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A New Cementation Factor Correlation in Carbonate Parts of Oil Fields in South-West Iran

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Abstract

Petrophysical parameters such as porosity, water and oil saturations, formation resistivity factor, etc. describe the storage capability of the porous media or the capacity of rocks to hold fluids. The modified Archie's equation $S_w^n = (a.R_w/(R_t.\Phi^m))$, also called the saturation equation, is used to determine the water saturation. Archie's parameters, namely m, n, and a, are sometimes assumed constant to simplify petrophysical measurements. But these parameters are not constant, particularly in heterogeneous reservoirs. Inaccurate estimates of these parameters can cause significant errors in the calculation of water saturation when using Archie's equation and lead to discrepancies between log interpretation and production test results. There are many factors affecting cementation factor (m) such as porosity, pore throat size, type of rock grains, type and distribution of clay content, degree of cementation, and overburden pressure. In the present paper, the results of electrical resistivity experiments are used to derive a new cementation factor correlation which can be applied to carbonate parts of Asmari and Sarvak formations located in south-west Iran. In Iran, the cementation factor is traditionally measured by Shell formula or is assumed equal to 2 to avoid difficulty. In the new formula, m increases with increasing porosity; however, in the Shell formula, m decreases with increasing porosity especially in the low porosity ranges, which is in disagreement with the current paper results. In addition, the results demonstrate that it is not possible to introduce constant m values or separate cementation factor correlations versus porosity for different petrofacies and rock types. Petrophysical evaluations are done to quantify hydrocarbon resources in formations under study. Then, the water saturation is calculated with different calculation methods of cementation factor, m. The calculated water saturations are compared with the measured water saturations of preserved cores.

Keywords: Water Saturation, Cementation Factor, Archie's Equation, Formation Resistivity Factor

1. Introduction

Petrophysics is the science dealing with the interaction of rock texture and its fluid contents. The successful evaluations of petrophysical reservoir properties are necessary for determining the hydrocarbon potential and performance of a reservoir system and also help the researchers predict the behavior of complex reservoir settings.

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Porosity and fluid saturations are among the most important reservoir parameters used in reserve estimates of oil and gas reservoirs. Fluid saturations can be estimated from resistivity measurements by using generalized Archie's equation, also called the saturation equation (Archie, 1942):

$$S_w^n = \frac{a}{\Phi^m}\frac{R_w}{R_t} \tag{1}$$

Originally, Archie's formula did not include a coefficient, but Winsauer et al. added it to the equation. Since then, a is commonly used as a part of Archie's equation (Winsauer, et al., 1952). In this equation, a is the tortuosity factor; R_w represents the water or brine resistivity and Φ is the rock porosity (fraction); R_t stands for the total resistivity of the system at the saturation; S_w and the exponents m and n are the cementation factor and saturation exponent respectively.

Archie's parameters are sometimes assumed constant to simplify petrophysical measurements. But, field evidence indicates a considerable range of variations for different lithologies and even for distinctive lithofacies within a single formation. Guyod introduced the term "cementation factor" for the exponent m (Guyod, 1944). Pirson established a scale indicating the degree of cementation using m values. Well-cemented rocks are represented by higher m values than poorly cemented rocks. According to Pirson's study, m is a measure of the degree of cementation and consolidation of the rock; the greater the degree of consolidation is the greater the value of the cementation factor becomes (Pirson, 1977). Ransom indicated that when there is additional conductance to the water-filled pore volume produced by electrically conductive solids (such as pyrite) or surface conductance due to ion exchange in shales, the exponent m varies and accounts for all these conductive substances present in the rock (Ransom, 1974, 1984). Haro showed that tighter packing of grains generally signifies a higher level of anisotropy and contributes to larger values for cementation factor (Haro, 2006). Salem and Chilingarian concluded that the degree of cementation is not as significant as the shape of grains and pores, and preferred the term "pore shape factor" instead of "cementation factor" (Salem & Chilingarian, 1999). Moreover, several studies showed that the cementation factor ranges from 1.0 to 3.0 (Archie, 1942, 1950; Guyod, 1944; Thornton, 1949; Waxman & Thomas, 1974; Williams, 1950; Wyllie & Rose, 1950).

Inaccurate estimates of the cementation factor can cause significant errors in the calculation of the water saturation when using Archie's equation and lead to discrepancies between log interpretation and production test results.

The current paper reviews logs and core measurements that lead to the new cementation factor formula. This formula can be used to calculate the cementation factor in carbonate parts of Asmari and Sarvak formations. Furthermore, to calculate the more accurate cementation factor, carbonate rocks are classified into different rock types and petrofacies based on texture, porosity types, permeability, and porosity values. Then, with the same rock type and petrofacies group, samples are plotted on the FRF-Φ log-log plots. Nevertheless, the scattered data indicate that it is not possible to introduce constant m values and separate cementation factor correlations versus porosity for each petrofacies and rock type.

Petrophysical evaluations are performed to identify and quantify hydrocarbon resources in subsurface and evaluate fluid and rock properties in five wells. The petrophysical evaluation approach adopted in the current paper is a probabilistic log analysis technique which takes continuous log data (Resistivity, NPHI, GR, RHOB, DT, PEF, etc.) and uses the response to create an answer. Subsequently, the water

saturation is calculated via different calculation methods of the cementation factor (new formula, Shell, and $m = 2$). The calculated water saturations are compared with the measured water saturations of preserved cores, and then appropriate recommendations are proposed for the respective formations.

2. Previous works

Formation resistivity factor (FRF) was introduced by Archie as the ratio of the resistivity of rock when completely saturated with a conducting fluid (R_o) to the resistivity of the saturating fluid (R_w). According to Archie, formation resistivity factor is always greater than one (Archie, 1942).

$$F = \frac{R_o}{R_w} = a.\Phi^{-m} \tag{2}$$

A log-log plot of the formation resistivity factor versus porosity yields values of m and a as the slope and intercept (at $\Phi = 1$) of the line obtained through regression respectively, where a is referred to as the "tortuosity factor" of the pore system.

Numerous methods have been developed to empirically derive the cementation factor. In all of these methods, the authors assumed that the tortuosity factor, a was equal to 1.0 (Bernal, 2004; Borai, 1987; Hasanigiv & Rahimi, 2008; Neustaedter, 1968). In addition, most of these methods were designed for a particular type of porosity and/or a certain permeability range. Some of these commonly used methods are listed below along with their authors' name.

