chalky	15	e.g.10	e.g.15		40
Chalky	Li	4						
III	C	1000	Coarsely	5				
Sucrosic Granular	M	500	sucrosic to	10	10			20
	F	250	extremely					
	VF	125	fine	10	e.g.10	e.g.15		35

Table 4.3: Modified Archie classification for porosity in carbonate rocks.

Another classification, which includes the aspects of matrix/porosity relations, is the Dunham Classification. It will be discussed during the courses and practical work of applied sedimentology.

4.1.5. LABORATORY ANALYSES OF POROSITY

The laboratory porosity determination on a number of core samples is used as the basis for calibration of all kinds of field porosity measuring tools. Care must be taken to choose representative samples, because the samples have small volumes (10^{-4} m^3) when compared to the volume of a m^3 surveyed by measurement tools (density, neutron, sonic). The investigated volume of a porosity-logging tool is normally circa 1,000 times larger than the volume of a core plug.

Depending on the type of material several porosity measurements are possible. In chapter 2 several measurements are already discussed for the determination of the bulk density and matrix density. The most important measurement methods for porosity are:

1. Water absorption: a number of methods are known to fill the pore space with a liquid of known density.
2. Absorption of an organic liquid in a vacuum
3. Determination of the volume of natural present water, for example by heating and weighting.
4. Injection of mercury at high pressures into sample pores. Here pore size distribution also can be determined.
5. The Buoyancy method, based on Archimedes' principle. It requires the saturated weight of a porous sample in air and the weight of the sample suspended in a liquid of known density.

In this chapter three methods will be reviewed:

1. The wet and dry weight method
2. Boyle's law porosimeter, and
3. The total porosity measurement

4.1.5.1. THE WET AND DRY WEIGHT METHOD

The sample is extracted with a solvent and dried. The bulk volume V_b is then obtained by a direct measurement of the dimensions or by measuring the displaced volume of a non-penetrating fluid such as mercury. The grain volume V_{gr} can be determined by measuring the weight W_1 of the dry

core sample. Thereafter it is saturated with a wetting liquid with density ρ_{fl} and the submersed weight W_2 is measured:

$$V_{pore} = \frac{W_2 - W_1}{\rho_{fl}} \quad (\text{eq. 4.5})$$

Then the porosity ϕ can be calculated from V_b and V_{gr} .

$$\phi = \frac{V_b - V_{gr}}{V_b} \quad (\text{eq.4.6})$$

4.1.5.2. BOYLE'S LAW POROSIMETER

The porosimeter is already discussed in chapter two. There three figures and relations are extensively explained.

4.1.5.3. THE TOTAL POROSITY MEASUREMENT

The bulk volume V_b is determined by submerging the sample in mercury as previously described. Then the sample is crushed to decompose it into the individual grains. The matrix volume V_{ma} is determined by utilising a compression chamber or by liquid displacement. The advantage of this method is that all pore spaces are taken into account including the isolated pores that are not connected to the pore network.

4.1.6. CORE - LOG CORRELATIONS

For groundwater measurements, the recognition of water, oil and gas and humidity of coal, standard core measurements are performed to get their porosity, permeability and grain density. The porosity can be plotted on a depth scale and correlated with porosity logs, such as the density, neutron or sonic log. In order to obtain a good correlation several criteria can be used :

1. Compare the logger's depth with the driller's depth as indicated on the log heading. When the bottom of the casing is found at the same depth a shift is probably not needed.
2. Observe the core recovery. When 100% core is recovered the core can be shifted as one unit. For smaller recoveries it is often possible to shift each core section separately within a range indicated by the non recovered section.
3. Clear lithology breaks in the core and on the log give often a good depth calibration point.
4. A gas-oil, oil-water or water-air contact observed in the core can be correlated with the log contacts.

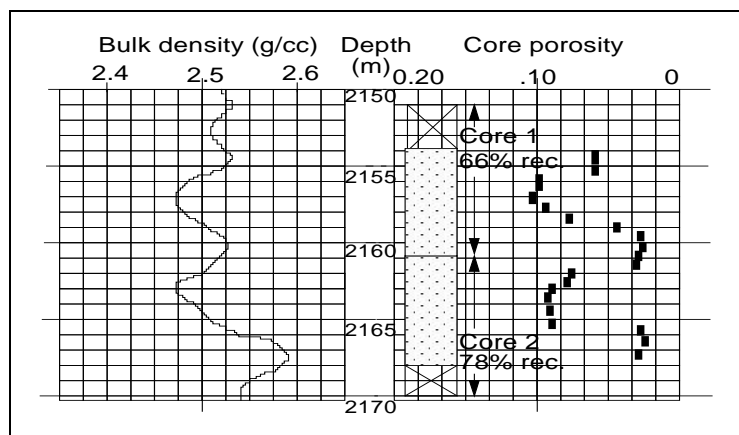


Figure 4.8: Density - core porosity correlation

4.2. PERMEABILITY

4.2.1. GENERAL DEFINITION OF PERMEABILITY

A rock that is used for the injection or production of water, oil or gas needs to have the ability to transport the substance through the connected pores. Or, in general terms, one needs to know the flow rate of flow of a fluid through a system consisting of porous media, tubes, etc.. It is dependent upon two basic properties:

- the fluid potential gradients, and
- the resistance to the flow of that fluid along the pathway traversed.

In terms of electric conductivity of a material it is called the ratio of the electric current and the electric potential. In the hydraulic equivalent the electric potential is replaced by the pressure drop ΔP and the electric current by the fluid flow Q . Ergo the calculable "constant" that integrates the "resistance" factors for porous media is named "permeability". In other words, the permeability is a measure of the relative ease with which a porous medium can transit a liquid or gas under a potential gradient. It is a property of the medium alone and is independent of the nature of the pore filling matter and of the force field (pressure gradient) causing movement. It is also a property of the medium that is dependent upon the shape and size of the pores. Consequently, permeability is influenced by grain size, shape, sorting, packing, degree of consolidation and cementation.

Porous rock can have two types of permeability:

- primary permeability, or the matrix permeability which is created during deposition and lithification of the sediment to rocks.
- secondary permeability is created during the alteration of the rock by compaction, fracturing solution, and cementation.

Compaction and cementation normally reduce the permeability, fracturing and solution normally increase it. When fresh water is present in a clay rich porous rock, several clay minerals like smectites and montmorillonites do swell and may cause a complete close off of pore space.

4.2.2. FLOW IN TUBE (POISEUILLE)

Hagen in 1839 and Poiseuille in 1846 worked on the laws affecting the flow of water through capillary tubes. The latter defined for a flow through a cylindrical tube Poiseuille's law :

$$Q = \frac{\pi \cdot r^4 \cdot \Delta p}{8 \cdot \mu \cdot L} \quad (\text{eq. 4.7})$$

with:

- Q : volumetric velocity cm^3/s
 r : radius tube in cm
 ΔP : pressure difference
 dyne/ cm^2
 μ : dynamic viscosity in
 poise or (gram/sec.cm)
 L : length tube in cm.

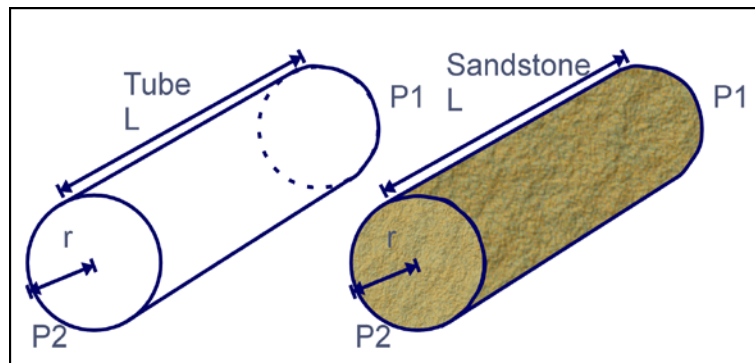


Figure 4.9: Comparison of flow in a tube with flow through sandstone

4.2.3. PERMEABILITY MEASURED ON CORE SAMPLES

In 1856 Darcy determined permeability experimentally by flowing water through sands proposed as filtering material for sanitary purposes, for the town of Dijon, France. His law extended for different fluids originally is written as :

$$Q = \frac{-k(h_2 - h_1)}{l} \quad (\text{eq. 4.8})$$

where:

Q : volumetric fluid velocity in $L^3 \cdot t^{-1}$

l : thickness of the sand L.

h_2, h_1 : the elevation above a reference level of water in manometers terminated above and below a vertical column of sand and L

k : a proportionality factor also in $L^3 \cdot t^{-1}$, which contains the properties of the fluid and the porous medium.

