

## POROSITY LOGGING

The porosity of a zone can be estimated either from a single “porosity log” (sonic, density, neutron, or magnetic resonance log) or a combination of porosity logs, in order to correct for variable lithology effects in complex reservoirs. In the carbonates, mineral mixtures are primarily drawn from calcite, dolomite, and quartz (either as sand grains or as chert); anhydrite and gypsum may also occur.

When using a single porosity log, the true porosity is calculated from interpolation between the values for the matrix mineral and the pore fluid (usually equated with mud filtrate, because of the shallow investigation of the porosity tools).

Density log:

Porosity is calculated from the mass-balance relationship:

$$\rho_b = \phi \cdot \rho_f + (1 - \phi)\rho_{ma}$$

where  $\rho_b$  is the bulk density,  $\phi$  is the porosity,  $\rho_{ma}$  is the matrix density, and  $\rho_f$  is the pore fluid density. If a sandstone, then the matrix density is 2.65 gm/cc (quartz), if a limestone, the matrix density is 2.71 gm/cc (calcite); if a dolomite, then the matrix density is about 2.87 gm/cc. The density log is scaled as bulk density in grams per cubic centimeter. If a “density porosity log” is displayed, then it will be an apparent porosity keyed to a specific mineral, usually calcite, in which case the curve will be indexed as “limestone equivalent porosity”. This porosity will be in error in all lithologies whose matrix density differs from that of calcite.

Neutron log.

Older neutron logs were scaled in counts, but modern neutron logs are recorded in apparent porosity units with respect to a given mineralogy. Calcite is commonly chosen as a default mineral, in which case the porosity values will be true porosities in limestone zones. Where zones are not limestone, the limestone-equivalent neutron log should be rescaled to the zone matrix mineral or combined with a density limestone-equivalent porosity in an estimate of the true porosity.

Neutron-density log combination:

The combination of density and neutron logs is now used commonly as a means to determine porosity that is largely free of lithology effects. Each individual log records an apparent porosity that is only true when the zone lithology matches that used by the logging engineer to scale the log. A limestone-equivalent porosity is a good choice for both neutron and density logs, because calcite has properties that are intermediate between dolomite and quartz. By averaging the apparent neutron and density porosities of a zone, effects of dolomite and quartz tend to cancel out. The true porosity may be

estimated either by taking an average of the two log readings or by applying the equation:

$$\phi = \sqrt{\frac{\phi_n^2 + \phi_d^2}{2}}$$

where  $\phi_n$  and  $\phi_d$  are neutron and density porosities. It has been suggested that the square-root equation is preferable as a means of suppressing the effects of any residual gas in the flushed zone.

### **Sonic log:**

If a sonic log is used for porosity estimation, the equivalent relationship is:

$$\Delta t = \phi \cdot \Delta t_f + (1 - \phi) \Delta t_{ma}$$

where  $\Delta t$  is the zone transit time,  $\phi$  is the porosity,  $\Delta t_{ma}$  is the matrix transit time, and  $\Delta t_f$  is the pore fluid transit time. The computation of porosity requires the stipulation of a matrix mineral transit time, which is about 55.5 microseconds per foot for quartz, 47.5 for calcite, and 43.5 for dolomite. So, transformation of the sonic log to a porosity log generates an apparent porosity trace keyed to one or other matrix mineral, in a similar fashion to the neutron and density logs.

