Correlation Between Cementation Factor And Carbonate Reservoir Rock Properties

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Abstract: A large proportion of hydrocarbons in the Middle East are contained in supergiant carbonate reservoirs, which cover about fifteen percent of the world's oil reserves. Carbonate reservoirs in the Middle East 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 petrophysical 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 petrophysical and elastic properties of carbonate rocks, which have an interlock with the cementation factor should be covered through core analysis and log data**.** NS1, NS-2, NS-3, NS-4 and NS-5 are the studied wells from the NS oil field, which is one of giant carbonate oil reservoirs in the Middle East. The study made across the Mishrif and Yamama limestone carbonate formations. Neurology software (V 5, 2008) was used to digitize the scanned copies of available logs (Self potential, Resistivity logs, Gamma ray, Neutron logs, Density log and Sonic log), while Interactive Petrophysics software (IP V3.5, 2008) had been used in order to represent the results of Computer Program Interpretation (CPI), which is the present day computer program that have been used by the geophysicist of Schlumberger (SLB) Company since 1995. Actual Archie's parameters (a, *m* and n) by Picket and Gomez methods, porosity and permeability from well log calculated and compared with core results. Elastic rock properties such as; shear wave velocity (V_S), compressional velocity (V_P), Bulk modulus (K_w), Young's modulus (E) and Poisson's ratio(υ) had been calculated. Four saturation models were used to calculate water saturation of carbonate formations (simple Archie equation, Dual water model, Modified Simandoux model and Indonesia model). In this study a new method was used to find correlation related cementation factor(*m*) and carbonate rock properties such, as the permeability (K), porosity (Φ), compressional-shear velocity ratio (V_P/V_S), Bulk modulus (K_m), and Biot's Constant by using Artificial Neural Network regression, also this study aimed to re-estimate original oil in place and calculate the overburden pressure in this field. Well log data and core analysis data were provided from the NS oil field.

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CHAPTER 1

1. Introduction

The evaluation of logging data in most carbonate reservoirs still a challenging task in the present days which need to specify of efforts and capitals to avoid incorrect interpretation. The incorrect interpretation leads to lost hydrocarbon zones or incorrect selection for the perforated intervals, as a result lost time and money.

Fluid flow through heterogeneous carbonate reservoirs (limestone and dolomite) is a substantially different process from the flow through the homogeneous sandstone reservoir. This variation is largely cause to the fact that carbonate rocks tend to have a more complex pore system (i.e the interrelationships among depositional lithologies, the geometries of depositional facies, and diagenesis) than sandstone. (Chilingarian et al, 1979; Mazullo, 1986). In the Middle East, Carbonate reservoirs 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 petrophyaical parameters in the reservoir rock. The cementation factor (*m*) is one of these parameters. Layering can be defined on the basis of cores and /or logs, which should be integrated with a detailed geologic field model that allows layers and rock types to be identified by log data correlation calibrated with cores data analysis (Focke, and Munn, 1987).

Archie in 1942, is the first researcher who had discernment for the porosity exponent, (*m*). He found that this exponent used in the description of the empirical correlation between porosity(ϕ), and formation factor (*F)* and that this relationship could have a valuable application to quantitative studies of electrical well logs. Physically, the (*m*) factor is a measure of the degree of cement and consolidation of the rock, therefore it is called cementation factor (Guyod, 1944). The cementation factor of the carbonate reservoir is the most important parameters for applying the petrophysical characterization, because its effect on the calculation of water saturation (S_W), Resistivity formation Factor (*F*), tortuosity (*a*) of the pore geometry to current flow, surface area of composite particles, and porosity (ϕ) (Héctor, et al, 2007; Ransom, 1974; Ransom, 1984).

The difficulties encountered in the interpretation of water saturation of conventional logs and Archie's formula have been the subject of many publications. The impact of diagnosis and rock wettability variations in Archies' parameters (*m*, n, and a) is difficult to quantify throughout the reservoir (Gilles, et al, 2007). Furthermore, there are anther difficulties that lead to misleading of information and lack of them which are error in reading of logging tools due to high environmental effects while drilling and run logging tools in open hole sections (Shujie, 2008).

The accurate calculations of petrophysical and elastic dynamic properties in carbonate reservoirs are the most challenging aspects of well log analysis. Many equations have been developed over the years based on known physical principles or on empirically derived relationships, Which are used to calculate carbonate rock properties. Practically, the formation water resistivity (R_w) estimates from Spontaneous Potential (SP) log. The formation rock resistivity (Rt) is usually obtained from deep resistivity log reading such as deep Induction or deep Lateralog. The porosity data can be estimated from several types of porosity logs, for instance Density, Neutron, or Sonic logs. The saturation exponent (n) and cementation exponent *(m)* are estimated from well logs and core data analysis or from prior experience with local formation characteristics. The conventional method is used to correlate core permeability and porosity measurements and to use the resulting porosity-permeability transform to calculate permeability from porosity logs. Finally, dynamic elastic properties can be obtained if the compression transit time (Δt_p) and corrected bulk density values are available. (Antwan, 1988; Jackson, P.D, et al, 2008; Lucia, 2007; Lee, 1989).

Overall, due to the large variation of petrophysical and elastic properties of carbonate reservoirs, petrophysical evaluation of these reservoirs is important in predicting their behavior. Well logs are considered one of the main sources of data for the geological and petrophysical parameters of reservoir formations. Cementation factor is one of the most important of these parameters because the accurate determination of this factor will improve the saturation value and consequently oil in place calculations.

1.1 Area of Study

NS oil field is located on the Arabian platform, in a gently folded zone, west of the Zagros fold belt as shown in figure (1-1). After the widespread deposition of anhydrite facies (Hartha Fm.), carbonate depositional conditions re-establish in response to generalized transgressed events. A thick shallow platform (Yammama Fm.) develops in the north of Arabian Gulf, passing to north-east to basinal shaly/marly facies (Balambo Fm.). During Barremian, the erosion of the Arabian shield introduced a large amount of clastic sediments (Zubair Fm.) into the basin, invading part of the former shelf area. The last sedimentary cycle is represented by shallow shelf limestone (Shuaiba Fm.) gradually passing eastward to basin deposits where shale and marl accumulate (Sarmond Fm.). NS oil field is considered as a giant oil field in the Middle East. Also, it is characterized by carbonate reservoirs. NS oil field has reserves in late Cretaceous Mishrif limestone reservoir& early cretaceous Yammamah limestone reservoir. (refers to Appndix, A-1), (Rohpetrol Company, 2008). The lithological column of the NS oil field is provided by INOC in 1985, in the final drilling report of a NS-3 oil well (refer to Appndix, A-2).

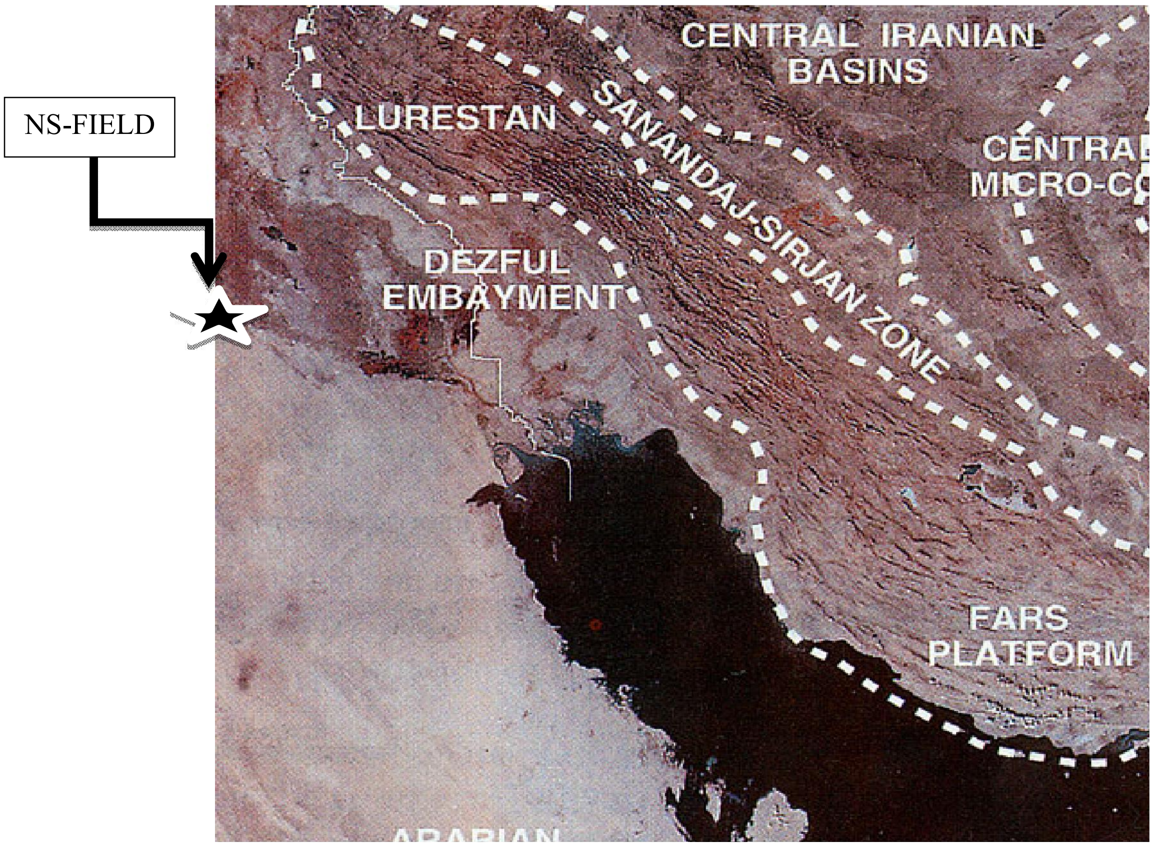

Figure (1 -1) Satellite Image for NS oil field location

1.2 Problem Statements

There are no comprehensive studies represented to the relationship between cementation factor with petrophysical and elastic properties for carbonate formations in the NS oilfield. Therefore, this study should provide **comprehensive correlations between cementation factor (*m*) and carbonate rock properties such as; permeability (K), porosity (Φ), compressional-shear velocity ratio (V_P/V_S), Bulk modulus (K_m), and Biot's Constant,** based on the conventional well logs data,core samples data analysis, and NS oilfield reports. **Applying these correlations should improve the accurate value of saturation and as a result improve the accuracy of hydrocarbon reserve calculations.**

1.3 Objectives of Study

1- To determine the petrophysical and elastic properties of carbonate rocks in the NS oilfield from well logs data and core sample data, by using Neurolog (NL) and Interactive Petrophysics software (IP).

2-To Find new correlations relating the cementation factor with petrophysical and elastic properties for carbonate formations in the NS oilfield, by using Artificial Neural Network(ANN).

3- To re-estimate the original oil in place and calculate the overburden pressure in the study field.

1.4 The Scope of Study

The scopes of study are followed:

1-Scan the available logs and convert to soft copy, after that the Neurology software (V2008) was used to digitize the scanned copies of logs for selected wells.

2- Use Interactive Petrophysics software (IP V3.5, 2008) to calculate actual values of petophysics and elastic properties for carbonate rocks in the study area.

3-Connecting the interpreted results of conventional methods with the available geologic information and core sample analysis.

4- Find and developed new correlations relating the cementation factor to the permeability (K), porosity (Φ), compressional-shear velocity ratio (V_P/V_S), Bulk modulus (K_m), and Biot's Constant by using an Artificial Neural Network Program(ANN).

5- Using the study results to re-estimate oil in place in carbonate formations in the NS field and calculate the overburden pressure.

6- Apply the study methodology on the Middle East carbonate reservoirs.

CHAPTER 2
LITRITURE REVIEW
2.1 Introduction

Middle East carbonate reservoirs contain supergiant oil and gas fields, which cover around fifteen percent of the world's oil reserves as shown in Figure (2-1). When reservoirs in other regions are depleted this ratio will rise and the giant carbonate reservoirs in the Middle East will come the main source to provide oil and gas for the whole world (Naomi and Standen, 1997).

Carbonate reservoirs become important to the petroleum industry after World War I, when exploration drilling resulted in the discovery of major oil reserve in carbonate rocks in the Middle East. (Chilingar et al, 1992).

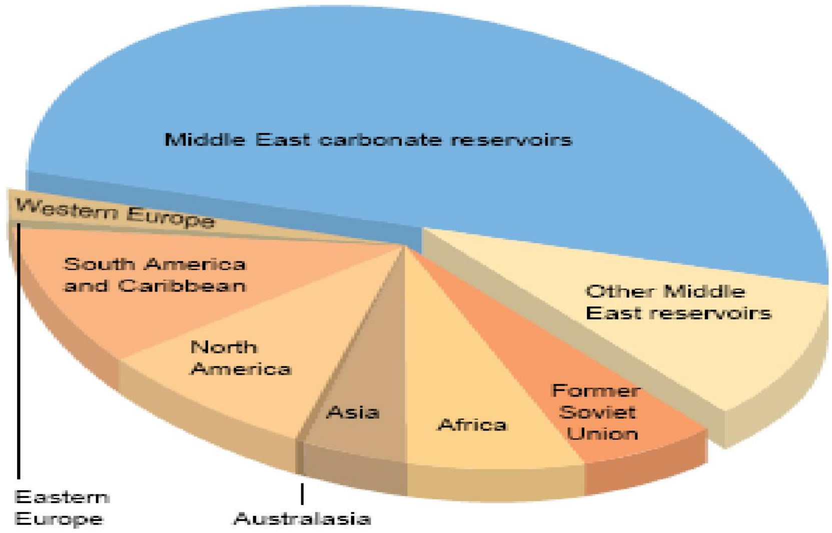

Figure (2-1): The ratio of carbonate reservoirs in the Middle East (Naomi, 1997)

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

$$Sw^n = \frac{a.Rw}{\phi^m R_t} \text{.....................}(1)$$

In this equation, (*a*) is the tortuosity factor, R_w is water or brine resistivity, Φ is rock porosity (fraction), R_t is true resistivity of the system at the saturation (S_W) and the exponents *(m)* and (n) are porosity and saturation exponents respectively. In order to apply saturation equation actual petrophysical parameters must be used for each layer or reservoir, the use of constant value will lead to misleading in water saturation interpretation. In another way the use of any saturation model is limited to type of reservoir (Carbonate or Sand) in which it will give reliable saturation results. Archie's formula has been widely used by many log analysts. This empirical formula provided the early basis of the quantitative petrophysical reservoir evaluation.

Archie in 1942, established the relationship between the resistivity, *Ro*, of the sand entirely filled with brine (*Sw=1)* and the resistivity of the water, *Rw,* for a large number of brine saturated cores as follows:

$$R_O = FR_W \text{............}(2)$$

Archie then found the formation factor, *F*, to be a function of the type of formation which varies with porosity. This basic relationship works as a method to classify sand formations:

$$F = \frac{a}{\phi^m} \text{............}(3)$$

Where, *m* is a formation dependent parameter (cementation exponent), assume a=1.

Archie found the exponent *m* takes a value of 1.3 in clean unconsolidated sand packs in a laboratory and that *m* falls in the range of 1.8 to 2.0 in the consolidated sandstones he tested.

2.1.1 Definition of Cementation Factor

The first discernment for the **porosity exponent**, *m* was given by Archie in 1942. He did not actually call it "*cement exponent*", but found that this exponent helped in the description of the empirical relationship between porosity, and formation factor, *F* and that this relationship could have a valuable application to quantitative studies of electric logs.

According to Guyod in 1944, who introduced the term of cementation factor for the exponent (*m*), it is a measure of the degree of cement and consolidation of the rock; the greater the degree of cement means the greater value of the porosity exponent. Lately, the cementation factor (*m*) has been accepted as a measurement of the tortuosity of the pore geometry to current flow. The factor *m* is related to the geometry imposed upon the bulk volume of interstitial water of both solid and fluid insulating materials (Ransom, 1974; Ransom, 1984). The cementation factor is strongly dependent on shape, surface area of composite particles and toruosity. It has been given considerable attention by researchers, because of the various physical effects of cementation factor on the physical behavior of sediments (Hilmi, 1993). According to (Héctor, et al in 2007), the cementation factor of the carbonate reservoir is the most important parameters for applying the petrophysical characterization.

2.1.2 Factors Affect for Cementation Factor

Researchers have shown that the value of the cementation factor is largely affected by the following factors: (Ransom, 1984; Rasmus, 1986, and Wardlaw, 1980).

1. Secondary Porosity: When laboratory measurements of porosity include secondary porosity, (porosity formed by modification of primary porosity, in addition to the intergranular porosity, it is sometimes difficult to draw a best fit line through the lab data to determine *m*. This is because the secondary porosity will not remain either a constant volume or a constant percentage through the range of porosities encountered in the reservoir. As a consequence, the porosity exponent will not reflect the true tortuosity of the pore system and essentially *m* could be, and probably is, different for each sample plotted. By mathematically modelling the fractures and Vug paths has been found that besides the degree of cement, Vugs tend to increase the formation factor (*m*) while fractures cause a reduction in the value of *m*. (Rasmus, 1986).

2. Pore Throat Size*:* The exponent *m* depends on factors related to pore geometry. In nature, grain size and shapes are not always uniformly distributed and this has a direct effect on the pore throat size distribution of the rock.

3. Conductivity of water and minerals*:* Ransom in 1974 and 1984, indicates that the exponent *m* has a direct relation with the pore geometry only when the electrical conductivity present in the rock comes from the water-filled pore volume. When there is additional conductance to the water-filled pore volume produced by electrically conductive solids (such as pyrite) and/or surface conductance due to ion exchange in shale, the exponent *m* varies and it accounts for all these conductive substances present in the rock. If these additional conductivities are accounted for independently, their value will be represented by the coefficient *a* (Patnode and Wyllie, 1950).

4. Surface Area per Unit Volume: When grains become less spherical, more oblate, more angular, flatter, or more complicated in shape, the surface area per unit volume increases and so does the value of *m*. (Ransom, 197; Ransom, 1984).

5. Cementation: Cement on intergranular pore spaces or even on solid grain surfaces can build up to the extent that some interstitial water or conductive minerals can be partially or totally isolated electrically from the system (Ransom, 1974; Ransom, 1984).

