Agip

FIELDS DEVELOPMENT
AND PRODUCTION

PETROPHYSICS OF RESERVOIR ROCKS
MULTIPHASE FLOW IN RESERVOIR ROCKS

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INDEX

1. INTRODUCTION

The petrophysics of reservoir rocks is largely based on the study of cores. In order to fully understand the importance of cores in a reservoir study, let us take a brief look at the procedures underlying hydrocarbon exploration.

It is a known fact that an oil company, holding an exploration permit, first tries to identify possible oil bearing structures in the permit zone by means of geophysical surveys. After possible structures have been located, geological exploration is started up using a drilling rig to ascertain whether or not hydrocarbons are present in the porous strata of the subsurface.

Such a drilling survey is carried out according to a detailed program that has been prepared by the various company departments involved in exploration. The subsurface geology of such a program includes cutting cores in order to obtain data that can be used to increase the knowledge of the surveyed formations.

The results of the drilling survey are either:

— negative: that is, the structure is dry and so exploration is abandoned;

— positive: that is, one or more hydrocarbon bearing formations have been located, and so exploration continues until passing on to the development and exploitation of the reservoir.

Thus there are two phases in oil research operations:

— exploration

— development and exploitation.

During the first phase cores are cut primarily for geological reasons, whereas in the second phase the cores are mainly used to gather data useful for the study of the reservoir; such a study aims to plan the methods and times for exploiting the reservoir, always bearing in mind that the primary objective is to obtain maximum recovery at the lowest possible cost.

At this point it is evident that cores are extremely important since they are samples of the rock taken from the relevant depths and thus provide **direct** information about the morphological and structural characteristics of the reservoir rock; such data are very important to calculate reserves and to calibrate well logs, as well as to study the distribution of fluids and their movement through the reservoir rock.

1.1 Cutting and preservation of Cores

A core barrel is used to cut bottom cores; this device consists of a 9 meter long pipe

in which the core is lodged and a coring bit which has a hole in the middle so that the core can enter the pipe where it is held in place by the core catcher.

The diameter of the core barrel can vary, and depends on the diameter of the drill pipes which vary, in turn, with the depth of the well. Two core barrels may be joined together to cut cores 18 meters long (60 feet).

Recovery may be total (100%), partial (<100%) or nul (0%); a good core recovery depends on the type of rock and the cutting skill of the driller.

There is also a core barrel which is provided with a rubber sleeve in order to cut cores from loose or poorly consolidated formations.

As soon as the core barrel reaches the well head the core is taken out of the inner barrel and prepared for shipment to the laboratory. This procedure should be performed with extreme care so that not even the slightest damage is done to the core.

The operation consists of the following steps in chronological order:
1. Removal of the core from the inner barrel
2. External cleaning of the core, using clean, dry rag to remove all drilling mud
3. Preparation of sections 1 meter long
4. Concise lithological description of the section
5. Wrapping the sections with metal foil
6. Placing the sections in a plastic bag which is then sealed at both ends
7. Placing sections in wooden boxes
8. Dipping sections in the boxes with liquid wax at pour point temperature
9. Closing the boxes after inserting the lithological description (point 4)
10. Marking the boxes with all identification data (field, well, core number, depth, etc.).
11. Shipment of the boxes to the laboratories.

Let us remember that there are also sidewall cores. These are taken when data are needed for a direct evaluation of an interval that has already been drilled and where obviously it is not possible to cut a bottom core.

1.2 Sampling and Analyses

Upon their arrival the cores are sampled in a laboratory which has been especially equipped for this procedure. Sampling has to take into account the various types of analyses that are performed on the cores: in fact, depending on the type of analysis -petrographical, petrophysical, paleontological, stratigraphical, etc., - each laboratory requires certain types of samples.

As far as petrophysics is concerned, the analyses may be either routine or special: routine analyses are carried out on all the cores and are mainly of geological interest; special analyses, on the other hand, only involve those cores which will be used in reservoir studies carried out during the development and production of a field. Special analyses, in fact, mainly involve the distribution and dynamics of fluid flow in the reservoir. For this purpose continuous mechanical coring is planned in order to involve the entire hydrocarbon bearing formation the study of which is a part of reservoir engineering.

In the sampling laboratory the core sections are removed from the containers and transferred (without all the preservation material) into new containers for sampling.

The unit of measure for numbering the samples is the decimeter for depths in meters, or the foot for depths in feet.

The frequency of core samples which are to be used in routine analyses is, in any case, 30 cm. in order to have uniform statistics both for the cores cut in meters as well as those cut in feet.

The size of the samples depends on the type of rock of the core samples: if the rock is homogeneous then the conventional sample is the so-called "plug", which consist of a 1" × 1" cylinder. If the rock is heterogeneous the sample is "full-size", that is, full diameter pieces having a length which varies according to the condition of the rock. The samples may be either horizontal or vertical.

Routine analyses are carried out in the following order:

1. extraction of residual fluids
2. cleaning
3. drying
4. porosity
5. permeability
6. formation resistivity factor.

A separate sample (1 × meter) is taken to determine the grain density.

Special analyses do not require a statistical sampling; cutting samples for special analyses follows certain criteria which depend on the variation of the petrophysical characteristics of the rock.

CORE TRIP
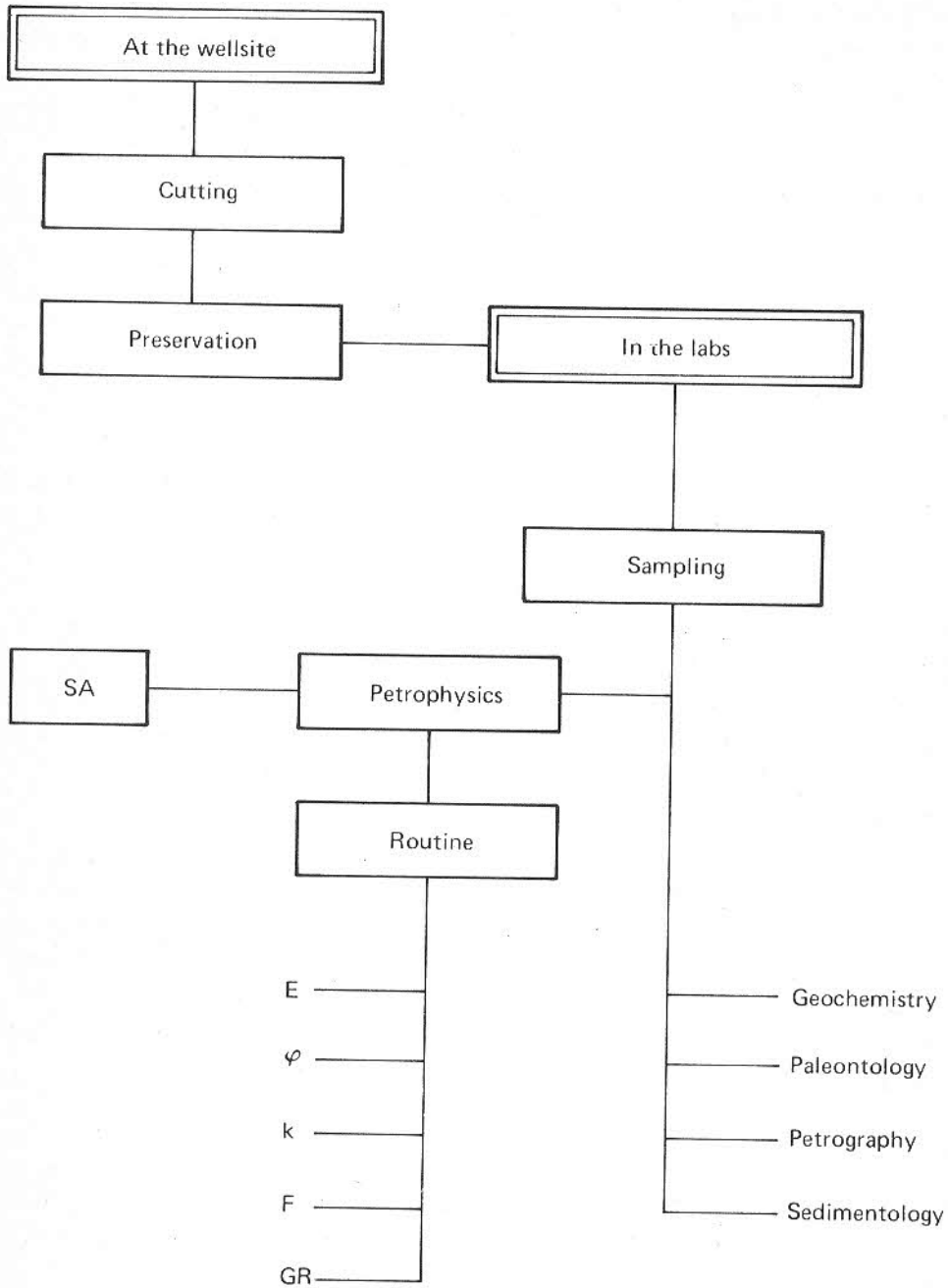
SA	= special analysis
E	= residual fluids extraction
φ	= porosity

k	= permeability
F	= formation resistivity factor
GD	= grain density

2. ROUTINE ANALYSES

2.1 Residual Fluid Saturation

Residual fluids are those present in the cores when they are recovered at the well head.

By extracting these fluids it is possible to determine the residual fluid saturation of the core sample.

The term "residual" means that the fluids extracted from the core in the laboratory are no longer, as far as quantity and composition are concerned, the same as those in the reservoir. This is due to phenomena which occur when the core is cut and brought to the surface.