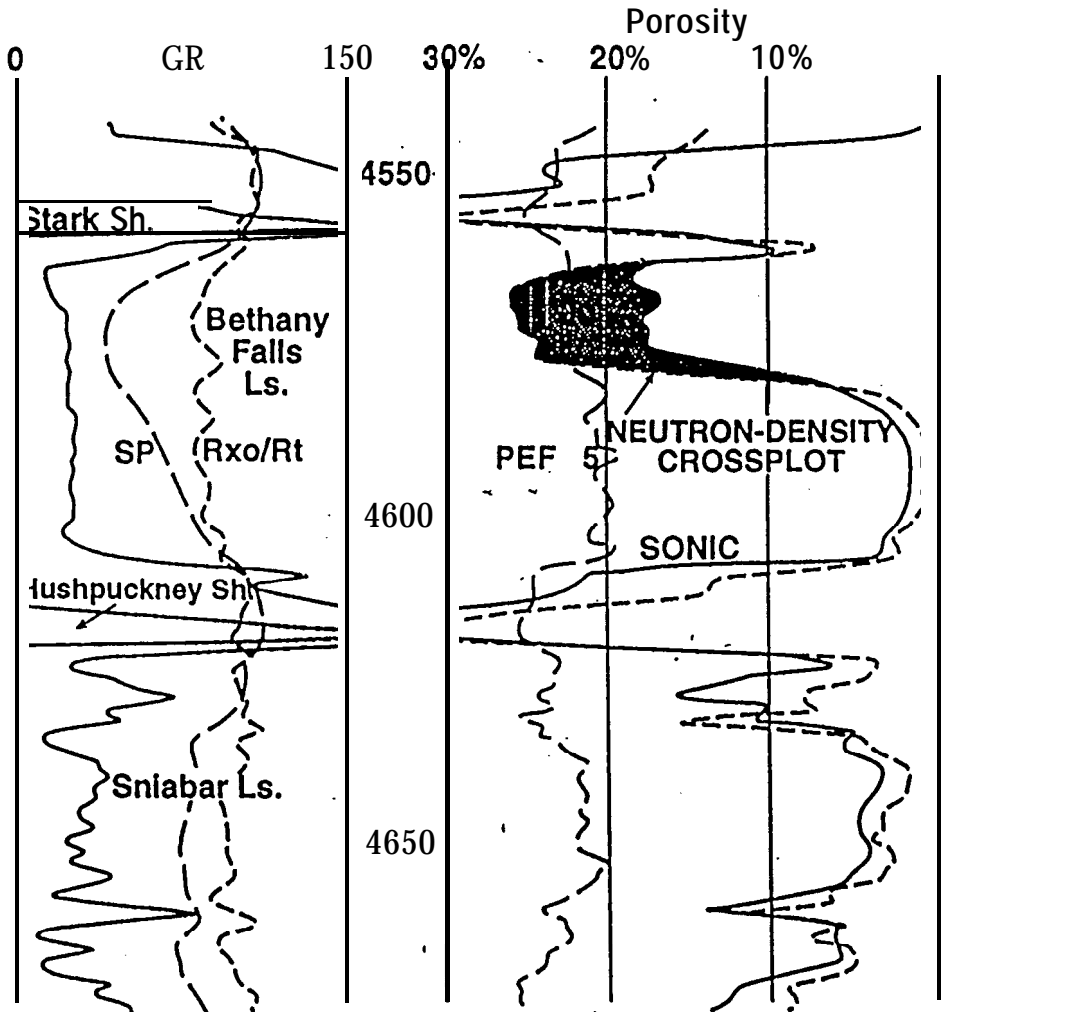
### **Primary and secondary porosity**

The neutron and density logs are responses to pores of all sizes. However, field observation over many years has shown that the sonic log is a measure of interparticle (intergranular and intercrystalline) porosity but is largely insensitive to either fractures or vugs. This discrimination can be explained largely by the way that the sonic tool measures transit time by recording the first arrival waveform which often corresponds to a route in the borehole wall free of fractures or vugs.

When sonic porosities are compared with neutron and density porosities, the total porosity can be subdivided between “primary porosity” (interparticle porosity) recorded by the sonic log and “secondary porosity” (vugs and/or fractures) computed as the difference between the sonic porosity and the neutron and/or density porosity. Typically, moderate values in secondary porosity are caused by vugs, because fracture porosity does not usually exceed 1 to 2% by volume.

