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Permeability Estimation and Reservoir Characterization Using the Hydraulic Flow Unit (HFU) Approach: A Case Study of the Paleocene Beda C Carbonate Reservoir, Sabah Oil Field, Sirte Basin

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تقدير النفاذية وتوصيف المكامن باستخدام نهج وحدات التدفق الهيدروليكي (HFU): دراسة حالة لمكمن الكربوناتي " Beda C" من عصر الباليوسين، حقل صباح النفطي، حوض سرت

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Abstract:
Permeability determination in carbonate reservoirs represents a major challenge in petroleum engineering due to severe rock heterogeneity resulting from complex depositional histories and diagenetic modifications. Core samples are typically available for only a limited number of wells due to high acquisition costs. Consequently, developing low-cost, accurate, and reliable predictive models for permeability is paramount for efficient reservoir management and development strategies. This paper presents a comprehensive study to establish an optimal permeability predictive model for the Paleocene Beda C formation within the Sabah Oil Field, located in the Sirte Basin, Libya. Data collected from eight cored wells were analyzed using the Hydraulic Flow Unit (HFU) methodology, which is based on the modified Kozeny-Carman equation and the Flow Zone Indicator (FZI) concept. Traditional empirical formulations (Timur, Wyllie-Rose, and Morris-Biggs) as well as classical regression models (linear, power, and exponential) were applied and statistically compared against the HFU method. The results demonstrate that traditional porosity-permeability correlations exhibit low predictive capability due to the highly scattered nature of carbonate petrophysical trends. In contrast, the HFU method effectively classified the heterogeneous reservoir into four distinct flow units, each characterized by unique pore-throat geometrical attributes. The HFU-derived models achieved high accuracy with coefficients of determination ($R2 \geq 0.70$). The developed framework was successfully validated through application to well logging data from the un-cored well G-18, offering a robust tool for fields-wide permeability prediction. Keywords: Carbonate Reservoir, Permeability Estimation, Hydraulic Flow Unit (HFU), Flow Zone Indicator (FZI), Sirte Basin, Reservoir Heterogeneity.

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الملخص:
يمثل تحديد النفاذية في المكامن الكربونية تحدياً رئيسياً في هندسة النفط بسبب غير التجانس الشديد للصخور الناتج عن التاريخ الترسيبي المعقد والتحويرات اللاحقة للترسيب (Diagenetic modifications). وعادةً ما تتوفر العينات الصخرية (Cores) لعدد محدود من الآبار نظراً لارتفاع تكاليف الحصول عليها. وبناءً على ذلك، يعد تطوير نماذج تنبؤيه منخفضة التكلفة ودقيقة وموثوقة للنفاذية أمراً بالغ الأهمية للإدارة الفعالة للمكامن واستراتيجيات التطوير. تقدم هذه الورقة البحثية دراسة شاملة لإنشاء نموذج تنبؤي

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أمثل للنفاذية لتكوين "بيداء "C التابع لعصر الباليوسين في حقل صباح النفطي الواقع بالحوض سيرت في ليبيا. تم تحليل البيانات المجمعة من ثماني آبار مأخوذ منها عينات صخرية باستخدام منهجية وحدة التدفق الهيدروليكي (HFU) ، والتي تعتمد على معادلة كوزيني- كارمان المعدلة ومفهوم مؤشر نطاق التدفق (FZI). تم تطبيق الصيغ التجريبية التقليدية (تيمور، وايلي-روز، وموريس-بيغز) بالإضافة إلى نماذج الانحدار الكلاسيكية ومقارنتها إحصائياً بأسلوب وحدة التدفق الهيدروليكي. أظهرت النتائج أن العلاقات التقليدية بين المسامية والنفاذية تمتلك قدرة تنبؤية منخفضة بسبب الطبيعة شديدة التشتت للخصائص البتروفيزيائية للكربونات. في المقابل، صنفت طريقة وحدة التدفق الهيدروليكي المكمن غير المتجانس بفعالية إلى أربع وحدات تدفق متميزة، كل منها تتميز بخصائص هندسية فريدة لأعناق المسام. حققت النماذج المشتقة من طريقة HFU دقة عالية بمعاملات تحديد .(R^2 \ge 0.70) تم التحقق من صحة الإطار المطور بنجاح من خلال تطبيقه على بيانات تسجيلات الآبار للبئر G-18 غير المأخوذ منه عينات صخرية، مما يوفر أداة قوية للتنبؤ بالنفاذية على مستوى الحقل بأكمله.

الكلمات المفتاحية: المكامن الكربوناتية، تقدير النفاذية، وحدة التدفق الهيدروليكي (HFU)، مؤشر نطاق التدفق (FZI)، حوض سرت.

1. Introduction

Accurately estimating hydrocarbon reservoirs requires a thorough grasp of the sedimentary, diagenetic, and petrophysical features of reservoirs. Permeability is one of the most important petrophysical features for assessing fluid flow in porous media. Well testing, core analysis, and/or well logging-based evaluations can all be used to estimate permeability; well logging and core data are frequently used most successfully [1-4].

A crucial factor in describing a reservoir is permeability. Although estimating permeability using well logs is typically the least expensive approach, predicting permeability in heterogeneous carbonates from well log data poses difficult and complicated issues. It is difficult to apply well-known and described mathematical models for the porosity-permeability relationship in such reservoirs. One useful method of reservoir zonation is the characterization of carbonate reservoirs into hydraulic flow units (HFU). [5 -9,10].

Carbonate reservoirs challenges for engineers and geologists to characterize because of their complexity due to depositional and diagenetic processes. The extreme petrophysical heterogeneity found in carbonate reservoirs is demonstrated by the wide variability observed, especially in porosity-permeability crossplots of core data analysis [11 – 13].

Determining discrete rock zones based on important petrophysical characteristics, including as porosity, permeability, fluid saturation, pore-throat aperture, and storage/flow capacity, is essential for accurate reservoir characterisation. By establishing these particular Hydraulic Flow Units (HFUs), customized porosity–permeability models can be developed to assess permeability throughout the reservoir. From a conceptual standpoint, an HFU is a unique volume of formation rock where the main flow-governing geological features are clearly distinct from the surrounding lithologies while remaining internally homogenous.characteristics of different rocks [4].

