عدد خاص
بالمؤتمر الليبي الدولي للعلوم التطبيقية
و الهندسية
27-28- سبتمبر 2022

Deviation investigation of the Pre-Upper Cretaceous Carbonate Reservoir's Cementation and Touristy Factors in Wells D5-103, D19-103, and D31-103, Intesar Field, Sirte Basin, Libya

Entesar A. Haman[1] , Khaled H. Kaukau[1], Nasser A. Altoumi[1]

[1]Department of Petroleum Engineering , Faculty of Oil and Gas Engineering University of Zawia, Libya

I.Haman@zu.edu.ly, K.kaukau@zu.edu.ly, N.altoumi@zu.edu.ly

الملخص
هناك الكثير من الخصائص الصخرية التي تؤثر على جودة عملية الإنتاج من المكمن ، وأهمها المقاومة الكهربائية للصخور. يعد تحديد الخصائص الكهربائية للصخور هو العامل الرئيسي لحساب عامل السمنتة (m) وعامل التعرج (a). توضح هذه الدراسة العلاقة بين المسامية ومعامل التركيب من خلال رسم العلاقة على ورقة لوغاريتمية لإيجاد معامل الإسمنت (m). يتم استخدام المعلومات التي تم الحصول عليها من سجلات الآبار للعديد من آبار النفط لحساب حجم الهيدروكربونات ودرجة تشبع خزانات الكربونات بالمياه. تتراوح درجة تشبع الهيدروكربونات لصخور الكربونات عادة من 43٪ إلى 99٪.
أهمية دراسة معامل السمنتة ودوره في هندسة المكامن النفطية وخصائصها الفيزيائية (النفاذية ، المسامية ، درجة التشبع ، خواص الشعيرات الدموية ... إلخ) في تحديد مواصفات الطبقات الجيولوجية والمواد الهيدروكربونية الخاصة بها. يعد الاختلاف في معامل التماسك المحسوب من هذين الشكلين من قانون آرتشي مهمًا ويمكن أن يؤدي إلى تقدير خاطئ للاحتياطيات بنسبة 20٪ . تظهر النتائج فرقًا بين ثوابت آرتشي والثوابت المحسوبة نتيجة لذلك ، فقد استنتج أرتشي هذه القيم من الصخور النقية بينما في الواقع هناك الكثير من الشوائب في الصخور ، ولهذا السبب يوجد خطأ في الحسابات.

Abstract

There are a lot of rock properties that affecting the quality of production operation from the reservoir, the most important one is the electrical resistivity of the rocks. The determination of the electrical properties of the rocks is the key factor for the calculation of cementation factor (m) and touristy factor (a). This study shows the relationship between the porosity and the composition coefficient by drawing the relationship on a logarithmic sheet to find the cement coefficient (m). The information obtained from the well records of a number of oil wells is used to calculate the size of hydrocarbons and the degree of water saturation of carbonate reservoirs. The degree of saturation of hydrocarbons for carbonate rocks usually ranges from 43% to 99%.

The importance of studying cement and its role in the engineering of oil reservoirs and their physical properties (permeability, porosity, degree of saturation, properties of capillaries, etc.) in determining the specifications of geological layers and their hydrocarbon materials. The difference in the cementation exponent calculated from these two forms of Archie's law is important, and can lead to a misestimating of reserves by at least 20% for typical reservoir parameter values. The results show a difference between Archi constants and calculated constants as result of that Archi figure out these values from pure rocks where as in actual there is a lot of impurities in the rocks, so this is why there is error in calculations and that what we are going to improve it.

Keywords: Cementation factor, Tortuosity factor, Saturation, Archie equation

1. Introduction

The area involved in this study is Sirt basin, which is located in the north central part of Libya. It covers a total surface area of almost five hundred thousand square kilometers. Even though petroleum exploration activities in Libya started more than 50 years ago, little is known about the structure of this basin. The studied wells are located in the area of Ajdabia Trough between the eastern margin of the Amal Trough and eastern edge of the Rakb High, in the south eastern part of the Sirt Basin. These selected wells include D5-103, D19-103 & D31-103. A more details of the location of these wells are shown in the (Fig 1).

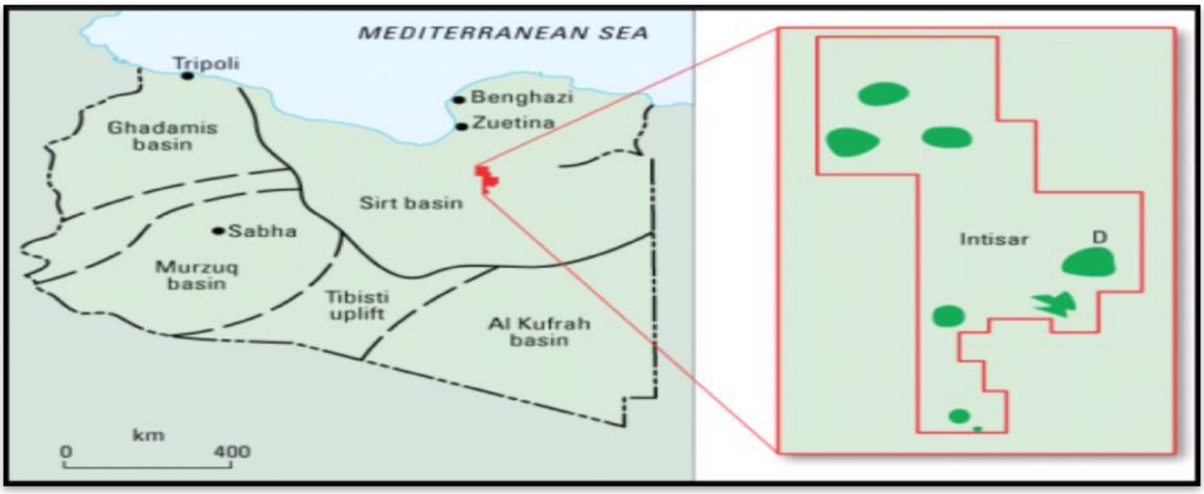

Figure 1 Location map of the studied area in south eastern Sirt Basin, Libya, including Intisar Oil field (From Zueitina Oil Company, 2020).

