# 4. FLUID SATURATION AND CAPILLARY PRESSURE

## 4.1 Fluid Saturations

We have seen that the viability of a reservoir depends upon three critical parameters. The first two of these are the porosity of the reservoir rock, which defines the total volume available for hydrocarbon saturation, and the permeability, which defines how easy it is to extract any hydrocarbons that are present. The final critical parameter is the hydrocarbon saturation, or how much of the porosity is occupied by hydrocarbons. This, and the related gas and water saturations are controlled by capillary pressure.

The pore space in a rock is occupied by fluids. In hydrocarbon reservoirs these fluids are hydrocarbon gasses, oil and an aqueous brine. We define the pore fraction of each of these as $S_g$, $S_o$ and $S_w$, respectively. Hence, $S_g + S_o + S_w = 1$.

The amount of each of these fluids present at a given level in the reservoir depends upon gravity (buoyancy) forces, which tend to stratify the reservoir fluids according to their density, external hydrodynamic forces such as flow from a remote aquifer, and interfacial forces that act between the various reservoir fluids and between the fluids and the rock matrix.

The interfacial forces either take the form of (i) forces on the interface between two fluids, or (ii) between the fluid and the solid matrix of the rock. Both effects rely upon differences in the relative strength of inter-molecular forces between gasses, liquids and solids.

- Liquid-gas or liquid-vapour forces result from the differences in molecular attraction of each of the gas and liquid molecules for molecules of the same fluid compared to the molecular attraction for molecules of the other fluid.

- The liquid-liquid forces result from the differences in molecular attraction of each of the liquid molecules for molecules of the same liquid compared to the molecular attraction for molecules of the other liquid.

- The fluid-solid forces result from the preference for fluid molecules to be attracted to the solid mineral surface rather than to molecules of the same fluid.

The interfacial forces give rise to what is known as a capillary pressure. *Capillary pressure* is the difference in fluid pressure across an interface between two fluids in a confined volume.

In the discussion of capillary pressure, we will first examine surface energy and wettability, and then go on to derive a general expression for capillary pressure.

## 4.2 Fluid-Fluid Interactions (Surface Tension)

The fundamental property of that state of matter that we call a fluid is that its molecules are free to move. In gasses the freedom is great, but in liquids the freedom is constrained by relatively strong *cohesive* (attractive) forces that operate between the molecules. Imagine a drop of liquid suspended in a gas. In the interior of the liquid drop, a molecule is completely surrounded by other liquid molecules. On average it is equally attracted to the molecules surrounding it in every direction. By contrast, a molecule that occupies the surface of the drop is strongly affected by the attractive forces of

its fellow molecules inside the drop, but only weakly attracted to molecules outside the drop. This is because there are much fewer molecules in the vapour phase that surrounds the drop. Hence, the molecules on the surface of the drop experience net inward attraction. Figure 4.1 illustrates this schematically.

This attraction ensures that the drop attains the shape with least surface area in any given environment. For example, in zero gravity, the drop will float and will be perfectly spherical; the sphere being the geometry with the least surface area per volume.
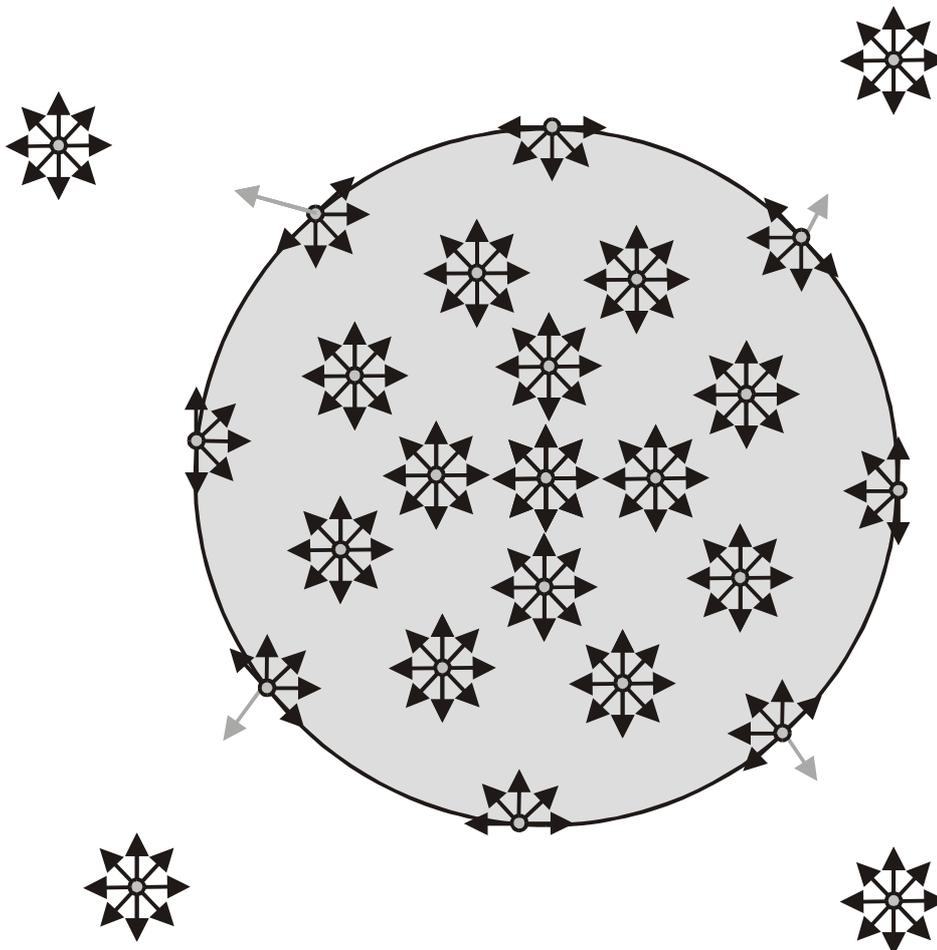
**Figure 4.1** Schematic illustration of surface energy.

To summarize; in the drop there are attractive forces between the molecules. The molecules inside the drop are surrounded by balanced attractive forces. The molecules at the surface experience a net inward force, which results in the drop contracting to the smallest surface area. The fluid pressure inside the drop is higher than that outside it, therefore the drop behaves as though it was contained in a skin.

If we have a drop of liquid suspended in a gas, and we want to increase the surface area of the drop, we must do *work* to move molecules from the interior of the drop to the surface. This is equivalent to saying that the surface possess *free surface energy*.
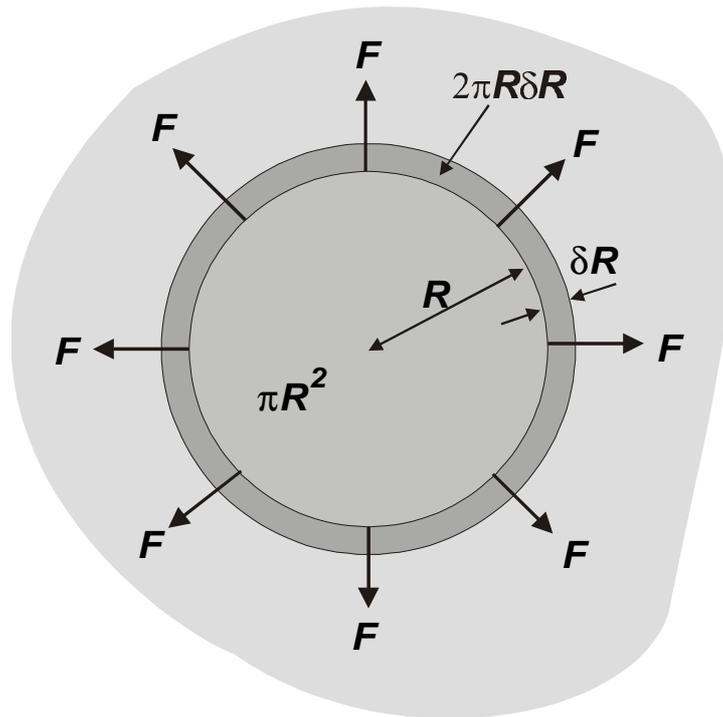
**Figure 4.2** Calculation of surface energy and surface tension.

Take the surface of any liquid droplet, and imagine that a circle is drawn on this surface with radius $R$. The area of the circle is $pR^2$ (Fig. 4.2). To increase the surface area of this drop by one unit of surface area, work must be done to move molecules from the interior of the drop to its new surface. The surface energy $s$ is equivalent to the work done $W$ per unit surface area increase $dA$, i.e., $s = W/dA$. But the work done $W$ is the force operating to make the change $F$ multiplied by the distance the force moves, so in the case of an imaginary circle on the surface of the liquid drop which increases its diameter from $R$ to $R + dR$, we can see that $W = FdR$ and hence, $s = FdR/dA$. When the droplet expands the surface area of the droplet and the area of the circle also expand. If the change in the radius of the circle is $dR$, the expanded circle has area $p(R+dR)^2$, and the change in area has been $dA = 2pRdR$ (Fig. 4.2). Hence, $s = FdR/2pRdR = F/2pR = F/L_p$, where $L_p$ is the perimeter of the original circle. Hence we can see that surface energy $s$ has the dimensions of [force]/[length], and is therefore a form of tension. Hence, the surface energy of a fluid interface is also called the *surface tension* of the fluid interface. Note therefore, that the surface tension is the force operating perpendicular to a line on a fluid interface divided by the length of that line. In our case the force was uniform around the circle, and the length of the circle (perimeter) was $2pR$.

We can write:

$$s = \frac{F}{L} \tag{4.1}$$

where:    $s$    = the surface tension ($\equiv$surface energy) in dynes/cm or N/m
          $F$    = the force operating on the surface (dynes or N)
          $L$    = the length of the line that the force operates on perpendicularly (cm or m).

