Variety of Cementation Factor between Dolomite and Quartzite Reservoir

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Abstract:

Cementation factor is one of the most important petrophysical reservoir rock properties. In quantitative interpretation of well log data; it is widely used to estimate porosity and water saturation. Many researchers have studied the effect of the cementation factor in porous media, which is mostly sandstone rocks, and occasionally carbonates rocks, that represent nearly half of the world's petroleum reserves. However, The purpose of this paper is illustration the variety of petrophysics Archie's law (cementation *exponent "m") between Carbonate (Dolomite) and Metamorphic (Quartzite) reservoirs. The result of open hole wire line technique is so important and shows how carefully change of cementation factor and its affect on water saturation in the same area of production and different reservoir depths. The cementation factor in this study was estimated and ranging from 1.9 to 2.8. Therefore, the relation between (m) values for two reservoirs is counterproductive.*

***Key words:** open hole wire line; porosity and resistivity Logs.*

1.Introduction.

Archie law is an empirical, and assumes electrical conductivity presents in the brine. Archie's law is parameterized by the cementation exponent denoted with m, and the saturation exponent denoted with n. The log interpretation requires estimation of n and m. Traditional, petrophysical and electrical properties are obtained from laboratory experiments. Tortuosity (a; pore geometry factor), cementation (m; pore geometry exponent) and saturation exponent factors are two critical parameters that significantly affect estimation of reservoir properties. However, coefficient (*a)* varies from 0.35 to 4.78 and (*m)* from 1.14 to 2.9 (higher in carbonates).

This work presents a difference of routine open hole tools to response attribute between Quartzite (Metamorphic rock) and Dolomite (Carbonate) reservoir rocks. However, there is, of course, expectation to virtually every role, which is why experience in a specific field. So, in this work, based on the Generalized Archie Equation Curve Fitting (GAECF), cementation factor is determined for selected intervals (productive) in a carbonate and quartzite reservoirs. These reservoirs refer to Cretaceous age and Cambro-Ordovician age, respectively. Observed variation in m-exponent, attributed to: degree of cementation (an increase in cementation *m)*, shape, sorting and packing of grains, types of pores: intergranular, vuggy, fractures (fractures m ~ 1.0, vugs m > 2.0), tortuosity , constriction in porous network , presence of conductive solids , compaction due to overburden pressure and thermal expansion.

Reservoirs Rock Properties:

The carbonate environment is typically one that has formed ‘in place’ via the growth of organisms and/or precipitation. One may also encounter evaporites (halite, anhydrite, gypsum) in association with the more routine limestone ($CaCO_3$) and dolostone ($CaMg(CO_3)_2$). While, Sandstones (SiO_2), on the other hand, are typically clastic in origin and consist of fragments of material that were originally deposited elsewhere, broken up and transported via water or wind, and re-deposited. In the sandstone world, complications are often associated with ‘clay/shale’, although other issues (such as feldspar, glauconite) arise in certain provinces.

The petrophysical properties of metamorphic rocks are often similar to their pre-metamorphic sedimentary counterparts as long as new or different minerals have not formed. The quality of the metamorphic rock is based on the amount of heat and pressure applied to it during the metamorphic processes. Changes that occur during metamorphism (Recrystallization - occurs when small crystals join together to create larger crystals of the same mineral).

Generally, Carbonate porosity determination (Jerry Lucia, 2004), as contrasted to sandstone, and it is a completely different issue. Now one is faced with interparticle (intergrain and intercrystal), and vuggy porosity. vuggy porosity is everything that is not interparticle, and includes vugs, molds and fractures. vugs are divided into two types, separate and touching. In general, porosities tend to be lower in deeper and older rocks due to the cementation and overburden pressure stress on the rock. These basic trends of porosity changes vs. depth are not noticeable clearly in the carbonates as compared to the sandstone and shale, where porosity is more affected by the depositional environments and secondary processes, both unrelated to the depth of burial.

Previous Studies:

Middle Eastern carbonate reservoirs are very heterogeneous in terms of rock types. electromagnetic propagation (EPT) log tool has been conjunction with standard electrical and porosity logs for deriving m in hydrocarbon-bearing zones, a normally difficult task with standard techniques (e.g., resistivity logs, Pickett plots, and sonic logs), and good confirmation has been obtained from core data in some cases (Focke et al., 1987). That study presents the results of a study of the relationship between variable m values measured on core plugs and detailed carbonate rock types, which is conclude, high m values are often representative for specific rock types and that these values should not be rejected but applied selectively in log analysis over those intervals where these rock types occur.

In 1987 Borai stated Carbonates found offshore Abu Dhabi, m decreases with decreasing porosity of six different fields and based on core and log data from five formations in 14 structures, a more representative correlation for m has been derived.