The log example shows the averaged neutron-density porosity log together with a sonic log in a Pennsylvanian limestone - shale sequence in a Kansas well. They are both scaled in limestone equivalent porosity units. Notice how the neutron-density and sonic porosity logs track fairly closely at about 3% porosity in the Sniabar limestone, but in the upper part of the Bethany Falls limestone, there is a marked increase in overall porosity and a distinctive separation of the sonic from the neutron-density porosity. These features are quite common in south-central Kansas and distinguish high-porosity oomoldic limestones from low-porosity wackestones. While the neutron and density logs are sensitive to all pore sizes, the sonic log porosity does not reflect all the

oomoldic pores. The distinction is commercially important because much of the oomolds are poorly connected vuggy pores that cause an increase in resistivity such that water-saturated oomoldic zones can look to be promising hydrocarbon shows and be confused with real oomoldic oil and gas producers. This has been enough of a problem to encourage the specific use of EPT (electromagnetic propagation tool) logging in some wells.

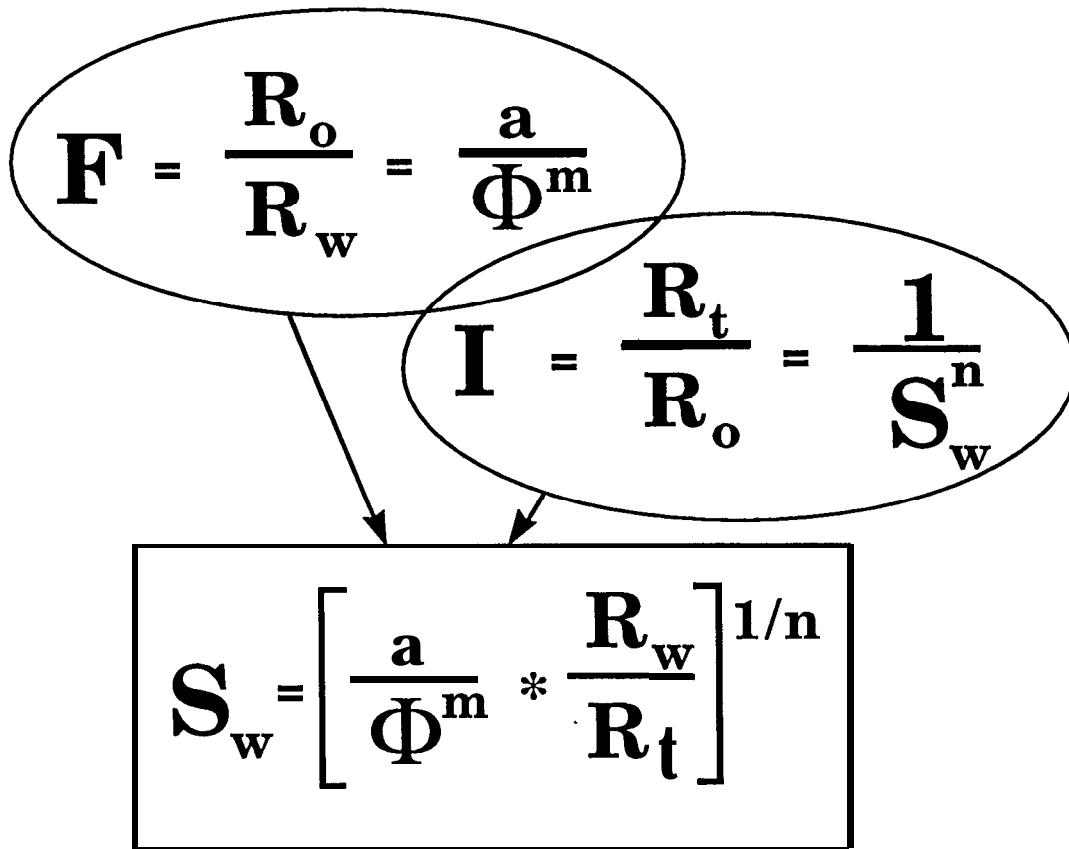


Comparison of neutron-density and sonic porosity logs in a Pennsylvanian section in Mesa Leathersland #1-14 NE-SE 14-30S-34W. Notice the oomoldic porosity zone in the upper part of the Bethany Falls Limestone.

