CHAPTER 4

The Reservoir Pore Space

Porosity: measurement. Permeability: measurement – effective and relative permeability. Classification and origin of pore space: primary, or intergranular – secondary, or intermediate – relation between porosity and permeability.

THE FIRST essential element of a petroleum reservoir is a reservoir rock, and the essential feature of a reservoir rock is *porosity:* the rock must contain pores, or voids, of such size and character as to permit the storage of oil and gas in pools 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. That is, the rock must be permeable (it is said to have *permeability*); otherwise there would be little if any accumulation into pools, nor could any petroleum that accumulated be produced by drilling wells, for it 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 average shale cannot become a reservoir rock, for the pores are so minute that the capillary attraction of the fluids for the mineral grains effectively holds the fluids in the rock. To try to get oil out of a shale would be like trying to remove ink from a blotter.

There is a wide variation among reservoir rocks in the size of the individual pores and in the arrangement of the pores with respect to one another. These variations are called *primary* if they are controlled by (1) the depositional environment of the rock, (2) the degree of uniformity of particle size, and (3) the nature of the materials that make up the rock. The variations are called *secondary* if they depend on things that have happened to the rock since it was deposited; these may include (1) fracturing and shattering, (2) solu-

[illegible]: Degree of [illegible] throat is called Tortuosity or geometry of grains pore throat

tion, (3) redeposition and cementation, and (4) compaction because of increased load.

Each pore of the reservoir rock may be thought of as a microspecimen of the reservoir and its petroleum pool, or as a microphysical and chemical laboratory where many physical relations and chemical reactions occur. The individual pore, with its fluid content and other associated phenomena, is the building unit, which, when multiplied countless trillions of times, becomes the pool and the reservoir. As such it becomes extremely important to both the exploration geologist and the petroleum engineer. The study of the pore space and its characteristics is termed *petrophysics*.[1]

The shape and size 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, and much of the reservoir pore space 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 average 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. Photomicrographs of pore casts viewed stereoscopically offer a good means of observing the pore structure.

The *pore pattern* results from the complex interplay of the various factors that influence the porosity of the reservoir rock. The pattern is comprised of the pore size, the pore shape, the nature of the connections between pores, the character of the pore wall, and the distribution and number of larger pores and their relations to one another. The size of individual pores ranges from subcapillary and submicroscopic openings through capillary-sized 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. The wall of the pore may be clean quartz, chert, or calcite, or it may be coated with clay-mineral particles, platy accessory minerals, or rock fragments. The crookedness of the pore pattern, called the *tortuosity*, is the ratio of the distance between two points by way of the connected pores to the straight-line distance. *Pinpoint porosity*, as the name implies, consists of minute, isolated pores visible under the binocular microscope or, when filled with oil, by ultraviolet rays.

Porosity and permeability are mass properties of a rock. The pore pattern of a clastic reservoir rock is a function of several petrographic characteristics. These include: (1) grains—sizes, shapes, sorting, chemical composition,

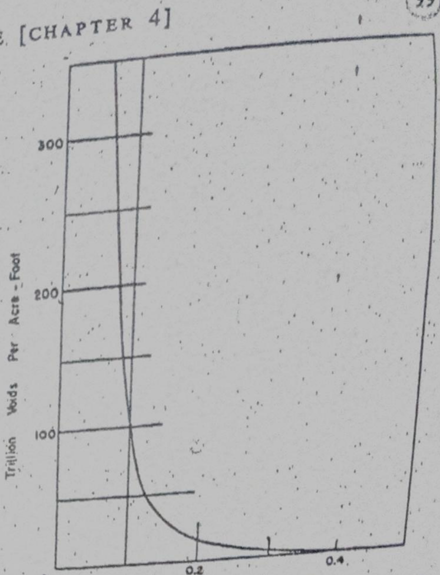


FIGURE 4-1

The probable number of pores per acre-foot of reservoir rock for varying particle sizes. [Redrawn from Jones, Petroleum Production, *Reinhold Publishing Corp., New York, Vol. 1, p. 14, Fig. 2-2.*]

mineral composition; (2) matrix—amounts of each mineral, how distributed, mineral and chemical composition; (3) cement—character, composition, amount, distribution with respect to grains and matrix.[2] The pore pattern of chemical reservoir rocks is dependent upon such factors as (1) fossil content, (2) fracturing and jointing, (3) solution and redeposition, (4) dolomite content, (5) recrystallization, (6) clay content, (7) bedding planes.

The number of separate pores in an acre-foot of average reservoir rock is enormous,[3] as may be seen in Figure 4-1. Since the average diameter of particles in most clastic reservoir rocks is between 0.002 and 0.01 inch (0.05–0.25 mm), the number of pores per acre-foot* of reservoir rock may be between 1 trillion and 1,000 trillion. Pores in most sandstone reservoirs have radii between 20 and 200 microns. It should be remembered that the calculations for the chart shown in Figure 4-1 are based on uniform, rhombohedrally packed particles and that the particles in the average clastic rock, being far from uniform in size, may give either larger or smaller figures. Carbonate rocks have a higher percentage of solution voids than sandstones of equal porosity, and probably contain a smaller number of pores per unit volume.

The surface area of the rock material in contact with the pore space increases greatly as the size of the particles diminishes. Jones[3] estimates that in

* An acre-foot is the volume of a one-acre area (43,560 square feet) one foot thick, or 43,560 cubic feet.

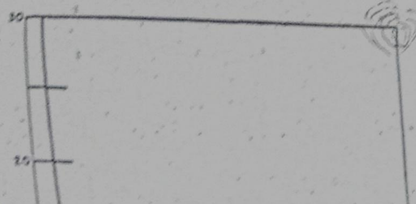


FIGURE 4-2

The surface area in acres per acre-foot of reservoir rock, depending upon the particle size. [Redrawn from Jones, Petroleum Production, Reinhold Publishing Corp., New York, Vol. 1, p. 15, Fig. 2-3.]

a sandstone consisting of rhombohedrally packed, medium-to-fine sand, with a particle diameter of 0.01 inch (0.25 mm), it is about 5,000 acres per acre-foot. The surface area may reach up to 30,000 acres per acre-foot in sandstone and siltstone. (See Fig. 4-2.) The large surface areas of the mineral material in the rocks with finer particle sizes become important in an understanding of such reservoir phenomena as wettability, adsorption, capillarity, solubility, and free surface energy. (See Chap. 10.)

POROSITY

Porosity is defined as the ratio of pore space to total volume of reservoir rock and is commonly expressed as a percentage. Two measurements, pore volume and bulk volume, are required to obtain the percentage porosity in accordance with the equation

$$\text{percentage porosity} = \frac{\text{pore volume}}{\text{bulk volume}} \times 100$$

Porosity varies greatly within most reservoirs, both laterally and vertically. If porosity is measured for each foot of core taken from the reservoir rock, as is the common practice, even some of the most uniform-appearing rocks show rapid and marked changes in porosity. The MicroLog (see pp. 80–81), especially, shows in detail the variable porosity that characterizes most reservoirs. The Springhill sand of the Manantiales field, Tierra del Fuego, Chile, is an

example of such variable porosity. (See Fig. 4-3.) Another example of rapid variation in both porosity and permeability is in the Cedar Lake field of western Texas, where a dolomite in the San Andres limestone (Permian) is the reservoir rock; a section through a small part of the field is shown in Figure 4-4.

While porosity is generally stated as the percentage of pore space in the reservoir rock, it is frequently stated in reservoir estimates as acre-feet of pore space, or as volume in barrels per acre-foot of reservoir rock. Since there are 5.6146 cubic feet per U.S. barrel of 42 gallons, an acre-foot has a volume of 7,758 barrels. A rock with 10 percent porosity, then, contains 775.8 barrels of pore capacity per acre-foot.

The ratio of total volume of pore space to total volume of rock is called the *absolute* or *total porosity*. It includes *all* of the interstices or voids, whether interconnected or not. The porosity measurement ordinarily used in reservoir studies, however, is the ratio of the interconnected pore spaces to the total bulk volume of the rock, and is termed the *effective porosity*. It is commonly 5–10 percent less than the total porosity. The permeability of a rock depends on the effective porosity. The effective porosity may also be termed the *available pore space*, since oil and gas, to be recovered, must pass through interconnected voids. A pumice or scoria, for example, though it has a high total porosity, has a low effective porosity.

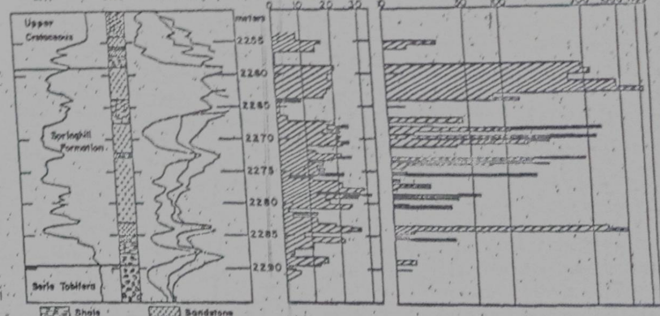


FIGURE 4-3 *Section through the Springhill sand (Cretaceous) producing in the Manantiales field, Magallanes Province, Tierra del Fuego, Chile. The sand is bounded by unconformities at the base and top, and the oil is of 42° Baumé gravity. This is an example of the variableness of the porosity, permeability, and character of a typical producing sand formation. [Redrawn from Thomas, Bull. Amer. Assoc. Petrol. Geol., Vol. 33, p. 1582, Fig. 3.]*

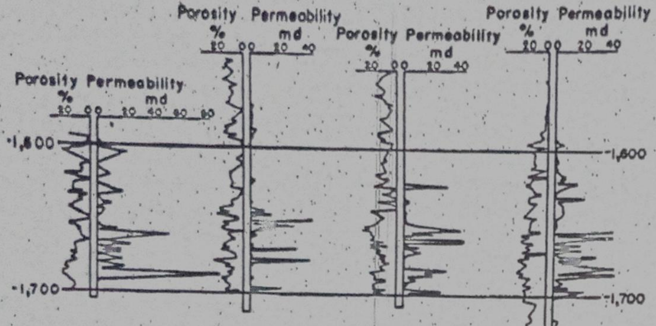


FIGURE 4-4 *Section showing the variable porosity and permeability in offsetting wells (1,320 feet apart) in the Cedar Lake field, western Texas. The producing formation is a crystalline dolomite within the San Andres formation (Permian). [Redrawn from Liebrook, Hiltz, and Huzarevich, Trans. Amer. Inst. Min. Met. Engrs., Vol. 192, p. 359, Fig. 5.]*

The porosity of most reservoirs ranges from 5 to 30 percent and is most commonly between 10 and 20 percent. Carbonate reservoirs generally have slightly less porosity than sandstone reservoirs, but the permeability of carbonate rocks may be higher. A reservoir having a porosity of less than 5 percent is generally considered noncommercial or marginal unless there are some compensating factors, such as fractures, fissures, vugs, and caverns, that are not revealed in the small sections of the rock cut by the core or the well bore. Representative porosities of some reservoir rocks are listed in Table 4-1, page 106. A rough field appraisal of porosities is (in percent):

Negligible	0–5
Poor	5–10
Fair	10–15
Good	15–20
Very good	20–25

Objective

Measurement

The measurements required for calculating porosity are made in the laboratory, either on small pieces of the rock cut from well cores or on well cuttings, and a number of methods for making them quickly and accurately have been devised and described.[4] Several qualitative methods of estimating porosity are also used, either to supplement the core analyses or to replace them if they are not available. These include:

The Electric Log. This is a measurement in millivolts of the natural electric potential of the rocks (the spontaneous potential, or SP). The low potentials are opposite the impervious beds, whereas the higher potentials are opposite the porous layers. (See pp. 77–81.)

