DEVELOPMENT OF COMPUTER APPLICATION TO COMPUTE ARCHIE PARAMETERS FROM WELL LOG DATA

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ABSTRACT: *Computation of water saturation requires some parameters; tortuosity factor a, cementation coefficient m, and saturation exponent, n; collectively referred to as Archie parameters. Values 1, 2, and 2 are assigned to the parameters a, m and n respectively; without recourse to the in-homogeneities in local geology, due to the rigours involved in determining site-specific values. Arch_Param, a computer program written around the 'conventional' Archie parameter determination technique, saves the rigours and automate the process of determining these parameters for any oil field from well data, and consequently, enhances the accuracy of computed hydrocarbon saturation. It runs on computers with the python interpreter installed. Arch_Param was used to compute Archie parameters for three wells within PATJ oil field, Niger Delta. The study revealed that a, ranged from 1.00 to 1.49 and averaged 1.29; m, from 1.72 to 2.21 and averaged 1.94 and n, from 1.26 to 6.58. Computing Archie parameters for the different reservoir revealed that tortuosity factor a, decreased with depth, cementation exponent m, increased with depth while saturation coefficient n, had random values.*

KEYWORDS: Water Saturation, Archie Parameters, Tortuosity Factor, Cementation Coefficient and Saturation Exponent

INTRODUCTION

Hydrocarbons are a family of organic compounds, composed entirely of carbon and hydrogen. Saturation is a state in which a body is completely soaked or wet with the liquid of interest. As related to the context of geophysics, hydrocarbon saturation is being related to rocks and it is an indication of the abundance of hydrocarbon in the pores of a rock.

All sedimentary rocks have porosity that is fluid saturated. The fluid is sometimes oil and/or gas, with water. If the pore space is not occupied by water, then it must be occupied by hydrocarbons. Therefore, by determining a value of water saturation from porosity and resistivity measurements, it is possible to determine the fraction of pore space that is occupied by hydrocarbons, that is, the hydrocarbon saturation. The Archie parameter values (Enikanselu and Olaitan, 2013) have been observed to vary from locality to locality, depending on the petrophysical properties of the given rock. Mathematically, hydrocarbon saturation S_H and water saturation S_W, are related by the equation:

$$S_H = 1 - S_W \qquad (1)$$

where:

S_W = water saturation (reservoir pore space filled with water)
S_H = hydrocarbon saturation (reservoir pore space filled with hydrocarbon; gas or oil)

Archie (1942) introduced a classic empirical model based on a set of relationships between formation resistivity, porosity and water saturation for shale-free sands. Winsauer et al (1952) modified the Archie's formula by introducing *tortuosity factor a*, into the relationship between porosity and formation factor. Fluid saturations can be estimated from resistivity measurements by the use of modified-Archie equation:

$$S_w{}^n = \frac{a}{\Phi^m}\, x\, \frac{R_w}{R_t} = \frac{1}{Ir} \qquad (2)$$

where:

n = saturation exponent,	a = tortuosity factor
m = cementation exponent,	Φ = porosity
R_t = formation / true resistivity,	R_w = formation water resistivity
S_w = water saturation,	Ir = resistivity index

Tortuosity factor, cementation exponent and saturation exponent are collectively referred to as Archie parameters and usually obtained through lithology assumptions using values of 1, 2 and 2 respectively.

In this study, the authors have attempted to automate via a computer program, the process used for the determination of Archie parameters from well data, determine the variability of these parameters with depth and establish the effect on water saturation of using the assigned values for Archie parameters vis-a-vis the field generated option. The possibility of developing computer programs in coding geophysical processes, Mbang et *al*., (2014), has motivated the study. The Python programming language was employed. The programme has enhanced the site-specific computation of Archie parameters and reduced the rigours associated with accurate determination of water (hydrocarbon) saturation for reserve estimates.

LITERATURE REVIEW

Accuracy in water saturation values relies on the uncertainty of Archie's parameters used either in Archie saturation equation for clean formations or in a shaly-sand Archie water saturation model for shaly formations (Hamada et al., 2010; Atkins and Smits, 1961; Kennedy et al, 2001; Dernika et al, 2007 and Sweeney and Jenning, 1960).

