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Comprehensive Petrophysical Assessment of Carbonate Reservoirs in the Shanul Gas Field (SW Iran): A Case Study with Implications for Hydrocarbon Exploration and Production

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Abstract

This study presents an integrated petrophysical workflow for the comprehensive characterization of the Upper Dalan and Kangan carbonate gas reservoirs in the Shanul Field, southwest Iran. By combining advanced cross-plot techniques (including M-N, MID, and RHOma-Uma plots) with probabilistic porosity modeling calibrated to core data, this work achieves a higher-resolution discrimination of lithology and more robust estimation of fluid properties compared to conventional single-log approaches. The results reveal significant heterogeneity within both formations but demonstrate the superior reservoir quality of the Upper Dalan, particularly within the UD2 subzone, and in the Ka-2a subzone of the Kangan. The improved workflow enables more accurate zonation and identification of high-quality, productive intervals, supporting optimized field development strategies. These findings provide methodological advances for challenging and heterogeneous carbonate systems, offering a reference framework for similar reservoirs in the Zagros Basin and beyond.

Keywords: Kangan formation; Upper Dalan formation; permeability; porosity; shale volume; water saturation; pay summary

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1. Introduction

The petrophysical characterization and interpretation of reservoir formations, through well logs, is an essential element to study and address its quantitative and qualitative evaluation [1].

This evaluation is also used to zone the studied formation in terms of having more and better ability to produce hydrocarbon, leading to a more focused development of the fields. The petrophysical analysis is one of the most important reservoir characterization methods, leading to the calculation of porosity, permeability and water saturation, determination of lithology, and shale volume. By combining data from core porosity–permeability analysis, well log interpretation (including gamma ray, resistivity, density, neutron, and sonic logs), and geological observations such as lithofacies descriptions and stratigraphic correlations, a comprehensive model of the reservoir was constructed. This integrated approach enables accurate zonation and property estimation across both wells.

As a result, the following exploration and production studies may be focused on the parts with better potential for hydrocarbon production, avoiding expenses with non-reservoir layers.

The purpose of this study is the petrophysical evaluation of the Upper Dalan and Kangan Formations in the Shanul gas field, located in the Zagros Basin, southwestern Iran. With a thickness of more than 400 m, these two formations are considered to be the most important and largest carbonate gas reservoirs in the Middle East [2]. Many studies have been conducted in Iran and in neighboring countries to determine the evaluation of its petrophysical properties, including different approaches, such as core analysis [3], reservoir characteristics [4], reservoir quality [5–7], petrophysical evaluation [8], and petrophysical parameters [9]. In previous studies on similar carbonate reservoirs in Iran and the broader Zagros Basin, standard interpretation methods were often based on individual log analyses or basic cross-plots for porosity and lithology estimation. These methods typically relied on conventional neutron-density or resistivity–porosity relationships, often without full integration of multiple log types or core-calibrated parameters. In contrast, this study introduces an integrated workflow combining M-N Plot, RHOma-Uma cross-plot, MID plot, and probabilistic porosity calculations calibrated with core porosity–permeability data. This approach provides a more detailed and accurate reservoir characterization, especially critical in lithologically heterogeneous zones with mixed dolomite, calcite, and shale content. Due to the importance of this type of reservoir, characterizing and interpreting in detail this reservoir in different situations is a contribution to its better understanding, and therefore the Shanul gas is here presented as one more case study, with some specific characteristics related to its geological context.

Previous studies on carbonate gas reservoirs in the Zagros Basin have focused primarily on isolated aspects such as core-based porosity–permeability relationships [3,5] or single-log lithology identification [7,9]. However, these approaches often lack the integration necessary to characterize spatial heterogeneity and zonation in complex carbonate systems. In this study, we address this gap by combining geological interpretation, core data, and advanced well log analysis techniques (M-N plot, MID plot, RHOma-Uma, and probabilistic porosity models). This integrated workflow allows for more reliable identification of reservoir zones and improved prediction of reservoir quality.

Recent studies emphasize that nanoscale structural transformations in organic-rich shales—arising from both diagenetic processes and bedding-parallel slip—can profoundly influence reservoir quality and hydrocarbon potential [10,11]. The integration of advanced nanoscale mineralogical and organic analyses, such as AFM-IR spectroscopy, provides new insights into shale characterization and petrophysical modeling [11]. These advances are particularly relevant for the heterogeneous carbonate and shaly facies present in the Shanul Field.

2. Geological Setting

The studied Shanul gas field is located in the Zagros region of Fars province (200 km south of Shiraz) (Figure 1), with Permo-Triassic carbonate reservoirs (Figure 2). The Permian sequence begins with the Faragan Formation, followed by the Late Permian Dalan Formation and the Early Triassic Kangan Formation. These two formations form the main reservoirs of the studied field [12]. Dalan formation is composed mainly of thick gas-rich carbonates [1], with a middle anhydrite unit (Nar formation) containing sour gas [4]. Kangan formation is also composed of carbonates, with a middle more dolomitic part. This field is composed mainly of dolomites and limestone, but evaporites and shale rocks are also present (Figure 2).

Figure 1. Location map of gas fields in Southern Iran [1].

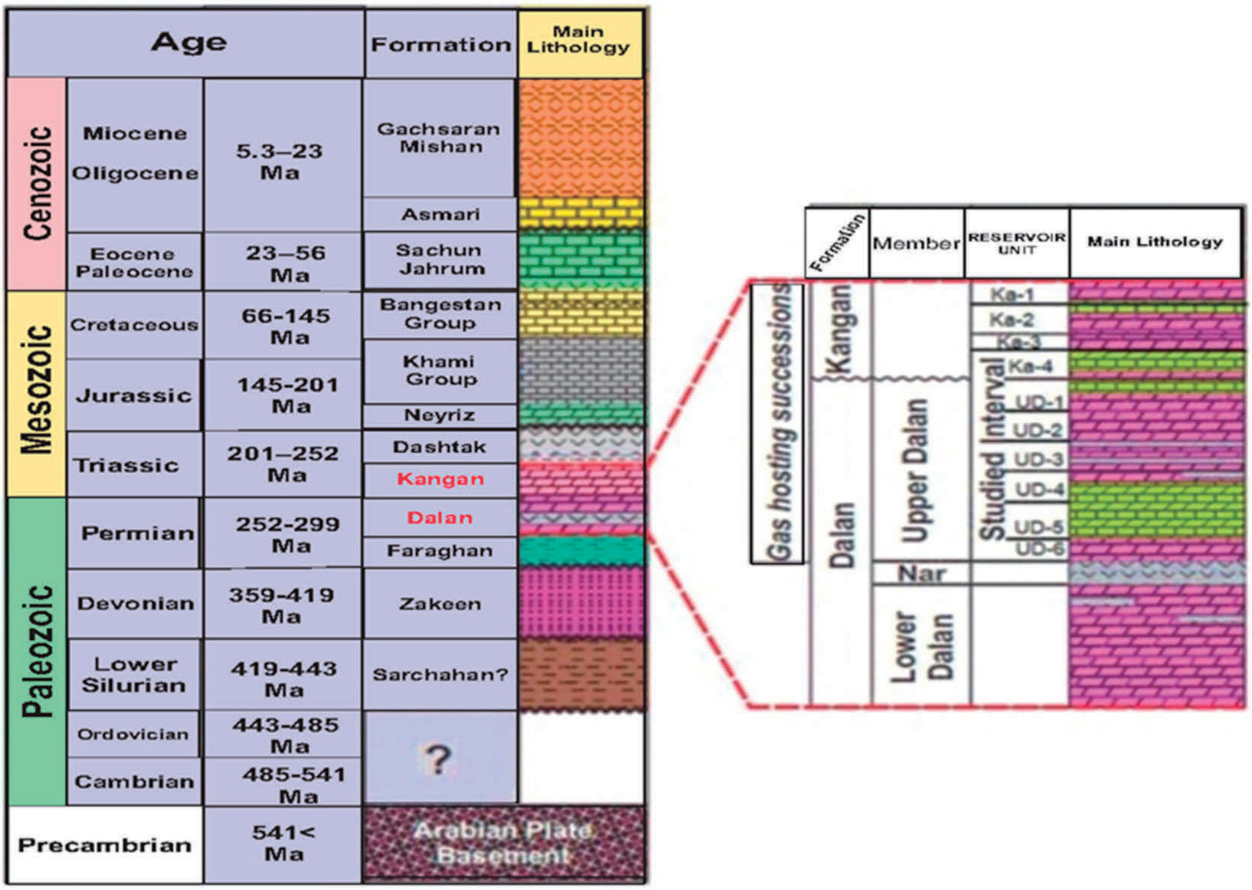


Figure 2. The stratigraphic column of the studied field [1].

3. Material and Methods

Two wells drilled in the Upper Dalan and Kangan formations have been studied, wells #4 and #6. The following well log data have been used to calculate petrophysical properties: Gamma Ray logs (Spectral Gamma Ray—SGR, and Computed Gamma Ray—CGR), Resistivity logs (Flushed Zone Resistivity—RXO, and True Resistivity—RT), Caliper log, Sonic log (Interval Transit Time [Delta-T], DT), Density log (RHOB), Neutron log (Neutron Porosity Index, NPHI)), Photoelectric Factor log (PEF), and Bulk Density Correction log (DRHO).