Radioactivity Logs. Gamma-ray logs measure the natural emission of gamma rays from the formations logged, and neutron logs measure the emission of gamma rays induced from the formation by the action of neutrons. (See pp. 81–83.) The neutron log is primarily influenced by the presence of hydrogen and consequently by the presence in the formation of the reservoir fluids, gas, oil and water. The presence of fluids indicates that the rock has porosity. The gamma-ray log and the neutron log are widely used to indicate the porosity of limestone and dolomite reservoirs. , sound is used.

Other Logs. MicroLog and Sonic log measurements are very useful in determining porosity. Caliper logs often give a qualitative indication of porous zones and provide data for quantitative porosity determinations from other logs.

Microscopic Examination of Well Cuttings. If cores are not available, the examination of well cuttings through a binocular microscope is often the only way of directly observing porosity. Oil in minute openings may be seen to fluoresce when under ultraviolet light. An experienced microscopist can quickly determine the nature of the porosity and give a qualitative estimate of its relative amount, using such terms as "tight," "dense," "vugs," "pinpoint," "porous," "cavernous," "intercrystalline," and "intergranular." The absence of individual pores visible under the microscope generally means that the rock has too low a porosity to store appreciable amounts of oil.

Low pore space in a reservoir may be noted under the microscope as being due to various factors: the rock may be a dense, finely crystalline, lithographic limestone or dolomite; it may consist of fine and very fine sand particles; it may contain much clay as matrix and as wall coating on the sand grains; it may contain too much cementing material; or it may contain a high percentage of material that squeezes into the pore space under compression.[5]

Drilling-time Logs. A sudden increase of footage in a drilling-time log—or a sudden increase in the speed of drilling as the bit "falls away"—frequently means a porous formation; the more porous a rock is, the less dense it is, and the easier it drills. Such a change is often regarded as indicative of a porous pay formation, and a core is cut to determine the character of the rock.

Loss of Core. The cores recovered in the ordinary rotary core barrel may add up to less than the distance cored. Quite often this loss of core is due to the fractured, porous, and unconsolidated nature of the reservoir rock, which the core barrel is unable to retain, and which, consequently, is pumped up as well cuttings. The fact that zones of poor core recovery may represent rocks of abnormally high porosity explains the rule of thumb: "no core recovery, good well." There is no way of telling definitely whether poor core recovery actually indicates high porosity, but the drilling-time log may help, since such a formation will probably drill faster than denser rocks. The advent of diamond core heads has resulted in nearly 100 percent core recovery; where they are used, it is generally possible to obtain a continuous record of the porosity.

PERMEABILITY

Permeability is the property that permits the passage of a fluid through the interconnected pores of a rock—its effective porosity—without damage to or displacement of the rock particles. Permeability is, in other words, a measure of the fluid conductivity of a rock, and it is probably the most important single property of a reservoir rock. Permeability, in the geology of petroleum, is not absolute but relative; a rock is termed permeable if an appreciable quantity of fluid will pass through it in a short time (for example, an hour); it is termed impermeable if the rate of passage is negligible. It is recognized, however, that nearly all rocks have some permeability when considered in terms of long periods of geologic time and low-viscosity gases and liquids.

The unit of measurement of the permeability of a rock in the CGS system has been named the darcy after Henri Darcy,[6] who experimented with the passage of liquids through porous media in 1856. Darcy's law is expressed by the equation

$$q = \frac{kA}{\mu} \times \frac{dp}{dx}$$

in which q is the volume flux (volume per unit time) in centimeters per second for horizontal flow, k is the permeability constant in darcys, A is the cross-sectional area in square centimeters, μ is the fluid viscosity in centipoises, and dp/dx is the hydraulic gradient (the difference in pressure, p, in the direction of flow, x) in atmospheres per centimeter. This equation defines completely the viscous or laminar flow of homogeneous fluids through porous media of uniform packing and of uniform cross section.* For a given value of k the flow rate through any porous block of rock is thus proportional to the difference in pressure across the block and to the area of the block, and inversely proportional to the viscosity of the fluid and to the length of the block.

The darcy has been arbitrarily standardized by the American Petroleum Institute in terms of CGS units for use in the petroleum industry as follows: "A porous medium has a permeability of one darcy when a single-phase fluid of one centipoise viscosity that completely fills the voids of the medium will

* In reservoir rocks we are not concerned with turbulent flow. A rigorous statement of Darcy's law requires that the acceleration of gravity and the direction of flow be taken into account. For extended discussions of the derivation and limitations of Darcy's law the reader is referred to Hubbert, Jour. Geol., Vol. 48 (1940), pp. 787–826, and to Morris Muskat, *Physical Principles of Oil Production*, McGraw-Hill Book Co., New York (1949), pp. 123–131.

flow through it under 'conditions of viscous flow' at a rate of one centimeter per second per square centimeter of cross-sectional area under a pressure or equivalent hydraulic gradient of one atmosphere (76.0 cm of Hg) per centimeter."[7] Under "conditions of viscous flow" the rate of flow is so low as to be directly proportional to the hydraulic gradient. The darcy is the coefficient of proportionality between the quantities, and the particular numerical value of the permeability is a property or attribute of the medium alone and not of the fluid.

The permeabilities of average reservoir rocks generally range between 5 and 1,000 millidarcys.* A rough idea of one darcy is obtained if one considers a cube of sand one foot on a side. If the sand has a permeability of one darcy (1,000 md), this one-foot cube will pass approximately one barrel of oil per day with a one-pound pressure drop. Commercial production has been obtained from rocks whose permeabilities were as low as 0.1 md, but such rocks may have highly permeable fracture systems that are not revealed in the standard laboratory analysis. Permeability, along with porosity, varies greatly both laterally and vertically in the average reservoir rock. The examples from Chile and Texas, shown in Figures 4-3 and 4-4 on pages 101 and 102, are typical of most reservoir formations. A reservoir rock whose permeability is 5 md or less is called a *tight sand* or a *dense limestone*, according to its composition. A rough field appraisal of reservoir permeabilities is:

Fair	1.0–10 md
Good	10–100 md
Very good	100–1,000 md

objective

A few representative porosities and permeabilities of oil pools are given in Table 4-1.

Measurement

The permeability of a reservoir rock is commonly determined in the laboratory by testing cores and pieces of core in a *permeameter*. Permeameters differ in design but generally consist of a core holder, a pump for forcing fluid through the core, manometers to measure the pressure drop across the core, and a flow meter for measuring the rate of flow of the fluid through the core. Laboratory methods are standardized so that measurements may be made rapidly and yet with sufficient accuracy for most reservoir problems. The test samples are generally cylindrical cores, 2 cm in diameter and 2–3 cm in length. Several methods have been devised and described.[8]

The fluid used in measuring the permeability of a reservoir rock is generally air or dry gas, and the pressure applied is the lowest that will cause a measurable rate of flow; serious errors result from pressures that cause turbulent flow. Air is most commonly used because it has little or no reaction with the rock

* A millidarcy (md) = 0.001 darcy.

TABLE 4-1 Representative Porosities and Permeabilities

Pool	Porosity		Permeability		Reference
Location, reservoir	Range %	Average %	Range md	Average md	
Bradford, Pennsylvanian Bradford sand (Devonian). (See also Fig. 4-17.)	2–26	15	0.1–500	50	1
12 pools producing from Smackover (Jurassic) limestone in southern Arkansas	12.5–21.3	16.9	50–2,000	737	2
Masjid-i-Sulaiman oil field, Iran, Asmari limestone		2		0.0005	
		5		0.007	3
		10		0.05	
		15		0.5	
Rangely oil field, Colorado, Weber sandstone (Pennsylvanian)		16		20	4
East Texas pool, Texas, Woodbine sand (Upper Cretaceous)		25	Up to 4,600	1,500	5
Ten Sections, Kern Co., California, Stevens sand (Upper Miocene)	15–30	20	10–3,000	140	6
Glenn pool, Oklahoma, Glenn sand (Pennsylvanian)		16		125	7
Oklahoma City field, Oklahoma, "Wilcox" sand (Ordovician), 9 analyses	8–22	16	79–2,497	688	8
Cumarebo oil field, Falcón, Venezuela, sands (Miocene)	3–39	21.7	1–3,397	200–300	9

1. C. R. Fettke, "The Bradford Oil Field," Pa. Geol. Surv., 4th series (1938), pp. 214–228.
2. Morris Muskat, *Physical Principles of Oil Production*, McGraw-Hill Book Co., New York (1949), p. 585.
3. H. S. Gibson, "Oil Production in Southwestern Iran," World Oil, May 1948, p. 273. Averages for four different Asmari limestone types.
4. W. Y. Pickering and C. L. Dorn, "Rangely Oil Field, Rio Blanco County, Colorado," in *Structure of Typical American Oil Fields*, Vol. 3 (1948), p. 143.
5. H. E. Minor and Marcus A. Hanna, "East Texas Field, Rusk, Cherokee, Smith, Gregg, and Upshur Counties, Texas," in *Stratigraphic Type Oil Fields*, Amer. Assoc. Petrol. Geol., Tulsa, Okla. (1941), pp. 625 and 626.
6. W. Tempelaar Lietz, "The Performance of the Ten Section Oil Field," Tech. Paper 2643 (September 1949), Trans. Amer. Inst. Min. Met. Engrs., Vol. 186 (1949), pp. 251–258.
7. K. B. Barnes and J. F. Sage, "Gas Repressuring at Glenn Pool," in *Production Practice*, Amer. Petrol. Inst. (1943), p. 57.
8. H. B. Hill, E. L. Rawlins, and C. R. Bopp, *Engineering Report on Oklahoma City Oil Field, Oklahoma*, RI 3330, U.S. Bur. Mines (January 1937), p. 199.
9. A. L. Payne, "Cumarebo Oil Field, Falcón, Venezuela," Bull. Amer. Assoc. Petrol. Geol., Vol. 25 (August 1951), p. 1869.

and does not cause any permanent change in the permeability. Furthermore, permeability measurements made with air are comparable with one another. It is recognized, however, that the permeability of a specimen of reservoir rock to air in the laboratory is not necessarily the same as the permeability of the rock to oil, gas, or salt water under reservoir conditions. Several factors tend to make permeability measurements using air higher than permeability measurements using reservoir fluids:

1. The sample is dried, and all gas, oil, and water are extracted from it before permeability measurements are made. Since most reservoir rocks are water-wet (that is, a thin film of reservoir water envelops each particle), the permeability of the dried specimen to air will be different from that of the normal water-wet specimen to gas or oil.