TORTUOSITY FACTOR, a: Tortuosity can be defined as the length of the path of a fluid passing through a unit length of rock. Theoretically, tortuosity factor a, is regarded as constant and given the value 1. In reality however, tortuosity factor a, for any particular reservoir and region depend on the following conditions (after RANSOM, 1984):

1. Surface conductance and ionic mobility occurring in water films adsorbed to solid surfaces
2. Salinity of formation water
3. Wettability relations between solid surfaces and hydrocarbons.
4. The presence and distribution of electrically conductive solid materials.

CEMENTATION EXPONENT, m: Cementation exponent is a physical quantity that is indicative of the degree of binding of the rock-forming sediments. In fluid volumetrics, cementation exponent m, is taken as a constant and assigned the value of 2. However, cementation exponent m, for any region depends on the following conditions (modified after RANSOM, 1984):

1. Pore-pore throat geometries
2. Anisotropy
3. Degree of electrical isolation by cementation
4. The occurrence of open fractures.

SATURATION EXPONENT, n: Saturation is the percentage of the pore space filled with a particular fluid. Theoretically, values of the saturation exponent m, are being taken as constants and assigned the value 2. There are cases where saturation exponent n, varies from the assumed value of 2 in strongly water wet reservoir rocks to more than 20 in strongly oil wet reservoir rocks (Hamada *et al.*, 2010). For any particular reservoir and region, saturation exponent depend on the following conditions (modified after RANSOM, 1984):

1. Formation wettability (degree and distribution).
2. In-situ configuration of the non-conductive fluid bodies (hydrocarbons)
3. Degree of electrical isolation due to oil-wetted portions.

Although “rule-of-thumb” values for the Archie parameters are often quite adequate for estimates of water saturation when making a decision whether to run a drill-stem test, they may be poor for reserve estimations, particularly for a major field. The errors can lead one into being either too pessimistic or too optimistic. Similar concerns apply to the value of the saturation exponent, n.

LOCATION AND GEOLOGY OF THE STUDY AREA

Archie parameters for three wells in PATJ oil field was computed in this study. PATJ oil field lies within the Niger Delta basin of Nigeria (Fig. 1). The Niger Delta is situated in the Gulf of Guinea and extends throughout the Niger Delta Province as defined by Klett and others (1997). From the Eocene to the present, the delta has prograded south-westward, forming depobelts that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1990).

The Tertiary section of the Niger Delta is divided into three formations, representing prograding depositional facies that are distinguished mostly on the basis of sand-shale ratios. The three stratigraphic sequences of Niger Delta, starting with the basal unit are: the marine shales of Akata formation, middle paralic Agbada Formation and the topmost Benin Formation (Short and Staublee, 1967).

