Towards a Petrophysically Consistent Implementation of Archie's Equation for Heterogeneous Carbonate Rocks

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New Carbonate Water Saturation transform:

When Gus Archie introduced his saturation relationship to resistivity in 1942 he arrived at the formulation empirically. Essentially, a rock is expected to have a single resistivity given its total porosity and unique hydrocarbon saturation. The three properties were related through empirically derived exponents applied to porosity and saturation and he proposed that these exponents are each 2. However, rocks as we know can be comprised of multiple pore systems and Petrophysics (a term introduced by Archie in 1950) informs us that the saturation in each pore system would be governed by the wettability and capillary pressure at that datum in the reservoir. This multi-modal pore architecture is very common in carbonates and Archie is believed to have recommended against the use of his relationship in carbonate rocks. For this reason, the Archie relationship can be considered inconsistent with Petrophysics in the form originally presented. In fact, there is yet another common sedimentary rock which exhibits multi-modal pore systems – the shaly sand. The pore sizes encountered in the shale fraction of the rock are several orders of magnitude smaller than those encountered in the sand fraction. Consequently, the saturation in the shale fraction of oil bearing shaly sands is unity while that in the sand fraction is very much lower often approaching values much less than 0.5. The industry developed shaly sand relationships that essentially set the saturation in the shale fraction to unity. Sometimes this was done by ascribing conductivity to the shale and setting its effective porosity to zero. If there is no porosity then the saturation is irrelevant. For our discussion here it is sufficient to note that the industry has recognized the need to account for saturation differences between different pore systems within the same rock.

However, application of this concept to carbonates (which are often very clean and clay-free) was rarely done. The absence of clay meant that all available saturation transforms reverted to Archie as they are meant to do. The multimodal porosity manifested in variations in porosity exponent required to fit the Archies relationship to the measured resistivity in brine-saturated rocks. Furthermore, due to rapid variations in the fractions of the different pore systems with depth a single exponent would rarely suffice and several researchers attempted to predict the exponent by relating it to the vug fraction in the rock, the latter being determined through acoustic or image measurements. Another puzzling aspect of carbonate rocks is that the saturation exponent also seemed to vary with depth in addition to depending on whether the rock is in primary drainage or under water-flood. The exponent during water-flood assumed very high values not found to be reasonable to explain the resistivity when the same rock is in primary drainage. One possible explanation relates to the fact that carbonates may change wettability state after ingress of hydrocarbons. If a rock becomes oil-wet after the migration of oil then the high saturation exponent seen during subsequent water-flood may be explained. However, a fully predictive model based on the structure of the carbonate rock still eluded the industry. This work introduces the first fully predictive model that we show explains much of the behavior observed in carbonates. We have accounted for the concept of capillary pressure equilibrium suggested in Petrophysics in the application of Archie's relationship to carbonate rocks. Information on pore geometry captured through specific log measurements is incorporated in an effective medium model that honors the structure of carbonate rocks. The model prediction of the porosity exponent has been verified on several carbonate core studies in many reservoirs across the Middle East, probably far more than has ever been achieved with any other transform in the industry. We also apply the model to well data from several wells to show that it yields a much more accurate estimate of the saturation and fluid content of the formation.

We do not claim that our model is perfect for all carbonate reservoirs. However, our observations show that it provides an accurate answer in 80% of the cases with at least a better estimate in a further 10% of formations.

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