For example, when a core is cut in an oil reservoir, it is flooded by the mud filtrate; furthermore, as the core barrel is being extracted the pressure inside the core sample decreases, freeing the gas which was dissolved in the oil; this in turn causes a partial displacement of the fluids originally in the core.

During flooding, the mud filtrate enters the core and displaces a fraction of oil so that the oil saturation decreases and the water saturation increases.

There is a further decrease in oil saturation when the gas dissolved in the oil is freed and displaces oil and water due to the decrease in pressure in the core during extraction of the core barrel.

As a result, part of the porous space remains occupied by the free gas.

There are two methods of extraction used in the laboratory:

1. extraction by solvent
2. dry vacuum extraction.

The results obtained from the extraction of residual fluids can provide indications about whether or not there are hydrocarbons in the formation, as well as their type. They may also indicate residual oil saturation after water drive, and in certain cases, the value of the irreducible water saturation.

2.2 Porosity

General

Porosity is one of the basic physical characteristics which define a reservoir rock.

It is the space which allows hydrocarbons accumulation, and it is one of the el-

ements necessary to determine the reserves of an oil pool.

Most of the sedimentary rocks consist of solid particles which, upon sedimentation and after packing, have formed spaces where the reservoir fluids (oil, water, gas) accumulate. These voids can have different shape and size, but they must be intercommunicating to enable the fluids to flow through the rock.

From a theoretical point of view, an idea on what is the porosity of a granular structure can be formed if we take as an instance a type of sand where all the grains are assumed to be spherical, with identical diameter. These grains can be arranged on a plane in an infinite number of ways: fig. 1 shows various types of beddings with porosity varying from 25.95% min. to 47.64% max.

Porosity is expressed as the percentage volume of voids in the bulk volume of the rock, and is called **absolute or total porosity**.

In the case of reservoir rocks, from a production viewpoint we must consider the porosity formed by communicating pores. This type of porosity is generally called **effective or useful porosity**.

If we take φ as the effective porosity of a rock, V_b as the bulk volume and V_p as the volume of the communicating pores, the effective porosity will be

$$\varphi = \frac{V_p}{V_b}$$

which is practically expressed as a percentage or decimal fraction.

If the rock contains non-communicating pores, and the total sum of the pores is expressed with V'_p, the total porosity φ' will be

$$\varphi' = \frac{V'_p}{V_b}$$

The difference

$$\varphi'' = \varphi' - \varphi = \frac{V'_p - V_p}{V_b}$$

is defined as **residual porosity**, representing the porosity formed by the sole non-communicating pores.

Total porosity is of some interest only because it is the one found in well logs; however, effective porosity values are commonly used. As a matter of fact, in reserv-

oir rocks the difference between absolute porosity and effective porosity is negligible; the latter can be 10% max lower than the former.

Porosity of reservoir rocks

From a petrophysical viewpoint, rock porosity can be divided into two main types:

— primary, also called intergranular or original; originating from the voids formed between mineral fragments during deposition; consequently, this is an original feature of the rock which depends on the shape and size of the grains, their arrangement, sedimentation, and **compaction** during and after sedimentation (fig. 2).

— secondary: related to the variations occurring after sedimentation, or to physical-chemical processes which cause conversion of sediments to rocks, altering their texture, structure and composition (diagenesis).

Examples of primary porosity:

Intercrystalline porosity (limestones)
Intergranular porosity (sands, sandstones)
Oolitic structure porosity (limestones).

Examples of secondary porosity:

Vuggy porosity
Fossils destruction porosity
Fracture porosity
Dissolution porosity
Dolomitization porosity
Silicification porosity
Recrystallization porosity

Porosity of clays

Clays are not reservoir rocks due to their extremely fine pores and grains which form impervious layers impermeable to fluids by exerting a strong capillary action. Therefore clays can form caprocks.

However, clays have a high porosity percentage: initially, upon sedimentation, porosity amounts to 90%, but compaction gradually reduces it to negligible values, as shown by the **apparent density-depth correlation in clays**, in fig. 3.

Determination of porosity

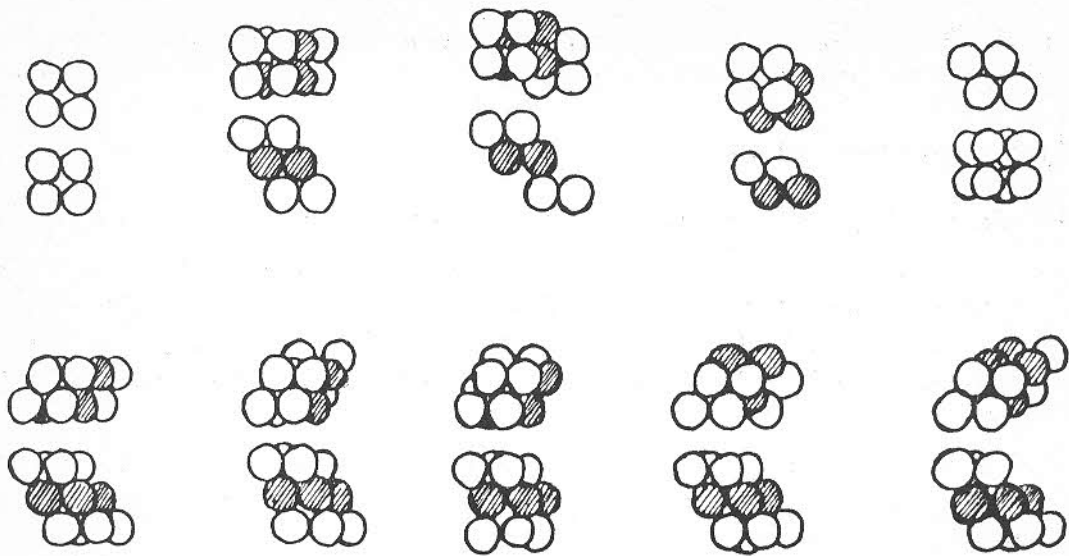Porosity can be determined in laboratory on cores by means of porosimeters.

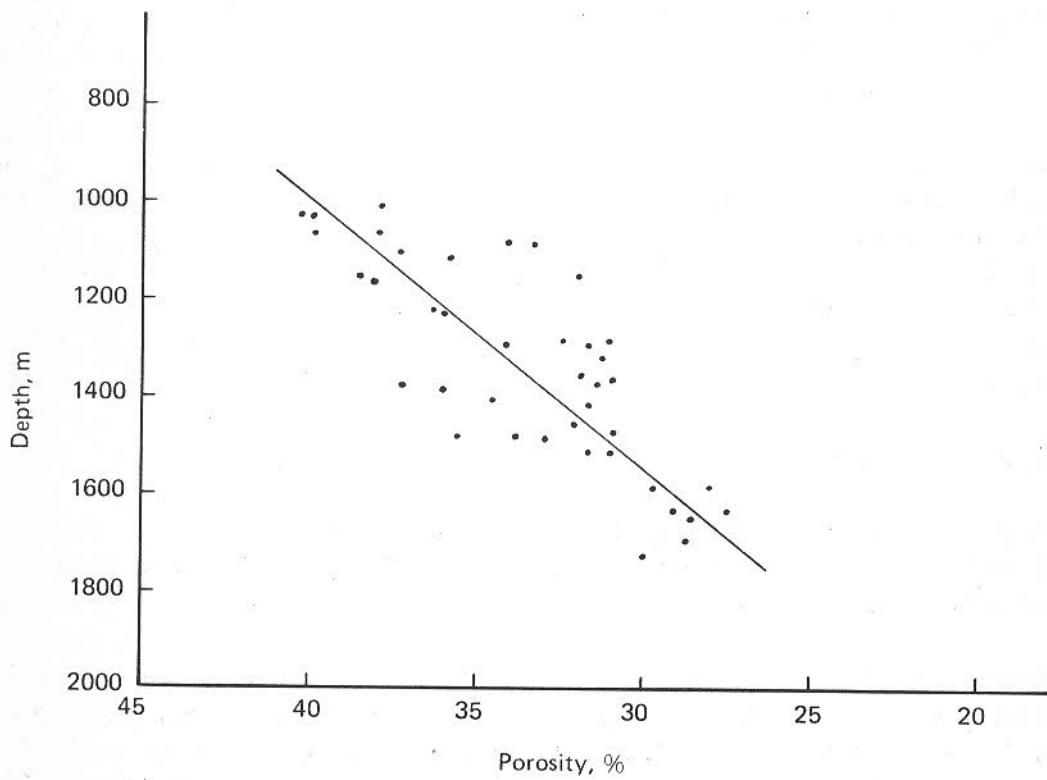Fig. 1 — Different reticular arrangements of spherical beads

