Integrating Rock Typing and Petrophysical Evaluations to Enhance Reservoir Characterization for Mishrif Formation in Garraf Oil Field

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Abstract

Accurate reservoir characterization is essential for successful hydrocarbon extraction, especially in complex fields such as the Garraf Oil Field. This study aims to enhance reservoir characterization by integrating different petrophysical assessments and rock typing methodologies. Density, neutron, and sonic porosity evaluations were used to assess porosity, while gamma-ray logs and resistivity measurements were used to determine shale volume. The Archie equation was employed to estimate water saturation and sensitivity analysis was used to determine the cutoff values. The study also utilized rock typing techniques, including hydraulic flow unit assessment and Rock fabric number cross-plots, to categorize reservoir rocks into flow units and identify unique rock types. The combination of these approaches led to the precise identification of reservoir heterogeneities and optimal oil production zones. The results showed that the Gamma-ray log is the best method for determining shale volume, and the closest method for porosity determination is the density log. The water resistivity value was estimated at 0.016, while the Archie parameters (a,m,n) were 1.1, 2.1, and 3.7, respectively, with cutoff values of 0.22 for shale volume, 0.11 for porosity, and 0.56 for water saturation. The study identified five rock types ranging from packstone, pack to wackstone, wackstone, wack to mudstone, and mudstone. Overall, the integration of petrophysical evaluations and rock typing techniques facilitates the accurate delineation of oil-rich zones with enhanced reservoir connectivity.

Keywords: Petrophysical properties; Rock typing; Carbonate reservoirs; Garraf oil field

1. Introduction

Reservoir characterization is crucial for the efficient extraction of hydrocarbon resources, especially in complex fields (Al-Baldawi, 2022; Gibrata et al., 2023). To achieve successful reservoir characterization, it is necessary to interpret key properties such as porosity, volume of shale, net pay, and water saturation (Gupta and Gairola, 2020; Al-Heeti and Al-Fatlawi, 2022; Al-Heeti et al., 2023). These properties help to gain comprehensive insights into subsurface geology, understand reservoir heterogeneity, and optimize oil production (Ma and Ma, 2019; Sen et al., 2021). Petrophysical workflows and rock physics modeling integrate log, core/cuttings, and production data to obtain meaningful physical properties (Skalinski and Kenter, 2015; Al Jenaibi et al., 2018; Sabea et al., 2022).

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To achieve successful reservoir characterization, it is necessary to be familiar with the principles of petrophysical information, common mineralogical properties of reservoir rocks, and scales of reservoir characterization information based on the sources and used tools (Bhardwaj and Sharma, 2020; Pamungkas and Gueye, 2020; Al Subait et al., 2022).

Reservoir characterization is vital for efficient hydrocarbon extraction, especially in complex fields (Hossain et al., 2018; Chafeet and Handhal, 2023). Successful characterization involves interpreting key petrophysical properties to gain insights into subsurface geology (Corcoran, 2005; Alyafei et al., 2016; Gibrata et al., 2023). These properties include porosity, volume of shale, net pay, and water saturation. Understanding these properties is essential for optimizing oil production and comprehending reservoir heterogeneity (Mohamed et al., 2017; Ren and Duncan, 2021; Paramo et al., 2023).

The Garraf Oil Field presents unique challenges due to its complex geological makeup (Neamah et al., 2022, Szabó et al., 2023). The objective of the current research is to understand the petrophysical properties and rock types of the Mishrif reservoir within the Garraf Oil Field, which is crucial for optimizing oil production. By applying integration of various methods and advanced techniques, such as hydraulic flow unit assessment and rock fabric number cross-plots, enables the precise categorization of reservoir rocks into distinct flow units. This categorization is instrumental in deciphering reservoir heterogeneity and identifying zones that are conducive to optimal oil production. A thorough understanding of the reservoir’s properties is crucial for making informed decisions regarding drilling, production strategies, and reservoir management. Without accurate characterization, the risk of suboptimal production and resource wastage increases significantly.