For porosity–permeability studies, 110 cores (65 in #4) and 45 in #6 have been collected and analyzed. Prior to data interpretation, environmental corrections were applied to raw log measurements to compensate for borehole effects, formation fluid variations, and tool response discrepancies. This ensures accurate porosity and saturation calculations. The overall methodological workflow followed several integrated steps to ensure robust reservoir characterization. First, environmental corrections were applied to the well log data to correct for borehole effects and tool response discrepancies. Then, lithology identification was conducted using classical cross-plot methods including the RHOma-Uma, MID Plot, and M-N Plot [13]. The M-N Plot is a lithology identification technique based on density, neutron, and sonic logs that helps eliminate porosity effects and distinguishes minerals such as dolomite and calcite. The RHOma-Uma Plot, which combines density, neutron, and PEF logs, is particularly effective in identifying lithology based on photoelectric absorption properties.

Porosity was computed using a probabilistic method combining RHOB, NPHI, and DT logs, calibrated against core porosity values to improve reliability [13]. Permeability was estimated by deriving a regression model from the core porosity–permeability cross-plot and applying it to the continuous porosity log.

Water saturation was calculated using the Indonesia equation [14], appropriate for shaly carbonate environments. This required inputs from resistivity logs (RT), effective porosity, and calculated Vsh, as well as laboratory-derived Archie parameters (m, n, and a). Shale volume (Vsh) was calculated using the Gamma Ray Index method based on SGR logs, with clean and shale-end members derived from local log signatures.

Finally, zonation of the reservoirs was performed based on Net-to-Gross ratio, porosity, Sw, and lithology, applying fixed cut-off values (Porosity $\geq$ 5%, Sw $\leq$ 50%, Vsh $\leq$ 30%) to define productive intervals. These zones were named UD1 to UD3 in Upper Dalan and Ka1 to Ka4 in Kangan Formation.

Reservoir zones have been defined based on Net-to-Gross ratios, lithological composition, porosity distribution, and water saturation values, allowing for the identification of intervals with better reservoir quality. The selection of interpretation methods in this study was based on the complex lithological nature of the Upper Dalan and Kangan formations, which are composed of mixed dolomitic, calcareous, shaly, and anhydritic facies. Conventional single-log interpretations often fail to differentiate lithologies or account for gas effect and secondary porosity accurately. Therefore, we employed multi-log cross-plots—such as M-N Plot, MID Plot, and RHOma-Uma plots—which are better suited for lithology determination in heterogeneous carbonate settings. Additionally, porosity was calculated using a probabilistic approach rather than traditional empirical equations, allowing integration of multiple logs to obtain more reliable estimates. These methods were selected based on their prior success in similar reservoir studies in the region [4,7], and their application here provides enhanced accuracy in reservoir zonation and property estimation.

Log Data Corrections

All well log data were subjected to standard corrections prior to interpretation, to account for environmental and borehole effects. This included corrections for borehole size (caliper), mud-filtrate invasion (deep/shallow resistivity separation and SP corrections), tool standoff, and environmental corrections based on service company charts. Density and neutron logs were corrected for borehole rugosity and standoff. Sonic log compressional travel times were calibrated using check shot surveys where available. The photoelectric factor (PEF) log was checked for consistency and corrected using cross-plots with core mineralogy data.

Core Data Representativeness

A total of 155 core plug samples were collected from both wells, with sampling intervals selected to represent the full lithological and reservoir heterogeneity of the Upper Dalan and Kangan formations. Core plugs were extracted approximately every 1.5–2 m, ensuring adequate coverage of each petrophysical subzone (UD1–UD3, Ka1–Ka4) and facies transitions. This strategy maximized statistical representativeness for calibration and validation of the log-derived parameters.

Experimental Determination of Archie Parameters

Archie exponents (cementation factor, m; saturation exponent, n) and tortuosity factor (a) were determined experimentally by laboratory measurements:

- Core plugs were dried, saturated with brine of known salinity, and their resistivity measured at 100% water saturation to determine the formation resistivity factor (FRF).
- Resistivity at varying water saturations was obtained by stepwise desaturation using the porous plate method.
- The m exponent was calculated by plotting log(F) versus log(ϕ), while n was obtained from log(Rt/Ro) versus log(Sw) for each sample set.
- Tortuosity factor a was initially assumed as 1; further analysis used the FRF at full saturation to verify this assumption.
- All procedures followed industry standards (e.g., 18).

4. Results and Discussion

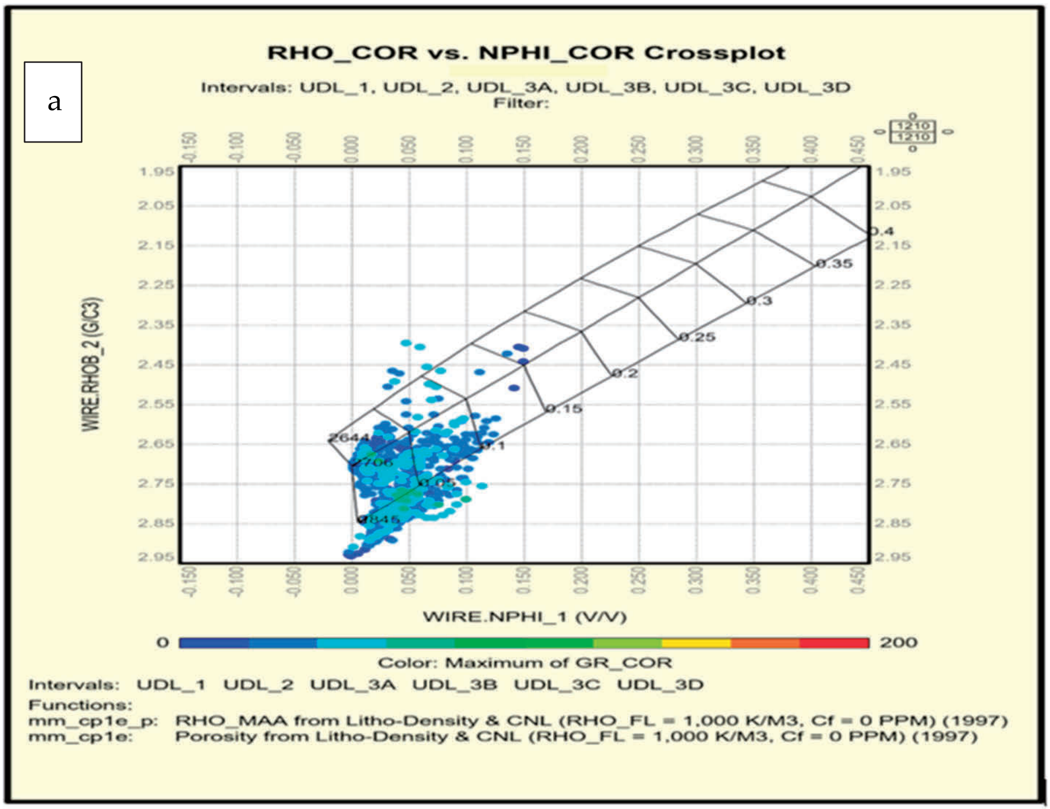
Petrophysical evaluation is presently the science of processing and interpreting the information obtained from the well logs and combining it with the results of the core to determine the reservoir zones and determine their quality in order to optimally exploit the fields. On the other hand, evaluating the petrophysical properties of the reservoir is one of the most important key factors in the evaluation, production, and expansion of hydrocarbon reservoirs. One of the basic applications of well logs in the studied formations is the recognition and investigation of petrophysical properties such as determining porosity, permeability, and water saturation and calculating the volume of shale. In this research, the petrophysical properties of Upper Dalan and Kangan formations have been evaluated in two well using petrophysical data and core porosity–permeability data.

