Lecture Five: Saturation

5.1. Definition

Saturation is defined as that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water). This property is expressed mathematically by the following relationship:

$$Saturation\ (S) = \frac{total\ volume\ of\ the\ fluid}{Pore\ volume} \qquad \text{……. (5-1)}$$

Applying the above mathematical concept of saturation to each reservoir fluid gives:

$$S_o = \frac{volume\ of\ oil}{pore\ volume} \qquad \text{……. (5-2)}$$

$$S_w = \frac{volume\ of\ water}{pore\ volume} \qquad \text{……. (5-3)}$$

$$S_g = \frac{volume\ of\ gas}{pore\ volume} \qquad \text{……. (5-4)}$$

where

S_o = oil saturation

S_g = gas saturation

S_w = water saturation

Thus, all saturation values are based on pore volume and not on the gross reservoir volume. The saturation of each individual phase ranges between zero to 100 percent. By definition, the sum of the saturations is 100%, therefore

$$S_g + S_o + S_w = 1 \qquad \text{……. (5-5)}$$

The fluids in most reservoirs are believed to have reached a state of equilibrium and, therefore, will have become separated according to their

density, i.e., oil overlain by gas and underlain by water. In addition to the bottom (or edge) water, there will be connate water distributed throughout the oil and gas zones. The water in these zones will have been reduced to some irreducible minimum. The forces retaining the water in the oil and gas zones are referred to as **capillary forces** because they are important only in pore spaces of capillary size.

5.2. Importance of Fluid Saturation

The saturation of reservoir fluids is important physical property of reservoir rocks. The knowledge of fluid saturation is much necessary in every phase of reservoir production. For example, it is used for the estimation of initial oil or gas in place, and for the identification of reservoir zones where a large quantity of oil is left behind. It is also involved in the evaluation of the enhanced oil recovery process.

5.3. Types of Fluid Saturations

After production, fluid saturations in a reservoir will alter significantly with time. This phenomenon can be observed due to the appearance of a new phase (such as free gas in oil reservoir or condensate liquid in gas reservoir). It can also be found following the injection of a driving fluid (such as water or gas) to enhance oil recovery. The following saturation concepts are commonly used in different stages of reservoir life: *initial saturation, current saturation, residual saturation*.

Initial saturation means the fraction of pore volume occupied by a given fluid (oil, gas or water) before an oil/gas reservoir production. Initial water saturation is also known as irreducible water saturation. Initial oil/gas saturations are vital parameters of determining oil/gas geologic reserves and predicting the performance of reservoir production. However, they are not easy to be determined accurately.

Individual fluid saturations vary with time and location in a producing reservoir. Following oil production, oil saturation decreases gradually, and water saturation and gas saturation increase gradually due to reservoir pressure decrease and water invasion/injection. Thereby, **current saturation** means the oil, gas, or water saturation during reservoir production.

- **Connate (interstitial) water saturation, S_{wc}**

The critical water saturation, connate water saturation, and irreducible water saturation are extensively used interchangeably to define the maximum water saturation at which the water phase will remain immobile.

S_{wc} is important primarily because it reduces the amount of space available between oil and gas. It is generally not uniformly distributed throughout the reservoir but varies with permeability, lithology, and height above the free water table.

- **Critical Oil Saturation, S_{oc}**

For the oil phase to flow, the saturation of the oil must exceed a certain value, which is termed critical oil saturation. At this particular saturation, the oil remains in the pores and, for all practical purposes, will not flow. After this saturation oil will flow.

- **Residual Oil Saturation, S_{or}**

During the displacing process of the crude oil system from the porous media some remaining oil will be left that is quantitatively characterized by a saturation value that is larger than the critical oil saturation. This saturation value is called the residual oil saturation, S_{or}. The term residual saturation is usually associated with the nonwetting phase (oil or gas) when it is being displaced by a wetting phase (water).

- **Movable Oil Saturation, S_{om}**

Movable oil saturation S_{om} is another saturation of interest and is defined as the fraction of pore volume occupied by movable oil as expressed by the following equation:

$$S_{om} = 1 - S_{wc} - S_{oc} \qquad \text{....... (5-6)}$$

where:

S_{wc} = connate water saturation.

S_{om} = critical oil saturation.