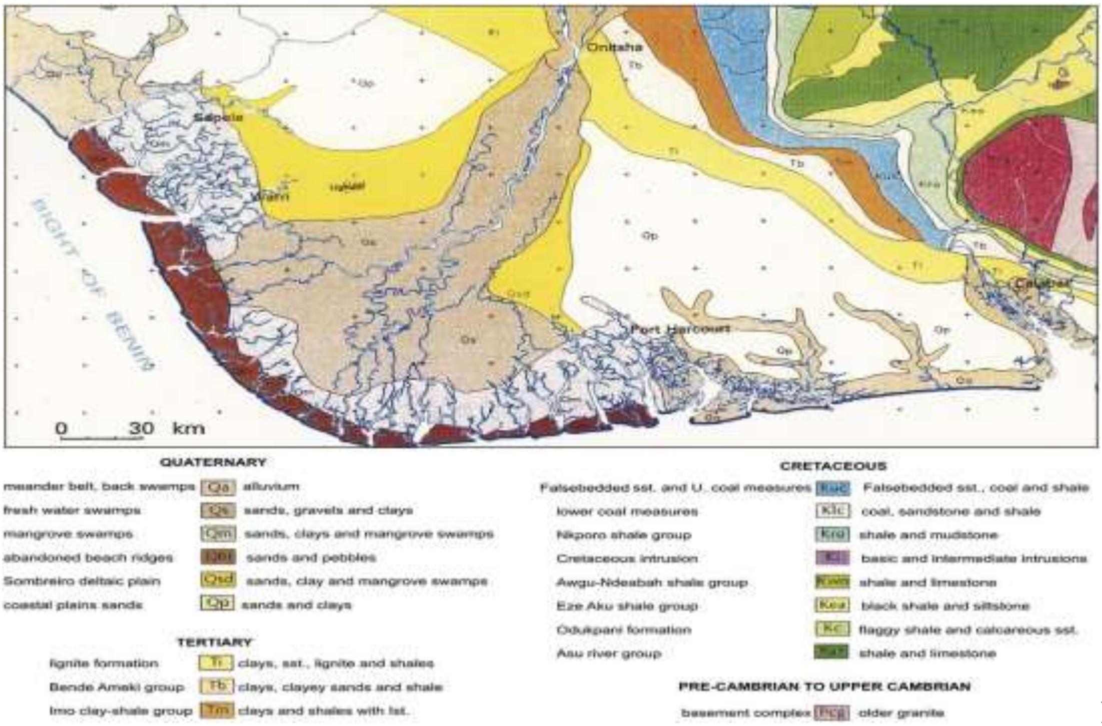


Figure 1: Geological Map of the Niger-Delta (after Reijers, 2011)

MATERIALS

The materials used for this study are:

1. Petrel software (2009): this software was used to load and process the well data, and consequently enhancing the visualisation of the data.
2. Well data: gamma-ray logs, resistivity logs, porosity logs and water saturation logs were used for the study.
3. Python programming interpreter

METHODOLOGY

Although, three different techniques are established in literature for determining Archie parameters, the Conventional method is utilised for this research work. This is partly due to its high reliance on well log data rather than core data. Other techniques that can also be used are Core Archie Parameter Estimate (CAPE) method (Maute *et. al*., 1992) or 3D method (Hamada *et. al*., 1996).

CONVENTIONAL TECHNIQUE

The conventional technique utilises as its building block the relationships put forth by Archie between the formation resistivity and its porosity. From the modification of Archie formula (Winsaeur *et. al*., 1952), the relationship between formation factor F, tortuosity factor a, cementation exponent m, and porosity Φ can be expressed as:

$$\log F = \log a - m \log \emptyset \quad (3)$$

Formation factor values F, and porosity values Φ, obtained from the well logs are converted into logarithmic values. Logarithmic values of formation factor, log F was plotted as the ordinate against logarithmic values of porosity, logΦ at the abscissa. Cementation factor, m, is determined from the slope of the least square fit straight line of the plotted points. Tortuosity factor, a, is given from the intercept of the line where Φ =1. The value of tortuosity factor a, is obtained from the anti-logarithm of the intercept.

The process of determining saturation exponent, n, is based on the relationship between resistivity index and water saturation in equation (2) given as:

$$S_w{}^n = \frac{1}{Ir}$$

where Sw and Ir represents water saturation and resistivity index respectively, and n stands for saturation exponent. The equation is further transformed into the form:

$$\log Ir = -n \log S_w \qquad (4)$$

When log *Ir* is plotted against log S_w, the saturation exponent *n*, is determined from the absolute value of the slope of the least square fit straight line of the plotted points.

All these processes were automated in the program developed with python programming language. In this study, Archie parameters for PATJ oil field were computed with the written program; Arch_Param. The well data were graphically presented using PETREL 2009 software, and geophysically analysed. The logs of primary import for the work are porosity logs, resistivity logs, water saturation logs and lithologic logs (specifically, gamma ray logs were used during this project work to indicate lithology). Reservoir units in the wells were identified. The petrophysical parameters to serve as input to the program were extracted from the well data. The program processes the input data and plots the logarithmic graph of the Formation resistivity factor (F) against porosity (Φ), and also the logarithmic graph of resistivity index (Ir) against water saturation (S_w). From the graphs, the software computes the slope and intercepts, processes them, and outputs the Archie parameter values. These values are solely dependent on the input data

PROGRAM DEVELOPMENT

The development of the program began by outlining the algorithm and designing the flow chart. This program utilises the relationship between the petro-physical parameters, as expressed using equations (3) and (4), to determine the Archie parameters for the formation. This program runs on any system with the *python interpreter* installed. The flow chart of the program is shown (Figure 2).

The program plots the needed graphs and compute the Archie parameters *a*, *m* and *n* automatically.