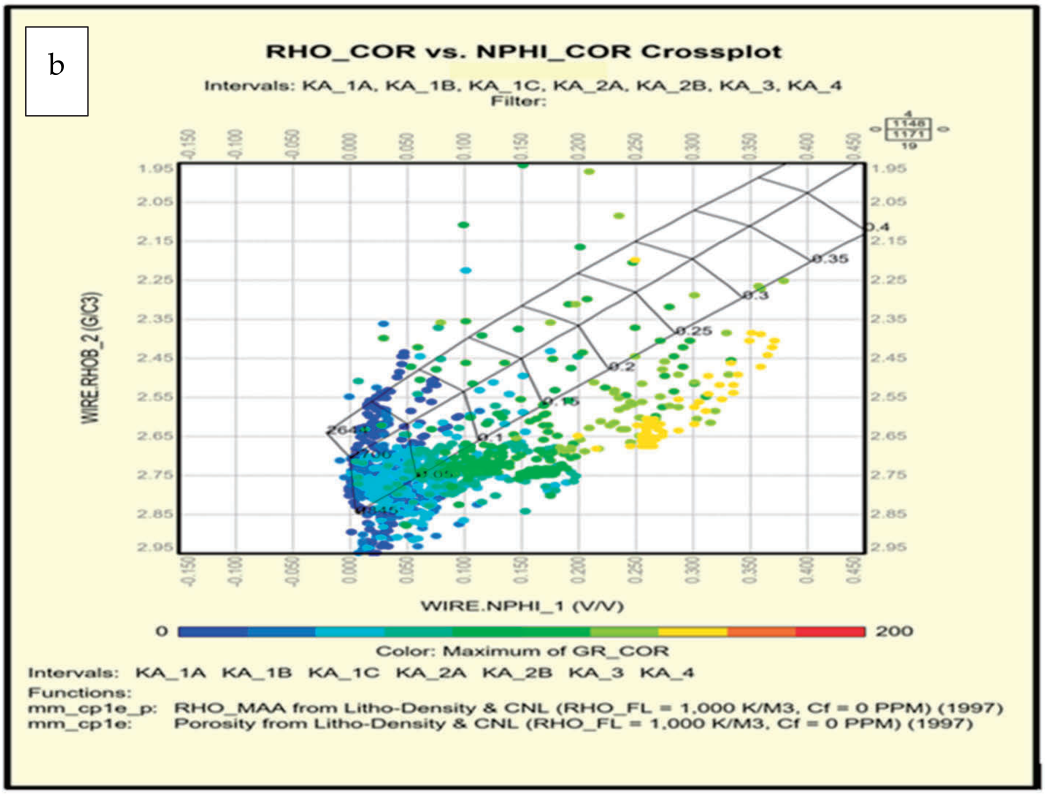
4.1. Mineralogy and Lithology

Determining lithology is considered a fundamental step for evaluating reservoir properties, and its determination leads to a very accurate evaluation of petrophysical parameters such as porosity and water saturation [6]. And it can be used to separate areas with reservoir characteristics from non-reservoir areas. Lithology diagnosis is possible using standard cross-plots, well-log charts, studying thin sections prepared from the core and descriptions of the core. In this study, the cross-plots used to identify lithology were 1. Neutron-density cross-plot; 2. M-N Plot method; 3. MID_Plot method; 4. RHOma-Uma Plot method.

- Neutron-density Cross-plot

This cross-plot is used to calculate porosity and lithology, having the best porosity diagnosis and also the best separation lithologies differentiation [15,16]. This cross-plot separates dolomite, limestone and sandstone lithologies well. Of course, the presence of gas causes errors in the reading of this cross diagram. The presence of shale in the formation causes the plotted points to move to the southeast of the diagram. Therefore, before using the cross-plot, both graphs should be corrected in terms of shale. The distance of the point from the matrix lines indicates the lithology percentage [15]. Figure 3 shows the neutron-density cross-plot of the studied formations and Table 1 its lithological interpretation.





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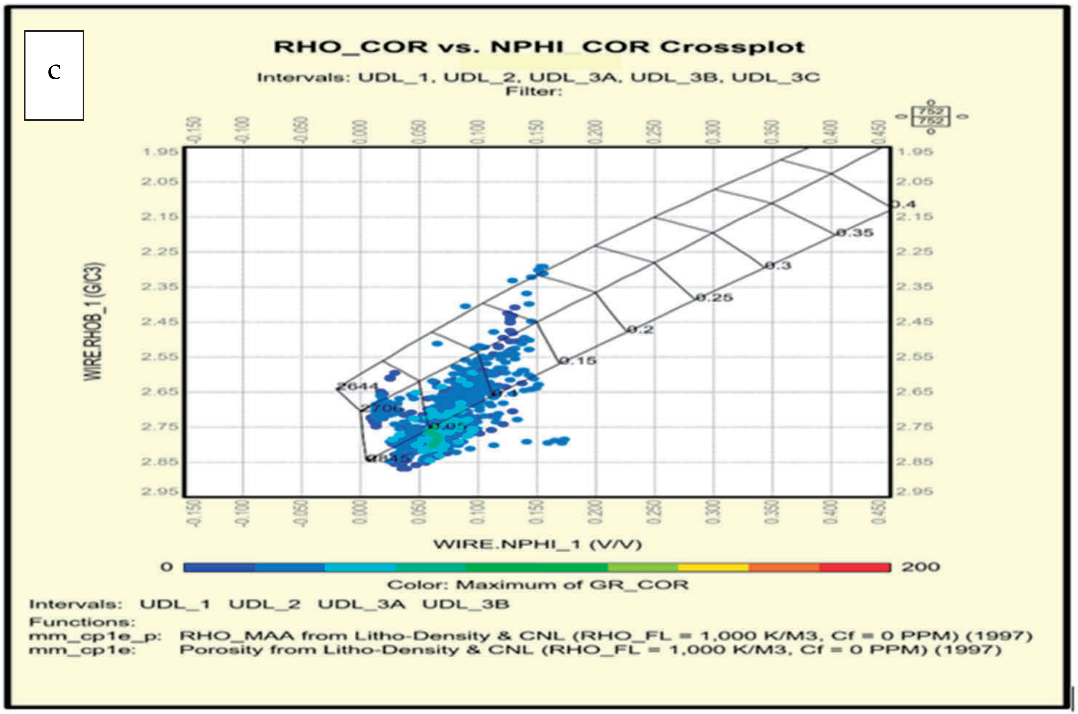


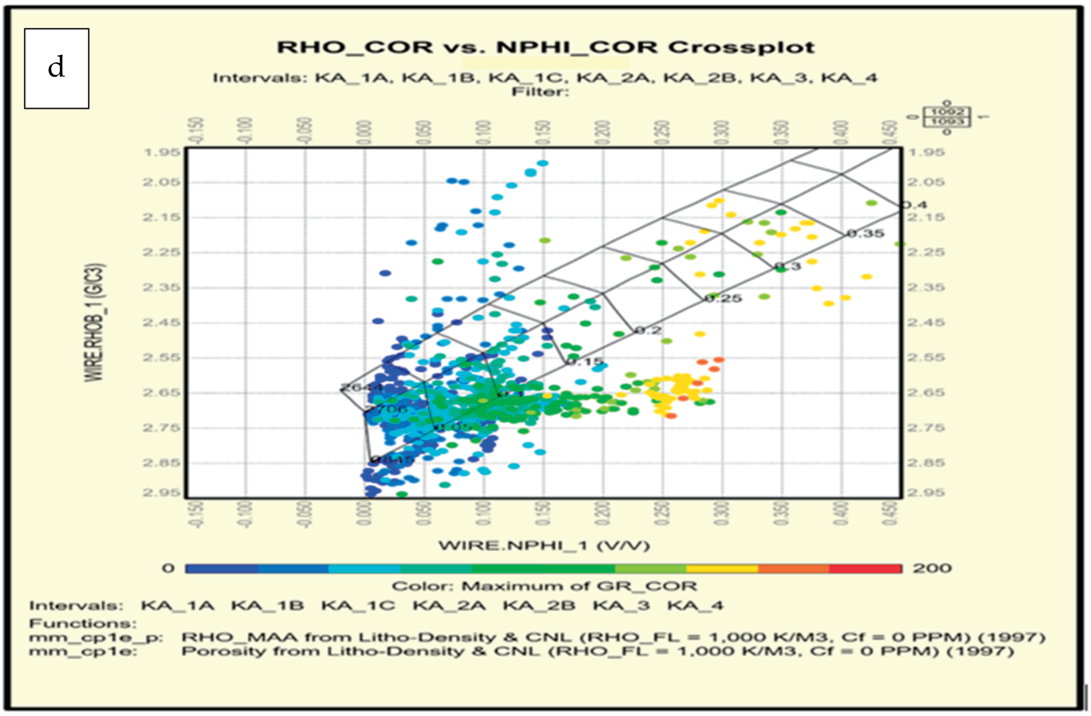


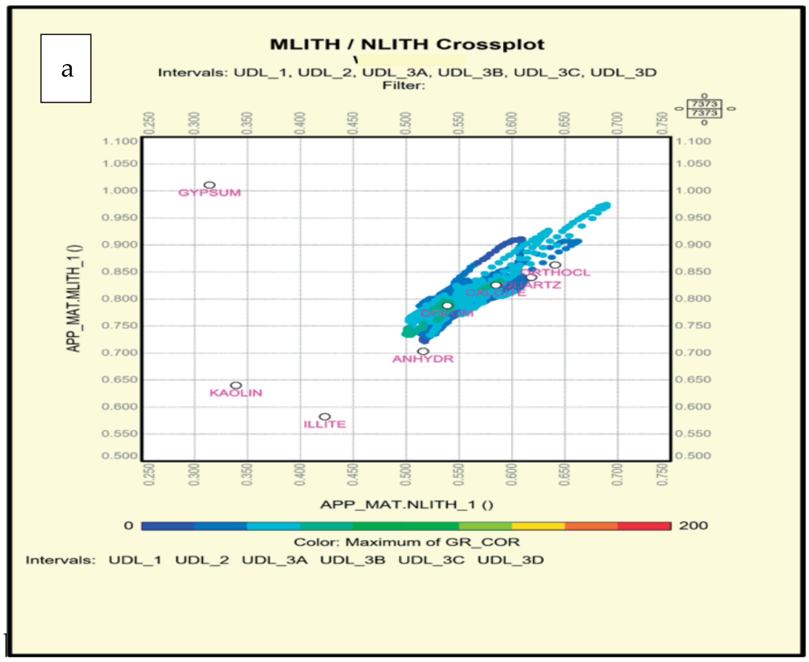
Figure 3. Neutron-density cross-plots. (**a**) upper Dalan formation of well 4; (**b**) Kangan Formation of Well 4; (**c**) upper Dalan Formation of well 6; (**d**) Kangan Formation of Well 6.

Table 1. Lithology interpretation based on neutron-density cross-plot.

