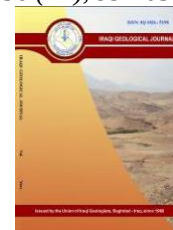




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Cementation Exponent Estimates and their Impact on Oil Initially in Place Calculations : A Case Study from Lower Qamchuqa Formation in the Bai Hassan Oilfield, Northern Iraq

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Abstract

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The effect of Cementation Exponent has been investigated on the calculated water and hydrocarbon saturations and the estimated oil initially in place. The Aptian Lower Qamchuqa (Shua'iba) Formation from the well BH-96, Bai Hassan Oilfield, is used as a case study. Four different values of Cementation Exponent were applied in calculating water saturation using the Archie equation. The static value of 2 commonly used for carbonate reservoirs was one of the cases used to calculate an average of 68% water saturation. In the second case, the value of 1.81 is used for m based on the average m values obtained through testing 22 core samples in the laboratory. The average of 60.5% S_w was calculated for the studied part of the Lower Qamchuqa Formation in this case. The Pickett plot method was used as a third case, and 1.65 was estimated as the m value through which the average of 54% S_w was calculated. In the fourth case, variable values of m were used for the different depth intervals from which core samples were tested in the laboratory. In this case, the calculated average water saturation was equal to 60%. The upper part of the studied section was generally of low porosity and high water saturation, whereas the middle and the lower parts contained hydrocarbons with different saturations. Using shale content, porosity, permeability, and water saturation cutoffs for the four different cases, the net to gross pay ratios were calculated. The ratios ranged between 56.5% in the case of using the 1.65 value of m and 47.6% in the case of using variable core tested m values, and accordingly, the difference of about 4 m in net thickness is expected to be underestimated or overestimated, respectively, when is calculated.

Keywords: Lower Qamchuqa; Bai Hassan; Cementation factor; Water saturation

1. Introduction

The Cementation Exponent (m), which is referred to as the "Cementation Factor", is a function of the shape and distribution of pores. The degree of cementation of particles depends on the nature, amount, and distribution of numerous cementing materials like silica, calcium carbonate, and a variety of clays. The increase of cementation causes decrease of porosity and increase of the Formation Factor

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(F) (Tiab and Donald, 2015) which in turn is dependant on the types of sediments and controlled by grain shape (Lucia, 2007). Cementation factor varies according to the type of rocks, the pore-shape, the type of porosity and its distribution, and to some extent the degree of compaction (Serra, 1984).

The cementation exponent (m), also known as cementation index or porosity index (Wang et al., 2022), is reflecting the cementation of the reservoir, the complexity of the pore-throat (tortuosity) and connectivity between the pores, in addition to the fracture opening. Its physical significance is to characterize the influence of the pore structure (microscopic characteristics of the reservoir space) on the conductivity of the rock. Factors influencing m include porosity, pore-throat size, type of rock particles, type and distribution of clay content, degree of cementation, and overburden pressure (Regland, 2002; Nabawy, 2015). All these are controlled by sedimentation, tectonics, and diagenesis. In this study, the m value for the Lower Qamchuqa Reservoir in a selected well of Bai Hassan Oilfield is estimated using different methods to show the impact of this important factor on the water and hydrocarbon saturations and the estimated oil initially in place.

2. The Study Area

Bai Hassan Oilfield is located southwest of the Kirkuk Oilfield, northern Iraq (Fig. 1). Tectonically, the field is located within the foothill region of the northwest-southeast trending Zagros Fold and Thrust Belt. The field was discovered in 1953 by the Iraqi Petroleum Company (IPC) and came on production in 1960 (Baban, 2008). The structure of Bai-Hassan is a double-plunged asymmetrical anticline of 34 km length and 3.8 km wide (Sadeq and Yousif, 2015). The structure consists of two main domes: Kithka at the southeast and Daoud at the northwestern, which are separated by the Shahal saddle (Fig. 2). The selected well for this study is BH-96, which lies on the SE flank of Kithka Dome.

According to Bellen et al. (1959), the Lower Qamchuqa (Shu'aiba) Formation, in its type section in the well Zubair-3, is comprised of chalky, argillaceous, and crystalline limestones, with some pseudo-oolitic limestones that are glauconitic in parts. The formation outside the type area is mainly composed of dolomites and dolomitized limestones (Ditmar et al., 1971). The thickness of the Lower Qamchuqa Formation in the High Folded Zone ranges between 250 and 300 meters, exceeding 500m in some areas (Buday, 1980).

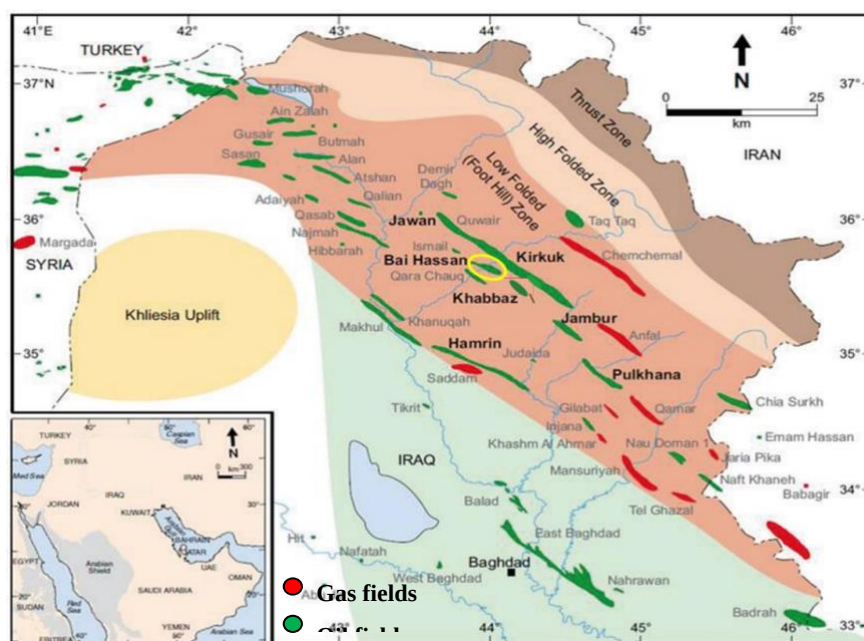


Fig. 1. Location of Bai Hassan Oilfield (after Al-Qayim et al., 2010)