- Formula for low porosity, non-fractured carbonates by Neustaedter (Neustaedter, 1968):

$$m = 1.87 + 0.019/\Phi \tag{3}$$

- Formula for low porosity and tight carbonates based on core and log studies from offshore Abu Dhabi samples by Borai (Borai, 1987):

$$m = 2.2 - 0.035(\Phi + 0.042) \tag{4}$$

- Formula for vuggy and intergranular/intercrystalline porosity carbonates by Nugent et al. (Nugent et al., 1978):

$$m = 2\log\Phi_{sonic} / \log\Phi_{total} \tag{5}$$

Rezaee et al. established a new method for determining m and a values through classifying FRF and Φ data based on current zone indicator and electrical flow unit (Rezaee et al., 2007).

Akbar et al. estimated the cementation factor for carbonates using borehole images and logs (Akbar et al., 2008).

3. Methodology

3.1. Determination of cementation factor versus porosity

To measure the formation resistivity factor, the sample is saturated with synthetic reservoir brine and after applying net confining stresses on the plug in overburden rig instrument, the electrical resistivity of the samples is measured. These experimental data are used to calculate the cementation factor via Equation 2. In the conventional methodology, experimental data from plug samples are plotted on

log-log plots according to the relationships expressed by Equation 2 (FRF vs. porosity). Linear least squares fits are performed on each data set to determine m and a values. Nonetheless, this method is appropriate for clean lithologies in which the cementation factor does not change with varying porosity. The cementation factor is the slope of the linear trend of FRF versus Φ on a double-logarithmic plot. But the slope of this line decreases with decreasing porosity. Based on the trend of m versus Φ, a new correlation is introduced. This formula can be used to calculate the cementation factor in the carbonate parts of Asmari and Sarvak formations.

3.2. Cementation factor determination based on rock types (flow zone index (FZI) method)

The main idea is to group data according to their flow zone index values. Then classification based on flow zone indicator is applied to the samples to find the more accurate cementation factor values. This rock typing method is based on modified Kozeny-Carmen equation and the concept of mean hydraulic radius.

$$RQI = 0.0314\sqrt{K/\Phi_e} \tag{6}$$

$$FZI = RQI/\Phi_z \tag{7}$$

$$\Phi_z = \frac{\Phi_e}{1-\Phi_e} \tag{8}$$

where, RQI, FZI, K, and Φ_e are rock quality index (μm), flow zone indicator (μm), permeability (mD), and effective porosity (fraction) respectively. Φ_z is pore to matrix volume ratio (PMR) or normalized porosity (Al-Ajmi & Holditch, 2000; Shahvar et al., 2010; Svirsky et al., 2004).

The logarithmic form of Equation 7 yields a straight line on a log-log plot of RQI versus $\Phi_z$with a unit slope. The intercept of this straight line at $\Phi_z = 1$ is the flow zone indicator. Samples that lie on the same straight line with similar FZI values have similar pore throat attributes and thereby constituting a flow unit. The following simple equation characterizes each discrete rock type (DRT):

$$\mathrm{DRT} = \mathrm{Round}(2\log(\mathrm{FZI}) + 10.6) \tag{9}$$

3.3. Cementation factor determination based on petrofacies

To calculate the more accurate cementation factor, carbonate rocks are classified into different petrofacies based on the texture and porosity types. Then, with the same petrofacies group, samples are plotted on the FRF-Φ log-log plot.

4. Petrophysical evaluation

Petrophysical evaluations are carried out to identify and quantify the hydrocarbon resources in subsurface and to determine fluid and rock properties. Almost the complete ranges of physical properties (resistivity, nuclear, acoustic resonance, etc.) are used in an attempt to achieve the goal of quantifying the down-hole rock and fluid properties. Fluid saturation can be found using Archie's equation provided that the values of a, m, and n are known.

5. Results and discussion

This part of study includes the core analysis results of the plug samples selected from 11 wells of Asmari and Sarvak formations. In the current study, formations were investigated from five different fields located in south-west Iran. The wells were selected in a way that the penetrated intervals

represented all the aspects of the properties of carbonate parts of the formations, making it possible to generalize the results to the other wells in these formations. Sarvak formation consists mostly of carbonates with a minor percentage and streaks of shale in limited intervals. Asmari formation in the field under study is mainly composed of carbonates with a minor percentage of shale, anhydrate, and sandstone in some intervals. However, the core samples were selected from the carbonate parts of the wells, and accordingly, the results of this study belong to the carbonates parts of these formations.

5.1. Cementation factor versus porosity

125 carbonate core samples were used in the present study to determine the cementation factor correlation as a function of porosity. The resistivity analyses were carried out at room temperature and different confining pressures using simulated formation brine based on the formation water analyses. Increasing the overburden pressure deforms the rock grains and causes shrinkage in pore volume and also an increase in the resistivity. Therefore, the cementation factor increases at a higher overburden pressure. Several studies show that the temperature has no significant effect on the cementation factor after correction for clay contents (Clavier et al., 1977; Dolka, 1981; Elias & Steagall, 1996; Waxman & Thomas, 1974).

Figure 1 illustrates the cementation factor values versus porosity under reservoir pressure conditions and Figure 2 represents the cementation factor distribution where tortuosity factor is equal to one. As observed, the cementation factor does not change significantly at porosity values higher than about 10 percent and rises with increasing porosity at lower porosity values. This difference in cementation factor at low and high porosity might be due to secondary porosity. Several studies show that the secondary porosity has a significant effect on the cementation factor at low porosity values. By mathematically modeling the fractures and vug paths, it was found that in addition to the degree of cementation, vugs tend to increase the cementation factor while fractures cause a reduction in the value of m. The effect is more pronounced at lower intergranular porosities and will not significantly influence the measured resistivity at high porosity values (Rasmus, 1987). A new formula is introduced based on the trend of m versus Φ. This formula can be applied to calculate the cementation factor in the carbonate parts of Asmari and Sarvak formations. Wells D and E are selected from Sarvak formation and the other wells belong to Asmari formation. The trends of m in two formations are similar to each other. Therefore, the new formula can be employed for the two formations. Table 1 represents the number of plug samples and cored intervals in each well.

$$\mathrm{m} = 2.461 - \frac{0.048}{\Phi + 0.031} \tag{10}$$

where, Φ is fractional porosity.

Figure 3 simultaneously illustrates the graphs of Borai, Shell, and the new formulas. In the Shell formula, m decreases with increasing porosity especially in the low porosity range (<10%), in disagreement with the current paper results. In the Borai formula, m rises with increasing porosity, indicating general similarity with our analysis.