All relations were associated with a water column (m) and flow capacity ($L^3 \cdot t^{-1}$). Viscosity of the fluid was not included. This principle is still in use with permeability estimations in groundwater flow measurements. The generalisation of the Darcy relation includes the viscosity and dimensioning of the porous medium, including the pore energy by surface, length and pressure drop:

$$Q = \frac{k \cdot A \cdot \Delta P}{\eta \cdot L} \quad (\text{eq. 4.9})$$

where:

Q : volumetric fluid velocity in $cm^3 \cdot s^{-1}$

A : surface area perpendicular to flow direction in cm^2

ΔP : pressure difference in atm.

η : dynamic viscosity of the fluid in cpoise (kg/sec.cm)

L : length in cm

k : permeability in Darcy (1 D=0.986*10⁻⁸ cm²)

4.2.4. CORRECTION FOR A FLOWING MEDIUM IN LABORATORY MEASUREMENTS

Nowadays permeability is, in principle, determined with the same equation Darcy published back in the nineteenth century. The Ruska permeameter is normally used for this measurement, with gas as the flowing medium. We usually want to know the permeability of the reservoir rock for fluids, hence for the determination of water or oil permeability corrections have to be made to the measured gas permeability. Darcy's law is different for gases, because the volume of gas that passes through the sample is not only dependent on the pressure differential but also on the absolute pressure itself. When taking the mass flow into consideration the following equation for gas can be used:

$$Q = \frac{k \cdot A \cdot \Delta P \cdot \bar{P}}{\eta \cdot L \cdot P_{atm}}, \dots, \text{at } 20^0 C, 1 \cdot atm \quad (\text{eq. 4.10})$$

where \bar{P} is the average pressure over the sample in atm, and P_{atm} the pressure outside the system.

4.2.5. CORRECTION FOR GAS SLIPPAGE

In contrast with liquids that adhere to the pore walls, gases are hardly affected by the same pore walls. Gases flow with an almost piston shaped flow profile, while liquids in the laminar flow regime exhibit a parabolic flow profile with a maximum flow in the center and zero flow velocity at the pore walls. The higher flow of gas compared to liquids is called gas slippage. In 1941 Klinkenberg was able to show that by gas slippage at the gas/solid boundary, measured gas permeability is higher than liquid permeability. He introduced the following correction:

$$k_a = k \left(1 + \frac{b}{\bar{P}} \right) \quad (\text{eq. 4.11})$$

where:

- \bar{P} : mean test pressure of the gas in the pores
- k_a : apparent or observed permeability with gas
- k : liquid permeability
- b : Klinkenberg factor

By carrying out measurements at different pressures on one sample, one can extrapolate in a " k_a versus $(1/p)$ " plot the k_a to the point $1/p=0$. At this point the pressure is infinite and there is no difference between liquids and gases. Here we find the true liquid permeability as depicted in Fig. 4.9. The Klinkenberg factor is inversely proportional to the radius of the capillaries and therefore also to permeability. Several authors have found slightly different relationships for different permeability fields (Fig.4.10). The slip effect is significantly recognizable below 100 mD.

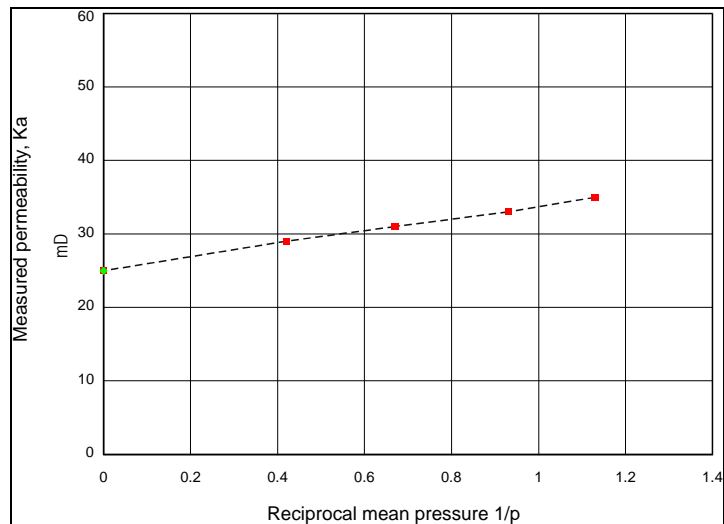


Figure 4.10: Correcting air permeabilities for slip flow (After Lynch, 1962)

4.2.6. CORRECTION FOR TURBULENCE

At higher flow velocities the flow regime changes from laminar to turbulent. This means that the liquid particles are not all moving parallel in the same direction but follow irregular vortexes with an overall resultant movement along the pore axis. The flow energy provided by the pressure differential is in this case not only used for the movement of the fluid as a whole but also spent on internal movements, that can be characterised by the kinetic energy of the fluid ($\rho \cdot v^2$). Darcy's law is therefore extended by a term that reflects the flow energy spent on the kinetic energy of the flowing medium itself. Forchheimer adapted Darcy's law as follows :

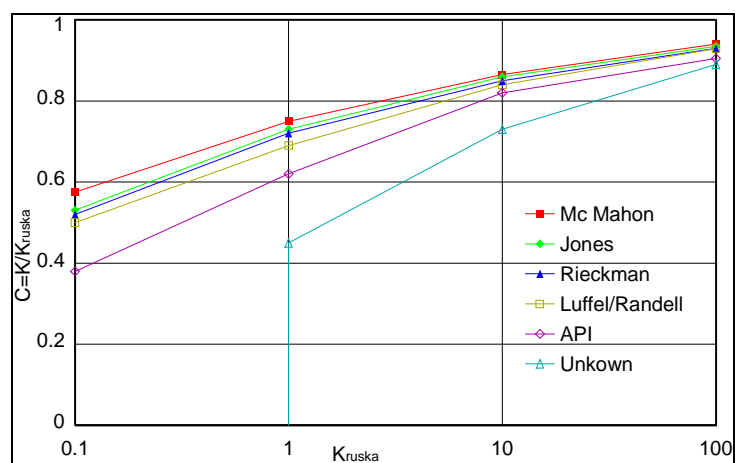


Figure 4.11: Influence of Klinkenberg factor on the liquid permeability K (van Baaren, 1982)

$$\frac{dP}{dL} = \eta \cdot \frac{v}{k} + \beta \cdot \rho \cdot v^2 \quad (\text{eq. 4.12})$$

with:

- β : turbulence factor (-)
- ρ : gas density ($\text{kg}\cdot\text{m}^{-3}$)
- v : gas velocity ($\text{m}\cdot\text{s}^{-2}$)
- dP/dL : pressure gradient ($\text{Pa}\cdot\text{m}^{-1}$)
- η : fluid viscosity ($\text{kg}\cdot\text{m}^{-1}\cdot\text{s}^{-1}$)
- k : permeability (m^2)

Some gas producing reservoirs have a high turbulence factor. The result is that the gas permeabilities measured at the well are lower than the liquid permeabilities measured on core samples. The turbulence effect is only important for gas production in reservoirs with a permeability significantly higher than 100 mD.

4.2.7. PERMEABILITY RELATED TO TEXTURE PROPERTIES

As mentioned before, the factors affecting the magnitude of permeability are:

1. Shape and size of sand grains:

If the grains are elongated, or large and flat and regularly placed with the length axis, the horizontal permeability (k_h) will be very high when compared to the vertical permeability (k_v). The vertical permeability will be medium-to-large (figure 4.11.a). If the rock is composed mostly of large and uniformly rounded grains, its permeability will be considerably high and of the same magnitude in both directions (figure 4.11.b). Further if the grains are small and of irregular shape, permeability quickly reduces to very low values (figure 4.11.c).

2. Sedimentation, compaction and zonation:

The types of porous rocks or reservoirs with directional permeability are called anisotropic. It affects fluid flow characteristics and the permeability that is found parallel and vertical to a bedding plane. During sedimentation grains submerge in water with their longest and flattest sides in a sub-horizontal position. Succeeding compression and compaction improves this arrangement of the grains. Hence very flat minerals, such as phyllo-silicates like biotite and muscovite, and clay/shale laminations, are serious obstructions for a vertical permeability. The ratio of horizontal to vertical permeabilities (or the k_h/k_v -ratio) usually ranges from 1.5 to 3. Fractures etc. may cause a $k_v \gg k_h$.