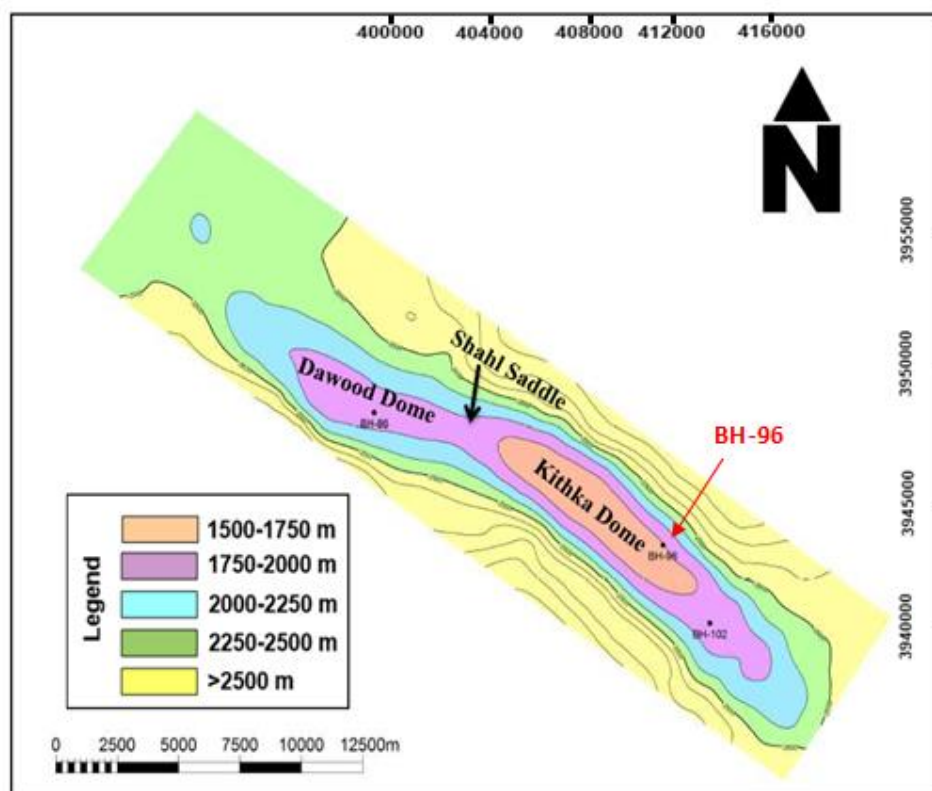


Fig. 2. The structural contour map of Bai Hassan Oilfield and location of the well BH-96 (after Shahab-2019)

The formation was deposited in a neritic environment, which was slightly affected by terrigenous supply (Al-Sadooni, 1978; Buday, 1980). Lower Qamchuqa in the Bai-Hassan Oilfield (the study area) is unconformably overlain by the shale beds of the Nahr Umr Formation and conformably underlain by the Garagu Formation (NOC, 1992). This formation is significant because it is part of the field's Cretaceous (Aptian) reservoirs.

3. Data and Methodology

The data used to achieve the goals of this study are mainly from the available wireline logs done for the penetrated upper 44.8m from the Lower Qamchuqa Formation in the well BH-96. The data came from Gamma Ray logs combined with Sonic, Density, and Neutron porosity logs. The data from the Micro Resistivity and Deep Resistivity logs were also adapted to be part of the used data in this study. Permeability values obtained from the core tests are also used in this study.

The following methodology steps are followed in this study:

- Replotting the logs with suitable scales using Techlog 64 2015.3 software
- Calculating shale volume using gamma-ray data
- Converting the recorded data of sonic and density logs to porosity values by using specific equations
- Correcting the calculated porosities from the effects of the shale content
- Calculating permeability for the entire studied section using Multiple Regression Analysis method.
- Estimating different values of Cementation Factor (m) using different methods
- Calculating water saturation (S_w) using the different estimated m values
- Calculating Net to Gross pay ratios and comparing the results

4. Results and Discussion

4.1. Shale Volume and Porosity Calculation

In order to achieve the goals of this study, the required parameters for calculating water and hydrocarbon saturations for the studied Lower Qamchuqa Formation by the Archie equation should be well prepared. Thus, the porosity of the formation has been determined through the three porosity logs of Sonic, Density, and Neutron. Additionally, the volume of the shale was also determined from the data of the Gamma ray, and the values of the calculated total porosities were corrected for the shale impact and converted to effective porosities. The calculated volume of shale and the corrected and non-corrected Neutron – Density values are plotted in Fig. 3.

The Lower Qamchuqa Formation, in the studied well, shows a gradual upward increase in the shale volume. The upper 19m of the formation is obviously different from the rest of the formation in terms of shale volume, with an average of about 20%. Shahab et al. (2022) also noticed the same condition of shale distribution when they studied the upper part of the Lower Qamchuqa Formation in the well BH-86. In contrast to the shale content, the porosity of the formation decreases upward. The porosity of the upper mentioned 19 m of the formation is very low, especially when correction from shale impact is done (PHIE-ND) (Fig.3). Zones of extremely low porosities exist in the upper part of the formation in addition to porous zones that never exceeded 4% porosity. Generally, the effective porosity at the middle and lower parts of the formation ranges between 5 and 10%, with a few narrow horizons of exceptionally high porosities exceeding 13%.

