

Chapter 2

Physical Properties of Reservoir Rocks

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A rock capable of producing oil, gas, or water is called *reservoir rock*. A reservoir rock may be any rock with sufficient porosity and permeability to allow oil and gas to accumulate and be produced in commercial quantities [1]. Petroleum generally occurs in sandstones, limestones, dolomites, conglomerates, and shales, but sometimes it is also found in igneous and metamorphic rocks. As a whole, sandstone and carbonate rocks are the most common reservoir rocks. However, reservoir rocks are quite variable in composition and physical properties [2]. The physical properties of reservoir rocks are the vital information for producers to estimate the geological reserve and ultimate recovery of an oilfield and determine the most efficient method of petroleum production.

Reservoir rocks may be investigated from two points of view, namely, microscopic and megascopic. If we study a core or a sample of a reservoir rock containing petroleum and place it under a magnifying glass (binocular or microscope), we can observe that the reservoir rock is made of a framework of minerals (rigid or friable) which fills but part of the void space. The void space in the rock is broadly known as *pore*. Oil, gas, or/and water can enter and fill in the pores if they are interconnected. In general, interconnected pores are interlaced within the mineral framework. The size, quantity, and shape of the interconnected pores in a reservoir rock determine the ability of the rock storing and transmitting fluids. Therefore, the physical properties of reservoir rocks are in essence dependent on the mineral framework of the rock, namely on the mineral composition and the texture of the rock.

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2.1 Matrix Features of Reservoir Rocks

Although we find oil and gas occasionally in igneous rocks, most of reservoir rocks are sedimentary in origin. Sedimentary rocks that contain oil and gas are generally divided into two categories: clastic sedimentary rocks and carbonate sedimentary rocks. The former chiefly includes conglomerate, sandstone, and mudstone, while the latter usually refers to limestone and dolomite. Sandstone is one of the most common and important petroleum reservoirs. Sandstone is a clastic sedimentary rock composed of more than 50 % sand-sized minerals or rock grains.

Sandstone is an aggregate of various particles. The size and nature of these particles in sandstone determine the characteristics of the rock. Actually, all clastic rocks have two basic properties: composition and texture. Rock texture indicates the way the particles or minerals are put together to constitute the rock. Some other properties, like structure, density, color, electrical properties, porosity, and permeability, are only second- or third-order derivatives of the two basic properties (composition and texture). In order to find the best way to exploit petroleum from underground rocks, it is necessary for the producers to know what a rock is composed of and how it is formed because the knowledge of the mineral composition and rock texture can give people an idea of how easy the petroleum may get into the rock.

In the description of sedimentary rocks, texture is a key content. It can help to interpret the mechanisms and environments of deposition. The texture of clastic sediments includes external characteristics of sediment grains, such as size, shape, and orientation [3]. Sediment texture is dependent on the grain morphology, surface features, and the fabric of the sediment.

Generally, rock's texture can be adequately studied by means of casting thin section and scanning microscope. For sand and silt-sized sediments, the analysis of rock's texture mainly focuses on the size, sorting, shape, and roundness of particles (grains). The grain-size of clastic rocks may vary from clay in shales; silt in siltstones; sand in sandstones; and gravel; cobble; to boulder-sized fragments in conglomerates and breccias (Fig. 2.1). Different rocks consist of different particles. As a result, the size, distribution, and nature of particles in a rock are responsible for many important physical and chemical properties of the rock, such as porosity, permeability, wettability, and so on. The grain-size composition and distribution of a reservoir rock are thus very important information for petroleum engineers to understand the properties of the rock.

2.1.1 Grain-Size Distribution of Rocks

Grain-size is one of the most important characteristics of rock particles. It is customarily defined as the average diameter of grains in sediments or lithified particles in clastic rocks, expressed in millimeter. It is a measure of the particle size of a rock.

Fig. 2.1 A display of grains ranging in size from silt to very coarse sand



Table 2.1 Grain-size classes for sediments and clastic rocks (Zhu [4])

Grain-size (mm)	Class	Sediment	Rock
>1000	Boulder	Gravel	Conglomerate and breccia
100–1000	Cobble		
10–100	Pebble		
2–10	Granule		
1–2	Huge sand	Sand	Sandstone
0.5–1	Coarse sand		
0.25–0.5	Medium sand		
0.1–0.25	Fine sand		
0.05–0.1	Coarse silt	Silt	Siltstone
0.005–0.05	Fine silt		
<0.005		Clay	Claystone (mudstone)

According to grain-size, the grains of clastic rocks can be classified into several broad groups: gravel, sand, silt, and clay (Table 2.1), which are generally called as grain-size classes. The rocks corresponding to each grain-size class above are known as conglomerate/breccia, sandstone, siltstone, and mudstone, respectively. In China, the accepted grain-size scale is classified with decimal system (Table 2.1). However, the common parameter is crystal size rather than grain-size in the description of chemical rocks, such as evaporates, recrystallized limestones, and dolomites.

2.1.1.1 Grain-Size Composition (Granulometric Composition)

A grain-size composition means the constitution of various size particles in a rock. It is customarily defined as the percentage of different size particles in a rock (e.g., sandstone), in weight. Mathematically, it can be expressed as

$$G_i = \frac{w_i}{\sum w_i} \times 100 \% \quad (2.1)$$

where G_i is the weight percent of i th group of rock particles, %; w_i is the weight of i th group of rock particles, g.

Using the grain-size composition of a rock, the size and distribution of particles in the rock can be quantitatively described. It is helpful to the understanding of the rock texture.

2.1.1.2 Grain-Size Analysis

The measurement of the grain-size distribution of a rock is called *grain-size analysis*. In general, there are various laboratory techniques available for grain-size analysis. However, what technique can be used in the analysis mainly depends on the size of grains, the volume of the rock, and the consolidated degree of the rock. Generally, a systematic method of grain-size analysis includes the following techniques: sieve analysis, sedimentation method, direct measurement, and other methods.

In grain-size analysis, direct measurement is a subsidiary method, just suitable for the samples consisting of larger size particles, e.g., cobble, boulder, etc. Other methods mainly include optical method, electrical method, thin section analysis, image and analysis. These methods are often used for special samples, such as tiny samples and tightly cemented samples. Sieve analysis and sedimentation method are the routine methods in grain-size analysis. The principles of the two methods are simply described as follows.

Sieve analysis

Sieve analysis is a quick method and can provide a reliably and relatively broad grain-size spectrum. It is thus a main method of grain-size analysis and often used for determining the grain-size distribution of conventional sandstones.

In this method, a rock sample should be first broken into dispersed grains or particles. Then the grains are separated into several fractions with a stack of sieves on a shaker (Fig. 2.2). Each fraction of the grains has different average grain-sizes. After that, each fraction of grains is weighed and the grain-size composition of the sample can then be calculated according to the weight of each fraction of grains.

A typical sieve analysis involves a nested column of sieves with wire mesh cloth (screen) which has different mesh sizes (opening size) (Figs. 2.2 and 2.3). The opening size of the nested sieves should be suitable for the grain size of the sample. The nested sieves should be placed in the order of decreasing opening size from top to bottom on a mechanical sieve shaker (Fig. 2.2). A pan should be placed below the stack of sieves to collect the aggregate that passes through the last sieve.

The mesh size of sieves is expressed in two ways. One is the number of openings per inch (linear) of mesh cloth, called mesh, e.g., 200 mesh means 200 openings per inch of mesh cloth. The other one is the size (diameter) of openings of mesh cloth

Fig. 2.2 A shaker used in sieve analysis



Fig. 2.3 Sieves used in sieve analysis



expressed in millimeter. In general, the opening size of a sieve is approximately $1/\sqrt{2}$ or $1/\sqrt{42}$ increase than that of the next sieve. The opening size of sieves used in China and USA is listed in Table 2.2. The series of 9, 10, 14, 20, 27, 35, 40, 60, 80, 100 mesh sieves are commonly used for the grain-size analysis of conventional sandstones.

The routine procedure of sieve analysis includes the following steps:

- (a) *Sample preparation*: first, select a representative sample from rock cores. Then let the sample be crumbled in a pulverizer to dispersed grains.
- (b) *Sieving*: put the dispersed grains of the sample into the top sieve of the stack of sieves on a shaker shown in Fig. 2.2. Turn on the shaker and let it run for enough time for the separation of the grains. During the process of shaking, the grains pass through each sieve from top to bottom. Each of the sieves

Table 2.2 Typical sieve no. and corresponding opening sizes in sieve analysis

Sieve size (China) [5]		Standard sieve size (U.S.) [6]	
Sieve no. (mesh)	Opening (mm)	Sieve no. (mesh)	Opening (mm)
4	4.599	4	4.760
5	3.962	5	4.000
6	3.327	6	3.360
7	2.794	7	2.830
8	2.362	8	2.380
9	1.981	10	2.000
10	1.651	12	1.680
12	1.397	14	1.410
14	1.165	16	1.190
16	0.991	18	1.000
20	0.833	20	0.840
24	0.701	25	0.710
27	0.589	30	0.590
32	0.495	35	0.500
35	0.417	40	0.420
40	0.350	45	0.354
60	0.245	50	0.297
65	0.220	60	0.250
80	0.198	70	0.210
100	0.165	80	0.177
110	0.150	100	0.149
180	0.083	120	0.125
200	0.074	140	0.105
250	0.061	170	0.088
270	0.053	200	0.074
325	0.047	230	0.063
425	0.033	270	0.053
500	0.025	325	0.044
625	0.020	400	0.037

retains part of the grains due to larger grain-size than the opening size of the sieve. The dispersed grains of the sample are thus separated into several fractions.

- (c) *Determine the weight of each fraction*: measure weight of the grains retained on each sieve with a balance. The weight of each fraction of grains is expressed as w_1, w_2, \dots, w_n . w_n is the weight of the grains in the pan. The cumulative weight, W of all fractions is then calculated by the weight of each fraction. Namely, $W = w_1 + w_2 + \dots + w_n$.
- (d) *Determine grain-size distribution*: the percentage of each grain fraction retained on each sieve can be determined by Eq. (2.1), expressed as G_1, G_2, \dots, G_n .

Sieve analysis has been used for decades to monitor the particle size of different particle materials [7]. For coarser materials, the sizes may range down to 0.150 mm; sieve analysis is accurate and the particle size distribution is consistent. However, for materials finer than 0.150 mm, this method is significantly less accurate. For finer particles or grains, it could be harder to make the particles pass through the openings of sieves because of the increasing mechanical energy required as well as effects of interfacial adsorption between particles and between particle and the mesh cloth.

This method assumes that all particles are orbicular or nearly so, and one particle can only pass through the square-shaped openings with larger sizes than its own diameter. For elongated and flat particles, sieve analysis can give a less reliable result because an elongated particle may pass through the screen from end-on, but would be prevented the other way (e.g., if it is side-on). For example, a needle-shaped particle can either pass through a mesh or be retained on the screen, depending on its orientation during sifting. Even so, the density of particles has no effect on the analysis results. Sieve analysis is a favorite method for loose or weakly cemented rocks, but it may not be suitable for soft or tight rocks. Such kind of rocks may generate size-distorted particles during the process of breaking the sample.

In addition, the precision of sieve analysis is also affected by the following factors: the number of sieves used in the analysis and their quality, moisture of grains, and sieving time. Experience of the user is also reflected in the measuring results.

In a word, this method is simple, easily available, and relatively reliable. It is widely used in grain-size analysis of particle materials and reservoir rocks. Sieve analysis can also provide useful information and materials for the study on mineralogy and particle shape in the future.

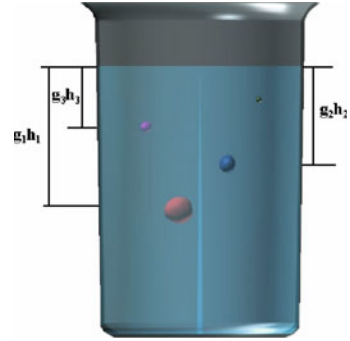
Sedimentation method

Sedimentation analysis appeared more than a century ago [8]. It was used in laboratories at the end of the nineteenth century and served as the most common method of soil and sediment particle size analysis.

Sedimentation method is a subsidiary method for the grain-size analysis of conventional sandstones. It is awfully appropriate for the grain-size analysis of tiny particles retained in the pan in sieve analysis. It is accurate for particles ranging between 0.053 and 0.074 mm, but it is less accurate for particles in sub-micrometers due to the effects of Brownian motion.

This method is based on the application of Stokes' law. Stokes' law describes the settling velocity of spherical particles in a viscous fluid under gravity (i.e., free falling). Under the conditions of low Reynolds numbers (i.e., laminar flow), the settling velocity of particles depends on the ratio of the particle density to the fluid density, the viscosity of the fluid, and the size of particles. Therefore, different particles have different settling velocities when subsiding in a viscous liquid (Fig. 2.4).

Fig. 2.4 Sketch map of particle settling



g_i : acceleration of gravity; h_i : distance

In the simplest case, the settling velocity of a particle is proportional to its size. According to the particle's velocity measured, the diameter of particles can be determined according to the Stokes equation of fluid mechanics:

$$d = \sqrt{\frac{18\gamma v}{g(\rho_s/\rho_L - 1)}} \quad (2.2)$$

where γ is the kinematical viscosity of suspension liquid, cm^2/s ; v is the terminal settling velocity of a particle in the liquid, cm/s ; g is gravity acceleration, cm/s^2 ; ρ_s is particle density, g/cm^3 ; ρ_L is liquid density, g/cm^3 ; d is particle's diameter, cm .

Equation (2.2) is valid for single spherical particle subsiding slowly in a fluid without the interference of other forces or motions. The concentration of particles in the liquid should be low enough to ensure that particles are adequately dispersive in the liquid and no appreciable interaction and interference between particles occur during the experiment. Therefore, the maximum mass concentration, commonly accepted, is usually less than 1 %. In addition, In order to reduce the interference of vessel wall to particle settling, the distance of a particle to the vessel wall should be at least 0.5 cm. In this situation, however, some particles may dissolve partially or fully in the fluid altering the grain-size distribution.

Mean size of particles

In clastic reservoir rocks, the particle size varies greatly in nature. In sieve analysis, each sieve actually retains an aggregate of different size particles. We thus know the size range of particles between the opening sizes of two adjacent sieves but grain-size of each particle. Therefore, it is very necessary to know the mean size of particles in each sieve for the study of rock texture. In an ordinary way, the mean size of particles in each sieve/fraction can be determined by the following formula:

$$\frac{1}{\bar{d}_i} = \frac{1}{2} \left(\frac{1}{\bar{d}_i'} + \frac{1}{\bar{d}_i''} \right) \quad (2.3)$$

where \bar{d}_i is the mean diameter of particles retained on i th sieve, μm ; \bar{d}_i' is the opening size of last sieve ($i-1$ th), μm ; \bar{d}_i'' is the opening size of i th sieve, μm .

2.1.1.3 Grain-Size Distribution

To display the results of the grain-size analysis of a rock, first find the percent of each fraction of grains. To do so, Eq. (2.1) can be used. Next, find the cumulative percent of all grains till i th fraction. The percentage of cumulative grains to i th fraction is determined by Eq. (2.1) using the total weight of all grains to i th fraction.

The result of grain-size analysis can be represented using either a table or a diagram. Table 2.3 shows the result of a grain-size analysis for a typical sandstone sample. Generally, the graphical method is more popular in oilfields, normally including grain-size distribution curve, cumulative grain-size distribution curve, grain-size frequency histogram, etc.

The curve of the weight percent of grains to their diameter is referred to as *grain-size distribution curve* or *grain-size frequency curve* (Fig. 2.5). A curve with cumulative weight percent on the y axis and grain-size (grain diameter or phi value) on the x axis is called *cumulative grain-size distribution curve* or *grading curve* (Fig. 2.6).

The two curves can visually display the grain-size distribution of a rock. Generally, a sharper peak of grain-size distribution or a steeper curve of cumulative grain-size distribution reflects more uniform grain-sizes (good sorting) of a rock; a flat peak or less steep curve reflects less uniform grain-sizes (poor sorting) in opposite manner. Different locations of the curve in the diagram indicate different average grain sizes of rocks (Fig. 2.7). From here we see that both the two curves can characterize illustratively the size and distribution of rock particles.

Table 2.3 The results of a grain-size analysis for a typical sandstone

Opening size of sieve (mm)	0.833	0.701	0.589	0.495	0.417	0.35
Weight percent (%)	2.10	13.11	54.15	18.50	7.44	4.70
Cumulative weight percent (%)	2.10	15.21	69.36	87.86	95.30	100.0

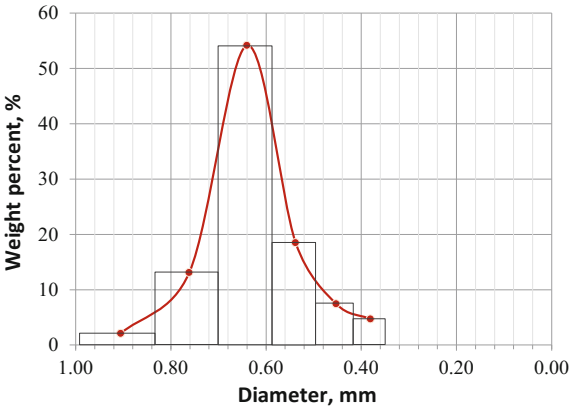


Fig. 2.5 Grain-size distribution curve

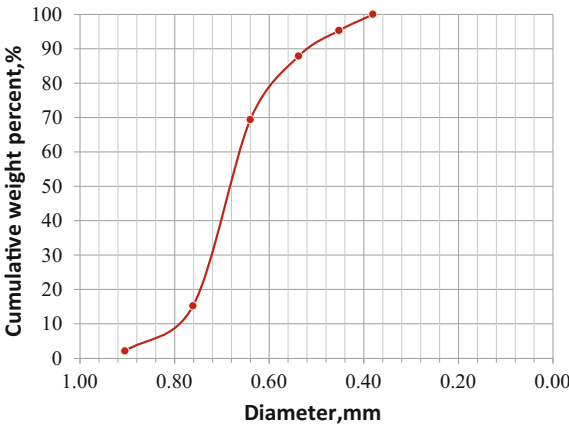


Fig. 2.6 Cumulative grain-size distribution curve

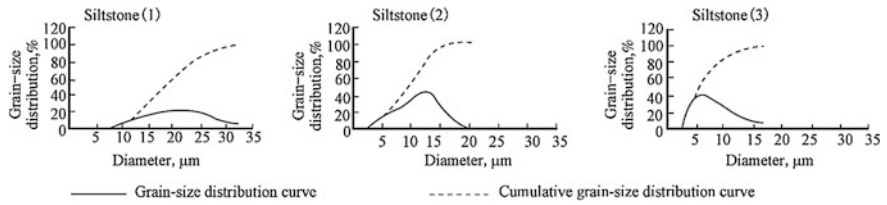


Fig. 2.7 Grain-size distribution curves of different siltstones

2.1.1.4 Grain-Size Statistical Parameters

Sorting of a grain population is a measure of the range of grain-sizes present and the magnitude of the spread or scatter of these sizes around the mean size [9]. It indicates the uniformity of grain-size distribution within a sedimentary rock. In well-sorted sediments, the grain-size of particles is very similar, while the particles consisting of poorly sorted sediments usually are distributed in a wide range of grain-size (Fig. 2.8). In the same way, a rock having a wide range of grain-size is said to be poorly sorting, whereas a well-sorted rock has a relatively narrow grain-size range. Well-sorted rocks are generally porous and have high permeability, but poorly sorted rocks have lower porosity and permeability.

Describing the significant feature of grain-size distributions, grain-size parameters can be used to evaluate the grain-size distribution or sorting of rock particles. Grain-size parameters can be determined in terms of different mathematical methods. Most grain-size parameters are defined based on graphical-statistical method, such as median, mean, standards deviation, skewness, kurtosis, etc. This is to say that these parameters are calculated with the grain diameters read from a graph (cumulative grain-size distribution curve). At present, the common parameters are customarily calculated with the method proposed by Folk and Ward. Here are several common grain-size parameters.

Standard deviation

Standard deviation is widely used to evaluate the sorting of rock particles. It describes the uniformity of grain-sizes in a rock. Folk and Ward (1957) proposed the following expression for calculating graphic standard deviation [10]:

$$\sigma = \frac{\phi_{84} - \phi_{16}}{4} + \frac{\phi_{95} - \phi_5}{6.6} \quad (2.4)$$

where phi (ϕ) is a logarithmic transformation: $\phi_i = -\log_2 d_i$; d_i is grain diameter in millimeters; The subscript of 5, 16, 84, and 95 denotes separately the 5, 16, 84, and 95 % by cumulative weight of a cumulative grain-size distribution curve. So, ϕ_5 , ϕ_{16} , ϕ_{84} , and ϕ_{95} represent the phi values at 5, 16, 84, and 95 cumulative percentage (Fig. 2.9).

The standard deviation of grain-size distributions of rocks ordinarily ranges from <0.35 to >4.00. Based on the statistical results of a lot of samples, a verbal

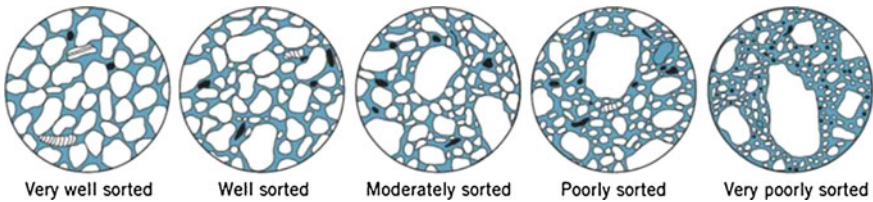


Fig. 2.8 Schematic diagram of sorting levels of sediment particles

Fig. 2.9 Schematic diagram for determining the values of ϕ_5 , ϕ_{16} , ϕ_{84} and ϕ_{95} on the curve of cumulative grain-size distribution

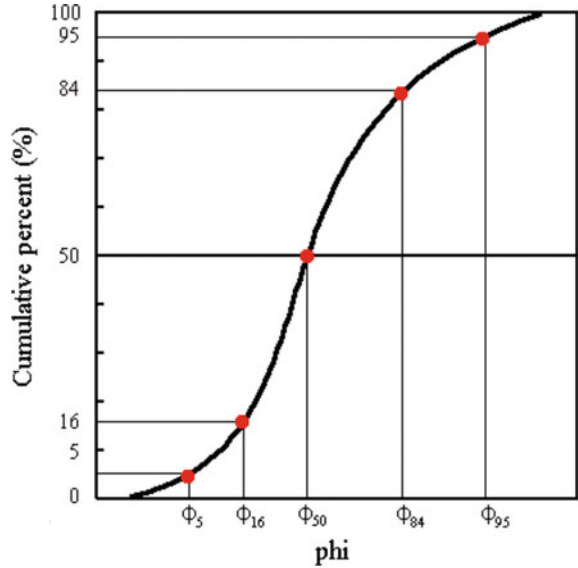


Table 2.4 Classification scale of standard deviation

Standard deviation	<0.35	0.35–0.50	0.50–0.71	0.71–1.00	1.00–2.00	2.00–4.00	>4.00
Scale	Very well sorted	Well sorted	Moderately well sorted	Moderately sorted	Poorly sorted	Very poorly sorted	Extremely poorly sorted

classification scale for sorting corresponding to various values of graphic phi standard deviation is presented by Folk and Ward (1974) (Table 2.4) [10, 11]. Obviously, the smaller the standard deviation is, the more the uniform rock particles are.

Skewness

Skewness is an additional measure of grain-size sorting. Actually, two samples may have the same average grain-size and sorting but may be quite different to their degrees of symmetry. Skewness measures the degree to which a grain-size distribution curve approaches symmetry. The grain-size distributions of most clastic sediments do not yield a perfect normal, or lognormal, distribution curve. Instead, they display an asymmetrical distribution. Folk’s inclusive graphic skewness (1957) is calculated by the equation [10]:

$$S_{kp} = \frac{\phi_{84} + \phi_{16} - 2\phi_{50}}{2(\phi_{84} - \phi_{16})} + \frac{\phi_{95} + \phi_5 - 2\phi_{50}}{2(\phi_{95} - \phi_5)} \tag{2.5}$$

where S_{kp} is skewness of grain-size distribution. The phi values (ϕ_i) represent the same percentages as those for standard deviation, namely ϕ_5 , ϕ_{16} , ϕ_{50} , ϕ_{84} , and ϕ_{95} represent the phi values at 5, 16, 50, 84, and 95 cumulative percentage.

In general, the skewness of a grain-size distribution varies between -1 and 1 , as $-1 < S_{kp} < 1$. Symmetrical grain-size curves (normal distribution) have a skewness equal to 0 ; those with a large proportion of fine particles are said to be fine skewed, or positively skewed (fine sediment has positive phi values, $S_{kp} > 0$) (Fig. 2.10a); those with a large proportion of coarse particles are said to be coarse skewed, or negatively skewed ($S_{kp} < 0$) (Fig. 2.10b). A verbal classification scale proposed by Folk (1966) [4] is listed in Table 2.5. Obviously, the more the value of the skewness deviates from zero, the greater the skewness of grain-size distribution.

Kurtosis

Kurtosis is a measure of the *sharpness* of a grain-size distribution curve. The sharpness or peakedness of a grain-size distribution curve is known as Kurtosis. Kurtosis describes the concentrative degree of grain-size distribution in a rock. Generally, a normal distribution curve is mesokurtic; a sharp-peaked curve is said to be leptokurtic; and a flat-peaked curve is platykurtic. Sharp-peaked curves indicate better sorting in the central portion of the grain-size distribution than the tails, and flat-peaked curves indicate the opposite.

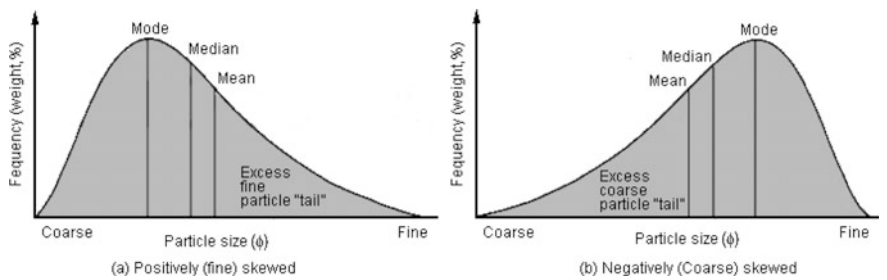


Fig. 2.10 Skewed grain-size frequency curves, illustrating the difference between positive (fine) and negative (coarse) skewness (Sam [9])

Table 2.5 Gradation of skewness (Folk 1966)

Skewness	<-0.30	-0.3 to -1	-0.1 to +0.1	+0.1 to +0.30	>+0.3
Scale	Strongly coarse skewed	Coarse skewed	Nearly symmetrical	Fine skewed	Strongly fine skewed

Folk's formula (1957) for calculating graphic kurtosis is as follows [10]:

$$K_p = \frac{\phi_{95} - \phi_5}{2.44(\phi_{75} - \phi_{25})} \quad (2.6)$$

where K_p is the kurtosis of a grain-size distribution; the phi values represent the same percentages as those of standard deviation.

In general, normal distribution curves have a kurtosis equal to 1; leptokurtic curves have a kurtosis higher than 1, and platykurtic curves have a kurtosis lower than 1. If a curve is very flat or double-peaked, K_p may be less than 0.6; A much sharp-peaked curve may have a K_p ranging from 1.5 to 3.

Mode

Mode (Mo) is the most frequently occurring grain-size in a population of rock particles. The modal diameter is the diameter of grains represented by the peak of a distribution curve or the steepest point of a cumulative curve, as shown in Fig. 2.10.

To a certain extent, it represents the grain-size of the majority and the sorting of rock particles.

Median

Median (Md) is the grain-size corresponding to the 50 % cumulative weight of a cumulative grain-size distribution curve. It represents the midpoint of a grain-size distribution. In a rock sample, half of the grains by weight are coarser than the median, and half are finer.

Mean

Mean of a grain-size distribution refers to the arithmetic mean of all grain-sizes in a rock sample. Actually, a graphic mean can be obtained according to the typical diameters determined from a cumulative distribution curve. The following expression is the commonly used algorithm:

$$M_z = \frac{d_{16} + d_{50} + d_{84}}{3} \quad (2.7)$$

where d_{16} , d_{50} , and d_{84} are particle diameters separately corresponding to 16, 50, and 84 % cumulative weight of the cumulative distribution curve, μm .

2.1.2 Specific Surface Area of Rocks

Specific surface area, or SSA for short, is an essential property of reservoir rocks. It is a measure of the total surface area of grains in a rock. The SSA of reservoir rocks has a particular importance for the study of adsorption and reactions on surfaces in petroleum engineering.

2.1.2.1 Specific Surface Area

Specific surface area is defined either by the total surface area of rock matrix divided by the volume of a rock, or the total internal surface area of void space divided by the volume of a rock, That is:

$$S = \frac{A}{V} \quad (2.8)$$

where S is the specific surface area of a rock, cm^2/cm^3 or $1/\text{cm}$; A is the total surface area of rock matrix or total internal surface area of the void space in the rock, cm^2 ; V is the bulk volume or the view volume of the rock, cm^3 .

Specific surface area can also be defined either by the total surface area of rock matrix divided by the mass of a rock (with units of cm^2/g). The specific surface area of conventional sandstones is about $500\text{--}5000 \text{ cm}^2/\text{g}$, and the specific surface area of shale is about $1,000,000 \text{ cm}^2/\text{g}$, namely $100 \text{ m}^2/\text{g}$.

In practical applications, specific surface area may be expressed as the surface area per unit solid volume of a rock V_s or per unit pore volume in a rock V_p , namely $S_s = A/V_s$, and $S_p = A/V_p$. Here S_s and S_p are the specific surface areas which are defined by V_s and V_p , respectively. Based on the relationship between V and V_p , or between V and V_s : $\phi = V_p/V = 1 - V_s/V$, the following expression can be obtained:

$$S = \phi \times S_p = (1 - \phi)S_s \quad (2.9)$$

where ϕ is the porosity of a rock, f; S is the specific surface area per unit bulk volume of the rock, cm^2/cm^3 ; S_p is the specific surface area per unit pore volume of the rock, cm^2/cm^3 ; S_s is the specific surface area per unit solid volume of the rock, cm^2/cm^3 .

Suppose an ideal porous medium composed of same size spherical particles. In this medium, the total internal surface area of void space equals the total surface area of all particles without regard to the effect of particle contact. Suppose the radius of the spherical particle is R (Fig. 2.11), the specific surface area of the medium can be easily determined by the formula: $S = 8 \times 4\pi R^2/(4R)^3$. Obviously, the specific surface area of a porous medium is inversely proportional to the particle radius (R) packing the medium. This conclusion also applies to sedimentary rocks. The specific surface areas of clastic rocks generally increase with the decrease in

Fig. 2.11 Packing of spherical particles

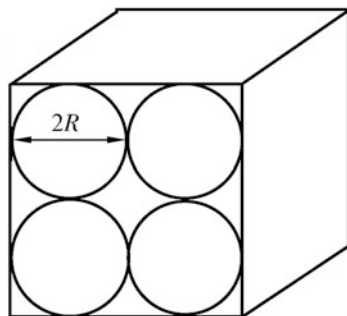


Table 2.6 The statistical results of the specific surface areas of rocks

Rocks	Grain diameter (mm)	Specific surface area (1/cm)
Coarse, medium sandstone	1.0–0.25	<950
Fine sandstone	0.25–0.1	950–2300
Siltstone	0.1–0.01	>2300

grain-size (Table 2.6). Therefore, specific surface area can characterize the average size and the dispersion degree of rock particles.

Essentially, the SSA of a rock characterizes the total surface area of rock particles exposed to fluids in the rock. When flowing through a rock, the fluid in rock pores is subject to the adsorption of rock particles. Therefore, SSA also represents indirectly the magnitude of the adsorption of rock particles to fluids flowing through the rock. The larger the SSA of a rock, the stronger the adsorption of particles to fluids. SSA can also help in understanding the important reservoir phenomena, such as adsorption, wettability, capillarity, solubility, and free interfacial energy (see Chap. 4). As a result, rock’s SSA is highly concerned by petroleum engineering.

2.1.2.2 Measurement of Specific Surface Area

The SSA of a rock can be measured by at least two techniques. One is based on the permeability of rocks, called gas permeability method or penetrant method; and the other is based on the adsorption of gas on particle’s surface, called gas adsorption method. Besides, the petrographic image analysis (PIA) and nuclear magnetic resonance (NMR) may also be used to measure the SSA of various particle materials at present [12]. Details of gas permeability method and gas adsorption method are briefly introduced as follows.

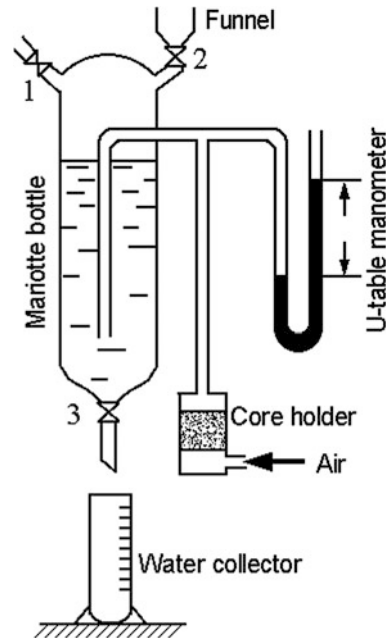
Gas permeability method

Based on the permeability of rocks to the gas flowing through the rock, gas permeability method is developed by Kozeny. Kozeny–Carman equation (1927) is widely used for all permeametry modifications [13]. In terms of the theory of Kozeny–Carman [14], the rock pores that fluids flow can be supposed to be a bundle of parallel capillary tubes, the SSA of a rock is then equal to the summation of the areas of all pore-walls when the fluid flows through the rock. Therefore, the SSA of a rock can be directly determined from the measurement of gas permeability (air is often used).

The apparatus of this method is shown in Fig. 2.12. It primarily consists of a Mariotte bottle, a core in core holder, and a piezometer. The porosity of the core is given.

In the measurement, first of all, close valve 3 and open valve 1, 2; then inject water to Mariotte bottle through the funnel until water level reaches the specified height. After that, close valve 1, 2 and let air flow into the bottle through the core until the water level of U-table reaches the specified pressure drop. Then, open valve 3 and let water flow into the water collector. When the pressure drop of

Fig. 2.12 Apparatus of SSA measurement



U-tube is unchanged, begin recording and measure the volume of water flowing out from valve 3 in a given period of time. Under the condition of stable flow, the flow rate of air flowing through the core is exactly equal to the flow rate of water flowing out from the bottle. Therefore, the flow rate of air through the core can be determined according to the water volume measured in a given time. Finally, the SSA of the rock core can be calculated using Kozeny–Carman equation:

$$S = 14\sqrt{\phi^3} \sqrt{\frac{AH}{Q_0\mu L}} \quad (2.10)$$

where S is the SSA of a rock core, cm^2/cm^3 ; ϕ is the porosity of the core, f ; A is the cross-sectional area of the core, cm^2 ; L is the length of the core, cm ; Q_0 is the flow rate of air through the core, cm^3/s ; H is pressure drop, cm water column; μ is the viscosity of air at room temperature, mPa s .

This method is simple, fast, and easy to use. It is widely used in oilfields. However, it fails to measure the surface area of a deep texture. That is to say, the surface area of tiny pores can hardly be measured by this method. Generally, it is appropriate for the rocks whose particle sizes range between 0.001 and 0.1 mm.

Gas adsorption method

Gas adsorbing on the surface of solids is a common phenomenon. Gas adsorption is often influenced by surface imperfections and irregularities [15]. In porous media, the influence is superposed by their internal structure, such as shape and dimensions of the pores. On the surface of a porous medium, the adhesion of gas on the surface

of the medium occurs due to the interaction between molecules of gas and the surface of the medium by the molecular interaction forces (van der Waals forces).

The principle of this method is based on the Brunauer–Emmett–Teller (BET) model. The BET model was built for determining the amount of gas adsorption on the surface of a sample at low temperatures [13]. The BET theory was developed by Brunauer, Emmett, and Teller in 1938 [16]. The BET theory aims to explain the physical adsorption of gas molecules on a solid surface and serves as the basis for the measurement of the SSA of porous media.

The gas adsorption technique involves determining the amount of inert gas, typically nitrogen (N_2), argon (Ar), krypton (Kr), or xenon (Xe). This method requires a single layer adsorption of inert gas on the solid surface at low temperatures. The surface area of the solid can be determined according to the area occupied by gas molecules.

In the measurement, the inert gas can enter not only the large-size rock pores through which fluids can freely flow, but also the tiny pores/fractures or dead-end pores in which fluids can hardly flow. As a result, the SSA measured by this method is frequently larger than that measured by gas permeability method. In gas permeability method, the surface of particles, though “smoothed out,” is determined without regard to particle’s roughness and dead-end pores.

At present, gas adsorption method is popular in the measurement of the SSA of reservoir rocks, especially in low-permeable rocks and shale. The reason is that the SSA and pore-size distribution of a rock can be time determined at a time using this method. Moreover, this method has a particular advantage of measuring the surface of fine structures and deep texture on particles. It should be, however, limited to porous media that do not have large specific surfaces [12].

In addition, the nuclear magnetic resonance (NMR) method appears to be currently the most accurate technique for estimating the specific surface area [12]. In this case, the specific surface areas S_{vg} and S_{pv} are obtained from [12]:

$$S_{vg} = A_{NMR} \rho_m \quad (2.11)$$

$$S_{pv} = \left(\frac{1 - \phi}{\phi} \right) A_{NMR} \rho_m \quad (2.12)$$

where A_{NMR} is the NMR surface area of dry material, m^2/g ; ρ_m is grain-matrix density, g/cm^3 ; S_{vg} is the SSA per unit grain volume, m^2/cm^3 ; S_{pv} is the SSA per unit pore volume, m^2/cm^3 .

Note that values of SSA obtained from NMR are generally higher than values obtained by the gas adsorption technique.

2.1.2.3 Estimation of Specific Surface Area

Besides the methods introduced above, the SSA of a rock can also be directly estimated according to the physical properties (porosity and permeability) of the rock.

Based on the simplified capillary model of rocks, Kozeny developed the following equation:

$$K = \frac{\phi^3}{kS^2} \times 10^8 = \frac{\phi^3}{2\tau^2 S^2} \times 10^8 \quad (2.13)$$

where k is Kozeny constant, $k = 2\tau^2$; τ is the average tortuosity of rock pores, f ; ϕ is rock porosity, f ; K is rock permeability, D ; S is the SSA of the rock, $1/m$.

Generally let $\tau = 1.4$, Eq. (2.13) is expressed as follows:

$$S \approx 5051\phi\sqrt{\phi/K} \quad (2.14)$$

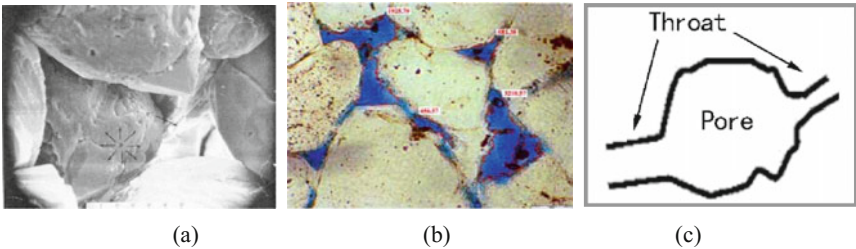
Equation (2.12) is the final expression of estimating the SSA of a rock.

2.2 Porosity of Reservoir Rocks

The first element of an oil/gas reservoir is the reservoir rock. The essential feature of a reservoir rock is *porosity*: the rock must contain pores or voids, which should be of such size and character as to permit the storage of oil and gas in reservoirs that are large enough to justify exploitation. Porosity, however, is not enough; the pores must be interconnected to permit the passage of oil and gas through the rock. In other words, the rock must be permeable (it is said to have *permeability*); otherwise there would be little if any accumulation into reservoirs, nor could any petroleum that accumulated be produced by drilling wells, as the accumulation of petroleum would not move into the wells fast enough. A pumice rock, for example, would not make a good reservoir even though the greater part of it might consist of pore space, for the pores are not interconnected and the porosity is not effective. The conventional shale generally cannot become a reservoir rock, for the pores are so tiny that the capillary attraction of the fluids for the mineral grains effectively holds the fluids in the rock. Trying to get petroleum out of a shale would be like trying to remove ink from a blotter. Therefore, the porosity and the pore structure of reservoir rocks are the key factors to affect the quality of reservoirs and control the off-take potentials of oil or gas wells.

2.2.1 Pore and Pore Structure of Reservoir Rocks

Pore refers to the void space not occupied by minerals within a rock (Fig. 2.13). In a rock, most pores are fully interconnected (Fig. 2.13b). From the interconnected point of view, the idea of “throats” can be important. If the void space in a rock is shaped like the cartoon shown in Fig. 2.13c, it can be loosely defined as the “throat.” A “throat” means the narrow void space connected with larger void space



(a) SEM microphotograph of bore body and pore throat (Jordon, 17); (b) Intergranular pores (outlined in red) in a andstone; (c) sketch map defining a throat and pore.

Fig. 2.13 Images and sketch map of rock pores

as shown in Fig. 2.13c. In a narrow sense, a “pore” means the larger space connected with narrow space in a void system. In the void system of a rock, the size of the “throat” limits the accessibility of the larger “pore.”

In sedimentary rocks, there is a wide variation in the size, shape, and arrangement of pores with respect to one another. The pore system of a rock depends essentially on the depositional environment and diagenetic process of the rock. The feature of a pore system is closely related with the microcosmic texture of the rock, namely related with the size, sorting, and arrangement of rock particles.

2.2.1.1 Pore Types of Reservoir Rocks

In petroleum reservoirs, there are various types of rock pores. Rock pores can be classified from different point of view. The common classification of pores in reservoir rocks is simply described as follows.

Classification by genesis

From the genetic point of view, rock pores in sedimentary rocks may be classified into two groups: primary pores and secondary pores, as shown in Table 2.7.

Table 2.7 Pore types classified by genesis (Richard [18])

Type		Origin
Primary/depositional pores	Intergranular or interparticle	Sedimentation
	Intergranular or interparticle	
Secondary/postdepositional pores	Intercrystalline pore	Cementation
	Fenestral pore	Solution
	Moldic pore	
	Vuggy	
	Fracture	Tectonic movement, compaction or dehydration

By definition, primary pores are the void space which formed when sediments first deposit and still remain after the sediments lithify. Primary pores contain two types: interparticle pores and intergranular pores. Interparticle pores are characteristics of sandstones, whereas intergranular pores are usually found in skeletal carbonate rocks.

Secondary pores form after deposition and are a result of diagenetic processes [19]. Recrystallization and notable dolomitization can generate intercrystalline pores. Solution can generate moldic, vuggy, and cavernous pores [18]. Because such pores are often isolated from one another, the permeability of rock matrix may be low. Fractures form in both the unconsolidated and brittle sediments. In the first instance, the fractures remain closed, but in brittle rocks, fracture may be preserved, enlarged by solution, or diminished by cementation [19]. Fracture porosity occurs not just in indurated sediments, but also in igneous and metamorphic rocks.

Intergranular pore [18]

Intergranular or interparticle pores occur in the spaces between the detrital grains that form the framework of a sediment (Fig. 2.14a). Intergranular pores are a main type of pores in sandstone, and are most common.

Intragranular pore [18]

Intragranular pores, those within grains, may exist naturally in skeletal grains or in diagenetically altered grains of any origin (Fig. 2.14b). Usually they occur in porous, skeletal allochems, which make up varying amounts of detrital sediments. Bryozoans, for example, have internal pores, as do corals sponges and many other reef-building organisms. In a bioclastic grainstone reservoir consisting of sand-sized bryozoans fragments, the bryozoans may contribute significantly to total porosity. In that case, intragranular pore corresponds with the distribution of skeletal grain-stones and packstones and, in turn, with facies maps. Common pore sizes are <0.01 to 1 mm [20].

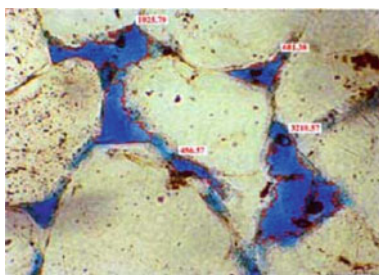
Intercrystalline pores are spaces between more or less equal-sized crystals, often related to early and late diagenetic recrystallization and dolomitization processes (Fig. 2.14c). Common pore sizes are <1–10 μm [20].