A flow unit is a continuous reservoir interval that shares uniform fluid-conduction and depositional characteristics both laterally and vertically. Core measurement data is used to identify Hydraulic Flow Units (HFUs), each of which corresponds to a unique Flow Zone Indicator (FZI). This method combines the normalized porosity index, which is determined by the ratio of pore space to matrix volume, with the Reservoir Quality Index (RQI), which is computed as the root ratio of permeability to porosity. of different rocks [6],[14]. Different Flow Zone Indicator (FZI) values, which are obtained mathematically from the Reservoir Quality Index (RQI) and normalized porosity (ϕ_z).volume, determine hydraulic flow units (HFUs). of different rocks [7], [15].

FZI values capture the combined impact of rock fabric and pore network topology, effectively modeling how pore space, throat configuration, path length, nodal connectivity, and structural tortuosity govern fluid conduction[6]. The Kozeny–Carman model is used to calculate permeability values for uncored well intervals [16], [17].

Helium porosimetry supplies the essential porosity and permeability data needed to assess the Flow Zone Indicator (FZI). This parameter is derived directly through the Reservoir Quality Index (RQI) framework to characterize hydraulic flow units in the formation [6]. In this approach, sandstone lithofacies are classified based on shared petrophysical characteristics and similar grain-to-pore framework microstructures [5].

2. Literature review

"In recent years, numerous investigations have focused on estimating permeability through methods based on hydraulic flow units (HFU), flow zone index (FZI), and effective flow (EF)."

For instance, [18] Porosity and permeability data were used to predict reservoir electrofacies (EFs) through clustering across two sedimentary and petrophysical dimensions. In addition, hydraulic flow units (HFUs) were defined to connect these EFs directly to productive zones in the sandstone intervals. [18], [19] Estimating Rock

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Permeability by Combining Core and Well Log Data Using K-Means Clustering and Flow Zone Indicator (FZI) Analysis." [19].

"An appropriate methodology was developed to establish empirical correlations for predicting permeability in un-cored intervals at the hydraulic flow unit level.".[20] "Cluster analysis was used to group reservoir zones into electrofacies based on permeability, porosity, bulk density, acoustic impedance, and transit time, while considering depth changes and zone continuity". "An analytical model for permeability was developed for incompressible fluid flow, utilizing non-equilibrium thermodynamic stability principles to optimize production rates while maintaining system stability [21]."
In another study, [1] predicted permeability using non-parametric regression and multivariate statistical analysis " An empirical equation based on seismic attributes was created to map the flow zone index (FZI) throughout the reservoir, and the ideal number of hydraulic flow units (HFUs) was found by spotting inflection points on the cumulative FZI frequency distribution curve [22].

The aim of this study is to utilize hydraulic flow unit and electrofacies (cluster analysis) concept with limited data to estimate the permeability of SAabah oil field

3. Geological setting of Sabah Oil Field:

The Sabah Oil Field is located in the southwest of the Sirte basin of Libya, and it was discovered in 1964, the production began at the end of 1978, in concessions No. 74 F and No. 131. The field forms part of a series of complex right-hand anti-slip structures located at a local elevation from northwest to Southeast within the Zilla Graben. A total of 70 wells have been drilled at the field, which currently houses a mix of active oil producers, injectors and monitoring wells.

The primary objective of this case study is the formation of Beda 'C', which represents the development of a large-scale carbonate platform. Geological interpretation suggests that this platform was formed during a tertiary subduction cycle in the early Paleocene epoch. The characteristics of the reservoir for the formation of Beda ' C ' are strongly influenced by complex genetic processes, the main of which is dolomization.
The structure is divided into three main tank units: zone I, tight zone and Zone II. The first zone shows the highest reservoir quality, characterized by heavy dolomite and frequent accumulations of alginate minerals such as Celestite, which leads to optimal porosity and the development of permeability. On the contrary, the second zone is predominantly limestone, which indicates a steady trend of reducing the quality of the reservoir **Figure (1)** shows the Top Structure Map of Sabah Field towards its base. Separating these two abundant zones is the narrow one, which is characterized by a very low initial porosity. However, the formation pressure test proved that such a narrow interval does not act as a vertical barrier for liquids, since natural fracture networks facilitate hydraulic contact between the first zone and the second zone.