2.1.3 Ranges for the Cementation Factor

Mathematically the cementation factor (*m*) can vary from 1.0 to infinity (Thornton, 1949; Wyllie and Ros, 1950). In practice, this factor ranges from 1.0 to 3.0 (Archie, 1942; Guyod, 1944). The values of $m=1.3$ and $m=1.8$ were referenced by Archie in 1942 as well. He stated that *m* takes a value of 1.3 in clean unconsolidated sands packed in the laboratory and that *m* falls in a range of 1.8 to 2.0 in consolidated sandstones. Between the range $1.0 \leq m \leq 3.0$ there are two values for the porosity exponent: $m=1.3$ and $m=1.8$. The value of $m=1.\ 3$ was found theoretically and corresponds to grains that have a spherical shape (Pirson, 1947).

Values of $m=1.0$ are considered with fractures aligned favourably in the direction of the current flow and a fracture porosity of 100% of the water filled porosity available (Ransom in 1974; Ransom, 1984). For non-touching Vug carbonates, the value of (*m*) ranges from 1.8 to as high as 4, while the (*m*) value may be less than 1.8 in the presence of fractures and other touching vug pore types (Wang and Lucia, 1993; Meyers, 1991).

Values of $m=3.0$ are found in non-connected moldic porosity, whereas Values of *m* are less than 1.3 when there are fractures or non-uniform features in the void space which are favorably aligned in the direction of the current flow. When there are inefficient current paths, irregular grain shapes, crystals and discontinuities, the (*m*) values reach higher than 1.3 (Hartmann and Beaumont, 1999).

Conventional wisdom suggests using *m* value of 2 when no other information is available. However, the resulting of water saturation will be too low if (*m*) is smaller than 2, and too high if m is larger than 2. By changing of the (*m*) value from 2 to 3 the water saturation changes from 32% to 71% or from oil production to water productive, as shown in table (2-1). (Lucia, 2007).

Table (2-1): The effect of (*m*) value on water saturation calculation.

Resistivity (R_t)	Porosity (ϕ)	R_w	n	*m*	$S_{w,Calculated}$
400	0.2	1.6	2	2	32%
400	0.2	1.6	2	3	47%
400	0.2	1.6	2	4	71%

2.2 Calculation of Carbonate Rock Properties

2.2.1 Determination of Clay Volume

One of the most controversial problems in the formation evaluation is the shale effect in reservoir rocks. The presence of conductive clays and shale considerably complicates the interpretation of resistivity data of partially saturated formations (Hamada, 1996). The shale type, the percentage present, and the mode of distribution in the formation have different effects on the resistivity and porosity. Generally, however, the presence of clay or shale in a sand bed lowers the true formation resistivity R_t and, if not corrected, will result in overestimating S_w, i.e., interpreting as water-bearing zones that are actually oil-bearing. Shale contains, in various proportions, clay minerals such as illite, montmorillonite, and kaolinite, as well as silt. Silt is a very fine-grained material that is predominantly quartz, but may include feldspar, calcite, and other minerals (Susan and Robert, 1990). Shale is usually more radioactive than sand or carbonate, gamma ray log and other logs can be used to calculate volume of shale in porous reservoirs. The volume of shale expressed as a decimal fraction or percentage is called V_{shale} (Asquith and Krygowski, 2004). The volume of clay can be calculated by two sets of well logging indicators which are Single Clay Indicators and Double Clay Indicators and the minimum value is from any number of clay indicators, the minimum value of V_{clay} is thus closest to the truth. (Schlumberger IP Manual, 2008; Thomas and Stieber, 1975).

2.2.1.1. Single Clay Indicators

1. Natural Gamma Ray (NGS) - spectral gamma ray (SGR): The gamma ray provides the measure of the total natural radioactivity of a formation. The spectral gamma ray tool also detects the naturally occurring gamma rays and defines the energy spectrum of the radiations. Because Potassium (K), Thorium (Th) and Uranium (UR) are responsible for the energy spectrum observed by the tool, their respective elemental concentrations can be calculated. A straight interpolation is used to relate V_{clay} with the NGS log readings (Schlumberger, 1982):

$$V_{sh} \le \frac{SGR - SGR_{\min}}{SGR_{\max} - SGR_{\min}} \quad \text{....................(4)}$$

$$(V_{sh})_{UR} \le \frac{UR - UR_{\min}}{UR_{\max} - UR_{\min}} \quad \text{....................(5)}$$

$$(V_{sh})_{K} \le \frac{K - K_{\min}}{K_{\max} - K_{\min}} \quad \text{....................(6)}$$

$$(V_{sh})_{Th} \le \frac{Th - Th_{\min}}{Th_{\max} - Th_{\min}} \quad \text{....................(7)}$$

Since the Uranium is associated with radioactive minerals other than those found in clay (i.e. Organic materials), so it is generally not a reliable clay indicator. By eliminating the uranium contribution from the total gamma ray response and defining the Corrected Gamma Ray CGR (i.e.: sum of thorium and potassium only) (Schlumberger, 1982):

$$V_{sh} \le \left[\frac{CGR - CGR_{\min}}{CGR_{\max} - CGR_{\min}}\right] \quad \text{....................(8)}$$

The above equation expresses V_{sh} linearly with increase of gamma ray reading.

Where: CGR: Corrected gamma ray logs reading in the zone of interest (API units).

CGR_{min}: Corrected gamma ray logs reading in a 100 % clean zone (API units).

CGR_{max}: Corrected gamma ray logs reading in 100% shale (API units).

2. **Neutron logs:** The following equation is often used to calculate the volume of clay by neutron log reading (Schlumberger IP Manual, 2008; Thomas and Stieber, 1975).

$$V_{sh} = \sqrt{\left(\frac{\Phi_N}{\Phi_{Nclay}}\right)\left(\frac{\Phi_N - \Phi_{Nclay}}{\Phi_{Nclay} - \Phi_{Nclean}}\right)} \quad \text{....................(9)}$$

3. Spontaneous Potential (SP) log: In water bearing sands of low to moderate resistivity containing laminated clay, it has been found that (Thomas and Stieber, 1975; Schlumberger, 1984):

$$V_{sh} \le 1 - \frac{PSP}{SP} \quad \text{....................(10)}$$

The above equation is used when the SP log reading taken depending on shale-base line. A straight interpolation is used to get the following relationship for computerized calculation if the value of SP reading is taken from the SP log directly without reference to shale-base line (Schlumberger, 1984; Schlumberger, IP Manual, 2008):

$$V_{sh} \le \frac{SP - SP_{clean}}{SP_{clay} - SP_{clean}} \quad \text{....................(11)}$$

4. Resistivity logs: The resistivity of a mixture of clay with some non – conductive mineral (quartz for example) will depend on clay resistivity and clay content. If the mixture has no porosity, then it can be expressed by an Archie – type formula (Thomas and Stieber, 1975):

$$R_t \leq \frac{R_{clay}}{(V_{clay})^b} \quad \text{..(12)}$$

In case of low porosity: some formation water will exist and so the resistivity will be lower therefore (Thomas and Stieber, 1975):

$$V_{sh} \leq \left(\frac{R_t}{R_{clay}}\right)^{1/b} \quad \text{...(13)}$$

The above equation is used in case of high to moderated values of porosities but,

In general form the following formula will used (Schlumberger IP Manual, 2008) (Thomas and Stieber, 1975):

$$V_{sh} \leq \left[\frac{R_{clay}\left(R_{\max} - R_t\right)}{R_t\left(R_{\max} - R_{clay}\right)}\right]^{1/b} \quad \text{.................................(14)}$$

Where:-

R_{max}: is the maximum resistivity reading in the clean hydrocarbon bearing interval.

1/b: is equal to one when $(R_t/R_{clay}) \geq 0.5$ or equal to $\{0.5/(1- R_t/R_{clay})\}$ when $R_t/R_{clay} < 0.5$.

2.2.1.2 Double Clay Indicators

1. Density – Neutron Method: This method is almost the best crossplot technique to get clay due it is less dependent on Lithology, less dependent on fluid type in porous media and badly washed out wellbores. It is better to use it in gauge boreholes. The uncertainty came from: highly under-compacted formation (shallow overpressures) (Elton and Fertl, 1981; Ruhovets and Fertl, 1982).

The density – neutron method can be used to calculate the clay volume as the distance, the input data falls between the 'clay point' and the 'clean line'. The following plot, Figure (2-2) illustrates this principle (Schlumberger IP Manual, 2008):

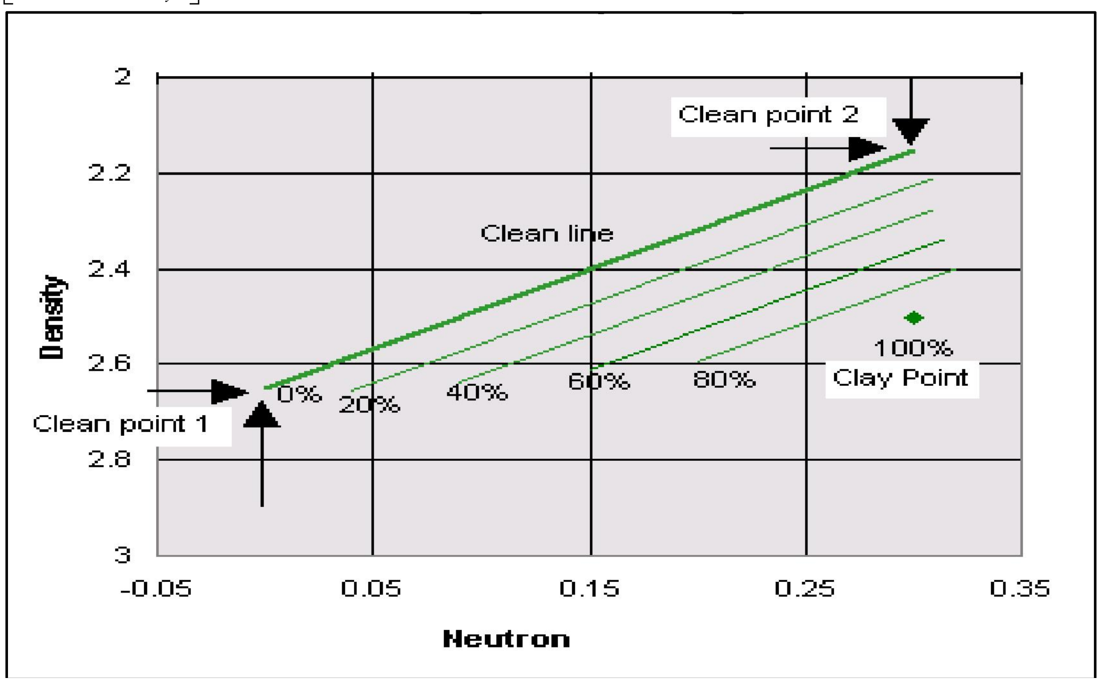

Figure (2-2) Neutron – density crossplot (Schlumberger, IP Manual, 2008)

Equation (44) had used to calculate clay volume by this method (Schlumberger, IP Manual, 2008):

$$V_{sh} = \left[\frac{(\rho_{C1} - \rho_{C2})(\Phi_N - \Phi_{N1}) - (\rho - \rho_{C1})(\Phi_{N2} - \Phi_{NC1})}{(\rho_{C2} - \rho_{C1})(\Phi_{Nclay} - \Phi_{N1}) - (\rho_{clay} - \rho_{C1})(\Phi_{NC1} - \Phi_{NC2})}\right] \text{..........(15)}$$

Where:-

ρ_{C1} & ρ_C: Clean density readings @ point 1 & 2.

ρ_{clay}: Clay density.

Φ_{NC1} & Φ_{NC1}: Clean neutron readings @ point 1&2.

2. Density – Acoustic Method: This method is the second crossplot techniques that have used to get V_{clay} which is characterized by less dependent on Lithology and less dependent on fluid type in porous media. It is better to use this method in gauge boreholes. The uncertainty came from badly washed out wellbores and highly under-compacted formation (shallow overpressures) (Elton and Fertl, 1981), (Ruhovets and Fertl, 1982). Equation (45) had used to calculate clay volume by neutron – acoustic method (Schlumberger, IP Manual, 2008):

$$V_{sh} = \left[\frac{(\rho_{C1} - \rho_{C2})(son - son_1) - (\rho - \rho_{C1})(son_{C2} - son_{C1})}{(\rho_{C2} - \rho_{C1})(son_{clay} - son_{C1}) - (\rho_{clay} - \rho_{C1})(son_{C1} - son_{C2})} \right] \text{...........}(16)$$

Where: Son_{c1} & $Son_{c2:}$ Clean sonic readings @ point 1 & 2. While Son_{clay} is the Sonic reading @clay point.

2.2.2 Porosity Calculations from Well Logs

2.2.2.1 Density logs

The density tool responds to the electron density of the material in the formation. Formation bulk density (ρb) is a function of matrix density, porosity, and density of fluids in the pores (salt water, fresh water mud, or hydrocarbons). The formula for calculating density-derived porosity is (Schlumberger, 1989):

$$\Phi_D = \frac{2.71 - \rho_b}{2.71 - \rho_{mf}} \text{.......................}(17)$$

Where:-

ρma: is the matrix density, [2.71 (gm/cc) for limestone, 2.87 (gm/cc) for dolomite and 2.65 (gm/cc) for sandstone].

ρf: is the fluid density (gm/cc) [fresh water mud = 1, for salt water mud 1.1].

2.2.2.2 Neutron logs

Neutron logs are porosity logs that measure the hydrogen concentration in a formation. In clean formations (i.e., shale-free), where the pores are filled with water or oil, because hydrogen in a porous formation is concentrated in the fluid-filled pores, energy loss can be related to the formation porosity. Whenever shale is part of the formation matrix the reported neutron porosity is greater than the actual formation porosity (Gilchrist et al, 2008). This occurs because the hydrogen that is within the shale's structure and in the water bound to the shale is sensed in addition to the hydrogen in the pore spaces. (Antwan, 1988).

2. 2.2.3 Sonic logs

The sonic log is a porosity log that measures interval transit time (Δt, or DT) of a compressional sound wave traveling through the formation, the interval transit time (Δt) depends upon both lithology and porosity. Wyllie time-average equation may be written as (Lee, 1989):

$$\Phi s = \frac{\Delta t_{\log} - \Delta t_{mat}}{\Delta t_f - \Delta t_{mat}} \text{..............}(18)$$

Where:-

Φs: is sonic-derived porosity, fraction.

Δt_{ma}: is the interval transit time in the matrix [Its value is 47.6 (µsec/ft) for

Limestone and 43.5 (µsec/ft) for dolomite).

Δt_{log}: is the interval transit time in the formation, µsec/ft.

Δt_f: is the interval transit time in the fluid within the formation [For fresh water mud = 189 (µsec/ft); for salt-water mud = 185 (µsec/ft)].

2.2.3 Archie's Equation Parameters

The first down hole log was an electric log recorded by Doll on September, 1927, in the Pechelbronn field, Alsace, France (Antwan, 1988). This was initially applied as a stratigraphic correlation tool between wells until Archie in1942, derived an empirical relationship between the electrical resistivity and porosity, thus enabling the first down hole assessment of porosity in situ. Since then alternative measurements have been developed for determining the porosity in situ, thus enabling the electrical resistivity to be used to determine the water saturation in the reservoir, and hence the hydrocarbon saturation. Consequently Archie's equation underpins the use of electrical resistivity in determining the hydrocarbon saturation, but requires a series of empirical parameters to be determined.

2.2.3.1 Porosity Exponent

Through his laboratory results, Archie demonstrated that the electrical resistivity of sandy rocks was related to porosity as shown in equation (3). Archie showed "m" increased with the degree of cementation of his sand samples, being lowest for loose sands. The Relationships for selected porous media and Archie's m parameter are shown in table (2-2) a more general relationship, was proposed by Winsauer et al in1952 as shown in equation (4). While Winsauer's equation has been applied to sets of down hole data, it does not satisfy the boundary condition: F =1. 0 when porosity=1.0 (Archie, 1942) extended these relationships to include water saturation equation, S_w as:

$$S_w = \frac{R_O}{R_W} \text{.................................}(19)$$

Where (n) is an empirically derived saturation exponent, typically taken to be 2.0, on the basis of laboratory studies of core (e.g. Archie 1942). Typically, Archie's formula became as equation (1). This equation have been found suitable for calculating water saturations in reservoir rocks, and have led to the resistivity approach becoming the method of choice for estimating oil in place (Adeoti, et al, 2009). Typically the two exponents "m" and "n" described above are determined from laboratory measurements on cylindrical core samples (e.g. 100mm long and 35mm diameter), sub-sampled from larger whole-core samples (Archie, 1942). More recently, effective medium models have successfully described resistivity porosity and saturation relationships, without the constraint of "a" not conducting matrix which is inherent in traditional methods as follows (Jackson, et al, 2008):

$$F = \left[\frac{1-(R_w / R_{ma})}{\Phi^m (1-(R_O / R_{\max}))} \right] \dots\dots\dots\dots(20)$$

Where: R_{ma} is the resistivity of the particle matrix.

Table (2-2): Values of Archie's m parameter (Jackson, et al, 2008)

Porous Medium	Value of Archie's m
Straight cylinders	1.0 (Herrick et 1993)
Inclined cylinders	>1.0 (Wyllie et al, 1952)
Change in diameter	>1.0 (Jackson, 1975)
Cemented Sandstones	1.8 – 2.0 (Archie 1942)
Loose Sandstone	1.3 (Archie 1942) 1.4 – 1.7 (Jackson et al., 1978) (Windle et al., 1975)
Shell Fragments	1.9 (Jackson et al., 1978)
Spheres Shell Fragments	1.25 – 1.9 (Jackson et al., 1978)
Vuggy Dolomite	2.0 – 5.0 (Focket et al., 1978)

2.2.3.2 Saturation Exponent

When Archie introduced his equation in 1942, it started a new era for the oil and gas industry because it made it possible for the first time to make quantitative hydrocarbon reserve estimates from resistivity and porosity logs. In its simplest form Archie's equation works remarkably well in "clean" water-wet sandstone formations (Bernard, 2008):

$$Rt = R_w.(S_w.\Phi)^2 \dots\dots\dots\dots\dots(21)$$

The value of the water saturation S_w is quite sensitive to the exponent in this equation. For example for a relatively small size oil reservoir using 2 instead of 1.8 in above equation easily returns several additional billion dollars of reserves and at the world-wide scale this becomes a trillion dollar (Jackson P.D.,et al,2008). The two exponents *(m* and n) are known to take different values for various reservoir rocks. This is especially true for carbonates for which rock typing and pore geometry characterization are essential for their petrophysical modeling (Gilles, et al, 2007).

