A Comprehensive Case Study on Estimating Petrophysical Properties in the Upper Shale Member of Luhais Oilfield's Zubair Formation

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Abstract
The Cretaceous period is renowned for the substantial oil reservoirs that were deposited during the Barremian epoch. The Zubair Formation is typified by sandstones, shales, and siltstones of layers. In the Luhais oil field, the Upper Shale Member has been identified as a source of oil, making it the subject of this research paper, which aims to evaluate the petrophysical properties of Cretaceous reservoirs in the Zubair Formation. The study utilized open-hole log data with thorough quality control of selected open-hole log data, including gamma-ray, caliper, neutron porosity, bulk density, sonic, and resistivity data. Four wells from the Luhais oil field (Lu-07, Lu-08, Lu-38, and Lu-39) were analyzed to evaluate the petrophysical properties. The analysis divided the formation into six main units and corrected formation tops for Upper Shale Member units USM (USM-1A, USM-1B, USM-1C, USM-1D, USM-1E, and USM-1F). To determine the permeability log, the study established a relationship between the quality-controlled Open Hole log and routine core analysis data, including Core Porosity CPOR and Core Permeability KAIR. Two statistical techniques were employed: classical and Multilinear regression. Equations were derived from both methods using core data from Lu-07 and Lu-08. The R-squared value was 0.76 in the classical method and 0.78 in the multilinear regression method. These equations were then used to estimate the permeability log for uncored wells (Lu-38 and Lu-39). The final analysis provided estimations for petrophysical average properties such as shale volume, porosity, fluid saturation, and permeability. The study also identified the net reservoir and net pay, which should facilitate the identification of reservoir and non-reservoir units of the field for future economic planning.

Keywords: Cretaceous reservoir; Luhais oilfield; Quality control; Upper shale member; Multilinear regression; Petrophysical average properties

1. Introduction

The Zubair Formation is a notable geological formation containing significant hydrocarbons in the lower Cretaceous period. It is primarily characterized by sequences of sandstone, shale, and siltstone layers, with limestone present in the uppermost part of the formation (Alsultan et al., 2021). The Zubair Formation is considered as a transition mature with intermediate hydrocarbon generation but with no expulsion (Al-Ameri, 2015). The Zubair Formation consists of five primary members. The Luhais oil field is divided into three distinct members, namely the upper shale member, the sand member, and the lower shale member. Removal of the middle shale member leads to the combination of the lower and upper sand members, giving rise to the middle sand member (Ashoor and Al-Muhalhal, 1999) (Alher et al., 2018).

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The Luhais oilfield, situated approximately 105 km west of Basrah city and 350 km southeast of Baghdad (Al-Garbawi and Al-Shahwan, 2019), occupies an area of around 900 km² with geographic coordinates of latitude 47°14’ to 47°19’ N and longitude 30°13’ to 30°24’ E (Albuslimi et al., 2021). The discovery of the oilfield dates back to 1961, with the first well being drilled at Luhais-1. Luhais oil field is connected to the Rumaila oilfield in pipeline degassing station PS1, as illustrated in Fig.1a. The Ratawi and Rachi fields are located to the east, whereas the Suba oilfield lies to the north.

The study primarily focuses on the upper shale member, which features a high concentration of shale (Ashoor and Al-Muhalhal, 1999). The concentration of shale in geological formations can significantly impact petrophysical properties, often resulting in challenges in interpreting open-hole log response data. Quality control measures are necessary to ensure that data accuracy and correlation with core data are reliable (Bateman, 2012). This is particularly crucial given the complexities involved in this type of analysis. Therefore, careful attention to detail is required to minimize errors and ensure that the results are reliable and can be used.

This research paper aims to accurately correct and analyze data to identify reservoir units for selected wells, as depicted in Fig.1b. Additionally, the paper seeks to determine the petrophysical properties of reservoir units, including shale volume, porosity, fluid saturation, and Permeability. These properties are essential in evaluating the amount of hydrocarbon accumulated in the reservoir and its economic value.