1.1 *Method of Study*

In an attempt to meet the purpose of this study, all the data available were used. These data include; wire line well log data, the logs used include; resistivity, gamma ray, sonic-neutron, and density logs. These logs were used in correlation and construction of maps and structural and Stratigraphy cross-sections. The logs were also used and analyzed (every three feet for Wells D5 & D19 and every 5 ft for Well D31) in order to estimate the porosity, fluid saturation, net pay thickness and hydrocarbon pore volume of the reservoir of this study.

1.2 General Geologichal History Of The Sirte Basin

The Sirt Basin, which is located on the north central part of Libya, is bounded by Mediterranean Sea to the north, Jable Eggi and Tibesti Arch to the south and southeast, Gargaf Arch to the Southwest, Jable Asowda- Nafousa Uplift to the west; Cyrenaica Platform to the east & northeast (Fig 2). The Sirt Basin covers an area of approximately 600,000km² that extends about 1200 km in the N-S and 700 km in the E-W directions (Hallett, 2002 and Elakkari, 2005). It is considered to be as a major continental rift basin that was formed during the Lower Cretaceous time (Fatyan and Sawzi, 1996; Guiraud and Bosworth, 1997). Rifting, which has proceeded in a triple junction fashion that include the Sirt, Tibesti, and Sarir Arms, was peaked in the Late Cretaceous, and ceased in the Early Tertiary (Gras and Thusn, 1998; Van Houten, 1980). The Sirt Arm, which consists of a serious of north westerly-oriented horsts and grabens connects in its southeast end with the E-W Sarir and the northeasterly oriented Tibesti arms (Fig 2).

Based on local and regional information, the early Palaeocene section is made up of two shallowing-upward cycles, where each cycle is underlain-and overlain by deeper, pelagic facies. A gradual shallowing-upward trend from basin to shallow platform is seen in both bio- and lithofacies. Mresah (1993) recognized seven lithofacies in the early Palaeocene, of the northeast Sirt Basin the rocks in the studied wells consists of mainly carbonate and clastic unit and the underlying fractured and weathered granitic Basement rock.

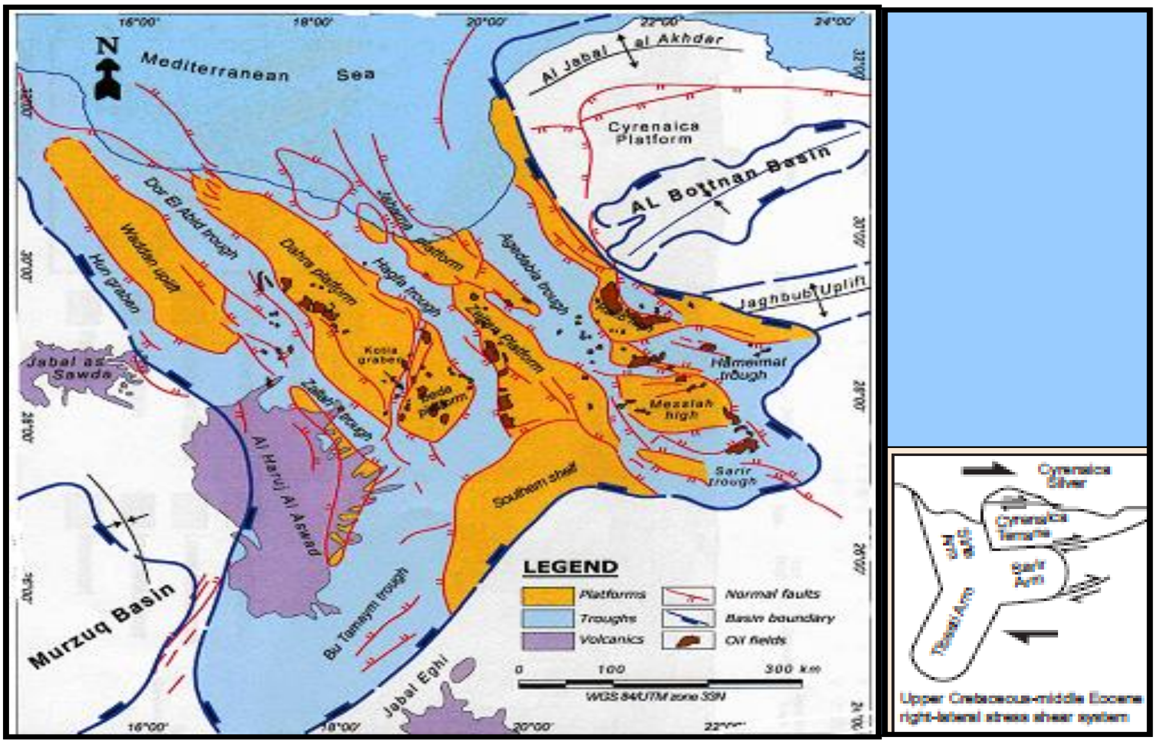

Figure 2. Major Tectonic Elements of The Sirt Basin (Waha Oil Company, 2008).

