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PETROPHYSICAL EVALUATION OF UPPER SABIL RESERVOIR IN INTISAR OIL FIELD, SIRTE BASIN, LIBYA

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دراسات بتروفيزيائية لتقييم خزان سبيل العلوي – في حقل انتصار - حوض سرت – ليبيا

الخلاصـــة: يهدف هذا العمل الى دراسة الخواص البتروفيزيائية لمنطقة حقل انتصار و تقييم خزان سبيل العلوى. حقل انتصار يقع في الجانب الشرقي من حوض سرت – بين خطى عرض '07 °28 و '40 °28 شمالا – وخطى طول '10 °20 و '47 °20 شرقا - وهو يتكون أساسا من الحجر الجيري تكونت في العصر الطباشيري. الحوض تركيبي المنشأ – والذى اخذ اتجاهات شمال شمال غربي - جنوب جنوب شرقي, تكون من هضاب مرتفعة وكتل صخرية منحدرة.

الخزان الرئيسي في منطقة الدراسة الذى ينتمى الى الحوض الرسوبي يتكون أساسا من الحجر الجيري والدولوميت والبقايا الهيكلية للشعاب المرجانية , مع وجود بعض من الحجر الرملي.

تم تحليل البيانات المتاحة من تسجيلات الآبار – وتم حساب حجم الطفلة عن طريق بيانات أشعة جاما في أربعة آبار (L1 : L4) , تتراوح من ٢:٤ % وتم خلال قياسات المسامية (قياسات النيوترون و الكثافة والصوتية) – وتم حساب المسامية الكلية ($Ø_{ND}$) - والتي تتراوح من ٢٦:٤٧%.

أيضاً تم رسم خريطة توزيع المسامية لخزان سبيل – وتوريع التشبع بالمياه, وتم حساب متوسط التشبع بالمياه في الآبار الأربعة وتحديد قيمة عامل السمنتة (m). وأظهرت قيم التشبع بالماء للصخر المحسوبة من سجلات الآبار تراوح من ١٣ الى ٣٥ %- ومنطقة تماس الزيت مع الماء كان على عمق ٨٦٥٧٦ قدم تحت سطح البحر – وحجم الهيدروكربون في الآبار تراوح من ١,٩٩ الى ٨,٧٥ قدم.

ABSTRACT: *Intisar (103-L) Oil Field is located in the eastern part of Sirte Basin, Libya. The structure of this field is coral reef. The field is producing from the Upper Sabil Reservoir (Upper Paleocene in age). This formation consists of limestone.*

Sedimentary sequences varying from continental to near shore and marine sediments was forming the stratigraphic sequences of the basin.

Sirte Shale (Upper Cretaceous, Campanian/ Turonian) is the dominant source rock in Sirte Basin petroleum province. The thickness of Sirte Shale ranges from a few hundred meters to as much as 3600 ft in the troughs. Sandstones are the most common reservoir rocks in sedimentary basins. Lime-stones and dolomite stones, some of which are the skeletal remains of ancient coral reefs, are other examples of reservoir rocks.

In the study area, shales and marl in Kheir Marl Formation are considered as the cap rock. A complete package of porosity and resistivity logs, including neutron, density, sonic and induction logs have been recorded over the Upper Sabil Reservoir in Intisar (L) Field. The logs of the Upper Sabil Reservoir of four wells were read every 2' and analyzed for detailed evaluation of porosity, water saturation, net pay, and hydrocarbon pore volume. Net pay thickness map have been established. The average hydrocarbon pore volume, oil water contact (O.W.C), initial oil reserves and the original oil in place were estimated.

INTRODUCTION

The purpose of this study is to carry out a petrophysical analysis of Upper Sabil Formation, in order to evaluate the potential of the reservoir.

Intisar (L) reef field is located in the concession 103 of Sirte Basin as shown in Fig. 1., about 8 km north- west of Intisar (A) Reef. Intisar (103-L) Reef lied between Latitudes 28° 07' and 28° 40' north and Longitudes 20° 10' and 20° 47' east. The elevation of the surface is (303 feet) above sea level.

In an attempt to meet the purpose of this study, all the data available include: - Well logs such as electrical resistivity, gamma ray, neutron, and density logs. These logs were used for correlation and construction of different maps and cross-sections. The logs were read and analyses every 2' interval for porosity, fluid saturation, net pay thickness and hydrocarbon pore volume. Base map, and logs are got from the Zueitina Oil Company were used in this study.

1- Geological setting

Sirte Basin is located in north-central part of Libya. It consists dominantly of carbonate rocks deposited at the Cretaceous time. Paleozoic strata are present only in certain parts of the basin. It is situated direct over the Precambrian rocks.

The reef was deposited in a fairly shallow epi-continental sea during the upper Paleocene time. Barr F.T. et al (1972) note that at The Deffah Oilfield is located in the south central region of Sirte Basin of Libya which is the youngest of the Libyan sedimentary basins and the main one producing hydrocarbons Barr et al. (1972).