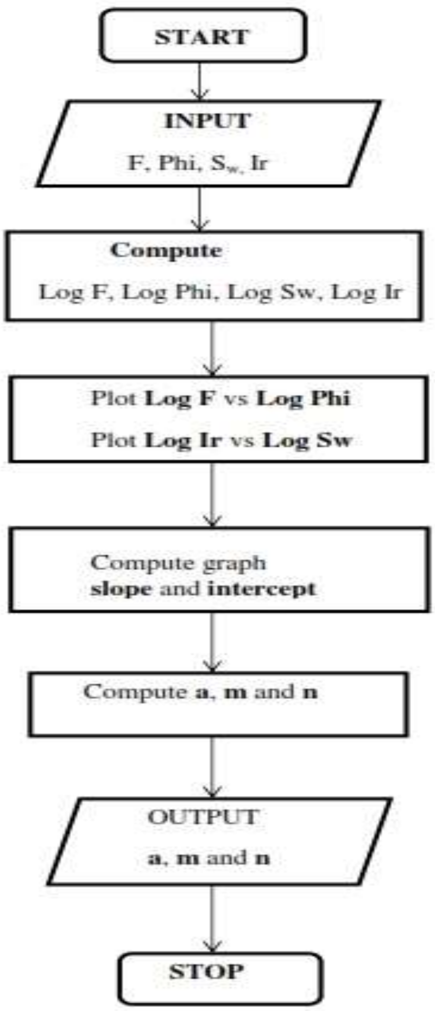


Figure 2: Flow chart showing the pattern of pogramme execution

RUNNING THE PROGRAM

The following steps should be taken when the program is to be used to compute Archie parameters for any given field:

- Type and store the codes in a file. The content of the file is referred to as a script.
- The file is to be saved with the file type: 'Python file'
- Open the command prompt of the PC.
- Navigate to the directory where the file is stored
- Type the file name on the command prompt window. Append ***'.py'*** at the end of the name
- Press the ENTER key, and the program begins to execute

PRESENTATION OF RESULTS

The logs, as presented with the PETREL software is shown in figure 3 below. Six wells were available for use but only three of the wells (i.e. TMB-04, TMB- 05 and TMB-06) contain data on the logs of importance

The computed petrophysical parameters for TMB-05 are given in Table 1. Archie parameters a, m and n for the well was computed using the developed program. The plots are shown in figures 4a and 4b. The same procedure was repeated for TMB-04 and TMB-06 and the results of the Archie parameters presented in Table 2. To avoid repetition, Archie parameters obtained from the use of the program Arch_Param, will hereafter be referred to as the field-derived values.

