University of Mosul

College of Petroleum & Mining Engineering

Department of Petroleum & Refining Engineering

# Petroleum Reservoir Engineering

**Third Year**

**Lecture 3**

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## Capillary hysteresis

It is generally that the pore spaces of reservoir rocks were originally filled with water, after which oil moved into the reservoir, displacing some of the water and reducing the water to some residual saturation. When discovered, the reservoir pore spaces are filled with a connate water saturation and an oil saturation. All experiments are designed to duplicate the saturation history of the reservoir. The process of generating the capillary pressure curve by displacing the wetting phase, i.e., water, with the nonwetting phase (such as with gas or oil), is called the ***drainage process***.

This drainage process establishes the fluid saturations, which are found when the reservoir is discovered. The other principal flow process of interest involves reversing the drainage process by displacing the nonwetting phase (such as with oil) with the wetting phase (e.g. water). This displacing process is termed the ***imbibitions process*** and the resulting curve is termed the ***capillary pressure imbibtion curve***. The process of saturating and desaturating a core with the nonwetting phase is called ***capillary hysteresis***. Figure 1 shows typical drainage and imbibitions capillary pressure curves. The two pressure-saturation curves are not the same. This difference in the saturating and desaturating of the capillary pressure curves is closely related to the fact that the advancing and receding contact angles of fluid interfaces on solids are different.

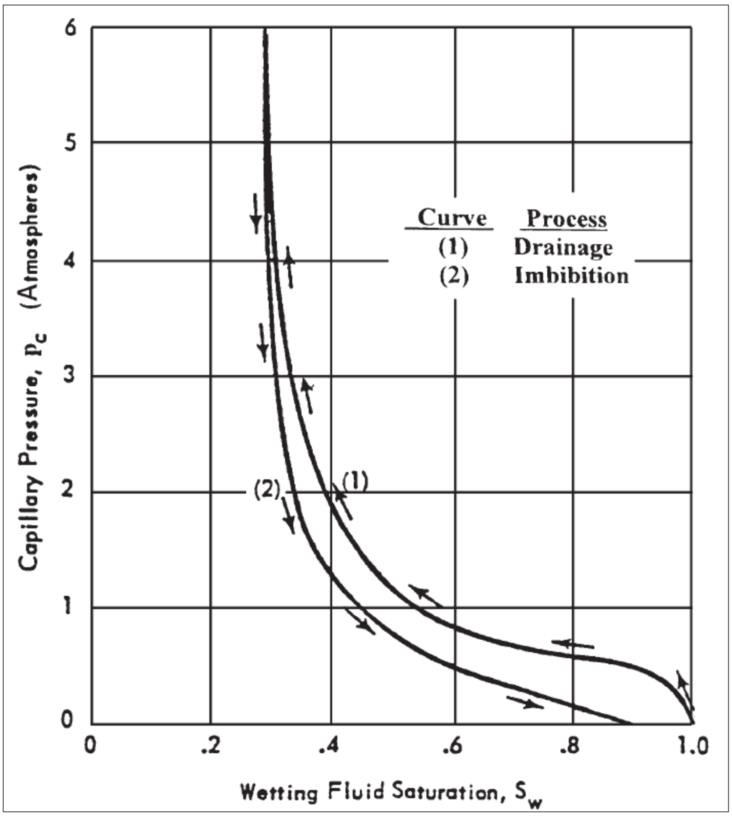


Figure 1: Capillary pressure hysteresis

## Initial saturation distribution in a reservoir

An important application of the concept of capillary pressures pertains to the fluid distribution in a reservoir prior to its exploitation. The capillary pressure-saturation data can be converted into height-saturation data and solving the height h above the free water level by using the following equation:

$$h = \frac{144\, p_c}{\Delta \rho} \tag{4-34}$$

where $p_c$ = capillary pressure, psia
$\Delta\rho$ = density difference between the wetting and nonwetting phase, lb/ft$^3$
$H$ = height above the free-water level, ft

Figure 2 shows a plot of the water saturation distribution as a function of distance from the free-water level in an oil-water system.