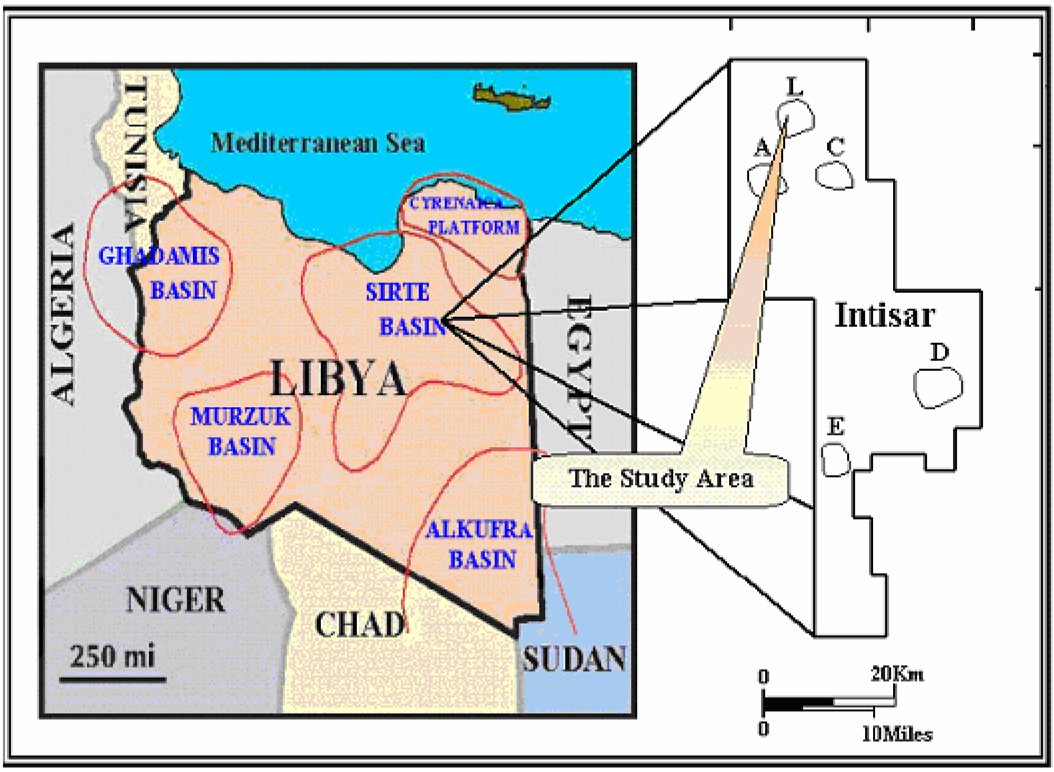

Fig. 1: Location map of Intisar (103-L) Oil Field, Sirte Basin, Libya (Zueitina Oil Company, 2006).

This basin was developed in early Upper Cretaceous (Cenomanian) time and was formed by the break-up of the pre-existing Sirte Arch into NNW-SSE trending sub-parallel horsts and grabens. The Deffah Oilfield is located on one of positive features (horst) called the Zelten Platform (Fig. 2 Consultancy report).

The depositional history of Sirte Basin started with a widespread Cenomanian marine Cretaceous time and the troughs are formed due to collapse of Sirte Arch, that filled in by sediments derived from the adjacent highs. By the end of Upper Cretaceous (Maestrichtian) time Sirte Basin had become stable Barr F.T. et al. (1972).

The Zelten high remained a paleo-high at the end of Maestrichtian time relative to adjoining shallow troughs which probably controlled the accumulation of hydrocarbons in the Deffah, Zelten, and Waha areas. The hydrocarbons found in Maestrichtian and Danian shallow marine carbonate on the synchronous highs along the high were presumably supplied from the fine-grained sediments accumulating in the troughs east and west of the high.

In structurally low areas the Deffah limestone rests on the Upper Cretaceous Waha Formation (Limestones), but in high structural areas it rest directly on granite basement.

The thickness of the Deffah Limestone in the Oilfield area varies from about 150 to about 580 feet. The thin areas are located over the basement highs, but to the east they are the result of gradual facies changes into the Hagfa Shales.

2. Stratigraphic of Sirte Basin:

Following the opening of Sirte Basin, sedimentary sequences varying from continental to near shore and marine sediments was deposited forming the Stratigraphic sequences of the basin. It can be divided into four Litho-Stratigraphic sequences described below:-

The first sequence overlying the basement is dominated by the Pre-Upper Cretaceous sedimentary sequence that existed before the basin was formed which include Hofra, Gargaf Quartzite and Nubian Sandstone's.

The Second sequence is the Upper Cretaceous Graben-Fill sediments deposited following the structural development of the grabens. The grabens were the accumulation sites of marine shale deposits and eroded from the structural high areas. The Stratigraphic sequence includes in a secondary order the Bahi, Lidam, Etel, Rachmat, Rakab, and Kalash Formations (Zueitina Oil Company).

The third sequence is represented by the Tertiary sediments and is part of the Graben-Fill stage started by the early Paleocene deposits. The Paleocene and Early Eocene rock deposits include the Hagfa, Beda, Dahra, Zelten and Gir formations that are widespread and have good lateral stratigraphic continuity.

