

RESERVOIR CHARACTERIZATION OF THE OLIGOCENE UNITS AND JERIBE FORMATION IN Khabaz Oilfield

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ABSTRACT

The study investigates the petrophysical properties and reservoir characteristics of the Oligocene units and Jeribe formation of the Khabaz Oilfield, northern Iraq, focusing on well A1, for the depths between 2234.97 and 2460 meters. The Jeribe formation is of Early Miocene, has been identified as a significant hydrocarbon reservoir. The interplay between dolomite and limestone influence permeability and porosity. Unlike limestone reservoirs, whose relationships are linear, dolomite reservoirs exhibit complex relationships between porosity and permeability due to the change of rock volume and porosity shape. The study employs gamma-ray, neutron, density, sonic, and resistivity logs, along with other well log data from A1 and A2 wells, for analyzing shale volume, porosity, and fluid saturation. The findings divide the Jeribe formation and Oligocene formation into subzones (A, B, BE, E Units) based on calculated porosity. That indicates the reservoir quality ranges from fair to very good, with effective porosity being an important factor affecting permeability. Neutron-density and M-N cross plots are utilized to delineate various lithological features, supporting the idea that limestone and dolomite are the main components of the reservoir. The results reveal that the dolomitic composition of the Jeribe formation has moderate permeability, while micro-fractures in Unit B enhance permeability significantly. The study highlights the critical role of effective porosity in enhancing fluid flow potential. This will provide valuable insights for planning hydrocarbon development and investment strategies of Khabaz Oilfield. Overall, this research emphasizes the importance of the comprehensive petrophysical analysis in understanding reservoir static and dynamic properties supporting and optimizing resource management.

Keywords: petrophysical properties; reservoir characterization; Oligocene units and Jeribe formation.

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1. Introduction

The Khabaz Oilfield, located in the Kirkuk Governorate of northern Iraq, is a significant site for hydrocarbon exploration and production. The geological column in this area includes the Jerebi formation, along with various stratigraphic units that encompass other formations and several Oligocene units [1].

The Jeribe formation, predominantly consisting of dolomitized limestone, serves as a significant reservoir rock within the Middle Miocene sequence in Northern Iraq [2]. Dolomitization of limestone leads to increased rock volume and resulting into increase porosity particularly in the selected well (A1), located between 2234.97 and 2460 meters' depths (RTKB). These formation displays various lithological compositions and depositional environments that affect their reservoir quality and hydrocarbon storage capacity. A comprehensive petrophysical analysis, utilizing well log data and core sample evaluations, is crucial for defining reservoir zones and evaluating their productivity [3].

In the study of dolomite reservoirs, fractures and vugs

play a critical role significantly enhancing permeability values. However, in the limestone reservoirs, the fractures are mostly micro-fractures, where the relationship between permeability and porosity is well-defined, and the percentage of connected pores correlates confidently with permeability [4]. This contrasts with dolomite reservoirs, where a clear correlation between the percentage of connected pores and permeability is absent, likely due to the complex nature of the sedimentary environment [5].

Petrophysical property analysis is vital in the petroleum industry, as it helps in understanding reservoir behavior and contributes to reservoir development [6]. Additionally, the modeling of these properties plays a crucial role in field development strategies [7]. The result of data analysis provides the model the essential parameters for estimating the Stock Tank Oil Initially in Place (STOIP), offering valuable insights for efficient field development [8, 9].

The selected well (A1) provides critical data for this analysis, covering stratigraphic sections (A-B-BE-E) within the Oligocene age and allowing for a detailed understanding of the reservoir characteristics and their implications for hydrocarbon development and production.

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2. Geological settings and previous work

The Khabaz oilfield is a minor subsurface asymmetrical anticline characterized by a steeper limb compared to the southwest limb. The Jeribe formation, a heterogeneous gentity, was originally characterized as organic detrital limestone and presumed to be of early Miocene age. It was subsequently incorporated into the middle Miocene stratigraphy. The Jeribe formation is overlain conformably by the Lower Fars formation and uncomfortably underlain by the Anah formation. It is predominantly homogeneous and comprises limestone, dolomite, dolomitic limestone, gypsum, and chert nodules. In order to achieve the aims, the Jeribe formation and Oligocene units were chosen in Khabaz oil field. The Khabaz oilfield is located between the Jambour and Bai Hassan oilfields, 23 km to the southwest Kirkuk Governorate (fig. 1).

The field has area of about 72 km as 18 km long and 4 km width. It is pointed out as a subsurface asymmetrical anticline.

The structure contour map reveals that the Khabaz field is formed of subsurface asymmetrical anticline dome with 155 m to 177 m thickness. with a normal fault perpendicular to the axis of fold on the southeast side of the field in the area where the B1 and B2 are located according to the field data and contour map of the formation [10].

During the last decades, the lithostratigraphy and structural setting of the Mesopotamian Basin have been extensively studied. The basin extends between the Tigris and Euphrates rivers, covering most of Iraq and parts of Syria and southeastern Turkey. It is divided into northern and southern sub-basins, with the northern basin spanning from the Tigris in the north to Baghdad, and the southern basin extending from Baghdad to the Arabian Gulf. These studies provide valuable insights into the geological framework and evolution of the region [11].

The thickness of the Khurmala formation varies throughout the field, ranging from 100 m at the northeastern limb of the Taq Taq anticline to 109 m at the southeast plunge. In other areas, it is 50 m in Aqra, 15 m in Shaqlawa, 40 m in Bekhma, 80 m in Koisanjaq, and 42 m in Tawke [12]. The formation is characterized by miliolids, small valvulinids, clavulinids, and very rare «ghosts» of indeterminable alveolinids, which are largely obliterated by recrystallization and dolomitization. Algae fragments and small gastropods are also present but cannot be identified with specificity. The Khurmala formation is dated to the Paleocene to Lower Eocene [13].

This age is largely determined by the stratigraphic position of the formation in the sequence. The formation has a thickness of 15 meters at the studied outcrop location. Based on field observations, the rock succession is divided into three units. The bottom part is a thin yellow bed of marl, the following medium unit is a thin bed of marly limestone, and the upper unit is a massive limestone. The oil column in Tawke is currently estimated to be 180 meters in the Paleocene reservoir and 900 m in the Cretaceous reservoir [14].

The lithostratigraphic column of the Khabaz oilfield is completely shaped of sedimentary rocks that belong from the Late Jurassic to the recent. The lithostratigraphic column is constituted of cycles of clastic sandstone carbonate, and evaporite rocks.