Formation	Well	Lithology
Kangan	4	Dolomite—limestone—shale, some anhydrite
Upper Dalan	4	Dolomite—limestone with some anhydrite
Kangan	6	Limestone—shale—dolomite—some anhydrite
Upper Dalan	6	Dolomite—some limestone

- M-N cross-plot

This cross-plot is used to interpret and to diagnose lithology in intervals that contain complex lithologies. This cross-plot is used to identify lithology by three porosity logs and to remove the effect of porosity, as well as to determine the mineralogy composition of the three. In this plot, N and M are plotted against each other. These two parameters are obtained according to Burke's relations [16]. In the M-N plot diagram, when the formation has no gas and the points above the dolomite-calcite line are plotted, they indicate secondary porosity. The points observed above the dolomite-calcite line in the M-N cross-plot are indicative of secondary porosity within the reservoir. This phenomenon is primarily caused by geological processes such as dissolution of carbonate minerals (vadose or phreatic diagenesis), recrystallization, and the development of natural fractures, all of which increase the effective pore space beyond the primary intergranular porosity. Core examination in these intervals confirms the presence of vuggy porosity and occasional micro-fracturing, especially in dolomite-rich layers. Such secondary porosity enhances the reservoir quality by increasing both porosity and, potentially, permeability. Integrating these geological and petrophysical observations ensures a more accurate interpretation of the cross-plot anomalies and highlights the importance of diagenetic processes in controlling reservoir properties in the Upper Dalan and Kangan formations. The state of lithology in the well will be determined based on the scatter of the data around the points corresponding to each of the minerals identified in the cross-plot. As can be seen, in both wells in the Kangan Formation and the Upper Dalan, the samples are located in the northeast of the cross-plot, which indicates the presence of gas in these two formations (Figure 4). In both wells the Kangan Formation shows some samples around anhydrite, calcite and to some extent dolomite, whereas the upper Dalan Formation shows samples concentrated around dolomite and calcite, with some anhydrite in well 6.



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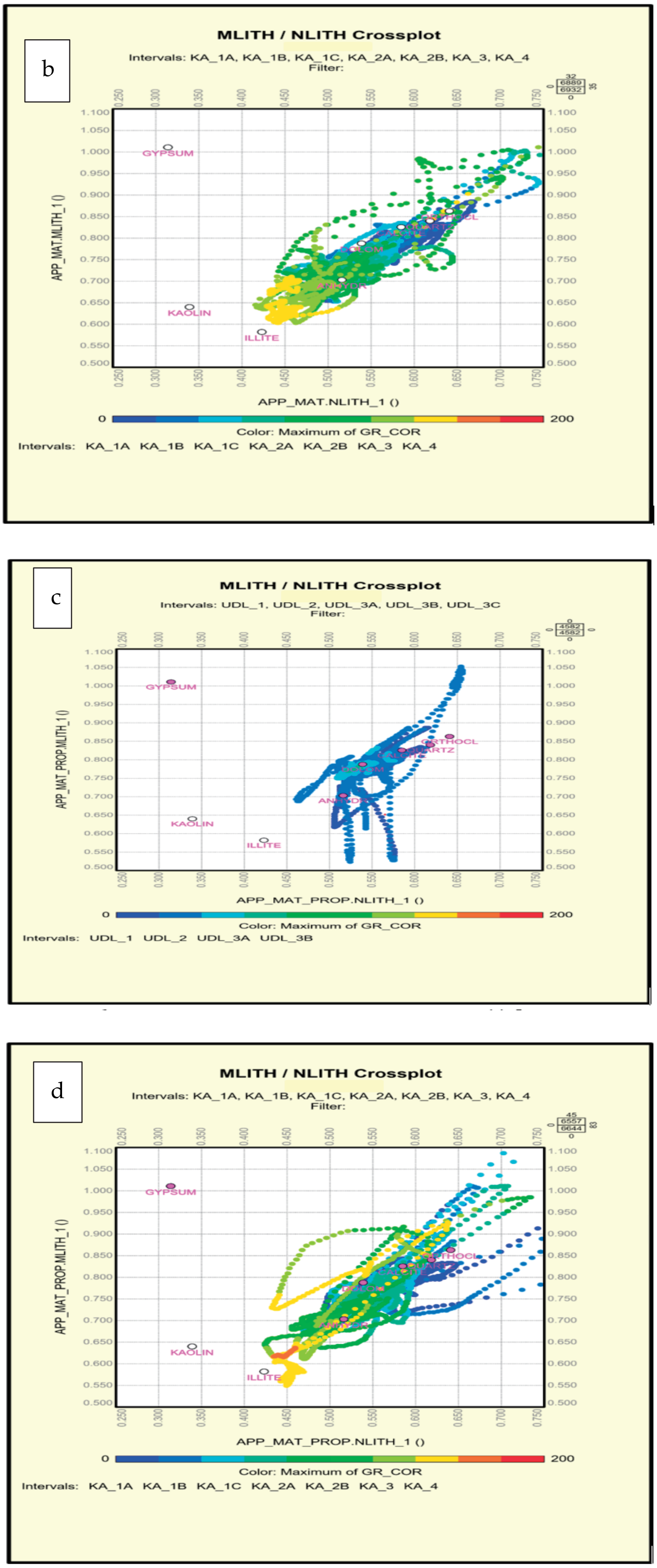
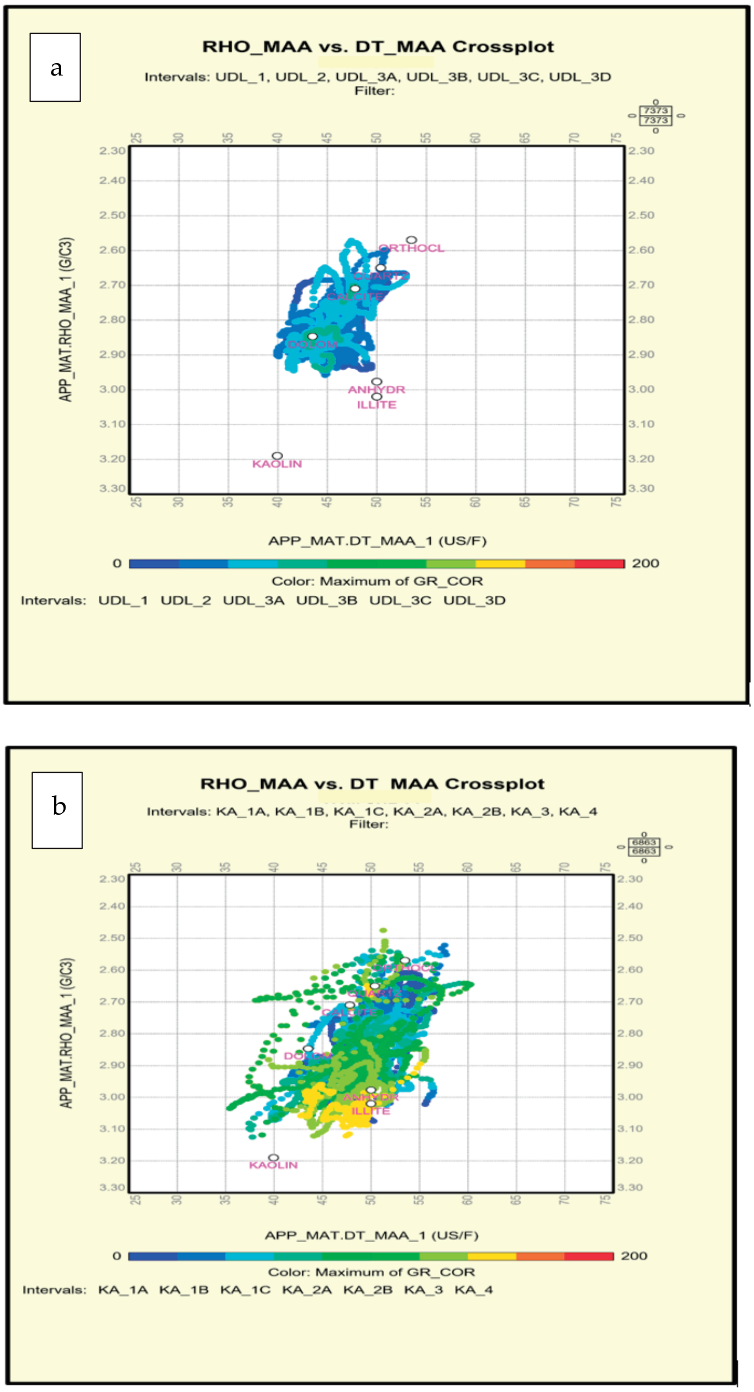


Figure 4. M-N cross-plots. (**a**) upper Dalan Formation in well 4. (**b**) Kangan Formation in well 4. (**c**) upper Dalan Formation in well 6. (**d**) Kangan Formation in well 6.

- MID cross-plot

This cross-plot is used to determine lithology, secondary porosity and gas. To identify the lithology more accurately, the MID plot diagram is used (Figure 5). To determine the lithology using this cross-plot, the matrix is determined first. This plot has more advantages than the M-N plot diagram. In MID-plot, significant parameters such as density and Δt matrix are used. Δt (sonic travel time) is the travel time of an acoustic wave through the formation, typically measured in microseconds per foot (μs/ft), and is an important parameter for evaluating porosity and lithology. This plot allows the simultaneous detection of three minerals.