Fenestral pore [18]

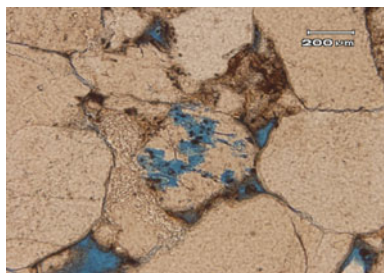
Fenestral or “bird’s-eye” pores result from desiccation or from expulsion of gas during decay of organic matter in muddy sediment. The pores may be millimeter to centimeter in size, they are elongate and planar in a direction parallel to bedding (Fig. 2.14d), and they are especially common in tidal-flat environments where sediments are alternately wet and dry. Fenestral pores may not be in flow communication with each other; consequently, they may have the petrophysical properties of small, separate vugs. If they are touching and are not filled with cement, they may present high permeability values at comparatively low porosity.

Moldic pore [18]

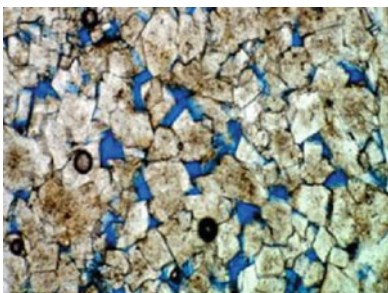
Moldic pores result from the selective removal, commonly by solution of primary depositional grains (Fig. 2.14e), e.g., fossils or ooids. Molds are fabric selective. That is to say, solution is confined to individual particles and does not cross-cut



(a) Interparticle pores in sandstone



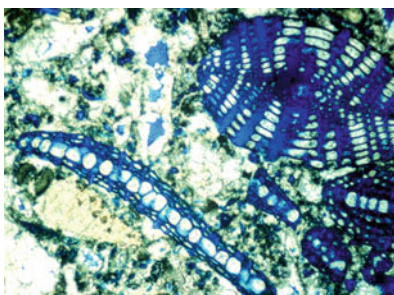
(b) Intraparticle dissolved pore



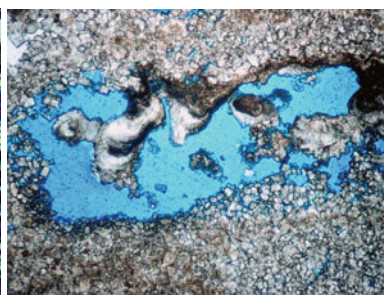
(c) Intercrystalline pore in dolostone



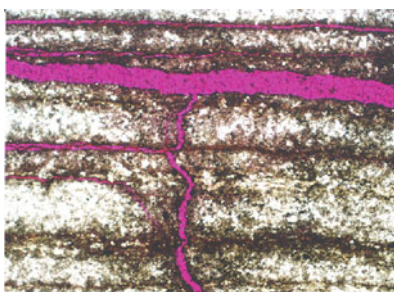
(d) Fenestral pores (white areas)



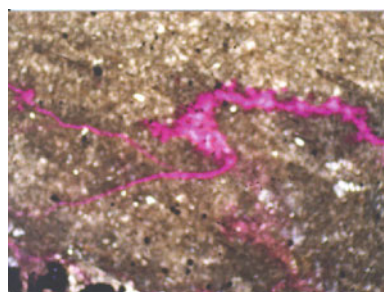
(e) Moldic pore



(f) Vuggy



(g) Tectonic fractures



(h) Dissolved fracture

Fig. 2.14 Illustration of pore genetic type in reservoir rocks

cement, matrix, and framework. Typically, in any rock it is all the grains of one particular type that are dissolved. Therefore, it requires a distinctive mineralogical or microstructural difference between the solubility of grains and matrix or cements.

Biomoldic pores refer to pores caused by removal of fossils. Pore sizes <0.5 to several millimeters. Dissolution of (mainly aragonitic) ooids results in the formation of oomoldic pores, particularly in meteoric vadose and meteoric phreatic environments. Common pore sizes <0.20 to >0.5 mm.

In an oomoldic rock, pores will be sub-spherical and of similar size. In biomoldic rocks, by contrast, pores may be very variable in size and shape, ranging from minute apertures to curved planar pores where shells have dissolved, and cylinders where echinoid spines have gone into solution.

Vuggy pore [18]

Vugs are a second type of pore formed by solution and, like molds, they are typically found in carbonates (Fig. 2.14f). Vugs differ from molds because they cross-cut the primary depositional fabric of the rock. Vugs thus tend to be larger than molds. They are often lined by a selvage of crystals. With increasing size vugs grade into what is loosely termed “cavernous pore.” People once proposed that the minimum dimension of a cavern is a pore which allows a speleologist to enter or which, when drilled into, allows the drill string to drop by more than half a meter through the rotary table. Large-scale vuggy and cavernous pore is commonly developed beneath unconformities where it is referred to as “paleokarst.” This serves as a petroleum reservoir in some fields such as Tahe oilfield.

Fracture pore [18]

Fractures occur in many kinds of rocks other than sediments. It often takes the form of microfaulting caused by slumping, sliding, and compaction. Fractures in plastic sediments are instantaneously sealed, however, and thus seldom preserve porosity. In brittle rocks, fractures may remain open after formation, thus giving rise to fracture porosity. This pore type is generally formed later than the other varieties of pore. It is important to note that fracture can be found in well-cemented sandstones and carbonates, but may also occur in shales and igneous and metamorphic rocks.

Fracture is much more difficult to observe and analyze than most other pore systems. Though fractures range from microscopic to cavernous in size, they are difficult to study in cores.

Fracture can occur in a variety of ways and situations. Tectonic movement can form fracture pores in two ways. Tension over the crests of compressional anticlines and compactional drapes can generate fracture (Fig. 2.14g). Fracture is also intimately associated with faulting and some oil fields show very close structural relations with individual fault systems.

Fracture can also form from atectonic processes. It is often found beneath unconformities. Here fractures, once formed by weathering, may have been enlarged by solution (especially in limestone paleokarst) and preserved without subsequent loss of their pore (Fig. 2.14h). Fracture is extremely important in both aquifers and petroleum reservoirs. This is because a very small amount of fracture

can give a very large permeability; the fractures connecting many pores of other types that might otherwise be ineffective.

In a word, sedimentary rocks generally contain more than one type of pores. The combination of open fractures with other types of pores is of particular significance. Fine-grained rocks, such as shales, microcrystalline carbonates and fine sands, have considerable porosity; but they often have very low permeability because of their narrow pore-throats and concomitant higher capillary pressures. However, the presence of fractures in such rocks makes it possible to yield easily the fluids contained in the rocks. The success of many oil and water wells in such formations often depends on whether they happen to penetrate the open fractures. Recognition of the significance of fractures in producing fluids from low-permeability rocks has led to the development of artificial fracturing technology. Similarly, the productivity of fractured carbonate reservoirs can be improved by injecting acid to the rocks to dissolve and enlarge the fractures.

Classification by pore size

Pores may be classified with respect to their size. Generally, the pores found in petroleum reservoirs may be placed, by size, in three groups: supercapillary, capillary, and subcapillary pores (Table 2.8).

Supercapillary pores include tubular openings greater than 0.5 mm in diameter and sheet openings (fractures) more than 0.25 mm in width. Large fractures and dissolved caverns in rocks, and the pores in carbonate rocks or weakly cemented sandstones belong to this category. In such pores, water obeys the ordinary laws of hydrostatics and the fluids can flow freely under gravity. That to say, fluid movement in such pores is determined more by gravity or normal pressure difference than capillary action.

Capillary pores include tubular openings between 0.5 and 0.0002 mm in diameter and sheet pores between 0.25 and 0.0001 mm in width. Pores in conventional sandstones are such openings. In this pore system, the flow of water does not obey the ordinary laws of hydrostatics but is primarily affected by capillary forces. Broadly speaking, fluids in these pores are subject to both gravity and capillary forces, and cannot flow freely due to greater friction along the pore walls.

Table 2.8 Pore types classified by pore size (He [21])

Type	Pore diameter (mm)	Fracture width (mm)	States of fluids in pores	Cases
Supercapillary pore	>0.5	>0.25	Flow freely	Dissolved pores or caverns, big fractures
Capillary pore	0.5–0.0002	0.25–0.0001	Can't flow freely unless $\Delta p > p_c$	Pores in conventional sandstones
Subcapillary pore	<0.0002	<0.0001	Can hardly flow under normal conditions	Pores in conventional mudstones

Under the condition of great pressure drop, however, fluids may be forced through capillary openings. It is possible for fluids to circulate through capillary pores if gravity force or pressure drop is greater than capillary force.

Subcapillary pores are tubular pores less than 0.0002 mm in diameter and sheet pores (fractures) less than 0.0001 mm in width. These pores are so small that great intermolecular force between particles and liquids makes fluids hardly flow in these pores. Fluids may enter such pores, but it tends to remain as if fixed to the walls, prohibiting further entrance of fluids. That is to say, under normal pressure drops of oil reservoirs, there is no circulation of fluids through such openings.

Obviously, the smaller the pore, the harder the flow of fluids in pores. For example, mud stones, clays, and shales, primarily containing minute pores or micropore, are always natural barriers to circulation unless sufficient pressure drops exists, which may force fluids flow through this kind of medium. Therefore, sub-capillary pores are usually noneffective for the circulation of fluids in oil reservoirs. In gas reservoirs, however, even subcapillary pores may be effective owing to the small molecule size and strong flowability of natural gas. For example, nanometer-scale pores in shale gas reservoirs are even effective for gas production.

In reservoir evaluation, pores are customarily assorted according to the median radius of pore-throats (R_{50}) of rocks (Table 2.9). The parameter (R_{50}) of rocks can be determined from the capillary curve of the rock.

Classification by pore connectivity

During the process of sediment lithification, sediments underwent various geologic processes. These processes will change rock texture and characterize a rock on microscopic scale, for example the cementation between particles, dissolution of minerals, recrystallization, and so on. After these variations, the void space in reservoir rocks changes greatly in pore-size, pore connectivity, and so on throughout the reservoirs.

In reservoir rocks, generally, most of pores are well interconnected, which provides continuous channels for fluid flow; but there is always a small amount of pores that are not connected or isolated due to various geologic variations in the rocks. In loose sand, all voids are interconnected, whereas part of pores in limestones, dolomites, and sandstones may be completely sealed off from the other pores, or blind (dead-end). Based on the connectivity of pores, consequently, the void space in rocks can be divided into: interconnected pore, isolated pore, and blind pore (Fig. 2.15).

Table 2.9 Pore types classified by the median radius of pore-throats (SYT 6285-2011 China)

Type	Median radius of pore-throats (R_{50}) (μm)
Extra-large pore	$R_{50} \geq 25$
Large pore	$15 \leq R_{50} < 25$
Median pore	$5 \leq R_{50} < 15$
Small pore	$3 \leq R_{50} < 5$
Ultra-small pore	$R_{50} < 3$

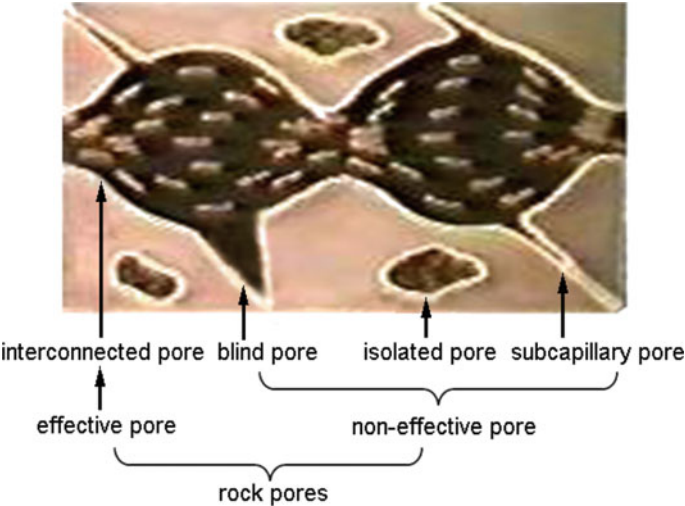


Fig. 2.15 Schematic diagram of pore types

Perceptibly, the pores that are not part of a continuous channel network do not contribute to oil and gas production. These pores are known as noneffective pores (Fig. 2.15), namely, they provide no space for fluid flow in reservoirs. Noneffective pores are not considered in the estimation of petroleum reserves. As a result, the measure of interconnected pore volume as opposed to total pore volume is of more interest to reservoir engineers in estimating producible fluid volume and analyzing reservoir performance.

In a word, interconnected supercapillary and capillary pores are effective for petroleum production, but interconnected subcapillary pores may be effective depending on gas or oil flowing in these pores. Whether it is gas flowing, or oil flowing, isolated pores are noneffective.

Classification by void shape

As viewed from the shapes, the void space of reservoir rocks may be classified to two sorts: pore/cave and fracture (Table 2.10). The former has a lower ratio of length to width, including primary and secondary pores. The latter has a higher ratio of length to width. Pore/cave is more or less tubular while fracture is round about fissuriform.

Table 2.10 Pore types classified by void shape (SYT 6285-2011, China)

Type		Length/width of void	Diameter of void, mm
Pore or cave	Pore	1:1—<10:1	<2
	Cave		≥ 2
Fracture		≥ 10:1	

In carbonate rocks, various pore types (pore, fracture and dissolved cavern) can be found. Pore means the voids between carbonate particles. It is often primary. Dissolved cavern is a secondary pore formed by the dissolution of groundwater. In general, dissolved caverns are larger than pores in carbonate rocks.

2.2.1.2 Types of Reservoir Space

In petroleum reservoirs, *reservoir space* means the void system which can hold gas or oil. Reservoir space may be composed of one of the three void types: pore, fracture, dissolved cavern, or free combination of the three void types. Reservoir space is thus complicated. Different combinations of void types form different types of reservoir space, in which fluids have different flow patterns. Both the types of reservoir space and flow patterns of fluids are very concerned by reservoir engineers, they are the important foundation of reservoir engineering calculation and have a great effect on the oil recovery.

Based on the combination type of voids, reservoir space of petroleum reservoirs can be classified as: single-porosity medium, dual-porosity medium, and triple-porosity medium.

Single-porosity medium means that the reservoir space of petroleum reservoirs consists of one type of voids. It may be single-pore, single-fracture, or single-dissolved cavern system. In this kind of reservoir, fluids are held and flow in the same void space.

The reservoir of dual-porosity medium has two types of voids. It may be pore-fracture system, dissolved cavern-pore system, or fracture-dissolved cavern system. For example, if a rock contains both fracture network and intergranular pores (e.g., a sandstone), the rock is called dual-porosity medium.

In a dual-porosity reservoir, such as a pore-fracture reservoir, the pores are customarily the space holding oil or gas, whereas the fracture network mainly acts as the flow passage of oil or gas. The flow through the fractures is accompanied by the exchange of fluid from and to the surrounding porous rock matrix. Exchange between the fracture network and the porous block (matrix) is normally represented by a term that describes the rate of mass transfer. The physical parameters of both the fracture and block are needed to be defined at each mathematical point in the flow domain. As a result, dual porosity and dual permeability are necessary to characterize the properties of this kind of reservoir. At present, this kind of reservoir is mainly found in carbonate rock, especially in limestone or dolomite. Such reservoirs exist extensively in carbonate rocks in Sichuan gas field of China.

Triple-porosity medium is the most complicated petroleum reservoir. It consists of three types of voids: intergranular pore, fracture and dissolved cavern/solution cavity. In this reservoir, the flow mechanism of fluids in each type of voids is different. Triple-porosity mediums have been found in Tahe oilfield in Western China.

2.2.1.3 Pore-Size Distribution

The topology of the pore space of a porous medium is very important in determining the properties of the medium. In terms of topology, we may know what size the pores are and how the pores are connected. In general, rock pores can be characterized by the terms: pore size and pore-size distribution.

In oilfield exploitation, pore size and its distribution of a reservoir rock are the significant foundation of recognizing the properties of reservoir rocks, and have a very important effect on reservoir behavior with respect to single-phase or multi-phase flow in the reservoir. Therefore, this kind of information is absolutely indispensable to recognize the mechanism of fluids flowing through porous mediums.

The number of discrete pores in a conventional reservoir of a cubic meter is enormous. Since the average diameter of particles in most sandstones is between 0.05 and 0.25 mm, the number of pores in a cubic meter rock may be between 10^9 and 10^{12} because the pores in most sandstones have radii between 20 and 200 μ . Moreover, the pore size in sandstone reservoirs is also extremely heterogeneous. Evidently, it is impossible to analyze the pore size in a rock one by one. The best way to investigate pore size is statistical analysis, by which one can give the distribution and sorting of a pore system.

In the laboratory, several techniques are commonly used for the analysis of the size and distribution of rock pores. They are mercury injection, thin section analysis, image analysis, gas adsorption, and so on.

Pore-size distribution

In engineering researches, pore size is typically described with a parameter, namely diameter. In real rocks, but, pores are much varied either in size or shape. There is scarcely a pore which is typically spherical. One way to define a “pore size” is by defining the pore diameter at a point within the pore space of rock as the diameter of the largest sphere that contains this point while still remaining entirely within the pore space [22]. Generally, the unit of measure typically associated with pore-size values is micrometers (more commonly referred to as microns), whereby 1 μ m equals 1×10^{-6} m. For reference, a human hair is approximately 25 μ m in diameter.

Pore-size distribution is the fraction of pore volume with respect to pore size. Alternatively, it may be defined by the fraction of pore area with respect to pore size. The former can be obtained from mercury injection analysis; whereas the latter can be determined from thin section analysis.

The measurement techniques (e.g., mercury injection) report pore-size information as a distribution of data points. For this reason, pore-size information is best described graphically, rather than with a single number. The most commonly used is the pore-size distribution curve and pore-size cumulative distribution curve (Fig. 2.16).

Clearly, the pore-size distribution curve, shown in Fig. 2.16, describes visually the size and distribution of rock pores. A sharp peak of distribution curve in

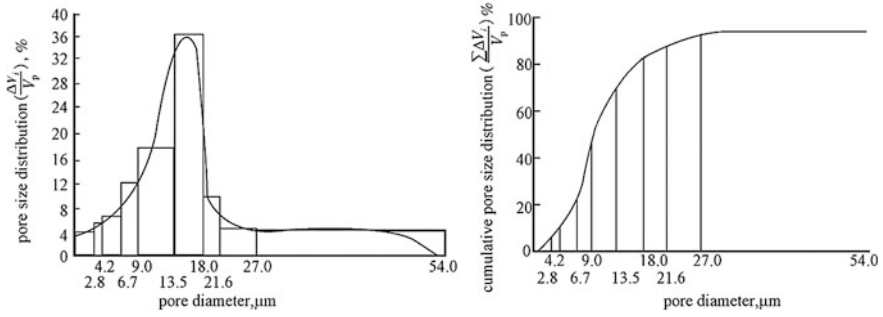


Fig. 2.16 Pore-size distribution curve (a) and pore-size cumulative distribution curve (b)

Fig. 2.16a reflects a uniform pore size (good sorting), yet a flat curve indicates a nonuniform pore size (poor sorting). Similarly, a steep cumulative curve reflects a uniform pore size. Different locations of curves indicate different average pore sizes. Thereby, the pore-size distribution curves can qualitatively characterize the size and distribution of rock pores.

Pore sorting evaluation

Besides pore-size distribution curves, an alternative method of describing pore-size distribution is to use statistical parameters. These parameters can describe the pore-size distribution in more detail. The common parameters include sorting coefficient, skewness and kurtosis, mean pore diameter, etc., they are easily obtained from the pore-size cumulative distribution curve.

Sorting coefficient

Sorting coefficient (S_p) is a standard deviation measure of pore sizes in a rock. It is often used for describing the uniformity of pore-throat sizes, also named uniformity coefficient, generally expressed as follows (Folk and Ward 1957):

$$S_p = \frac{\phi_{84} - \phi_{16}}{4} + \frac{\phi_{95} - \phi_5}{6.6} \quad (2.15)$$

where $\phi_i = -\log_2 d_i$, subscript i represents 5, 16, 84 and 95; d_i is a mean pore diameter corresponding to the i th accumulative pore volume, μm ; The subscript of 5, 16, 84, and 95 separately denotes 5, 16, 84, and 95 % of accumulative pore volume in pore-size cumulative distribution curve.

In general, the smaller the sorting coefficient (S_p), the more uniform the pore-size, and then the better the sorting of the pore-size.

Skewness

Skewness (S_{kp}) is a measure of the asymmetry of pore-size distribution, or the departure from symmetry of a pore-size distribution. It is defined as follows (Folk and Ward 1957):

$$S_{kp} = \frac{\phi_{84} + \phi_{16} - 2\phi_{50}}{2(\phi_{84} - \phi_{16})} + \frac{\phi_{95} + \phi_5 - 2\phi_{50}}{2(\phi_{95} - \phi_5)} \quad (2.16)$$

where S_{kp} is skewness of pore-size distribution; $\phi_i = -\log_2 d_i$, subscript i means 5, 16, 50, 84, and 95; d_i is a mean pore diameter corresponding to the i th accumulative pore volume, μm . The subscript of 5, 16, 50, 84, and 95 denote separately 5, 16, 50, 84, and 95 % of accumulative pore volume.

The asymmetry of a pore-size distribution can be given by its skewness. In general, the skewness of rock pore-size varies between -1 and 1 , namely $-1 < S_{kp} < 1$.

If a pore-size distribution curve is symmetrical (normal distribution), the skewness of rock pores is zero. If skewness is positive, it indicates that the curve has a tail in big pore that is “coarse skewed”; or a negative value indicates that the curve is skewed toward small pores, named “fine skewed.”

Kurtosis

Kurtosis (K_p) is a measure of the degree of peakedness, that is, the ratio between the spread of the pore diameters in the tails and the spread of the pore diameters in the central portion of the distribution (Folk and Ward 1957):

$$K_p = \frac{\phi_{95} - \phi_5}{2.44(\phi_{75} - \phi_{25})} \quad (2.17)$$

where K_p is the kurtosis of pore-size distribution; $\phi_i = -\log_2 d_i$, subscript i means 5, 25, 75, and 95; d_i is a mean pore diameter corresponding to the i th accumulative pore volume, μm ; The subscript of 5, 25, 75, and 95 denote separately 5, 25, 75, and 95 % of accumulative pore volume.

Kurtosis is used for describing the concentration of major pores in a rock. It is also referred to as sharpness.

Generally, normal distribution curve has a K_p of one, called mesokurtic. If the curve is flat or double peaks, K_p may be less than 0.6, called very platykurtic. A curve represented by a high narrow peak (very leptokurtic) may have K_p values ranging from 1.5 to 3.

If rock pores is composed of two or more different void types (such as pore, fracture, even dissolved cavern), double peaks, even multi-peak, will occur on the distribution curve.

Mean pore diameter

Median pore diameter (D_{50}) is the diameter (μm) which is larger than half of the pores in the distribution and smaller than the other half (i.e., the middlemost member of the distribution) [23]. It reflects the overall pore size as influenced by the chemical or physical origin of the rock and any subsequent alteration. It may be a very misleading value, however.

Mean pore diameter (D_m) is the measure of the overall average pore size. It is an arithmetic mean by the pore diameters of a few feature points of pore-size

cumulative distribution curve. The following averaging methods are commonly used [23].

$$D_m = \frac{D_5 + D_{15} + D_{25} + \cdots + D_{85} + D_{95}}{10} \quad (2.18)$$

or

$$D_m = \frac{D_{16} + D_{50} + D_{84}}{3} \quad (2.19)$$

or

$$D_m = \frac{D_{25} + D_{50} + D_{75}}{3} \quad (2.20)$$

In Eqs. (2.18)–(2.20), D_i ($i = 5, 15, 16, 25, 50, 75, 84, 85$, and 90) means the pore diameters corresponding to $5, 15, 16, 25, 50, 75, 84, 85$, and 95 % of cumulative pore volume.

2.2.1.4 Pore Structure

The pore structure of reservoir rocks results from the complex interplay of the various factors that influence the porosity of the reservoir rock. Pore structure means the all characters of whole pore system, including the pore size and shape, the connectivity between pores, the surface roughness of pore-throats, the pore-size distribution, and the connecting pattern of pores. The size, shape, distribution, and communication ways of pores control all mechanic and hydraulic properties of a rock, such as conductivity, deformation behavior, anisotropy, etc.

The pore structure of clastic rocks is mainly affected by several petrographic characteristics, which include: (1) grains: size, shape, sorting, chemical composition, mineral composition; (2) matrix: the amount of each mineral, the distribution of minerals and chemical composition; (3) cement: composition, amount, distribution with respect to grains and matrix. The pore structure of chemical rocks is mostly dependent on the following factors: (1) fossil content, (2) fracturing and jointing, (3) solution and redeposition, (4) dolomite content, (5) recrystallization, (6) clay content, (7) bedding planes.

The size of individual pores ranges from subcapillary through capillary openings to solution cavities of all shapes and sizes, including caverns formed in carbonate rocks.

The individual pore may be tubular, like a capillary tube; or it may be nodular and may feather out into the bounding constrictions between nodules; or it may be a thin, intercrystalline, tabular opening that is 50 – 100 or more times as wide as it is thick [24]. The wall of pore may be clean quartz, chert, or calcite, or it may be coated with clay mineral particles, platy accessory minerals, or rock fragments.

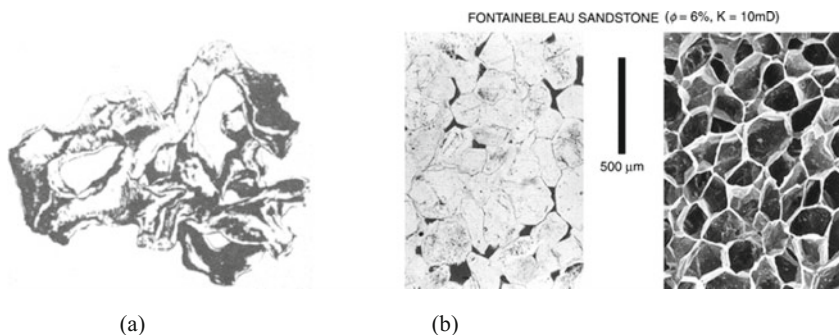
The feature of some individual pores may be observed in well cuttings and cores by the unaided eye. Many pores, however, can be seen only with a binocular or petrographic microscope. More fine detail of pores can be examined through electron micrography because much of the reservoir pores is submicroscopic in size. Pores filled with oil may also be observed under ultraviolet rays. The fluorescence of oil trapped in minute fractures and intercrystalline pores, not visible to the eye, stands out prominently, and pools have been discovered when this was the only way the oil was observed. Casts of the interconnected pores may be made by forcing wax or plastic material under pressure into a core or rock fragment and then dissolving away the surrounding rock material. Such a pore cast of the ordinary reservoir sandstone looks much like a piece of bread, while the cast of a rock with angular grains and crystals has the appearance of rock candy (Fig. 2.17). Photomicrographs of pore casts viewed stereoscopically offer a good means of observing the pore structure (Fig. 2.17b).

Several parameters have been proposed to describe the pore structures of reservoir rocks in the past, such as aspect ratio, coordination number, pore tortuosity, threshold pressure, and so on. The common parameters are described as follows.

Aspect ratio (pore/pore-throat size ratio) is the ratio of pore radius to pore-throat radius [26]. Or it is defined as the ratio of pore diameter to pore-throat size. This is a fundamental control on hydrocarbon displacement [27].

The pore/pore-throat size ratio is a very important factor in estimating recovery efficiency because large pores connected by small pore-throats are difficult to drain [28]. As nonwetting fluids are withdrawn from a system of large pores and small pore-throats, the nonwetting fluid column breaks apart in the narrow throats, leaving a large amount of fluids isolated in the large pores.

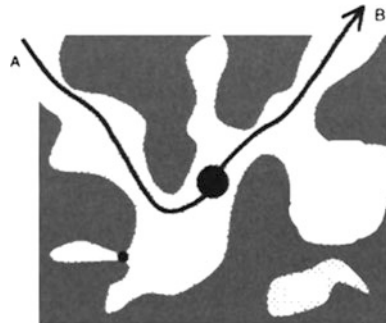
Pore-to-pore accessibility is determined by *coordination number*, or the number of pore-throats that connect with a pore [28]. In general, it ranges between 2 and 15.



(a) Cast of pore space in sandstone (Collins, 25); (b) Thin section (left) and epoxy pore cast (right) of Fontainebleau sandstone (after Zinszner and Pellerin, 2007)

Fig. 2.17 Pore casts retort distillation at atmospheric

Fig. 2.18 Schematic diagram of tortuosity of a path AB in a porous medium (after Christopher and William [30])



The connectivity of a pore network is generally characterized by a coordination number which represents the number of independent paths through which pores are connected to each other. An average coordination number representing the connectivity between constrictions to chamber is an important parameter. In other words, we would like to know, on an average, how many pore constrictions (namely, throats) are connected to a pore chamber. Likewise, there can be a coordination number which represents an average number of pore chambers connected to a pore constriction. A reasonable estimate of an average coordination number for sandstones is between 4 and 8 [28].

Pore tortuosity is defined as the ratio of the effective average path of connected pores in a rock to the straight-line distance of the two end pores measured (Fig. 2.18). It is actually the ratio of the true length of a pore to its projection [29]. The tortuosity has nothing to do with the size of the pores but entirely depends on the connectivity of the pore system. Tortuosity, a dimensionless factor, expresses the degree of complexity of the sinuous pore path. It is not easy to determine directly the value of the parameter. By experience, it is about in the range of 1.2–2.5.

2.2.2 Porosity of Reservoir Rocks

The development of oil and gas reservoirs shows that the void space holding oil or gas is only small part of whole rock volume. Oil or gas is not in the underground lakes or streams of oil which once was a popular idea. Porosity is a measure of the void space of reservoir rocks, and thus represents the storage capacity of the reservoirs. Porosity is the best-known physical characteristic of petroleum reservoirs.

Porosity is very important rock property because it can be used to measure the potential volume of hydrocarbons in reservoir rocks. All recovery computations must be based on the knowledge of this parameter. It is one of the most important reservoir parameters in the study of petroleum reservoir engineering.

2.2.2.1 Porosity

As shown in Fig. 2.19, the total volume of a rock (V_b), also known as bulk volume, or view volume, is composed of the pore volume (V_p) and the solid volume (matrix volume) of rock particles (V_s) (Fig. 2.19), that is:

$$V_b = V_p + V_s \quad (2.21)$$

The porosity of a rock is defined as the ratio of the void volume of the rock to the total volume of the rock, mathematically expressed as:

$$\phi = \frac{V_p}{V_b} \times 100 \% \quad (2.22)$$

where ϕ is the porosity of a rock, %; V_p is the volume of void space in the rock, cm^3 ; V_b is the bulk volume of the rock, cm^3 .

The void space includes all pores, cracks, vugs, inter- and intra-crystalline spaces. The porosity is conventionally given the symbol ϕ , and is expressed either as a fraction varying between 0 and 1, or a percentage varying between 0 and 100 %. The fractional form is often used in engineer calculations.

From Eq. (2.21), we know $V_p = V_b - V_s$. Combine it with Eq. (2.22), then:

$$\phi = \left(1 - \frac{V_s}{V_b} \right) \times 100 \% \quad (2.23)$$

where V_s is the total volume of solid composing the rock matrix, cm^3 .

It should be noted that the porosity does not give any information concerning pore size, pore-size distribution, and pore connectivity. Thus, rocks of the same porosity may have widely different physical properties. An example of this might be a carbonate rock and a sandstone. Each could have a porosity of 0.1, but carbonate pores are often much unconnected resulting in its permeability being much lower

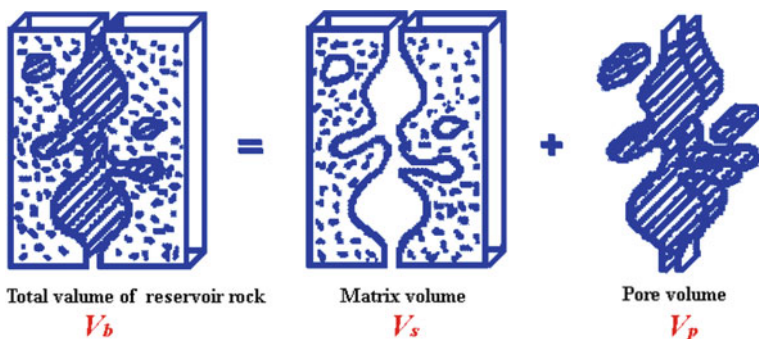


Fig. 2.19 Total volume, matrix volume and pore volume of a reservoir rock

than that of the sandstone. Different definitions of porosity have been recognized and used within the hydrocarbon industry. For example, total porosity, connected porosity, effective porosity, primary porosity, secondary porosity, fracture porosity, etc.

2.2.2.2 Absolute Porosity and Effective Porosity

Absolute porosity is the total porosity. It is defined as the ratio of the total void volume of a rock to the total volume of the rock.

Connected porosity means the ratio of the connected pore volume to the total rock volume.

Effective porosity is the ratio of the effective pore volume to the total rock volume. Here, effective pores means the pores which can transmit fluids in conventional reservoir conditions. Effective pore does not include isolated pores and the tiny pores which are too small to effectively transmit fluids. Even in high quality reservoirs, an appreciable difference between the total porosity and effective porosity often exists. In general, the effective porosity of a rock is less than its absolute porosity in most cases.

It should be emphasized that the effective space of a rock is often not equal to the spaces of fluids flowing actually in the rock due to the effect of adsorption of fluids on the surface of the rock particles. A term “flowing porosity” is thus used to describe the percent of pore volume of fluids really occupying in rock pores when fluids flow through the rock. Flowing porosity may be considered as the fraction of the volume of space occupied by fluids flowing in pores to the rock volume. Flowing pore volume does not contain the space which is occupied by the liquid film adsorbed on the surface of rock particles. Thereby, the flowing porosity is usually less than the effective porosity of a rock; and the flowing porosity is changeable. It often changes with displacement pressure difference, physical properties of fluids, and the surface properties of rock particles.

Effective porosity is of significance in petroleum production. If a rock has a high total porosity, but a low effective porosity (e.g., pumice), the oil in rock could not be recovered even if the rock might conceivably be saturated with oil because the oil could not find effective passages to flow through the rock to a well drilled into the stratum. The effective porosity characterizes the properties of a rock holding and transmitting fluids. In petroleum industry, effective porosity is thus used for calculating the *original oil in place* (OOIP).

Generally, the values of absolute porosity and effective porosity can be determined in the laboratory. It is worth noting that, under normal circumstances, effective porosity is called porosity for short in petroleum engineering.

In addition, the following porosities used in petroleum production should also be known [31]:

Primary porosity: the porosity of the rock resulting from its original deposition.

Secondary porosity: the porosity resulting from diagenesis.

Microporosity: the porosity resident in small pores (<2 mm) commonly associated with detrital and authigenic clays.

Intergranular porosity: the porosity due to pore volume between the rock grains.

Intragranular porosity: the porosity due to voids within the rock grains.

Dissolution porosity: the porosity resulting from dissolution of rock grains.

Intercrystal porosity: microporosity existing along intercrystalline boundaries usually in carbonate rocks.

Moldic porosity: a type of dissolution porosity in carbonate rocks resulting in molds of original grains or fossil remains.

Fenestral porosity: a holey (“bird’s-eye”) porosity in carbonate rocks usually associated with algal mats.

Vug porosity: porosity associated with vugs, commonly in carbonate rocks.

2.2.2.3 The Range of Porosity Values in Nature

In recently deposited sediments, such as those you might find on the floor of a lake, porosity may be very high (values up to 80 % have been recorded). More common materials, such as loose sands, can have porosities as high as 45 %. These materials are either extremely unstable or stabilized by cements. In reservoir rocks, high porosities can also be found due to dissolution (secondary porosity), particularly in carbonates. Generally, porosities can be very low in carbonate rocks. In some cases, the total porosity of carbonate rocks may be very high, but their permeability can be very low as the pores and vugs that make up the pore structure are unconnected. In massy fractured carbonates, the porosity of matrix can be as low as 1 %. Igneous and metamorphic rocks almost always have porosities less than 1 %. Sandstones, generally, lie in the range 5–25 %. Table 2.11 gives the approximate ranges of porosities for some common lithologies.

Table 2.11 The range of porosity values for rocks (after Paul [31])

Lithology	Porosity range (%)
Unconsolidated sands	35–45
Reservoir sandstones	15–35
Compact sandstones	1–15
Compact carbonate rocks	<1–5
Shales	0–45
Clays	0–45
Massive limestones	5–10
Vuggy limestones	10–40
Dolomite	10–30
Chalk	5–40
Granite	<1
Basalt	<0.5
Gneiss	<2
Conglomerate	1–15

Table 2.12 Gradation of reservoir porosity [23]

Clastic rock		Carbonate rock	
Type of reservoir porosity	Porosity, ϕ (%)	Type of reservoir porosity	Porosity, ϕ (%)
Extremely high porosity	$\phi \geq 30$		
High porosity	$25 \leq \phi < 30$	High porosity	$\phi \geq 20$
Moderate porosity	$15 \leq \phi < 25$	Moderate porosity	$12 \leq \phi < 20$
Low porosity	$10 \leq \phi < 15$	Low porosity	$4 \leq \phi < 12$
Extremely low porosity	$5 \leq \phi < 10$	Extremely low porosity	$\phi < 4$
Ultra-low porosity	$\phi < 5$		

Porosity is a vital parameter of petroleum reserves calculation, reservoir evaluation, and engineering calculation. The classification and evaluation of petroleum reservoirs is also based on the parameter. The gradations of porosity for reservoir rocks are shown in Table 2.12 according to the industry standard of China. Generally, there are different gradation for clastic rocks and carbonate rocks due to different types, size, and scale of pores in the two types of rocks.

2.2.2.4 Dual Porosity*

Dual porosity has been developed in the oil industry to deal with specific problems associated with fractured petroleum reservoirs. In the most general sense, the use of dual porosity indicates that the reservoir has a complex porosity system that can be divided into fracture porosity and a smaller scale porosity that exists in the pore spaces within the rocks [32]. In some cases, this kind of porosity system is referred to as a double porosity system.

In double porosity system, the matrix usually has low permeability but high porosity and thus dominates the storage, while the fracture system has high permeability but low porosity, and dominates fluid flow.

As a general rule, fractured reservoir rocks are made up of two porosity systems: the first intergranular porosity (Fig. 2.20a) formed by void spaces between the

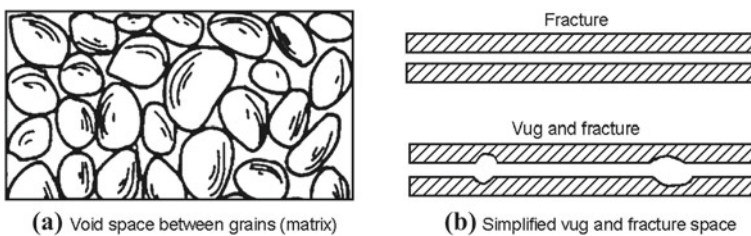


Fig. 2.20 Sketch map of pores, vug and fractures

grains of the rock, and the second formed by void spaces of fractures and vugs (Fig. 2.20b). The first type is called primary porosity and is typical of sandstone or limestone. The second type is called secondary porosity, or vugular porosity (referring to only vugs)/fracture porosity (referring to only fractures).

Secondary porosity is generally found in compact, brittle rocks of relatively low intergranular porosity, such as compact limestones, shales, shaly sandstones, siltstones, schists, etc. Secondary porosity is normally caused by rock fracturing, jointing, and dissolution by circulating water.

In a fractured reservoir, the total porosity (ϕ_t) is the result of the simple addition of the primary and secondary porosities:

$$\phi_t = \phi_p + \phi_f \quad (2.24)$$

where ϕ_p = matrix void volume/total bulk volume, called primary porosity; ϕ_f = fracture void volume/total bulk volume, named fracture porosity.

From the experimental results of porosity measurements on various types of rocks, it can be found that the fracture porosity of a rock is generally considerably less than the primary porosity of the rock.

We should note that the two porosities (ϕ_p , ϕ_f) are defined based on the total bulk (matrix + fractures) volume of a rock. However, it is not easy to obtain a typical core of a dual-porosity system in practice. The cores used to measure in the laboratory are usually from the part of the matrix of a fractured rock. The porosity of the rock determined in the laboratory is therefore referred to as matrix porosity (ϕ_m) because it is only related with the matrix volume of the fractured rock. So, the matrix porosity (ϕ_m) is defined as follows:

$$\phi_m = \frac{\text{void volume of matrix}}{\text{matrix bulk volume}} \quad (2.25)$$

Suppose the total bulk volume of rock is one unit and the fracture porosity is ϕ_f . The matrix bulk volume is then $(1 - \phi_f)$; and the void volume of matrix is then $(1 - \phi_f)\phi_m$. The fracture and primary porosities are presented schematically in Fig. 2.21, where the unit of bulk is scaled in the upper part. In this case, the primary porosity, as a function of matrix porosity, is expressed by the following equation:

$$\phi_p = \frac{\text{void volume of matrix}}{\text{total bulk volume of rock}} = \frac{(1 - \phi_f)\phi_m}{1} = (1 - \phi_f)\phi_m \quad (2.26)$$

Then the total porosity is:

$$\phi_t = (1 - \phi_f)\phi_m + \phi_f \quad (2.27)$$

By experience, when $\phi_t < 10\%$, the maximum of fracture porosity is often lower than $0.1\phi_t$ ($\phi_{f\max} < 0.1\phi_t$), whereas the maximum of fracture porosity is probably lower than $0.04\phi_t$ ($\phi_{f\max} < 0.04\phi_t$) when $\phi_t > 10\%$. From the reservoir

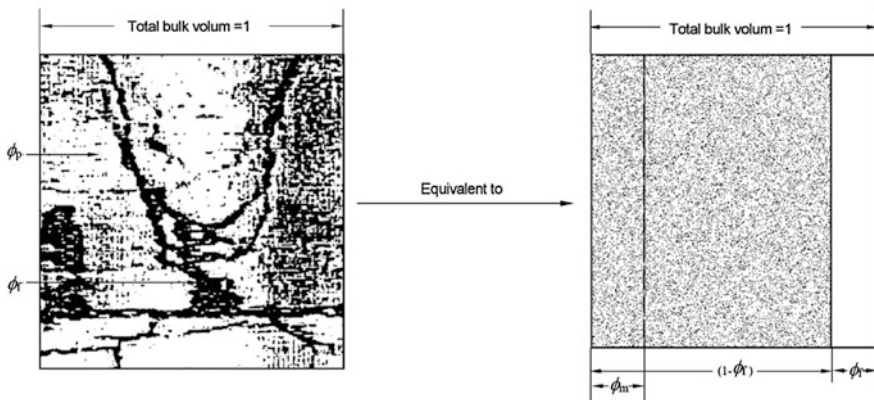


Fig. 2.21 Sketch map of double porosity

space point of view, fracture porosity is much lower than matrix porosity, and sometimes is ignored. However, the existence of fractures is significant for the storage of oil or gas in tight rocks ($\phi_f < 5\%$), especially for the flow of oil or gas in compacted rocks.

2.2.3 Factors Affecting Porosity

Primary pore is the original void space created when the rock was formed in geological processes. The porosity of a rock is created and altered by geological processes, and is thus affected by a host of factors during deposition, as well as in the long periods of the following diagenesis.

The initial (pre-diagenesis) porosity is affected by the following microstructural parameters. They are grain-size, packing pattern of particles, particle shape, and grain-size distribution. However, the initial porosity in real rocks is usually subsequently affected by secondary factors, such as compaction and geochemical diagenetic processes. This section briefly reviews these factors and controls on porosity.

2.2.3.1 Grain-Size and Packing Pattern

In real rocks, the effect of grain-size and packing pattern to porosity is quite intricate by reason of the heterogeneity of grain-size and shape. To simplify this problem, begin with the analysis of porosity determination of an ideal medium.

The ideal medium is an imaginary rock which is packed with spherical grains in same size or not. In theory, the porosity of an ideal medium can be easily calculated by the grain-size.

Suppose an imaginary rock is a regular cubic packing with same size spherical grains (Fig. 2.22a), and the packing is the least compact arrangement (one grain packing on the top of the other). The porosity of the cubic packing is calculated as follows:

Considering the cube filled with eight grains of radius r .