2. Reservoir rocks almost always contain some clay minerals, many chemically unstable. Some of these, especially the montmorillonites, take up water and swell to an extent depending on the character of the water. As the water is eliminated in the laboratory preparation of the sample, the clay minerals may either lose their water or break up into smaller particles, and either of these changes modifies the permeability measurement of the rock. Colloidal clay material in the reservoir rock may become loosened within the sample as it is being cleaned and dried. Thus fine pores may become clogged, or at least the pore pattern may be changed from what it was in the reservoir.

Where it is planned to flush the reservoir rock with water, as in water flooding for secondary recovery operations, it is desirable to make special permeability measurements with the same water that is to be used. What would then be measured is *permeability to water*, and that is generally lower than permeability to air. The efficiency and success of secondary recovery operations, in which water is pumped into the reservoir to drive or flush oil out of the pores, depend largely on using a water that does not swell the clay materials present in the rock.

3. Incomplete desaturation of the core may cause air trapping, or Jamin action. Thus the resistance to flow is markedly increased where gas and liquid globules alternate in a capillary-sized channel, as, for example, air globules in water or gas globules in oil.[9] When liquids are used for permeability tests, therefore, extreme care must be taken to eliminate all gas and air from the specimen tested; otherwise the permeability will be unduly low.

4. Permeability is independent of the fluid passing through the rock and also of the differential pressure. The permeability of a rock to gas, however, is greater than its permeability to liquid, probably largely due to the slippage of the gas along the rock wall, which does not occur with liquids. When air or other gas is used for the measurement, the higher the pressure, the smaller the volume, and consequently the mean free path of the gas molecules is greatly reduced until at high pressures gases and liquids are very similar. In order to correct for this difference between air and liquid, the *Klinkenberg*

scale has been devised.[10] It is based on the idea that "permeability to a gas is a function of the mean free path of the gas particles," which means that permeability depends on factors such as temperature, pressure, and composition of the gas. Of these factors, pressure is the most flexible. Low pressure results in the maximum mean free path, and it is at low pressure also that maximum slippage occurs. The Klinkenberg permeability factor (b) is obtained by measuring the permeability to air at several differing pressures, and extrapolating the curve to infinite pressure, at which the permeability will approximate the permeability to a liquid. The Klinkenberg permeability equivalent to air permeabilities in tight sands (below 1 md) may be as much as 100 percent higher, the correction approaching zero for high permeabilities. The Klinkenberg permeability factor, then, is a measure of the fractional error that comes from the slippage when low-pressure gas is used instead of a liquid. The relation is linear on log-log paper and is approximately[11]

$$\text{Klinkenberg permeability factor } (b) = 0.777\, k_{He.}^{-0.39}$$

Permeability is usually measured parallel to the bedding planes of the reservoir rock. Along this *horizontal*, or *lateral, permeability*, is found the main path of fluids flowing into the bore hole. Permeability across the bedding planes, or *vertical permeability*, is also frequently measured and is usually less than the horizontal permeability. High vertical permeability may permit bypassing and channeling of the water from below or the gas from above, thus changing the relative saturations at the bore hole and adversely affecting the productivity of the well.

The reason why horizontal permeability is generally higher than vertical permeability lies largely in the arrangement and packing of the rock particles during deposition. As flat grains tend to align and overlap parallel to the depositional surface, dissolving solutions move most easily in this direction, and in so far as the solutions have a solvent action on the minerals, they increase the horizontal permeability. Minor partings within a formation, and layering due to size-grading of particles, are more likely to extend parallel to the bedding than across it, so that they also tend to make permeability greater in the horizontal direction. It should be noted that what we generally measure in the laboratory is the permeability along the bedding planes. Where the reservoir rock has a steep or vertical dip, however, the direction of greater permeability may be more nearly parallel to the well bore than normal to it.

High vertical permeabilities are chiefly the result of fractures and of solution along fracture and joint planes that cut across the bedding. They are most commonly encountered in carbonate rocks and other brittle rocks and in clastic rocks with a high content of soluble material. They may also characterize loosely packed and uncemented sandstones.

If enough cores are taken and examined, sufficient permeability data are obtained by standard laboratory methods within the accuracy called for by the various geologic, engineering, and production problems. Field methods

of obtaining permeability data, though not as accurate as the laboratory methods, are yet extremely useful and often furnish the only information one has on the permeability of a particular rock.

1. If there is so much free water in a formation that it enters the hole and dilutes the drilling mud in a rotary-drilled well, or partly fills the hole in a cable-tool well, it indicates that the formation is permeable. In cable-tool wells the rate at which the water enters the hole gives an even better idea of the gross permeability of the formation drilled than a laboratory examination of the core.

2. In a rotary operation the drilling mud is pumped down the well bore inside the drill pipe and out through the drill bit, and the cuttings are circulated up from the bottom of the hole with the drill mud, and brought to the surface in the annular space between the drill pipe and the wall of the well. When the drilling mud does not return to the surface, or only a part of it returns, the well is said to have *lost circulation*. When this happens, it means that the mud is draining off from the well bore and is entering a formation that has high permeability and a pressure less than the pressure of the drilling mud.

3. When there is a sudden decrease in the time it takes to drill a given thickness of formation, it indicates a softening of the formation; the bit has probably entered a bed of high porosity and presumably of high permeability.

4. One of the best over-all, or gross, measures of permeability is a production test, in which the decrease in bottom-hole pressure is measured against the production rate. If the formation is highly permeable, the rate of decrease in bottom-hole pressure with increasing production rate will be low, but if the formation is relatively impermeable, the decrease in bottom-hole pressure with increasing production rate will be high. The rate of recovery of reservoir pressure after a production test is also significant, for this gives an idea of the volume of the system and whether it is sealed or not. An open-flow test of the producing formation is a standard procedure when the total effect of the permeability, or fluid conductivity, of the reservoir plus the method of completing the well is needed for making accurate estimates of reserves and producing capacities.

5. A permeability profile of the reservoir rock may be made with an electric pilot,[12] which is an apparatus for locating, in a bore hole, the interface between two liquids of dissimilar electric conductivity. Salt water is run into the hole until the reservoir rock is completely covered. It is then forced into the formation by oil pumped into the well. The rate of fall of the oil–salt-water interface is measured by an electric pilot as it moves down the hole with the interface. The permeability of any part of the section of the reservoir is determined as a percentage of the permeability of the entire section.

6. Permeability may be determined qualitatively by pumping radioactive mud into a reservoir rock and then passing a Geiger counter down the well.

The counter registers the radioactivity opposite the reservoir rock. High radio-
activity shows where the greatest amount of radioactive mud entered the for-
mation and thus corresponds to zones of high permeability.

7. The permeability of drill cuttings or core fragments may also be calcu-
lated by the relationship that exists between the permeability of a rock and
its capillary pressure curve.[13] (See also pp. 451–457.)

Effective and Relative Permeability

Kw: effective permeability

Darcy's law governing the flow of fluids through a porous material is based
on the assumption that only one fluid is present and that it completely satu-
rates the rock. In nature, however, the reservoir pore spaces contain gas, oil,
and water in varying amounts, and each interferes with and impedes the flow
of the others. Where a fluid does not completely saturate the rock, as is
generally the case, the ability of the rock to conduct that fluid in the presence
of other fluids is called its *effective permeability* to that fluid.[14] The effective
permeabilities to air, gas, oil, and water, are designated, respectively, as k_a,
k_g, k_o, and k_w.* It has been found that a given value of fluid saturation† bears
a constant relation to the effective permeability; if the one changes, the other
changes proportionately. This relation, however, differs for different rocks
and must be determined experimentally. The factors that seem to influence the
relation are clay swelling, adsorbed films, hydrophobic and hydrophilic sur-
faces, the presence of other, immiscible fluids, and the gas pressure.

The ratio between the effective permeability to a given fluid at a partial
saturation and the permeability at 100 percent saturation (the absolute per-
meability) is known as the *relative permeability*.[15] It is expressed as k_g/k,
k_o/k, or k_w/k (or as k_{rg}, k_{ro}, or k_{rw}), meaning the relative permeability to
gas, oil, or water, respectively, and ranges from zero at a low saturation to 1.0
at a saturation of 100 percent. It is the ratio of the amount of a specific fluid
that will flow at the given saturation, in the presence of other fluids, to the
amount that would flow at a saturation of 100 percent, the pressure gradient
and the other fluids being the same. Since the pore space of all reservoirs is
full of gas, oil, and water, in varying proportions, the relative permeability of
the rock to one fluid is dependent upon the amount (saturation) and nature
of the other fluids present. It is always necessary, in fact, to use relative per-
meabilities rather than single-fluid permeabilities in reservoir studies. The
relative permeability of a rock to any fluid increases as its saturation with that

* It is suggested (API RP No. 27, p. 4) that effective permeabilities always be written
in the same order. Thus $k_{o(60,13)}$ means: "The effective permeability of the medium to
oil when the percentage fluid saturation of the medium is 60 percent oil, 13 percent
water, and 27 percent gas (millidarcys or darcys). The gas concentration is obviously
derived by difference." And $k_{w(50,40)}$ means: "The effective permeability of the medium
to water when the percentage saturation is 50 percent oil, 40 percent water, and 10
percent gas."

† The saturation is the ratio of a fluid to the total pore volume.

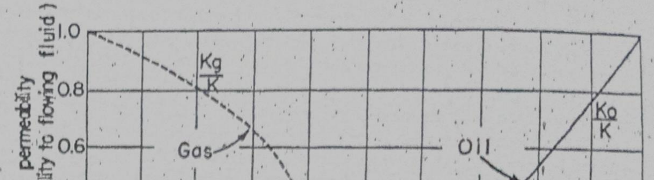


FIGURE 4-5 *Typical relative permeability relations with varying saturations of gas and oil.*

fluid increases, until finally, at 100 percent saturation, the full value of k is
reached.

The relative permeability must be determined experimentally for each
rock and each combination of fluid saturations. During production these ratios
are continually changing. Charts of relative permeability are generally similar
in pattern to the typical charts shown in Figures 4-5 and 4-6.[16] It may be ob-
served in Figure 4-5 that there is no permeability to oil until the oil saturation
has reached 30 percent or more. The reason is that the oil preferentially wets
the rock surface and therefore clings to it and fills the smaller pore spaces.
(See pp. 445–451 for a discussion of wettability.) During this period when
the relative permeability ranges between 1.0 and 0.63, the gas has been moving
freely. In other words, as long as the oil saturation ranges between zero and
30 percent, and the gas saturation between 100 and 70 percent, only gas will
move through the rocks. At the point where the lines cross, the relative per-
meability is the same for gas and oil, and both should flow equally well. Above
that point, the oil saturation increases to 100 percent, and the relative per-
meability of the rock to oil increases to 1.0 (which is k for the rock). During
this period the gas saturation decreases from 0.15 to zero, the gas occurs as
discontinuous bubbles, and the relative permeability of the rock to gas finally
reaches zero.