Fig.1. Geological maps present a detailed and thorough representation of the Luhais oilfield: (a) the precise location of the Luhais Oil Field, as indicated by Alher et al. (2018), and (b) the Zubair structural contour map for the study wells

2. Geological and Stratigraphic Description

The Luhais oil field situated in Iraq produces crude oil from Zubair and Nahr-Umar formations. (Al-Zaidy and Mohammed, 2017). The Zubair Formation was first discovered in the Zubair oil field by Glynn Jones in 1948 and was later revised by Nasr and Hudson in 1953. The Zubair Formation comprises sandstones, shales, and limestones that were deposited in a variety of environments, including fluvial-deltaic, deltaic, and marine (Al-Zaidy and Mohammed, 2017). In the Luhais oilfield, the uppermost part of the Zubair Formation consists of multiple domes and an asymmetrical anticline fold.
structure (Alher et al., 2018), as shown in Fig.1b of the upper shale structural contour map. The depth of the upper shale in the Zubair Formation varies from 2770 to 2848 m, with a total thickness of 78 m.

The formation is divided into six subunits based on lithology and depositional environment: USM-1A, USM-1B, USM-1C, USM-1D, USM-1E, and USM-1F. The Takhadid-Qurna transversal fault bounds it to the north, while the Al-Batin transversal fault in the Basra block bounds it to the south. According to Al-Garbawi and Al-Shahwan (2019), the field has a length of around 20 km and a width of 5-10 km. To create a structural map, the study area used was 6.5 km long and 5 km wide, based on the location of 11 wells. This approach was taken to increase the data density for the structural map.

The Zubair Formation represents a geological formation in the Zubair Subzone of the Mesopotamian basin. It was deposited during the early cretaceous period (Al-Zaidy, 2019), specifically during the Arabian Plate (AP8) sedimentary cycle of the Thamama Group and the Late Tithonian-Aptian secondary cycle, known as Barremian-Aptian, about 131-113 million years ago (Al-Aradi et al., 2022), as shown in Fig.2. a and Fig.2b. The formation is a regional characteristic that extends throughout Iraq, Kuwait, Saudi Arabia, Iran, and Syria, mainly comprising oil-producing sandstone and shale units. Notably, it has been reported to be a productive reservoir unit in this region, with significant hydrocarbon reserves (Harris et al., 2012). Moreover, the formation is situated within the stable shelf and is considered a regional feature (Jassim and Goff, 2006).

**Fig.2.** The stratigraphic column of southern Iraq. (a) represents the deposition of the Zubair Formation in the region, with modifications based on a study by (Al-Zaidy and Mohammed, 2017). (b) A log view explains the lithology and stratigraphy variations of the Zubair Formation and its members.
3. Materials and Methodology

3.1. Materials

3.1.1. Data preparation and quality control

Quality control is an indispensable aspect of data analysis and should be regarded as equally important as the data preparation process. The significance of log-quality control has been well-established in various studies, including Neinast and Knox of Sun Oil Company in 1973 (Bateman, 2012). It is essential to carry out quality control before analyzing data to ensure the validity and accuracy of the collected data. All data, such as open-hole logs and routine core analysis data, have been confirmed and authorized by Basrah Oil Company to be used in this research paper, as shown in Table 1. Therefore, ensuring that the collected data met the highest quality standards was imperative. Adherence to the following guidelines is critical: firstly, verifying whether the log covered the entire study area. Secondly, validate and confirm the accuracy of the data by analyzing the log response. Finally, ensure that the environmental corrections (mud cake, mud weight, matrix type, and hole size corrections) have been applied to the wireline log data (Al-Aradi et al., 2022).

Table 1. The available data and its applicable use in petrophysics

<table>
<thead>
<tr>
<th>Input Data</th>
<th>Curve Name</th>
<th>Units</th>
<th>Characteristic measured</th>
<th>Applications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gamma Ray</td>
<td>GR</td>
<td>API</td>
<td>Natural GR emissions from rock formations: high GR in shale and low in sand</td>
<td>Depth Shifting /Well-logs</td>
</tr>
<tr>
<td>Caliper</td>
<td>CALI</td>
<td>in</td>
<td>Borehole Diameter</td>
<td>Bad Hole Flag</td>
</tr>
<tr>
<td>Neutron Porosity</td>
<td>NPHI</td>
<td>v/v</td>
<td>Concentration of hydrogen</td>
<td>Total Porosity / Effective Porosity</td>
</tr>
<tr>
<td>Bulk Density</td>
<td>RHOB</td>
<td>g/cm³</td>
<td>The density of electrons measures thus the density of minerals and fluids in a formation.</td>
<td></td>
</tr>
<tr>
<td>Acoustic (Sonic)</td>
<td>DT</td>
<td>us/ft</td>
<td>Interval transit time of compressional waves</td>
<td>Primary Porosity</td>
</tr>
<tr>
<td>Resistivity</td>
<td>RT/RXO</td>
<td>ohm.m</td>
<td>Electrical resistivity of the entirety of formation (mineral and fluid, including adsorbed water and solutes)</td>
<td>Fluid Satuations</td>
</tr>
<tr>
<td>Core Porosity</td>
<td>CPOR</td>
<td>v/v</td>
<td>Measurement of Porosity and Permeability in the laboratory is part of RCA.</td>
<td>Estimation Permeability log</td>
</tr>
<tr>
<td>Core Permeability</td>
<td>KAIR</td>
<td>mD</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