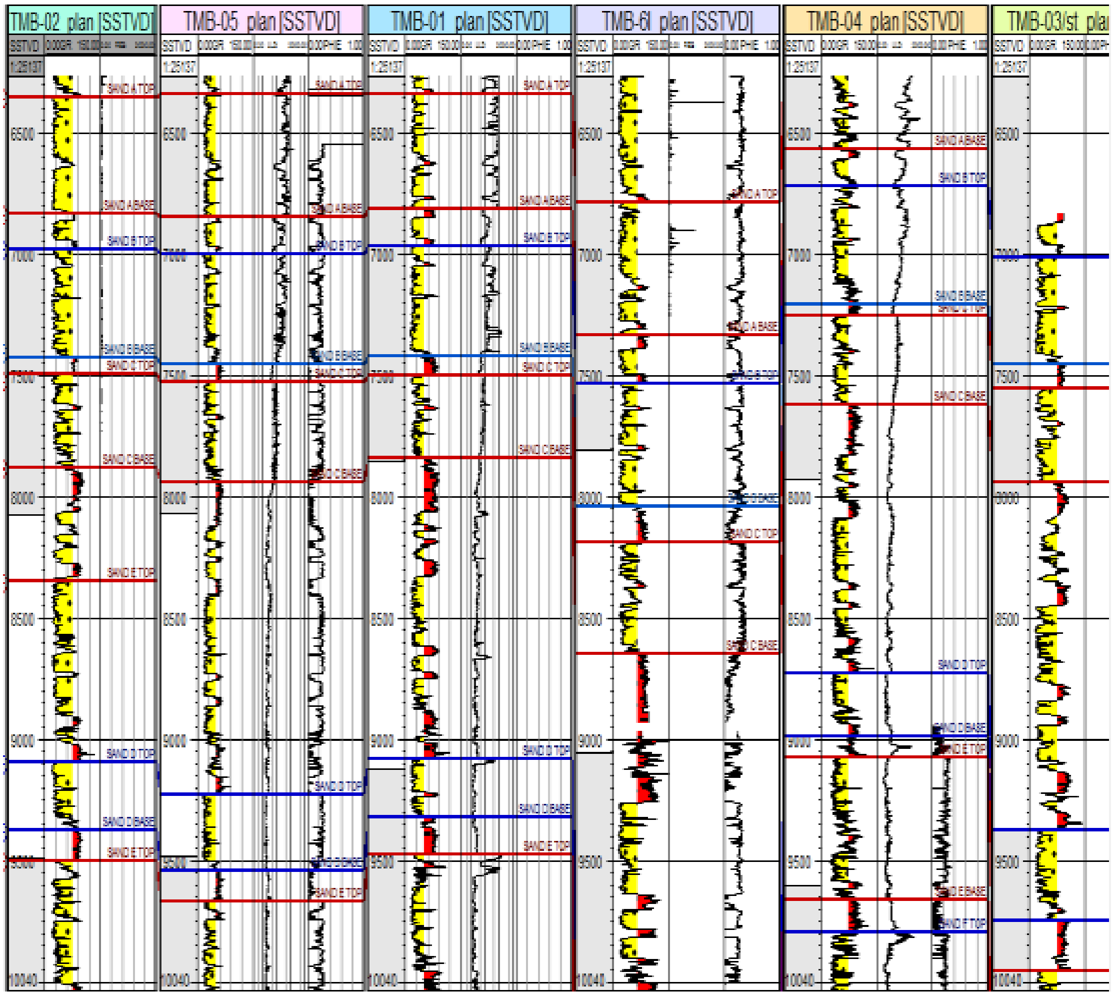
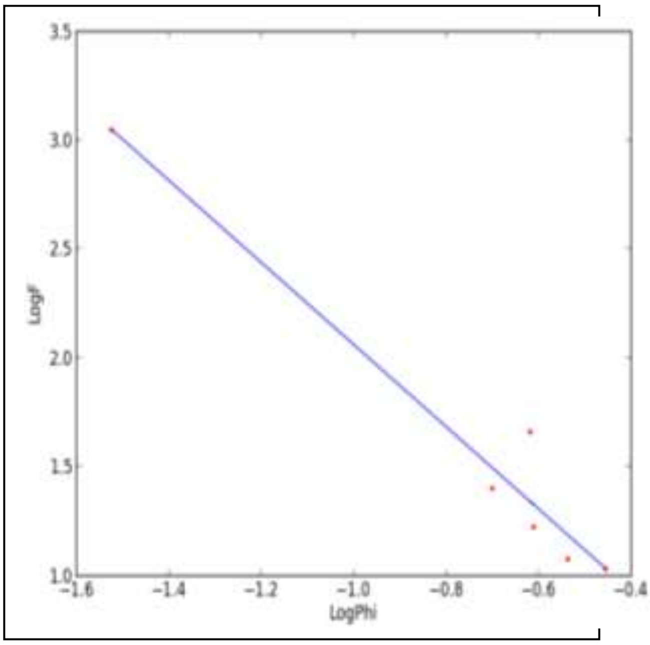


Figure 3: Figure showing a graphical display of the well data using PETREL™ 2009



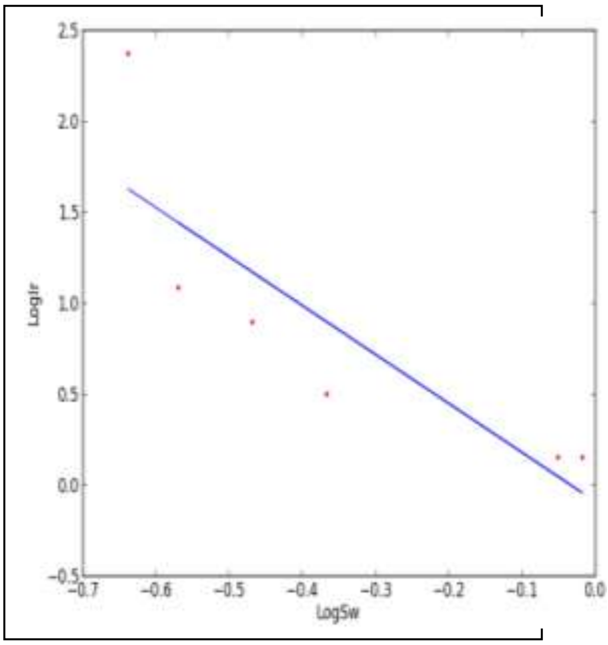


Figure 4: (a) Graph of Log F against Log Φ (b) Graph of Log Ir against Log S_w for **TMB-05**