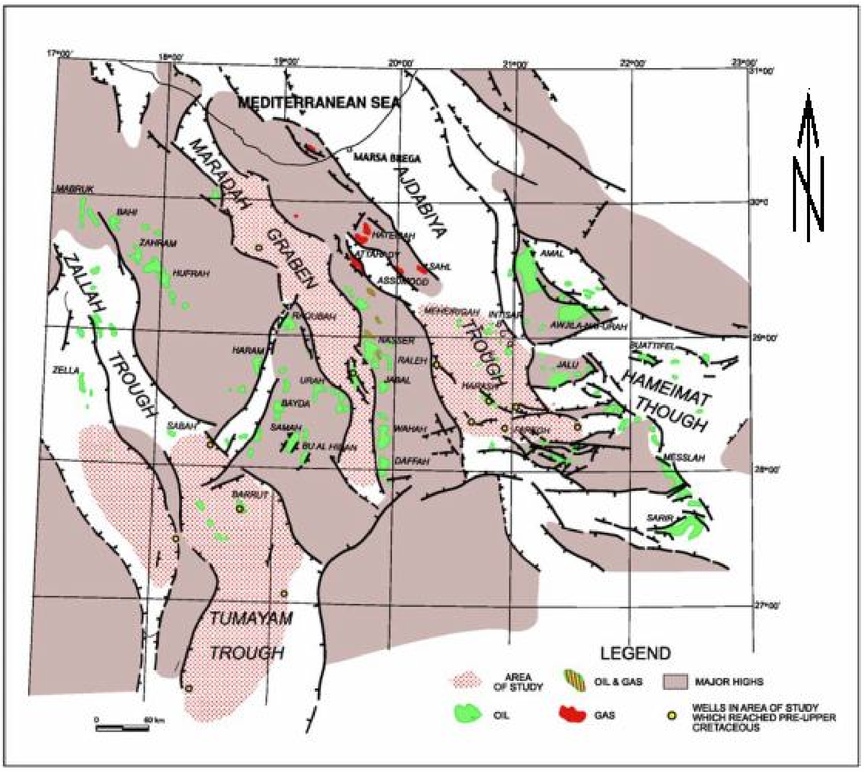

Fig. 2: Structural map of the Sirte Basin, with oil and gas fields, (from Rusk, 2002).

The fourth sequence starts near beginning of the Lower Eocene. It is characterized by the slight to moderate local thickness variation within the Upper Gir Formation.

The general stratigraphy in concession 103 has been described in detail by Parizek, et al. (1984), as follows (Figs. 3, 4):

2.1 Lower Sabil Formation (Lower Paleocene):

This formation consists mostly of dolomite, hard brown, microcrystalline with poor porosity overlain by low energy, pelletal biomicrite. The upper part consists of calcarenite and calcilutite.

2.2 Sheterat Shale Formation (Lower Paleocene):

Sheterat shale consists of 35 feet of calcareous shale, dark green. This facies was deposited in open marine, shallow water, low energy environment. The average thickness is about 80 feet.

2.3 Upper Sabil Formation (Upper Paleocene):

This facies is in fact the base of Intisar (L) oil field. It consists of algal forminiferal biomicrite with scattered coral debris in which the porosity has been diminished by calcite cement in fill. The average thickness is about 1221 feet.

2.4 Kheir Marl Formation (Upper Paleocene):

The Kheir Marl was deposited in marine and low energy environment. It consists of soft and white marl, soft becoming more shaly in the upper part, of the reservoir. The average thickness is about 322 feet.

2.5 Gir Formation (Lower Eocene):

The Gir formation is typically sequence of interbeded dolomites and anhydrite with Subordinate amounts of limestone and shale.

The bottom of the Gir Formation consists of calcarenite, brown, very fine grained hard and dense with some fossil fragments, which is cemented by calcilutite gray-brown argillaceous with gray calcilutite matrix. It is overlain by calcilutite, brown, firm compact and argillaceous grading to calcarenite which is very fine grained, firm and in parts variably sucrosic. This stratum has no visible porosity and no oil show. The uppermost part of Gir Formation mostly consists of calcilutite which is creamy, firm hard and fine grained with traces of gray brown chert and poor intergranular porosity. The average thickness is about 1941 feet.

2.6 Gialo Formation (Middle Eocene):

This Formation consists of two members. El-Giza and the Jakira member.

2.6.1 El-Giza Member:

The bottom layer consists of calcarenite which is brown, firm with poor primary porosity and has brown oil stain in about 5% of the samples and pale yellow fluorescence in about 20% of the samples. It grades upwards to bio-calcilutite with fairly good intra and inter-clast porosity.