3.2. Methodology

3.2.1. Lithology identification

The identification of lithology is an indispensable component of geological studies. In this regard, the lithology was identified by meticulously analyzing open hole logs, including gamma ray, neutron porosity, and bulk density data. Nevertheless, the primary interpretation of the open hole logs in the wells indicates that the predominant lithologies in the Luhaik oil field are sandstone and shale. The M-N plot analysis methodology can effectively establish the reservoir lithology with high accuracy, as shown in Fig. 3.
This methodology describes the equations proposed by Schlumberger (1997) for the two independent variables, M and N.

\[ M = \frac{\Delta t_f - \Delta t}{(\rho_b - \rho_f)} \times 0.01 \]  
\[ N = \frac{\phi_{nf} - \phi_n}{(\rho_b - \rho_f)} \]  

Where:
- \( \Delta t_f \) = Travel time of fluid within the formation, \( \mu s/ft \)
- \( \Delta t \) = Travel time of the formation, \( \mu s/ft \)
- \( \rho_b \) = The density of the formation, \( g/cm^3 \)
- \( \rho_f \) = The density of the fluid, \( g/cm^3 \)
- \( \phi_{nf} \) = The neutron porosity of the fluid, \( v/v \)
- \( \phi_n \) = The neutron porosity of the formation, \( v/v \)

Fig.3. M-N cross plot illustrates the type of lithology in the upper shale member

The methodology proposed by Schlumberger in 1997 entails describing two independent variables, M and N, to identify lithology concentrations in the reservoir while the Quanti Elan method is employed to determine lithology for each depth, offering quantitative evaluations of cased and open-hole logs and in-situ assessment of quantified logging data. Numerical optimization techniques are used to achieve these evaluations. The Quanti Elan model encompasses a three-way relationship triangle comprising T (tool vector), V (volume vector), and R (response matrix), which can be used to solve three types of problems, as shown in Fig.4. Schlumberger developed this advanced mineralogy assessment technique for use in Techlog software (Ali et al., 2022).
3.2.2. Estimation of shale volume

According to Kennedy (2015), shale within a reservoir rock can significantly affect its petrophysical properties, such as porosity, permeability, and water saturation. Compared to sandstone, shale has porosity and no permeability, making it less suitable for hydrocarbon storage and flow. Gamma-ray logs are widely used to estimate shale volume; the older rock equation developed by Larionov in 1969 was used to estimate the shale volume in the cretaceous period reservoirs (Upper Shale Member), as shown in equations (3) and (4).

\[
\text{IGR} = \frac{\text{GR}_{\text{log}} - \text{GR}_{\text{min}}}{\text{GR}_{\text{max}} - \text{GR}_{\text{min}}} \\
V_{\text{sh}} = \frac{0.33 \times 2^{(2 \times \text{IGR})} - 1}{\text{GR}_{\text{max}} - \text{GR}_{\text{min}}}
\]

Where:
- IGR = Gamma ray index, v/v
- GR<sub>log</sub> = Gamma-ray reading from the log, API
- GR<sub>min</sub> = GR reading in the clean zone, API
- GR<sub>max</sub> = GR reading in the Shale zone, API
- V<sub>sh</sub> = Shale volume, v/v

3.2.3. Estimation of porosity

Porosity is a crucial characteristic of rock formations that directly impacts the ability to store and transmit fluids. The sizes of these pores are of significant importance in determining the quantity of fluids that can be stored and identifying the reservoir. Various methods are available to calculate porosity, including density, density-neutron, and sonic. Among these methods, density is essential in this study, as it requires fewer corrections than other methods (such as mud weight and mud cake corrections). The density-neutron method tends to overestimate the total porosity in sand shale formations, while the sonic method represents the primary porosity of the formation.