The surface tension of a fluid-fluid interface is commonly measured by using a loop of wire. If  loop of wire is placed upon a fluid-fluid interface, it will be held in place by surface tension. Figure 4.3 shows the general arrangement. In this case we will be assuming that the lower fluid has the greater forces of attraction between its molecules. If we apply a small upward force to the loop it tries to leave the surface, but the surface tension hold the loop down (Fig. 4.3). There are two fluid interfaces that contribute to this, the outer circle and the inner circle. Both need to be overcome to remove the loop from the interface. The force required (from Eq. (4.1)) is $F = F_{inner} + F_{outer} = 2\pi s R_{inner} + 2\pi s R_{outer} = 4\pi s R_{mean}$. Hence;

$$s = \frac{F}{4\pi R_{mean}}$$

**(4.2)**

where,  $F$   = the force required to lift the loop from the surface interface (dynes or N)
  $s$   = the surface tension (dynes/cm or N/m)
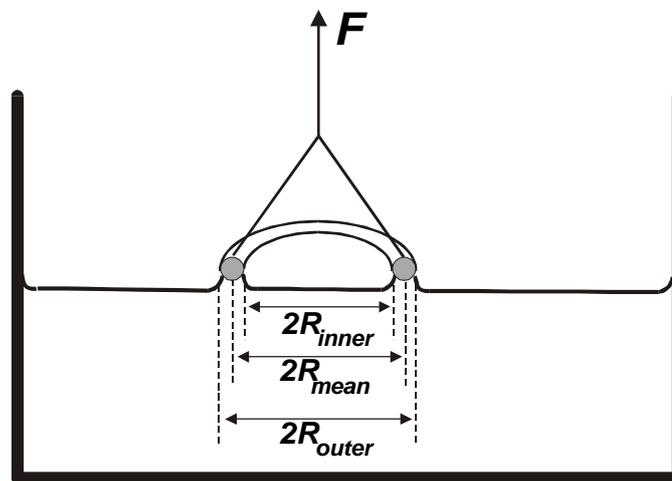  $R_{mean}$  = the mean radius of the loop (cm or m).



**Figure 4.3** Calculation of surface energy and surface tension.

Table 4.1 shows the surface tensions of some common fluid-fluid interfaces.

**Table 4.1** Surface tensions of some common fluid interfaces.

| Interface | Surface Tension @ 20°C | |
|---|---|---|
| | (N/m) | (dynes/cm) |
| Water-Air | 0.0726 | 72.6 |
| Benzene-Air | 0.0289 | 28.9 |
| Cyclohexane-Air | 0.0253 | 25.3 |
| n-Hexane-Air | 0.0184 | 18.4 |
| n-Octane-Air | 0.0218 | 21.8 |
| Water-Oil | Approx. 0.0350 | Approx. 35.0 |
| Mercury-Air | 0.3680 | 368.0 |
| **Units:** 1 N/m = 1000 dynes/cm | | |

Note that the liquid drop cannot exist in isolation. The arguments put forward so far have considered a single fluid in a gas. In practice both the fluid in the droplet and the fluid in which the droplet exists contribute to the interfacial effects. It is the *relative* attractions of the molecules of each fluid for themselves and each other that are important. In the case of a liquid drop in a gas, the effect of the gas can usually be ignored. This is because the cohesion forces operating between the molecules in the fluid are much greater than those in the gas because the fluid has a much higher density (number of molecules per unit volume).

The interfacial tension of an interface is a fundamental property of that interface. If a liquid has an interface with a gas, then some molecules of the liquid will be found in a vapour phase in the gas above the interface. These molecules reduce the surface tension. As temperature increases the concentration of the vapour phase increases, and the surface tension decreases. At the critical point there are as many molecules in the gas phase as in the liquid phase, the interface effectively disappears, and the surface tension becomes zero.

## 4.3    Fluid-Solid Interactions (Wettability)

We have seen that a fluid has a preferential attraction to itself, and the relative strengths of such cohesive forces result in surface tension that develops on a fluid-fluid interface. However, the molecules of a fluid may also have a preferential attraction to solid interfaces. If two fluids occupy a solid surface, the fluid whose molecules display the greatest attraction for the atoms that compose the solid will be the fluid that occupies most of the surface, displacing the other fluid.

The *wettability* of a surface is the type of fluid which is preferentially attracted to that surface.

Figure 4.4a shows the general case of a single solid immersed in two immiscible fluids at an unstable initial state. Now, imagine that the molecules of Fluid A are attracted to the solid molecules more than those from Fluid B are. Fluid A will then displace Fluid B on the surface. However, the molecules of Fluid A and Fluid B are contemporaneously also experiencing attractions from their fellow molecules and, to a smaller extent, the molecules of the other fluid. Consequently, Fluid A cannot displace all of Fluid B from the surface unless the attraction between the molecules on the surface of the solid and those in Fluid A is very great. In the general case a stable state will be encountered where Fluid A occupies the majority of the surface. At this equilibrium state, the *contact angle* *q* characterizes the balance between the various cohesive forces (Fig. 4.4b).
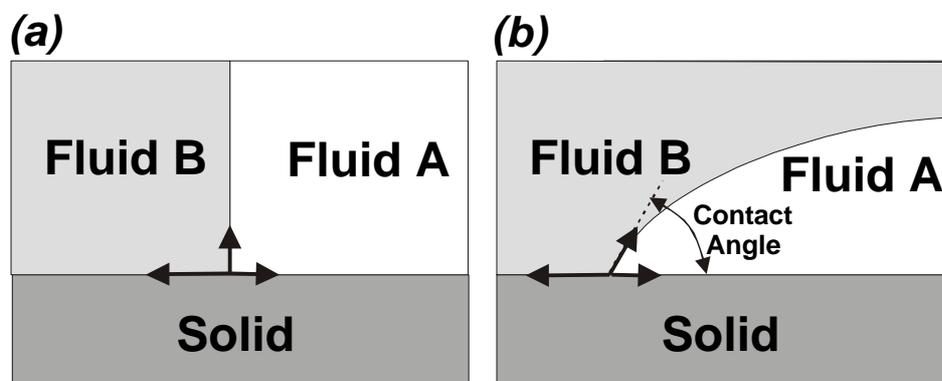


**Figure 4.4** Surface wettability.

Clearly, the contact angle can be used as a measure of wettability. Figure 4.5 and Table 4.2 show three possible scenarios.
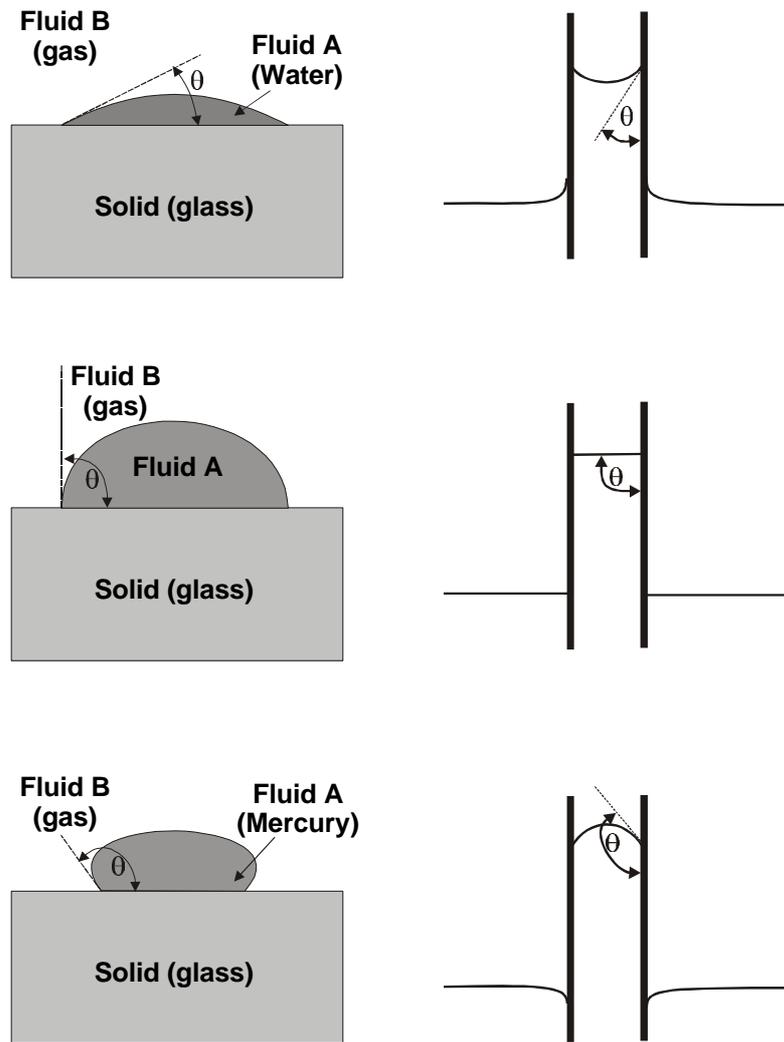


**Figure 4.5** Contact angles for different wettabilities.

**Table 4.2**  Contact angles for different wettabilities.

| Contact Angle relative to Fluid A, *q* (degrees) | Description |
| --- | --- |
| 0 | Extremely Fluid A wet |
| 0-30 | Significantly A wet |
| 30-60 | Moderately Fluid A wet |
| 60-90 | Weakly Fluid A wet |
| 90 | Neutrally wet |
| 90-120 | Weakly Fluid B wet |
| 120-150 | Moderately Fluid B wet |
| 150-180 | Significantly B wet |
| 180 | Extremely Fluid B wet |

## 4.4 Capillary Pressure

### 4.4.1 Derivation of the Capillary Pressure Equation

Take a spherical droplet of fluid, of radius $R$. Its surface area is $4\pi R^2$.

If the sphere is increased in size by increasing its radius from $R$ to $R+dR$, the increase in surface area $dA$ is $4\pi(R^2+rdR+dR^2)$-$4\pi R^2$, which as $dR^2{\rightarrow}0$ is $dA=8\pi RdR$.