It is essential at this point to introduce and define four important concepts:

● Transition zone

● Water-oil contact (WOC)

● Gas-oil contact (GOC)

● Free water level (FWL)

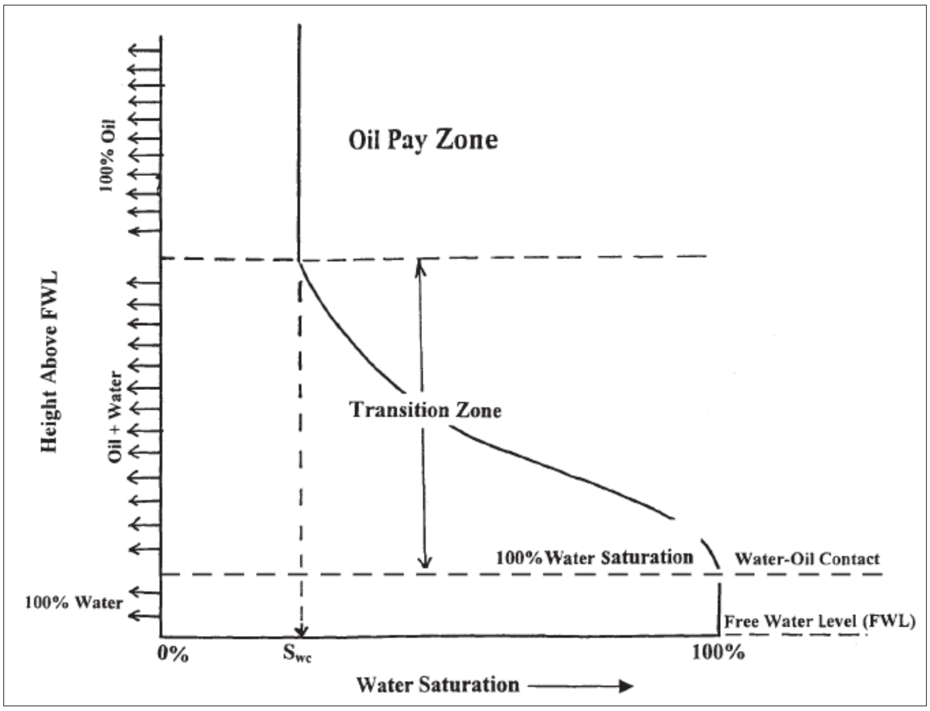


Figure 2: Water saturation profile.

Figure 3 illustrates an idealized gas, oil, and water distribution in a reservoir. The figure indicates that the saturations are gradually changing from 100% water in the water zone to irreducible water saturation some vertical distance above the water zone. This vertical area is referred to as the ***transition zone***, which must exist in any reservoir where there is a bottom water table. The transition zone is then defined as the vertical thickness over which the water saturation ranges from 100% saturation to irreducible water saturation $S_{wc}$. The important concept to be gained from Figure 3 is that there is no abrupt change from 100% water to maximum oil saturation. The creation of the oil-water transition zone is one of the major effects of capillary forces in a petroleum reservoir.

Similarly, the total liquid saturation (i.e., oil and water) is smoothly changing from 100% in the oil zone to the connate water saturation in the gas cap zone. A similar transition exists between the oil and gas zone. Figure 2 shows the gas-oil and water-oil contacts. The WOC is defined as the uppermost depth in the reservoir where a 100% water saturation exists. The GOC is defined as the minimum depth at which a 100% liquid, i.e., oil + water, saturation exists in the reservoir.