The situation shown in Figure 4-6 differs in that the wetting fluid is not oil,
but water. There is always some residual water in all pore spaces; but, as this
chart shows, it does not begin to flow through the rock until the saturation is
above 20 percent. Water at the low saturation is interstitial or "conn-

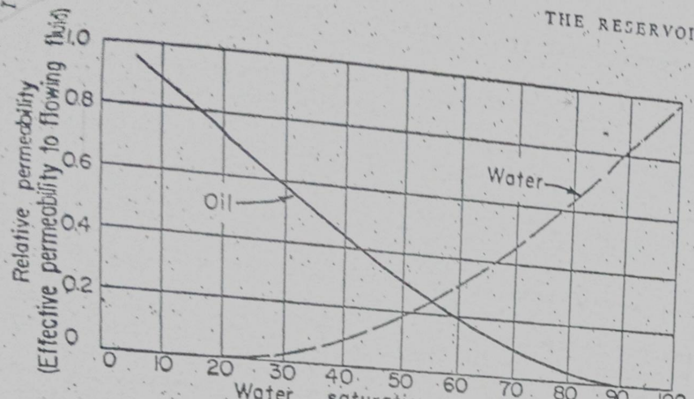


FIGURE 4-6 *Typical relative permeability relations with varying saturations of water and oil.*

water, which preferentially wets the rock and fills the finer pores. (For a discussion of connate and interstitial water see pp. 152–156.) As the water saturation increases from 5 to 20 percent, the oil saturation decreases from 95 to 80 percent; yet up to this point the rock permits the oil to flow, but not the water. Where the lines cross, at a saturation of 56 percent for water and 44 percent for oil, the permeability of the rock is the same for both fluids, and both flow equally well. As the water saturation rises above that level, the water flows more freely, and when the oil saturation gets down to about 10 percent, the oil stops moving; in other words, the rock then shows no permeability to the oil, and only water flows through it.

The relations shown in Figures 4-5 and 4-6 have a wide application to problems of fluid flow through permeable rocks. Probably the most important application they have to the geology of petroleum is the conclusion that there must be at least 5–10 percent saturation with the nonwetting fluid before that fluid begins to flow, and 20–40 percent saturation with the wetting fluid. This means that for oil or gas (as the nonwetting fluid) there must be a minimum of 5–10 percent saturation of the pore space before the fluid can begin to move through the water-saturated rock and accumulate into pools—provided, of course, that these relations, which prevail in the laboratory and through the life of an oil and gas pool, can be extrapolated to geologic time. Conversely, every oil pool has a residual oil saturation of 5–10 percent, which is not recoverable by ordinary production methods. These features will be considered in more detail later, under migration and accumulation of petroleum (Chap. 12).

CLASSIFICATION AND ORIGIN OF PORE SPACE

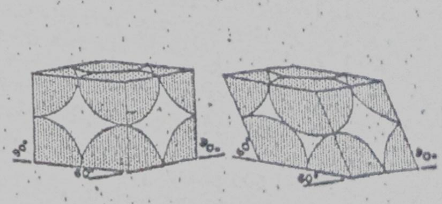
Two distinct general types of pore space in sedimentary rocks are recognized.[17] They are *primary, or intergranular, porosity* and *secondary, or intermediate, porosity*.

Primary, or Intergranular, Porosity

This is sometimes called *original porosity* because it is an inherent characteristic of the rock, established when the sediment was deposited. A sandstone is a permeable rock having primary porosity. Less permeable examples are shales, chalks, and crystalline rocks. The character of primary porosity is determined by the arrangement and form of the pores, the degree to which they are interconnected, and their distribution in the sedimentary rock unit.[18] The term "packing" refers to the manner in which the particles of a clastic rock are fitted together.[19] The primary porosity of a rock is largely dependent upon its packing characteristics, which in turn depend largely on the uniformity or lack of uniformity of grain size. If all the grains in a sandstone were perfect spheres of uniform size, the porosity would range from 47.6 percent if the spheres were cubically packed to 25.9 percent if the spheres were rhombohedrally packed, with a mean of 36.7 percent. (See Fig. 4-7.) The porosity of aggregates of spheres, all packed in the same way, is theoretically independent of the size of the spheres, provided the spheres are all of the same size. Thus a sandstone composed of uniformly round, large grains will have the same porosity as a sandstone composed of uniformly round, small grains, if the packing is the same in both. Uniformity of grain size is never completely reached in clastic reservoir rocks, however, as may be seen from the porosity of an average sandstone, which is about 20 percent. The pores formed between the larger grains are filled with smaller, or matrix, particles. The resulting rock occupies a minimum space, for normal sedimentary processes, such as wave and current action, shake the particles down until the tightest packing possible for the particular combination of varying grain sizes and shapes being deposited has been reached.

FIGURE 4-7

Comparison of porosity in cubic packing of spheres (left) and rhombohedral packing (right). [Redrawn from Graton, Jour. Geol., Vol. 43 (1953), p. 800, Fig. 5.]



The nearest approach to uniform grain size is found in clastic rocks made up of well-sorted, well-rounded sand grains or oolites. The grains of very fine clastics are generally less well rounded than the grains of coarser materials because the natural agencies that produce rounding are not effective on very small particles.[20] In rock of uniform grain size, the smaller the grains are, the greater is the porosity; this effect is due to such factors as friction, adhesion, and bridging, which are greater with smaller grains because of the higher ratio of surface area to volume and mass.[21] The shape of clastic rock particles commonly varies from round through angular to flat and mica-like, and the size from coarse to fine or even colloidal; and there are widely varying amounts of cementing material between the individual grains. The porosity in the average clastic reservoir rock, therefore, is the combined effect of many variables, such as particle size, particle shape, sorting, packing, and character and amount of cementing material. Porosity declines rapidly with the addition of fine matrix particles that fill in the interstitial spaces. Many of the minor variations in porosity and permeability commonly encountered in the average clastic reservoir rock result from changes in depositional environment, to which mineral particles are extremely sensitive.

The porosity of most sandstone reservoir rocks is chiefly primary. Where porosity is extremely high, the sand grains are frequently loose and uncemented and may come up with the oil, sometimes in large quantities. For example, the loose sand grains that came up with the oil from the "Wilcox" formation (Ordovician), in the Oklahoma City field, had a porosity of 30 percent when tightly packed, whereas consolidated cores from the same field averaged about 16 percent in porosity.[22] Extremely low porosity is generally due to dirty sand, irregularity of grain size, and a high proportion of matrix material, and sometimes to a tight cementing of these constituents with silica, calcite, or dolomite.

The conditions that affect permeability differ considerably from those that affect porosity.[23] Some of the geologic conditions that have a bearing on the permeability of potential reservoir rocks are:

1. *Temperature.* Increase in temperature decreases the viscosity of a liquid, and the permeability varies inversely with the viscosity.

2. *Hydraulic gradient.* The rate of flow is directly proportional to the hydraulic gradient. Probably all rocks are permeable in some degree if the pressure difference is sufficiently high and the viscosity of the fluids sufficiently low. We are chiefly concerned, however, with low gradients, most of which will average less than 50 pounds per square inch pressure drop per mile, and few exceed 500 pounds per square inch pressure drop per mile.

3. *Grain shape and packing.* It has been found that with variable grain size, the permeability increases as the shapes of grains depart from that of true spheres. Thus the permeability of a sand composed of angular grains is greater than that of a sand composed chiefly of spherical grains of similar

size, largely because the angular grains are packed more [illegible] also develop bridging. Rocks composed mainly of flat, mica-shaped particles and needle-like crystals pack loosely, have a high porosity, and in general, probably, have a high permeability. Decreasing grain size, on the other hand, increases porosity; but, because of the greater tortuosity and the higher capillary pressures, with a consequent higher saturation by the wetting liquid, the relative permeabilities are lower.

Compaction and cementation obviously reduce permeability based on primary porosity, whereas solution channels increase permeability. Fracturing, shattering, joint planes, and bedding planes, especially, increase permeability greatly by the large cross-sectional area of the tabular openings they produce. Permeability varies inversely with the length of flow and therefore inversely with tortuosity; so whatever shortens the path increases the permeability.

Carbonate reservoir rocks commonly have more secondary porosity than sandstones. There is no sharp boundary, and it is frequently difficult to distinguish between primary porosity and secondary porosity in carbonate rocks, but primary porosity is evident in some carbonate rocks, in such forms as (1) pores within and between fossil shells, fossil casts, coquina rock, fossil fragments, foraminifera, and algae; (2) pores between carbonate crystals and on cleavage planes within the crystals—called *intercrystalline porosity;* (3) pores associated with oolites and oolitic limestone; (4) pores along bedding planes, due to changes in depositional conditions at the bedding planes, to clastic material such as clay and silt, and possibly to crystal structures different from those in the body of the rock; (5) fractures due to desiccation or shrinkage occurring at the time of deposition.

Some of the diagenetic processes in carbonate rocks[24] continue after the rock has become lithified, and these contribute to the secondary porosity. Compaction, cementation, solution, recrystallization, and dolomitization are all common in diagenetic as well as post-diagenetic changes. The porosity that results from these processes, when it can be determined, may be said to be secondary, whereas that which merely modifies primary depositional characteristics may be said to be primary. Intercrystalline porosity may be either primary or secondary, and it is often difficult to determine which it is. The same is true of fractures, which may be formed either from secondary deformation or from primary shrinkage. Examples of some different types of limestone porosity are shown in the thin sections in Figure 4-8.

Examples of reservoirs that are chiefly in carbonate rocks of primary porosity are the oolitic and coquina lens of the Lisbon field, in Louisiana[25] (see also p. 311) and the Pennsylvanian coquina formation of the Todd field, in western Texas[26] (see pp. 308–310). The oil in the Southern fields of Mexico is produced from the El Abra limestone (Cretaceous). The pores in this reservoir are chiefly in shell fragments and in hollow casts of corals and of many types of mollusks, including rudistids, with intercommunication

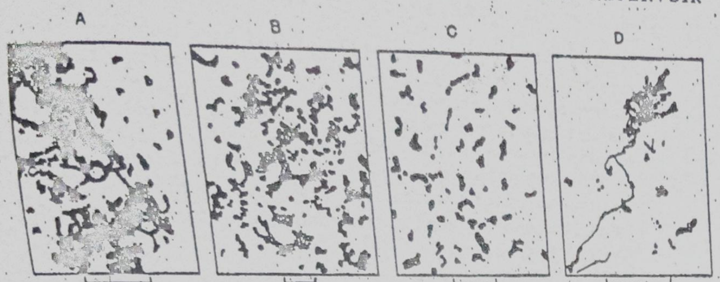


FIGURE 4-8 *Thin sections of plastic-impregnated limestone reservoir rocks showing the pores in black; scale, 1/100 inch. A, a reef type of porosity; B, primary porosity; C, pinpoint porosity; D, fracture porosity. [Redrawn from Stewart, Craig, and Morse, Tech. Paper 3517, Trans. Amer. Inst. Min. Met. Engrs., Vol. 198 (1953), pp. 93–102.]*

largely due to fracturing and shattering. The interiors of the casts are drusy; some of them contain bitumen (albertite) at the outcrop, whereas they contain oil, gas, or asphalt where penetrated by wells.[27] The El Abra formation is a reef limestone, and much of its porosity is primary—a characteristic of many organic reefs. (See also p. 361.)