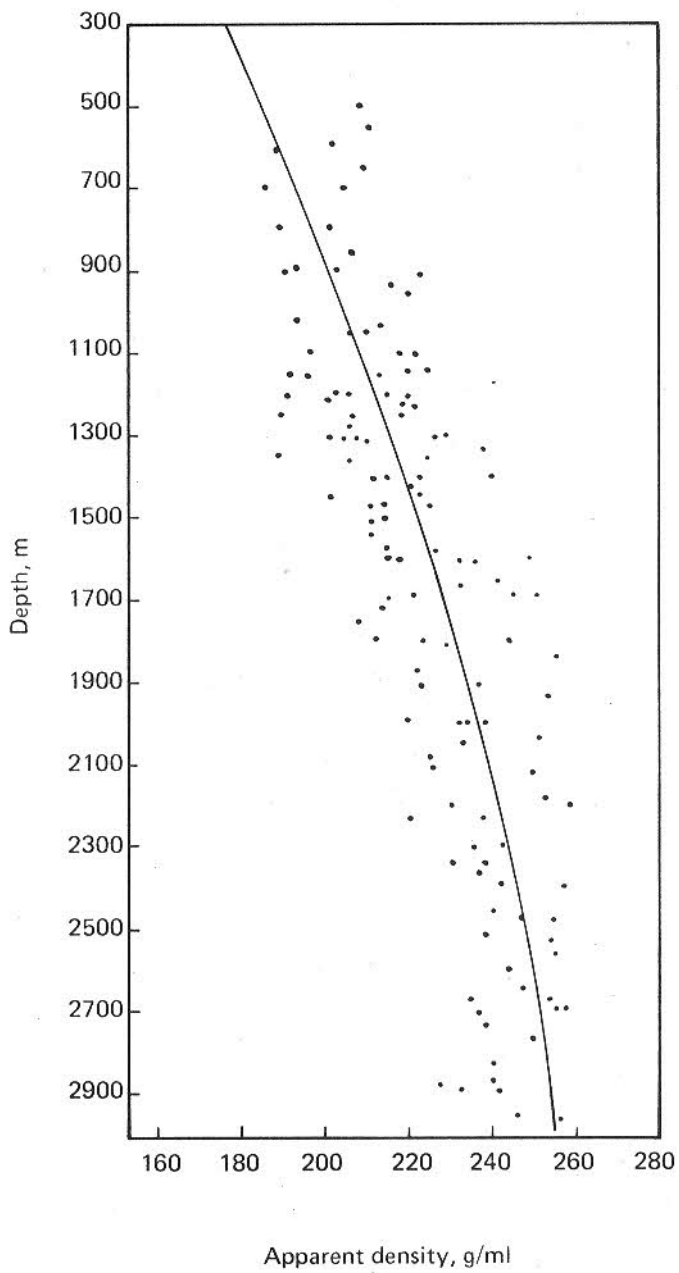Fig. 2 — Sands of the Po Valley
Porosity vs. depth

Fig. 3 — Apparent density of clays vs. depth

On the basis of the definitions hereinabove, the geometric extension of porosity can be calculated as follows:

$$\text{Porosity } \varphi,\ \% = \frac{\text{Bulk vol.} - \text{Grain vol.}}{\text{bulk vol.}} \cdot 100 = \frac{V_b - V_s}{V_b} \cdot 100$$

$$\text{Porosity } \varphi,\ \% = \frac{\text{Void vol.}}{\text{Bulk vol.}} \cdot 100 = \frac{V_p}{V_b} \cdot 100$$

$$\text{Porosity } \varphi,\ \% = \frac{\text{Void vol.}}{\text{Grain vol.} + \text{Void vol.}} \cdot 100 = \frac{V_p}{V_s + V_p} \cdot 100$$

Therefore, when these parameters are known, i.e. bulk volume of sample (V_b), volume of pores (voids) (V_p), volume of solid part (grains) (V_s), porosity can be determined.

Consequently, any method of porosity determination in laboratory must enable the measurement of these parameters, or at least two of them.

Methods of determination

The method used in AGIP laboratories is based on Boyle's Law, by which the bulk volume and the solid volume of the sample are measured.

Another procedure is the saturation method which enables direct measurement of pore volume by gravimetry, and bulk volume by pycnometry.

2.3 Permeability

Definition

One more basic physical feature of a reservoir rock is permeability, i.e. the capacity of a porous rock to transmit fluids without altering its structure or causing shifting of rock parts. Thus, it is an intrinsic property of the rock connected to its lithologic structure, texture and pore configuration; it indicates the productivity of an oil pool.

Darcy's Law and Standard Units

The quantitative expression of permeability is given by the relation experimentally found by Darcy in 1856 by studying water flow through horizontal sandy filters. During his experiments Darcy found that the amount of water flowing linearly through the sandy filter in unit time, was directly proportional to the hydraulic

gradient and to the area of the filter section, and inversely to filter thickness.

Considering Darcy's Law under a general aspect, the formula will be:

$$V_s = \frac{q}{A} = -\frac{k}{\mu}\left(\frac{dp}{ds} - \rho g \frac{dZ}{ds}\right)$$

where:

s = distance along the direction of flow, cm

V_s = rate of flow across a unit area of the porous medium in unit time, cm/sec.

q = flow rate, cm^3/sec.

A = average cross-sectional area perpendicular to lines of flow at the point which V_s refers, cm^2

Z = vertical coordinate directed downwards, cm

ρ = fluid density, g/ml

g = gravity acceleration, cm/sec^2

$\dfrac{dp}{ds}$ = pressure gradient along 's', at the point which V_s refers, atm

μ = fluid viscosity, cp

k = permeability of the medium, Darcy

Darcy's Law, as expressed hereinabove, relates the different variables which influence the viscous flow of a homogeneous fluid (single-phase) through the porous medium, 100% saturated by this same fluid, and provided that the latter does not exert any chemical or physical action on the medium. The formula implies a proportionality constant 'k' (permeability) which is, as previously specified, a peculiar characteristic of the medium, independently of its dimensions, pressure gradient on fluids used (only the incompressible ones) and fluid viscosity. Consequently, for a given value of 'k', the flow rate of a fluid, under stationary condition, through a porous rock is directly proportional to the pressure difference existing in different points of the rock, and to the inlet rock surface, while being inversely proportional to fluid viscosity and rock thickness, i.e.:

$$q = k \frac{A \triangle P}{L \mu} \quad \text{from which} \quad k = q \frac{L \mu}{A \triangle P}$$

For practical purposes, it should be stated that a porous medium has permeability characteristics that can be determined by experimental measurements.

In the field of oil research, the American Petroleum Institute (API) has standardized the 'Darcy' value, giving the following definition:

— a porous medium has a permeability of one darcy when a single-phase fluid with one cp viscosity, filling the whole porous volume of the medium, flows through it

under viscous flow conditions, at a rate of 1 cu.cm/sec per sq.cm. of cross sectional area under a pressure gradient of one atm.

For practical purposes, a submultiple of one darcy, called millidarcy, is used.

Variations of Permeability

The application of Darcy's Law to determine the permeability of reservoir rocks, is based on the assumption that the flowing fluids exert no action on the rock, and that, under viscous flow conditions, there is no difference in the flowing mechanism between liquid phase and gaseous phase: in effect, theoretically, the permeability of a medium must be considered as constant, i.e. independent of the type of fluid used and of the differential pressure.

However, practically, if the liquid interacts chemically and physically with the minerals forming the rock, the permeability value varies. For example, the hydration phenomena affecting the clayey minerals determine permeability damage caused by clay swelling with consequent reduction of the pore volume. Thus, rock permeability to sea water will be higher than that to fresh water.

Another phenomenon found for the first time by Klinkenberg evidences that permeability to a gas flow is higher than that to a liquid due to a kind of slip which gas molecules develop along the walls of the pores.

In viscous flow, the speed of a liquid along the walls of a capillary tube is supposed to be null because of internal molecule friction; on the contrary, in case of gas each molecule contributes to speed which acquires a finite value also along the walls when the dimensions of the capillary tube flow channels approach in magnitude the mean free path of the average gas molecule.

Klinkenberg states that permeability to gases is a function of free molecule path and, consequently, it varies together with all the other factors (temperature, pressure, gas nature) which condition the mean free path.

Klinkenberg has obtained a relation that relates permeability to a gas and permeability to a liquid, which can be expressed as follows:

$$k_g = k_l \left(1 + \frac{b}{p_m}\right)$$

where:

k_g = permeability of the medium to a gas which saturates 100% of the porous volume (at constant temperature)

k_l = permeability of the medium to a single-phase liquid which saturates 100%

of the porous volume (at constant temperature)

p_m = mean pressure at which the gas is flowing

b = Kinkenberg constant for a given type of gas and rock

This equation states that permeability to gas varies upon changing of the mean pressure, relating the permeability to the reciprocal of the mean flushing pressure. The variation of permeability of three different hydrocarbon gases can be graphically reproduced. The various lines cross the axis of the ordinates in the same point which represents (for an infinite pressure $\frac{1}{P_m}$ = 0) the permeability to a single phase liquid k_l ; the curve slope expresses b (fig. 4).

However, there is a relation between b and k which, graphically reproduced on bilogarithmic coordinates, gives a diagram that can be used to approximately determine the correct permeability (fig. 5).

Permeability of Reservoir Rocks

First of all, the permeability of a reservoir rock is connected to its porous configuration, thus all geological and petrophysical factors influencing effective porosity also affect permeability. Permeability due to wide voids such as fractures and vugs, will be higher than that determined by many small pores. Very fine-grained clastic rocks will show a permeability much lower than that with coarse grains.

In reservoir rocks, vertical permeability is generally different from horizontal permeability which is usually higher. The reason is to be soughi in the sedimentation process where grains tend to form horizontal beddings and to overlie each other on the flat side, and to arrange themselves with their major axis in the direction of the current. This will originate horizontal channels where passage is easier and permeability greater, the latter being further increased by the circulation of solvent waters which flow better in the same direction.

Usually, the pool fluids are drained to the wells along this horizontal permeability.

High vertical permeability values can at the same time be due to fractures which extend vertically throughout the bedding planes, and have been subsequently widened by dissolution.

