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A Machine Learning Based Approach for Electrofacies and Permeability Prediction in Heterogeneous Shaly Sand Reservoirs: A Case Study from the NEAG-5 Field, Egypt

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Abstract

Permeability prediction in heterogeneous shaly sand reservoirs is very challenging due to the complexity of clay mineral distribution and depositional facies. In the Middle Bahariya Formation in the NEAG-5 Field, Western Desert of Egypt, permeability varies significantly within similar porosity ranges, resulting in considerable uncertainty in reservoir characterization. This study presents an integrated static reservoir characterization workflow combining core data, X-ray diffraction (XRD), scanning electron microscopy (SEM), and machine learning based electrofacies modeling to investigate the primary controls on permeability. Four reservoir rock types were identified, each exhibiting distinct permeability ranges and mineralogical signatures. The results demonstrate that permeability heterogeneity is predominantly controlled by clay content, with illite, kaolinite, and smectite exerting pore bridging, pore filling, and pore lining effects, respectively. High quality rock types are characterized by low clay content and the absence of illite, whereas poor quality units contain clay volumes exceeding 40%. The field wide porosity permeability relationship yielded an R² of 0.8623 and an RMSE of 0.5512, whereas rock type specific relationships substantially reduced the prediction error, with R² values of 0.9520 – 0.9929 and RMSE values of 0.0958 – 0.2190. These results demonstrate that conditioning permeability estimation to reservoir rock type provides a more consistent representation of the heterogeneous pore system than a single field wide transform. The developed workflow can therefore be applied to extend core derived permeability information to uncored intervals and wells, enabling a more representative field scale permeability distribution for reservoir modeling and rock type characterization. The integration of electrofacies and mineralogical data enabled the development of robust porosity–permeability transforms applicable across the field. The proposed workflow provides a reliable methodology for permeability prediction in uncored wells and can be extended to similar heterogeneous shaly sand reservoirs worldwide.

Keywords

Bahariya Formation, Permeability prediction, Electrofacies, Machine learning, Heterogeneous Shaly sand reservoirs, Clay mineralogy

1. Introduction

The field was discovered by well NEAG C91-1 (NEAG 5-1) which was drilled in May 2011 to test the extension of oil bearing sands in Middle Bahariya formation located in the west of the North East Abu Gharadig Concession (NEAG). It is 27 km of northeast of BED-16 oil field, 35 km northeast of the BED-3 gas field and 38 km northwest of the BED-1 oil field (Fig. 1). Several studies have demonstrated that complex interactions among depositional facies, clay mineralogy, pore structure, and diagenetic processes strongly control reservoir quality and permeability heterogeneity in shaly sandstone reservoirs [1–12]. Accurate permeability estimation is fundamental to reservoir characterization, dynamic simulation, well placement, and field development planning. In heterogeneous shaly sandstone reservoirs, however, permeability may vary by several orders of magnitude within intervals having comparable porosity [13]. This behavior reflects the combined influence of depositional facies, pore