To increase the radius of the sphere from $R$ to $R+dR$ requires work to be done moving molecules from the inside of the droplet to the surface. As work done $W$ is the product of the surface tension $\sigma$, and the change in surface area $dA$, we can say $W = \sigma\, dA = 8\pi\, \sigma\, RdR$.

But the work done is also the force operating to cause the change multiplied by the distance the force moves. By definition any pressure $P$ is equal to the force $F$ operating per unit area $A$, perpendicular to that area. Hence, $F = PA$. The force operating on the spherical surface of the droplet is therefore equal to the nett pressure ($P_{in} - P_{out}$) multiplied by the area of the spherical droplet $4\pi R^2$, i.e., $F = 4\pi R^2(P_{in} - P_{out})$. Since $P_{in} > P_{out}$, the net pressure ($P_{in} - P_{out}$) is positive, and the net pressure and resulting force is outward. The distance the force moves is also outward, and its value is clearly $dR$. Hence, the work done is $W = F\, dR = 4\pi R^2(P_{in} - P_{out})\, dR$.

Equating these relationships to eliminate $W$, gives

$$(P_{in} - P_{out}) = \frac{2\,\sigma}{R}\,.$$

(4.3)

Note that the derivation equates the work done. This type of derivation does not rely on the interface of the spherical droplet being static, as it is based upon the conservation of work (energy). It is also independent of direction because work is a scalar quantity.

The *capillary pressure* is defined as the difference between the pressures in each of the two fluids forming an interface. Hence Eq. (4.3) is an equation for capillary pressure.

The capillary pressure is proportional to the surface tension. Note that the greater of the two pressures is developed in the fluid which contains the centre of curvature of the curved fluid interface.

The geometry of pore systems in rocks is complex, but can be approximated by a bundle of capillary tubes. If the pore throat is represented by a capillary tube such as that shown in Fig. 4.6, we can note that the radius of the capillary tube $R_{tube}$ can be expressed in terms of the radius of curvature of the surface of the fluid-fluid interface R by $R_{tube}$ = R $\cos\theta$, where $\theta$ is the contact angle defined in the previous section. Hence, we can write the equation

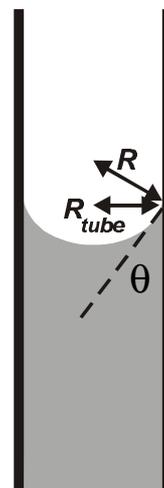$$P_{cap} = (P_{in} - P_{out}) = \frac{2\,\sigma\,\cos\theta}{R_{tube}}$$

(4.4)



**Figure 4.6** Capillary pressure in a tube (pore throat).

Note that the pressure is proportional to the surface tension and cos$q$, but inversely proportional to the radius of the tube. Hence, as the radius of the tube increases, the capillary pressure decreases.

The difference in pressure (the capillary pressure) causes the interface to rise up the capillary tube until the weight of the suspended column of fluid balances the capillary force that is associated with the capillary pressure. Hence Eq. (4.4) can be used to describe the rise of fluids in a capillary tube.

## 4.4.2 Capillary Force

The capillary force acting on the periphery of the meniscus is, according to Eq. (4.1) $F = s\,L = 2ps R_{tube}$ .

A proportion of this force acts up the capillary tube $F_{up} = F\cos q = 2ps R_{tube}\cos q$.

At equilibrium (i.e., the meniscus is static), the upward capillary force is balanced by an equal and opposite force due to the weight of the suspended column of fluids.

The weight of the suspended column of fluids is $p\,R^2_{tube}\,h\,g\,(r_{liquid} - r_{vapour})$, where $h$ is the height of the fluid column, $g$ is the acceleration due to gravity, and $r_{liquid}$ and $r_{vapour}$ are the densities of the liquid phase below the meniscus and the vapour phase above the meniscus, respectively.

Hence, we can write $2ps R_{tube}\cos q = p\,R^2_{tube}\,h\,g\,(r_{liquid} - r_{vapour})$, and by rearrangement

$$h = \frac{2s\cos q}{R_{tube}\,g\left(r_{liquid} - r_{vapour}\right)} = \frac{P_{cap}}{g\left(r_{liquid} - r_{vapour}\right)} \qquad \textbf{(4.5)}$$

Hence, the height to which the fluid rises depends inversely upon the tube radius (pore throat radius); the larger the tube (pore throats) the less the fluid rises.

The capillary pressure in a simple system of glass tubes of different radii can be calculated from Eq. (4.5) by measuring the height of the capillary rise, while knowing $g$, and the densities of the liquid and the vapour. In practice the density of the vapour is small at surface conditions and can be ignored. It cannot, however, be ignored at down-hole conditions, where its density may approach the density of the fluid.

## 4.4.3 Reservoir Scenarios

There are two scenarios that are of particular importance in a hydrocarbon reservoir. These are the gas/water and oil/water systems. In these scenarios, it should be noted that the *free water level* is defined as the level at which $P_{cap} = 0$, i.e., the pressure in the two fluids forming the interface is the same.

**Gas/Water System.**  A model of the capillary pressure in a gas/water system is shown in Fig. 4.7. The free water level is the height of the interface when the radius of the capillary tube tends to infinity (i.e., the capillary pressure is zero and $h=0$). In Fig. 4.7, this is approximated by a wide bath of fluid. The interface at the free water level may exist at any given absolute pressure $P_{FWL}$. Capillary forces exist inside the restricted capillary tubing that result in the rise of the water to a height $h$ above the free water level.

The pressure in the gas phase above the meniscus in the capillary tube is $P_{gas}$, where $P_{gas} = P_{FWL} - r_{gas} \, g \, h$.

The pressure in the water phase below the meniscus in the capillary tube is $P_{water}$, where $P_{water} = P_{FWL} - r_{water} \, g \, h$.

Hence the capillary pressure is $P_{cap} = P_{gas} - P_{water} = (r_{water} - r_{gas}) \, g \, h$, which is consistent with Eq. (4.5).

Using Eq. (4.4), the height to which the water rises can be obtained by rearranging this equation to give

$$h = \frac{P_{cap}}{g \left( r_{water} - r_{gas} \right)} = \frac{2 \, s \cos q}{R \, g \left( r_{water} - r_{gas} \right)} \tag{4.6}$$
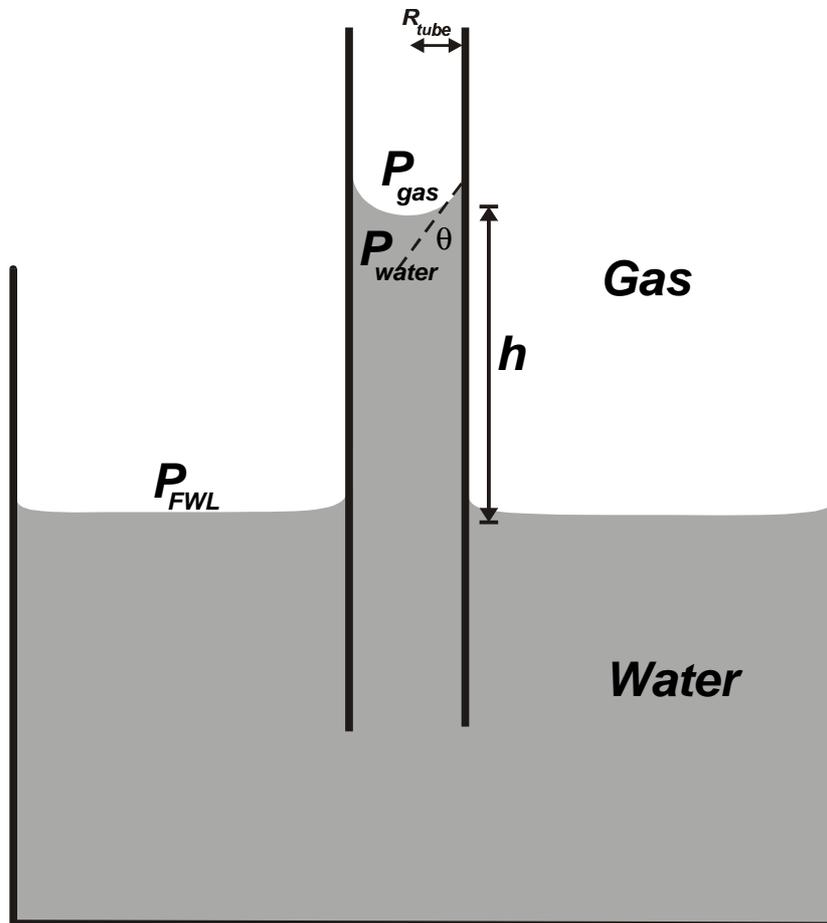


**Figure 4.7** Capillary pressure in a gas/water system.

**Oil/Water System.** A model of the capillary pressure in a oil/water system is shown in Fig. 4.8. The free water level is the height of the interface when the radius of the capillary tube tends to infinity (i.e., the capillary pressure is zero and $h=0$) as before. This interface exists at a given absolute pressure $P_{FWL}$. Capillary forces exist inside the restricted capillary tubing that result in the rise of the water to a height $h$ above the free water level.

The pressure in the oil phase above the meniscus in the capillary tube is $P_{oil}$, where $P_{oil} = P_{FWL} - r_{oil} \, g \, h$.

The pressure in the water phase below the meniscus in the capillary tube is $P_{water}$, where $P_{water} = P_{FWL} - r_{water} \, g \, h$.

Hence the capillary pressure is $P_{cap} = P_{oil} - P_{water} = (r_{water} - r_{oil}) \, g \, h$, similarly to the last case.