Well D1-103 was drilled into the Basement and had an initial production of 7627 BOPD. Well D9-103 also drilled into the Basement and had an initial production of 1500BOPD. Both of these wells produce from devitrified rhyolite and highly weathered granophyres. Additional drilling has shown that it is not possible to predict production from the Basement and it is highly variable (Williams, 1972). The thickness of the Formation is variable in these wells. It reaches about 325' in well D5-103, whereas in well D19-103 the thickness increases to more than 991'. West ward from well D19-103, the thickness of the Formation decreases where it approaches about 192' in well D31-103. Clearly the variation of thickness reservoir Formation might have been related to tectonic activities of Sirt Basin during the Palaeozoic to Late Cretaceous time. These activity have triggered variation in the rate of subsidence, which in turn affected variation in thickness of this formation (fig 3).

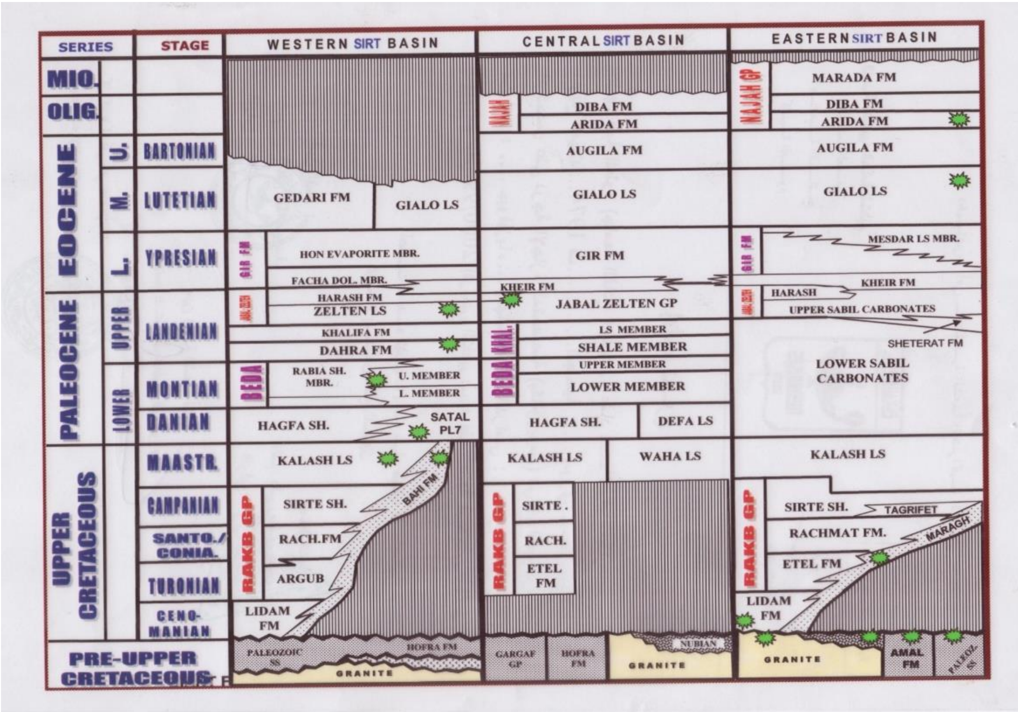

Figure 3. Generalized Stratigraphic Column in the western, central & eastern Sirte Basin. (Sirte and Tibesti arms), (Modified after Barr and Weeger, 1972)

1.3 Log Analysis

Several equations and techniques have been used in this study. Data of wire line logs and for the three wells D5, D19 & D31 are listed and given by the company among those were porosity and resistivity readings, the calculations were done by using Microsoft Excel. The detailed information, procedures, and results obtained are tabulated and in figures, and calculated the oil in place. Most of the petroleum fields were appeared as a result of a hydrocarbon migration after it is formed in a sedimentary basin (source rocks) by decomposition of an organic residues which was graved in the Sedimentary rocks. This migration continues until the hydrocarbons arrive to rocks, which resist its vertical motion because these rocks are impermeable and makes an insulator overlay (cap rock) on the petroleum sediments, which finally called the reservoir.

Also the layers which the hydrocarbons centralized on it should have some characteristics such as porosity and permeability which made this reservoir more economic and producer. Therefore the oil initially in place can be evaluated as the quantity of the hydrocarbons existed in the rock pores in these layers. In order to know the volume of these pores, it is important to find a suitable ways that give good results with fewer costs and in short time.

1.3.1 Archie Equation

A particular relation proposed by G.E. Archie between the formation factor (F) and porosity (phi), in which $F = \varphi^{-m}$, where the porosity exponent, m, is a constant for a particular formation or type of rock. This relation is also known as the Archie II equation.When scientists apply

Archie's first law, they often include an extra parameter a, which was introduced about 10years after the equation's first publication by Winsauer et al. (1952), and which is sometimes called the "tortuosity" or "lithology" parameter.

1.3.2 Humble Formula

A particular relation between the formation factor (F) and porosity (phi) proposed by the Humble Oil Company. The original formula was expressed as F = 0.62 / phi2.15. A nearly equivalent form, with a simpler porosity exponent, is F = 0.81 / phi2. These formulae are considered most suitable for relatively high-porosity, sucrosic, or granular, rocks. (See Winsauer WO, Shearin HM, Masson PH and Williams M: Resistivity of Brine-Saturated Sands in Relation to Pore Geometry, AAPG Bulletin 36 (1952): 253-277).