Also, variability of the three Archie parameters a, m and n with depth was considered. This was done to investigate the effect of depth on these parameters. The relationship of these parameters with depth is shown in Table 3 below.

Table 1: Petro-physical parameters for TMB – 05

SAND	Porosity (Φ)	Formation Factor (F)	Sw	Resistivity Index (Ir)
SAND A	0.352	10.71	0.27	12.12
SAND B	0.291	11.81	0.34	7.78
SAND C	0.240	45.56	0.43	3.13
SAND D	0.245	16.67	0.96	1.42
SAND E	0.200	25.00	0.89	1.41
SAND G	0.030	1107.81	0.23	233.17

Table 2: Archie parameter results computed for TMB - 04, -05 and -06

Well	A	M	N
TMB – 04	1.00	2.21	1.26
TMB – 05	1.49	1.89	2.66
TMB – 06	1.39	1.72	6.58

Table 3: Variation of Archie parameters with depth

Reservoir Unit	Depth (m)	Tortuosity Factor, a	Cementation Coefficient, m	Saturation Exponent, $\|n\|$
Sand A	1858 -2236	2.08	1.40	0.15
Sand B	2061 – 2450	0.58	2.41	0.24
Sand C	2211 – 2637	0.28	3.80	0.62
Sand D	2661 – 3230	3.35	1.12	21.52
Sand E	2766 - 3579	1.14	1.92	8.86

A comparison was made during the course of this work to determine the difference in water and hydrocarbon saturation, obtained using the 'assigned' Archie parameter values from the field-derived values. The result obtained for reservoir units in TMB – 04 and TMB - 05 is given in tables (Tables 4 and 5). The same procedure was carried out for TMB - 06 and the results have been averaged (Table 6).

Table 4: Comparison of S_w / S_h derived from Conventional and Field-derived Archie Parameters for TMB - 04

RESERVOIR	**Sw values using**		**Difference in Sw Value**	**S_H obtained from**	
	Assigned Archie parameter	Computed Archie parameter		Assigned Archie parameter	Computed Archie parameter
SAND A	0.1759	0.0634	0.1125	0.8241	0.9366
SAND B	0.3840	0.2189	0.1651	0.616	0.7811
SAND C	0.2667	0.4035	-0.1367	0.7333	0.5965
SAND D	0.6074	0.5571	0.0502	0.3926	0.4429
SAND E	0.5044	0.3375	0.1669	0.4956	0.6625
SAND F	0.0946	0.0206	0.0741	0.9054	0.9794
SAND G	0.1275	0.0432	0.0843	0.8725	0.9568

Table 5: Comparison of S_w / S_h derived from Conventional and Field-derived Archie Parameters for TMB - 05

RESERVOIR	**Sw values using**		**Difference in Sw Value**	**S_H obtained from**	
	Assumed Archie parameter	Computed Archie parameter		Assumed Archie parameter	Computed Archie parameter
SAND A	0.2494	0.3915	-0.1421	0.7506	0.6085
SAND B	0.3585	0.4624	-0.1039	0.6415	0.5376
SAND C	0.3489	0.6512	-0.3023	0.6511	0.3488
SAND D	0.8390	0.8765	-0.0375	0.161	0.1235
SAND E	0.8416	0.8784	-0.0368	0.1584	0.1216
SAND F	0.0656	0.1288	-0.0632	0.9344	0.8712

Table 6: Difference in averaged-water saturation derived from Assigned and Field-derived Archie Parameters for the three wells