Currently, reservoir characterization involves several key steps, including seismic surveys, core analysis, well logging, and reservoir modeling (Guo et al., 2023). Rock typing, a process of categorizing reservoir rocks into distinct groups based on their petrophysical properties and lithology, is a well-established technique (Alobaidi, 2016; Al-Jawad et al., 2020; Salman et al., 2022; Shahat et al., 2023; Zhang et al., 2023; Salman et al., 2023). Similarly, petrophysical evaluations involve measuring critical parameters such as porosity, permeability, and saturation to estimate the reservoir’s productivity potential (Fang and Yang, 2015; Qadri et al., 2019; Domagała et al., 2021). While these two techniques have been used separately, there is a growing recognition of the benefits of their integration. Combining rock typing with petrophysical evaluations allows for a more accurate and detailed reservoir description, aiding in reservoir simulation and production optimization (Montenegro et al., 2007; Chandra et al., 2015; Hasan, 2020).

This study aims to address the challenges of the Garraf Oil Field due to its complex geological makeup by employing a multifaceted approach that combines various petrophysical methods and advanced rock typing techniques for the Mishrif reservoir.

**Geological Setting**

The Garraf Oil Field is located in Dhi Qar Governorate, approximately 265 km southeast of Baghdad and 85 km north of Nasiriyah city (Fig.1). The Garraf oil field is a northwest-southeast trending anticline with 24 km length and 5 km width. Many wells were drilled in Gharraf oil field since 1984. Garraf oil field represents forms of a series of anticlinal structures developed on the southern flank of the Zagros Mountain front flexure, the trend of the anticline is parallel to the main Zagros trend. The primary oil accumulation in the Garraf structure is located in the Mishrif reservoir, which is located between approximately 2270 and 2450 m total vertical depth (TVD). It is the uppermost oil accumulation in the Gharraf structure (Didanloo et al., 2015).
In well Ga-3, the thickness of the Formation measures around 209 m. The Mishrif Formation (Cenomanian to the Early Turonian) has a gradual contact with the underlying Rumelia Formation, whereas the overlying Khasib Formation is in unconformable contact (Fig.2). It primarily consists of shallow-water, shelf carbonates, such as bioclastic limestones, as well as algal, coral, and rudist bioherms (Al-Dabbas et al., 2010). This formation holds considerable importance as a significant oil reservoir and serves as a productive hydrocarbon reservoir in numerous oilfields in Iraq.

2. Materials and Methods

The current study is based on data from two wells supplied by Dhi Qar Oil Company, Ga-92p deviated well and Ga-3 vertical well.

To achieve precise characterization of the Mishrif reservoir and identifying the optimal oil-rich zones the following aspects are investigated, lithological identification, porosity assessment (by employing a multi-method approach that includes density, neutron, and sonic porosity measurements), the volume of shale determination (by employing gamma-ray logs and resistivity measurements), water saturation estimation (through Pickitt plot analysis and using the Archie equation to derive critical parameters \( a, m, n \)), Sensitivity analysis conducting (to establish cutoff values for these parameters for water saturation assessments), and advanced rock typing techniques analysis (including hydraulic flow unit assessment and Rock fabric number cross-plots).
Formation evaluation is a critical aspect of reservoir characterization, and it relies on a variety of well logging tools to gather essential data (Mahmood and Al-Fatlawi, 2021; Gao et al., 2023; Szabó et al., 2023). The available data includes caliper logs, gamma-ray logs, resistivity logs, sonic logs, density logs, and neutron logs. These logs provide crucial information about the formation's lithology, porosity, fluid content, and rock properties.

Caliper logs offer insights into borehole diameter variations, helping us identify irregularities and potential issues in the wellbore (Renteria et al., 2022). Gamma-ray logs are employed to determine shale content within the formation, aiding in the evaluation of reservoir composition (Inanc and Vogt, 2018). Resistivity logs measure the formation's electrical resistivity, which can be indicative of fluid types and their saturations (Merletti et al., 2023).
Sonic logs provide valuable information on the rock's acoustic properties. They are used for porosity calculations, fracture identification, seismic attributes inversion, and determining the dynamic mechanical properties of the rock (Carvalho and Carrasquilla, 2019; Chakraborty et al., 2021). Density logs are used to measure bulk density, which is an important parameter for estimating porosity and lithology in rocks (Ahmed et al., 2022). By analyzing the bulk density, it is possible to estimate the porosity of the rock and provide insights into the lithology of the rock, (Ijasan et al., 2013). Neutron logs are important for evaluating porosity and identifying fluid types based on hydrogen content measurements (Horsfall et al., 2013). These logs provide information about the hydrogen index (HI) and are commonly expressed in apparent water-filled porosity units assuming a constant matrix lithology (Niculescu and Negut, 2015).