3. Methodology

The present study focused on two wells, A1 and A2, from the Khabaz oilfield, utilizing available well logs to analyze the petrophysical properties. A gamma-ray log was employed to calculate the shale volume, while neutron density, and sonic logs were used to estimate total, effective, and secondary porosity. Additionally, a resistivity log was applied to calculate both water and oil saturation, contribut-

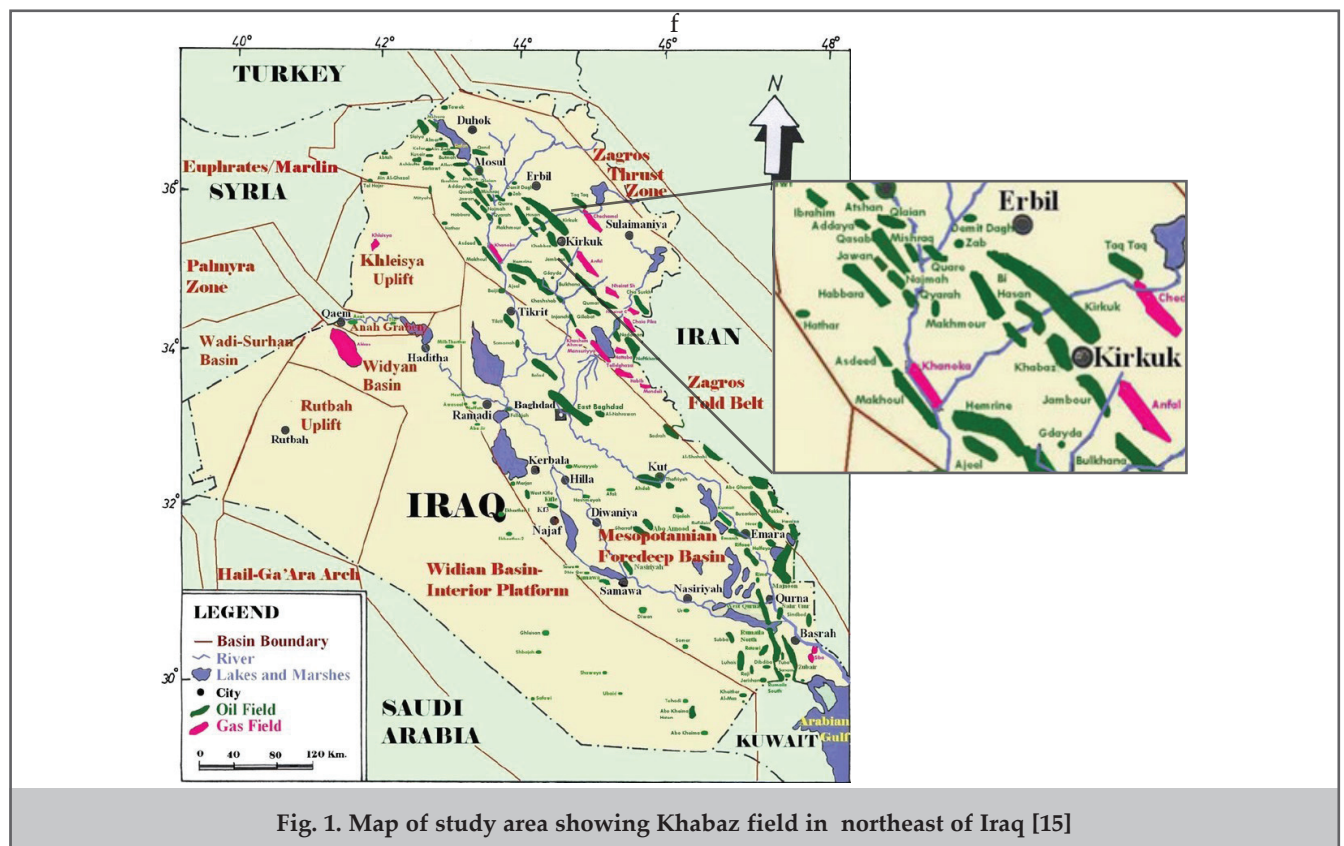


Fig. 1. Map of study area showing Khabaz field in northeast of Iraq [15]

Well name	Easting	Northing	Depth m
A1	417 650	3932 200	3350
B1	425 502	3927 730	3120
B2	424 685	3927 939	3294
A2	423 850	3929 471	3100

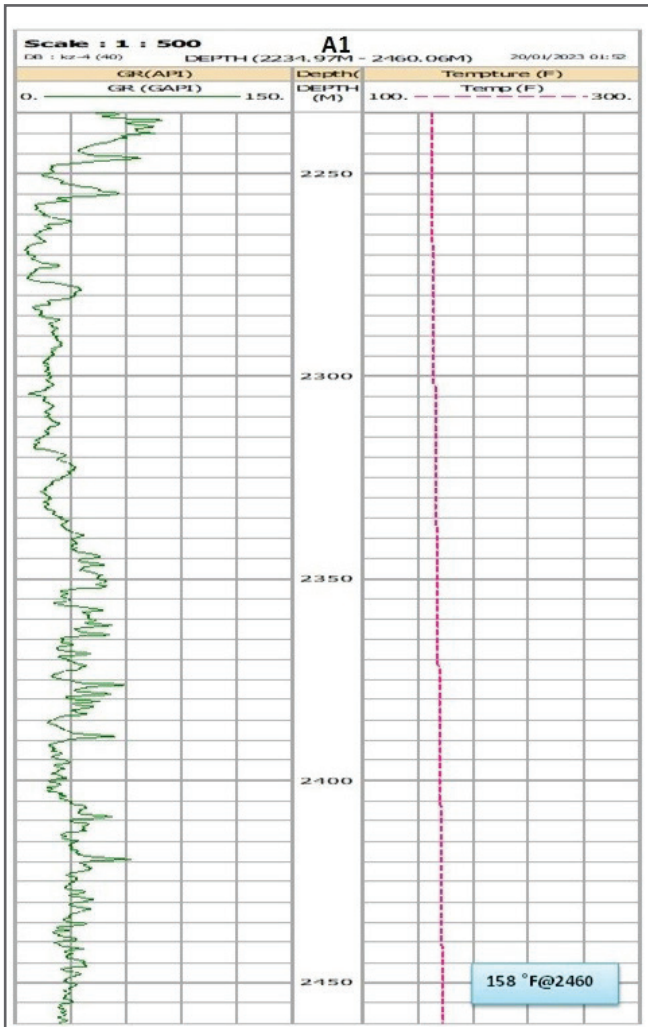


Fig. 2. Formation temperature of the Jeribe formation and Oligocene units in the selected boreholes (A1)

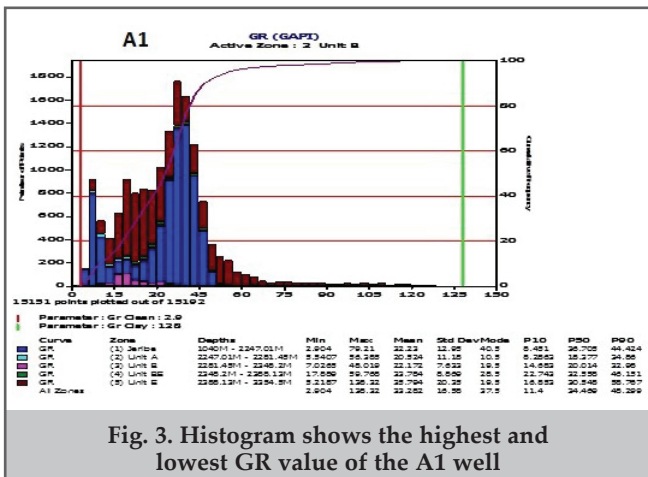


Fig. 3. Histogram shows the highest and lowest GR value of the A1 well

ing to the analysis of porosity, lithology description, mineral composition, and shale volume.