In this analysis, density and sonic methods were employed to calculate all types of porosities (total and effective), and the poor density reading in the washout area was substituted with sonic data to better fit the core porosity data. The density log method was used to calculate primary and effective porosity as per equations (5) by (Wyllie et al., 1958) and (6) by (Asquith and Krygowski, 2004).

\[
\text{\bar{\phi}}_D = \frac{(\rho_{\text{ma}} - \rho_b)}{(\rho_{\text{ma}} - \rho_t)} \\
\text{\bar{\phi}}_{\text{DE}} = \frac{(\rho_{\text{ma}} - \rho_b)}{(\rho_{\text{ma}} - \rho_t)} - \frac{((\rho_{\text{ma}} - \rho_{\text{sh}})/(\rho_{\text{ma}} - \rho_t)) \times V_{\text{sh}}}{\text{GR}_{\text{max}} - \text{GR}_{\text{min}}}
\]

Where:
- \text{\bar{\phi}}_D = Total porosity derived from density log, v/v
- \text{\bar{\phi}}_{\text{DE}} = Effective porosity derived from density log, v/v
- \rho_b = Formation density from log, g/cm<sup>3</sup>
- \rho_{\text{ma}} = Matrix density, g/cm<sup>3</sup>
- \rho_t = density of fluid, g/cm<sup>3</sup>
ρ_{sh} = Shale density, g/cm³
V_{sh} = Shale volume, v/v

The Sonic Log method was used to calculate primary and effective porosity as per equations (7) and (8) by (Wyllie et al., 1958) and (Dresser Atlas., 1979), respectively.

\[ \phi = \frac{(\Delta t_{\log} - \Delta t_{ma})}{(\Delta t_{f} - \Delta t_{ma})} \]  \hspace{1cm} (7)
\[ \phi_{SE} = \left( \frac{(\Delta t_{\log} - \Delta t_{ma})}{(\Delta t_{f} - \Delta t_{ma})} \right) - \left( \frac{(\Delta t_{sh} - \Delta t_{ma})}{(\Delta t_{f} - \Delta t_{ma})} \times V_{sh} \right) \]  \hspace{1cm} (8)

Where:
\( \phi \) = Total porosity derived from sonic log, v/v
\( \phi_{SE} \) = Effective porosity derived from the sonic log, v/v
\( \Delta t_{\log} \) = Formation transit time from log, µs/ft
\( \Delta t_{ma} \) = Matrix transit time, µs/ft
\( \Delta t_{sh} \) = Shale transit time, µs/ft
\( \Delta t_{f} \) = Fluid transit time, µs/ft
\( V_{sh} \) = Shale volume, v/v

For the analysis, a fixed regression value of 2.65 g/cm³ was used to establish the correlation between core porosity and bulk density log. In contrast, 56 us/ft was used to correlate core porosity and sonic log. These correlations were then used to calculate the fluid density and travel time, as illustrated in Fig. 5. Also, the other porosity constants, as shown in Table 2, were adjusted to achieve a better fit between core porosity and calculated porosities.

Table 2. The constant values that are utilized in porosity equations

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Remark</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \rho_{ma} )</td>
<td>2.65 g/cm³</td>
<td>Matrix Sandstone</td>
</tr>
<tr>
<td>( \rho_{sh} )</td>
<td>2.55 g/cm³</td>
<td>Shale density</td>
</tr>
<tr>
<td>( \rho_{f} )</td>
<td>0.93 - 0.96 g/cm³</td>
<td>Fluid densities were determined above and below oil-water contact (OWC) at 2748.5 mTVDSS.</td>
</tr>
<tr>
<td>( \Delta t_{ma} )</td>
<td>56 us/ft</td>
<td>Matrix Sandstone</td>
</tr>
<tr>
<td>( \Delta t_{sh} )</td>
<td>86 us/ft</td>
<td>Shale transit time</td>
</tr>
<tr>
<td>( \Delta t_{f} )</td>
<td>154.5 us/ft</td>
<td>Fluid transit time</td>
</tr>
</tbody>
</table>