3. Cementation:

Permeability of porous rocks is affected by cementation and the distribution of the cementing material within the pore space.

4. Fracturing and solution:

Fracturing is an additional secondary permeability feature. However, when porous strata alternate

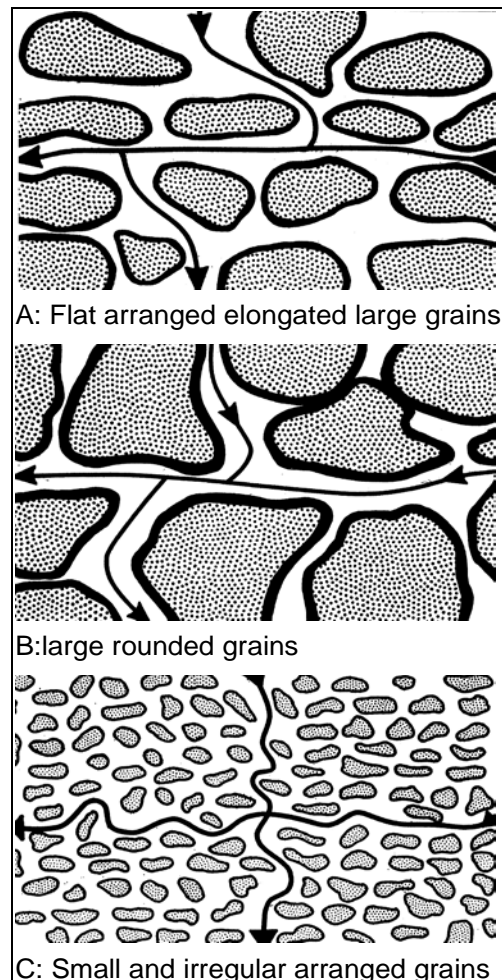


Figure 4. 12: Textures versus differences in permeability (revised after Djebbar 1996)

with chemical sediments (salt, limestone, etc.), or are connected by fractures, mineral solution by percolating surface and subsurface acidic water, increases and decreases the permeability in the different zones.

4.2.8. RELATION BETWEEN PORE SPACE AND PERMEABILITY

Permeability is depending on the amount of pores, pore shape and thus the complement of the present minerals and their spatial characteristics. Kozeny produced a fundamental correlation which defines permeability as a function of the specific pore surface area and porosity. He consider a porous rock with a cross-section A and length L , consisting of n parallel capillary tubes, all of the same radius r (cm) and length L (cm) and cemented between the tubes. Here he combined the flow rate of Poiseuille's equation with Darcy's law getting the relation:

$$k = \frac{n \cdot \pi \cdot r^4}{8A_c} \quad (\text{eq. 4.13})$$

with A_c as the capillary tube surface. Porosity itself is defined as the ratio of the pore volume and bulk volume or:

$$\phi = \frac{V_p}{V_b} = \frac{n \cdot \pi \cdot r^2}{A_c} \quad (\text{eq. 4.14})$$

When ϕ is inserted in equation 4.13, the permeability for a series of capillary tubes can be defined as:

$$k = \frac{\phi \cdot r^2}{8} \quad (\text{eq. 4.15})$$

with: k in cm^2 ($\approx 10^8 \text{ D}$), ϕ as a fraction. Now the ratio of the internal surface area A_s of the tubes and the pore volume V_p give the internal surface area per unit pore volume ($S_{Vp} = 2/r$). Now the total area in the pore space per unit of grain volume, (S_{Vgr}) can be defined as:

$$S_{Vgr} = S_{Vp} \cdot \frac{\phi}{1-\phi} \quad (\text{eq. 4.16})$$

Substituting $S_{Vp} = 2/r$ and combining equation 4.13 with 4.16, gives the relation:

$$k = \left(\frac{1}{2s_{Vgr}^2} \right) \cdot \frac{\phi^3}{(1-\phi)^2} \quad (\text{eq. 4.17})$$

When the pores are expressed as the complement of grains, the tubes have to be replaced by a winding flow path. Then a new term has to be implemented; the tortuosity (τ), which is the actual flow path length (L_a) divided by the minimum length between the two ends of the flow path (L):

$$\tau = \left(\frac{L_a}{L} \right)^2 \quad (\text{eq. 4.18})$$

Now the tortuosity is inserted in equation 4.17, which results into:

$$k = \left(\frac{1}{2\tau \cdot s_{Vgr}^2} \right) \cdot \frac{\phi^3}{(1-\phi)^2} \quad (\text{eq. 4.19})$$

2τ is replaced by a constant K_z , or K_s which is defined as a shape factor for the spatial pore space characteristics. For the major part of the porous media it appeared to have a value of 5. This results into a general relation of:

$$k = \left(\frac{1}{5s_{Vgr}^2} \right) \cdot \frac{\phi^3}{(1-\phi)^2} \quad (\text{eq. 4.20})$$

4.2.9. EMPIRICAL RELATIONS

Permeability is a geometrical property and is therefore depending on rock properties such as composition, texture and fabric. If the composition is assumed to be essentially constant then the texture will be the dominant factor. Many semi-empirical relationships are created between permeability and the textural properties grain size, sorting and porosity. The relation by van Baaren (1979) proved to give useful results for non shaly sandstones :

$$k = 10 \cdot D_{dom}^2 \cdot C^{-3.64} \cdot \phi^{m+3.64} \quad (\text{eq. 4.21})$$

Where:

- k : one-phase permeability (mD)
- D_{dom} : dominant grainsize (micron) from cutting inspection with a microscope.
- C : a constant derived from the sorting observed with a microscope (Table 4.5)
- ϕ : porosity, fraction of bulk volume. Derived from well log evaluation.
- m : cementation factor. Estimated by scratching of rock samples (Table 4.4).

This relation enables permeability data to be obtained during initial field development, before a core is cut and analysed in the laboratory, a process that can take several weeks to accomplish. The relation can in principle be applied within hours of logging the well and therefore uses readily available data sources such as cuttings, and/or sidewall samples, together with the porosity derived from well logs.

Consolidation	Cementation factor	
	atmospheric	in-situ ³
unconsolidated sand	1.4	1.6
unconsolidated to friable sand	1.5	1.7
friable sandstone	1.6	1.8
hard to friable sandstone	1.7	1.9
hard sandstone	1.8	2.0
very hard sandstone	2.0	2.2

Table 4.5: relation of cementation factor (m) and sand

Sorting	C	$D_{dom.max.}/D_{dom.min.}$
extremely well to very well sorted	0.70	2.5
very well to well sorted	0.77	
well sorted	0.84	3.5
well to moderately sorted	0.87	
moderately sorted	0.91	8
moderately to poorly sorted	0.95	
poorly sorted	1.00	

Table 4.4: relation of sorting, C, to the spread in dominant grainsize, D_{dom} .

4.2.10. PERMEABILITY FROM LOGS

4.2.10.1. INTRODUCTION

To derive permeability from logs many methods have been proposed in literature. In this section only the methods that are used on a routine basis are discussed. During exploration or appraisal drilling cores are taken across the reservoir section of interest. Porosities can often be derived with a high degree of accuracy from the wireline logs when a correlation with the porosities measured on core samples is made. In turn permeabilities measured on core samples can usually be related to porosities, provided the relation is restricted to one sedimentological unit. The following symbols are used in the equations that describe these relations :

		<u>dimension</u>
k	= Permeability in	mD
ϕ	= Porosity in fraction of bulk volume	%
S_{wirr}	= Irreducible water saturation as a fraction of the pore volume	%
D_{dom}	= Dominant grainsize diameter in microns	μm
S_o	= Sorting expressed as a constant (Trask) see eq. 3.4.	d.l.
m	= Cementation factor as used in the Archie equation (Chapter 6)	d.l.

4.2.10.2. PERMEABILITY AS A FUNCTION OF POROSITY

Depending on the environment of deposition core permeabilities can often be correlated with the core porosities. These relations have the following kind of layout :

$$k = 10^{(C_1 + C_2 \cdot \log(\phi))} \quad (\text{eq. 4.22})$$

and

$$k = 10^{(C_1 + C_2 \cdot \phi)} \quad (\text{eq. 4.23})$$

C_1, C_2 are constants that are determined by the regression analysis on permeability - porosity data pairs.