The methodology began with the collection of digital well log data for wells A1 and A2, obtained from the North Oil Company. These logs were scanned and converted from their original paper or image formats into digital data in LAS format, which allowed for easier processing through the software Neuralog V2010.11. Following this, the petrophysical properties were analyzed using the Interactive Petrophysics v3.6 software. This analysis included the calculation of porosity, using common mathematical equations and standard Schlumberger charts [16], applied to the well log data.

The data from the A1 well, alongside the reports and maps of the wells, were integral to this study. The Khabaz field's Jeribe formation was the focus, with the well coordinates and gross depths detailed in table 1 [10].

Well logs data were processed and petrophysical properties were calculated using the Petrophysical Interactive (IP) software. The petrophysical properties including porosity (density of the formation matrix ρ_{ma} 2.8 gm/cc) and sonic logs (interval transit time of formation matrix Δt_{ma} 45 μ sec/ft), permeability water saturation and N/G ratios were modeled and distributed across the Khabaz field using Petrel software. The steps of creating the study are as follow:

The reservoir then was divided into zones and layers depended on the porosity results achieved from the well logs. The arithmetic method was utilized to scale up of petrophysical properties porosity, water saturation and net to cross values. The lithology of the reservoir was identified by combination between M-N Cross Plot method, which used in study as well as compared to field observation (final geological reports).

Petrophysical modeling is performing an operation of distributing the fully set of continuous log properties to the reservoir as completely [17]. Three-dimensional property modeling processed based on well logs data (neutron, density, sonic, gamma, caliper and resistivity logs e.g. LLD, MSFL and LLS). The properties were distributed between the wells of study. Consequently, it realistically conserves reservoir heterogeneity and matches the well information [18].

The porosity values that gained by utilizing the well logs (density, neutron and sonic) which was used to build porosity model. Equations used in calculations as the following:

$$\varnothing_{N-D} = \frac{\varnothing_N + \varnothing_D}{2} \quad (1)$$

where \varnothing_D – porosity from density log; \varnothing_N – porosity from neutron log.

$$\varnothing_e = \varnothing_t \times (1 - V_{sh}) \quad (2)$$

where \varnothing_e – Effective porosity; \varnothing_t – Total porosity ($\varnothing_{(N-D)}$); V_{sh} – shale volume.

4. Determining formation temperature

1. Formation temperature is essential information required in log interpretation while resistivities of drilling mud, mud filtrate and formation water are changing with temperature. The temperature of formation becomes higher when the depth increases. Thence, it is of importance for log analysis. The varying temperature degrees with depth is called geothermal gradient, which changes at various areas depending on yearly surface area, but, average tem-

perature gradient Gt of (3.0 °F/100 m) depth has been registered all over the world.

- The formation temperature can also be determined by the linear regression equation illustrated below [19] (fig. 2).

5. Reservoir characterizations

5.1. Shale volume determination

Shale volume in Khabaz oilfield was calculated by employing GR technique that has some models.

The preliminary stage to decide the shale volume is measured of gamma ray index.

The process of calculating gamma ray is the first step to measuring shale volume. By using the following equation, [20]:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (3)$$

where I_{GR} – gamma ray index; GR_{log} – gamma ray reading of formation; GR_{min} – minimum gamma ray (clean sand or carbonate); GR_{max} – maximum gamma ray (shale)

The second step is application of [21] equation, which is special for after Cretaceous age successions

$$V-Shale = 0.083 \times (2^{(3.7 \times I_{GR})} - 1) \quad (4)$$

The shale volume accounts of the Jeribe formation and Oligocene units' samples can be offered with depth illustrating the vertical distribution within the formation stratigraphy (fig. 4).

5.2. Porosity estimation

From both geological and reservoir engineering perspectives, porosity is considered one of the most critical rock properties

$$\text{porosity } \varnothing(\%) = \frac{V_b - V_{gr}}{V_b} \times 100 = \frac{V_p}{V_b} \times 100 \quad (5)$$

where V_b – bulk volume, V_{gr} – grain volume.

There are various types of porosity logs, as outlined below:

1. Neutron Log:

Neutron logs measure the quantity of hydrogen in a formation. In clean, shale-free formations where the pores are filled with water or oil, the neutron log measures the fluid occupying the pores (PHIN). The purposes of interpreting neutron logs are:

- Porosity
- Lithology identification
- Gas indication

2. Density Log:

Gamma rays from a chemical source (Co60) interact with the electrons in the formation's elements. The formation bulk density (ρ_b) is a function of the matrix density, porosity, and