Using Eq. (4.4), the height to which the water rises can be obtained by rearranging this equation to give

$$h = \frac{P_{cap}}{g \, (r_{water} - r_{oil})} = \frac{2 \, s \, \cos q}{R \, g \, (r_{water} - r_{oil})} \qquad (4.7)$$
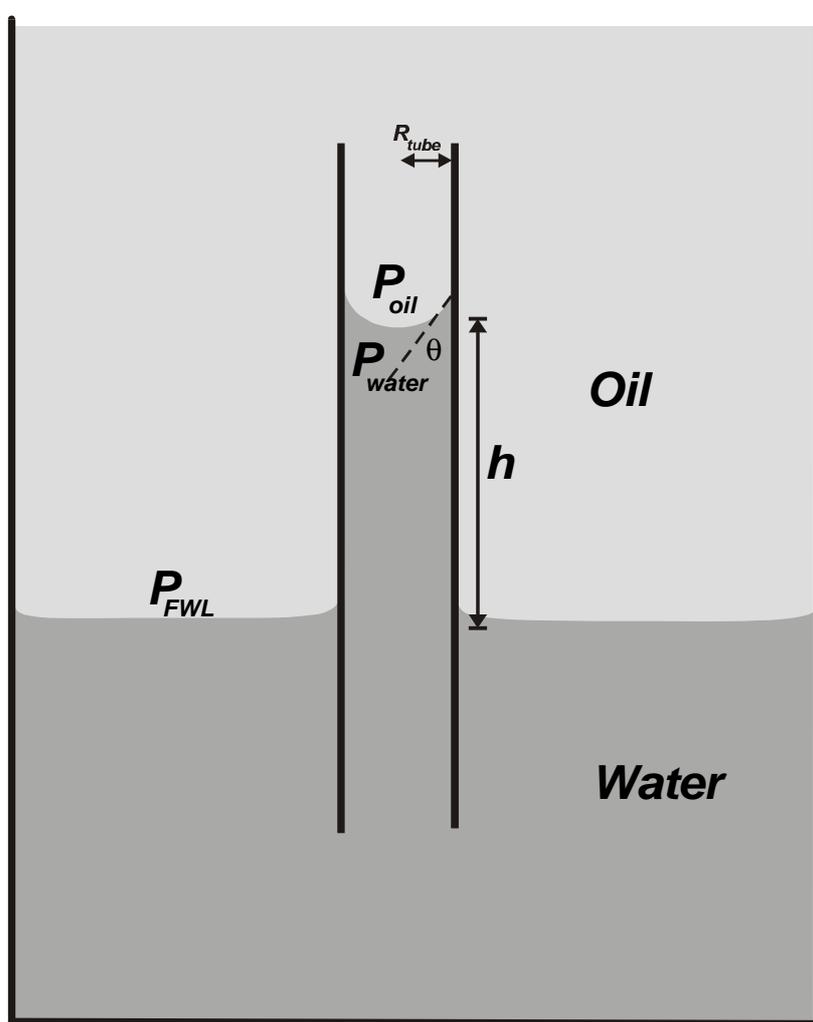


**Figure 4.8**  Capillary pressure in a oil/water system.

**Knowledge of Parameters.**    The capillary pressure depends most critically upon the interfacial tension and the wetting angle. These parameters change with pressure and temperature for any given fluid/fluid/solid system. Measurements can be made accurately in the laboratory in simplified systems

such as the capillary tube, but are very difficult to carry out in the rock itself. The result is that we use a range of values which are generally considered to be standard, but should not be considered to be accurate. These are given in Table 4.3.

**Table 4.3** Standard interfacial tension and wetting angle values for common mixtures of reservoir fluids and solids.

| System | Wetting Angle, $q$ (degrees) | cos $q$ | Interfacial Tension at 20°C, $s$ (dynes/cm [N/m]) |
|---|---|---|---|
| Water/Gas/Mineral | 0 | 1 | 72 [0.072] |
| Water/Oil/Mineral | 0 | 1 | 35 [0.035] |
| Air/Mercury/Mineral | 0 | 1 | 368 [0.368] |

The mercury/air. solid system is included because it is used in mercury porisimetry for obtaining porosity, capillary pressure, and pore size distributions. This technique will be described later.

## 4.5    Implications of Capillary Pressure in Reservoirs

So far we have restricted ourselves to a simple single capillary tube. Real rocks contain an array of pores of different sizes connected together by pore throats of differing size. Each pore or pore throat size can be considered heuristically to be a portion of a capillary tube. Real rocks may be completely water-wet, and indeed are commonly so. They may, however be oil-wet or neutrally wet or have a mixed wettability, where some mineral grain surfaces are water-wet and some are oil-wet. For the purposes of this discussion we will consider only water-wet rocks.

### 4.5.1  Capillary Rise and Reservoir Fluid Pressures

Assume that the pores of the rock are water-wet and can be represented by capillaries of five sizes: very small, small, medium, large and very large. The capillary rises in each of these pores will be as shown in Fig. 4.9. The capillary pressure at each of these menisci is the difference between the pressure in Fluid A above the menisci (say gas) and the pressure in Fluid B below the menisci (say water), as defined earlier (Eq. 4.3).
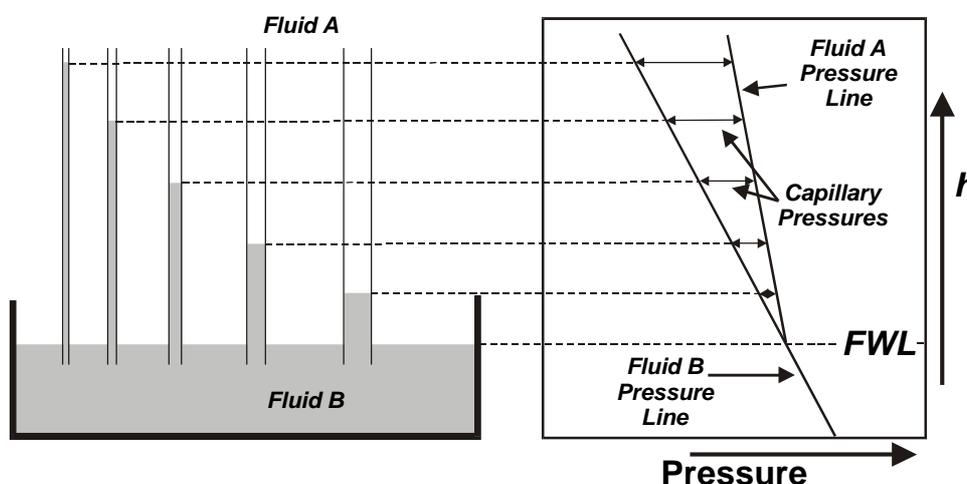


**Figure 4.9** Capillary rise and capillary pressures.

The capillary pressures are shown in the graph in Fig. 4.9. We can see that Fluid A (gas) has increasing pressure with depth due to the column of Fluid A above it, and this is described by the line labeled 'Fluid A Pressure Line', which has a gradient $r_{FluidA}$ $g$ $h$. Fluid B (water) has increasing pressure with depth due to the column of Fluid B above it, and this is described by the line labeled 'Fluid B Pressure Line', which has a gradient $r_{FluidB}$ $g$ $h$. Fluid A sits above Fluid B because it is less dense. Its lower density results in it having a steeper gradient. Where the two line intersect, the pressures in both fluids are the same and the capillary pressure is therefore zero. This is the free water level.

## 4.5.2 Displacement Pressure

If we have a capillary tube or a rock that contains 100% saturation of a non-wetting fluid (e.g. gas) and we introduce a wetting fluid (e.g. water) to one end, the capillary pressure will draw the wetting fluid into the tube or the pores of the rock spontaneously. If the pathway is down or horizontal this process can continue as long as there is more tube or rock for the wetting fluid to fill. If the pathway is upward or vertical, the process will continue until the capillary force pulling the fluid into the tube or rock pores is balanced by the gravitational force acting on the suspended column of fluid (Fig. 4.10).
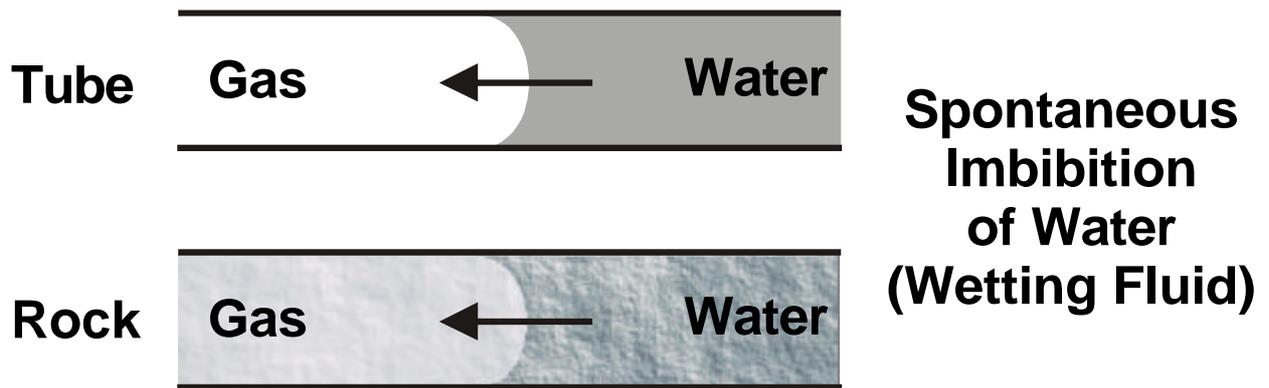


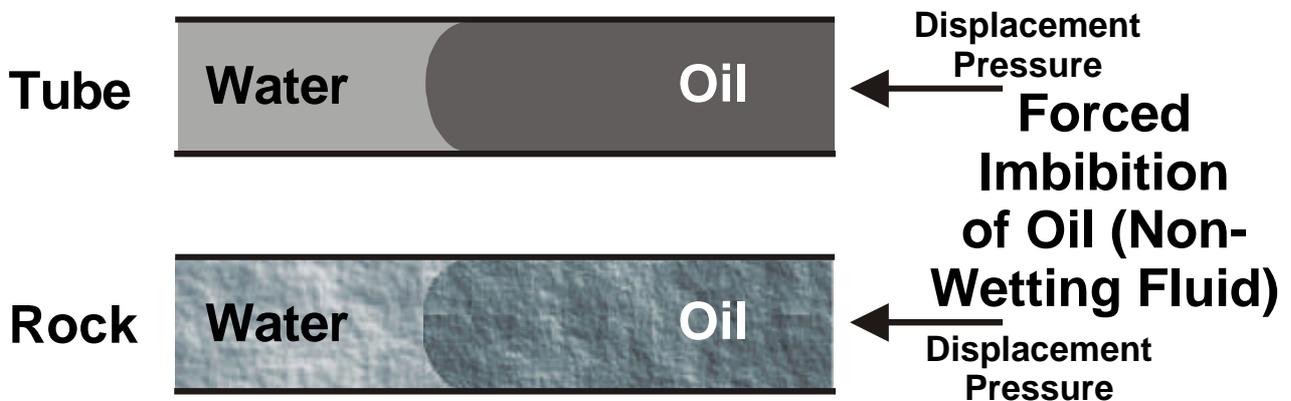**Figure 4.10** Capillary pressure spontaneously drawing up a wetting fluid..