Woody et al., 1996 studied textural types and Petrophysical Properties (effective porosity and permeability) of dolomite, and conclude understanding diagenetic history, and crystal textures that may result various diagenetic conditions, can be a predictor of petrophysical properties of dolomite reservoirs.

Salem and Chilingarian (1999) conclude the cementation factor of shaly sand depends on the shape, type, and size of grains; the shape and size of pores and pore throats; and the size and number of dead-end pores. The dependence of *m* on the degree of cementation is not as strong as its dependence on the shape of grains and pores. Therefore, it is suggested that it is more accurate to call *m* “shape factor” instead of “cementation factor”. Their study was derived from well-log data and illustrate the shape factor is not a constant, but is a variable depending on many physical parameters and lithological attributes of porous media. An average value of 2.28 was obtained for *m*, which can be used for similar reservoirs.

Li and Qiang, 2004 investigate sensitivity analysis was carried out between m, the threshold factor, and secondary porosity to understand their interdependency of metamorphic reservoir in SinoPec oil field in China. It was found that the magnitude of secondary porosity had a strong and inverse correlation with m, while the relationship was weak and inverse with the threshold factor. They proposed equations based on published charts that correlate the cementation exponent with both fracture porosity and total porosity. Secondary porosity values were calculated using both a constant m value of 2 and the new equations.

Procedure:

Common porosity estimators are the density, neutron and sonic, used individually, in tandem, or all three together. In these different studied reservoirs the neutron, sonic porosity are available and density not.

An alternative porosity estimator is the neutron log, which is subject to many more environmental corrections (than other porosity log), in addition to experiencing a relatively larger shale effect and potentially large light hydrocarbon suppression. The routine porosity estimator is the sonic log, which requires no environmental correction, but like the neutron, will often be more sensitive to shale. One should also be aware of the 'adjustments' to the acoustical porosity that may be necessary in 'soft rock' country: sometimes in country that is not thought of as soft rock. But, the Schlumberger Principles Manual, and observations from studied reservoirs experience, if the bounding shales have travel time >100 µs/ft, both of the common porosity transforms (Wyllie and Raymer) may require a correction factor. Therefore, corrected neutron by following equation;

$$PHI_{nc}= PHI_{nlog}- (V_{sh} \text{ x } PHI_{nsh})$$

Saturation formula of reservoir rocks from resistivity measurements is one of the most crucial problems in petrophysics and log analysis. The interpretations of these measurements are usually based on Archie relations. In petrophysics, Archie's formula relates the *in-situ* electrical resistivity of a sedimentary rock (*Rt*) to its porosity (Ø) and brine saturation (*Sw*):

$$R_1 = \frac{a}{\emptyset^m}\frac{R_w}{S_w}$$

The tortuosity factor *(a)*, *Rw* is the brine resistivity, *n* the saturation exponent and *m* the cementation exponent. Conventionally, values of both cementation and saturation exponent are most commonly assumed to be equal to 2. Significant deviations have been observed in laboratory measured data for *m* and *n* from complex lithologies. The discrepancies are mainly due to rock heterogeneity and the complicated pore structure. In light of the differences in sandstone and carbonate, it is perhaps surprising that water saturation can (often) be successfully estimated with the same equation and (similar) parameters. Metamorphic rocks are normally associated with fracture porosity. The value of the cementation exponent, m is difficult to confirm, and usually a constant number such as 2 is used.

Results and Discussion:

According to this paper; the method used is Pickett cross plot (1963) utilized for calculating the m parameter values (Fig. 1 and 2). This plot utilizes a basic rearrangement of the Archie equation;

logRt = - m logΦ + log (aRw) – n log Sw and if Sw = 100%, the equation becomes;

logRt= -m logΦ + log (aRw). The straight line plot on log-log grid for deep resistivity (Rt) versus neutron porosity (Ø), where Y= mx+b is the equation of a straight line. The slopes of the 100% water saturation line determine "m". Table (2) shows the different values for this parameter each reservoir in the studied wells. Figures (3.a and 3.b) include all cross plots of the studied wells for different reservoirs.

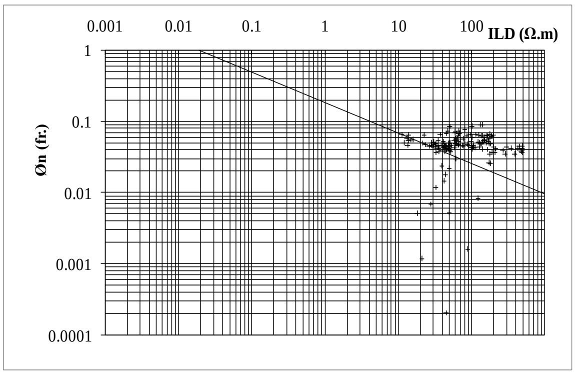

Fig. 1. Pickett cross plot for dolomite,Well1.