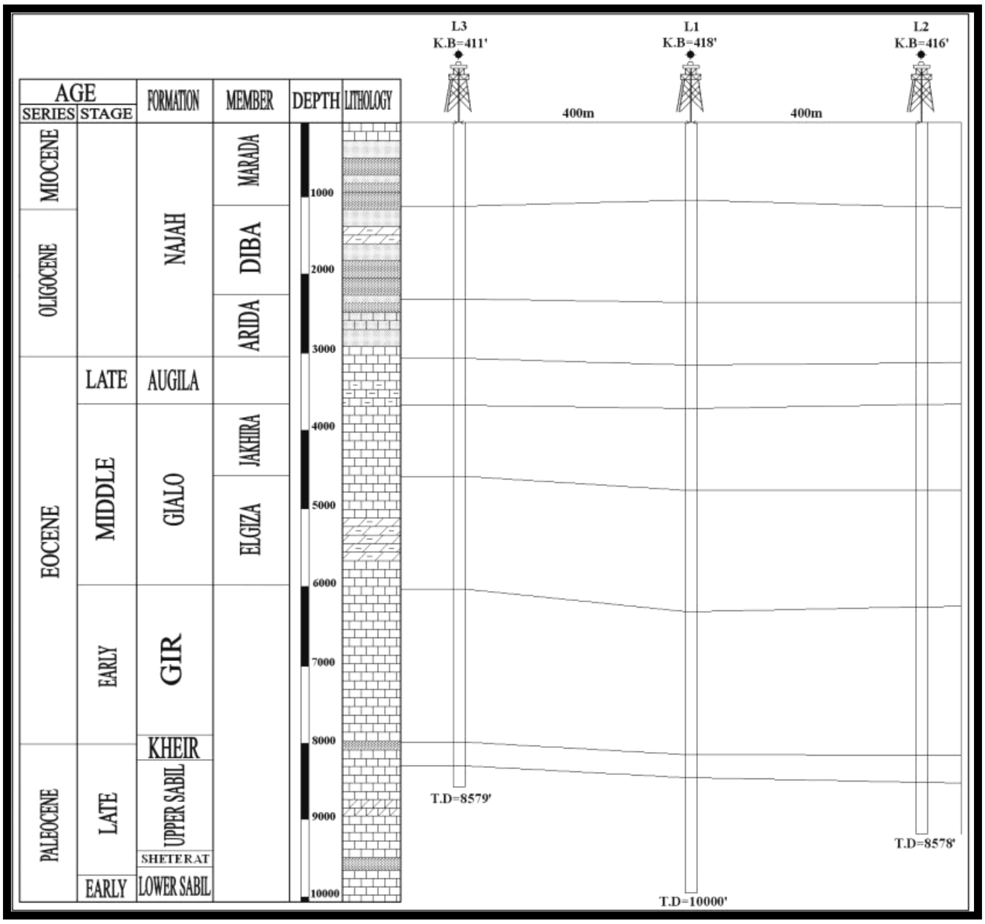

Fig. 3: Geological cross-Section across the Deffah (B) Oil Field (L1, L2 and L3), Sirte Basin.

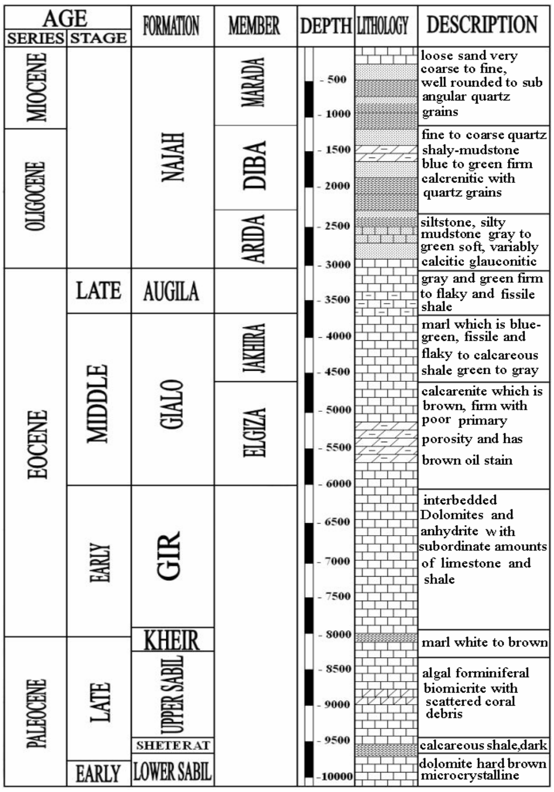

Fig. 4: Stratigraphic Columnar section of study area.

The top of this member consists of traces of light green marl with minute amounts of dolomite or dolomitic calcarenite which is brown, fine grained, hard and tight. The average thickness is about 1485 feet.

2.6.2 Jakira Member:

The bottom 300 feet consists of marl which is blue-green, fissile and flaky grading upward to calcareous shale which is green to gray and then further upwards to bio-calcarenite which is white firm, fine to medium grained with calcilutite matrix. The average thickness is about 487 feet.

2.7 Augila Formation (Late or Upper Eocene):

The bottom of this formation consists of gray and green firm to flaky and fissile shale with carbonate traces. The upper part of the Augila Formation consists of white, soft and firm calcilutite with glauconite and fine quartz grains, grading upward in parts to green-gray silt stone at the top. The average thickness is about 484 feet.

2.8 Najah Formation (Oligocene and Miocene):

This formation consists of three members. Arida, Diba and the Marada member.

2.8.1 Arida Member:

It consists of siltstone, silty mudstone which are gray to green, soft, variably calcitic glauconitic and pyretic. The average thickness is about 613 feet.

2.8.2 Diba Member:

The siltstone contains some fine to coarse sub-angular quartz grains. Grain size decreases upwards into a shaly-mudstone which is blue to green firm and fissile, in part calcrenitic with quartz grains. The average thickness is about 1226 feet.

2.8.3 Marada Member:

It consists of loose sand very coarse to fine, well rounded to sub angular quartz grains. There are minute amount of white to yellow clay with some brown iron stain. The average thickness is about 1197 feet.

3. Source Rock, Reservoir Rock and Cap Rock:

3.1 Source Rock:

Given many thousands of years, a stack of mud and organic remains many kilometers thick may pile up on the sea floor, especially in nutrient-rich waters. Given enough time, the overlying sediments that are constantly being deposited will bury these organic remains and mud so deeply that they will eventually be turned into solid rock. It is believed that high heat and intense pressure help along various chemical reactions, transforming the soft parts of ancient organisms found in the deep-sea sludge into oil and natural gas. At this point, this ooze at the bottom of the ocean turns into source rock.