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4.2 Formation Resistivity Factor (FR)

Experiments done by Archie (1942) revealed that the resistivity of a water-filled rock (R_o) that is filled 100% with water having a resistivity of R_w can be related to a Formation Factor (F) as in the Equation 1.

$$R_o = F \times R_w \dots\dots\dots (1)$$

Additionally, Archie found in his experiments that F can be related to porosity and cementation exponent (m), and tortuosity (a) by Equation 2.

$$FR = a / \phi^m \dots\dots\dots (2)$$

In most of reservoir and log analyses, the value 1.0 is used for the tortuosity (a) in Equation 2. Accordingly, in laboratory experiments, FR and ϕ are first measured in order to mathematically find out the value of the cementation exponent (m).

In this study, 22 rock samples from the Lower Qamchuqa Formation, representing approximately 38m of the formation's gross thickness, are tested in the laboratory to determine an average m value for the formation (Fig.4).

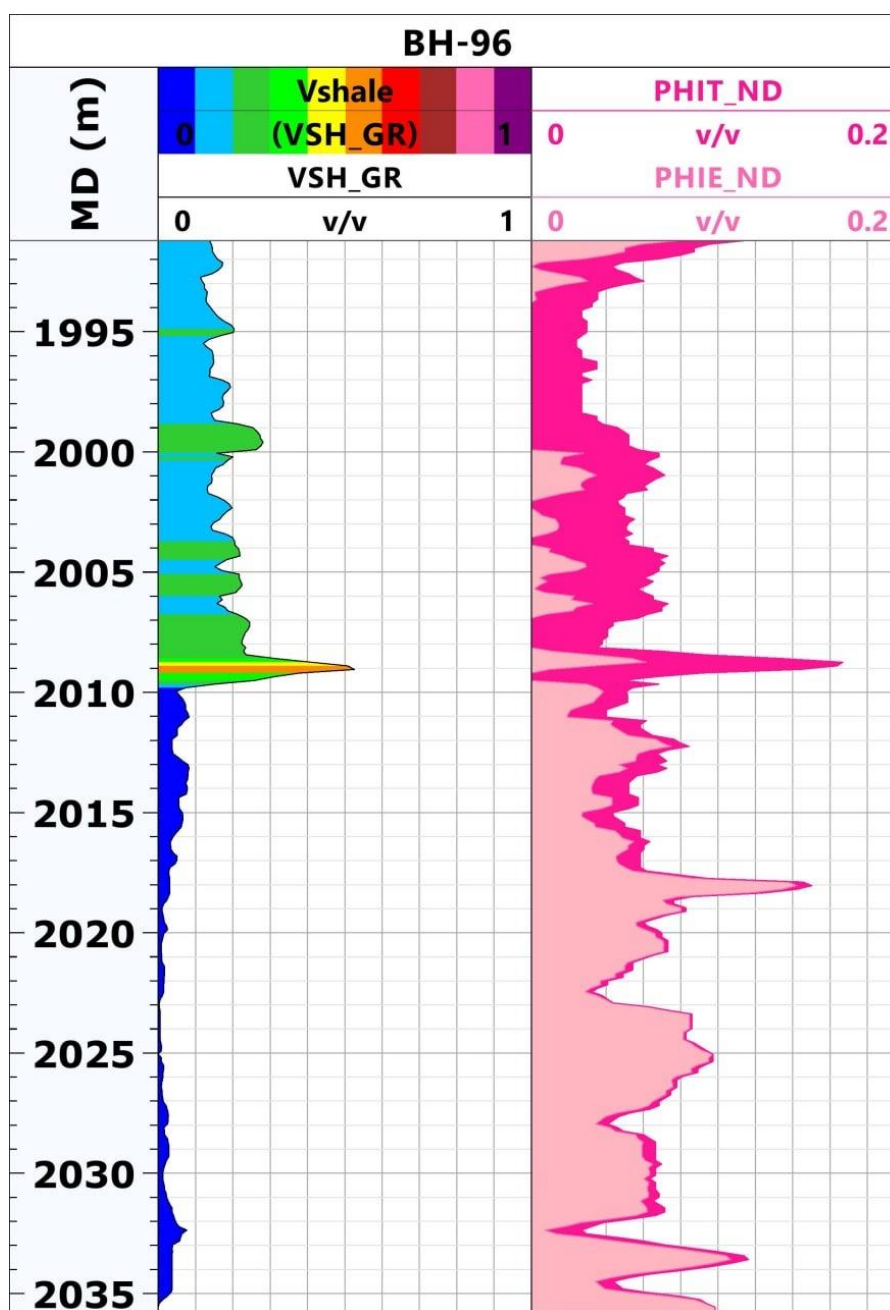


Fig. 3. Volume of shale, corrected and non-corrected Neutron – Density porosity values for the Lower Qamchuqa Formation in the well BH-96.

4.3. Cementation Exponent

Jackson et al. (1978; in Doveton, 1994) found that the m value increased in grain packs as shapes became progressively less spherical. Mendelson and Cohen (1982; in Doveton, 1994) observed that the m value was lowest when grains had the same shape and orientation.

Generally, the value of m ranges between 1.0 and 5.0, in chalky rocks and compacted formations, m is approximately equal to 2. The m value is lower than 1.6 for poorly cemented and bigger than 3.5 for very well cemented rocks. If connected vugs or fractures are present in the rock, the value of m can be less than 1.8, while for the non-connecting vuggy carbonates, it can vary between 1.8 and 4. According to Wang et al. (2022), the expected m value for fractured reservoirs is less than 2, while for reservoirs with vugs, the m value is between 2.67 and 7.3.

The value of m differs from reservoir to reservoir and from well to well within the same oilfield; therefore, a reliable value of m is best determined by laboratory measurements (Tiab and Donaldson, 2015). In addition to the estimated average m value for the studied Lower Qamchuqa Formation obtained through laboratory measurements which was equal to 1.81, the technique of the Pickett plot is also used for estimating an additional value of m (Fig.5).