	$(Sw)_{avg}$ Assigned Archie Parameters	$(Sw)_{avg}$ Arch_Param	Difference in Sw
Sand A	0.1994	0.3472	-0.1478
Sand B	0.4112	0.4879	-0.0767
Sand C	0.3430	0.6108	-0.2679
Sand D	0.6887	0.7661	-0.0774
Sand E	0.6380	0.6896	-0.0516

DISCUSSION OF RESULTS

TMB-04 contained seven reservoirs (Reservoir A – H) within the depth window 6136 ft – 10406 ft (1858m – 3151m), TMB-05 contained six reservoirs (Reservoir A - E and G) within the depth window 6383 ft -11149 ft (1933m- 3376m). TMB -06 contained six reservoirs (Reservoirs A - E and H) within the depth window 6829ft – 12645ft (2068m – 3829m). The correlation of the reservoirs across the wells revealed that the area has been faulted. The region around TMB-06 and TMB-03 has been displaced downward relative to the other wells. Within the vicinity of study, the Benin Formation extended from the surface to a depth of between 6095ft – 6787ft (1846m – 2055m), the Akata Formation was within depth range of 6095ft – 12586ft (1846m – 3811m), while the Agbada Formation extended from depth of 11076ft (3354m) and downwards beyond the logs.

Field-derived Archie parameters computed with Arch_Param for the three wells are given in Table 2. For the three wells, values of tortuosity factor a, ranged from 1.00 to 1.49 with an average of 1.29 , cementation exponent m, ranged from 1.72 to 2.21 with an average of 1.94 and saturation coefficient n, ranged from 1.27 to 6.58 with an average value of 3.50. These values are a shift from the common quick log estimates of 1, 2 and 2 for tortuosity factor, cementation exponent and saturation coefficient, respectively.

Arch_Param was also used to determine Archie parameters across reservoirs in order to be able to predict the variability of the parameters with depth. Only five reservoirs could be picked across the three wells; and are thus the reservoirs whose petrophysical parameters were used. The reservoirs are reservoirs A – E and the determined Archie parameters are given (Table 3). From the table**,** tortuosity factor a, was observed to generally decrease with depth with its value ranging from 2.08 at the topmost reservoir (Reservoir A) to 1.14 at the bottom reservoir (Reservoir E). Values for cementation exponent m, was however observed to have an overall increase with depth while saturation coefficient n, showed no regular pattern and no viable inference could be drawn.

Water saturation values for each of the reservoirs mapped within the wells was calculated using the field-derived Archie parameter values, and the results compared with that obtained using the 'assigned values'. For TMB-04, it was observed that water saturation values obtained using the '*assigned*' Archie parameter values were higher for all the reservoirs *(except reservoir C)* than was obtained using the field-derived values (Table 4). This will have an adverse effect on computed hydrocarbon saturation, making promising prospects to be written off and jettisoned. The contrary is however the case for reservoirs in TMB-05 and TMB-06. Water saturation values calculated using program 'Arch_Param' values for Archie parameters exceeded those obtained using common values (Table 5). As such, relying on the water saturation (and indirectly hydrocarbon saturation) obtained using 'assigned' Archie parameter values, reservoirs with lesser likelihood of hydrocarbon-in-place will be envisioned as hydrocarbon prospect. This has the potential of increasing the number of dry holes; and thereby resulting in huge economic losses.

Conclusively, water saturation obtained using 'assigned values' and Arch_Param computed values of Archie parameters for reservoirs in the three wells were averaged and presented in the table (Table 6). It was observed that water saturation obtained with field-derived Archie parameters were higher than those from assigned values of Archie parameter. The converse inadvertently applies to the hydrocarbon saturation of the reservoirs, and as such, hydrocarbon saturation derived from Arch_Param will be lower than those obtained from 'assigned' Archie parameter values. Consequently, relying on the 'assigned values' of 1, 2 and 2 for tortuosity factor, saturation coefficient and cementation exponent respectively, will raise and dash the hopes of the client, resulting in an increase in dry holes and also bringing about huge financial losses.

IMPLICATION TO RESEARCH AND PRACTICE

This study has provided a viable solution to the determination of Archie parameters in any particular locality contrary to the conventional assumption of constancy of the values. Such site-specific values will facilitate computation of a more accurate water (hydrocarbon) saturation; thereby enhancing management economic decisions. Although "rule-of-thumb" values for the tortuosity factor a, cementation exponent m, and the saturation exponent, n, are often quite adequate for estimates of water saturation when making a decision whether to run a drill-stem test, they may be poor for reserve estimations, particularly for an oil field. The errors can lead one into being either too pessimistic or too optimistic about its probable productivity, depending on the peculiarities prevalent in the oil field of interest. It is therefore better to obtain, via Arch_Param and use, site-specific Archie parameter values when carrying out formation evaluation of a field.