The exponent (n) has been studied during the last 55 years by a large number of authors and experienced by petrophysicists all around the world. Indeed in carbonates (n) can range from less than 1.5 to more than3, and m can exceed 4 in some vuggy rocks. To make things worse various rock types tend to be distributed in some carbonate formations with a high level of heterogeneity. Determining the right average value to use for n and m in such heterogeneous formations in order to obtain accurate estimates for hydrocarbons in place is quite a challenge (Jackson, et al, 2008).

Archie compiled the work of (Martin et al, 1938; Jakosky and Hopper, 1937), and suggested that the following relationship was applicable when pores are partially filled with brine:

$$Rt = R_o.(S_w^{-n})^2 \dots\dots\dots\dots\dots\dots(22)$$

$$Rt / R_o = I_R = (S_w^{-n})^2 \dots\dots\dots\dots(23)$$

The values of n are usually obtained in the laboratory by stepwise reducing the water saturation in a core plug and measuring the resistivity at each step. A plot of this resistivity versus water saturation will eventually yield the value of the saturation exponent as being the slope of the line joining all the measured points. The above equations are currently the basis by which the water saturation equation is derived (Bernard, 2008).

$$(S_w^n)^2 = \frac{a.R_w}{\Phi^m .Rt} \dots\dots\dots\dots\dots\dots(24)$$

2.2.3.3 Tortuosity Exponent

The parameter (a) was introduced by Winsauer, et al in 1952, and is a measure of the geometry of the pore space; what he called in his paper (a measure of the constriction, enlargement and intermeshing of the pore channels). Winsauer found that the only way his experimental core data could fit into Archie's law was by assigning values of a = 0.62 and m = 2.15.

2.2.4 Determination of Rt, Rxo and Di

True resistivity may be obtained from DIL or DLL, so any invasion correction should be applied to obtain the true resistivity which will lead to good interpretation for water saturation (Toby, 2005). The resistivity of the flushing zone (Rxo) also had obtained from the MSFL tool by Micro SFL and mud cake correction chart Rxo-3 (Richard, 1963). The invasion correction charts, also referred to as "tornado" or "butterfly" charts, assume a step-contact profile of invasion and that all resistivity measurements have already been corrected as necessary for borehole effect, Tornado chart (refer to

Appndix, B-1) had used, the general solution of this chart for true formation resistivity, R_t is (L.F. Quintero, et al, 1992):

$$(\frac{Rt}{R_{ILd}})^2 + B\frac{Rt}{R_{ILd}} + C = 0 \qquad (25)$$

Where:-

$$B = 0.59a - 2.21C + 1.35$$

$$C = -(1.44a - 2.47C + 2.76)$$

$$a = \frac{R_{LL8}}{R_{ILd}} - 1$$

$$b = \frac{R_{ILm}}{R_{ILd}} - 1$$

$$C = \frac{a}{b}$$

R_{ILd}: Deep induction resistivity, ohm-meter.

R_{ILm}: Medium induction resistivity, ohm-meter.

R_{LL8}: Laterolog - 8 resistivity, ohm-meter.

The solution of the above equations is:

$$\frac{R_t}{R_{ILd}} = -0.5((B^2 - 4C)^{0.5} + B) \qquad (26)$$

The logic of above equations is described by flow chart (refer to Appendix, B-2).

2.2.5 Determination of (R_w) and (R_{mf}) from SP Log

Initial water saturation in hydrocarbon reservoirs has an enormous impact on the calculation and production of original oil in place. In addition, permeability is regarded as the most important variable in selecting perforation intervals, layers for injection, and to forecast production. When laboratory measurements (core, water analysis, etc.) are available, these two variables are properly constrained. However, such measurements are not always available, and if they are, their reliability may be questionable. Therefore, there is a strong need for alternative methods to estimate the initial water saturation and permeability. Two of the main parameters needed to calculate water saturation, movable hydrocarbon and permeability by conventional methods are R_w and R_{mf}, which can be obtained from connate water analysis and special core analysis, respectively The logic of this method is described in flow chart (refer toAppendix, B-3). The spontaneous potential log reading is described in the following equation (Lee M. Etnyre, 1989).

$$SSP = -K \log \frac{R_{mf}}{R_w} \qquad (27)$$

R_{mfe}: equivalent mud filtrate resistivity, ohm-m., R_{we}: equivalent formation water resistivity, ohm-m., SP: spontaneous potential log reading.

2.2.6 Calculation of Water Saturation

The calculation of water saturation is one of the most troublesome aspects of log analysis. Many equations have been developed over the years based on known physical principles or on empirically derived relationships. Resistivity measurements are, by far, the most commonly used measurements to determine (Sw) in the earliest days of well logging, it was recognized that the presence of hydrocarbons was indicated by anomalously high resistivity in porous intervals (Jackson, P.D, et al, 2008) (L. Adeoti, et al, 2009).

2. 2.6.1 Resistivity Models

2.2.6.1.1 Simple Archie Equation

Archie in 1942, was introduced equation, which based on laboratory experiments on clean sands, water wettability and non- vugy carbonates. The earliest research established that for a formation with constant porosity and water salinity, an increase in resistivity indicated the presence of hydrocarbons. Archie qualified this relationship as shown in equation (3). This equation will be in error in clean sands if the formation water salinity is extremely low. (Antwan M. Avedisian, 1988).

2.**2.6.1.2 Simandoux Model**

Simandoux in 1963, proposed equation based on experimental data on a homogeneous mixture of sand and montmorillionite. Shale volume does not correspond the wetted shale, because the natural calcium montmorillionite was not in the fully wetted state. This model has been widely used in complex reservoir rocks (Lee M. Etnyre, 1993).

$$S_w = (0.4R_w\phi^{-2})\left\{-\frac{V_{sh}}{R_{sh}} + \left[\frac{5\phi^2}{R_wR_t} + (\frac{V_{sh}}{R_{sh}})^2\right]^{0.5}\right\} \qquad (28)$$

Where:

$V_{sh} =$ Shale volume and $R_{sh} =$ Shale Resistivity

2.2.6.1.3 Modified Simandoux equation

This model was introduced by Atlan et al., in 1968 and Bardon and Pied in 1969 related the following parameters (Lee M. Etnyre, 1993) as:

$$\frac{1}{R_t} = \frac{\Phi^m S_w^n}{aR_w} + V_{sh}\frac{S_w}{cR_{sh}} \qquad (29)$$

Where:-

C: is a fitting parameter.

2.2.6.1.4 Indonesia Formula

Poupon and Leveaux, 1971, proposed an empirical model called "Indonesia formula". This equation was developed based on the typical characteristic of fresh formation waters and high degrees of shelliness that presents in many oil reservoirs in Indonesia. In this model the conductivity relationship between Rt and Sw is a result of conductivities of the clay, formation water and additional conductivity from the interaction between both of them. The empirical relationship can be written as (Lee M. Etnyre, 1993).

$$S_w^{0.5} = (R_t)^{-0.5}\left[\frac{V_{cl}^d}{R_{cl}^{0.5}} + \frac{\Phi^{0.5m}}{(aR_w)^{0.5}}\right] \ldots\ldots(30)$$

Where:-

$$d = 1 - 0.5Vcl$$

2.2.6.2 Conductivity Models

The concentration of sodium cations can be measured in term of cation exchange capacity (CEC), expressed in mille equivalents per gram of dry clay. For practical purpose Qv, cation exchange capacity per unit of pore volume, is usually used. These models can give better results as they can be matched closely to laboratory measurements. It is not as popular as the cost of doing the laboratory tests and the lack of core data often precludes the use of these models, the most commonly used cation exchange capacity models are:

2.2.6.2.1 Waxman and Smith's Model

Waxman and Smith in1968, based on extensive laboratory work and theoretical study, proposed a saturation-resistivity relationship for shaly formation using the assumption that cation conduction and the conduction of normal sodium chloride act independently in the pore space, resulting parallel conduction paths. This model can be written as follows (Waxman, and Smith, 1968: Djebbar and Erlec, 2004).

$$\frac{1}{R_t} = \frac{S_W^2}{F.R_W} + \frac{B.Q_V.S_W}{n^*} \ldots\ldots(31)$$

Where:

n*: Archie saturation exponent for shaly sands.

B: Equivalent conductance of clay exchangeable cations.

CEC: clay exchangeable cations; CEC values can be measured on rock samples obtained from conventional or sidewall cores. Q_v is CEC per unit pore volume.

2.2.6.2.2 Dual -Water Model

The Dual-Water model is modified from Waxman-Smits equation by taking into account the exclusion of anions from the double-layer. It represents the countering conductivity restricted to the bound water, where countering resides in the free water, which is found at a distance away from clay surface. This model says that apparent water conductivity depends on the relative volumes of clay bound water and free water. Dual-water equation is given by two types of formation water (Peters, M, 1986).

A. Bound Water Saturation S_{WB}: which defined as the fraction of total porosity occupied by bound water.

B. Free Water Saturation S_{WF}: which defined as the fraction of total porosity occupied by free water.

$$S_{wT} = Y + \left[\frac{R_{wT}}{\Phi_T^2 R_t} + Y^2\right]^{1/2} \ldots\ldots(32)$$

Where:-

$$Y = \frac{S_{wB}(R_{wB} - R_{wF})}{2R_{wB}}$$

R_{wT}: Resistivity of free water

S_{wT}: Total water saturation

R_{wB}: Resistivity of bound water

Whereas S_{wT} can be calculated as:

$$S_{wT} = S_w = \left[\frac{S_{wT} - S_{wB}}{1 - S_{wB}} + Y^2\right]^{1/2} \ldots\ldots(33)$$

2.2.6.2.3 Modified Waxman Smith's model

This model is based on the Juhasz model without the B. Q_V, it uses the apparent bound water resistivity R_{wB} whereas the interested formation is shale i.e. V_{clay} = 100%, two sets of equations are used (Djebbar Taib and Erlic Donaldson, 2004):

1- When $R_w \geq R_{wB}$

$$R_O = \frac{[F.R_{wB}.R_w]}{[R_{wB}.(1 - V_{clay}) + V_{clay}.R_w]} \ldots\ldots(34)$$

$$S_{wT} = \left(\frac{R_O}{Rt}\right)^{1/n} \ldots\ldots(35)$$

2- When $R_w < R_{wB}$

$$X = \frac{V_{Clay}(R_{wB} - R_w)}{82R_{wB}} \ldots\ldots(36)$$

$$S_{wT} = X + \left[\frac{F.R_w}{R_t} + X^2\right]^{1/n} \ldots\ldots(37)$$

Note that if $R_w = R_{wB}$, the equation becomes a simple Archie formula, since X value will equal to zero.

2.2.7 Calculation of Cementation factor *(m)*

Determination of Archie's parameters a, m and n which are among the most uncertain parameters of conventional interpretation is sometimes wrong because of the erroneous porosity conversions and inaccurate water saturation exponent. Such uncertainty always induces a considerable effect on the values of hydrocarbon saturation. (Hartmann Dan J., and Beaumont Edward A, 1999).

2. 2.7.1 F-ϕ Plot Method

This method is used to calculate *m* from laboratory measurements as *F* can be measured in core full saturated with brine where $F = \frac{Ro_{Lab.}}{Rw}$ and ϕ is also can be measured laboratory for the same core or cab be taken form logs at the same depth of this core. The theoretical basis of this method depends on the relation between the formation factor and the porosity as shown in equation (3):

$$F = \frac{a}{\phi^m}$$

Becomes with the use of logarithms:

$$\log F = \log a - m \log \Phi ......(38)$$

Equation (38) is a straight line equation on log–log scale, where (*m*) is the slope and (a) is the intercept at $\Phi = 1$. The calculation of (*m*) as suggested by Focke and Munn in 1987 is made by assuming a=1 in equation (38) so (*m*) will equal:

$$m = -\frac{\log F}{\log \Phi} .....(39)$$

2.2.7.2 Pickett Method

The rock variables and exponents include the cementation factor (*m*), the saturation factor (n) and the tortuosity exponent (a). The importance of these factors lies in the need for the optimal estimation of the total water saturation (Jesús and Salazar,2007) the present work, Pickett's method was utilized for calculating these parameters. This method was presented by Pickett, and it is usually called Pickett's method (Pickett, 1966; Douglas, 1978).The Pickett cross-plot can provides some useful information on formation characteristics. This plot utilizes a basic rearrangement of the Archie's equation:

$$Rt = \left[\frac{F.R_w}{S_w^n}\right] \quad \text{And} \quad F = \frac{a}{\Phi^m}$$

Which, becomes with the use of logarithms

$$\log Rt = -m \log(\Phi) + \log aR_w - n \log S_w ....(40)$$

In the water bearing zone S_W = 1, then the equation (40) will be:

$$\log Rt = -m \log(\Phi) + \log aR_w ....(41)$$

Equation (41) is a straight line equation on log – log paper, where m is the slope and (a. R_w) is the intercept at Φ=1 (the corrected porosity for shale and hydrocarbon effects), while the row is calculated by the SP method or other methods, then (a) can be determined. The restrictions of this method are, the crossplot works best in clean formations of a reasonably wide porosity range and constant R_w in the zone of interest, moreover the value of (*m*) and (a) is averaged for the selected formation so in case of deal with complex lithology the values of (*m* and a) will vary for each level and the average values will lead to erroneous results. Pickett method is also very useful in calculating the saturation exponent (n), the theoretical base can be derived as follows:

Archie's equation (1) for reduced water levels, while Archie's equation for irreducible water levels is:

$$S_w^n = \frac{a.R_w}{\Phi^m.Rt_{rii}} ....(42)$$

In 100% water bearing formation (S_w =1) and equation (1) will be:

$$1 = a.\frac{R_w}{\Phi^m.Rt} ....(43)$$

Which is:

$$a.R_w = \Phi^m.Rt ....(44)$$

Morris and Bigges in 1968, observed that the multiplicand of S_w and Φ for the levels that fall on the parabola in S_w versus Φ have a constant value, as stated by Morris and Bigges 1968 by plotting S_w against Φ in a linear scale and drawing a hyperbola from the minimum water saturation and select the levels that fall on this parabola which represent the irreducible water saturation levels. In other words: (C = Φ. S_{wi}) then equation (44) will be:

$$(\Phi.S_{wi})^n = a.\frac{R_w}{Rt_{rii}} ....(45)$$

Substituting equation (45) in equation (44) yields:

$$\Phi^n.S_{wi}^n = \frac{\Phi^m.Rt}{Rt_{rii}} ....(46)$$

Which yield in to:

$$(S_{wi}^n.Rt_{rii}).\Phi^{n-m} = Rt.....................(47)$$

With logarithm to both sides and rearrangement of equation (47) which yield:

$$\log Rt = \log(S_{wi}^n.Rt_{rii}) + (n-m).\log \Phi...........(48)$$

Equation (48) is a straight line equation on log-log scale with R_t on y-axis and Φ on x-axis, the intercept is (S_{wi}^n. R_{trri}) with a slope of (n-m) usually the importance of this plot to find (n) as (m) is known from Pickett plot. It must be noted that as the derivation of equation (48) depends on irreducible levels so only the levels of irreducible water saturation will plotted on it.

2.2.7.3 Φ_{EPT} Method

The **E**lectromagnetic **P**ropagation **T**ool (**EPT**) measures the propagation time of electromagnetic wave which is differs from water to those of gas and oil, this tool opens up a way to evaluate water saturation that is relatively independent of water resistivity i.e. formation water salinity, so it is most accurate and important in case of high invasion and dissimilarity in formation water salinity, the tool has good accuracy in fresh water (Watfa, 1988). The dielectric constant of the material affects the way in which an electromagnetic wave pass through it are shown in table (2-3) (Schlumberger, 1988).

Table (2-3): Relative dielectric constant and propagation time for common minerals and fluids (Schlumberger, 1988)

No	Mineral	Relative Dielectric Constant	Propagation Time t_{pl} (ns/meter)
1	Sandstone	4.65	7.2
2	Dolomite	6.8	8.7
3	Limestone	7.5 - 9.2	9.1 - 10.2
4	Anhydrite	6.33	8.4
5	Halite	5.6 - 6.35	7.9 - 8.4
6	Gypsum	4.16	6.8
7	Dry Colloids	5.76	8
8	Shale	5 - 25	7.45 - 16.6
9	Oil	2-2.4	4.7 - 5.2
10	Gas	1	3.3
11	Water	56 - 80	25.3
12	Fresh Water	78.3	29.5

The environmental factors that have been affected the EPT tool response are hole size, hole shape, drilling fluid type, mud cake and formation temperature. The most reliable factor which have essential effects on the reading of EPT tool is hole shape (Schlumberger, 1988). The apparent water filled porosity is derived from log reading in a way similar to the derivation of porosity from sonic Δt (Schlumberger, 1988; Watfa, 1988):

$$\Phi_{EPT} = \frac{T_{Pl} - T_{Pma}}{T_{PW} - T_{Pma}} \quad \text{...(49)}$$

Where:-

T_{pL}: Propagation time log reading in nsec/m.

T_{pma}: Matrix Propagation Time for known lithology is used as per table (3)

In case of unknown lithology the T_{pma} can be estimated from CNL and FDC logs by the following procedure (Schlumberger, 1988; Tixire, et AI, 1965):

1- From CNL-FDC cross plot determines porosity Φ_x.

2- Estimate ρ_{ma} (Apparent matrix density) by interpolating between the lithology lines or using Φ_x from step (1) and the bulk density reading from the FDC.

3- $$\rho_{ma} = (\rho_b - \Phi_X \rho_f)/(1 - \Phi_X) \quad \text{......................(50)}$$

Where:-

ρ_b: grain density from log reading.

ρ_F: fluid density.

Φ_x: total porosity from Density – Neutron logs.