**Figure 4.11** A force is needed to overcome the capillary pressure to displace a wetting fluid with a non-wetting fluid.

If we have a capillary tube or a rock that contains 100% saturation of a wetting fluid (e.g. water) and we introduce a non-wetting fluid (e.g. oil) to one end, the non-wetting fluid will not be spontaneously drawn up into the tube or the pores of the rock. This is because the wetting fluid is held inside the tube or the rock by the capillary force. To introduce the non-wetting fluid into the tube or the rock, we must apply an external force to overcome the capillary force holding the wetting-fluid in place (Fig. 4.11). This is called the *displacement force* or *displacement pressure*, and is equal in magnitude, but opposite in sign (direction) to the capillary force and capillary pressure respectively.

**IMPORTANT:** In oil reservoirs, the reservoir rock initially contains water and is water-wet. Oil migrates into the reservoir rock displacing the water. A displacement force is required to overcome the capillary forces in the water saturated water-wet reservoir rock. This force is supplied by gravity operating upon the differential buoyancy of the two fluids that results from their different densities. There is a level at which oil cannot replace water further because the driving force is insufficient to overcome the capillary force. This does not occur at the free water level, but at some height above the free water level defined by the displacement pressure. Thus, in reservoirs, the oil/water contact (*OWC*) is above the free water level (*FWL*).

Hence, if we have a number of capillary tubes of different radii arranged horizontally and containing a wetting fluid (e.g., water) (Fig. 4.12), and we wish to force a non-wetting fluid into the tubes (e.g., oil), a lower displacement pressure will be required to replace the water in the larger tubes than to replace the water in the thinner tubes. One can use the analogy with rocks, but remember that the pore space in rocks is composed of pores of different sizes connected by pore throats of varying size that are smaller than the pores. Hence the displacement force or pressure required to force a non-wetting fluid into a rock saturated with a wetting fluid will be controlled by the size of the pore openings.
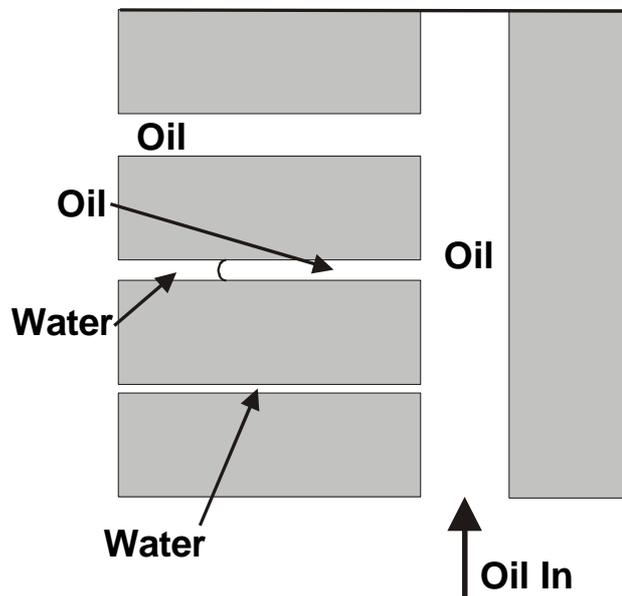


**Figure 4.12** Displacement pressure.

**An Example.** Assume that a rock is composed of five sizes of pore in equal number, and for the sake of simplicity, these pores are connected by pore throats of the same size as the pores. The rock is completely saturated with a wetting fluid. Table 4.4 shows the size, number and volume of pores together with their respective displacement pressures.

**Table 4.4** Pore size and displacement pressure example.

| Pore Radius [mm] | Individual Pore Volume [mm$^3$] | Pore Number [-] | Volume of Pores [mm$^3$] | Contribution to Total Pore Volume [%] | Displacement Pressure [Pa ´10$^3$] |
|---|---|---|---|---|---|
| 1 | 3.1415 | 10000 | 31415 | 0.132 | 70 |
| 2.5 | 19.6349 | 10000 | 196349 | 0.825 | 28 |
| 5 | 78.5498 | 10000 | 785398 | 3.301 | 14 |
| 10 | 314.1593 | 10000 | 3141593 | 13.206 | 7 |
| 25 | 1963.4954 | 10000 | 19634954 | 82.535 | 2.8 |

The data given in Table 4.4 can be plotted as a displacement versus pressure plot (Fig. 4.13). In this rock the pressure required to begin to displace water by oil is the initial displacement pressure (2800 Pa in this case). The level in the reservoir at which this is the case is called the *100% water level* which should be the same as the *OWC*, and is above the *FWL* by a height related to the size of the displacement pressure and controlled by the largest pore openings in the rock. If the rock was composed of 100% of pores of 25 micron size, this would be the level above which there would be 100% oil saturation and below which there would be 100% water saturation. However, the rock also contains smaller pores, with higher displacement pressures. Thus there will be a partial water saturation above the 100% water level occupying the smaller pores, and this water saturation will reduce and become confined to smaller and smaller sized pores as one progresses to higher levels above the 100% water level. Water will only be displaced from a given pore size if there is a sufficiently large force to overcome the capillary force for that size of pore. Commonly, the force driving the oil into the reservoir rock (due to differential buoyancy) is insufficient to overcome the capillary forces associated with the smallest pores. Hence, the smallest pores in an oil zone remain saturated with water, and there is an *irreducible water saturation* ($S_{wi}$) in the reservoir.
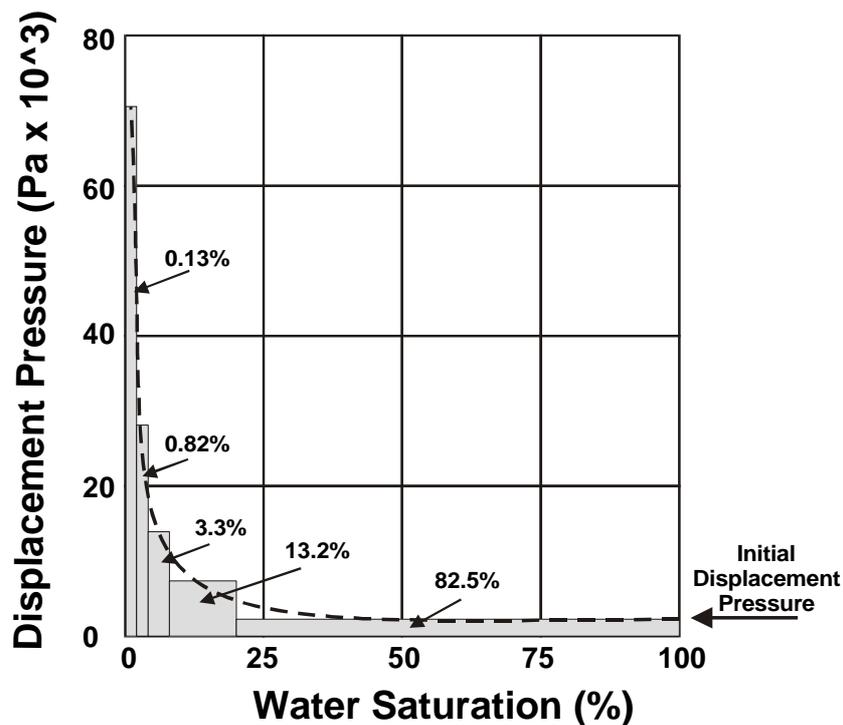


