CHAPTER

6

The Reservoir

Chapter 1 showed that one of the seven essentials prerequisites for a commercial accumulation of hydrocarbons is the existence of a reservoir. Theoretically, any rock may act as a reservoir for oil or gas. In practice, the sandstones and carbonates contain the major known reserves, although fields do occur in shales and diverse igneous and metamorphic rocks. For a rock to act as a reservoir it must possess two essential properties: It must have pores to contain the oil or gas, and the pores must be connected to allow the movement of fluids; in other words, the rock must have permeability.

This chapter is concerned with the nature of hydrocarbon reservoirs, that is, with the internal properties of a trap. It begins by describing porosity and permeability and discussing their relationship with sediment texture. This discussion is followed by an account of how postdepositional (diagenetic) changes may diminish or enhance reservoir performance. Following this discussion is a section on the vertical and lateral continuity of reservoirs and the calculation of oil and gas reserves. The chapter concludes with an account of the various ways of producing hydrocarbons from a reservoir.

6.1 POROSITY

6.1.1 Definition and Classification

Porosity is the first of the two essential attributes of a reservoir. The pore spaces, or voids, within a rock are generally filled with connate water, but contain oil or gas within a field. Porosity is either expressed as the void ratio, which is the ratio of voids to solid rock, or, more frequently, as a percentage:

$$\text{Porosity}(\%) = \frac{\text{volume of voids}}{\text{total volume of rock}} \times 100.$$

Porosity is conventionally symbolized by the Greek lowercase letter phi (ϕ). Pores are of three morphological types: catenary, cul-de-sac, and closed (Fig. 6.1). Catenary pores are those that communicate with others by more than one throat passage. Cul-de-sac, or dead-end, pores have only one throat passage connecting with another pore. Closed pores have no communication with other pores.

Catenary and cul-de-sac pores constitute effective porosity, in that hydrocarbons can emerge from them. In catenary pores hydrocarbons can be flushed out by a natural or

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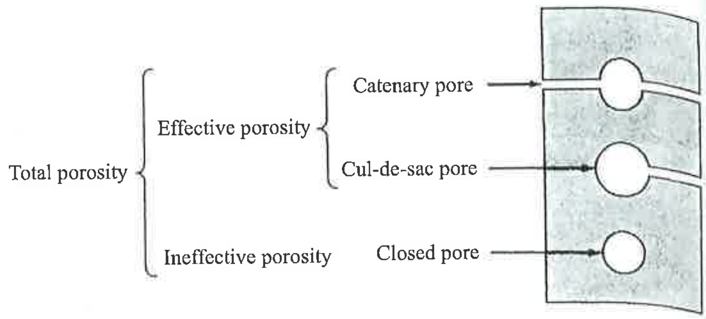

FIGURE 6.1 The three basic types of pores.

TABLE 6.1 Classification of the Different Types of Porosity Found in Sediments

Time of formation	Type	Origin
Primary or depositional	Intergranular, or interparticle Intragranular, or intraparticle	Sedimentation
	Intercrystalline Fenestral	Cementation
Secondary or postdepositional	Vuggy Moldic	Solution
	Fracture	Tectonics, compaction, dehydration, diagenesis

artificial water drive. Cul-de-sac pores are unaffected by flushing, but may yield some oil or gas by expansion as reservoir pressure drops. Closed pores are unable to yield hydrocarbons (such oil or gas having invaded an open pore subsequently closed by compaction or cementation). The ratio of total to effective porosity is extremely important, being directly related to the permeability of a rock.

The size and geometry of the pores and the diameter and tortuosity of the connecting throat passages all affect the productivity of the reservoir. Pore geometry and continuity are difficult to analyze. In some studies pores are filled by a fluid, which then solidifies, and the rock is then dissolved by acid to reveal casts of the pores. Collins (1961) used molten lead in sandstones, and Wardlaw (1976) used epoxy resin in carbonates.

Several schemes have been drawn up to classify porosity types (e.g., Robinson, 1966; Levorsen, 1967; Choquette and Pray, 1970). Two main types of pore can be defined according to their time of formation (Murray, 1960). Primary pores are those formed when a sediment is deposited. Secondary pores are those developed in a rock some time after deposition (Table 6.1). Primary pores may be divided into two subtypes: interparticle (or intergranular) and intraparticle (or intragranular). Interparticle pores are initially present in all sediments. They are often quickly lost in clays and carbonate sands because of the combined effects of compaction and cementation. Much of the porosity found in sandstone reservoirs is

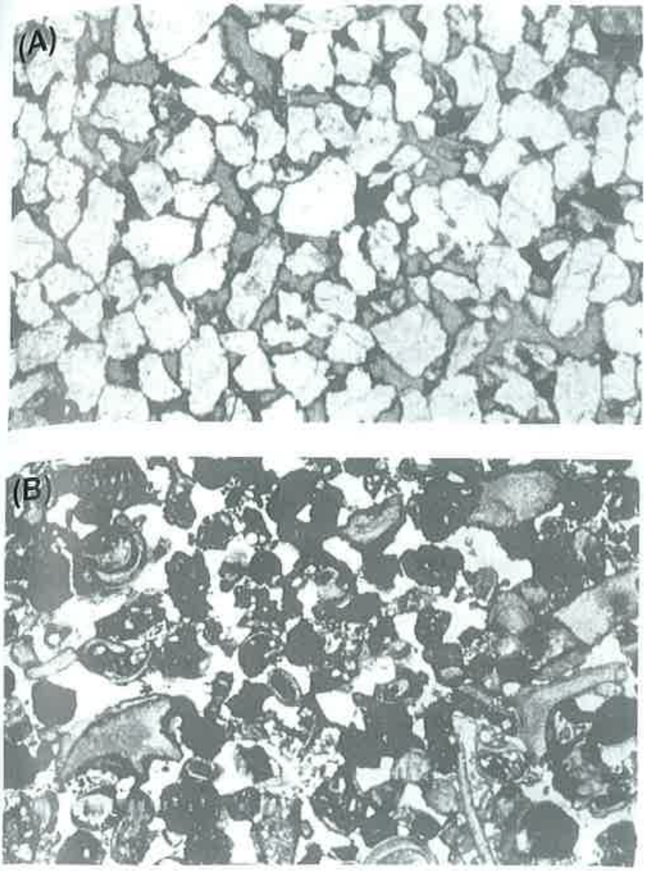

FIGURE 6.2 Thin sections illustrating the different types of primary porosity. (A) Intergranular porosity in Middle Jurassic Brent sandstone (North Sea, United Kingdom). Field of view is approximately 1 cm. (B) Intergranular and intragranular (within fossils) porosity in skeletal pelletal limestone. Field of view is about 1 cm.

preserved primary intergranular porosity (Fig. 6.2(A)). Intraparticle pores are generally found within the skeletal grains of carbonate sands (Fig. 6.2(B)) and are thus often cul-de-sac pores. Because of compaction and cementation they are generally absent in carbonate reservoirs.

Secondary pores are often caused by solution. Many minerals may be leached out of a rock, but, volumetrically, carbonate solution is the most significant. Thus solution-induced porosity is more common in carbonate reservoirs than in sandstone reservoirs. A distinction is generally made between moldic and vuggy porosity. Moldic porosity is fabric selective (Fig. 6.3), that is, only the grains or only the matrix has been leached out. Vugs, by contrast, are pores whose boundaries cross-cut grains, matrices, and/or earlier cement. Vugs thus tend to be larger than moldic pores (Fig. 6.4). With increasing size vuggy porosity changes into cavernous porosity. Cavernous pores are those large enough to cause the drill string to drop by half a meter or to contain one crouched mud-logger. Examples of cavernous porosity are known from the Arab D Jurassic limestone of the Abqaiq field of Saudi Arabia (McConnell, 1951) and from the Fusselman limestone of the Dollarhide field of Texas (Stormont, 1949), both having cavernous pores up to 5 m high.

FIGURE 6.3 Portland limestone (Upper Jurassic) showing biomoldic porosity due to solution of shells. Portland Island, Dorset, United Kingdom.

FIGURE 6.4 Core of Zechstein (Upper Permian) dolomite showing vuggy porosity (North Sea, United Kingdom).

Secondary porosity can also be caused not by solution but by the effects of cementation. Fenestral pores occur where there is a "primary or penecontem-poraneous gap in rock framework larger than grain-supported interstices" (Tebbutt et al., 1965). Strictly speaking, therefore, such pores would appear to be primary rather than secondary. In fact, fenestral pores are characteristic of lagoonal pelmicrites in which dehydration has caused shrinkage and buckling of the laminae. This type of fabric has been described from Triassic lagoonal carbonates of the Alps, where it is termed *loferite* (Fischer, 1964), and also from Paleocene dolomite pellet muds from Libya (Conley, 1971).

Intercrystalline porosity, which refers to pores occurring between the crystal faces of crystalline rocks, is a far more important type of secondary porosity than is fenestral porosity. Most recrystallized limestones generally possess negligible porosity. Crystalline dolomites, on the other hand, are often highly porous, with a friable, sugary (saccharoidal) texture. This type of intercrystalline porosity occurs in secondary dolomites that have formed by the replacement of calcite. Dolomitization causes a 13% shrinkage of the original bulk volume, thereby increasing the porosity. Intercrystalline pores tend to be polyhedral, with sheet-like pore throats in contrast to the more common tubular ones (Wardlaw, 1976).

Fracture porosity is the last major type of pore to consider. It is extremely important not so much because it increases the storage capacity of a reservoir but because of the degree to which it may enhance permeability. Fractures are rare in unconsolidated, loosely cemented sediments, which respond to stress by plastic flow. They may occur in any brittle rock, not only sandstones and limestones but also shales, igneous, and metamorphic rocks (Stearns and Friedman, 1972). Because fractures are much larger than are most pores, they are seldom amenable to study from cores alone (Fig. 6.5). Furthermore, the process of coring itself may fracture the rock. Such artifacts must be distinguished from naturally occurring pores. Kulander et al. (1979) have outlined several significant criteria that can be used for this purpose. Fractures may also be recognized from wireline logs, seismic data, and the production history of a well. Cycle skip on sonic logs can be caused by fractures (and other phenomena). A random bag o' nails motif on a dipmeter can be caused by fractures (and other phenomena). Fractures can also be "seen" by the borehole imaging tools (Fig. 6.6). Anomalously low velocities in seismic data may be due to fractures, although again this effect may be due to other types of porosity and/or the presence of gas. High initial production followed by a rapid pressure drop and rapid decline in flow rate in production well tests is often indicative of fracture porosity.

Brittle rocks tend to fracture in three geological settings (Fig. 6.7). Fracture systems may dilate where strata are subjected to tension on the crests of anticlines and the nadirs of synclines. Detailed outcrop studies have demonstrated the correlation between fracture intensity and orientation and the structural style and trend of the anticline (e.g., Harris et al., 1960). Fractures often occur adjacent to faults, and in some cases a field may be directly related to a major fault and its associated fractures (Fig. 6.8). Fracture porosity is also found beneath unconformities, especially in carbonates, where the fractures may be enlarged by karstic solution, as in the Castellan field of offshore Spain. Fracture porosity also occurs in sandstones; for example, in the Buchan field of the North Sea, in which a fractured Devonian sandstone reservoir lies beneath the Cimmerian unconformity (Butler et al., 1976).

Basement rocks sometimes serve as petroleum reservoirs because fracture porosity is sufficiently abundant for them to flow. These reservoirs are commonly dual porosity systems

FIGURE 6.5 Fractured core of Gargaf Group sandstone (Cambro-Ordovician). Sirte basin, Libya.

where solution porosity has formed from the leaching of unstable mineral grains. This may be due to hydrothermal alteration where magma intrudes source rocks, as in the Dineh-Bi-Keyah field in Apache County, Arizona (McKenny and Masters, 1968; Biederman, 1986). Alternatively the solution porosity may be due to weathering where basement is unconformably onlapped by source rocks, as in the Augila field of the Sirte basin, Libya (Williams, 1972). In such fields the importance of fracturing is not so much because it enhances porosity, but because it dramatically improves permeability.

Figure 6.9 summarizes the relationship between porosity and permeability for the different types of pore systems.

6.1.2 Porosity Measurement

Porosity may be measured in three ways: directly from cores, indirectly from geophysical well logs, or from seismic data, as discussed earlier in Chapter 3. The last two of these

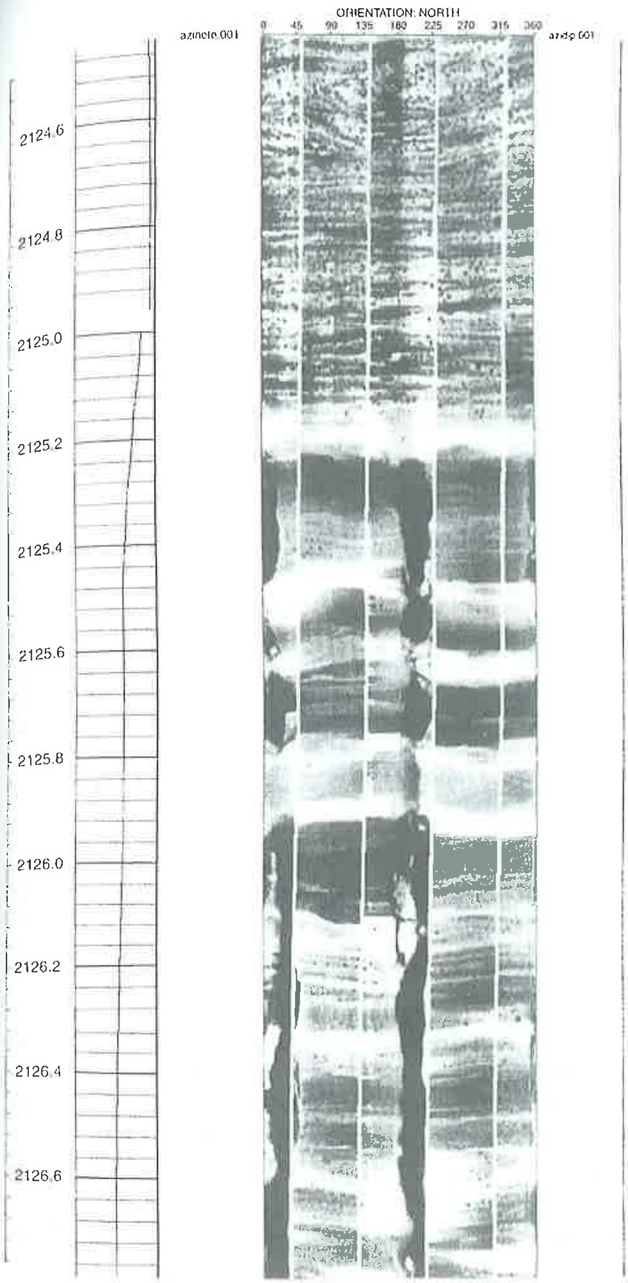

FIGURE 6.6 Borehole Formation Microimager (FMI) image showing fracture porosity at sequence boundary between fractured bedded limestone overlain by unfractured laminated limestone. *Courtesy of Schlumberger.*

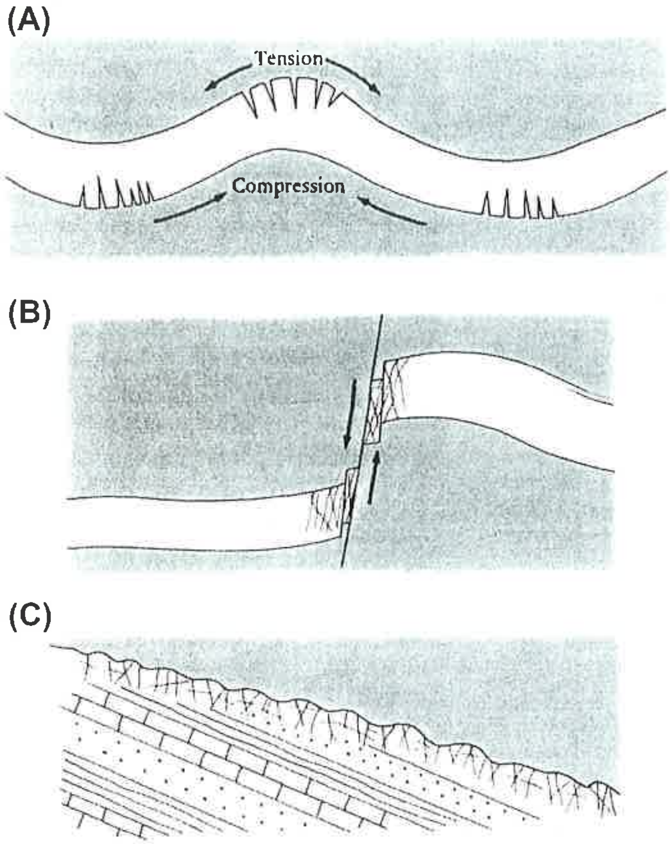

FIGURE 6.7 Illustrations of the various ways in which fracture porosity is commonly found. (A) Fractures may develop on the crests of anticlines and the nadirs of synclines. (B) Fractures may develop adjacent to faults. (C) Fractures may occur beneath unconformities.

methods are discussed in this chapter. The following account deals only with porosity measurement from cores. The main reason for cutting a core is to measure the petrophysical properties of the reservoir. The porosity of a core sample may be measured in the laboratory using several methods (Anderson, 1975; Monicard, 1981). For homogeneous rocks, like many sandstones, samples of only 30 mm^3 or so may be cut or chipped from the core. For heterogeneous reservoirs, including many limestones, the analysis of a whole core sample is generally necessary. Several of the more common porosity measuring procedures are briefly described in the following sections.

6.1.2.1 Washburn–Bunting Method

One of the earliest and simplest methods of porosity measurement is the gas expansion technique described by Washburn and Bunting in 1922. The basic apparatus is shown in Fig. 6.10. Air within the pores of the sample is extracted when a vacuum is created by

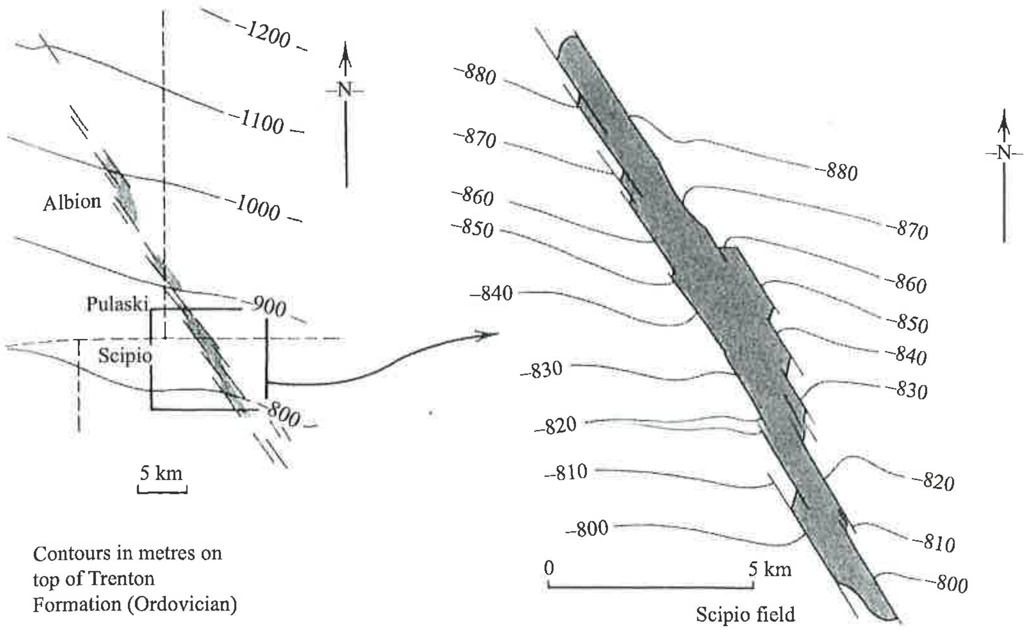

FIGURE 6.8 Map of the Scipio–Pulaski–Albion trend of fields. Production comes from fractured Trenton (Ordovician) dolomite. Right-hand map is a detail of the boxed area in the left-hand map. *From Levorsen (1967). Used with permission.*

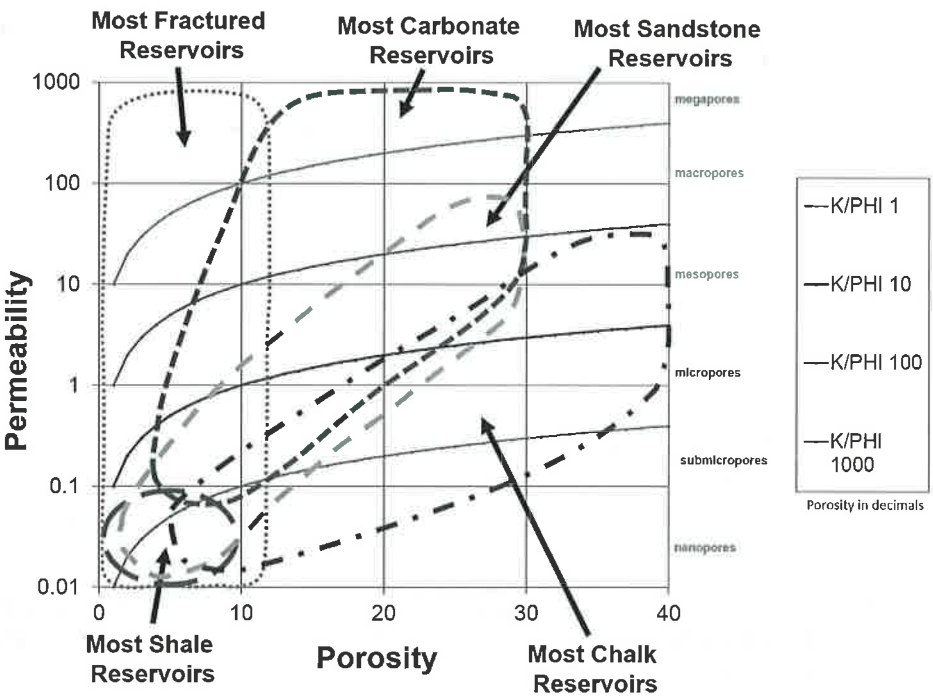

FIGURE 6.9 Graph to illustrate the relationship between porosity and permeability for the different types of reservoirs. Note that fracturing will enhance permeability dramatically for any type of reservoir. The contours represent a constant K/PHI ratio and divide the plot into areas of similar pore types. Data points that plot along a constant ratio have similar flow characteristics. *Modified from Selley (1988).*

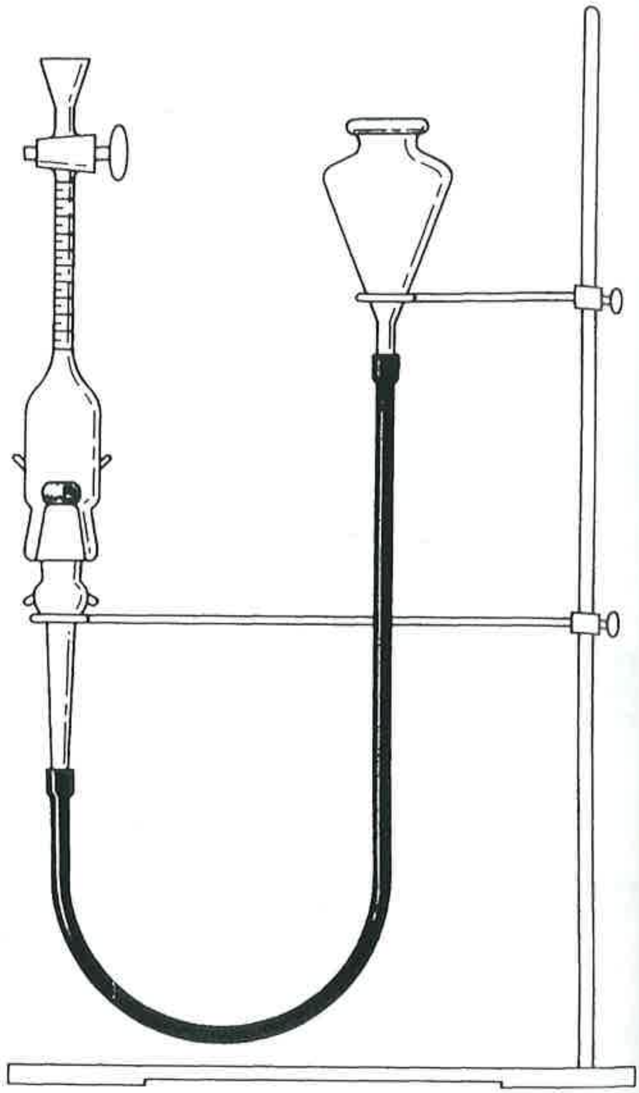

FIGURE 6.10 Washburn–Bunting apparatus for measuring porosity by the gas expansion method.

lowering and raising the mercury bulb. The amount of air extracted can be measured in the burette. Then:

$$\text{Porosity (\%)} = \frac{\text{volume of gas extracted}}{\text{bulk volume of sample}} \times 100.$$

Bulk volume must be determined independently by another method, which generally involves applying Archimedes principle of displacement to the sample when totally submerged in mercury.