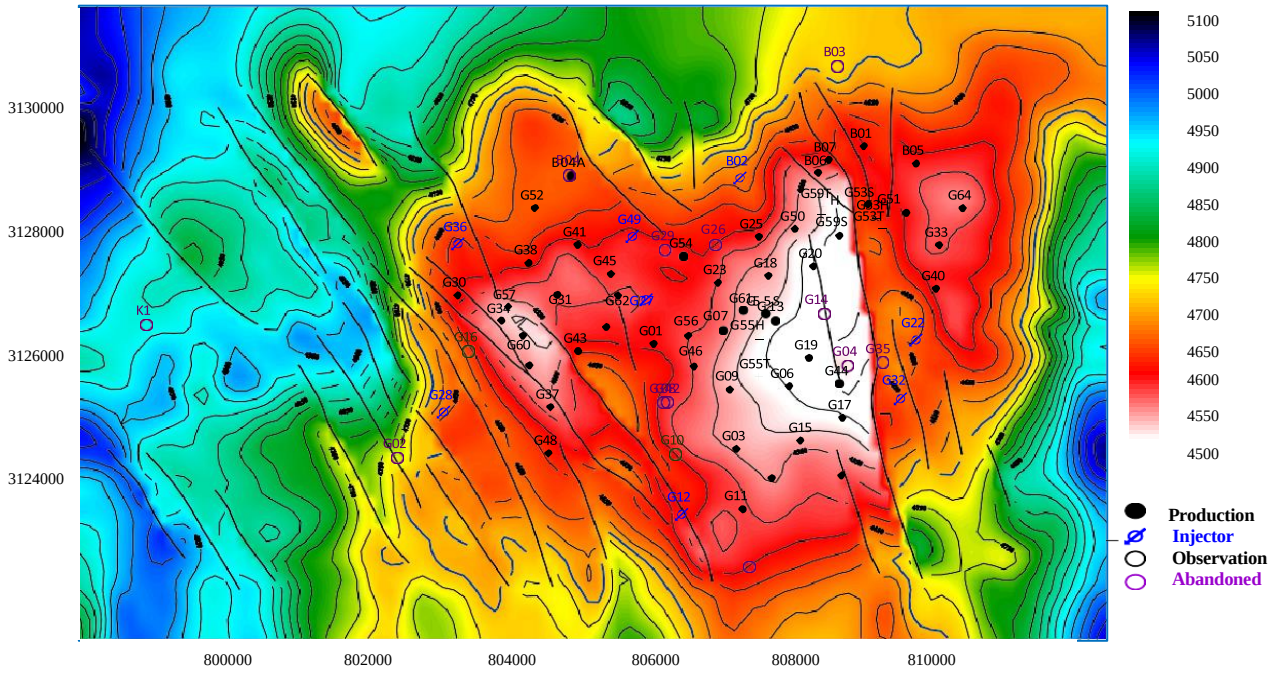


Figure (1) Top Structure Map of Sabah Field.

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4. Mathematical and Theoretical Framework

4.1 Basic Petrophysical Relationships

Porosity*(ϕ)*:- can be defined as the total void space as a measure of the total bulk volume of a permeable rock . It can be defined as the space or pores in a reservoir rock which is not occupied.
Mathematically can be defined as:

$$\phi = \frac{V_p}{V_b} = \frac{V_b - V_{gr}}{V_b} = \frac{1 - V_g}{V_b} \quad \ldots\ldots\ldots\ldots, \ldots\ldots (1)$$

Where V_p is Pore Volume, Vb is Bulk Volume , Vg is Grain Volume and ϕ is the friction porosity.
Permeability *(k)*: is defined as a measure of the a ability of the permeable rock to transmit fluid.
It is defined from the basic Darcy equation here given as:

$$q = \frac{k\, A\, \Delta P}{\mu\, L} \quad \ldots\ldots\ldots\ldots\ldots\ldots (2)$$

Where q is permeability rate, K is permeabilityin (Md), A is cross section area, μ is fluid viscosity and $(\Delta P / L)$ is pressure gradient (pressure drop per unit length)

4.2 Traditional Empirical Correlations

Historically, the petroleum industry developed multiple empirical correlations linking porosity and irreducible water saturation (S_{wc}) to absolute permeability. These classical relationships include widely empirical correlations were evaluated in this study:

1- Morris and Biggs (Oil Reservoir):

$$k = 250\left(\frac{\phi^3}{S_{wc}^2}\right) \quad \ldots\ldots\ldots\ldots\ldots\ldots (3)$$

2- Morris and Biggs (Gas Reservoir):

$$k = 80\left(\frac{\phi^3}{S_{wc}^2}\right) \quad \ldots\ldots\ldots\ldots\ldots\ldots (4)$$

3- Timur proposed the following expression for estimating the permeability from connate water saturation and porosity:

Timur Equation:

$$k = 0.136\,\frac{\phi^4}{S_{wc}^2} \quad \ldots\ldots\ldots\ldots\ldots\ldots (5)$$

4- Coates-Dumanoir relationship for the free-fluid model introduced a new equation that ensured zero permeability a zero porosity and when S_{wi} = 100%.

Coates-Dumanoir Relationship (Free-Fluid Model):

$$k = \left[100\,\phi^2\left(\frac{1 - S_{wc}}{S_{wc}}\right)\right]^2 \quad \ldots\ldots (6)$$

5- Wyllie and Rose proposed two empirical correlation relationship for the porosity, water saturation and permeability with the following formulas:

Wyllie and Rose Equation 1:

$$k = \left[\frac{100\phi^{2.25}}{S_{wc}}\right]^2 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (7)$$

Wyllie and Rose Equation 2:

$$k = \left[\frac{100\,\phi^2 1 - S_{wc}}{S_{wc}}\right]^2 \quad \ldots\ldots\ldots\ldots\ldots\ldots (8)$$

4.3 Classical Regression Analysis

When core data is available, engineers frequently attempt to correlate porosity and permeability using standard statistical regression models. The three most common mathematical models evaluated in this study are:

- *Linear Model:* $k = a + b\phi$ ……(9)
- *Exponential Model:* $k = a\,.\,e^{b\phi}$ ……(10)
- *Power Model:* $k = a\,.\,\phi^b$ ……(11)

where a and b represent empirical regression coefficients specific to the localized dataset.

4.4 Theory of Hydraulic Flow Units (HFU)

The HFU methodology is grounded in a modification of the Kozeny-Carman equation, which relates permeability to porosity and the mean hydraulic radius of the pore throats. The fundamental equation is expressed as:

$$k = \left[\frac{1}{2\,\tau^2 S_{gv}^2}\right]\left[\frac{\phi_e^3}{(1 - \phi_e)^2}\right] \quad \ldots\ldots\ldots\ldots\ldots\ldots (12)$$

Where φ_e is effective porosity, τ is pore tortuosity, and S_{gv} is the surface area of exposed to fluid per unit volume of solid materialmathematically manipulated this relationship to isolate the geological parameters from the petrophysical measurements. By dividing by effective porosity and taking the square root [6], the parameters are redefined:

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1- ***Reservoir Quality Index (RQI) in micrometers (µm):*** The (*RQI*) pro vides a pore-scale measure of flow efficiency by combining permeability and porosity into a single parameter.

$$RQI = 0.0314\sqrt{\frac{K}{\phi_e}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (13)$$

2- ***Normalized Porosity index (ϕ_z):***

$$\phi_z = \frac{\phi_e}{1-\phi_e} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (14)$$

3- ***Flow Zone Indicator (FZI) in micrometers µm) :***

$$FZI = \frac{1}{\sqrt{F_s \tau\, S_{gv}}} = \frac{RQI}{\phi_z} \quad \ldots\ldots\ldots,,,\ldots\ldots\ldots (15)$$