Volume of the cube is: $(4r)^3$.

Total volume of the eight grains in the cube is: $8 \times \frac{4\pi r^3}{3}$

The pore volume of the cubic packing is: $(4r)^3 - 8 \times \frac{4\pi r^3}{3}$

Then the porosity of the cubic packing is:

$$\phi = \frac{V_b - V_s}{V_b} = 1 - \frac{V_s}{V_b} = 1 - \frac{32\pi r^3}{3 \times 64r^3} = 1 - \frac{\pi}{6} = 47.46 \% \quad (2.28)$$

where V_b is the bulk volume of a packing, cm^3 ; V_s is the total volume of grains in the packing, cm^3 .

From here we see that the *maximum* porosity of the cubic packing is 47.6 %, and it is independent of grain-size (Fig. 2.22a). In a similar way, the porosity of the cubic with rhombohedral arrangement (i.e., the most compact arrangement, Fig. 2.22b) can be determined, and is 25.96 %. So, the porosity of an ideal rock may vary from about 26 to 48 % (Fig. 2.22), depending upon the pattern of packing (how the grains are packed together); and the value of the porosity is independent of the grain-size. For real rocks, however, the way of grain packing depends upon the conditions of deposition.

Theoretically, porosity has nothing to do with grain-size for a regular cubic packing with same size spherical grains. This is also true for other ordered packing, but not true for the random arrangement of spherical grains. In real depositional environments, ordered packings cannot be formed because deposition is energetically unstable, and grain-size is heterogeneous. Therefore, it does not prove true in grain assemblages of a real rock due to variable sizes and shapes of rock particles.

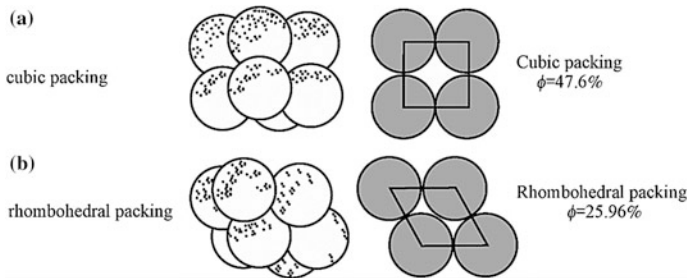


Fig. 2.22 Ideal rock: **a** cubic packing; **b** rhombohedral packing (after Gratton and Fraser)

2.2.3.2 Grain Sorting

Real rocks contain a distribution of various size grains, and the distribution is often multimodal. To understand the effect of grain sorting on porosity, in the same way, consider an ideal rock consisting of two size spherical gains (Fig. 2.23c). It can be figured out that the porosity of the packing does not exceed about 37 %, and the porosity reaches its minimum when packed with the particles of two sizes each in half (Fig. 2.23c).

It can be proved that the porosity of real rocks is always related with the size and sorting of rock particles. In general, well-sorted sediments are more porous and have higher porosity than poorly sorted ones because small grains take up space between large grains (Fig. 2.23). The statistical results of real rocks show that the porosity of rocks is usually decrease with the increase in grain-size. The reason is that fine-grained sediments is well sorted and more spherical than that coarse-grained sediments.

For clastic rocks, a general rule is proved as shown in Fig. 2.24. The increase in porosity only becomes significant when sorting coefficient is lower than 2; and the

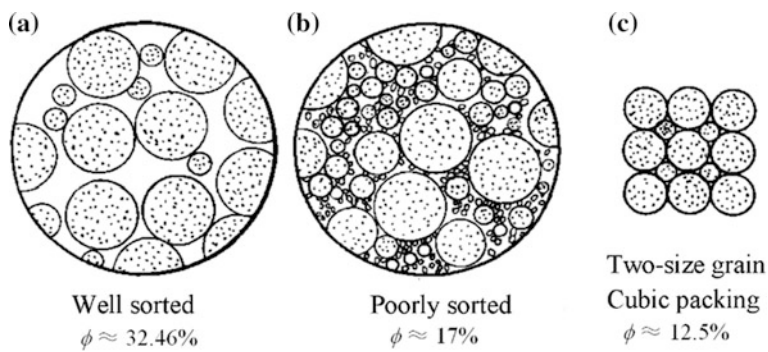
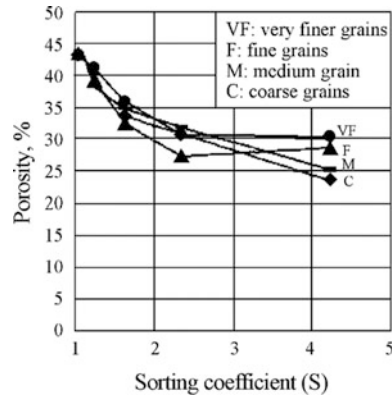


Fig. 2.23 Effect of sorting on porosity (Bear [33])

Fig. 2.24 Correlation between porosity and sorting (Yang et al. [34])



smaller the sorting coefficient is, the larger the porosity of the rock is. As sorting coefficient is close to 1, the influence of grain-size on porosity is weakened. That is to say, the porosity of a rock is independent of grain-size only when grains are very uniform (namely, sorting coefficient ≈ 1).

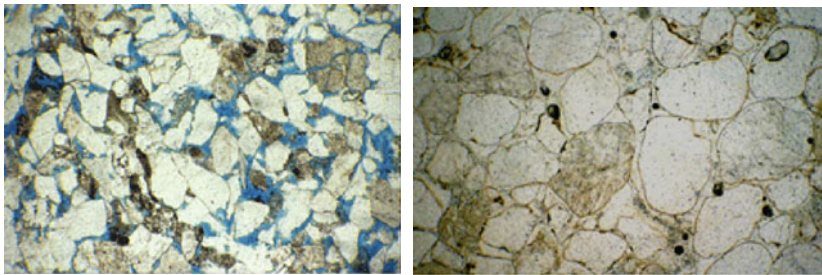
2.2.3.3 Grain Shape

The primary porosity of rocks mainly depends upon the shape (sphericity and roundness), sorting, and packing pattern of sediment particles. Angularity of sediment may increase or decrease porosity, depending if the particles bridge openings or are packed together like pieces of a mosaic [35]. On the whole, porosity often increases with sphericity and roundness of grains, but the maximum porosity often occurs in unconsolidated, subangular, well-sorted sedimentary rocks (Fig. 2.25).

2.2.3.4 Mineral Components of Rocks

Sandstones are commonly composed of five principal ingredients: rock fragments (lithic grains), quartz grains, feldspar grains, matrix, and cement [36]. In sandstones, quartz is the most abundant mineral; feldspar is the next abundant (Table 2.13). Matrix often consists of clay minerals and silt-grade quartz grains. Clay minerals can fill in pores during diagenesis. Cement also precipitates around and between grains during diagenesis [36]. Common cements are argillaceous, calcareous, and siliceous matter. A few of ferruginous matters also exist in clastic rocks.

Owing to the effect of wettability, quartz sandstones are better than feldspar sandstones on the capacity of holding oil. Feldspar often has better wettability than quartz does, which leads to a thicker liquid film on the surface of feldspar particles than on the surface of quartz particles. The liquid films on grain surfaces are usually



Left is a sandstone with very angular grains. The spaces between the grains are filled with blue resin. Right the grains are well rounded. Their rims have a light covering of hematite (red iron oxide), which gives a pinkish tinge to the stone.

Fig. 2.25 Thin section photographs of two sandstones

Table 2.13 Mineral composition of conventional sandstones

Mineral component	Quartz	Feldspar	Clay minerals	Carbonate minerals
Average content (%)	65	10–15	5	<1

Table 2.14 The effect of argillaceous matter to sandstone porosity (杨胜来 2004)

Content of argillaceous cement (%)	<2	2–5	5–10	10–15	15–20
Porosity (%)	28–34	29–31	25–30	<25	<20

immovable. Therefore, the pore space, where fluids are held, is slightly decreased by the liquid films adsorbed on the surface of particles in feldspar sandstones.

Cements in a rock usually reduce rock porosity because part of the voids is occupied by them (Table 2.14). The major components of calcareous cement are calcite and dolomite. Calcareous cement has greater effect on porosity than argillaceous cement. The porosity of sandstones will be sharply decreased as the amount of calcareous matter is higher than about 3 % in a rock.

2.2.3.5 Buried Depth and Compaction

With the increase in depth of reservoir rocks, geostatic pressure and formation temperature gradually increase, the grain arrangement thus becomes more compact. This change means the inelastic and irreversible locomotion occurring on the grain arrangement, the porosity of the rock is then sharp declined. Figure 2.26 shows the relationship between sandstone porosity and the buried depth of the rock.

As overburden pressure is increasing, grains in rocks become increasingly compact. The partial pressolution occurs at the places where grains contact each other. However, dissolved minerals, such as quartz, may also form new crystals in pore, which leads to a further decrease in porosity. In severe cases, it can cause pores to disappear and a rock to lose its permeability.

The relationship between the porosity and buried depth of carbonate rocks is shown in Fig. 2.27. The porosity of carbonate rocks also decreases remarkably with the decrease in depth. Research shows that carbonate sediments deposit in a quite confined environment, and have close relationship with biological action. After diagenesis, carbonate rocks are susceptible to various physicochemical changes in different environments, such as dissolution under groundwater, recrystallization under appropriate temperature and pressure, etc. As a result, multifarious pore patterns may be formed in carbonate rocks; and primary porosity are easy to change because of the effects of environments.

In a word, the factors affecting primary porosity mostly include sedimentary environment, dolomitization, chemical erosion, and tectonic stress.

Compared with sandstones, carbonate rocks are relatively brittle and thus easy to generate fractures by tectonic stress. The total porosity of carbonate rocks is thus greatly increased. Under the same stress conditions, dolomite may generate more fractures, limestone follows, and marl is the worst.

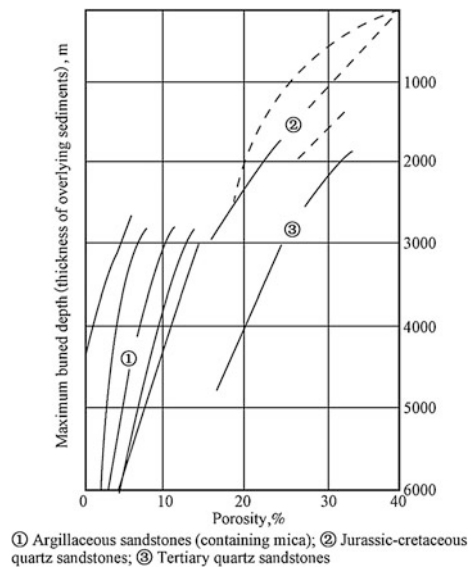
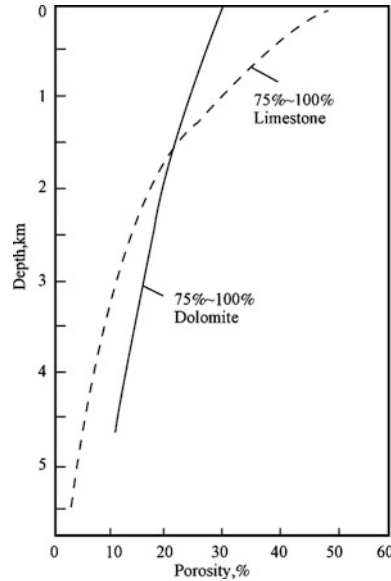


Fig. 2.26 Porosity-depth diagram of sandstone (Mayer-Curr 1978, from [21])

Fig. 2.27 Porosity-depth diagram of carbonate rocks (Schmoker et al. 1982, from [21])



In addition, the solution and transport of dissoluble minerals, such as halite, anhydrite, in sedimentary rocks can also increase the porosity of rocks.

2.2.4 Measurement of Porosity

Rock porosity can be determined with two kinds of techniques: core analysis and well logging. Well logging is an indirect method. It explains rock porosity through the relationship between the electrical characteristics of rocks and porosity. This method involves complex principles, thus not introduced here. The essential method is to measure porosity with a core in the laboratory. The cores are extracted from wells. Generally speaking, the porosity determined with cores is more accurate than that from down-hole tools (e.g., well logging), but suffering from sampling problems [31].

All methods developed for determining porosity in the laboratory are based on the definition of porosity. From the following definition:

$$\phi = \frac{V_p}{V_b} = \left(1 - \frac{V_s}{V_b} \right) \quad (2.29)$$

where ϕ is the porosity of a rock, %; V_p is the total pore volume of the rock, cm^3 ; V_b is the bulk rock volume of the rock, cm^3 ; V_s is the total volume of solid particles composing the rock matrix, cm^3 .

We see that rock porosity is related with three basic parameters: bulk volume, pore volume, or particle/matrix volume. It can be easily determined according to any two of the three parameters. The techniques used to measure these parameters are simply described as follows.

In these techniques, the sample should be clear and dry. The sample may be either a regular geometric shape (cube, cylinder) or any other shape.

2.2.4.1 Measurement of Bulk Volume V_b

The bulk volume of a sample can be determined by either a vernier caliper or other methods depending on the geometry of the sample is regular or not.

The common methods are: (i) vernier calipers, (ii) Archimedes' method (coating the sample with paraffin; saturating the sample with kerosene), and (iii) fluid displacement (mercury measurement) [37].

Vernier caliper

This method is only suitable for this kind of sample which has a regular geometry (cube or cylinder) and is not chipped or notched. The precision of the common vernier caliper is 0.02 mm (SY/T 5536-1996, China). If the sample is a perfect, smooth cylinder, the length and diameter measured by a caliper can give a very

accurate bulk volume of the sample [31]. Note that the results should be the arithmetic average of several measurements but not one measuring. Repeatability and accuracy of measuring mainly depend on the surface texture of the sample.

In the repeat helium expansion determinations of porosity on regular samples, the caliper bulk volume of the samples with smooth surface textures is used, and the measuring precision should fall within ± 0.3 porosity percent regardless of actual porosity [31]. Inaccuracies can arise with samples having very high permeability. High-permeability sandstones are usually friable, and have large pore size. Such rocks do not produce smooth surface texture when cylinder plugs are drilled, and the accurate determination of sample bulk volumes becomes difficult. Therefore, the caliper bulk volume of such samples is less accurate, and other methods for bulk volume should be used.

Archimedes Method—coating the sample with paraffin

It is a gravimetric method ground on Archimedes' principle, and has higher accurate for bulk volume measurement. The procedure of measurement is simply described as follows:

- (a) Clean and dry a rock sample.
- (b) Weigh the sample in its dry state to give the dry weight, w_1 .
- (c) Coat the sample with a thin layer of paraffin in melted paraffin to make it waterproof.
- (d) Weigh the coated sample in air and give the weight, w_2 ;
- (e) Immerse the coated sample into water, and weigh it in water, then give the weight, w_3 .

Clearly, w_3 is less than w_2 . The loss of the weight of the sample in water is caused by the buoyancy of water. It is the weight of water displaced by the immersed sample.

The volume of water displaced by the sample is just equivalent to the volume of the immersed sample. So, the bulk volume of the sample can be determined according to the volume of the coated sample and the volume of the paraffin layer on the sample's surface. Namely, it is:

$$V_b = \frac{w_2 - w_3}{\rho_w} - \frac{w_2 - w_1}{\rho_p} \quad (2.30)$$

where V_b is the bulk volume of the sample, cm^3 ; ρ_w is water density, g/cm^3 ; ρ_p is paraffin density, g/cm^3 .

The method is mainly developed for loose, poorly consolidated, or easily collapsed and crashed rocks. The shape of samples may be irregular. As a result, this method finds wide applicability in oilfields.

Archimedes Method-saturating the sample with kerosene

An alternative method for bulk volume measurement is way based on the sample fully saturated with kerosene. A dried sample is first weighed in air, then fully saturated it with a given-density kerosene. Suspended under a balance, the saturated sample is weighed in air, and then in the kerosene in which the sample is saturated. The weights of the saturated sample in air and in kerosene are denoted by W_{dry} and W_{sus} , respectively.

According to Archimedes' principle, the buoyance acting on the sample in kerosene is equal to the weight of kerosene displaced by the suspended sample. The bulk volume of the sample can then be determined by the following formula:

$$V_b = \frac{W_{\text{dry}} - W_{\text{sus}}}{\rho_o} \quad (2.31)$$

where W_{dry} is the weight of the saturated sample in air, g; W_{sus} is the weight of the saturated sample in kerosene, g; ρ_o is the density of kerosene, g/cm^3 .

This method allows the bulk volume of any irregular sample to be found accurately, but the sample cannot be collapsed or crashed.

Note that there are few sources of significant error in this method, provided no fluid drains from the plug whilst it is weighed in air [31]. The most difficult thing is determining how much excess fluid should be removed from the surface of the plug, especially for Vuggy limestones. This kind of sample should use special analysis method, namely *whole core (full-diameter core) measurements*.

Fluid Displacement

This method notes the displacement of fluids on a graduated scale when the rock sample is placed in a container containing the fluid. If the fluid automatically enters the pores, the result loses its veracity. Mercury is usually used as a measuring fluid. The fluid used for saturating the sample can also be used as the displacing fluid.

The apparatus for mercury displacement is shown in Fig. 2.28. The sample is first placed in the test chamber, then mercury is pumped into the chamber, which leads to the sample being immersed in mercury. The bulk volume of the sample is thus the difference between chamber volume and mercury volume pumped into the chamber. So, the bulk volume of a sample can be rapidly measured.

Under normal circumstances, mercury cannot penetrate into the voids of conventional rocks due to mercury molecules bigger than rock pores. However, it may

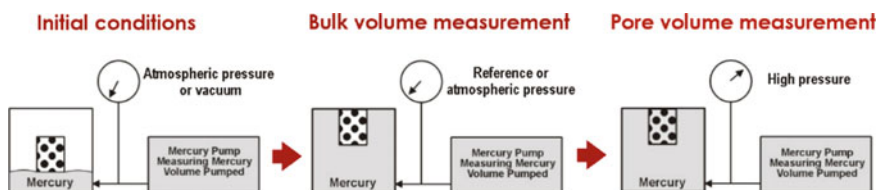


Fig. 2.28 Mercury injection apparatus (Paul [31])

give erroneous results if the sample has large pores or fractures. In addition, there is also a tendency to give a high bulk volume if any air is trapped on the surface of the sample.

Accordingly, this method is valid only if no mercury enters the voids of the sample. This method is appropriate for the measurement of irregular samples. It is worth noting that after measurement, the sample can no longer be used for other experiments and must be safely disposed of.

2.2.4.2 Measurement of Pore Volume V_p

In addition to determining the porosity, pore volume is also a vital rock parameter in various dynamic investigation of petroleum reservoir engineering, such as flow test, displacement test, and the study on microscopic mechanism of enhanced oil recovery (EOR), etc.

In the laboratory, the determination of the pore volume of a rock is chiefly based on the measurement of the volume of fluid contained in the rock. Many methods can be used to measure the pore volume of a rock. The common methods include (i) gas porosimetry, (ii) Liquid saturation method, (iii) buoyancy method, and (iv) mercury injection [37].

Different fluids, such as gas, kerosene, have different molecular size. Therefore, the results measured using different fluids are very different. Because gas can enter very small pores, e.g., subcapillary pores, the pore volume measured using gas is very close to the total pore volume of a sample. Kerosene, however, can only enter bigger pores, e.g., capillary and supercapillary pores, which leads to the result equivalent to the effective pore volume of the sample.

Gas porosimeter

Gas porosimeter is shown in Fig. 2.29. It consists of two chambers connected by tubing equipped with a valve. A clean and dried core sample should be prepared in advance.

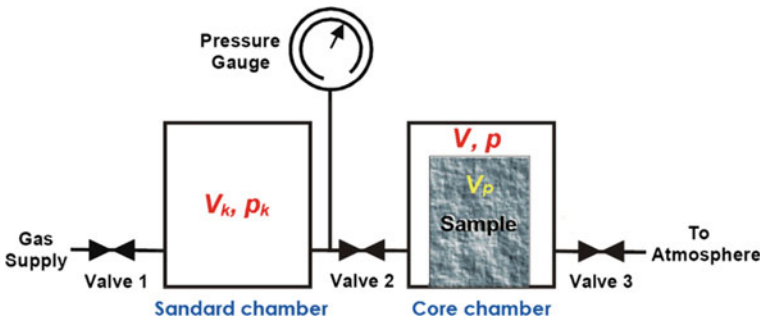


Fig. 2.29 Principle diagram of gas porosimeter

This method relies on the ideal gas law, or rather Boyle's law. The dried sample is sealed in a core chamber of given volume (V) at atmospheric pressure (p_{0030}) (Fig. 2.29). Be careful, no void space between the sample and the wall of the chamber should be remained. This chamber is attached by a valve to another chamber (standard chamber) of given volume (V_k). The standard chamber is filled with gas at a given pressure (p_k). After the valve between the two chambers is slowly opened, the gas of standard chamber expands tardily to the core chamber at isothermal conditions. When the pressure of gas in the two chambers arrives a stable value, e.g., p , the volume of gas expanding to the core chamber is equal to the pore volume (V_p) of the sample. In terms of Boyle's Law, the pressure times the volume for a gas is constant. Thus Boyle's law can be written for the equilibrium system as follows:

$$V_k \cdot p_k = p(V_k - V_p) \quad (2.32)$$

The pore volume V_p is then determined by the following expression:

$$V_p = \frac{V_k(p_k - p)}{p} \quad (2.33)$$

where V_k is the volume of standard chamber, cm^3 ; p_k is the pressure of standard chamber before gas expanding, MPa; p is the pressure of the system after gas expanding, MPa; V is the volume of gas expanding to the core chamber, cm^3 ; V_p is the pore volume of the sample, cm^3 .

Any gas can be used, but the commonest is helium. The porosity determined by this method is known as "gas porosity." Despite the fact that the pore volume measured by this method is the connected pore volume of a rock, the value of the porosity calculated by this pore volume is regarded as the total porosity of the rock in respect that gas molecules (e.g., helium) are so small to enter almost all pores.

Consequently this method gives higher porosities than fluid saturation method and mercury injection method do. The method is fast, accurate, insensitive to mineralogy, and leaves the sample available for further petrophysical analysis. It can also be used to irregular samples. Inaccuracies may arise when samples are very low porosity. Low-permeability samples require longer equilibration times to allow helium to diffuse into the narrow pores.

Liquid saturation method [31]

This method measures the effective (connected) pore volume of the rock on because it is based on measuring the volume of fluid saturating the rock. The procedure of this method is as follows:

- (a) Clean and dry a rock sample.
- (b) Weigh the sample in its dry state to give the dry weight, W_{dry} .
- (c) Fully saturate the sample in a wetting fluid. Conventionally toluene, dichloromethane or kerosene are used, but now it is more common to saturate the sample with a synthetic brine which is similar to the formation water in

reservoir conditions, i.e., they contain the same concentrations of major dissolved salts as the formation water.

- (d) Weigh the saturated sample after drying any excess fluid from its surface to give its saturated weight, W_{sat} .
- (e) Determine the density ρ_{fluid} of the saturating fluid by weighing a given volume of it.

The pore volume is then determined by the following equation:

$$V_p = \frac{W_{\text{sat}} - W_{\text{dry}}}{\rho_{\text{fluid}}} \quad (2.34)$$

where W_{dry} is the weight of the rock in its dry state, g; W_{sat} is the weight of the saturated sample in air, g; ρ_{fluid} is the density of fluid saturating the sample, g/cm³.

This method is very simple and easy to operate. However, the volatilization of kerosene may result in errors depending on the time of weighing the sample.

The porosity measured by this method is often named “liquid porosity.”

Buoyancy Method [31]

This method is somewhat similar to the liquid saturation method, and also measures the effective (connected) pore volume of a rock. The apparatus is shown in Fig. 2.30.

The procedure of this method is as follows:

- (a) Clean and dry a rock sample.
- (b) Weigh the sample in its dry state to give the dry weight, W_{dry} .
- (c) Fully saturate the rock in a wetting fluid as before.

Weigh the saturated sample suspended in a bath of the same fluid with which it was saturated to give its suspended weight, W_{sus} . This is shown in Fig. 2.30. Note

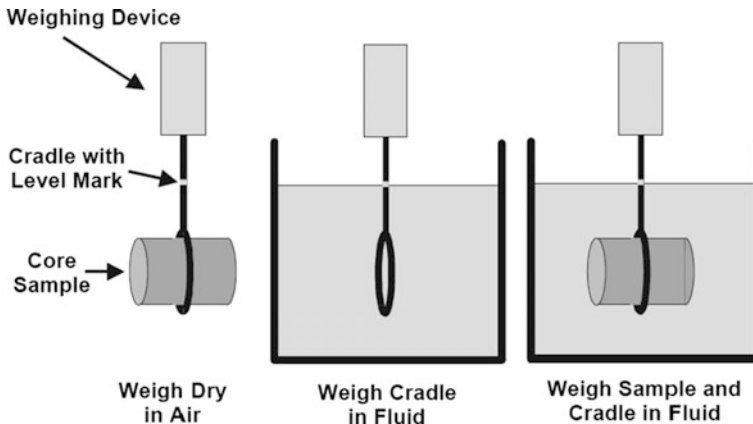


Fig. 2.30 The buoyancy method for porosity determination

that a cradle is needed to suspend the sample in the fluid, and this has a weight W_{cradle} when in the fluid. So the actual measured weight when the sample and cradle are suspended in the fluid is $(W_{\text{sus}} + W_{\text{cradle}})$. The effect of the cradle must be taken away, hence the weight of the cradle when suspended in the fluid (up to the same level), W_{cradle} , must be taken account of in the final calculation.

Determine the density ρ_{fluid} of the saturating fluid by weighing a known volume of it.

The pore volume is then obtained by the following expression:

$$V_p = V_{\text{bulk}} - V_{\text{matrix}} = V_{\text{bulk}} - \frac{(W_{\text{dry}} - (W_{\text{sus}} + W_{\text{cradle}}) + W_{\text{cradle}})}{\rho_{\text{fluid}}} \quad (2.35)$$

where V_{bulk} is the bulk volume of the sample, cm^3 ; V_{matrix} is the volume of solid particles composing the rock matrix, cm^3 ; W_{dry} is the weight of the rock in its dry state, g; W_{sus} is the weight of the saturated sample in the same fluid with which it was saturated, g; W_{cradle} is the weight of the cradle suspending the sample in the fluid, g; $W_{\text{sus}} + W_{\text{cradle}}$ means the total weight of the sample and cradle when they are suspended in the fluid, g; ρ_{fluid} is the density of fluid saturating the sample, g/cm^3 .

Mercury injection [31]

The rock is evacuated and then immersed in mercury. At laboratory pressures, mercury will not enter the pores of most rocks. Mercury displacement can therefore be used to calculate the bulk volume of the rock. However, the pressure on the mercury is raised in a stepwise fashion, which can force the mercury into the pores of the rock (Fig. 2.28). If the pressure is high enough, the mercury will invade all the pores. A measurement of the amount of mercury lost into the rock provides the pore volume directly. The porosity can then be calculated from the bulk volume and the pore volume. Clearly this method also measures the connected porosity. In practice, there is always a small pore volume that is not accessed by the mercury even at the highest pressures. This is pore volume that is in the form of the minutest pores. So the mercury injection method will give a lower porosity than the two methods described above. This is a moderately accurate method. It has the advantage that it can be done on small irregular samples of rocks, and the disadvantage that the sample must be disposed of safely after the test.

Other Techniques

Other techniques include (i) analyzing all evolved fluids (gas + water + oil) and assuming that their volume is equal to the volume of the pore space, (ii) CT scanning, and (iii) NMR techniques [31].

2.2.4.3 Measurement of Matrix Volume

The matrix/solid volume of a rock sample may be measured either by gas porosimeter, or by immersion method.

Gas porosimeter

The principle of measuring the matrix volume of a sample is the same as that of measuring pore volume by gas porosimeter (Fig. 2.29). First, the dry sample is introduced in the core chamber (no core sleeve) of given volume (V). The residual void volume in the core chamber is the chamber volume (V) minus the total solid volume of the sample (V_s). In the same way, open the valve between the two chambers slowly, and let gas expands from core chamber to another at constant temperature. The pressure of the system is p when gas expansion arrives to an equilibrium state. The Boyle's law is then written for the equilibrium system as follows:

$$V_k \cdot p_k = p(V_k + V - V_s) \quad V_k \cdot p_k = p(V_k + V - V_s) \quad (2.36)$$

The solid volume V_s can be calculated by the following expression:

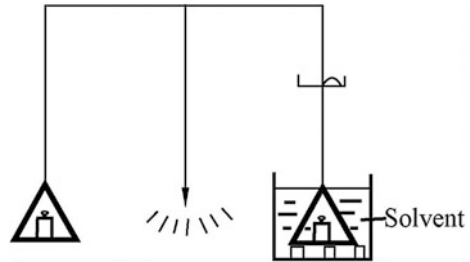
$$V_s = V - \frac{V_k(p_k - p)}{p} \quad (2.37)$$

where V_k is the volume of standard chamber, cm^3 ; p_k is the pressure of standard chamber at initial state, MPa; p is the pressure of the system at equilibrium state, MPa; V is the volume of core chamber, cm^3 .

Immersion method

The solid volume V_s can also be determined by the buoyancy effecting on the solid matrix of the sample immersed in a liquid (Fig. 2.31). First of all, weigh the sample in its dry state to give the dry weight, W_{dry} . Then fully saturate the sample in a wetting fluid with a density ρ at measurement temperature. After that, suspend the saturated sample in the same liquid, and weigh the saturated sample in the liquid to give its suspended weight, W_{sus} .

Fig. 2.31 Apparatus of immersion method



The solid volume V_s can be calculated by the following formula:

$$V_s = \frac{W_{\text{dry}} - W_{\text{sus}}}{\rho} \quad (2.38)$$

where W_{dry} is the weight of the sample in its dry state, g; W_{sus} is the weight of the saturated sample in the same fluid with which it was saturated, g; ρ is the density of fluid saturating the sample, g/cm³.

Owing to the buoyancy is dependent of the density of liquid, carbon tetrachloride (CCl_4 , $\rho_{20^\circ\text{C}} = 1.6$) or chlorothene NU ($\text{C}_2\text{H}_3\text{Cl}_3$, $\rho_{20^\circ\text{C}} = 1.32$) are commonly used. The former is heavier and much more toxic than the latter.

2.2.4.4 Unconsolidated Core Analysis

Unconsolidated core means the loose or weakly cemented rock cores in which there is no or few cement between the particles in the rocks (Fig. 2.32).

As shallow hydrocarbon reservoirs becomes increasingly common, friable, or unconsolidated core is often encountered. Unconsolidated core gives rise to particular problems in coring, storage, handling, plugging, and analysis [31].

Unconsolidated sand is arguably the most difficult material to work with in core analysis. Its extremely friable nature means that any rough handling damages the pore structure irreversibly, and samples can turn into a pile of mud in your hand. In order to obtain results which accurately reflect reservoir properties, extreme care must be taken during every step of coring, handling, transportation, and preparation. Additionally, laboratory equipment and procedures need to be specially designed to minimize sample disturbance.

The most common way of handling, shipping, storage, and plugging this type of core is in a frozen state [31]. The core is frozen with liquid nitrogen or dry ice as soon as it emerges from the coring barrel. It is then placed in a special core holder for next pretreatment of the core and relevant measurements.

Before analysis, an unconsolidated core is necessary to be especially treated by some encapsulating materials which can undergo washing, sample preparation, and

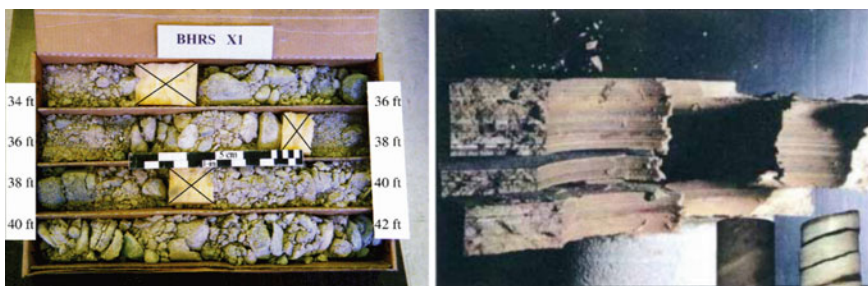


Fig. 2.32 Unconsolidated cores

measurement. Research is being conducted around the world to find materials that can stabilize and protect the unconsolidated sample. Various organic compounds and other materials are available as shown in Table 2.15.

What materials can be selected for protecting unconsolidated cores depends on the proposed core analysis programs. Techniques have been developed to protect friable rocks during all stages of sample preparation. With careful selection and application, these techniques can help provide accurate core analysis data.

In measurements, in order to let the fluids to easily flow through the core and not damage the core, the two ends of the core should be enveloped by screen clothes or other porous materials. The opening size of screen clothes should not only be small enough to prevent the particles in the sample flow away, but also be large enough to keep the moving particles away from blocking the screen opening. Commonly used screens are 200 mesh or 120 mesh.

Generally, two or more layers of screens are suggested to use for unconsolidated cores. If two layers of screens are used, one should be fine openings for preventing the particles flow away, and another is bigger openings for increasing the strength of the cover.

Furthermore, there should not be any chemical reactions between the screen materials and the solvents (e.g., brine) used in the process of washing and testing the cores. Therefore, the screen made of high quality rustless steel is often used.

When an unconsolidated sample is strictly treated by enveloped material and screen clothes, it can be measured with the same methods for conventional rocks.

Table 2.15 Various encapsulating materials for unconsolidated cores (He and Tang [38])

Material	Advantage	Disadvantage
Lead sleeve	Malleable, good adhesion to samples	Reacting with some brines and mercury
Teflon tape	No chemical reaction with other substances	Difficult to accurately determine porosity and permeability
Heat-shrinkable Teflon tube	No chemical reaction with other substances, easy to use	Poor adhesion to rock samples at low confining pressure. Samples are probably distorted due to tube shrinking under heating and pressurizing
Aluminum sleeve	Malleable, good adhesion to samples	At low confining pressure, reacting with some brines may results in poor adhesion to the sample
Epoxy paint or other coating material	Cheap, easy to use	Dissolving in organic solvents, poor mechanical strength, and probably seeping into the sample
Tin coating	Malleable, good adhesion to samples	Reacting with some brines and mercury

2.2.5 Representative Elementary Volume

2.2.5.1 Representative Elementary Volume (REV)

Application of the macroscopic laws in physics to porous media assumes that these media are interiorly continuous. That to say, the values of physical properties (porosity, permeability, saturation) of a porous medium can be defined at each point of the medium as a differentiable function of the point considered. Discontinuity, however, is the fundamental characteristic of a porous medium since at microscopic scale a point is either in the solid or in the void space, if we take the variable “porosity” as an example. The problem of discontinuities is quite common in physics, but what makes porous media so special is that the dimensions of the minimum volumes to be taken into account in order to include the effect of these discontinuities may vary considerably in the same medium, depending on the property considered.

Let O be a mathematical point inside the domain occupied by the porous medium. Consider a volume ΔV_i (say, having the shape of a sphere) much larger than a single pore or grain, for which O is the centroid. For this volume, we may determine the porosity of the medium:

$$\phi_i = (\Delta V_p)_i / \Delta V_i \quad (2.39)$$

where ΔV_i is the given volume of a medium, cm^3 ; $(\Delta V_p)_i$ is the volume of void space within ΔV_i , cm^3 .

To determine how small ΔV_i should be in order for ϕ_i to represent the porosity in the neighborhood of O , a sequence of values ΔV_i , $i = 1, 2, 3, \dots$ may be obtained by gradually shrinking the size of ΔV_i , around O as a centroid: $\Delta V_1 > \Delta V_2 > \Delta V_3 \dots$.

For large values of ΔV_i , the porosity ϕ_i may undergo gradual changes as ΔV_i is reduced, especially when the considered domain is inhomogeneous (e.g., layers of sandstone). Below a certain value of ΔV_i depending on the distance of O from boundaries of inhomogeneity, these changes or fluctuations tend to decay, leaving only small-amplitude fluctuations that are due to the random distribution of pore sizes in the neighborhood of O . However, below a certain value ΔV_0 we suddenly observe large fluctuations in the porosity ϕ_i . This happens as the dimensions of ΔV_i approach those of a single pore. Finally, as $\Delta V_i \rightarrow 0$, converging on the mathematical point O , ϕ_i will become either one or zero, depending on whether O is inside a pore or inside the solid matrix of the medium. Figure 2.33 shows the relationship between ϕ_i and ΔV_i .

The porosity ϕ_i of the medium at point O is defined as the limit of the ratio $(\Delta V_p)_i / \Delta V_i$, as $\Delta V_i \rightarrow \Delta V_0$:

$$\phi(O) = \lim_{\Delta V_i \rightarrow \Delta V_0} \phi_i(O) = \lim_{\Delta V_i \rightarrow \Delta V_0} \frac{[(\Delta V_p)_i(O)]}{\Delta V_i} \quad (2.40)$$

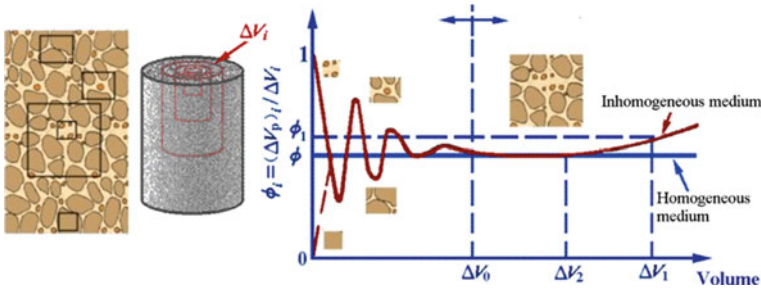


Fig. 2.33 Representative elementary volume (modified after Bear [33])

For values of $\Delta V_i < \Delta V_0$, we must consider the actual presence of pores and solid particles; in this range there is no single value that can represent the porosity at O (Fig. 2.33). The volume ΔV_0 is therefore the representative elementary volume (REV) or the physical (or material) point of the porous medium at the mathematical point O .

The limiting process in Eq. (2.40) is sometimes called the extrapolated limit. Obviously, the limit $\Delta V_i \rightarrow 0$ is meaningless. From the definition of the REV it follows that its dimensions are such that the effect of adding or subtracting one or several pores has no significant influence on the value of ϕ .

We shall assume that both ΔV_0 and ΔV_p vary smoothly in the vicinity of O . Then:

$$\phi(O) = \lim_{O \rightarrow O'} \phi(O') \quad (2.41)$$

The expression means that it is a continuous function of the position of O within the porous medium.

Thus, by introducing the concept of porosity and the definition of REV, we have replaced the actual medium by a fictitious continuum in which we may assign values of any property (whether of the medium or of the fluids filling the void space) to any mathematical point in it.

2.2.5.2 Significance of REV

REV means the smallest rock's volume whose properties can characterize the average physical properties of the reservoir rock.

Based on the concept of REV, we can use small samples to measure the physical properties (e.g., porosity, permeability, and saturation) of conventional rocks. Small core is drilled from full-diameter cores, and also called conventional core or core plug which is generally less than 1 inch (2.54 cm) in diameter (Fig. 2.34). But for these rocks having large-size fractures or dissolved caverns, whole cores

Fig. 2.34 Full diameter core and core plugs cut for laboratory measurements



(full-diameter core) are necessary for the measurement of physical properties of rocks. Full-diameter core is the core taken at the time of well drilling (Fig. 2.34).

2.2.6 Compressibility of Reservoir Rocks

Rocks when buried at reservoir depths are subject to both internal and external stresses (Fig. 2.35). The internal stress results from the pressure of fluids in rock pores. The external stresses are exerted by the weight of the overburden (overlying formations) and any accompanying tectonic stresses. Overburden pressures vary from area to area depending on factors such as depth, nature of the structure, consolidation of the formation, and possibly the geologic age and history of the rocks [39]. Depth of the formation is the most important consideration, and a typical value of overburden pressure is approximately 0.023 MPa per meter of depth [39].

The weight of the overburden simply applies a compressive force to the reservoir. The pressure in the rock pore spaces does not normally approach the overburden pressure. A typical pore pressure, commonly referred to as the reservoir pressure, is approximately 0.01 MPa per meter of depth, assuming that the reservoir is sufficiently consolidated so the overburden pressure is not transmitted to the fluids in the pore spaces [39].

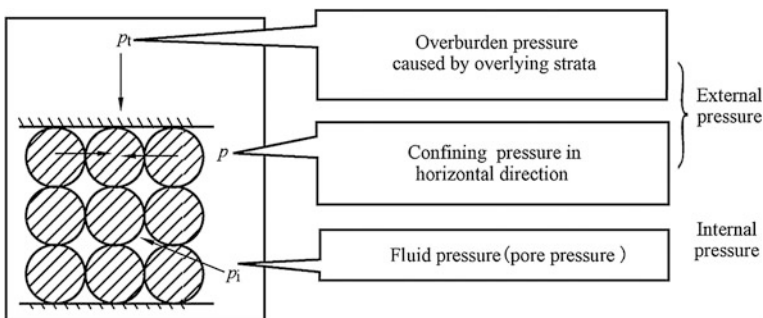


Fig. 2.35 Schematic diagram of stresses in reservoir

Before production, internal pressure (pore pressure) and external pressure (overburden pressure, confining pressure) in reservoirs maintain balance each other. Once the reservoir is disturbed by drilling and consequently production, the pressure balance is broken.

The pressure difference between overburden and internal pore pressure is referred to as the *effective overburden pressure* [39]. During pressure depletion (oil reservoir production), the initial pore pressure decreases and the effective overburden pressure increases since the overburden load remains constant. This increase in pressure difference causes the following effects:

- (a) The bulk volume of the reservoir rock is reduced;
- (b) Sand grains constituting the rock expand;
- (c) Fluids within the pore spaces expand.

The first two volume changes tend to reduce the pore space of the rock. Obviously, both the decrease in pore volume and the expansion of fluids will continuously drive fluids flowing out from pores. Moreover, the output of fluids from the reservoirs will lead to the farther decline in pore pressure and the release of the elastic energies of rock and fluids. The elastic energy of a rock is actually an exhibition of rock compressibility. The elastic energies from the rock and fluids are thus the major drive energies of oil production in an undersaturated oil reservoir, especially in the initial stage of reservoir production.

2.2.6.1 Rock Compressibility

Reservoir rocks can be compressed due to their porosity. Rock compressibility is defined as the reduction in pore volume per unit of rock volume with a unit change in reservoir pressure, expressed as C_f . Mathematically it is given by:

$$C_f = \frac{1}{V_b} \cdot \frac{\Delta V_p}{\Delta p} \quad (2.42)$$

where C_f is the rock compressibility, 1/MPa; V_b is the bulk volume of the rock, m^3 ; ΔV_p is the change in pore volume, m^3 ; Δp is the change in reservoir pressure, MPa.

In Europe or the United States, rock compressibility is commonly defined as the fractional change in pore volume of the rock with a unit change in pressure and given by the following equation:

$$C_p = \frac{1}{V_p} \cdot \frac{\Delta V_p}{\Delta p} \quad (2.43)$$

where C_p is the rock compressibility, 1/MPa; V_p is the pore volume of the rock, m^3 ; ΔV_p is the change in pore volume, m^3 ; Δp is the change in reservoir pressure, MPa.

Due to the relationship $V_p = \phi V_b$, the compressibility C_f is related to the compressibility C_p by the following expression: $C_f = \phi C_p$, where ϕ is the porosity of the rock, and expressed in fraction.

Obviously, Eq. (2.42) or (2.43) exhibits the reduction in pore volume caused by reservoir pressure drop. It is the compressibility of a rock. The reduction of pore volume will continuously drive oil flowing from the reservoir to a well. Therefore, rock compressibility not only denotes the elastic energy of a rock but also characterizes the ability of the rock driving oil.

Despite the values of rock compressibility typically in the order of $1 - 2 \times 10^{-6}$ 1/MPa, considerable elastic energies can be released from reservoir rocks due to their huge bulk volume.

Example 2.1 Calculate the reduction in the pore volume of a reservoir due to a pressure drop of 2 MPa. The reservoir original pore volume is one million cubic meters with an estimated rock compressibility of 5×10^{-4} MPa⁻¹.

Solution

Applying Eq. (2.42) gives

$$\Delta V_p = C_f \cdot V_b \cdot \Delta p = 5 \times 10^{-4} \times 10^6 \times 2 = 1000(m^3)$$

We can see that the decrease in pore volume is caused by released elastic energy of the rock is notable. So the elastic energy of a rock is an important energy of drive oil flowing, especially in the early stage of the undersaturated oil reservoir production.