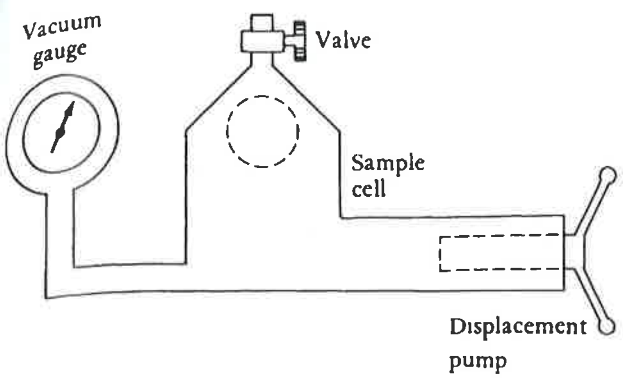

FIGURE 6.11 Boyle's law porosimeter.

6.1.2.2 *Boyle's Law Method*

Boyle's law (pressure × volume = constant) can be applied to porosity measurement in two ways. One way is to measure the pore volume by sealing the sample in a pressure vessel, decreasing the pressure by a known amount, and measuring the increase in volume of the contained gas. Conversely, the grain volume can be measured and, if the bulk volume is known, porosity can be determined. The Ruska porosimeter is a popular apparatus based on this technique (Fig. 6.11).

6.2 PERMEABILITY

6.2.1 Fundamental Principles

The second essential requirement for a reservoir rock is permeability. Porosity alone is not enough; the pores must be connected. Permeability is the ability of fluids to pass through a porous material. The original work on permeability was carried out by H. Darcy (1856), who studied the flow rates of the springs at Dijon in France. His work was further developed by Muskat and Botset (1931), Botset (1931), and Muskat (1937). They formulated Darcy's law as follows:

$$Q = \frac{K(P_1 - P_2)A}{\mu L},$$

where

Q = rate of flow;
K = permeability;
$(P_1 - P_2)$ = pressure drop across the sample;
A = cross-sectional area of the sample;
L = length of the sample;
μ = viscosity of the fluid.

The unit of permeability is the Darcy. This is defined as the permeability that allows a fluid of 1 centipoise (cP) viscosity to flow at a velocity of 1 cm/s for a pressure drop of 1 atm/cm.

Because most reservoirs have permeabilities much less than a Darcy, the millidarcy (md) is commonly used. Average permeabilities in reservoirs are commonly in the range of 5 to 500 md. Permeability is generally referred to by the letter *K*.

6.2.2 Permeability Measurement

The permeability of a reservoir can be measured in three ways. On the grandest scale it can be measured by means of a drill stem or production test. In this test, a well is drilled through the reservoir. Casing is set and perforated, tubing is run within the casing, the interval to be tested is sealed off with packers, and the interval is allowed to flow. The rate of flow and the drop in pressure at the commencement and conclusion of the test can be measured, and reservoir fluid can be recovered at the surface. Thus all the parameters are known to enable permeability to be calculated from Darcy's law. This type of test is, of course, in many ways the most obvious—and significant. The advantages and limitations of production testing are beyond the scope of this text.

The second way of measuring permeability is from wireline logs. It has long been possible to identify permeable zones in a qualitative way from Spontaneous Potential (SP) and caliper logs, but only recently has it been possible to quantify permeability from logs with any degree of reliability.

The third way of measuring permeability is by means of a permeameter (Fig. 6.12). The version illustrated here is for a fixed laboratory based rig that forces gas through a prepared rock sample. It is conventional to cut plugs from the whole core at intervals of half a meter or so. Whole core analysis is more time-consuming and expensive. It is, however, essential for rocks with heterogeneous pore systems, such as fractured and vuggy reservoirs, and heterogeneous rock fabrics, such as conglomerate and biolithite.

Mobile permeameters are also available. The "probe" permeameter, also called the "mini-" permeameter was first developed nearly half a century ago (Dykstra and Parsons, 1950). It was little used until the 1970s (Weber et al., 1972), since then it has undergone a renaissance. The probe permeameter involves placing a nozzle on a flat rock surface, ensuring that there is an effective seal around the aperture, and then pumping a fluid, generally nitrogen gas, into the rock and measuring the rate of flow. The mini-permeameter has several great advantages over the conventional one. It is sufficiently light and portable that it can be carried around and used on cores in a core store, or on rock outcrops in the field (Hurst and Goggin, 1995). It is fast to operate, and can thus take many readings over a small area of rock, thus testing for small-scale reservoir heterogeneities.

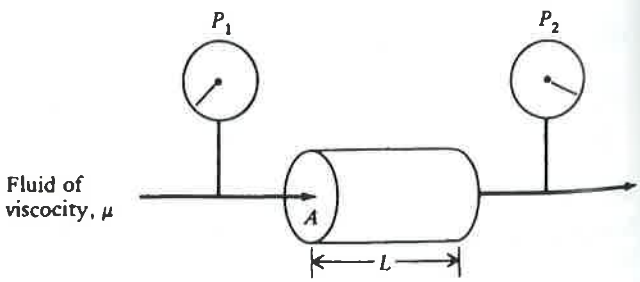

FIGURE 6.12 Basic arrangement for the measurement of permeability. This sketch illustrates a rig suitable for measuring a core plug within a laboratory. "Mini-" or "probe" permeameters are now also widely used in which gas is pumped through a sealed nozzle on a flat rock surface. For further details see text.

Hurst and Rosvoll (1991) report that average permeabilities measured with a minipermeameter were comparable to those obtained by whole core analysis, but both are lower than the permeability measured from plugs cut from the same core.

Shale and mudrock reservoirs are exceeding fine-grained and fracture prone. Data for core porosity, permeability, grain-density, and core saturations can therefore be inaccurate (Luffel and Guidry, 1992). A special sampling and measurement technique referred to as Gas Research Institute (GRI) (Crushed Shale) analysis was developed by Core Lab and the Gas Research Institute for these fine-grained rocks (Core Laboratories, 2014). The method determines the bulk density of the fine-grained rock after which samples are reduced to small particles, 0.5–0.85 mm in diameter. Coring- and sampling-induced fractures are eliminated and pore pathways are shortened. Pore liquid removal and quantification by distillation extraction is then performed. Dry grain volume determination finishes the measurement sequence and provides porosity, grain density, and core saturations. GRI "crushed" core analysis method provides the following: bulk density, grain density, total interconnected porosity, gas filled porosity, core saturations (Sw, So, Sg), and matrix permeability to gas.

6.2.3 Interpretation of Permeability Data

Darcy's law is only valid when there is no chemical reaction between the fluid and the rock and when only one fluid phase completely fills the pores. The situation is far more complex for mixed oil and gas phases, although a Darcy-type equation is assumed to apply. Darcy's law is also only valid for a uniform type of pore system. In dual porosity systems, where, for example fractures and vugs occur, more complex relationships exist than can be accurately expressed by Darcy's law.

A fourth problem is due to the fact that core plugs are commonly contaminated with petroleum and detritus from the drilling mud. Thus they need to be cleaned before measurement can take place. Sadly this cleaning process may also modify the original petrophysical characteristics of the specimen, particularly the clay minerals.

Flow rate depends on the ratio of permeability to viscosity. Thus gas reservoirs may be able to flow at commercial rates with permeabilities of only a few millidarcies, whereas oil reservoirs need minimal permeabilities of the order of tens of millidarcies. For this reason permeability is measured in the laboratory using an inert gas rather than a liquid. Under some conditions—small pore dimensions, very low gas densities, and relatively large mean free paths of gas molecules—the normal condition of zero velocity and no slip at solid surface may not be met. This is the Klinkenberg effect, and a correction is necessary to recalculate the permeability of the rock to air measured in the laboratory to the permeability it would exhibit for liquid or high-density gas (Klinkenberg, 1941). This correction may range from 1% or 2% for high-permeability rocks to as much as 70% for low-permeability rocks.

Permeability is seldom the same in all directions within a rock. Vertical permeability is generally far lower than permeability horizontal to the bedding. Permeability is thus commonly measured from plugs cut in both directions.

When a single fluid phase completely saturates the pore space, permeability is referred to as absolute or specific and is given the dimension L2. The effective permeability refers to saturations of less than 100%. The terms K_w, K_g, and K_o are used to designate the effective permeability with respect to water, gas, and oil, respectively. Effective permeability ranges between 0 and K at 100% saturation, but the sum of permeabilities to two or three phases is always less than one. Relative permeability is the ratio of the effective permeability for a particular fluid at a given saturation to a base permeability. The relative permeability ranges from 0.0 to 1.0. Thus for oil,

$$K_{ro} = \frac{K_o}{K};$$

for gas,

$$K_{rg} = \frac{K_g}{K};$$

and for water,

$$K_{rw} = \frac{K_w}{K}.$$

where

K = absolute permeability (or permeability at irreducible wetting phase saturation);
K_r = relative permeability;
K_g = effective permeability at 100% gas saturation;
K_w = effective permeability at 100% water saturation;
K_o = effective permeability at 100% oil saturation.

Figure 6.13 shows the typical relative permeability relationship for different saturations. It is necessary to consider the relative saturations of how the oil and gas are distributed, and the

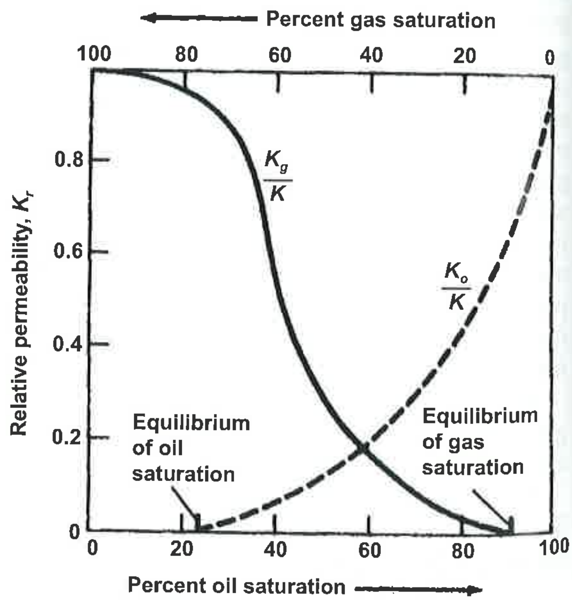

FIGURE 6.13 Typical curves for the relative permeabilities of oil and gas for different saturations.

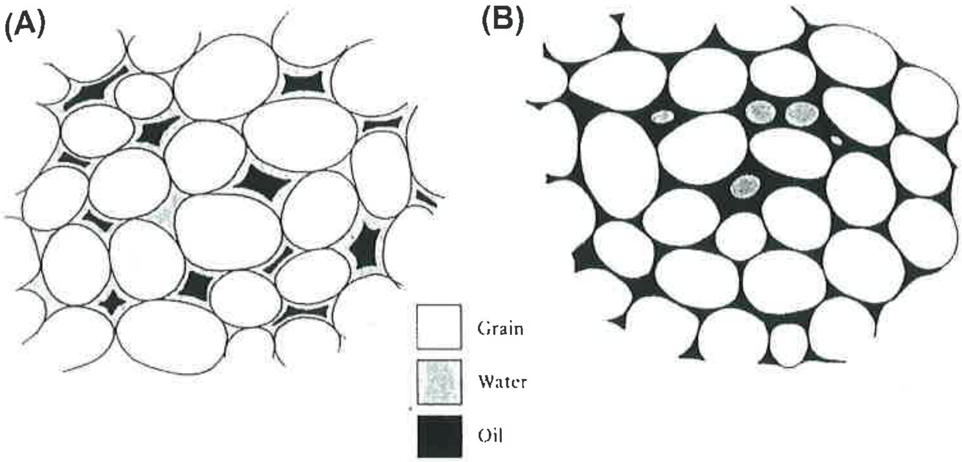

FIGURE 6.14 The concept of wettability in reservoirs. (A) A water-wet reservoir (common). (B) An oil-wet reservoir (rare).

presence or absence of water. Most reservoirs are water-wet, having a film of water separating the pore boundaries from the oil. Few reservoirs are oil-wet, totally lacking a film of connate water at pore boundaries (Fig. 6.14). A mixed, or intermediate wettability condition may also occur.

6.3 CAPILLARY PRESSURE

The consideration of the wettability of pores leads us to the concept of capillarity, the phenomenon whereby liquid is drawn up a capillary tube (Fig. 6.15). The capillary pressure is the difference between the ambient pressure and the pressure exerted by the column of liquid. Capillary pressure increases with decreasing tube diameter (Fig. 6.16). Translated

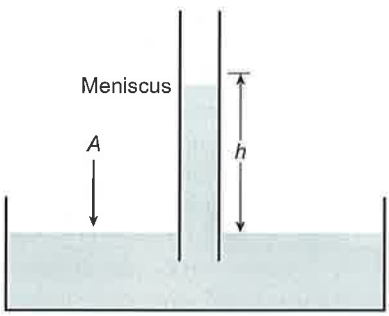

FIGURE 6.15 Capillary tube in a liquid-filled tank. The pressure on the water level (A) equals the pressure due to the hydrostatic head of water (h) minus the capillary pressure across the meniscus.

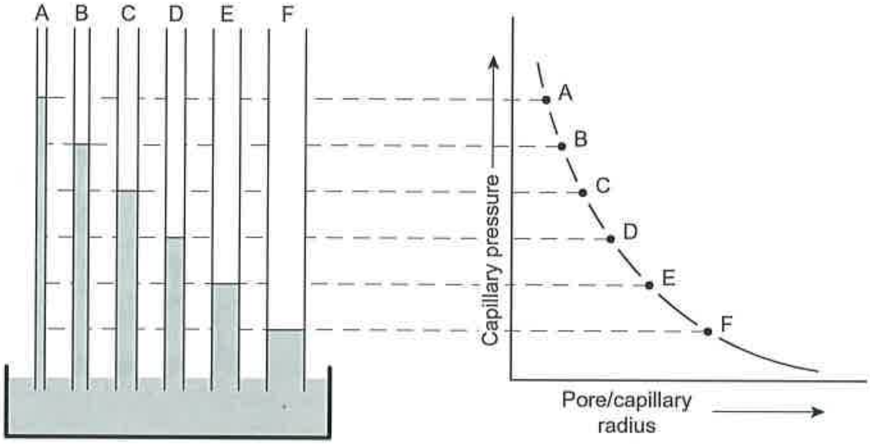

FIGURE 6.16 Capillary tubes of various (exaggerated) diameters showing that the heights of the liquid columns are proportional to the diameters of the tubes.

into geological terms, the capillary pressure of a reservoir increases with decreasing pore size or, more specifically, pore throat diameter. Capillary pressure is also related to the surface tension generated by the two adjacent fluids—it increases with increasing surface tension. In water-wet pore systems the meniscus is convex with respect to water; in oil-wet systems it is concave (Fig. 6.17). For a mathematical analysis of capillary pressure, see Muskat (1949), Dickey (1979), and Chierici (1994). For an account of how capillary pressure analysis may be applied to petroleum reservoirs, see Vavra et al. (1992).

Reservoirs are commonly subjected to capillary pressure tests in which samples with 100% of one fluid are injected with another (gas, oil, water, and mercury may be used). The pressure at which the injected fluid begins to invade the reservoir is the displacement pressure. As pressure increases, the proportions of the two fluids gradually reverse until the irreducible saturation point is reached, at which no further invasion by the second fluid is possible at any pressure. Data from these analyses are plotted as capillary pressure curves (Fig. 6.18). Curve 1 is typical of a good quality reservoir—porous and permeable. Once the entry, or displacement, pressure has been exceeded, fluid invasion increases rapidly for a minor pressure increase until the irreducible water saturation is reached. At this point no further water can be expelled irrespective of pressure.

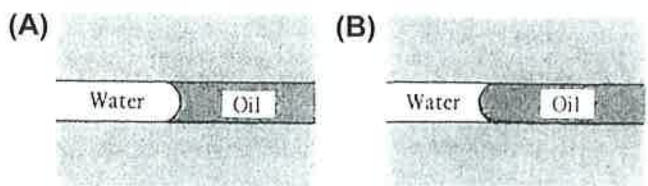

FIGURE 6.17 Cross-sections of capillary tube/pores showing meniscus effect for (A) oil-wet and (B) water-wet reservoirs. Water-wet reservoirs are the general rule.

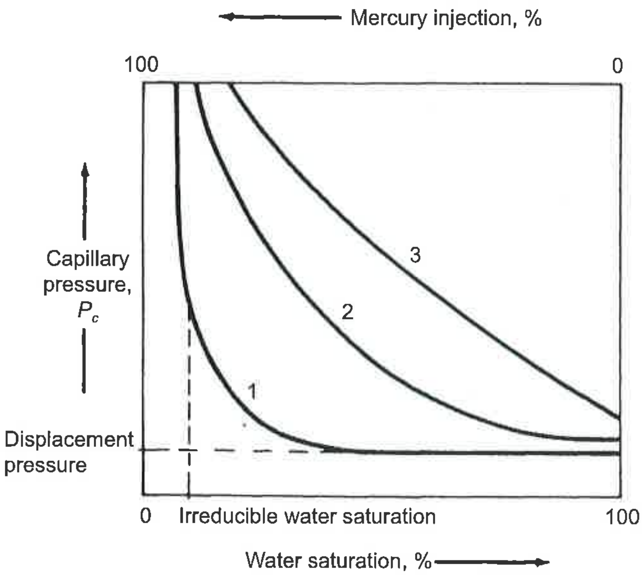

FIGURE 6.18 Capillary pressure curves for various reservoirs: (1) a clean, well-sorted sand with uniform pore diameters, (2) an intermediate quality reservoir, and (3) a poor quality reservoir with a wide range of pore diameters. For full explanation see text.

Curve 2 is for a poorer quality reservoir with a higher displacement pressure and higher irreducible water content. Curve 3 is for a very poor quality reservoir, such as a poorly sorted sand with abundant matrix and hence a wide range of pore sizes. Displacement pressure and irreducible water saturation are therefore both high, and water saturation declines almost uniformly with increasing pressure.

6.4 RELATIONSHIP BETWEEN POROSITY, PERMEABILITY, AND TEXTURE

The texture of a sediment is closely correlated with its porosity and permeability. The texture of a reservoir rock is related to the original depositional fabric of the sediment, which is modified by subsequent diagenesis. This diagenesis may be negligible in many sandstones, but in carbonates it may be sufficient to obliterate all traces of original depositional features. Before considering the effects of diagenesis on porosity and permeability, the effects of the original depositional fabric on these two parameters must be discussed. The following account is based largely on studies by Krumbein and Monk (1942), Gaithor (1953), Rogers and Head (1961), Potter and Mast (1963), Chilingar (1964), Beard and Weyl (1973), Pryor (1973), and Atkins and McBride (1992). The textural parameters of an unconsolidated sediment that may affect porosity and permeability are as follows:

Grain shape (roundness, sphericity)
Grain size

Sorting
Fabric (packing, grain orientation)

These parameters are described and discussed in the following sections.

6.4.1 Relationship between Porosity, Permeability, and Grain Shape

The two aspects of grain shape to consider are roundness and sphericity (Powers, 1953). As Fig. 6.19 shows, these two properties are quite distinct. Roundness describes the degree of angularity of the particle. Sphericity describes the degree to which the particle approaches a spherical shape. Mathematical methods of analyzing these variables are available.

Data on the effect of roundness and sphericity on porosity and permeability are sparse. Fraser (1935) inferred that porosity might decrease with sphericity because spherical grains may be more tightly packed than subspherical ones.