**Figure 4.13** Displacement/pressure curves.

Note that once oil is in place, the operation of temperature and pressure may geochemically alter the properties of the mineral surfaces such that they become oil-wet. This occurs only in the presence of oil, so it can be imagined that a mature reservoir may have a mixed wettability, with water-wet small pores containing water and oil-wet larger pores containing oil. This has implications when we want to move oil and water through the rock during production.
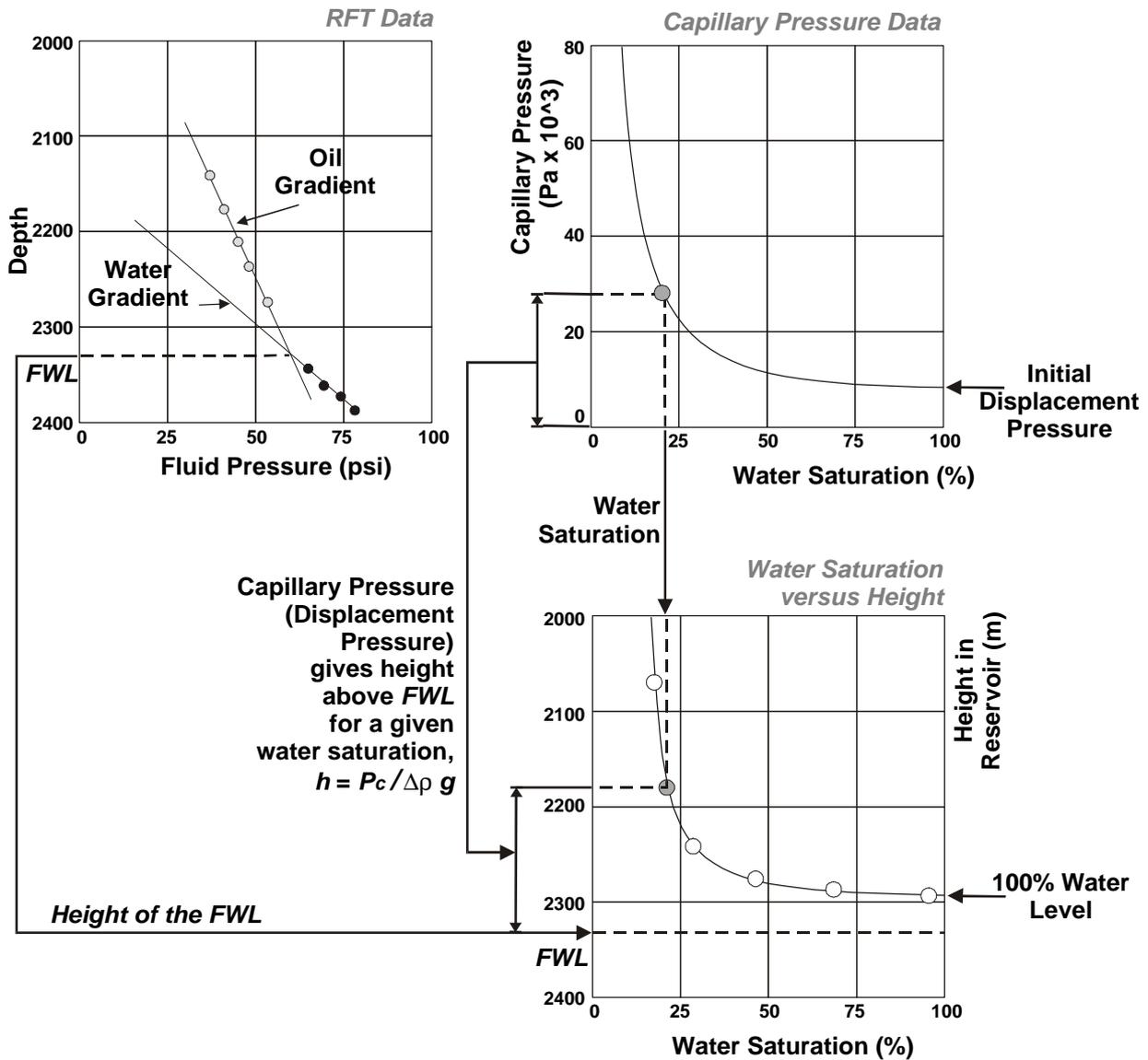


**Figure 4.14** Calculation of water saturation in a reservoir.

The curve shown in Fig. 4.13 is continuous for a reservoir rock because the rock contains a continuous pore size distribution. This curve is called the *capillary pressure curve*. The capillary pressure curve describes the pressure required to displace from the rock a wetting fluid at initially 100% saturation to a given saturation.

The capillary pressure is related to the height above the *FWL* by the relationship

$$P_c = \Delta r \, g \, h \tag{4.8}$$

So, if the capillary pressure curve is known, and the *FWL* is known, we can calculate the water saturation at any point in the reservoir as in Fig. 4.14. If this water saturation agrees with the water saturations obtained from wireline tools and core in a given well, the wireline water saturation data can be used with confidence as a predictor of water saturation in the uncored sections of other wells in the same field.

## 4.6    The Measurement of Capillary Pressure Curves for Rocks

There are many ways of measuring capillary pressure curves in rocks. The most common are described below. A detailed description of these will be given in courses given later in the MSc course.

### 4.6.1  Porous Plate

The sample is saturated completely with a wetting fluid (usually water), and its effective porosity is measured. It is then placed on a porous plate in a pressure vessel. Gas or oil is introduced into the vessel around the sample at a low pressure (Fig. 4.15). The porous plate is constructed so that it will only let through water. The pressurized oil or gas displaces some of the water from the sample (throughout the whole sample) and the displaced water passes through the porous plate, whereupon it is collected and its volume is measured. The vessel is left at the set pressure until no more water evolves, which may take several days. The pressure of the gas or oil is then increased, and more water evolves and is measured. The procedure is repeated usually about 7 times at increasing pressures (e.g., 1, 2, 4, 8, 16, 32, 64 psi). A capillary curve can then be constructed with pressure versus the water saturation in the sample (Fig. 4.16).
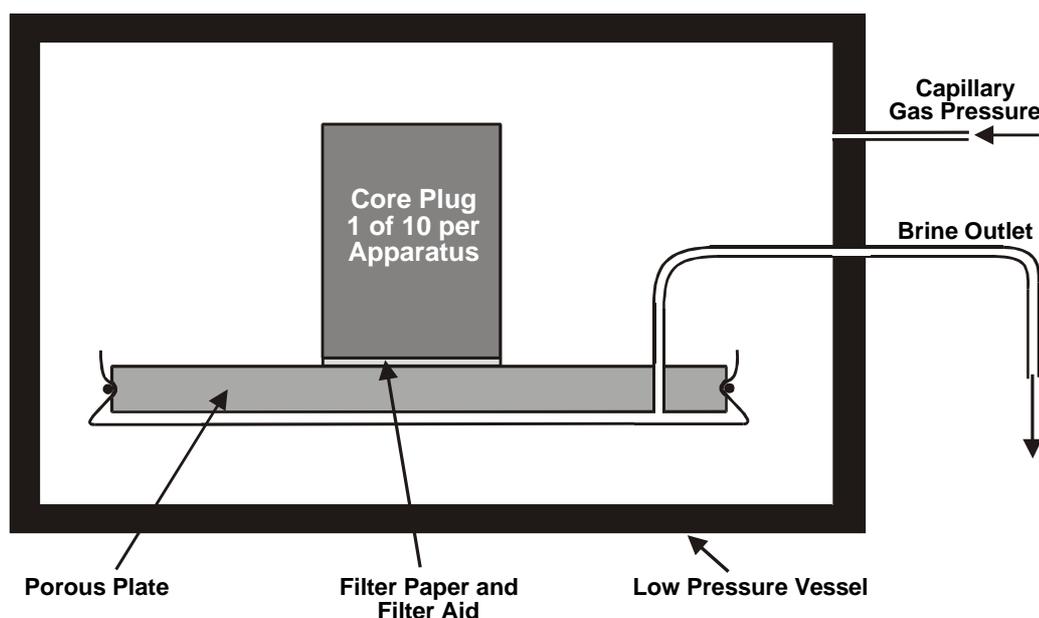


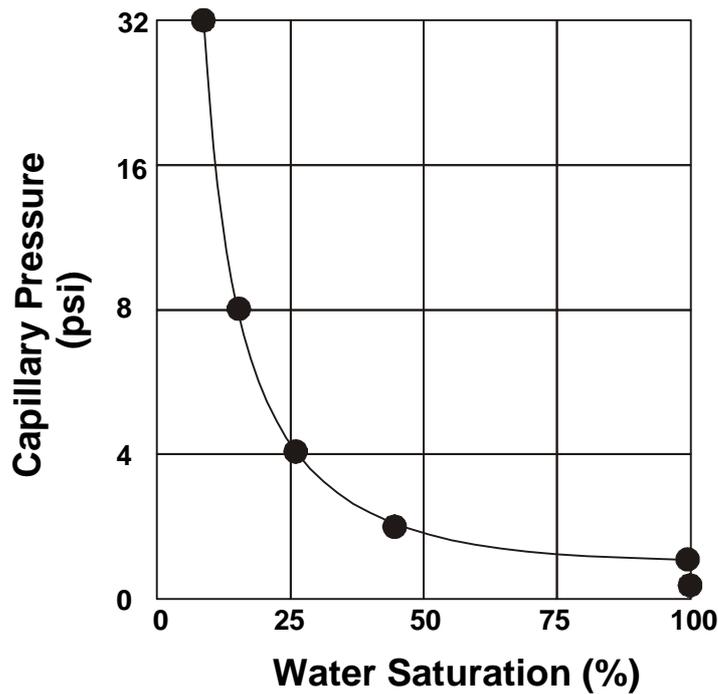**Figure 4.15** Porous plate capillary pressure measurement.

**Figure 4.16** Capillary press curve from porous plate measurements.

The maximum pressure is limited by the pressure at which the porous plate begins to let the gas or oil pass through with the water.

There is also a range of specialized dynamic and semi-dynamic versions of the porous plate technique that can be used on confined cores together with direct measurement of sample fluid saturations using X-Ray, CT and gamma radiometric imaging techniques.

**Advantages:**        Can use actual reservoir fluids for the measurements.
                 Accurate.
**Disadvantages:**    Slow.
                 Only provides a few data points on the capillary pressure curve.