Fig. 5. The Variation of fluid parameters depending on core porosity data
3.2.4. Estimation of water saturation

Water saturation Sw is a pivotal petrophysical attribute important in reservoir evaluation. Sw measures the amount of water in the pore space, which is paramount in estimating the volume of hydrocarbons that can be extracted from a reservoir. In 1944, Gus Archie proposed an equation widely used to estimate Sw. The expression gives the fundamental form of the Archie equation:

\[ S_w = \left( \frac{a \times R_w}{\phi^m \times R_t} \right)^{1/n} \]  

(9)

\[ S_{xo} = \left( \frac{a \times R_{mf}}{\phi^m \times R_{xo}} \right)^{1/n} \]  

(10)

Where:

- \( S_w \) = Water Saturation, v/v
- \( S_{xo} \) = Flushed zone water saturation, v/v
- \( R_w \) = formation water resistivity, ohm.m
- \( R_{mf} \) = Mud filtrate resistivity, ohm.m
- \( R_t \) = Formation resistivity, ohm.m
- \( R_{xo} \) = Flushed zone resistivity, ohm.m
- \( \phi \) = Total porosity, v/v
- \( a \) = Tortuosity factor
- \( m \) = Cementation exponent
- \( n \) = Saturation exponent

The formation water and mud filtrate resistivities were calculated from the Salinity chart at formation temperature, as shown in Table 3, can be expressed through the following equations (Schlumberger, 2009):

\[ T_f = (G.G \times TVDSS) + T_s \]  

(11)

\[ R \@ T_f = R \@ T_s \left( \frac{T_s + 6.77}{T_f + 6.77} \right) \]  

(12)

Where:

- \( T_f \) = Temperature Formation, F˚
- \( T_s \) = Temperature surface, F˚
- \( G.G \) = Temperature gradient, F˚/m
- \( TVDSS \) = Total vertical depth subsurface, m
- \( R \@ T_f \) = Refers to the resistivity of water or mud filtrate calculated at the formation temperature.
- \( R \@ T_s \) = Refers to the resistivity of water or mud filtrate calculated at the surface temperature.

Table 3. The applied and computed parameter values from the NaCl salinity chart

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Remark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation water salinity</td>
<td>210000 ppm</td>
<td>The salinity was estimated in this field based on a nearby oilfield and confirmed by (Awadh et al., 2019).</td>
</tr>
<tr>
<td>Mud filtrate salinity</td>
<td>11100 ppm</td>
<td>The salinity was estimated using the Rmf parameter of Lu-08 at surface temperature, representing the only available data. This methodology was to obtain an approximation estimation of the salinity levels.</td>
</tr>
<tr>
<td>( R_w )</td>
<td>0.019 ohm.m</td>
<td>Both resistivities were determined using the Resistivity of NaCl Water Solutions chart (Schlumberger, 2009) at ( T_f = (0.0364 \times TVDSS) + 78 )</td>
</tr>
<tr>
<td>( R_{mf} )</td>
<td>0.22 ohm.m</td>
<td></td>
</tr>
</tbody>
</table>
The Archie parameters (a, m, n) are constants that are calculated using core data and well-logs. These parameters may vary depending on the properties of the reservoir’s fluids and rock type. The Pickett plot method is a commonly used technique for predicting these constants. This method involves establishing a correlation between the resistivity log and the total porosity, as demonstrated in Fig.6. By assuming the value of a=1 and using $R_w=0.019$ ohm.m from Table 3, the prediction of parameters m and n becomes relatively straightforward, resulting in $m = 1.72$ and $n = 2.15$, respectively.

\[ E_{SW}=0.35: \text{log}(XY) = (\text{log}(X) - \text{log}(1 + 0.01898)) \]
\[ E_{SW}=0.50: \text{log}(XY) = (\text{log}(X) - \text{log}(1 + 0.01898)) - \text{log}(1 + 0.01898) \]
\[ E_{SW}=0.75: \text{log}(XY) = (\text{log}(X) - \text{log}(1 + 0.01898)) - \text{log}(1 + 0.01898) \]

\[ \text{Advanced filter: } SHH=0.55 \]