The average value of m can be obtained by a Pickett plot depending on the data for the true resistivity (R_t) and the calculated NDE porosity. The slope of the line, which starts from the value of the formation water resistivity at 100% porosity and passes through the sample points located at the left side of the sample population, represents the m value, and the line itself is the 100% water saturation line. The estimated m value for the Lower Qamchuqa Formation in the studied well of BH-96 by the Pickett plot was equal to 1.65.

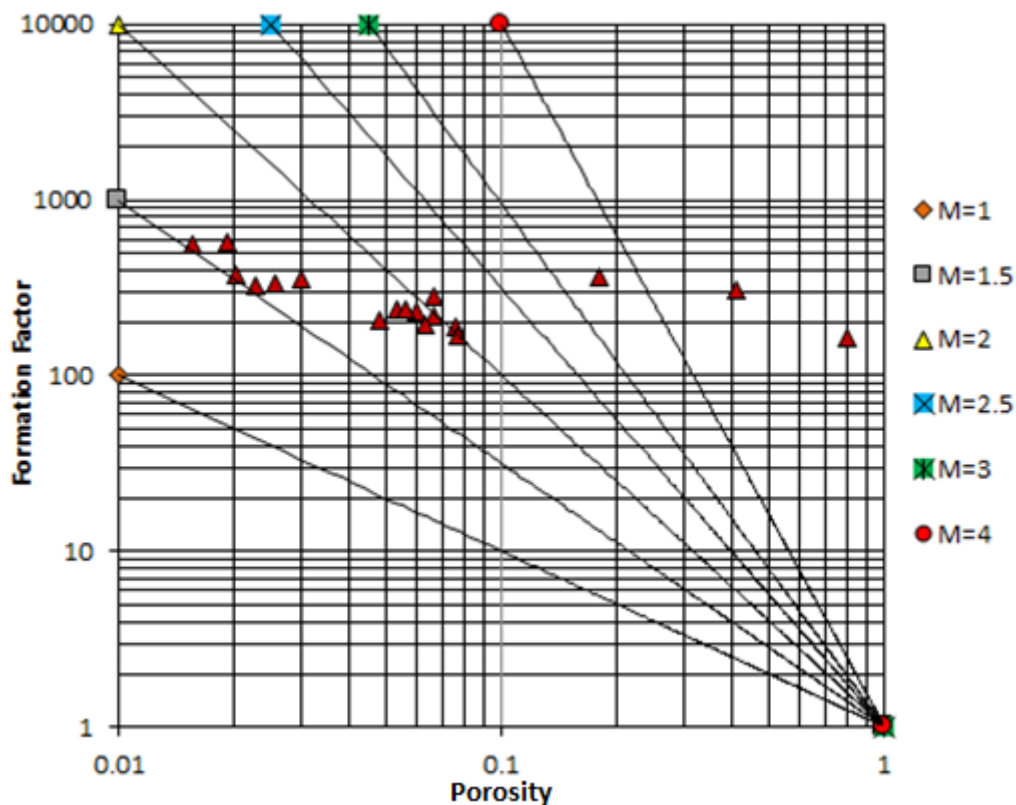


Fig. 4. Estimated m values for the laboratory tested core samples of Lower Qamchuqa Formation in the well BH-96.

4.4. Water and Hydrocarbon Saturations

The main goal of any reservoir characterization process is to best estimate water and hydrocarbon saturation values in order to get a reliable value for the volume of oil in place and reserves. All the parameters required for calculating S_w by Archie's formula should be confidently determined.

The application of Archie's equation to calculate water saturation using the static and conventional value of 2 for the cementation exponent is not best applied in reservoirs with serious heterogeneity and complex pore structure. Determination of reasonable m value for carbonate reservoirs is of a great challenge. Using the value 2 for the m exponent in Archie's equation is not applicable any more especially for triple porosity system heterogeneous reservoirs (reservoirs with matrix porosity, fractures, and vugs).

Asquith (1985) mentioned an interesting example depending on Elliott's (1983) report about a case in the vuggy Canyon Reef zone in Scurry County, Texas, where the analysts mistakenly evaluated a wet reservoir as a productive reservoir due to arbitrarily using the value 2 for m when applying Archie's equation. Later, when more accurate estimation was done for the m value using the Pickett plot, they were satisfied that the value was 3.7 instead of 2, and thus all the previously calculated values of S_w were underestimated.