Oolites are small round accretions, generally of calcite but also of silica. These accretions grow concentrically around a nucleus of foreign matter. Their diameters range from 0.25 to 2.0 mm and are commonly between 0.5 and 1.0 mm. Their name, which means "eggstone," is based on their similarity in appearance to fish roe. Larger accretions, of pea size, are called *pisolites*. The pore space associated with oolites is of two kinds. The greater part of it is between the oolites and is similar to that between the grains of any clastic rock. In some rocks, however, the oolites may have dissolved out, leaving voids, which are separated by undissolved matrix and cementing material. A rock consisting only of oolites or oolite casts frequently forms an excellent reservoir, highly porous and permeable.

There are many pools in oolitic limestone and dolomite reservoirs whose porosity is chiefly primary. In the Magnolia field, Columbia County, Arkansas,[28] more than 120 million barrels of oil has been produced from the dense, brown, oolitic Smackover limestone (Jurassic). The porosity of the clean oolite rock is about 20 percent and its permeability about 1,000 md, but the calcareous and chalky parts of the reservoir are less porous and permeable. The trap is a symmetrical, elongate dome fold, with a structural closure of 270 feet, covering an area of about 4,700 acres. The Reynolds oolite rock, in the upper part of the Smackover limestone, occurs extensively through the subsurface of southern Arkansas. It is the lowest producing formation in the Schuler field,[29] where the oolite rock consists of typical spherical oolites, rang-

ing in size from very small to large, and a few pisolites. The oolites are loosely cemented, and the porosity is therefore high, being over 23 percent in places and averaging 16.7 percent. Both the horizontal and the vertical permeability locally exceed 15,000 md and have an overall average of 1,176 md. In the Carthage gas field of Panola County, Texas (one of the great gas fields of the United States), one of the important pay formations is the Upper Pettet limestone (Lower Cretaceous). This consists of a gray, fossiliferous, partly crystalline, porous, oolitic limestone varying up to 32 feet in thickness, which pinches out up the dip across a broad fold.[30] (See Fig. 8-4.) The McCloskey "sand" of the Illinois Basin, which is the equivalent of the Ste. Genevieve formation (Upper Mississippian) on the outcrop, is one of the most widespread and productive oolitic formations. The oil in many pools is in the pores between the oolites or in the casts left by dissolved oolites, or in both.[31]

Numerous examples of pools in which the reservoir rock is a limestone with both primary and secondary porosity could be cited. One of the larger pools of this kind is the Redwater pool, in Alberta, Canada,[32] which underlies an area of nearly sixty square miles. This is estimated to contain 1.5 billion barrels of oil in place, of which at least 600 million barrels is considered recoverable. The reservoir rock is an organic limestone, the Leduc (D-3) member of the Woodbend formation (Upper Devonian), and the oil has accumulated along its up-dip northeast edge, which wedges out within a shale formation as a stratigraphic trap. (See Fig. 7-49, p. 331.) The limestone, which is of the biostrome type, has an effective porosity of about 7 percent and an average permeability of 800 md. The pore space consists of a variable combination of spaces among fragments of limestone debris, fossil casts, fractures, and intercrystalline openings. A section through a dolomitic core from the nearby and similar Leduc field shows that it also has a combination of several types of porosity. (See Fig. 4-13, p. 127.)

Secondary, or Intermediate, Porosity

In secondary porosity the shape and size of the pores, their position in the rock, and their mode of interconnection bear no direct relation to the form of the sedimentary particles. It has also been called *induced porosity*.[33] Such porosity is found, for example, in a cavernous limestone and also in a fractured chert or a siliceous shale. Most of the reservoirs characterized by secondary porosity are in the carbonate rocks—limestones and dolomites; and this type of porosity is therefore often termed "limestone porosity" or "carbonate porosity." Secondary porosity may result from and be modified by (1) solution; (2) fractures and joints; (3) recrystallization and dolomitization; (4) cementation and compaction.

Solution. Percolating surface waters containing carbonic acid and organic acids penetrate the rock along various kinds of openings,[34] such as primary pores, fissures, fractures, joint planes, intercrystalline openings, and bedding planes. As these acid waters pass through the rock, they dissolve out the more soluble cations, including the carbonates of calcium and magnesium and salts of sodium and potassium, thereby still further opening the channels and increasing the porosity. Connected calcite crystals in a dolomite, preferentially dissolved out, may form new channels and expose additional mineral grains to the dissolving solutions. The process of solution goes on as long as the solvents are moving through the rock, and it continually changes the nature of the porosity and permeability.

The order of solubility of the commoner carbonates in acid solution is: (1) aragonite, (2) calcite, (3) dolomite, and (4) magnesite. Where dolomite and calcite are mixed in rocks of uniform grain size, twenty-four parts of calcite are dissolved for each part of dolomite until all of the calcite has gone into solution.[35] In less homogeneous rocks the ratio varies with the relative sizes of the crystals and with the way in which the carbonates are distributed. Dolomite is scarcely affected on a weathered surface, whereas calcite is strongly attacked.

Increased porosity develops in those parts of the rock where solution goes on more rapidly than redeposition. Some of the dissolved matter, however, is precipitated in other parts of the rock, thus forming a cement that reduces the porosity. Part of the dissolved matter, carried to the surface, may escape into the streams of the region. Solution phenomena are especially important in limestone and dolomite reservoirs, and, since most clastic rocks contain varying amounts of calcium and magnesium carbonates and other soluble minerals, they affect nearly all reservoir rocks to some extent.

Solutions of organic acids are formed mainly in the zone of weathering,[36] and largely through the decay of organic matter. Howard and David[37] added elm and maple leaves to water, soil bacteria, and limestone, and left the mixture exposed to open air. They obtained CO_2 in increasing amounts for the first two months and then in declining amounts for eleven months. Bacterial action also is strongest at the weathering surface. Countless numbers of organisms, both plant and animal, grow and later decompose in the soil and at the surface of the ground, and combine to assist in the chemical breakdown of many of the minerals found there.

At a weathering surface, therefore, both chemical and biochemical activity are high, and both help to supply organic and inorganic acids to the surface waters. The large springs, sink holes, and karst topography found in many limestone regions today give evidence of the importance of solution in the development of porosity. Because of the combination of solvent action with weathering, carbonate rocks immediately below unconformities are commonly very porous. An example of buried pre-Pennsylvanian karst topography, developed in Ordovician limestones in western Kansas, is shown in Figure 7-58, page 338.

Unconformities are common in most areas of sedimentary deposits. So far

as they represent subaerial surfaces that have undergone weathering and erosion, they generally mark zones of solution porosity that may serve as reservoirs, and their position can be predicted in advance of drilling where the stratigraphy and geologic history have been worked out. The close relationship between porous, permeable limestone or dolomite reservoirs and overlying unconformity surfaces makes every unconformity an especially interesting target for a wildcat well. Many pools occurring in solution porosity formed below widespread unconformities might be cited. A few are described on pages 336–341.

Several examples of cavernous porosity have been described in the geologic literature.[38] A striking example is the large cavern found in the Dollarhide pool of Andrews County in western Texas.[39] Nine wells put down on forty-acre spacing within an area of one square mile encountered the cavern, as shown by the sudden dropping of the drilling bit. The cavern, which was full of oil, occurs in the Fusselman limestone (Silurian). Its height varied up to sixteen feet. There is approximately a thousand feet of limestone and dolomite of Silurian and Devonian age between the cavernous section and the pre-Permian unconformity. It is believed, however, that the cavern was formed during the pre-Permian erosion period.

In the highly productive Arab zone (Upper Jurassic) of the oil pools of Saudi Arabia, the porosity of the limestones is in their dolomitized and oolitic portions, which contain, besides many vugs and openings of finger size, cavernous openings up to three feet across, in which the drilling tools dropped. The result, in the Abqaiq field, at least,[40] is a permeability so high that the oil comes up almost as if it were being drawn from a tank.

Fractures and Joints. Fractures and joints in brittle rocks afford common and important types of secondary porosity.[41] The brittle reservoir rocks include limestones, dolomites, cherts, shales, siliceous sedimentary rocks, igneous rocks, and metamorphic rocks. Interbedded shales, sandstones, and limestones may show selective fracturing in certain beds. Since fractures afford channels for the movement of water, they are likely to be enlarged and modified by solution. They frequently combine with other types of both primary and secondary porosity to make a complex porous pattern; in fact, the presence of fractures often changes the permeability from millidarcys to darcys. The influence of fractures in determining the location of solution channels is shown diagrammatically in Figure 4-9.

Three causes are considered to account for most fractures. The first is diastrophism, such as folding and faulting. Some fractures may form at depth, where they accompany an increase in the volume of the rock resulting from the dilatant effect of the folding and bending of the strata.[42] The second cause is the removal of overburden by erosion in the zone of weathering.[36] As sediments are unloaded through erosion, the upper parts expand, and incipient weaknesses in the rocks become joints, fractures, and fissures. An increase of fracturing below an unconformity is therefore to be expected. Probably much

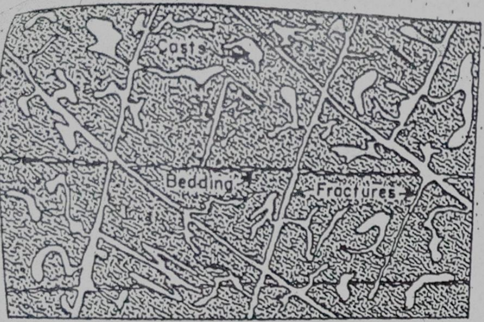


FIGURE 4-9

Idealized section showing how fractures aid in increasing permeability. Solutions passing through dissolve the wall material and widen the fractures, which connect otherwise isolated cavities and pores.

of the initial solution channeling through which surface waters percolate is the result of the gradual increase in jointing and fracturing that accompanies weathering. The third cause of fracturing is a reduction in volume of shales, while in place in the ground, due to diagenetic mineral changes coupled with a loss of water during compaction. Where intervening layers do not shrink, but act as struts or dividers, the loss of volume in the shales and siltstones is expressed in fractures, many of which have irregular and conchoidal forms, in contrast to the regular planes in fracture systems accompanying diastrophism.[43]

Nearly all reservoirs in limestone, dolomite, and siliceous rocks have at least some fracture porosity. The fracture planes combine with whatever porosity already existed to form an interconnecting system that greatly increases the permeability of the rock. Thus two systems of permeability are involved in many dense, fractured reservoirs: (1) the low-permeability blocks between fractures, where the oil moves slowly through short distances into (2) the high-permeability fractures that eventually lead to the well bore.[44] The percentage of water in fracture porosity is generally lower than in intergranular porosity, which means a higher percentage of the porosity in fractured reservoirs will consist of oil and gas. Even heavy, viscous oils that will not flow through rocks of low permeability may accumulate and move along fractures and be produced commercially. Thus any brittle rock, no matter how dense and compact it may appear on its outcrop or in well cuttings, may become a reservoir rock as a result of fracturing, fissuring, and shattering.

Some of the pools where fracture porosity in the reservoir rock is of great importance are mentioned below.