Contrary to a popular belief, dead dinosaurs do not turn into oil. Since almost all oil comes from rocks that were formed underwater, floating ocean life (tiny, tiny creatures known as diatoms, foraminifera, and radiolaria - all just as small as a grain of sand), that settle to the bottom of the sea is what eventually turns into oil, so we can said that source rock is the rock, which has enough amounts of organic matter to yield commercial mounts of hydrocarbons.

In the study area, probably dark bituminous, Upper Cretaceous Sirte Shales are the source rock of the hydrocarbons in the Satal Reservoir.

Sirte Shale (Upper Cretaceous, Campanian/ Turonian) is the dominant source rock in Sirte Basin petroleum province (Parsons and others (1980).

The thickness of Sirte Shale ranges from a few hundred meters to as much as 900 m in the troughs. These rocks are within the oil-generating window between depths of 2,700 and 3,400 m in the central and eastern Sirte Basin.

3.2 Reservoir Rock:

Sandstones are the most common reservoir rocks in sedimentary basins. Limestone and dolomite, some of which are the skeletal remains of ancient coral reefs, are other examples of reservoir rocks.

Intisar (L) reservoir consists of algal forminiferal biomicrite with scattered coral debris that concentration in Upper Sabil formation indicating shallow water, high energy marine environment.

3.3 Cap Rock:

In the study area shale and marl (white to brown) in Kheir Marl Formation (soft becoming more shaly in the upper part of the Formation) act as a regional seal to the Upper Paleocene of Upper Sabil reservoir of the primary play.

4. Well Logging Interpretation:

4.1 Introduction:

Petrophysical means the study of the rock properties as porosity, permeability, and fluid distribution. In this study a complete package of porosity and resistivity logs, neutron, density, sonic and induction logs, have been recorded over the Upper Sabil Reservoir in Intisar (L) Field. The logs of the Upper Sabil Reservoir of four wells were read every 2' and analyzed for detailed evaluation of porosity, water saturation, net pay, and hydrocarbon pore volume.

4.2 Determination of shale volume:

To determine volume of shale requesting to several types of the Logs, such as Gamma ray logs, Neutron and Density X-Plot. The first logs are important, in our calculations to estimate volume of shale in the Upper Sabil reservoir were depended on gamma Ray logs. The recorded log was processed by equations 1 and 2 (Schlumberger, 1987).

I_{GR}= (GR_{log}-GR_{clean})/ (GR_{shale}-GR_{clean}) … Eq. (1)

V_{sh}=0.083× {2 $^{(3.7\times IGR)-1}$} ×100…………..Eq. (2)

where: $I_{G.R}$ = Gamma ray index (API).,

G.R = Gamma ray reading (log).

G.R $_{Clean}$ = minimum reading (log).

G.R $_{Shale}$ = maximum reading (log).

V_{sh} = Volume of shale. The total Volume of Shale results of each well are given in table1.

Table 1: average of total Volume of Shale (%) is ranging from 2% to 4% in the Upper Sabil reservoir across Intisar (L) oil field

Well #	Average Volume of shale %
L1	3.5
L2	4
L3	3
L4	2

4.3 Porosity calculation:

All porosity logs, neutron, density, and sonic logs were used to quantitatively determine the total porosity ($Ø_{ND}$) and secondary porosity ($Ø_{sec}$) of the reservoir. Here the secondary porosity represents isolated pore space not detected by sonic logs. The total porosity values were determined using density - neutron cross-plots (Burollet, 1960) and using equation 4. Usually both methods provide good estimates of total porosity, except that equation 3 Density porosity ($Ø_D$) which will be determined from equation 3 depending on the rock type (Schlumberger, 1987).

$Ø_D$= (ρ_{log}-ρ_{ma})/ (ρ_{fl}-ρ_{ma}) ………………….. Eq. (3)

$Ø_{ND}$= {($Ø_N^2$+$Ø_D^2$)/2}$^{0.5}$ ……..…………...Eq. (4)

where: ρ_{log} = Bulk density, gm/cc (log) - ρ_{fl} = Fluid density, 1.1gm/cc. ρ_{ma} = Matrix density, 2.71gm/cc. - $Ø_N$ = Neutron porosity (log). $Ø_D$ = Density porosity.

4.3.1 Calculation of the secondary porosity:

The secondary porosity ($Ø_{sec}$) values are calculated using equation 5. This equation is based on the fact that sonic waves of the sonic logs will travel through the matrix and avoid isolated pore space.

Therefore, in vuggy or moldic carbonate, the sonic derived porosity (Øs) values are determined using equation 6 (Schlumberger, 1987)..

$Ø_{sec}$=$Ø_{ND}$ -$Ø_S$ …………………….………Eq. (5)

$Ø_S$= (Δt_{log}-Δt_{ma})/ (Δt_{fl}-Δt_{ma}) …………….Eq. (6)

Where:

Δt = Formation travel time, µs/ft (log). ,

Δt_{fl} = Fluid travel time, 189 µs/ft (for salt water).

Δt_{ma} = Matrix travel time, 47.5µs/ft (for Lime stone).

The total porosity results of each well are given in table 2.

This was done to show the vertical distribution of the calculated porosity of the Reservoir.

Table 2: average of total porosity (%) is ranging from 26% to 47% in the Upper Sabil reservoir across Intisar (L) oil field.