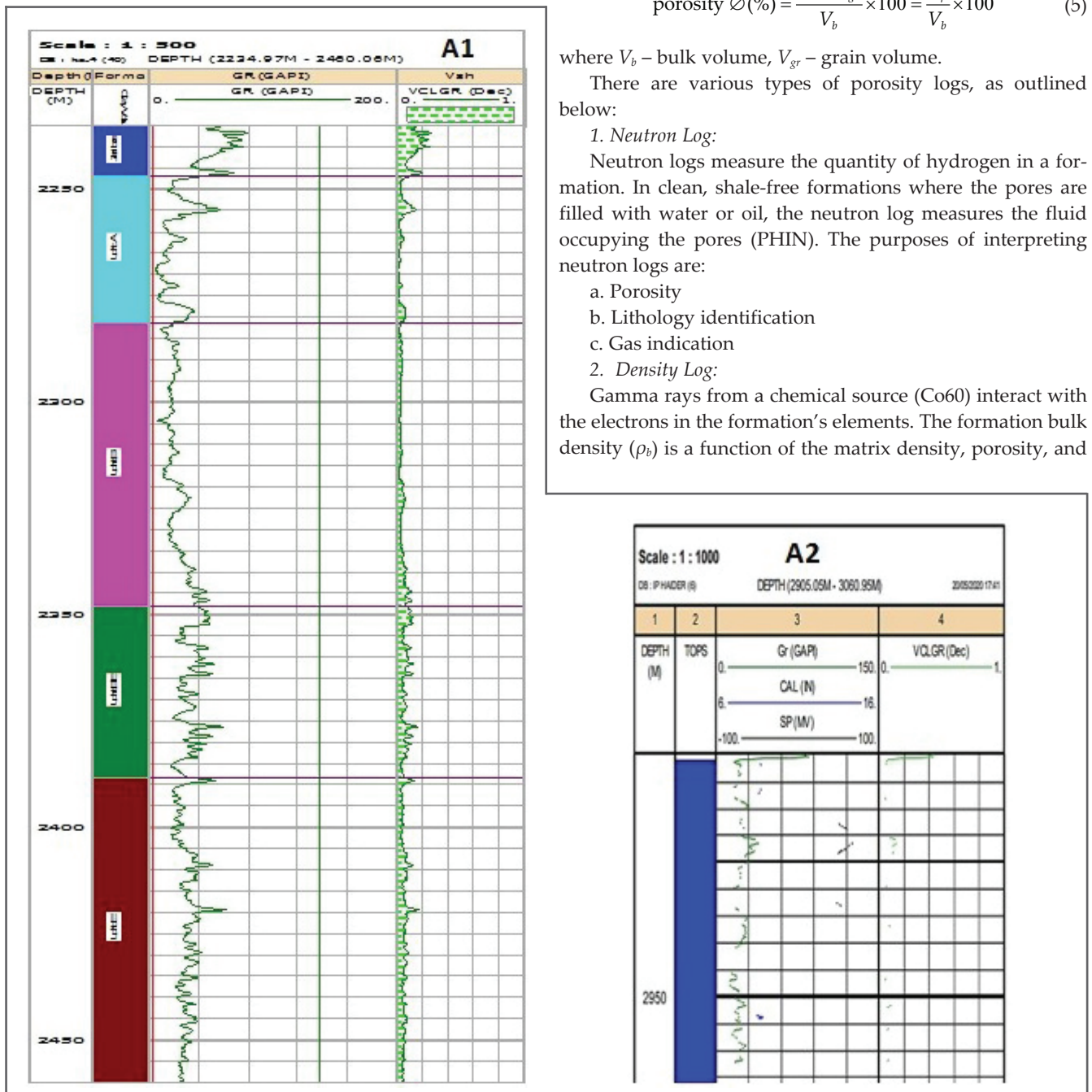


Fig. 4. Shows the relationship between GR and V. Sh. to the Jeribe formation and Oligocene units A1 and A2

fluid density in the pores. The purposes of interpreting density logs are:

- a. Porosity
- b. Lithology identification
- c. Gas indication

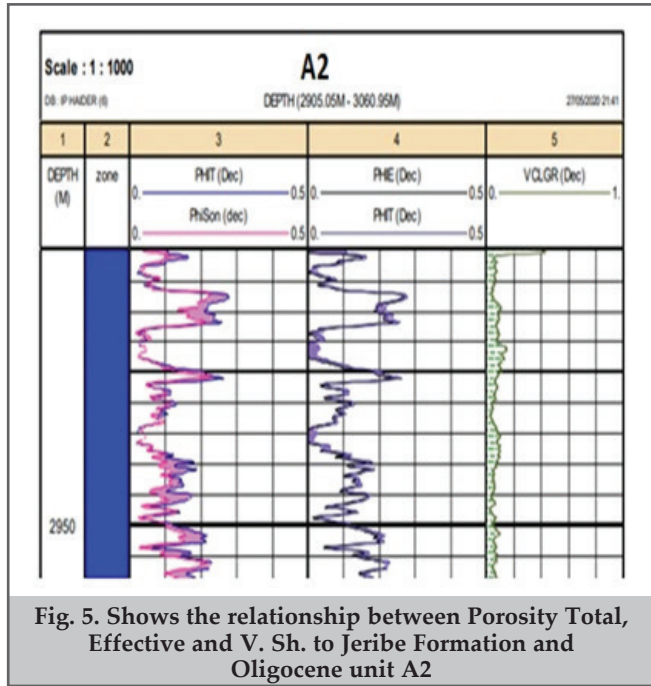


Fig. 5. Shows the relationship between Porosity Total, Effective and V. Sh. to Jeribe Formation and Oligocene unit A2

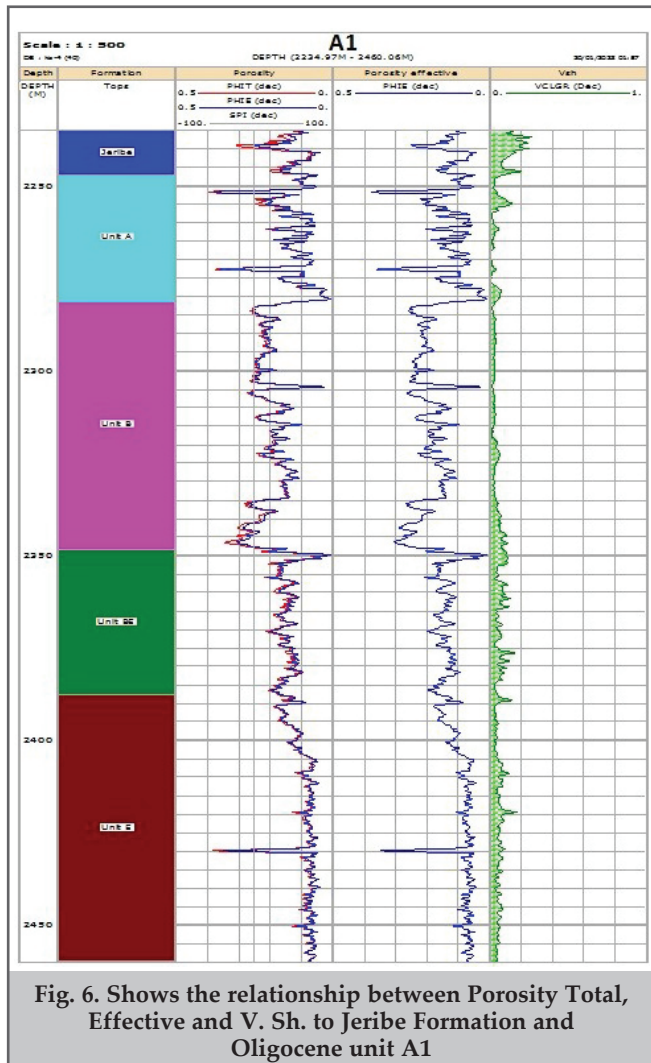


Fig. 6. Shows the relationship between Porosity Total, Effective and V. Sh. to Jeribe Formation and Oligocene unit A1

3. Sonic Log:

Sonic logs measure the interval transit time (Δt) of a compressional sound wave traveling through the formation along the borehole axis. Sonic logs record matrix porosity but do not account for secondary porosity from fractures or vugs. The purposes of interpreting sonic logs are:

- a. Porosity
- b. Lithology identification
- c. Cement bond quality

The total porosity (\varnothing_t) is calculated using the following equation:

$$\varnothing_t = \frac{\varnothing_D - \varnothing_N}{2} \quad (6)$$

where \varnothing_t =total porosity; \varnothing_D =porosity of density log; \varnothing_N =porosity of neutron log.

$$\varnothing_p = \frac{(\rho_m - \rho_b)}{(\rho_{ma} - \rho_f)} \quad (7)$$

where \varnothing_p =porosity from the density log; \varnothing_b =bulk density from the log; \varnothing_{ma} =matrix density; \varnothing_f =fluid density of fluid.

Attributing to Schlumberger (1972), density of the matrix (ρ_{ma}) of the Jeribe dolomite succession is 2.876 gm/cm³, and density of the fluid (ρ_f) is 1.1 gm/cm³. The matrix densities of the Oligocene units are as follows:

- Unit A: Density of the matrix for carbonate succession is 2.71 gm/cm³, and density of fluid (ρ_f) is 1.1 gm/cm³.
- Unit B: The matrix density of the dolomite succession is 2.876 gm/cm³, and the fluid density (ρ_f) is 1.1 gm/cm³.
- Unit E and BE: The matrix density of the carbonate succession is 2.71 gm/cm³, and the fluid density (ρ_f) is 1.1 gm/cm³.