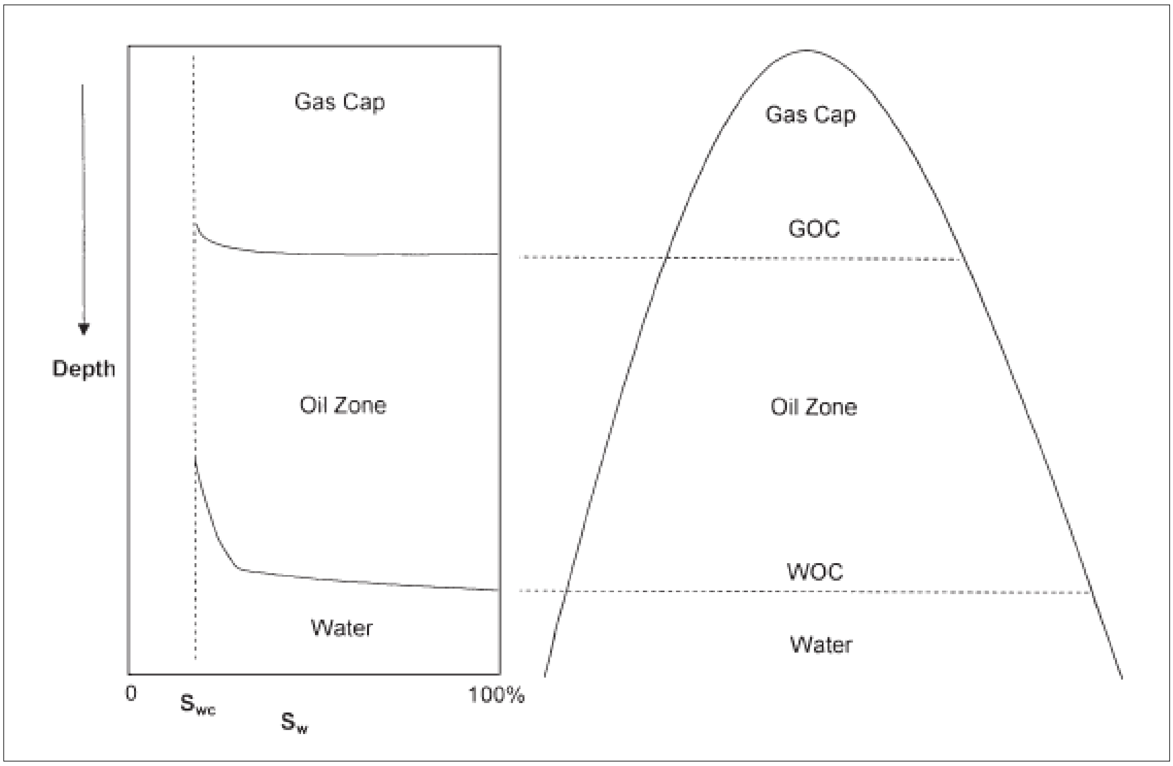


Figure 3: Initial saturation profile in a combination-drive reservoir.

Section A of Figure 4 shows a schematic illustration of a core that is represented by five different pore sizes and completely saturated with water, i.e., wetting phase. Assume that we subject the core to oil (the nonwetting phase) with increasing pressure until some water is displaced from the core, i.e., displacement pressure $P_d$. This water displacement will occur from the largest pore size. The oil pressure will have to increase to displace the water in the second largest pore.

There is a difference between the free water level (FWL) and the depth at which 100% water saturation exists. The free water level is defined by zero capillary pressure. Obviously, if the largest pore is so large that there is no capillary rise in this size pore, then the free water level and 100% water saturation level, i.e., WOC, will be the same. This concept can be expressed mathematically by the following relationship:

$$FWL = WOC + \frac{144\, p_d}{\Delta \rho}$$

where $p_d$ = displacement pressure, psi
$\Delta\rho$ = density difference, lb/ft$^3$
FWL = free water level, ft
WOC = water-oil contact, ft

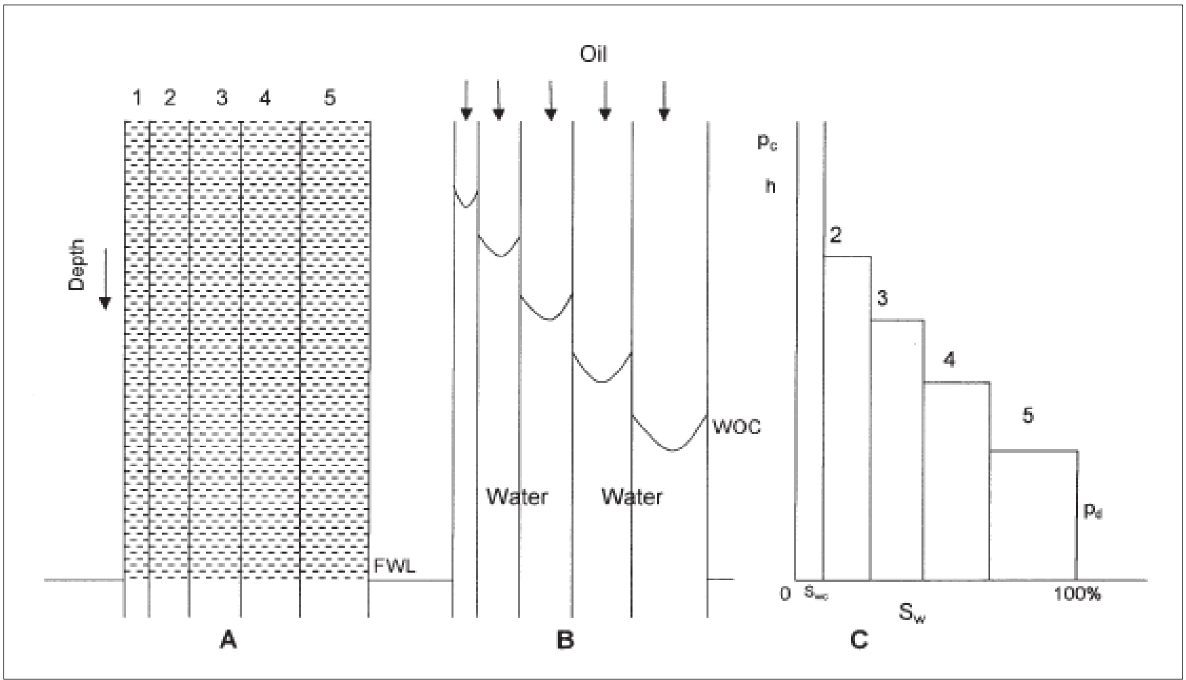


Figure 4: Relationship between saturation profile and pore-size distribution.