- **Critical Gas Saturation, S_{gc}**

As the reservoir pressure declines below the bubble-point pressure, gas evolves from the oil phase and consequently the saturation of the gas increases as the reservoir pressure declines. The gas phase remains immobile until its saturation exceeds certain saturation, called critical gas saturation, above which gas begins to move. If S_{gc} = 5% then gas doesn't flow until its S_{gc} exceeds 5%.

5.4. Saturation Averaging

Proper averaging of saturation data requires that the saturation values be weighted by both the interval thickness hi and interval porosity ϕ. The average saturation of each reservoir fluid is calculated from the following equations:

$$S_o = \frac{\sum_{i=1}^{n} \emptyset_i \times h_i \times S_{oi}}{\sum_{i=1}^{n} \emptyset_i \times h_i} \qquad \text{....... (5-7)}$$

$$S_w = \frac{\sum_{i=1}^{n} \emptyset_i \times h_i \times S_{wi}}{\sum_{i=1}^{n} \emptyset_i \times h_i} \qquad \text{....... (5-8)}$$

$$S_g = \frac{\sum_{i=1}^{n} \emptyset_i \times h_i \times S_{gi}}{\sum_{i=1}^{n} \emptyset_i \times h_i} \qquad \text{.......} (5\text{-}9)$$

where the subscript i refers to any individual measurement and hi represents the depth interval to which ϕi, Soi, Sgi, and Swi apply.

Example 1

Calculate average oil and connate water saturation from the following measurements:

Sample	h_i, ft	ϕ, %	S_o, %	S_{wc}, %
1	1.0	10	75	25
2	1.5	12	77	23
3	1.0	11	79	21
4	2.0	13	74	26
5	2.1	14	78	22
6	1.1	10	75	25

Solution:

Construct the following table and calculate the average saturation for the oil and water phase:

Sample	h_i, ft	ϕ	ϕh	S_o	$S_o\phi h$	S_{wc}	$S_w\phi h$
1	1.0	0.10	0.100	0.75	0.0750	0.25	0.0250
2	1.5	0.12	0.180	0.77	0.1386	0.23	0.0414
3	1.0	0.11	0.110	0.79	0.0869	0.21	0.0231
4	2.0	0.13	0.260	0.74	0.1924	0.26	0.0676
5	2.1	0.14	0.294	0.78	0.2293	0.22	0.0647
6	1.1	0.10	0.110	0.75	0.0825	0.25	0.0275
			1.054		0.8047		0.2493

Calculation of average oil saturation

$$S_o = \frac{\sum_{i=1}^{n} \emptyset_i \times h_i \times S_{oi}}{\sum_{i=1}^{n} \emptyset_i \times h_i}$$

$$S_o = \frac{0.8047}{1.054} = 0.7635 = 76.35\%$$

Calculation of average water saturation

$$S_w = \frac{\sum_{i=1}^{n} \emptyset_i \times h_i \times S_{wi}}{\sum_{i=1}^{n} \emptyset_i \times h_i}$$

$$S_w = \frac{0.2493}{1.054} = 0.2364 = 23.64\%$$

5.5. Laboratory Measurement of Fluid Saturation

Fluid saturation in reservoir rocks can be determined by essentially two different approaches: direct and indirect. The direct approach involves using preserved core plug samples. The indirect method is based on traditional well-logging techniques where fluid saturations are not measured on core plugs but are measured for the entire formation itself at various depths.

Soxhlet Extraction is the most common method for calculating the saturation, and is routinely used by most laboratories.