The average permeability values of reservoir rocks can vary from few millidarcys to 1,000 millidarcys; however, higher values are possible (thousands of millidarcys). In addition, there are reservoir rocks where the matrix, when analysed, shows very low permeability values ($\sim$0.1 md) which can be commercially productive due to the presence of a network of fractures which contributes to the total flow capacity.
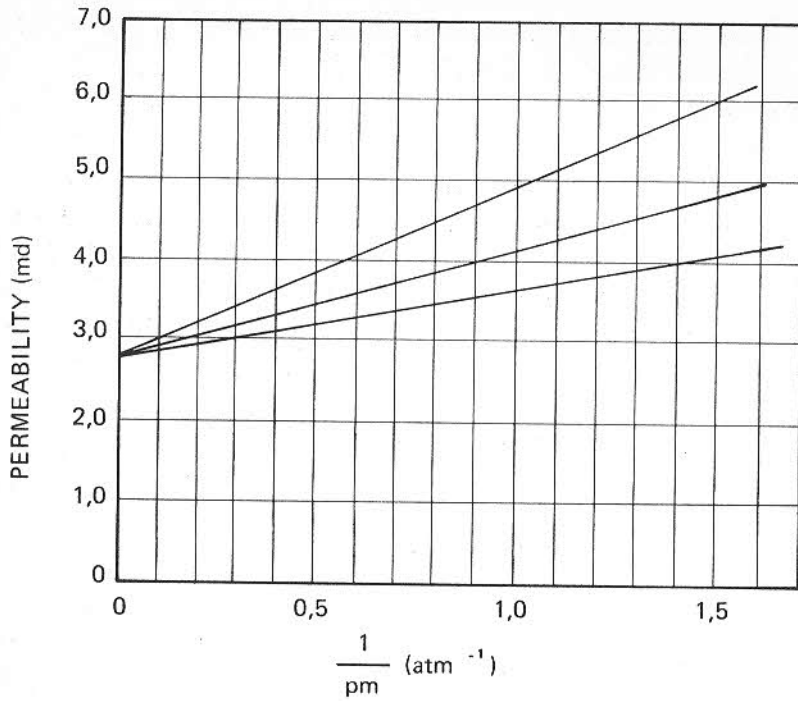
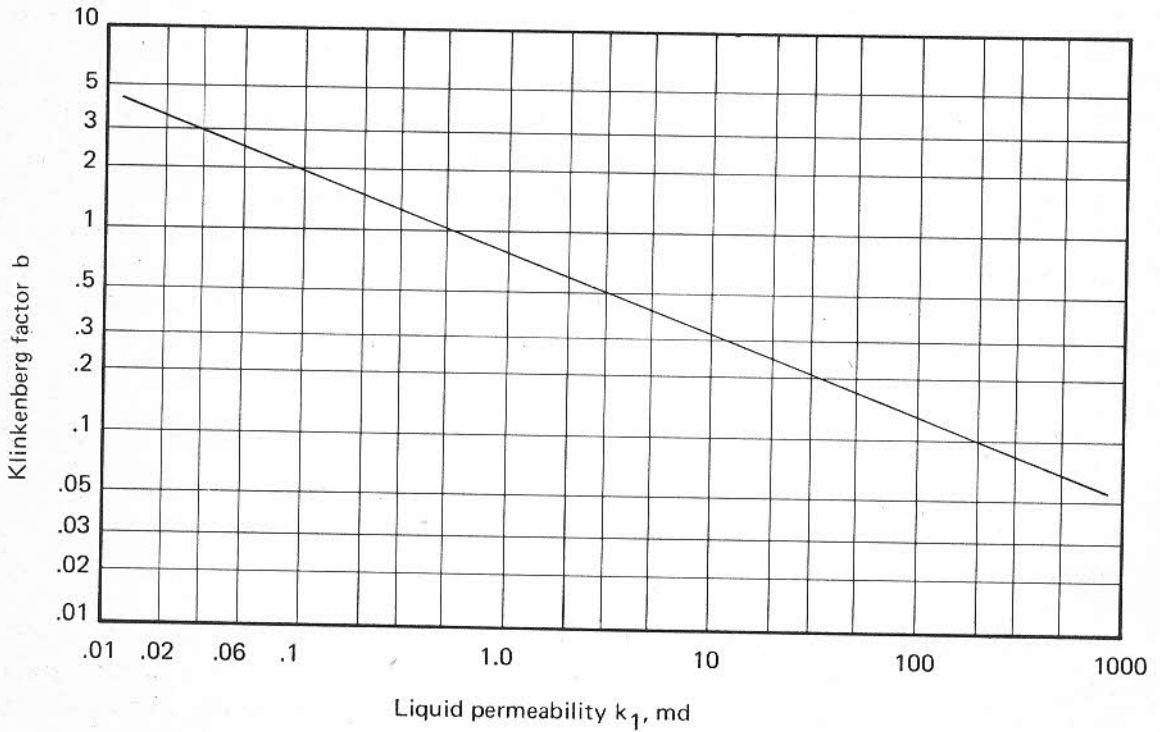**Fig. 4** — Variation of permeability to different gases vs. mean pressure

Fig. 5 — Klinkenberg factor <u>b</u> vs. permeability to liquid

- 14 -

Determination of Permeability

The permeability of a homogeneous fluid saturating 100% of the medium is called **absolute permeability**.

Permeability can be determined on cores only in laboratory.

The apparatus used in laboratories for the determination of the permeability are called **permeameters.**

According to Darcy's Law, the determination of the permeability of a porous medium will require:

a) knowledge of the dimensions of the core sample (length and cross-sectional area);

b) viscous flow of a fluid through the core sample obtained by differential pressure (flow rate and pressure);

c) knowledge of the viscosity of the fluid used.

2.4 Formation Factor

Electric conductivity must be considered among the geochemical parameters of a reservoir rock.

Since the sedimentary rocks composing the reservoir rocks are impregnated with water having a varying degree of salinity, when these rocks are hydrocarbon bearing they may be considered as formations where the water has been partially substituted by hydrocarbons. Since the matrix of a reservoir rock is not a conductor, a porous formation has an electric conductivity which depends almost entirely on the water contained therein, since hydrocarbons are not conductors.

Therefore, the conductivity or resistivity of a formation constitutes a specific parameter which depends on:

a) the degree of interstitial water saturation and its chemical composition and temperature;

b) the texture of the rock, that is, the lithological type; the shape, distribution and tightness of the grains; and the degree of tortuosity of the channels formed by the communicating pore spaces;

c) the wettability of the rock with respect to the fluids contained therein.

For a given rock there is a constant ratio between its resistivity when it is saturated 100% by salt water (R_o) and the resistivity of the saturating water (R_w). This ratio is called **formation resistivity factor** or, simply, **formation factor** (F):

$$F = \frac{R_o}{R_w}$$

The formation factor is a dimensionless magnitude which represents the intrinsic resistivity of a porous formation: for this reason it is essential for interpreting electric logs. It varies according to the total geometry of the porous space, and is thus tied to the effective porosity of the rock. After much theoretical and experimental research, numerous scientists (Archie, Guyod, Martin, Winsauer) have tried to express this connection in mathematical terms; they derived a formula which has been most widely accepted as follows:

$$F = c\,\emptyset^{-m}$$

where **c** and **m** are constants, connected to various types of rock. For many cases the formula may be written as follows (Humble):

$$F = \frac{0.62}{\emptyset^{2.15}}$$

varying from

$$F = \frac{1}{\emptyset^2}$$

for highly compact formations to

$$F = \frac{0.75}{\emptyset^2}$$

for friable formations.

c is equal to 1 or slightly less for almost all rocks: in this case the formula becomes simplified:

$$F = \emptyset^{-m}$$

where **m**, which is called the cementation factor, depends on the degree of consolidation of the formations and has values ranging from 1.3 for unconsolidated sands to 2.2 for calcareous formations.

The cementation factor indicates the degree of consolidation or cementation of the rocks. In fact, if we consider an unconsolidated, clean sand that is saturated by salt water, and we imagine that its pores form a bunch of linear, parallel capillaries, its effective porosity is equal to the quantity of saturating water and its resistivity is equal to the ratio between the resistivity of the water and the porosity ($R_w/\emptyset$);

consequently, the formation factor is given by the reciprocal of the porosity itself, whereas the cementation factor will be m = 1.

It is different for sands which are more or less consolidated; this is because actually their porosity is formed by winding channels, and **m** will always be greater than 1, with average values ranging from 1.3 to 2.2 and may arrive up to 3 for highly cemented formations. In fact, cementation causes a partial filling of the pore space with non conductive material and thus creates a reduction of the volume of conductive fluids and an increase in the total path that the current has to follow: therefore, there is an overall increase in resistivity. It is thus evident that the greater the cementation factor, the greater will be the formation factor since the porosity is always a fraction of the whole.

In short, the cementation factor is approximative and indicative of the influence that the morphological characteristics of the medium have on the resistivity, and thus on the formation factor.

3. SPECIAL ANALYSIS

3.1 Rock compressibility

The reservoir rock of an oil pool is subjected to a compression higher than that of the cores examined in the laboratory. The knowledge of the compressibility effects on porosity and permeability can be useful when converting laboratory data to field data.

The influence of the geostatic load on the petrophysical characteristics of the reservoir rock can be determined in the laboratory by means of special equipment.

In the case of porosity, the tests are conducted on a water-saturated core by applying increasing pressures to the outer surface of the sample. The liquid squeezed out of the core corresponds to the porous space lost by the sample because of compression.