The reduction in the pore volume due to pressure decline can also be expressed in terms of the changes in the reservoir porosity. Equation (2.43) can be rearranged to give:

$$C_p = \frac{1}{V_p/V_b} \cdot \frac{\Delta V_p/V_b}{\Delta p} = \frac{1}{\phi} \cdot \frac{\Delta \phi}{\Delta p} \quad (2.44)$$

It can be obtained from Eq. (2.44):

$$C_p \partial p = \frac{1}{\phi} \cdot \partial \phi \quad (2.45)$$

Integrating the above relation gives:

$$\int_{p_0}^p C_p \partial p = \int_{\phi_0}^{\phi} \frac{1}{\phi} \cdot \partial \phi \quad (2.46)$$

Then

$$\phi = \phi_0 e^{-C_p \Delta p} \quad (2.47)$$

where C_p is the compressibility of a rock, 1/MPa; Δp is the change in pressure, MPa; p_0 is original pressure, MPa; p is current pressure, MPa; ϕ_0 is the porosity of a rock at original pressure, %; ϕ is the porosity of the rock at pressure p , %;

Equation (2.47) shows the relationship between rock porosity and reservoir pressure. Rock porosity changes with reservoir pressure. Equation (2.47) can also be used for the correcting porosity values from laboratory to reservoir conditions.

As mentioned above, a decline in reservoir pressure will cause two effects: pore volume decrease and fluids expansion, and both of which will drive fluids in pores flowing from the reservoir to a well. As a result, there are two kinds of elastic energies in reservoirs, one from the rock matrix; another from fluids in rock pores.

When the reservoir is being depleted, the total oil amount displaced by formation elastic energy clearly includes two parts: one is the part displaced by rock matrix expansion, denoted by ΔV_{of} ; another is displaced by fluid expansion, expressed as ΔV_{oL} .

Namely,

$$\Delta V_o = \Delta V_{of} + \Delta V_{oL} \quad (2.48)$$

where ΔV_o is the total oil amount displaced by formation elastic energy, m^3 ; ΔV_{of} is the oil amount displaced by rock matrix expansion, m^3 ; ΔV_o is the oil amount displaced by fluid expansion, m^3 .

From Eq. (2.42), the oil amount displaced by rock matrix equals to the reduction in pore volume caused by the expansion of rock grains. It is given by the following expression:

$$\Delta V_{of} = \Delta V_p = C_f V_b \Delta p \quad (2.49)$$

where ΔV_{of} is the oil amount displaced by rock matrix expanding, m^3 ; ΔV_p is the change in pore volume of the rock, m^3 ; C_f is the rock compressibility, 1/MPa; V_b is the bulk volume of the rock, m^3 ; Δp is the change in reservoir pressure, MPa.

From the definition of rock compressibility C_f , a similar parameter (C_L) is introduced to describe the compressibility of fluids. Considering the fluids in rock pores, the oil amount displaced by fluids expansion is calculated as follows:

$$\Delta V_{oL} = \Delta V_L = C_L V_b \Delta p = C_L \phi V_b \Delta p \quad (2.50)$$

where ϕ is rock porosity, f; ΔV_L is the change in fluid volume, m^3 ; V_p is the pore volume of the rock, m^3 ; and V_b is the bulk volume of the rock, m^3 .

Then substitute Eqs. (2.45) and (2.46) for ΔV_{of} and ΔV_{oL} in Eq. (2.52):

$$\begin{aligned} \Delta V_o &= \Delta V_{of} + \Delta V_{oL} = C_f V_b \Delta p + C_L \phi V_b \Delta p \\ &= (C_f + C_L \phi) V_b \Delta p \end{aligned} \quad (2.51)$$

Let

$$C_t = C_f + C_L\phi \quad (2.52)$$

Then

$$\Delta V_o = C_t V_b \Delta p \quad (2.53)$$

Here, C_t is named as the total compressibility of the formation, 1/MPa.

2.2.6.2 Formation Compressibility

Total compressibility of the formation is defined as the total change in pore volume and fluid volume in unit rock volume with a unit change in reservoir pressure:

$$C_t = \frac{1}{V_p} \cdot \frac{\Delta V_o}{\Delta p} \quad (2.54)$$

where C_t is the total compressibility of the formation, 1/MPa; ΔV_o is the total oil amount displaced by the formation, which is equivalent to the total change in pore volume and fluid volume, m^3 ; V_b is the bulk volume of formation, m^3 ; Δp is the change in reservoir pressure, MPa.

Formation compressibility is the term commonly used to describe the total compressibility of a formation. It also represents the total ability of the formation driving oil by the elastic energies of the formation (i.e., the elastic energies of rock and fluids).

Numerically

$$C_t = C_f + C_L\phi \quad (2.55)$$

In an undersaturated reservoir, the total compressibility includes: the compressibilities of oil, irreducible (connate) water, and rock matrix. Namely:

$$C_t = C_f + (C_o S_o + C_w S_w)\phi \quad (2.56)$$

Contrarily, in a saturated reservoir:

$$C_t = C_f + (C_o S_o + C_w S_w + C_g S_g)\phi \quad (2.57)$$

where C_o , C_w , and C_g is the compressibilities of oil, connate water, and natural gas, respectively, 1/MPa; S_o , S_w , and S_g are the saturations of oil, connate water, and natural gas, respectively, %; ϕ is the porosity of the rock, f .

Note that, in spite of C_L being about two orders of magnitude larger than C_f , the order of the product $C_L\phi$ is almost the same with that of C_f because the porosity is only about 20 % of the rock. The total elastic energy of a rock is roughly equivalent to that of fluids in the rock and cannot be ignored.

2.3 Fluid Saturation of Reservoir Rocks

The saturation of reservoir fluids is another important physical property of reservoir rocks. The knowledge of fluid saturation is much necessary in every phase of reservoir production. For example, it is used for the estimation of initial oil or gas in place, i.e., geological reserves, at discovery stage, and for the identification of reservoir zones where a large quantity of oil is left behind. It is also involved in the evaluation of the enhanced oil recovery process [40].

2.3.1 Fluid Saturation

The pores in petroleum reservoirs are always completely saturated with fluids. In general, most rocks are completely saturated with groundwater. Under the right conditions, some of the pores in rocks may be occupied by other liquids, such oil or/and gas. In reservoir pores, actually, there is never an occasion or location where nothing exists (i.e., truly “void space”). In petroleum reservoirs, the pores may be completely filled with the following fluids: (1) oil and its associated impurities in the liquid phase; (2) natural gas and its associated impurities in the vapor phase; (3) water—either connate water or water that flowed or was injected into the reservoir. Because of the difference between the specific gravities of fluids, reservoirs exhibit dominance of a particular fluid saturation at different depths. For example, an oil zone having high oil saturation can be overlain by a gas cap and underlain by formation water.

During the development of oil reservoirs, it is basically concerned that the volumes occupied by oil, gas, and water severally as these volumes represent the amount of oil, gas, and water in reservoirs. The quantity of a liquid in rock pores can be described by the term, *saturation*. The relative amounts of oil, gas, or water when more than one phase is present in the rock can then be characterized by individual phase saturation.

2.3.1.1 Concept of Fluid Saturation

Fluid saturation is defined as the fraction of pore volume occupied by a given fluid in a reservoir rock, often expressed as percentage.

$$S_i = \frac{V_i}{V_p} \times 100 \% = \frac{V_i}{\phi V_b} \times 100 \% \quad (2.58)$$

where the subscript i denotes the i th fluid in the reservoir rock, such as oil, gas, or water; V_i is the volume of the i th fluid filled in rock pores, cm^3 ; V_p is the total volume of rock pores, cm^3 , V_b is the bulk volume of the rock, cm^3 .

In the pores of oil-bearing rocks, there always remains some water which was there before hydrocarbon being trapped. If oil, gas, and water simultaneously exist in reservoir rocks, the saturation of each fluid is defined by the following expressions:

Oil saturation:

$$S_o = \frac{V_o}{V_p} \times 100 \%. \quad (2.59)$$

Gas saturation:

$$S_g = \frac{V_g}{V_p} \times 100 \%. \quad (2.60)$$

Water saturation:

$$S_w = \frac{V_w}{V_p} \times 100 \%. \quad (2.61)$$

where S_o , S_g , and S_w denote oil saturation, gas saturation, and water saturation severally, %; V_p is the pore volume of a rock, cm^3 ; V_o , V_g , and V_w represent the oil volume, gas volume, and water volume in the rock, respectively, cm^3 .

And at any time during the life of an oil or gas reservoir, the following relationship must hold true in the reservoir. It is the continuity condition.

$$S_o + S_g + S_w = 100 \% \quad (2.62)$$

For example, a reservoir having an oil saturation of 70 % implies that 70 % of the pore space in the rock is occupied by liquid petroleum. This saturation value represents an aggregate of hydrocarbon components present as liquid. In this case, there are only two fluids, oil, and water, in the reservoir, the remaining 30 % of the pore space is thus occupied by formation water, as expected. If a gas cap exists, overlying the oil zone in the reservoir, gas saturation would dominate in the top section. Note that it is common for oil or gas saturation to be zero, but water saturation is always greater than zero.

In a word, in a hydrocarbon reservoir, the sum of initial fluid saturations, if more than one fluid exists in reservoir, should be 100 % of the pore space.

For example, in an oil reservoir, the following expression is valid, when no free gas is present (undersaturated reservoir):

$$S_{oi} + S_{wi} = 100 \%. \quad (2.63)$$

where S_{oi} is initial oil saturation, %, and S_{wi} is initial water saturation, %.

In a gas reservoir, if there is no liquid condensate in the rock, initial gas saturation can be calculated in a manner similar to Eq. (2.63):

$$S_{gi} + S_{wi} = 100 \% \quad (2.64)$$

where S_{gi} is initial gas saturation, %.

Producing oil and gas reservoirs usually exhibit initial hydrocarbon saturations in excess of about 70 %. The rest of the pore space is filled with formation water that is not mobile in most instances. This water saturation is often referred to as reducible water or connate water saturation which fills the pores during deposition of the rock.

If oil, gas, and water simultaneously exist in a reservoir, such as the oil reservoir with a gas cap as shown in Fig. 2.36, the saturations of the three phases must add up to 100 %. At some depths, however, the saturation of one fluid could be zero. Descending from the top of the reservoir to the bottom, the saturations of gas, oil, and formation water under initial conditions of the reservoir can be summarized as follows.

In gas cap:

$$S_{gi} + S_{wi} + S_{ogr} = 100 \% \quad (2.65)$$

where S_{ogr} is the interstitial-oil saturation in the gas cap, %.

In gas-oil transition zone:

$$S_g + S_o + S_{wi} = 100 \% ; S_o > S_{ogr} \quad (2.66)$$

In oil zone:

$$S_{oi} + S_{wi} = 100 \% ; S_g = 0 \quad (2.67)$$

In oil-water transition zone:

$$S_o + S_w = 100 \% ; S_w > S_{wi} \text{ and } S_o < S_{oi} \quad (2.68)$$

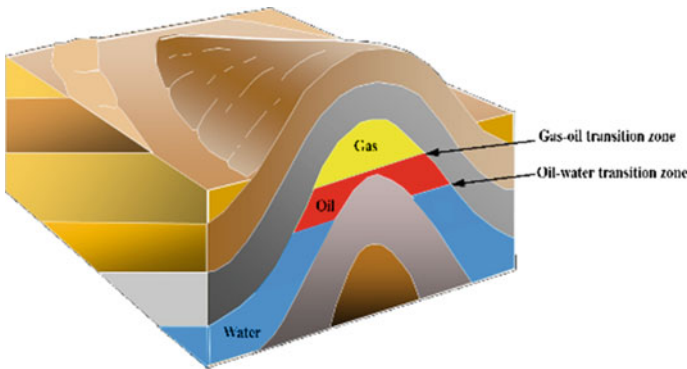


Fig. 2.36 Schematic diagram of oil-gas reservoir

In bottom water zone:

$$S_w = 100 \% ; S_o = 0 \quad (2.69)$$

In general, fluid saturations in a reservoir are not expected to vary significantly in lateral directions unless geologic barriers occur. However, they do vary in vertical direction in transition zones as a consequence of capillary effects. Topics on capillary pressure and transition zone are discussed in Chap. 3.

2.3.1.2 Common Fluid Saturations

After production, fluid saturations in a reservoir will alter significantly with time. This phenomenon can be observed due to the appearance of a new phase (such as free gas in oil reservoir or condensate liquid in gas reservoir) [40]. It can also be found following the injection of a driving fluid (such as water or gas) to enhance oil recovery.

The following saturation concepts are commonly used in different stages of reservoir life: *initial saturation*, *current saturation*, *residual saturation*.

Initial saturation means the fraction of pore volume occupied by a given fluid (oil, gas or water) before an oil/gas reservoir production. Initial water saturation is also known as irreducible water saturation. Initial oil/gas saturations are vital parameters of determining oil/gas geologic reserves and predicting the performance of reservoir production. However, they are not easy to be determined accurately. Generally, the initial oil/gas saturation is customarily determined according to the value of initial water saturation.

Individual fluid saturations vary with time and location in a producing reservoir. Following oil production, oil saturation decreases gradually, and water saturation and gas saturation increase gradually due to reservoir pressure decrease and water invasion/injection. Thereby, current saturation means the oil, gas, or water saturation during reservoir production, and usually called oil, gas, or water saturation for short. As long as the dissolved gas always remains in solution, the following expression is valid during the life of an oil reservoir:

$$S_o + S_w = 100 \% \quad (2.70)$$

where S_o and S_w are separately the oil and water saturations at any stage of reservoir production, %.

The values of S_o and S_w depend the location in reservoir and the time of reservoir production.

In addition, several landmark saturations in the life of a reservoir will be briefly described as follows.

Initial water saturation

The common belief is that a reservoir initially saturated by water; then the oil comes from migration, and the water is expelled from the reservoir and replaced by oil that fills the pores in the reservoir rock. Practically, the water saturation will never get to zero percent because some of the water will be trapped in some small pores and pore-throats. During hydrocarbon accumulation in the reservoir, water saturation may be reduced to a very small value, typically 10–40 %, till no more water can escape from the pores of the reservoir.

The water trapped in rock pores and becomes immobile called *residual water*. The saturation of this part of water is called *residual water saturation*. Sometimes it is also referred to as *connate water saturation*, *primary water saturation*, or *irreducible saturation* depending on different viewpoints from different investigators (Table 2.16).

The water saturations listed in Table 2.16 indicate essentially the initial water saturation in a petroleum reservoir before production. In addition, the following symbols for initial water saturation: S_{wi} , S_{wc} , S_{wir} often occur in petroleum literatures [41]. Care must be taken to ensure correct interpretation of the symbol. The following definitions should help.

- S_{wir} —irreducible water saturation, being or below which water cannot flow [41].
- S_{wc} —connate water saturation. “Connate” implies born, originated with the formation of rocks. It is the saturation of water trapped in the pores during formation of the rock [41]. It may or may not be irreducible.
- S_{wi} —initial/original water saturation. It truly means the water saturation on discovery, but it may or may not be irreducible [41].

In most cases, the term *irreducible water saturation* is prevailing in petroleum engineering, and exactly means the initial/original water saturation. In order to avoid confusion, therefore, the initial water saturation and irreducible water saturation are consistently expressed with symbol S_{wi} in the following description.

Table 2.16 Names and meanings of initial water saturation in a petroleum reservoir

Name	Meaning
Primary water saturation	From the viewpoint of sedimentology, it means the saturation of water sealed in pores of sediment during the process of diagenesis
Connate water saturation	
Irreducible water saturation	From the viewpoint of the formation of oil/gas reservoirs, it means the saturation of water remained in pores of rocks during hydrocarbon accumulation
Residual water saturation	
Irreducible saturation	From the viewpoint of fluid displacement, it means the saturation of water which could not be expelled from pores by hydrocarbon during petroleum reservoirs
Critical saturation	

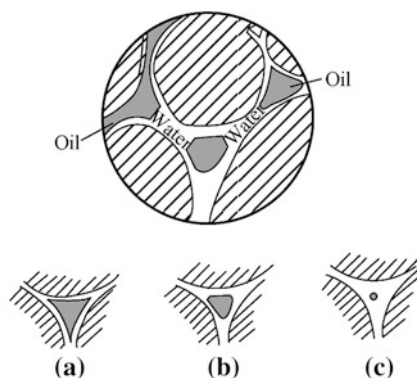
Note that irreducible saturation usually means the saturation below which the fluid cannot flow in the rock. In this case, the reservoir fluid is adhered to the surface of rock particles due to the effect of adsorptive force and interfacial tensions, which will be described in Chap. 3, between fluids and rock particles or between two immiscible fluids in rock pores.

From the origin of initial water in rock pores, as is known to all, connate/original water in reservoirs either surrounds the grains or fills the small pores or dead-end pores for the sake of wettability (see Chap. 3). Hydrocarbons occupy the center of the large pores and cracks in most petroleum reservoir (Fig. 2.37).

Experience shows that there is a good relationship between initial water saturation and the physical properties of sandstones. In general, it is found to vary inversely with the porosity and permeability of rocks with larger pores in basin-wide studies. For example, in coarse-grained sandstones, oolitic and vuggy limestones, initial water saturation is usually relatively lower, while very fine-grained sandstones have a relatively high initial water saturation. In convectional sandstones, initial water saturation is round about 20–30 %, but it may be about 40–50 % in low-permeability reservoirs, and probably lower than 10 % in high-permeability reservoirs.

Based on the values of the porosity and initial water saturation in an oil reservoir, moreover, the original oil in-place (OOIP) of the oil reservoir can be easily estimated. OOIP is the vital basic data for reservoir development design and reservoir production.

Example 2.2 The oil-bearing area of an oil reservoir is 16 km^2 , and the net-pay thickness of the reservoir is 10 m. The porosity of the reservoir is 20 %. The initial water saturation is 30 %. The volume factor of in-place oil is 1.2. The relative density of the oil is 0.85. Estimate the original oil in place (oil geological reserves) of the reservoir.



(a) Oil saturation of the order of 80% (productive zone); (b) Oil saturation of the order of 50% (transitional zone); (c) Oil saturation of the order of 10%~20% (water-bearing zone)

Fig. 2.37 Diagram showing the distribution of oil (nonwetting fluid) in pores of a rock filled with water (wetting fluid) (Monicard [42])

Solution

The volume of original oil in-place in the reservoir is:

$$V_o = Ah\phi(1.S_{wi}) = 16 \times 10^6 \times 10 \times 20 \% \times (1 - 30 \%) = 2.24 \times 10^7 (\text{m}^3)$$

The original oil in-place of the reservoir is then (surface volume or quality):

$$N = V_o/B_o = 2.24 \times 10^7 / 1.2 = 1.87 \times 10^7 (\text{m}^3)$$

$$N' = N \times \rho_o = 1.87 \times 10^7 \times 0.85 = 1.59 \times 10^7 (\text{t})$$

Residual oil saturation and remaining oil saturation

At the end of the productive life of a reservoir, the oil that still remains in rock pores is referred to as *residual oil*. The fraction of pore volume occupied by residual oil in rocks is known as *residual oil saturation*, generally expressed as S_{or} .

Residual oil saturation points to a value below which oil is no longer mobile within porous media [40]. Residual oil saturation can be obtained from the core displacement in the laboratory. Knowledge of residual oil saturation is of great interest to reservoir engineers as it can be used to estimate the ultimate recoverable reserves of oil reservoirs. Some studies prefer the term *remaining oil saturation* (ROS) in quantifying the oil left behind following the primary or a subsequent recovery [40]. But the meanings of the two terms are essentially different.

Following the depletion of a typical reservoir based on natural drive mechanisms or secondary drive, a substantial portion of movable oil is usually left behind in the reservoir [40]. The fraction of pore volume occupied by this movable oil left in reservoir rocks is known as *remaining oil saturation*, simply denoted by S_o . The remaining oil saturation encountered in the reservoir could be rather high. Reservoir engineers are interested to know the distribution of remaining oil saturations in a matured field, especially in the zones of bypassed oil for further recovery. The task requires multidisciplinary studies involving petrophysics, geology, geophysics, production, and reservoir simulation.

Note that remaining oil usually refers to the oil remaining in reservoirs and being movable. It generally includes the oil either in unswept dead oil area or in low-permeable layers/areas. The most important is that remaining oil can be recovered by secondary oil production method. Residual oil, however, means the immovable oil left in reservoirs after secondary oil recovery, and existing pores in extremely dispersed state. It is thus the target of tertiary oil recovery.

In the late of secondary oil recovery, an oil reservoir will implement appropriate improved or enhanced oil recovery (IOR or EOR) operations. Following a successful enhanced oil recovery operation in an oil reservoir, the remaining oil saturation is further reduced in the reservoir. For example, the study of a typical oil reservoir throughout its life cycle may lead to the following scenario, as shown in Table 2.17.

It is apparent from Table 2.17 that not all of the movable oil can be produced even by implementing improved or enhanced recovery methods. Sometimes, it is

Table 2.17 Typical changes in oil saturation throughout the reservoir life cycle (Abdus et al. [40])

Average value of oil saturation in the reservoir	Saturation (f)	Source of data
Initial	0.80	Petrophysical studies
Following primary production	0.68	Production history/reservoir studies
Following improved and enhanced recovery	0.55	Production history/reservoir studies
Irreducible/residual	0.22	Petrophysical studies

no longer feasible to produce a reservoir in an economic sense when oil saturation is lower than a limit value. The ultimate recovery from oil reservoirs is found to average around 35 % worldwide [40]. It is the primary goal of reservoir engineers to improve recovery based on technological innovation and new approaches in reservoir management, including detailed studies and intensive monitoring.

In a gas reservoir, similarly, there also exist such terms: residual gas saturation and remaining gas saturation. Not repeat here. However, as gas is much more mobile than oil and water, in contrast to oil reservoirs, the residual gas volume at the end of a gas reservoir life is markedly low [40].

Movable oil saturation [40]

It is important to recognize that only a fraction of the oil in place is ultimately produced in most reservoirs. This poses a challenge to attain better recovery, requiring a thorough understanding of reservoir behavior. This necessitates the estimation of movable oil saturation, which represents the maximum volume of oil that can be moved or produced ultimately from a reservoir. Hence, movable oil saturation is defined as the difference between initial oil saturation and residual oil saturation. Mathematically, it is expressed as:

$$S_{om} = S_{oi} - S_{or} = 1 - S_{wi} - S_{or} \quad (2.71)$$

where S_{om} is movable oil saturation, %; S_{oi} is initial oil saturation, %; S_{wi} is initial water saturation, %; S_{or} is residual oil saturation, %.

Similarly, movable gas saturation in a gas reservoir can be estimated based on the initial and final gas saturation.

Critical gas saturation [29]

Consider an oil reservoir in which no gas evolves out of liquid phase within the reservoir as long as the reservoir produces above the bubblepoint. When the reservoir pressure declines below the bubblepoint, gas evolves out of liquid phase but is not immediately mobile. Following the buildup of free gas saturation to a certain threshold value, referred to as critical gas saturation, the vapor phase begins to flow toward the wellbore. Critical saturation is a term used in conjunction with increasing fluid saturation.

2.3.2 *Factors Affecting Fluid Saturation*

Fluid saturation distribution is fairly complex in a reservoir, and has great uncertainty. Generally, the distribution of fluids in rock pores depends on many factors related with rock and fluid. For example, it is affected by the physical properties of rocks and fluids, the interactions between the rock and fluids, and the affinity between the rock and fluids, a property known as wettability (see Chap. 3).

The pore structure of a rock and the surface property of rock grains are the most important factors affecting fluid saturation. In general, larger pore-size, better connectivity of pores and smooth pore wall give better permeability and smaller flowing resistance of hydrocarbons in rock pores, which results in higher hydrocarbon saturation and lower irreducible water saturation.

Different hydrocarbon fluids have different compositions, which give different physical properties of fluids, and thus lead to different hydrocarbon saturations in reservoirs. For example, high-viscosity oil, which has larger size molecules and stronger acting forces between fluid molecules and between fluid and rock, is not easy to enter smaller pores. Therefore, there is higher residual water saturation and lower oil saturation in reservoirs in this situation and vice versa.

Besides factors described above, residual oil saturation is also controlled by the following factors: the pore-throat size ratio, pressure difference, development process, and so on. The smaller are the pore-throat size ratio and the specific surface area of a rock, the easier is the displacement of oil in pores, and thus the residual oil saturation is lower. Different wetting types of rocks (oil wetting or water wetting) give rise to different patterns of water displacing oil, which thus leads to different residual oil saturations in different reservoirs. And higher pressure difference between the reservoir and the production wells makes oil easy to flow in pores and thus results in lower residual oil saturations in the reservoir.

2.3.3 *Measurement of Fluid Saturation*

Like other property parameters of rocks described above, the fluid saturations in various phases of a reservoir life may be determined either by direct measurement of V_o , V_g , and V_w of a cored sample (in this case only residual liquids are measured, if the core has not been preserved carefully), or by the indirect method, e.g., capillary pressure measurement and well logging.

In general, the fluid saturations in a core have been flushed by the mud filtrate and are not representative of the in situ reservoir conditions. Only samples cored with oil-based mud and taken high in the oil column (where the relative permeability to water is ignorable) have a value of water saturation at in situ reservoir conditions, after having performed the correction for the loss of dissolved gas in oil and stress effect. In the case of oil-based mud filtrate invasion, water saturation will remain immobile if S_w is less than 50 % and mild surfactants are used in the mud.

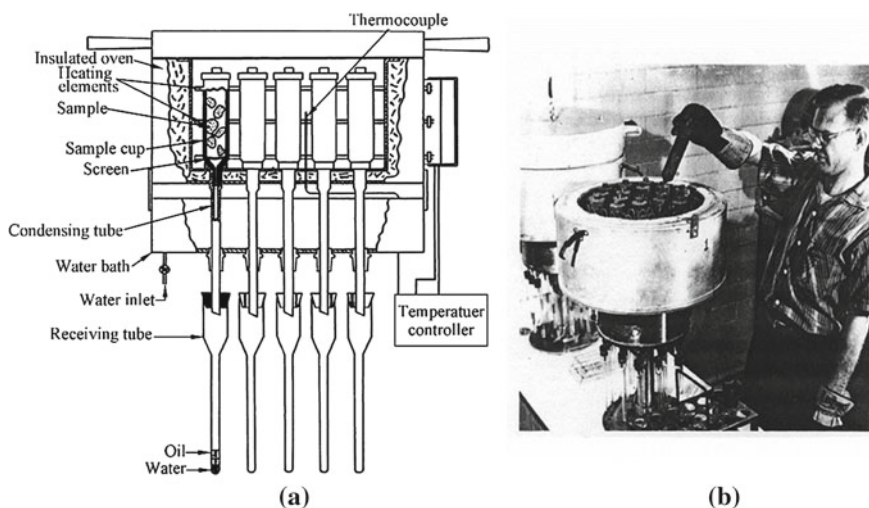
Discussion in this section is only restricted to the directly methods in the laboratory. Capillary pressure method will be introduced in Chap. 3, but well logging techniques is not concerned here.

By means of the definition, fluid saturation is just related with the pore volume and fluid volume contained in a rock. Here is only the introduction of the measurement of fluid volume.

Fluid volume can be determined either by extracting the fluids from a core sample or by heating the core to vaporize fluids from the sample. In determining the fluid volume of a sample, two techniques are commonly employed: vaporizing fluids from the sample, known as *retort distillation*, and leaching fluids from the sample, known as *solvent extraction*.

2.3.3.1 Retort Distillation

Figure 2.38 shows a typical oven of retort distillation which mainly consists of a heating element, a condenser and a graded receiver. The rock sample is placed in a cylindrical metal holder with a screw cap on the top. The top is sealed and the sample holder is placed within a retort oven. The sample, which can be small cylindrical core plug or crushed core, is heated to high temperature to distill the fluids which are then condensed and received. A temperature controller raises either in stages or directly the temperature of the core to a selected level, at which point the water within the core is vaporized and then recovered. The temperature is then increased to 650 °C to vaporize and distill oil from the sample. The vaporized oil and water are subsequently collected in a small graded tube through a condenser to be measured. The volumes of oil and water are read and recorded for future calculations.



(a) Diagrammatic illustration (Robert P. Monicard, 1980); (b) Picture of a conventional retort (Core Lab, 1983)

Fig. 2.38 Oven of retort distillation at atmospheric pressure

Then the saturations of oil, water, and gas can be determined as follows:

$$S_o = \frac{V_o}{V_p} \times 100 \%, \quad S_w = \frac{V_w}{V_p} \times 100 \% \quad (2.72)$$

$$S_g = 100 - S_o - S_w \quad (2.73)$$

where V_p is the pore volume of the sample, given, cm^3 ; V_o is the oil volume collected from the sample in the experiment, cm^3 ; V_w is the water volume collected from the sample in the experiment, cm^3 .

The advantage of this method is that it takes a relatively short time, typically less than 24 h, and multiple samples can be run at the same time. The disadvantage is that heating process burns oil to the pore surfaces. When heated to higher temperatures (such as 650°C), the oil tends to crack and coke. This is known as the *coking effect* and thus results in oil recovery less than the initial amount in the sample [44]. Sometimes, the loss of the oil could be up to 30 %. A correction (Fig. 2.39a) has been empirically developed to overcome this problem. The correction is often based on calibration curves that had been made previously using oil samples similar to the oil from the core samples. If no oil sample is available, a standard correction is generally proved adequate. For example, two typical oil correction curves are shown in Fig. 2.39a.

In addition, another problem in the heating process is the removal of crystallization water, which is the bound water in clays and other hydrates, when temperature rises to 650°C or over the temperature. Subsequently, the water recovery is higher than it should be. Figure 2.39b presents an example of water recovery versus time. The first plateau represents the volume of water held in the pores by capillary force. The second plateau is the additional water due to the vaporizing of the crystallized water. In this way, the result can be calibrated for the given samples.

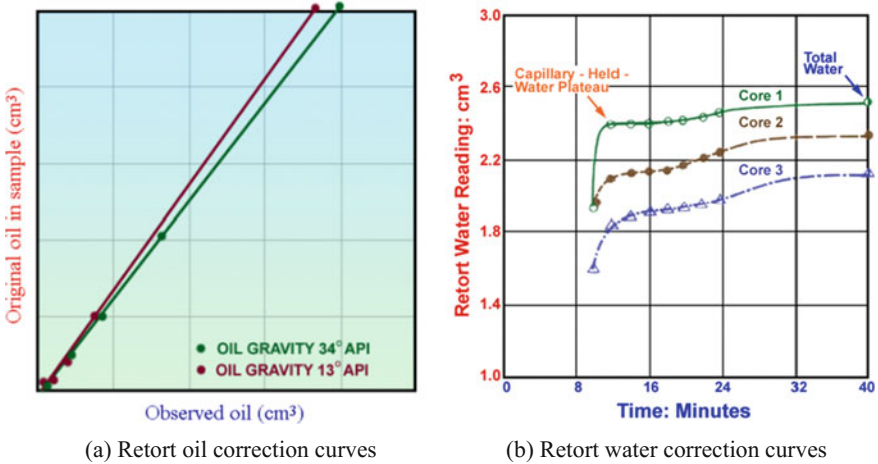


Fig. 2.39 Retort correction curves

A final disadvantage of this method is it destroys the sample; therefore no further measurement can be done with the sample.

Example 2.3 The corrected volumes of oil and water recovered from the retort distillation are 4.32 and 1.91 cm³, respectively. Prior to this experiment, the bulk volume of the sample containing oil and water was measured to be 34.98 cm³ and the matrix volume of the sample was 26.34 cm³. Determine the saturations of this sample.

Solution

The following stepwise procedure is presented.

- (a) The pore volume of the sample is: $V_p = V_b - V_s = 34.98 - 26.34 = 8.64$ (cm³).
- (b) Applying Eqs. (2.59) and (2.61), the oil and water saturations are separately:

$$S_o = \frac{V_{oi}}{V_p} \times 100 \% = \frac{4.43}{8.64} \times 100 \% = 50 \%$$

$$S_w = \frac{V_{wi}}{V_p} \times 100 \% = \frac{1.91}{8.64} \times 100 \% = 22 \%$$

- (c) The gas saturation cannot be measured directly and therefore is determined by the Eq. (2.62):

$$S_g = 100 - S_{oi} - S_{wi} = 100 - 50 - 22 = 28 \%$$

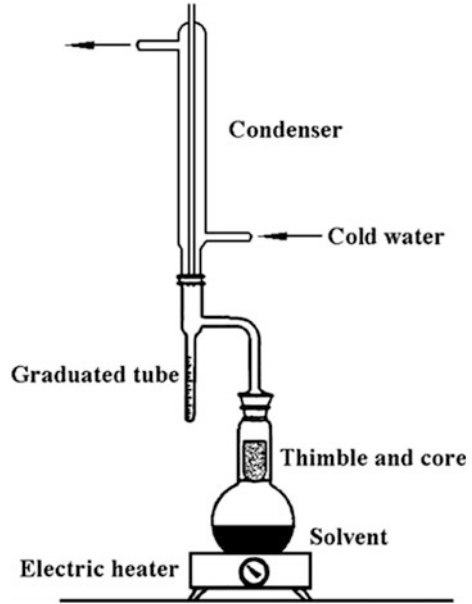
2.3.3.2 Solvent Extraction

Laboratory devices of this method, known as extractors (Dean–Stark type, Fig. 2.40), are closed vessels containing a liquid organic solvent (toluene, pentane, octane, xylene, acetone, carbon disulphide, etc.) that is miscible with the oil but not the water. The sample can be either immersed in the solvent or exposed to dripping condensed vapors.

In Dean–Stark extraction method, the solvent is heated to temperatures close to 110 °C so that the vapor of the solvent to rise through the core and to leach out oil and water from the sample. The water condenses in a cooled tube in the top of the apparatus and is collected in a graduated cylinder (Fig. 2.40). The oil removed from the samples remains in solution in the solvent. The solvent and oil continuously cycle through the extraction process.

The volume of water collected from the sample can be read from the graduated tube. And the weight of water is calculated from the volume of water by the relationship

Fig. 2.40 Dean–Stark type extractor



$$W_w = \rho_w V_w \quad (2.74)$$

where ρ_w is water density in g/cm^3 ; V_w is the volume of water received from the sample, cm^3 .

The method provides an accurate measurement result of water content in a sample. The content of oil leached from the sample can then be calculated by the difference between the weight of water recovered and the total weight loss after extraction and drying, namely:

$$W_o = W_{\text{wet}} - W_{\text{dry}} - W_w \quad (2.75)$$

where W_o is the oil amount contained in the sample; W_{wet} is the weight of the sample prior to the extraction (original sample, not cleaned!); W_{dry} is the weight of the sample after the test, cleaned and dried; W_w is the weight of water collected from the sample. The units of all weights are in gram.

Oil volume is then calculated as:

$$V_o = W_o / \rho_o \quad (2.76)$$

where ρ_o is oil density in g/cm^3 ; V_o is the oil volume in the sample, cm^3 .

The saturations of oil, water, and gas are then determined by Eqs. (2.72) and (2.73).

The advantages of this method are that the measurement results are quite accurate, and the sample can be used for further analysis. The primary disadvantage of this method is the long time it takes to complete the measurement [44]. For example, a complete extraction may take several days to weeks in the case of low API gravity crude or presence of heavy residual hydrocarbon deposit within the core. Low-permeability rock may require longer extraction time, sometimes weeks.

Example 2.4 A saturated sample is extracted in extraction apparatus by heating the solvent. When the reading of graduated tube becomes constant, stop extracting and record the volume of water collected, $V_w = 1.4 \text{ cm}^3$. After cooling, remove the core and dry it. Obtain the weight of the dry sample, $W_{\text{dry}} = 53 \text{ g}$. Using the saturation method, saturate the sample again with fresh water ($\rho_w = 1.00 \text{ g/cm}^3$) and weigh it. Its weight is 58 g (W_{wet2}). Given that the weight of the saturated sample is 57 g (W_{wet1}); the oil density is 0.88 g/cm^3 . Determine the saturation of oil and water.

Solution

The calculation of oil and water saturations is as follows:

(a) The pore volume of the sample:

$$V_p = \frac{V_{\text{wet2}} - V_{\text{dry}}}{\rho_w} = \frac{58 - 53}{1.00} = 5 \text{ cm}^3$$

(b) Determine oil weight by Eq. (2.70):

$$W_o = W_{\text{wet1}} - W_{\text{dry}} - W_w = 57 - 53 - 1.4 = 2.6 \text{ (cm}^3\text{)}$$

(c) Oil volume:

$$V_o = \frac{W_o}{\rho_o} = \frac{2.6}{0.88} = 2.96 \text{ cm}^3$$

(d) By Eqs. (2.59) and (2.61), the oil and water saturations are:

$$S_o = \frac{V_{oi}}{V_p} \times 100 \% = \frac{20.96}{5} \times 100 \% = 59.2 \%$$

$$S_w = \frac{V_{wi}}{V_p} \times 100 \% = \frac{1.4}{5} \times 100 \% = 28 \%$$

(e) The gas saturation is therefore calculated by the Eq. (2.62):

$$S_g = 100 - S_{oi} - S_{wi} = 100 - 59.2 - 28 = 12.8 \%$$

2.3.3.3 Vacuum Distillation

The oil content in whole cores or large core samples is often determined by vacuum distillation. The assembly of a vacuum retort is shown in Fig. 2.41. An additional vacuum pump is added to a retort system for the sake of completely distilling the fluids contained in the center of the larger core. This technique can fully remove oil from the sample without sample destruction.

In the test, the sample is placed within a leak-proof vacuum system, and is heated to higher temperature, usually lower than 450 °C. The fluids contained in the sample are vaporized and collected after being condensed by liquid nitrogen or other coolant, such as mixture of methyl alcohol and dry ice. The fluids distilled from the sample are collected in a calibrated receiving tube which is immersed in a cold bath of alcohol and dry ice at about -75 °C. This prevents the oil from being drawn into the vacuum system. After that, the volumes of oil and water should also be subject to the same corrections as in the atmospheric retort distillation.

2.3.3.4 Error Correction of Fluid Saturation Measurement

A common method of obtaining fluid saturations is the measurements taken on core samples. Unfortunately, the fluid content in the core in the laboratory is altered by two processes: (1) the flushing of mud and mud filtrate into the adjacent formation, and (2) the release of confining pressure as the core is pulled to surface. Besides, during the test, there are also some errors caused by handling, such as washing cores in water, drying cores at high temperatures, or the lack of protective measures for the core.

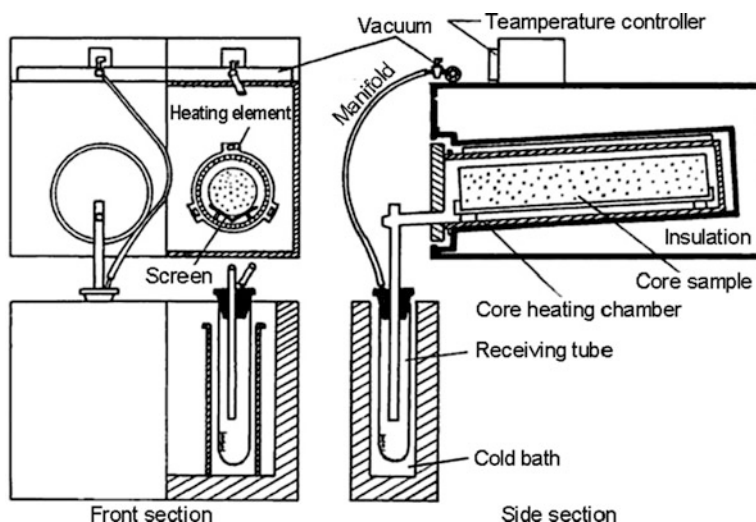


Fig. 2.41 Vacuum distillation (Monicard [42])

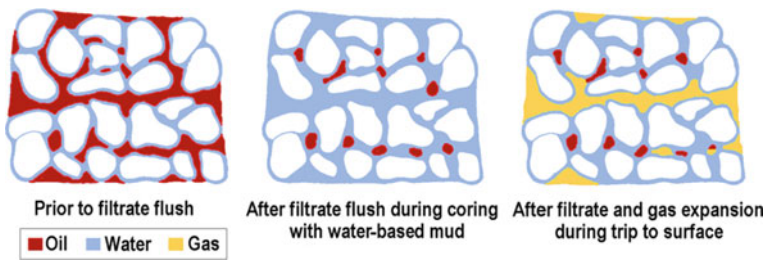
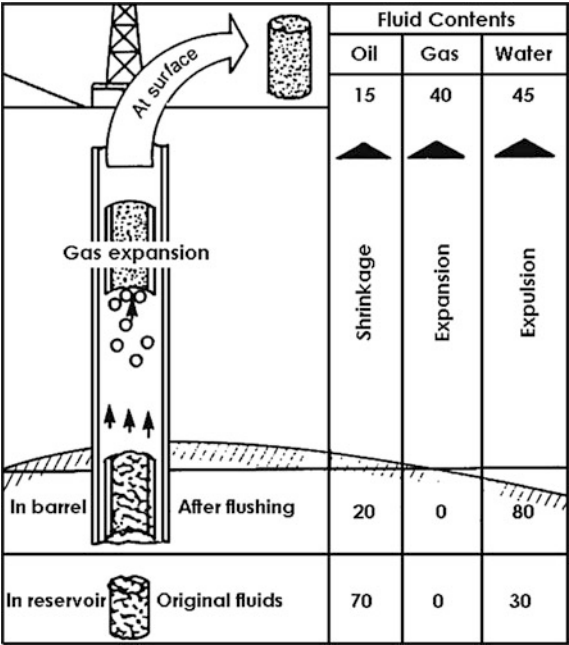


Fig. 2.42 Saturations in sand during coring and recovery (CoreLab [43])

Figure 2.42 illustrates on a microscopic level the invasion process of a water-based mud into an oil-bearing formation. The left diagram is prior to being penetrated by the mud, therefore the saturations present are the connate water and oil. The middle diagram shows the formation after the mud has penetrated and fluid invasion has flushed the original reservoir fluids. Note the increase in water saturation during this time. The right diagram shows the gas expansion as the core is brought to the surface. Invasion by mud filtrate is shown in situ by a reduction in oil saturation and an increase in water saturation. To minimize the invasion problem, it is suggested to use oil-based muds (OBM) as the coring fluid [44].

When a core is brought from in situ to the surface, the fall in pressure and temperature will result the change in oil saturation due to the dissolved gas escaping from oil. An example of saturation changes in the core from in situ to surface conditions is shown in Fig. 2.43. Note the significant decrease in oil saturation due

Fig. 2.43 Example of saturation changes in the core from insitu to surface conditions (Helander [45])



to the invasion process. Also, note the gas expansion as the core is brought to surface, subsequently expelling the fluids in the core. In this illustration, primarily water is expelled. Finally, as the pressure and temperature are reduced, the oil will shrink in volume, therefore also reducing the saturation [44]. In addition, evaporation is inevitable during handling or transporting the saturated sample if the necessary precautions were not taken.

Other research has led to using empirical factors to correct measured core saturations to original conditions (Amyx et al. 1963). The deviation in oil saturation can be corrected in two ways:

Correct the deviation caused by pressure drop using oil volume factor:

$$S_{o1} = S'_o \times B_o \quad (2.77)$$

where B_o is oil volume factor, dimensionless; S'_o is the oil saturation measured in the laboratory, %; S_{o1} is the oil saturation corrected by oil volume factor, %.

Correct the deviation in sampling using empirical coefficient:

$$S_o = S_{o1} \times 1.15 \quad (2.78)$$

where 1.15 is empirical coefficient; S_o is the oil saturation corrected by empirical coefficient, %. It is equivalent to the oil saturation at reservoir conditions.

2.4 Permeability of Reservoir Rocks

In addition to porosity, permeability is also a rock property depending on the pore space of rocks. However, permeability is a measure of the ability of a rock to transmit fluids through the pore network in the rock whereas porosity just characterizes the capacity of the rock holding fluids. In petroleum reservoirs, rock permeability is one of the most valuable characteristics that the reservoir engineer seeks to determine. The oil in a reservoir rock can be extracted through bore holes only if the rock is permeable. A solid of no porosity would be impermeable to a fluid, and it is also possible for a rock of high porosity to be impermeable, namely zero permeability. Such a rock, though saturated with oil will give no production when the reservoir is drilled.