1.3.3 What is Formation Resistivity Factor & Porosity?

Formation Factor is the ratio of the resistivity of a rock filled with water (Ro) to the resistivity of that water (Rw). G.E. Archie postulated that the formation factor (F) was a constant independent of Rw and solely a function of pore geometry (the Archie equation I). It has since been shown that F is independent of Rw only for a certain class of petrophysically simple rocks (Archie rocks).

Porosity Exponent is the exponent, m, in the relation of formation factor (F) to porosity (phi). For a single sample, F is related to phi using the Archie equation $F = \varphi^{-m}$, with m being the only coefficient needed. In complex formations, such as shaly sands or carbonates with multiple pore types, a constant m does not give good results. One solution is to vary m, with the variability related to parameters such as porosity, shaliness, or rock texture, or else determined directly from logs in zones where the water saturation is known or can be computed from a no resistivity measurement such as electromagnetic propagation. In carbonates with multiple pore types, such as fractures, vugs, interparticle porosity and micro porosity, one solution is to use equations with different porosity exponents for each pore type. The volume of each pore type must then be determined from logs or borehole images.

$m = -\log F/\log \varphi$ Which;

includes no a parameter, being derived from $\rho_o = \rho_f \varphi^{-m}$

A comprehensive investigation of petro physical properties of carbo-nate rocks, which have an interlock with the cementation factor should be covered through core analysis and log data. The matrix of a rock is, for all practical purposes, non-conducting, the only conductor present inside the rock is being the salt-water solution contained in the pore space, Therefore, the electrical conductivity of a rock depends upon its interconnected solution- filled porosity.

As a result, the resistivity of a rock Rt would be expected to vary with the formation water resistivity Rw in the pore space, and also the pore space varies with rock type and rock pore structure, We might state, therefore, that: -

$$R_t = f(R_w, \text{Rock Structure})$$

The influence of rock structure (pore geometry) can be analyzed in the following manner.

When the rock is saturated with salt water whose resistivity is R_w a current will circulate through the electric current and a corresponding potential drop is observed. The electrical resistance of the rock sample can be determined with ohm's law. When the rock is fully saturated with water, the resistivity is R_o because the only conducting medium in the rock sample is the salt water, and also R_w is the resistivity of the conductive fluid. So the ratio between (R_o & R_w) is called formation resistivity factor (FR). However, a more general definition of (F_R), therefore, would b:-

$$F_R = \frac{Resistivity\ of\ rock\ 100\%\ saturated\ with\ a\ conductive\ fluid}{Resistivity\ of\ the\ conductive\ fluid}$$

Therefore: - $F_R = \frac{Ro}{Rw}$ …………………………… (1)

The formation resistivity factor depends on the tortuous path of the ions, and the porosity (Φ). Because F_R is a dimensionless quantity, it depends only on rock properties and it is an important parameter in log interpretation as will be seen later.
On the basis of laboratory measurements of F_R and (Φ) on core samples, Archie suggested the following empirical relationship:-

$F_R = \Phi^{-m}$ ………………………………….…(2)

In 1952, Winsauer and other workers measured formation factors and porosities in 29 sample of a highly varied suite of North American formations and they generalized Archie's equation to: -

$FR = a\Phi^{-m}$……………………………………………(3)

Eq. (1) is similar to Archie's equation, but it usually provides a better fit to a given set of data. Theoretical and experimental investigations showed that the values of (a & *m*) vary mainly with pore geometry. The exponent *m* varies mainly with the degree of consolidation of the rock and is called the *"cementation factor"*.
The cementation factor *m* varies over a wide range of values, from 1.3 to approximately 3.0 and the coefficient a is the coefficient of the porosity (intercept) in general form of Archie equation varies from 0.35 to 4.78.

1.4 Water saturation

Since the influence of rock structure is represented by the formation resistivity factor, FR, this might be stated as: -

$$Rt = f\ (\ Rw, F_R\ )$$

This certainly is the case for a 100% water saturated rock where (RT = Ro) since: -

$Ro = FR * Rw$ …………………....…………….. (4)

The presence of oil or gas makes the rock more resistive than when the same rock is water saturated. Therefore, the functional relationship of the true rock resistivity should be expressed as: -

$$Rt = f(Rw, FR\ , hydrocarbon\ \ influence)$$

The ratio between two resistivity values is called the resistivity index I_R: -

$$IR = \frac{\text{resistivity of a rock containg oil or gas}}{\text{resistivity of the same rock containg water}} \quad (5)$$

Therefore: - $I_R = \frac{Rt}{Ro}$ .... (6)

Archie found an empirical relationship between the resistivity index I_R and water saturation S_w that took the form [2]:-

$$Sw = \left(\frac{1}{IR}\right)^{\frac{1}{n}} \quad (7)$$

The saturation exponent n depends on the rock type, primarily the manner in which the pores are connected. Values of *n* ranged from 1 to 2.5. Using the expressions of I_R, R_o, & F_R given by Eqs. 3, 4, & 5 allows Eq. 1.8 to be written as [2]: -

$$Sw = \left(\frac{Ro}{Rt}\right)^{\frac{1}{n}} \quad (8)$$

$$Sw = \left(\frac{F_R \;\; Rw}{Rt}\right)^{\frac{1}{n}} \quad (9)$$

$$Sw = \left(\frac{a \; Rw}{\phi^m \; Rt}\right)^{\frac{1}{n}} \quad (10)$$

Equations 8 through 10 are used to calculate water saturation in reservoir rocks. The formation volume factor (ßoi) is one of the most important factors for the calculation of original oil in place which could be calculated using this equation:

ßoi =1.05+(N*0.05)..(11)

$N = GOR/100$ ....(12)

2 Results and Interpretation

In this study we calculated the Formation Factor (FF) using the available data (Rt, PHI), also calculate the Formation Factor using Archi assumptions to end up comparing the results to each other to configure the difference between them, the assumptions used and the ones used by Archi also figure out the merge of error after drawing the relation from our figures and Archi's. And we found the total water saturation (Sw), and calculated the (ßoi), total (PHI), Then the original oil in place only to find the remaining oil (Nr). For the completion of this study the available data from (WOC) are listed below:

Table 1 The Available Data for The Three Wells D5-103, D19-103 And D31-103, in Intisar Field, Sirt Basin, Libyan.

DATA	Value
Well D5-103 (PHI, Resistivity Logs) Thickness of the Zone of Interest (ft)	325
Well D19-103(PHI, Resistivity Logs) Thickness of the Zone of Interest (ft)	994
Well D31-103(PHI, Resistivity Logs) Thickness of the Zone of Interest (ft)	442
Area (acres)	3325
GOR (Scf/Stb)	509
Recovery Factor (%)	56
Permeability (md)	200

2.1 Calculating the Archi Parameters

The aim of this kind of calculations is to derive the true values of a (touristy factor) and m (cementation factor) for the given rock type and compare them with the Archi parameter to estimate the margin of error.
The procedure of the calculation is listed below:

1. Find FF (formation factor) for each point.
2. Plot FF vs F on log log paper (F on x- axis, FF on y-axis).
3. Find the slope (m) and the intercept (a).
4. Find the resistivity index (I) and Sw for each point assuming n=2.
5. Calculate relative error between Archi equation and new correlation.

2.1.1 Well D5-103 Parameters Calculation

Table 2 below shows the main results that obtained from the analysis of the resistivity and porosity data resulted from well logging for well D5-103.

Table 2 FF Archi And Sw Calculation for Well D5-103, in Intisar Field, Sirt Basin

PHI (%)	PHI	FF archei	Sw	Depth (ft)
26.63	0.2663	14.10125	0.976534	9867.981
25.97	0.2597	14.8271	0.990437	9871.019
25.14	0.2514	15.82229	1.007877	9874.056
21.87	0.2187	20.90752	0.820267	9877.093
22.01	0.2201	20.64239	0.739659	9880.131
21.73	0.2173	21.17779	0.697558	9883.168

From the above results we can figure out the values of e=water saturation and hence the hydrocarbon saturation for each depth in the zone of interest, a relationship between porosity and formation factor is plotted to figure out the true value of the cementation factor (m) and tortuosity factor (a) for well D5-103 as shown in (fig 4).

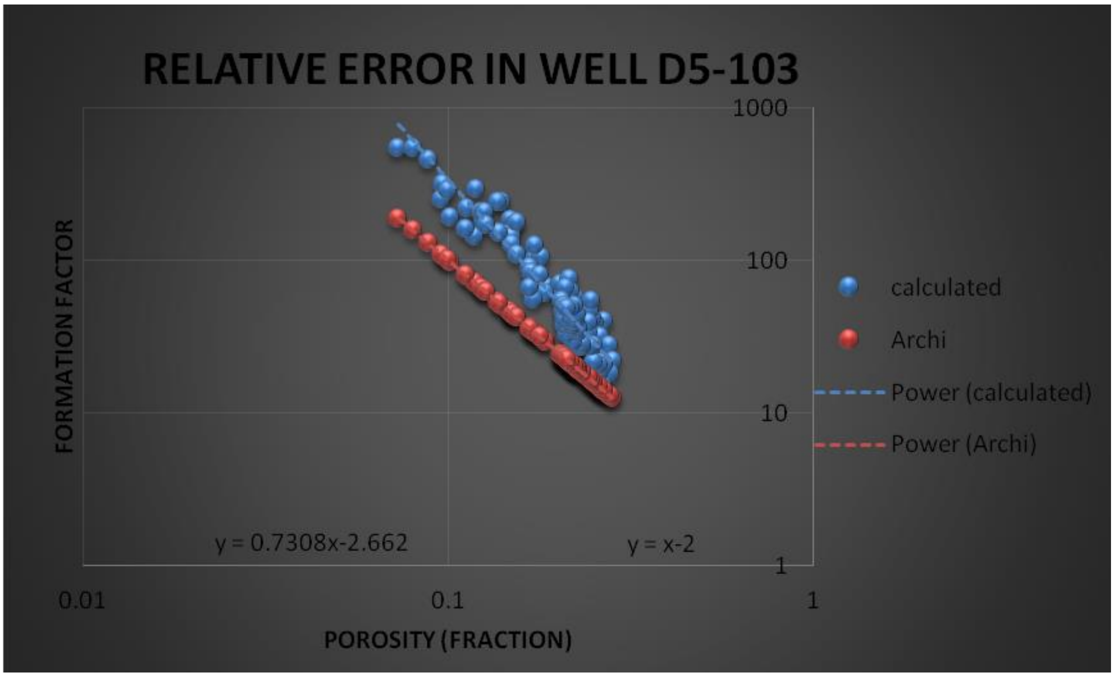

Figure 4 Relative Error in Well D5-103

2.1.2 Well D19-103 Parameters Calculation

Table 3 below shows the main results that obtained from the analysis of the resistivity and porosity data resulted from well logging for well D19-103.