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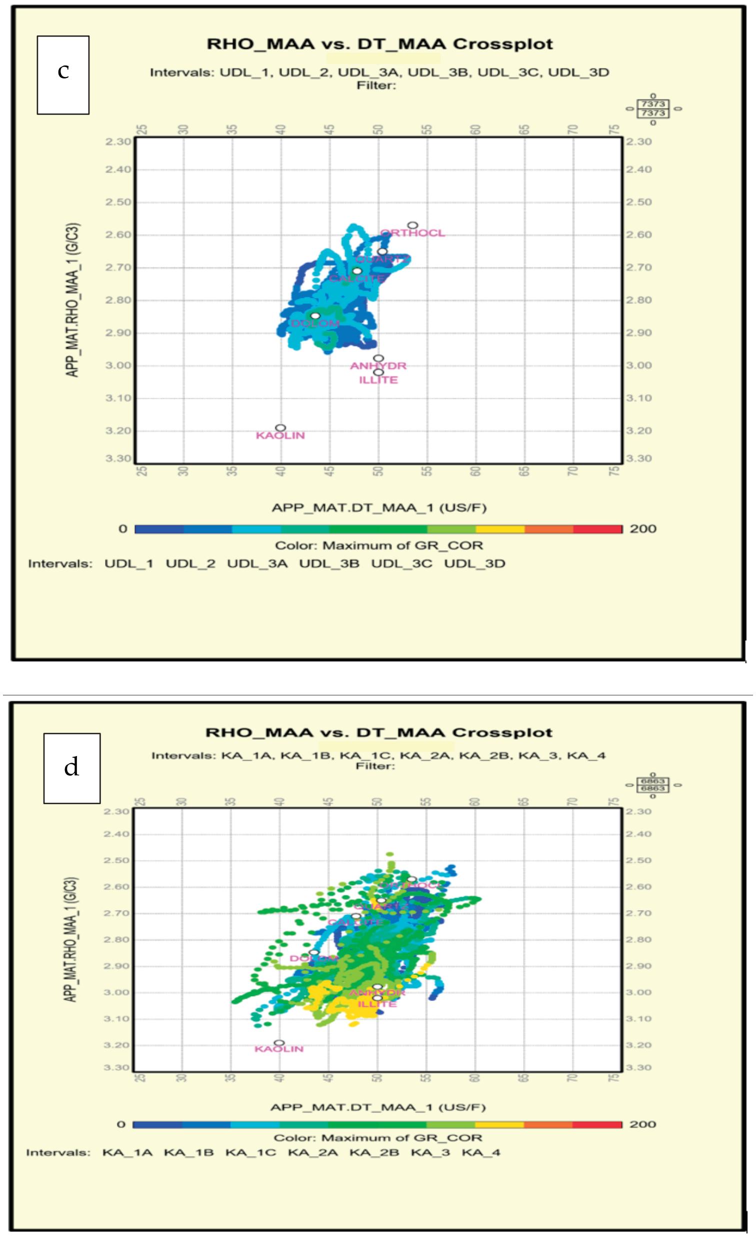

Figure 5. MID plot diagrams. (**a**) Upper Dalan Formation in Well 4; (**b**) Kangan Formation in Well 4; (**c**) Upper Dalan Formation in Well 6; (**d**) Kangan Formation in Well 6.

Kangan Formation shows most data around the anhydrite, calcite and to some extent dolomite, whereas in the Dalan Formation, dolomite and calcite predominate. Also a higher concentration of Calcite is detected in well 6.

- RHO_{mat}—U_{mat}

This cross-plot is used to identify lithology by three neutron logs, density and photoelectric absorption (PEF) diagram. In the RHO_{mat}-U_{mat} diagram, the points related to different minerals are determined and the lithology in the well will be determined (PEF). In fact, this cross-plot is the best plot to determine lithology through the photoelectric absorption mined based on the scatter of the data around the points corresponding to each of the minerals identified in the cross-plot. In both wells, and for both formations, the higher concentration of data is around dolomite and calcite minerals (Figure 6).

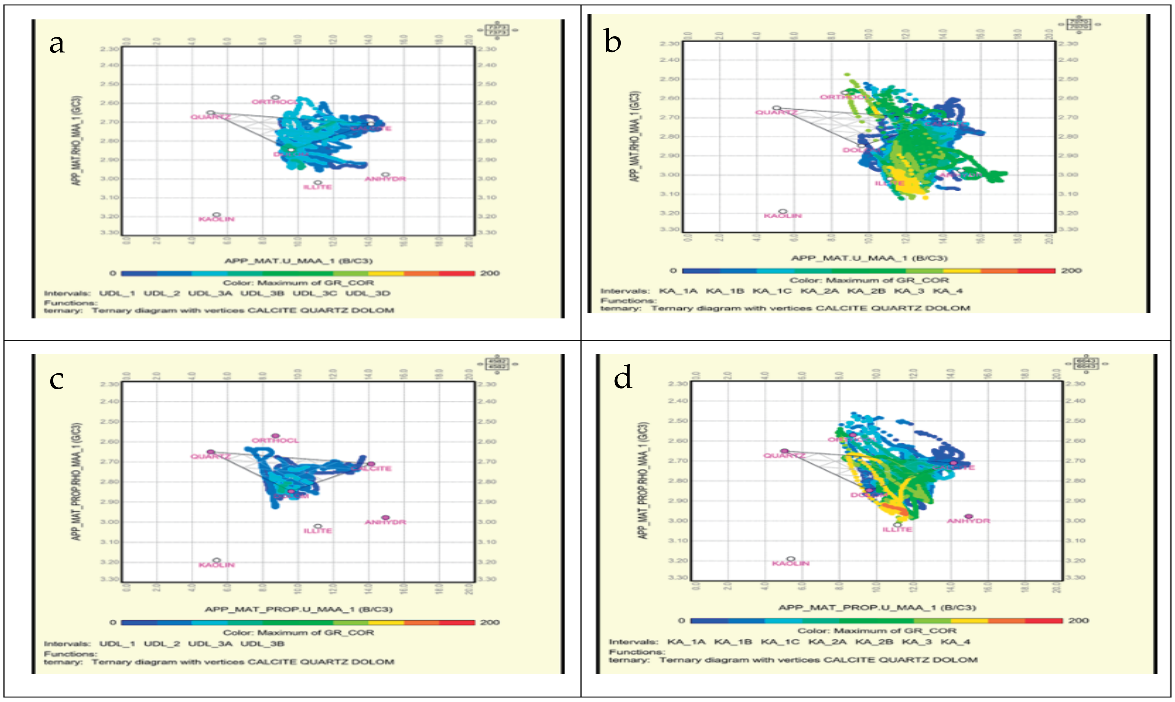

Figure 6. RHO_{mat}-U_{mat} cross-plots. (**a**) upper Dalan formation in well 4. (**b**) Kangan Formation in Well 4. (**c**) upper Dalan formation in well 6. (**d**) Kangan Formation in Well 6.

4.2. Porosity

Porosity is one of the most important parameters in the accurate characterization of hydrocarbon reservoirs [16], being one of the most sensitive factors in estimating the flow properties and geomechanical parameters of hydrocarbon reservoirs. However, using direct methods to measure porosity is not feasible in many situations, requiring high amounts of time and money. Moreover, porosity data obtained directly during the drilling path will be discontinuous and therefore not complete. Therefore, it is better to use methods whose results are continuous and applicable in all projects. By calculating the porosity by petrophysical evaluations using probabilistic methods, the response of all the effective parameters is included, and the obtained porosity is closer to the real porosity of the formation. In this research, the calculation of porosity in both studied wells was done by solving simultaneous equations using a probability method (Tables 2 and 3).

Table 2. Average petrophysical parameters calculated in Well 4.

Reservoir Formation	Porosity (%)	Water Saturation (%)	Shale Volume (%)
Kangan	70	0.67	35
Upper Dalan	70	0.90	20

Table 3. Average petrophysical parameters calculated in Well 6.

Formation	Gross (m)	Net (m)	NET/GROSS	Avg. Porosity (%)	Avg. Water Saturation (%)	Avg. Shale Volume (%)	Avg. Permeability (mD)
Kangan	178.48	19.97	0.11	4.8	24.4	28	0.02
Upper Dalan	184.33	126.14	0.68	3.7	30	1.7	0.042

4.3. Permeability

Permeability and its distribution are some of the most basic geological parameters to describe the properties of reservoir rock [17]. Since the fluid must pass through the pores of the reservoir rock, permeability is considered the main criterion in determining the optimal methods of increased harvesting and investigation of the behavior of production from the reservoir. Porosity and permeability are closely connected, and its relationship is a very important parameter for the characterization of carbonate reservoirs [17,18]. This relationship has been established in cores from the Upper Dalan Formation (Figure 7) and used to calculate the average permeability obtained in Kangan Formation and Upper Dalan formations (Table 2).