The integration of these diverse data sets enhances our understanding of the geological and petrophysical properties critical for successful hydrocarbon extraction in this complex field (Figs. 3 and 4).

![Graph showing data analysis results](image)

**Fig. 3.** Available data of deviated well Ga-92p

### 3. Results

The results indicate the determination of porosity, the calculation of shale volume, the assessment of water resistivity, water salinity, Archie's parameters, water saturation, and the categorization of rock types using hydraulic flow units (HFU) and rock fabric number (RFN). These analyses were performed utilizing the TECHLOG and IP software tools (Liang et al., 2022; Alzubaidi et al., 2021). This process relies on various data sources and techniques:

#### 3.1. Lithology Determination

**3.1.1. Lithology by neutron-density**

The identification of lithology through neutron-density cross-plotting is a long-established technique within the realm of petrophysical analysis. This method holds significant importance in the
fields of geology and reservoir characterization. It revolves around the application of measurements obtained from well logging tools, specifically those related to neutron and density data, to differentiate between different rock types and their respective porosity characteristics (Serra and Serra, 2004). Neutron and density logs furnish insights into the hydrogen and electron densities of the subsurface formation, respectively. Through the creation of a cross plot that juxtaposes these two measurements, discernible clusters associated with various lithologies become apparent, facilitating their accurate identification. The result reflected that the mean lithology of the Mishrif reservoir is limestone (Fig.5).

Fig. 4. Available data of vertical well Ga-3

Fig. 5. Neutron-density cross plot
3.1.2. Lithology by M-N plot

In essence, the M-N cross plot method leverages calculated values of M and N, derived from specific mathematical formulas, to construct a visual representation. This graphical depiction serves as a valuable tool for categorizing lithological characteristics and aids in the discernment of different mineral compositions within the Mishrif Formation. Within this cross-plot, three prominent lithological lines emerge, representing sandstone (silica), limestone, and dolostone (dolomite). These lithology lines are typically associated with specific porosity values, expressed as percentages. The M-N cross plot plays a pivotal role in categorizing the density and neutron mineral mixture, providing valuable insights into lithology-dependent quantities represented by M and N.

Additionally, the cross plot M-N technique is instrumental in the classification of major lithological and mineralogical constituents within the Mishrif Formation (Santos et al., 2003). Notably, the predominant mineral identified in this context is calcite, which serves as the primary constituent of limestone rock formations (Fig.6). The formulae for calculating the lithology-dependent quantities M and N are as follows:

\[
M = \frac{\Delta t_f - \Delta t_{log}}{\rho_b - \rho_f} \times 0.01
\]

\[
N = \frac{\phi_{Nf} - \phi_N}{\rho_b - \rho_f}
\]

Where:
- \(\Delta t_f\) represents the interval transit time for fresh water, taking the value of 189 m/s, and 185 m/s for salt mud.
- \(\rho_b\) stands for the density log reading.
- \(\rho_f\) signifies the density of fresh water, which is either 1 g/cm³ or 1.1 g/cm³ for salt mud.
- \(\phi_{Nf}\) denotes the porosity of neutrons for the fluid, assumed to be 1.
- \(\phi_N\) represents the neutron porosity.
3.2. Volume of Shale

The determination of the volume of shale is a fundamental undertaking in the field of petrophysics and reservoir characterization. This volume calculation holds pivotal importance as it provides critical insights into the composition and heterogeneity of subsurface formations (Tiab and Donaldson, 2015). Shale volume has been calculated by several methods, as follows:

3.2.1. Shale volume by Gamma ray log

The gamma-ray log is a measure of a formation's natural radioactivity. The most abundant radioactive elements in sedimentary rocks are potassium, thorium, and uranium. Each of these elements continuously emits gamma rays, which can be detected by a scintillation counter placed within the borehole. As a result of certain clay minerals possessing radioactive elements, the capability to distinguish between clay free and clay-rich sandstones are possible using the gamma-ray log provided that the clays carry the above radioactive elements, as follows:

\[ V_{sh} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \]  

Where:
- \( V_{sh} \): Volume of Shale.
- \( GR_{log} \): gamma ray reading in interested zone.
- \( GR_{min} \): minimum gamma ray reading (clean zone).
- \( GR_{max} \): maximum gamma ray reading (Shale zone).