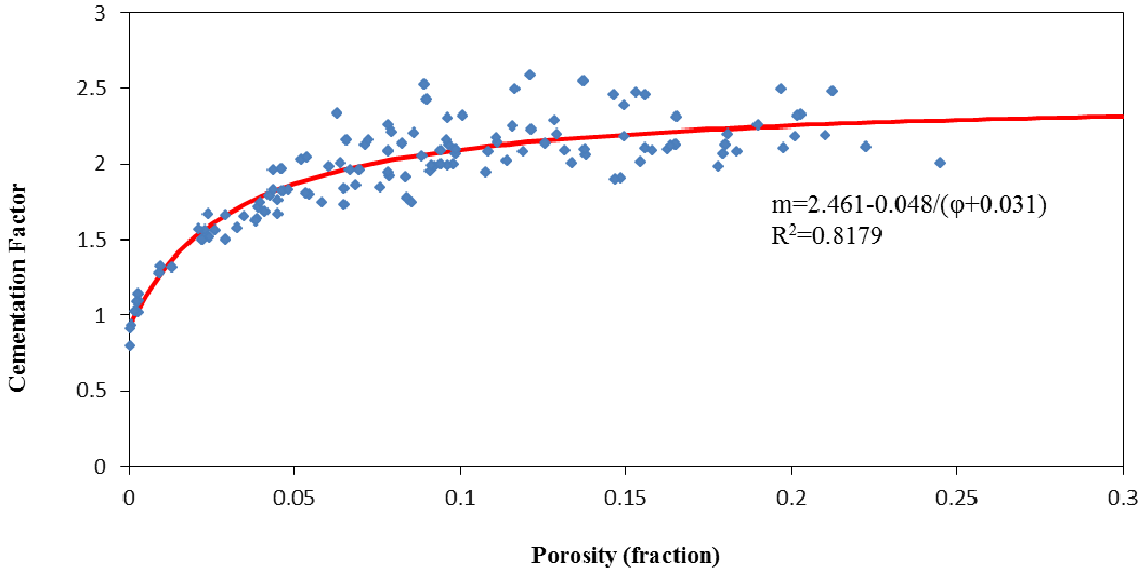

Figure 1
Cementation factor versus porosity (a = 1).

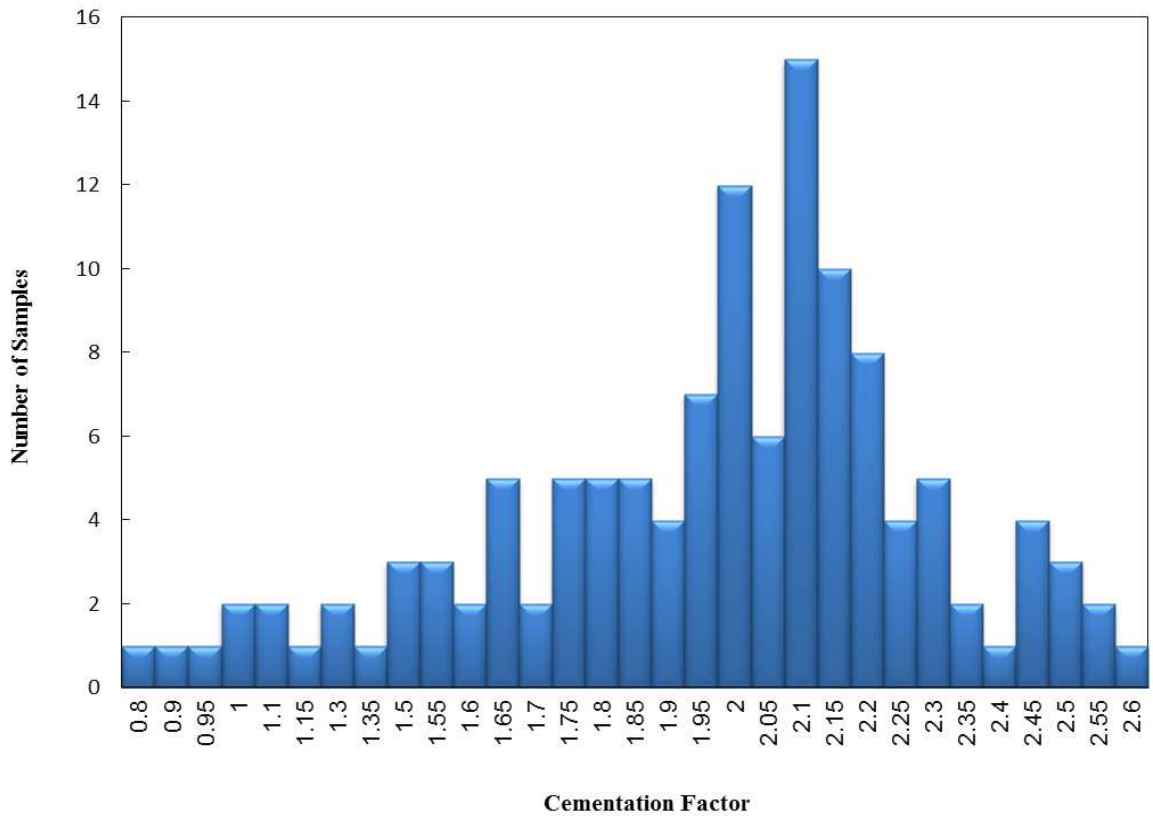

Figure 2
Distribution of cementation factor (a = 1).

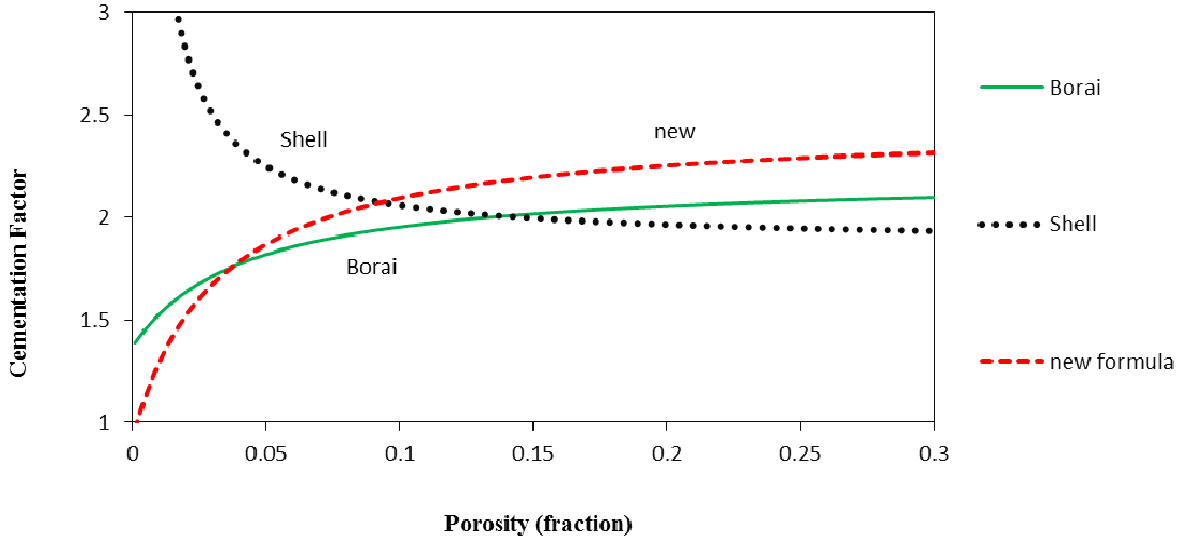

Figure 3
Cementation factor versus porosity (Borai, Shell, and the new formula).