Effective porosity (\varnothing_e), which represents the pore volume containing hydrocarbons and free formation water (excluding clay-bound water), can be calculated using the following equation

$$\varnothing_e = \varnothing_t \times (1 - V_{sh}) \quad (8)$$

Secondary porosity is measured by the difference between the total porosity (from neutron and/or density logs) and the sonic log, represented by the secondary porosity index (SPI)

$$SPI = \varnothing_t - \varnothing_s \quad (9)$$

where \varnothing_t =total porosity; \varnothing_s =porosity from the sonic log.

The porosity calculation using the sonic log revealed variations in the lithological properties of the Jeribe formation and Oligocene units. To account for these lithological changes, the sonic porosity was calculated using the following equation (Eq. 9), adjusted according to the lithological differences observed in the studied intervals of well A1 (Wyllie typical values):

$$\varnothing_s = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_{fl} - \Delta t_{ma}} \quad (10)$$

Matrix Δt : 51-55 $\mu\text{sec}/\text{ft}$ (SS); 47.5 $\mu\text{sec}/\text{ft}$ (LS); 43.5 $\mu\text{sec}/\text{ft}$ (DOL) and fluid Δt : 189 $\mu\text{sec}/\text{ft}$ (saltwater)

The lithology of the Jeribe formation and unit B, composed of dolomite, has a matrix travel time (Δt_{ma}) of 43.5 $\mu\text{sec}/\text{ft}$, while the fluid travel time (Δt_{fl}) for the saltwa-

Divisions of reservoir rocks of the Jeribe formation and Oligocene units in well A1 Khabaz oilfield				
Formation or unit	Zones	Depths	Type of rock	Porosity value
Jeribe formation		(12 m) thick in that located between (2235-2247 m)	Dolomite with very few of the marl	Fair to good (12-17%)
Oligocene units	A	About (34 m) thick that located between (2247-2281m)	Limestone	Fair to very good (12-25%)
	B	About (67 m) thick that located between (2281-2348 m)	Dolomite with very few of the micro fractured	Good to very good (20-30%)
	C	About (40 m) thick in A1 that located between (2348-2388 m)	Limestone	Fair to good (12-17%)
	D	About (72 m) thick that located between (2388-2460 m)	Limestone	poor (5.5-7%)

ter-based drilling mud is 189 $\mu\text{sec}/\text{ft}$. In contrast, the lithology of unit A, unit BE, and unit E, composed of limestone, has a matrix travel time (Δt_{ma}) of 47.5 $\mu\text{sec}/\text{ft}$, with the same fluid travel time (Δt_{fl}) of 189 $\mu\text{sec}/\text{ft}$.

Figure 5 demonstrates the relationship between porosity and secondary porosity (SPI) for well A1. Despite high secondary porosity values in certain Oligocene units, the total porosity remains the highest. There is no significant difference between the total and effective porosity in some smaller units, primarily due to the influence of shale volume.

Porosity varies from high to good in some zones (such as zone B), while it is less favorable in other sections, particularly in the lower part of the reservoir. The highest secondary porosity index (SPI) is noted in Zone B, where the shale volume is relatively low, indicating a nearly clean zone (as indicated by the gamma ray log) (fig. 6).

6. Divisions of reservoir rocks of the Jeribe formation and Oligocene units

According to the values of porosity for mentioned (A1 and A2) wells, the Jeribe formation and Oligocene unit's successions according to North porosity classification [22] are detached into divided to subzones as above table 2.

7. Identification of lithology and mineralogy

Lithology is a most geological expression employed to explain the kinds of formation rocks. Reservoir lithology and features are the basis for the study of the formation of reservoirs.

Various lithologies appear within the reservoir of various reservoir levels.

The lithology of the reservoir was evaluated by neutron-density cross plot and M-N cross plot, which utilized in the petrel software.

7.1. Neutron-density cross plot for lithology identification

This plot is essential for a lot of log interpretation processes. Plot of ρ_b vs. ϕ_N gives a clear lithology description with minerals quartz, dolomite and calcite [23].

By depending on neutron density cross plots, it is possible to detect the Jeribe formation sequences and subunits which are dependent on the Oligocene for well (A1), where most points can be seen concentrated in limestone line and some others between limestone and dolomite lithology lines, as shows in (fig. 7).

7.2. M-N cross plot for mineral identification

In other more sophisticated mineral structures, lithology explanation is made easier by using M-N plot [9]. This technique mixed three porosity logs emerging in the lithology. Depending on the sonic-density and density-neutron cross plot charts. Plotting M values against those N, the chart has one spot of individual mineral calcite, dolomite, sandstone, gypsum, sulfur, and secondary porosity parts [24].

Each well investigated reveals that most spots are grouped at calcite and dolomite areas whereas the rest scatter in secondary porosity areas. It is also noted that there are a number of points scattered in the region of gas presence in the upper right of the figure, as shown in (fig. 8).

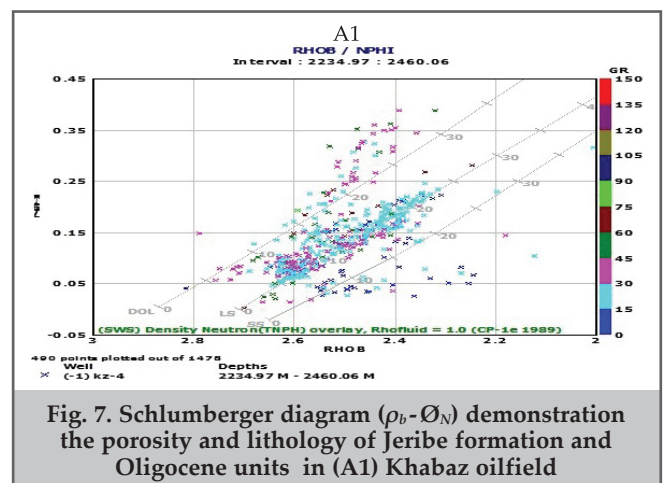


Fig. 7. Schlumberger diagram ($\rho_b - \phi_N$) demonstration the porosity and lithology of Jeribe formation and Oligocene units in (A1) Khabaz oilfield

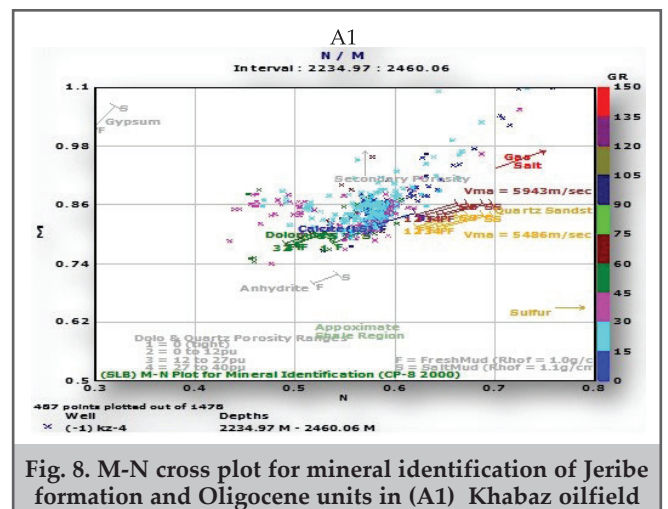


Fig. 8. M-N cross plot for mineral identification of Jeribe formation and Oligocene units in (A1) Khabaz oilfield