Well #	Average porosity (%)
L1	35
L2	28
L3	26
L4	47

Porosity map (Fig. 5), was constructed to show the porosity distribution in the Upper Sabil Reservoir across Intisar (L) Oil Field. The porosity in the field is ranging between 26 % to 47%. The best reservoir average porosity is in the middle of the field and decreases in all direction. The porosity values on the map represent the average porosity, determined using equation 7 below (Schlumberger, 1987).

$Ø_{ave}$=∑ (Øi×hi)/ ∑ (hi) ……………….Eq (7)

Where:

$Ø_{ave}$ = average total porosity.

$Ø_i$= porosity value of unit thickness.

h_i = unit thickness.

4.4 Reservoir Parameter:

Knowledge of reservoir parameters such as Cementation Factor (m), Saturation Exponent (n), Formation Water Resistivity (R_w), Resistivity of Formation (R_t), and porosity are required for the determination of reservoir Water Saturation (S_w). Porosity was discussed in the previous sections and the other parameters will be explained in some details below.

4.4.1 Cementation Factor (m):

The cementation exponent (m) is an essential parameter in Archie Formula to determine water saturation.

This factor plays the role for the relation that bind between reservoir parameters. This parameter can be obtained from special core analysis, where available. It was determined using picket cross-plot between R_t and $Ø_{ND}$ of well L2-103. In this study, Picket cross-plot was used as Fig. 6.

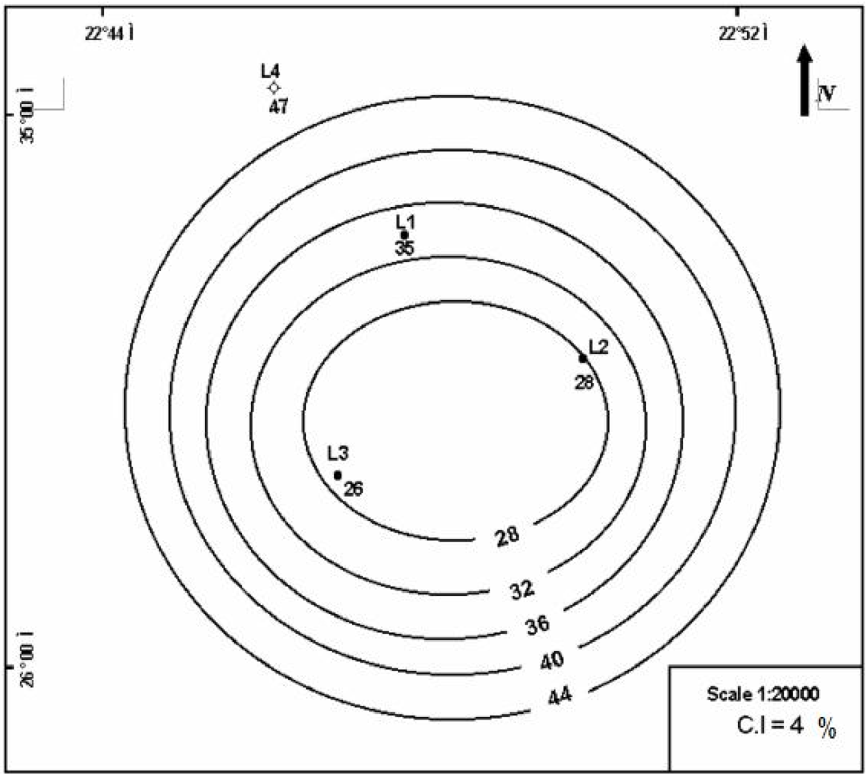

Fig. 5: shows the porosity map distribution of the Upper Sabil reservoir across Intisar (L) Oil Field. (CI= contour interval).

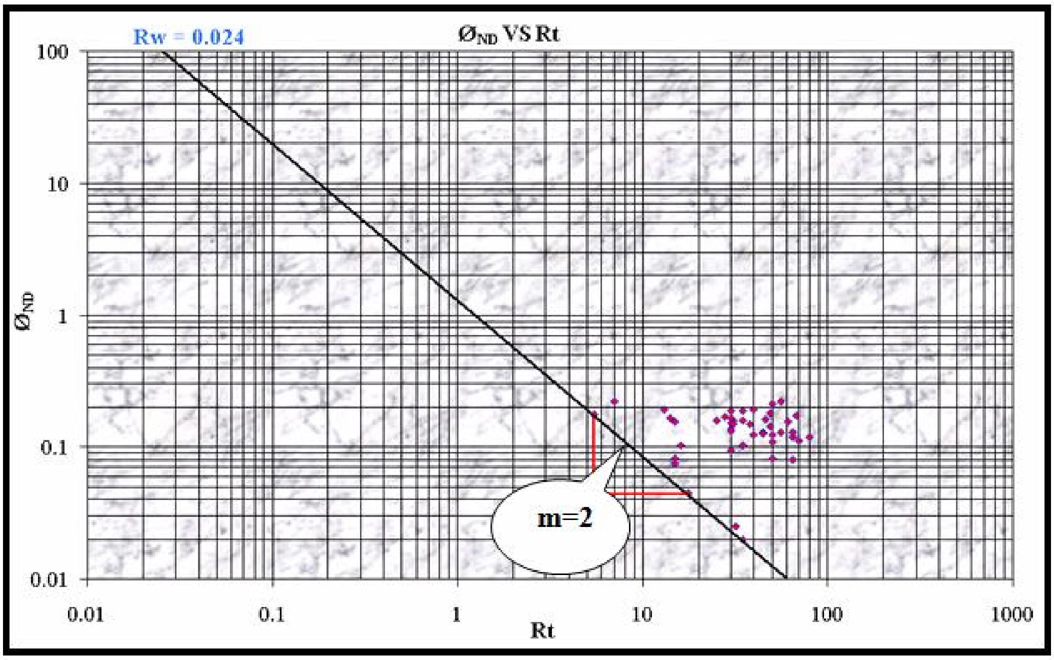

Fig. 6: Determination of cementation factor (m) at Upper Sabil reservoir in well (L2-103).