In the case of permeability, k is measured at increasing steps of pressure applied to the outer surface of the core.

The decrease of porosity and permeability is then plotted in a diagram in % as a function of pressure.

The compressibility of a reservoir rock is the result of two distinct factors:

a) expansion of grains as a consequence of the depletion of the reservoir;

b) further compaction of the producing formation upon increasing of the effective geostatic load due to the depletion of the reservoir.

In some cases, rock compressibility effect can be extremely important when calculating the oil in place from the depletion data.

These calculations use an effective compressibility coefficient "c_e" where the influences exerted by oil, water and pore volume compressibility are available.

This coefficient is expressed with the formula:

$$c_e = \frac{S_o c_o + S_w c_w + c_f}{S_o}$$

where:

S_o = oil saturation
S_w = water saturation
c_o = oil compressibility
c_w = water compressibility
c_f = pore volume compressibility

3.2 Capillarity

General

Two fluid phases are generally present in oil pools. It is generally agreed that all oil-bearing formations were water-saturated before hydrocarbon migration. Therefore, even though the hydrocarbon fluid is monophase (liquid or gaseous), a second phase consisting of the water that could not be completely displaced, is always present.

It can be demonstrated that there is a pressure difference P_c called "capillary pressure" between the two faces of a surface acting as interface between two fluids, expressed by:

$$P_c = \sigma \left(\frac{1}{R_1} + \frac{1}{R_2} \right)$$

where   is the interfacial tension, R_1 and R_2 are the main radii of curvature.

Under static equilibrium conditions, calling $\triangle P$ the pressure difference between the two fluids, the equation will be:

$$\triangle P = P_c$$

For $\triangle P \neq P_c$ the static equilibrium is not possible.

Another parameter contributing to the capillary phenomena is the angle formed by the interface surface with the solid wall of the capillary, called "contact angle", which depends on the physical properties of the pair of fluids and of the solid part with which the fluids are in contact.

The contact angle being known, we have:

$$P_c = \frac{2\,\sigma \cos\theta}{r}$$

In fig. 6, to obtain the equilibrium at the interface surface pressure P_1 of fluid (1) must be greater than pressure P_2 of fluid (2) by a value equal to:

$$P_1 - P_2 = \frac{2\,\sigma \cos\theta}{r}$$

If $P_1 - P_2 < P_c$, the wetting fluid (2) will move to displace the non-wetting fluid (1)

(imbibition); if $P_1 - P_2 > P_c$, the wetting fluid (2) will be displaced by the non-wetting fluid (1) (drainage).

Fig. 7 shows a capillary with variable radius. In this case the non-wetting fluid can enter the capillary if its overpressure is at least equal to the min P_c corresponding to the inlet radius; for the increasing overpressure there will be a gradual progress of the surface inside the capillary until fluid (2) is totally removed from the capillary due to an overpressure equal to the max P_c corresponding to the outlet radius.

In fig. 8 the curve in the direction of the drainage differs from that in the direction of imbibition; this phenomenon is called **hysteresis**.

Capillary Pressure Curves

For a porous medium (which is a system more complex than a capillary tube), a relationship between saturation and capillary pressure may be obtained. This relationship between capillary pressure and saturation may enable the determination of a characteristic curve "capillary pressure-saturation" called "Capillary Pressure Curve", which can be obtained experimentally.

Fig. 9 shows the trend of two curves; they indicate how the saturation of the wetting phase remains 100% as long as capillary pressure does not exceed a min value called "threshold pressure" corresponding to the largest inlet pores.

Fig. 9a concerns a porous medium with very uniform pore dimensions; fig. 9b concerns a porous medium with very heterogeneous pore dimensions.

Moreover, the two curves show a vertical asymptotic trend against a "min irreducible" value of saturation. This saturation is called "irreducible" since the required pressures are outside the practical application field, though it may theoretically drop below that value.

An explanation can be given by fig. 10 showing a schematic diagram of three possible saturation states of a porous medium where two phases, oil and water (wetting) are present.

The water adheres to the solid surface of the grains. Due to a very low saturation in water (fig. 10a) the water forms rings around the contact points of the grains, called "pendular rings", while the saturation state is called "pendular saturation". These rings are not in contact with each other, thus no differential pressure can be transmitted from one ring to the other, and the rings are practically motionless. As the water saturation increases, the rings become larger and larger and come into contact with each other due to a sufficiently high saturation, forming a continuous network. This saturation state is called "funicular" (fig. 10b).

So far, oil (the non-wetting phase, thus occupying the central part of the pores) has maintained a funicular saturation. By further increasing the water saturation, a point will be reached where oil is no longer a continuous phase, but is divided into small isolated drops which occupy the central part of the pores. This phase is called "insular" saturation (fig. 10c).

If, for a specific porous medium, the capillary pressure curve of two given fluids is known, the fluid distribution by gravity can be quantitatively determined. Let us suppose that we have a specimen of the porous medium in question, initially 100% water-saturated and partially submerged in water (fig. 11). The ambient atmospheric air forms the non-wetting phase. As previously stated, the equilibrium depends on $\triangle P = P_c$. On the other hand, when the equilibrium is attained, $\triangle P$ will be a function of the height 'h' only.

In effect, calling P_a the atmospheric pressure, the equation will be:

$P\,water = P_a - \rho_w\,g\,h$ but being

$\triangle P = P\,air - P\,water$ then $\triangle P = {}_w gh = P_c$

Since P_c is a function of the water saturation S_w, upon equilibrium the water saturation will have, for each height, the value which is equalled, on the capillary pressure curve, by the value:

$$P_c = \rho_w\,gh$$

Use of Capillary Pressure Curves

The capillary pressure curves are used to determine the distribution of fluid saturations, at initial conditions, thus the reserves in place.

Since the pools generally consist of non-homogeneous formations, it will be necessary to have a family of curves determined on samples where permeabilities cover the range of values existing in the pool.

These curves will then be converted from the "capillary pressure" variable to the "height above water table" variable, considering that:

$$P_c = \triangle \rho gh$$

Moreover, since the curves are sometimes determined in laboratory with two fluids different from those present in the pool, the curves must be converted, i.e. having obtained a capillary pressure curve employing a pair of fluids (1 — 2), the curve concerning another pair of fluids (3 — 4) can be determined, considering that:

$$\frac{\sigma_{(1-2)}\cos\theta_{(1-2)}}{P_{c(1-2)}} = \frac{\sigma_{(3-4)}\cos\theta_{(3-4)}}{P_{c(3-4)}}$$
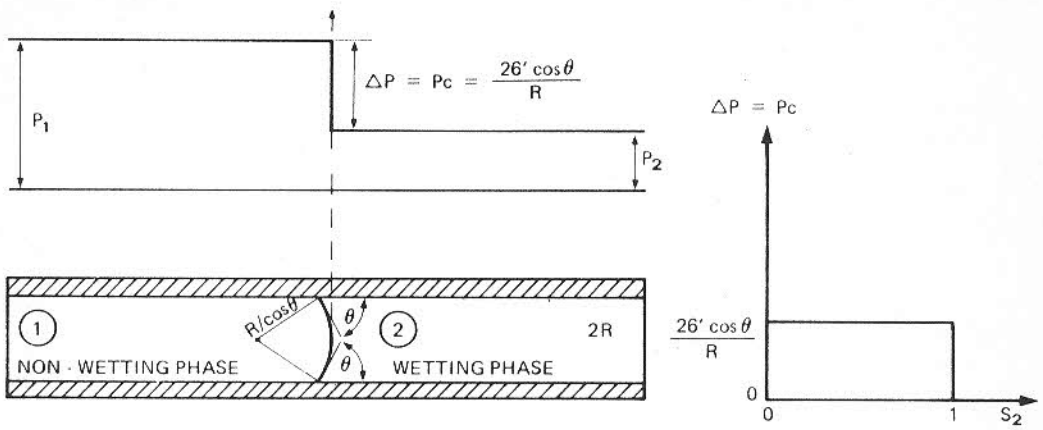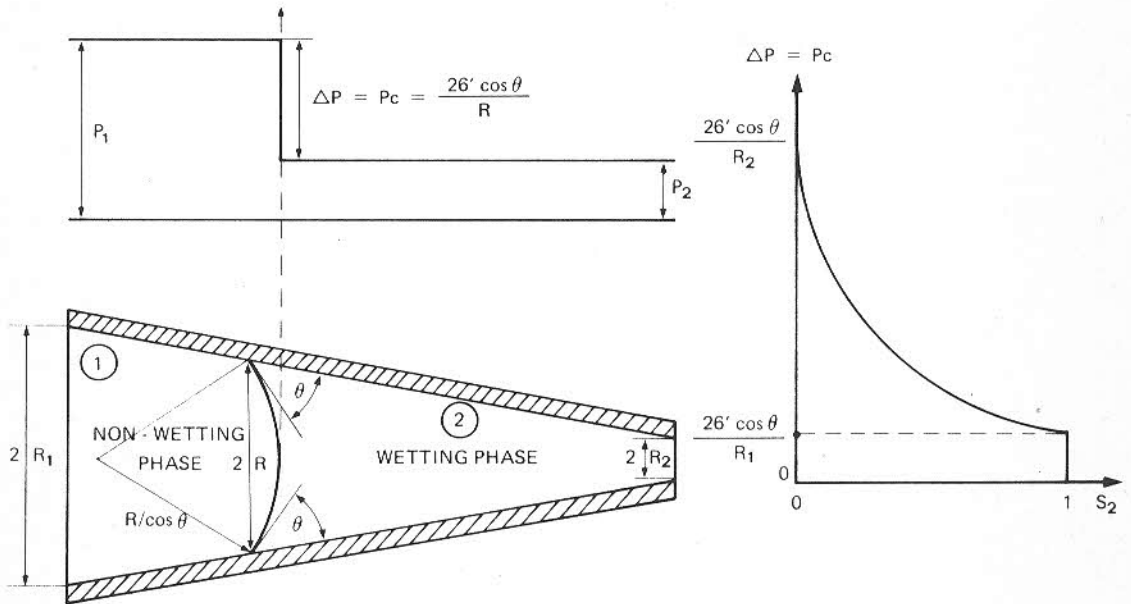
Fig. 6 — Constant radius capillary
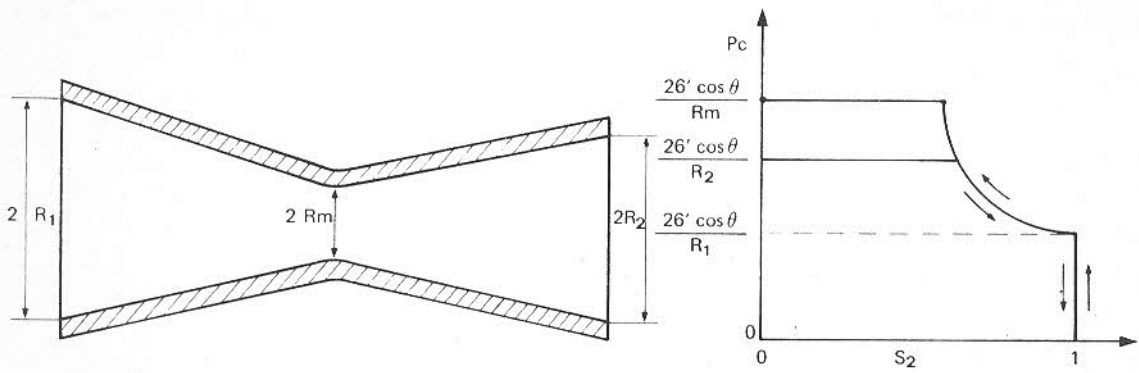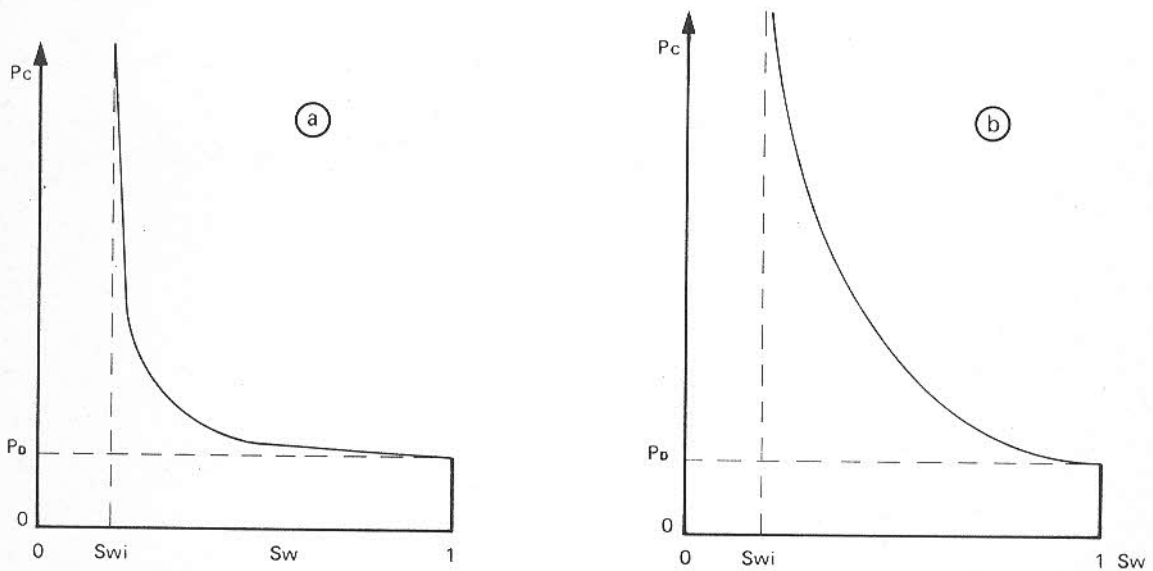

Fig. 7 — Variable radius capillary

Fig. 8 — Hysteresis phenomenon

Fig. 9 — Capillary pressure curves

A   PENDULAR
     SATURATION

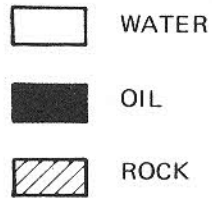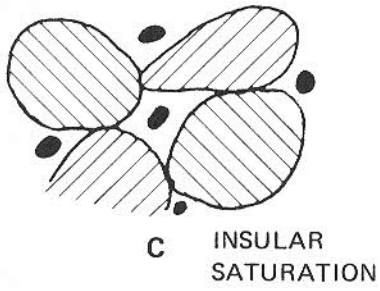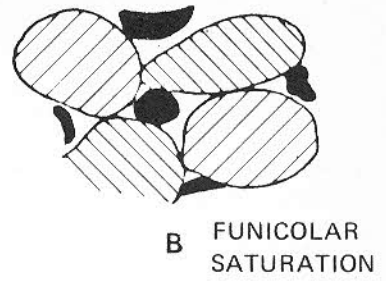B   FUNICOLAR
     SATURATION
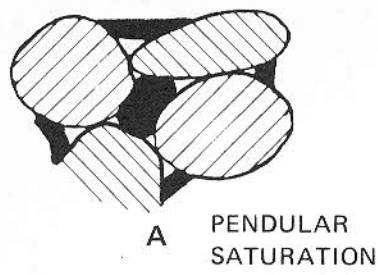
C   INSULAR
     SATURATION

WATER

OIL

ROCK

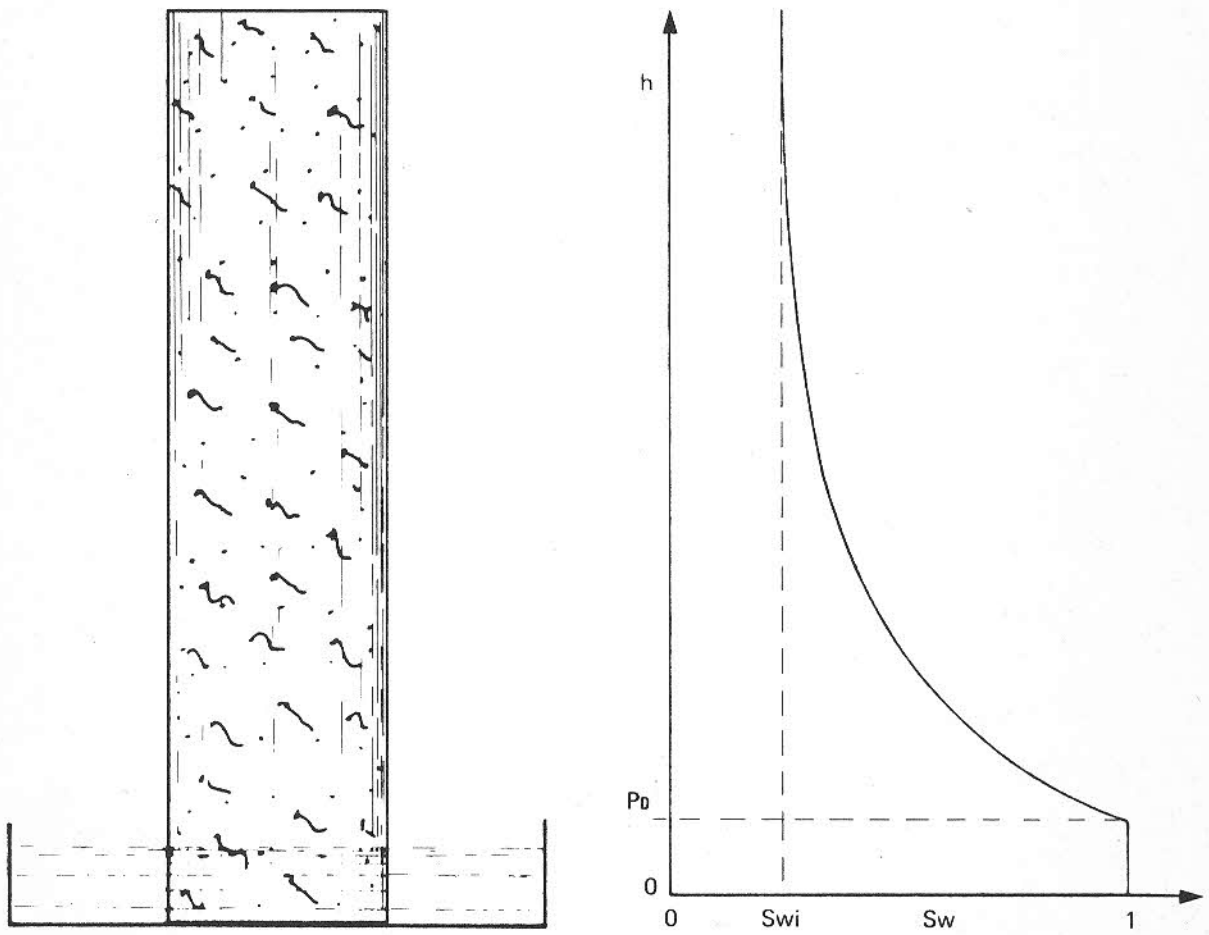Fig. 10 — Different saturation states

Fig. 11 — Distribution of water saturation by gravity

since these ratios depend, for a specific porous medium, only on saturation.