4- The T_{pma} is calculated by the following equation (for two minerals):

$$T_{pma} = -3.95\,\rho_{ma} + 19.9 \quad \text{.......... ....(51)}$$

5- When lithology is more complex, two or three –mineral model is used as:

$$T_{pma} = T_{pma\,1} \times V_1 + T_{pma\,2} V_2 + T_{pma\,3} V_3 \quad \text{.......... ......(52)}$$

Where:-

T_{pma}: matrix propagation time.

T_{pma1}: matrix propagation time for mineral (1).

T_{pma2}: matrix propagation time for mineral (2).

T_{pma3}: matrix propagation time for mineral (3).

V1, V2 and V3: Fractions of matrix of mineral (1, 2, 3) respectively.

t_{pw}: Propagation Time of Water, which is calculated by the following equation:

$$T_{pw} = 20\left[\frac{710 - F^{\circ}/3}{444 - F^{\circ}/3}\right] \quad \text{.......... ....(53)}$$

Where: F^0 is formation temperature in Fahrenheit.

Schlumberger used EPT log to interpret log response for variable cementation factor(*m*) calculation(Tabibi and Emadi,2003). The following expression introduced to calculate cementation factor (m_{EPT}):

$$m_{EPT} = \frac{LogRt_{EPT} - LogRxo_{EPT}}{Log(\phi Sxo)_{EPT}} \quad \text{...(54)}$$

Where: $Rt_{EPT} =$ total resistivity from EPT log, $Rxo_{EPT} =$ flushed zone resistivity from EPT log, $Sxo_{EPT} =$ water saturation in flushed zone from EPT log.

The cementation factor(*m*) results obtained from logs in the(hydrocarbon-bearing zone) in carbonate reservoir have been achieved with the EPT log. This tool provides a saturation value in the flushed zone from the electrical logs. The investigation depth of this tool is very shallow. As a result, the vertical resolution from EPT is very good. The porosity value ϕ obtained from porosity tools (which are required for the calculation of *m*). With (S_{XO}) from the EPT (corrected for salinity effects), Rxo from a resistivity tool, and the effective resistivity of the water in the flushed zone (derived from R_{mf} with correction for mixing with formation water), cementation factor *(m) can* be calculated from the Archie's equation (Focke and Munn, 1987).:

$$S_{XO}{}^{n} = \frac{R_{mfe}}{\phi^m R_{XO}} \quad \text{...................................(55)}$$

2.2.7.4 Level by Level Method

Gomez (1977 and 1978) was the first researcher who presented a method to calculate (*m*) and (a) for each level, he proved the intendancy of (a) with (*m*) and their strong relationship to texture of formation, so they can be used as a permeability index. Also he was the first one who stated the importance to calculate (a) for each level and change its name to Tortuosity factor. By applying the Simandoux equation to the mud filtrate in flushed zone Formation Factor (F) can be obtained:

$$F = \left[\frac{R_{xo}}{R_{mf}} \cdot \frac{(R_{xo})_{Clay}}{R_{Clay} - (V_{Clay} - S_{xo})}\right] . S_{xo} \text{..........................(56)}$$

Where:-

$S_{xo} = \{1\text{-}0.5(1\text{-}S_w)\}$.

$(R_{xo})_{clay}$: Obtained from MSFL log in shale zone

R_{clay}: Obtained from ILD log in shale zone

Sw: Obtained by the same Simandoux equation in version zone.

$$S_W = \left[-\frac{V_{Clay}}{R_{Clay}} + \sqrt{\frac{V_{Clay}}{R_{Clay}} + \frac{4}{F.Rt.R_w}}\right] . \frac{F.R_w}{2} \text{....................(57)}$$

By using the computed value of F and Φ from logs; (a) and (*m*) are determined by the following equation:

$$\log a = \left[\frac{(A \log \Phi_x + \log F)}{(1 - B \log \Phi_x)}\right] \text{..(58)}$$

$$m = \frac{\log a}{\log \Phi_x} \text{..(59)}$$

Where:-

A: Equal to 1.8 for sand and 2.03 for carbonate.

B: Equal to 1.29 for sand 0.9 and for carbonate.

The flow chart (refer to Appendix, B-4) describes the iteration process for Gomez method.

2.2.8 Permeability Determination from Well Logs

Permeability cannot be obtained directly from well logs. The conventional method is used to correlate core permeability and porosity measurements and to use the resulting porosity-permeability transform to calculate the permeability from porosity logs. This method too often averages out the robust permeability variations that are characteristic of carbonate reservoirs (Lucia, 2007).

Sutton E.W. in 1961, studied the capability of using electrical and sonic logs in the Delaware sand in the Ford and Geraldine field as formation evaluation tools, where permeability can be estimated in this field from the sonic velocity logs. This is primarily a result of the rather good correlation which exists between porosity and permeability. Because of this, Sutton suggested that the permeability could also be estimated from the microlaterolog. In some zones, permeability is controlled by the amount of shale presence.

Timur A. in 1968, Investigated the relationships between permeability, porosity and residual water saturation in a three different oil field. He tested several relations for k, *Φ* & Sw_i, by statistical technique to find the standard error of estimate and correlation coefficient for each field, and then for all fields. He found the best estimation of permeability through the empirical equation:

$$K = 0.136 \frac{\Phi^{4.4}}{Sw_i^{\,2}} \text{.......................(60)}$$

The equation is applicable for a clean consolidated sandstone formation with a medium porosity in an oil-bearing reservoir.

Rodrignez & Pirson in1968, showed the advantages of the continuous dipmeter as a tool for studies in directional sedimentation and directional tectonics. They were also noted that the strongest grain orientation is parallel with the direction of maximum permeability in bedding planes. Rodrignez and Pirson attacked across their studies to the directional variations of directional resistivity in X-Y plane of sedimentary rock, and they concluded that the electrical resistivity should correlate closely with permeability variations as modified Kozeny equation in the following form:

$$K = \frac{10^8}{2R_O / R_w} \frac{\Phi^2}{S_w^{\,2}(1-\Phi)^2} \text{................................(61)}$$

Where, the symbols have been previously defined.

Mohaghegh, et al, 1997, derived correlation to calculate the permeability (*K*) by using well log parameters; gamma ray index (γ), bulk density (ρ_D) and deep induction (I_D), as shown in the following equation:

$$K = 126.5 + 0.0011\gamma - 50.3\rho_D + 0.0625I_D \text{..........(62)}$$

In 1997, Saner, et al estimated permeability from well logs using resistivity and water saturation data. They found correlation related permeability (*K*) and resistivity formation factor (*F*) as follows:

$$LogK = 7.04 - d.19F \text{..(63)}$$

Parra, et *al*, in2001, used digital processing of optical macroscopic (OM); X-ray computed thermograph (CT) images, and the petrography to characterize the pore space of the pore system of vuggy carbonates in south Florida. The results of this analysis provided supporting information to evaluate nuclear magnetic resonance (NMR) well log. The measurements were established empirical equation to extract permeability from (NMR) well logs as follows:

$$K = 1014FZI^2 \frac{\Phi^3}{(1-\Phi)^2} \text{...................................(64)}$$

$$FZI = \left[\frac{0.01(1 - \frac{BVI}{\Phi})}{1 + 1.05(\frac{BVI}{\Phi} - 1)} \right]^{0.337} \quad ....(65)$$

FZI, is the flow zone indicator, BVI is bound fluid volume.

2.3 Calculation of Elastic Rock Properties from Well Logs Data.

Computation of compressional wave velocity (V_P) and shear wave velocity (V_S) requires for determination of the dynamic elastic properties. Dynamic elastic properties can be obtained if the compression transit time (Δt_p) and corrected bulk density values are available (Lee, 1989).

$$\Delta t_p = \phi(\Delta t_f - \Delta t_m) + \Delta t_m \text{..................}(66)$$

$$\Delta t_S = \phi(\Delta t_f - \Delta t_m) + \Delta t_m \text{....................}(67)$$

Where: Φ is porosity from sonic log Δt_p is compressional transit time, Δt_S is shear wave transit time, $\Delta t_f = 189 \mu s/ft$ For fluid, $\Delta t_m = 47.6 \mu s/ft$ for carbonate matrix.

The compressional velocity and shear wave velocity calculates by the following equation (Tixier, et al, 1980; Wafa and Al-Ameri, 2012):

$$V_p = \frac{10^6}{\Delta t_p} \text{......................................}(68)$$

$$V_S = \frac{10^6}{\Delta t_S} \text{.......... ....}(69)$$

Bulk modulus (K_m) and Young's modulus (E) are then computed from the V_P, V_S and formation density (ρ). (Shlemberger, 2008; Yu, and Smith, 2011).

$$K_m = \rho V_p^2 - 4/3.\rho.V_s^2 \text{.....................}(70)$$

$$E = 3K_m(1 - 2\upsilon) \text{.......................................}(71)$$

Where υ is Poisson's ratio

$$\upsilon = \frac{\left[(V_p / V_s)^2 - 2 \right]}{2\left[(V_p / V_s)^2 - 1 \right]} \text{.........................}(72)$$

Bulk modulus is a measure of material's resistance to change in volume. When porosity increase in the rock that lead to decrease the rock's resistance to change in volume and thus decrease its bulk modulus. This makes the bulk modulus a good porosity indicator especially in stiffer rocks like carbonates. Whereas bulk modulus refers to incompressibility, Young's modulus or the stiffness modulus is a measure of the stiffness of a material. Again if the porosity of rock increase, the stiffness will decrease and thus lower its Young's modulus (Yu, J, and Smith, 2011).

The Biot constant(α) is a complex function of porosity, Permeability, clay content, grain to grain contact, grain strong and overburden and confining pressure (Schlemberger, 1989). The Biot constant can be expressed as follows (Kumer and Scott, 2001).

$$\alpha = \frac{\upsilon}{1 - \upsilon} \text{...........................}(73)$$

2.4 Overburden Pressure Calculation

At a given depth, the overburden pressure is the pressure exerted by the cumulative weight of the overlying sediments. The cumulative weight of the overlying rocks is a function of the bulk density, the combined weight of the matrix and formation fluids contained within the pore space. Overburden increases with depth, as bulk density increases and porosity decreases. With increasing depth, cumulative weight and compact, fluids are squeezed out from the pore spaces, so that matrix increases in relation to pore fluids. This leads to a proportional decrease in porosity as compaction and bulk density increase with depth. An average value of 2.31 gm/cc can be assumed to be a reasonable average value of bulk density at depth(approximating to an overburden gradient of 1.0 psi/ft), but more accurate determinations should be made when more accurate measurements or data becomes available (Haweker, 2001).The overburden pressure calculated by using the following relationship (Respol Company, 2008):

$$P_O = Z.(P_V - \alpha.P_P) \text{.........................}(74)$$

Where:

Po= Overburden Pressure, α= Biot Constant, P_P= Pore Pressure,

P_v= vertical pressure=d_V. ρ_b. g, d_V= vertical depth, g= gravity acceleration,

ρ_b=bulk density, Z=(1+υ/3(1-υ)). υ= Poisson's ratio

2.5 Calculation of Original Oil in Place by Volumetric Method

Reserves estimation is one of the most essential tasks in the petroleum industry. It is the process by which the economically recoverable hydrocarbons in a field, area, or region is evaluated quantitatively (Demirmen, 2007).

The volumetric method is probably the easiest method one can use to estimate the reserves. This method requires a limited amount of information, and can be used even in the absence of the actual drilling of a well. Obviously, if data can be collected from a well, the volumetric estimates will be subject to much less uncertainty than if no well data were available. In the absence of a drilled well, most of the parameters are estimated by analogy, i.e., data based on geological and geophysical inferences based on nearby wells. The following equation is used to estimate oil in place in the volumetric method (Bessiuoni, 1994).

$$N = \frac{7758A}{B_{Oi}} \sum_{i=1}^{n} h_i \Phi_i (1 - S_{wi}) \ldots\ldots\ldots\ldots\ldots\ldots(75)$$

Where:

N=Oil in place (STB), A= Derange area(acres), h_i= Individual zone thickness(Ft),ϕ_i=Porosity

B_{Oi}= Initial formation volume factor (RB/STB), S_{wi}= Water saturation for each individual zone.

Reserves are defined by;

$$R = N.E_r \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(76)$$

$$E_r = 1 - \frac{1 - S_w - S_g}{1 - S_w} \left(\frac{B_{Oi}}{B_O} \right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(77)$$

where; E_r= Recovery Factor, B_O=Formation volume factor(RB/STB), and S_g= Gas saturation.

The choice of methodology depends on development and production maturity, degree of reservoir heterogeneity, and the type, quality, and amount of data. The flow chart for well logs interpretation, when the well logs data are available is listed (refer to Appendix, B-5).

2.6 Cementation Factor (*m*) relations with (F) and (ф)

There are many correlations related cementation factor with porosity, Archie in 1942, from laboratory experiment established a relationship between formation resistivity factor and porosity, which the regression constant is the cementation factor represent to the slope (m) of a log-log plot between the formation resistivity factor (F) and porosity (Φ) as shown in equation(38). Winsauer, et al in 1952 were concerned with the effect of the pore geometry and tortuosity on the resistivity of the rock. By taking into account that the resistivity is the response to the fluids contained in the rock pore throats, they introduced the tortuosity factor, *a,* to the Archie formula. Winsauer, et al., found that the best fit in a formation factor versus porosity plot does not go through the lower right corner, as Archie's equation would indicate, but intercepts the abscissa at values of porosity less than 100% as shown in equation (3).

Wylie and Rose in 1950 introduced a sequence of equations and general explanations to find correlation related *m* and porosity. The resistivity of the saturation fluid(Rw)*,* and the resistivity of the saturated medium,(Ro), can be related by:

$$R_O = \frac{L}{A_C} = R_W \frac{L_e}{\phi A_C} \ldots\ldots\ldots\ldots\ldots\ldots(78)$$

Then,

$$R_w = R_O \frac{L_e / L}{\phi} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(79)$$

Where,Ac is the total cross sectional area of the Core, Le is the length of the conducting channel and L is the actual length of the core. However, by definition:

$$F = \frac{R_O}{R_W} = \frac{L_e / L}{\phi} = \frac{a^{0.5}}{\phi} \ldots\ldots\ldots\ldots\ldots(80)$$

Where, $a = \left(L_e / L \right)^2$ =*Tortuosity*. Combining Equation (3) and equation(74):

$$m = \frac{Ln\left(\phi / a^{0.5} \right)}{Ln\phi} \ldots\ldots\ldots\ldots\ldots\ldots\ldots(81)$$

Equation (68) indicates that the cementation exponent depends on the tortuosity which is a measure of the enlargement, constriction and intermeshing of the pore channels. This tortuosity is an implicit measure of the pore-size distribution.

In 1987 A. M. Borai, introduced a new correlation for the cementation factor (*m*) has been developed to cover the full range of porosities encountered offshore Abu Dhabi.

$$m = 2.2 - 0.035/(\phi + 0.042) \ldots\ldots\ldots\ldots\ldots\ldots(82)$$

Use of this new relationship of cementation factor(*m)* has significantly reduced calculated water saturations in low-porosity carbonate reservoirs and eliminated the conflict between log and test results.

In 1987, Focke and Munn, found in heterogeneous carbonate reservoirs the cementation factor, *m*, is a major factor of uncertainty in the calculation of hydrocarbon-water saturation. The following trends are given for the limestone cores and for permeability values:

$m = 1.2 + 0.1286\phi \ldots\ldots\ldots\ldots(77)$ For K< 0.1 md

$m = 1.4 + 0.0857\Phi \ldots\ldots\ldots\ldots(84)$ For K=0.1 to 1 md

$m = 1.2 + 0.0829\Phi \ldots\ldots\ldots\ldots(85)$ For K=1 to 100 md

$m = 1.22 + 0.034\Phi \ldots\ldots\ldots\ldots(86)$ For K> 100 md

Maute in 1992, presented a data-analysis approach to find Archie's parameters (*m* and *n)* from standard resistivity measurements on core samples. The Core Archie-parameter Estimation (CAPE) method finds *(m)* and (n) by decreasing the error between computed and measured water saturations (S_W). The CAPE technique provides a natural physically meaningful method of "averaging" Archie's parameters, and with an error statistic, aids in reservoir into different sets of Archie's parameters. Furthermore researcher showed that the tortuosity factor (a) is a weak-fitting parameter, with no physical significance.

Vera and Daniel, in 1996 had shown that the values of the (*m*) and (*n*) exponents are largely affected by reservoir pressure and temperature conditions, mineralogy, pore throat size distribution, pore geometry, and the wettability condition of the reservoir rock, among other relevant factors. This fact reveals the need to carry out laboratory resistivity measurements in order to obtain representative values of such parameters for a particular reservoir system.

Adisoemarta, et al., in 2000, used the typical form of Archie's relation, but they found differing values for cementation factor (*m*) and tortuosity factor (*a*). The higher value of (*m*) relates to vuggy porosity and the lower value of (*m*) suggests fracture porosity was shown by conventional results. Researchers show the calculated cementation factor(*m*) is related to the flow area contrast between pore throat and pore body.

In 2005, Attia studied the effects of petrophysical rock properties on the Archie's equation parameters. Results showed that the tortuosity factor is not a constant value, but it varies largely according to many parameters such as porosity, cementation factor and formation resistivity factor. Researcher introduced empirical correlation between the tortuosity factor (a) and cementation factor (*m*) at5% NaCl for synthetic cores also he found an empirical correlation between formation resistivity factor (F) and tortuosity factor (a) in the same conditions as shown in the following equations:

$$a = 0.9m^{1.33} \ldots\ldots\ldots\ldots\ldots\ldots(87)$$

$$a = 0.087F^{0.16} \ldots\ldots\ldots\ldots\ldots\ldots(88)$$

The values of Archie's exponents (*m* and n) play a significant role in formation evaluation. Conventionally, values are assumed to be *m* = n = 2. Significant scatter in laboratory measured data for (*m*) and (n) have been noted and this is usually attributed to rock heterogeneity, the complicated pore structure in complex lithology and wettability characteristics at the pore scale. Attempts to provide an understanding of observed resistivity behavior primarily refer to ideal systems which do not exhibit the complexity of reservoir core. 3D imaging and analysis of the pore scale structure within the core material allows one to directly measure the pore structure, tortuosity and the degree of interconnections of the pore systems and the spatial distribution of the fluid phases. This can give insight into the behavior of (*m*) and (n) in realistic pore geometries (Knackstedt, et al, 2007).