Where, in these equations, $F_s\tau^2$ is Kozeny constant (varies from (5 to 100) in real reservoir rocks), S_{gv} is pore volume-to-grain volume ratio, ***RQI*** and ***FZI*** are in micrometers (***µm***), ***k*** is permeability (in mD), ϕ_e is effective porosity

.*The modified Kozeny-Carman relationship can thus be simplified into a linear logarithmic form:*

$$RQI = FZI \times \phi_z \quad \ldots\ldots\ldots\ldots\ldots,,,,,\ldots (16)$$

Taking the logarithm of both sides yields:

$$(\log(RQI) = \log(FZI) + \log\phi_z) ,,,\ldots (17)$$

On a log-log plot of **RQI** versus ϕ_z, samples possessing similar pore-throat characteristics will align along a straight line with a unit slope. The intercept of this line at $\phi_z = 1$ yields the mean ***FZI*** for that specific hydraulic flow unit. Once the ***FZI*** mean is established for a unit, permeability can be accurately reverse-calculated using:

$$k = 1014 \cdot FZI_{mean}^2 \left(\frac{\phi_e^3}{(1-\phi_e)^2}\right) \quad \ldots\ldots\ldots\ldots\ldots\ldots,,,\ldots (18)$$

4.5 Methodology and Workflow

The research methodology was structured to systematically evaluate and compare the accuracy of various permeability prediction techniques against direct core measurements from the Sabah field.

1- Data Acquisition and Preparation: Core data (porosity and permeability) from eight wells (G-01, G-04, G-06, G-41, G-42, G-43, G-48, and G-53) in the Sabah field were compiled and quality-controlled.
2- Empirical Evaluation: Permeability was calculated using published correlations (Timur, Wyllie & Rose, Morris & Biggs) utilizing the available porosity and water saturation data.
3- Statistical Regression: Global cross-plots of the entire core dataset were generated to perform linear, exponential, and power regression analyses.
4- *HFU* Classification: The *HFU* technique was applied by computing *RQI*, ϕ_z, and *FZI* for every core sample. Logarithmic histograms of *FZI* were utilized to mathematically determine the optimum number of discrete hydraulic flow units within the reservoir.
5- *HFU* Correlation Development: Mean *FZI* values were extracted for each identified flow unit, enabling the generation of distinct porosity-permeability equations for each sub-facies.
6- Log Calibration and Validation: Well log data from well G-18 (Gamma Ray, Density, Neutron, Resistivity) was analyzed to compute continuous log porosity. The established predictive models were then applied to this log porosity, and the resulting permeability profiles were statistically compared against actual core data from well G-18 to validate the optimal model.

Table 1: Reservoir Permeability Classification Scale

Permeability Range (mD)	Reservoir Quality Class
< 1	Poor / Tight
1 — 10	Fair / Moderate
10 — 100	Good
> 100	Excellent / High Yield

5. Results And Discussion

5.1 Evaluation of Traditional Correlations and Regressions

Initial cross-plotting of core porosity against core permeability displayed a highly scattered cloud, typical of complex carbonate systems. Standard regression analysis on the composite dataset yielded very poor coefficients of determination (R^2 values below 0.45), indicating that treating the (Beda C) formation as a single homogeneous reservoir rock type introduces massive predictive errors. Linear, power, and exponential regressions failed to capture the high-permeability trends seen in lower-porosity fractured zones and overestimated permeability in micro-porous matrix blocks. Similarly, testing the established empirical models (Wyllie-Rose, Morris-Biggs, and Timur) generated significant deviations from measured core data. This poor fit is statistically quantified by high Average Absolute Percent Relative Errors (*AARE*) and low R^2 values. These models assume that a single universal pore-throat to porosity ratio governs the entire formation, an assumption that is completely invalidated by the heavy diagenetic heterogeneity of the Sirte Basin carbonates.

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Table (2) present the classifications depended on FZI mean as porosity ranges, by these correlations could be estimate the permeability using porosity from logs for Sabah oil field.

Table (2): Reservoir rock classification by HFU method

R^2	Permeability Correlation	Porosity Max	Porosity Min	HFU Unit
0.698	$k = 737.88\phi^{3.2086}$	0.161	0.039	HFU #1
0.717	$k = 2161.8\phi^{3.5201}$	0.250	0.161	HFU #2
0.736	$k = 2917.4\phi^{3.7533}$	0.300	0.250	HFU #3
0.712	$k = 6006.6\phi^{4.0364}$	0.40	0.300	0 HFU #4

These four distinct relationships confirm that as porosity transitions through varying physical thresholds, the internal pore-throat architecture (and consequently the fluid flow capacity) shifts fundamentally, requiring a unique mathematical definition for accurate prediction**.**

5.2 Performance of existing porosity and permeability correlations

The calculations processes of all data set were start from applied the empirical correlations (Morris & Biggs, Wyllie & Rose 1 and Wyllie & Rose 2), and compare the results with core data. Then try to find out the best regression for the permeability as function in porosity with linear, exponential and power regressions.

By using the equations (3), (6) and (7), using porosity and water saturation from core data to estimate the permeability. Figures (2), (3) and (4) below shows the cross plot between measured permeability and calculated permeability using correlations in log-log plot.