6.4.2 Relationship between Porosity, Permeability, and Grain Size

Theoretically, porosity is independent of grain size for uniformly packed and graded sands (Rogers and Head, 1961). In practice, however, coarser sands sometimes have higher porosities than do finer sands or vice versa (e.g., Lee, 1919; Sneider et al., 1977). This disparity may be due to separate but correlative factors such as sorting and/or cementation.

Permeability declines with decreasing grain size because pore diameter decreases and hence capillary pressure increases (Krumbein and Monk, 1942). Thus a sand and a shale may both have porosities of 10%; whereas the former may be a permeable reservoir, the latter may be an impermeable cap rock.

6.4.3 Relationship between Porosity, Permeability, and Grain Sorting

Porosity increases with improved sorting. As sorting decreases, the pores between the larger, framework-forming grains are infilled by the smaller particles. Permeability decreases with sorting for the same reason (Fraser, 1935; Rogers and Head, 1961; Beard and Weyl, 1973). As mentioned earlier, sorting sometimes varies with the grain size of a particular

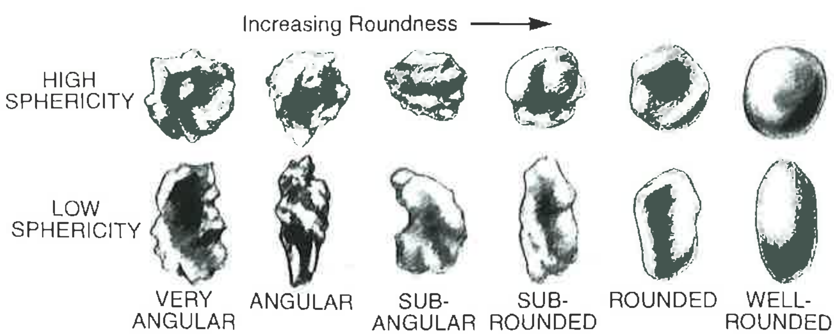

FIGURE 6.19 Sand grains showing the difference between shape and sphericity.

reservoir sand, thus indicating a possible correlation between porosity and grain size. Fig. 6.20 summarizes the effects of sorting and grain size on porosity and permeability in unconsolidated sand.

6.4.4 Relationship between Porosity, Permeability, and Grain Packing

The two important characteristics of the fabric of a sediment are how the grains are packed and how they are oriented. The classic studies of sediment packing were described by Fraser

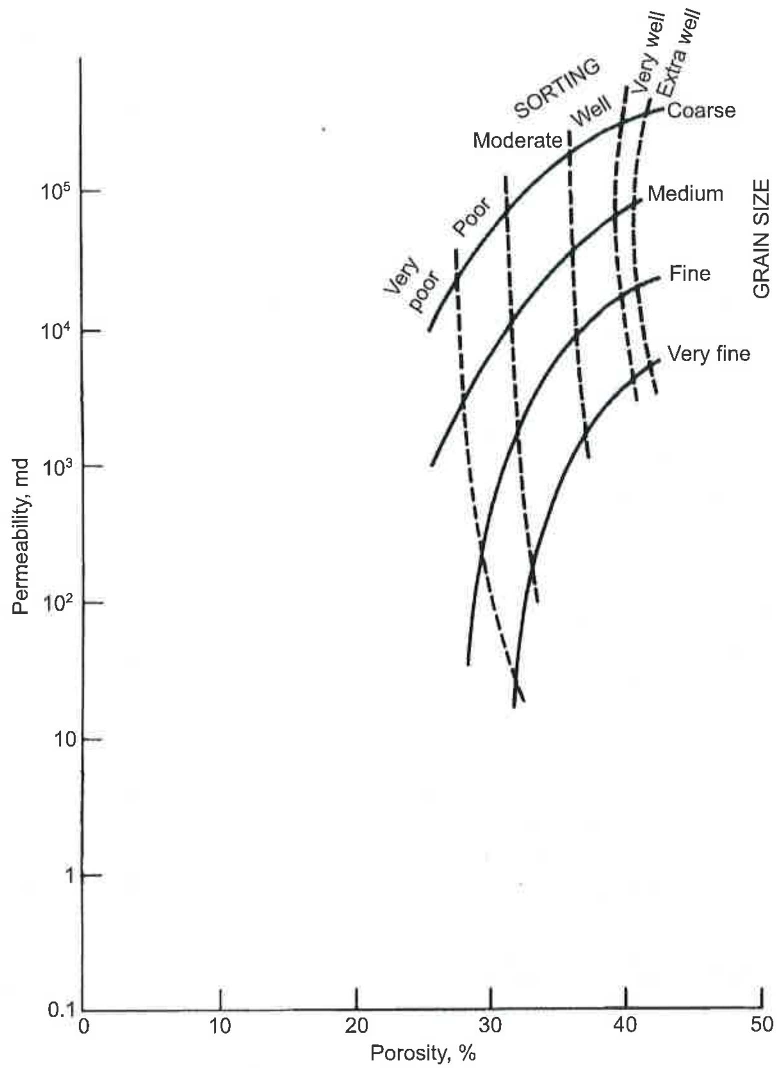

FIGURE 6.20 Graph of porosity against permeability showing their relationship with grain size and sorting for uncemented sands. *After Beard and Weyl (1973), Nagtegaal (1978).*

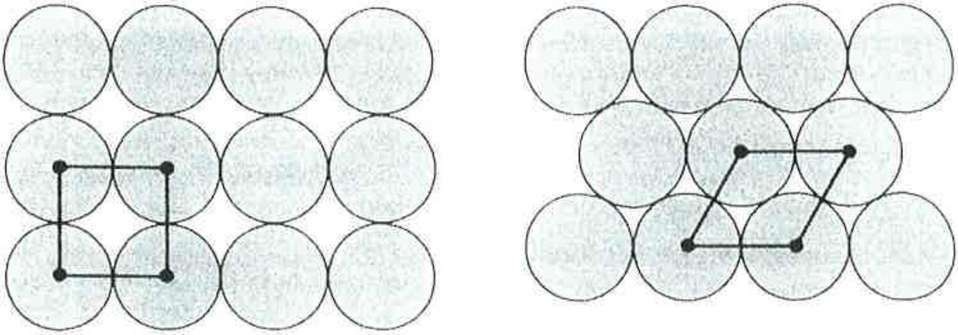

FIGURE 6.21 The loosest and tightest theoretical packings for spheres of uniform diameter.

(1935) and Graton and Fraser (1935). They showed that spheres of uniform size have six theoretical packing geometries. These geometries range from the loosest cubic style with a porosity of 48% down to the tightest rhombohedral style with a 26% porosity (Fig. 6.21).

The significance of packing to porosity can be observed when trying to pour the residue of a packet of sugar into a sugar bowl. The sugar poured into the bowl has settled under gravity into a loose packing. Tapping the container causes the level of sugar to drop as the grains fall into a tighter packing, causing porosity to decrease and bulk density to increase. Packing is obviously a major influence on the porosity of sediments; several geologists have tried to carry out empirical, as opposed to theoretical, studies (e.g., Kahn, 1956; Morrow, 1971). Particular attention has been paid to relating packing to the depositional process (e.g., Martini, 1972). Like grain sphericity and roundness, packing is not amenable to extensive statistical analysis. Intuitively, one might expect sediments deposited under the influence of gravity, such as fluidized flows and turbidites, to exhibit looser grain packing than those laid down by traction processes. However, postdepositional compaction probably causes rapid packing adjustment and porosity loss during early burial.

6.4.5 Relationship between Porosity, Permeability, and Depositional Process

Several studies have been made to try to establish the way in which the depositional process and environment of a sediment may effect its reservoir characteristics. This is not easy to resolve because grain size and sorting are related not only to the final depositional environment, but also reflect the characteristics of the rocks from which they were derived.

For what it is worth, Pryor (1973) recorded permeabilities averaging 93, 68, and 54 darcies, and porosities averaging 41%, 49%, and 49% for point bars, beaches, and dunes, respectively. Atkins and McBride (1992) reported comparable values for porosity, and noted that trapped air bubbles and packing effects accounted for several percent of the porosity. There is no doubt that porosity and permeability are rapidly reduced due to packing adjustments and compaction early on during burial.

6.4.6 Relationship between Porosity, Permeability, and Grain Orientation

The preceding analysis of packing was based on the assumption that grains are spherical, which is generally untrue of all sediments except oolites. Most quartz grains are actually prolate spheroids, slightly elongated with respect to their C crystallographic axis (Allen, 1970). Sands also contain flaky grains of mica, clay, shell fragments, and other constituents. Skeletal carbonates have still more eccentric grain shapes. Thus the second element of fabric, namely, orientation, is perhaps more significant to porosity and permeability than packing is. The orientation of grains may have little effect on porosity, but a major effect on permeability.

Most sediments are stratified, the layering being caused by flaky grains, such as mica, shells, and plant fragments, as well as by clay laminae. Because of this stratification the vertical permeability is generally considerably lower than the horizontal permeability. The ratio of vertical to horizontal permeability in a reservoir is important because of its effect on coning as the oil and gas are produced. Variation in permeability also occurs parallel to bedding. In most sands the grains generally show a preferential alignment within the horizontal plane. Grain orientation can be measured by various methods (Sippel, 1971). Studies of horizontally bedded sands have shown that grains are elongated parallel to current direction (e.g., Shelton and Mack, 1970; von Rad, 1971; Martini, 1971, 1972). For cross-bedded sands the situation is more complex because grains may be aligned parallel to the strike of foresets due to gravitational rolling. Figure 6.22 shows that permeability will be greatest parallel to grain orientation, since this orientation is the fabric alignment with least resistance to fluid movement (Scheiddegger, 1960).

Studies of the relationship between fabric and permeability variation have produced different results on both small and large scales. Potter and Pettijohn (1977) have reviewed the conflicting results of a number of case histories, some of which show a correlation with grain orientation and some of which do not. It is necessary to consider not only small-scale permeability variations caused by grain alignment but also the larger variations caused by sedimentary structures.

Grain-size differences cause permeability variations far greater than those caused by grain orientation. Thus in the cross-bedded eolian sands of the Leman field (North Sea), horizontal permeabilities measured parallel to strike varied from as much as 0.5 to 38.5 md between

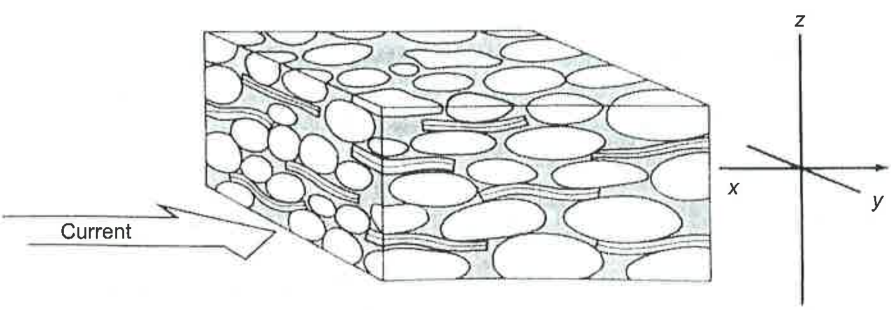

FIGURE 6.22 Block diagram of sand showing layered fabric with grains oriented parallel to current. Generally, $K_x > K_y > K_z$.

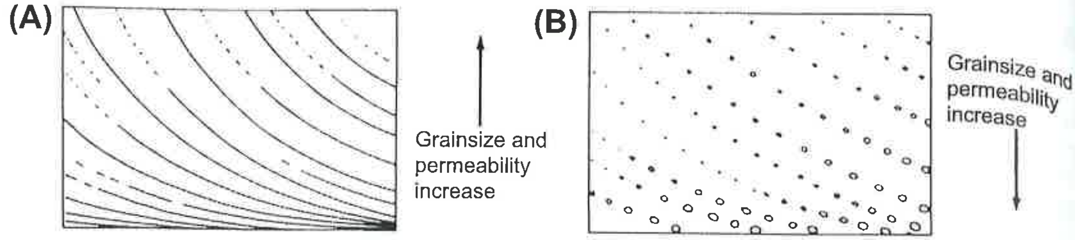

FIGURE 6.23 Permeability variations for (A) downward-fining and (B) downward-coarsening avalanche cross-beds.

adjacent foresets. This range in permeabilities is attributable to variations in grain size and sorting. Similarly, because eolian cross-beds generally show a decreasing grain size from foreset to toeset, permeability diminishes downward through each cross-bedded unit (Van Veen, 1975). Conversely, in many aqueously deposited cross-beds, avalanching causes grain size to increase downward. Thus permeability also increases down each foreset for the reason previously given (Fig. 6.23).

Detailed accounts of permeability variations within sedimentary structures, mainly cross-bedding, have been given by Weber (1982) and Hurst and Rosvoll (1991). The latter study reported 16,000 mini-permeameter readings. These showed that that there was greater variation of permeability found within sedimentary structures than between them.

On the still larger scale of whole sand bodies, grain-size-related permeabilities often have considerable variations (Richardson et al., 1987). When discussing the use of the SP log as a vertical profile of grain size it was pointed out that channels tend to have upward-fining grain-size profiles, and thus upward-decreasing permeability. By contrast barrier bar and delta mouth bar sands have upward-coarsening grain-size profiles, and thus upward-increasing permeability. These vertical changes in permeability are also often accompanied by commensurate variations in porosity. Thus there is a strong sedimentological control over the vertical and lateral variation of porosity and permeability within petroleum reservoirs on a hierarchy of scales, from variations within sedimentary structures, variations within sand bodies, and variations within formations, due to sand body trend (Fig. 6.24).

An example of the scale and significance of these variations is provided by a study of a Holocene sand-filled channel in Holland. Permeability increased from 25 md at the channel margin to 270 md in the center some 175 m away (Weber et al., 1972). Pumping tests showed that the drawdown was nearly concentric to the borehole, which suggests that the permeability had little preferred direction within the horizontal plane (Fig. 6.25).

6.5 EFFECTS OF DIAGENESIS ON RESERVOIR QUALITY

The preceding section examined the control of texture on the petrophysics of unconsolidated sediment. Once burial begins, however, many changes take place, most of which diminish the porosity and permeability of a potential reservoir. These changes, collectively referred to as *diagenesis*, are numerous and complex. The following account specifically

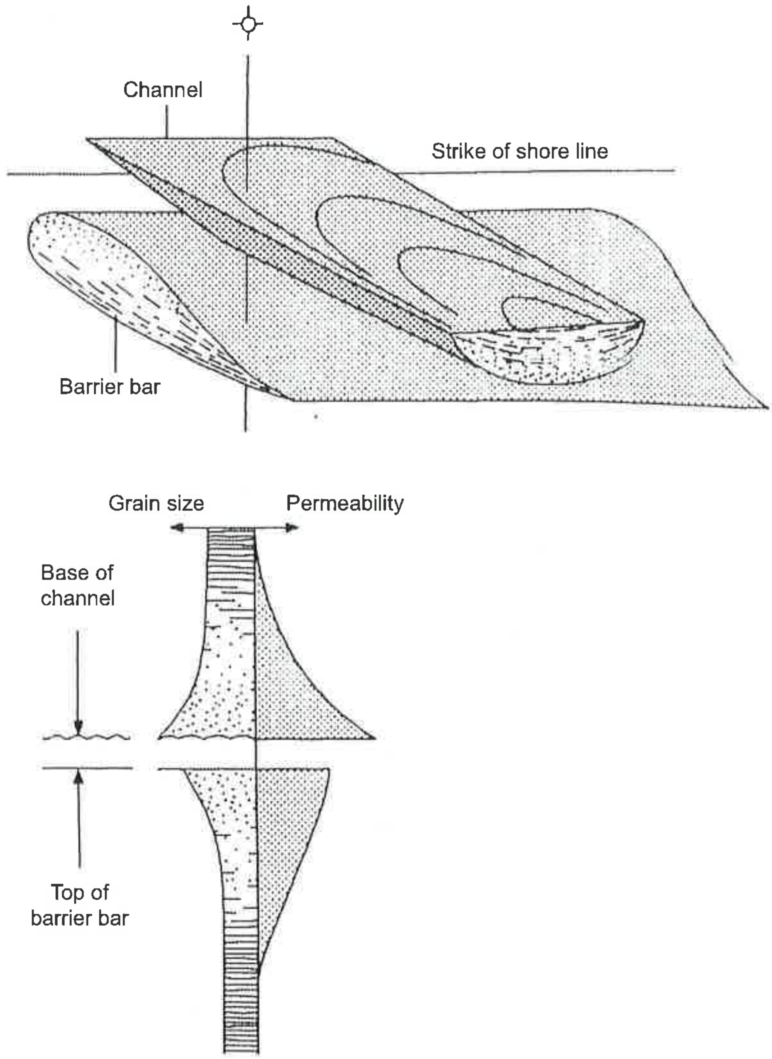

FIGURE 6.24 Diagram to show the permeability variations and trends in sand bodies. Channels often have upward-fining grain-size profiles, so permeability may decline upward within a channel. Barrier sands often have upward-coarsening grain-size profiles, so they often show an upward-increasing permeability. On a regional scale channels tend to trend down the paleoslope, whereas barrier bar sands will parallel it. This hierarchy of permeability variations effects the flow of fluids within petroleum reservoirs. *From Selley (1988).*

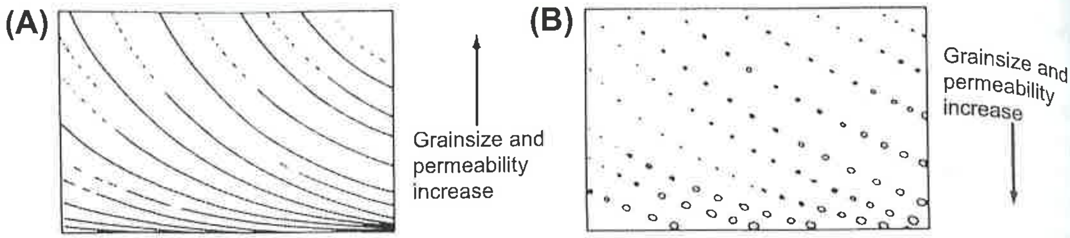

FIGURE 6.23 Permeability variations for (A) downward-fining and (B) downward-coarsening avalanche cross-beds.

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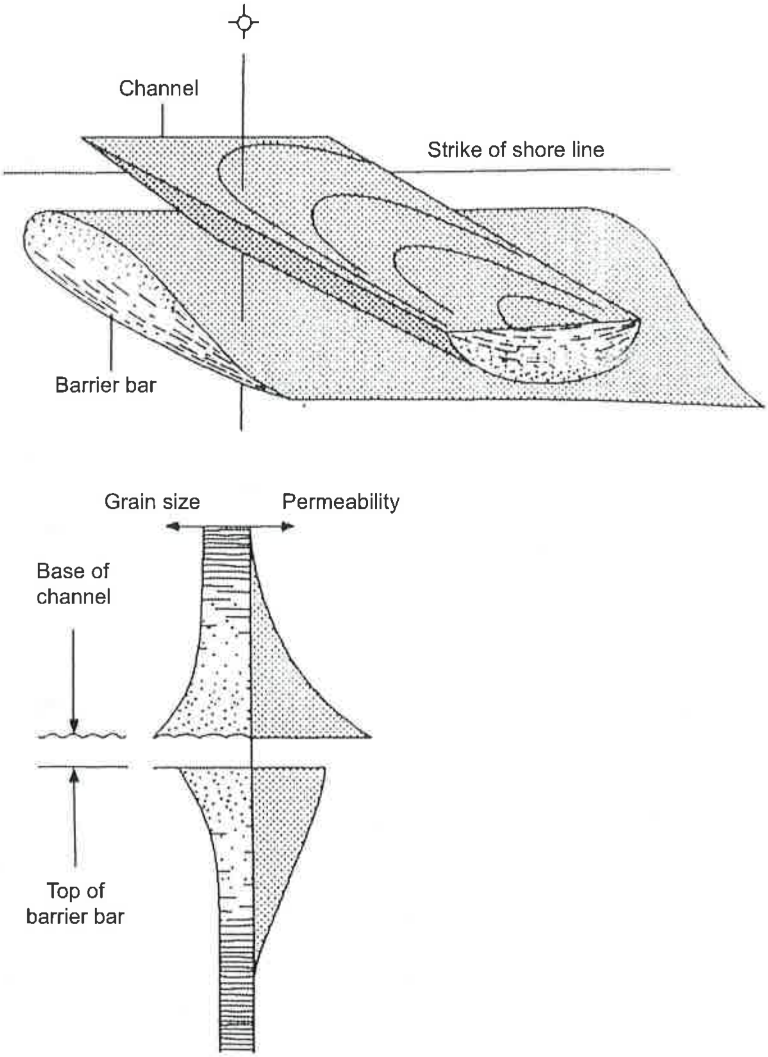

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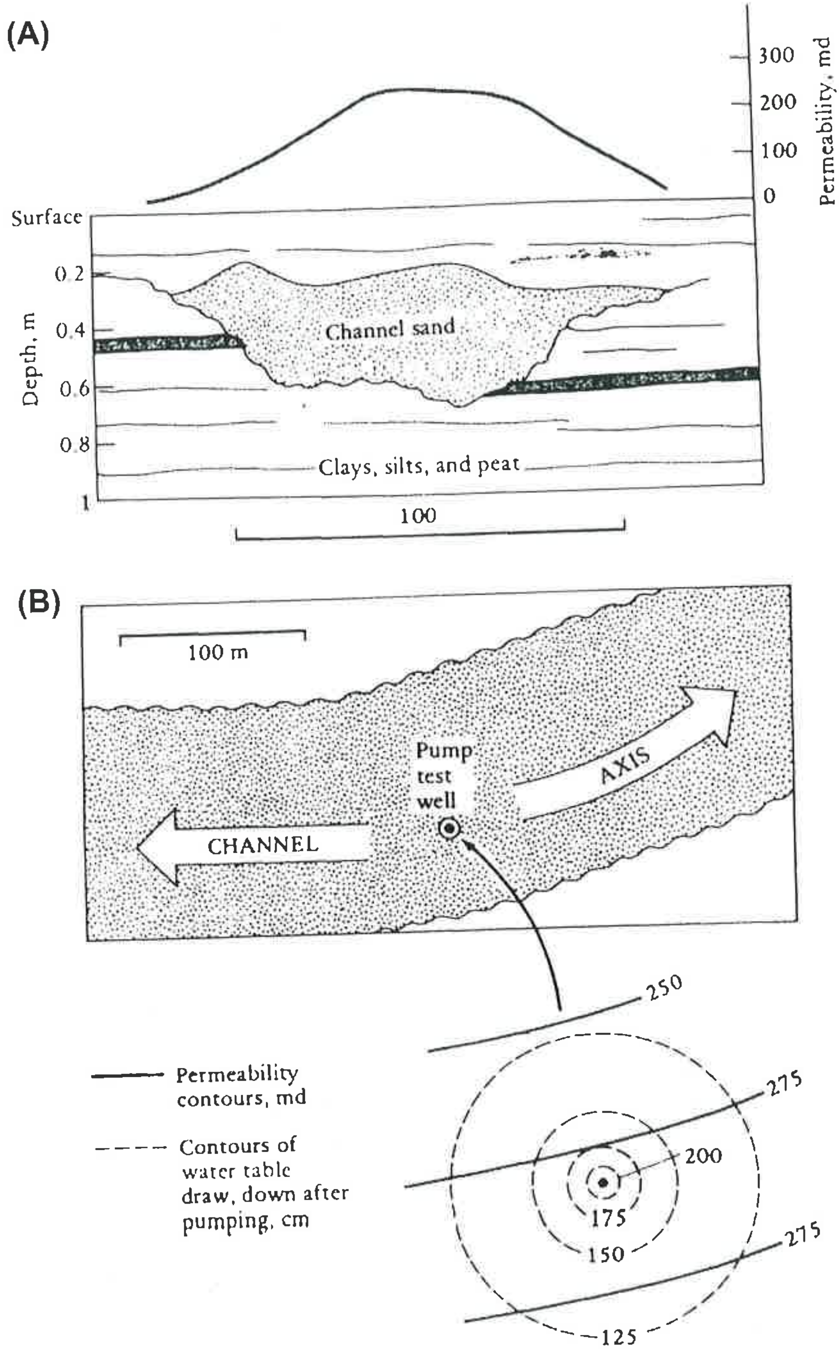


FIGURE 6.25 Permeability variations in a Holocene Dutch channel sand: (A) a cross-section showing how permeability increases toward the channel axis and (B) maps showing how contours of the water level drop are concentric around the pump test well. *After Weber et al. (1972).*

focuses on the effect of diagenesis on reservoir quality. More detailed accounts are found in Blatt et al. (1980), Selley (1988), and Friedman et al. (1992). The diagenesis of sandstone and carbonate reservoirs is considered in turn.