Table 1
Number of plug samples, cored intervals, and formations.

	No. of Samples	Depth (meter)	Formation
Well A	43	1933-2182	Sarvak
Well B	10	2554.77-2707.33	Asmari
Well C	15	251.59-2671.8	Asmari
Well D	5	2472.79-2482.54	Asmari
Well E	4	2674.35-2697.28	Sarvak
Well F	3	2521.6-2743.83	Asmari
Well G	5	3291.69-3516.49	Asmari
Well H	8	1765.88-1808.42	Asmari
Well I	8	2507.83-2508.45	Asmari
Well J	17	3002.88-3210.93	Asmari
Well K	7	2961.13-3168.3	Asmari

5.2. Cementation factor and rock type classification

In the following section, FZI values were used for the classification of the samples. Figure 4 and Figure 5 demonstrate the results of applying FZI approach to the formations under study. With the same DRT groups, samples are plotted on the FRF-Φ cross-plot in Figure 6. The scattered data in each DRT indicate that this approach is not either successful for binning porosity and FRF in well-defined groups. Figure 7 shows the cementation factor versus porosity for different rock types. Moreover, the scattered data for each rock type imply that it is not possible to introduce separate cementation factor correlation versus porosity for each rock type. In general, it can be stated that the classification of samples based on the FZI values for calculating the cementation factors for each DRT is not possible.

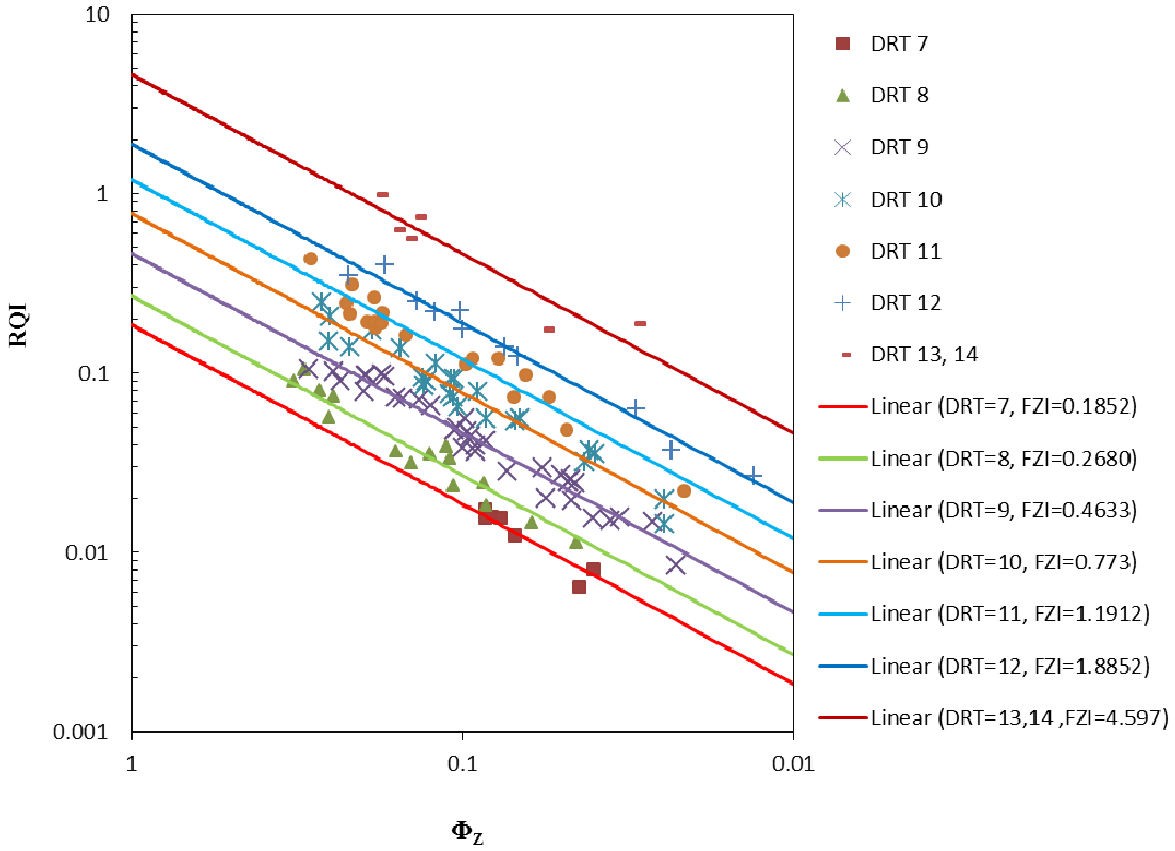

Figure 4
Log-log plot of RQI versus Φ_z (rock typing by RQI/FZI technique).