Pools in Basement Rocks. In California nearly 16,000 barrels of oil per day was produced from reservoirs in fractured igneous and metamorphic basement rocks. The most important producer is the Edison pool, near Bakersfield.[45] (See also p. 74.) Others, in fractured Franciscan (Jurassic?) schist, are the Torrance, Wilmington, Venice, El Segundo, and Playa del Rey pools, south and southwest of Los Angeles.[46]

Several wells produce from fresh basement granite in the Amarillo field,

in the Texas Panhandle. One such well alone* has produced more than a million barrels of oil. Such production is undoubtedly the result of fractures in the granite, since nearby wells were either dry or nearly so. Presumably the oil has entered the granite from the sediments that were deposited along the flanks of the buried mountain range along which the field runs. (See also Fig. 3-8.)

Pools in Fractured Sediments. The Santa Maria district (see Fig. 7-62, p. 341), in California, has produced nearly 400 million barrels of oil, of which 75 percent came from fractured shale reservoir rocks and 25 percent from sands. Individual wells with initial productions of 2,500 barrels of oil per day were common, and some wells produced as much as 10,000 barrels per day.[47] Individual wells have produced more than a million barrels. The fractured reservoir rocks consist chiefly of cherts of the Monterey formation (Miocene), cherts interbedded with some calcareous shales, and sandstones, all of which are hard and brittle and generally fracture conchoidally. The oil occurs in fracture planes. It is difficult to obtain evidence of an oil pay because the core recoveries are poor in the brittle, fractured rock, and the oil is washed out with the drilling fluid. Loss of drilling mud is the best indication of a potential pay zone. The fractured chert reservoirs of the Santa Maria region are characterized by low porosities but high permeabilities, which make them satisfactory reservoirs for the heavy oils of the region (6–37° API gravity, but averaging less than 18°).

The Spraberry field of western Texas (see Fig. 13-11, p. 604) consists of a number of pools, some of which may later be found to connect with one another, extending over an area 150 miles long and up to 75 miles wide.[48] The pay formations extend through a vertical distance of nearly a thousand feet of Permian rocks, and the field has been variously estimated to contain a billion or more barrels of oil in place. The amount of oil recoverable under the present technology, however, may be small because of the low permeability of the reservoir. The trap is formed by a stratigraphic gradation up-dip into less permeable rocks. The reservoir rock consists chiefly of black, brittle shale, silty shale, varied sandy shales, calcareous and noncalcareous siltstone, and minor amounts of fine sand. Its particle diameters vary from $\frac{1}{30}$ to $\frac{1}{45}$ mm (the lower limit for sandstone is $\frac{1}{16}$ mm). Porosity is generally less than 10 percent, and the average permeability is $\frac{1}{2}$ md. Oil pools are unusual in reservoir rocks of such low porosity and low permeability. The effective permeability, therefore, is due almost entirely to fractures and conchoidal openings, which extend through the finer materials in all directions, but chiefly vertically. An isopotential map of the Tex-Harvey pool in the Spraberry field is shown in Figure 13-21, page 617, and indicates the trend of the major fractures by the size of the wells.[42] Fractured shale also forms the trap in the Florence field, Colorado (discussed on p. 282).

The Oriskany sand (Lower Devonian) of Pennsylvania and New York is a

* Richard B. Rutledge in a personal communication.

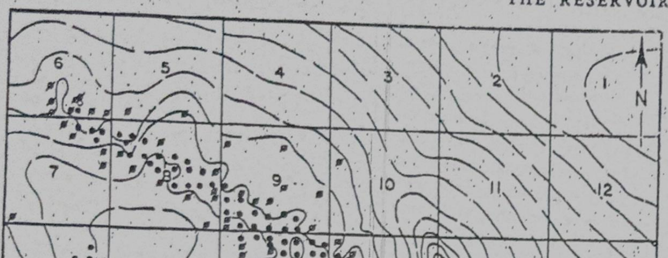


FIGURE 4-10 *Structural map of the Deep River field, Michigan. Contour interval 20 feet. Production is obtained from a dolomitic zone enclosed in the Rogers City limestone (Devonian). The dolomite is presumably related to a fracture permitting magnesium-bearing solutions to enter the limestone. The trap is formed by the dolomite zone, as well as the porosity. Note that the top of the fold is nonproductive.* [Redrawn from Hunt, *Independent Petroleum Association of America*, Vol. 19 (April 1949), p. 42.]

tight, fine-grained sand whose permeability averages less than 500 md and whose porosity ranges from 2 to 10 percent. It contains many gas pools, generally on anticlines,[49] and the gas from the more productive wells comes from small open fractures that appear to be joint planes.[50]

Permeability in carbonate reservoir rocks is often chiefly due to fractures. The reservoir of the West Edmond pool of Oklahoma (see Fig. 14-7, p. 644), for example, has been carefully studied and reported on.[51] The main producing formation of the field is the Bois d'Arc limestone formation at the top of the Hunton group (Devonian-Silurian). The trap is of the stratigraphic type, a permeable bed being truncated up the dip to the east and northeast by both the pre-Mississippian and the pre-Pennsylvanian unconformities. The porosity is partly primary, resulting from intercrystalline openings, fossil casts, and an oolitic member, the authors cited differing on the percentage. The permeability of the limestone and dolomite is low, but the entire pay section is cut by numerous fractures, which divide it into blocks of varying sizes. The oil has drained from the rocks into the highly permeable fractures, and moves along them to the producing wells.

Fractures are indirectly responsible for the Deep River field in Michigan.[52] (See Fig. 4-10.) The oil is contained in a narrow, elongate body of porous dolomite within an impervious limestone at the top of the Rogers City formation (Devonian). The dolomite is believed to have been formed by magnesium-bearing ground waters moving along fractures through the normal limestones of the formation. The dry holes find neither dolomite nor oil. Vertical fractures have been found to be common in the Ellenburger dolomite (Cambro-Ordovician) of western Texas. One core thirty-six feet long contained fractures extending vertically throughout its entire length; the smallest were barely visible and the largest about one millimeter wide.[53]

The Scipio-Albion field in Michigan forms a remarkably straight and narrow belt for more than 25 miles and averages 3,500 feet in width. (See Fig. 4-11.) Oil and gas production is obtained from a dolomitized zone in the Trenton limestone (Ordovician). The Trenton is commonly contoured as a sag or slight syncline, but the probabilities are that it represents fracturing and minor faulting over a deep-seated fault in the basement. Presumably the narrow belt of dolomite is secondary and came in along the fault and fracture system. The field is estimated to contain more than 100 million barrels of oil

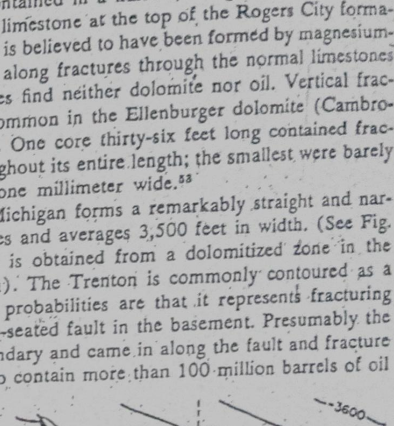


FIGURE 4-11

Map showing the Scipio–Pulaski–Albion trend field in southwestern Michigan. Producing area cross-hatched.

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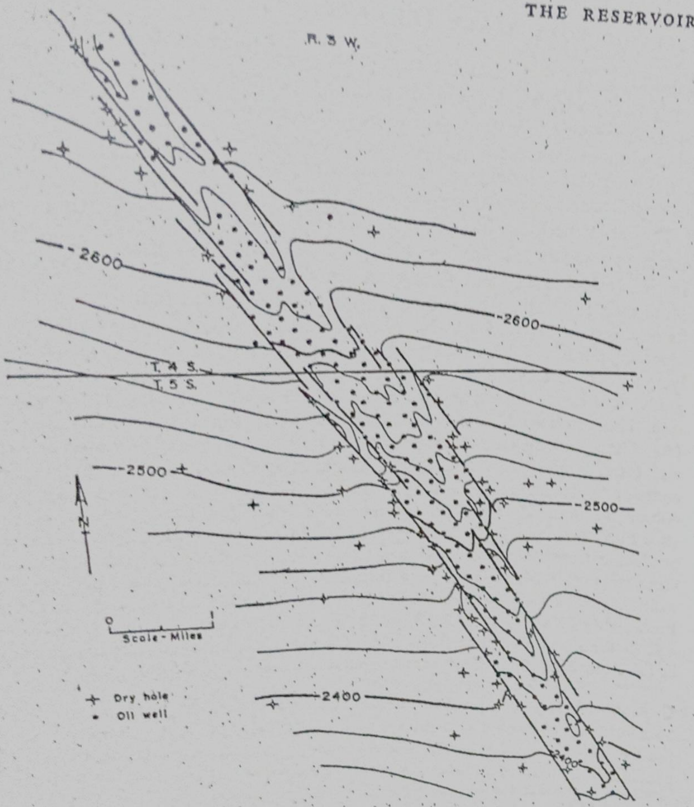

FIGURE 4-12 *Structure map of the Scipio pool in Michigan. Structure is on top of the Trenton formation (Ordovician) and between 5 and 10 of the holes show direct evidence of crossing faults. [Courtesy of Dan A. Busch.]*

and more than 200 billion feet of gas.[54] A detail of the Scipio area is shown in Figure 4-12.

In the Northern fields (Panuco area) of Mexico the reservoir rock consists of the Tamaulipas, Agua Nueva, and San Felipe limestones (Cretaceous).[54] These are all tight, close-grained, and compact, and have low porosity except for that afforded by induced openings, such as joints, fossil casts, and fractures, which give them high permeability. They are cut by faults, which, though of

small displacement, have caused considerable shattering, as shown in cores and in fragments blown from the wells. Crevices large enough for drilling tools to drop through were found associated with the faults. The production of the Northern fields has reached nearly one billion barrels of oil of 12.5° API gravity. The heaviness of the oil prevents it from penetrating the low intercrystalline porosity of the limestone, and it occurs almost entirely in the fracture openings. Production is erratic, and wells with production ranging from mere showings up to 30,000 barrels per day or more are found within a few hundred feet of each other. The high permeability of portions of the reservoir rock is shown by a salt-water gusher that produced over 100,000 barrels of water per day.

Extensive fracturing and shattering characterize the porosity and permeability of the Cretaceous limestones and basement granite reservoirs of the Mara and La Paz oil fields in western Venezuela.[55] (See also Fig. 6-31, p. 263.) The oil column in the Mara field is more than 5,000 feet thick, and the producing limestone, with a low permeability, much of it below 0.1 md, and a total thickness of about 1,800 feet, is highly productive anywhere within the section where fracturing develops. The fracturing is frequently in closely spaced, vertical planes, probably related to the sharp folding and faulting that form the traps, and extends into the underlying granite, which also contains oil above the oil-water contact.*

Oil from the rich oil pools of southwestern Iran is found in the Asmari limestone (from Upper Oligocene to Lower Miocene). The Masjid-i-Sulaiman (see Fig. 6-12, p. 248) and Haft Kel (see Fig. 2-2, p. 18) pools have been studied carefully,[56] and it is found that, no matter how rich the well cuttings appeared to be, no appreciable production was obtained until a fissure was penetrated. Samples of cuttings showed porosity ranging from 2 to 15 percent, but the permeability was only between 0.00005 and 0.5 millidarcy, depending upon the amount of recrystallization (the more complete the recrystallization, the higher the porosity and permeability). The well productivity varies with the amount of the fissuring; if there were no fissuring, there would be no production. Two stages of fracturing have been observed.[57] The earlier, oil-free fractures are filled with calcite and other minerals, and many are vug-lined, with well-formed crystals. These apparently had nothing to do with the movement of oil, which is confined to a later set of fractures. The Agha Jari pool is also characterized by fracture permeability[58] (see Fig. 6-21), the reservoir being freely connected throughout even though the Asmari limestone is generally of low permeability. The highly fissured and fractured limestone is overlain by a salt formation 50–150 feet thick, which acts as a cover, or roof rock. Much of the fracturing of the Asmari limestone in the oil fields of Iran, and in its outcrop in the mountains, is along the pitch of the folds, and evidence of underground interconnection of points fifty miles apart has been observed.