## “THE ARCHIE EQUATION”

In his classic paper, Archie (1942) proposed two equations that described the resistivity behavior of reservoir rocks, based on his measurements on core data. The first equation governs the resistivity of rocks that are completely saturated with formation water. He defined a “formation factor”,  $F$ , as the ratio of the rock resistivity to that of its water content,  $R_w$ , and found that the ratio was closely predicted by the reciprocal of the fractional rock porosity ( $\Phi$ ) powered by an exponent, he denoted as “ $m$ ”. The value of  $m$  increased in more consolidated sandstones and so was named the “cementation exponent”, but seemed to reflect increased tortuosity in the pore network. For generalized descriptors of a set of rocks with a range of  $m$  values, workers after Archie introduced another constant, “ $a$ ”. In a second equation, Archie described resistivity changes caused by hydrocarbon saturation. Archie defined a “resistivity index”,  $I$ , as the ratio of the measured resistivity of the rock,  $R_t$ , to its expected resistivity if completely saturated with water,  $R_o$ . He proposed that  $I$  was controlled by the reciprocal of the fractional water saturation,  $S_w$ , to a power, “ $n$ ”, which he named the “saturation exponent”.

The two equations may be combined into a single equation, which is generally known as “the Archie equation”. Written in this form, the desired, but unknown, water saturation ( $S_w$ ) may be solved.


$$\mathbf{F} = \frac{\mathbf{R}_o}{\mathbf{R}_w} = \frac{\mathbf{a}}{\Phi^m}$$
$$\mathbf{I} = \frac{\mathbf{R}_t}{\mathbf{R}_o} = \frac{\mathbf{1}}{\mathbf{S}_w^n}$$
$$\mathbf{S}_w = \left[ \frac{\mathbf{a}}{\Phi^m} * \frac{\mathbf{R}_w}{\mathbf{R}_t} \right]^{1/n}$$

Although “rule-of-thumb” numbers for the cementation exponent,  $m$ , and the saturation exponent,  $n$ , are often quite adequate for estimates of water saturation when making a decision whether to run a drill-stem test, they may be poor for reserve estimations, particularly for a major field. They can also be misleading when applied to a carbonate unit that has (for example) significant oomoldic porosity, or fractures. The errors can lead one into being either too pessimistic or too optimistic. Similar concerns apply to the value of the saturation exponent,  $n$ . For water-wet formations,  $n$  is approximately equal to two, but will be much higher in formations that are oil-wet. Some background to “ $m$  and “ $n$ ” in sandstones and carbonates are given in the following sections.

## FORMATION FACTOR - POROSITY RELATIONSHIPS FOR SANDSTONES

Archie (1942) measured the formation factor of a variety of sandstones (a simple laboratory procedure involving a Wheatstone bridge) and compared these with their porosities to deduce the variation of  $m$  with type of sandstone. He found that  $m$  was 1.3 for unconsolidated sands and ranged between 1.8 and 2.0 for consolidated sandstones. Guyod gave the name cementation exponent to  $m$ , but noted that the pore geometry controls on  $m$  were complex and went beyond simple cementation. However, a useful rule-of-thumb comparative scale is widely quoted as::

$m$	
1.3	unconsolidated sandstones
1.4 - 1.5	very slightly cemented
1.6 - 1.7	slightly cemented
1.8 - 1.9	moderately cemented
2.0 - 2.2	highly cemented

In 1952, Winsauer and other workers measured formation factors and porosities in 29 samples of a highly varied suite of North American sandstones. They generalized Archie's equation to:

$$F = \frac{a}{\Phi^m}$$

Since low porosity sandstones are more highly cemented than higher porosity sands, the constant 'a' functions as a slippage element which automatically incorporates the cementation exponent changes associated with sandstones of differing porosities. By taking logarithms of both sides, this can be transformed to a straight line relationship:

$$\log F = \log a - m \log \Phi$$

On fitting  $\log F$  to  $\log \phi$ , they came up with a relationship for sandstones:

$$F = \frac{0.62}{\Phi^{2.15}}$$

which is known as the "Humble equation" (since they worked for the Humble Oil Company) and is the most widely used equation for sandstones in the world.