It was constructed by plotting porosity ($Ø_{ND}$) values versus deep resistivity (R_t) values of well L2- 103 by three cycle log-log paper.

A line of resistivity at 100% S_w was drawn through the most south-west data points and the slope of this line; represent the (m) value. It has been found that (m) equals 2 in the Upper Sabil reservoir.

Saturation exponent (n) can only be obtained from special core analysis data. The saturation exponent (n) for this study is taken as 2 in the water saturation calculation (Zueitina Oil Company, 2006).

4.4.2 Formation Water Resistivity (Rw):

The formation water resistivity was determined using the Picket cross-plot and the Formation water resistivity value is equal to 0.024 Ω.m at the formation temperature.

4.4.3 Determination of water Saturation (Sw):

The water saturation is calculated using Archie Equation 8 (Schlumberger, 1987).

$S_w = (a \times R_w / (Ø^m \times R_t)^{1/n})$ ……..………….. Eq. (8)

Where:

a = Tortuosity factor equal 1.

Ø = Total porosity ($Ø_{ND}$) %.

m = Cementation factor equal 2.

Rt = Formation resistivity Ω.m.

n = Saturation exponent equal 2.

The average water saturation was calculated by the equation 9. To show the distribution of the water saturation, maps were constructed as shown in Fig. 7.

$S_w\ avg = \sum (Ø_i \times Sw_i \times h_i / \sum (Ø_i \times h_i)$ ………… Eq. (9)

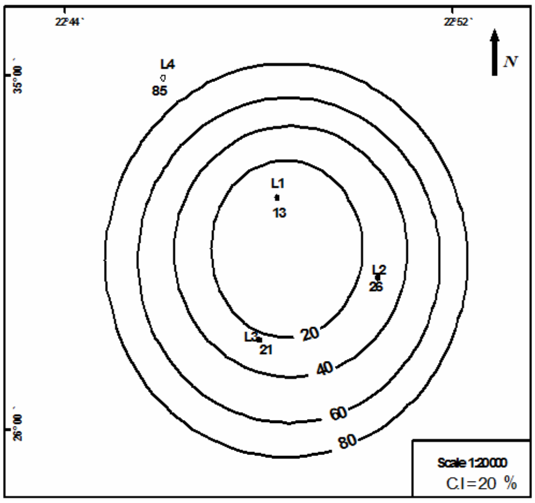

Fig. 7: Water saturation (S_w) map distribution in the Upper Sabil Reservoir across Intisar (L) Oil Field.

The average water saturation (S_w) values of each well are summarized in table 3. The value 85 in L4 well may due to that the measured Sw was at depth more than oil water contact.

Table 3: average of water saturation (%) is ranging from 13% to 85% in the Upper Sabil Reservoir across Intisar (L) oil field.

Well #	Average Sw (%)
L1	13
L2	26
L3	21
L4	85

4.4.4 Net pay thickness:

The net pay thickness of the Upper Sabil reservoir represents intervals having porosity greater than or equal to the porosity cut-off of 10%, water saturation less than cut-off of 50%, and volume of shale less than of 25%.

The net pay thickness is shown on the net pay thickness map of the Upper Sabil reservoir (Fig. 8), the average net pay thickness of each well is summarized in table 4.

Table 4: average net pay thickness (ft) is ranging from 48 ft to 188 ft in the Upper Sabil reservoir across Intisar (L) oil field.

Well #	Average net pay thickness (ft)
L1	188
L2	60
L3	76
L4	48

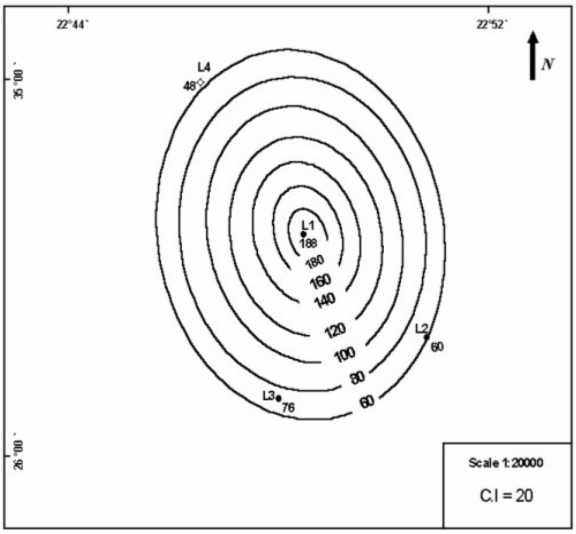

Fig. 8: Net pay thickness map distribution in the Upper Sabil Reservoir across Intisar (L) Oil Field.