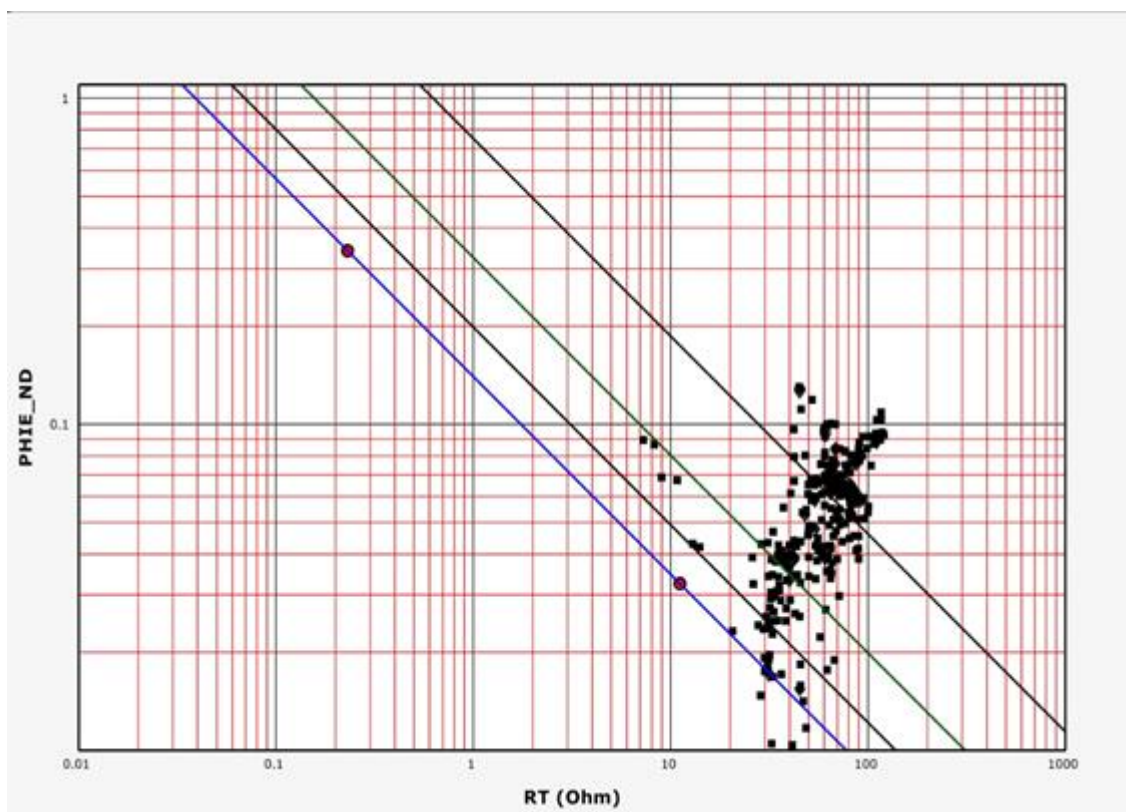


Fig. 5. A pickett plot for estimating the m value depending on the true resistivity versus porosity for the studied Lower Qamchuqa Formation in the well BH-96.

In this study, a comparison was made between the different cases of the calculated S_w values using different estimated m values. Figure 6 shows the plot of four different cases of water (and hydrocarbon) saturations for the studied Lower Qamchuqa Formation using different values of m .

Generally and in all applied cases, the upper part of the formation consists of a semi-to-full water-bearing reservoir, whereas the middle and lower parts contain hydrocarbons in different ratios.

In the first case, where the static value of 2 is used for the m , an average value of 68% for the water saturation was estimated. In the second case, the used m value was equal to 1.81 which was obtained from the average of the m values measured in the laboratory. In the second case, the average S_w value for the formation was 60.5%. In the third case, the value of 1.65 was used for the m , which was estimated through the Pickett plot method, through which an average of 54% of S_w was calculated. Because the cementation exponent is affected by the value and type of porosity, as well as the pore throat sizes, vertical variations in the lithology and rock properties result in different m values.

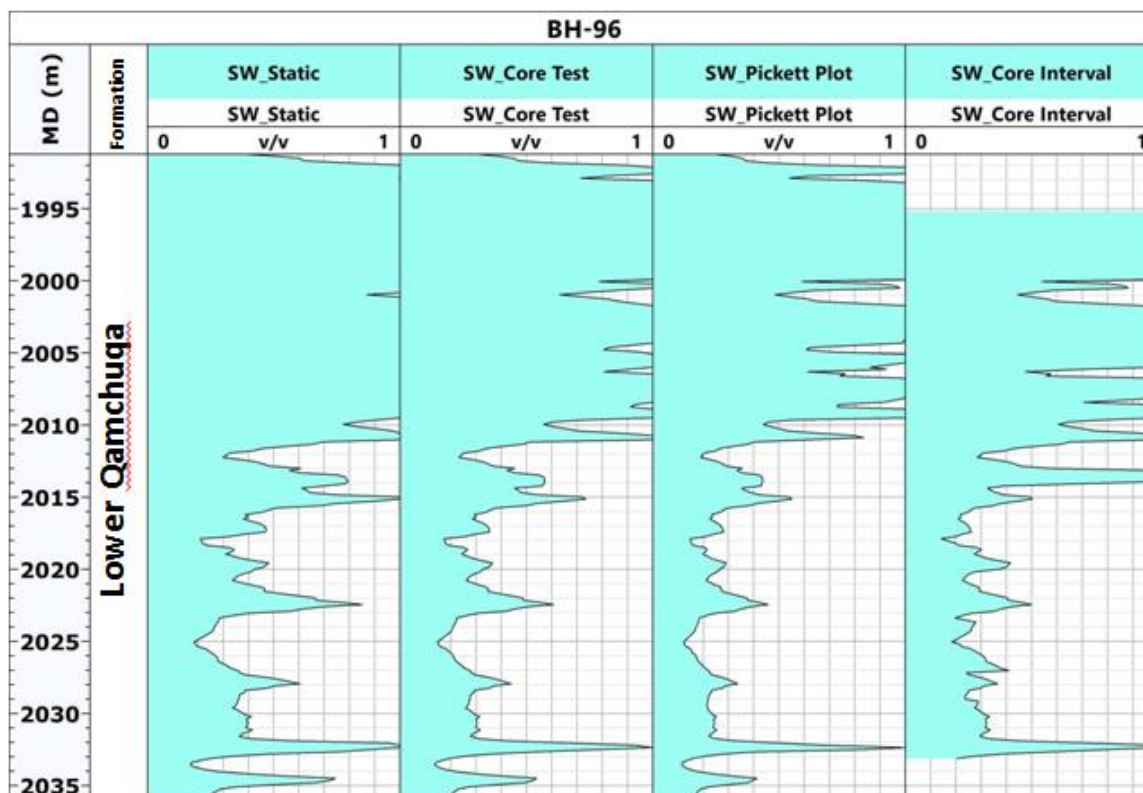


Fig. 6. Different cases for calculated S_w values for the Lower Qamchuqa Formation in well BH-96 using various m values (static = 2, core test = 1.81, Pickett plot = 1.65, and variable m from core interval tests).