Accurate values of the cementation factor *m* are required to calculate water saturation from resistivity logs. The *m* value is a function of the Vug-porosity ratio, which can be estimated using separate-Vug porosity calculated from acoustic logs, and total porosity using the following equation (Lucia, 2007):

$$m = 2.14\left(\frac{\Phi_{sv}}{\Phi_t}\right) + 1.76 \ldots\ldots\ldots\ldots\ldots\ldots(89)$$

Where: Φ_{sv} = separate-Vug porosity, and Φ_t =total porosity.

Masoud et al, in 2008, investigated correlation could estimate the cementation factor in Iranian carbonate reservoir. They found the cementation factor (m) is more dependent to porosity (Φ) as follow:

$$m = \frac{1}{0.36 - 0.08\ln\phi} \ldots\ldots\ldots\ldots\ldots(90)$$

They concluded this relation is depended for porosities lower than 5%, whereas this dependency decreases for porosities higher than 5%. However, in middle east the value of porosity in carbonate reservoirs is generally more than 5%, that lead to decrease for using this correlation.

The uncertainty of saturation calculations was investigated by Masoud Asadollahi, et al, in 2008, in this study the results showed that: Importance of different parameters in saturation determination is case dependent. The best way for primary evaluation of this subject is a comparison of the ratios of each parameter variations to the mean value of that parameter. Both cementation factor and saturation exponent are the most important uncertain parameters in petrophysical studies of a reservoir. To find the most important one, it should be investigated in each case. Since the uncertainty term of m and n are dependent to porosity and water saturation so they could be variable even during the life of a single reservoir.

Hassani and Rahimi in 2008, calculated the cementation exponent (*m*) based on core resistivity analysis data from three formations (Asmari, Ilam and Sarvak) in two different fields, some new correlations for (*m*) have been derived to minimize the error in calculation of water saturation. In the rock type Ooid Grainstone -Packstone them values trends are introduced as:

$$m = \frac{2.48 - 0.048}{\phi + 0.01} \ldots\ldots\ldots\ldots\ldots\ldots(91)$$

However in the dolomitized packstone - wackestone rock the *m* values trends:

$$m = \frac{2.52 - 0.045}{\phi + 0.001} \text{..........................(92)}$$

A modified K–C model is developed in 2011,by Hasan and Enamul, based on an accurate theoretical approach. The modified model incorporates the tortuosity term in a more representative manner. It is shown that the tortuosity term can be approximated accurately using theoretical and experimental approaches based on effective porosity and cementation exponent. The incorporation of the validated tortuosity model into the original K–C model leads to a variable power on the porosity term as a function of cementation exponent(m).

2.7 Cementation Factor(m) Relations with Permeability(K)

There are very few correlations calculated from well log data related cementation factor (m) with permeability (K) in carbonate reservoir. Rose and Bruce in1949 have shown that the tortuosity may be expressed as:

$$a = \left(\frac{\phi}{Kt_S}\right)\left(\frac{\sigma}{P_d}\right) \text{..............................(93)}$$

Where σ and P_d are the interfacial tension and the displacement pressure respectively, and t_S is the pore shape factor, K= permeability. The combined Equation (87) with equation (75) by Wyllie and Rose in 1949, and found the following correlation to calculate m:

$$m = \frac{\ln\left(\Phi.Kt_s.Pd/\sigma\right)^{0.5}}{\ln\Phi} \text{..................(94)}$$

Wylie & Rose in1950 discussed some theories about quantitative evaluation of the physical characteristics of reservoir rocks. They have expanded an empirical proposed by Tixier in1949 showed that the order of magnitude of formation permeability may be obtained from the relationship:

$$K = C\left(\frac{1}{P_c^{\,2} F^{\left(2-\frac{1}{m}\right)} S_W}\right) \text{.......................(95)}$$

Where: m=cementation factor, Pc=capillary pressure (psi), C= Constant=21.2*δ^2/ts

δ=interfacial tension dyn/cm^2 and ts=constant (2-2.5)

If Pc is unobtainable (i.e., in the absence of an oil-water contact in the reservoir), Wyllie & Rose in 1950, suggested another correlation between irreducible water saturation, permeability and formation factor, which is**:**

$$k^{\frac{1}{2}} = c\,\frac{\phi^3}{Swi} \text{....................................(96)}$$

Where: c is a constant equal 250 for oil bearing, and 79 for gas.

Coates & Dumanoir in 1973, developed an approach to improve log derived-permeability. The permeability index was derived as a function of porosity, formation resistivity at irreducible water saturation (Rt_{irr}), hydrocarbon density (□□) and rock type (w) depending on cementation factor. The basic relationships:

$$K = \left[\frac{C.\Phi^{2w}}{w^4.Rw/Rt_{irr}}\right]^2 \text{.........................(97)}$$

Where:

$$C = 23 + 465\rho h - 188\rho h^2$$

$$w^2 = 3.75 - \Phi + \frac{(\log(Rw/Rt_{irr}))^2}{2}$$

The textural parameter (w) is the exponent in the equation that relates bulk volume of water (Φ. S_{wi}) to the resistivity ratio (R_w/R_{tirr}) assuming that m and n are equal:

$$Sw_i^{\,n} = \frac{F.R_w}{Rt_{irr}} \text{...(98)}$$

But, $F = \dfrac{1}{\phi^m}$ then,

$$Sw_i^{\,n}.\Phi^m = \frac{Rw}{Rt_{irr}} \text{...(99)}$$

Let n=m, so

$$(Sw_i.\Phi)^m = \frac{Rw}{Rt_{irr}} \text{..(100)}$$

Thus,

$$m = \frac{\log(Rw/Rt_{irr})}{\log(Sw_i.\Phi)} \text{.......................................(101)}$$

Then,

$$w^2 = 3.75 - \Phi + \frac{\sqrt{m\log(sw_i\Phi)}}{2} \text{...................(102)}$$

Clemenceau in 1977, introduced a paper about the variation of cementation exponent (m) with permeability, and studied the previous relations of porosity and formation (F), and the influence of cementation exponent variation. His laboratory work covered most of the physical characteristics including porosity, permeability, formation resistivity factor, tortuosity, cross sectional area index, and packing index. He concluded that the linear relation of the formation factor and porosity with a constant cementation exponent has certain application. Clemenceau proposed an equation to derive the variable cementation exponent (m) from the permeability value:

$$m = 1.28 + \frac{2}{2 + \log K} \ldots\ldots\ldots\ldots\ldots\ldots(103)$$

Gomez in 1977 discussed some considerations for the possible use of the parameter (a) and (m) as a formation evaluation tool through well logs, his conclusion that computed (a) and (m) from well logs can be used for detecting permeable zones, as follows:

$$K = \frac{\Phi^m}{a.Sw_i^{\,2}}\left(\frac{\Phi}{1-\Phi}\right)^2 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(104)$$

Where, the above parameters had previously defined.

The cementation factor (m), sometimes referred as cementation exponent or (porosity exponent), has been the subject of many researchers, trying to find its best value and to define its actual physical meaning. Several relationships are proposed in the literature to estimate permeability when the effective pore radius (RP), and cementation factor (m) are known. An improved rock permeability relationship was proposed in the following relation (Hagiwara, 1984):

$$K = C.\Phi^m.Rp^2 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(105)$$

Median effective pore-throat radius data exist to better define the constant *C*, having a value of 32.65, therefore the equation becomes:

$$K = 32.65\Phi^m Rp^2 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(106)$$

In 1995 Balan, et al, introduced three different approaches for permeability determination from a heterogeneous reservoir well logs data. These are empirical, statistical, and the "virtual measurement" methods. They used multiple variable regression, and artificial neural networks respectively to determined empirical models. The results from applied methods are compared with core permeability, which is considered to be the standard formation. In this first stage of this study present only the model development phase in which they are testing the capability of each method to match the presented data. Based on this, the best two methods are to be analyzed in terms of prediction performance in the second stage.

Examination of the data shows a decrease in porosity and permeability with an increase in overburden pressure. A correlation between porosity and overburden pressure and also between permeability and overburden pressure has been developed using linear regression analysis. Both correlations are Found to be logarithmic. The irreducible water saturation and residual oil saturation increase with increased overburden pressure levels. While the relative permeability to oil decreases with increasing overburden pressure, a corresponding negligible decrease in water relative permeability was observed by Ali, et al., in 1997.

An analytical method has been presented by Arash in 2011, in order to estimate the permeability of the near well-bore area by using the depth of filtrate invasion in an over balanced drilling procedure. Knowing the drilling mud specifications leads to estimate the filtrate permeability in the reservoir layers in the presence of residual oil saturation. At the first step, a modeling of mud cake flow resistance has been presented based on the concept of hydraulic radius. For a specified water based mud, cake flow resistance and rate of filtrate invasion change versus variation of invasion depth. Consequently by knowing the invasion depth and drill mud specification, rate of invasion can be estimated. It has been proved that rate of invasion is related to formation permeability. In the present study, this relation has been modeled in order to estimate the permeability of oil formation layers in an arbitrary radial flow system.

2.8 Cementation Factor (*m*) Relations with Acoustic Velocity

Although, there are very few studies related velocities (V_P and V_S) and cementation factor (m), several relationships between these parameters have been established by some researchers. A relationship of cementation factor (m) with the compressional velocity (Vp) and shear wave velocity (Vs) was proposed by Hugh in 1981. He showed that the increase in the shear velocity (Vs) is due to the increase of the strength of the rock of the cement. The trend of the plotting of the cementation factor values (*m)* and the compressional- shear velocity was a near horizontal. This plot showed the relationship between (*m)* versus the ratio of (Vp/Vs) is independent of increases in porosity value that indicate there is a direct relationship between *m* and the (Vp/Vs) ratio.

Susan in 1992 illustrated that Relationships between elastic velocities and rock properties in carbonates are very complex. The dissimilarity among results from the literature suggests that it is useful to investigate formations of interest individually. This study depended on well log data from three Paleozoic carbonate formations in Alberta in Canada: the Pekisko, Wabamun and Leduc. In the Leduc formation the compressional velocity (Vp) and Share wave velocity (Vs) were inversely correlated with porosity. Vp was less sensitive to porosity and showed more scatter than Vs. In the Pekisko limestone, with increased porosity there was a slight decrease in Vp, but no apparent response in Vs. In the Wabamun, velocity-porosity correlations were weak; however the very low porosities in this formation may limit the utility of this observation. The ratio (Vp/Vs) did not appear to be correlated to porosity in any of the formations.

Héctor, et al. in 2007,explained the velocity of compression and shears waves are related with the porosity of the matrix in the oil saturated carbonate rocks,as shown in the following correlations:

$$V_p = 6.6248 - 10.348\Phi_m \text{........................(107)}$$

$$V_s = 3.3378 - 5.3726\Phi_m \text{........................(108)}$$

They also found correlations between sonic speeds with formation factor:

$$V_p = 3.2602F_m^{0.0823} \text{..............................(109)}$$

$$V_s = 1.7812F_m^{0.0852} \text{..............................(110)}$$

Where:

$F_m = \dfrac{a}{\Phi_m^{\ m}}$, V_p = speed of compression in (Km/s), V_s = speed of shears in (Km/s),

Φ_m = matrix porosity,. in fraction, F_m = Factor of the resistivity of formation, m=cementation factor.

CHAPTER 3

3. Methodology:

A continuous profile of petrophysical and elastic rock properties were calculated for the carbonate reservoir intervals (Mishrif and Yamama Formations) through the application of practical and modern software's. This method is based on the following subsequent and consequent steps as shown in the diagram in the Figure (3-1).

3.1 Field Selection

The first stage of this study, is selected the NS oil field as one of the Middle East oil fields. In this field there are two sets of open hole logs for different depths provided by Schlumberger Company, the first one from 1924m to 2532m and the other one from 2528m to 3430m. The first set is passed through the most important carbonate reservoir in Nasiriya field (Mishrif) and the second is run basically to evaluate the formations from Shaaiba to Sulaiy and the second carbonate reservoir (Yammama) (refer to Appendex,B-1). The basic logs interpretation also includes determination of true total porosity and true resistivity for all field formations, estimation of formation water and mud filtrate resistivity. Geographical location map for a selected field explains the location of this field in the Middle East (refer to Appendix, C-1).

3.2 Wells Selection:

NS-1, 2, 3, 4 and NS- 5 are selected wells, to collect logs and core data.NS-3 is selected well, to collect the most useful data which are logging data, drilling data, completion data, testing data, Computer Processed Interpretation(CPI) and flowing data. All selected wells are production and distributed to cover different areas from the NS oilfield,therefore there are a high realability in the data of these fields (refer to Appendix, C-2 and C-3).

3.3 Digitizing Logging Data

Neura-Log (NL) is the most widely-used log digitizing solution in the oil and gas industry. Neura-Log's automated tracing streamlines data workflow, enhancing productivity by obtaining reliable information for time-critical projects.. As a firstly the available logs are scanned and converted to soft copy, after that the Neura-Log software V 2008.5 should use to digitize the scanned copies of logs for studied wells so the results are LAS files, which will loaded to the Interactive Petrophysics software(IP), then the reading measurements taken as one reading per 0.1524 meter. The main page of the NL software shows the options that use to digitalize log sheets (refer to Appendix, C-4).

3.4 Depth Matching

In this study the available logs are Deep Induction Laterolog (DIL), Micro Spherical Focused Log (MSFL), Spherical Focused Log (SFL), Bulk Density (ROHB), Neutron Log (NPHI), Sonic Log (DT), Calliper Log (CAL), Spontaneous Log (SP) and Gamma Ray Log (GR). The log curves are checked to be in depth with each other. The tension curve can be used to identify possible zones where the tool string has become temporarily stuck, which will put the curves off depth and result in "flat lining", (Toby Darling, 2005). All log curves then depth-matched, the available gamma ray readings taken as a reference guide for depth matching, true corresponding between gamma ray readings and other logging tools was clear at formations tops.

3.5 Environmental Corrections

Environmental corrections were made using the current Schlumberger charts (SLB, 2005), which are supplied to (IP) as the environmental correction module, actual mud properties, calliper log, hydrostatic pressure and temperature gradient were provided to get accurate corrections. The effects of drilling fluids type (FCL-CL) on the well geometry were clear by inducing wash out zones in most formations. Washing effects on the readings of logging tools were eliminated especially on neutron, IP was used and applied per 0.154 m to achieve corrections, which lead to avoid erroneous in water saturation interpretations. By using (SLB, 2005) correction charts the log reading were corrected to actual well conditions, these are Deep Induction Laterolog (DIL). Micro Spherical Focused Log (MSFL), Spherical Focused Log (SFL). Bulk Density (ROHB), Neutron Log (NPHI) and Gamma Ray Log(GR).

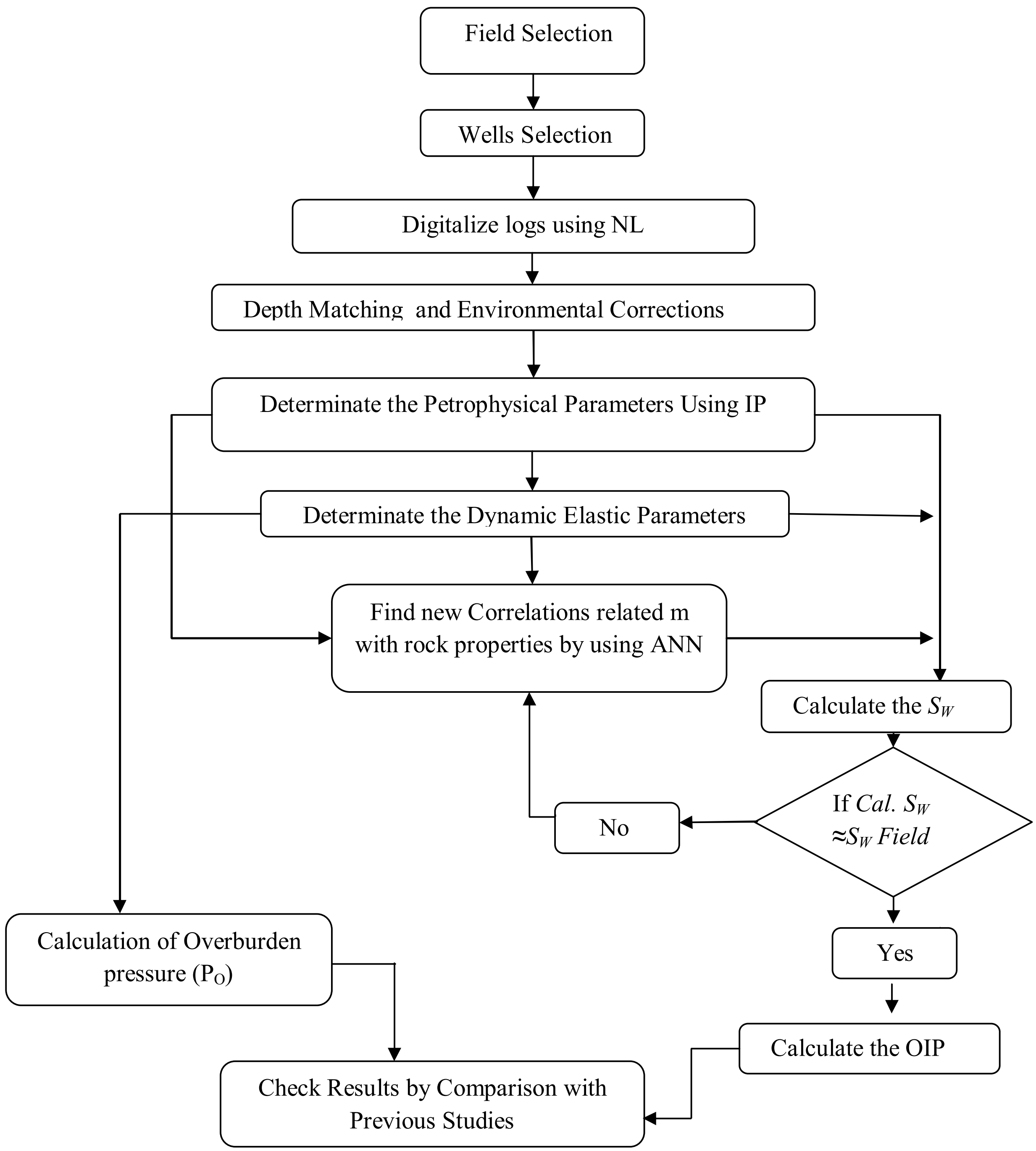

Figure (3- 1): The study methodology diagram

3.6 Determination of Petrophysical Carbonate Reservoir Properties

In this phase, depending on well logs data the Interactive Petrophysics software (IP V3.5, 2008) had been used to calculate the petrophysical reservoir rock properties properties (R_t, R_{xo}, R_w, R_{mf}, Φ, V_{Clay}, *m*, a, n and K=f(Φ)). The IP is the present day computer program that have been used by the geophysicist of Schlumberger (SLB) Company since 1995.The background theory and equations, that used to calculate each parameter are listed in section (2.2). The IP software output shows the results of calculations of these parameters (refer to Appendix, C-5).