Methods for the Determination of Capillary Pressure Curves

Restored State Method

The equipment is shown in fig. 12; it consists of a sample-holding cell, porous porcelain diaphragm, air source with pressure regulation and gauges. The method is described with reference to the air-water system.

A 100% water-saturated sample is placed in the cell with one end in capillary contact with the porcelain diaphragm, which is also 100% saturated. The capillary contact between sample and diaphragm is obtained by placing kleenex tissues in between.

The cell is then closed, and constant air pressure is applied to attain capillary equilibrium.

Because of its nature, the diaphragm threshold pressure exceeds the max pressure used in the test, thus the air cannot enter the diaphragm. i.d. the diaphragm behaves as an element permeable to water and impermeable to air.

The water can flow from the sample, and is measured in a burette linked to the cell. Equilibrium is attained when the burette level is constant. Then the sample is removed from the cell and weighed to determine saturation:

$$S = 1 - \frac{P_{sat} - P_{ist}}{P_{sat} - P_{sec}}$$

where:

P_{sat} = weight of 100% water-saturated sample;
S = water saturation of sample;
P_{sec} = weight of dry sample;
P_{ist} = instantaneous weight of sample at the end of the step considered.

Then the sample is placed again in the cell and a higher pressure is applied. Thus the capillary pressure curve is obtained by steps.

Centrifuge Method

The difficulties met with the gravity drainage method to obtain the capillary pressure curve are due to the fact that the gravity acceleration value is rather small. However, greater accelerations can be obtained by means of a centrifuge.

The various pressure steps are obtained by varying sample acceleration in the centrifuge.
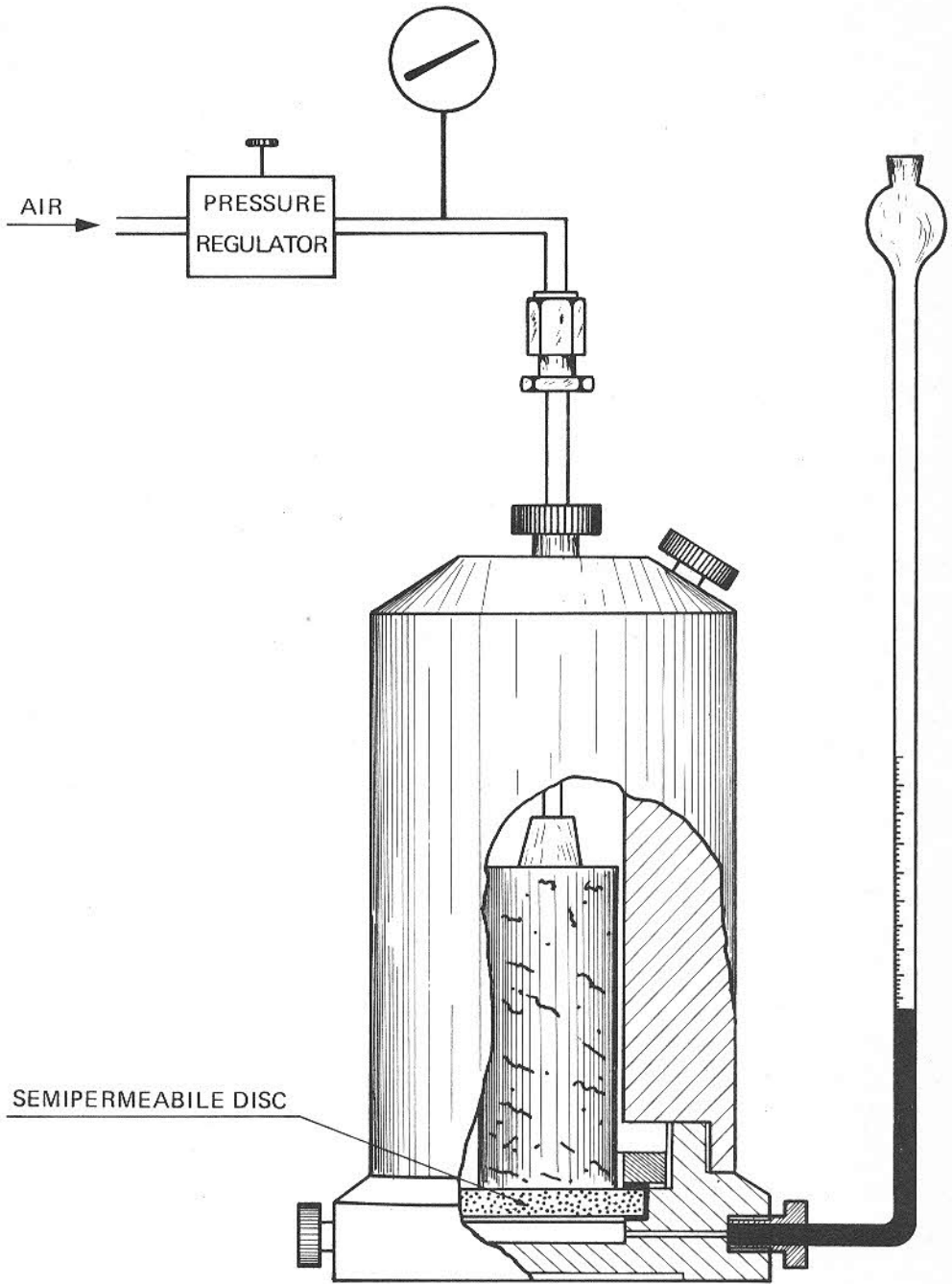
SEMIPERMEABILE DISC

Fig. 12 — Apparatus for determining capillary pressure curves by "restored state" method

Saturation can be measured by a stroboscope method of illuminating the centrifuge rotor; this allows a reading on the core-holder graduated burette (fig. 13), of the water volume removed while the sample holder is rotating. After a sufficient number of saturation measurements at different accelerations are taken, the capillary pressure curve can be determined.

The pressure is calculated according to the rotor radius, density of the pair of fluids used, sample height and centrifuge rounds.

Since the first three factors are constant, it will be sufficient to vary the centrifuge rounds to obtain the required pressure steps.

Mercury Injection Method (Purcell Method)

The essential equipment is shown in fig. 149: positive-displacement mercury pump, sample cell, vacuum pump, gauge and vacuum gauge. In this method the wetting phase is represented by vacuum (air at very low absolute pressure), while the non wetting phase is represented by the mercury injected into the sample at increasing pressures.

Once the sample has been placed in the cell, and the mercury level has been brought to the reference mark on the window located on the lower side of the cell, the cell is evacuated. Then the volume of the mercury injected into the cell is measured with the pump, when its level reaches the reference mark on the window located on the upper side of the cell.

Subtracting this volume from the known cell volume, the bulk sample volume is obtained. Then the vacuum pump is cut-off, while injecting gas to increase the pressure on the mercury where the sample is submerged. Mercury penetration into the sample is shown by the mercury dropping below the reference mark on the top window. The volume of the mercury penetrated into the sample is determined by measuring with the pump the mercury required for restoring the reference level. The procedure consists of a sequence of pressure increases and pump feeds, and is continued till the required max pressure is attained. The resulting pressure and saturation data give the capillary pressure curve for the air-mercury system.