Where:

$$M = \frac{\Delta_{flog} - \Delta_{tlog}}{\rho_b - \rho_f} \quad (11)$$

$$N = \frac{\varnothing_{Nf} - \varnothing_N}{\rho_b - \rho_f} \quad (12)$$

Δ_{flog} —transit travel time from sonic log $\mu\text{sec}/\text{ft}$; Δ_{tlog} —time of transit travel for formation fluid equal 189 $\mu\text{sec}/\text{ft}$; \varnothing_N —porosity from neutron log; \varnothing_{Nf} —porosity for the formation fluid equal 1; ρ_b —bulk density from density log g/cc ; ρ_f —bulk density of the formation fluid equal to 1 g/cc .

8. Determination of archie parameter (a, m, n)

Archie equation in carbonate reservoir is rather difficult because of the increasing dependency of its parameters on carbonate characteristics. The three parameters of Archie (m, n, a) for reservoir were selected by employing Pickett plot shown in table below. Carbonate pore geometry and wettability experience have a lot of impact on the cementation exponent (m) and saturation exponent (n) of Archie’s formula. Hence, the Archie’s parameters (a, m, n) experience the greatest impact on reservoir volume calculation, while resistivities are of lesser importance (table 3).

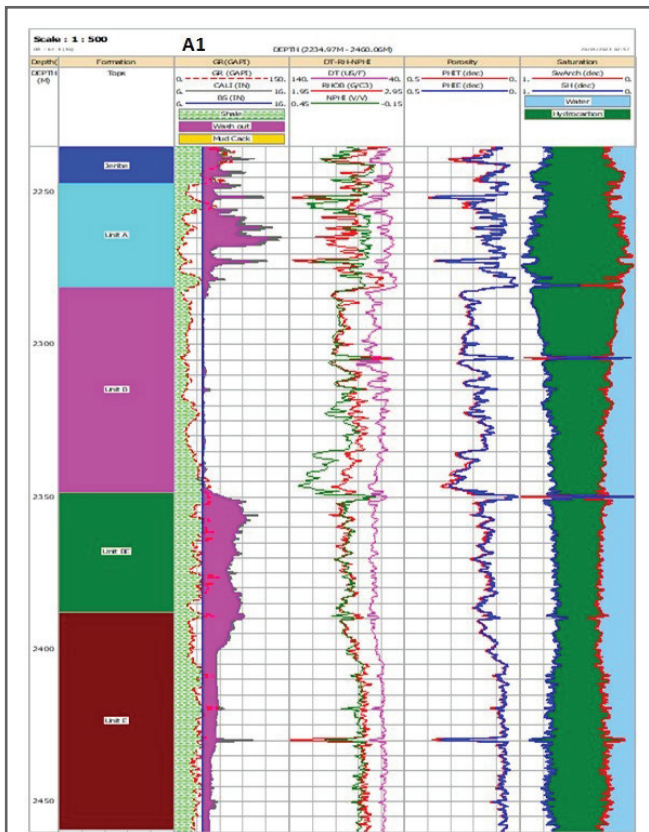


Fig. 9. Divisions of reservoir rocks and saturation of hydrocarbon and water of the Jerbie formation, Oligocene units in the A1 well

Archie parameter (a,m,n) in well A1 Khabaz oilfield			
Well no.	a	m	n
A1	1.04	1.47	2.1

9. Reservoir fluid and formation analysis

Fluid analysis (water and hydrocarbon saturation):

1 – In fact, assessing the reservoir fluids is a basic criterion of prospect assessment.

Development programming, and reservoir administration [25].

2 – Water saturation value is necessary to estimate of reserves, formation water resistivity (R_w) at formation temperature is necessary for water saturation calculation [26].

Connate water saturation (S_w) and flushed zone water saturation (S_{xo}) can be calculated from information supplied by well logs.

Flushed zone saturation (S_{xo}) is the fraction of the pore volume filled with flushing agent (normally drilling fluid). However, from the laboratory information of reservoir water, it showed that the value of salinity that is equivalent to NaCl in well A1 recorded 142160 ppm at 75 °F [10] (table 4).

By claim, hydrocarbon saturation can be measured as follows:

$$R_{w75} = \frac{1}{2.74 \times 10^{-4} \times CSP^{0.955}} + 0.0123 \quad (13)$$

$$R_{w@ft} = R_{w75} \frac{81.77}{ft + 6.77} \quad (14)$$

where R_w – water resistivity at 75 F for formation; $R_{w@ft}$ – water resistivity at temperature F for formation; CSP – NaCl concentration in ppm; P_{pm} – part per million.

Water saturation of a reservoir’s uninverted zone is calculated using the Archie (1942) formula (43):

$$S_w = \left(\frac{a}{\varnothing^m} \times \frac{R_w}{R_t} \right)^{\frac{1}{n}} \quad (15)$$

Water saturation related to the flushed zone (S_{xo}) relies on Archie’s equation as well. However, two elements are replaced to the equation below:

$$S_w = \left(\frac{a}{\varnothing^m} \times \frac{R_{mf}}{R_{xo}} \right)^{\frac{1}{n}} \quad (16)$$

$$S_h = 1 - S_w \quad (17)$$

3 - Movable hydrocarbon saturation (named the movable oil index or the producible oil index POI) is illustrated in the equation below [27]:

$$M_{os} = S_{xo} - S_w \quad (18)$$

Residual and movable hydrocarbon saturations are calculated from the equations below:

$$R_{os} = 1 - S_{xo} \quad (18)$$

The BVW is the part of the rock which is evaluated to be formation water:

$$BV_w = S_w \times \varnothing \quad (20)$$

The is the part of the rock which is evaluated to be of water Invaded zone:

Resistivities and Formation temperature in well A1 Khabaz oilfield			
Well no.	FT	$R_{w@FT}$	$R_{mf@ft}$
A1	177	0.025	0.230