3.7 Determination of elastic rock properties

Sonic Log is used to determine the compressional velocity (V_P), shear wave velocity (V_S), and ((V_P) / (V_S) ratio. Then, depending on these values the elastic dynamic rock properties such as Bulk modulus (K_m), Young's Modulus (E), Poisson's Ratio (υ) and Biot's Constant (α), are calculated as shown in the equations in the section (2.3).

3.8 Find New Correlations

From results of petrophysical and elastic carbonate reservoirs in sections (3.3,3.4, 3.5,3.6 and 3.7), and based on statistical basis, this study should developed correlations relating the total effect of the important petrophysical properties such as permeability (*K*), porosity (Φ), Formation resistivity factor (*F*), compressional wave velocity and shear wave velocity ratio, Bulk modulus (K_m), and Biot's Constant with cementation factor, by using Artificial Neural Network regression.

Neural networks are composed of simple elements operating in parallel. These elements are inspired by biological nervous systems. As in nature, the network function is determined largely by the connections between elements. The researcher can train a neural network to perform a particular function by adjusting the values of the connections (weights) between elements. Commonly neural networks are adjusted, or trained, so that a particular input leads to a specific target output. Such a situation can be shown as follows: there, the network is adjusted, based on a comparison of the output and the target, until the network output matches the target. Typically many such input/target pairs are needed to train a network. One type of network sees the nodes as (artificial neurons), these are called ANN. Natural neurons receive signals through synapses located on the dendrites or the membrane of the neuron. When the signals received are strong enough (surpass a certain threshold), the neuron is activated and emits a signal though the axon. This signal might be sent to another synapse, and might activate other neurons (Demuth, et al, 2006). Neural networks have several advantages. Most important is the ability to learn from data and thus potential to generalize, i.e. produce an acceptable output for previously unseen input data (important in prediction tasks). This even holds (to a certain extent) when input series contain low-quality or missing data (Patterson, 1996).

3.9 Calculation of Water Saturation

The IP should calculate (S_W) using four methods (simple Archie equation, Dual Water Model, Modified Simandoux Model and Indonesia Model) as shown in the section (2.2.6), these results should agree with the previous calculations for water saturation. Then the OIP should estimate and compare with previous studies.

3.10 Calculation of oil in place

The water saturation should calculate depending on calculated petrophysical parameters and cementation factor value from correlations, then the oil in place can be estimated by volumetric method. The other parameters provided from NS oil field reports. The method of calculations is shown in the section (2.5).

3.11 Calculation of overburden pressure

Depending on the elastic carbonate reservoir properties, which calculated from well log data, the overburden pressure can be calculated for each carbonate formation. The section (2.4) shows the method of calculations.

CHAPTER 4

Expected Results

1-The NL software output data should use as input data in the IP software. The sample of initial results from Gamma Ray log for Mishrif Formation in the NS-3 well are listed in Appendix (D-1).

2- The IP program should calculate the following petrophysical properties (R_t, R_{xo}, R_w, R_{mf} Di, and Φ) for each formation, which are the most important parameters should use to achieve final results. A sample of initial results for these parameters is shown in Appendix (D-2), and (D-3).

3-Calculate the variable cementation factor (*m*) using Pickett Method (Eqt.41) and Gomez method as shown in the equation (59). This equation should feed to the IP software. The results of variable *m* should use as input data in the ANN.

4- The lithological description for NS oil field should evaluate by litho- crossplot methods. It is confirm the results of previous geological studies about presence of carbonate and clastic- shaly formations; it is also corresponding to the lithological column provided by daily drilling reports, core description and final well report. A sample of initial results for litho-crossplot between PHIN and DT for Mishrif Formation is shown in Appendix (D-4).

5- Irreducible water saturation (S_{wi}) can be determined by plotting water saturation(Calculated from Archie Equation) versus porosity in a linear scale and drawing hyperbola from minimum water saturation and select the levels that fall on this parabola which represent irreducible water saturation levels. The initial application of this method in Mishrif Formation is shown in Appendix (D-6).

6-The IP software calculates permeability (K) depending upon S_{wi} value and Φ value from well logs. The results should agree with core analysis data. The following empirical equation is used to calculate K:

$$K = a.\frac{\Phi^b}{Sw_i^{\ C}}$$

Where a, b, and c are constants, could find from Schlumberger (Chart K3)

7- The ANN software should provide accurate correlation between (***m***) and rock properties, because it is ability to learn from data and thus potential to generalize, i.e. produce an acceptable output for previously unseen input data (important in prediction tasks).

8- Four methods (Simple Archie equation, Dual Water Model, Modified Simandoux Model and Indonesia model) will use to calculate water saturation as shown in the section (2.2.6), Which increase the confidence in results that should agree with the previous values of S_W.

9-Determine the overburden pressure using calculated results of Poisson's ratio and Biot's constant gives more reliability in results.

ACTIVITIES/ MONTH	***Feb.- June 22013***	***July- Dec 2013***	***Jan.- June 2014***	***July- Dec. 2014***	***Jan.- June 2015***	***July- Dec. 2015***
Literature reviews	√					
Selection of oilfield and oil wells and data Collection	√					
Transfer the log data to digital (LAS) by using Neuralog(NL) program	√	√	√			
Depth Matching and Environmental Corrections using IP		√	√			
Input digital data (LAS) to the IP software to calculate the petrophysical properties.		√	√			
Using IP software to calculate the Elastic rock properties			√	√		
Using ANN software to find new correlations between *m* and rock properties				√	√	
Calculate S_W				√	√	
Calculate P_O&OIP				√	√	
Check Results					√	√

GANTT CHART

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APPENDIX A

Table (A-2): Lithological column from Kifil FM to Sulaiy FM. NS-3, (INOC, 1985)

No	Formation	Top(m)	Bottom(m)	Main Lithology	Thickness(m)
1	**Kifl**	**1910**	**1929.5**	**Limestone**	**19.5**
2	**Mishrif**	**1929.5**	**2101**	**Limestone-clayey**	**171.5**
3	**Rumaila**	**2101**	**2148**	**Shale & Clay**	**47.0**
5	**Ahmadi**	**2148**	**2251.5**	**Cretaceous-limestone**	**103.5**
6	**Maudud**	**2251.5**	**2412**	**Shale & limestone & sand**	**160.5**
7	**Nahr Umr**	**2412**	**2529.5**	**Dolomite**	**117.5**
8	**Shu'aiba**	**2529.5**	**2592**	**Sandstone & some shale**	**62.5**
9	**Zubair**	**2592**	**3097**	**Limestone-clayey & some shale**	**505**
10	**Ratawi**	**3097**	**3197**	**Limestone**	**80.0**
11	**Yammama**	**3177**	**3403.5**	**Limestone**	**226.5**
12	**Sulaiy**	**3403.5**	**3440.5**	**Limestone**	**17.5**

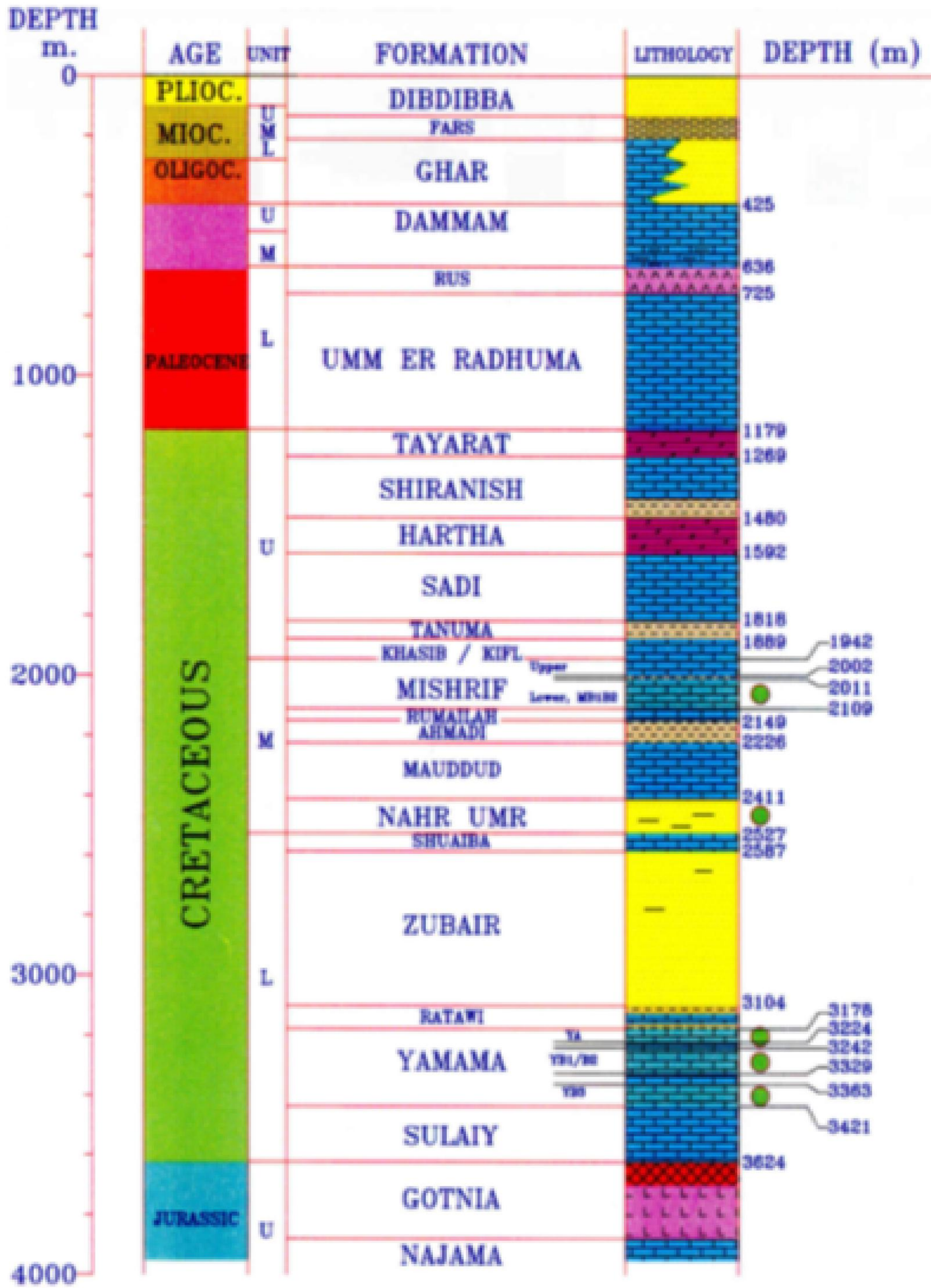

Figure (A-1) Geological age for NS oil field formations (Repsol Company, 2008)

APPENDIX B

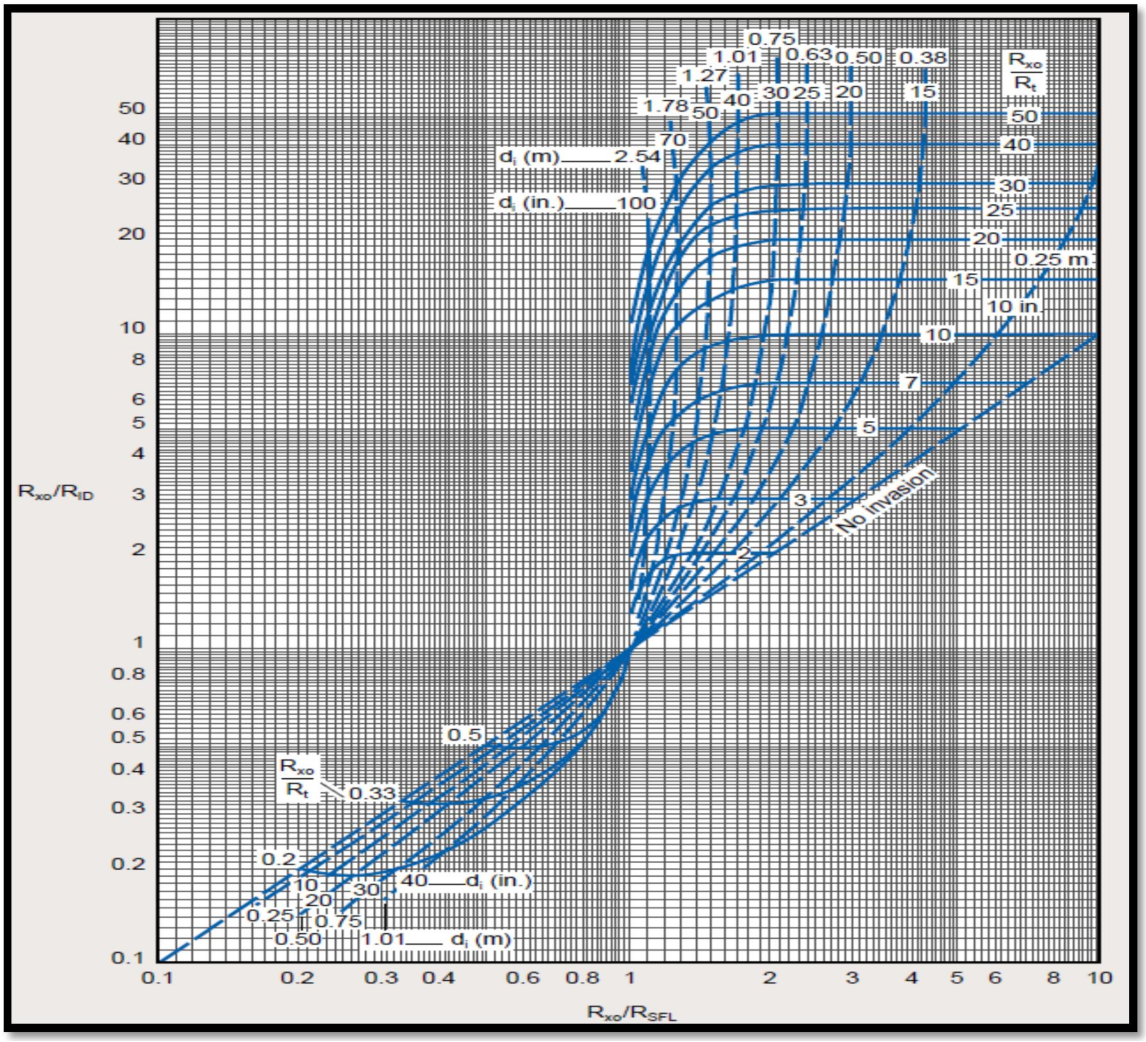

Figure (B- 1): R_t, R_{xo} and d_i chart (Schlemberger, 2005)

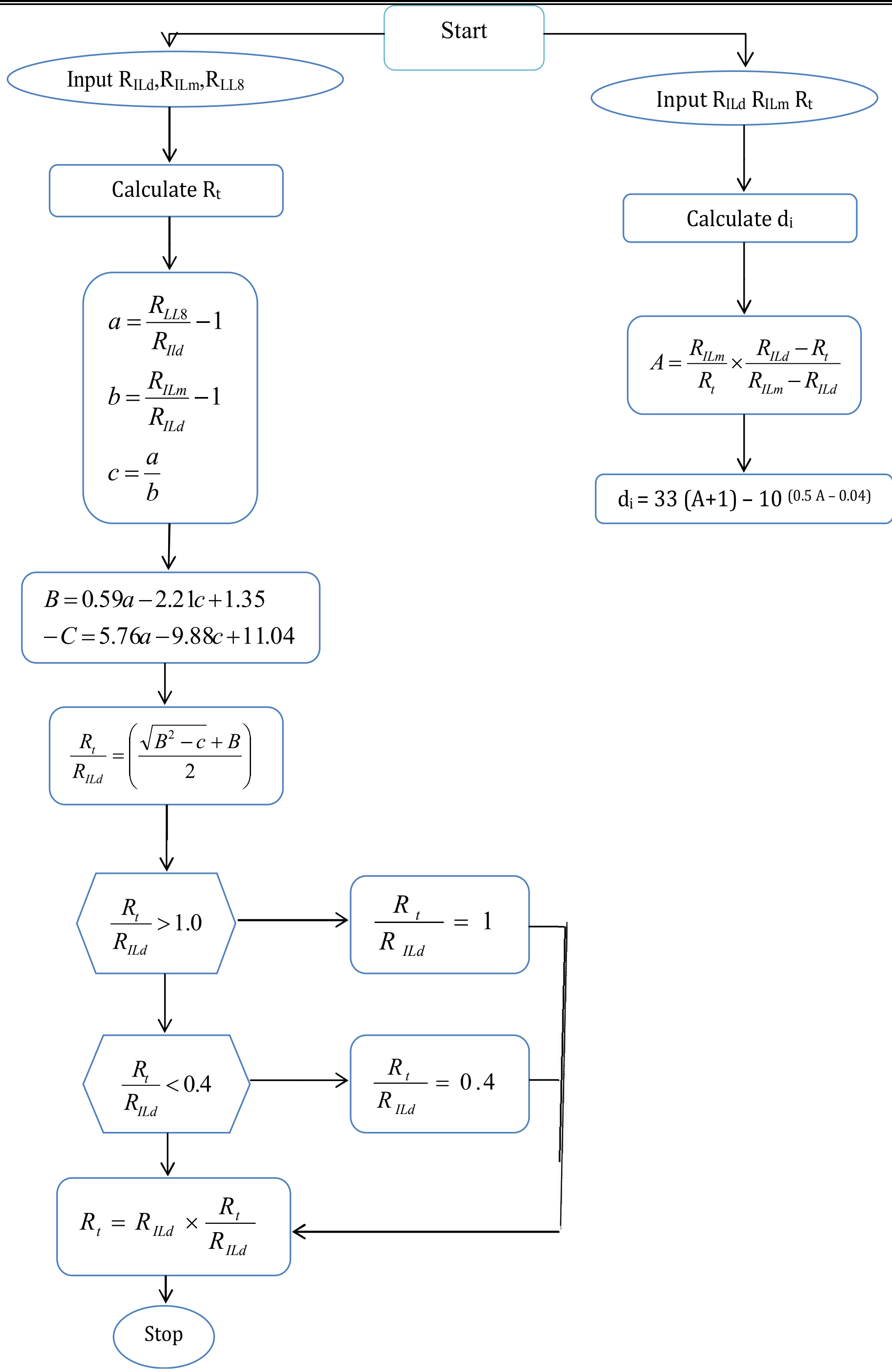

Figure (B -2): R_{XO}, R_t and D_i flow chart(L.F. Quintero,et al,1992)