* Walter S. Olson in a personal communication.

Recrystallization—Dolomitization Phenomena. Some carbonate reservoir rocks are nearly pure limestone, and some are nearly pure dolomite, but more are intimate and variable mixtures of the two. Where oil and gas occur in reservoirs consisting of both limestone and dolomite, the dolomite and dolomitic rocks are generally the more prolific producers of petroleum, chiefly because of their greater porosity. The origin of dolomite[59] and the reason for its greater porosity have long challenged investigators,[60] and because of the large amounts of petroleum associated with dolomites these problems are of interest to the petroleum geologist.

The basis for much of the discussion of the porosity of dolomite was the theory proposed by Elie de Beaumont in 1836. He pointed out that the molecular replacement of limestone by dolomite would result in a volume shrinkage of 12–13 percent. The chemical equation that explains the replacement is written as

$$2CaCO_3 + MgCl_2 \longrightarrow CaMg(CO_3)_2 + CaCl_2$$

Orton[61] used this idea in 1886 to explain the porosity in the Lima-Indiana field. Later workers[62] discounted the molecule-for-molecule mechanism of the replacement of limestone by dolomite, believing that the patches of solid dolomite in limestone indicated a volume-for-volume replacement.

Petrographic studies by Hohlt,[63] however, have revived the molecular replacement theory. He has shown that there is a pronounced tendency for calcite crystals in limestone to orient their *c*-axes in the plane of the bedding, presumably in response to pressure. In dolomites, however, the crystals are always oriented completely at random. Hohlt's explanation of this fact is that the shrinkage of the *c*-axis of the crystal during transformation from calcite to dolomite creates voids in the rock; the packing, in effect, is looser than in limestone. Hohlt also utilizes the random orientation of the crystals in dolomites to explain why solvent waters penetrate dolomites more readily than limestones. Dolomites offer much larger intercrystalline space for the passage of dissolving solutions and so present a much greater area of attack. Thus, in spite of their lower solubility, dolomites may be dissolved to as great an extent as limestone if attacked by more solution over a longer time.

Carbonate rocks also deform, in part, by distortion of the individual grains; when the material is recrystallized, the original textures may be obscured. Cloos,[64] by measuring the distortion that occurred in a certain folded oolitic rock, has shown the extent of the internal distortion that may occur in many folded carbonate rocks. Individual oolites, which had originally been spheres, were flattened and elongated until the entire rock mass was almost completely recast internally.

Many oil and gas pools in dolomite and dolomitic limestone could be cited. The oil in several of the organic-reef oil pools in western Canada, for example, occurs in dolomite. A section through a core from the producing D-3 reservoir (Upper Devonian) in the Leduc field southwest of Edmonton[65] is shown in

Figure 4-13. The rock contains vugs connected by minute cracks or crevices, and it has a variable amount of primary porosity. The original rock was chiefly an organic limestone, but it has now been dolomitized, and all of its primary biological structures have been obliterated. A part of the production is from detrital material, for, as in most organic-reef deposits, the reservoir material is a complex of many lithologic facies and rock types.

The oil in the Lima-Indiana field of Ohio and Indiana[66] occurs in porous dolomitic zones in the Trenton (Ordovician) limestone, which extends over an area 160 miles long and up to 40 miles wide. (See also Fig. 7-23, p. 307.) More than 500 million barrels of oil has been produced from this field since its discovery in 1884. It includes many separate pools, each associated with a separate, porous, dolomitized portion of the limestone, and the whole field lying across the Cincinnati and Findlay arches. The dolomitic producing rock grades into dense limestone up-dip toward the south, forming a stratigraphic trap. The porous dolomite, which is generally in the upper twenty or thirty feet of the Trenton formation, may be either a primary dolomite or one that was formed by replacement of limestone; it is crystalline, and in places it contains an abundance of solution cavities. The Deep River and the Scipio-Albion dolomitized trends in southwestern Michigan have been described. (See Figs. 4-11 and 4-12 and pages 123–124.) Sections through other pools producing from dolomite rocks are shown for the Belcher field of Ontario, Canada (Fig. 7-24, p. 308), the Ellenburger dolomite of the Apco field of western Texas (Figs. 7-60 and 7-61), and the Arbuckle dolomite of the Kraft-Prusa field of Kansas (Fig. 7-58, p. 338), the last two of Cambro-Ordovician age. Dolomitized Tamabra limestone (Cretaceous) forms the reservoir rock in the Poza Rica oil field of Mexico. (See Fig. 8-10, p. 356.)

Cementation and Compaction. After a pore space or pore pattern has been formed, whether it is primary, secondary, or both, it is generally modified by one or both of two common secondary changes, cementation and compaction. Both tend to reduce the percentage of pore space and the permea-

FIGURE 4-13

Section through a typical core from the D-3 dolomitized reef (Middle Devonian) of the Leduc field in Alberta, Canada, showing the intermingling of different kinds of porosity. The blank areas are nonporous and barren of oil. [Redrawn from Waring and Layer, Bull. Amer. Assoc. Petrol. Geol., Vol. 34, p. 307, Fig. 13.]

bility of the rock. These two processes may occur at any time during or after the deposition of the rock. In general the porosity of sedimentary rocks tends to decrease with an increase in depth of burial, increase in temperature, and increase in age.[67]

Cementation. Some cementation is primary; the cement may be precipitated, or it may be deposited along with the clastic material. Silica, carbonates, and other soluble materials may be precipitated contemporaneously with the deposition of detrital material. Primary cementing material is subject to recrystallization later, and it is then difficult to distinguish recrystallized cementing material from that introduced after the sediment became consolidated. Sandstones containing a siliceous cement deposited with the sand grains, or precipitated during the diagenesis, are called orthoquartzites to distinguish them from the metaquartzites, which result from metamorphic processes. Krynine has estimated that 90–95 percent of the quartzitic sandstones of the Appalachian region have a primary quartz cement.[68] If this is true, it improves the prospects for petroleum production in that region, which might otherwise be considered poor because of the opinion that quartzitic sandstones are always the result of regional diastrophism and metamorphism, and hence that all the potential reservoir rocks were impermeable, and all the oil has been squeezed out.

Materials that are insoluble and are therefore not precipitated may act like precipitated cements in that they fill voids, compact, and hold the grains together. Clay minerals, especially, are not soluble, but they are physically unstable, and they respond quickly to changes in pressure, temperature, and character of the water. They are deposited as interstitial detritus in varying form and amounts in nearly all sediments, and they form a common cementing material. Some clays alter to chlorites, sericites, and carbonates. As the water is squeezed out of the clays and muds, they are compressed tightly into the finer spaces between grains, where they act as a binding material holding the sand grains together. Graywackes are clastic rocks held together chiefly by primary detrital bonding material. Clay formed from weathering of feldspar grains, for example, clogs the pores in the Chanac formation (Tertiary) on the east side of the San Joaquin Basin of California, where it forms a bonding material as well as an up-dip obstruction that traps several oil pools. A different kind of detrital cement occurs in the sands of the McMurray formation (Cretaceous), near Athabaska Landing in northeastern Alberta. These sands are cemented by a viscous, heavy oil that may have been deposited along with the sand grains. When the oil is removed, the sand separates into loose grains.

The precipitation of cementing materials in the pores of clastic rocks, either during or after their diagenesis, is a secondary factor that modifies their porosity and permeability. The most common cementing materials in clastic reservoir rocks are, in the order of their abundance, quartz, calcite, dolomite, siderite, opal-chalcedony, anhydrite, and pyrite. Several minerals are frequently present in the same rock as cementing materials.[69] Most sandstones

show evidence of cementation, together with more or less interlocking of grains, as a result of solution of grains in contact, solution of fine-grained siliceous matrix material, or introduction of silica from outside sources. (See Fig. 3-3.) A variety of minerals may act as cementing material. Forty core samples of feldspathic sandstones from wells in central and southern California showed the following secondary minerals deposited in the open pores or formed within the detrital clay matrix:[70] quartz, albite, orthoclase, microcline, dolomite, calcite, anatase, kaolinite, glauconite, barite, and pyrite.

Quartz, which is the most important precipitated cementing material of many clastic reservoir rocks, is also the first to be precipitated.[71] Silica is not found in the reservoir waters, and hence the source of the large amounts of silica cementing material, and the manner in which it was precipitated, have been the subject of much study, but the mechanisms are not fully understood.[72] The sources that have been suggested include: (1) silica precipitated from silica-bearing surface or meteoric waters; (2) silica carried by streams into the ocean, where it was precipitated along with the sand being deposited; (3) precipitated silica dissolved from small grains of silica-bearing minerals at the points of contact of sand grains as a result of pressure or rubbing during deposition, or of pressure during and after diagenesis (the Riecke principle);[73] (4) silica dissolved out of the clay minerals,[74] and carried in water squeezed out of the shales during loading and compaction. The nature of secondary silica overgrowth and the effects on a sandstone are shown graphically in Figure 4-14.

A spectacular sandstone reservoir rock showing secondary silica crystal growth occurs in the Petrólea field of eastern Colombia, where most of the oil obtained from the Barco formation (Lower Eocene) is found in the so-called "sparkling sandstone."[75] (See Fig. 6-37, p. 269.) These rocks derive their name from the fact that, where they crop out, the myriads of crystal faces on the secondary quartz sparkle in the sun. These sands average 12.5

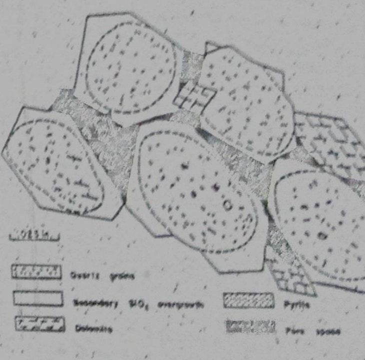

FIGURE 4-14

Thin section of an orthoquartzite showing secondary growth and recrystallization resulting in a marked change from the original pore pattern of the rock. [Redrawn from Krynine, Jour. Geol., Vol. 56 (1948), p. 152, Fig. 12.]

percent in porosity and 79 md in permeability, and the porosity is chiefly primary.

The source of carbonate cements is more readily explained than that of silica cements, for even sandstones commonly contain some carbonate, which may be dissolved and reprecipitated elsewhere. Carbonate cementing material in sandstones may be in the form of euhedral crystals of calcite or dolomite interspersed with the sand particles; or it may be plastered on the surfaces as a binder between sand grains; or it may be in the form of residues from former carbonate fossils, either preserved as recognizable fossils or concentrated in small residual patches.