A crossplot of permeability versus porosity is used to determine the most appropriate relation, which in turn can then be applied to find permeabilities in uncored intervals from porosity log values.

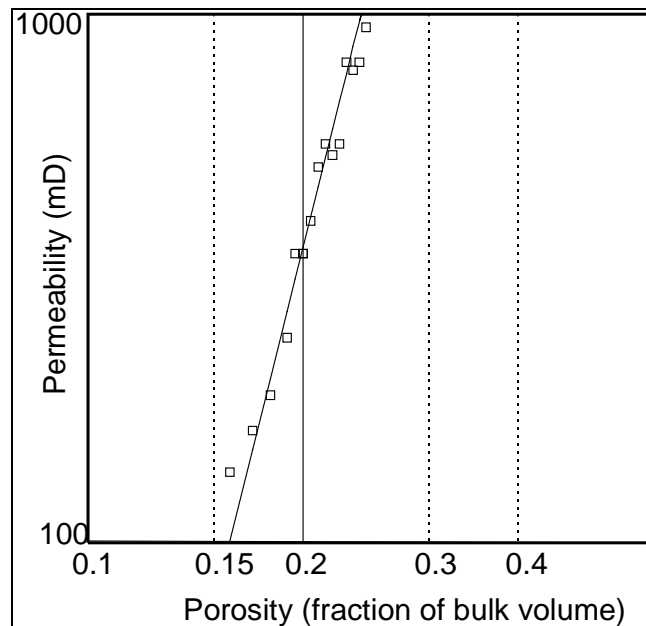


Figure 4.13: Example of the porosity versus permeability of laboratory results from several reservoir sandstones

4.2.10.3. PERMEABILITY BY POROSITY AND IRREDUCIBLE WATER SATURATION IN RESERVOIRS AND CONTAMINATED SANDS

Equations like eq. 4.20, 4.22 and 4.23 only use the porosity of the reservoir. This approach is not unique because rocks with the same porosity can have widely different grainsizes and therefore a wide range of permeabilities. Porous rocks with large grains will have a higher permeability than small grained reservoirs. If the reservoir or contaminated sand contains the maximum amount of oil, the irreducible water volume will cling to the grain surfaces, provided the rock is water wet. For a reservoir that consists of small grains the grain surface area will be much larger than for a reservoir composed of large grains. The irreducible water saturation (S_{wirr}) is in that case a measure for grainsize, and also an indication for permeability. The following equation is by Wyllie and Rose is one of the many found in literature :

$$k = \left(100 \cdot \phi^2 \cdot \frac{1 - S_{wirr}}{S_{wirr}} \right)^2 \quad (\text{eq. 4.24})$$

When core measurements are available it is worthwhile to determine the constants experimentally.

4.2.11. FIELD EXAMPLES

Laboratory results on cores

When the permeability is plotted versus the porosity on double logarithmic paper a straight line is often retrieved. In these cases the cementation factor (m), grain size and sorting usually are constant. In Figure 4.12 permeabilities measured on core samples are plotted vs. the porosities, and compared with the relation (straight line) derived with equation 4.21. The average grain size and cementation factor “ m ” used in the relation for this clean sandstone are 250 microns and 1.8.

Drilling example: Invasion

One of the purposes of the mud column is to maintain an overpressure in the borehole with respect to the fluid pressure in the reservoir rock. As a result, water will filter from the mud into the rock. The invading mud filtrate will displace a part of the oil in the rock around the well bore and create an invaded zone as depicted in figure 4.13. In the figure d_{i1} and d_{i2} are respectively the diameters of invasion of a high and a low porosity sandstone (SST) layer, and d_h is the borehole diameter.

Solid (clay) particles contained in the mud will be deposited along the hole opposite permeable zones, and form a mud-cake with a permeability that is much lower than the permeability of the invaded reservoir rock. The rate of mud filtrate flow into the formation will be controlled by the low permeability of the mud cake, and be in first approximation independent of the permeability of the various layers, except of course when the permeability is close to zero. The distance into the reservoir rock that the invasion will progress in a given time period is therefore governed by the rock porosity and not by the magnitude of the permeability. The depth of invasion in a low porosity rock is as a consequence deeper than in a high porosity (larger storage capacity) rock.

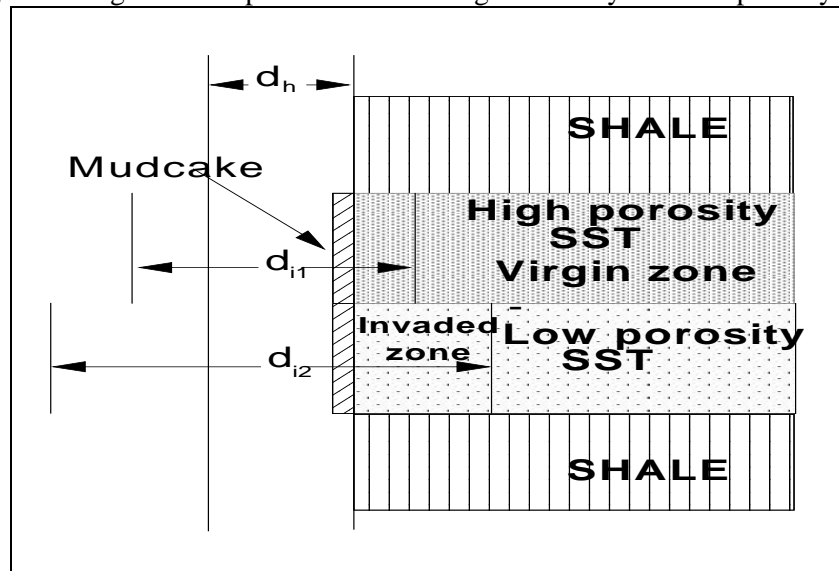


Figure 4. 14: The invasion profile in a reservoir sand

4.3. CAPILLARITY

4.3.1. INTRODUCTION

The accumulation of fluids in a reservoir rock is affected by the interaction of rock and fluids, which in the static situation is dominated by two forces: the gravity and the interfacial tension. To explain the distribution of fluids, and the positions of oil-water and oil-gas contacts knowledge of interfacial tension, wettability and capillary pressure is essential. These concepts will be explained in the following sections.

4.3.2. SURFACE TENSION

Surface energy

Surface tension of a gas-liquid interface has its origin in the fact that at a surface the intermolecular (van der Waals) forces are unbalanced and the surface molecules thus experience a net pull directed into the bulk of the solution (Fig. 4.1.A). Consequently, energy is required to increase the surface area of an interface. This explains why droplets and bubbles spontaneously minimise their surface area by creating a spherical shape. The force per unit length is referred to as the surface tension.

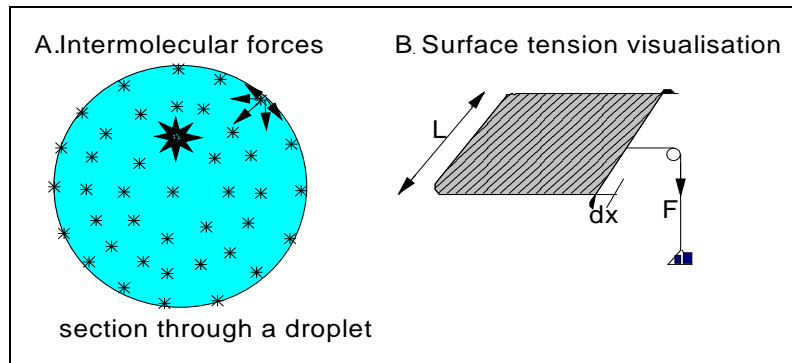


Figure 4. 15: Representation of the intermolecular forces and the surface tension visualisation

A visualisation of the surface tension is realised by considering a soap film in a rectangular metal or glass frame. One side of the rectangle can be moved over distance dx and the force F required for this displacement can be measured as shown in gure 4.14-B. At equilibrium, a force balance gives the relations:

$$\gamma = \frac{F}{2l} \quad (\text{eq. 4.25})$$

and

$$F = 2 \cdot \gamma \cdot l \quad (\text{eq. 4.26})$$

with:

γ : surface tension, force per unit length in N/m

l : length of the rectangle wire in m

F : force put on the wire in N

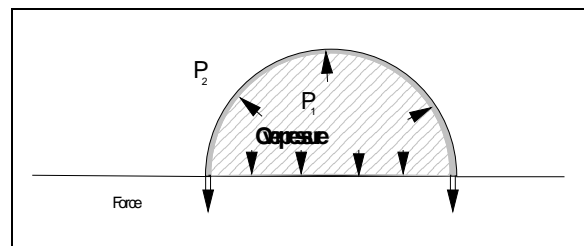


Figure 4.16: Visualisation of the surface tension of a soap bubble.