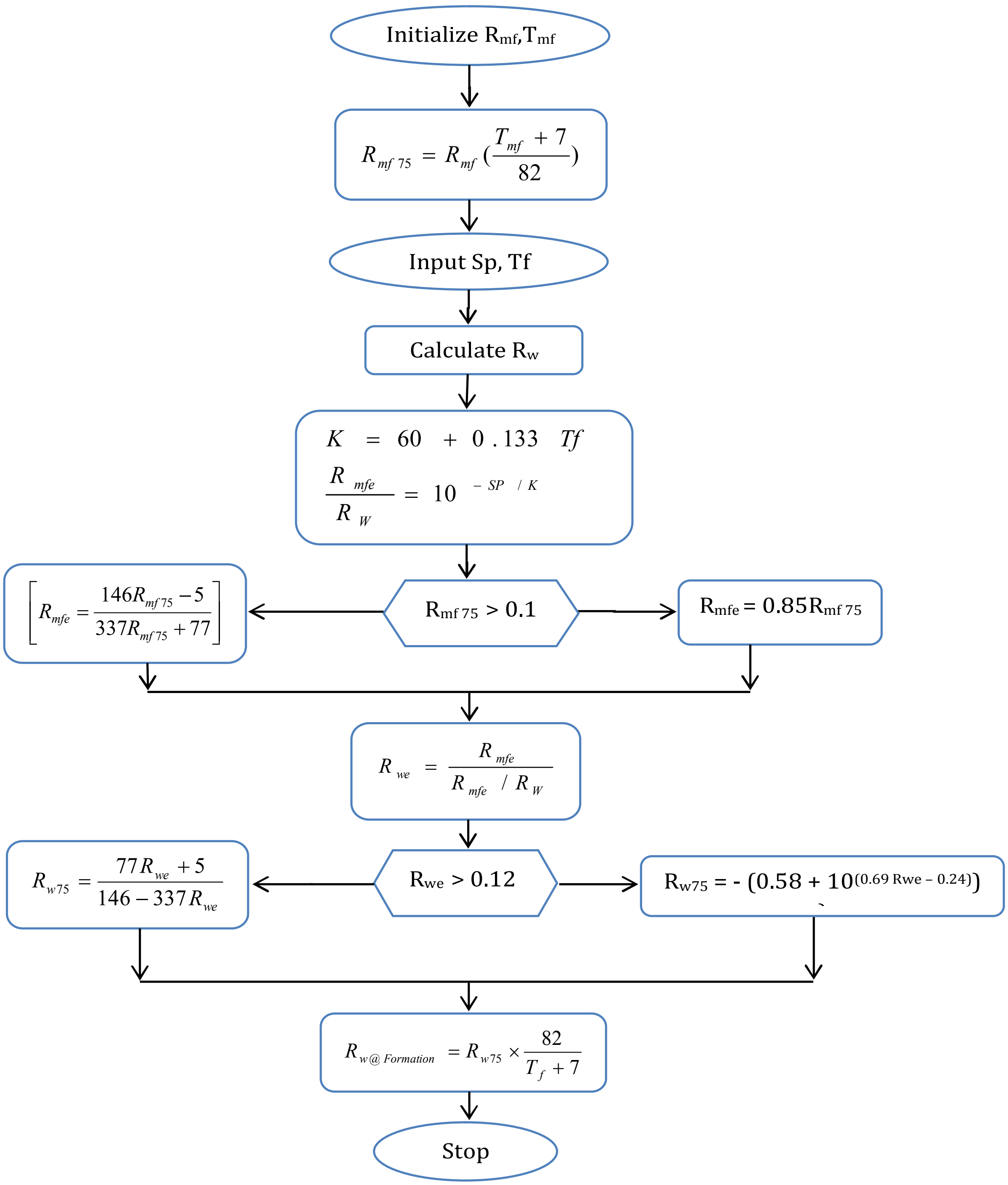

Figure (B 3): R_w Calculation flow chart from Sp (Lee M. Etnyre,1993) & (Antwan M., 1988).

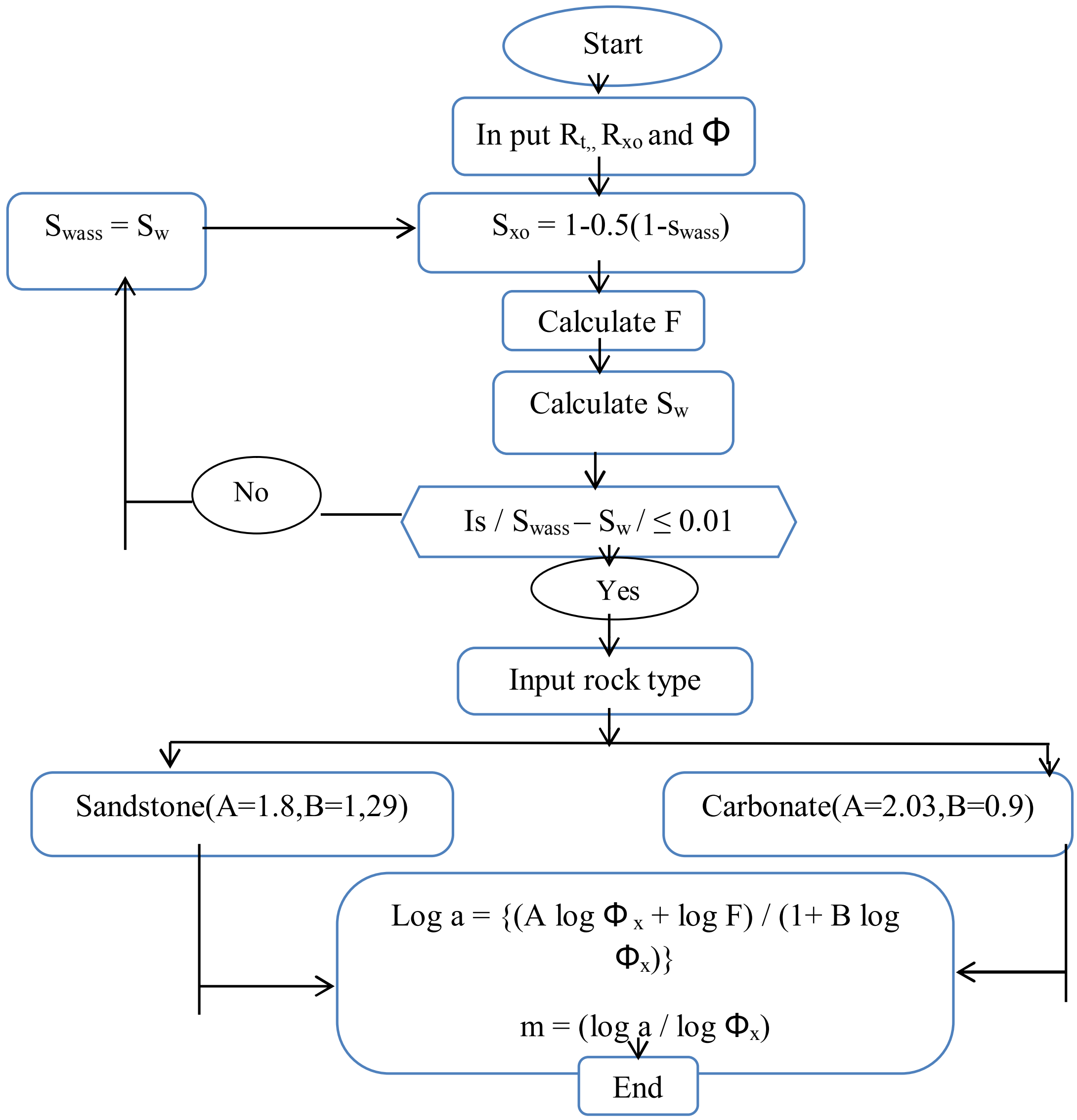

Figure (B-4): Gomez iteration flow chart (Gomes, 1978)

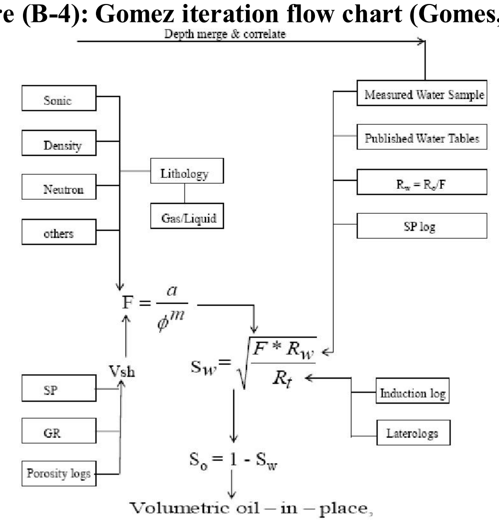

Figure (B-5): Flowchart for well log interpretation to calculate volumetric OIP (Bessiouni, 1994)

APPENDIX C

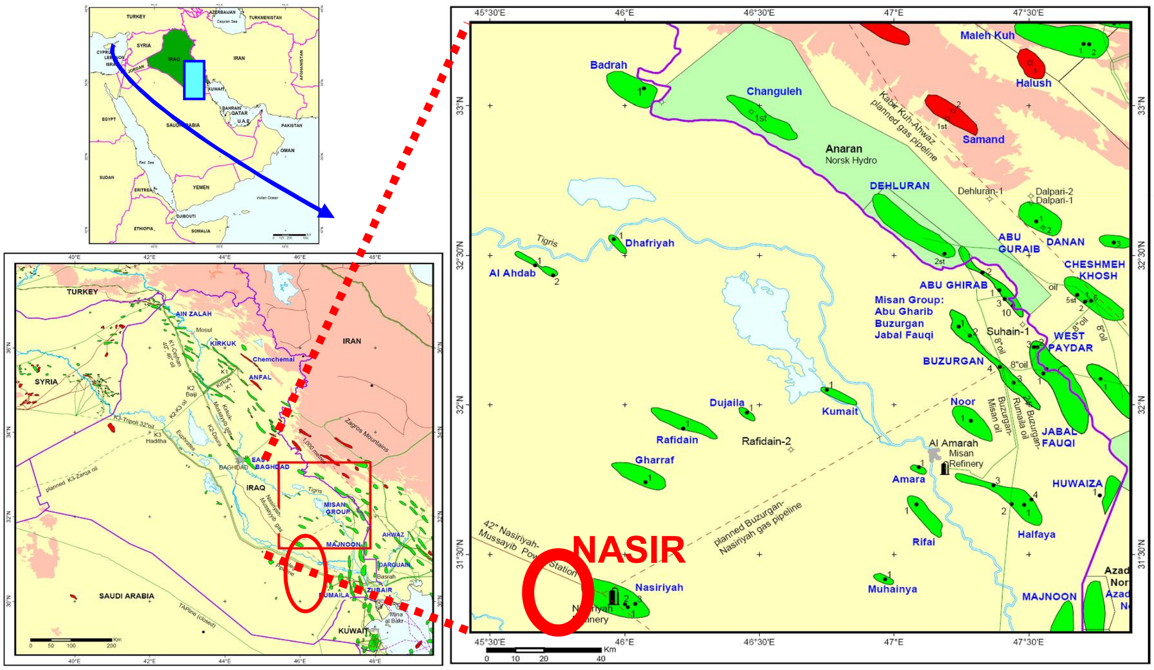

Figure (C-1) Geographical location map for NS-oil field (Repsol Company, 2008)

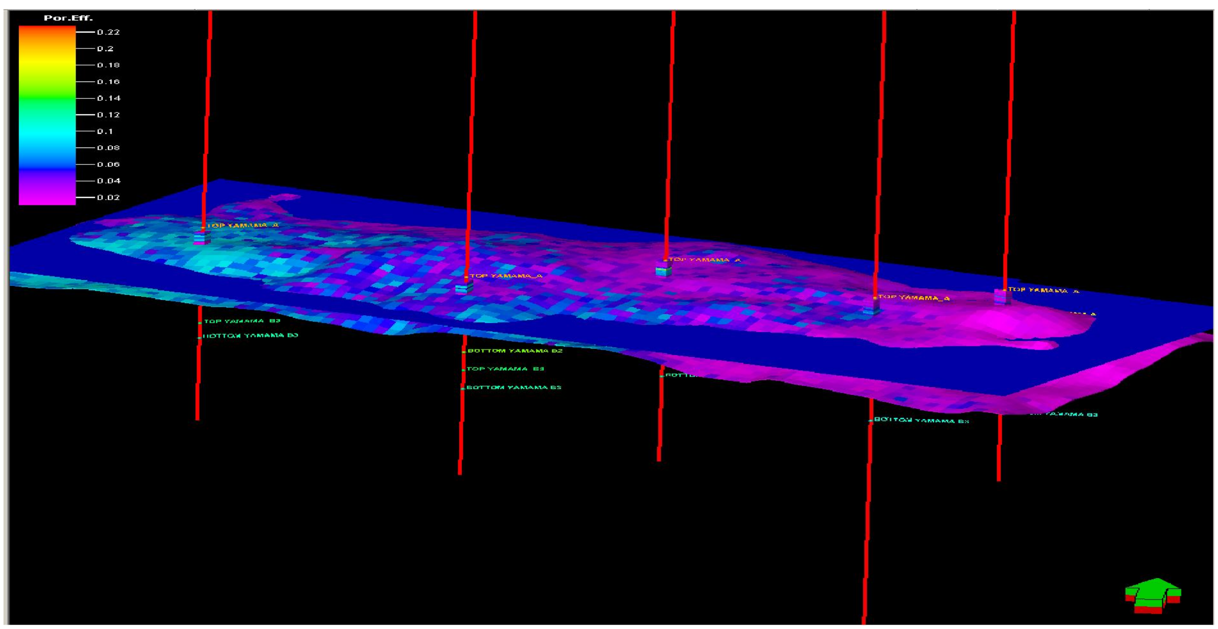

Figure (C-2): 3-D image of the selected wells(Repsol Company,2008).

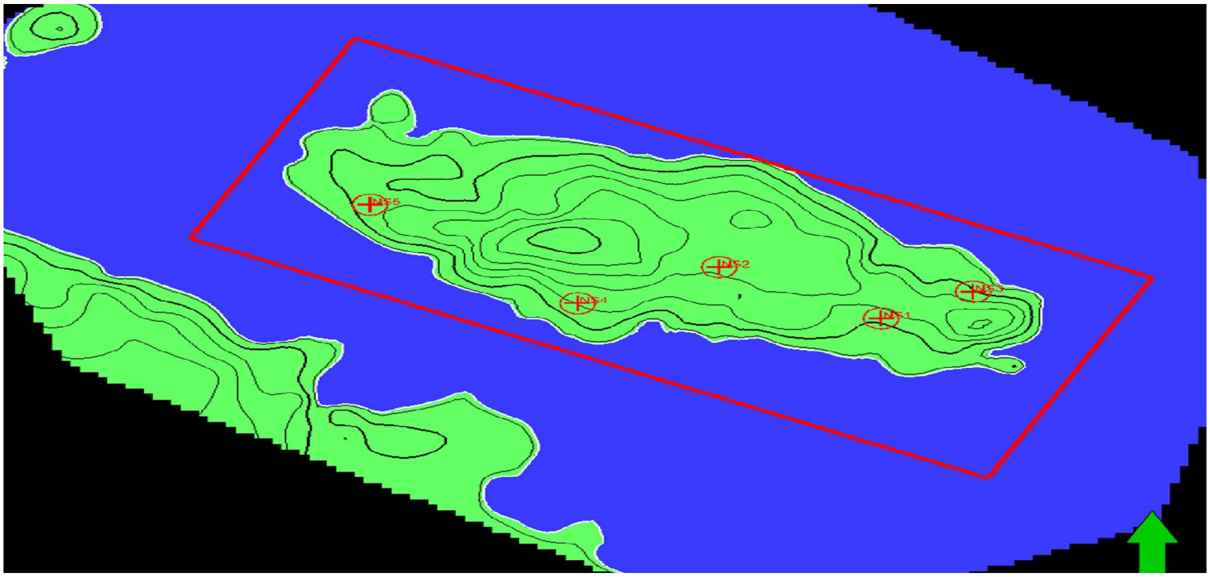

Figure (C-3): Top view of the selected wells(Repsol Company,2008).