Therefore, in the fourth case, the depth interval from which the tested rock samples were selected (from 1995m to 2033m) was subdivided into zones, and the m value of each zone was applied for calculating the S_w separately. Thus, in this case, no single value of average m is used to calculate S_w of the formation, but rather a value of m for each zone based on the depth intervals representing the laboratory-tested samples. The calculated average S_w for the tested portion of the Lower Qamchuqa Formation in the fourth case was also equal to 60%.

Although the calculated relatively high average S_w values for the four cases make the Lower Qamchuqa Formation in well BH-96 not so attractive as a reservoir, practically most of the zones of high S_w values are located at the upper part of the formation, where the lowest porosity zones exist. The selected cutoff value for the permeability was 1 mD which is believed to be acceptable for oil-bearing reservoirs (Glover, 2008). Fig. 7 shows the selected porosity cutoff (3%) for the studied section from the cross plot of porosity versus permeability.

Porosity versus S_w values as calculated using the different estimated m values mentioned in the four cases (2, 1.81, 1.65, and variable values of m as measured in the lab for the selected core samples) (Figs.8-11). Highest S_w cutoff value was 70% for the case of using the static 2 value of m . The lowest cutoff value of S_w was equal to 54% for the case of using m value equal to 1.65 as measured from the Pickett plot method.

In both cases of using the average of the measured m values in the laboratory, or using different values for the measured m , the S_w cutoff value was almost the same (60%).

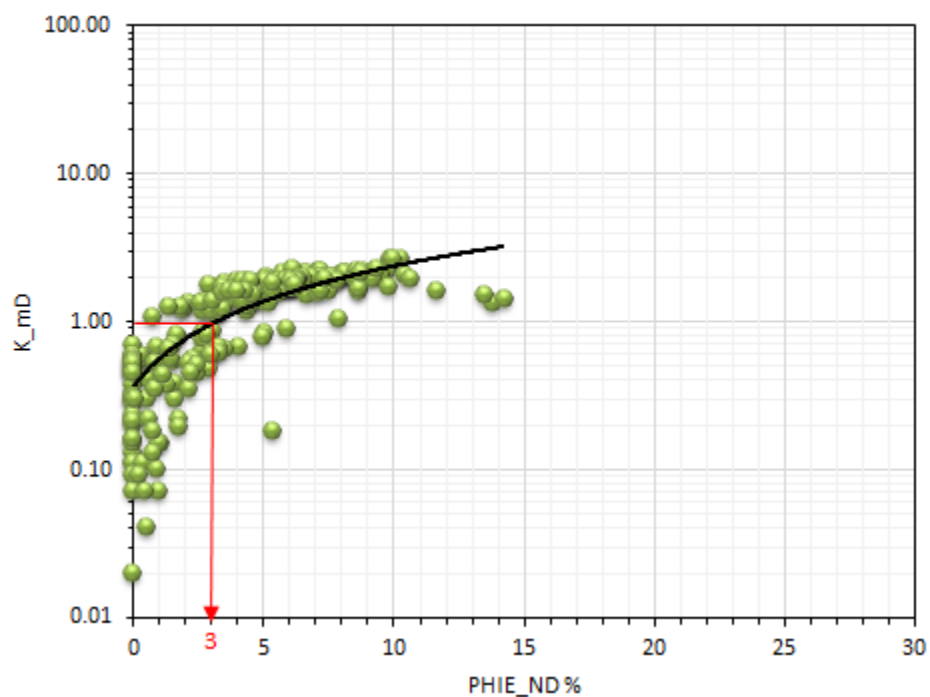


Fig. 7. Porosity vs. Permeability cross plot for determining porosity cutoff for the studied Lower Qamchuqa reservoir in the well. BH-96.

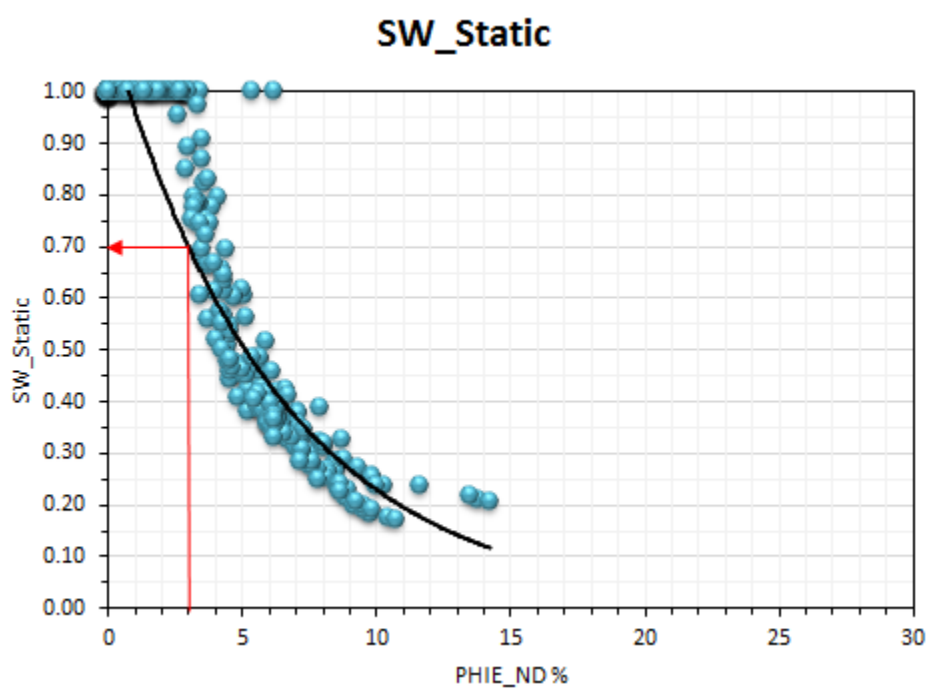


Fig. 8. Sw cutoff selection for the calculated water saturation of the Lower Qamchuqa Formation using the static m value of 2.

