

Chapter 4

Fundamentals of Rock Properties

The material of which a petroleum reservoir rock may be composed can range from very loose and unconsolidated sand to a very hard and dense sandstone, limestone, or dolomite. The grains may be bonded together with a number of materials, the most common of which are silica, calcite, or clay. Knowledge of the physical properties of the rock and the existing interaction between the hydrocarbon system and the formation is essential in understanding and evaluating the performance of a given reservoir.

Rock properties are determined by performing laboratory analyses on cores from the reservoir to be evaluated. The cores are removed from the reservoir environment, with subsequent changes in the core bulk volume, pore volume, reservoir fluid saturations, and, sometimes, formation wettability. The effect of these changes on rock properties may range from negligible to substantial, depending on characteristics of the formation and property of interest, and should be evaluated in the testing program.

There are basically two main categories of core analysis tests that are performed on core samples regarding physical properties of reservoir rocks. These are:

Routine core analysis tests

- Porosity
- Permeability
- Saturation

Special tests

- Overburden pressure
- Capillary pressure
- Relative permeability
- Wettability
- Surface and interfacial tension

The above rock property data are essential for reservoir engineering calculations as they directly affect both the quantity and the distribution of hydrocarbons and, when combined with fluid properties, control the flow of the existing phases (i.e., gas, oil, and water) within the reservoir.

POROSITY

The porosity of a rock is a measure of the **storage capacity (pore volume)** that is capable of holding fluids. Quantitatively, the porosity is the ratio of the pore volume to the total volume (bulk volume). This important rock property is determined mathematically by the following generalized relationship:

$$\phi = \frac{\text{pore volume}}{\text{bulk volume}}$$

where ϕ = porosity

As the sediments were deposited and the rocks were being formed during past geological times, some void spaces that developed became isolated from the other void spaces by excessive cementation. Thus, many of the void spaces are interconnected while some of the pore spaces are completely isolated. This leads to two distinct types of porosity, namely:

- **Absolute porosity**
- **Effective porosity**

Absolute porosity

The absolute porosity is defined as the ratio of the **total pore space** in the rock to that of the **bulk volume**. A rock may have considerable absolute porosity and yet have no conductivity to fluid for lack of pore interconnection. The absolute porosity is generally expressed mathematically by the following relationships:

$$\phi_a = \frac{\text{total pore volume}}{\text{bulk volume}} \quad (4-1)$$

or

$$\phi_a = \frac{\text{bulk volume} - \text{grain volume}}{\text{bulk volume}} \quad (4-2)$$

where ϕ_a = absolute porosity.

Effective porosity

The effective porosity is the percentage of **interconnected** pore space with respect to the bulk volume, or

$$\phi = \frac{\text{interconnected pore volume}}{\text{bulk volume}} \quad (4-3)$$

where ϕ = effective porosity.

The effective porosity is the value that is used in all reservoir engineering calculations because it represents the interconnected pore space that contains the recoverable hydrocarbon fluids.

Porosity may be classified according to the mode of origin as original induced.

The **original porosity** is that developed in the deposition of the material, while **induced porosity** is that developed by some geologic process subsequent to deposition of the rock. The intergranular porosity of sandstones and the intercrystalline and oolitic porosity of some limestones typify original porosity. Induced porosity is typified by fracture development as found in shales and limestones and by the slugs or solution cavities commonly found in limestones. Rocks having original porosity are more uniform in their characteristics than those rocks in which a large part of the porosity is induced. For direct quantitative measurement of porosity, reliance must be placed on formation samples obtained by coring.

Since effective porosity is the porosity value of interest to the petroleum engineer, particular attention should be paid to the methods used to determine porosity. For example, if the porosity of a rock sample was determined by saturating the rock sample 100% with a fluid of known density and then determining, by weighing, the increased weight due to the saturating fluid, this would yield an effective porosity measurement because the saturating fluid could enter only the interconnected pore spaces. On the other hand, if the rock sample were crushed with a mortar and pestle to determine the actual volume of the solids in the core sample, then an absolute porosity measurement would result because the identity of any isolated pores would be lost in the crushing process.

One important application of the effective porosity is its use in **determining the original hydrocarbon volume in place**. Consider a reservoir with an areal extent of A acres and an average thickness of h feet. The total bulk volume of the reservoir can be determined from the following expressions:

$$\text{Bulk volume} = 43,560 Ah, \text{ ft}^3 \quad (4-4)$$

or

$$\text{Bulk volume} = 7,758 Ah, \text{ bbl} \quad (4-5)$$

where

A = areal extent, acres

h = average thickness

The reservoir pore volume PV can then be determined by combining Equations 4-4 and 4-5 with 4-3. Expressing the reservoir pore volume in cubic feet gives:

$$PV = 43,560 Ah\phi, \text{ ft}^3 \quad (4-6)$$

Expressing the reservoir pore volume in barrels gives:

$$PV = 7,758 Ah\phi, \text{ bbl} \quad (4-7)$$

Example 4-1

An oil reservoir exists at its bubble-point pressure of 3,000 psia and temperature of 160°F. The oil has an API gravity of 42° and gas-oil ratio of 600 scf/STB. The specific gravity of the solution gas is 0.65. The following additional data are also available:

- Reservoir area = 640 acres
- Average thickness = 10 ft
- Connate water saturation = 0.25
- Effective porosity = 15%

Calculate the initial oil in place in STB.