6.5.1 Effects of Diagenesis on Sandstone Reservoirs

The effects of diagenesis on sandstone reservoirs include the destruction of porosity by compaction and cementation, and the enhancement of porosity by solution. In this section the factors that control regional variations of reservoir quality are discussed first. Then the details of cementation and solution are described, and the section concludes with an account of diagenesis associated with petroleum accumulations.

6.5.1.1 Regional Variations on Sandstone Reservoir Quality

Studies of recent sands, such as those of Pryor (1973), show that they have porosities of some 40–50% and permeabilities of tens of darcies. Most sandstone reservoirs, however, have porosities in the range of 10–20% and permeabilities measurable in millidarcies. Although fluctuations do occur, the porosity and permeability of reservoirs decrease with depth. This relationship is of no consequence to the production geologist or reservoir engineer concerned with developing a field, but it is important for the explorationist who has to decide the greatest depth at which commercially viable reservoirs may occur.

The porosity of a sandstone at a given depth can be determined if the porosity gradient and primary porosity are known (Selley, 1978):

$$\phi^{D} = \phi^{P} - GD,$$

where

ϕ^{D} = porosity at a given depth;
ϕ^{P} = primary porosity at the surface;
G = porosity gradient (%ϕ/km);
D = burial depth.

Reviews of porosity gradients and the factors controlling them have been given by Selley (1978) and Magara (1980). The main variables that affect porosity gradients are the mineralogy and texture of the sediments and the geothermal and pressure regimes to which they are subjected. The more mineralogically mature a sand is, the better its ability to retain its porosity (Dodge and Loucks, 1979). Taking the two extreme cases, chemically unstable volcaniclastic sands tend to lose porosity fastest, and the more stable pure quartz sands tend to have the lowest gradients (Fig. 6.26).

Texture also affects the gradient: Poorly sorted sands with abundant clay matrix compact more and lose porosity faster than do clean, well-sorted sands (Rittenhouse, 1971). A similar effect is noted in micaceous sand, as, for example, in the Jurassic of the North Sea (Hay, 1977). Geothermal gradients also affect the porosity gradient of sand, as shown in Fig. 6.27. Because the rate of a chemical reaction increases with temperature, the higher the geothermal gradient, the faster the rate of porosity loss. Pressure gradient also affects porosity. Abnormal pressure preserves porosity, presumably by decreasing the effect of compaction (Atwater and Miller, 1965).

FIGURE 6.26 Graph showing how the porosity gradient decreases with increasing mineralogical maturity. *After Nagtegaal (1978).*

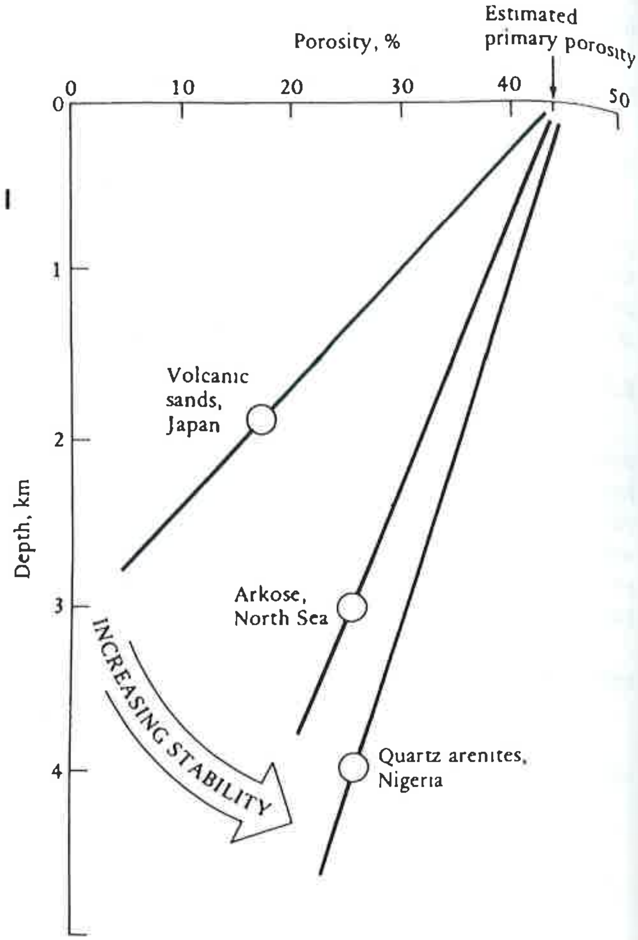
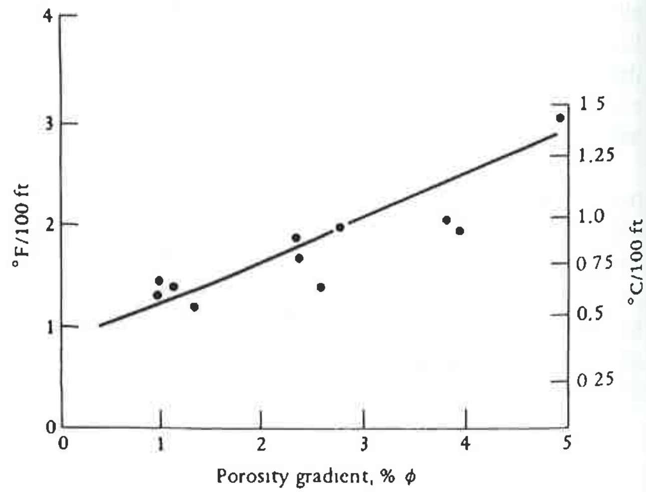


FIGURE 6.27 Graph of geothermal gradient versus porosity for various sandstones showing how they tend to increase together. *From Selley (1978).*



Oil and gas have been commonly observed to preserve porosity in sands (e.g., Fuchtbauer, 1967; O'Brien and Lerche, 1988). Once petroleum enters a trap, the circulation of connate water is diminished, and further cementation inhibited. Some studies show, however, that cementation in a petroleum-saturated reservoir is not completely inhibited, but continues at a reduced rate (Saigal et al., 1993). Gregory (1977) demonstrated the inhibiting effect of petroleum on porosity destruction for the Tertiary sediments of the Gulf Coast, USA. This study shows that water-wet sands have lower porosities than petroleum-saturated sands for the same depth, and that gas preserves porosity more effectively than oil (Fig. 6.28).

The linear rate of porosity loss with depth shown by Fig. 6.28 has been observed in many basins. This has led to the view that porosity is lost at a slow and steady rate, concomitant with burial, and implies that there is little circulation of connate fluid (e.g., Bloch, 1991; Bloch and Helmold, 1995; Cazier et al., 1995; Walderhaug, 1996).

This steady-state model contrasts markedly with the "throbbing basins" model, which is based on evidence that cementation occurs in response to the episodic expulsion of hot water from overpressured shales. The evidence for these "hot Hushes" is based on studies of fluid inclusions and isotope data (e.g., Lynch, 1996). For further accounts on this controversy, see Horbury and Robinson (1993).

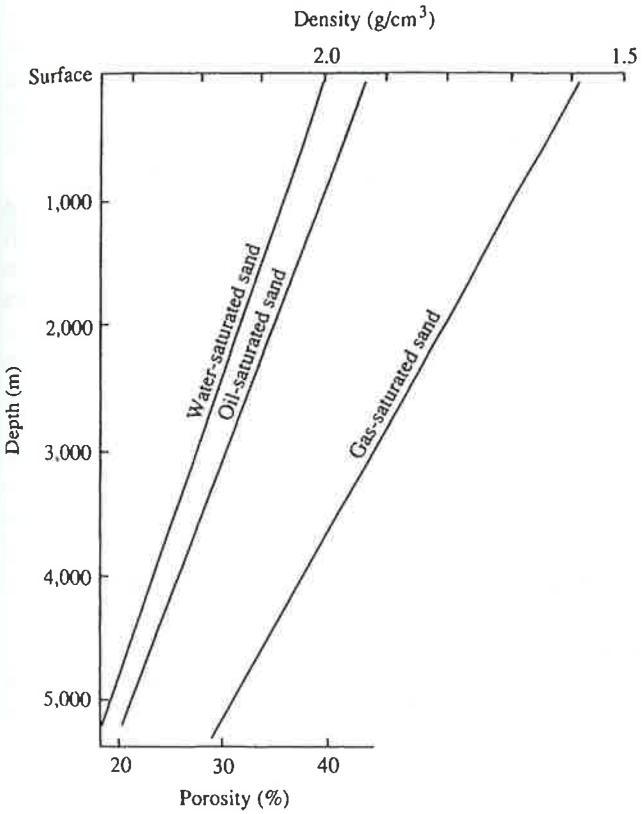


FIGURE 6.28 The graph of porosity and density plotted against depth for Tertiary sandstones in the U.S. Gulf Coast, from data in Gregory (1977). Note how porosity diminishes linearly with increasing depth. These data show how petroleum preserves reservoir porosity, gas being more effective than oil.

6.5.1.2 *Porosity Loss by Cementation*

On a regional scale the porosity of sandstones is largely controlled by the factors previously discussed (mineralogy, texture, geothermal and pressure gradient). Within a reservoir itself porosity and permeability vary erratically with primary textural changes and secondary diagenetic ones. The diagenesis of sandstones is a major topic beyond the scope of this text. It is treated in depth by McDonald and Surdam (1984), Friedman et al. (1992), and Morse (1994). The following account deals concisely with those aspects particularly relevant to petroleum geology.

Diagenetic changes in a sandstone reservoir include cementation and solution, which are now discussed in turn. A small amount of cementation is beneficial to a sandstone reservoir because it prevents sand from being produced with the oil. The presence of sand in the oil not only damages the reservoir itself but also the production system. Extensive cementation is deleterious, however, because it diminishes porosity and permeability. Many minerals may grow in the pores of a sandstone, but only three are of major significance: quartz, calcite, and the authigenic clays.

Quartz is a common cement. It generally grows as optically continuous overgrowths on detrital quartz grains (Fig. 6.29(A)). The solubility of silica increases with pH, so silica cements occur where acid fluids have moved through the pores.

Calcium carbonate is another common cement. It generally occurs as calcite crystals, which, as they grow from pore to pore, may form a poikilitic fabric of crystals enclosing many sand grains (Fig. 6.29(B)). The grains frequently appear to "float" in the crystals. Detailed observation often shows that grain boundaries are corroded, suggesting that some replacement has occurred. Calcite solubility is the reverse of silica solubility; that is, it decreases with pH. Thus calcite cementation is the result of alkaline fluids moving through the pores.

Quartz and carbonate cements are both found at shallow depths, their distribution being dependent on the history of the pore fluids that have migrated through the rock. With increasing depth carbonate cements are replaced by quartz as the zone of metagenesis approaches. At the depths where petroleum is encountered quartz and carbonate cements commonly occur in sands adjacent to shales. These cemented envelopes were first documented by Fothergill (1955) and Fuchtbauer (1967). Selley (1992) showed how envelopes could be identified on wireline logs (Fig. 6.30), and discussed two modes of formation. It is possible that they result from the precipitation of minerals as connate water is expelled from the adjacent shales. Alternatively they may be the residue left behind where a diagenetic front of acid connate water has moved through a cemented sand (Sultan et al., 1990). Examples have also been described from the U.S. Gulf Coast, and their origin debated by Moncure et al. (1984) and Sullivan and McBride (1991). Figure 6.31 illustrates the distribution of cemented envelopes in the Campos basin turbidites of offshore Brazil described by Carvalho et al. (1995).

Clay may be present in a sandstone either as a detrital matrix or as an authigenic cement. As clays recrystallize and alter during burial, this distinction is not always easy to make. The presence of clay in a reservoir obviously destroys its porosity and permeability. The mineralogy of clays is very complex, but basically there are three groups to consider. These, the kaolinitic, illitic, and montmorillonitic clays, have different effects on reservoirs and different sources of formation.

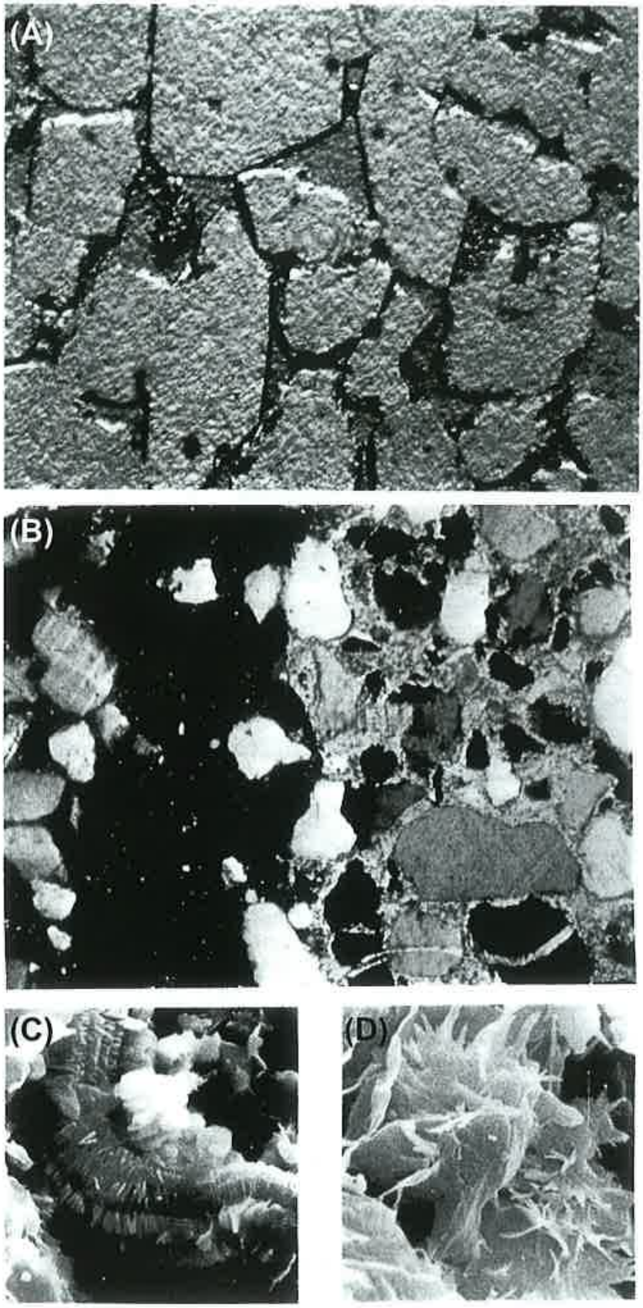


FIGURE 6.29 Photomicrographs of various types of sandstone cement: (A) silica cement in optical continuity on detrital quartz grains, (B) calcite cement with poikilitic fabric of large crystals enclosing corroded quartz grains. (C) authigenic kaolin crystals within pores, and (D) authigenic illite showing fibrous habit. (A) and (B) are thin sections photographed in ordinary and polarizing light, respectively. (C) and (D) are scanning electron micrographs.

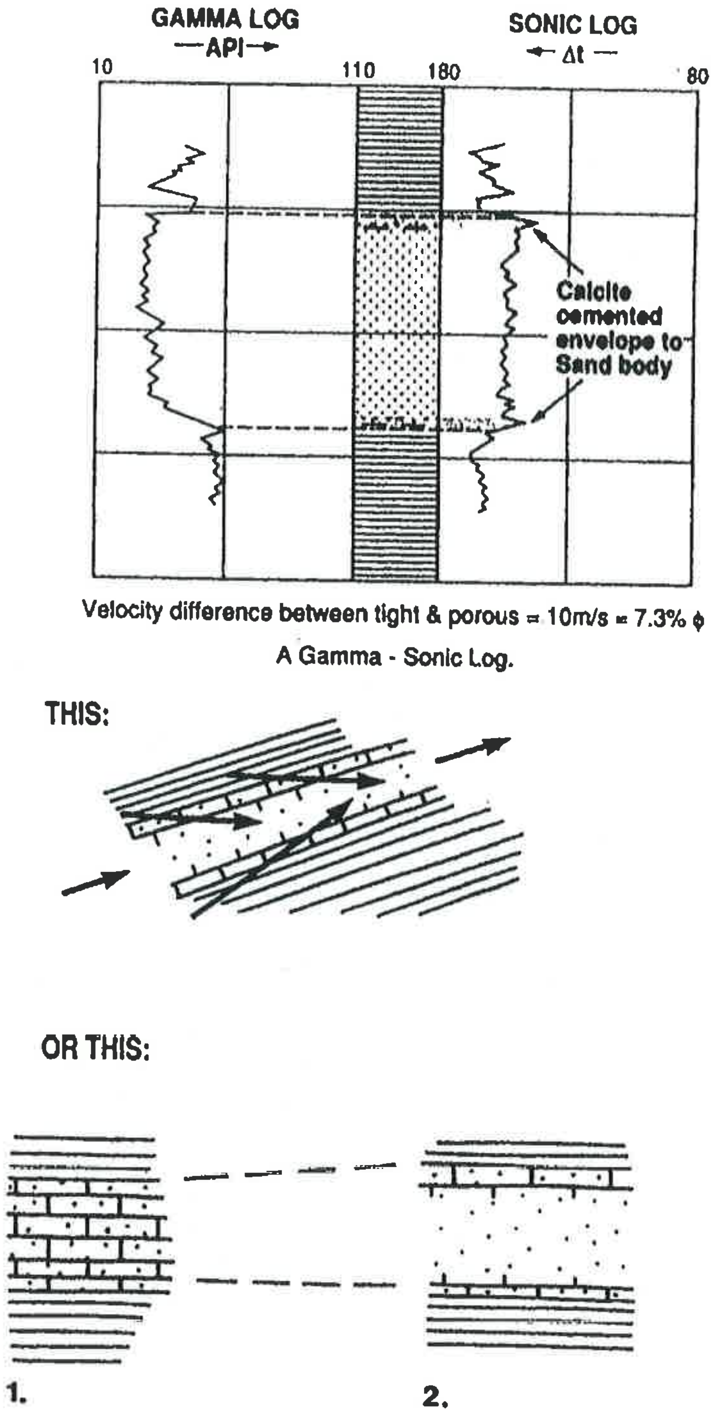


FIGURE 6.30 Gamma sonic log from a well in the UK North Sea to illustrate a Paleocene sand with cemented envelope, and illustrations that show the envelope may result either from the precipitation of minerals as connate waters flow into the sand from compacting shale or from a diagenetic front of acid fluid leaching a passage through an earlier cemented sand. *From Selley (1992).*

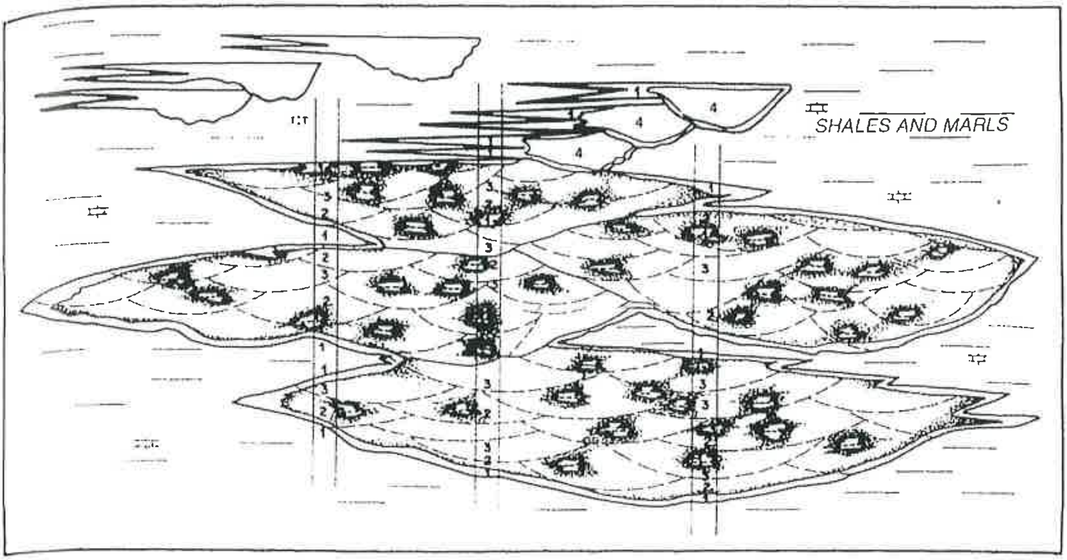


FIGURE 6.31 Diagram to show the distribution of cemented envelopes in Campos basin (Cretaceous) turbidite reservoirs, offshore Brazil. *Reprinted from Carvalho et al. (1995); pp. 226–244, with kind permission from Elsevier Science Ltd.*

Kaolinite generally occurs as well-formed, blocky crystals within pore spaces (Fig. 6.29(C)). This crystal habit diminishes the porosity of the reservoir, but may have only a minor effect on permeability. Kaolinite forms and is stable in the presence of acid solutions. Therefore it occurs as a detrital clay in continental deposits, and as an authigenic cement in sands that have been flushed by acidic waters, such as those of meteoric origin.

