11.6 In practice

In this section we look at practical applications of capillary pressure and related properties.

Relation between capillary pressure and saturation revisited

From the previous section you know a little about capillary pressures and relationships between capillary pressures and saturation of the wetting fluid. This last relation is very important, so we re-iterate it here. We will take water as the wetting fluid.

At low water saturation the water will primarily live in the small pores (the small crooks and crannies of the porous rock). The radii of curvature will be small and therefore the capillary pressure will be high. A high capillary pressure means that we have to impose a large pressure gradient to move the water out. At very low saturations, the water may become immobile. This means that the wetting fluid is disconnected and can not transmit a pressure difference so we can not force the flow out.

At high water saturation, the water fills the larger pores as well. The radii of curvature in the larger pores are larger, and therefore the capillary pressure is lower. These pores can be easily drained by imposing a pressure difference just a little higher than this capillary pressure.

Is the relation between capillary pressure and saturation the same for all reservoir rocks? If not, what rock properties would it depend on?

Measuring capillary pressure

We mention one method that can be used to find the relation between saturation and capillary pressure. It is the method of mercury injection. A core sample is inserted in a mercury chamber. Then mercury is forced into the pores under pressure. Note that mercury normally is a nonwetting fluid. The volume of mercury injected at each pressure determines the non-wetting saturation from which the wetting saturation can be computed.

What are the disadvantages of this method?

Converting laboratory measurements to reservoir conditions

If mercury injection is used to measure capillary pressure/saturation curves for a rock, we are measuring capillary pressures using a completely different fluid from what is found in the reservoir. Of course, the method will still tell us a lot about the rock, but we cannot use the capillary pressure data directly.

Suppose that lab measurements are done using an air/mercury system, but in the reservoir we have air/water. In analogy with capillary tube we have

$$p_{cL} = \frac{2\sigma_{ma}\cos\theta_{ma}}{r}.$$

where the subscript L indicates the lab measurement. In the reservoir the same analogy would give for air/water

$$p_{cR} = \frac{2\sigma_{wa}\cos\theta_{wa}}{r}.$$

We get

$$p_{cR} = \frac{\sigma_{wa} \cos\theta_{wa}}{\sigma_{ma} \cos\theta_{ma}} p_{cL} .$$

In most cases the contact angles are unknown so they are usually ignored and we get

$$p_{cR} = \frac{\sigma_{wa}}{\sigma_{ma}} p_{cL} .$$

So we must know the surface tensions and the capillary pressure in the lab to find an approximation to the capillary pressure in the reservoir.

Is ignoring the angles a big problem? Not really in most cases.

As example, suppose we compare a mercury/air experiment with a water-air experiment. The data are

$$\sigma_{ma} = 480 \text{ dyne/cm}$$
$$\sigma_{wa} = 70 \text{ dyne/cm}$$
$$\theta_{ma} = 140^\circ \text{F}$$
$$\theta_{wa} = 0^\circ \text{F}$$

Note that the surface tension is measured in dyne (10-5 N) per cm of surface (check that this gives the correct units for capillary pressure in equations that we have derived in previous sections).

Not ignoring the angles we would get a capillary pressure ratio of 5.253. If they are ignored then the ratio is 6.857. Not too bad.

Averaging capillary –pressure data

Capillary pressure data obtained are generally obtained by tests performed on small cores of reservoir rock. The cores are of course extremely small parts of the reservoir and may not be fantastic representations of the reservoir rock. We know that permeability and porosity influence saturation/capillary pressure findings. How can we relate the information obtained on the cores to the general reservoir? A popular correlation function is the Leverett J function, given by

$$J(S_w) = \frac{p_c}{\sigma}\sqrt{\frac{k}{\phi}}, \quad \text{or sometimes} \quad J(S_w) = \frac{p_c}{\sigma\cos\theta}\sqrt{\frac{k}{\phi}} .$$

The function depends on the rock type, but generally one function can be used for one reservoir.

A typical J-curve is sketched in figure 11-15. So, from this curve the capillary pressure can be determined if the saturation, permeability and porosity are known.