The thickness of the transition zone may range from a few feet to several hundred feet in some reservoirs. Recalling the capillary rise equation, i.e., height above FWL,

$$h = \frac{2\sigma(\cos\phi)}{rg\Delta\rho}$$

The above relationship suggests that the height above FWL increases with decreasing the density difference $\Delta\rho$. This means that in a gas reservoir having a gas-water contact, the thickness of the transition zone will be a minimum since the density difference ($\Delta\rho$) will be large. Also, a low API gravity oil reservoir with an oil-water contact will have a longer transition zone than a high API gravity oil reservoir (Figure 5).

Also, the above expression shows that as the radius of the pore r increases the volume of h decreases. Therefore, a reservoir rock system with small pore sizes will have a longer transition zone than a reservoir rock system comprised of large pore sizes.

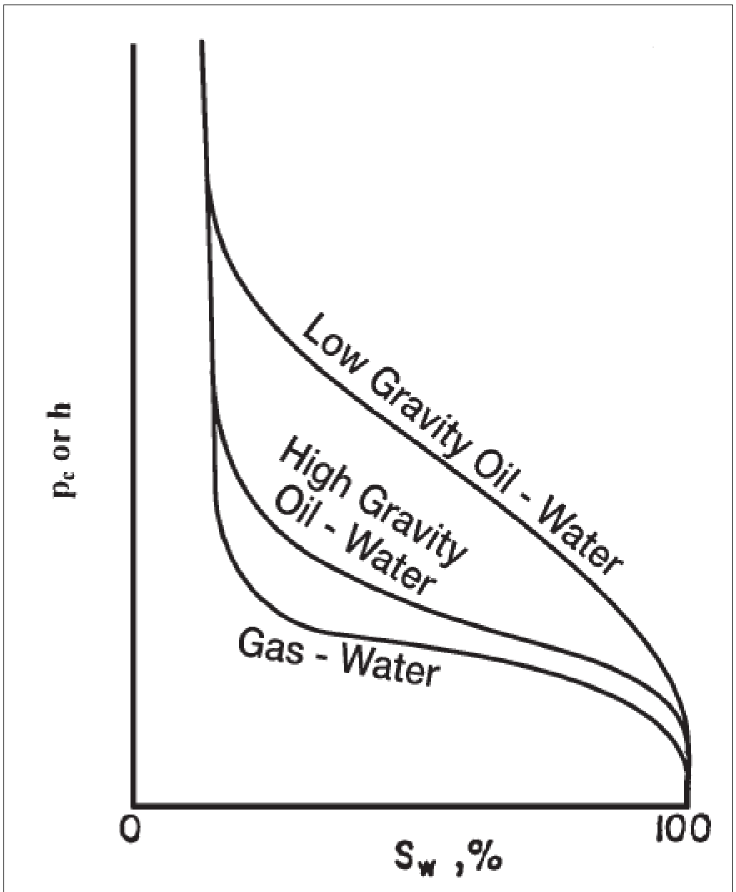


Figure 5: Variation of transition zone with fluid gravity.

The reservoir pore size can often be related approximately to permeability, and where this applies, it can be stated that high permeability reservoirs will have shorter transition zones than low permeability reservoirs as shown in Figure 6. The tilted water-oil contact could be caused by a change in permeability across the reservoir. It should be emphasized that the factor responsible for this change in the location of the water-oil contact is actually a change in the size of the pores in the reservoir rock system (Figure 7).