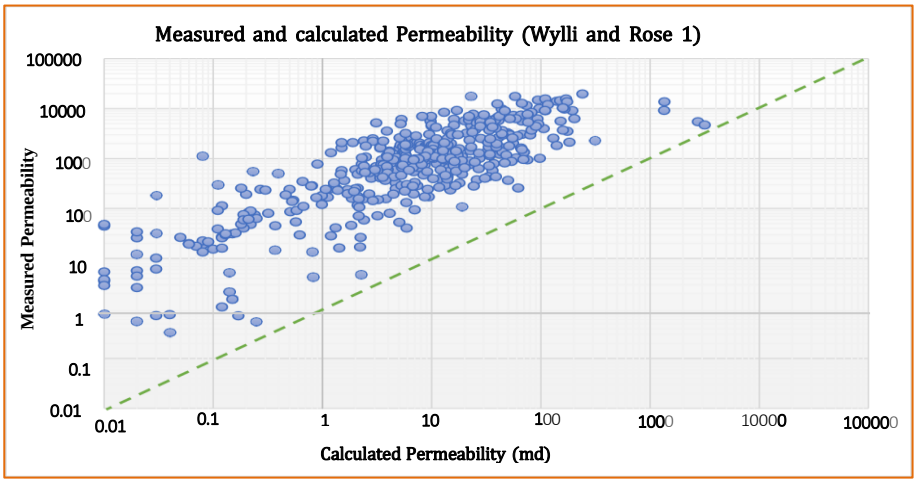


Figure (2): Wyllie and Rose 1 cross plot

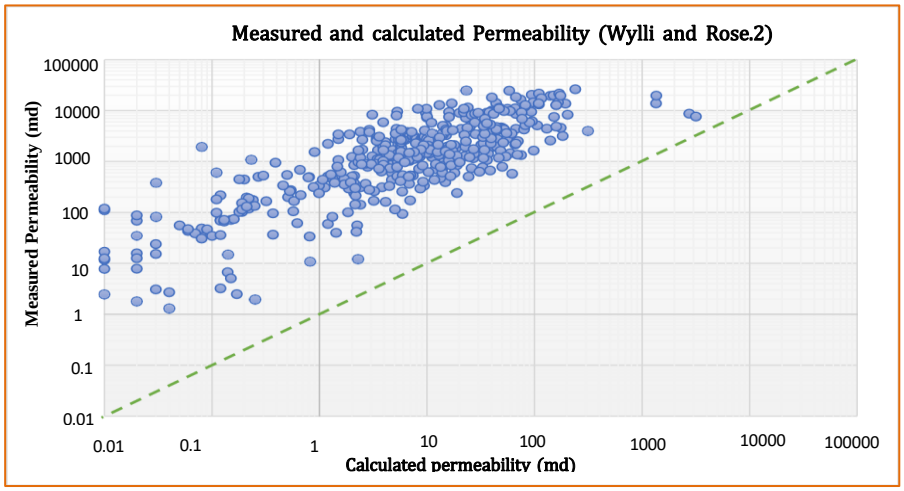


Figure (3): Wyllie and Rose 2 cross plot

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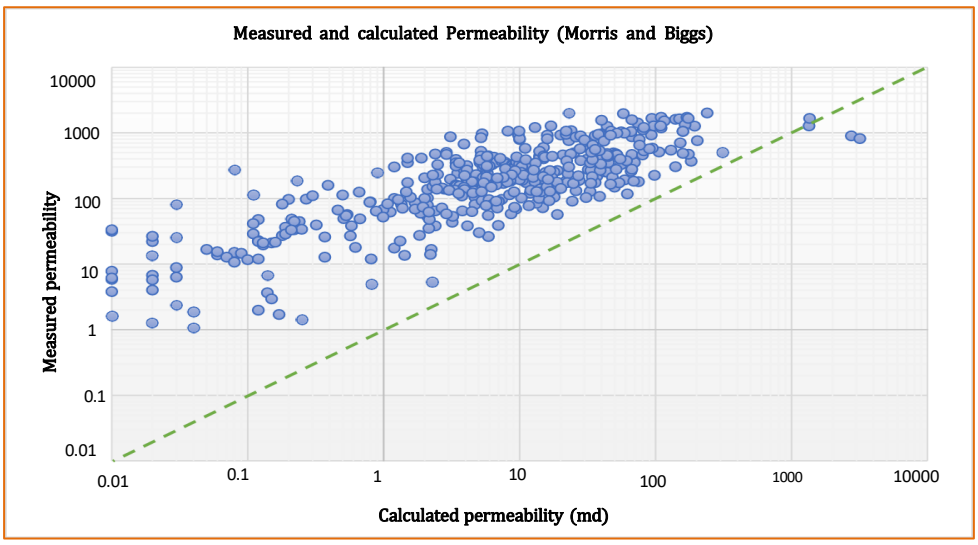


Figure (4): Morris and Biggs cross plot**.**

5.3 Hydraulic Flow Unit Analysis

To resolve this heterogeneity, HFU analysis was applied. A mathematical analysis of the log(FZI) frequency distribution for the collective core samples was performed. By decomposing the multi-modal histogram, four distinct normal log FZI distributions were isolated, indicating that the Beda C reservoir consists of 4 distinct Hydraulic Flow Units.

Table 3: HFU Reservoir Rock Classification Summary

HFU No	Mean FZI (µm)	R^2 Value	Rock Quality Description
HFU 1	0.42	0.78	Poor Matrix / Micro porous Limestone
HFU 2	1.15	0.84	Fair / Intergranular Pore Space
HFU 3	2.85	0.91	Good / Medium to Coarse Dolomite
HFU 4	6.40	0.95	Enhanced Quality / Vuggy & Fractured Dolostone

Table 3 summarizes the results of the classification. *HFU4* represents the highest quality rock type, consisting of heavily dolomitized, highly connected pore systems and micro-fractured intervals with an exceptional mean *FZI* of 6.40 µm and an R^2 value of 0.95. *HFU3* represents the standard high-yield dolostone. *HFU2* comprises fair quality limestones, whereas *HFU1* isolates the tight, poorly sorted matrix blocks where fluid flow is heavily restricted. When plotting *RQI* against φz on a log-log plot according to the partitioned *HFUs*, the data sorted beautifully into four tight, parallel lines with a unit slope, demonstrating the theoretical validity of the grouping.

5.4 Validation Using Well Logs (Well G-18)

To test the predictability of the developed HFU models in un-cored wells, open-hole well logging data from well G-18 were utilized. Continuous effective porosity *(φ logs)* was evaluated from Density *(RHOB)* and Neutron (*NPHI)* logs, after accounting for shale volume *(Vshale)* using Gamma Ray *(GR)* corrections:

$$V_{shale} = (GR_{log} - GR_{min}) / (GR_{max} - GR_{min})$$

The calculated log-porosity profile was calibrated against existing core plugs from well G-18, showing a near-perfect match. Next, the appropriate HFU equations were applied to predict continuous permeability. Statistical error evaluation parameters, including Average Percent Relative Error (ARE) and, Standard Deviation (SD), were calculated to quantify model precision.