Permeability, as the name implies (ability to permeate), is a measure of how easily a fluid can flow through a rock. It is a critical property in defining the flow capacity of a rock. The study of permeability is perhaps the most important single study in the science of petroleum production. Without a sound knowledge of the permeability of a reservoir, it is impossible to estimate the probable rate of production of oil or the best methods of economic production. Consequentially, rock permeability is an indispensable basic parameter of reservoirs for the oil production and the dynamic investigation of petroleum reservoir engineering.

2.4.1 Darcy's Law and the Absolute Permeability of Rocks

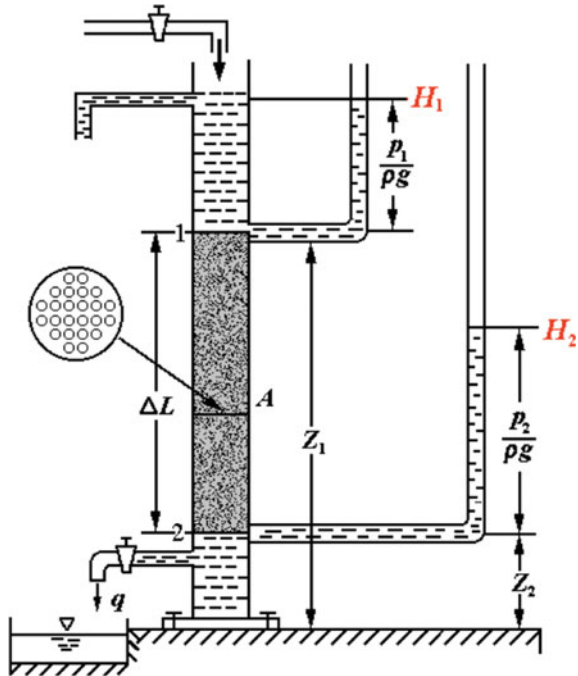
Darcy's law, published in 1856, has served as the basis for all modern analysis of fluids flowing through porous mediums. In order to get quantitative information on the permeability of sand layers to water about 150 years ago, Darcy designed a simple experiment of water flowing through a sand-packing column, and hence developed an important empirical expression which was further developed to the vital Darcy law used in the petroleum industry today. At present, Darcy law is the most reasonable approximation for the description of the behavior of a fluid passing through the complicated and tortuous porous medium.

2.4.1.1 Darcy Law

In order to study the behavior of water flowing through sand filter, Henry Darcy, a French hydrology engineer, in 1856, conducted experiments to emulate the flowing of a subsurface aquifer and determine the flow rate of water through the sand filter.

Darcy used the apparatus shown in (Fig. 2.44), where he used a vertical sand pack through which water flowed under the influence of gravity while measuring the fluid pressures at the top and bottom of the pack by the heights of piezometric

Fig. 2.44 The apparatus of Darcy experiment



tubes. Here the drop in fluid pressures can be calculated from H_1-H_2 providing the density of the fluid is known.

Darcy found that the volumetric flow rate of water through the packed column is a function of (a) the dimension of the porous medium, and (b) the difference in hydraulic head, as given in the following:

$$Q \propto \frac{A(H_1-H_2)}{L} \quad (2.79)$$

where Q is the volumetric flow rate, cm^3/s ; A is the cross-sectional area of flow, cm^2 ; H_1 , H_2 are the hydraulic head at points 1 and 2, respectively, cm water column; and L is the length of the porous medium, cm .

After a proportionality constant was introduced to Eq. (2.79), an empirical expression, called Darcy's law, was generalized by Darcy. Darcy's law states that the volumetric flow rate of a homogeneous fluid through a porous medium is proportional to the pressure gradient and to the cross-sectional area normal to the direction of flow, and inversely proportional to the length of the porous medium and the viscosity of the fluid. It may be stated in several different forms depending on the flow conditions. The following outlines its common forms:

$$Q = K \frac{A\Delta p}{\mu L} \times 10 \quad (2.80)$$

where K is a proportionality constant for the medium in Darcy (D) unit; Q is the volumetric flow rate of fluid, cm^3/s ; A is the cross-sectional area of flow, cm^2 ; L is the length of porous medium, cm ; ΔP is the pressure difference between inlet and outlet of the sand pack column, MPa ; μ is the viscosity of fluid, mPa s ($1\text{cP}=1\text{ mPa s}$); $\Delta P/L$ is the pressure gradient, MPa/cm .

Special attention should be paid to the unit of pressure. It is the unit of "MPa" here (Darcy unit system). But in China's oilfields, "atm" is often used for pressure (field unit system). If the unit of pressure is "atm," Darcy's formula should be expressed as: ($1\text{ atm} = 0.0981\text{ MPa} \approx 0.1\text{ MPa}$)

$$Q = K \frac{A\Delta p}{\mu L} \quad (2.81)$$

In the formula above, the units of other parameters remain unchanged except for pressure.

The law as stated in its original form involves some limitations originally propounded by Darcy [46]. The experimentally derived form of Darcy's law was limited to homogeneous (single-phase) incompressible fluids. It implies that for the heterogeneous or multiphase fluid systems the law may not be valid. Since its discovery, it has been found valid for any Newtonian fluid. In the petroleum industry Darcy's law is formulated in terms of pressure gradient and generalized for oil and gas flow, which led to the concept of multiphase flow. Darcy's equation may

be adjusted to account for unsaturated and multiphase flow. This was accomplished by separating the properties of the rock from that of the fluid by manipulating the proportionality constant K , thereby obtaining a “generalized” law as shown in Eq. (2.80) [47]. By doing so, permeability becomes a property of the porous media, dictated by pore geometry alone. Likewise, despite it was established under the condition of unconsolidated sands, it may as well be found valid for consolidated rocks, such as sandstone, carbonate rock and so on. In addition, Darcy did not envisage the possibility of the fluid interacting with and perhaps hydrating the porous medium. Yet the absence of such effects must be explicitly assumed in the above-stated formulation of the law [46].

In Darcy’s law, it is the generalized use of the term “fluid.” This includes any liquid—not only water—and all gases not interacting with the porous medium. The distinction between them is expressed only by the differences in their viscosity, which is explicitly introduced in the relationship between the rate of flow and the driving force.

2.4.1.2 Absolute Permeability of Rocks

When Darcy’s law is used for describing the flowing of fluids in reservoir rocks, proportionality constant K is known as the *absolute permeability* of the rock in the case of single-phase flow in the rock. The absolute permeability of a rock is a measure of its ability to transmit fluid where the fluid completely saturates the porous medium [40].

In Eq. (2.80), when pressure gradient remains unchanged for a sample in single-phase flow, the relationship between flow rate Q and proportionality constant K is linear, which means that the ability of the rock transmitting fluid increases with the increase in proportionality constant. Therefore, the proportionality constant K , named absolute permeability, characterizes quantitatively the permeable property of the rock and the ability of the rock conducting fluids.

Permeability is specifically expressed in Darcy, but a few reservoir rocks have permeabilities more than 1 Darcy. In geological applications, the Darcy is commonly too large for practical purposes in fields, so the millidarcy (mD) is commonly used, where $1000 \text{ mD} = 1\text{D}$, following the conventions of the metric system.

Permeability varies greatly both in lateral and vertical directions in conventional reservoir rocks. Although the reservoir permeability is found to vary from less than 1 mD to several Darcies, commercial oil-bearing reservoirs operate between a few to a few hundred millidarcies in many instances. A rock whose permeability is 5 mD or less is called a tight sandstone or a dense limestone, according to its composition [48]. In general a cutoff of 1 mD is applied to oil-bearing reservoir rocks, below which the rock is not considered as a reservoir rock unless unusual circumstances apply (e.g., it is a fractured reservoir.) [31]. The gradations of permeability for reservoir rocks are shown in Table 2.18 according to the industry standard of China.

Table 2.18 Gradation of reservoir permeability [23]

Clastic rock		Carbonate rock	
Gradation	Permeability (K) (mD)	Gradation	Permeability (K) (mD)
Extremely high	$K \geq 2000$		
High	$500 \leq K < 2000$	High	≥ 100
Moderate	$50 \leq K < 500$	Moderate	$10 \leq K < 100$
Low	$10 \leq K < 50$	Low	$1 \leq K < 10$
Extremely low	$1 \leq K < 10$	Extremely low	$K < 1$
Ultra-low	$K < 1$		

It should be noted that permeability can be much less than 1 mD in unconventional reservoirs such as tight gas and shale gas reservoirs. Since gas requires much less driving force to move in the porous media, certain gas reservoirs may produce economically when the rock permeability is much less. In general, an oil reservoir having has very low permeability (in the low single digits of millidarcies) may not be viewed as a good candidate for substantial production over a long period [40]. One notable exception occurs with a fractured reservoir having low matrix permeability. In this case, fluid flow may occur predominantly through a network of highly conductive microchannels [40].

The explicit meaning of “Darcy” may be stated as follows: a porous medium would have a permeability of 1 Darcy when a fluid having viscosity of 1 cp flows at a rate of 1 cm³/s under a unit pressure gradient, 1 atm/cm. That is:

$$\begin{aligned}
 1D &= \frac{(1 \text{ cm}^3/\text{s})(1/100 \text{ dyn} \cdot \text{s}/\text{cm}^2)(1 \text{ cm})}{(1 \text{ cm}^2)(981,000 \text{ dyn}/\text{cm}^2)} \\
 &= 1.02 \times 10^{-8} \text{ cm}^2 \approx 10^{-8} \text{ cm}^2 = 1 \mu\text{m}^2
 \end{aligned}$$

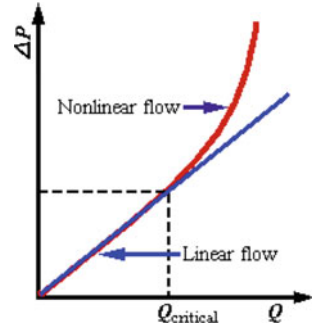
Therefore, the permeability of a rock has the dimension of area (L²). The area unit (L²) is physically related to the cross-sectional area of pore-throats in a rock. Relatively large pore-throats of a rock imply relatively large values of L² and thus correspond to relatively high values of permeability. That is to say, the permeability of a rock represents the average cross-sectional area of pores in the rock.

Thereby, the greater the average cross-sectional area of rock pores, the higher the rock permeability, the better the permeable property of the rock, and the easier fluids flow through the rock.

2.4.1.3 Validity of Darcy’s Law

From Eq. (2.81), Darcy’s law reveals a linear relationship between the flow rate q and the pressure difference ΔP for a fluid through a porous medium. That is to say, Darcy’s law is a linear law. Darcy’s law is valid only if the flow through a porous medium is linear or laminar. Typically, if the curve of Q - ΔP is a straight line

Fig. 2.45 Relationship between flow rate and pressure difference



across coordinate origin, the flow of fluid through porous medium is linear (Fig. 2.45).

However, it has been proved by experiments that the linear of Darcy's law exists only in certain flow regime. Turbulent or nonlinear flow occurs when pressure difference is large enough (Fig. 2.45).

The validity of Darcy's law may be verified by calculating the value of a dimensionless number used in fluid dynamics: *Reynolds number*. In general, the Reynolds number has different definitions depending on the character of flow.

From the experiments on pipe flow, Reynolds number found that the flow is laminar so long as the velocity of flow is less than a lower critical velocity v_c . Based on the analogy between pipe flow and the flow through porous mediums, the flow through rocks may be assumed to depend upon the dimensions of the pore space. F. I. Kotyakhov suggested that the critical velocity of flow in rocks may be determined by Reynolds number. For the flow in rocks, the Reynolds number may be typically defined as:

$$R_e = \frac{v\rho\sqrt{k}}{17.5\mu\phi^{3/2}} \quad (2.82)$$

where R_e is Reynolds number; v is the velocity of fluid through a rock, cm^3/s ; μ is fluid viscosity, mPa s ; ϕ is rock porosity, %; K is rock permeability, D .

Experience has shown that the critical Reynolds number of average reservoir rocks is about 0.2–0.3. For flow of fluids in a given reservoir rock, if Reynolds number is less than the critical Reynolds number (0.2–0.3), the velocity of the fluid is less than the critical velocity and the flow is laminar (linear).

Example 2.5 The absolute permeability of a core plug is measured with brine. The rock sample is 4 cm long and 3 cm^2 in cross-sectional area. The brine has a viscosity of 1.0 mPa s and is flowing at a constant rate of 0.5 cm^3/s under a 2.0 atm pressure drop. Calculate the absolute permeability of the sample.

Solution

Applying Darcy's equation, i.e., Equation (2.81), gives:

$$K = \frac{Q\mu L}{A\Delta p} = \frac{0.5 \times 1 \times 4}{3 \times 2} = 0.333(\text{D})$$

Example 2.6 Rework the preceding example assuming oil of 2.0 mPa s is used to measure the permeability. Under the same pressure drop, the flow rate is 0.25 cm³/s.

Solution

Applying Darcy's equation yields:

$$K = \frac{Q\mu L}{A\Delta p} = \frac{0.25 \times 2.0 \times 4}{3 \times 2} = 0.333(\text{D})$$

From the two examples, we can see that rock permeability has nothing to do with the fluids flowing through the rock. Actually, it only depends on the texture of a rock, namely depending on the pore structure of the rock.

2.4.2 Rock Permeability Measurement

Typically, rock permeability is measured on cores in the laboratory by application of Darcy's law under steady-state conditions. During the measurement of rock permeability, the following conditions must be satisfied:

- (a) Laminar (viscous) flow of a fluid in the rock;
- (b) No reaction between the fluid and the rock;
- (c) Only one and incompressible fluid present at 100 % pore space.

In the laboratory, oil, gas or water may be used for the measurement of rock permeability. Except condition (a), actually, other two conditions are not easy to satisfy in laboratory. When oil or water is used for the test, the measurement result may deviate from the real value of rock permeability due to the physical adsorption of oil on the surface of rock particles or the clay swelling caused by passing water in the rock. Consequently, this measurement is generally performed on clean and dried samples; and dry gases (usually air, nitrogen or helium) are often used as measuring fluid. The reasons include:

- (a) The state of steady flow can be rapidly reached;
- (b) Dried gas does not alter the surface structure of minerals in the rock;
- (c) 100 % fluid saturation for one fluid in rock pores is easy to build;
- (d) The availability of gases.

The only problem is the gas expansion in rock pores, which results in obvious slippage effect in the measurement.

2.4.3 Gas Permeability and Klinkenberg Effect

2.4.3.1 Equation of Gas Permeability

Rock permeability is often measured on rock cores with permeameter in the laboratory. Figure 2.46 shows the flow chart of a permeameter. Air or nitrogen is usually used as the measuring fluid. Upstream and downstream pressures are measured by manometers on both sides of the core and the flow rate of the gas is measured by means of a calibrated flowmeter at outlet.

Darcy's equation defining permeability is linked to laminar flow in porous media. This laminar flow cannot be achieved in gas flowing. Suppose there is a core sample in core holder. When measuring, let upstream pressure and downstream pressure be p_1 and p_0 , respectively, as shown in Fig. 2.47.

When gas flows through the core at constant temperature, the volumetric flow rate Q of the gas will vary with pressure because of the great compressibility of gas. Therefore, the values of Q at each cross-sectional area are different, which result in no validity of Darcy's law in this flow. Suppose the flow of gas through the core is steady (not change with time), the mass flow rate of gas is then the same at each cross section.

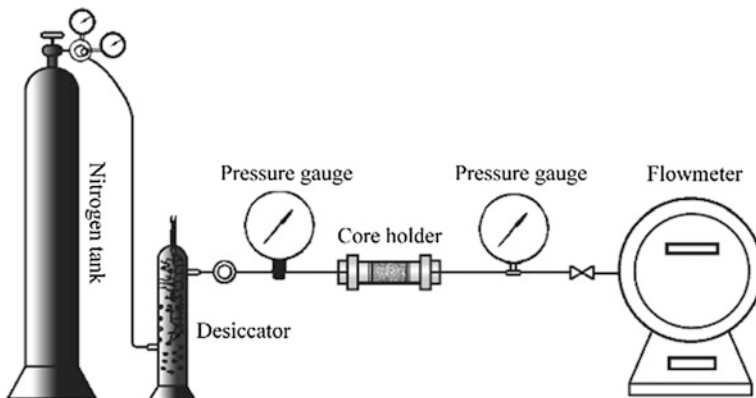
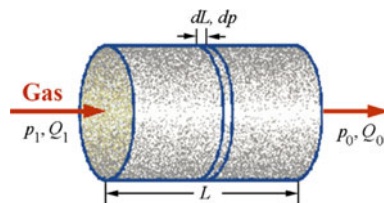


Fig. 2.46 Typically flow chart for a permeameter

Fig. 2.47 Flow of gas in a core



Assume that the gas flowing in a rock follows ideal gas behavior (at low pressures), the following relationships are valid according to Boyle's law:

$$Qp = Q_0p_0 = \text{const.} \quad (2.83)$$

where Q is the volumetric flow rate of a gas at any slice of the core, cm^3/s ; p is the pressure at the slice corresponding to the flow rate Q , MPa; Q_0 is the volumetric flow rate of the gas at pressure p_0 , cm^3/s ; p_0 may be the pressure of outlet or inlet, MPa.

From Eq. (2.83), we have

$$Q = Q_0p_0/p \quad (2.84)$$

Suppose the volumetric flow rate of the gas is constant at each slice of the core, a differential equation of Darcy's law can be applied:

$$Q = -K \frac{A}{\mu} \cdot \frac{dp}{dL} \times 10 \quad (2.85)$$

Note that a negative sign appears on the right side of Eq. (2.85) as gas flows from high pressure to low pressure.

Combine Eqs. (2.84) and (2.85), then:

$$K = -\frac{Q_0p_0\mu}{A} \cdot \frac{dL}{pdp} \times 10^{-1} \quad (2.86)$$

Separate variables and integrate for length L :

$$\int_{p_1}^{p_2} Kpdp = -\int_0^L \frac{Q_0p_0\mu}{10A} dL \quad (2.87)$$

Then

$$K_a = \frac{2Q_0p_0\mu L}{A(p_1^2 - p_2^2)} \times 10^{-1} \quad (2.88)$$

where K_a is the permeability of rock to gas, D; p_1 is upstream pressure, MPa; p_2 is upstream pressure, MPa; p_0 may be downstream pressure or upstream pressure, MPa; Q_0 is the volumetric flow rate of the gas at pressure p_0 , cm^3/s .

Equation (2.88) is the formula of gas permeability. It can be seen that the gas permeability is a function of the square difference of pressure, but not a function of pressure difference.

2.4.3.2 Klinkenberg Effect

Klinkenberg (1941) [49] discovered that the gas permeability of a rock is different from the permeability measured using nonreactive liquids at the same conditions. The permeability of a sample to gas is always larger than that to liquid. The difference is considered to be caused by *slippage effect*, a phenomenon well known with respect to gas flow in capillary tubes. Klinkenberg postulated, on the basis of his experiments, that liquids have a zero velocity at the surface of rock particles, while gases exhibit some finite velocity at the grain surface. In other words, the gases exhibited *slippage* at the grain surface. The slippage resulted in a higher flow rate of the gas at a given pressure difference.

This effect is related with the different physical actions of a liquid and a gas flowing in a porous network. At lower pressures, this effect is most noticeable while it gradually becomes less noticeable as pressure increases.

Darcy's law describes the flow of viscous fluids, e.g., conventional liquids, in porous media. When a viscous liquid flows in a capillary tube, the velocities of the liquid in the tube gradually decrease from the center to the wall of the tube. The velocity profile of the liquid in tube is conic shape. Namely, the velocity of the liquid at the wall of the tube is zero, and the velocity at the center of the tube is the maximum (Fig. 2.48).

According to the kinetic theory of gas, however, gas molecules are considered as tiny spheres with diameters of approximately $1/10,000 \mu$. At atmospheric pressure, gas molecules move extremely fast (near the velocity of sound) and stochastically collide between gas molecules. The mean free path of a gas is inversely proportional to gas pressure. It may be very large for low-pressure gases.

When flowing in a rock, at pressures much higher than atmospheric pressure, most of gas molecules collide each other instead of with the walls of pores because of the large number of molecules in the unit volume of the rock. The internal friction of gas flow in the pores is chiefly ascribed to the collisions between gas molecules.

On the other hand, when the pressure is low enough, the distance between gas molecules is comparable to the pore sizes. In this situation, the internal friction causing by collisions of gas molecules tends to disappear and the flow is clearly affected by the collisions between gas molecules and the wall of pores molecular flow then occurs and friction factor is no longer meaningful in this flow. Because there are collisions instead of adsorptions between gas molecules and the wall of pores, gas molecules is definitely mobile rather than immovable on the internal

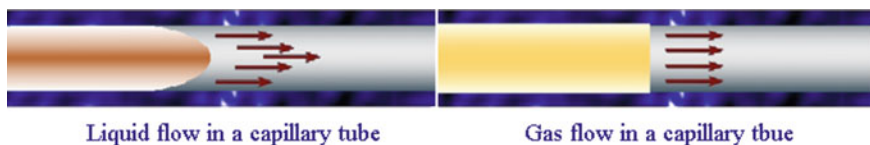


Fig. 2.48 Velocity profiles for a viscous fluid and a gas in capillary tubes

surfaces of pores. The velocity of gas molecules on the internal surfaces of pores is absolutely not zero. Comparing with the flow of a liquid in capillary tube, gas molecules flowing in a tube seem to slip from the surfaces of pores. Thus, whenever the mean free path of gas molecules approaches the dimensions of pores, gas molecules are always in motion on the pore surfaces and contribute an additional flux which results in an increase in the permeability of a rock. This phenomenon is called *slippage phenomenon (effect)*, or *Klinkenberg effect*.

Klinkenberg has reported variations in the permeability of a rock when different gases are used to measure the rock (Fig. 2.49). Figure 2.49 shows that gas permeability is a linear function of the reciprocal of average pressures for permeability measurement; and each gas has different linear relationships. Moreover, the lighter the gas molecules, the greater the slope of the straight lines. The results shown in Fig. 2.49 indicate that gas permeability increases with the decrease in the average pressure and the molecular weight of gas. The gas permeability of a roc is not a constant.

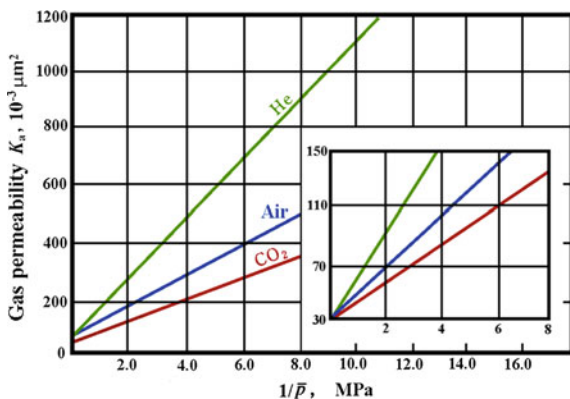
However, when extrapolating the lines in Fig. 2.49 to infinite average pressure, all lines extend to the same point at the permeability axis. The value of the point was designated K_∞ , and called equivalent liquid permeability or Klinkenberg permeability.

Based on the experimental results, Klinkenberg related the apparent permeability K_a measured for gas at an average pressure \bar{p} to the true permeability K_∞ , by an equation with the form:

$$K_a = K_\infty \left(1 + \frac{b}{\bar{p}} \right) \quad (2.89)$$

where K_a is gas permeability, D , K_∞ is named equivalent liquid permeability, Klinkenberg permeability, or absolute permeability, D ; \bar{p} is average pressure, and defined as the arithmetic mean of upstream flowing pressure and downstream flowing pressure, namely: $\bar{p} = (p_1 + p_2)/2$, MPa; b is a constant for a given gas in a given medium, called *slip coefficient*.

Fig. 2.49 The permeabilities to gases at different average pressures (Klinkenberg [49])



Slip coefficient b depends upon the mean free path of gas molecules, the average pressure \bar{p} and the pore size of a porous medium, and can be expressed as:

$$b = \frac{4C\lambda\bar{p}}{r} \quad (2.90)$$

where $C \approx 1$; r is the average pore radius of the porous medium; λ is the mean free path of gas molecules at average pressure \bar{p} ; λ is related with the size of the gas molecule and the density of gas molecules by the following expression:

$$\lambda = \frac{1}{\sqrt{2}\pi d^2 n} \quad (2.91)$$

where d is the diameter of the gas molecule; n is the density of gas molecules at average pressure \bar{p} .

Equations (2.89)–(2.91) indicate that gas permeability is directly dependent on the size of gas molecules, the pore size of a rock, and the average pressure for measurement. The smaller the size of gas molecules and pore radius, the lower the average pressure, and the larger the gas permeability K_a ; and the slippage effect is more remarkable. Therefore, slippage effect is an essential reason causing the departure of gas permeability from the rock permeability. Many phenomena described above can be explained from the slippage point of view.

It needs to be emphasized that Klinkenberg effect (slippage effect) is physically significant in any situation where the mean free path of gas molecules in a porous medium approaches the pore dimension, i.e., the effect can be ignored when molecular collisions with the pore wall rather than between gas molecules are significant. Gas permeability is then enhanced by “slip flow.” Therefore, It is not hard to see that slippage effect is greater in fine-grained, lower permeability rocks than in higher permeability rocks (Fig. 2.50). Generally, the correction for slippage effect is necessary for rocks which absolute permeability is lower than 10 mD.

The most reliable way to correct Klinkenberg effect is the graphic method based on the experimental data. It is procedure is as follows:

- For a given sample, measure several sets of permeabilities to a given gas;
- Plot each datum of gas permeability versus the reciprocal of average pressure ($1/\bar{p}$) in a cartesian coordinates system. Then draw the straight line fitting these data.
- The absolute permeability is obtained by extrapolating the line to the point of $1/\bar{p} = 0$ on the gas permeability axis. The intercept (K_∞) of K_a axis is the absolute permeability of the sample. Namely, $K = K_\infty$.

Example 2.7 The following data (Table 2.19) were obtained during permeability measurement in the laboratory. Given that the length of a sandstone core is 1.30 cm; its area is 1.36 cm^2 ; the viscosity of the gas is 0.0183 mPa s .

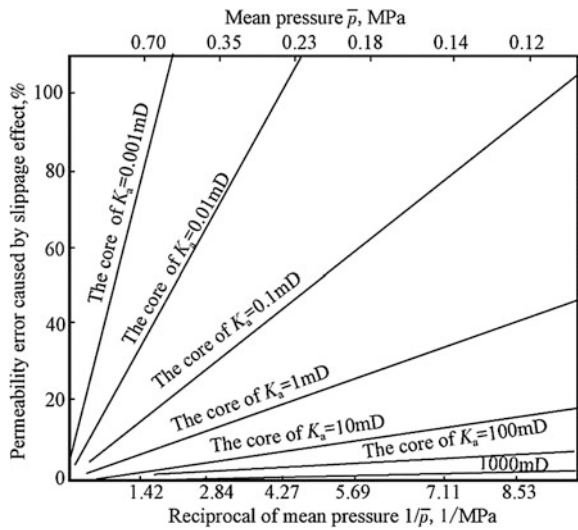


Fig. 2.50 Correction chart for Klinkenberg effect (CoreLab [43])

Table 2.19 The results of gas permeability measurement for a sandstone core

No.	Flow rate, Q (cm ³ /s)	Upstream pressure, p_1 (MPa)	Reciprocal of average pressure, $1/\bar{p}$ (1/MPa)	Gas permeability, $K_a(D)$
1	0.405	0.113	9.4	0.512
2	1.790	0.150	8.0	0.501
3	3.456	0.186	7.0	0.492
4	6.179	0.233	6.0	0.488

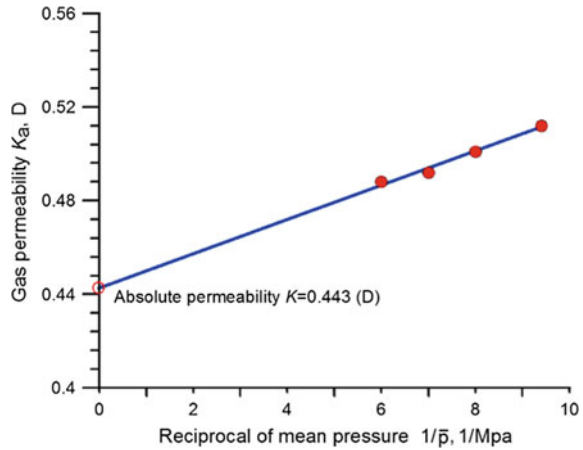
The downstream pressure for each test is 0.1 MPa. Determine the absolute permeability of the core.

Solution

Using Eq. (2.88), the gas permeability for each measurement is calculated as follows:

$$\begin{aligned} K_{a1} &= \frac{2Q_0 p_0 \mu L}{A(p_1^2 - p_0^2)} \times 10^{-1} \\ &= \frac{2 \times 0.405 \times 0.1 \times 0.0183 \times 1.30}{1.36(0.113^2 - 0.1^2)} = 0.512(D) \end{aligned}$$

Fig. 2.51 The correction for the Klinkenberg effect using experimental data of gas permeability



Similarly,

$$K_{a2} = 0.501(D);$$

$$K_{a3} = 0.492(D);$$

$$K_{a4} = 0.488(D)$$

The gas permeabilities, listed in Table 2.19, are then plotted versus $1/\bar{p}$ as shown Fig. 2.51; and a best-fit line drawn through these points. The absolute permeability of the core is read at the intercept as 0.443 D.

2.4.4 Measurement of Rock Permeability

2.4.4.1 Type of Core Analysis

In the laboratory, there are two categories of core analysis measurement. They are conventional core analysis and special core analysis.

Conventional core analysis [42]

In conventional core analysis, two cases can be considered: partial analysis and complete analysis

Partial analysis only includes porosity and air permeability measurements. This kind of analysis is only for exposed and not fresh or extracted samples.

In this case, air permeability and porosity are customarily measured using a perfectly geometrical sample, which is cut as either a cylinder or a cube. Before measurements, the sample should be carefully washed with solvent. Then the analysis for the sample includes the following measurements:

- (a) Air permeability either with a variable head permeameter or with a constant head permeameter;

- (b) Horizontal and vertical permeabilities with a cubic sample; if not, two cylindrical samples must be collected.
- (c) Porosity either by immersion (see Sect. 2.2.4) which immediately gives the true mass densities or by gas expansion or by some other methods, but the first probably gives the best results.

Complete analysis includes the measurements of all physical properties of a rock, namely, the porosity, air permeability, and water, gas, and oil saturation measurements. This complete analysis can only be carried out for fresh or well-preserved samples. In this case, the method which seems to give the best results for fluid saturation is the so-called fluid summation method.

For finishing these analyses, a fresh core is divided into three parts, each for one testing. Using fresh samples, complete analysis should include the following measurements:

- (a) A cube (for porosity, horizontal, and vertical permeability) or a cylinder (for porosity, horizontal permeability) is collected from one part.
- (b) One part (about 40 g) is used for determination of gas saturation.
- (c) One part selected as far as possible from the core center is coarsely ground: approximately 125 g. It is used for determination of oil and water saturation through the atmospheric pressure distillation method.

Special core analysis [42]

Special core analysis includes the following contents:

- (a) Capillary pressure: i) by the restored state method; ii) by mercury injection, evaporation, or centrifuging.
- (b) Liquid permeability.
- (c) Relative gas/oil permeability.
- (d) Relative water/oil permeability.
- (e) Water flood susceptibility test.
- (f) Formation factor and resistivity ratio.
- (g) Other measurements: wettability, etc.

These tests are necessary for the study of reservoir problems and make it possible to predict field behavior in time and to estimate reserves. They are usually made in specialized laboratories.

2.4.4.2 Measurement of Rock Permeability

In the laboratory, several techniques can be used for permeability measurements of cores, depending on sample dimensions and shape, degree of consolidation, type of the fluid used (gas, water or oil), ranges of confining and fluid pressure applied, and permeability range of the core.

For consolidated rocks, samples are generally collected in geometric shapes:

- (a) Either full cylinders with the following approximate dimensions: diameter = 2.3–4.0 cm and height = 2.5–5.0 cm.
- (b) Or cubes with 2 cm sides.
- (c) Or hollow cylinders for radial circular flow measurements.

When the state of consolidation is insufficient, it is necessary to make a small assembly or to coat:

- (a) For example, to coat a fragment with wax in order to measure permeability in side wall core analysis or for unconsolidated sand.
- (b) Coating with bakelite or plastic (“plasticore” by means of a thermosetting plastic).

A special technique is necessary for measuring the permeability of cores from fissured limestone deposits. These measurements are made on whole cores.

In a word, the laboratory measurement of rock permeability can usually be divided into: conventional small core analysis and whole core analysis.

Measurement of small core

In general, a cube (K_h , and K_v) or a cylinder (K_H) sample is collected, washed with a combination of a solvent extraction apparatus and a centrifuge and then dried in an appropriate manner. Cylinder sample may be cut either parallel or perpendicular to the bedding plane of the rock, depending on the direction of flow of interest.

In the laboratory, gas permeability is measured by passing a gas of known viscosity through a core sample of measured dimensions and then measuring flow rate and pressure drop. Then the gas permeability values will be corrected for the Klinkenberg effect by means of laboratory data so as to obtain absolute permeability of the rock. Two types of instruments are usually used in the laboratory:

- (a) Constant head permeameter, core laboratories type.
- (b) Variable head permeameter, IFP type.

Measured values using constant head equipment range from a low of 0.1 mD to 20 D. Data accuracy declines at high and low permeability values and is within $\pm 0.5\%$ of true value otherwise.

Constant head permeameter (Core Laboratories type) This equipment is designed for plug or whole core permeability measurements. This experiment may be used for single or multiphase, compressible fluid or liquid measurements and can also be used under reservoir pressure and temperature.

Figure 2.52 shows a diagram of a constant head permeameter. A clean, dry sample is placed in a holder; it must fit snugly and allow no air to bypass along the sides of the sample. Air is usually used as gas flow. Upstream and downstream pressures are measured by manometers on both sides of the core and air flow is measured by means of a calibrated outlet. Air permeability can then be calculated using Eq. (2.88).

Hassler core holder may be used with this instrument. The Hassler system is an improvement of the rubber plug system whose tightness is limited at certain pressures. The core is placed in a flexible rubber tube (Fig. 2.53). The Hassler cell has these advantages:

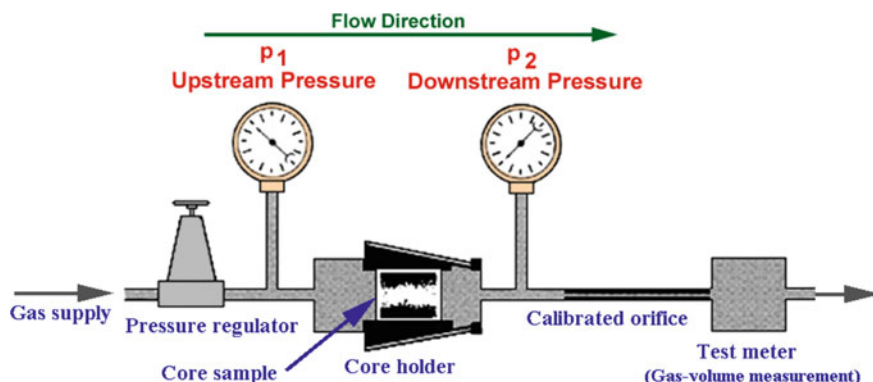
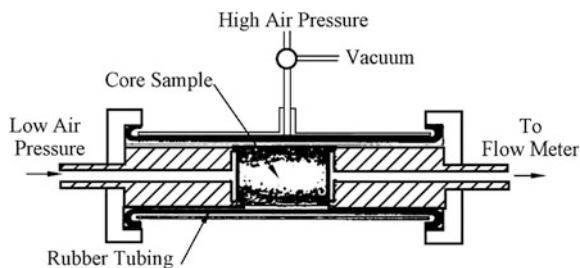


Fig. 2.52 Schematic diagram of a constant head permeameter

Fig. 2.53 Hassler type core holder (Torsæter and Abtahi [50])



- (a) Excellent tightness.
- (b) Can be used for samples of different sizes.
- (c) Much higher pressure or Δp can be used.

It can be used for measuring relative permeability.

Variable head permeameter (IFP type)

At present, the method of “flow-tube air permeability” is widely used in China. Figure 2.54 shows the apparatus of the method, which is also called variable head permeameter. It consists of the following parts [42]

- (a) Core holder with a rubber stopper.
- (b) A glass tube for flow rate measurements. This tube consists of three different sections with diameter gradations from the top down of 1–10–50 mm so that there are three ranges of sensitivity (for $1 < k < 2000$ mD) [42].
- (c) A constant level water tank.
- (d) A rubber bulb for bringing water up to desired point (or for suction under partial constant vacuum).
- (e) A valve for cutting off the suction bulb from the inner space.

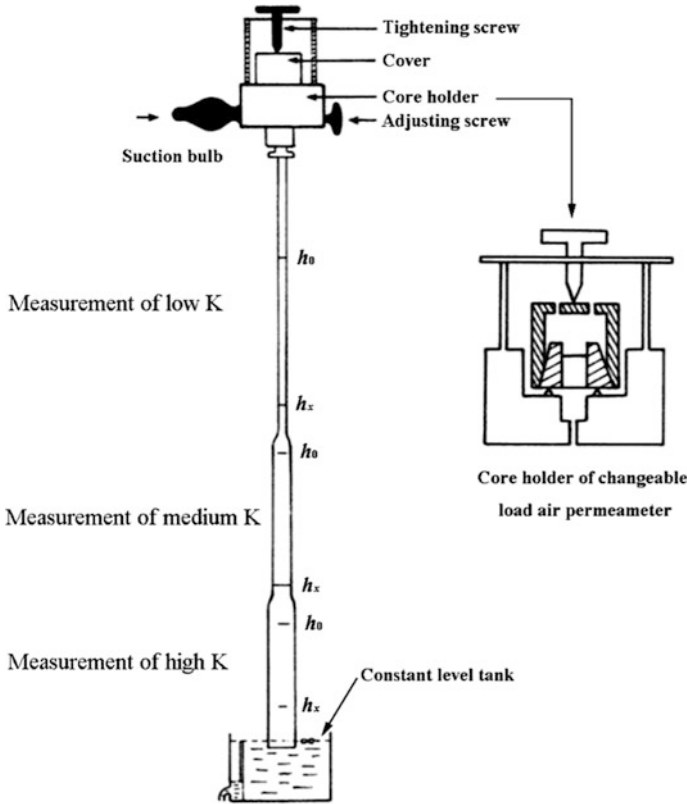


Fig. 2.54 Variable head permeameter, IFP type (Torsæter and Abtahi [50])

In the test, the top of the core keeps connected with the atmosphere. When air is pumped out by suction bulb, the water level in tube is quickly brought to a desired position h_0 of the tube. When pumping is stopped, the water level in tube falls under hydrostatic head; and the pressure difference is thus built between the two ends of the core due to the negative pressure in tube. Then outside air enters into the tube through the core.

The speed of water level falling down depends on the permeability of the core. That is to say, if the permeability of the core is great, the water level falls fast. Conversely, it falls slowly. Accordingly, when the time of water level falling from the position h_0 to the position h_x in the tube is measured, the permeability of the core can be given by an equation with the following form:

$$K_a = \frac{B\mu L}{TA} \times 10^6 \quad (2.92)$$

where K_a is air permeability, mD; μ is air viscosity, mPa s; L is sample length, cm; A is the cross-sectional area of the sample, cm²; T is the time of water level falling from h_0 to h_x in the tube, s; B is a constant depending on the geometry and units of the apparatus, cm³/atm.

Constant B can be determined either by measurement or by calculating as follows:

$$B = C \left\{ -2F[\ln(Cp_0 - h_x) - \ln(Cp_0 - h_0)] - \frac{V^* - 1033.6p_0F + h_0F}{Cp_0} \left[\ln \frac{Cp_0 - h_x}{h_x} - \ln \frac{Cp_0 - h_0}{h_0} \right] \right\} \quad (2.93)$$

where F is the cross-sectional area of flow tube, cm²; p_0 is atmospheric pressure, atm; h_0 is the height between the water level in the tank and the position h_0 in the tube, cm; h_x is the height between the water level in the tank and the position h_x in the tube, cm; C is a constant, $C = 2067.2$; V^* is the void volume over h_0 in the tube, cm³.

The flow tube consists of three different sections with different inside diameter, which corresponds to different values of $(h_0 - h_x)$. Thereby, different sections of the tube may be selected to measure depending on the permeability of the core.

Measurement of whole core

Whole core, also called full-diameter core, measurements are normally restricted to carbonates and formations containing vugs and fractures. These measurements can be made on sandstones, but care must be taken to ensure that the invasion of drilling fluid solids does not reduce horizontal permeabilities. This type of reduction can happen in sandstones as well as in chalky limestones. In the latter, ground limestone powder that has been produced by the temperature and by pressure conditions encountered while coring is sometimes plastered on the core, causing permeability reduction. This powder must be removed prior to whole core horizontal permeability measurements, as it forms a “skin” that will result in erroneously low permeability values. This material can sometimes be cut away easily when the core is wet, otherwise sand blasting or rasping of the dry core may be necessary to remove the plaster coat.

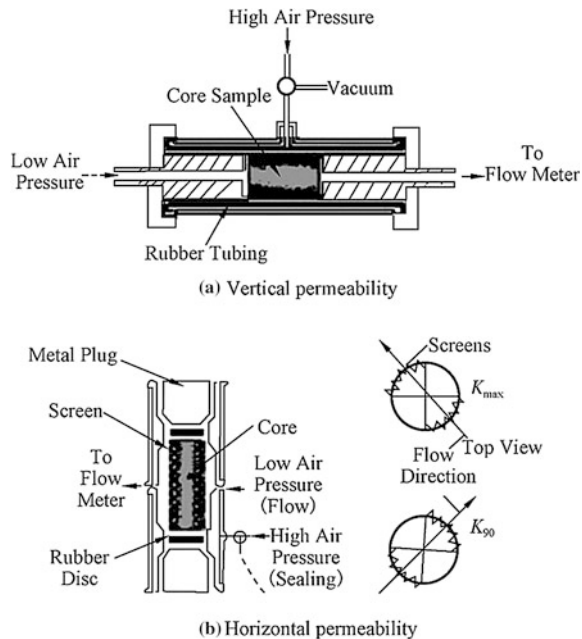
The plugs in this case were cut from the center of the full-diameter core and were not subjected to damage. The data indicate that permeability reduction was greatest for the high-permeability section, but all full-diameter values were reduced.

Measurement of vertical permeability

The permeability which is measured by fluid flowing vertically through the bedding planes of a sample is known as vertical permeability of the sample.

Vertical permeability on a full-diameter sample is easily measured using a Hassler core holder, as illustrated in Fig. 2.55a. The sample is placed in the apparatus and the rubber tubing is then collapsed around the core. With the introduction of high pressure air to the holder, the tubing provides a seal along the sides

Fig. 2.55 Horizontal and vertical permeability measurement apparatus for full-diameter cores



of the sample. Low-pressure air is introduced on the upstream end of the core and the measurements needed to compute permeability are easily made. After upstream and downstream pressures and flow rates being measured, gas permeability can be determined by Eq. (2.88).

Measurement of horizontal permeability

Permeability measured with gas flowing parallel to the bedding planes of a sample is called horizontal permeability of the sample.

Measuring the horizontal permeability of a whole core is more complex. Screens are placed on opposite sides of the full-diameter core (Fig. 2.55b) and the sample is then moved into the core holder. Non-permeable rubber disks are placed on each end of the sample and the rubber tubing is again for collapsing around the core. Low pressure air, introduced into the center of the holder, passes through the rubber boot, intersects with the screen, and flows vertically in the screen. The air then flows through the full-diameter sample along its full height and emerges on the opposite side, where the screen again allows free flow of the air to the exit port. In this test, the flow length is actually a function of the core diameter. The cross-sectional area of flow is a function of the length of the core sample and of the core diameter. The screens are selected to cover designated outer segments of the full-diameter sample. In most cases, the circumference of the core is divided into four equal quadrants and the screens occupy two opposite quadrants.