**Fig.6.** The relationship between total porosity and deep resistivity according to Pickett’s plot

The Schlumberger equations in 1989 are used to calculate the total amount of hydrocarbons present in the reservoir, including movable and residual hydrocarbons:

\[ S_h = 1 - S_w \]  
\[ S_m = 1 - S_{xo} \]  
\[ S_{mo} = S_{xo} - S_w \]

Where:
- $S_h$ = Hydrocarbon saturation, v/v
- $S_m$ = Residual oil saturation, v/v
- $S_{mo}$ = Movable oil saturation, v/v

Also, to determine the distribution of the fluids within the total porosity, the following equations were used (Schlumberger, 1998):

\[ BVW = S_w \times \Omega \]  
\[ RVO = S_{xo} \times \Omega \]  
\[ MVO = S_{mo} \times \Omega \]

Where:
- $BVW$ = Bound volume water, v/v
- $RVO$ = Residual volume oil, v/v
- $MVO$ = Movable volume oil, v/v

### 3.2.5. Estimation of permeability

Permeability is a fundamental property of rock layers that characterizes the ability to transmit fluids. The Darcy or millidarcy is the standard unit of measurement for permeability and measures how
easily fluids move through rock formation (Drygaś et al., 2020). High permeability often correlates with economic viability due to increased production potential (Reservoir Productivity). High permeability enhances productivity, while low permeability limits fluid flow.

Wireline logs do not provide direct calculation of permeability. The only way to obtain permeability data is through routine core analysis. In this study, two methods were used to calculate permeability: the classical method and the multilinear regression method.

The classical method is a statistically driven approach utilized to determine the permeability of geological formations based on routine core analysis data. It involves creating a semi-log plot that illustrates the relationship between the core permeability and core porosity, as shown in Fig. 7.

**Fig. 7.** The relationship between core porosity and core permeability to estimate the permeability equation of the classical method that shows R-square = 0.76

The following equation illustrates the outcome of the correlation between core permeability and core porosity, as depicted in Fig. 7.

\[ \text{KAIR} = 10(15.61748 \times \text{CPOR} - 1) \]  \hspace{1cm} (19)

Where:

- KAIR = Core permeability, mD
- CPOR = Core porosity, v/v

The multilinear regression (MLR) method is a statistical technique that uses multiple explanatory variables to predict the outcome of a response variable. The main objective of MLR is to model the linear relationship between the independent and dependent variables. Fig. 8. represents the relationship between core permeability (dependent variable) and shale volume, core porosity, and water saturation (independent variables). The calculated permeability of the MLR method is given by equation 20.
Fig. 8. The relationship between the dependent and independent variables was applied to estimate the permeability using the MLR method that showed R-square = 0.78

\[
KAIR = 10 \times (0.4478839 \times V_{sh} + 13.79546 \times CPOR - 0.4456025 \times Sw - 0.4120519)
\]

(20)

Where:
- \(KAIR\) = Core permeability, mD
- \(CPOR\) = Core porosity, v/v
- \(V_{sh}\) = shale volume, v/v
- \(Sw\) = Water saturation, v/v

It was possible to apply the cored well permeability equation to uncored wells by employing the following equations:

\[
K_{Classical} = 10(+15.61748 \times \phi - 1)
\]

(21)

\[
K_{MLR} = 10(-0.4478839 \times V_{sh} + 13.79546 \times \phi - 0.4456025 \times Sw - 0.4120519)
\]

(22)

Where:
- \(K_{Classical}\) = Permeability log estimation using the classical method, mD
- \(K_{MLR}\) = permeability log estimation using multilinear regression method, mD

3.2.6. Petrophysical averages estimation

To determine the average petrophysical properties of the upper shale member units within the Zubair formation, a filter called “cutoff” is employed on a set of petrophysical properties, including shale volume, total porosity, Permeability, and water saturation. The cutoffs were derived from cross plot and histogram results, as illustrated in Fig.9. The application of these cutoffs on the petrophysical analysis data facilitates the identification of the reservoir thickness flags, depending on the type of cutoffs applied (Taghizadeh Sarvestani and Zeyghami, 2023). Specifically, the gross thickness flag represents the total thickness of the upper shale member units. In contrast, the net sand (rock) flag represents the total thickness of the upper shale member units, excluding the shale volume, which can be evaluated by applying a shale volume cutoff of 0.55. The net reservoir flag, on the other hand, signifies the porous or permeable thickness of the upper shale member units containing fluid, which can be determined by applying a porosity cutoff of 0.064 and a permeability cutoff of 1 mD (Taghizadeh Sarvestani and Zeyghami, 2023) on the net sand. Finally, the net pay flag indicates the porous or
permeable thickness of the upper shale member units filled with hydrocarbon exclusively, can be ascertained by applying a water saturation cutoff of 0.55 on the net reservoir.