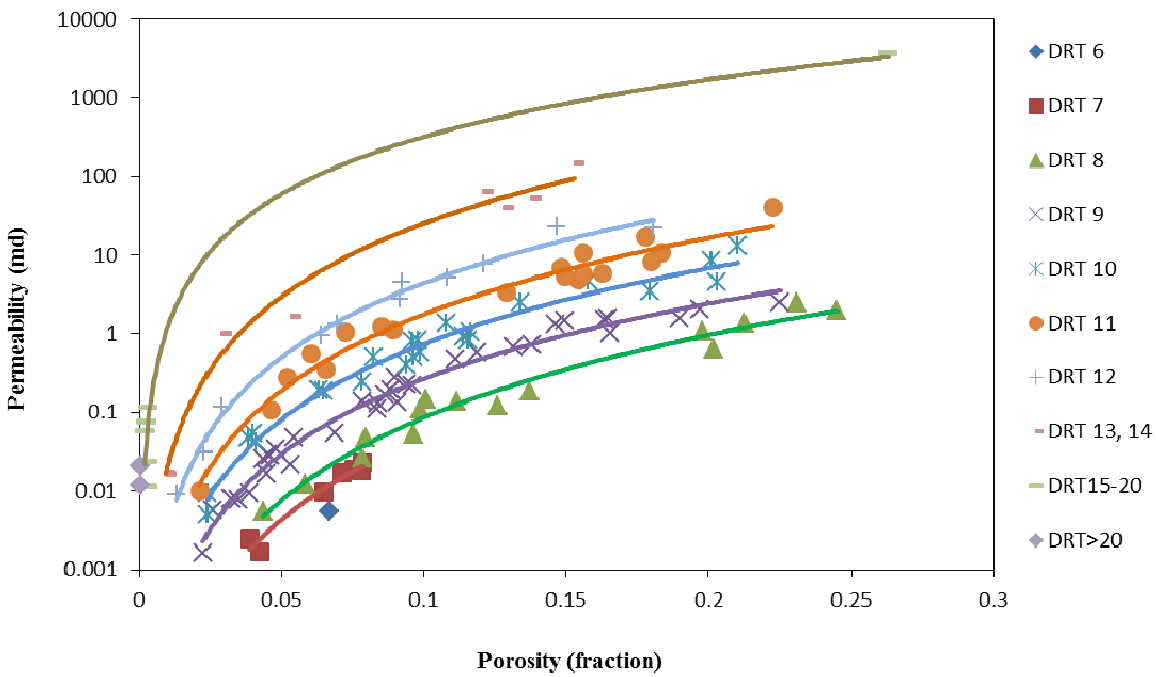

Figure 5
Semi-log plot of permeability versus porosity as classified using DRT's.

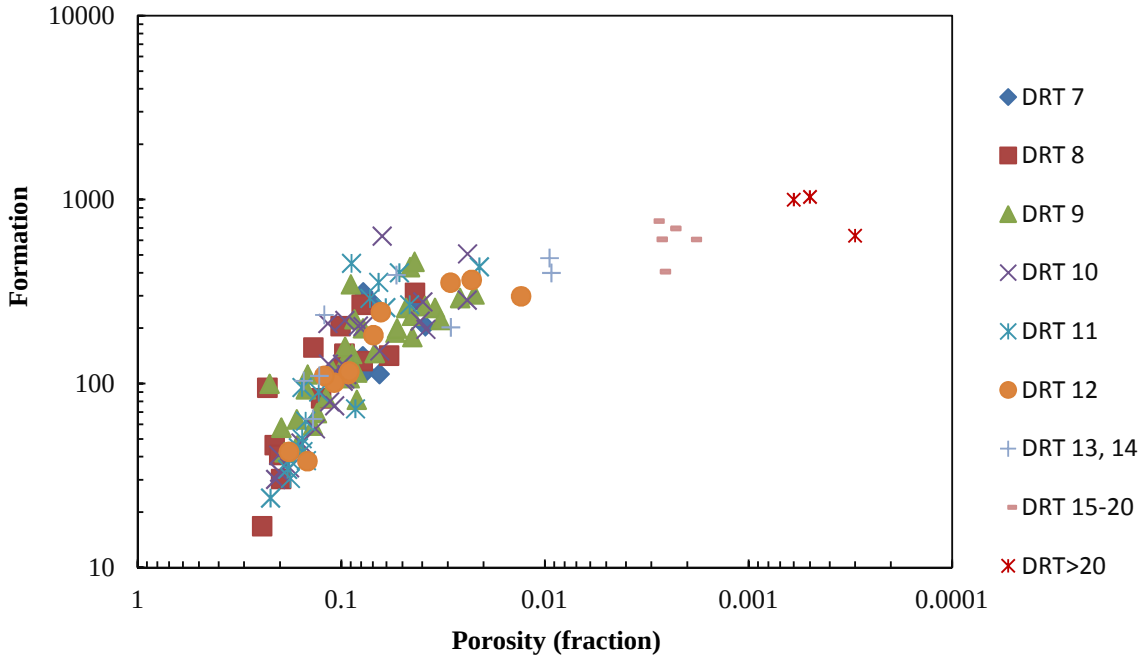

Figure 6
Log-log plot of formation resistivity factor versus porosity as classified using DRT's.

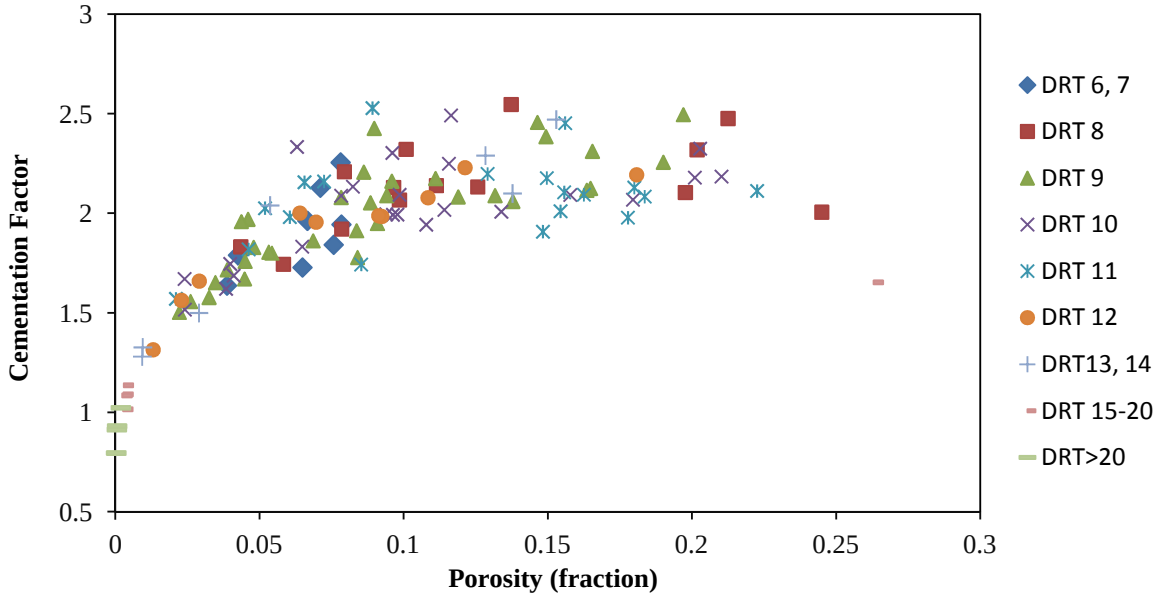

Figure 7
Cementation factor versus porosity as classified using DRTs.