5.5 Comparison Analysis for prediction Permeability using Porosity

As complete apply different methods to estimate permeability by using porosity in Sabah oil field and all method give results different from the another so needs to measure the quality of each method by using core data for well G-18 and after complete the analysis of logs to estimate porosity, **Table (4)** shows the Comprising between HFU method with Linear, Power, Exponential , Wylli and Rose eq1 , eq2 and Morris and Biggs eq methods by using four performance indicators, including correlation coefficient square (R^2), absolute average Division (AAD %), average error (AE %), as well as absolute average error (AARE %). Standard Deviation (SD), were calculated to quantify model precision.

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Table 4: Statistical Comparison for Well G-18 Permeability Prediction

Method / Correlation	R^2	AARE (%)	SD (mD)
Linear Regression	0.38	145.2	45.3
Exponential Regression	0.42	112.5	38.1
Timur Correlation	0.49	88.4	29.4
Wyllie-Rose Model	0.51	82.1	26.8
HFU Model (This Work)	**0.89**	**12.4**	**4.2**

As summarized in Table 3, the HFU technique dramatically outperformed all other methods. It achieved an R2 value of 0.89 and restricted the Average Absolute Percent Relative Error (AARE) to just 12.4%, compared to errors exceeding 80% for classical workflows. This confirms that dividing the reservoir into rock-vug/pore-throat families using FZI is crucial for generating high-fidelity permeability profiles from logging indicators. **Figure (5) to Figure (7)** shows cross plots of three studied models.

Linear model: $k = a + b\varphi$. **Power Model:** $k = a.e^{b\varphi}$ **and Exponential Model:** $k = a$ **and** φ^b Respectively.