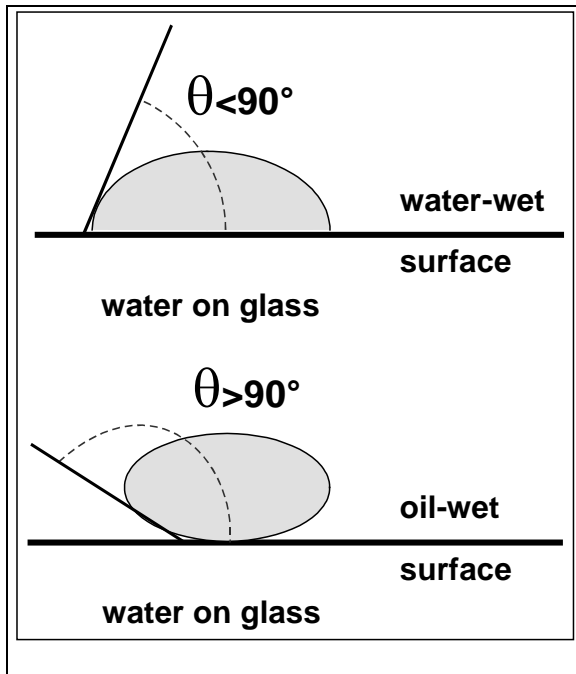
Soap bubble

Consider a hemispherical soap bubble placed on a flat liquid surface (Fig.4.15). In a state of equilibrium the surface tension acting along the periphery of the circle ($2\pi r\gamma$) pulls the soap film down. This force has to be balanced by the excess pressure pushing the soap film upwards. In order to have no net force on the liquid plane of the bubble, this upward force must be equal to the force acting downwards: $2\pi r\gamma = \pi r^2 \Delta p$ (eq. 4.27), again resulting in equation 4.25.

4.3.3. WETTABILITY

4.3.3.1. WETTABILITY ON A SMOOTH SURFACE

If a liquid is placed in contact with a solid, the surface of the liquid will tend to contract to its minimum surface area. However there may also be an attractive force between the liquid and the solid. This force is variable, dependent on the affinity of the liquid and the solid (Fig. 4.16).



4.3.3.2. SIGNIFICANCE OF WETTABILITY

The significance of reservoir rock wetting preference can be illustrated with a few examples :

- In water wet rock the affinity between the water and the rock is much larger than the affinity between the rock and the oil. Consequently if both water and oil are present in the pores of the rock in significant quantities, the water will be distributed as a film that tightly clings to the pore surface. In contrast the oil will contract in globules and will be found in the middle of the pores as depicted in the left part of figure 4.17.
- If the affinity between the rock and the oil is larger than the affinity between rock and water the opposite situation will be found. The rock is now covered with an oil film and the water is found in the middle of the pores as shown in the right hand part of figure 4.17.

The contact angle θ measured through the liquid indicated by the arcs is called the contact angle. A solid is said to be wet by a liquid if the contact angle is less than 90° . The liquid is intermediate wetting from 70° to 110° , and non-wetting if the angle is greater than 110° . Complete wetting of the solid by the liquid is achieved for: $\theta = 0^\circ$, and complete non-wetting (theoretically) with $\theta = 180^\circ$.

Figure 4.17: Wettability of water on a glass surface

Most reservoirs are assumed to be water wet. The left-hand picture gives already an indication about the effect of wettability on the fraction of the oil volume that can eventually be produced. If the oil occupied originally say 80 % of the pore volume, it would have formed a continuous phase despite the fact that it is pushed to the middle of the pores by the water that clings to the rock.

When, due to production, the oil saturation is reduced to say 25 %, the oil will become the discontinuous phase and restricted to isolated globules surrounded by water. The water phase is then continuous and can still flow, but the oil volume cannot be reduced further by primary production mechanisms, such as pressure depletion and water drive. Injection of chemicals or gas is required to reduce the surface tension between the water and oil and mobilise the oil left behind during the primary production phase.

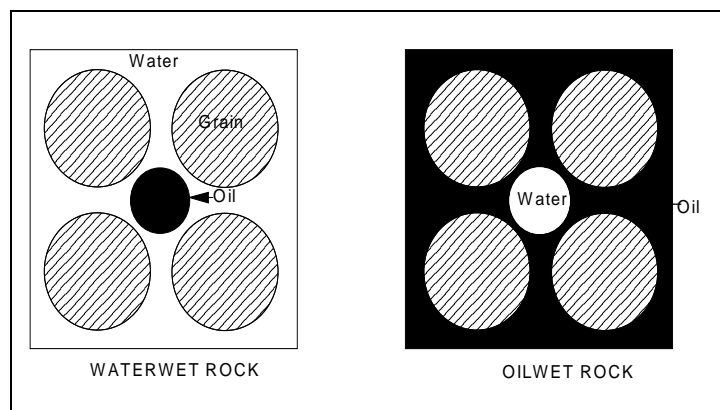


Figure 4.18 Distribution of the water in a water wet and oil wet reservoir.

4.3.4. CAPILLARY PRESSURES IN A TUBE

We have seen that the pressure difference Δp across a curved interface is given by equation 4.27. However the interfacial tension is directed along the interface which makes an angle θ with the wall of the tube. The tension component that lifts the column of water is therefore equal to $\gamma \cdot \cos(\theta)$ parallel to the capillary axis. Equation 4.28 is modified to read :

$$\Delta P = P_1 - P_2 = \frac{2 \cdot \gamma \cdot \cos(\theta)}{r} \quad (\text{eq.4.28})$$

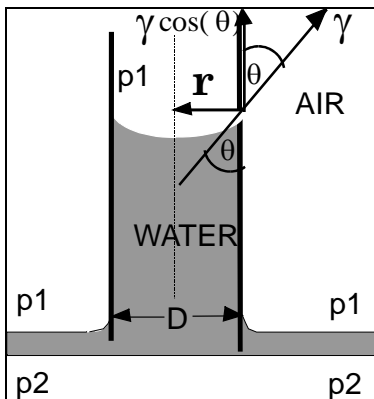


Figure 4. 19: Capillary tube

Equation 4.28 defines the capillary pressure in terms of the radius of the tube. It is this pressure difference which causes the rise of a wetting liquid in a capillary. This can be explained by the affinity of the water for the glass surface of the tube. The water literally creeps up the tube and drags due to its internal cohesion other water molecules upward as well. If the two fluids are air and water, the following relationships are clear:

$$\Delta P = P_c = (\rho_{water} - \rho_{air}) \cdot g \cdot h \quad (\text{eq.4.29})$$

where ρ_{air} and ρ_{water} are the densities of respectively air and water; h the liquid rise, g the acceleration of gravity, and P_c the capillary pressure. Equation 4.29 can be rearranged to find the height "h" of the capillary rise:

$$h = \frac{P_c}{(\rho_{water} - \rho_{air}) \cdot g} \quad (\text{eq.4.30})$$

In combination with equation 4.28 we obtain for this air/water/solid system :

$$h = \frac{2 \cdot \gamma \cdot \cos(\theta)}{r \cdot g \cdot (\rho_{water} - \rho_{air})} \quad (\text{eq.4.31})$$

Because surface tension, contact angle and densities are constant for given fluids. It is clear that the height to which the water will rise is inversely proportional to the radius of the tube. If air was replaced by oil similar reasoning leads to the relation :

$$h = \frac{2 \cdot \gamma \cdot \cos(\theta_{o/w})}{r \cdot g \cdot (\rho_{water} - \rho_{oil})} \quad (\text{eq.4.32})$$

It should be noted that the contact angle θ of the water air combination is now replaced by $\theta_{o/w}$, the contact angle of the water - oil system. For a very wide tube (r approaches infinity) both h and P_c will be equal to zero. The water level, which will then be the same inside and outside the tube is called the "**free water level**".

4.3.5. CAPILLARY PRESSURE IN RESERVOIR ROCK

4.3.5.1. CAPILLARY PRESSURE CURVES

Reservoir rock contains numerous pores of different size (radius). If the porous rock shows to be extremely homogeneous and with a constant pore size "r", we could apply equation 4.32 directly to calculate the capillary rise "h", as the interfacial tensions (IFT) and contact angles of various fluid - solid systems are known from laboratory measurements. The data of Table 4.6 are commonly used for

this approximation.