5.3. Cementation factor and petrofacies

Samples with the same petrofacies group are plotted on the FRF-Φ cross-plot. The purpose of this section is to classify the plug samples based on petrofacies to obtain an accurate cementation factor value for each petrofacies. The petrofacies were available for the plug samples of three wells, namely well A, B, and C. The plug samples were classified into six petrofacies based on the porosity type and texture. The petrofacies and number of plug samples in each petrofacies are represented in Table 2.

Table 2
Petrofacies and number of plug samples in each petrofacies.

Petrofacies	Dolomudstone	Dolopackstone	Dolowackstone	Dolostone	Wackestone	packstone
No. of Plug Samples	4	16	5	21	3	18

The scattered data in each petrofacies indicate that this approach is not either successful for binning porosity and FRF in well-defined groups. Figure 8 illustrates the FRF-Φ log-log plot based on the plug facieses and Figure 9 illustrates the cementation factor versus porosity for different petrofacies. The scattered data for each petrofacies indicate that it is not possible to introduce constant m values and separate cementation factor correlations versus porosity for each petrofacies.

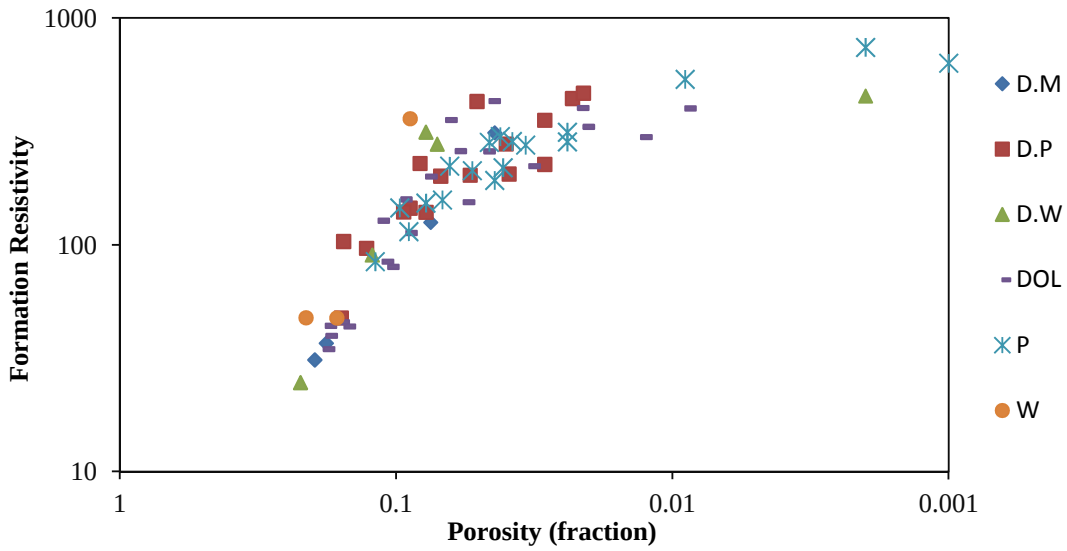

Figure 8
Log-log plot of formation resistivity factor versus porosity as classified using petrofacies.

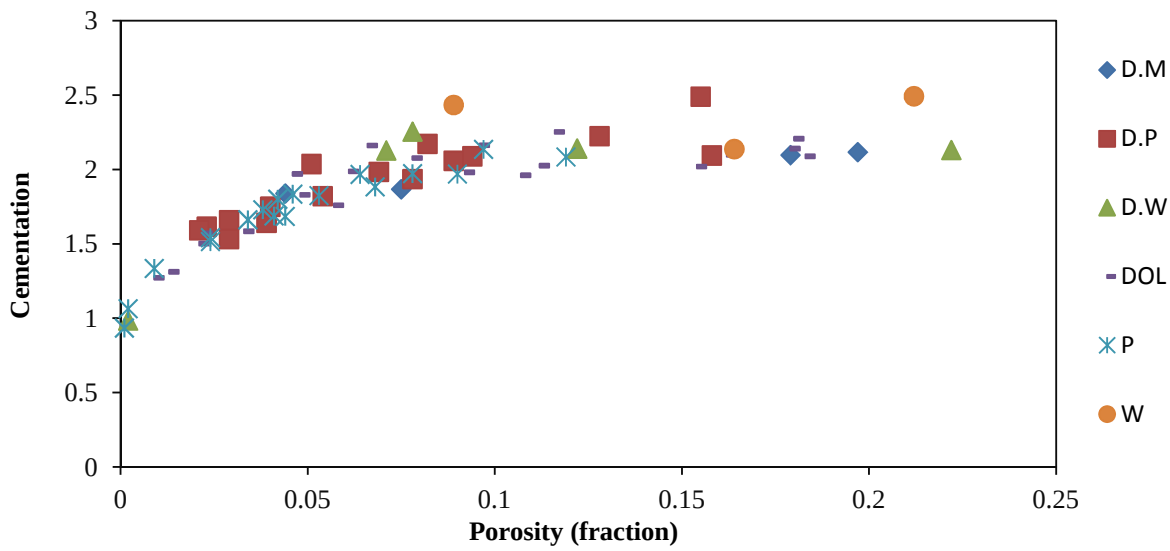

Figure 9
Cementation factor versus porosity as classified using petrofacies.

6. Core and calculated log data comparison

Porosity is calculated in the present study using conventional petrophysical evaluation methods. Core to log data depth match is necessary because the driller's depth do not always match with the logger's depth. Through comparison between the core and log porosities, core depths were shifted up or down to provide good agreement with log data. After depth matching, the core and log porosities were compared with each other. The average porosity values of log and core data for the specified wells are presented in Table 3. Generally good agreement can be seen between core and log porosity.

Table 3
Average porosity of log and core data.

	Well D	Well H	Well I	Well J	Well K
Av. Core Porosity	0.0224	0.1450	0.0496	0.0647	0.1174
Av. Log Porosity	0.0251	0.1572	0.0451	0.0563	0.1025
Relative Error %	12.05	8.41	9.07	12.98	12.69

In Iran, the cementation factor in petrophysical evaluation is traditionally measured by the Shell formula or is taken equal to two to avoid difficulty. Table 4 tabulates the mean squared error (MSE) results in the water saturation calculation for different calculation methods of m and $n = 2$.

Table 4
MSE results in water saturation calculation with different calculation methods of $\boldsymbol{m}$.