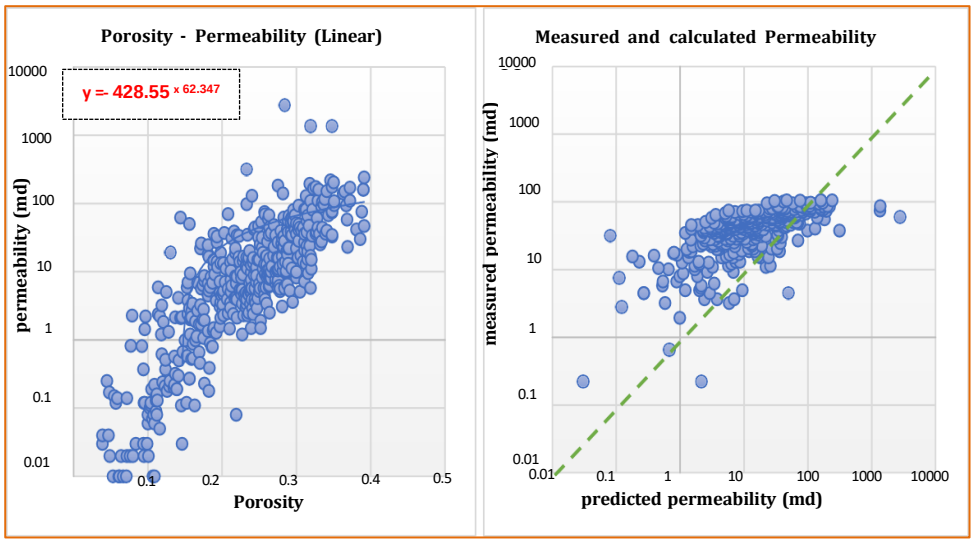


Figure (5) Linear regression

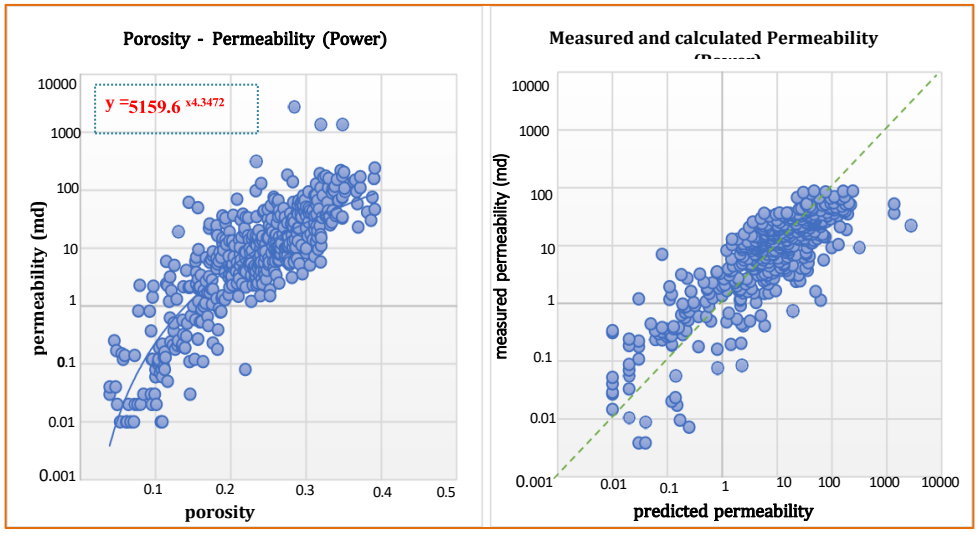


Figure (6): Power regression

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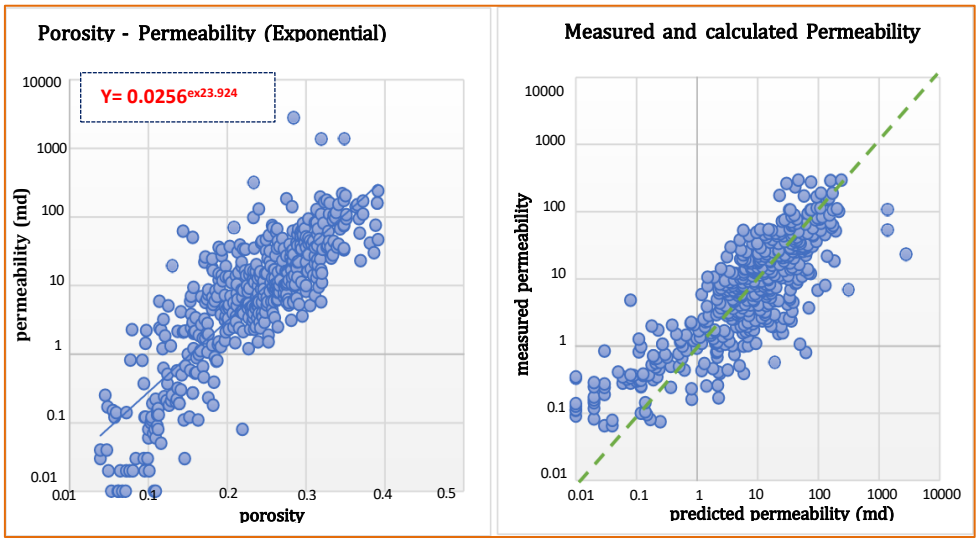


Figure (7): Exponential regression

5.6 Log analysis for well (G-18).

The wireline data sets provided by ZOC consisted of digital logged curves in industry standard LAS format for the well, contains the gamma ray, SP, sonic, density, resistivity's and neutron logs.

The main target for quick look interpretation is to determine both rock reservoir and non-rock reservoir, and to select hydrocarbon and water zone. To estimate gas and oil regions by using gamma ray log, resistivity log, neutron log and density log to perform quick look interpretation for well "G-18", the **figure (8)** below shows the Formation Evaluation using well logging for Well G-18.

Generally, density and neutron logs putted in with each other in the well, to indicate the gas zone and oil zone. When porosity computed, the effect of shale on porosity logging responses must be evaluated. The formula used to compute the porosity from density log is listed below:

$$\emptyset D = \frac{P_{matrix} - P_{log}}{P_{matrix} - P_{fluid}} \quad \ldots\ldots(19)$$

If the amounts of gas and shale in the formation under evaluation have approximately the same effect on both the Density and Neutron measurements, the following set of equations can be used to calculate a value of effective porosity: the **table (5)** below represent the porosity estimation by log analysis for well (G-18)

$$\emptyset_T = \sqrt{\frac{\emptyset_N^2 + \emptyset_D^2}{2}} \quad \ldots\ldots\ldots\ldots\ldots\ldots(20)$$

$$\emptyset_e = \emptyset_T(1 - V_{sh}) \ldots\ldots\ldots\ldots\ldots\ldots(21)$$

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Table (5): Porosity estimation by Logs Analysis

Logs data													
DEPT	GR	DRHO	NPHI	RHOB	RHOB(Correction)	V_{shale}	V_{shale}	Lith. Ind	Rock Density	Fluid Density	Density	ϕ_D	ϕ_{logs}
ft	GAPI	gm/cc		gm/cc	gm/cc	fraction	%		gm/cc	gm/cc			
5480.0	41.71342	0.0525	0.334	2.609	2.662	1.000	100	Shale	2.970	1.000	2.970	0.156	0.261
5480.5	37.24746	0.0452	0.319	2.628	2.674	0.874	87.369	Shale	2.970	1.000	2.937	0.136	0.245
5481.0	32.44909	0.0453	0.296	2.613	2.659	0.738	73.799	Shale	2.970	1.000	2.902	0.128	0.228
5481.5	24.44788	0.0421	0.183	2.641	2.683	0.512	51.170	Shale	2.970	1.000	2.843	0.087	0.143
5482.0	21.29817	0.0302	0.111	2.653	2.683	0.423	42.262	Shale	2.970	1.000	2.820	0.075	0.095
5482.5	18.34927	0.0335	0.064	2.739	2.772	0.339	33.922	Shale	2.970	1.000	2.798	0.014	0.047
5483	15.3863	0.0626	0.054	2.753	2.815	0.255	25.542	Shale	2.970	1.000	2.776	-0.022	0.041
5483.5	12.94621	0.0544	0.028	2.754	2.809	0.186	18.641	carbonate	2.710	1.135	2.758	-0.031	0.030
5484	10.96153	0.0348	0.016	2.809	2.844	0.130	13.028	carbonate	2.710	1.135	2.744	-0.062	0.046
5484.5	9.15098	0.0263	0.006	2.888	2.914	0.079	7.907	carbonate	2.710	1.135	2.731	-0.115	0.081
5485	7.41269	0.0314	0.001	2.954	2.985	0.030	2.991	carbonate	2.710	1.135	2.718	-0.169	0.120
5485.5	6.35506	0.0209	-0.004	2.945	2.966	0.000	0.000	carbonate	2.710	1.135	2.710	-0.163	0.115
5486	6.36234	0.0135	-0.006	2.954	2.968	0.000	0.021	carbonate	2.710	1.135	2.710	-0.164	0.116
5486.5	7.24912	0.0105	-0.006	2.949	2.960	0.025	2.529	carbonate	2.710	1.135	2.717	-0.154	0.109
5487	7.8612	0.0178	-0.005	2.947	2.964	0.043	4.260	carbonate	2.710	1.135	2.721	-0.153	0.109
5487.5	9.61023	0.0141	-0.004	2.912	2.926	0.092	9.206	carbonate	2.710	1.135	2.734	-0.120	0.085
5488	12.61232	0.0128	0.000	2.896	2.908	0.177	17.697	carbonate	2.710	1.135	2.756	-0.094	0.066
5488.5	15.45683	0.0224	0.006	2.908	2.930	0.257	25.741	Shale	2.970	1.000	2.777	-0.086	0.061
5489.0	18.23493	0.046	0.014	2.814	2.860	0.336	33.598	Shale	2.970	1.000	2.797	-0.035	0.026
5489.5	21.64444	0.0186	0.027	2.754	2.773	0.432	43.241	Shale	2.970	1.000	2.822	0.027	0.027
5490.0	24.12744	0.0014	0.050	2.700	2.701	0.503	50.264	Shale	2.970	1.000	2.841	0.076	0.064
5490.5	26.48863	0.0216	0.140	2.645	2.666	0.569	57	Shale	2.970	1.000	2.858	0.103	0.123