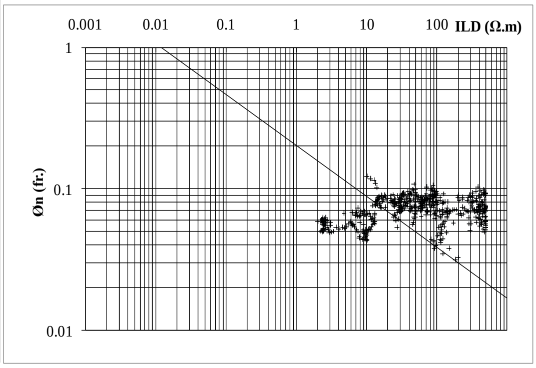

Fig. 2. Pickett cross plot for Quartzite,Well 1.

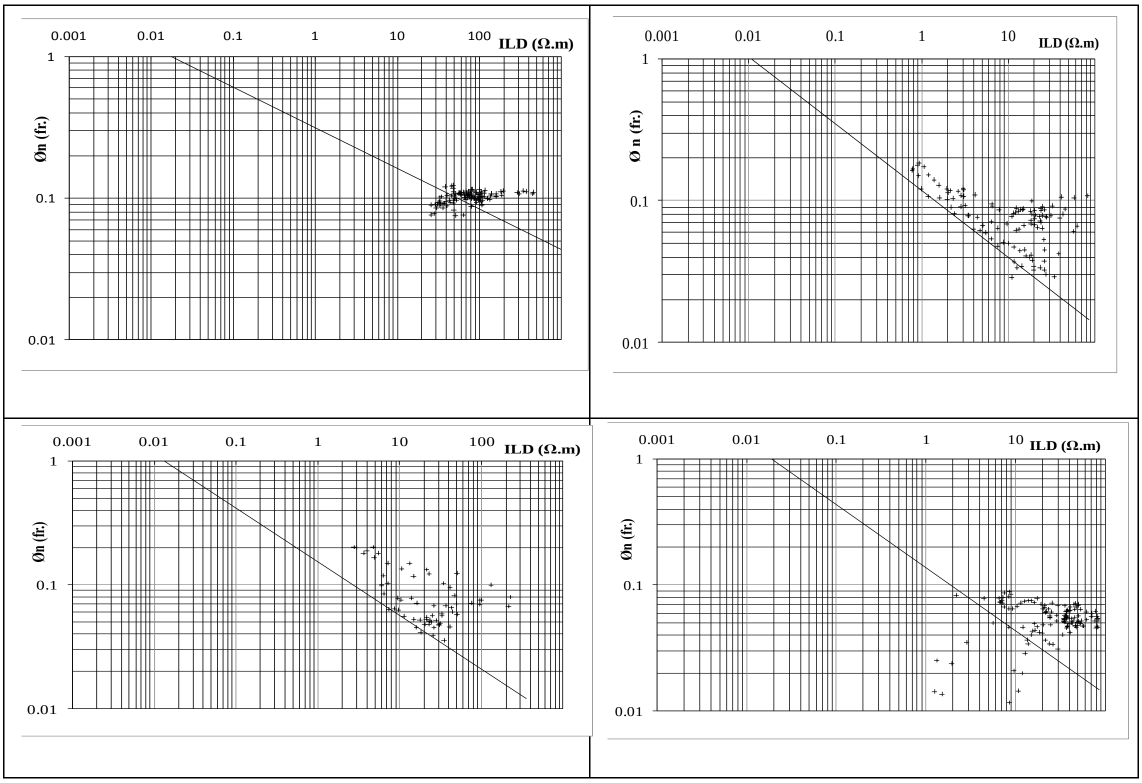

Figure (3.a) Pickett cross plots of Dolomite reservoir (wells 2, 3, 4 and 5)

The Pickett cross plot of five wells present cementation exponent values (Table 1). The values cementation exponent data in carbonate reservoirs indicate large variations, therefore heterogeneous carbonate reservoirs should be split into layers on the basis of dominant rock type.

Table (1) Cementation factor values.

Reservoir type	Well No.				
	1	2	3	4	5
Quartzite	1.939	2.896	2.633	2.214	2.701
Dolomite	2.778	1.636	2.151	2.336	1.942

The cementation exponent (m) reflects the tortuosity of the ionic electrical flow through brine saturated rock. An (m) of 2.0 is commonly used; smaller values correspond to a less tortuous path, with fractures being a somewhat extreme example. Should the path be ‘extra’ tortuous, such as when the pore throats are well-cemented, or a portion of the porosity is poorly connected vugs, m will increase.