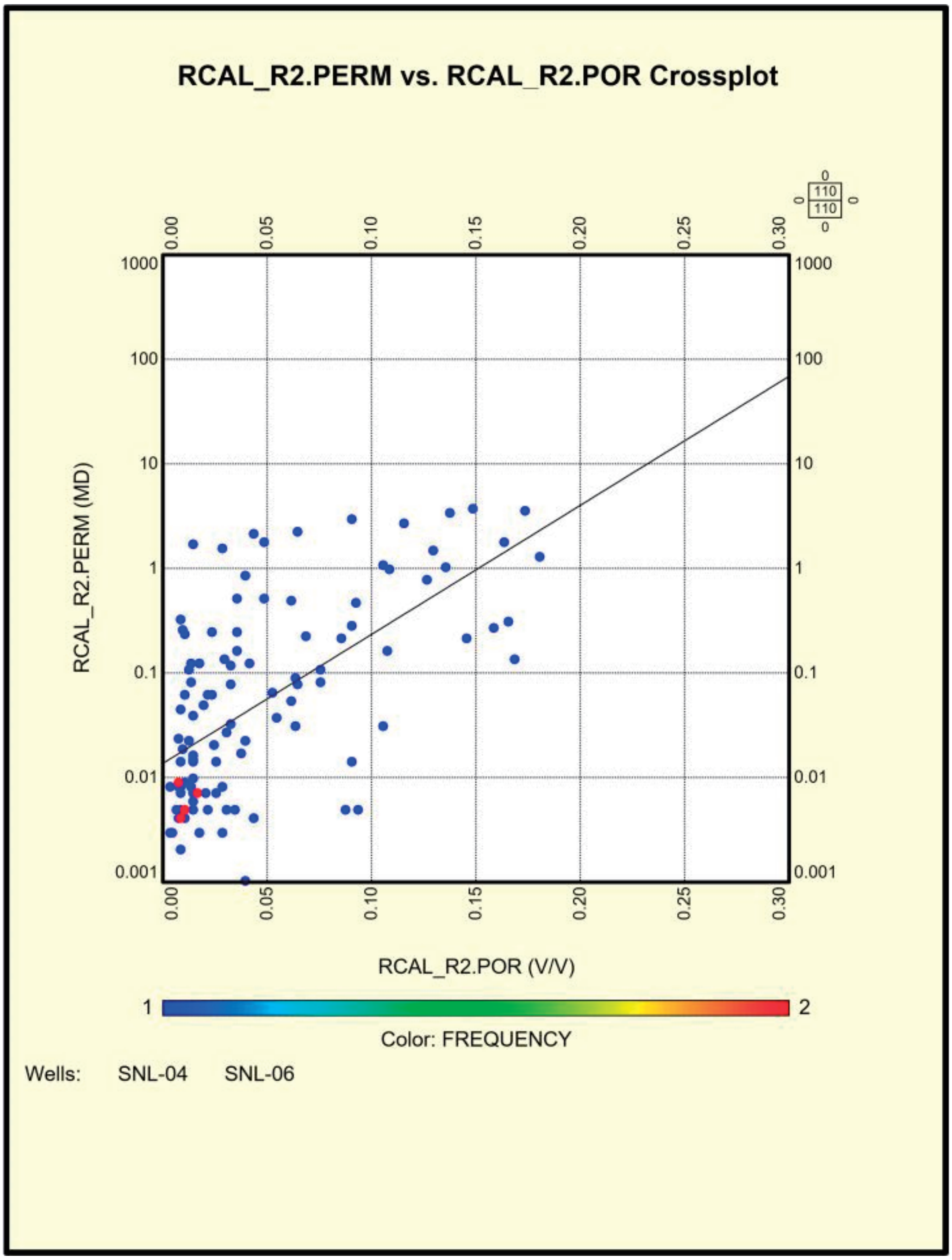

Figure 7. Cross-plot of core porosity versus core permeability of the upper Dalan Formation, with data from both wells.

Calculated Permeability for both formations in both wells is presented in Figure 8, as frequency diagrams.

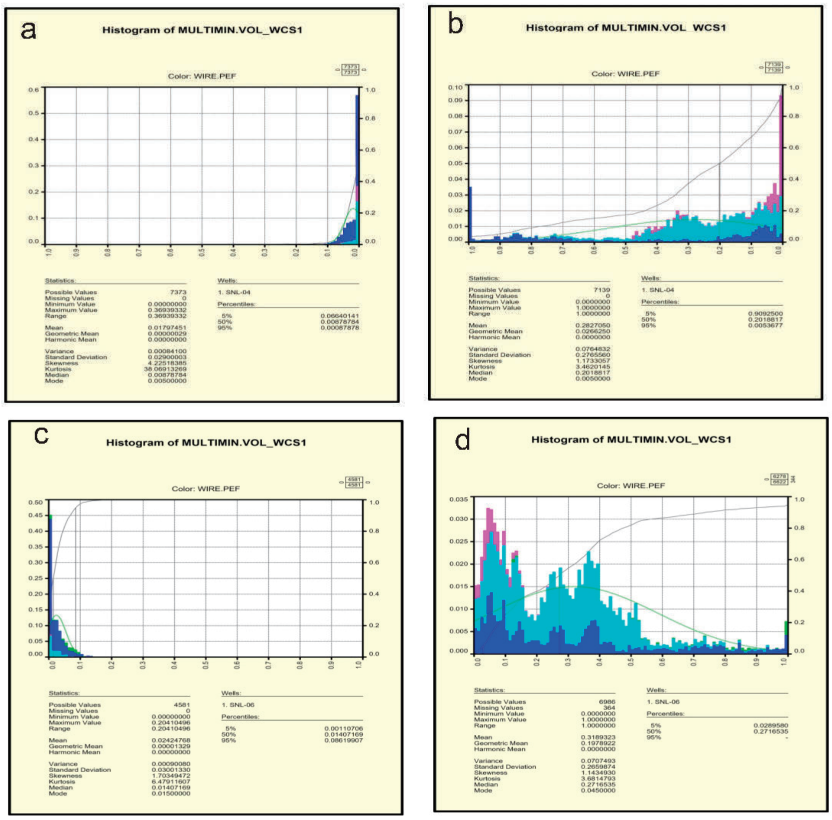

Figure 8. Permeability frequency diagrams of the studied formations. (**a**) Upper Dalan Formation in Well 4; (**b**) Kangan Formation in Well 4; (**c**) Upper Dalan Formation in Well 6; (**d**) Kangan Formation in Well 6.

4.4. Archie Coefficients

(a) Cementation Factor

Cementation coefficient m is one of Archie's coefficients, relating to the pore geometric shape factor. The cementation factor m is calculated in the core laboratory by performing the formation resistance factor (FRF) test, so core information plays a very important role in controlling the results of petrophysical evaluation. With the collected data, the use of linear regression showed the highest convergence rate compared to other regressions, including logarithmic and exponential.

Here, PHIE represents the effective porosity (%).

The relationship between the cementation factor (m) and effective porosity (PHIE) is given by:

$M = 0.0434 \times \text{PHIE} + 1.6131$

The coefficient of regression for this equation is R^2 = 95%. (Figure 9).

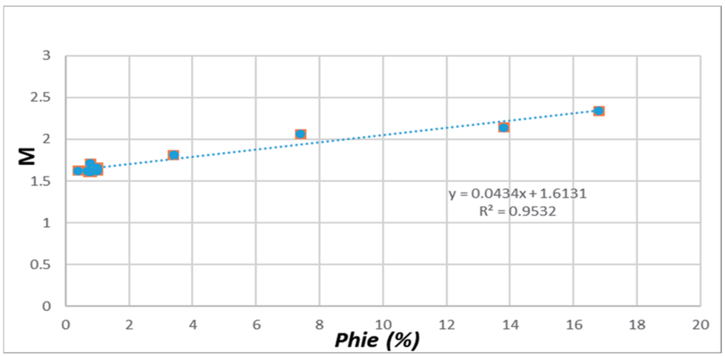

Figure 9. Diagram plotting porosity (Phie%) against M.

It should be noted that the regression relationship established for the cementation factor is based solely on available core data from the studied wells and was not systematically validated across all lithology types or broad porosity intervals. The core dataset did not allow for separate calibration in intervals dominated by limestone, dolomite, or anhydrite, nor were outlier facies sufficiently represented. Furthermore, the derived m–PHIE relationship was not comprehensively compared with established empirical or theoretical models such as those by Rasmus, Timur, or classic Schlumberger relationships. While our results are consistent with similar regressions in Middle East carbonates, future work should seek to expand the core database and perform comparative validation against a wider range of models and geological scenarios to ensure greater accuracy and practical applicability.

(b) Saturation Exponent

Water saturation Exponent n is one of the important and key parameters in determining water saturation. This parameter is usually obtained from the analysis of the electrical properties of the core. To obtain this parameter, the logarithmic graph of saturation index (Rt/Ro) against water saturation should be drawn for core data. The slope of the line fitted to the drawn points indicates the Water Saturation Exponent, which has been calculated as 1.92 in this study (Figure 10).

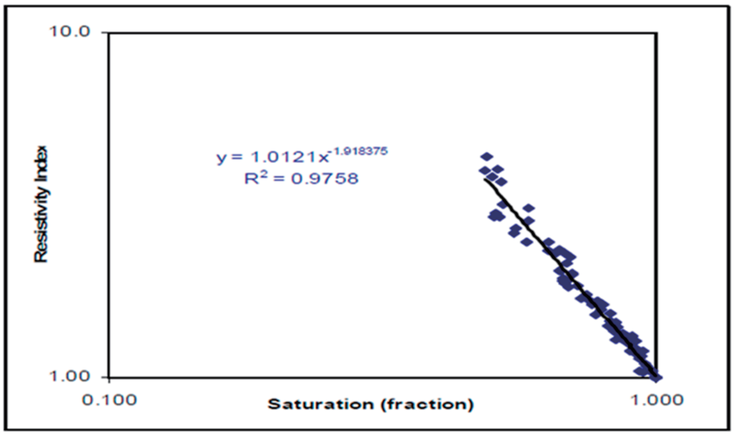

Figure 10. The logarithmic diagram of the specific resistance index against the water saturation fraction of both wells.