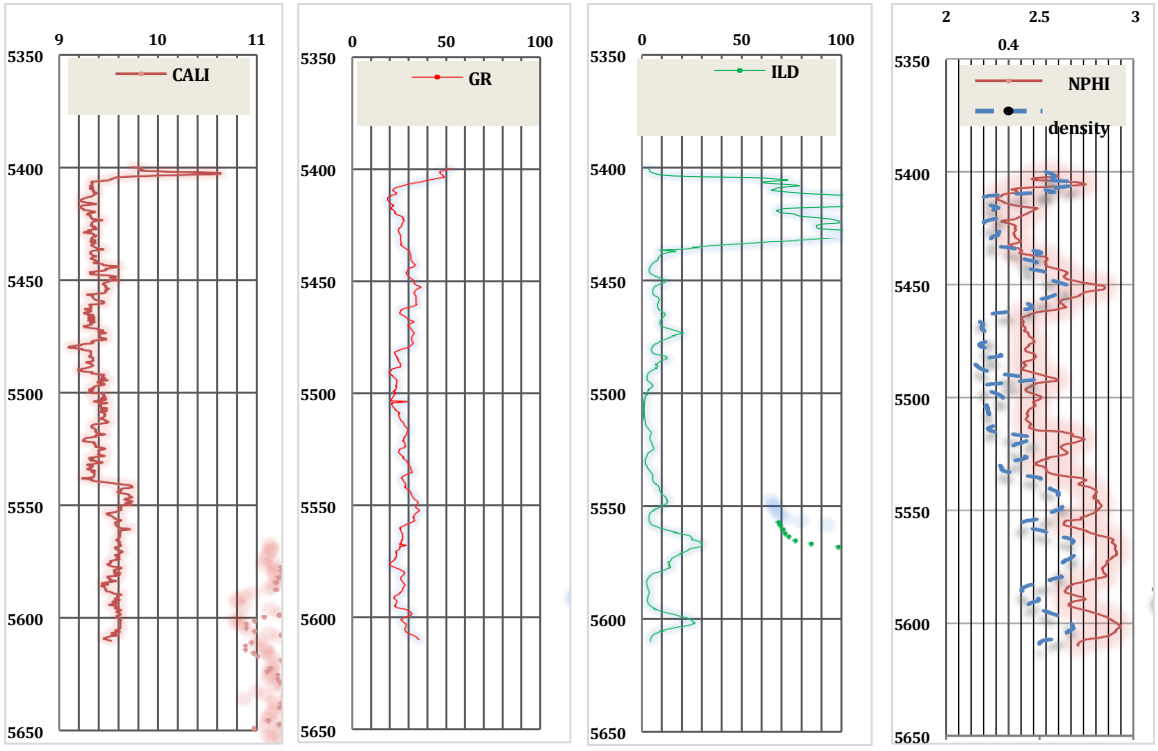


Figure (8): Formation Evaluation using well logging for Well G-18

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6.1 Conclusions

1. Carbonate reservoirs like the Beda C formation in the Sabah Field exhibit complex, non-linear porosity permeability relationships due to severe diagenetic alterations (dolomitization anfracture presence).
2. Traditional empirical models (Timur, Wyllie-Rose, Morris-Biggs) and standard regressions are highly inaccurate when applied globally to heterogeneous formations, resulting in massive over/under-estimations.
3. The Hydraulic Flow Unit (*HFU*) approach based on the Flow Zone Indicator (*FZI*) successfully partitioned the (Beda C) reservoir into distinct rock classes with clear petrophysical boundaries.
4. Applying HFU distinct formulations provided a major increase in accuracy, yielding an $\mathbf{R^2}$ of 0.89 and minimizing the *AARE* to 12.4% during blind-testing in well G-18.

6.2 Recommendations

1. The HFU framework developed in this study should be fully integrated into the fields-wide geocellular model to populate permeability fields across un-cored sections of the Sabah Field.
2. Advanced clustering techniques, such as Artificial Neural Networks (ANN) or modern machine learning algorithms, could be coupled with FZI parameters to automate HFU identification directly from logging suites.
3. Special Core Analysis (SCAL) testing, including mercury injection capillary pressure (MICP),should be Systematically conducted on representative samples of each HFU to further evaluate absolute pore-throat radius cut-offs.

Nomenclature

***FZI*:** Flow Zone Indicator (μm)	$\boldsymbol{\phi_D}$**:** Porosity from Density Log
***HFU*:** Hydraulic Flow Unit	$\boldsymbol{\phi_N}$**:** Neutron Porosity
GR: Gamma Ray Log	$\boldsymbol{\phi_T}$**:** Total Porosity
k: Permeability (md)	$\boldsymbol{V_p}$**:** Pore Volume (cm^3)
$\mathbf{R^2}$**:** Coefficient of Determination	$\boldsymbol{Vb}$**:** Bulk Volume (cm^3)
***RQI*:** Reservoir Quality Index μm)	$\boldsymbol{V_{gr}}$**:** Grain Volume (cm^3)
$\mathbf{S_{gv}}$**:** Surface Area per Grain Volume	$\boldsymbol{S_o}$**,** $\boldsymbol{S_g}$**,** $\boldsymbol{S_w}$**:** Oil, Gas, and Water Saturations
$\boldsymbol{\phi}$**:** Porosity (fraction or %)	$\boldsymbol{S_{wc}}$**:** Connate/Irreducible Water Saturation
$\boldsymbol{\phi_e}$**:** Effective Porosity (fraction)	$\boldsymbol{V_{sh}}$**:** Volume of Shale (fraction)
$\boldsymbol{\phi_z}$**:** Normalized Porosity	***AARE*:** Average Absolute Percentage Relative Error

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