## *4.6.2 Centrifuge*

The sample is saturated completely with a wetting fluid (usually water), and its effective porosity is measured. It is placed in a centrifuge and rotated at progressively higher speeds. The speed of rotation generates a centripetal force that displaces the wetting fluid from the sample replacing it with air or oil (if an oil reservoir is attached to the inside of the rotating sample). The volume of the evolved fluid is measured by collecting it in a graduated vial attached to the outside of the spinning arrangement, and read using a stroboscope. At slow rotation speeds, the force is only sufficient to displace water from the largest pores. At higher speeds the force is able to displace water from smaller and smaller pores in the sample. The pressures on the fluids can be calculated from an equation based upon the rotary motion of the centrifuge. This is plotted against the water saturation in the sample calculated from the measured volume of evolved fluids for each spin speed (Fig. 4.17).
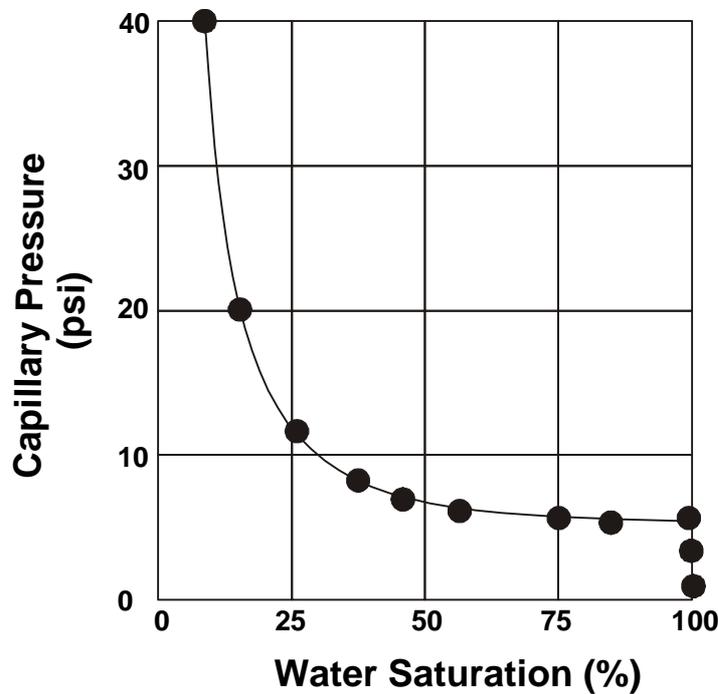


**Figure 4.17**  Capillary pressure curve from centrifuge measurements.

**Advantages:**      Fast.
**Disadvantages:**   Commonly only used with air as the displacing fluid.
                     Only provides a few data points on the capillary pressure curve.
                     As pressure is a function of distance from the spin centre, the fluid saturation
                     across the sample varies, and the measured values are taken as the mean value.

## 4.6.2 Mercury Porosimetry

A dry sample of any shape, but of known weight, is placed in a chamber which is filled with mercury. The mercury is a non-wetting fluid and does not spontaneously enter the pores of the rock. This the bulk volume of the rock can be measured. The pressure on the mercury is increased in a step-wise fashion. At each step, the mercury enters smaller and smaller pores overcoming the capillary pressure operating against the non-wetting fluid (Fig. 4.18). At each stage the amount of mercury intruded is measured. A graph can be constructed of mercury pressure at each step against volume of mercury intruded. This is the capillary pressure curve. This data can also be inverted to provide the pore size and grain size distributions of the rock, and the raw data also provides a rough estimate of the connected porosity of the rock.
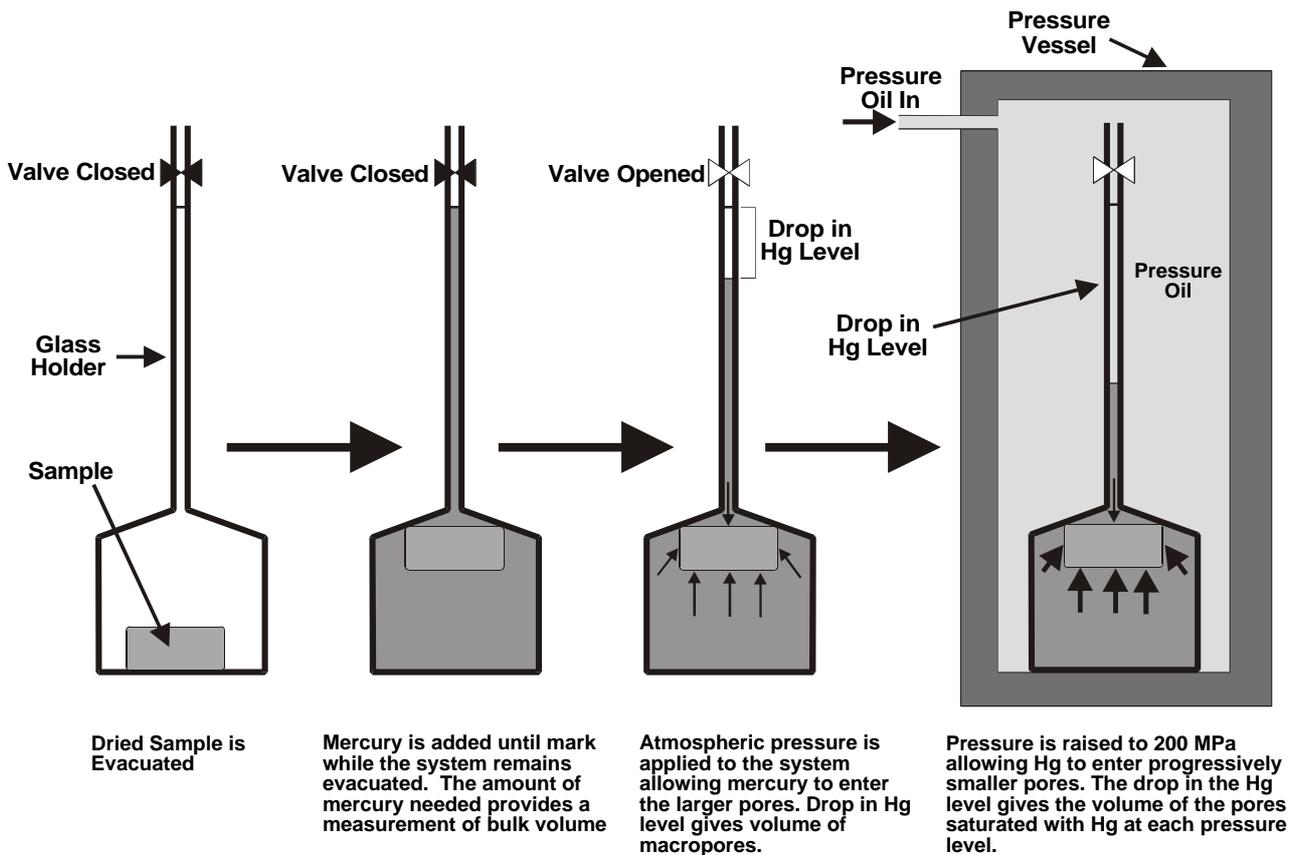


**Figure 4.18** Mercury porisimetry.

**Advantages:**      Fast.
                     Provides porosity of sample.
                     Provides pore size distribution.
                     Provides grain size distribution.
                     Can be used on small, irregular samples, such as cuttings.
                     Gives many data points for intrusion.
**Disadvantages:**   Cannot be used with reservoir fluids.
                     Data must be corrected to give reservoir values.
                     Can only be used in imbibition cycle.

## 4.7    Capillary Pressure Data Correction

We require the capillary pressure curve for the reservoir fluids and the reservoir rock. Measurements, however, are generally made with other fluids. We must, therefore have a method for correcting the data to give the capillary pressure for the reservoir fluids. The corrections are simple and take account of the different interfacial tensions and wetting angles for different fluid combinations at 20°C only.

The measured capillary pressure for a mercury/air/sample system $P_c$(Hg/air/rock) is

$$P_c(\text{Hg/air/rock}) \ = \frac{2s\cos q}{R} = \frac{2\times368\times1}{R} \tag{4.9}$$

The required capillary pressure for a oil/water/sample system $P_c$(oil/water/rock) is

$$P_c(\text{oil/water/rock}) \ = \frac{2s\cos q}{R} = \frac{2\times35\times1}{R} \tag{4.10}$$

In both cases the values for interfacial tension and wetting angle come from Table 4.3. Since the value of *R* is the same whatever the fluids are, we can equate and rearrange Eqs. (4.9) and (4.10) to give

$$\frac{P_c(\text{Hg/air/rock})}{P_c(\text{oil/water/rock})} = \frac{368}{35} = 10.5 \; ; \quad \text{and} \quad \frac{P_c(\text{oil/water/rock})}{P_c(\text{Hg/air/rock})} = \frac{35}{368} = 0.09524 \tag{4.11}$$

Similarly,

$$\frac{P_c(\text{Hg/air/rock})}{P_c(\text{gas/water/rock})} = \frac{368}{72} = 5.1 \; ; \quad \text{and} \quad \frac{P_c(\text{gas/water/rock})}{P_c(\text{Hg/air/rock})} = \frac{72}{368} = 0.1960 \tag{4.12}$$

and,

$$\frac{P_c(\text{oil/water/rock})}{P_c(\text{gas/water/rock})} = \frac{35}{72} = 0.4861 \; ; \quad \text{and} \quad \frac{P_c(\text{gas/water/rock})}{P_c(\text{oil/water/rock})} = \frac{72}{35} = 2.057 \tag{4.13}$$

Hence, to convert $P_c$(Hg/air/rock) to $P_c$(oil/water/rock) we should divide by 368 and multiply by 35 (i.e, multiply by 0.09524). Table 4.5 summarizes the conversions.

**Table 4.5**  Capillary pressure conversions.

| From | To | Multiply by |
|---|---|---|
| Mercury/Air/Rock | Oil/Water/Rock | 0.09524 |
| Mercury/Air/Rock | Gas/Water/Rock | 0.19608 |
| Oil/Water/Rock | Mercury/Air/Rock | 10.5 |
| Oil/Water/Rock | Gas/Water/Rock | 2.057 |
| Gas/Water/Rock | Mercury/Air/Rock | 5.1 |
| Gas/Water/Rock | Oil/Water/Rock | 0.4861 |
| **Note:** This is only valid for 20°C | | |

These conversions are valid for the values of interfacial tension and wetting angle measured at 20°C and given in Table 4.3. However, these parameters change with pressure and temperature, and are therefore different in the sub-surface. Values of interfacial tension and wetting angle are very difficult to obtain for sub-surface conditions, and one might commonly have to make do with those at 20°C. However, sub-surface values should always be used when available as the interfacial angle is particularly sensitive to changes in temperature, with values as low as 10 dynes/cm for oil/water systems, and as low as 25 dynes/cm for gas water systems.