4.5 Estimation of the reserve:

4.5.1 Oil Water Contact (O.W.C):

It is the contact line between the oil and water in the reservoir. This line is identifying the depth of the oil and water. It is calculated by plotting water saturation values versus sub-sea depths (Fig. 9), this plot indicates that the oil water contact of the Upper Sabil Formation is located at sub-sea depth of 8576'.

4.5.2 The Initial Oil Reserves:

To calculate the hydrocarbon pore volume, we collected all values of HPV of the Upper Sabil reservoir in each well (Table 5) and entered them in the equation 10.

HPV=h×Ø× (1-Sw) ……………………E.q. (10)

Where: HPV = Net hydrocarbon pore volume (ft). , h = Net pay thickness (ft).

Ø = Net pay porosity (%). , S_w = Net pay water saturation (%).

The average Hydrocarbon pore volume of each well is summarized in Table 5.

Table 5 : Average hydrocarbon pore volume.

Well #	Average HPV (ft)
L1	8.75
L2	6.1
L3	5.93
L4	1.99

The original oil in place was estimated to be 5.6 BSTB using equation 11. This is equivalent to initial oil in place of 4.3 BSTB at Formation Volume Factor (F.V.F) of (1.3) (Zueitina Oil Company) calculated using equation 12.

OOIP= HPV× 7758× A ……………….. Eq. (11)

IOIP=OOIP/F.V.F ………………..……..Eq. (12)

Where: (OOIP) is the Original oil in place (RB).

(A) is the Area in acres (1270 Acre).

(7758) is the Number of barrels per feet, (IOIP) is the Initial oil in place (STB).

(F.V.F) is the Formation volume factor (1.3 RB/STB), (Zueitina Company).

The recoverable factor (RF) of (20%) in Intisar (L) Oil Field (Zueitina Company) is the ratio of the recoverable reserve to the factor; the recoverable oil is 861,538 MSTB in Intisar (L) Oil Field using equation 13.

The calculated recoverable oil in Upper Sabil Reservoir using equation 13 equals to 861,538 MSTB.

Oil recoverable =IOIP×RF ……………..Eq. (13)

Where: IOIP =Initial oil in place (STB).

RF = Recoverable factor (20%), (Zueitina Company).

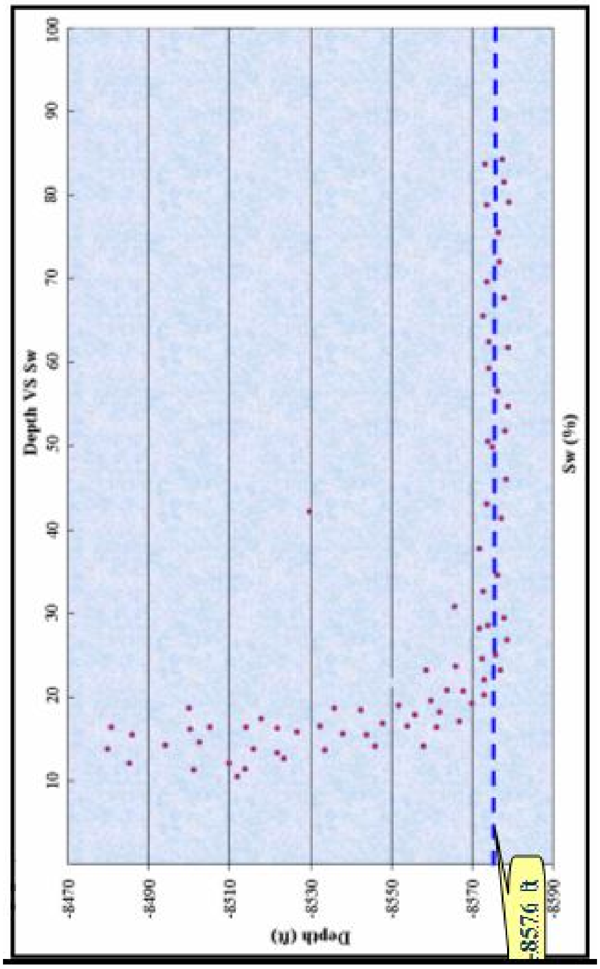

Fig. 9: Water Saturation versus Depth in well L2-103.

CONCLUSION

Intisar Oil Field is located in the eastern part of Sirte Basin, Libya. The field is producing from the upper Sabil reservoir (Upper Paleocene). The type of reservoir rock is limestone.

Four wells were evaluated petrophysical parameters for the reservoir. The average of total volume of shale (%) is ranging from 2% to 4%, average of total porosity (%) is ranging from 26% to 47%. The saturation exponent (n) was considered as 2 in the water saturation calculation. The formation water resistivity value is equal to 0.024 Ω.m.

The average of water saturation (%) is ranging from 13% to 85%. The average net pay thickness (ft) is ranging from 48 ft to 188 ft.

The oil-water contact of the Upper Sabil Formation is located at sub-sea depth of (-8576'). The average hydrocarbon pore volume of each well is ranging from 1.99 to 8.75 ft. The original oil in place was estimated to be 5.6 BSTB. This is equivalent to initial oil in place of 4.3 BSTB at Formation Volume Factor (F.V.F) of (1.3). The calculated recoverable oil in Upper Sabil Reservoir equals to 861, 538 MSTB.

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