Fig. 9. The alteration of the reservoir thickness flags depends on the applied cutoffs.

In the evaluation of a well's hydrocarbon-bearing zone, the determination of its HC\textsubscript{PORTH} or effective hydrocarbon thickness assumes required significance. This is because the HC\textsubscript{PORTH} value is instrumental in assessing the fluid flow dynamics within porous formations. To obtain an accurate quantification of this parameter, advanced petrophysical analysis is necessary. Equation 23 was applied to calculate the HC\textsubscript{PORTH} value for each well in the upper shale member units.

\[
\text{HC}_{\text{PORTH}} = \sum (h \times \Phi \times (1 - S_w))
\]

Where:
- HC\textsubscript{PORTH} = hydrocarbon pore thickness, v/v
- \(h\) = Net pay thickness, m
- \(\Phi\) = Porosity, v/v
- \(S_w\) = Water saturation, v/v

4. Results and Discussion

The quality control applied to open-hole data has been instrumental in increasing the accuracy of the data. This improvement has, in turn, contributed significantly to the preparation of the formation Picking scheme, which relies heavily on well-logs. Preparation of Tops Picking involves interpreting the well-log data to detect the changes in rock properties or characteristics indicative of the transition between geological formations. Table 4. illustrates the impact of quality control on the accuracy of the Formation Picking scheme.
Table 4. Top picking scheme for selecting formation tops

<table>
<thead>
<tr>
<th>USM Tops</th>
<th>Lithology</th>
<th>Reservoir Quality</th>
<th>Pick Criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td>USM-1A</td>
<td>Limestone</td>
<td>Tight-reservoir</td>
<td>Inflection points where the trend changes in logs from constant values below (GR slightly increasing in the top, Pick at (NPHI minimum / DENS maximum).</td>
</tr>
<tr>
<td>USM-1B</td>
<td>Shale / Thin layers of sandstone and limestone at the base</td>
<td>Non-reservoir</td>
<td>3-4 blocky shale, The Top of the coarsening upward sequence, Pick at (GR minimum / NPHI minimum / DENS maximum). In some intervals, there were washouts in the shale, which impacted the density response.</td>
</tr>
<tr>
<td>USM-1C</td>
<td>Sandstone</td>
<td>Good reservoir quality</td>
<td>The top of the fining upward sequence with GR slightly decreases from baseline Pick at (NPHI maximum / DENS minimum).</td>
</tr>
<tr>
<td>USM-1D</td>
<td>Shale</td>
<td>Non-reservoir</td>
<td>Pick at (NPHI maximum / DENS minimum) at the top of the fining upward sequence at the maximum GR.</td>
</tr>
<tr>
<td>USM-1E</td>
<td>Sandstone</td>
<td>Good to moderate reservoir quality</td>
<td>One thin sand at the top, the top of the coarsening upward sequence, Pick at (GR maximum / NPHI minimum / DENS maximum).</td>
</tr>
<tr>
<td>USM-1F</td>
<td>Shale / Particular regions of the crest have some sandstone at the bottom.</td>
<td>Moderate reservoir quality</td>
<td>The top of the fining upward sequence with GR increases from baseline Pick at (NPHI minimum / DENS maximum).</td>
</tr>
</tbody>
</table>

Furthermore, the present study has demonstrated significant correlations between parameters, especially between core and total porosity and between core and effective porosity. The level of agreement between the variables is substantial, as the coefficient of determination R-squared stands at 0.7, as illustrated in Fig.10. The methodology used classical and multilinear regression techniques to create permeability logs based on core data and quality-controlled open-hole logs. Both approaches showed excellent correlation between the permeability log and core data, exhibiting R-squared values of 0.76 for classical and 0.78 for multilinear regression methods, as demonstrated previously in the methodology in Fig.7. and Fig.8. As well as in the petrophysical analysis summaries for cored wells, Lu-07 and Lu-08 in Fig.12. and Fig.13. Based on the promising outcomes, the permeability methods were subsequently applied to uncored wells Lu-38 and Lu-39, as depicted in Fig.14. and Fig.15.
Fig. 10. The correlation between the core porosity, and the total and effective porosities