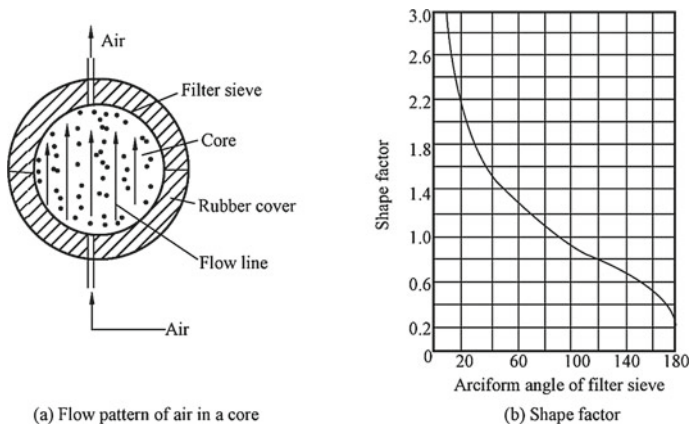


Fig. 2.56 Illustration of horizontal flow in core and shape factor chart (He [21])

In this measurement, a shape factor is introduced to gas permeability equation as follows:

$$K_{ha} = E \cdot \frac{2Q_0 p_0 \mu}{L(p_1^2 - p_2^2)} \times 10^{-1} \quad (2.94)$$

where K_{ha} is the horizontal gas permeability of the sample, D ; L is core length, cm; p_1 is upstream pressure, MPa; p_0 is downstream pressure or upstream pressure, MPa; p_2 is downstream pressure, MPa; Q_0 is the volumetric flow rate of gas under p_0 , cm^3/s ; E is shape factor; μ is gas viscosity, mPa s.

Shape factor generally depends on the diameter of the sample and the arciform angle of filter sieve which is used for assigning gas to the lateral surface of the sample, e.g., $E = 1$ if the area of filter sieve equals to the 1/4 lateral area of the sample (Fig. 2.56b).

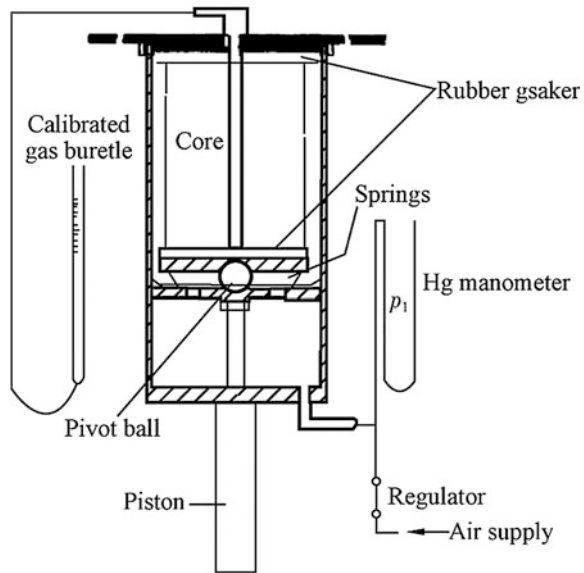
It needs to be emphasized that at least twice measurements are necessary for horizontal permeability of a full-diameter sample. The second measurement is made at right angles to the first. When fractures are visible in the core, the first measurement is made parallel to these fractures. The maximum horizontal permeability is recorded as k_{\max} and the other at 90° to the direction of this flow is labeled k_{90} (Fig. 2.55b).

Measurement of radial permeability

The permeability which is measured under the condition of gas flowing radially in a cylindrical sample is called radial permeability of the sample.

The apparatus for circular radial flow test is shown in Fig. 2.57. According to Darcy's law, gas radial permeability can be determined by the following expression:

Fig. 2.57 Full-diameter radial permeameter (Monicard [42])



$$K_{ra} = \frac{Q_0 p_0 \mu \ln\left(\frac{d_e}{d_w}\right)}{\pi h (p_1^2 - p_2^2)} \times 10^{-1} \quad (2.95)$$

where K_{ra} is gas radial permeability of sample, D; d_e is sample diameter, cm; d_w is the diameter of the inner pore in the sample, cm; h is the height of the sample, cm; p_1 is upstream pressure, MPa; p_0 is downstream pressure or upstream pressure, MPa; p_2 is downstream pressure, MPa; Q_0 is the volumetric flow rate of gas under p_0 , cm³/s; μ is gas viscosity, mPa s.

The point of the test is that the small inner pore must be drilled in midmost of the cylinder core so as to keep absolutely same radius of flowing in all directions.

2.4.5 Factors of Affecting Rock Permeability

Permeability is a measure of the ability of a rock to transmit fluids. It is a critical property to define the flow capacity of a rock. From the sedimentary point of view, numerous factors affect the magnitude and/or direction of rock permeability, including various factors in the process of sedimentary and diagenesis, such as rock texture, sedimentary structure, overburden pressure, and formation temperature and so on. The effects of these factors on rock permeability are much more complicated than that on rock porosity.

2.4.5.1 Sedimentation and Tectonism

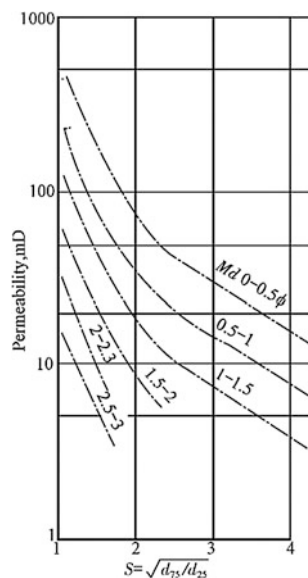
Rock texture

Since the pore structure and porosity of a rock are basically determined by rock skeleton texture, it controls the permeability of the rock as well. From the rock texture point of view, following factors are mainly involved: grain-size, sorting, grain arrangement, the component, and content of cementing, and cementation type, etc.

Experimental evidence indicates that rock permeability is direct proportional to the square of grain diameter ($K \propto cd^2$, where c is a characteristic of the rock properties) at certain sorting. Therefore as grain-size increases, an increase in permeability occurs. Figure 2.58 illustrates the significant effect of grain-size and sorting on rock permeability. It is not as dramatic as grain-size; however, the illustration does show that an increase in sorting (better or well sorted) will improve the permeability. This is why in gravel pack operations the selection of the gravel is important, both from a size and sorting viewpoint.

Particle shape and texture influence permeability to a great extent. Elongated or irregular particles create flow paths more tortuous than the spherical particles (Fig. 2.59). Also, particles with a rough surface texture provide more frictional resistance to flow than smooth textured particles. Thus, both elongated shape and rough texture reduce the rate of fluid flowing through the rock, i.e., reduce rock permeability.

Fig. 2.58 Effect of grain-size and sorting on permeability (Bear and Weyl [51])



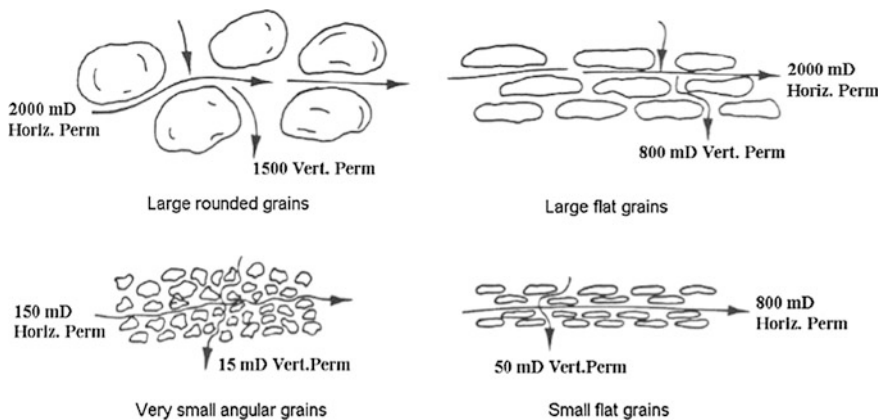


Fig. 2.59 Textural parameters and permeability (Link 1982)

As shown in Fig. 2.59, the shape and packing of grains also affect the directivity of permeability. Notice in these examples, the more angular the grains or the flatter the grain shape, a more pronounced anisotropy develops.

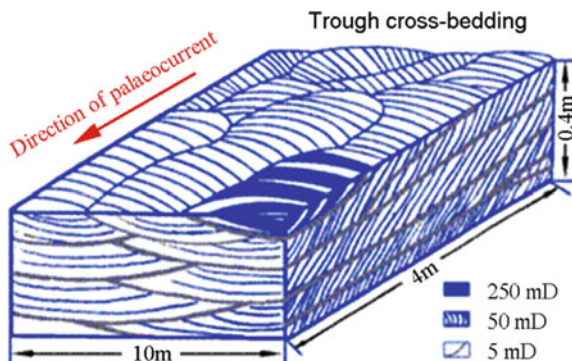
Reservoirs with directional permeability are called *anisotropic* [12]. Anisotropy greatly affects fluid flow characteristics of the rock. The difference in permeability measured parallel and vertical to the bedding plane is the consequence of the origin of the sediment, because grains settle in the water with their longest and flattest sides in a horizontal position. Subsequent compaction of the sediment increases the ordering of the sand grains so that they generally lie in the same direction [12].

Platy minerals such as muscovite, and shale laminations, act as barriers to vertical permeability. In this case, the ratio of vertical permeability (i.e., perpendicular to the bedding plane) to horizontal permeability (i.e., along the bedding plane) (K_h/K_v) generally ranges from 1.5 to 3 and may exceed 10 for some reservoir rocks. Sometimes, however, K_v is higher than K_h due to fractures or vertical jointing and vertical solution channels. Joints act as barriers to horizontal permeability only if they are filled with clay or other minerals.

The importance of the clay minerals as a determinant of permeability is often related not only to their abundance but also to their mineralogy and composition of the pore fluids. The clay minerals, which coat the grain surfaces, expand and/or become dislodged due to changes in the chemistry of the pore fluids or mud filtrate invasion, will considerably reduce the permeability.

In sandstone rocks, fracturing is not an important cause of the secondary permeability, except where sandstones are interbedded with shales, limestones, and dolomites. In carbonates, the solution of minerals by percolating surface and sub-surface acidic waters as they pass along the primary pores, fissures, fractures, and bedding planes, increases the permeability of the reservoir rock.

Fig. 2.60 Permeability directivity in beddings



Sedimentary structure

Permeability is a vector property, and as such, is greatly affected by directional heterogeneity within a rock. The commonest cause of such heterogeneities is bedding. It is a general rule that the vertical permeability within a reservoir is lower than that in the bedding plane (horizontal permeability). In most cases, the vertical permeability is often about a third of that in the horizontal direction. It should be noted that some of the difference between the vertical and horizontal permeabilities results from differences in the way the local stress fields in the vertical and horizontal directions compact pores and close microcracks [31].

In addition, along different directions (such as perpendicular or parallel to the direction of palaeocurrent), there are different permeabilities in a rock. Permeabilities in different directions sometimes may be a difference of several orders of magnitude (Fig. 2.60).

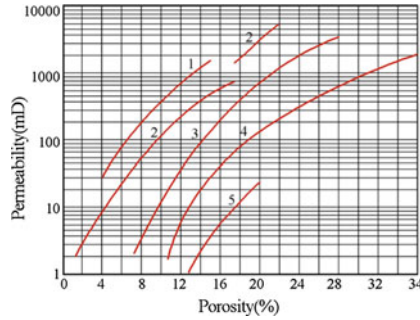
In a word, the skeleton texture of rocks determines the magnitude of rock permeability while sedimentary structure controls the directivity of rock permeability.

Fracture

Both in clastic and carbonate rocks, there are fractures. Among the factors affecting rock permeability, fracture always plays an important role.

In most strata, fracture often has little contribution to total pore space; but it has significant effect on rock permeability because the isolated pores in rocks can be connected with each other by fractures, which thus increase the ability of rock transmitting fluids.

In conventional rocks, the formation and distribution of fractures mainly depend on the lithology and position of reservoir rocks in structure. In general, fractures may be formed in the position of structure with larger curvature. The more brittle the rock, more fractures occur in the rock.



1-Coarse and very coarse grains; 2-Coarse and medium grains; 3-Fine grains; 4-Argillaceous particles; 5- Clay particles

Fig. 2.61 Permeability-porosity relationship (Chilingarian and Wolf 1964, form [21])

2.4.5.2 Pore Structure

Permeability is highly dependent on the pore structure (pore size, tortuosity, connectivity, porosity, etc.) of a rock. The most popular correlation expressing permeability as a function of porosity and pore size is derived by Kozeny–Carman:

$$K = \frac{\phi r^2}{8\tau^2} \quad (2.96)$$

where K is rock permeability, D ; ϕ is rock porosity, f ; r is average pore radius, cm; τ is the tortuosity of rock pores, dimensionless.

Obviously, rock permeability increases with the porosity and the pore size of a rock, and decrease with the increase in the tortuosity of rock pores. Figure 2.61 shows a relationship of permeability versus porosity obtained from rock samples or porous media. In addition, experience has shown that rock permeability increases as well with the increase in the connectivity of pores and the decrease in the aspect ratio.

In a word, the larger the pore sizes, the better the pore structure, the higher the rock permeability.

2.4.5.3 Diagenesis

Geostatic pressure

The action of geostatic pressure in rocks leads to a decrease in pore space as a result of rock particles becoming more closely packed. Permeability is thus sensitive to pressures that compact the rock. This compaction can occur in any direction not just

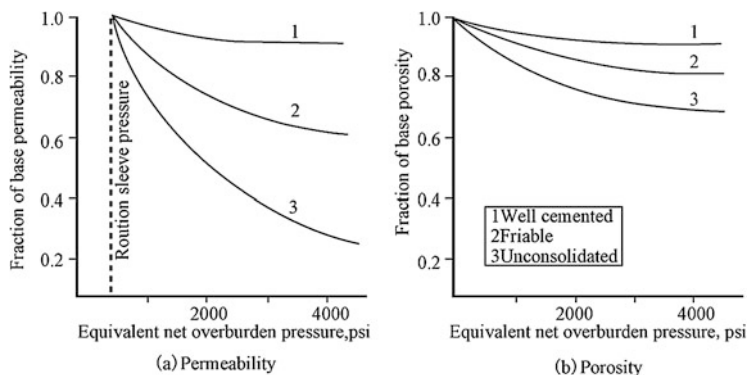


Fig. 2.62 Comparison of the effect of overburden pressure on permeability and porosity (Paul [31])

vertically. However, vertical compaction is usually the most important. Figure 2.62a shows the effect of increasing the hydrostatic confining pressure on the permeability of a rock. As shown on the figure, well-consolidated rock has a high modulus of rigidity and does not reduce in volume significantly under confining pressures. The change in slope for the second sample could be due to crushing of the sand grains or fracture closure point. Permeability measurements are normally made on samples of this type with only an adequate confining pressure to prevent bypass of the flowing fluid around the sample. Unconsolidated or poorly consolidated rock undergoes much greater reduction of permeability under confining pressure.

Formation temperature

Research shows that a complementary relationship occurs on the effects of overburden pressure and formation temperature to rock permeability.

Figure 2.62 shows the effect of overburden pressure on permeability compared to the effect upon porosity. It can be seen that overburden pressure affects permeability much more than porosity. This is because permeability is very sensitive to the tortuosity of pore paths in which fluid flows, and such changes are associated with very small changes to the rock porosity. Overburden pressure compacts the rock pressing the grains together. The size of the pores reduces little, but the pore-throats that control the passage of fluids between the pores undergo much greater closure, affecting the permeability to a greater extent.

H.A. Byplakof et al. found that the effect of pressure on permeability will decrease with the increase in temperature, especially under lower pressure. This is because the rock matrix and the fluids in rock pores expand when temperature increases, which exactly counterworks the compaction of the rock. Necessarily, the decrease in permeability caused by pressure increase is weakened.

It is worth noting that rock permeability is not fixed for a given reservoir. Some human factors, such as the physical and chemical reactions caused by poor

compatibility between rock and outside working fluid, as well as the inappropriate treatment and unreasonable recovery rate, will lead to the change in rock permeability.

Cementation

Whatever in the early or in the late diagenetic stage, both the deposit of cement materials and cementation will decrease the pore space of a rock and increase the aspect ratio of pore system. These changes finally lead to a decrease in rock permeability.

2.4.6 Estimation of Rock Permeability

Theoretically, a reservoir rock may be equivalent to an ideal porous medium which consists of capillary tubes (Fig. 2.63). The estimation of rock permeability here is based on the principle of equivalent filtrational resistance between real rock and the ideal porous medium.

Consider a rock of cross-sectional area A and length L as an ideal porous medium which is made up of straight capillary tubes in a parallel, with the spaces between the tubes sealed by a cementing material (Fig. 2.62b). If all capillary tubes are the same radius r (cm) and length L (cm), the total flow rate Q (cm³/s) of a fluid through the bundle of tubes, according to Poiseuille's equation, is:

$$Q = \frac{nA\pi r^4 \Delta p}{8\mu L \tau} \times 10 \quad (2.97)$$

where r is the radius of capillary tubes, cm; τ is the tortuosity of rock pores, dimensionless; n is the number of capillary tubes in unit cross-sectional area of the ideal medium; Δp is the pressure loss over length L , expressed in MPa. A is the

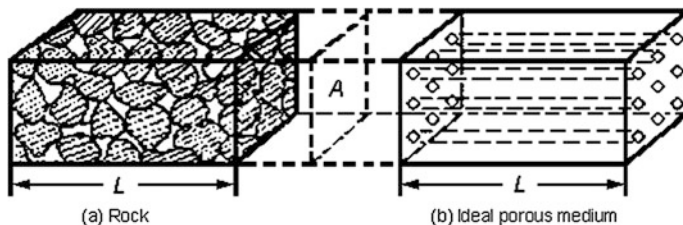


Fig. 2.63 Schematic diagram of real rock and ideal porous medium

cross-sectional area, including cemented zones, of this bundle of capillary tubes, namely the ideal medium, cm^2 . μ is fluid viscosity, mPa s .

On the other hand, Darcy's law can be used to characterize the flow of the same fluid through the rock. The flow rate is thus:

$$Q = K \frac{A \Delta p}{\mu L} \times 10 \quad (2.98)$$

where K is rock permeability, D . Other parameters are the same as above.

Combine Eqs. (2.97) and (2.98), and solving for K gives:

$$K = \frac{n\pi r^4}{8\tau} \quad (2.99)$$

By definition, the porosity of the ideal porous medium is:

$$\phi = \frac{V_p}{V_b} = \frac{nA\pi r^2 L}{AL} \quad (2.100)$$

Combine Eqs. (2.99) and (2.100), an estimation of rock permeability is obtain as follows:

$$K = \frac{\phi r^2}{8\tau^2} \quad (2.101)$$

where K is rock permeability, D ; ϕ is rock porosity, f ; τ is the tortuosity of rock pores, dimensionless; r is the average radius of rock pores, cm .

If $\tau = 1$, $K = 0.125\phi r^2$;

If $\tau = 1.2$, $K = 0.087\phi r^2$;

If $\tau = 1.4$, $K = 0.064\phi r^2$.

Besides, rock permeability can also be determined or estimated by other methods, such as well logging, well tests, production data, or other correlations based on rock permeability. These methods refer to the relevant books available.

2.4.7 Permeability of Fractured Rocks*

In principle, the permeability established in the case of a conventional reservoir remains valid in the case of a fractured reservoir. But in the presence of two systems (matrix and fractures), permeability has to be redefined in relation to matrix ("matrix" permeability), to fractures ("fracture" permeability) and to the fracture-matrix system ("fracture-matrix" permeability or total system permeability).

This redefinition may create some confusion in relation to a fractured reservoir and fracture permeability, which may be interpreted either as “single-fracture permeability” or as “fracture network permeability,” or sometimes as entire “fracture-bulk volume permeability.” The resulting expression of permeability is, therefore, examined in more detail. Therefore, some expressions of permeability involving fracture will be examined and discussed in detail.

2.4.7.1 Permeability of Pure Fracture System

Single-fracture case

The feature of fractures must be first described for defining fracture permeability. Generally, the density n and width b of fractures are often used to depict the fractures of a rock.

The density n of fractures is the ratio of the total length of fractures in flowing cross section to the area of the flowing cross section:

$$n = \frac{L}{A} \quad (2.102)$$

where A is the flowing cross-sectional area, cm^2 ; L is the total length of fractures in the flowing cross section, cm .

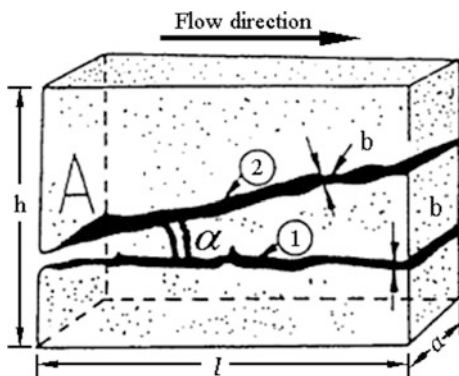
Then, fracture porosity can be denoted by the ratio of fracture area to rock area:

$$\phi_f = \frac{Lb}{A} = nb \quad (2.103)$$

where ϕ_f is fracture porosity, f ; b is the average width of fractures, cm .

In single-fracture case, the flow cross section is represented only by the fracture void areas (excluding the surrounding matrix area). In a simplified case of a block, where the fracture is parallel to the flow direction (Fig. 2.64, fracture ① is parallel to the horizontal flow direction), the flow rate through the fracture is given by,

Fig. 2.64 Matrix block containing two fractures: fracture 1 ($\alpha = 0$); fracture 2 ($\alpha > 0$)



$$q_f = ab \frac{b^2}{12\mu} \cdot \frac{\Delta p}{l} \quad (2.104)$$

where a is the width of the block, cm; ab is the effective “real flow cross-section” of a single fracture as shown in Fig. 2.64: $A = ab$, cm²; l is the length of the block, cm; p is pressure drop between two ends of the block, atm.

If the single fracture forms an angle with the flow direction (Fig. 2.64, fracture ②), the real cross-section (ab) will remain unchanged, but the fracture will be projected on the flow direction:

$$q_f = ab \frac{b^2 \cos^2 \alpha}{12\mu} \cdot \frac{\Delta p}{l} \quad (2.105)$$

On the other hand, based on the Darcy concept, if limited to the entire cross-flow section. $A = ab$, the rate is expressed by:

$$q = A \frac{K_f}{\mu} \cdot \frac{\Delta p}{l} = ab \frac{K_f}{\mu} \cdot \frac{\Delta p}{l} \quad (2.106)$$

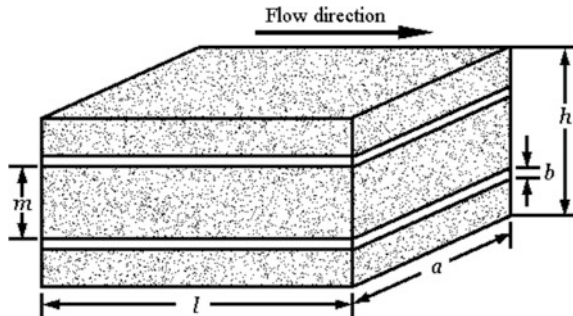
where K_f is the permeability of single fracture, cm².

The further comparison of Eqs. (2.105) with (2.106) will lead to,

$$K_f = \frac{b^2}{12} \cos^2 \alpha \quad (2.107)$$

For a fracture system having n fractures of similar orientation, namely the fracture system is formed by parallel groups of fractures; the fracture permeability is expressed by:

Fig. 2.65 Multi-fracture layer. (Fractures are parallel to the bedding planes)



$$K_f = \frac{\cos^2 \alpha}{12} \sum_i^n b_i^2 \quad (2.108)$$

where α is the included angle of fractures with the flow direction, °; b_i is the average width of i th fracture, cm; K_f is fracture permeability, cm^2 .

Multi-fracture case

If, instead of a single fracture, the flow is examined through a fracture system formed by several parallel fractures (n) as shown in Fig. 2.65, separated by matrix of height “ m ,” then the flowing equation (similar to the case of single fracture) will give:

$$q = n \times ab \frac{b^2}{12\mu} \cdot \frac{\Delta p}{l} = ah \frac{K_f}{12\mu} \cdot \frac{\Delta p}{l} \quad (2.109)$$

Thus:

$$K_f = \frac{b^2}{12} \cdot \frac{nb}{h} \quad (2.110)$$

In terms of the definition, the fracture porosity based on Fig. 2.65 is:

$$\phi_f = \frac{nabl}{ahl} = \frac{nb}{h} \quad (2.111)$$

Substituting ϕ_f for nb/h in Eq. (2.110), then:

$$K_f = \frac{b^2 \phi_f}{12} \quad (2.112)$$

where ϕ_f is fracture porosity, f ; b is the average width of fractures, cm; K_f is fracture permeability, cm^2 .

2.4.7.2 Permeability of Fracture-Matrix System

The permeability of a fracture-matrix system may be represented by the simple addition of the permeabilities of matrix K_m and fractures K_f :

$$K_t = K_m + K_f \quad (2.113)$$

where K_t is the (total) permeability of a rock, cm^2 ; K_m is the matrix permeability of the rock, cm^2 ; K_f is the fracture permeability of the rock, cm^2 .

If Eq. (2.113) refers to the block described in Fig. 2.64 where the specific permeabilities of matrix and fracture were discussed, it is evident that the total

permeability will depend on flow direction. Any change in direction of flow will change the value of K_f , since K_f depends on the relationship between fracture and flow directions.

If the fracture network of the rock consists of n parallel fractures which form an angle (α) with the flow direction, the total permeability is expressed by combining Eq. (2.108) as:

$$K_t = K_m + \sum_i^n K_{fi} \cos \alpha \quad (2.114)$$

where K_{fi} is the fracture permeability of i th fracture, expressed in cm^2 , and determined by Eq. (2.112).

2.5 Average of Rock Parameters

Property parameters, e.g., porosity, permeability, and so on, of reservoir rocks are the vital foundation for the evaluation of reservoir properties, the estimation of geologic reserve and the performance design of hydrocarbon reservoirs. But the original rock parameters, obtained directly or indirectly from wells, are usually an aggregate of scattered data in a wide range of scale. Because smaller scale heterogeneities always exist, the values of rock properties from core analysis or well logging must be averaged to represent the characteristic of the entire reservoir or individual beddings for studies of petroleum engineering. The commonly used averaging techniques are presented below.

2.5.1 Arithmetic Mean

Arithmetic mean is the simplest method; and it can be expressed as follows:

$$\bar{\phi} = \frac{\sum_{i=1}^n \phi_i}{n}, \quad \bar{K} = \frac{\sum_{i=1}^n K_i}{n} \quad (2.115)$$

where $\bar{\phi}$ is the average porosity of given reservoir unit, %; ϕ_i is the porosity of each sampling point, %; \bar{K} is the average permeability of the rock unit, mD; K_i is the permeability of each sampling point, mD; n is the number of sampling points.

This method is mainly used to determine the average values of rock parameters from well logging for individual beds.

2.5.2 Weighted Average

The averaging technique is often used to determine the average values of parameters of reservoirs. It also includes the following two kinds of methods.

Generally weighted

This averaging can be calculated either by thicknesses of layers or by areas controlled by sampling points, or by volumes represented by sampling points. These methods, taking permeability for an example, are briefly depicted as follows.

Thickness-weighted:

$$\bar{K} = \frac{\sum_{i=1}^n K_i h_i}{\sum_{i=1}^n h_i} \quad (2.116)$$

where h_i is the thickness of each layer or bed, m; K_i is the permeability of each layer or bed, mD. n is the number of data.

This method is often used to determine the average values of reservoir properties in the direction vertical to the bedding.

Area-weighted:

$$\bar{K} = \frac{\sum_{i=1}^n K_i A_i}{\sum_{i=1}^n A_i} \quad (2.117)$$

where A_i is the influenced area of each sampling point (e.g., each well), m²; K_i is the mean permeability in area A_i , mD; n is the number of sampling points.

Table 2.20 Permeability data from a core analysis report

Depth (m)	Permeability (mD)
3998–4002	150
4003–4007	110
4007–4009	170
4010–4015	130

Table 2.21 The length (h) of cores and the product of the length and permeability of each core

Thickness of bedding, h (m)	Permeability, K (mD)	$K_i h_i$
4	150	600
4	110	440
2	170	340
5	130	650
$\sum h_i = 15$		$\sum K_i h_i = 2030$

Table 2.22 Permeability data from a core analysis report

Sample	Length of cores, h (m)	Permeability (mD)
1	0.2	80
2	0.1	20
3	0.5	50
4	0.1	30
5	0.3	70

Table 2.23 The product of the length and permeability of each core

Sample	Length of cores, h (m)	Permeability, K (mD)	$h_i \ln(K_i)$
1	0.2	80	0.88
2	0.1	20	0.30
3	0.5	50	1.96
4	0.1	30	0.34
5	0.3	70	1.27
–	$\sum h_i = 1.2$	–	$\sum h_i \ln(K_i) = 3.96$

This method is often used to determine the average values of reservoir parameters in the direction parallel to the bedding.

Volume-weighted:

$$\bar{K} = \frac{\sum_{i=1}^n K_i A_i h_i}{\sum_{i=1}^n A_i h_i} \quad (2.118)$$

where A_i is the influenced area of each sampling point, m^2 ; h_i is the reservoir thickness corresponding to the area A_i , m; K_i is the mean permeability of each sampling point, mD.

This method is mainly used in dynamic research of petroleum reservoir engineering to determine the average values of parameters in an oil group.

Example 2.8 Permeability data from a core analysis report are listed in Table 2.20. Calculate the average permeability of the reservoir from which the core is sampled.

Solution

From Table 2.20, the length of each core can be determined by the depth range of coring. The results are listed in the first column of Table 1.21. The product of the length and permeability of each core are then calculated and listed in the last column of Table 2.21.

Then, the average permeability of the reservoir is:

$$\bar{K} = \frac{\sum_{i=1}^n K_i h_i}{\sum_{i=1}^n h_i} = \frac{2030}{15} = 135.3 \text{ (mD)}$$

Specially weighted

It is rare to encounter a homogeneous reservoir in actual practice because heterogeneity is common in petroleum reservoirs. All physical properties of rocks vary in petroleum reservoir, merely different variations for different properties. Generally, rock permeability is more variable than porosity, and more difficult to determine. Yet a good knowledge of permeability distribution in a reservoir is critical to the prediction of reservoir depletion by any recovery process. Therefore, it is necessary to find an average permeability to represent the flow characteristics of the entire reservoir or individual unit. The proper way of averaging permeability depends on how permeabilities were distributed as the rock was deposited.

Following special permeability-averaging techniques are commonly used to determine an appropriate average permeability to represent an equivalent homogeneous system.

Logarithmic average permeability:

$$\log \bar{K} = (\log K_1 + \log K_2 + \cdots + \log K_n)/n \quad (2.119)$$

Reciprocal average permeability:

$$\frac{n}{\bar{K}} = \frac{1}{K_1} + \frac{1}{K_2} + \cdots + \frac{1}{K_n} \quad (2.120)$$

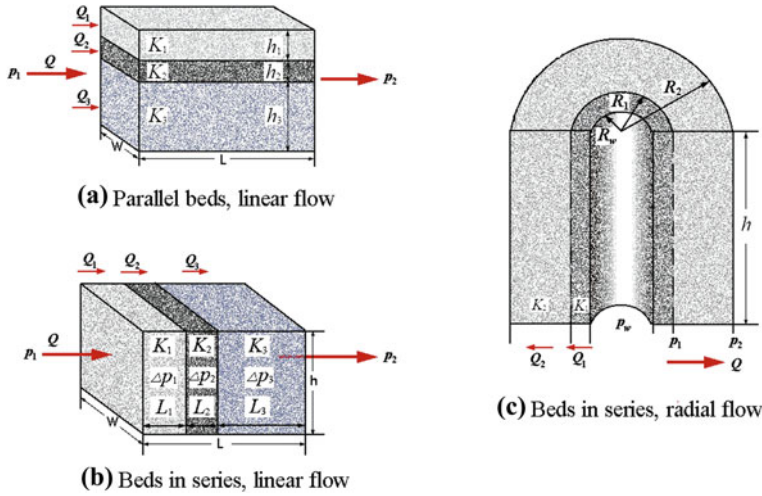
Harmonic average permeability:

$$\bar{K} = \frac{\sum_{i=1}^n h_i}{\sum_{i=1}^n h_i/K_i} \quad (2.121)$$

Equation (2.121) is basically used for calculating the average value of vertical permeability of oil layer.

Geometric average permeability:

Experiments have illustrated that the most probable permeability behavior of a heterogeneous medium (formation), made up of n randomly distributed samples (regions) of differing uniform permeabilities, K_1 to K_n , approaches that of a uniform system having a permeability that is equal to the geometric average. The geometric average is defined mathematically by the following relationship:



Q_i : flow rate; P_i : pressure; ΔP_i : pressure difference; K_i : permeability; h_i : thickness of a bed; L_i : width of the rock; R_i : radius of the bed.

Fig. 2.66 Types of composite layers

$$\bar{K} = \exp \left[\frac{\sum_{i=1}^n h_i \ln(K_i)}{\sum_{i=1}^n h_i} \right] \quad (2.122)$$

where K_i is the permeability of core sample i , mD; h_i is the thickness of core sample i , m; n is the total number of samples.

If the thicknesses (h_i) of all core samples are the same, Eq. (2.122) can be simplified as follows:

$$\bar{K} = \sqrt[n]{K_1 \times K_2 \times \cdots \times K_n} \quad (2.123)$$

Example 2.9 Given the following core data (Table 2.22), calculate the geometric average permeability of the cores.

Solution

According to the data of Table 2.22, the product of the length and permeability of each core can be calculated. The results are listed in the last column of Table 2.23.

Then the geometric average permeability is:

$$\bar{K} = \exp \left[\frac{\sum_{i=1}^n h_i \ln(K_i)}{\sum_{i=1}^n h_i} \right] = \exp \left(\frac{3.96}{1.2} \right) = 52.22(\text{mD})$$

2.5.3 Average Based on Flow Process

Permeability variations can occur laterally or vertically in a reservoir as well as in the vicinity of a wellbore. Since permeability is a measure of the ability of a rock transmitting fluids, the most accurate permeability behavior of a heterogeneous rock, which is made up of randomly distributed regions of differing permeabilities, should be determined by the flow process of fluid through the rock.

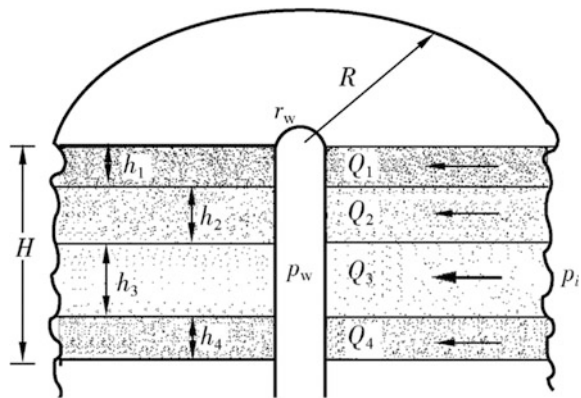
The detailed analysis is extremely complex. However, it is possible to analyze two simple systems of different permeabilities that occur within core analysis and petroleum reservoirs. These are (a) flow through beds in series, and (b) flow through beds in parallel (Fig. 2.66).

2.5.3.1 Parallel Beds—Linear Flow

Linear flow through parallel beds without vertical communication is shown in Fig. 2.66a. Each bed has different permeability. The pressures at the inlet (p_1) and outlet (p_2) of the complete unit will be the same for all beds, but each bed i will transport a different fraction Q_i of the total flow rate Q . Thus:

$$Q = \sum_i Q_i \quad (2.124)$$

Fig. 2.67 Parallel beds, radial flow



Suppose bed i has a length L , a width W , a net thickness h_i , and a uniform permeability K_i . Noting that the total thickness of the complete unit is the sum of each net thickness ($H = \sum h_i$). Applying Darcy's law for the linear flow of a fluid with viscosity μ gives:

$$\frac{\bar{K} H w (P_1 - P_2)}{\mu L} = \sum_i \frac{K_i h_i w (P_1 - P_2)}{\mu L} \quad (2.125)$$

where \bar{K} is the average permeability of the complete unit.

After canceling common terms, and substitute h_i for H , we obtain following expression:

$$\bar{K} \sum_i h_i = \sum_i K_i h_i \quad (2.126)$$

Solving for \bar{K} gives:

$$\bar{K} = \frac{\sum_i K_i h_i}{\sum_i h_i} \quad (2.127)$$

Apparently, the average permeability for linear flow through parallel beds of different permeabilities equals the thickness-weighted average of the individual permeability. If each bed has the same thickness, the average permeability is then the arithmetic average of the each permeability.

2.5.3.2 Parallel Beds—Radial Flow

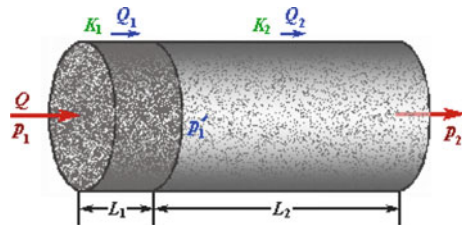
This is the case of several parallel layers in which fluid simultaneously flows toward the well (Fig. 2.67). Each layer supplies a flow rate Q_i , determined by Darcy's law. The total flow rate through all layers is $Q = \sum Q_i$.

In the case of radial flow through a parallel combination of beds, we have:

$$Q_i = \frac{2\pi K_i h_i (P_i - P_w)}{\mu \ln \frac{R}{r_w}} \quad (2.128)$$

$$Q = \frac{2\pi \bar{K} H (P_i - P_w)}{\mu \ln \frac{R}{r_w}} \quad (2.129)$$

Fig. 2.68 Illustration of contaminated core



where \bar{K} is the average permeability of the parallel combination unit, D; K_i is the permeability of the i th bed, mD; H is the total thickness of the parallel beds, cm; P_i is the terminal pressure of the system, atm; P_w is bottom hole pressure, atm; R is the radius of formation edge, cm; r_w is well radius, cm; Q_i is the flow rate supplied by each layer, cm³/s; Q is the total flow rate through the parallel beds, cm³/s.

Substituting Q_i for Q in Eq. (2.128), we obtain:

$$\frac{2\pi\bar{K}H(P_i - P_w)}{\mu \ln \frac{R}{r_w}} = \frac{2\pi(P_i - P_w) \sum_i K_i h_i}{\mu \ln \frac{R}{r_w}} \quad (2.130)$$

Simplify Eq. (2.130), then:

$$\bar{K} = \frac{\sum_i K_i h_i}{\sum_i h_i} \quad (2.131)$$

It is clear that the average permeability for radial flow in parallel beds is the same relationship as the linear flow, namely the thickness-weighted average permeability.

2.5.3.3 Beds in Series—Linear Flow

Consider a core contaminated by drilling fluid. Generally, a thin mud cake is formed at one end of the core after the drilling fluid experiment. Mud cake and the clean part of the core constitute a series combination of beds with different permeabilities (Fig. 2.68). Determine the average permeability of the core contaminated.

Suppose:

- mud cake: thickness = L_1 , cm; permeability = K_1 , D;
- clean part of the core: thickness = L_2 , cm; permeability = K_2 , D;
- pressures at the two ends of the core: p_1 and p_2 , atm;
- pressure at the cross section of the mud cake contacted with the clean part of core is p_1' , atm;
- total flow rate of fluid passing through the core is Q , cm³/s;
- fluid viscosity is μ , mPa s
- flow rate through mud cake is Q_1 , cm³/s; flow rate through the unpolluted part of the core is Q_2 , cm³/s.

Under the condition of continuous steady flow, the flow rate of the single-phase fluid is constant, namely $Q = Q_1 = Q_2$; and the total pressure drop Δp is equal to the sum of the pressure drops across each bed:

$$\Delta p = \Delta p_1 + \Delta p_2 \quad (2.132)$$

Applying Darcy's formula for the mud cake and the clean part of the core separately:

For the mud cake:

$$Q_1 = -K_1 \frac{A(p' - p_1)}{\mu L_1} \quad (2.133)$$

Then:

$$\Delta p_1 = (p' - p_1) = -\frac{Q_1 \mu L_1}{AK_1} \quad (2.134)$$

For the clean part of the core:

$$Q_2 = -K_2 \frac{A(p_2 - p')}{\mu L_2} \quad (2.135)$$

Then:

$$\Delta p_2 = (p_2 - p') = -\frac{Q_2 \mu L_2}{AK_2} \quad (2.136)$$

For the whole core:

$$Q = -\bar{K} \frac{A(p_2 - p_1)}{\mu L} \quad (2.137)$$

where \bar{K} = the average permeability of the core.

Then:

$$\Delta p = (p_2 - p_1) = -\frac{Q \mu L}{A \bar{K}} \quad (2.138)$$

Substituting for the pressure drops in Eq. (2.132) by Eqs. (2.134), (2.136) and (2.138):

$$\frac{Q \mu L}{A \bar{K}} = \frac{Q_1 \mu L_1}{AK_1} + \frac{Q_2 \mu L_2}{AK_2} \quad (2.139)$$

Simplify Eq. (2.139):

$$\frac{L}{\bar{K}} = \frac{L_1}{K_1} + \frac{L_2}{K_2} \quad (2.140)$$

Then:

$$\bar{K} = \frac{L_1 + L_2}{L_1/K_1 + L_2/K_2} \quad (2.141)$$

This is the average permeability of linear flow through beds in series. Compare it with Eq. (2.121), we see that Eq. (2.141) is exactly the expression of the harmonic mean of permeability.

2.5.3.4 Beds in Series—Radial Flow

Permeability in the neighborhood of the well changes with the effects of well completion depending on the method and treatment. Consider the formation near a wall. Part of it is damaged by drilling fluid, as shown in Fig. 2.66c. The formation thus turns into a combination of two zones in series. The average permeability of the damaged formation needs to determine.

As the flow of single-phase through formation is radial, the combination of polluted zone and unpolluted formation is equivalent to a series combination of layers.

Suppose:

- Polluted zone: radius = R_1 , cm; permeability = K_1 , mD; edge pressure of polluted zone = p_1 , atm;
- Unpolluted formation: permeability = K_2 , mD; supply radius of oil layer = R_2 , cm, terminal pressure = p_2 , atm;
- Radius of wellbore is R_w , cm; bottom hole pressure is p_w , atm;
- Thickness of the formation is h , cm;
- Total flow rate through the formation is Q , cm^3/s ;
- Viscosity of fluid is μ , mPa s;
- Flow rate through polluted zone = Q_1 , cm^3/s ; flow rate through unpolluted formation = Q_2 , cm^3/s ;

Under the condition of continuous steady-state flow, the rate of radial flow is constant, namely $Q = Q_1 = Q_2$; and the total pressure drop Δp is equal to the sum of the pressure drops across each zone:

$$\Delta p = \Delta p_1 + \Delta p_2 \quad (2.142)$$

Substituting for the pressure drop by applying radial Darcy's equation gives:

$$\frac{Q\mu \ln \frac{R_2}{R_w}}{2\pi K h} = \frac{Q_1\mu \ln \frac{R_1}{R_w}}{2\pi K_1 h} + \frac{Q_2\mu \ln \frac{R_2}{R_1}}{2\pi K_2 h} \quad (2.143)$$

So that,

$$\bar{K} = \frac{\ln \frac{R_2}{R_w}}{\frac{1}{K_1} \ln \frac{R_1}{R_w} + \frac{1}{K_2} \ln \frac{R_2}{R_1}} \quad (2.144)$$

The calculation can be extended to a larger number of rings. And the calculation can also be utilized for estimating the effects of mud invasion, acidizing, or fracturing.

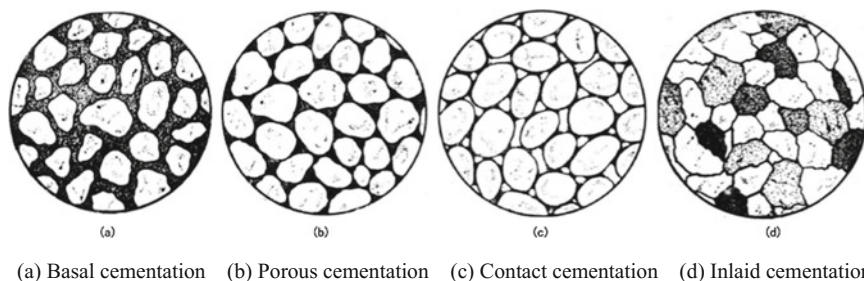


Fig. 2.69 Illustration of cementation type for clastic rocks (Zhu [4])

2.6 Sensitivity of Reservoir Rocks

In reservoir rocks, there are always some minerals which are sensitive to some factors (such as invading fluids, flow rate, and so on) and thus cause a decrease in reservoir permeability in the process of oil/gas production. This phenomenon is known as *formation/reservoir damage* or *reservoir sensitivity*. Formation damage is an undesirable operational and economic problem that can occur during the various phases of an oil/gas reservoir life time, including well drilling, hydraulic fracturing, oil/gas production, workover operations, etc. Formation damage may be caused by various processes, including chemical, physical, biological, and thermal interactions of formation and fluids, and deformation of formation under stress and fluid shear. In order to avoid, control, and remedy formation damage, the sensitivity of reservoir rocks needs to well understood. And various properly experimental techniques are necessary to evaluate the sensitivity of petroleum reservoirs.