3.2.2. Shale volume by resistivity log

The resistivity log gauges the opposition encountered by an electrical current as it traverses through a geological formation. These measurements, expressed in ohms per meter, are acquired through two methods: one involves directly introducing an electrical current into the formation, while the other induces a current and assesses the ensuing response at the detector. The resistivity of rock, being an insulator, relies on various factors, including the type and quantity of fluids present in the pore spaces or absorbed by clay minerals, the geometry of the pores, the thickness of the rock beds, the depth of penetration, and the conditions within the borehole itself.

To estimate the volume of clay in a formation, the resistivity method draws a connection between the resistivity of clay minerals (Rcl), typically extracted from a nearby shale deposit, and the true resistivity of shaly sands (Szabó et al. 2023). This estimation process is governed by equation 4, as follows:

\[ V_{sh} = \left( \frac{R_{sh}}{R_t} \right)^{0.67} \]  

Where:
- \( R_{sh} \): resistivity of shale (Adjacent Shale Bed)
- \( R_t \): interested zones resistivity

3.2.3. Shale volume by Neutron-Sonic method

The neutron-density method of calculation clay volume relates the variation in the neutron and density porosities) between a shaly sand and an adjacent shale bed. Because clay minerals contain high amounts of hydrogen, neutron porosity will record higher than the density porosity. Thus, a linear relationship between clay volume and the amount of difference between the neutron and density porosities is formulated. As the amount of clay increases, the difference between neutron and density
porosities increases. The neutron-density for calculating volume of clay by applying equation 5, as follows:

$$V_{sh} = \frac{\phi_N - \phi_D}{\phi_{Nsh} - \phi_{Dsh}}$$

where:

- $V_{sh}$: shale volume.
- $\phi_N$: neutron porosity.
- $\phi_D$: density porosity.
- $\phi_{Nsh}$: neutron porosity at shale zone.
- $\phi_{Dsh}$: density porosity at shale zone.

### 3.2.4. Shale volume by Neutron-Density method

The neutron-sonic method calculates clay volume using a combination of neutron and sonic porosities between a shaly sand and a certain shale bed. The neutron-sonic equation for calculating volume of clay by applying equation 6, as follows:

$$V_{Sh} = \frac{\phi_N - \phi_S}{\phi_{Nsh} - \phi_{Ssh}}$$

Where:

- $V_{Sh}$: Clay volume.
- $\phi_N$: neutron porosity.
- $\phi_S$: sonic porosity.
- $\phi_{Nsh}$: neutron porosity at shale zone.
- $\phi_{Ssh}$: sonic porosity at shale zone.

All previous shale volume calculation methods has been calculated for the two wells Ga-92p and Ga 3 (Figs.7 and 8).

**Fig. 7.** Shale volume methods for deviated well Ga-92p
The method of estimating the volume of clay using deep resistivity logs has a notable limitation. When water saturation in a formation increases, it leads to an increase in the true resistivity, which, in turn, causes an overestimation of the volume of clay. Additionally, clays have a significant impact on both neutron and density porosities, which can further affect the accuracy of clay volume estimates.

Considering these factors, it's worth noting that estimating clay volumes using gamma ray logs is often regarded as the superior method for calculation. Gamma ray logs provide a more reliable and less affected measurement when it comes to clay content in formations. This is because gamma ray logs primarily detect the natural radioactivity of the formation and are less influenced by changes in water saturation or clay content, making them a preferred choice for accurate clay volume assessments.