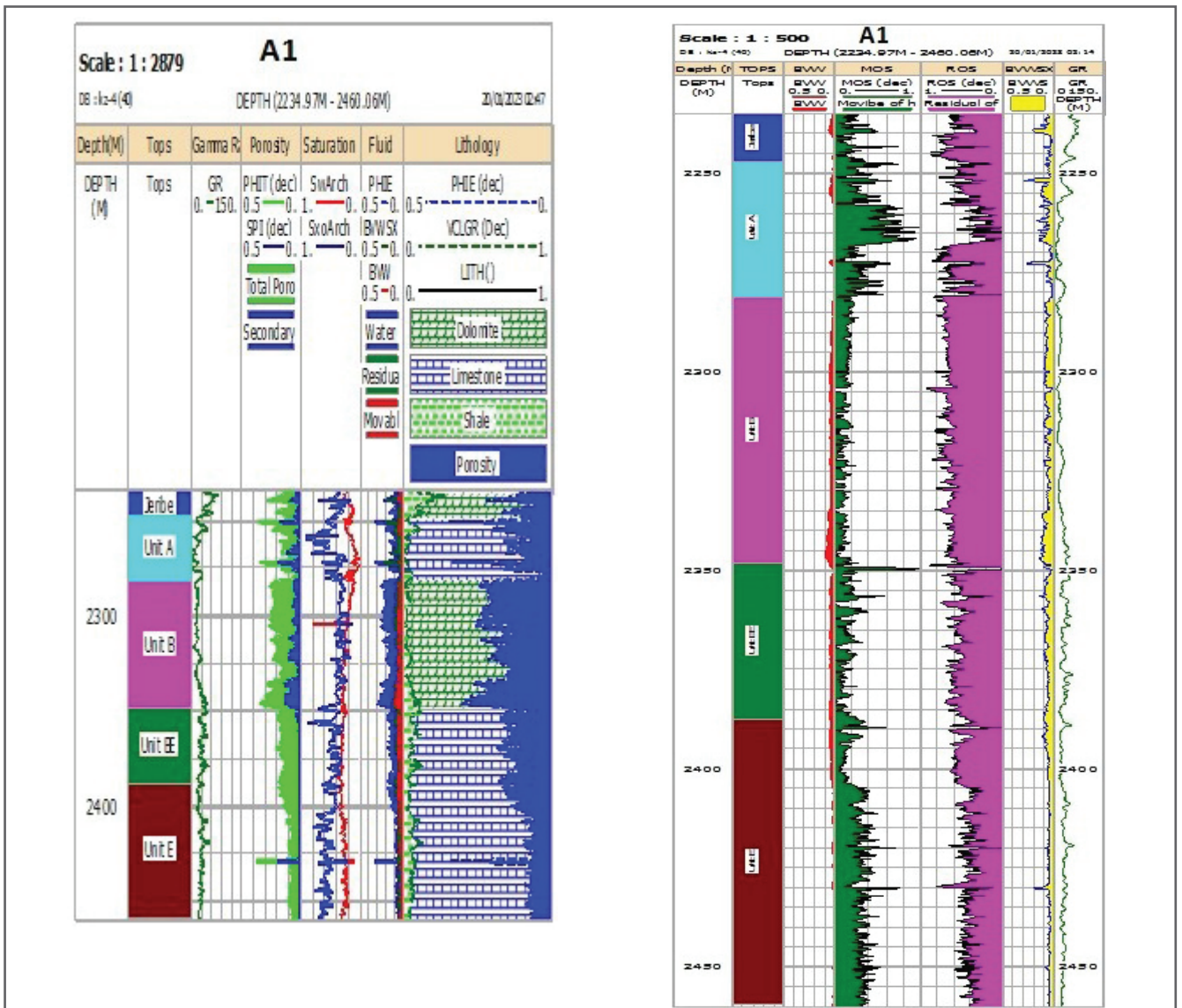


Fig. 10. Fluid analysis (water and hydrocarbon saturation) of the Jerbie formation, Oligocene units in the A1 well

$$BV_x = S_{x0} \times \varnothing \quad (21)$$

Moveable hydrocarbon saturation is calculated as follows:

$$S_{mo} = S_{hy} - S_{hr} \quad (22)$$

or

$$S_{mo} = S_{x0} - S_w \quad (23)$$

where S_{hy} – hydrocarbon saturation.

Computer processes interpretation (CPI) is the outcome of log analyses and clarifications in significant ways for the majority of petrophysical features of reservoirs. The graph illustrates multi columns properties of the reservoir for example (porosity, fluid, lithology, and bulk volumes) analysis which signifies continuous spread of petrophysical features of the formation of rock. These data aid to assess the role of diagenesis in consolidating or lessening reservoir quality [28].

As for well A1 a selected study for Tertiary reservoir of Khabaz oilfield. Its outcomes of CPI plotting were indicated that best promising zones have a good movable hydrocarbon values in unites A and E, despite of porosity values is good for unite B (as shown in track of porosity).

10. Permeability estimation

Permeability, is a measure of how easily fluids can flow through porous rocks. It is one of the most important requirements for reservoir rocks. It is measured in millidarcies (md), where 1 md is 1/1000th of a darcy. Since rock permeability relies solely on effective porosity. It is greatly influenced by grain size, shape, distribution, packing pattern, matrix type, isotropy and homogeneity (Asquith, 2004). Additionally, permeability is affected by the degree of cementation, rock compaction, type and amount of infilling material, and can be classified into five categories, as shown in the table 5 by [22].

md	Type of permeability
<1-15	Poor to fair
15-50	Moderate
50-250	Good
250-1000	Very good
>1000	Excellent

Depth (m)	Formation	a	b	c
2235-2247	jaribe	195777.38	6.928	2.1
2247-2281	Unit A	429.925	5.243	2.3
2281-2348	Unit B	60.36	2.375	1.9
2348-2388	Unit BE	182275.44	6.081	0.346
2388-2460	Unit E	86202.9	7.657	2.1

In the current study, the permeability of the Jeribe formation and Oligocene units in well A1 was analyzed based on reports provided by the South Oil Company. These permeability values generally correlate with porosity values, with high permeability observed in certain units, such as unit B, and low permeability in others, like Jeribe and unit A. The lowest permeability was observed in unit E. Based on the available data from the company and using Wyllie’s equation, the permeability values for each unit were calculated as follows (table 6):

$$K = a \frac{\varnothing^b}{S_{wi}^c} \tag{24}$$

where K – permeability (md); \varnothing – porosity (fraction); S_{wi} – irreducible water saturation (fraction); a, b, c – are statistically determined method parameters for each study.

Using these parameters and the permeability data obtained from the company reports, permeability for each of the units above was calculated using the IP software and Wyllie’s method. Based on North’s (1985) classification, the permeability for each unit is as follows:

– Jeribe formation:

This formation consists of dolomite with very little marl, and has a thickness of around 12 meters, between the depths of 2235-2247 meters in well A1. The permeability of these rocks is described as moderate (15 md).

– Oligocene formation:

This formation is divided into several units:

- Unit A: Composed of limestone, this unit has a thickness of approximately 34 meters, between the depths of 2247-2281 meters. The permeability is classified as good (87 md).
- Unit B: Composed of dolomite with micro-fractures, this unit has a thickness of about 67 meters, between the depths of 2281-2348 meters in well A1. The permeability is classified as very good (250-1000 md).
- Unit BE: This unit, composed of limestone, has a thickness of about 40 meters, between the depths of 2348-2388 meters in well A1. The permeability is classified as good (80 md).
- Unit E: Composed of limestone, this unit has a thickness of about 72 meters, between the depths of 2388-2460 meters in well A1. The permeability is described as negligible, with values of less than (1 md).