Illitic clay is quite different from kaolin. Authigenic illite grows as fibrous crystals, which typically occur as furlike jackets on the detrital grains (Fig. 6.29(D)). These structures often bridge over the throat passages between pores in a tangled mass. Thus illitic cement may have a very harmful effect on the permeability of a reservoir. This effect is demonstrated in Fig. 6.32, which is taken from studies of the Lower Permian Rotliegende sandstone of the southern North Sea by Stalder (1973) and Seemann (1979). Illitic clays typically form in alkaline environments. They are thus the dominant detrital clay of most marine sediments and occur as an authigenic clay in sands through which alkaline connate water has moved.

The montmorillonitic, or smectitic, clays are formed from the alteration of volcanic glass and are found in continental or deep marine deposits. They have the ability to swell in the presence of water. Reservoirs with montmorillonite are thus very susceptible to formation damage if drilled with a conventional water-based mud and must therefore be drilled with an oil-based mud. When production begins, water displaces the oil, causing the montmorillonitic clays to expand and destroy the permeability of the lower part of the reservoir.

Kaolinite, illite, and montmorillonite may all be found in shallow reservoirs, depending on the source material and the diagenetic history. With increasing burial the kaolinites and montmorillonites alter to illite, the collapse of montmorillonites being a possible cause of overpressure, and related to the expulsion of petroleum as discussed earlier. As catagenesis merges into metagenesis, illite crystallinity increases and they evolve into the hydromicas and micas.

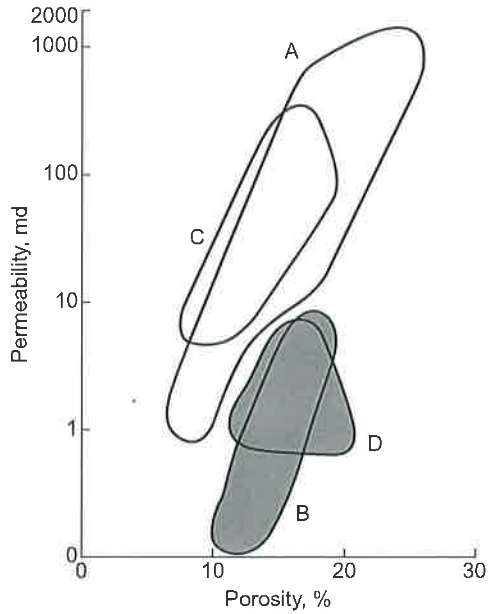


FIGURE 6.32 Porosity–permeability data for illite (B and D) and kaolin (A and C) cemented Rotliegende reservoir sands of the North Sea. *After Stalder (1973), Seemann (1979).*

6.5.1.3 Porosity Enhancement by Solution

Cementation reduces the porosity and permeability of a sand. In some cases, however, solution of cement or grains can reverse this trend. Schmidt et al. (1977) have outlined the petrographic criteria for the recognition of secondary solution porosity in sands. It generally involves the leaching of carbonate cements and grains, including calcite, dolomite, siderite, shell debris, and unstable detrital minerals, especially feldspar. Leached porosity in sands is generally associated with kaolin, which both replaces feldspar and occurs as an authigenic cement.

The fact that carbonate is leached out of the sand and the predominance of kaolin indicate that the leaching was caused by acidic solutions. There are two sources of acidic leaching: epidiagenesis or, more specifically, weathering due to surface waters (Fairbridge, 1967) and decarboxylation of kerogen (Schmidt et al., 1977).

Meteoric water rich in carbonic and humic acids weathers sandstones, and other rocks, at the earth's surface. In many cases kaolinization and leaching generate solution porosity that is enhanced by fracturing. Usually, the weathering-induced porosity is destroyed during reburial by normal diagenesis. The secondary porosity may only be preserved within hydrocarbon reservoirs; the preservative effect of hydrocarbons on porosity has already been noted. Thus many geologists from Hea (1971) to Al-Gailani (1981) and Shanmugam (1990) attributed subunconformity secondary porosity to the effects of epidiagenesis. These views are supported by isotope and fluid inclusion analyses that show that cements formed concomitant with leaching in low temperatures and salinities. These results are consistent with reports of stratified freshwaters preserved beneath unconformities, suggesting that a palaeoaquifer has been preserved (e.g., Macauley et al., 1992).

Examples of subunconformity sand reservoirs with secondary porosity include the Sarir sand of Libya (which formed the basis for Hea's study), the Cambro-Ordovician sand of Hassi Messaoud, Algeria (Balducci and Pommier, 1970), the sub-Cimmerian unconformity Jurassic sands of the North Sea (Bjorlykke, 1984; Selley, 1984, 1990), and Prudhoe Bay, Alaska (Shanmugam and Higgins, 1988).

An alternative source for the acid fluid is the decarboxylation of coal or kerogen, causing the expulsion of solutions of carbonic acid (Schmidt et al., 1977; Loucks et al., 1979). According to this theory, acidic solutions are expelled from a maturing source rock ahead of petroleum migration. These acid fluids generate secondary solution porosity in the reservoir beds. This mechanism explains solution porosity, which has been observed in sandstones that have not undergone uplift and subaerial exposure (Jamison et al., 1980).

6.5.1.4 Diagenesis Associated with Petroleum Accumulations

Sandstone petroleum reservoirs may have undergone a complex diagenetic history, as outlined earlier, before the emplacement of the petroleum. Porosity and permeability are often higher in hydrocarbon reservoirs than in the underlying water zones. As discussed in the preceding section, this discrepancy may be due to epidiagenesis, where the reservoir lies beneath an unconformity. In such instances the changes in porosity and permeability may be above or beneath the oil/water contact. As already noted, however, the presence of hydrocarbons inhibits cementation by preventing connate water from continuing to move through the trap. Flow may continue in the underlying water zone, however, so porosity and permeability are reduced by cementation after oil or gas has migrated into the trap.

Postmigration silica cement in water zones beneath traps has been described from the Silurian Clinton sand of Ohio (Heald, 1940) and the Jurassic reservoirs of the Gifhorn trough, Germany (Philip et al., 1963). Calcite and anhydrite postdate migration in the Permian Lyons sand of the Denver basin (Levandowski et al., 1973), and from the Fulmar sands of the North Sea (Saigal et al., 1993). Many other instances of postmigration cementation are known.

In extreme cases postmigration cementation may be so pervasive as to act as a seat seal, giving rise to "frozen-in" paleotraps, as in the Raudhatain field of Kuwait (Al-Rawi, 1981). Because of postmigration cementation it is important to cut cores below the oil/water contact of a field. If a water-drive production mechanism is anticipated, then the permeability of the aquifer must be known. Data must not be extrapolated from the reservoir downward.

The situation may be still further complicated by partial emigration of petroleum from a trap. This may occur though leakage at the crest, in which case the paleopetroleum/water contact parallels the modern one. In some cases, however, the tectonic tilting of a trap after petroleum invasion generates a tilted paleopetroleum/water contact. This occurs in the Morecombe gas field in the Irish Sea. Here an upper illite-free and a lower platy-illite cemented zone are separated by a sloping surface that cross-cuts the present gas/water contact, and is interpreted as a paleogas/water contact that has since tilted. Quartz and carbonate cement are more prevalent beneath than above the present-day gas/water contact (Ebbern, 1981; Woodward and Curtis, 1987; Stuart, 1993). The Morecambe field thus has four different types of reservoirs in terms of their diagenetic history, porosity, and permeability. Try explaining that to a petroleum reservoir engineer.

The previous pages show that the porosity and permeability of a reservoir is the result of its original texture, on which may have been imprinted diverse diagenetic processes, some of which may enhance, but most of which will diminish, its reservoir quality. Fig. 6.33 is thus a very naive attempt to summarize the potential diagenetic pathways of sandstones and the resultant reservoir quality.

6.5.2 Effects of Diagenesis on Carbonate Reservoirs

The carbonate rocks include the limestones, composed largely of calcite ($CaCO_3$), and the dolomites, composed largely of the mineral of the same name ($CaMg(CO_3)_2$). As reservoirs,

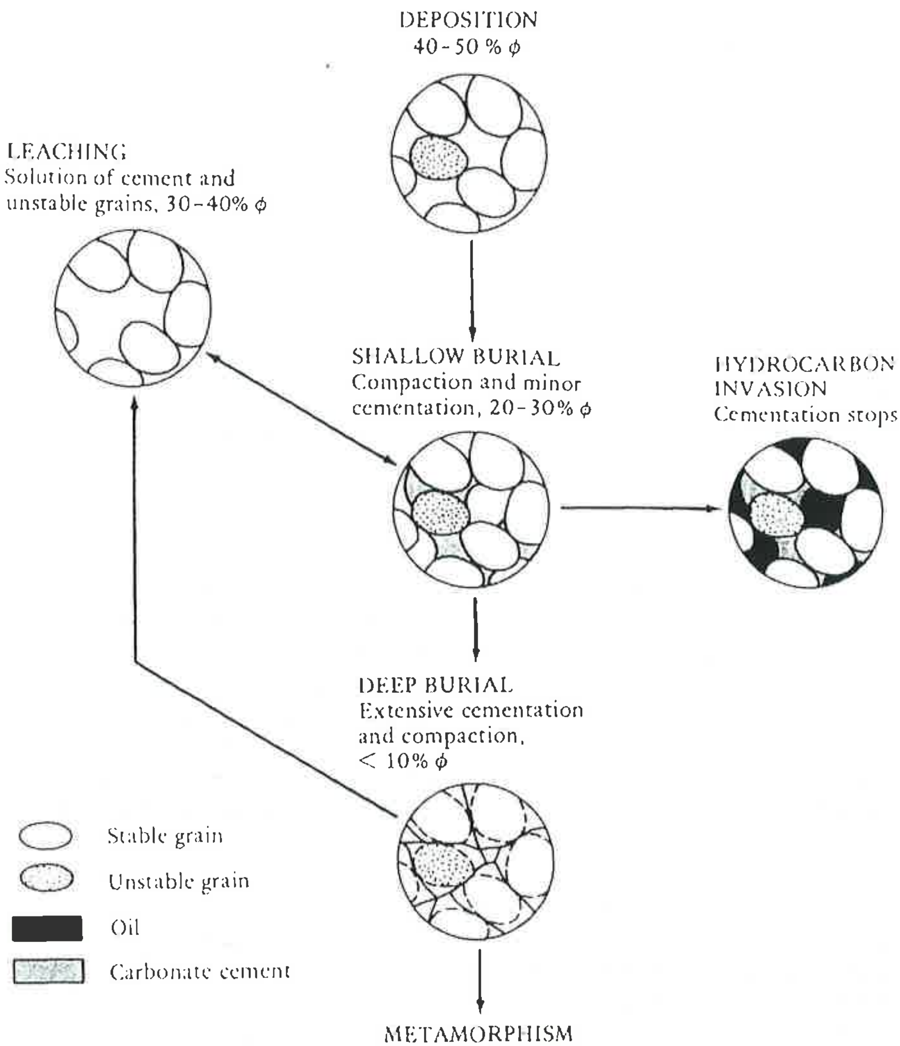


FIGURE 6.33 Simplified flowchart of the diagenetic pathways of sandstones.

carbonates are as important as sandstones, but their development and production present geologists and engineers with a different set of problems. Silica is chemically more stable than calcite. Thus the effects of diagenesis are more marked in limestones than in sandstones. With sandstone reservoirs the main problem is to establish the original sedimentary variations, working out the depositional environment and paleogeography, and using these to predict reservoir variation as the field is drilled. The effects of diagenesis are generally subordinate to primary porosity variations, which is seldom true of carbonate reservoirs.

When first deposited, carbonate sediments are highly porous and permeable and are inherently unstable in the subsurface environment. Carbonate minerals are thus dissolved and reprecipitated to form limestones whose porosity and permeability distribution are largely secondary in origin and often unrelated to the primary porosity. Thus with carbonate reservoirs, facies analysis may only aid development and production in those rare cases where the diagenetic overprint is minimal.

Having discussed the general effects of diagenesis on carbonate reservoirs, it is now appropriate to consider them in more detail. Major texts covering this topic have been published by Reeckmann and Friedman (1982), Roehl and Choquette (1985), Tucker and Wright (1990), and Jordan and Wilson (1994) and Lucia (1999). Shorter accounts that specifically relate carbonate diagenesis to porosity evolution have been given by Purser (1978) and Longman (1980). The following description is based on these references, concentrating on those aspects of diagenesis that significantly affect reservoir quality. Carbonate reefs, sands, and muds are considered separately.

6.5.2.1 Diagenesis and Petrophysics of Reefs

Reefs (used in the broadest sense of the term) are unique among the sediments because they actually form as rock rather than from the lithification of unconsolidated sediment. Modern reefs are reported with porosities of 60–80%. Because reefs are formed already lithified, they do not undergo compaction as do most sediments. Porosity may thus be preserved. However, porosity is only likely to be preserved when the reef is maintained in a static fluid environment, such as when it is rapidly buried by impermeable muds. Where a steady flow of alkaline connate water passes through the reef, porosity may gradually be lost by the formation of a mosaic sparite cement. Where acid meteoric water flows through the reef, the reef may be leached and its porosity enhanced.

Before a reef is finally buried, sea level may have fluctuated several times. Thus several diagenetic phases of both cementation and solution may have been superimposed on the primary fabric and porosity of the reef. It is not surprising, therefore, that there may be no correlation between the reservoir units that an engineer delineates in a reef trap and the facies defined by geologists. This phenomenon is illustrated by the Intisar reefs of Libya, described in Chapter 7 (Brady et al., 1980).

6.5.2.2 Diagenesis and Petrophysics of Lime Sands

Like reefs, lime sands may have high primary porosities (Enos and Sawatsky, 1979). Because they are unconsolidated, however, they begin to lose porosity quickly on burial. Mud compacts and shells fracture as the overburden pressure increases. Like reefs, lime sands may be flushed by various fluids. Acid meteoric waters may leach lime sands and increase porosity, whereas alkaline fluids may cause them to become cemented. Early cementation takes various distinctive forms, which may be recognized microscopically. These forms include fibrous, micritic, and microcrystalline cements formed in the spray zone (beach rock) and on the sea floor (hard ground). These early cements diminish porosity somewhat and may diminish permeability considerably where they bridge pore throats. Early cementation, however, may enhance reservoir potential because it lithifies the sediment, and, as with reefs, the effect of compaction is then diminished. Later diagenesis depends on the fluid environment. Acidic meteoric water may enhance porosity by leaching; alkaline connate water may cause a mosaic of sparite crystals to infill the pores. Where there is no fluid flow, porosity may he preserved and hydrocarbons may invade the reservoir.

Carbonate sands that have not undergone early shallow cementation have less chance of becoming reservoirs. As the sands are buried, they lose porosity rapidly by compaction; although again they are susceptible to secondary leaching when invaded by acid meteoric water during later epidiagenesis. Figure 6.34 summarizes the diagenetic pathways for carbonate sands.

6.5.2.3 *Diagenesis and Petrophysics of Lime Muds*

Recent carbonates are largely composed of the mineral aragonite, the orthorhombic variety of calcium carbonate. Aragonite is unstable in the subsurface, where it reverts to the hexagonal isomorph calcite. This polymorphic reaction causes an 8% increase in bulk volume, which results in a loss of porosity. Coupled with compaction, this porosity loss means that most ancient lime mudstones are hard, tight, and splintery rocks. They have no reservoir potential unless fractured or dolomitized. A significant exception to this general rule occurs when the lime mud is calcitic rather than aragonitic. The coccolithic oozes, which occur in Cretaceous and younger rocks, are of original calcitic composition. Lacking the aragonite–calcite reaction, these lime muds remain as friable chalks with porosities of 30–40%. Ordinarily, they have very low permeabilities because of their small pore diameters. Chalks are not usually considered to be reservoirs and may even act as cap rocks. In certain circumstances, however, they can act as reservoirs. For example, fractures may enhance their permeability as in the Austin Chalk (Upper Cretaceous) of Texas. In the similar Cretaceous Chalk of the North Sea, reservoirs occur in the Ekofisk and associated fields of offshore Norway. Here overpressure has inhibited porosity loss by compaction, whereas fracturing over salt domes has increased permeability (Scholle, 1977). These chalk reservoirs are thus dual porosity systems in which petroleum occurs both within microporosity between the coccoliths, and within the cross-cutting fractures.

Because of their uniformity, porosity gradients of lime muds can be constructed analogously to those drawn for sandstones (Scholle, 1981). These porosity gradients can seldom be prepared for the more heterogeneous calcarenites, although there are exceptions (see Schmoker and Halley, 1982).

6.5.2.4 *Dolomite Reservoirs*

The second main group of carbonate reservoirs includes the dolomites. Dolomite can form from calcite (dolomitization) and vice versa (dedolomitization or calcitization) as shown in the following reaction:

$$2\,CaCO_3 + Mg^{2+} = CaCO_3MgCO_3 + Ca^{2+}.$$

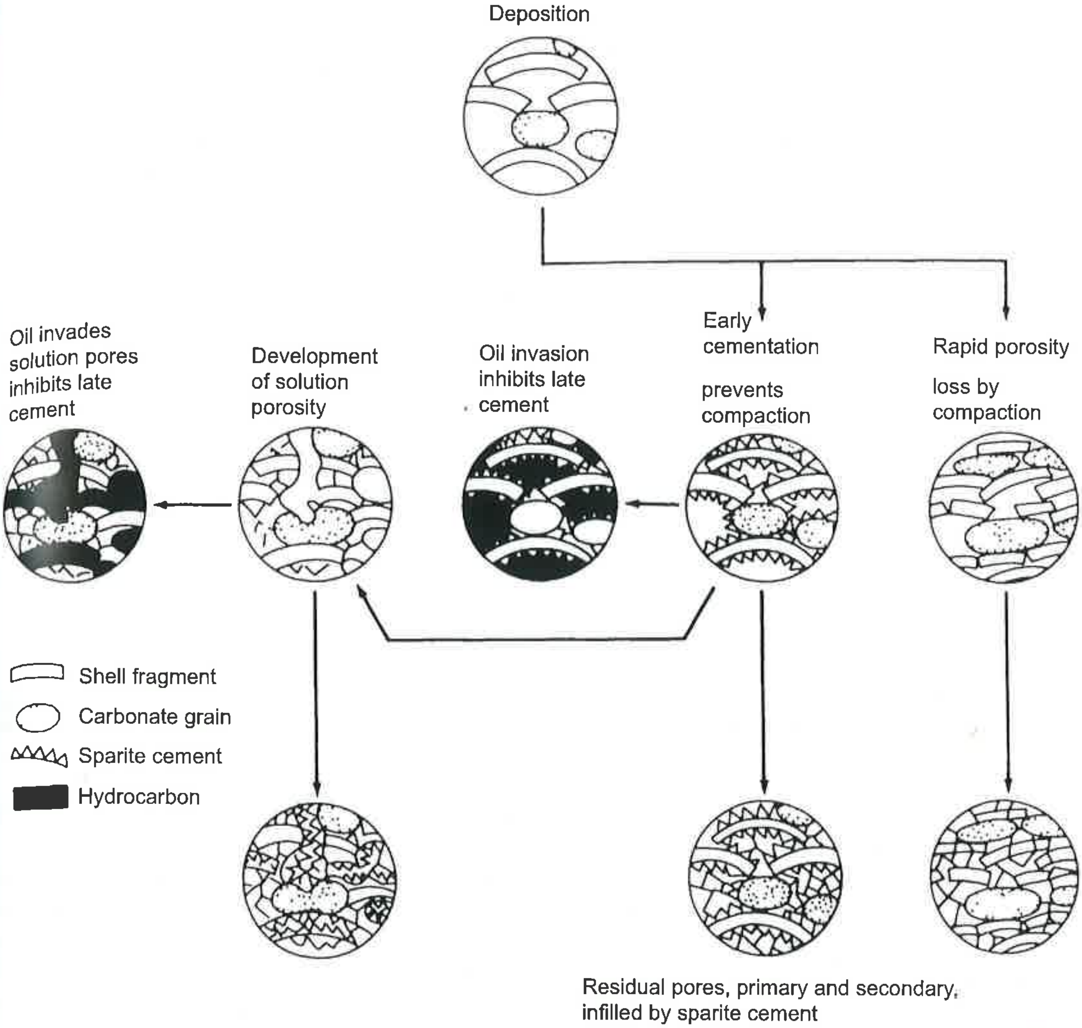


FIGURE 6.34 Simplified flowchart of the diagenetic pathways of lime sand.

The direction in which this reaction moves is a function not only of the Mg–Ca ratio but also of salinity (Fig. 6.35).