CONCLUSION

Arch_Param was developed during the course of this work to save the rigours and help automate the processes for determining Archie parameters for any field of interest from well log data, and consequently, to positively impact accuracy of computed hydrocarbon saturation.

For this particular study area, tortuosity factor ranged between 1.00 and 1.49, cementation exponent ranged between 1.72 and 2.21 and saturation coefficient ranged between 1.26 and 2.58. Investigation of the Archie parameters for variation with depth revealed that tortuosity factor decreased with depth; cementation exponent increased with depth while the saturation coefficient varied randomly with depth. On a more general note, water saturation values of each of the reservoirs within the wells were observed to be generally lower with the 'assigned values' compared to when Arch_Param field derived values were used as Archie parameters. This is capable of increasing the hope of the client on the quantity of hydrocarbon to expect from such fields, which would be far from the reality.

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ACKNOWLEDGEMENTS

The authors hereby acknowledge the benevolence of the department of Applied Geophysics, Federal University of Technology, Akure, Nigeria, for the permission to use the workstation and the input well log data.

PROGRAM Arch_Param

```
#        inputing parameters
print " "
print "please make sure that the number of data points are equal"
print " " ; print " "; print " "
Sw = map(float, raw_input('Please Enter the values for water saturation, Sw:\n').split())
F = map(float, raw_input('Please Enter the values for Formation factor, F:\n').split())
Ir = map(float, raw_input('Please Enter the values for Resistivity index, Ir:\n').split())
Phi = map(float, raw_input('Please Enter the values for porosity, Porosity:\n').split())
LOGF = map(log10, F)
LOGPhi = map(log10, Phi)
LOGIr = map(log10, Ir)
LOGSw = map(log10, Sw)
#        computing for a and m
count1 = len(F)
sumX =float( sum(LOGPhi))
sumY = float (sum(LOGF))
sumX2 = float(sum([pow (x, 2) for x in LOGPhi]))
```

```
sumXY = float (sum(x*y for x,y in zip(LOGPhi, LOGF)))
xMean = float(sumX / count1)
yMean = float (sumY / count1)
slope1 =(sumXY - (sumX *yMean))/ float((sumX2 - (sumX*xMean)))
Yint = yMean - slope1 * xMean
m = abs(slope1)
a = pow(10, Yint)
#	computing for n
sumX_2 = sum(LOGSw)
sumY_2 = sum(LOGIr)
sumX2_2 = sum([pow (x, 2) for x in LOGSw])
sumXY_2 = sum(x*y for x,y in zip(LOGSw, LOGIr))
xMean_2 = float(sumX_2 / count1)
yMean_2 = float (sumY_2 / count1)
slope2 =(sumXY_2 - (sumX_2 *yMean_2))/float((sumX2_2 - (sumX_2*xMean_2)))
Yint2 = yMean_2 - slope2 * xMean_2
n = abs(slope2)
# for best fit line graph
LOGFnew = [89009]
LOGIrnew = [89009]
for i in range (len(F)):
	b = (Yint + slope1*LOGPhi[i])
	LOGFnew.append(b)
del LOGFnew[0]
for j in range (len(F)):
	d = (Yint2 + slope2*LOGSw[j])
	LOGIrnew.append(d)
del LOGIrnew[0]
#	plotting the graphs
plt.plot(LOGPhi, LOGF, 'r.')
plt.plot(LOGPhi, LOGFnew, 'b-')
plt.xlabel('LogPhi')
plt.ylabel('LogF')
plt.show()
plt.plot(LOGSw, LOGIr, 'r.')
plt.plot(LOGSw, LOGIrnew, 'b-')
plt.xlabel('LogSw')
plt.ylabel('LogIr')
plt.show()
#	outputing the results
print "Tortuosity factor, a = %f" % (a)
print "Cementation factor, m = %f" % (m)
print "Saturation exponent, n = %f" % (n)
```