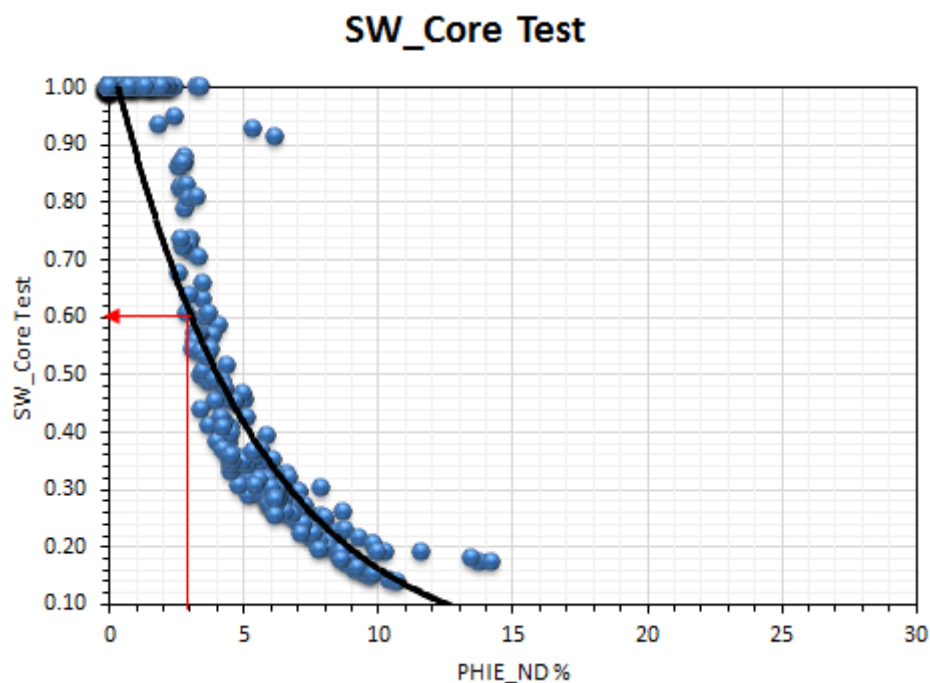


Fig. 9. Sw cutoff selection for the calculated water saturation of the Lower Qamchuqa Formation using the m value of 1.83 estimated from the core tests

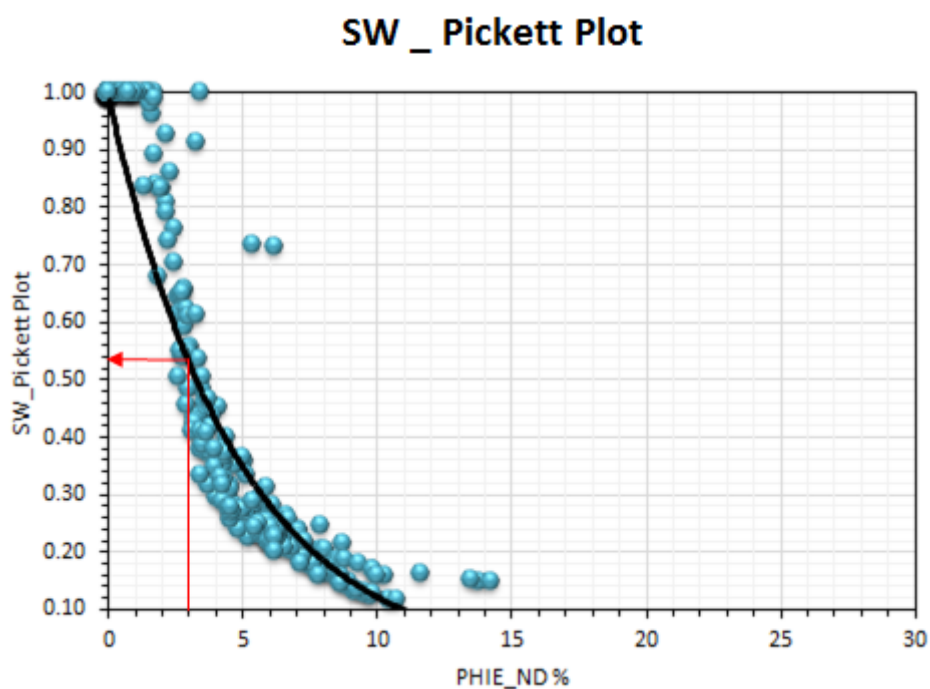


Fig. 10. Sw cutoff selection for the calculated water saturation of the Lower Qamchuqa Formation using the m value of 1.65 estimated from the Pickett plot

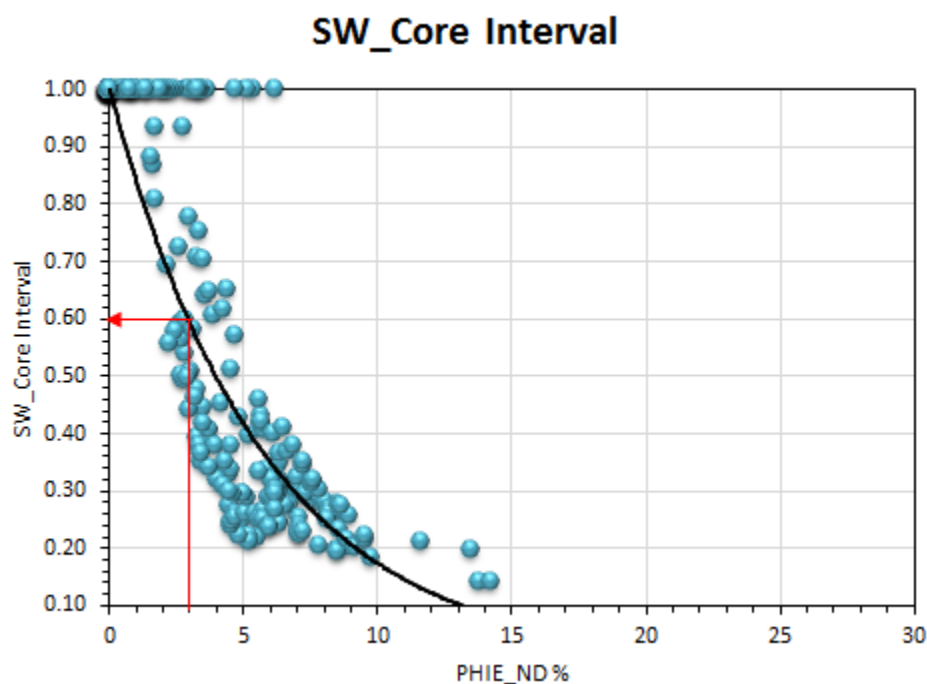


Fig. 11. Sw cutoff selection for the calculated water saturation of the Lower Qamchuqa Formation using different values of m as measured for the tested cores.