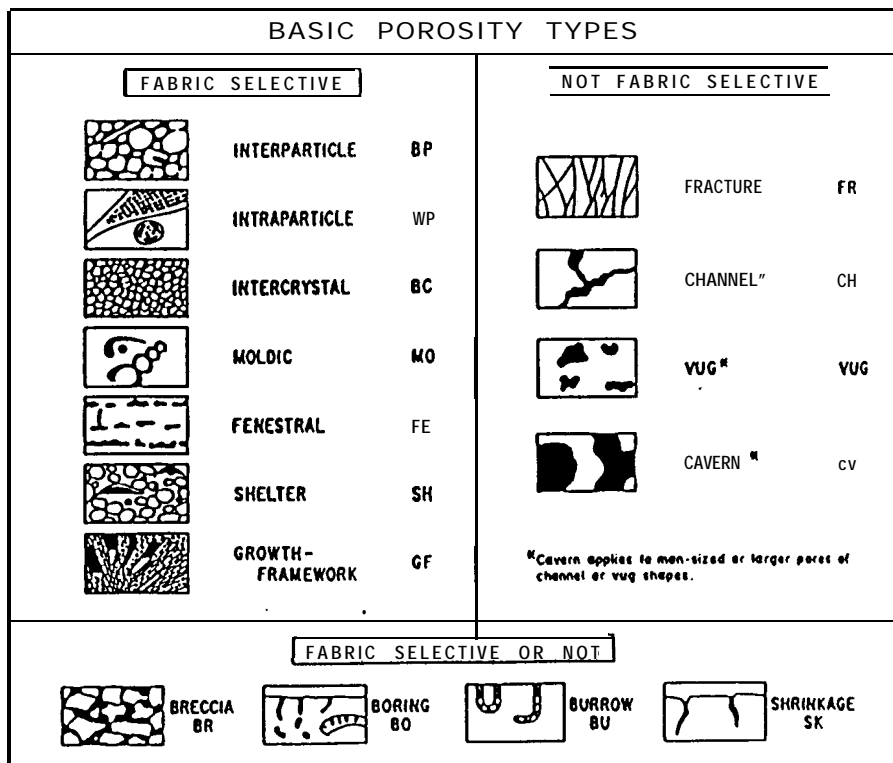
## FORMATION FACTOR - POROSITY RELATIONSHIPS FOR CARBONATES

Porosity in sandstones generally takes the form of *intergranular* pores: the pore space between the grains of quartz and other detrital minerals. In some cases there may be *intercrystalline* porosity caused most commonly by calcite or quartz cement introduced by diagenesis in the lithification of the sandstone. Porosity in carbonate rocks (limestones and dolomites) can take a wide variety of forms as shown in the illustration from Choquette and Pray (1970). The geological classification of carbonate pore types is based on *genesis*; geologists are interested in the history of pore formation. The petrophysicist should pay attention to the geological description and interpretation of carbonate pore types in a reservoir. However, there will be times when such detailed information is limited or non-existent and the petrophysicist should focus on the morphology of the pores, because it is this aspect that affects the wireline log measurement.

Petrophysicists subdivide pore types between:

- (1) **interparticle: intergranular and intercrystalline porosity;**
- (2) fracture
- (3) vug: either moldic porosity from the dissolution of grains or vugs that are larger than the grains.

Notice that all the genetic forms in the carbonate classification of Choquette and Pray can be assigned to these broad petrophysical categories.



from Choquette and Pray,1970

The most widely used form of the Archie equation for both limestones and dolomites is the basic:

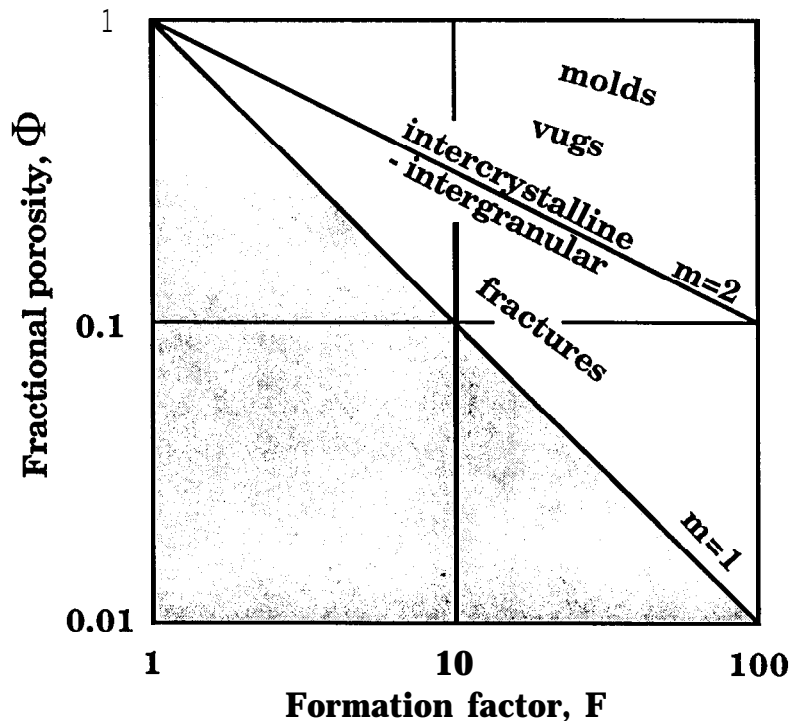
$$F = \frac{1}{\Phi^2}$$

This choice is not intuitively obvious when comparing the complex variability of carbonate pore types with the relatively simple pore structure of sandstones, given the variability of the sandstone cementation exponent,  $m$ . However, a cementation exponent value of two ( $m = 2$ ) is a good choice for carbonate rocks whose porosity is dominantly intercrystalline as shown by numerous core measurements and log evaluations. Dullien (1992) showed that for a rock framework with uncorrelated pore and solid components, the expected value of  $m$  should be 2. The uncorrelated pore space will contain both electrically connected pore space and “dead end” pore space that is by-passed by electrical flow. If there is an increase in unconnected pore space (vugs), then there will be an increase in  $m$ ; if there is an increase in connected pore space (fractures), then there will be a decrease in  $m$ .

Rule-of-thumb values of  $m$  quoted in the log analysis literature for various pore systems are:

	$m$
intergranular/intercrystalline	2.0
fractures	1.4
vugs	2.3
moldic	3+

Obviously, these numbers will be controlled by the degree of fracturing, vugginess, and proportion of moldic porosity and can lead to a wide variety of  $m$  values observed in the field.





## RESISTIVITY INDEX - SATURATION RELATIONSHIPS

Archie's second equation is:  $I = \frac{R_t}{R_o} = \frac{1}{S_w^n}$  which states that the resistivity index, I, is defined as the ratio between the measured resistivity,  $R_t$  and the expected resistivity of the zone, if it was completely saturated with formation water,  $R_o$ ; the resistivity index is a function of the reciprocal of the fractional water saturation,  $S_w$ , powered by a saturation exponent,  $n$ .

Laboratory measurements of the resistivity index in water-wet rocks show that an  $n$  value of 2 is not an unreasonable figure to use in most cases. However, lab measurements also show that an equivalent rule-of-thumb figure for oil-wet rocks would be about 9. The difference is matched by intuition: in partially-saturated water-wet rocks, the water phase would provide a continuous film on grain surfaces to conduct electrical current through the rock, albeit on a much more tortuous route than fully water-saturated rocks; in oil-wet rocks, the surfaces would be coated with oil and the water phase would be restricted to a partially connected system of conductive globules within the pore network.

Although the physical model may be straightforward, the consequences of the choice of an oil-wet or water-wet saturation exponent will result in drastically different water saturation estimates. Traditionally, log analysts have assumed the formation to be water wet and used a saturation exponent value of two ( $n = 2$ ) unless otherwise dry measured values are available. Combining the two original Archie equations together and rearranging to solve for water saturation,  $S_w$  gives:

$$S_w = \left[ \frac{a \cdot R_o}{R_t \Phi^m} \right]^{1/n}$$