3.3 Relative Permeability curves

Should the porous medium contain at the same time several fluids that cannot be mixed with each other, the permeability concept is generalized, and an "effective permeability" is introduced for each available fluid. It can be perceived that these effective permeabilities of each phase are lower than the permeability of the
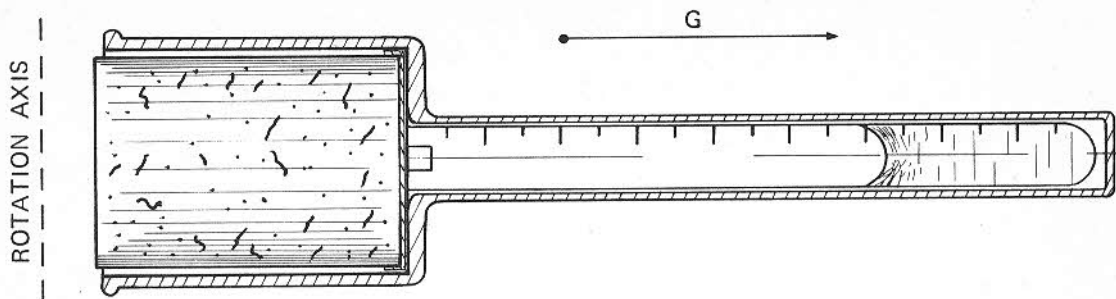
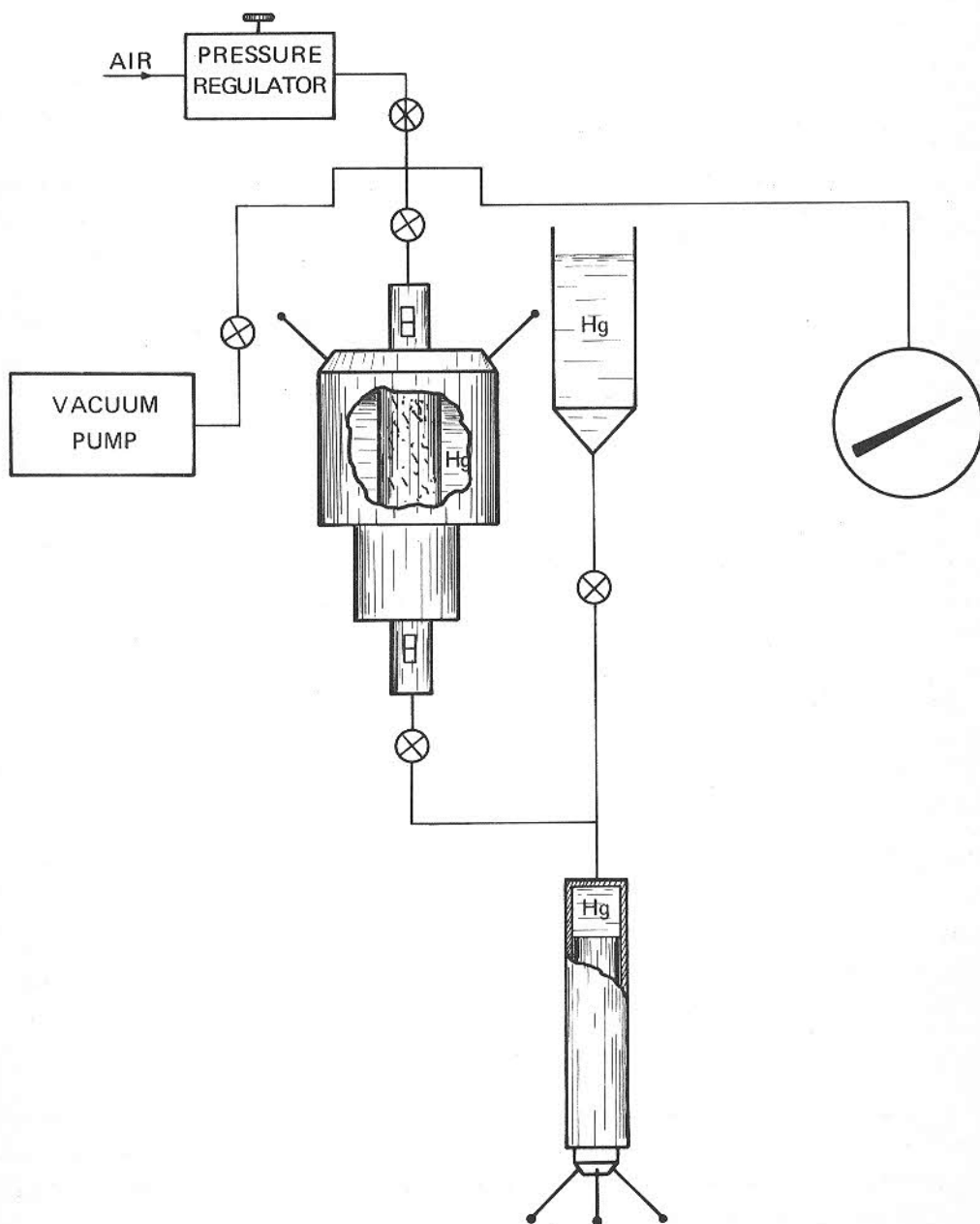Fig. 13 — Core - holder with graduated burette (centrifuge)

Fig. 14 — Apparatus for determining capillary pressure curves bu Purcell method

medium, and that they are a function of the saturation of their own fluids.

Being more expressive, it has now come into use to consider the relative permeability instead of the effective one, as shown herebelow:

$$k_w = \frac{k_w}{K} \qquad\qquad k_{nw} = \frac{k_{nw}}{K}$$

where k_w (wetting phase) and k_{nw} (non-wetting phase) are the effective permeabilities, and K is the absolute permeability of the medium.

Let us take, for instance, two gas-oil relative permeability curves. The qualitative trend of the curves in fig. 15 shows that the wetting phase (oil) is continuous, thus its saturation state is "funicular"; this means that oil can move. On the contrary, the non-wetting phase (gas) is in an "insular" saturation state, i.e. in the form of isolated small bubbles which occupy the central part of the pores: this means that the gas cannot move.

When the non-wetting phase saturation reaches and exceeds the critical equilibrium value, the phase enters a "funicular" saturation state and acquires a finite and increasing permeability because of its saturation. Finally, when the saturation of the wetting phase changes from "funicular" to "pendular", the phase loses its mobility while its saturation becomes residual.

From the curves we can calculate the critical gas saturation and the residual oil saturation from which oil recovery is obtained.

Determination Methods

The methods for determining the relative permeability curves can be classified as follows:

— Steady-state methods ———————< static
                                     dynamic
— Unsteady-state methods.

The steady-state methods are those where measurements are conducted when a steady condition is obtained in the sample, i.e. a condition where all the variables considered during the experiment (pressures, flow rates, saturations) do not vary in the time.

A procedure common to these methods is the measurement of the applied pressure differences, the flow rates of each fluid and the saturation. Sample dimensions and fluid viscosity being known, the relative permeabilities can be calculated with the above data by Darcy's equation:
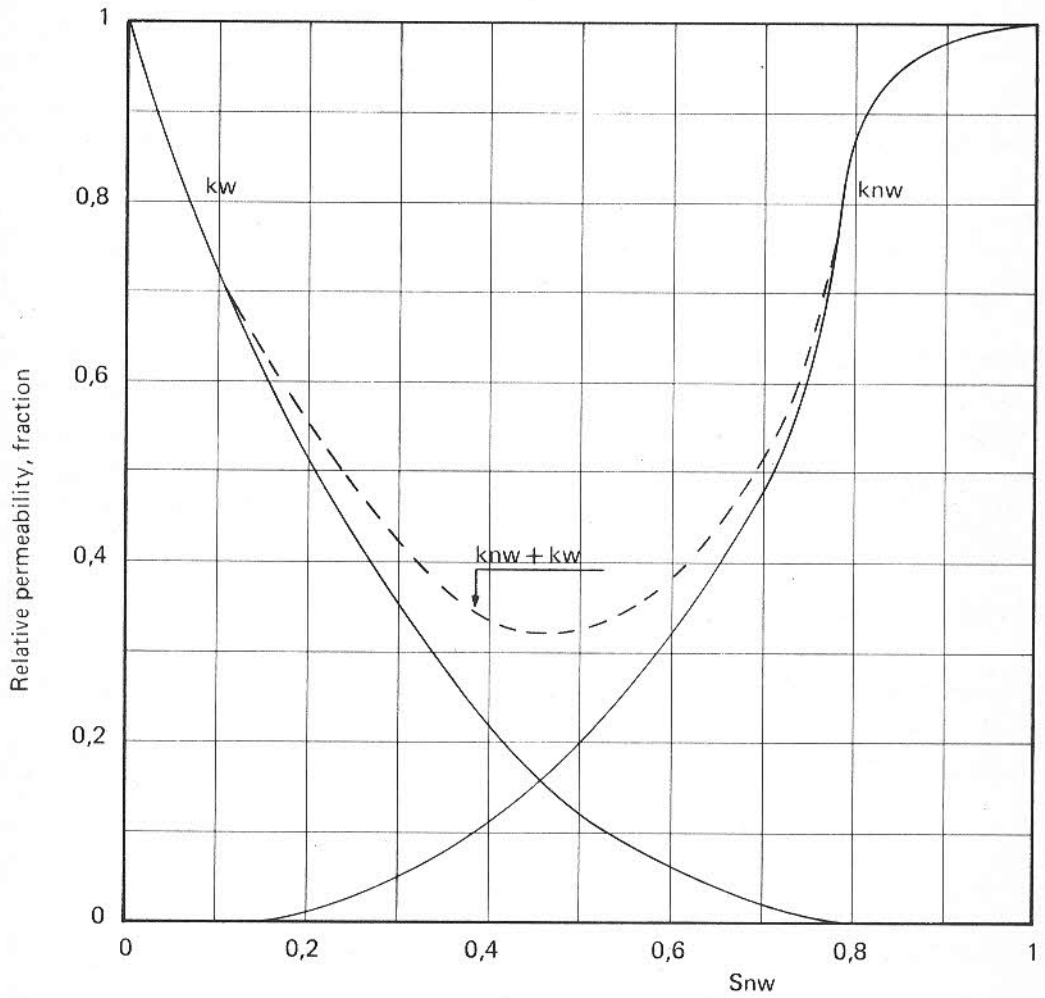
Fig. 15 — Relative permeability curves

$$k = \frac{\mu q L}{K A \triangle P}$$

Now sample saturation can be varied with the aid of suitable means, waiting for a steady condition to be obtained once more. Measurements are repeated, thus obtaining relative permeability curves by steps.

The steady-state methods are divided into static and dynamic, according to the magnitude which is directly controlled to obtain a saturation change. Static methods imply action on capillary pressure, i.e. on the pressure difference between the two fluids; dynamic methods imply action on the ratio between the two flow rates.

Unsteady state methods consist in injecting only one of the two fluids into the sample initially fully (or almost) saturated with the other fluid.

The result is a transient state during which the flow rate of the two fluids, pressures and saturation vary from point to point in the sample and according to time. In particular, this transient state is characterized by the behaviour, as a function of time, of the volume of the two fluids flowing from the sample. Since this behaviour is a function of the relative permeability curves of the sample, knowing the theory of this phenomenon we obtain the curves in question.

These are the methods used in AGIP laboratories:

— Welge, **unsteady-state**;
— Hafford (for oil-gas curves), steady-state/static;
— Penn-State (for water-oil curves), steady-state/dynamic.

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