In sandstones, rock sensitivity is mainly caused by cementing agents in rocks. The sensitivity of reservoir rocks is thus dependent on the components, content, and distribution of cementing agents in sandstones.

In this section, the cementing agent and cementation type of sandstone reservoirs are first briefly reviewed. After that, the mineralogy and sensitivity of reservoir rocks, and the method of evaluating reservoir sensitivity are presented.

2.6.1 Cementing Agent and Cementation Type

2.6.1.1 Cementing Agent

Cementing agents, or cements for short, are minerals which are chemically precipitated from pore fluids around and between grains in clastic rocks. The cement plays a part in welding and hardening clastic sediments during lithification. It forms an integral and important part of the rock. The formation of cement agents affects the porosity and permeability of the rock, and always make reservoir quality worse.

Many minerals may become cements. The most common in petroleum reservoirs is clay minerals, but calcite, other carbonates iron oxides, and so on also undergo the process.

In clastic rocks, cements generally are crystalline and noncrystallized authigenic minerals, and the content of cements is generally less than 50 %. In sandstones, and the most common cements—in decreasing order of frequency—are calcite, dolomite, quartz, siderite, anhydrite, muscovite, kaolinite, chlorite, and hematite, and so on. In total, more than 40 minerals in rocks are known as cementing agent. They mainly include argillaceous, siliceous, calcareous, ferruginous, sulfate cements, etc. Perceptibly, different cement agents give rise to different sensitivities and result in different damage to petroleum reservoirs.

2.6.1.2 Cementation Type

In clastic rocks, the distribution and contact pattern of cement agents with grains is known as *cementation type*. The cementation type of a rock primarily depends on the component, amount, and formation conditions of cementing agents. Generally, the following four cementation types may be found in rocks: basal, porous, contact, and inlaid cementations (Fig. 2.69).

Basal cementation

There is a lot of fillings between clastic particles. Particles without contacting with each other, float in fillings in such cementation (Fig. 2.69). This type of cementation generally represents the rapid sedimentation of high-density fluids. Basal cementation is also called progenetic cementation because it is formed in the period of sedimentation. In this kind of rock, the cementation is very strong owing to the large amount of cements; and the major void space is the micropores occurring in cementing agents. As a result, the quality of the rock with basal cementation is poor, and this kind of rock can hardly hold oil or gas.

Porous cementation

It occurs in the rocks with grain-supporting structure. Clastic particles constitute the bracket-like structure, and most of particles are of point contact (Fig. 2.69b). In porous cementation, cements are relatively less, and only fill heterogeneously in the pores between particles. The strength of porous cementation is weaker than that of basal cementation. Therefore, the quality of rocks with porous cementation is better than that of rocks with basal cementation.

Table 2.24 Physical properties of rocks with different cementation types

Physical property	Contact cementation	Porous cementation	Basal cementation
Porosity (%)	23–30	18–28	8–17
Permeability (mD)	50–1000	1–150	<1

Contact cementation

In this kind of cementation, clastic particles are of point contact or long contact (Fig. 2.69c); and cements are much fewer, usually less than 5 %. Cement deposits the places where particles contact each other. Cements are mostly authigenic mineral or weathered detritus; and argillaceous cements are very common. Relatively, the quality of rocks with contact cementation is the best. They can hold oil and gas very well.

Inlaid cementation

In the period of diagenesis, clastic particles of sandy sediments can contact more tightly due to the effect of pressure solution in evidence. The contact formed between particles evolves into long contact and concavo-convex contact, even into sutured contact (Fig. 2.69d). As a result, inlaid cementation is formed between particles. In this kind of cementation, clastic particles sometimes cannot be clearly distinguished from siliceous cements; and it looks like no cements between particles. Therefore, this kind of cementation is also known as no-cement cementation. The rock with inlaid cementation has no capacity of holding oil and gas.

It is obvious that the porosity and permeability of rocks are greatly influenced by the cementation type of rocks. Table 2.24 lists the physical properties of rocks which are from the formations of tertiary system in North China depression.

2.6.2 Sensitive Minerals in Cements

The sensitivity of reservoir rocks is basically induced by the sensitive minerals in cement agents of rocks. Sensitive minerals means the minerals which are sensitive to water, oil, salt, or other matters invading into oil beds, or sensitive to the velocity of fluid flowing through the bed during the process of oil production; and the permeability of oil beds is thus decreased by the sensitivity of minerals.

In petroleum reservoirs, sensitive minerals usually include the following groups: water-sensitive minerals, salinity-sensitive minerals, acid-sensitive minerals, alkali-sensitive minerals, and minerals sensitive to flow velocity.

Water-sensitive minerals

In petroleum reservoirs, water-sensitive minerals mean the minerals which are sensitive to aqueous solutions with lower salinity than that of formation water. On contacting low-salinity water, some physical and chemical changes will occur in water-sensitive minerals, including hydration swelling, dispersion, desquamation, and migration. Thereby, once water sensitivity occurs in a reservoir, the rock pores and throats will be severely blocked, and the permeability of the reservoir will be greatly declined.

Water-sensitive minerals generally include various clay minerals, such as montmorillonite, illite/smectite mixed-layer minerals, chlorite/smectite mixed-layer minerals, hydromuscovite, etc.

Salinity-sensitive minerals

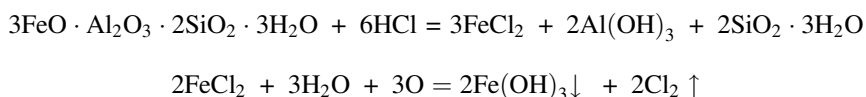
In petroleum reservoirs, if the salinity of formation water is changed by invading fluids, the following changes will occur in some minerals in the reservoir: hydrating and swelling, dehydrating and shrinking, and even cracking and breaking off. These changes finally lead to a great deal of fines occurring in pores. The fines then migrate with fluids flowing in pores, and could pile up at narrow throats. The reservoir permeability could be terribly damaged at the end. The phenomenon is called *salinity sensitivity*. These minerals are known as salinity-sensitive minerals.

Salinity sensitivity minerals usually include gypsum, barite, calcite, celestite, halite, magnetite, etc.

Acid-sensitive minerals

Acid-sensitive minerals denote the minerals which react with acid invading in reservoirs and then generate chemical precipitation; and in the process of chemical reaction, fine particles could be released from the rock matrix. In petroleum production, acidizing (pumping acidizing fluids into wells) is the most essential well stimulation. In well acidizing, the acid sensitivity of minerals can cause rock pore-throats to be seriously plugged by the precipitates formed in reaction and the fines released from the rock matrix. As a result, the permeability of reservoir rocks can be notably declined.

Acid-sensitive minerals generally include hydrochloric acid-sensitive minerals and hydrofluoric acid-sensitive minerals. Common hydrochloric acid-sensitive minerals are iron-containing minerals, such as Fe-rich chlorite, ferroan calcite, ankerite, hematite, siderite, pyrite, glauconite, hydrobiotite, etc. These minerals react with hydrochloric acid and release ferrous ions (Fe^{2+}). In oxygen-rich solutions, Fe^{2+} can be converted to the precipitate $\text{Fe}(\text{OH})_3$ (Fe^{3+}). And under acidic conditions (5–6 pH), Fe^{2+} becomes the colloidal precipitate. These precipitate will block the pores and finally cause serious reservoir damage. For example, the chemical reactions of Fe-rich chlorite with hydrochloric acid are:



In order to prevent the damage of Fe^{2+} and $\text{Fe}(\text{OH})_3$ to reservoirs, addition agents, such as iron chelating agent, oxygen-cleaner, and so on, can be added into acidizing liquids in well acidizing.

Hydrofluoric acid-sensitive minerals are Ca/Mg-containing carbonate minerals, mainly including limestone (CaCO_3), dolomite ($\text{CaMg}(\text{CO}_3)_2$), anorthite, scolecite zeolite, and so on. Reacting with hydrofluoric acid, these minerals produce indissoluble fluoride which can plug pores and finally cause reservoir severe damage.

In addition, part of silicate minerals, such as monox, quartz, feldspar, etc., are also sensitive to hydrofluoric acid. Under certain conditions, they can react with hydrofluoric acid and produce the precipitates of fluorosilicate and fluorin-aluminate and silicone gel. The petroleum reservoirs are then damaged by these precipitates

Alkali-sensitive minerals

Alkali-sensitive minerals are the minerals which can react with the high-pH fluids invading in the reservoir and then disperse, desquamate, or generate new silicate precipitates and silicon gelinite. As a result, rock pores are plugged by these fine particles and precipitate; and the permeability of reservoir rocks is markedly decreased

Alkali-sensitive minerals include feldspar, albite, chalcedony, microcrystalline quartz, hydromuscovite, and opal.

Minerals sensitive to flow velocity

In petroleum reservoirs, the high-speed flow of fluids can cause fines of minerals to fall off the rock matrix and to flow with the fluid. The rock pores could thus be blocked by migrating fines, which then leads to a decline in rock permeability. This sensitivity is caused by the flow velocity of fluids flowing in reservoir rocks. So, the minerals sensitive to the flow velocity of fluids in rocks are referred to as velocity-sensitive minerals.

Velocity-sensitive minerals are usually the minerals whose particle size is less than 37 μm . Velocity-sensitive minerals may be clay minerals or non-clay minerals, such as kaolinite, microcrystalline quartz, microcrystalline feldspar, etc.

2.6.2.1 Clays and Clay Mineralogy

Petroleum reservoirs contain more or less clay minerals. Clays are one of the most important groups of minerals that destroy the permeability of reservoir rocks because some of them are sensitive to various invading fluids during oil/gas production. Clays are a very complex family of minerals.

Clay minerals

Clays are generally platy-shaped or fibrous-shaped minerals that present in sedimentary rocks as packs of crystals. Clay minerals are very small in size. It is normally considered to be less than 2 μm in clay size according to standard particle size classifications. They can only see with aid of electron microscope.

Table 2.25 Description of the authigenic clay minerals (Faruk [52])

Mineral	Molecular formula	Morphology
Kaolinite	$\text{Al}[\text{4Si}_4\text{O}_{10}](\text{OH})_8$	Stacked plate or sheets
Chlorite	$(\text{Mg}, \text{Al}, \text{Fe})_{12}[(\text{Si}, \text{Al})_8\text{O}_{20}](\text{OH})_{16}$	Plates, honeycomb, cabbagehead rosette or fan
Mite	$(\text{K}_{1-1.5}, \text{Al}_4[\text{Si}_{7-6.5}, \text{Al}_{1-1.5}\text{O}_2](\text{OH})_4$	Irregular with elongated spines or granules
Smectite	$(1/2\text{Ca}, \text{NA})_{0.7}(\text{Al}, \text{Mg}, \text{Fe})_4[(\text{Si}, \text{Al})_8 \text{O}_{20}] \cdot n\text{H}_2\text{O}$	Irregular, wavy, wrinkled sheets, webby or honeycomb
Mixed Layer	Illite-smectite	Ribbons substantiated by filamentous morphology
	Chlorite-smectite	

From the composition, clays are hydrous aluminum silicate minerals, sometimes with variable amounts of iron, magnesium, alkali metals, alkaline earths, and other cations. They include two categories: *crystalline layered silicate (phyllosilicates)* and *noncrystalline silicate*. Most of crystalline clay minerals have a scaly or platy shape, and are layered structure. A few clay minerals have a nemaline or baculine shape, and are chain-layered structure. Contacting with water, they become soft and plastic. Many clay minerals have the ability of strong adsorption and ion exchange.

In sandstone reservoirs, the most common clays are the phyllosilicates, such as kaolinite, montmorillonite, illite, and chlorite; and noncrystalline silicates are rare. Typical clay minerals are shown and described in Table 2.25.

In sandstones, various clay minerals can be found. Based on the features of crystal structure, clay minerals can be classified on the whole into three groups: (1) kaolinite group, (2) smectite (or montmorillonite) and illite group, and (3) chlorite group. Mixed-layer clay minerals can be formed from several of the three basic groups.

Kaolin group generally includes the minerals: kaolinite, dickite, halloysite, and nacrite [53]. Smectite group includes dioctahedral smectites, such as montmorillonite and nontronite, and trioctahedral smectites, for example saponite [52]. Illite group includes the clay-micas. Illite is the only common mineral [52]. Chlorite group includes a wide variety of similar minerals with considerable chemical variation [52].

By nature, the sensitivity of clay minerals, or the damage of clay to petroleum reservoirs, depends on the type and the amount of the exchangeable cations, such as K^+ , Na^+ , Ca^{2+} , in clays and the type of layered structures of clay minerals.

Structure of clay minerals

Research shows that different crystal structures of clays often lead to different behaviors of swelling and fine migration of clay minerals. Therefore, the knowledge of clay structure is necessary for a good understanding of mineral sensitivity.

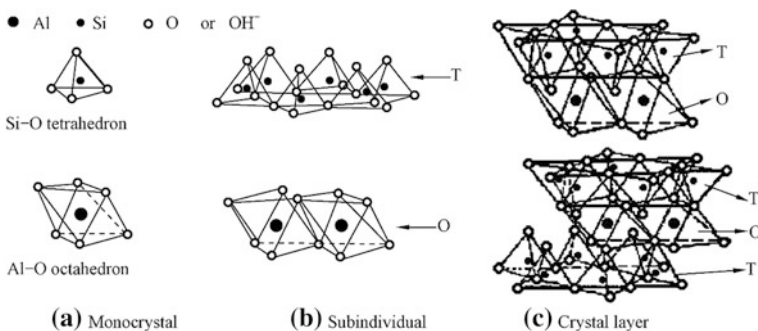


Fig. 2.70 Schematic diagram of the structure of clay minerals (何更生 1994)

The primary crystal units of clay minerals are the monocrystals of Si-O tetrahedron and the monocrystal of Al-O octahedron (Fig. 2.69a). Each tetrahedral monocrystal consists of 4 oxygen ions (O^{2-}) on its vertex and 1 silicon ion (Si^{4+}) in its center. In the same way, each octahedral monocrystal consists of 6 oxygen ions (O^{2-}) or hydroxide ions (OH^{-1}) on its vertex and 1 aluminum ion (Al^{3+}) or magnesium ion (Mg^{2+}) inside it.

Clay minerals are characterized by overlapped two-dimensional *sheets* of corner sharing Si-O tetrahedron and AlO_4 octahedron, namely:

Monocrystal $\xrightarrow{\text{Horizontal extension}}$ **Subindividual** $\xrightarrow{\text{Vertical overlap}}$ **crystal** $\xrightarrow{\text{Extension and overlap}}$ **Clay mineral**

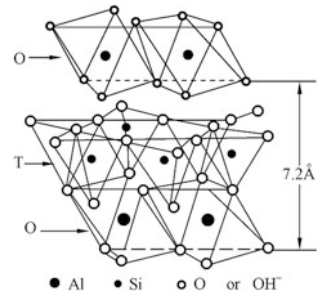
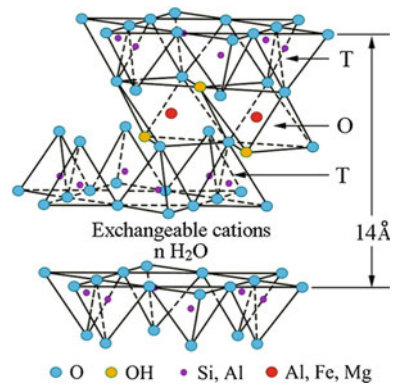
The sheet of Si-O tetrahedron is formed by monocrystals of Si-O tetrahedron extending horizontally. Each tetrahedron shares three of its vertex oxygen ions with other tetrahedra forming a hexagonal array in two-dimensions. The fourth vertex is not shared with another tetrahedron and all of the tetrahedra “point” (fourth vertex) in the same direction; i.e., all of the unshared vertices are on the same side of the sheet (Fig. 2.70b). A sheet of Si-O tetrahedron can be expressed in $n(Si_4O_{10})$, and is called subindividual of Si-O tetrahedron for short. Generally, it is expressed in symbol *T* (Fig. 2.70b).

As such, the sheet of Al-O octahedron is formed by the lateral extension of Al-O monocrystals. Each octahedron, inclining to the same direction, shares two of its vertex oxygen ions (O^{2-} or hydroxide ions (OH^{-1})) to form octahedral sheet (Fig. 2.70b). The unshared vertex on the surface of connected side also forms part of one side of the octahedral sheet but an additional oxygen ion is located above the gap in the tetrahedral sheet at the center of the six tetrahedra. A sheet of Al-O octahedron is also called subindividual for short, and expressed in symbol *O* (Fig. 2.70b). Subindividual of Al-O octahedron can be expressed in $n[Al_4(OH)_{12}]$ if aluminum ions (Al^{3+}) are in the center of octahedrons, or in $n[Mg_6(OH)_{12}]$ if magnesium ions (Mg^{2+}) are in the center of octahedrons.

After that, clay minerals may be formed by overlapped tetrahedral sheets and octahedral sheets. According to the way that tetrahedral and octahedral sheets are packed into *crystal layers*, clay minerals can be categorized into the following groups:

1. Structure of TO (1:1 clay)
2. Structure of TOT (2:1 clay)
3. Structure of TOT·O (2:1 + 1 clay)

A 1:1 clay consists of one tetrahedral sheet and one octahedral sheet in each crystal layer (Fig. 2.71), and Kaolinite group is such structure. A 2:1 clay consists of an octahedral sheet sandwiched between two tetrahedral sheets (Fig. 2.72), and examples are smectite, illite, and attapulgite. Smectite/illite group is such structure. A 2:1 + 1 clay consists of an octahedral sheet sandwiched between two tetrahedral sheets, and an external octahedral sheet. That is to say, a 2:1 + 1 clay consists of one TOT and one T crystal layers (Fig. 2.73). Chlorite group is such structure.

Fig. 2.71 Kaolinite structure**Fig. 2.72** Smectite structure

Physicochemical properties of clay minerals.

Kaolinite group

As shown in Fig. 2.71, kaolinite is a layered silicate mineral, with the 1:1 structure (TO). Kaolinite crystal is a triclinic system. In the two sides (up and down side) of a crystal layer, there are different elements. One side of a TO layer is composed of oxygen atoms, while another side contains hydroxide ions and oxygen atoms. When TO crystal layers are packed together, hydrogen bonds will be formed by the oxygen atoms of one crystal layer linked to the hydrogen atoms of another crystal layer in Kaolinite structure. The hydrogen bonds formed in Kaolinite leads to a tighter joint and closer spaces between crystal layers than that between crystal layers of Montmorillonite, and thus water can hardly enter in crystal layers. In addition, the capacity of exchange cation (K^+) is relatively low in kaolinite crystal. Therefore, kaolinite is a relatively stable, nonswelling clay, and not easy to hydrate; but it easily disperses and migrates under the action of external force.

In spite of a few hydrogen bonds, in fact, van der waal's force is the major combination force between crystal layers of kaolinite. The link between crystal layers is relatively weak, and the hardness of kaolinite is thus lower. Cleavages are

common in kaolinite. Accordingly, kaolinite can hardly undergo the action of mechanical force. Under the effect of high-speed fluids, cleavages will split into scaly fines, and these fines will then migrate with the flow of fluids in rock pores. During the migration of fine particles, these fines will block the pores or throats of the rock, and then lead to a significant decline in rock permeability.

Smectite/illite group

Smectite group has a 2:1 structure (TOT). A 2:1 clay consists of one octahedral sheet (T) sandwiched between two tetrahedral sheets (O) (Fig. 2.72). A notable feature of smectite is that the high valence cations (Al^{3+} , Si^{4+}) in crystal may be replaced by low valence cations (Mg^{2+} , Ca^{2+} , Na^{1+} , etc.) in solution. For example, Al^{3+} is replaced by Mg^{2+} , and Si^{4+} is replaced by Na^{1+} . The results of cation exchange are: (1) additional negative charges on clay due to a loss of positive charges. Consequently, the negatively charged clay will adsorb further the

Fig. 2.73 Illite structure

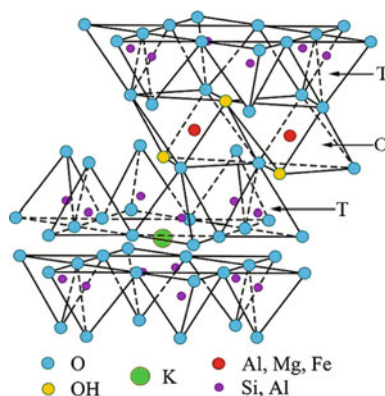
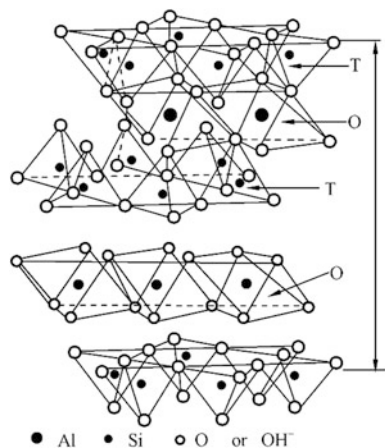


Fig. 2.74 Chlorite structure



exchangeable cations (Mg^{2+} , Ca^{2+} , Na^{1+} , etc.) between crystal layers or on the surface of crystal to balance additional negative charges; (2) unbalanced charges providing a favorable condition for next ion exchange. As a result, smectite has a large cation exchange capacity, and thus is easily swelling and dispersion.

Between the crystal layers of smectite, there is only van der waal's force, which leads to a weak link and wide space between the crystal layers (Fig. 2.72). Thereby, water molecules or other polar molecules are easily adsorbed by the cations into the crystal interlayers. When exposed to low ionic-strength aqueous solutions, the interlayer cations in smectite will adsorb a lot of water molecules to form thick envelopes of water films over the clay (Fig. 2.72). This process will cause a visible increase in the space between crystal layers and thus lead to clay swelling. Usually, the volume of a smectite clay can be increased 13–20 times by its swelling. Exposed to low-salinity aqueous solutions, as a result, the hydration of smectite will cause crystal layers to expand and crack. Under the effect of fluid flow, moreover, a smectite clay will split along the cleavages into thin and curved squamae. These squamae will further coagulate to glomeration and migrate with fluid flowing in rock pores.

However, the cation exchange capacity of illite is much lower than that of smectite in spite of the similarity in their structure (Fig. 2.73). Moreover, the occurrence of potassium ions (K^+) between crystal layers of illite also lead to a strong binding force between crystal layers (Fig. 2.73), which thus make it very hard for water molecules to enter into the space between crystal layers of illite. Therefore, illite is a nonswelling clay.

Chlorite group

As shown in Fig. 2.74, chlorite is a 2:1 + 1 clay (TOT-O), namely, an “O” sheet is sandwiched between two “TOT” units. In this structure, a lot of hydrogen bonds occurs excepting the van der waal's force between crystal layers, which leads to a very strong binding force between crystal layers. Chlorite is also a nonswelling clay.

However, iron cations, such as Fe^{2+} or Fe^{3+} , are common in chlorite. For example, chamosite is an iron-rich mineral. It is often associated with pyrite and siderite, and may become limonite after weathering. The most important is that iron-rich chlorite will react with acid and generate precipitates under acidic conditions. These precipitates fills in rock pores and finally cause severe damage to reservoirs. Iron-rich chlorite is an acid-sensitive mineral.

Unstable mechanism of clay minerals

Once contacting with water, clay minerals will swell, disperse or flocculate in water. “Swelling” means the case where clay adsorbs water and the bulk volume of the clay increase greatly. “Dispersion” is the case where clay particles separate and suspend in a liquid. “Flocculation” denote the phenomenon that the clay particles in a liquid aggregate to form clumps or “flocs.” All the phenomena are the result from clay instability, but different unstable mechanisms responsible for different phenomena.

Swelling

Exposed to aqueous solution, clay minerals will adsorb water molecules and swell. The phenomenon is also known as *clay hydration*. Based on the hydration mechanism, clay hydration can be classified to two phases.

Surface hydration (crystalline swelling)

Surface hydration occurs when clays are exposed to concentrated brine or aqueous solutions containing large amount of divalent or multivalent cations. Surface hydration is caused by the hydration of interlayer cations. This leads to weak clay swelling and less formation damage.

In the process, the adsorption energy of water on the surface of clays is the primary action force. The amount and the thickness of water adsorbed on the clay basically depend on the hydration energy of cations and the charge density on the surface of clay. Research shows that when the exchangeable cations of montmorillonite are Ca^{2+} , Mg^{2+} , and H^+ , the interlayer attractive force of clay increases, the hydrated film is thus thinner, and the arrangement of water molecules on the clay is directional and regular; whereas when the exchangeable cations are Na^+ , the interlayer attraction of clay decreases, the hydrated film becomes thick, and the arrangement of water molecules on the clay is not regular. Therefore, sodium montmorillonite swells more than calcium montmorillonite. Generally, the order of clay swelling capacity is as follows: montmorillonite > mixed-layer clays contained swelling layer > illite > kaolinite.

The affection of clay composition to the capacity of surface hydration can be explained from the cation exchange point of view. Water-sensitive 2:1 phyllosilicate clay minerals have permanent layer charge because of the isomorphous substitution in either the octahedral sheet (typically from the substitution of low charge species such as Mg^{2+} , Fe^{2+} , or Mn^{2+} for Al^{3+}) or the tetrahedral sheet (where Al^{3+} or occasionally Fe^{3+} substitutes for Si^{4+}) [54]. For example, it is common for smectites to have both tetrahedral charge and octahedral charge. These isomorphous substitutions lead to net negative charges on the crystal layers which must be satisfied by the presence of charge-balancing cations somewhere else in the structure. Therefore, when clays contact with aqueous solution, the crystal layers will be forced to split due to the net negative charges on the crystal layers (repulsive force), and water molecules are easy to enter into the interlayers following the cations adsorbed by the clay from water to balance the negative charges on the interlayers. The tendency of the cation exchange of clays depends on *Law of Mass Action* and ionic valence of cations between layers. The exchange of cations is directly determined by the adsorption energy of exchangeable cations between layers. As a general rule, the higher the valence of cations, the stronger the attractive force of cations on clays. As a result, the higher the valence of cations in clays, the more difficult clay hydration. The weaker the repulsive force between clay particles, the more difficult it is for the clays to disperse.

The order of replaceability of the common cations in clays from most to least easy cations is $\text{Li}^+ > \text{Na}^+ > \text{K}^+ > \text{Rb}^+ > \text{Cs}^{2+} > \text{Mg}^{2+} > \text{Ca}^{2+} > \text{Sr}^{2+} > \text{Ba}^{2+} > \text{H}^+$ [55]. With the exception of potassium in illites, the firmness with which cations are held in the clay structure increases with the valence of the cation. Hence, the

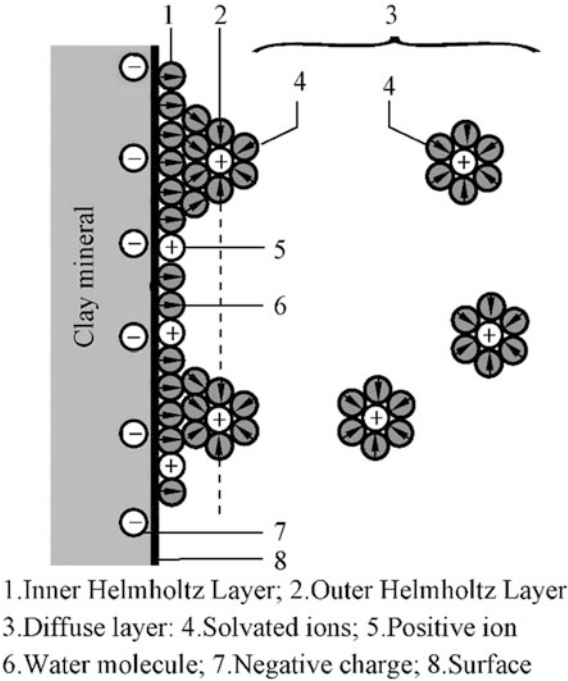
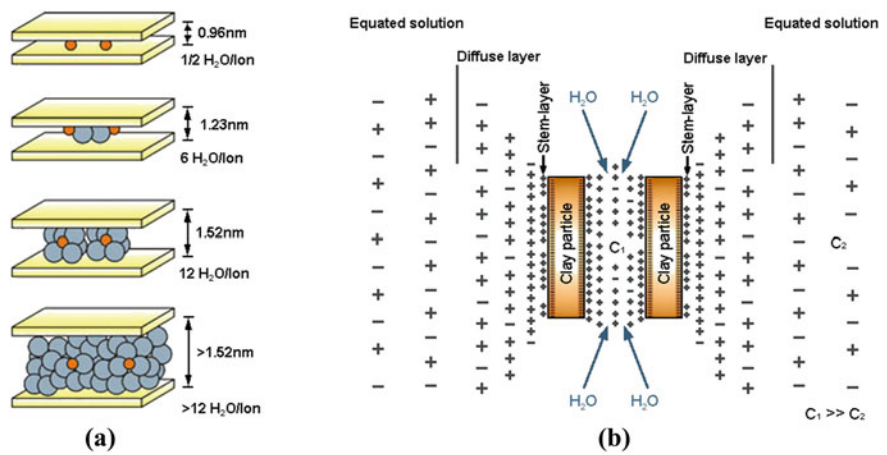


Fig. 2.75 Model of double electrode layer (from Wikipedia)



(a) Crystalline swelling results in an increase in the space between interlayers of swellable clay particles by the hydration of cations; (b) Expansion of neighbour clay particles by osmotic pressure

Fig. 2.76 Crystalline and osmotic swelling of clay minerals (Joerg et al. 2011 [57])

difference of dilatibility between sodium montmorillonite and calcium montmorillonite can be explained by the higher adsorption energy of calcium ions (Ca^{2+}). The replaceability of calcium ions from montmorillonite is smaller than that of sodions, the repulsive force and dilatibility between Ca^{2+} -clay particles are smaller than that between Na^{+} -clay particles.

Osmotic swelling

Osmotic swelling occurs when clays are exposed to dilute solutions or solutions containing large quantities of sodions (Na^{+}). It is caused by the electric double layer formed on the surface of clay minerals. Osmotic swelling makes stronger clay swelling and more formation damage.

In aqueous solution, exchangeable cations are attracted to the clay particles by the negative electric field arising from the negative charge on the particles. Hence, the electric field acts as a semi-permeable membrane in that it will allow water to enter the double layer but will not allow the exchangeable cations to leave the double layer [56]. Thus, when the total ion (cations and anions) concentration in the double layer between the clay particles is higher than that in the aqueous solution (pore fluid), the water in fluid diffuses into the double layer to dilute its ion concentration. This phenomenon creates an osmotic repulsive pressure between the clay particles. The osmotic pressure is primarily related with the difference of the ion concentrations between the clay double layer and surrounding fluid. Because of the osmotic pressure, the distance between clay particles increases greatly, and then the clay swelling occurs.

When the salinity of an invading fluid is lower than that of formation water, the water in invading fluid is attracted to the surface of the clay due to higher ion concentration on the clay surface than that in the invading fluid. As a result, oriented water film is formed on clay surface, and the repulsive force of double layers is thus increased (Fig. 2.75). As the repulsive interaction of double layers on clay surface, clay particles push each other away, which then leads to continuous clay swelling. Consequently, the osmotic equilibrium of the semi-permeable membrane on clay particles is a key factor to affect the hydration film of clay swelling. In other words, osmotic hydration is the major factor of clay swelling (Fig. 2.76). For example, when montmorillonite is exposed to low-salinity solution, surface hydration, occurring firstly, makes its crystal layers swell and doubles its volume; the following osmotic swelling continues the hydration of the clay, and leads its volume to increase by many times as well. Montmorillonite is the most easily expansive clay minerals.

In a word, clay swelling is related with many factors; and the following factors are the key to control the swelling of clays: the type of clays, the composition of exchangeable cations in clays, the ion composition, and concentration of aqueous solution.

Flocculation and dispersion

Flocculation and dispersion are also the important features of clay-water system. When clay particles clot in aqueous solutions, it is known as the flocculation or

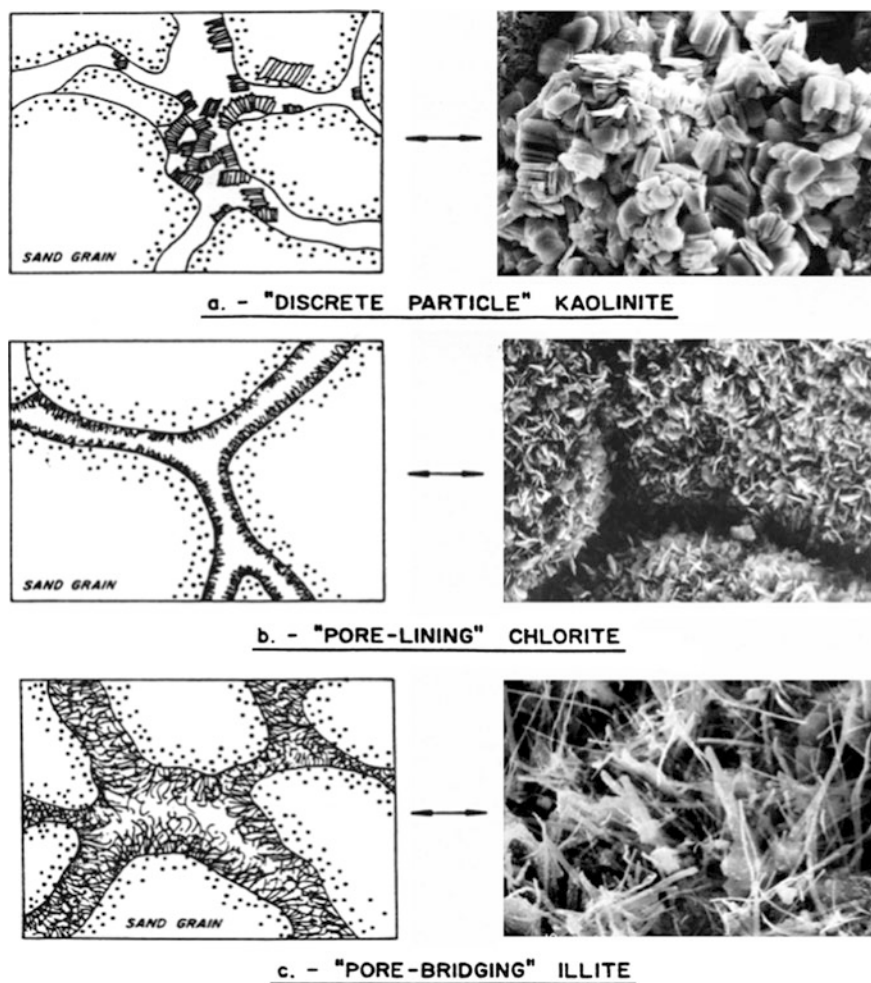


Fig. 2.77 Occurrences of clay minerals in sandstone

aggregation of clays. When clays split and disperse in aqueous solutions, it is known as the dispersion of clays. The flocculation and dispersion of clays can be explained by the theory of double layer of counterions (Fig. 2.75).

In electrolyte solutions, negatively charged anions and positively charged cations coexist in the solution by reason of ionization. When in contact with an electrolyte solution, the negatively charged clays will attract the cations in the solution to keep the charge balance of clays; and this process will lead to an electrical double layer formed on the surface of clays (Figs. 2.75 and 2.76).

Primarily, the negative clay attracts part of cations to form a firmly attached layer around the surface of the clay; the layer of cations attracted on the clay is known as the Stern layer. When other cations in the solution are further attracted by the negative clay, they will be repelled by the Stern layer as well as the cations that are trying to approach the clay. The attraction-repulsion dynamic process results in a diffuse layer of oppositely charged ions (counterions) on the clays. The concentration of counterions is higher near the surface of the clay; and it gradually decreases with distance to the clay until the charge equilibrium has been reached in the solution.

When counterions are far away from negative clay particles, clay particles are scattered in the solution due to the repulsion of negative charges on the surface of the clay particles. However, when counterions are near the clay particles in the solution, clay particles attract each other owing to the effect of charge balance and flocculation, in this way, occurs in the solution.

Investigations have shown that Ca^{2+} , Mg^{2+} , or H^+ in solutions is favorable for clay flocculation, but Na^+ makes clay disperse. Moreover, the increase in electrolyte concentration is also favorable for clay stabilization and flocculation.

In the original conditions, clay minerals in petroleum reservoirs are stable on account of high salinity of formation water. However, the low salinity of invading fluids or Na^+ in invading fluids will cause clay minerals to disperse and migrate, and finally result in serious formation damage.

Occurrence of clay minerals

The occurrence of clay minerals has great effects on the flowing of fluids in petroleum reservoirs. The occurrences and distribution of clay minerals in reservoir rocks primarily depend on the source of sediment, sedimentary environment, and hydrodynamic conditions. Based on the shape of clay mineral aggregate in rock pores and the the effects of clays on physical properties of reservoir rocks, the occurrences of clay minerals may be divided into three types, as shown in Fig. 2.77.

Patch type (Discrete particle type)

“Patch type,” as shown in Fig. 2.77a, means the occurrence of clay minerals, like “disperse patches,” packs in the rock pores. Pores thus become locally narrow and micropores between the clay particles are well developed. In this kind of occurrence, kaolinite, a few of needle-shaped mica and montmorillonite, etc., are very common. As a result, fine migration easily arises because of the effect of high-speed fluids.

Table 2.26 Physical properties of rocks with different occurrences of clay minerals

Rock sample	Occurrence	Grain-size (μm)	Sorting coefficient	Mean pore size	Porosity (%)	Permeability (mD)
1	Patch type	346	1.23	242	14.1–24.9	150–1173
2	Bridging type	150	1.36	0.9	8.45–19.1	0.09–0.31

Fig. 2.78 SEM photo of montmorillonite and quartz grains in sandstone

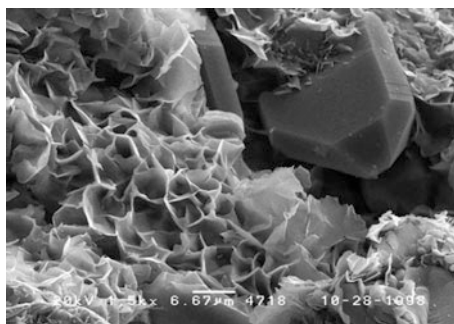
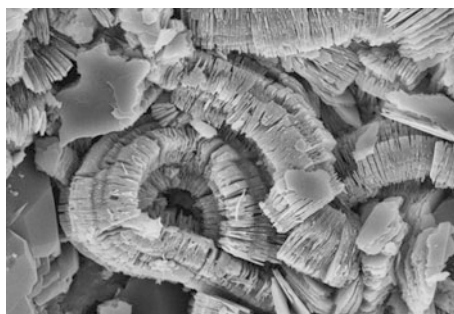


Fig. 2.79 SEM photo of kaolinite



Pore-lining type

In this occurrence, clay minerals, like the lining of pores, arrange parallel to the grain surface with the grains wrapped partially or fully (Fig. 2.77b). This type of occurrence belongs mainly to montmorillonite, illite, chlorite, and so on. The fluid suffers a weak resistance when flowing through them. Generally, fine migration is rare, but hydration and swelling are very common in this type of occurrence. The pore-throats are thus narrowed. If micropores are developed well, the damage of water blocking may even be caused.

Pore-bridging type

The hairy or fibrous clays, such as chlorite, illite (hydromica), easily form bridges in pores between grains (Fig. 2.77c). However, the “bridges” in pores are easily broken off by the shock of fluids through the pores. As a result, fine migration occurs along the flow of fluids. In such type of occurrence, micropores are easily developed. When fluids pass through the micropores, the flow is very circuitous. In this way, the resistance of fluid flowing through the rocks is much increased. The permeability of the rock to fluid is thus remarkably decreased. The quality of the petroleum reservoir thus becomes very poor.

In addition, the kaolinite, shell-type smectite, illite-smectite interlayer minerals, and chlorite-smectite interlayer minerals sometimes overlap mutually at pore-throats, and could narrow the pore-throats due to a high potential of hydration, swelling, and water blocking.

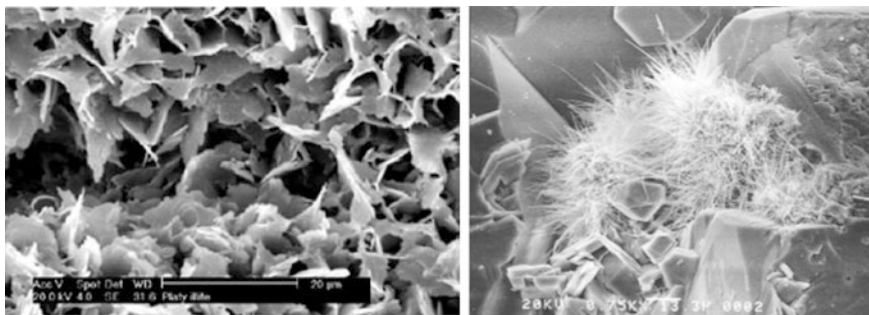


Fig. 2.80 SEM photos of illite

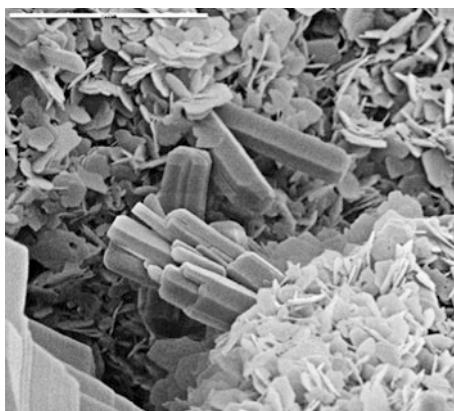
In most cases, there is not only one kind of occurrence of clay minerals in sandstone reservoirs. It is very common that several occurrences coexist in reservoirs. It should be noted that the occurrence of clay minerals usually has greatly influence on the physical properties of reservoir rocks (Table 2.26).

Major reservoir problems caused by common clay minerals in petroleum reservoirs

Montmorillonite

The crystal of montmorillonite is quite fine. A sheet of montmorillonite crystal is usually in the shape of curly blade. Its aggregate is petal-like or honeycomb (Fig. 2.78). The most notable reservoir problem induced by these minerals is seriously water sensitivity, especially when sodium montmorillonite occurs in the reservoir. If exposed to water, sodium montmorillonite may expand by 5–9 times volume. As a result, reservoir permeability will be significantly declined.

Fig. 2.81 SEM photos of chlorite and apatite



Kaolinite

Kaolinite is the most common clay mineral in sandstone reservoirs. It often fills in pores in page-like, worm-like shapes (Fig. 2.79).

The potential impact of kaolinite on reservoirs is as follows:

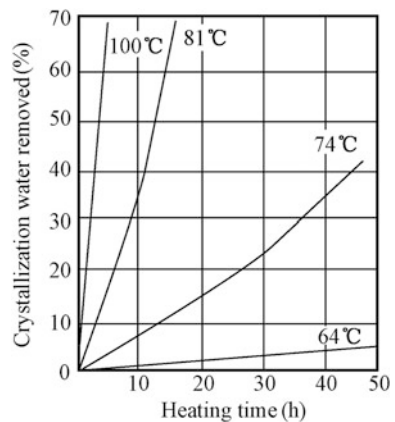
- (a) Kaolinite fills intergranular pores, and thus turns original intergranular pores into tiny intercrystalline pores. Tiny intercrystalline pores contribute little to the permeability of rocks. Rock permeability is thus visibly decreased.
- (b) The adhesion of kaolinite aggregate on the surface of rock particles is weak. Under the shear stress of fluids through the rock, kaolinite aggregate easily crashes or falls off from the surface of rock particles, and move with the fluid in rock pores. Consequently, the pores or throats of the rock could be severely blocked.