System	θ	$\cos(\theta)$	γ (dyne/cm)	$\gamma \cdot \cos(\theta)$
air/fresh water/solid	0	1	72	72
air/saline water/solid	0	1	83	83
oil/water/solid	0	1	35	35
kerosene/brine/solid	0 (30)	1 (0.866)	50 (48)	50 (42)
air/kerosene/solid	0	1	24	24
toluene/brine/solid	0	1	38	38
air/mercury/solid	40 for air	0.766	480	368

Note: γ is the interfacial Tension, 1 dynes/cm = 0.001 N/m or 1 mN/m

Table 4. 6: Interfacial tensions and contact angles of various fluid/solid systems.

Natural rock has a distribution of pore radii, which we have to take into account. Let us assume we have a rock sample containing pores of only three different sizes: small, medium and large. Since “ P_c ” and “ h ” are inversely proportional to the pore radius, the fluid distribution will be as shown in Figure 4.20 for a gas - water - solid system, in which we only show one capillary of each class. The pressure difference between the water and the gas gradients in the height versus pressure cross-plot, at the levels of the three menisci in the capillaries is equal to P_c .

Figure 4.20 shows the same sample 100% water bearing. If the water is displaced by oil we must exceed the capillary pressure for each pore size. Let us assume the values of r to be: 10, 5 and 2.5 μm with a $P_c = 1, 2$ and 4 psi. If we further assume that the number of pores (straight capillaries) is equal for each size, we can plot the pore volume of each size against the required injection pressure P_c . The value of P_c required for initial displacement is called the initial displacement pressure at the 100% water level.

If the sample has a continuous distribution of tubes the left hand side of figure 4.19 evolves into a capillary pressure curve, as shown in figure 4.20 and 4.21.

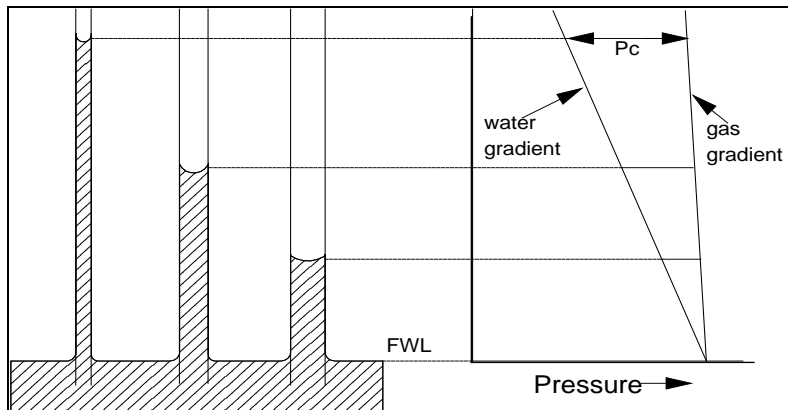


Figure 4. 21: Schematic representation of capillary pressure in reservoir rock.

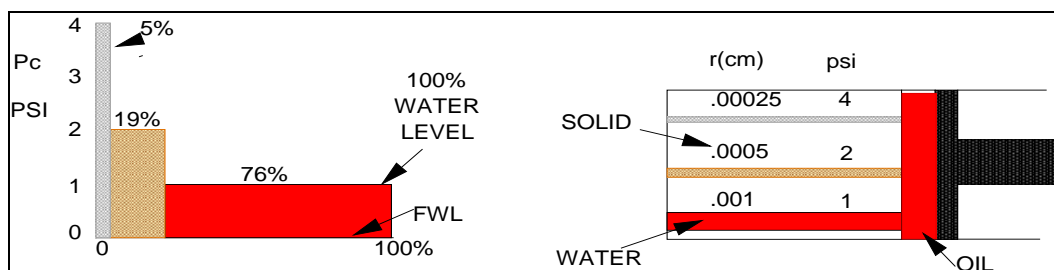


Figure 4. 20: Displacement of water by oil and the corresponding capillary pressure curve.

4.3.5.2.SATURATION LEVEL DEFINITIONS FOR HYDRO-CARBON RESERVOIRS

In water wet rock the following definitions are formulated:

- **Free Water Level (FWL)**

For a very wide tube (r approaches infinity) both capillary rise and pressure differential will be equal to zero. The water level, which will be the same inside and outside the tube is called the FWL. This is illustrated in the capillary pressure curve of figure 4.21, at the point where $S_w=100\%$ and $P_c=0$.

- **FOL (Free Oil Level)**

The Free Oil Level can be obtained with reservoir pressures measured with the wireline formation tester. The FOL is located at the transition of the gas bearing to the oil bearing part of the reservoir. For practical purposes it can be considered to be the GOC (Gas Oil Contact) in the reservoir.

- **100% Water Level**

The 100% Water Level is the level where hydrocarbons start from the bottom up to occupy pore space in a water-wet reservoir. This is not the same level as the FWL because a threshold pressure has to be overcome before hydrocarbons fill the pore space.

- **Oil Water Contact (OWC) or Gas Water Contact (GWC)**

The definitions that the OWC or GWC are the levels above which respectively water free oil and gas are produced are difficult to verify, because that would involve numerous production tests. For practical reasons the 50% oil or gas saturation levels are often taken instead. This is usually accurate for high permeable reservoirs. A second definition is the OWC or GWC are the deepest depths where respectively oil or gas is encountered (similar but not identical to the 100% Water Level), based on the log analysis.

- **Connate water saturation / Irreducible water saturation**

The connate water saturation refers to the smallest water saturation that can be reached in a water wet reservoir at the top of the oil column. The connate water is immovable and is supposed to form a film on the grains. Increasing the capillary pressure does not decrease the connate water saturation.

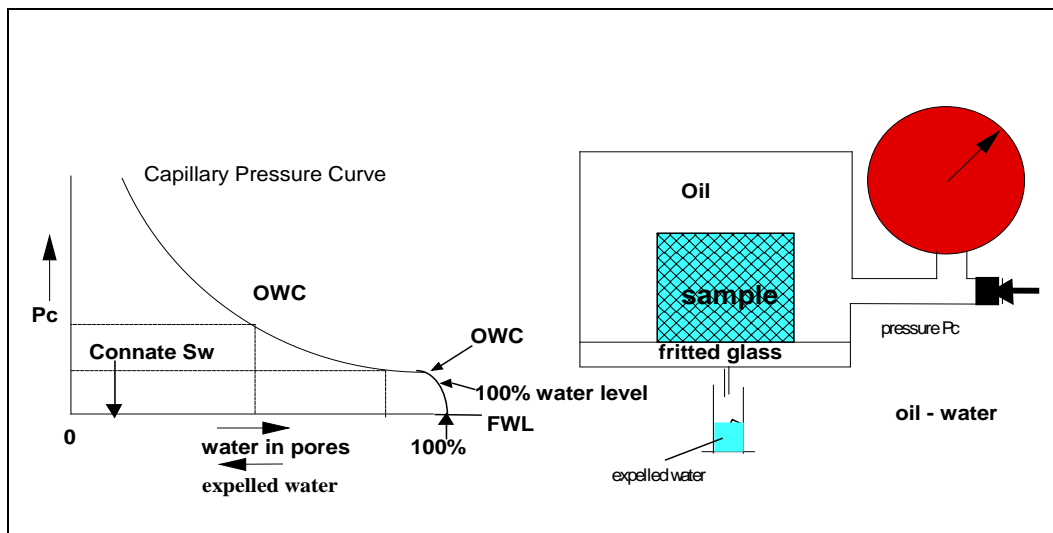


Figure 4. 22: Capillary pressure curve measurement and capillary pressure curve.

In water-wet rock the sequence of the levels from the bottom up is: the FWL, followed by the shallower 100 % Water Level and then at the shallowest depth the OWC or GWC. In oil wet rock the OWC can be located deeper than the FWL. In some cases the reservoir has a mixed wettability: oil wet in the upper part of the oil leg and water wet in the transition zone and in the water leg.