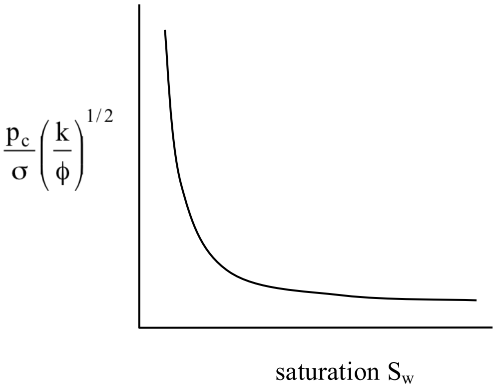

Fig 11-15 Typical Leverett-J curve

Height of saturation in the reservoir

Let's look at another practical example. Suppose we have a nicely stratified reservoir: the water is in the bottom of the reservoir, oil on top of the water and gas on top of the oil. Of course in between the regions of full water, full oil and full gas saturation are (large) regions of mixed phases. This is illustrated in figure 11-16.

Here we assume that we can find a free water surface, a flat surface separating the 100% water area from the water/oil region at which the capillary pressure is 0. We will also assume that the water and oil phases are connected and that the system is in equilibrium.

As we discussed in lecture 25, the free water surface in a water-wet reservoir will be below the oil-water contact. Refer to the slides of this lecture for an illustration.

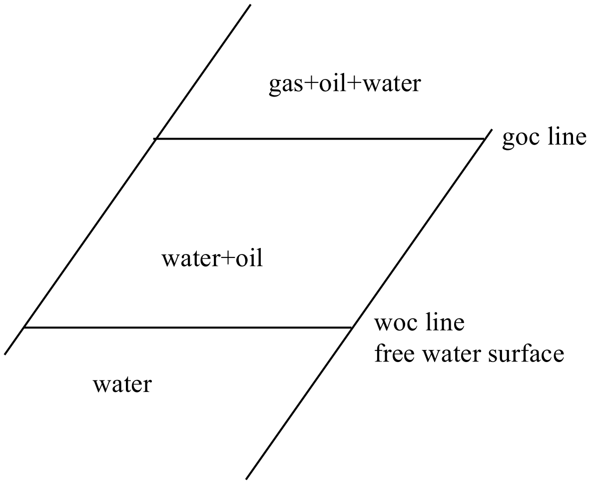

Fig 11-16 A reservoir with a free water surface

Because the capillary pressure at the free water surface is 0, the pressure at this surface in the oil phase and the water phase is the same (it is assumed the surface is flat). We can then use a capillary tube analogy to find a relation between height above the free water surface and capillary pressure (here we assume that the height does not extend above the gas-oil contact line).

$$h = \frac{p_c}{(\rho_w - \rho_o)g}.$$

We can also express the difference in capillary pressures at heights h_2 and h_1 above the free water surface as

$$h_2 - h_1 = \frac{p_{c2} - p_{c1}}{(\rho_w - \rho_o)g}.$$

Suppose that a laboratory test is done on a core sample with air/water. The water saturation is equal to 0.35. The capillary pressure measured in the lab is equal to 18 psi. Calculate the height above the free water surface of the 35% saturation plane in the reservoir if you know that

$$\sigma_{wo} = 24 \text{ dynes}, \sigma_{wg} = 72 \text{ dynes}, \rho_w = 68 \text{ lb/cu ft}, \rho_o = 53 \text{ lb/cu ft}.$$

Watch your units!

In the gas zone, we have three phases and things are a bit more complicated. If all three phases are connected then

$$(p_c)_{wg} = (p_c)_{wo} + (p_c)_{og}.$$

However, we have to be careful. If the water phase becomes disconnected at a certain height, then the water saturation will be equal to the threshold saturation at all levels above this height. If the water becomes disconnected, we introduce the free oil surface (at the goc line) and compute with respect to this level using oil and gas as the connected phases.

In the second example we calculate water and oil saturation in the gas zone from capillary-pressure data. Suppose that the oil zone thickness is 70ft and that we are interested in the oil, gas and water saturations at a height of 120 ft. We have the following data

$$\sigma_{wo} = 25 \text{ dynes}, \sigma_{wg} = 72 \text{ dynes}, \sigma_{og} = 50 \text{ dynes}, \rho_w = 68 \text{ lb/cu ft}, \rho_o = 53 \text{ lb/cu ft}, \rho_g = 7 \text{ lb/cu ft}.$$

We know that the threshold saturation of water is 16% at heights of 70 ft or higher above the free water surface. Ans.: $S_o=2\%$, $S_g=82\%$