A distinction is made between primary and secondary dolomites. Primary dolomites are generally bedded and often form laterally continuous units. Characteristically, they occur in sabkha (salt marsh) carbonate sequences, passing down into fecal pellet lagoonal muds and up into supratidal evaporites. Such dolomites are generally cryptocrystalline, often with a chalky texture. They may thus be porous, but, because of their narrow pore diameter, lack permeability. Examples of primary dolomites in sabkha cycles have been described from the Jurassic Arab-Darb formation of Abu Dhabi (Wood and Wolfe, 1969). Such dolomites are

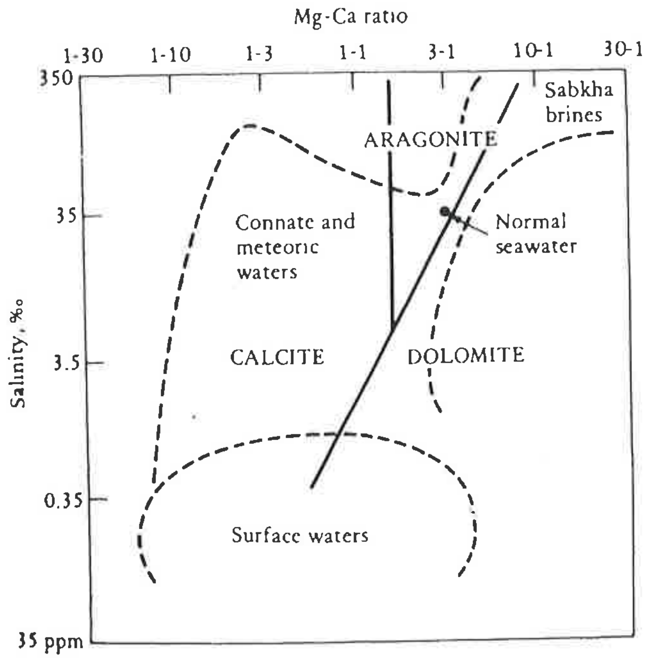


FIGURE 6.35 Graph of Mg–Ca ratio plotted against salinity showing stability fields of aragonite, calcite, and dolomite. Note how dolomitization may be caused by a drop in salinity even for low Mg–Ca ratios. *Modified from Folk and Land (1974); reprinted by permission of the American Association of Petroleum Geologists.*

believed to be primary, or at least penecontemporaneous, although the exact chemistry of their formation is still debated.

Secondary dolomites cross-cut bedding often occurring in irregular lenses or zones frequently underlying unconformities or forming envelopes around faults and fractures (Fig. 6.36). These secondary dolomites are commonly crystalline and sometimes possess a friable saccharoidal texture (Fig. 6.37). Porosity is of secondary intercrystalline type and may exceed 30%. Unlike primary dolomites, secondary dolomites are permeable. When calcite is replaced by dolomite, bulk volume is reduced by some 13%, and hence porosity increases correspondingly. Secondary dolomites beneath unconformities sometimes undergo fracturing. Sometimes this is so extensive that they collapse into breccias (Fig. 6.38).

Thus secondary dolomites are often important reservoirs, as in the Devonian reefs and carbonate platforms of Alberta (Toomey et al., 1970; Luo and Machel, 1995). Regionally extensive subunconformity dolomites occur, for example, on the Wisconsin, San Marcos, and Cincinnati arches of the United States (see Badiozamani, 1973; Rose, 1972; Tedesco, 1994; respectively). These regionally extensive arches host numerous petroleum accumulations where limestones have undergone dolomitization, solution, and fracturing for tens of meters deep beneath truncating unconformities. Petroleum reservoirs in secondary dolomite are very complex, and it may be difficult to assess their reserves and to characterize the reservoir. In the Lisburne field at Prudhoe Bay, Alaska, for example, a limestone bears the dolomitization overprint of two superimposed unconformities (Jameson, 1994).

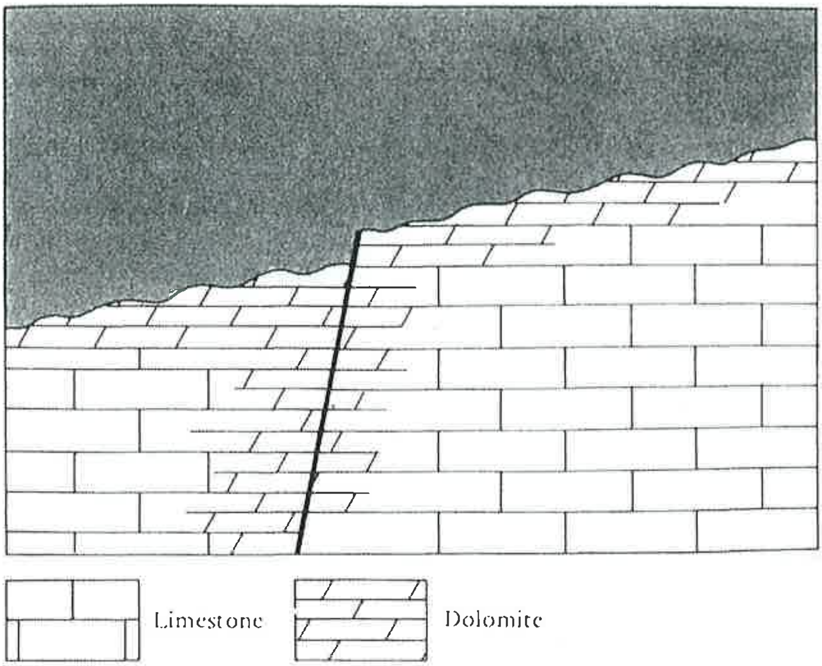


FIGURE 6.36 Cross-section showing how secondary dolomites are often related to faults and unconformities.

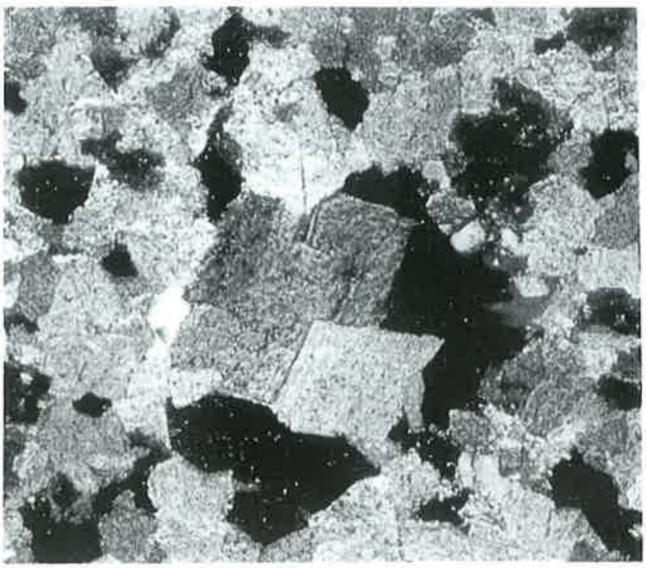


FIGURE 6.37 Thin section of a secondary dolomite reservoir, showing coarsely crystalline fabric. Zechstein (Upper Permian). North Sea, United Kingdom.

FIGURE 6.38 Collapsed breccia of Zechstein (Permian) dolomite reservoir from beneath the Cimmerian unconformity. Auk Field, North Sea, United Kingdom. *Courtesy of Shell UK.*

6.5.2.5 Carbonate Diagenesis and Petrophysics: Summary

The preceding section gave a simplified account of the complexities of carbonate diagenesis and porosity evolution. Many scholarly studies of these topics have been carried out in universities and oil companies, but even in the latter it is always germane to ask what contribution a particular study has made to the prediction of reservoir quality (Lucia and Fogg, 1990). Most carbonate diagenetic studies tend to be essentially descriptive.

Attempts to produce porosity gradients for limestones have been produced (Scholle, 1981; Schmoker and Halley, 1982). But local variations in reservoir properties are normally too rapid for these to be of much use as a means of predicting reservoir quality. As with sandstones, secondary solution porosity may be attributed to unconformity-related epidiagenesis, or to the decarboxylation of source rocks (Mazzullo and Harris, 1992). Epidiagenetic processes may enhance porosity and permeability beneath unconformities. Stress-release fractures increase permeability, enabling meteoric water to invade the rock. This results in dolomitization, in the development of solution porosity, and, in extreme cases, in the formation of paleo-karst, which may collapse to form a heterogeneous carbonate rubble. These types of carbonate reservoir are characteristic of truncation stratigraphic traps. Specific field examples are cited in Chapter 7. Sequence stratigraphy is now widely applied to carbonate sequences as a means of identifying unconformities, and thus predicting horizons of solution porosity and dolomitization (Loucks and Sarg, 1993; Saller et al., 1994).

Jardine et al. (1977) and Wilson (1975, 1980) have reviewed the relationships between carbonate reservoir quality, facies, and diagenesis. Wilson (1980) recognizes the following six major carbonate reservoir types, ranging from those whose porosity is largely facies controlled to those with extensive diagenetic overprints.

1. Shoals with primary porosity still preserved; for example, the Arab D of Saudi Arabia and the Smackover of Louisiana.
2. Buildups with primary porosity preserved; for example, some Alberta Devonian reefs and the Golden Lane atoll of Mexico.
3. Forereef talus with primary porosity preserved; for example, the Poza Rica and Reforma fields of Mexico.
4. Pinchout traps where grainstones with preserved porosity or intercrystalline dolomitic porosity are sealed up-dip by sabkha evaporites; for example, the San Andres of West Texas.

5. Subunconformity reservoirs, for which porosity is largely secondary due to solution, fracturing, and dolomitization; for example, the Natih and Fahud fields of Oman.
6. Calcitic chalks with permeability enhanced by fractures; for example, the Ekofisk and associated fields of the North Sea.

Finally, Fig. 6.9 shows the relationship between porosity, permeability, and the various types of pore found in carbonate and other reservoirs.

6.5.3 Atypical and Fractured Reservoirs

Some 90% of the world's oil and gas occur in sandstone or carbonate reservoirs. The remaining 10% occur in what may therefore be termed atypical reservoirs, which range from various types of basement to fractured shale. As discussed earlier, theoretically any rock can be a petroleum reservoir if it is both porous and permeable. Atypical reservoirs may form by two processes: weathering and fracturing.

The role of weathering in the formation of solution porosity in sandstones and carbonate has already been noted. The weathering of certain other rocks has a similar effect. Minerals weather at different rates; so polymineralic crystalline rocks can form a porous veneer as the unstable minerals weather out, leaving a granular porous residue of stable mineral grains. This situation usually occurs in granites and gneisses, where the feldspars leach out to leave an unconsolidated quartz sand. This granite wash is a well site geologist's nightmare. The transition from arkose via in situ granite wash to unweathered granite may be long and gentle.

A number of fields produce from weathered basement reservoirs. In the Panhandle–Hugoton field of Texas and Oklahoma the productive granite wash zone is some 70 m thick, although this zone ranges from red shale, via arkose, into fractured granite (Pippin, 1970). The Augila field of the Sirte basin, Libya, also produces from weathered and fractured granite. Some wells in this field flowed at more than 40,000 BOPD (barrels oil per day) (Williams, 1972). The Long Beach and other fields of California produce from fractured Franciscan (Jurassic) schists (Truex, 1972).

Fracturing can turn any brittle rock into a reservoir. Porous but impermeable rocks can be rendered permeable by fracturing as, for example, in chalk and shale. Even totally nonporous rocks may become reservoirs by fracturing. Fractures can be identified from wireline logs, from visual inspection of cores, and from production tests. Parameters of great importance include fracture intensity, which controls porosity and permeability, and fracture orientation, which affects the isotropy of the reservoir (Pirson, 1978; pp. 180–206). Fracture intensity may be expressed by the fracture intensity index (FII):

$$\mathrm{FII} = \frac{(\phi_t - \phi_m)}{(1 - \phi_m)},$$

where ϕ_t = total porosity and ϕ_m = porosity not due to fractures. More recently Narr (1996) has shown how the probability of a borehole intersecting a fracture may be expressed as

$$P_t = \frac{D}{S_{av}},$$

where P_t = probability of a fracture being intercepted, D = diameter of the borehole, and S_{av} = average fracture spacing.

Because fractures are commonly vertical, fractured reservoirs are particularly amenable to production by means of deviated horizontal wells. This approach has been notably successful in the Austin Chalk of Texas where seismic is used to locate faults and adjacent acoustically slow fractured zones, both of which may be penetrated by horizontal wells.

Fractured reservoirs present particular problems of production, the main danger being that oil in the fractures may be rapidly produced and replaced by water, thus preventing recovery from the rest of the pores (Aguilera and Van Poollen, 1978). Examples of reservoirs that produce almost entirely from fractures include the Miocene Monterey cherts of California, which produce oil in the Santa Maria and other fields. Recovery rates are low, of the order of 15,400 barrels per acre (Biederman, 1986).

Shales, which are generally only cap rocks, may themselves act as reservoirs when fractured. Some shale source rocks produce free oil from fractures with no associated water. An example of this phenomenon is provided by the Cretaceous Pierre shale of the Florence field, Colorado (McCoy et al., 1951). Production is erratic, although one well in this field is reported to have produced 1.5 million barrels of oil. Gas production from fractured shale is more common, with many fields producing from Paleozoic shales in Kentucky, Kansas, and elsewhere in the eastern United States. A more detailed account of shale gas is given in Chapter 9. Further details on anomalous and fractured reservoirs can be found in Nelson (1987). Because of advancements in technology (e.g., horizontal drilling and multistage fracture stimulation) and excellent production results, shales are now seen as major reservoirs for oil and gas (a significant change from when the second edition of this book was written in 1998).

6.6 RESERVOIR CONTINUITY

Once an oil or gas field has been discovered, its reserves and the optimum method for recovering them must be established. A detailed knowledge of reservoir continuity is a prerequisite for solving both these problems. Few traps contain reservoirs that are uniform in thickness, porosity, and permeability; most are heterogeneous to varying degrees. Fluid flow in a reservoir is controlled by the amount and type of reservoir heterogeneity (Weber, 1992). Bed continuity, the presence of baffles to flow, and permeability distribution all influence fluid flow. Common reservoir heterogeneity types include faults (sealing and nonsealing), boundaries of genetic units, permeability zonation within genetic units, baffles within genetic units, laminations and cross-bedding, microscopic heterogeneity, and fracturing (open and closed). Thus a reservoir is commonly divided into the gross pay and the net pay intervals. The gross pay is the total vertical interval from the top of the reservoir down to the petroleum:water contact. The net pay is the cumulative vertical thickness from which petroleum may actually be produced. In many fields the net pay may be considerably less than the gross pay. The difference between gross and net pay is due to two factors: the primary porosity with which the reservoir was deposited and the diagenetic processes that have destroyed this original porosity by cementation or enhanced it by solution. There are, however, three main processes that control reservoir continuity: depositional barriers, diagenetic barriers, and tectonic barriers (Haldersen et al., 1987).

6.6.1 Depositional Barriers

Schemes to classify and quantify the lateral continuity of sands have been produced by Potter (1962), Polasek and Hutchinson (1967), Pryor and Fulton (1976), and Harris and Hewitt (1977). Figure 6.39 is based on the scheme proposed by Potter (1962). Two major groups of sand may be recognized according to their lateral continuity: sheets and elongate bodies. Sheets are more or less continuous with length:width ratios of 1:1.

Sheet sands occur in many environments, ranging from turbidite fans and crevasse-splays to coalesced channel sands in braided alluvial plains. Sheets may be discontinuous because of nondeposition or later erosion, with the sands being locally replaced by shales. Discontinuous sheets grade into belt sands, which, although still extensive, contain many local elon gate vacuoles.

Of the elongate sands with length:width ratios greater than 3:1, the best known are ribbons, or shoestrings (Rich, 1923), which are generally deposited in barrier bar environments. Dendroids are bifurcating shoestrings and include both fluvial tributary channel sands and deltaic and submarine fan distributary channels. Pods are isolated sands with length:width ratios of less than 3:1. They include some tidal current sands and some eolian dunes.

Considered vertically, sands may be differentiated into isolated and stacked reservoirs (Harris and Hewitt, 1977). Stacked sands are those that are in continuity with one another either laterally or vertically. The latter are often referred to as multistorey sands (Fig. 6.40). Pryor and Fulton (1976) have produced a more rigorous analysis of sand body continuity

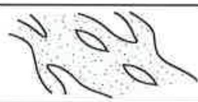
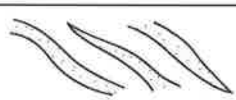
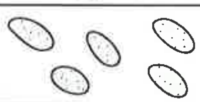
	Name	Length-width ratio	
	Sheet	≏ 1.1	
Elongate	Belt	Sheet with holes	
	Dendroid	> 3–1 bifurcating	
	Ribbon, or shoestring	> 3–1	
	Pod	< 3–1	

FIGURE 6.39 Nomenclature of sand body geometry. *After Potter (1962).*

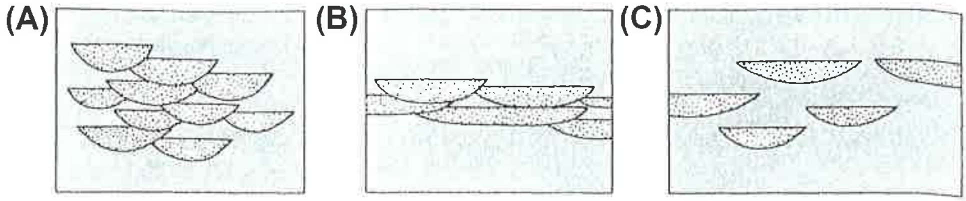


FIGURE 6.40 Descriptive terms for vertical sand body continuity: (A) vertically stacked (multistorey), (B) laterally stacked, and (C) isolated. *After Harris and Hewitt (1977).*

with a lateral continuity index (LCI) and a vertical continuity index (VCI). The LCI is calculated by constructing a series of cross-sections, measuring maximum and minimum sand body continuities, and dividing that length by the length of the section. The VCI is calculated by measuring maximum sand thickness for each well and dividing it into the thickness of the thickest sand. Pryor and Fulton (1976) applied these indices to detailed core data on the Holocene sands of the Rio Grande. Table 6.2 summarizes their data.

Weber (1982), however, approached the problem from the opposite direction, compiling data on the continuity of shale beds for different environments. Many fields have reservoirs with alternating productive sand and nonproductive shale. In these cases detailed correlation is essential both to select the location of wells during development drilling and to predict how fluids will move as the field is produced. These fluids include not only naturally occurring oil and gas but any water or gas that may be injected to maintain pressure and enhance production (Fig. 6.41). The Handil field of Indonesia illustrates just how heterogeneous a reservoir can be (Verdier et al., 1980). It is essentially an anticlinal trap with some faulting. The gross pay is some 1600 m thick; however, it is split up into many separate accumulations with their own gas caps and oil:water contacts. Separate accumulations are partly due to faults, but also occur because the formation has a sand:shale ratio of 1:1, with individual units being 5–20 m thick. Subsurface facies analysis using cores and logs (as discussed in Chapter 3) shows that the productive sands include discontinuous sheets and pods of marine sands interbedded with, and locally cut into by, channel shoestrings (Fig. 6.42). This arrangement is not an isolated case; many other shallow marine reservoirs exhibit a similar complexity, notably those of the Niger delta (Weber, 1971).

TABLE 6.2 Maximum Lateral Continuity Indices (LCI) and Vertical Continuity Indices (VCI) for Holocene Sand Bodies of the Rio Grande Delta

	Average LCI			
Environment	**Perpendicular**	**Parallel**	**Average VCI**	**Average sand thickness (m)**
Fluvial	0.49	0.83	0.75	5–7
Fluviomarine	1.0	1.0	0.84	7–8
Pro-delta	0.3	0.17	0.56	1.5

From Pryor and Fulton (1976). Reprinted with permission.

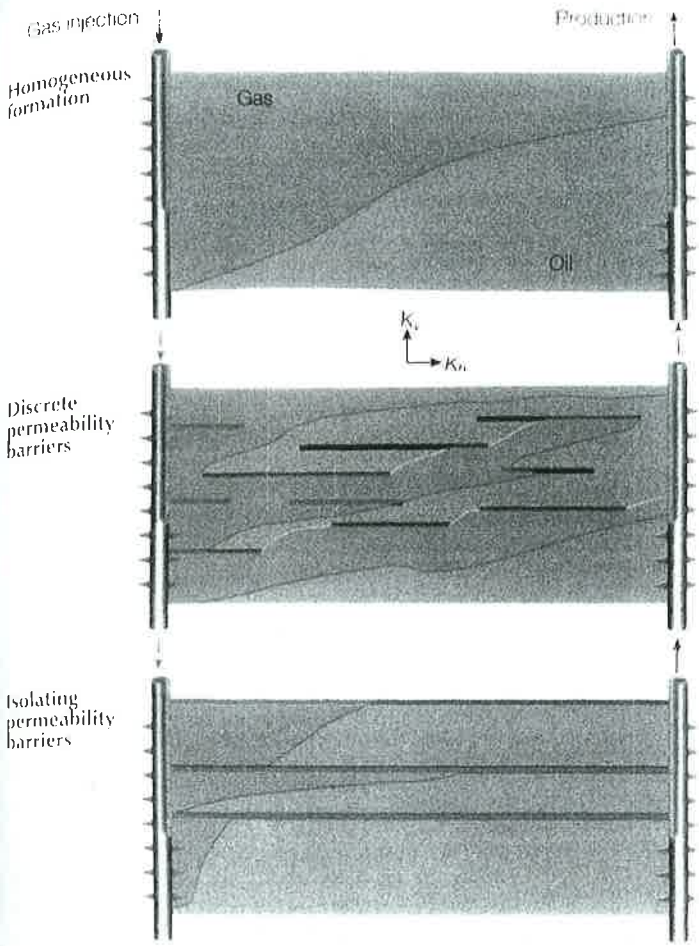


FIGURE 6.41 Illustrations showing the effects of shale continuity on reservoir performance. In homogenous reservoir (upper) the sweep efficiency is low. When the reservoir has discrete zones separated by permeability barriers the efficiency is improved (middle). Isolating permeability barriers leads to the most efficient sweep. *From Ayan et al. (1994); courtesy Schlumberger Oilfield Review.*

Though geologists always like to attempt to use their art to aid reservoir engineers, there comes a time when their services are dispensed with and statistical methods are used. These range from stochastic modeling to fractal analysis (see Martin, 1993; Stolum, 1991; respectively).

6.6.2 Diagenetic Barriers

Diagenetic barriers within reservoirs were extensively discussed earlier in the chapter and need little further elaboration. These are due to the effects of cementation, and may occur in both carbonate and terrigenous reservoirs. They may be related to diagenetic fronts and to petroleum:water contacts.