(c) Tortuosity Factor

The tortuosity factor a is also commonly calculated in core laboratories through formation resistance factor (FRF) tests. In many preliminary petrophysical studies, **a** is assumed to be equal to 1 for simplification, which implies that the electrical current or fluid flow path is direct within the porous media. However, this is a simplified assumption; more general and physically-based tortuosity models exist in the literature that account for pore geometry and media heterogeneity (e.g., [19]). The assumption a = 1 is often utilized for initial comparison or when limited data are available. For more advanced or accurate reservoir simulations, it is recommended to apply theoretical or empirical tortuosity models that explicitly relate **a** to porosity and rock structure.

It is important to note that the calculation of Archie's parameters, particularly cementation factor (m) and saturation exponent (n), was based on a limited number of core plug samples from both wells. While the regression results show high correlation coefficients, the effects of different lithologies (e.g., dolomite vs. limestone vs. anhydrite-rich facies) and pore structures (intercrystalline, vuggy, or moldic porosity) were not fully resolved due to data constraints. Future studies including petrographic pore typing and a larger core sample base would provide more accurate calibration and allow differentiation of electrical properties by lithofacies.

4.5. Water Saturation

Determining the water saturation in the formation is one of the most important steps in petrophysical evaluation. The success rate of many drilling operations, production and completion of oil and gas wells depends on the accuracy of the methods used in its measurement. Therefore, accurate estimation of this parameter is very important in the development of exploration and exploitation of oil and gas reservoirs. Generally, more than one type of fluid occupies the pores in oil and gas reservoirs. In oil reservoirs, oil and water occupy the pores, whereas in gas reservoirs, gas and water occupy the pores. At certain points in the production of oil reservoirs, oil, gas and water can occupy the empty pores. Therefore, the amount of each of these fluids must be known. In this study, water saturation has been calculated using Indonesia's equation, considered to be preferable for shaly formations [14]:

$$Sw = \left[\left(\frac{a}{\varphi^m} \right) \times \left(\frac{Rw}{Rt} \right)^n \times Vsh^{2 - Vsh} \right]^{\frac{1}{n}}$$

Parameter definitions:

- *Sw:* Water saturation—percentage of water occupying the pore spaces of the rock.
- *a:* Archie's coefficient—typically assumed as 1 for clean formations.
- *φ:* Effective porosity (%)—the fraction of pore volume available to fluids.
- *m:* Cementation exponent—related to the grain packing and pore geometry.
- *Rw:* Formation water resistivity—in Ohm·m.
- *Rt:* True formation resistivity—in Ohm·m.
- *n:* Saturation exponent—depends on the rock type.
- *Vsh:* Shale volume (%)—the proportion of shale in the formation.

Although the Indonesia equation was used for primary Sw calculations due to the shaly nature of the studied carbonate reservoirs, a comparison with the Simandoux model was performed for all sample intervals. The Simandoux equation, which provides an alternative for shaly formations, was applied using the same log and core parameters. Results showed that both approaches yielded comparable Sw values across clean carbonate intervals (differences < 4%). However, in intervals with higher shale content (Vsh > 20%), the Indonesia model produced more consistent results with core-derived Sw and production tests. Given the distribution of shales and fine laminations in these formations, the Indonesia equation was selected as the preferred model.

The average water saturations obtained in the Kangan and Upper Dalan formations are presented in Tables 3 and 4.

Table 4. Cutting limits of the studied formation in Well 6.

Reservoir Formation	Gross (m)	Net (m)	NET/GROSS	Avg. Porosity (%)	Avg. Water Saturation (%)	Avg. Shale Volume (%)	Avg. Permeability (mD)
Kangan	174.66	40.23	0.23	4.0	31.4	32	0.027
Upper Dalan	114.53	105.02	0.92	6.4	22.4	2.4	0.128

4.6. Shale Volume (Vsh)

For the shale volume calculation, Spectral Gamma Ray (SGR) log was used instead of Computed Gamma Ray (CGR), as SGR provides more accurate readings in carbonate-shale mixtures due to its ability to distinguish between uranium, thorium, and potassium contributions.

The volume of shale (*Vsh*) was determined using the Gamma Ray Index (IGR) method [20]:

$$Vsh = \frac{GRlog - GRclean}{GRshale - GR\ clean}$$

where:

GRlog = Measured gamma-ray log reading

GRclean = Gamma-ray reading in a clean (shale-free) formation

GRshale = Gamma-ray reading in a shale-rich zone

The obtained values are presented as frequency diagrams in Figure 11.

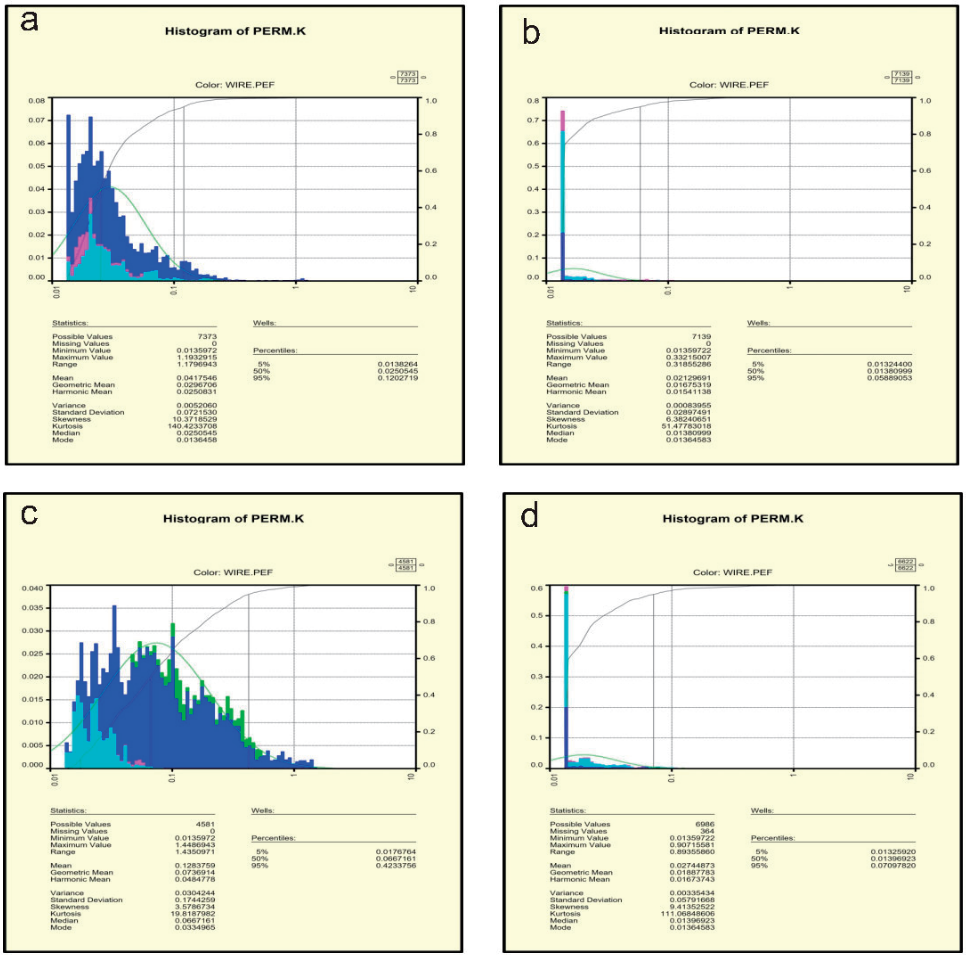

Figure 11. Vsh frequency diagrams of the studied formations. (**a**) upper Dalan Formation in Well 4. (**b**) Kangan Formation in Well 4. (**c**) upper Dalan Formation in Well 6. (**d**) Kangan Formation in Well 6.

4.7. Petrophysical Evaluation

(a) Pay summary

The Pay Summary module can be used to calculate average petrophysical variables such as shale volume, effective porosity, and water saturation in each formation. Cut off values are petrophysical limiting properties, separating the part of the reservoir that participates in hydrocarbon production from other parts that do not play an important role in the operation of the reservoir [1]. In other words, it is used to identify layers with good economic value. In this study, thresholds were defined based on prior works on similar carbonate reservoirs in the region [4,7,17,21] as follows: porosity cut-off—5%; water saturation cut-off—50%; shale volume cut-off—30%.

Based on these cut-off values, a Pay summary has been established (Table 4).

(b) Net to Gross

The ratio of useful thickness to total thickness (N/G or Net to Gross ratio) is used to determine the part of the reservoir that has a useful contribution to the production operation. The closer the value of this parameter is to 1, the better the reservoir quality of studied formation. Tables 2 and 3 present the average calculated petrophysical parameters in the studied wells and formations.

4.8. Reservoir Zoning

Zoning in reservoirs is one of the practical goals of exploratory studies to identify reservoir layers [21]. This causes the next studies to focus more on areas that have more potential for hydrocarbon production. The Kangan Formation was divided into 4 zones (Ka_1–Ka_4), with Ka_1 and Ka_2 zones divided into two sub-layers each (Figure 12). Some layers showed higher content of gas, such as Ka-$_{2a}$ in well 4 (with calcite and some dolomite and shale) and Ka-1b in well 6 (with dolomite and some calcite and shale). Also, the Upper Dalan formation in the studied field was divided into 3 zones (UD_1–UD_3), with UD3 into four sublayers in well 4 and into two sublayers in well 6. The best reservoir layers with larger volume of gas are UD-2 in well 4 and UD_{3b}, in well 6, both with dominant dolomite and some calcite.