4.3.6. CAPCURVES FROM THEORY TO PRACTICE

4.3.6.1.LABORATORY ANALYSIS OF CAPILLARY PRESSURE CURVES

Care should be taken to carry out these measurements on representative samples, which cover the various lithologies, permeabilities and porosities present in the reservoir. The samples are cleaned with a hot solvent extraction (mixture of methanol, chloroform and water) to remove the oil. The samples are usually dried at about 105° C for clean reservoir rock, or at 60 °C and a relative humidity of 45 % to allow the clay to preserve the clay-bound water. It should be realised that generally the cleaning procedure results in water wet rock. There are various techniques to determine the capillary pressure curve:

- the diaphragm or porous plate technique;
- the centrifuge technique; and
- the air / mercury technique.

Only the porous plate technique will be discussed here. This technique uses a pressure vessel filled with oil in which the water saturated sample is immersed. The pressure in the oil is increased stepwise. At each step the displaced water is measured in a graduated cylinder, as shown in figure 4.21.

A fritted glass disk (porcelain of very low permeability) allows only water to pass. This disk is called a semi-permeable membrane. The capillary pressure curve pertaining to that sample is obtained by plotting the pressure against displaced water as shown on the left hand side of figure 4.21. The water saturation (S_w), plotted on the x-axis, is given as a fraction of the pore volume. The porous plate technique has the advantage that the samples are preserved and can be used for other analyses. The disadvantage is that it is very time consuming because after every pressure step one has to wait till equilibrium is reached and water production stops. The porous plate technique is restricted to rather low pressures up to 12 bar to prevent leakage through the porous plate. When mercury is used instead of oil, and air instead of water, the measurement starts with a dry sample, and can be carried out much quicker. Moreover much higher pressures can be used.

4.3.6.2.EXAMPLES OF CAPILLARY PRESSURE CURVES

Typical capillary pressure curve of two homogeneous sandstones (SST); one with large well sorted grains, the other with small and poorly sorted grains; and a vuggy dolomite are shown in figure 4.22.

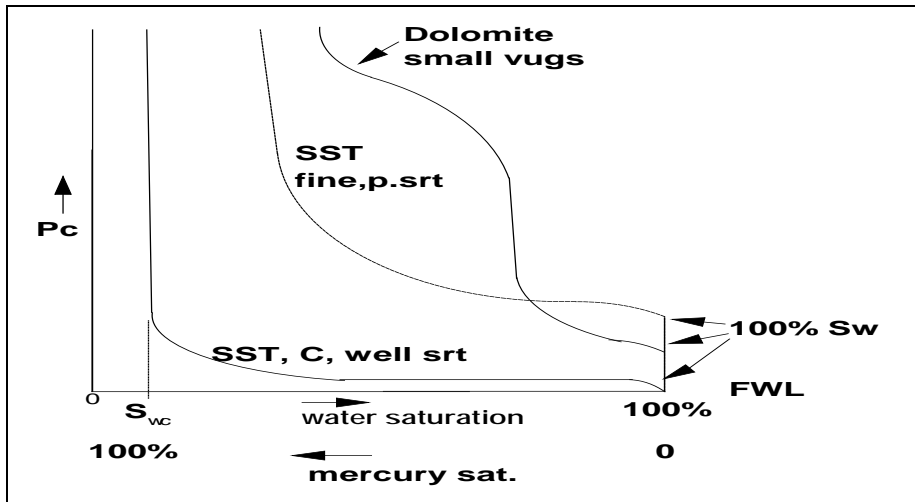


Figure 4. 23: Capillary pressure curves examples

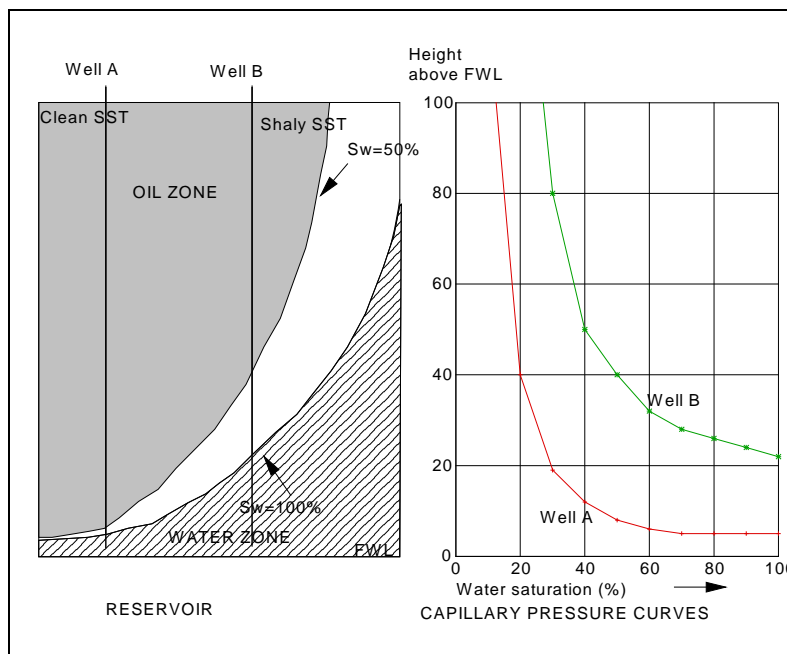


Figure 4. 24: Fluid distribution in a heterogeneous reservoir

4.3.7. CONVERSION FROM LABORATORY TO RESERVOIR CONDITIONS

In order to make use of the measured air/mercury capillary pressure curves, correction for the differences in contact angles and interfacial tensions between the laboratory fluids and reservoir fluids combinations have to be made. Based on equation 4.28 the following conversion is worked out :

Air and mercury filled sample:

$$P_c(Hg / air) = \frac{2 \cdot \gamma \cdot \cos(\theta)}{r} = \frac{2 \times 480 \times 0.776}{r} \quad (\text{eq.4.33})$$

Oil and water filled reservoir:

$$P_c(\text{oil} / \text{water}) = \frac{2 \cdot \gamma \cdot \cos(\theta)}{r} = \frac{2 \times 35 \times 1}{r} \quad (\text{eq.4.34})$$

Combining eq. 4.33 and 4.34 yields:

$$\frac{P_c(\text{Hg} / \text{air at surface})}{P_c(\text{oil} / \text{water in reservoir})} = \frac{480 \times 0.776}{35} = 10.5 \quad (\text{eq.4.35})$$

Similarly for a gas - water - solid system we obtain:

$$\frac{P_c(\text{Hg} / \text{air at surface})}{P_c(\text{gas} / \text{water in reservoir})} = \frac{480 \times 0.776}{72} = 5.1 \quad (\text{eq.4.36})$$

The converted values are often simplified to 10 and 5. This is justified because the inaccuracies in the contact angle and interfacial tension of the fluids is usually large, unless special laboratory equipment is used to measure these parameters separately under reservoir conditions.

To convert the maximum pressure measured on a capillary pressure curve in the laboratory, into an equivalent height above the FWL for reservoir conditions, the following equation is used :

$$h = \frac{\gamma_{res} \cdot \cos(\theta)_{res} \cdot P_c(\text{max.lab}) \cdot C}{\gamma_{lab} \cdot \cos(\theta)_{lab} \cdot g \cdot \Delta\rho} \quad (\text{eq.4.37})$$

LABORATORY	γ	θ	$\cos(\theta)$	$\gamma \cdot \cos\theta$	P_{cmax} (bar)
air/brine	72	0	1	72	12
kerosene/brine	50	0	1	50	1.4
kerosene/brine	48	30	0.866	42	1.4
air/kerosene	24	0	1	24	5
mercury/air	480	140	0.766	368	4000

Table 4. 7: Input values for laboratory cap. curves used in equation 4.37.

with :

γ_{res} : IFT or inter facial tension of the fluids/solid of the reservoir in mN/m

θ_{res} : contact angle fluid/solid reservoir in degrees

γ_{lab} : IFT of the fluids/solid of the laboratory in mN/m

θ_{lab} : contact angle fluids/solid laboratory in degrees

$P_{c(\text{max.lab})}$: Maximum pressure measured in the laboratory in bar

g : Gravity acceleration in 9.81 m/sec^2

$\Delta\rho$: Density difference reservoir fluids in kg/m^3

C : Constant : 100,000 when using the above units

4.4. LABORATORY ANALYSIS OF CAPILLARY PRESSURE CURVES

4.4.1. CAPCURVES: MEASUREMENTS WITH MERCURY

Introduction laboratory analysis of capillary pressure curves with mercury injection

A second method to discuss is the measurement of capillary pressure curves by mercury injection and retraction. The measured data are applicable for:

- the analysis of the response of capillary pressure curves.
- the determination of the pore size distribution.
- to gather attributes of pore geometry.