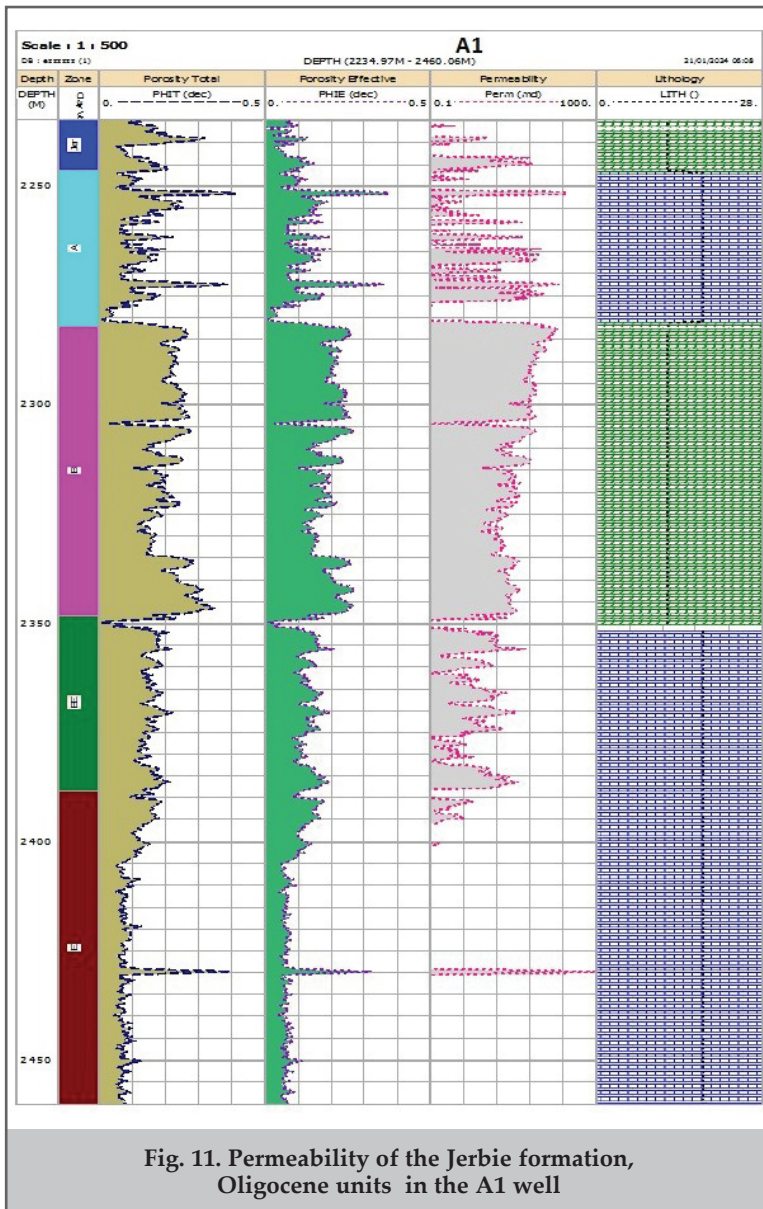


Fig. 11. Permeability of the Jeribe formation, Oligocene units in the A1 well

Conclusions

1. Temperature measurement: As illustrated in (fig. 2), the temperature in well A1 increases at a rate of 4 degrees for every 100 meters. At a depth of 2460 meters, the temperature recorded at the base of the last unit of the formation was 158 °F.
2. Shale volume measurement: (fig. 4) indicates that the volume of shale within the Jeribe formation in well A1 exceeds 20%, although it represents a small portion of the drilled interval.
3. Porosity relationship: (fig. 4) demonstrates the relationship between porosity and secondary porosity (SPI) for well A1. Despite the high values of secondary porosity observed in certain units of the Oligocene formation, the overall total porosity remains the highest. There is no significant difference between total porosity and effective porosity in some smaller units, primarily due to the absence of shale volume. Unit B, as shown in (fig. 5), exhibits the highest SPI, indicating it is the most porous area in the reservoir. Therefore, this unit can be considered a crucial zone regarding permeability and storage capacity in the Tertiary reservoir.
4. Formation classification: Based on the calculated porosity values for the selected intervals using indirect methods (logs) and effective porosity, the Jeribe formation and Oligocene units were divided into several categories:
 - Jeribe formation: This formation consists of dolomite with minimal marl content and has a thickness of approximately 12 meters between depths of 2235-2247 meters. The porosity of the rocks in this range is classified as moderate (12-17 %), thus qualifying as intermediate reservoir rocks according to traditional exploration literature.
 - Oligocene formation: This formation is subdivided into several units:
 - Unit A: Composed of limestone, with a thickness of about 34 meters between depths of 2247-2281 meters, the porosity is classified as good (12-25 %), qualifying as very good reservoir rocks.
 - Unit B: Characterized by dolomite and micro-fractures, with a thickness of approximately 67 meters between depths of 2281-2348 meters, this unit has a porosity classified as very good (20-30 %).
 - Unit BE: This unit, also composed of limestone, has a thickness of around 40 meters between depths of 2348-2388 meters, with porosity classified as good (12-17 %), thus defined as good reservoir rocks.
 - Unit E: Comprising limestone, this unit has a thickness of approximately 72 meters between depths of 2388-2460 meters in well A1, and is classified as having negligible to weak porosity (5.5-7 %), qualifying as poor reservoir rocks according to traditional exploration literature.
5. Rock composition: (fig. 7) illustrates that the Jeribe formation and Oligocene units are primarily located between limestone and dolomite, indicating that the Tertiary reservoir in the Khabaz field is fundamentally composed of a matrix combination of limestone and dolomite.
6. Mineral composition: By plotting the M-N values according to the selected section, the analysis indicates that the formations consist of a mixture of limestone and dolomite, as well as secondary porosity, shown by the intersection of the M-N plot with the ρ_b curve relative to porosity (ϕ_N), as depicted in (fig. 8).
7. Hydrocarbon concentration: Figures 9 and 10 indicate that the highest concentration of movable hydrocarbons (MOR) in the Tertiary reservoir is found in small sections of the Jeribe unit, with a high percentage in unit A and the upper part of unit B. Additionally, the water zone is clearly evident in unit E.
8. This study provides a comprehensive analysis of the permeability characteristics of the Jeribe formation and Oligocene units in well A1, utilizing data from the North Oil Company and applying Wyllie's equation for permeability calculations. The findings highlight the critical role of effective porosity in determining permeability, which is significantly influenced by factors such as grain size, shape, distribution, packing patterns, cementation, and rock compaction.

The analysis reveals that the permeability values vary considerably across different units. The Jeribe formation demonstrates moderate permeability, attributed to its dolomitic composition with minimal marl content. In contrast, unit B exhibits high permeability, classified as very good due to its dolomite composition with micro-fractures. Units A and BE also present favorable permeability levels, while unit E shows negligible permeability, indicating limited fluid flow potential.

Overall, the correlation between permeability and porosity across the analyzed units underscores the importance of these properties in assessing reservoir potential. This study contributes valuable insights into the hydrocarbon reservoir characteristics of the Khabaz field, essential for effective resource management and exploration strategies.

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