Be aware, however, that small pores, by themselves, don’t necessarily mean high m; it is the ‘effectiveness’ of the conduction path. The cementation exponent of both clean sand and IC/IP carbonates may vary within a relatively short (vertical) distance, and can assume a multitude of values within a given reservoir.

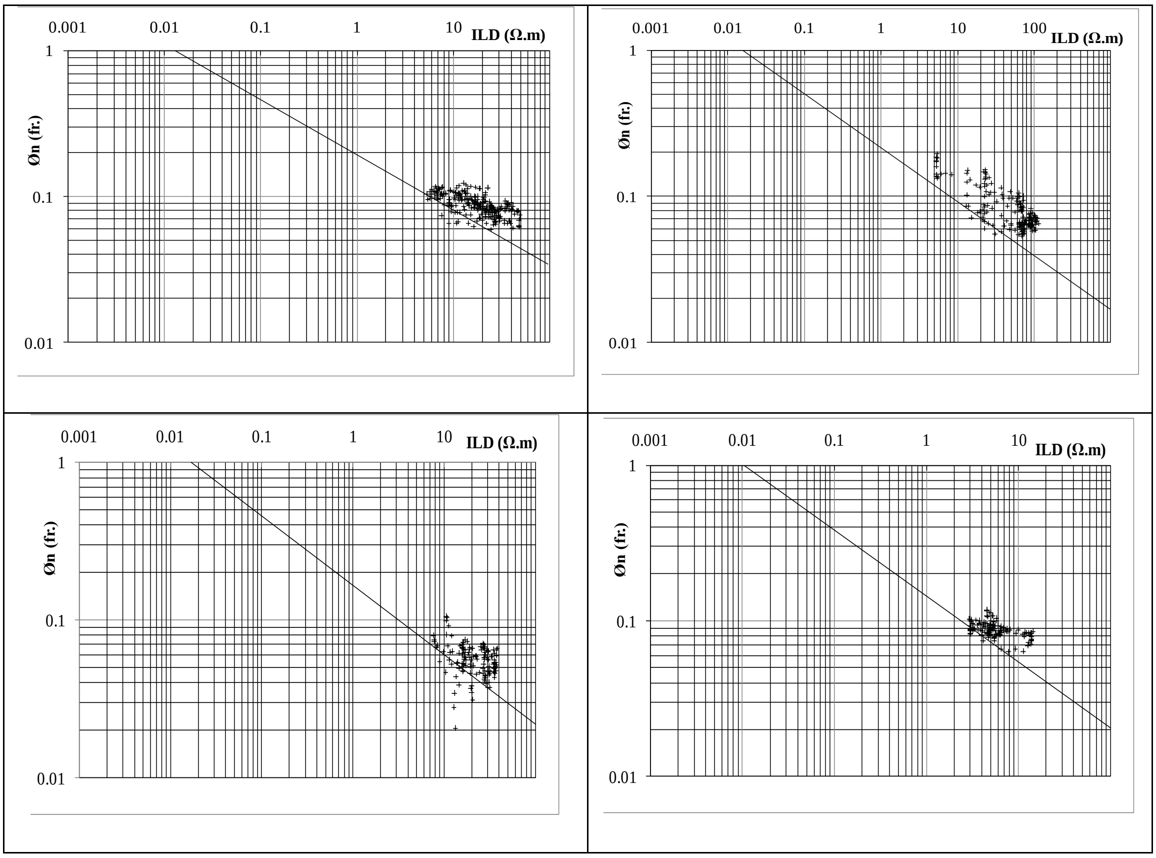

Figure (3.b) Pickett cross plots of Quartzite reservoir (wells 2, 3, 4 and 5)

Conclusion:

Cementation factor is widely used in the quantitative interpretation studies using well log data, and commonly assumed 2 for carbonate reservoirs and 2.15 for sandstones reservoirs rock, these values are introduced by Archie and Humble and it is widely used to estimate porosity and water saturation.

Many researchers have studied the effect of the cementation factor in porous media, which is mostly sandstone rocks, and occasionally carbonates rocks, that represent nearly half of the world's petroleum reserves. However, the purpose of this work is illustration the variety of petrophysics Archie's law (cementation exponent "m") between Carbonate (Dolomite) and Metamorphic (Quartzite) reservoirs.

The result obtained by using open hole wire line technique information shows how carefully change of cementation factor and its affect on water saturation in the same area of production and different reservoir depths. The cementation factor in this study was estimated and ranging from 1.9 to 2.8. Therefore, the relation between (m) values for two reservoirs has direct effect on the estimation of oil saturation through the porous media.

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