

Basic Relationships of Well Log Interpretation

INTRODUCTION

GENERAL

Well Logging is the practice of making a detailed record (log) of the geologic formations penetrated by a borehole.

The log may be based on visual inspection of samples brought to the surface (geological logs; core logs) or physical measurements made by instruments lowered into the hole (geophysical logs).

Logging data are used to identify productive zones, to determine depth and thickness of zones, to distinguish between oil, gas, or water in a reservoir, and to estimate hydrocarbon reserves.

Of the various types of logs, the ones used most frequently in hydrocarbon exploration are called openhole logs. The name open hole is applied because these logs are recorded in the uncased portion of the wellbore. All the different types of logs and their curves discussed in this text are of this type.

Remember that a borehole represents a dynamic system; that fluid used in the drilling of a well affects the rock surrounding the borehole and, therefore, log measurements. In addition, the rock surrounding the borehole has certain properties that affect the movement of fluids into and out of it.

The two primary parameters determined from well log measurements are porosity and the fraction of pore space filled with hydrocarbons (i.e., hydrocarbon saturation). The parameters of log interpretation are determined directly or inferred indirectly and are measured by one of three general types of logs:

- electrical
- nuclear
- acoustic or sonic logs

Rock properties or characteristics that affect logging measurements are: *porosity, lithology, mineralogy, permeability, and water saturation*. Additionally, the *resistivity* of the rock is important because it is directly measured and is an essential part in the interpretation process. It is

essential that the reader understand these properties and the concepts they represent before proceeding with a study of log interpretation.

Porosity

Porosity can be defined as the ratio of voids to the total volume of rock. It is represented as a decimal fraction or as a percentage and is usually represented by the Greek letter phi, ϕ .

$$\text{porosity, } \phi = \frac{\text{volume of pores}}{\text{total volume of rock}} \quad 1.1$$

The amount of internal space or voids in a given volume of rock is a measure of the amount of fluid a rock will hold. This is illustrated by Equation 1.1 and is called the *total porosity*. The amount of void space that is interconnected, and thus able to transmit fluids, is called *effective porosity*. Isolated pores and pore volume occupied by adsorbed water are excluded from a definition of effective porosity but are included in the definition of total porosity.

Lithology and Mineralogy

In well-log analysis, the terms *lithology* and *mineralogy* are used with some ambiguity. *Lithology* is often used to describe the solid (*matrix*) portion of the rock, generally in the context of a description of the primary mineralogy of the rock (e.g., a *sandstone* as a description of a rock composed primarily of quartz grains, or a *limestone* composed primarily of calcium carbonate). In the early days of log interpretation (with limited measurements), this was usually a sufficient description.

The ambiguity between lithology and mineralogy is best seen in porosity cross plots which, through time, have moved from estimating lithology to estimating mineralogy, while the underlying measurements and interpretive techniques have remained essentially the same.

In this text, *shale volume* will be used preferentially because most of the interpretive techniques in which the volumes are used derive those volumes from the properties of nearby shales.

Permeability

Permeability is the ability of a rock to transmit fluids. It is related to porosity but is not always dependent upon it. Permeability is controlled

by the size of the connecting passages (pore throats or capillaries) between pores. It is measured in darcys or millidarcys (md) and is represented by the symbol K . The ability of a rock to transmit a single fluid, when it is completely saturated with that fluid, is called *absolute permeability*.

Effective permeability refers to the ability of the rock to transmit one fluid in the presence of another fluid when the two fluids are immiscible.

Relative permeability is the ratio between effective permeability of a fluid at partial saturation and the permeability at 100% saturation (absolute permeability).

When relative permeability of a formation's water is zero, the formation produces water-free hydrocarbons (i.e., the relative permeability to hydrocarbons is 100%). *With increasing relative permeabilities to water, the formation produces increasing amounts of water relative to hydrocarbons.*

Water Saturation

Water saturation is the amount of pore volume in a rock that is occupied by formation water. It is represented as a decimal fraction or as a percentage and has the symbol S_w .

$$\text{water saturation, } S_w = \frac{\text{formation water occupying pores}}{\text{total pore space in the rock}} \quad 1.2$$

Although hydrocarbon saturation is the quantity of interest, water saturation is usually used because of its direct calculation in equations such as Archie's equation, discussed in a later section in this chapter. Hydrocarbon saturation is usually determined by the difference between unity and water saturation:

$$S_h = 1 - S_w \quad 1.3$$

Irreducible water saturation or $S_w \text{ irr}$ is the term used to describe the water saturation at which all the water is adsorbed on the grains in a rock or is held in the capillaries by capillary pressure. At irreducible water saturation, water does not move and the relative permeability to water is zero.