As cementation often results from solution in place, the two processes work in opposite directions. Where solution is greater than the deposition of cement, porosity increases. Where deposition is greater than solution, porosity decreases. Both solution and cementation change the pore pattern unpredictably, especially the permeability.[76] Once a petroleum pool has formed, there is no further movement of the interstitial waters, and solution and cementation have reached a standstill. We may therefore conclude that solution and cementation in the reservoir occurred almost wholly before the petroleum accumulated.

Compaction. Three effects of load pressure are important in the geology of petroleum: (1) compaction of the reservoir sediments; (2) compaction of the nonreservoir sediments, especially the shales; (3) compression of the reservoir fluids. We are concerned here only with the compaction of the reservoir sediments.

Compaction of a reservoir rock is due chiefly to the increasing weight of the overburden. Its effect, like that of cementation, is to reduce porosity. The reduction of pore space by compaction in a sealed reservoir system causes an increase in reservoir fluid pressure. Compaction is especially significant in reservoir sediments containing shales or clays and colloidal material. Large amounts of adsorbed water are squeezed out of these by an increase in load pressure, and because the clays and colloids are highly plastic, they flow between the grains to form a cementing or bonding agent and thereby reduce the porosity. Clean sandstones found in some of the deepest wells, drilled below 15,000 feet, show no evidence of crushing,* which indicates that such rocks may well prove productive at great depths, whereas muddy or dirty sandstones would be made impermeable by pressure at far shallower depths. Even in clean sandstones, however, there is evidence that the number of grain contact points increases with depth, which means that pore space decreases downward.[77]

Compaction of a reservoir rock is of two kinds, plastic and elastic. Plastic compaction is the squeezing of the soft accessory minerals of the matrix, such as clays, weathered products, and colloids, into the open pores as the pressure increases and the water is driven out. The result is a loss of porosity, a reduction of permeability, and an overall lessening of the rock volume. (See Fig.

* R. B. Hutchinson, of the Superior Oil Company, Bakersfield, California, in a personal communication.

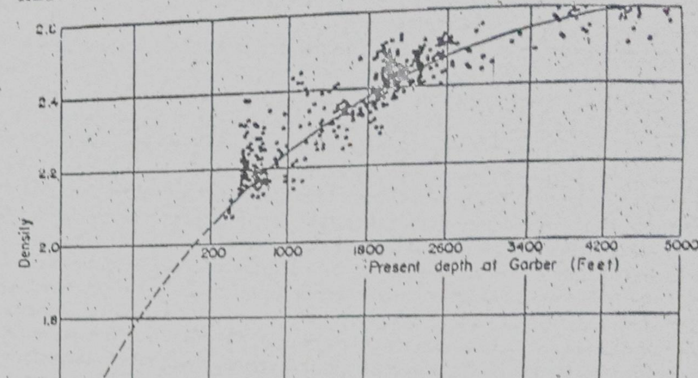

FIGURE 4-15 *Chart showing the progressive increase in density of the rocks with depth in the oil field of Garber, Oklahoma. [Redrawn from Athy, Problems of Petroleum Geology, Amer. Assoc. Petrol. Geol. (1934), p. 815, Fig. 1.]*

9-13.) Most plastic compaction occurs during the early diagenesis of the rock, when the high water content is being removed. Long-continued load pressures, however, undoubtedly maintain the process of plastic pore reduction long after diagenesis, though at a progressively slower rate. Figure 4-15 shows how the density increases with depth in the Garber field of Oklahoma. Cementation, as well as compaction, plays a part in this increase, and it becomes difficult if not impossible to separate the two processes. In sandstones, plastic compaction is evidenced by the squeezed, strained, and deformed soft minerals, by rearrangement of the grains, by closer packing, by breaking of the edges of the grains, and by closer adjustment of the same grains to the matrix material. A rock plastically deformed does not return, even in part, to the original volume. The volume of such a rock is therefore a function of the highest load pressure it has undergone during its geologic life.

A rock that has undergone elastic compaction, on the other hand, can, when the load pressure is reduced, return at least partially to the original volume. Such return is most likely to occur in a firm sandstone. Its occurrence means that energy was stored in the compressed sand grains while the load pressure was increasing and was released when the pressure diminished. It might be thought of as somewhat analogous to the energy stored in a coiled

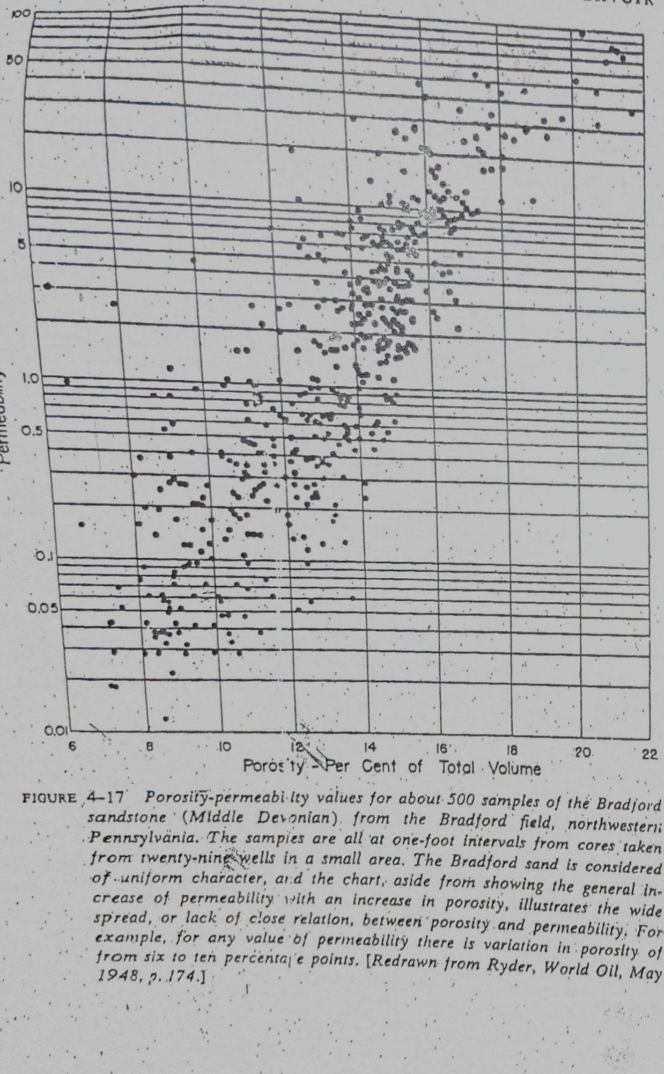

FIGURE 4–17 *Porosity-permeability values for about 500 samples of the Bradford sandstone (Middle Devonian) from the Bradford field, northwestern Pennsylvania. The samples are all at one-foot intervals from cores taken from twenty-nine wells in a small area. The Bradford sand is considered of uniform character, and the chart, aside from showing the general increase of permeability with an increase in porosity, illustrates the wide spread, or lack of close relation, between porosity and permeability. For example, for any value of permeability there is variation in porosity of from six to ten percentage points. [Redrawn from Ryder, World Oil, May 1948, p. 174.]*

fractured limestone; the k_{max} line represents the maximum permeability found by measurements parallel to the fracture system. The permeability of unfractured dolomite increases in both directions uniformly with porosity.

While porosity is a dimensionless quantity, permeability reflects in measurable units the resistance that a rock sets up against the flow of a homogeneous fluid through it. Theoretically, permeability can be related to the geometry of the rock texture according to the equation[83]

$$k = 2 \times 10^7 \times \frac{\Sigma^3}{(1-\Sigma)^2} \times \frac{1}{S^2}$$

in which k = permeability, Σ = fractional porosity, and S = the specific surface of the solid material. S is the specific surface of the pores and is equal to the surface of the solid material contained in one cubic centimeter of rock. The equation suggests that the higher the porosity and the smaller the specific surface, the higher the permeability. The smaller the individual pores, the greater becomes the specific surface, and consequently the less the permeability.

Artificial, or Man-made, Porosity and Permeability. Various methods of forming or increasing the pore space and the permeability of reservoir rocks have been devised. The early method was to *shoot* a well—that is, to explode a charge of nitroglycerin in the well bore opposite the reservoir. The fracturing of the reservoir increases the effective radius of the well bore and increases the porosity and permeability surrounding the hole and consequently permits more oil and gas to flow into the well. The response varies with different rocks, depending largely on whether the explosion packs the particles tighter or fractures the rock. Forcing acids into the reservoir rock under pressure is called *acidization*.[84] The acid enters the reservoir rock along connected porosity

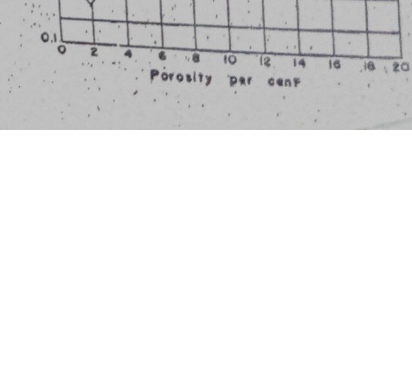

FIGURE 4–18

The relation between permeability and porosity in a group of Paleozoic limestone and dolomite reservoir rocks of western Texas. Kmax *is parallel to the fracture system and* $K_{90°}$ *is at right angles. The difference (shaded) between* Kmax *and* $K_{90°}$ *shows the amount and distribution of the secondary porosity between fractures and vugs. [Redrawn from Kelton, O. & G. Jour., November 24, 1949, p. 119.]*

openings and dissolves the soluble material as it penetrates the rock, thereby increasing both the permeability and the porosity. The permeability of limestone reservoirs, especially, is increased, and some sand reservoirs with a carbonate or other acid-soluble cement show a decided increase in production as a result of acidization. Various methods of hydraulic fracturing—driving a liquid containing sand grains into the pores of a reservoir rock by the use of extremely high injection pressure—have been developed.[85] Later, when the pressure is relieved, the liquid drains out, leaving the sand grains behind to hold the fractures open. These methods are known by various trade names: *Hydrafrac, Stratafrac, Sandfrac,* etc. Where the initial reservoir pressures are still available within the reservoir, many phenomenal increases in oil production have resulted.

CONCLUSION

The two essential mass properties of reservoir rock are effective porosity and permeability. Effective porosity provides storage space for oil and gas, and permeability permits them to move through the rock. Much progress has been made by the production engineer and in the core laboratories toward a better understanding of the factors that influence the porosity and permeability of reservoir rocks—particularly the role of clays, the effects of differing reservoir waters, and the petrophysics of different kinds of openings. A vast number of detailed quantitative data have been accumulated on the porosity and permeability of specific reservoirs, on the varying effect of each on oil and gas production; and on the interrelations of the pore space and the fluid content. There is yet much to learn, however, particularly on improving oil recoveries from rocks of extremely low porosity and low permeability, on the role of grain size in determining porosity and permeability, and on relating the different kinds of porosity and permeability to depositional environment—all of which will give a better understanding of underground conditions and aid in making more accurate predictions.

Selected General Readings

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