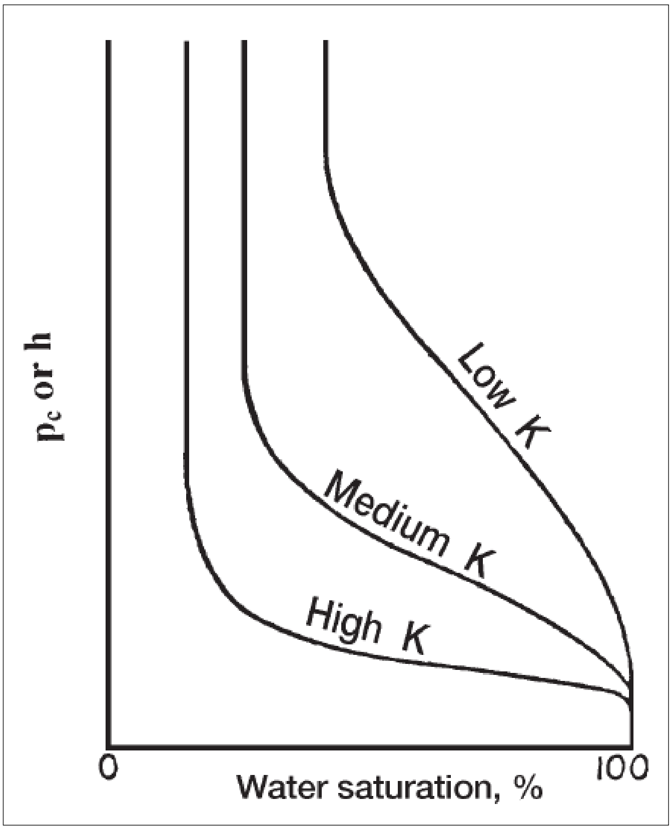


Figure 6: Variation of transition zone with permeability.

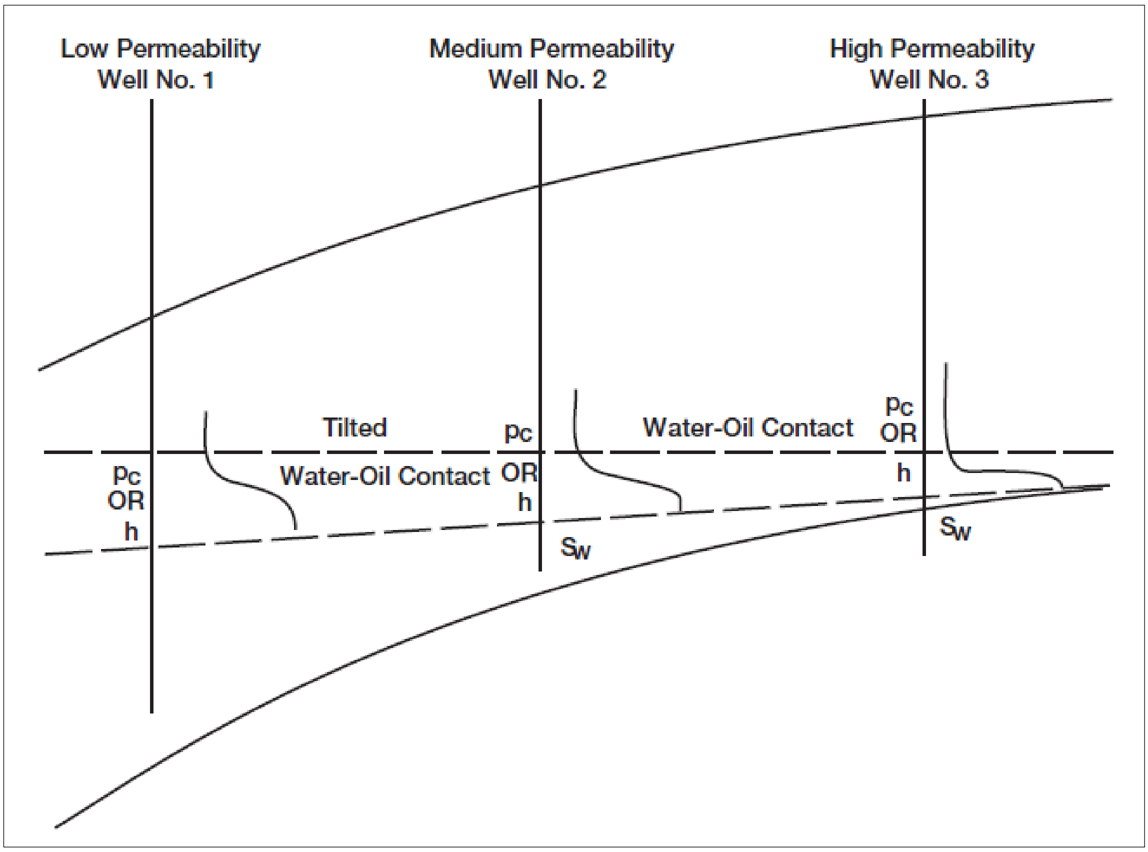


Figure 7: Tilted water-oil contact (WOC).