Table 3 FF Archi And Sw Calculation Sample for Well D19-103

Rt (ohm.m)	FF	PHI (%)	PHI	FF archi	Sw	Depth
1.0947	57.61579	10.93	0.1093	83.70659	0.011684	10169.97
0.6545	34.44737	16.54	0.1654	36.5535	0.009932	10172.97
0.4208	22.14737	21.34	0.2134	21.95893	0.009569	10175.98
0.2289	12.04737	25.49	0.2549	15.39077	0.010837	10178.98
0.205	10.78947	25.8	0.258	15.02314	0.011312	10181.98

From the above results we can figure out the values of water saturation and hence the hydrocarbon saturation for each depth in the zone of interest, a relationship between porosity and formation factor is plotted to figure out the true value of the cementation factor (m) and tortuosity factor (a) for well D19-103 as shown in (fig 5).

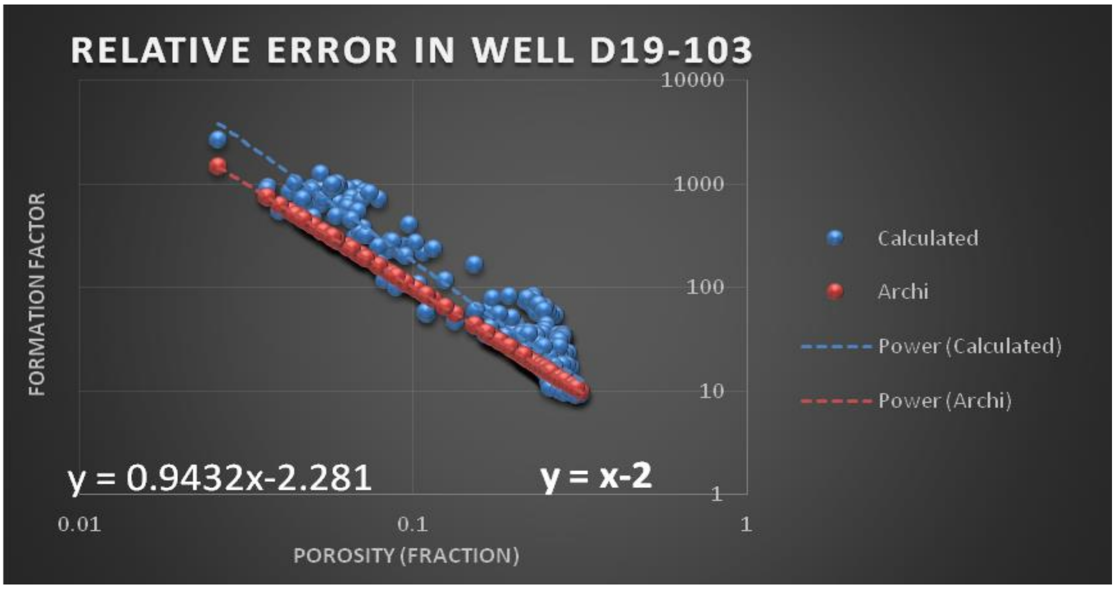

Figure 5 Relative Error in Well D19-103

2.1.3 Well D31-103 Parameters Calculation

Table 4 below shows the main results that obtained from the analysis of the resistivity and porosity data resulted from well logging for well D31-103

Table 4 FF Archi And Sw Calculation sample for Well D-31-103

Rt (ohm.m)	FF	PHI(%)	PHI	FF archi	Sw	depth
0.6348	31.74	21.66	0.2166	21.31489	0.802192	9767.671
0.5558	27.79	23.07	0.2307	18.78905	0.803872	9770.073
0.4759	23.795	22.48	0.2248	19.78825	0.892011	9772.476
0.4759	23.795	20.13	0.2013	24.67814	0.998403	9774.878
0.4759	23.795	21.89	0.2189	20.86933	0.916553	9777.28
0.5558	27.79	22.6	0.226	19.57867	0.820936	9779.683
0.5558	27.79	23.07	0.2307	18.78905	0.803872	9782.085
0.6347	31.735	22.13	0.2213	20.41913	0.784871	9784.488

From the above results we can figure out the values of e=water saturation and hence the hydrocarbon saturation for each depth in the zone of interest, a relationship between porosity and formation factor is plotted to figure out the true value of the cementation factor (m) and tortuosity factor (a) for well D31-103 as shown in (fig 6).