As shown in Figure 5-1, toluene is boiled in a flask; its vapors move upwards and the core becomes engulfed in the toluene vapors (at approximately 110°C). The toluene together the toluene dissolves any oil with which it comes into contact. Eventual water within the core sample will be vaporized. The toluene solvent and water vapors enter the inner chamber of the condenser; the cold water circulating about the inner chamber condenses both vapors to immiscible liquids.
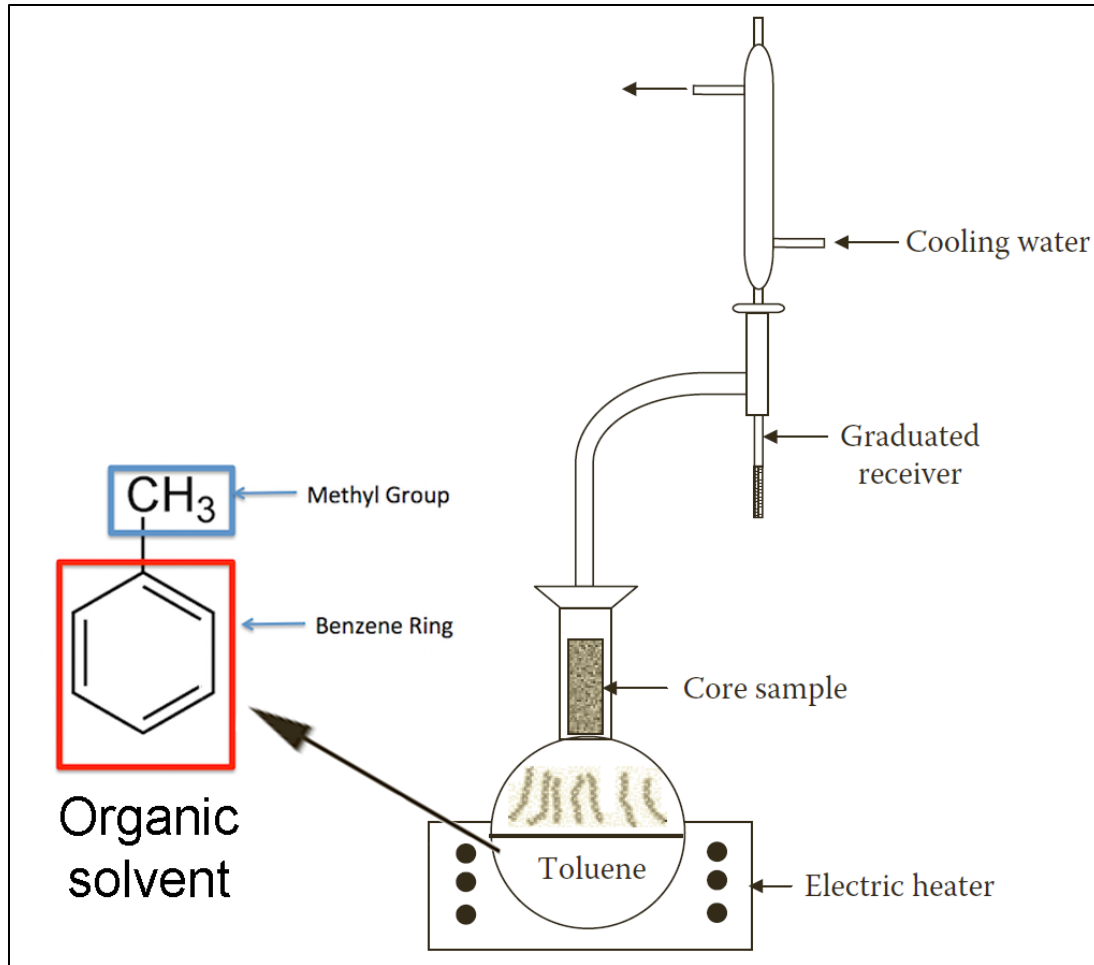
Fig. 5-1 Saturation calculation

Example 2

A core sample has a bulk volume of 95 cc is saturated with oil and water. The initial core weight is 225.9 gm. The sample is placed in Soxhlet Extraction and 4.4 cc of water is extracted. After drying the core sample the weight is now 209.75 gm. Find Ø, Sw and So if ρ_o= 0.85 gm/cc and ρ_w= 1 gm/cc.

Solution:

Weight of fluids (water+oil)= W_{sat}- W_{dry}

W_{fluids} =225.9- 209.75 = 16.15 gm

W_{water} = V_{water} × ρ_w = 4.4 gm

$W_{oil} = W_{fluids} - W_{water}$

$W_{oil} = 16.15 - 4.4 = 11.75 \text{gm}$

$V_{oil} = \dfrac{W_{oil}}{\rho_{oil}} = \dfrac{11.75}{0.85} = 13.82 \text{ cc}$

$V_{water} = 4.4 \text{ cc}$

$V_{pore} = V_{water} + V_{oil} = 13.82 + 4.4 = 18.22 \text{ cc}$

$\emptyset = \dfrac{V_p}{V_b} = \dfrac{18.22}{95} = 0.192 = 19.2\%$

$S_w = \dfrac{V_w}{V_p} = \dfrac{4.4}{18.22} = 0.24$

$S_o = \dfrac{V_o}{V_p} = \dfrac{13.82}{18.22} = 0.759$