Resistivity

Resistivity is the rock property on which the entire science of logging first developed. Resistivity is the inherent property of all materials, regardless of their shape and size, to resist the flow of an electric current.

Different materials have different abilities to resist the flow of electricity. While the resistance of a material depends on its shape and dimensions, the resistivity is an invariant property; the reciprocal of resistivity is conductivity.

In log interpretation, the hydrocarbons, the rock, and the fresh water of the formation are all assumed to act as insulators and are, therefore, nonconductive (or at least very highly resistive) to electric current flow. Salt water, however, is a conductor and has a low resistivity.

The measurement of resistivity is then a measurement, albeit indirect, of the amount (and salinity) of the formation water. The unit of measure used for the conductor is a cube of the formation, one meter on each edge. The measured units are ohm-meters²/meter and are called ohm-meters.

$$R = \frac{r \times A}{L} \qquad 1.4$$

where:

R = resistivity (ohm-m)

r = resistance (ohms)

A = cross-sectional area of substance being measured (m²)

L = length of substance being measured (m)

Resistivity is a basic measurement of a reservoir's fluid saturation and is a function of porosity, type of fluid (i.e., hydrocarbons, salt water, or fresh water), amount of fluid, and type of rock. Because both the rock and hydrocarbons act as insulators but salt water is conductive, resistivity measurements made by logging tools can be used to detect hydrocarbons and estimate the porosity of a reservoir.

During the drilling of a well, fluids move into porous and permeable formations surrounding a borehole, so resistivity measurements recorded at different distances into a formation often have different values.

Resistivity is measured by *electric logs*, commonly known as laterologs and induction logs.

Archie's experiments showed that the resistivity of a water-filled formation (R_o) could be related to the resistivity of the water (R_w) filling the formation through a constant called the formation resistivity factor (F):

$$R_o = F \times R_w \quad 1.5$$

Archie's experiments also revealed that the formation factor (F) could be related to the porosity of the formation by the following formula:

$$F = \frac{a}{\phi^m} \quad 1.6$$

where m is the cementation exponent whose value varies with grain size, grain-size distribution, and the complexity of the paths between pores (tortuosity), and a is the tortuosity factor. The higher the tortuosity of the formation, the higher the value of m . The tortuosity factor (a) is commonly set to 1.0, but is allowed to vary by some petrophysicists.

Water saturation (S_w) is determined from the water filled resistivity (R_o) and the actual (*true*) formation resistivity (R_t) by the following relationship:

$$S_w = \left(\frac{R_o}{R_t} \right)^{\frac{1}{n}} \quad 1.7$$

where n is the saturation exponent, whose value typically varies from 1.8 to 2.5 but is most commonly assumed to be 2.

By combining equations 1.6 and 1.7, the water-saturation formula can be rewritten in the following form:

$$S_w = \left(\frac{F \times R_w}{R_t} \right)^{\frac{1}{n}} \quad 1.8$$

This is the formula that is most commonly referred to as the Archie equation for water saturation (S_w). All present methods of interpretation involving resistivity curves are derived from this equation. In its most general form, Archie's equation becomes:

$$S_w = \left(\frac{a \times R_w}{R_t \times \phi^m} \right)^{\frac{1}{n}} \quad 1.9$$

Table 1.1 illustrates the range of values for a and m . In first-pass or reconnaissance-level interpretations, or where there is no knowledge of the local parameters, the following values can be used to achieve an initial estimate of water saturation:

$$a = 1.0; m = n = 2.0$$

Now that the reader is introduced to some of the basic concepts of well log interpretation, our discussion can continue in more detail about the factors that affect logging measurements.

Table 1.1. Different coefficients and exponents used to calculate formation factor (F)

a : Tortuosity factor	m : Cementation exponent	Comments
1.0	2.0	Carbonates ¹
0.81	2.0	Consolidated sandstones ¹
0.62	2.15	Unconsolidated sands (Humble formula) ¹
1.45	1.54	Average sands (after Carothers, 1968)
1.65	1.33	Shaly sands (after Carothers, 1968)
1.45	1.70	Calcareous sands (after Carothers, 1968)
0.85	2.14	Carbonates (after Carothers, 1968)
2.45	1.08	Pliocene sands, southern California (after Carothers and Porter, 1970)
1.97	1.29	Miocene sands, Texas–Louisiana Gulf Coast (after Carothers and Porter, 1970)
1.0	$\phi^{(2.05-\phi)}$	Clean granular formations (after Sethi, 1979)