	$\boldsymbol{m}$: new formula	$\boldsymbol{m = 2}$	$\boldsymbol{m}$: Shell
Well D	0.0373	0.0788	0.1858
Well H	0.2373	0.1345	0.1408
Well I	0.0785	0.1034	0.1177
Well J	0.0343	0.0707	0.1457
Well K	0.1401	0.1166	0.1239

Since the Borai formula is similar to our new cementation factor formula, the comparison is carried out between the Shell and the new formula. For low porosity wells, the Shell and the new formulas respectively exhibited the largest and smallest errors in the water saturation calculation. Furthermore, in high porosity wells, the Shell and the new formula had the minimal and the maximal errors in the water saturation calculation respectively. Figure 10 demonstrates the comparison of MAE's in the water saturation calculated by different calculation methods of m in different porosity ranges.

A method for the calculation of the cementation factor was proposed in order to minimize the MAE's between the calculated water saturation and core water saturation. In this proposed method, the cementation factor is calculated by the new formula and Shell formula at low ($\Phi \leq 0.1$) and high porosities ($\Phi > 0.1$) respectively. It is obvious that this range of porosity for low and high porosity is an approximation. Figure 11 to Figure 15 respectively represent the lithology, core and log porosity, measured core water saturation, and calculated log water saturation with two calculation methods for m (the new formula and the Shell formula) in the cored intervals of the wells under study.

According to the petrophysical evaluation, Sarvak formation in Well D consists of limestone with a little shale in certain limited intervals. The average porosity in layer B is around 4.2% and the calculated cementation factor by the new formula exhibits fair consistency between the core and calculated water saturation.

Asmari formation in Well H consists mainly of carbonates (dolomite and limestone) with streaks of anhydrate and shale in certain limited intervals. Two layers of this well have the core saturation data. The average porosities in layers Z1 and Z2 are approximately 17.1% and 9.4% respectively. The core and calculated water saturation provided by the Shell formula are more consistent than the new formula.

According to the petrophysical evaluation, Asmari formation in Well I consists mainly of carbonates with streaks of anhydrate and shale in certain limited intervals. In the low porosity intervals of layers Z4 and Z5, the core and calculated water saturation obtained by the new formula are more consistent than the Shell formula.

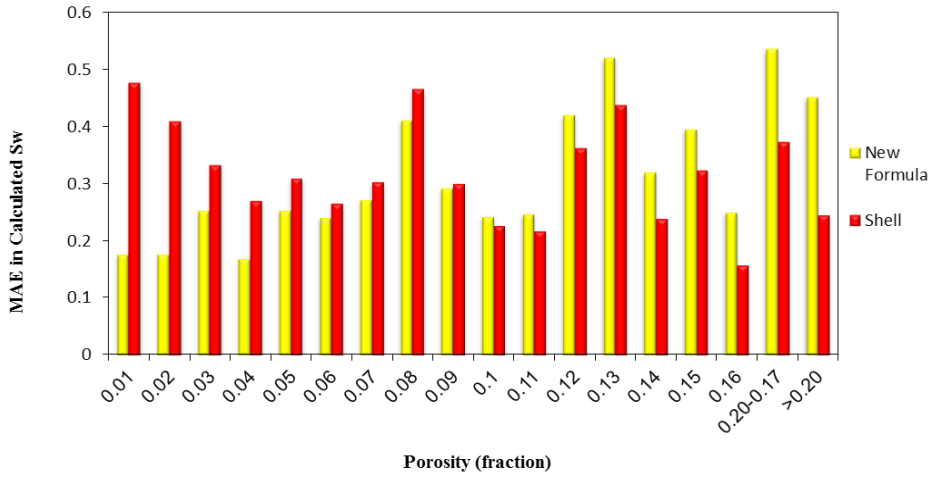

Figure 10
MAE's in calculated water saturation by different calculation methods of m at different porosity ranges.

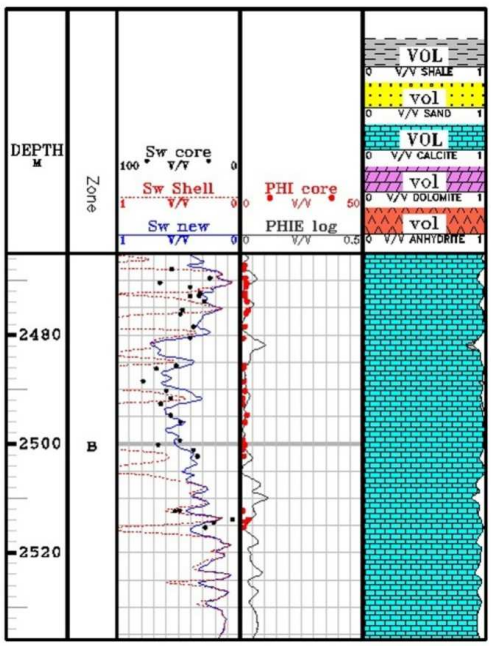

Figure 11
Lithology, core and log porosity, measured core water saturation, and calculated log water saturation with two calculation methods for m (the new and Shell formulas) in Well D.

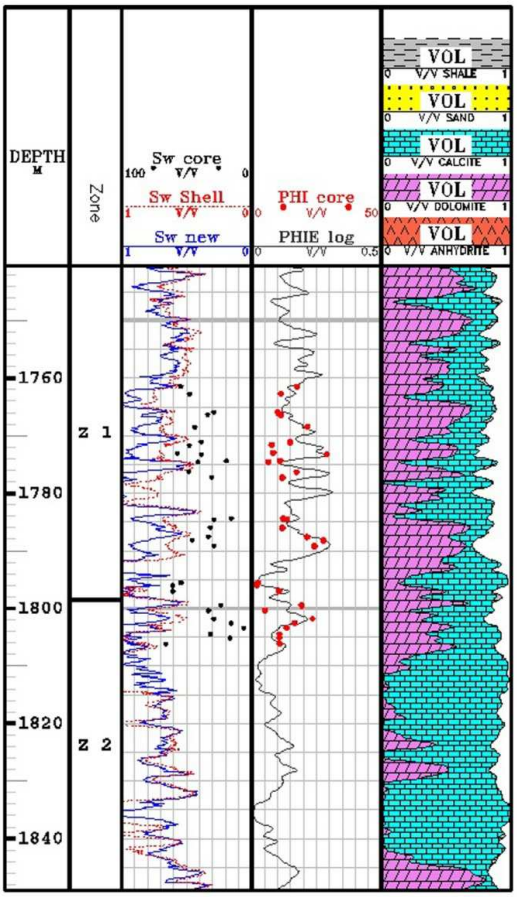

Figure 12
Lithology, core and log porosity, measured core water saturation, and calculated log water saturation with two calculation methods for m (the new and Shell formulas) in Well H.