Illite

Illite has the most complex appearance. But its single crystal is tiny. From the genesis point of view, Illite can be, by its shape, divided into two categories: irregular flakes illite and hairy, fibrous or ribbons illite (Fig. 2.80). The former generally distributes on the surface of rock particles, and thus affects rock permeability by reason of narrowing the pores which contribute to the flow of fluids through the rock. The latter, however, has much more complex effects on the pore system of rocks. It may bridge in pores and then led to many tiny pores. The pore space of the rock becomes more complicated. The permeability of the rock is thus destroyed. In addition, when contacting with fresh water or affecting by the shear stress of fluids, fibrous illite may disperse or break to pieces and migrate with the fluid. The pores could be plugged by the fragment of illite. Rock permeability is greatly declined.

The cation exchange capacity of illite is smaller than that of smectite, but higher than that of kaolinite. Illite has scarcely water sensitivity. Due to the huge specific

Fig. 2.82 Dehydration curves of gypsum at different temperatures (He [21])



surface area increased by illite, however, a rock may have a high irreducible water saturation.

Chlorite

Chlorite often covers the surface of rock particles in the shape of willowleaf, or fills in pores in the shape of pompon-like aggregates (Fig. 2.81). It is bridge-type growing in pores. In petroleum reservoirs, common chlorite is iron-rich minerals. When contacting with chlorhydric acid, it releases iron ions and then generate colloidal precipitate of ferric hydroxide. The colloidal precipitates will plug pore-throats and throats, and finally result in serious reservoir damage.

2.6.2.2 Sulfate Cement

The sulfate minerals in reservoir rocks mainly include gypsum ($\text{CaSO}_4 \cdot n\text{H}_2\text{O}$) and anhydrite (CaSO_4). A remarkable characteristic of sulfate minerals is dehydration at high temperature. It affects the accurate determination of the water saturation of reservoir rocks. If the amount of sulfate in a reservoir rock is more than 5 %, it will significantly affect the veracity of the irreducible water saturation measured in the laboratory.

When heated to a certain temperature (e.g., 64 °C), crystallization water in gypsum will vaporize slowly out from the gypsum. If the temperature is over 80–100 °C, crystallization water vaporizes quickly. With the increase in temperature, the speed of water vaporization doubles. Figure 2.82 shows gypsum dehydration curves at different temperatures.

In core analysis, gypsum dehydration should be taken into account. It may result in a visible experimental error. For example, in the measurement of the water saturation of a core, if the core is extracted with toluene (boiling point 105 °C), the result (water saturation) is on the high side. The sum of the saturation of fluids containing in the core, sometimes, is even higher than 100 %.

In order to avoid the error caused by gypsum dehydration at high temperature, two methods can be used in core analysis: (a) washing core at low temperature using centrifugal machine; (b) using the azeotropic liquid mixed by chloroform and methanol in the proportion of 13:87. The boiling point of the azeotropic liquid, 53.5 °C, is lower enough than the temperature of gypsum dehydration. The azeotropic liquid does not cause the dehydration of gypsum.

2.6.2.3 Carbonate Cement

Carbonate minerals are one of the major cements of clastic rocks. Carbonate minerals include limestone (CaCO_3), dolomite ($\text{CaMg}(\text{CO}_3)_2$), ferroan calcite, ankerite, siderite (FeCO_3), Na_2CO_3 , K_2CO_3 , and so on. In sandstones, calcite (CaCO_3) and dolomite are the most common. In clastic reservoirs, the content of

carbonate cement varies widely, generally ranging from 9.5 to 21 %. Occasionally, some rocks, e.g., quartz sandstones, contain a little carbonate minerals.

An important feature of carbonate minerals is that they can react with acid. When contacting with acid, carbonate minerals may improve rock permeability or cause a damage to the rock depending on the type of the acid. When reacting with hydrochloric acid, most of carbonate minerals, except for ferroan minerals, can be dissolved and no chemical precipitates formed. In this situation, chemical reaction causes no damage to reservoir rocks. The carbonate minerals which can react with acid but no precipitates generating are called *acidic minerals*. On the contrary, when mud acid (a mixture of hydrofluoric acid and hydrochloric acid) is used in well stimulation, calcareous minerals can react with the hydrofluoric acid in mud acid and produce precipitates. The precipitates will then block in pore-throats and finally cause serious formation damage. In this case, these carbonate minerals are known as *acid-sensitive minerals*.

To hydrochloric acid, the common acidic minerals are carbonate minerals, including calcite (CaCO_3), dolomite ($\text{CaMg}(\text{CO}_3)_2$), sodium salt (Na_2CO_3), hoevellite (K_2CO_3), and so on. But these minerals are sensitive to fluorhydric acid.

Based on the features that acidic minerals can dissolve in acid without precipitates formed, the permeability of petroleum reservoirs can be improved by pumping acidic fluids into the reservoir. The method that uses acidic fluids and improves rock permeability is called *acidizing*. It is one of the essential well stimulations in petroleum production. With this method, the output of oil/gas wells or the injectability of water wells can be greatly improved.

In oilfields, well acidizing basically depends on the type and amount of acidic minerals in reservoir rocks. The most common acidizing fluid used in sandstone reservoirs is mud acid (a mixture of hydrofluoric acid and hydrochloric acid) whereas hydrochloric acid is the major acidizing fluid used in carbonate reservoirs. In conventional sandstones, however, hydrochloric acid stimulation can be used only when the carbonate content in the rock is more than 3 %.

A typical chemical reaction of carbonate minerals with hydrochloric acid is as follows:



Based on the equation, the amount of carbonate in a rock can be determined. The amount of carbonate can be calculated according to the volume of CO_2 released from the reaction above. If using the amount of CaCO_3 represents the total amount of all carbonate in the rock, the content of carbonate in the rock can be calculated by the following expression:

$$C = \frac{V\rho}{4.4W} \times 100 \% \quad (2.145)$$

Table 2.27 Sensitivity minerals in reservoirs and their sensitivity (Shen [58])

Sensitive minerals	Potential problems	Sensitivity degree	Conditions of sensitivity	Method of controlling sensitivity
Montmorillonite	Water sensitivity	Highest	Fresh water	Fluids with high-salinity, anti-swelling agent
	Velocity sensitivity	Middling	Fresh water, high flow velocity	Acidizing treatment
	Acid sensitivity	Middling	Acidizing treatment	Inhibiting agent of acid
	Alkali sensitivity	Middling	Chemistry flooding	Inhibiting agent
Illites	Velocity sensitivity	Lowest	High flow velocity	Low flow velocity
	Plug micropore	Middling	Fresh water	Fluids with high salinity, anti-swelling agent
	K ₂ SiF ₆ precipitates	Lowest	Hydrofluoric acid	Inhibiting agent of acid
Kaolinite	Velocity sensitivity	Middling	High flow velocity, high PH, high transition pressure	Low flow velocity, stabilizing agent of particles, low transition pressure
	Al(OH) ₃ precipitates	Middling	Acidizing treatment	Inhibiting agent of acid
	Alkali sensitivity	Middling	Chemistry flooding	Inhibiting agent
Chlorite	Fe(OH) ₃ precipitates	Highest	Rich-oxygen, after acidizing	oxygen scavenger
	MgF ₂ precipitates	Middling	Hydrofluoric acid at high PH	Inhibiting agent of acid
	Velocity sensitivity	Lowest	High flow velocity, high pH	Low flow velocity
Carbonate	CaF ₂ or MgF ₂ precipitates	Middling	Hydrofluoric acid	Before acidizing, wash with hydrochloric acid, inhibiting agent of acid
Ankerite	Fe(OH) ₃ settling	Middling	High pH, rich-oxygen	Inhibiting agent of acid, oxygen scavenger
Pyrite	Sulfide settling	Middling	Ca ²⁺ , Sr ²⁺ , Ba ²⁺ in fluid	anti-scaling agent
Siderite	Fe(OH) ₃ precipitates	Lowest	High PH, rich-oxygen	Inhibiting agent of acid, oxygen scavenger
Mixed-layer clay	Velocity sensitivity	Middling	High flow velocity	Low flow velocity
	Water sensitivity	Middling	Fresh water	Fluid with high-salinity, anti-swelling agent
	Acid sensitivity	Lowest	Acidizing treatment	Inhibiting agent of acid
Feldspar	Feldspar precipitates	Lowest	Hydrofluoric acid	Inhibiting agent of acid
Quartz particles uncemented	Velocity sensitivity	Middling	High flow velocity, high transition pressure	Low flow velocity, low transition pressure

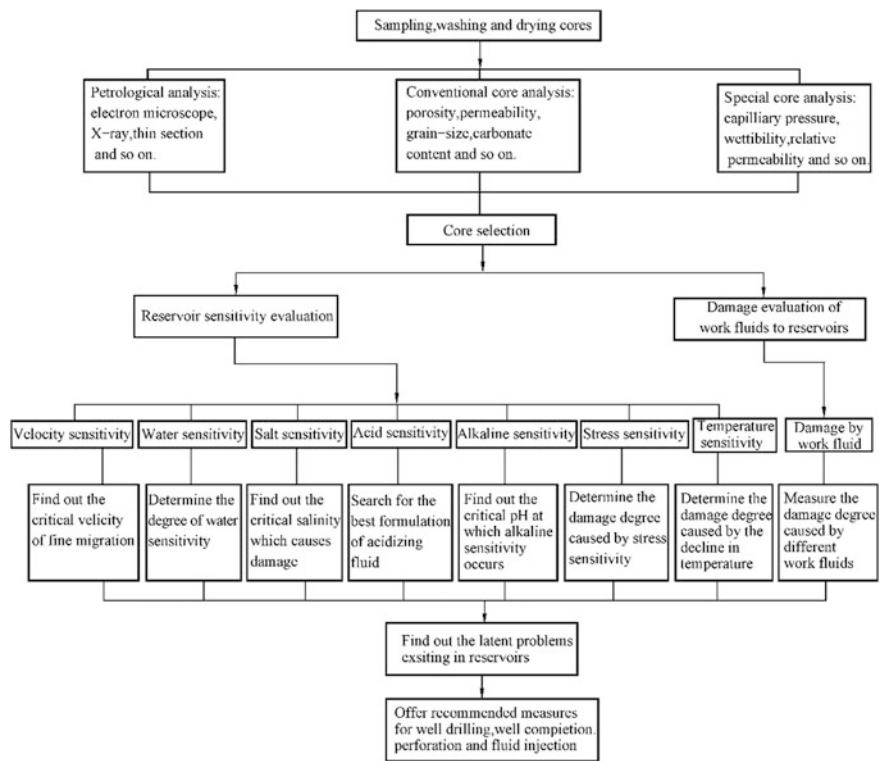


Fig. 2.83 Experimental flowchart of laboratory evaluation for formation damage (何更生 1994)

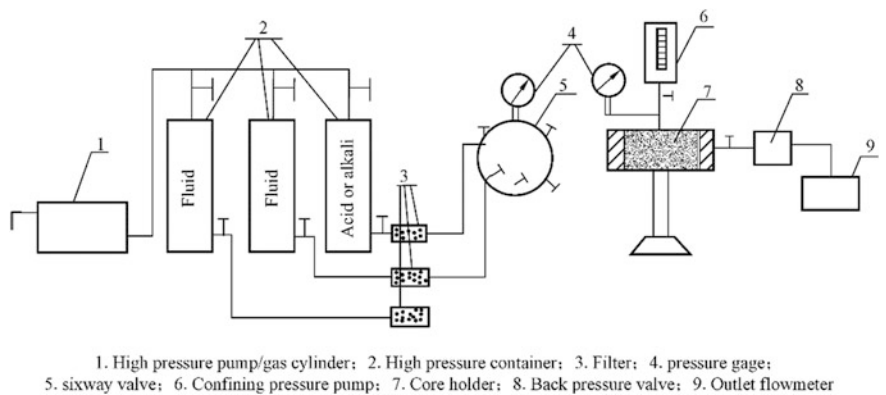


Fig. 2.84 Schematic illustration of core flow test (SYT5358-2010 China)

where C means the amount of CaCO_3 , %; V is the volume of CO_2 released from the reaction between the rock and HCl , cm^3 ; ρ is the density of CO_2 gas in experimental temperature and pressure, g/cm^3 ; W is the total weight of the core sample, g.

In a word, there are a lot of sensitive minerals in petroleum reservoirs. Different minerals cause different reservoir problems and different potential damages to reservoirs (Table 2.27). Therefore, it is quite necessary to use special techniques to evaluate reservoir sensitivity in petroleum production.

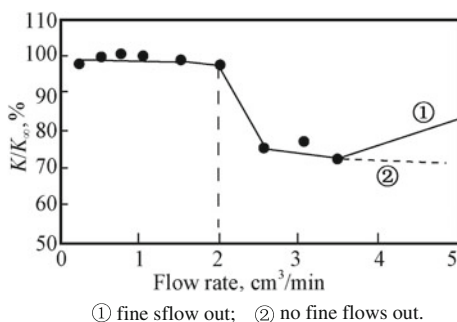
2.6.3 Assessment Methods of Reservoir Sensitivity

In general, petroleum reservoir may have several kinds of sensitivity, typically including water sensitivity, salinity sensitivity, acid sensitivity, alkali sensitivity, and flow velocity sensitivity. The evaluation on reservoir sensitivity chiefly focuses on the effects of physical-chemical reactions between invading fluids and the rock on the permeability of the rock. Systematical evaluation for reservoir sensitivity includes a series of experimental analysis (Fig. 2.83), e.g., petrology analysis, conventional core analysis, special core analysis, core flow testing, and so on. The measurement of reservoir sensitivity is primarily based on the core flow testing. A flow chart of core flow testing is shown in Fig. 2.84. It is a typical procedure of the evaluation on reservoir sensitivity. The testing procedures of common reservoir sensitivity are briefly described below.

2.6.3.1 Evaluation on Flow Velocity Sensitivity

In formations, unconsolidated clays and particles (diameter $<37\ \mu\text{m}$) are totally called “*finer*.” Usually, these fines are not tightly fixed on the surface of grains.

Fig. 2.85 Experimental curve of flow velocity sensitivity (Shen [58])



They can migrate with the fluids flowing through the pores and easily pile up at narrow throats to form “*bridge plug*.” A lot of “*bridge plugs*” finally result in a remarkably decrease in rock permeability, and the reservoir is thus damaged.

Experiments indicate that fine migration generally increases with the flow velocity of fluids in a rock, but different rocks exhibit different sensitive degrees to flow velocity. Some responds weak, which is regarded as *insensitivity to velocity*. On the contrary, if rock permeability decreases considerably with the increasing velocity, the rock is sensitive to velocity. When the flow velocity of fluids causes a remarkable decline in rock permeability, the velocity is known as *critical velocity*, symbolized v_c . If a rock is sensitive to the flow velocity, the critical velocity or critical flow rate (Q_c) should be determined because it is an important basis for petroleum engineers to determine the reasonable production of oil wells or the reasonable injection rate of water wells.

Generally, critical velocity can be determined from the experiment of flow velocity sensitivity. The experiment of measuring flow velocity sensitivity aims at finding the relationship between the alteration of rock permeability and the flow velocity of the fluid passing through the rock.

Experimental procedure

- (a) Preparation of the test fluid. According to the industry standard, a test fluid should not have any physical and chemical reaction with the rock. In general, formation water or kerosene is customarily used. In addition, the test fluid should be first filtrated through the filter membrane with openings of 0.22 μm diameter.
- (b) Setting of confining pressure. Put a saturated core sample in the core holder. Measure gas permeability first. Then keep the same flow direction of fluid injection with the gas flow when gas permeability is measured. Let the confining pressure of the core slowly increase to 2 MPa. During the test, confining pressure should always be kept 1.5–2.0 MPa higher than the inlet pressure of the core.
- (c) Design of flow rate. Following series of flow rates: 0.1, 0.25, 0.5, 0.75, 1.0, 1.5, 2.0, 3.0, 4.0, 5.0, 6.0 cm^3/min , is often used to inject formation water to the core in the order of increasing flow rate and then measure the permeability of the core under steady flow for each flow rate. Note that the pressure gradient in each test should be less than 2 MPa/m. Besides, initial flow rate and its intervals should be chosen according to the value of gas permeability of the core.
- (d) Plot the curve of permeability (or permeability/equivalent liquid permeability) to flow rate, as shown in Fig. 2.85.

When injection velocity is higher than the critical velocity, namely injection flow rate higher than the critical flow rate, this curve shows a sharp decline in permeability, such as the flow rate of 2.5 cm^3/min shown in Fig. 2.85. It indicates that the rock is sensitive to this flow velocity (rate). After that, the interval of flow rate may be properly increased. If the critical rate cannot be found in whole test, end the test

Table 2.28 Graduation of flow velocity sensitivity (SYT5358-2010 China)

Damage rate of permeability (%)	Damage degree of permeability
$D_v \leq 5$	No damage
$5 < D_v \leq 30$	Weak
$30 < D_v \leq 50$	Middle to weak
$50 < D_v \leq 70$	Middle to strong
$D_v > 70$	Strong

when flow rate is over 6.0 cm³/min. For low-permeability tight rock core, the test should be ended when flow rate is lower than 6.0 cm³/min but pressure gradient has been over 2 MPa/cm.

It is noteworthy that the fines migrating with the fluids may either form “bridge plug” in narrow pores or throats or be swilled out from the outlet of the core by the fluid. When flow rate is enough higher, part of fines may be rinsed out of the core. The permeability of the rock sample may increase gently at the late period of the test (Fig. 2.85).

Evaluation of flow velocity sensitivity

The rate of permeability change

The rate of permeability change caused by velocity sensitivity is defined as [59]:

$$D_{vn} = \frac{|K_n - K_i|}{K_i} \times 100 \quad \% \quad (2.146)$$

where D_{vn} is the rate of change in permeability corresponding to each flow velocity, %. It is also called the damage rate of permeability; K_i is the initial permeability measured at the minimum flow rate, mD; K_n is the permeability corresponding to each flow rate before critical velocity, mD.

Critical velocity

According to experimental results, plot the curve of K_n/K_i to flow rate. The critical velocity can then be determined based on the curve and the value of D_{vn} . From Fig. 2.85, we can see that with the increase in flow rate (flow velocity), the sample permeability could occur obvious decline at a certain flow rate. If the decline in permeability exceeds 20 %, it marks the occurrence of critical velocity.

Table 2.29 Graduation of water sensitivity (SYT5358-2010 China)

Damage rate of water sensitivity (%)	Damage degree of water sensitivity
$D_w \leq 5$	No damage
$5 < D_w \leq 30$	Weak
$30 < D_w \leq 50$	Middle to close to weak
$50 < D_w \leq 70$	Middle to close to strong
$70 \leq D_w < 90$	Strong
$D_w > 90$	Extremely strong

The last flow velocity (flow rate) before 20 % decline in permeability is known as *critical velocity*, as the flow rate 2 cm³/min shown in Fig. 2.85.

Damage rate of permeability

Damage rate of permeability is determined by the following expression [59]:

$$D_v = \max(D_{v1}, D_{v2}, D_{v3}, \dots, D_{vn}) \quad (2.147)$$

where D_v is the damage rate of permeability, %; $D_{v1}, D_{v2}, \dots, D_{vn}$ are the rates of permeability change corresponding to different flow velocities (flow rates), respectively, %.

Based on the damage rate of permeability, the damage degree of flow velocity to permeability can then be evaluated. According to the industry standard, the gradation of permeability damage is listed in Table 2.28.

2.6.3.2 Evaluation on Water Sensitivity

Under the original conditions of petroleum reservoirs, clay minerals in rocks are steady due to the higher salinity of formation water. During the process of well drilling, well completion, and water flooding, low-salinity fluids will invade into the reservoir. On contacting low-salinity invading fluids, water-sensitive minerals will swell, disperse, and even migrate with fluids. The reservoirs will be seriously damaged. The purpose of water sensitivity evaluation is to find out the degree of permeability damage caused by water sensitivity of minerals. In general, *water sensitivity index* can be used to determine the degree of permeability damage caused by water sensitivity. Water sensitivity index is defined as follows [59]:

$$D_w = \frac{|K_i - K_w|}{K_i} \times 100 \% \quad (2.148)$$

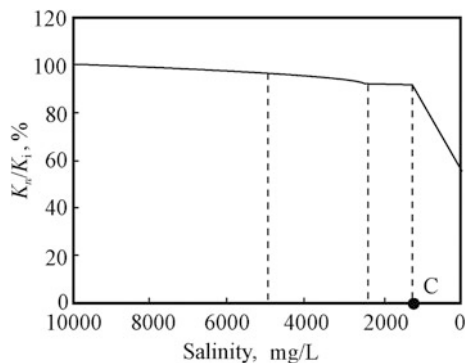
where D_w is water sensitivity index, also called damage rate of water sensitivity, %; K_i is the permeability measured by the initial fluid. Initial fluid may be formation water or standard brine. The salinity of a standard brine should equal to that of the formation water which is from the reservoir, mD; K_w is the permeability measured by distilled water, mD.

According to the industry standard, the gradation of water sensitivity is shown in Table 2.29.

2.6.3.3 Evaluation on Salinity Sensitivity

Clay minerals in reservoir rocks could swell, shrink, cracking when obvious change occurs in the salinity of formation water. If the salinity of formation water is lowered by the invading fluid, some clay minerals in the rock will swell and disperse; whereas some of them will shrink and crack when the salinity of formation

Fig. 2.86 Experimental curve of salinity sensitivity evaluation (沈平平 1995)



water is increased by invading fluids. In both cases above, clay minerals will release a lot of fines, which finally results in fine migration and formation damage.

Therefore, it is very necessary to evaluate the salinity sensitivity of a reservoir rock in petroleum production. The aim of evaluation on salinity sensitivity is to find out the *critical salinity* or *critical salt concentration* at which the rock permeability declines visibly. This test is called *salinity sensitivity evaluation experiment*.

Experimental procedure

Because the decline in rock permeability may be caused by either low-salinity fluids or high-salinity fluids, the salinity sensitivity test usually includes two parts: lowering-salinity test and increasing-salinity test.

Lowering-salinity test

Lowering-salinity test should be based on the result of water sensitivity test. If the rate of permeability damage measured by distilled water in water sensitivity test is lower than 20 %, the lowering-salinity test is not necessary; whereas it is necessary if the rate of permeability damage is higher than 20 %.

The salinity interval of the test fluid: the salinity interval is generally determined in term of the permeability measured by the test fluid and the distilled water in water sensitivity test. If the damage rate of permeability at one interval of salinity is higher than 20 %, the interval of salinity should be shortened. Lowering-salinity test should include at least four tests using different salinity fluids.

The flow rate of the test should be determined according to the results of flow velocity sensitivity test. In lowering-salinity test, the initial fluid, either being formation water or standard brine, should be first used to measure the rock permeability. After that, the series of lower salinity fluids are then used in turn to test.

Increasing-salinity test

This test is necessary only for the following two cases: the salinity of invading fluids is higher than that of formation water; or the salinity sensitivity evaluation for special requirement.

The salinity interval of the test fluid: it is determined according to the salinity difference between the invading fluid and formation water. Generally, at least three fluids of different salinities should be used for one test; but a large salinity

difference between the invading fluid and formation water suggests a denser salinity interval of test fluids.

In the same way, the flow rate of the test should be determined according to the results of flow velocity sensitivity test. The initial fluid, either being formation water or standard brine, should be first used to measure the rock permeability. Then, the series of higher salinity fluids are in turn used to test.

In each testing, flow rate should be constant. When the volume of the fluid injecting into the core is about 10–15 times PV (pore volume) of the core, stop injecting fluid. Then under the conditions of testing, keep the fluid inside the core at least 12 h so as to let the minerals in the rock contact and react adequately with the injected fluid. Afterwards, using the same salinity fluid and the same flow rate displaces the core, measure the permeability of the core.

Critical salinity

The rate of permeability change caused by the salinity of injected fluid is calculated by [59]:

$$D_{sn} = \frac{|K_i - K_n|}{K_i} \times 100 \% \quad (2.149)$$

where D_{sn} is the rate of permeability change corresponding to n th salinity of the injected fluid, %; K_i is the permeability measured using the initial fluid, mD; K_n is the permeability corresponding to n -th salinity of the injected fluid, mD.

Plot the experimental curve of permeability ratio (K_n/K_i) to the salinity, as shown in Fig. 2.86. It should be plotted in terms of the order of salinity in the experiment whatever in lowering-salinity test or increasing-salinity test.

Based on the experimental curve and the data of D_{sn} , the critical velocity can be easily determined. From Fig. 2.86, it can be seen that a visible decline in permeability can occur at a certain salinity. The last salinity before 20 % decline in permeability is known as *critical salinity*, as the point *C* in Fig. 2.86.

2.6.3.4 Evaluation on Acid Sensitivity

Acid sensitivity means the phenomenon that the minerals in reservoir rocks react with acidizing fluids invading into the rocks, and then cause a decline in rock permeability due to the occurrence of precipitate and fines released from the reaction between minerals and acidizing fluids.

Acid sensitivity is one of the most primary factors inducing formation damage. In the acid stimulation of production wells, the acidizing formulation should be carefully selected according to the mineral composition of reservoir rocks. An appropriate acidizing formulation or stimulation can correctly improve the quality of the reservoir around the well. On the contrary, the reservoir is probably damaged again by the acidizing, and the secondary damage will lead to a further decrease, but not increase in the oil-gas output of production wells. Even worst, no output from the well.

Table 2.30 Gradation of acid sensitivity (SYT5358-2010 China)

Damage rate of acid sensitivity (%)	Damage degree of permeability
$D_{ac} \leq 5$	No
$5 < D_{ac} \leq 30$	Weak
$30 < D_{ac} \leq 50$	Middle to close to weak
$50 < D_{ac} \leq 70$	Middle to close to strong
$D_{ac} > 70$	Strong

Acid sensitivity evaluation aims at the optimization of acidizing formulations so as to maximize the efficiency of the acid stimulation.

For conventional acidizing experiments, the experimental fluid is customarily the fluid of 15 %HCl or 12 %HCl + 3 %HF. In general, 15 %HCl is used in carbonate reservoirs, whereas 12 %HCl + 3 %HF is used in conventional sandstones.

Experimental procedure

- First of all, measure the permeability of the sample using the KCl brine whose salinity should equal to the salinity of formation water. Note that the direction of fluid flow in the sample should be the direction of fluids flow in reservoirs when measuring the permeability of the sample.
- Pump acidizing fluid into the sample from the inverse direction of permeability measurement. If the sample is a sandstone, the amount of 0.5–1.0 PV acidizing fluid is enough, whereas a carbonate sample usually needs the amount of 1.0–1.5 PV 15 % HCl.
- Stop pumping the acidizing fluid. Stimulate the process of shut in and wait for the reaction between the acidizing fluid and the sample. Usually, half an hour is enough for the reaction in carbonate samples, but a sandstone sample needs at least one hour for the reaction.
- Pump the KCl brine into the sample again along primary direction (the direction of permeability measurement), and displace fully the acidizing fluid out of the sample. The salinity of the KCl brine is the same with the formation water.
- Measure the permeability of the acidized sample. Calculate the variation in permeability of the sample, and evaluate the acid sensitivity of the sample.

Evaluation of acid sensitivity

The damage rate of acid sensitivity is defined as follows [59]:

$$D_{ac} = \frac{K_i - K_{acd}}{K_i} \times 100 \% \quad (2.150)$$

where D_{ac} is the damage rate of acid sensitivity, %; K_i is the permeability of the sample before acidizing treatment, mD; K_{acd} is the permeability of the sample after acidizing treatment, mD.

Plot the experimental curve of the permeability ratio (K_{acd}/K_i) to the cumulative injection volume of the acidizing fluid. According to the industry standard, the gradation of acid sensitivity is shown in Table 2.30.

2.6.3.5 Evaluation on Alkaline Sensitivity

Formation water is generally neuter or weak alkaline, pH value ranging 4–9. In petroleum production, some fluids invading into the reservoir could be alkaline, e.g., drilling fluids, alkaline flooding fluids in EOR. Their pH values are usually higher, about 8–12. When invading into petroleum reservoirs, alkaline fluids can lead to a series of physical and chemical reactions due to the increase in pH value of formation water.

When invading into petroleum reservoirs, high-PH fluids can react with formation water and lead to precipitates of divalent cations and emulsible substance. They can also react with paraffin and asphaltene in crude oil and generate flocculation and deposition, called *organic fouling*, in the reservoir around the well hole. All of these reaction products could plug pores and cause a remarkable decline in reservoir permeability.

In addition, clay minerals can dissolve partially in alkali solutions. After the cleavage of clays being dissolved, the structure of clay minerals is damaged; and a lot of fine particles are thus released from clay minerals. Fine migration occurs. As a result, rock pores could be blacked by migrating fines and reservoir permeability could be visible decreased. Generally, the order of the solubility of clay minerals in alkali solutions is: $\text{NaOH} > \text{KOH} > \text{Na}_2\text{CO}_3 > \text{NaHCO}_3$.

The purpose of alkaline sensitivity evaluation is to find out the critical pH value at which the alkaline sensitivity of reservoir rocks begins to occur. The results of this test lay the important foundations for the design of all kinds of work fluids in petroleum production.

In an ordinary way, the experimental fluid is the specified KCl solution which has the same salinity with the formation water. A 8 % (mass fraction) KCl solution is often used if the data of formation water is not available.

Experimental procedure

- (a) The preparation of alkaline solutions: the pH value of the first KCl solution should be 7.0. Then gradually increase the pH value of KCl solutions by 1–1.5 pH value till the value 13.0.
- (b) Measure the initial permeability of the sample with the KCl solution whose salinity equals to the salinity of formation water.
- (c) According to the increasing order of pH, inject in turn the alkaline solutions into the sample. In each injection, stop injecting solution when the volume of injected solution is about 10–15 times PV of the sample.
- (d) Wait for at least 12 h till clay minerals reacts completely with the alkali solution.
- (e) Using the same KCl solution displaces the core again, and measure the permeability of the sample.

Table 2.31 Gradation of alkaline sensitivity (SYT5358-2010 China)

Damage rate of alkaline sensitivity	Damage degree of permeability
$D_{al} \leq 5$	No
$5 < D_{al} \leq 30$	Weak
$30 < D_{al} \leq 50$	Middle to close to weak
$50 < D_{al} \leq 70$	Middle to close to strong
$D_{al} > 70$	Strong

Evaluation of alkaline sensitivity

The rate of permeability change caused by the alkaline solutions injected into the sample is defined as follows [59]:

$$D_{aln} = \frac{K_i - K_n}{K_i} \times 100 \% \quad (2.151)$$

where D_{aln} is the rate of permeability change caused by the alkaline solutions injected into the sample, %; K_i is the sample permeability measured by the first KCl solution, mD; K_n is the sample permeability after displaced by n-th alkaline solution, mD.

Plot the experimental curve of the permeability ratio (K_{aln}/K_i) to the pH value of alkali solutions. The critical pH value can be determined according to the value of D_{aln} and the shape of the curve. With the increase in pH values of alkali solutions, the damage rate of permeability could exceed 20 % at a certain pH value. The last pH value before 20 % damage rate of permeability is known as *critical pH value*.

The rate of permeability damage caused by alkaline sensitivity can be determined by the following expression [59]:

$$D_{al} = \max(D_{al1}, D_{al2}, D_{al3}, \dots, D_{aln}) \quad (2.152)$$

where D_{al} is the damage rate of permeability, %; D_{al1} , D_{al2} , ..., D_{aln} are the rate of permeability change corresponding to each alkaline solution, respectively, %.

According to the industry standard, the gradation of alkaline sensitivity is shown in Table 2.31.

Exercise

Define the following terms and discuss their significance in reservoir production

(1) Grain-size composition	(2) Nonuniform coefficient
(3) Sorting coefficient	(4) Specific surface area
(5) Effective porosity	(6) Rock compressibility
(7) Total compressibility of formation	(8) Irreducible water saturation
(9) Initial gas saturation	(10) Critical gas saturation
(11) Rock absolute permeability	(12) Equivalent liquid permeability

(continued)

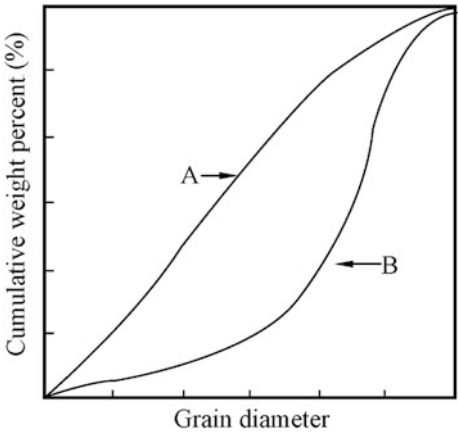
(continued)

(13) Darcy's law	(14) Slippage effect
(15) Clay mineral	(16) Velocity sensitivity
(17) Water sensitivity	(18) Salinity sensitivity
(19) Acid sensitivity	(20) Alkaline sensitivity

Question

1. What are the main methods for grain-size analysis? What are the principles of main methods for grain-size analysis?
2. How to express grain-size distribution? What statistical parameters may be used to evaluate grain-size distribution?
3. What are the features of grain-size distribution?
4. The cumulative grain-size distribution curves of two rock samples are shown in Fig. 2.87. According to the curves, plot schematically the grain-size distribution curves of the two samples, and analyze qualitatively the grain-size distribution features of the two samples.
5. What are the methods for the measurement of specific surface area of a rock?
6. Why does the flow rate of water from Mariotte bottle equals the flow rate of air through the core when the water column of piezometer was kept unchanged in the experiment of specific surface area measurement by gas permeability?
7. Can the specific surface area of a core be measured by the method of gas permeability when the core is saturated by a liquid? Why?
8. What is the significance of the specific surface area of a rock?
9. How to express the distribution of pore size? How to classify the pores of a rock according to the pore size of the rock?
10. What is the range of rock porosity in petroleum reservoirs? What is the relationship between the porosities of ϕ_a , ϕ_e , and ϕ_{ff} ?

Fig. 2.87 The cumulative grain-size distribution curves of two samples



11. What are the methods for the measurement of rock porosity? Describe the basic principle of porosity measurement in the laboratory.
12. What are the major factors of affecting rock porosity?
13. What is the physical meaning of 1 Darcy?
14. What is the commonly used unit of rock permeability? Give the conversion of different units.
15. What conditions must be satisfied in the measurement of rock permeability using Darcy's equation?
16. What factors does the rock permeability mainly depend on? Is the rock permeability dependent on the properties of the fluid flowing through the rock?
17. What is the conventional range of rock permeability in petroleum reservoir?
18. Is the rock absolute permeability equal to the liquid permeability or the gas permeability of the rock? Which is higher between any two of them? Why?
19. How to determine the absolute permeability of a rock from the data of gas permeability measured in an experiment?
20. Is it true or false, the following expression: the higher the porosity of a rock, the higher the permeability of the rock? Why?
21. What are the major factors of affecting fluid saturation?
22. How many methods are there for fluid saturation measurement? What method is more appropriate for the fluid saturation measurement of the rock containing crystallization water?
23. What are the main components of cement agents? What is the cementation type of rocks? How many cementation types are there in general in rocks?
24. What are the commonly sensitive minerals in cement agents? What are the features of each sensitive minerals?
25. What is the purpose of reservoir sensitivity evaluation?
26. What are the major reasons, in your opinion, causing formation damage after learning the knowledge of the physical properties of reservoir rocks?
27. What experiments does the reservoir sensitivity evaluation include?
28. What is the principle of permeability measurement in the laboratory? Describe the procedure of data processing of permeability measurement. Plot the experimental flow chart, and mark the name of each instrument in flow chart.
29. Why should the carbonate content in rocks be measured?

Derivation

1. From what you have learned, deduce the following expression of the total compressibility of an oil reservoir:

$$C_t = C_f + \phi(S_o C_o + S_w C_w)$$

where C_t is the total compressibility of formation; C_f is rock compressibility; C_o , C_w are oil and water isothermal compressibility, respectively; S_o , S_{wi} are oil and reducible saturation, separately.

2. Educe the following equation from the definition of specific surface areas:

$$S = \phi S_p = (1 - \phi) S_s$$

where S , S_p , and S_s denote separately the specific surface areas defined by view volume, pore volume, and matrix volume of a rock. ϕ is rock porosity.

3. Derive the following estimating equation of rock specific surface area from grain-size distribution:

$$S = C \frac{6(1 - \phi)}{100} \sum_{i=1}^n G_i / d_i$$

where S is the specific surface area defined by the bulk volume of a rock; ϕ is rock porosity; $G_i\%$ is the weight percent of grains with average diameter d_i ; d_i is the average diameter of i th fraction grains.

4. Derive the following equation from Darcy’s law, and explain the meaning of each symbol in the equation:

$$K_a = \frac{2Q_o P_o \mu L}{A(P_1^2 - P_2^2)}$$

Calculation

1. The porosity and specific surface area, measured in experiments, of a sandstone are 23 % and 950 cm²/cm³, severally. Estimate the permeability of the sandstone if pore tortuosity $\tau = 1$ and 1.4 separately.
2. The results of grain-size analysis for two rock samples are shown in Table 2.32. Assume the shape coefficient of rock particles $C = 1.3$.
Answer the following question:

(a) Plot the grain-size distribution curves and cumulative grain-size distribution curves of the two samples.

(b) Calculate the nonuniform coefficients and sorting coefficients of the two samples.

(c) Calculate the specific surface areas of the samples.

(d) What conclusions can you drawn out from the calculations above?
3. The weight of a dry sample is 32.0038 g. After saturated by kerosene, the weight of the sample in kerosene is 22.2946 g. The weight of the saturated

Table 2.32 Results of grain-size analysis for samples

No. of samples	Porosity (%)	Opening size of sieves (mm)					
		1–0.5	0.5–0.25	0.25–0.1	0.1–0.05	0.05–0.01	<0.01
1	27.0	5.05	53.35	24.7	7.95	5.75	3.05
2	28.3	0	2.95	76.15	10.5	5.4	4.7

- sample in air is 33.8973 g. Determine the pore volume, porosity, and view density of the sample. Given that the density of kerosene is 0.8045 g/cm^3 .
4. The weight of a core containing oil and water is 8.1169 g. After the core is extracted, 0.3 cm^3 water is separated from the core. The weight of the dried core is 7.2221 g. After saturated by kerosene, the weight of the core in kerosene is 5.7561 g while it is 8.0535 g in air. Calculate the water saturation, oil saturation, and porosity of the core. Given that water density is 1 g/cm^3 ; oil density is 0.8760 g/cm^3 ; and the density of kerosene is 0.8 g/cm^3 .
 5. The weight of a sample contained oil and water is 6.5540 g. After extracted and dried, its weight is 6.0370 g. The volume of water separated from the sample is 0.3 cm^3 . The porosity of the sample, measured by saturated kerosene, is 0.25. Suppose the view density of the sample is 2.0 g/cm^3 ; oil density is 0.8750 g/cm^3 ; and water density is 1 g/cm^3 . Determine the oil, gas, and water saturations of the sample.
 6. The length of a core is 10 cm. Its cross-sectional area is 2 cm^2 . Under the pressure difference of 0.15 MPa, let the oil, whose viscosity is 2.5 mPa s, flow through the core. The flow rate of the oil is $0.0080 \text{ cm}^3/\text{s}$. If the core is completely saturated by oil, calculate the absolute permeability of the core. If it is completely saturated by the brine whose viscosity is 0.75 mPa s, determine the flow rate of the brine under the pressure difference of 2.5 atm.
 7. A sample, 2.77 cm length and 3.35 cm diameter, is completely saturated by the brine. The viscosity of the brine is 1 mPa s. The brine flows through the sample under the pressure difference of 251 cm mercury column. The downstream pressure is 1 atm. The flow rate of the brine is $0.02 \text{ cm}^3/\text{s}$. Calculate the liquid permeability of the sample when the brine flows through the sample. If the sample is completely saturated by gas with 0.0175 mPa s viscosity and let the gas flow through the sample, the flow rate of the gas is $0.12 \text{ cm}^3/\text{s}$. Output pressure is 1 atm. Determine the gas permeability of the sample. Compare the gas permeability to that measured by brine. What conclusions can you draw from the comparison? Why?
 8. Given that the reducible water saturation of an undersaturated oil reservoir is 24 %. The isothermal compressibilities of oil and water are $70 \times 10^{-4} \text{ 1/MPa}$ and $4.5 \times 10^{-4} \text{ 1/MPa}$, respectively. The rock compressibility is $1.4 \times 10^{-4} \text{ 1/MPa}$. The average porosity of the reservoir is 27 %. Calculate the total compressibility of the reservoir. If the oil-bearing volume of the reservoir is 1500 m^3 , initial reservoir pressure is 27 MPa, and the saturation pressure of the oil is 20 MPa, estimate the recoverable reserves of the oil reservoir.
 9. A laterally heterogeneous rock, consisting of three beds, is shown in Fig. 2.88. The porosities and permeabilities of three beds are listed in Table 2.33. Calculate:
 - (a) Arithmetic means of the porosity and permeability of the rock
 - (b) Average porosity of the rock based on equal storing capacity.
 - (c) Average permeability of the rock based on the equivalent filtrational resistance.

Fig. 2.88 Illustration of the heterogeneous rock

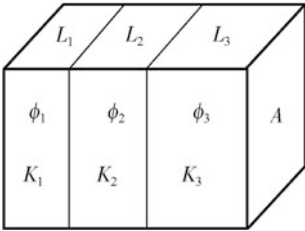


Table 2.33 Porosities and permeabilities of the beds in a heterogeneous rock

Beds	Thickness (cm)	Porosity (%)	Permeability (mD)
1	3	18	160
2	14	22	320
3	11	24	350

Table 2.34 The porosities and permeabilities of the cores from a well

No.	Coring depth (m)	Thickness of cores (m)	Porosity (%)	Permeability (mD)
1	2280.22–2280.96	0.76	12.5	800
2	2280.98–2286.22	5.24	3.82	250
3	2286.22–2289.20	2.98	28.1	210
4	2289.20–2290.00	0.8	29.5	200
5	2290.00–2290.85	0.85	16.8	150

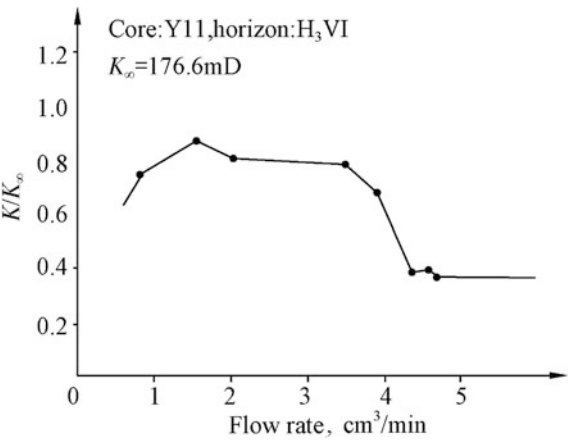
10. The porosities and permeabilities of the cores from a well are shown in Table 2.34. Assume that the cross-sectional area of each core is the same, and porosity and permeability are homogeneous in the direction parallel to the bedding planes.
Evaluate:

- (a) Arithmetic means of the porosity and permeability of the whole coring section.
- (b) Weighted averages of the porosity and permeability of the whole section.
- (c) Equivalent porosity of whole section according to equal storing capacity.
- (d) Equivalent permeability of whole section based on the principle of equivalent filtrational resistance.
11. The average pore radius of a reservoir rock, from pore-size distribution curve, is 1×10^{-4} cm. The porosity of the rock is 10 %. Estimate the permeability of the rock. The pore tortuosity of the rock is given: $\tau = 1$.
12. A reservoir contains clay minerals which include illite/smectite mixed-layer, chlorite/smectite mixed-layer minerals, illite and dilatible chlorite, etc. Due to the potential damage, water sensitivity analysis is

Table 2.35 Results of water sensitivity experiments

No. of cores	K_L (mD)	K_w (mD)
1	251.0	191.0
2	100.0	55.5
3	3.79	1.01

Fig. 2.89 Experimental result of velocity sensitivity of a core



carried out with three cores of the reservoir. The analysis results are shown in Table 2.35. K_L is the permeability measured using formation water while K_w is measured using pure water. Calculate water sensitivity index of each core and evaluate the water sensitivity degree for each core.

13. The velocity sensitivity experiment of a core from a formation is down with kerosene. The $K/K_{\infty}-Q$ curve, platted according to the experimental result, is shown in Fig. 2.89.

Determine:

1. The critical velocity of the core from the curve in Fig. 2.89.
2. What conclusion can you draw out from the experimental result in Fig. 2.89.

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