Solution

Step 1. Determine the specific gravity of the stock-tank oil from Equation 2-68.

$$\gamma_o = \frac{141.5}{42 + 131.5} = 0.8156$$

Step 2. Calculate the initial oil formation volume factor by applying Standing's equation, i.e., Equation 2-85, to give:

$$\begin{aligned} B_0 &= 0.9759 + 0.00012 \left[600 \left(\frac{0.65}{0.8156} \right)^{0.5} + 1.25(160) \right]^{1.2} \\ &= 1,396 \text{ bbl/STB} \end{aligned}$$

Step 3. Calculate the pore volume from Equation 4-7.

$$\text{Pore volume} = 7758 (640) (10) (0.15) = 7,447,680 \text{ bbl}$$

Step 4. Calculate the initial oil in place.

$$\text{Initial oil in place} = 12,412,800(1 - 0.25)/1.306 = 4,276,998 \text{ STB}$$

The reservoir rock may generally show large variations in porosity vertically but does not show very great variations in porosity parallel to the bedding planes. In this case, the arithmetic average porosity or the thickness-weighted average porosity is used to describe the average reservoir porosity. A change in sedimentation or depositional conditions, however, can cause the porosity in one portion of the reservoir to be greatly different from that in another area. In such cases, the areal-weighted average or the volume-weighted average porosity is used to characterize the average rock porosity. These averaging techniques are expressed mathematically in the following forms:

$$\text{Arithmetic average } \phi = \Sigma \phi_i / n \quad (4-8)$$

$$\text{Thickness – weighted average } \phi = \Sigma\phi_i h_i / \Sigma h_i \quad (4-9)$$

$$\text{Areal – weighted average } \phi = \Sigma\phi_i A_i / \Sigma A_i \quad (4-10)$$

$$\text{Volumetric – weighted average } \phi = \Sigma\phi_i A_i h_i / \Sigma A_i h_i \quad (4-11)$$

where

n = total number of core samples

h_i = thickness of core sample i or reservoir area i

ϕ_i = porosity of core sample i or reservoir area i

A_i = reservoir area i

Example 4-2

Calculate the arithmetic average and thickness-weighted average from the following measurements:

Sample	Thickness, ft	Porosity, %
1	1.0	10
2	1.5	12
3	1.0	11
4	2.0	13
5	2.1	14
6	1.1	10

Solution

- Arithmetic average

$$\phi = \frac{10 + 12 + 11 + 13 + 14 + 10}{6} = 11.67\%$$

- Thickness-weighted average

$$\begin{aligned} \phi &= \frac{(1)(10) + (1.5)(12) + (1)(11) + (2)(13) + (2.1)(14) + (1.1)(10)}{1 + 1.5 + 1 + 2 + 2.1 + 1.1} \\ &= 12.11\% \end{aligned}$$

SATURATION

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:

$$\text{fluid saturation} = \frac{\text{total volume of the fluid}}{\text{pore volume}}$$

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

$$S_o = \frac{\text{volume of oil}}{\text{pore volume}} \quad (4-12)$$

$$S_g = \frac{\text{volume of gas}}{\text{pore volume}} \quad (4-13)$$

$$S_w = \frac{\text{volume of water}}{\text{pore volume}} \quad (4-14)$$

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%. By definition, the sum of the saturations is 100%, therefore

$$S_g + S_o + S_w = 1.0 \quad (4-15)$$

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.

Connate (interstitial) water saturation 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.

Another particular phase saturation of interest is called the *critical saturation* and it is associated with each reservoir fluid. The definition and the significance of the critical saturation for each phase is described below.

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.

Residual oil saturation to water, S_{orw}

During the displacing process of the crude oil system from the porous media by water or gas injection (or encroachment), there will be some remaining oil 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 to water S_{orw} . The term residual saturation is usually associated with the **nonwetting phase** when it is being displaced by a **wetting phase**.

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:

$$S_{om} = 1 - S_{wc} - S_{oc}$$

where

S_{wc} = connate water saturation

S_{oc} = 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 a certain saturation, called *critical gas saturation***, above which gas begins to move.

Critical 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.

Average Saturation

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

$$S_o = \frac{\sum_{i=1}^n \phi_i h_i S_{oi}}{\sum_{i=1}^n \phi_i h_i} \quad (4-16)$$

$$S_w = \frac{\sum_{i=1}^n \phi_i h_i S_{wi}}{\sum_{i=1}^n \phi_i h_i} \quad (4-17)$$

$$S_g = \frac{\sum_{i=1}^n \phi_i h_i S_{gi}}{\sum_{i=1}^n \phi_i h_i} \quad (4-18)$$

where the subscript i refers to any individual measurement and h_i represents the depth interval to which ϕ_i , S_{oi} , S_{gi} , and S_{wi} apply.

Example 4-3

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

Sample	h_i , ft	ϕ , %	S_{or} , %	S_{wcr} , %
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}	$S_{wc} \phi h$
1	1.0	.10	.100	.75	.0750	.25	.0250
2	1.5	.12	.180	.77	.1386	.23	.0414
3	1.0	.11	.110	.79	.0869	.21	.0231
4	2.0	.13	.260	.74	.1924	.26	.0676
5	2.1	.14	.294	.78	.2293	.22	.0647
6	1.1	.10	.110	.75	.0825	.25	.0275
			1.054		0.8047		0.2493

Calculate average oil saturation by applying Equation 4-16:

$$S_o = \frac{.8047}{1.054} = 0.7635$$

Calculate average water saturation by applying Equation 4-17:

$$S_w = \frac{0.2493}{1.054} = 0.2365$$

WETTABILITY

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. The concept of wettability is illustrated in Figure 4-1. Small drops of three liquids—mercury, oil, and