(a) Kangan Formation

Investigations show that the lithology of the Kangan section in both wells is a combination of shale calcite and some dolomite and anhydrite veins. According to the diametric chart, in the entire interval of charting, spills are observed intermittently in the walls of the wells but did not cause damage to the charts. The ratio of useful thickness to total thickness is 0.11 in well 4 and 0.23 in well 6. In this formation, Ka-2a zone in well 4 and Ka-1b zone in well 6 were recognized as the best reservoir horizons, due to the larger gas volume compared to the other zones. In other words, according to the results and interpretation of both well logs, the upper part of Ka2 has the best reservoir quality compared to all the other other zones in this formation, considering the volume of gas, porosity. and permeability

(b) Upper Dalan Formation

Investigations show that the lithology of the upper corridor in both wells in case 4 is a combination of dolomite and calcite and a very small amount of shale and anhydrite veins. This identification has been confirmed by ongoing petrographical studies. According to the diametric chart, in the entire interval in both wells, there is intermittent spillage on the wall of the well, but these spills did not cause damage to the charts. This formation has good reservoir properties and porosity development. The ratio of useful thickness to total thickness in this section is 0.68 in well 4 and 0.92 in well 6. In both studied wells, UD-2 zone was identified as the best, due to the larger volume of gas compared to other zones. In other words, according to the results and interpretation of both well logs, the UD2 has the best reservoir quality compared to all the other zones in this formation, considering the volume of gas, porosity. and permeability.

It is worth noting that Well 4 and Well 6 are situated in slightly different structural positions within the Shanul anticline. While Well 4 is drilled near the crest of the structure, well 6 is located further eastward on a structurally lower flank. These positional differences may reflect localized facies variation and diagenetic trends, resulting in the better-developed reservoir quality observed in the Upper Dalan Formation of Well 6 (e.g., higher N/G and porosity values). Such structural context emphasizes the importance of spatial reservoir modeling and field-wide heterogeneity assessment in development planning.

In addition to quantitative cut-offs of porosity, water saturation, and shale volume, the boundaries of key reservoir zones (e.g., Ka-2a, UD-2) were further justified by considering diagenetic and structural features. Core descriptions and borehole image logs indicated that zones such as UD-2 displayed enhanced secondary porosity due to dissolution and dolomitization, as well as a higher frequency of open microfractures, both of which improve reservoir quality. In Ka-2a, the presence of intercrystalline dolomite, vuggy porosity, and evidence of late-stage diagenesis align with the best reservoir intervals confirmed by production data. These geological observations provide an independent basis for the zonation scheme, strengthening interpretations derived from petrophysical parameters alone.

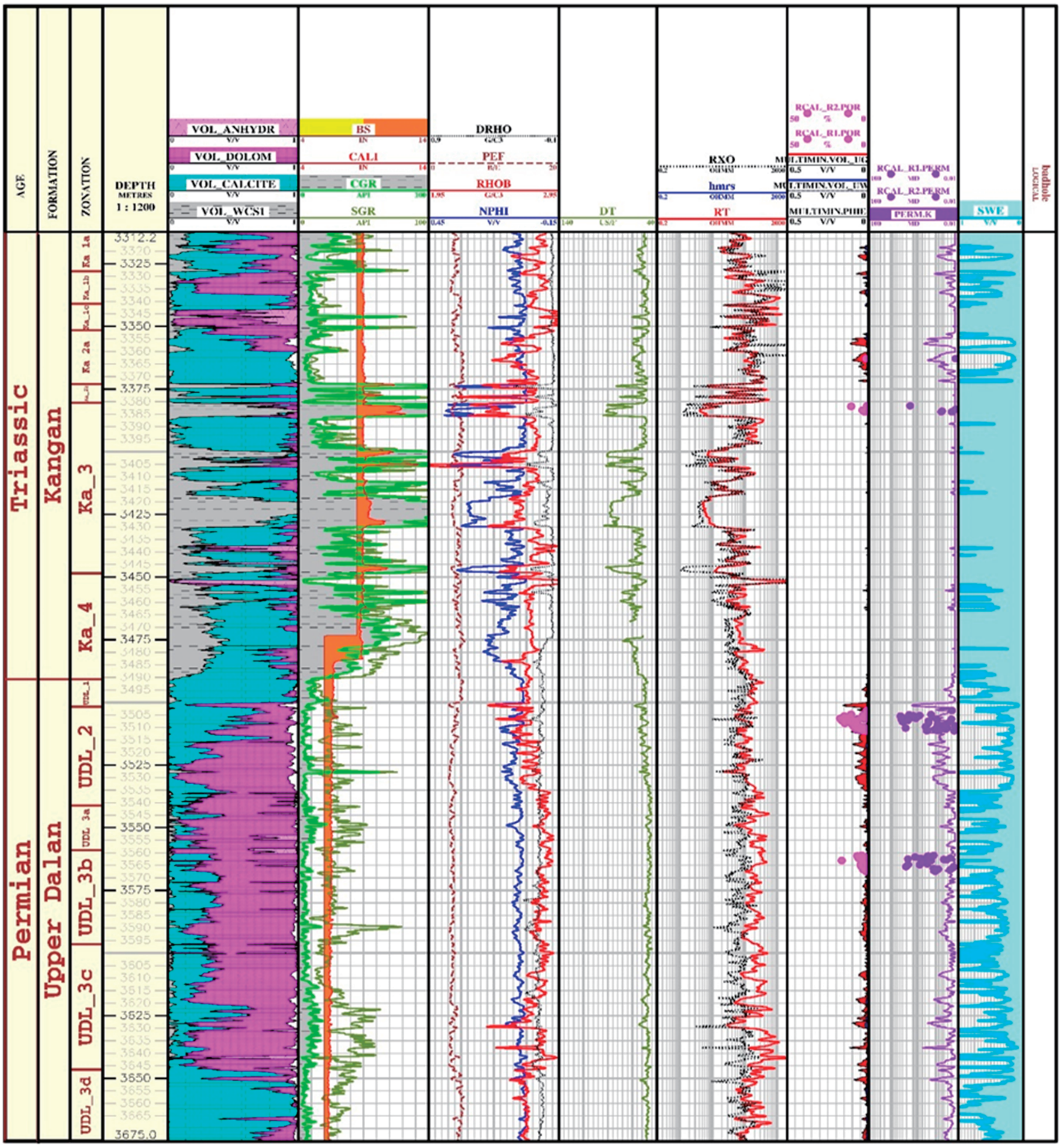

Figure 12. Petrophysical evaluation of well 4 of the studied field. The log includes lithology, reservoir zones, and a set of petrophysical curves such as gamma ray, density, neutron, sonic, effective porosity, water saturation, hydrocarbon saturation, and permeability. The objective of this log isto identify intervals with reservoir potential based on acceptable porosity and permeability and high hydrocarbon saturation.

Compared to conventional log interpretation methods used in earlier studies in the Zagros Basin [4,5,7], which often relied on single-log porosity estimation (e.g., using only

RHOB or NPHI) and qualitative lithology assessment, the integrated workflow applied in this study offers several improvements. The use of cross-plot methods such as MID and RHOma-Uma enabled more precise differentiation between dolomite, calcite, and shale, especially in intervals affected by gas. Additionally, the probabilistic porosity modeling used here produced more consistent results across wells and formations, as it incorporates multiple log responses and was calibrated against core data. This contrasts with earlier approaches that often overestimated porosity in gas-bearing or fractured zones. Our reservoir zonation results also exhibit better alignment with core descriptions and production trends than prior models based solely on GR and RT thresholds.

5. Conclusions

This study provides a refined petrophysical assessment of the Upper Dalan and Kangan carbonate formations in the Shanul Gas Field, offering both practical insights and methodological advancements. Key conclusions include the following:

- An integrated log interpretation workflow was developed, combining conventional logs with advanced cross-plot techniques (M-N Plot, MID Plot, and RHOma-Uma), enhancing lithology identification in mixed facies systems.
- Probabilistic porosity modeling enabled the incorporation of multiple log responses, producing more accurate and continuous porosity estimates compared to traditional single-log approaches.
- The calculation of Archie parameters (cementation factor m, saturation exponent n) was based on core-calibrated data, with recognition of the need for further differentiation across lithofacies.
- The zonation of both formations into sub-layers based on net-to-gross ratio, porosity, and saturation helped identify high-potential pay zones, notably UD-2 and UD3b in the Upper Dalan and Ka-2a in the Kangan.
- The spatial difference between the two studied wells reflected geological heterogeneity within the field, demonstrating how structural positioning and depositional variations influence reservoir quality.

The results of the present study offer direct insights for optimizing hydrocarbon production and development planning in the Shanul Gas Field. The reservoir zonation and detailed property assessment presented here provide a robust basis for targeted well placement in high-quality subzones (such as UD2 in Upper Dalan and Ka-2a in Kangan). These findings support prioritizing perforation and stimulation operations in intervals characterized by superior porosity, permeability, and gas content, while avoiding low-quality or tight zones. Furthermore, integrating petrophysical zonation with dynamic reservoir surveillance data (e.g., production logging, pressure monitoring) allows for adaptive adjustments to production strategies, such as infill drilling, water/gas injection, or re-completion in response to changing reservoir conditions. For maximum benefit, these recommendations should be further supported by comprehensive dynamic modeling and economic evaluations in future studies.

Overall, this study contributes to more accurate reservoir modeling and efficient field development strategies in heterogeneous carbonate gas systems and may serve as a reference model for similar fields in the Zagros Basin and beyond.

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