One particular type of diagenetic barrier that has attracted cause for concern is the occurrence of discontinuous horizons of carbonate cements that sometimes break up into isolated

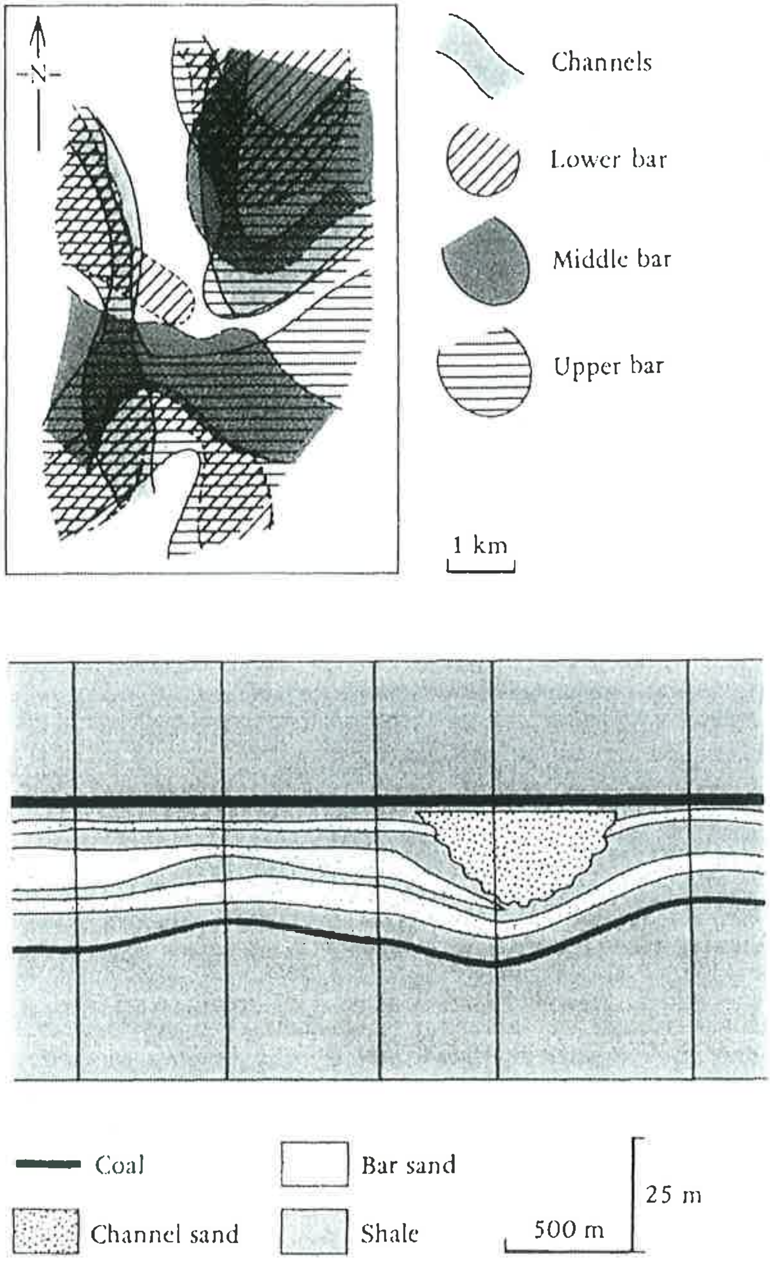


FIGURE 6.42 Map and cross-section of part of the Handil field, Indonesia, indicating the degree of vertical and lateral continuity of reservoirs found in shallow fluviomarine sands. *Modified from Verdier et al. (1980); reprinted by permission of the American Association of Petroleum Geologists.*

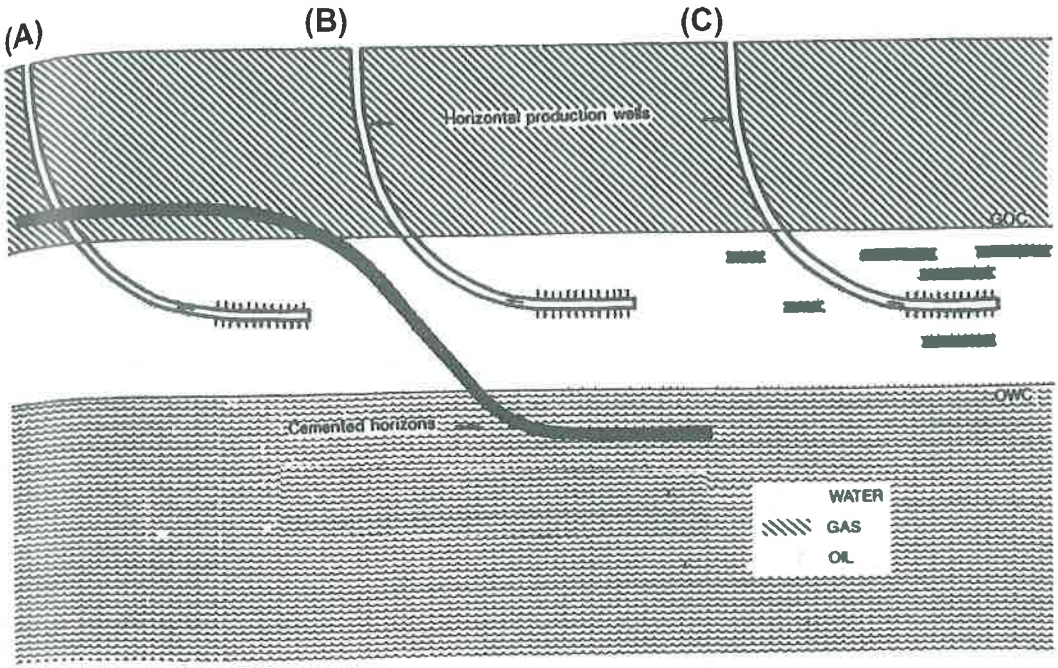


FIGURE 6.43 Illustration showing how horizontal wells may be used to overcome the problems of continuous discordant (left) and discontinuous concordant (right) carbonate cemented horizons within a reservoir. *From Gibbons et al. (1993).*

concretions colloquially referred to as "doggers." These are particularly common in the Jurassic sandstones of northwest Europe, where they are sufficiently abundant to give the eponymous name Dogger to the Middle Jurassic. Within the Jurassic reservoirs of the North Sea great attention has been paid to their significance as permeability barriers (Hurst, 1987; Gibbons et al., 1993). Once they have been identified it may be possible to drill wells to produce petroleum at maximum efficiency (Fig. 6.43).

6.6.3 Structural Barriers

Faults are a common structural barrier within petroleum reservoirs. Faults are sometimes permeable and allow fluid movement; sometimes they are sealed and inhibit it. Open faults are beneficial if they allow petroleum to migrate from a source rock into a reservoir, and are beneficial if they are impermeable and prevent the escape of petroleum from a trap. Within a trap, however impermeable faults inhibit effective petroleum production. Much research has been done on the imaging of faults, and on trying to establish whether they are open or closed. Figure 6.44 shows how faults with a throw of less than 12 m may be below the present limits of seismic resolution. For subseismic scale faults their frequency can be modeled using various statistical methods, including fractal analysis (Childs et al., 1990; Heath et al., 1994; Walsh et al., 1994).

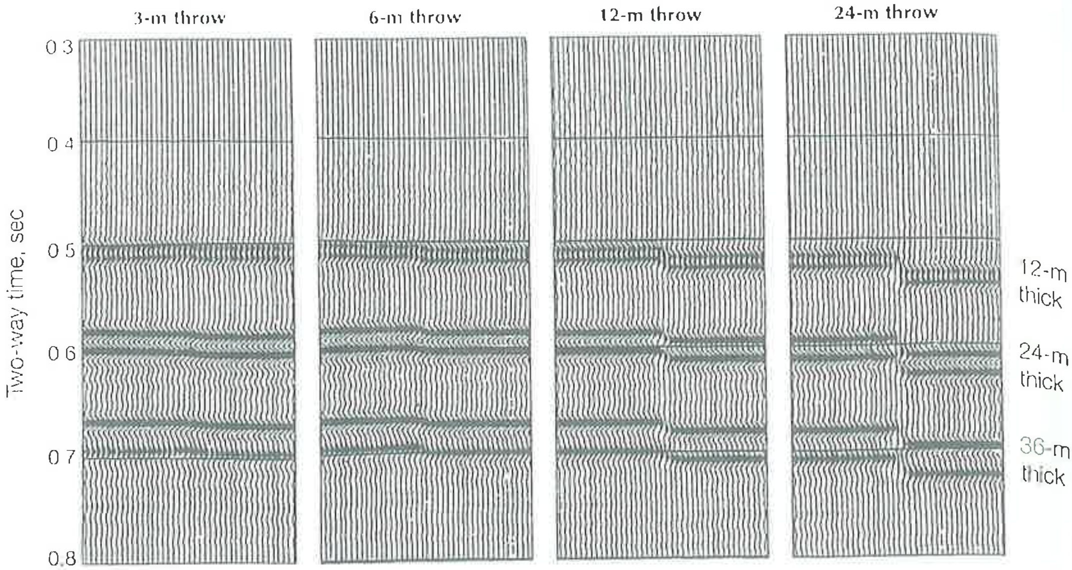


FIGURE 6.44 Modeled responses for a 48-m seismic wave imaging faults of diverse throws crosscutting beds of diverse thickness. Note that a fault of less than 12 m cannot be imaged by a seismic signal $\lambda/4$ bed thickness. *From Aston et al. (1994); courtesy of Schlumberger Oilfield Review.*

The determination of whether a fault is open or closed depends on many variables, including the physical properties of the rocks, the fluid pressures, and the juxtaposition of permeable sands and impermeable shales. Cunning computer programs are available, such as Badley's FAPS (Fault Analysis Software), that attempt to predict the frequency and permeability of small-scale faulting. This is discussed later in Chapter 7, in the context of fault traps.

6.7 RESERVOIR CHARACTERIZATION

Once an accumulation of petroleum has been discovered it is essential to characterize the reservoir as accurately as possible in order to calculate the reserves and to determine the most effective way of recovering as much of the petroleum as economically as possible (Lucia and Fogg, 1990; Lake et al., 1991; Worthington, 1991; Haldersen and Damsleth, 1993). The principal goal of reservoir characterization is to obtain higher recoveries with fewer wells in better positions at minimum cost through optimization (Slatt, 2006). Reservoir characterization first involves the integration of a vast amount of data from seismic surveys, from geophysical well logs, and from geological samples (Fig. 6.45). Note that the data come in a hierarchy of scales, from the megascopic and mesoscopic to the microscopic. It is important to appreciate both the scale and the reliability of the different data sets. For example, the problems of reconciling porosity and permeability data from logs and rock samples has already been mentioned.

The first aim of reservoir characterization is to produce a geological model that honors the available data and can be used to predict the distribution of porosity, permeability, and fluids

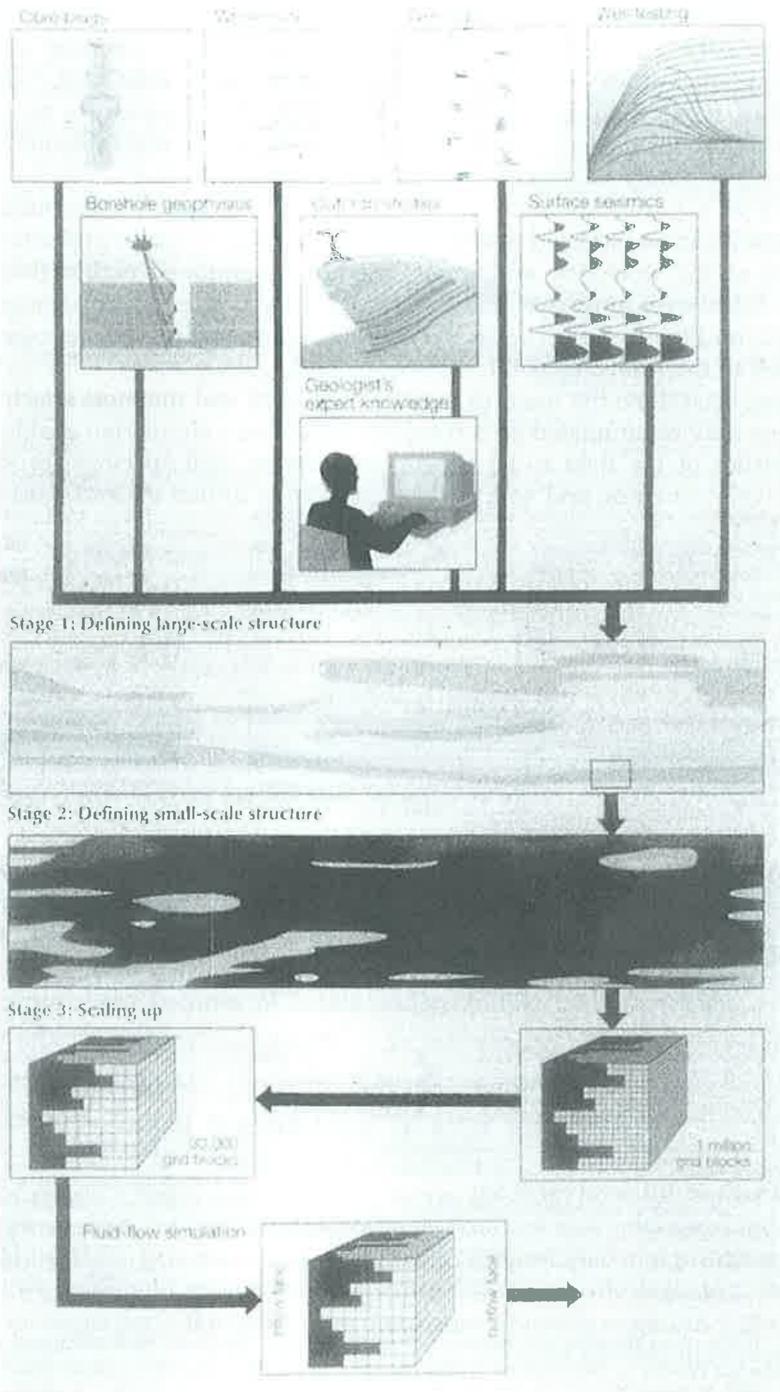


FIGURE 6.45 Diagram showing the stages involved in reservoir characterization. Note how it requires the integration of geophysical, geological, and reservoir engineering data, and involves consideration of data reliability on a range of scales: macroscopic, mesoscopic, and microscopic. *From Corvey and Cobley (1992); courtesy of Schlumberger Oilfield Review.*

throughout the field (Geehan and Pearce, 1994). Reservoirs possess a wide range of degrees of geometric complexity (Fig. 6.46). The rare, but ideal, "layer-cake" reservoir is the easiest to model and to predict from, but reservoirs range from "layer-cake" via "jigsaw puzzle" to "labyrinthine" types. Geologists apply their knowledge to produce a predictive model for the layer-cake model with ease, and the jigsaw variety with some difficulty. But the labyrinthine reservoir can only be effectively modeled statistically.

The location of a particular reservoir on the layer-cake–jigsaw–labyrinthine spectrum decides whether it can be modeled deterministically using geology, or probabilistically using statistics, such as the stochastic and fractal methods mentioned earlier (Weber and van Guens, 1990). Whichever approach is used, the objective is to produce a three-dimensional grid of the field, and to place a value for the porosity, permeability, and petroleum saturation within each cell of the grid (Fig. 6.47).

Once this has been done the reserves may be calculated and the most effective method of producing them may be simulated on a computer. Computer simulation enables the production characteristics of the field to be tested for different well spacings, production rates, enhanced recovery schemes, and so forth. As the field is drilled up and goes on stream an

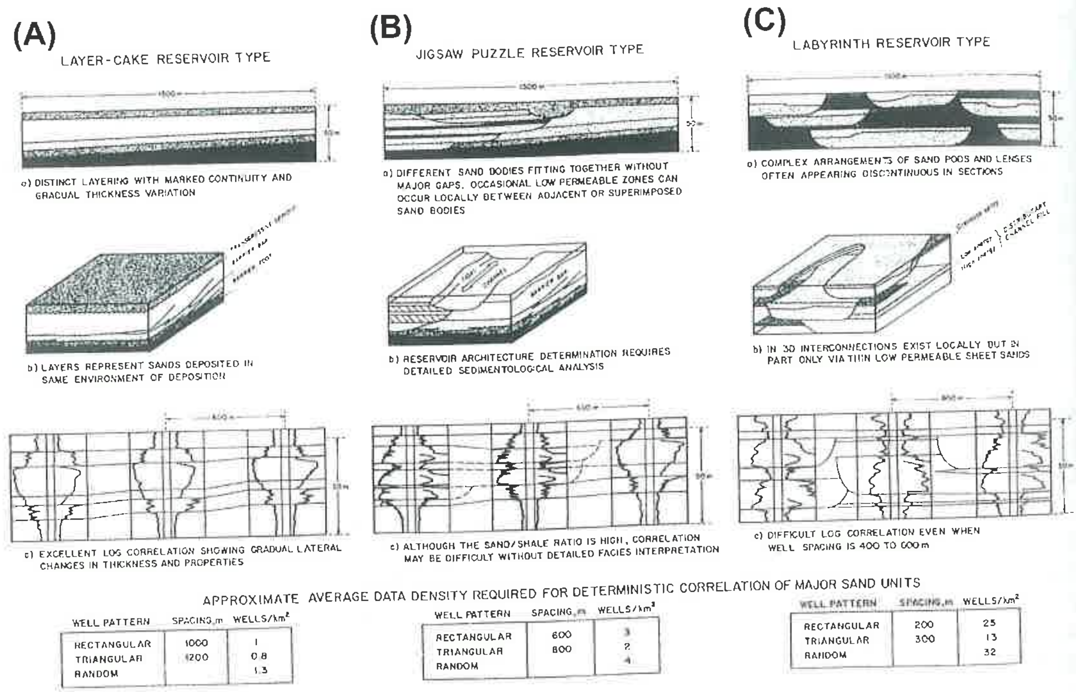


FIGURE 6.46 Illustrations showing the spectrum of reservoir types that may be encountered ranging from the simplest layer-cake via jigsaw, to labyrinthine types. The simpler varieties can be modeled deterministically using geology, but the more complex types can only be modeled probabilistically using statistics. *From Weber and van Guens (1990).*

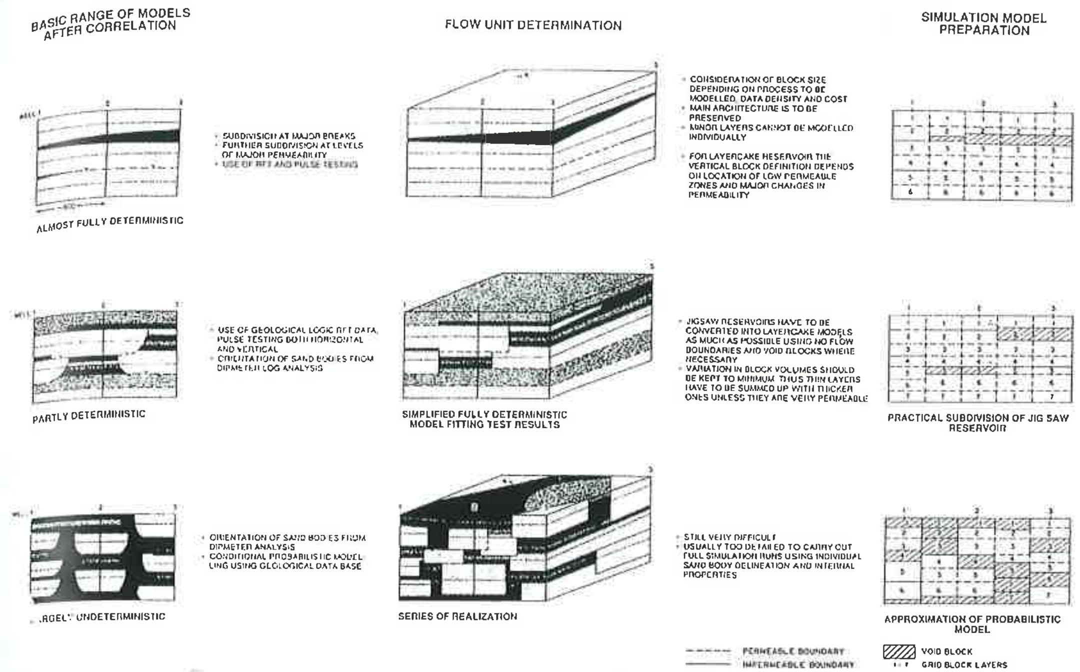


FIGURE 6.47 Illustration showing how reservoirs may be gridded into a series of cells for which a value for the porosity, permeability, and petroleum saturation must be given. Then it is possible to produce an accurate assessment of the reserves and a data for computer simulation to establish the most effective way of producing the petroleum from the reservoir. *From Weber and van Guens (1990).*

iterative process constantly updates and revises the reservoir grid, and enables progressively more accurate production scenarios to be tested.

Reservoir characterization leads to an incremental improvement in production. The improvements come about because of better understanding of the geologic complexities of fields.

6.8 RESERVE CALCULATIONS

Estimates of possible reserves in a new oil or gas held can be made before a trap is even drilled. The figures used are only approximations, but they may give some indication of the economic viability of the prospect. As a proven field is developed and produced, its reserves are known with greater and greater accuracy until they are finally depleted. The calculation of reserves is more properly the task of the petroleum reservoir engineer, but since this task is based on geological data, it deserves consideration here. Several methods are used to estimate reserves, ranging from crude approximations made before a trap is tested to more sophisticated calculations as hard data become available.

6.8.1 Preliminary Volumetric Reserve Calculations

A rough estimate of reserves prior to drilling a trap can be calculated as follows:

$$\text{Recoverable oil reserves (bbl)} = V_b \cdot F,$$

where V_b = bulk volume and F = recoverable oil (bbl/acre-ft). This formula assumes that the trap is full to the spill point. The bulk volume is calculated from the area and closure estimated from seismic data. A planimeter is used to measure the area of the various contours (Fig. 6.48). The volume is then calculated as follows:

$$V = h\left(\frac{a_o}{2} + a_1 + a_2 + a_3 + \ldots + a_{n-1} + \frac{a_n}{2}\right)$$

where

V = volume;
h = contour interval;
a_o = area enclosed by the oil/water contact;
a_1 = area enclosed by the first contour;
a_n = area enclosed by the nth contour.

Obviously, the closer the measured contour intervals, the more accurate the end result. The recoverable oil per acre-foot is the most difficult figure to assess unless local information is available from adjacent fields. It may be calculated according to an estimate of the average porosity of the reservoir (say, 10–30%) and an estimate of the recovery factor (generally 30% or more for sands, and 10–20% for carbonate reservoirs). The recovery factor will vary according to well spacing, reservoir permeability, fluid viscosity, and the effectiveness of the drive mechanism. Generally, several 100 bbl/acre-ft of oil may be recovered.