3.3. Porosity Calculation

The porosity of a rock is defined as the ratio of the pore volume to the bulk volume of the reservoir rock on percentage basis the measurement of porosity is important to the petroleum engineer since the porosity determines the storage capacity of the reservoir for oil. All methods for calculating the effective porosity are used in order to compare them with the porosity of core and choosing the suitable state. The porosity can be calculated by according to the following equations 7, 8, 9 and 10 (Silva et al., 2019; Dasgupta et al., 2019; Ojo et al., 2018):

\[
\phi_S = \frac{\Delta t_{log} - \Delta t_m}{\Delta t_f - \Delta t_m}
\]  

(7)

Where

\(\phi_S\) : Porosity by sonic log
\(\Delta t_{log}\) : The recorded travel time, (µsec/ft)
\(\Delta t_m\) : Matrix travel time, (µsec/ft)
\(\Delta t_f\) : Fluid travel time, (µsec/ft)

Density log
\[ \phi_D = \frac{\rho_m - \rho_b}{\rho_m - \rho_f} \]  
(8)

Where

\( \phi_D \) : Porosity by density log

\( \rho_m \) : Matrix density, gr/cc

\( \rho_b \) : The recorded bulk density, gr/cc

\( \rho_f \) : Fluid density, gr/cc

Neutron log

Neutron-Density logs

\[ \phi_{ND} = \frac{\phi_N - \phi_D}{2} \]  
(9)

Where

\( \phi_{ND} \) : Porosity by neutron–density logs

\( \phi_N \) : Porosity by neutron log

\( \phi_D \) : Porosity by density log

Neutron-Sonic logs

\[ \phi_{NS} = \frac{\phi_N - \phi_S}{2} \]  
(10)

Where

\( \phi_{NS} \) : Porosity by neutron–sonic logs

\( \phi_N \) : Porosity by neutron log

\( \phi_S \) : Porosity by sonic log

After calculation porosity by the previous methods, it should be compared with porosity measured by core. The best method is porosity by density which is close to core porosity (Fig.9).

3.4. Formation Water Resistivity

Formation water is the reservoir water that is not contaminated with drilling mud. The resistivity of the formation water (Rw) is an important parameter since it is required for the saturation's calculation. The value of (Rw) can vary widely from well to well in some reservoirs because of the variation parameters that include salinity, temperature, freshwater invasion, and changing depositional environments. However, for determining the reservoir water resistivity have been developed, including chemical analysis of produced water sample, resistivity porosity logs, and various empirical methods (Archie, 1942).

3.5. Archie’s Parameters

The Archie equation's parameters a, m, and n play a crucial role in accurately estimating water saturation in subsurface reservoirs, with each parameter representing specific geological and petrophysical characteristics. Where, a is the tortuosity factor, m is the cementation exponent, and n is the saturation exponent. These parameters provide insights into the complexity of the rock formation and the behavior of fluids within it.
The tortuosity factor (Gibrata et al. 2023) accounts for the convoluted path that electrical currents must take as they traverse through the porous medium of the rock. It reflects the degree of tortuosity or meandering of the fluid pathways within the reservoir. In carbonate formations, where pore structures can be intricate and interconnected, the tortuosity factor helps capture the electrical resistance caused by the indirect path that current takes, affecting the overall resistivity measurement. Deviations from the typical value of 1 can occur due to the varying degree of pore complexity and fluid movement within the reservoir rock.

The cementation exponent (Gibrata et al. 2023) characterizes the resistivity contrast between the rock matrix and the pore fluids. It indicates the degree of cementation or bonding between the mineral grains in the rock. In carbonate reservoirs, the value of m can vary widely due to factors such as the mineralogy, diagenesis, and compaction history of the rock. Higher m values indicate stronger cementation and tighter pore spaces, leading to lower effective porosity and potentially lower water saturation. Lower m values correspond to more open pore structures with increased potential for fluid movement (Archie, 1942).

The saturation exponent (Gibrata et al. 2023) represents the relationship between the water saturation and the effective porosity of the rock. While it is commonly assumed to be 2 in many applications, it can deviate from this value in carbonate reservoirs due to complex pore geometries and fluid behavior. n affects the sensitivity of water saturation to changes in porosity. In some cases, n values less than 2 indicate an increased sensitivity, implying that relatively small changes in porosity can result in significant variations in water saturation. Pickett's plot are used to estimate Rw, and Archie’s parameters it will be described as the following.
Pickett's plot

Pickett's (1966) proposed a method which depends on a cross plot between resistivity at water zone vs. porosity to estimate cementation factor (a,n,m) from well logs (Archie, 1942), this method is depends on Archie equation. The results from two wells are a=1.1, m=2.1, n=3.7 (Fig.10).