Many of the values in Table 4.5 are given to 4 significant figures accuracy. However, it is common for only two significant figures to be used (i.e., 10 for 10.5 and 5 for 5.1). This is often justified on the grounds that our knowledge of the values of interfacial tension and wetting angle is not accurate. The lack of accurate data introduces errors in any final calculations. However, noting that these inaccuracies occur is no excuse for introducing further voluntary inaccuracies by making such assumptions as using 10 instead of 10.5. The error introduced by this assumption can result in errors of millions of dollars on the bottom line.

Now we can convert mercury derived capillary pressure data to the capillary pressure for the reservoir fluids, we can write Eq. (4.8) in terms of the mercury capillary pressure.

$$P_c\left(Hg/air/rock\right) = 10.5 \times P_c\left(oil/water/rock\right) = 10.5 \times \Delta r\, g\, h \tag{4.14}$$

and

$$P_c\left(Hg/air/rock\right) = 5.1 \times P_c\left(oil/water/rock\right) = 5.1 \times \Delta r\, g\, h \tag{4.15}$$

These equations are very useful, because they allow the height in the reservoir for a given saturation to be calculated from capillary curves measured by mercury porisimetry, which is the most common capillary pressure technique practiced in the industry.


## 4.8    Fluid Distributions in Reservoirs

Capillary pressure curves can tell us much about the variation of saturations across a reservoir. The following example is taken from the personal notes of Theo. Grupping, and is a particularly good example.

In deltaic-type deposition sands may be laid down in fan-like bodies. The current that is responsible for the deposition is fast in the proximal region and becomes progressively slower as one progresses distally or laterally. Hence, in the proximal region the grain size of the resulting rocks is large (only large grains have time to fall from the fast current). Distally and laterally the grain size of the resulting rocks becomes finer as smaller sand particles have time to fall out of the slower current. Eventually, at the extreme edges of the fan, the current is so slow that very fine clay particles are also deposited, becoming interspersed with the fine sand grains.

- The proximal large grained clean sands have large pores and large pore throats. Therefore, they have small initial displacement pressures, and their water can easily be displaced by migrating oil.

- The distal fine grained clean sands have small pores and consequently small pore throats. They have higher initial displacement pressures, and their water cannot be displaced by migrating oil as easily as for the coarser grained rocks.

- The distal fine grained shaly sands (containing interspersed clay) have the smallest pores and consequently the smallest pore throats, and these pores and pore throats are blocked by the clay particles. They have very high initial displacement pressures; the great majority of their water is immobile and cannot be displaced by migrating oil. Figure 4.19 shows the results of 5 wells drilled progressively more distally in the same sub-marine fan.
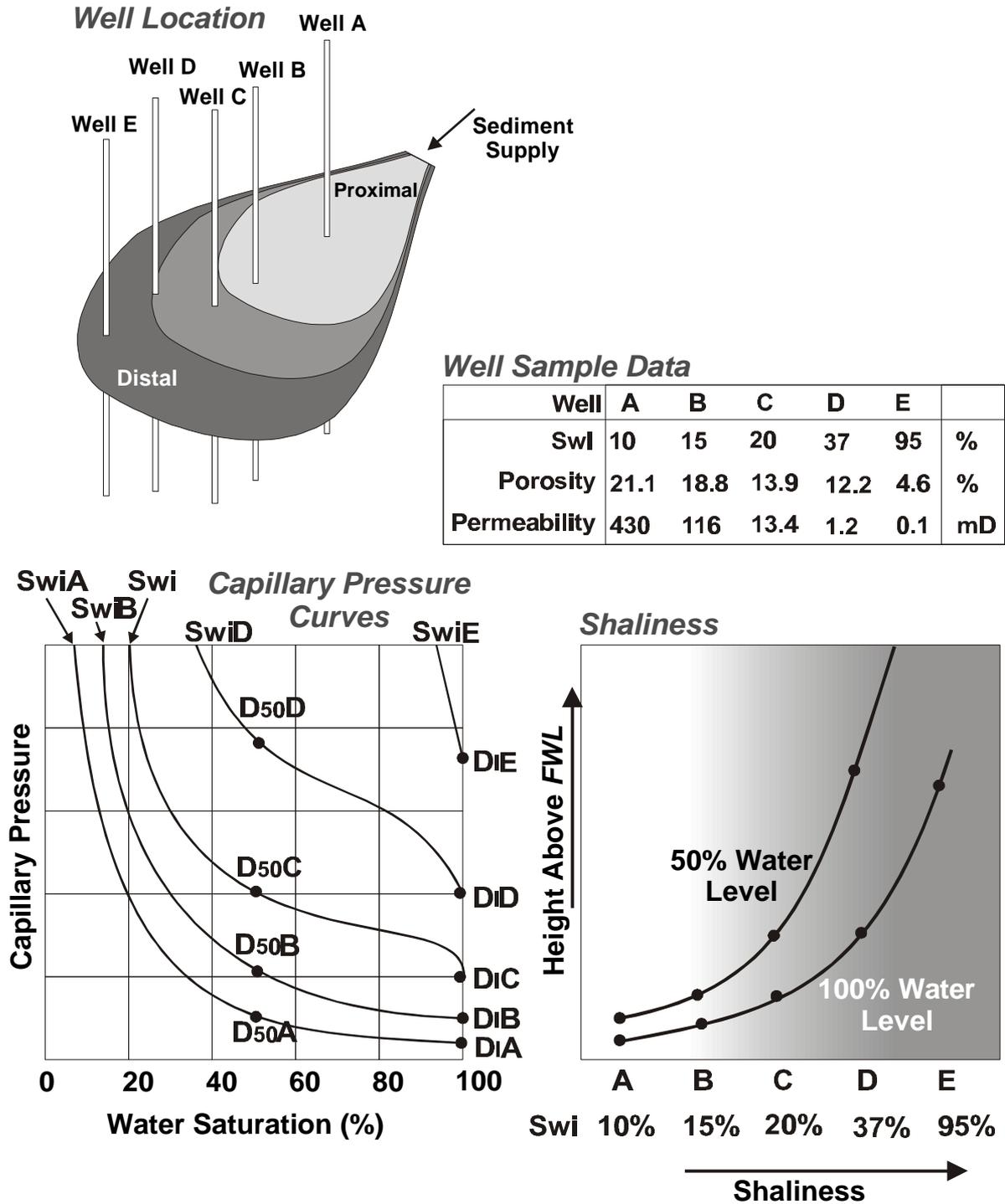


**Figure 4.19**  Capillary pressure curves and facies.

The first part shows the fan geometry and position of the wells (labeled A to E). The second part shows the capillary pressure curves for each of 5 samples taken from each of the wells with the 100% water point labeled $S_{100}A$ to $S_{100}E$, the initial displacement pressure labeled $D_IA$ to $D_IE$, the 50% water point labeled as $S_{50}A$ to $S_{50}E$, and the irreducible water saturation labeled $S_{wi}A$ to $S_{wi}E$. The third part shows the height above the free water level as a function of facies and water saturation, with the same saturation labels as in part 2. Note the following:

- The initial displacement pressure becomes greater as the sample becomes more shaly (finer grained) as one moves distally.

- The irreducible water saturation becomes greater as the sample becomes more shaly (finer grained) as one moves distally.

- The capillary pressure curve for the proximal samples are quite flat from 100% water to about 60% water indicating that only low pressures are required to replace about the first 40% of water with oil (in the largest pores with the largest and most accessible pore throats).

- At any given capillary pressure, more water is retained as the sample becomes more shaly (finer grained) as one moves distally.

- The height above the free water level of 100% water saturation increases as the sample becomes more shaly (finer grained) as one moves distally.

- The height above the free water level of 50% water saturation increases as the sample becomes more shaly (finer grained) as one moves distally.

So, the grain size controls the height of the 100% water saturation level. Now imagine four layers of sand that have different grain sizes, porosities and permeabilities, and that have become folded (Fig. 4.20). Each layer has its own capillary pressure characteristics associated with its grain size, and that capillary pressure is related to the height of the 100% water level above the free water level as shown. It can be seen that it is possible to drill through layers which are 100% water zones existing between oil or gas zones from the same reservoir. In this case Well C has two oil water contacts. It is the bottom one that is the true *OWC*. Because multiple *OWC*s are confusing, we tend to talk about *oil down to* (*ODT*) and *gas down to* (*GDT*) levels when there are multiple hydrocarbon/water contacts.
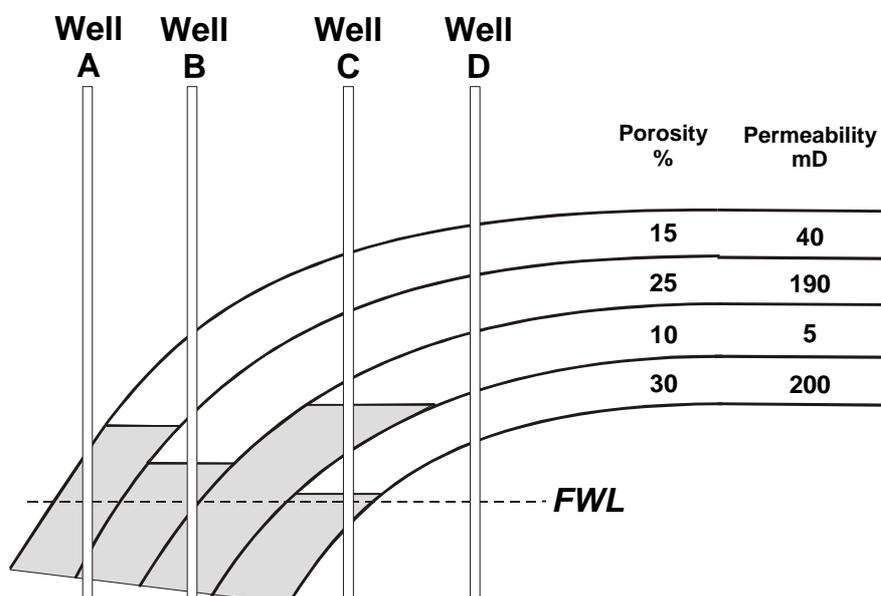


**Figure 4.20** Suspended water zones.