Subsequent, capillary pressure data, by mercury injection, of water-oil systems are comparable with the strongly water-wet capillary pressure curves obtained by other methods, when they are normalized using Leverett'sj-function. Note that in this case the state of wettability must be considered.

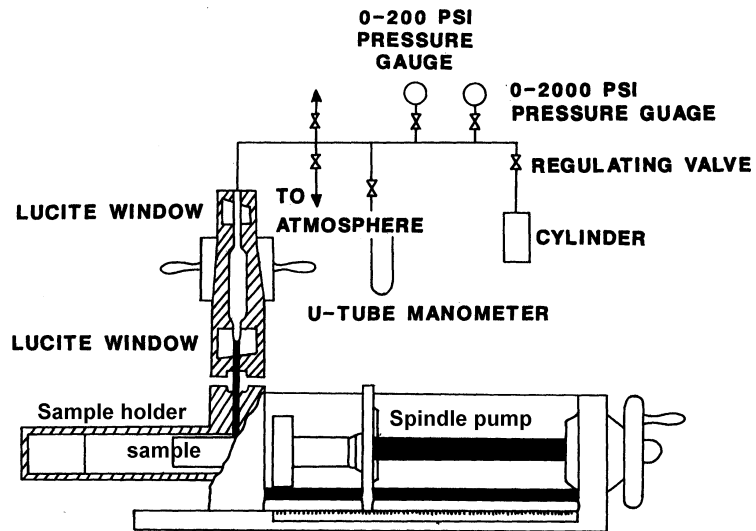


Figure 4. 25: Capillary pressure device for mercury injection

The disadvantages of the mercury injection method are:

- One can drink small amounts of liquid mercury without many problems. However Mercury vapor is toxic and will damage health by hair loss, teeth loss and other nasty illnesses in its syndrome. Hence, strict safety precautions must be followed when using mercury.
- Mercury cannot be safely removed after injection. Thus the remaining core with mercury has to be considered as chemical waste.
- The method is destructive when high pore pressures have to be used. Weak matrix samples can be destroyed, which results in inaccurate values for pore sizes.

A mercury injection procedures goes as follows:

1. The core is placed in the sample chamber of the mercury injection equipment (Figure 4.24).
2. The sample chamber is evacuated, and incremental quantities of mercury are injected while the pressure required for injection of each increment is recorded.
3. The incremental pore volumes of mercury injected are plotted as a function of the injection pressure to obtain the injection capillary pressure curve (Figure 4.25).
4. When the volume of mercury injected reaches a limit with respect to pressure increase a mercury withdrawal capillary pressure curve can be obtained by decreasing the pressure in increments and recording the volume of mercury withdrawn (Figure 4.25). A limit will be approached where mercury ceases to be withdrawn as the pressure approaches zero (S_{wmin}).
5. A third capillary pressure curve is obtained if mercury is re-injected by increasing the pressure incrementally from zero to the maximum pressure at S_{imax} .

The closed loop of the withdrawal and re-injection is the characteristic capillary pressure hysteresis loop. Mercury is a nonwetting fluid; therefore, the hysteresis loop exhibits a positive pressure for all saturations-that is, the hysteresis loop is above the zero pressure line. In order to transpose mercury injection data to represent water-oil or water air capillary pressure curves, the mercury capillary pressure data are normalized using Leverett'sj-function:

$$J = \frac{P_c \sqrt{\left(\frac{k}{\phi}\right)}}{\sigma \cdot \cos \theta} \quad (\text{eq.4.38})$$

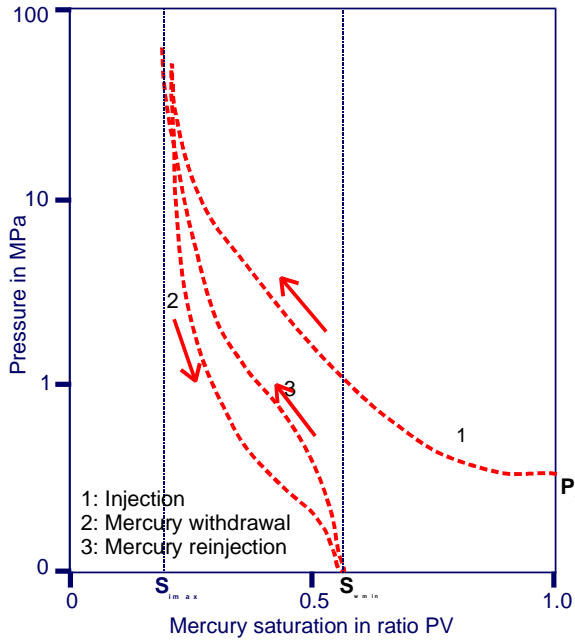


Figure 4. 26: Mercury injection, drainage and reinjection

relationship between the contact angle and the saturation of water-oil systems as follows:

$$\cos\theta_{a-w} = 1.0 = \left(\frac{P_{c-aw}}{\sigma_{aw}} \right) \cdot \left(\frac{r}{2} \right) = f(S_w) \quad (\text{eq.4.40})$$

In this way an air-displacing water capillary pressure curve is obtained. An oil-displacing water capillary pressure curve is formulated by using :

$$\cos\theta_{o-w} = \left(\frac{P_{c-ow}}{\sigma_{ow}} \right) \cdot \left(\frac{r}{2} \right) = f(S_w) \quad (\text{eq.4.41})$$

The ratio of the capillary pressures at each saturation from $S_w = 1.0$ to $S_w = S_{iw}$ is obtained, and the contact angle for a water-oil system in a porous medium can then be plotted as a function of the wetting phase saturation. Implicit the next equation shows the assumption that the pore size is the same for a given wetting phase saturation of the two fluids:

$$\cos\theta_{o-w} = \left(\frac{P_{c-ow}}{\sigma_{ow}} \right) \cdot \left(\frac{P_{c-aw}}{\sigma_{aw}} \right) = f(S_w) \quad (\text{eq.4.42})$$

with;

$\sigma_{Hg} = 480 \text{ N}(10^{-3})/\text{m}$, $\theta = 140^\circ$ and k defined in Darcies.

Then capillary pressure transposed from mercury data to represent water-wet, water-oil, or water-air systems (P_{CW-O} or P_{CW-A}) can be obtained from:

$$\frac{P_{cw-o}}{\sigma_{w-o} \cdot \cos\theta^\circ} = \frac{P_{cw-a}}{\sigma_{w-a} \cdot \cos\theta^\circ} = \left(\frac{P_{cHg}}{\sigma_{Hg} \cdot \cos 140^\circ} \right) \cdot \sqrt{\frac{k}{\phi}} \quad (\text{eq.4.39})$$

There is a close correspondence that can be obtained between J-function-normalized mercury capillary pressure curves and curves obtained for water-oil systems using a centrifuge (Figure cap3). As far as it is accepted practice to consider the contact angle for an airwater system to be equal to zero, one can use this to obtain a

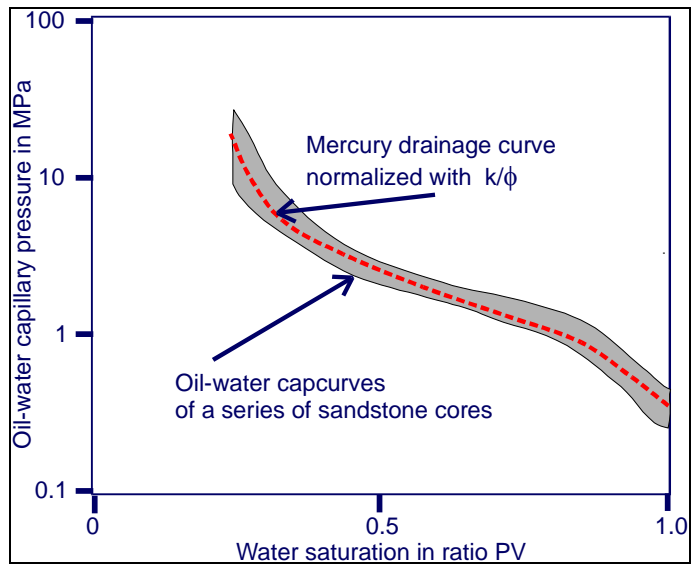


Figure 4. 27: Primary drainage of oil-water versus k/ϕ normalized mercury