3.6. Water Saturation

Water saturation is a critical parameter in the assessment of hydrocarbon reservoirs, particularly in carbonate formations. It represents the proportion of pore space within a reservoir rock that is filled with water, as opposed to hydrocarbons. Accurate determination of water saturation is essential for estimating reservoir reserves, predicting production behavior, and designing effective production strategies. The Archie equation, developed by Gus Archie in the 1940s, has been a fundamental tool for calculating water saturation in carbonate reservoirs. This empirical equation takes into account the porosity of the rock, the resistivity of the formation water, and the resistivity of the rock itself to estimate the water saturation. The Archie equation 11 application as follows:

\[ S_W^n = \frac{a \times R_W}{\Phi^m \times R_t} \]  (11)

Where
- \( S_W \) : the water saturation (fraction).
- \( R_W \) : the water resistivity (ohm-m).
- \( R_t \) : formation resistivity (ohm-m).
- \( \Phi \) : porosity
- a, n, and m: Archie’s parameters

The results of water saturation calculation in Ga-3 and Ga-92p are shown in Figs.11 and 12.
Net pay represents a portion of the reservoir characterized by favorable petrophysical properties and economically viable hydrocarbon reserves. This parameter is pivotal in the estimation of initial hydrocarbon quantities, making it a critical aspect of reservoir assessment. The associated net-to-gross ratio (NGR) quantifies the ratio between the thickness of net pay within the reservoir and its overall (gross) thickness. A significant step in this process involves establishing a link between conventional core measurements and a reference parameter that can distinguish between reservoir rock and non-reservoir rock. In the oil industry, cut-off values are commonly referred to as limiting thresholds (Baker et al., 2015; Jiang et al., 2002; Al-Fatlawi, 2018). These thresholds serve as decisive points above or below which values are accepted or rejected. They play a vital role in determining net pay and net-to-
gross intervals within the reservoir. Additionally, it's essential to differentiate between the terms "net reservoir" and "net pay." Net reservoir denotes intervals within the formation containing any fluid type with the capacity to flow. In contrast, net pay shares the same characteristics as net reservoir but specifically excludes water, thereby identifying hydrocarbon intervals. The estimated cutoff values of Mishrif Formation are shown in Figs. 13, 14 and 15, which volume of shale cutoff = 0.22, porosity cutoff = 0.11 and water saturation cutoff = 0.56.

**Fig. 13.** Volume of shale cutoff

**Fig. 14.** Porosity cutoff

**Fig. 15.** Water saturation cutoff
3.8. Rock Typing by Rock Fabric

Rock typing by rock fabric, as proposed by Lucia, is a methodology used to categorize carbonate reservoir rocks based on their depositional and diagenetic attributes. This approach aims to capture the variability in petrophysical and fluid flow properties within carbonate formations, which can be highly heterogeneous due to the complex interplay of factors like sedimentary history, mineralogy, and diagenesis. The rock fabric number, introduced by Lucia, is a key parameter in this categorization (Lucia, 2007).

The (RFN) value characterizes the degree of porosity and permeability development in a carbonate rock. Different (RFN) ranges correspond to distinct rock types, each with its own petrophysical characteristics. The rock types are associated with various depositional and diagenetic environments, including mud-dominated facies, grain-dominated facies, and intermediate facies (Lucia, 1995). These categories help in understanding fluid flow behavior, reservoir connectivity, and well performance. From this method packstone to mudstone (Fig.16).

![Rock fabric number plot](image)

Fig. 16. Rock fabric number plot

3.9. Rock Typing Based on Hydraulic Flow Units and Lorenz Plots

Rock typing based on hydraulic flow units and Lorenz plots is a methodology used to classify reservoir rocks within carbonate formations according to their fluid flow characteristics. This approach is especially valuable for understanding and predicting fluid flow behavior, permeability distribution, and connectivity in heterogeneous carbonate reservoirs. It involves the identification of distinct hydraulic flow units (HFUs) and the use of Lorenz plots to visualize and analyze the distribution of permeability within these units. Hydraulic flow units are rock intervals with similar petrophysical and flow properties, often characterized by common depositional and diagenetic features. These units represent zones with comparable fluid flow behavior, making them crucial for reservoir modeling and simulation. HFUs are defined by integrating various rock attributes, such as porosity, permeability, pore size distribution, and mineralogy, to capture the complex relationships that influence fluid flow.