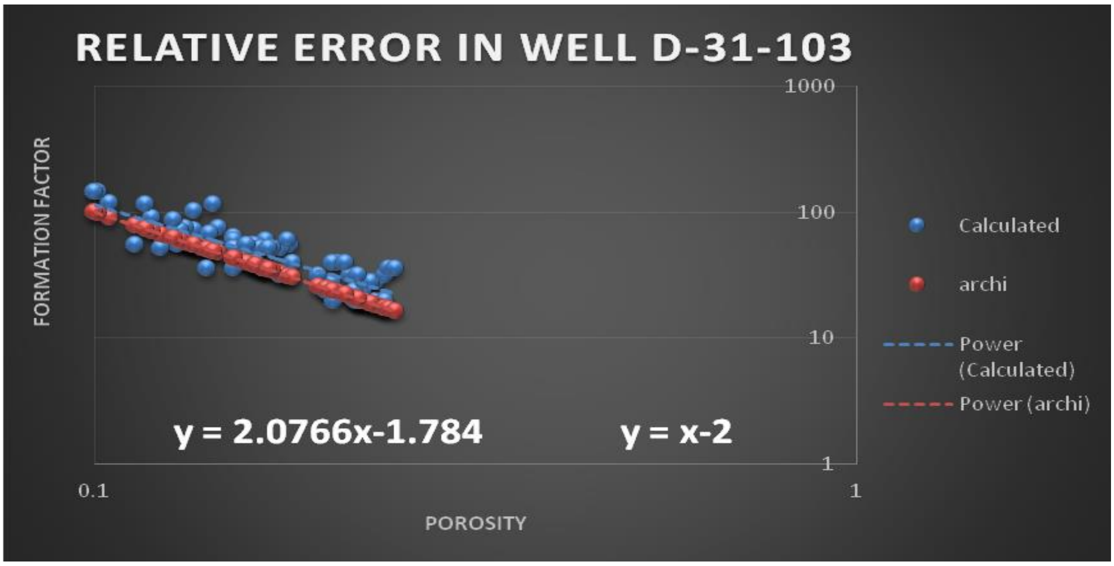

Figure 6 Relative Error in Well D31-103

2.2 Obtaining of a suitable logging data for the interpretations

The tables (2, 3 & 4) represent of well logging data that was collected and performed for the three wells D5-103, D19-103 & D31-103. The data points showing in tables were obtained for the formations every two and five a foot where wells D5, D19 selected every tow foot and D31 selected for five foot. The correct logging data of true resistivity RT and effective porosity are present in the tables (2, 3 & 4) and was obtained by: -

- For the representative true resistivity value in the formation the, deep resistivity of induction devices reading was considering as R_T value.
- Effective porosity of the formation was determined by using complex lithology model using three porosity tools which available.

As illustrated previously, to complete the quantitative interpretation processes, water bearing zone data must be available "Sw=100%". Therefore, the best well was chosen for the study was "D19" because there is a clear "water bearing zone" on it as a result of a sharply declining in the true resistivity recording Rt for the formation.

2.3 Filtration of the selecting logging data

The selecting water zone data of well "D19" was filtrated by dropping the points that give non-representative values for the formation, as a result of error in logging tool reading or presence of " shale " or " carbonat " or " some other impurities " in the formations. However, the data, which remained after filtration, were used in calculating the values of the parameters a & m for carbonate Fm as will be seen in the below this Chapter, these data are showing in table (5, 6 & 7), and the interval that the selecting data are spread on it is 2 & 5 feet. Figures (4), (5) & (6) are showing the plotting of (formation factor vs. porosity) before and after data filtration respectively. The good to very good reservoir rock potential is related to better water saturated, that was preserved in deposition environment. This is indicated by the high percent of formations saturated. Which as shown in (Fig. 5).

2.4 *Advantages of using well logs in Determination a & m*

When a formation is 100% water saturated, appropriate values of a & m constants for each level can be computed from well log data. Generally, previously published formation factor-porosity relations are from laboratory measurements under ambient conditions. Recently, attempts to measure porosity and resistivity under reservoir conditions have increased however there are many adverse effects that cannot be avoided during coring, sample preparation, and measurements. There are only a few publications on the determination of electrical parameters from well logs because study of the Archie constants from core samples has attracted more interest.The cementation factor varies depending on porosity and pore geometry. This factor is affected by post depositional events such as cementation, mineral transformation, compaction, dissolution, and fracturing. Most of these processes are controlled by fluids filling the pores; therefore, the oil and the water zones of a reservoir are not similarly affected by pore fluids after oil accumulation in the trap. When these digenetic differences are significant, electrical parameters studied in the water zone using well logs may not be representative of the oil zone of the same reservoir. A quick look at the age of some of these data indicates another problem: while there is a huge amount of existing Archie's law data, most are proprietarily, and the few datasets that have been published are relatively old.

Carbonate reservoirs in the Middle East Sirt Basin are very heterogeneous in terms of rock types. Therefore, the reservoir should be split into layers on the basis of the dominant rock type in order to define average values and trends of physical rock properties. The cementation factor (m) has specific effects on petro physical and elastic properties in porous media. The accurate determination of cementation factor (m) gives reliable saturation results and consequently hydrocarbon reserve calculations. A comprehensive investigation of petro physical properties of carbo-nate rocks, which have an interlock with the cementation factor should be covered through core analysis and log data.

Table 5 : Summary of Relative Error in Well D5-103 For Archi Parameters.

Variable	Value
a (Calculated)	0.738
m (Calculated)	2.662
a (Arcii)	1
m (Archi)	2
Relative Error for (m) %	24.88
Relative Error for (a) %	35.5

Table 6 : Summary of Relative Error in Well D19-103 For Archi Parameters.

Variable	Value
a (Calculated)	0.9432
m (Calculated)	2.281
a (Arcii)	1
m (Archi)	2
Relative Error for (m) %	12.3
Relative Error for (a) %	6

Table 7 : Summary of Relative Error in Well D31-103 For Archi Parameters.

Variable	Value
a (Calculated)	2.0766
m (Calculated)	1.784
a (Arcii)	1
m (Archi)	2
Relative Error for (a) %	51.8
Relative Error for (m) %	12

This data represents a good reservoir in well D-19 where the error for Archie parameters is low indicated to this interpretation for the study area. Petrophysical evaluation is challenging, essentially because of unconnected porosity which increases the uncertainties in initial water saturations, net hydro-carbon in place calculations and reserves.