4.5 Net to Gross Pay Ratio

The effect of the variations in the estimated m values can be better investigated when the net to gross (N/G) pay ratios are determined for the studied Lower Qamchuqa Formation. The process of reserve or Oil Initially in Place (OIIP) calculation is affected intensively by the average S_w value and the collective thickness of the pay intervals. In order to calculate the N/G pay ratio or thickness, suitable cutoff values for shale content, permeability, porosity, and water saturation should be selected.

Cut-off limit of 50% shale can be used to differentiate the reservoir from non-reservoir intervals. This type of cut-off is often used in preliminary log evaluations and is based on the assumption that reservoir permeability is destroyed once a rock contains more than 50% shale (Jahn et al., 2003). The entire parts of the studied Lower Qamchuqa Formation in the well BH-96 are of less than 30% shale content (except a very narrow horizon at the depth 2009 m, Fig. 3). Thus, the entire section can be considered as a reservoir. Finally, based on the selected cutoff values for shale content, permeability, porosity, and the different cases of S_w , the N/G reservoir and pay ratios were calculated (Tables 1).

Different ratios of N/G pay were obtained when different estimated m values were applied. Accordingly, different OIIP volumes will be expected when reserve estimations are done for the reservoir and the field. Most promising will be the case where the estimated value of 1.65 from the Pickett plot is applied (Case 3). In this case, the highest N/G pay (highest net pay thickness) is obtained, which is about 56.5%. Additionally, the lowest Bulk Volume Water (BVW) is also expected in this case (0.014), which means the highest quantity of reservoir hydrocarbons and the lowest quantity of water will be associated with the recovered oil. The average S_w for the net pay part of the formation is the lowest among the four applied cases ($S_w = 23.5\%$).

The second case, where the value of m was estimated from the average of the core test measurements (1.81), gave the second promising result and was close to the case 3 regarding the N/G pay (55.4%) or BVW (0.018).

In case 1, in which the static value of 2 was applied for m , about 49% of N/G pay is calculated with an expectation of the lowest volume of reservoir hydrocarbons among the four applied cases with an average S_w value of 35.5% ($BVW = 0.023$) for the net pay portion of the formation.

In case 4, where variable m values used for the different depth intervals, the calculated net pay thickness appeared to be the lowest (N/G pay = 47.6%) with about 0.018 BVW value (30.4% S_w).

Table 1. N/G reservoir and pay ratios for the Lower Qamchuqa Reservoir in the four different cases of estimated m values.

Cases	Flag Name	Gross thickness m	Net thickness m	Net to Gross	BVW	Av. Shale Volume	Av. Porosity	Av. Water Saturation
Case 1 ($m=2$)	ROCK	44.8	44.2	0.987	0.027	0.093	0.04	0.68
	RES		26.21	0.585	0.022	0.039	0.061	0.399
	PAY		21.93	0.49	0.023	0.028	0.066	0.355
Case 2 ($m=1.81$)	ROCK		44.2	0.987	0.026	0.093	0.04	0.65
	RES		26.21	0.585	0.001	0.039	0.061	0.306
	PAY		24.84	0.554	0.018	0.033	0.063	0.292
Case 3 ($m=1.65$)	ROCK		44.2	0.987	0.021	0.093	0.04	0.54
	RES		26.21	0.585	0.014	0.039	0.061	0.244
	PAY		25.3	0.565	0.014	0.034	0.062	0.235
Case 4 (variable m)	ROCK		44.05	0.983	0.024	0.093	0.04	0.6
	RES		26.06	0.582	0.021	0.038	0.061	0.35
	PAY		21.33	0.476	0.018	0.032	0.061	0.304

The four different estimated values of m for the studied upper part of the Lower Qamchuqa Formation in the well BH-96 revealed about a 9% difference between the lowest calculated N/G pay ratio (Case 4) and the highest calculated N/G pay ratio (Case 3). In terms of net thickness, there is a probability of missing about 4 m from the reservoir (or mistakenly adding 4m to the reservoir), with an average hydrocarbon saturation ranging between 64.5% and 72.5%. The 4 m thickness for the extended area (and closure) of the Lower Qamchuqa Formation in the Bai Hassan Structure definitely means millions of barrels of oil.

5. Conclusions

The cementation exponent (m) is an important factor that plays an effective role when an attempt is made to estimate the reserve for any reservoir. Applying the suggested value of 2 for carbonate reservoirs without paying attention to the details of the lithology and the diagenesis processes that may have occurred and affected the pore system of the rock will mislead the analyst and cause overestimation or underestimation of the evaluation process of the reservoir. The upper part of the studied section from the Lower Qamchuqa Formation in the well BH-96 is generally of relatively high shale content, low porosity, and high water saturation. The middle and lower parts of the formation contain horizons of different hydrocarbon saturations. The four estimated m values applied for calculating water saturation in the studied section revealed the possibility of missing 4 m of net pay thickness (when the m value as in case 4 is applied) or mistakenly adding 4 m of net pay thickness (when the m value of 1.65 is applied), which in turn means missing or adding millions of barrels of oil to the estimated OIIP or to the estimated reserve.

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