This method of calculating reserves is very approximate, but may be the only one available before bidding for acreage. It may also be useful for ranking the order in which to drill a number of prospects.

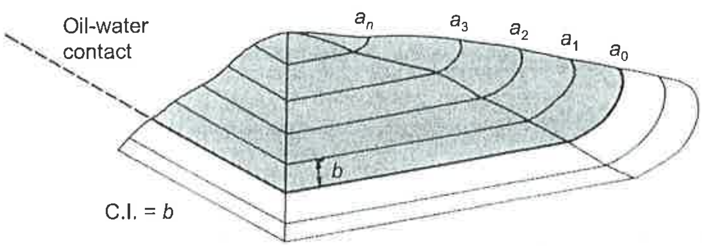


FIGURE 6.48 Isometric sketch of a trap showing how a planimeter survey measures the areas above selected contours. For additional explanation see text.

6.8.2 Postdiscovery Reserve Calculations

Once a field has been discovered, accurate reservoir data become available and a more sophisticated formula may be applied:

$$\text{Recoverable oil (bbl)} = \frac{7758\ V\phi(1 - S_w)R}{\text{FVF}},$$

where

V = the volume (area × thickness);
7758 = conversion factor from acre-feet to barrels;
ϕ = porosity (average);
S_w = water saturation (average);
R = recovery factor (estimated); and
FVF = formation volume factor.

These variables are now discussed in more detail. As wells are drilled on the field, the seismic interpretation becomes refined so that an accurate structure contour map can be drawn. Log and test data establish the oil:water contact and hence the thickness of the hydrocarbon column (Dahlberg, 1979).

The porosity is calculated from wireline logs calibrated from core data, and the water saturation is calculated from the resistivity logs. The recovery factor is hard to estimate even if the performances of similar reservoirs in adjacent fields are available. Approximate values have been given previously.

The FVF converts a stock tank barrel of oil to its volume at reservoir temperatures and pressures. It depends on oil composition, but this dependence can generally be approximated by calculating the FVF's dependence on the solution gas:oil ratio (GOR) and oil density (API gravity). The FVF ranges from 1.08 for low GORs and heavy crudes to values of more than 2.0 for volatile oils and high GORs. The GOR is defined as the volume ratio of gas and liquid phase obtained by taking petroleum from one equilibrium pressure and temperature, in the reservoir, to another, at the surface, via a precisely defined path. For a restrictive set of subsurface conditions it may be calculated from the following equation:

$$\text{Gas:oil ratio (in the reservoir)} = \frac{Q_g}{Q_o} = \frac{\mu_o K_g}{\mu_g K_o}$$

where

Q = flow rate at reservoir temperatures and pressures;
μ = viscosity at reservoir temperatures and pressures;
K = effective permeability;
g = gas; and
o = oil.

Figure 6.49 shows the relationship between FVF and GOR. A more accurate measurement of FVF can be made in the laboratory. Ideally, a sample of the reservoir fluid is collected in a pressure bomb and reheated to the reservoir temperature. Temperature and pressure are

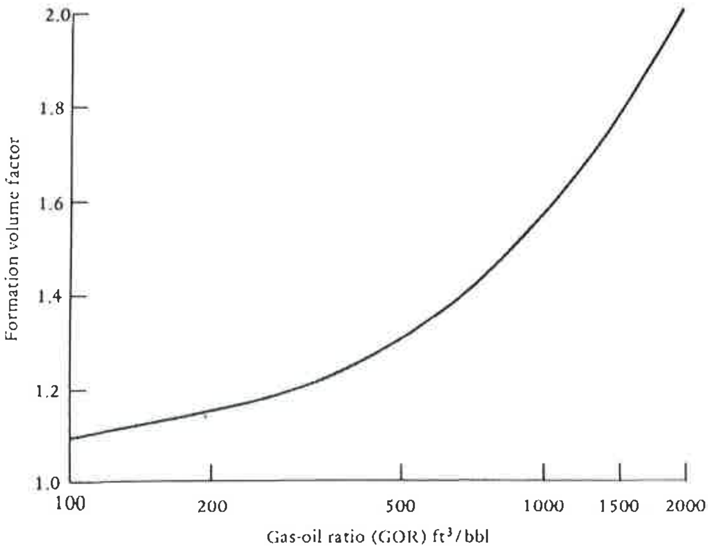


FIGURE 6.49 Graph showing the relationship between FVF and the gas:oil ratio (GOR).

reduced to surface temperature and pressure so that the respective volumes of gas and oil can be measured accurately. This procedure is referred to as pressure–volume–temperature analysis.

As a field is produced, several changes take place in the reservoir. Pressure drops and the flow rate diminishes. The GOR may also vary, although this depends on the type of drive mechanism, as discussed in the next section. These changes are sketched in Fig. 6.50. The changes may be formulated in the material balance equation, which, as its name suggests, equates the volumes of oil and gas in the reservoir at virgin pressure with those produced and remaining in the reservoir at various stages in its productive life. At its simplest level, the material balance equation is a variant of the law of conservation of mass:

Weight of hydrocarbons originally in reservoir =
Weight of produced hydrocarbons +
Weight of hydrocarbons retained in reservoirs.

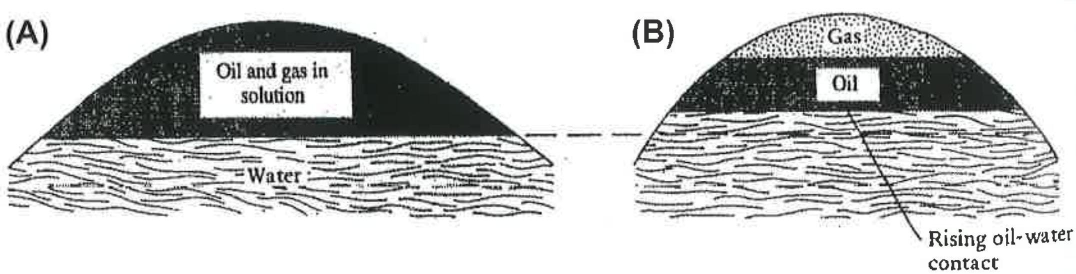


FIGURE 6.50 The changes within a reservoir that may be caused by production: (A) the situation at virgin pressure before production and (B) the situation with depleted pressure after commencement of production.

If all the weights are expressed as stock tank barrels of oil and stock tank cubic feet of gas, then weight can be substituted by volume.

The mass balance equation has several complex variations. Although its solution is a job for the petroleum reservoir engineer, much of the data on which it is based are provided by geologists.

6.9 PRODUCTION METHODS

As mentioned in the review of the mass balance equation in the previous section, hydrocarbons may be produced by several mechanisms. Three natural drive mechanisms can cause oil or gas to flow up the well bore: water drive, gas drive, and gas solution (or dissolved gas) drive.

6.9.1 Water Drive

In water drive production, oil or gas trapped within a reservoir may be viewed as being sealed within a water-filled U-tube (Fig. 6.51). When the tap is opened, oil and gas will flow from the reservoir because of the hydrostatic head of water (Fig. 6.52). Not all aquifers have a continuous recharge of the earth's surface. The degree of water encroachment and pressure maintenance depends on the size and productivity of the aquifer. Note that as the field is produced, water invades the lower part of the trap to displace the oil (Fig. 6.53); only in the most uniform reservoirs does the oil:water contact rise evenly. Because adjacent beds seldom have the same permeability, water encroachment advances at different rates, giving rise to fingering. A further complication may be caused by coning of the water adjacent to boreholes. The extent of coning depends on the rate of production and the ratio between vertical and horizontal permeability.

When a field with a water drive mechanism is produced, the reservoir pressure drops in inverse proportion to the effectiveness of the recharge from the aquifer. Generally, little change occurs in the GOR. With an effective water drive, the flow rate remains constant

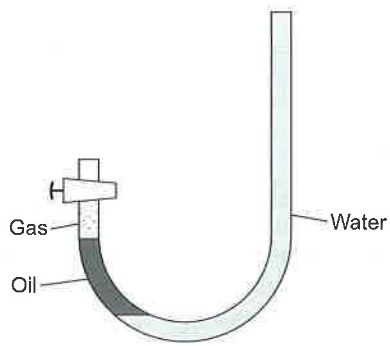


FIGURE 6.51 Sketch showing the principle of water drive petroleum production by analogy with a water-filled U-tube. When the valve is opened (i.e., the trap drilled into), the hydrostatic head of water causes the oil and gas flow.

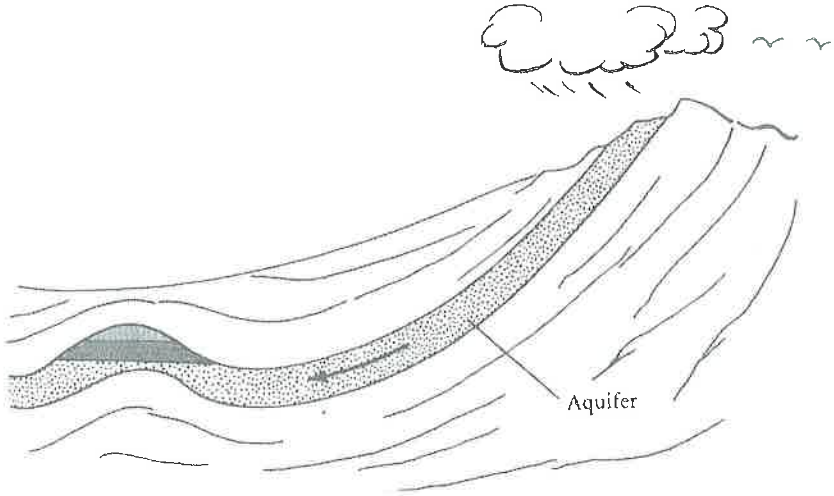


FIGURE 6.52 A typical geological setting for a water drive mechanism. As the field is produced, petroleum is displaced by water from the aquifer.

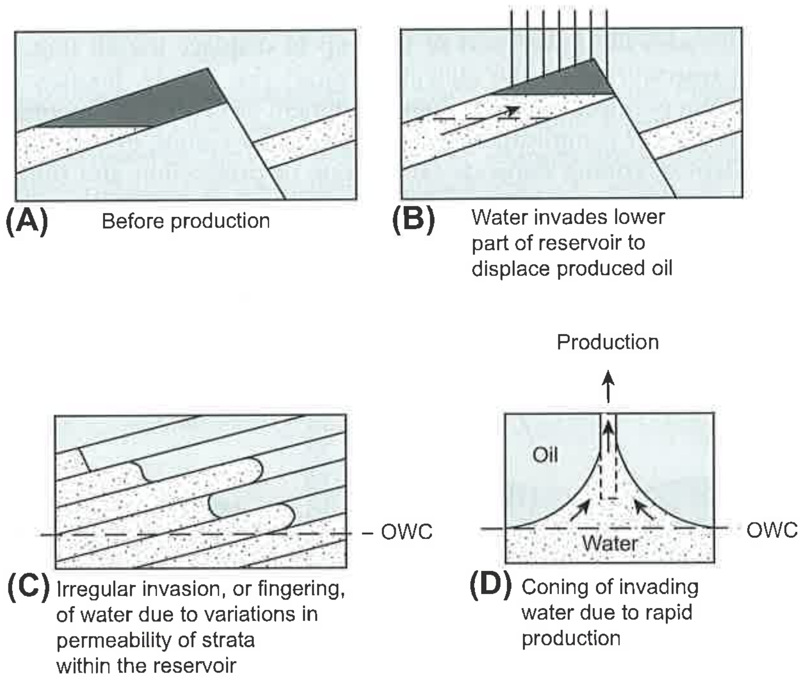


FIGURE 6.53 Water drive mechanism (A) before production and (B) during production. (C) and (D) illustrate potential irregularities in the rising oil/water contact.

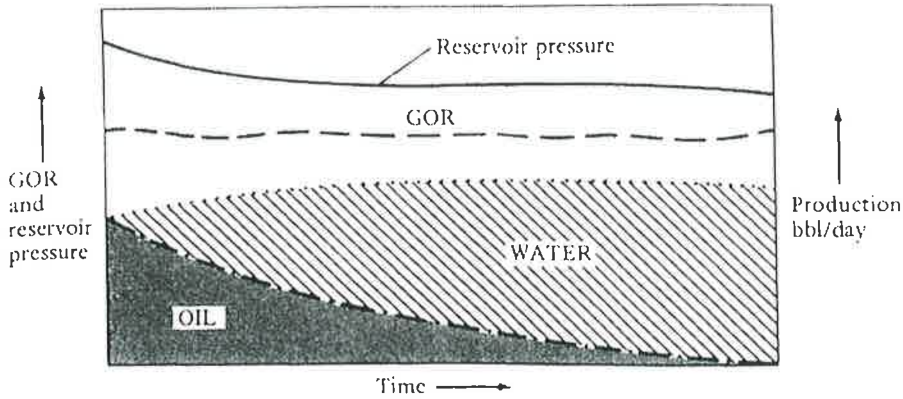


FIGURE 6.54 Typical production history for a water drive field. For explanation see text.

during the life of the fluid, but oil production declines inversely with an increase in water production. These trends are illustrated in Fig. 6.54. The water drive mechanism is generally the most effective, with a recovery factor of up to 60%.

6.9.2 Gas Cap Drive

A second producing mechanism is the gas cap drive, in which the field contains both oil and gas zones. As production begins, the drop in pressure causes gas dissolved in the oil to come out of the solution. This new gas moves up to the gas cap and, in so doing, expands to occupy the pores vacated by the oil. A transitional zone of degassing thus forms at the gas:oil contact. Drawdown zones may develop adjacent to boreholes in a manner analogous to, but the reverse of, coning at the oil/water contact (Fig. 6.55).

The production history of gas cap drive fields is very different from that of water drive fields. Pressure and oil production drop steadily, while the ratio of gas to oil naturally increases (Fig. 6.56). The gas cap drive mechanism is generally less effective than the water drive mechanism, with a recovery factor of 20–50%.

6.9.3 Dissolved Gas Drive

The third type of production mechanism is the dissolved gas drive, sometimes called the solution gas drive. This type of drive occurs in oil fields that initially have no gas cap. Production is analogous to a soda fountain. As production begins, pressure drops and gas bubbles form in the oil and expand, forcing the oil out of the pore system and toward the boreholes. As the gas expands, it helps to maintain reservoir pressure. Initially, the gas bubbles are separated. As time passes, they come together and may form a continuous free-gas phase, which may accumulate as a gas cap in the crest of the reservoir. This point is termed the critical gas saturation, and care should be taken to prevent it from being reached. It may be avoided either by maintaining a slow rate of production or by reinjecting the produced gas to maintain the original reservoir pressure.

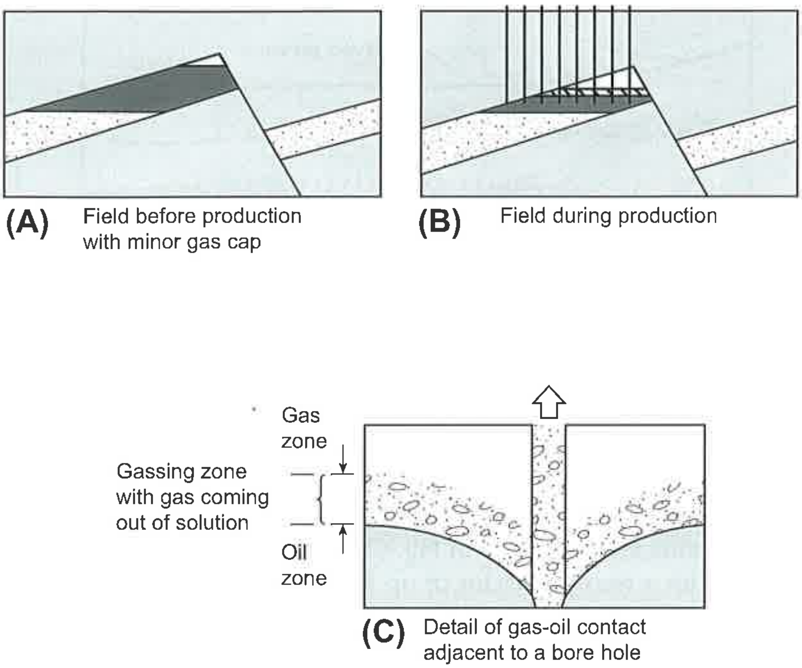


FIGURE 6.55 The gas expansion drive mechanism. A transitional zone develops at the gas/oil contact as pressure drops and the gas separates from the oil. Note the drawdown effect, which may develop adjacent to boreholes (C).

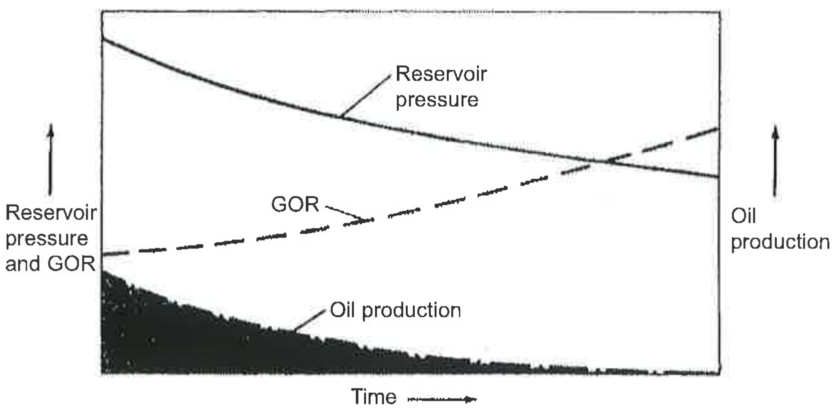


FIGURE 6.56 The typical production history of a field with a gas drive mechanism. For explanation see text.

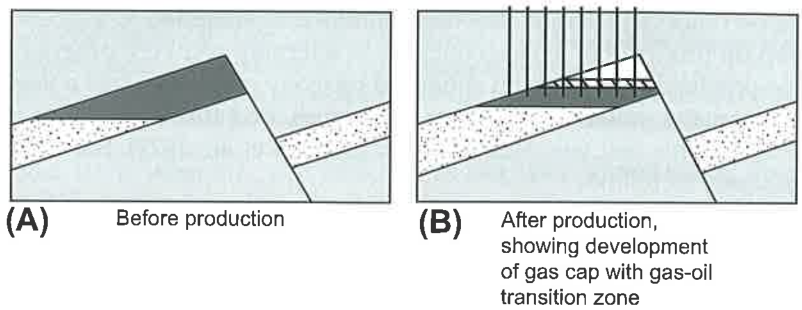


FIGURE 6.57 A field with a gas expansion drive mechanism. If the pressure drops sufficiently to cross the critical gas saturation point, then a free-gas cap may form (B).

Figure 6.57 illustrates what happens in a reservoir with a gas expansion drive, and Fig. 6.58 shows the typical production history. This drive mechanism is generally considered to be the least efficient of the three, with a recovery factor in the range of 7–15%.

6.9.4 Artificial Lift and Enhanced Recovery

Not all fields produce by natural drive mechanisms, and even these natural drive mechanisms do not recover all the oil. Artificial methods are used to produce oil from fields lacking natural drive, and enhanced recovery methods increase the recoverable reserves.

A well will flow oil to the surface it the static pressure at the bottom of the well exceeds the pressure of the column of mud and the frictional effect of the borehole. In many shallow fields with low reservoir pressure and in depleted fields, the wells do not flow spontaneously. In such instances the oil is pumped to the surface using the nodding donkey or bottom hole pumps described in an earlier chapter.

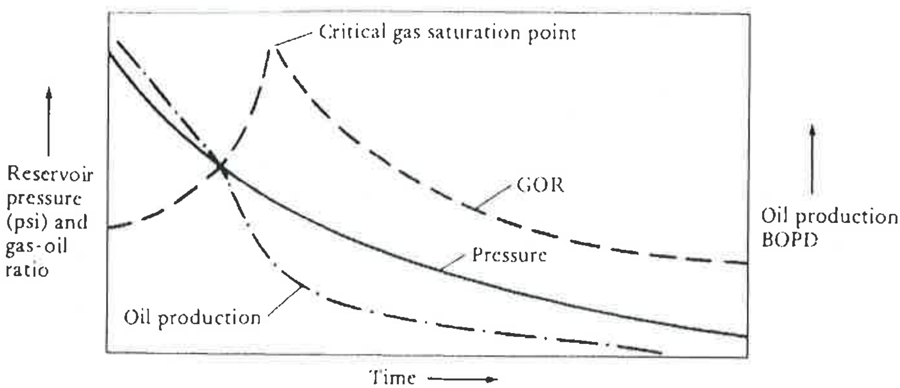


FIGURE 6.58 Graph illustrating the production history of a field with a gas expansion drive. Note how the GOR increases until the critical gas saturation point is reached; then it drops off sharply as the gas separates out.

Once a field becomes depleted, it may be abandoned or subjected to a secondary recovery program to step up production. In due course even a tertiary recovery program may be initiated. Today the practice is to initiate an enhanced recovery program when a field first goes on stream. There are many enhanced recovery techniques, and this rapidly expanding field is beyond the scope of this text (see Nelson, 1985; Langres et al., 1972). Some of the methods are briefly discussed as follows.

One of the main objectives of enhanced recovery is to maintain or re-establish the original reservoir pressure. This objective can be accomplished in one of several ways. Gas may be injected, either petroleum gas from the same or adjacent field or naturally occurring or industrially manufactured inert gases, such as carbon dioxide or nitrogen. Alternatively, liquids may be injected; these liquids may be seawater or connate waters from adjacent strata. Careful chemical analysis and the treatment of injected waters is essential to prevent and monitor unwanted chemical changes taking place within the reservoir. Some waters damage permeability by precipitating salts in pore spaces and causing clays to swell (Giraud and Neu, 1971). Seawater must be treated to destroy bacteria, since they degrade oil and increase its viscosity. More elaborate enhanced recovery methods involve the injection of detergents (micellar floods) to emulsify heavy oil and move it to the surface. Electric radiators have been used to mobilize oil from shales and from conventional petroleum reservoirs (Pizarro and Trevisan, 1990). For these and further details of enhanced recovery, see de Haan (1995).

Nuclear explosions have been used in attempts to enhance petroleum recovery in both the United States and the former USSR (see Howard and King, 1983; Orudjev, 1971; respectively). What better way to end this chapter than with a bang?

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