2.5 Reseve Clculation

Reserve estimation is one of the most important parameters that must take into account during the planning phase for preparing the well to production.

- Oil Initial In Place Estimation (OIIP)

From the given data forward we can determine the value of OIIP :

$$OIIP = \frac{7758\ A\ h\ \emptyset\ (1 - S_{wi})}{\beta_{oi}}$$

Where :
A= area of the reservoir (acre).
H= net pay thickness (ft).
$\emptyset$=porosity (fraction).
Swi= initial water saturation (fraction).
Boi = oil formation volume factor (bbl/STB).
The following table shows the main parameters to calculate reserve.

Table 8 Reserve Parameters

Parameters	Value
Area	3325 Acre
GOR	509 Scf/Stb
F.V. F (ßoi)	1.315 bbl/stb
$\emptyset$ avg	0.195735
Sw avg	0.572909
So avg	0.427091
H	587 ft
RF	56 %

$$OOIP = \frac{7758*3325*587*0.1957*(1-0.5729)}{1.315} = 962441121.3 \text{ STB}$$

– The Oil Recoverable

Oil Recoverable = OIIP * RF

Where:
RF= Recovery Factor = 56%

Nr = OOIP*RF =962441121.3*0.56=538967027 STB

3 Conclusion

From the results that have been obtained after this study, we can conclude the following:
1. Well logs are considered as one of the basic tools for the reservoir evaluation as results if high degree of certainty that it allows.
2. Resistivity log in one of the most significant logs that can be used for determination of existence of hydrocarbons as result of conductivity and resistivity of the rock and fluid which can be measured and compared with each other.
3. The values of porosity for the three wells was range between 1 to 31.92 %.
4. The values of water saturation were range between 0.4 to 100% in some zones.
5. From the relative error estimation, the deviation is generally resulted from the contamination of rock type with impurities and it was a mixture of shaly sand and dolomite.
6. The Oil Initial InPplace (OIP) is (962441121.3 STB) and Recvoable Reserves is (538967027 STB), by considering the recovery Factor (RF) is (56%).
7. Carbonate reservoirs have a highly complex internal structure, generally have lower primary recovery factors than sandstone reservoirs, and are often underdeveloped.
8. Carbonate reservoirs typically have a complex reservoir architecture, with large and abrupt variations in rock and pore type distribution, resulting from lateral and vertical variations in depositional conditions. Each carbonate fields needs a customized reservoir surveillance program to optimize production, because unique combinations of matrix and fracture permeabilities in carbonate fields require application of different supplementary recovery technologies.

Acknowledgments

We are very much grateful to Allah Almighty for giving us health and ability to finish this work. We would like to thank department of Petroleum Engineering in university of Zawia.

References

[1] Ching h. wu; 1992; petroleum engineering 311reservoir petrophysics class notes : department of petroleum engineering texas a&m university college station, texas.

[2] Archie, G.E.; 1942; "The Electrical resistivity Lof as an Aid in Determining Some Reservoir Characteristics"; Trans. AIME.
[3] Rezaee, M. R., Motiei, H. & Kazemzadeh, E; (2007); A new method to acquire m exponent and tortuosity factor for microscopically heterogeneous carbonates; Journal of Petroleum Science and Engineering 56, 241-251.
[4] Gomez, C. T., Dvorkin, J. & Vanorio, T; (2010); Laboratory measurements of porosity, permeability, resistivity, and velocity on Fontainebleau sandstones; Geophysics 75, E191.
[5] Haro, C; (2010); The Equations Archie Forgot: Anisotropy of the Rocks; SPE Reservoir Evaluation & Engineering 13, 823-836.
[6] Glover, P. (2009); What is the cementation exponent? A new interpretation. The Leading Edge 28, 82-85.
[7] Salem, H. S. & Chilingarian, G. V. (1999); The cementation factor of Archie's equation for shaly sandstone reservoirs. Journal of Petroleum Science and Engineering 23, 83-93.
[8] Medina, C. R., Rupp, J. A. & Barnes, D. A; (2011); Effects of reduction in porosity and permeability with depth on storage capacity and injectivity in deep saline aquifers: A case study from the Mount Simon Sandstone aquifer; International Journal of Greenhouse Gas Control 5, 146-156.
[9] Saeed Rafiee, Abdolnabi Hashemi, and Mohammad Shahi; 2014; A New Cementation Factor Correlation in Carbonate Parts of Oil Fields in South-West Iran; Iranian Journal of Oil & Gas Science and Technology, Vol. 3, No. 2, pp. 01-17.
[10] Myeres, M. (1991); Pore combination modelling: a technique for modelling the permeability and resistivity properties of the complex pore system. SPE 22662.
[11] Hilmi S. Salem.(1993); Derivation of The Cementation Factor (Archi's Exponent) And The Kozeny-Carman Constant From Well Log Data, and Their Dependence on Lithology and Other Physical Parameters. SPE, 26309.
[12] Hector, P., Fernando S., Guadalupe, G., Jesus R., and Carlos V.; (2007); Petrophysical Characterization of Carbonate Naturally fractured Reservoir for Use in Dual Porosity Simulator; SPG-RT-183, Stanford, Calefornea.
[13] Fadhil Sarhan Kadhim, Ariffin S., Ahmed K.; Researcher 2016; Correlation Between Cementa-tion Factor And Carbonate Reservoir Rock Properties;
[14] http://www.sciencepub.
[15] Focke, J.W. and Munn. M (1987); Cementation Exponents in Middle East Carbonate Reservoir. SPE 13735, Formation Evalimdon, Jun.