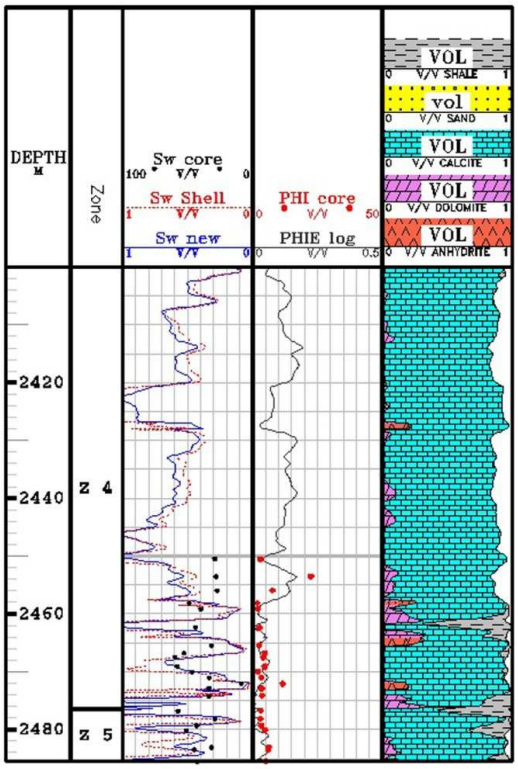

Figure 13
Lithology, core and log porosity, measured core water saturation, and calculated log water saturation with two calculation methods for m (the new and Shell formulas) in Well I.

The results of petrophysical evaluation show that Asmari formation in Well J consists mainly of the carbonates with streaks of shale in certain limited intervals and three anhydrate strikes in upper parts of the well. The average porosities of all the layers are below 6% and the calculated cementation factor by the new formula shows moderate consistency between the core and calculated water saturation.

According to the petrophysical evaluation, Asmari formation in Well K is mainly composed of carbonates with some shale and sandstone in certain intervals. Furthermore, some parts of Asmari formation in this well consist of pure sandstone and sandstone with a minor percentage of shale. Carbonate parts of this well have moderate porosity and there are no distinctive differences between the calculated water saturation by two calculation methods of m (the Shell and new formulas).

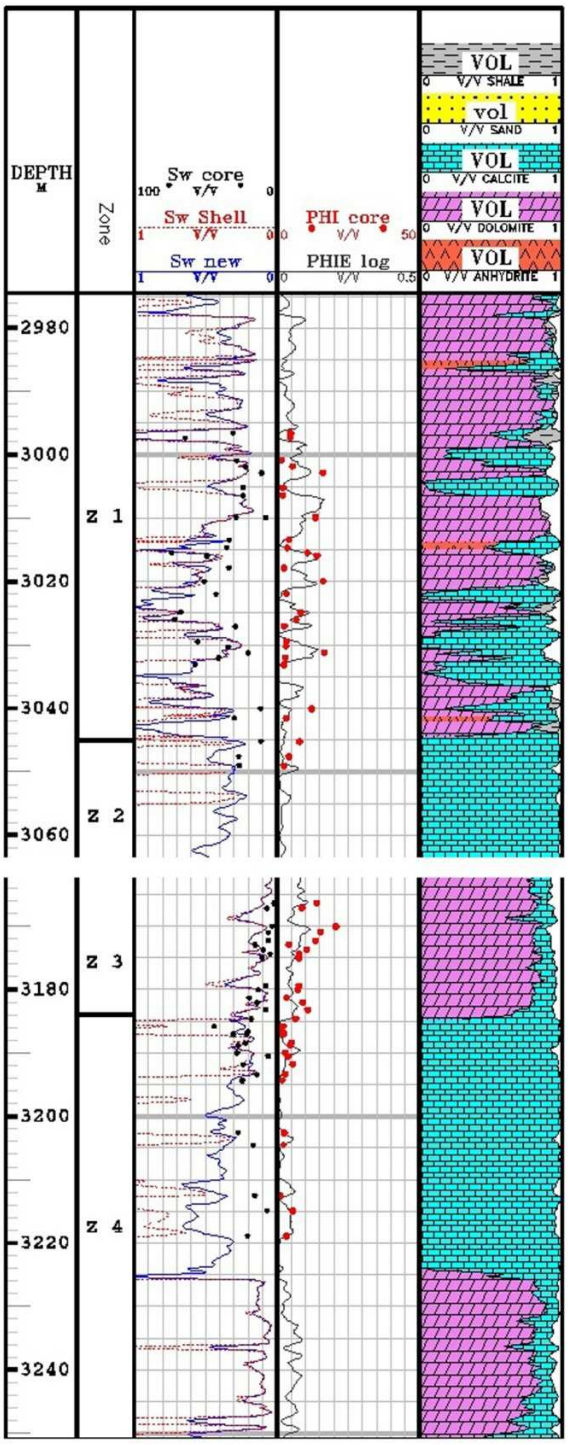

Figure 15
Lithology, core and log porosity, measured core water saturation, and calculated log water saturation with two calculation methods for m (the new and Shell formulas) in Well K.

7. Conclusions

It is not appropriate to use constant average values for the cementation factor in an entire formation or well because there are several factors affecting this parameter. According to the resistivity core data, a new cementation factor correlation was derived. This formula can be used to calculate the

cementation factor in the carbonate parts of Asmari and Sarvak formations. The cementation factor does not change significantly at porosity higher than about 10%. The classification of rocks based on FZI is inadequate to obtain accurate values for cementation factor. Although the cementation factor depends on the rock properties, it is not possible to introduce constant m values and separate cementation factor correlations versus porosity for each petrofacies.

A new method was proposed herein to calculate more accurate water saturation values. In this proposed method, porosity must be divided into two groups, i.e. high and low porosity ranges. Then, for high and low porosity groups, m is calculated separately by the Shell and new formulas respectively.

Nomenclature

a	: Tortuosity factor
CGR	: Corrected gamma ray
DT	: Sonic log
DRT	: Discrete rock type
F	: Formation resistivity factor
FRF	: Formation resistivity factor
FZI	: Flow zone indicator
GR	: Gamma ray
m	: Cementation factor
MAE	: Mean absolute error
MSE	: Mean squared error
n	: Saturation exponent
NPHI	: Neutron log
PHIE	: Effective log porosity
PHIcore	: Core porosity
RQI	: Reservoir quality index
R_o	: Resistivity of the rock (entirely filled with brine or water $S_w = 1$).
R_t	: Total resistivity of the rock at the saturation $\mathrm{S_w}$
R_w	: Water or brine resistivity
S_w	: Water or brine saturation
Greek Symbols	
Φ	: Porosity
Φ_{sonic}	: Calculated porosity from sonic log
Φ_{total}	: Calculated porosity from total porosity logs
Φ_{z}	: Normalized porosity

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