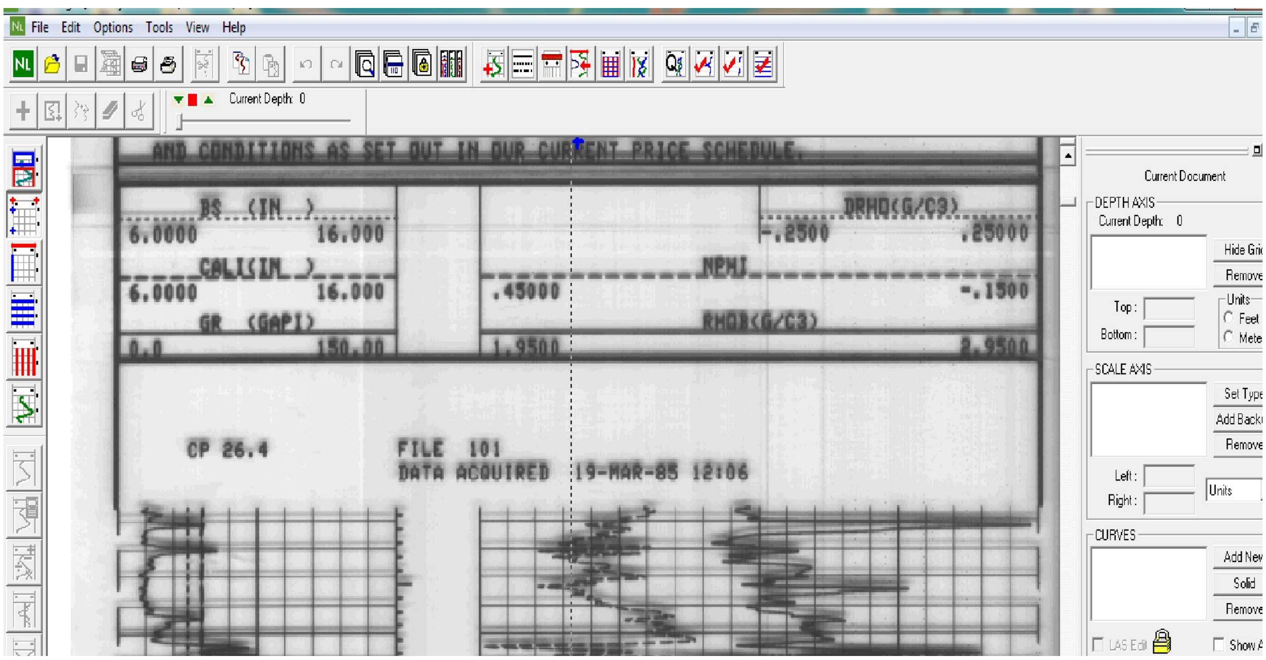

Figure (C-4): The main page of NL software.

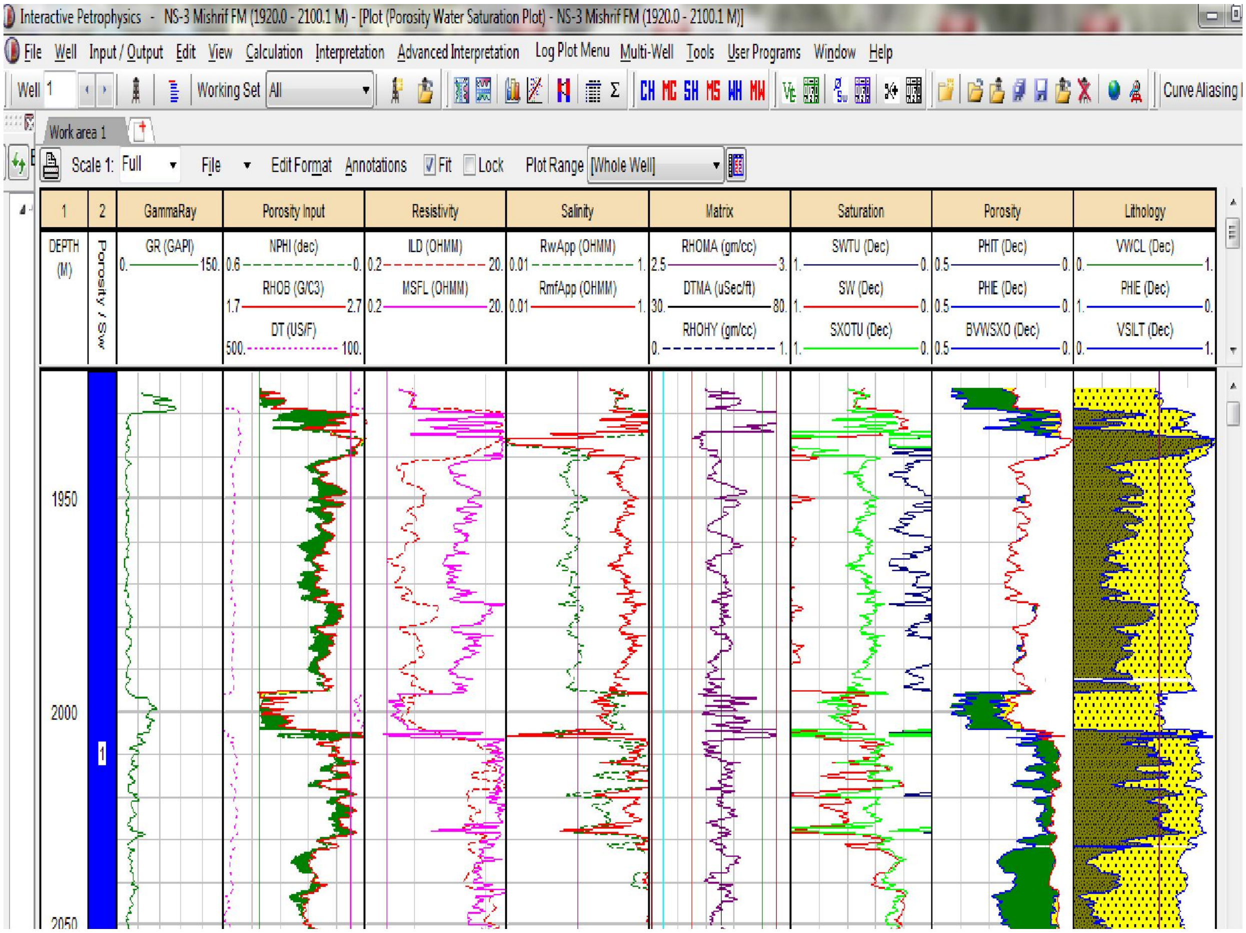

Figure (C-5): Example for the IP output results.

APPENDIX D

Table (D-1): sample of output results for Mishrif Formation, NS-3 oil well.

DEPTH	GR
1925.0000	35.31746032
1925.1524	36.11111111
1925.3048	36.90476190
1925.4572	39.28571429
1925.6096	42.46031746
1925.7620	54.36507937
1925.9144	56.74603175
1926.0668	60.46523440
1926.2192	65.04581787
1926.3716	72.41471039
1926.5240	76.98448629
1926.6764	70.22580093
1926.8288	54.53157535
1926.9812	54.17419191
1927.1336	51.53924394
1927.2860	52.11321037
1927.4384	52.77780711
1927.5908	56.33336543

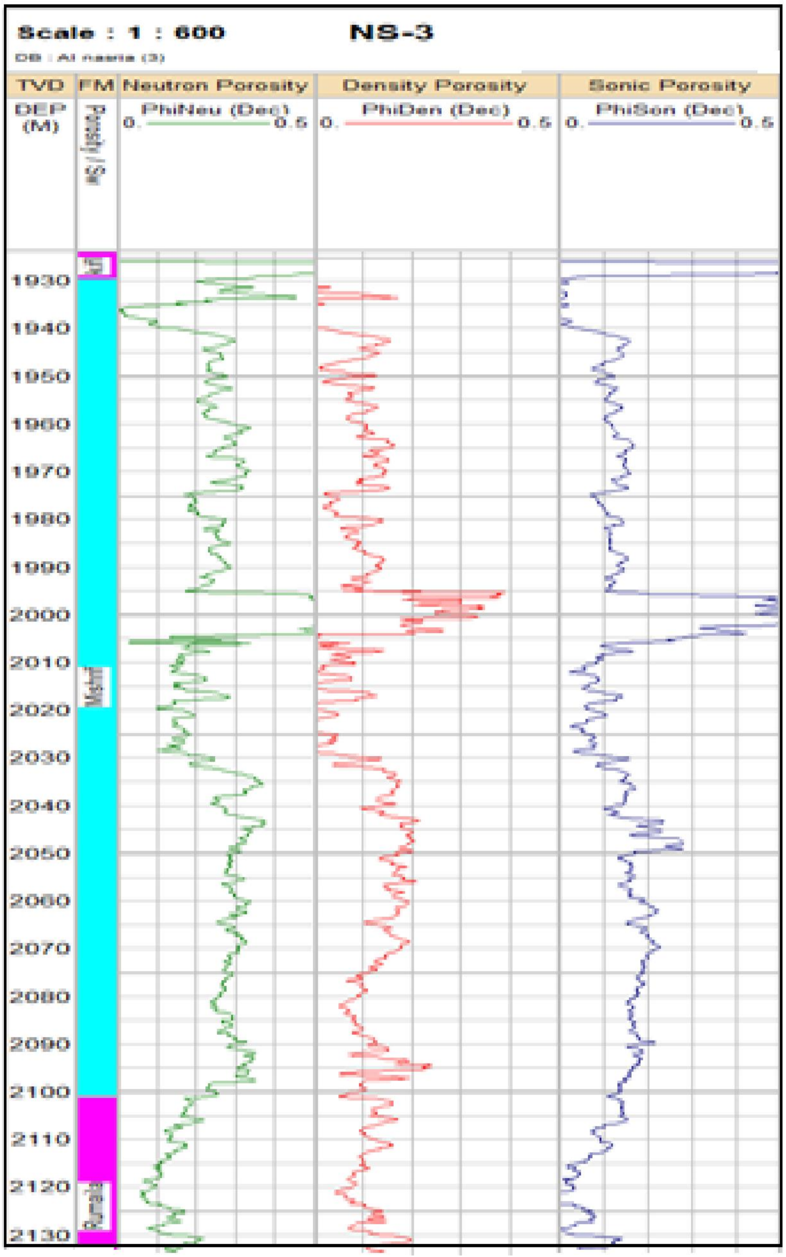

Figure (D-2): ϕ results by N, D and S-log for Mishrif FM.

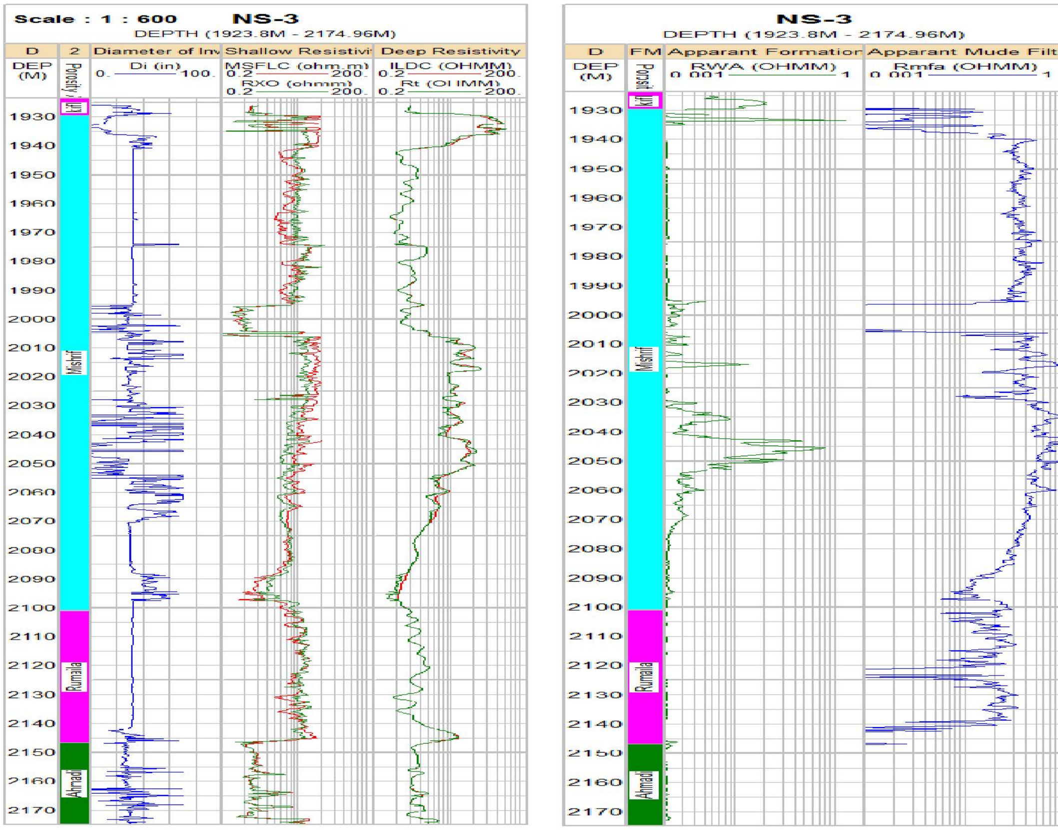

Figure (D-3): R_t, d_i, R_{xo} R_{mfa} and R_{wa} results for Mishrif FM.

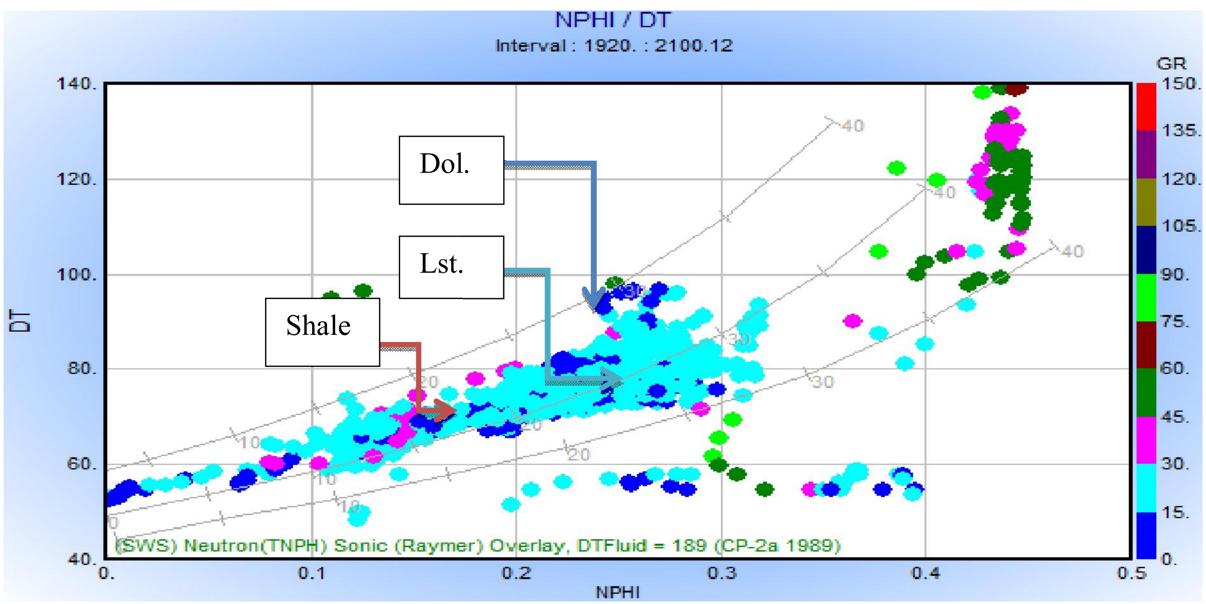

Figure (D-4) Φ_N VS. DT Cross-plot for Mishrif Formation.

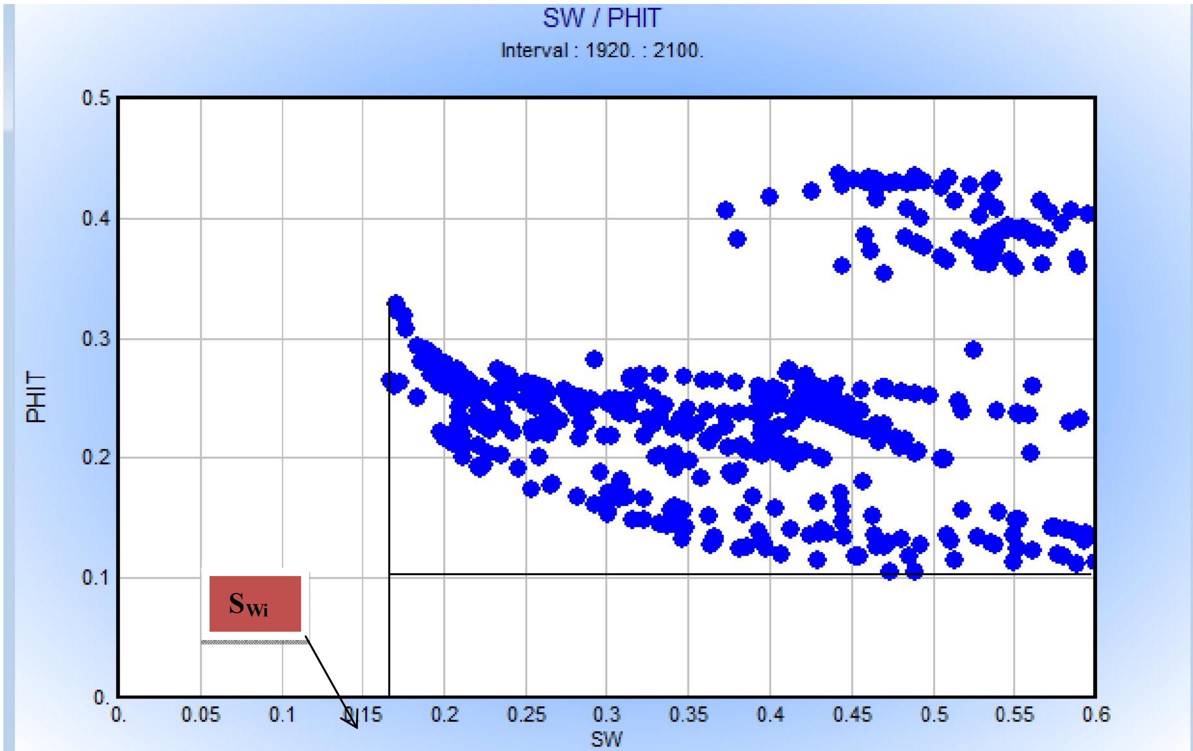

Figure (D-6): S_{wi} Determination by Φ-S_w plot for Mishrif Formation.