A more precise depiction of the hydrocarbon and water saturation behavior and existence has been revealed upon conducting a cross-sectional analysis of the study wells. This analysis has brought to light the presence of a minute quantity of immovable oil, commonly known as Tar, as shown in Fig. 11, especially at depths of 2750-2760 m, which corresponds to the upper shale member USM-1E reservoir unit. This was discovered in both the wells on the Western and Eastern flanks.

Fig. 11. A cross-sectional view of the study wells, explaining the petrophysical properties and the behavior of fluid accumulation within the reservoir rocks.
Fig. 12. Petrophysical analysis summary for well Lu-07 (Cored Well)

Fig. 13. Petrophysical analysis summary for well Lu-08 (Cored Well)
Fig. 14. Petrophysical analysis summary for well Lu-38 (Uncored Well)

Fig. 15. Petrophysical analysis summary for well Lu-39 (Uncored Well)
The average petrophysical properties of upper shale members are presented in Table 5. The interpretation results for each unit were represented as follows: USM-1A represents the uppermost unit of the Zubair Formation and comprises predominantly limestone lithology. The shale volume in this unit is 0.10 of the total composition. The rock exhibits a tight non-reservoir structure with a micro-porosity of around 0.09 and a low permeability of 4.53 mD, making storing the fluid in this unit more difficult. USM-1B is composed mainly of minor limestone and sandstone. However, this unit has a significant amount of shale, a brittle rock. Shale tends to be washed out during drilling, resulting in a bad hole flag. This, in turn, introduces uncertainty in the data quality. USM-1C represents the reservoir unit in the Luhais oilfield with a high hydrocarbon saturation Pay zone (Al-Shahwan et al., 2018), primarily composed of sandstone with an approximate shale volume of 0.13. The feature of this unit was notable for its superior rock quality, exhibiting a high porosity of approximately 0.20 and a high permeability of 370.65mD. USM-1D is mostly shale and serves as a cap rock separating USM-1C from underlying units. USM-1E is predominantly sandstone, with a shale volume of approximately 0.09. This unit is similar in rock quality to unit USM-1C, with a high porosity of about 0.21 and a high permeability of 322.02mD. The wells in the middle of the fold show a high amount of Hydrocarbon saturation, while wells on the flank exhibit low Hydrocarbon saturation because these wells are too close to the oil-water contact. USM-1F consists of a shale layer at the top, with sandstone layers. The shale volume is approximately 0.24. The rock's porosity demonstrates a low to moderate level of approximately 0.13, while its permeability is low to moderate at 16.98 mD (Lewis et al., 2006). The rock quality is classified as poor to moderate and exhibits high water saturation because this unit is below the oil-water contact.
5. Conclusions

A comprehensive analysis was conducted on the Upper Shale Member units of the Luhais oilfield using well-logs and routine core analysis. The results indicated that the lithology of these units comprised sandstone, shale, and limestone in varying proportions. Among all the study wells, the USM-1A unit was found to have the highest limestone content. Based on the collected data, petrophysical properties, and previous studies, the Upper Shale Members were divided into six units: USM-1A, USM-1B, USM-1C, USM-1D, USM-1E, and USM-1F. The permeability in these units was discovered to be dependent on the type of rock lithology. The USM-1C (370.65mD) and USM-1E (322.02mD) demonstrated high permeability in these zones and were the optimal units in the Upper Shale Member.

Meanwhile, USM-1F (16.98mD) demonstrated low to moderate permeability. The remaining units were considered to be impermeable due to high shale content. The USM-1C unit was identified as the optimal unit for drilling.
reservoir unit in the Luhais oil field and exhibited the most substantial hydrocarbon accumulation content in the Upper Shale Member of the Zubair Formation. In contrast, USM-1E and USM-1F had low hydrocarbon content as they were situated below the oil-water contact. The Luhais field was observed to have hydrocarbon saturations lower than the water saturation. Heavy oil (Tar) was noted on the flank of the fold at depths of approximately 2750. These observations have significant implications for the field's overall hydrocarbon potential.

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