Lorenz plots are graphical representations of cumulative pore volume versus cumulative permeability for different rock samples within a given HFU. These plots help visualize the variability in permeability distribution within a unit and provide insights into the reservoir's heterogeneity. Lorenz plots enable the quantification of reservoir connectivity, the identification of high-permeability streaks or barriers, and the determination of flow unit boundaries (Riazi, 2018; Shah et al., 2022).
By combining the identification of HFUs with Lorenz plots. There are five sedimentary facies within Mishrif Formation varied from packstone, packstone to wackstone, wackstone to mudstone and mudstone (Al-Dabbas et al., 2010). The results are shown in Figs 17, 18 and 19.

![Lorenz plot](image)

**Fig. 17. Lorenz plot**

Lorenz plot can analyze and characterize the storage and flow capacity of different rock types within a hydrocarbon reservoir. It is a valuable tool for understanding the heterogeneity and connectivity of reservoir rocks, which is crucial for optimizing oil and gas production. The Lorenz plot typically involves plotting two key parameters against each other: porosity (storage capacity) and permeability (flow capacity). Porosity represents the ability of a rock to store fluids, such as oil or gas, while permeability quantifies the ease with which fluids can flow through the rock. These parameters are essential for determining how easily hydrocarbons can be stored within the rock and how effectively they can be produced. According to Li et al., 2021, the porosity represents the volume of pore space available for storing hydrocarbons. High porosity indicates that a rock has a greater storage capacity, as it can hold more hydrocarbons, while low porosity means limited storage capacity. While, the flow capacity or permeability is a measure of the ability of a rock to transmit fluids through its pore network. Rocks with high permeability allow fluids to flow easily, making them favorable for production, while rocks with low permeability impede fluid flow. In a Lorenz plot, data points are typically taken from core samples or well-log data representing different rock types within the reservoir. The plot consists of a scatter of data points, each representing a specific rock sample (Li et al., 2021).

The hydraulic flow unit histogram is a graphical representation of the distribution of hydraulic flow units within a reservoir. Hydraulic flow units are defined as representative elementary volumes of reservoir rock with similar geological and petrophysical properties. These properties, such as porosity and permeability, play a crucial role in fluid flow within the reservoir. The histogram provides a visual representation of the frequency or occurrence of different hydraulic flow units within the reservoir. It helps in understanding the variability and distribution of flow units, which can be useful for reservoir characterization and predicting permeability (Figs. 18 and 19).

The histogram typically displays the hydraulic flow units on the x-axis and the frequency or percentage of occurrence on the y-axis. Each bar in the histogram represents a specific flow unit, and the height of the bar indicates the frequency or percentage of occurrence of that flow unit within the reservoir (Fig. 18).
After integration of all the used methods, five sedimentary facies are distinguished and are varied from packstone facies (high permeability) to mudstone facies (very low permeability) (Fig. 19).

4. Conclusions

A comprehensive reservoir characterization investigation is accomplished for the Mishrif reservoir in Garraf Oil Field. Applying various methods such as the assessment of porosity through density, neutron, and sonic porosity measurements, providing a thorough examination of the reservoir's porosity distribution. The volume of shale is accurately determined through the use of gamma-ray logs and resistivity measurements, adding precision to our understanding of the reservoir's composition. The study employs the Archie equation to derive essential parameters (a, m, n) for estimating water saturation, with cutoff values meticulously determined through sensitivity analysis. Furthermore, advanced rock typing techniques, such as hydraulic flow unit assessment and rock fabric number cross-plots from the cores from depth 2320 m to 2395 m, are analysed, facilitating the categorization of reservoir rocks into distinct flow units, depending on the Storage Capacity (core porosity) and flow
Capacity (core permeability). Among these methodologies, gamma-ray logs prove to be the most reliable for determining shale volume, while density logs closely approximate core porosity measurements. Water resistivity is estimated at 0.016, and Archie parameters (a, m, n) are determined as 1.1, 2.1, and 3.7, respectively. The established cutoff values are 0.22 for shale volume, 0.11 for porosity, and 0.56 for water saturation. This comprehensive approach results in the identification and classification of five distinct sedimentary facies ranging from packstone, packstone to wackstone, wackstone, wackstone to mudstone, and mudstone.

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