throat architecture, clay mineral abundance and distribution, and diagenetic modification of the pore system. Consequently, conventional porosity permeability relationships may not adequately represent flow capacity where clay minerals exert strong controls on pore connectivity. In the Middle Bahariya Formation of the NEAG-5 Field, Western Desert of Egypt, this problem is particularly evident because permeability ranges from less than 1 mD to more than 1000 mD within a reservoir system characterized by strong vertical and lateral facies variability. Core observations indicate that intervals with similar porosity can exhibit markedly different permeability, suggesting that pore connectivity and clay related pore modification play a major role in controlling flow capacity. Previous studies have demonstrated the importance of hydraulic rock typing, and electrofacies analysis for reservoir characterization; however, these approaches may not fully explain the mineralogical mechanisms responsible for permeability contrasts in heterogeneous shaly sandstones [14–19]. Although rock types and machine learning based electrofacies methods have been widely applied to propagate reservoir rock types from cored to uncored intervals, an important gap remains in linking the resulting rock quality classes to the mineralogical and pore scale controls responsible for permeability variation [20]. In particular, the role of individual clay minerals and their distribution within the pore system is commonly treated qualitatively, while the relationship between clay mineralogy, pore throat characteristics, and rock type dependent permeability remains insufficiently constrained in heterogeneous shaly sandstone reservoirs of the Western Desert of Egypt [21]. The specific research problem addressed in this study is how to distinguish and predict permeability differences between reservoir intervals having similar porosity but different clay mineral composition, pore throat connectivity, and depositional facies, particularly where core control is limited or absent. Conventional field wide porosity permeability transforms cannot explicitly account for these controls, creating uncertainty when permeability is extrapolated into uncored intervals [12,22,23]. To address this problem, this study develops an integrated workflow that combines routine and special core analysis, rock type characterization, X-ray diffraction (XRD), scanning electron microscopy (SEM), and machine learning assisted electrofacies modeling. Core derived reservoir rock types are first established from petrophysical and pore throat characteristics and subsequently linked to conventional well log responses using the Indexed and Probabilized Self Organizing Map (IPSOM). XRD and SEM observations are then used to investigate the mineralogical and pore scale controls associated with the identified rock types. The resulting rock type specific porosity permeability relationships are propagated through electrofacies classification to estimate permeability in uncored intervals. The principal contribution of the study is not the use of electrofacies classification alone, but the integration of core derived hydraulic rock typing with mineralogical and pore scale evidence to explain and propagate permeability heterogeneity. The workflow distinguishes four reservoir rock types with contrasting porosity, permeability, pore throat characteristics, and clay mineral signatures, and uses their log responses to extend the classification into uncored intervals. This integration provides a geological basis for permeability prediction and helps distinguish permeability variations that cannot be explained by porosity alone: (1) quantify the permeability heterogeneity of the Middle Bahariya reservoir using core derived petrophysical and rock types information; (2) establish reservoir rock types based on porosity, permeability, pore throat characteristics and depositional context; (3) investigate the influence of clay mineralogy and clay morphology on reservoir quality using XRD and SEM data; (4) develop an IPSOM based electrofacies model to propagate the core derived rock type classification into uncored intervals and (5) establish rock type specific porosity permeability relationships for reservoir scale permeability estimation.

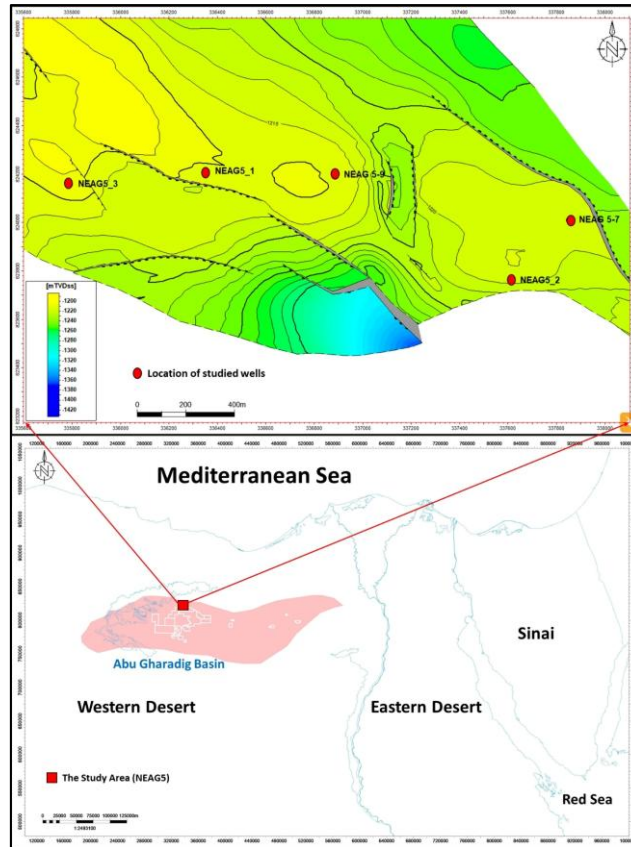


Fig. 1. Location map of the Abu Gharadig basin in Egypt showing the location of the study area (NEAG 5 Field) oil field with locations of studied wells.

2. Geological Setting

2.1 Stratigraphy

The Abu Gharadig Basin has a long, complex geological history, Fluvial marine to shallow marine environments prevailed throughout Early to Middle Cretaceous times, resulted in the deposition of the Alam ElBueib, Alamein, Kharita, Bahariya and Abu Roash reservoirs. The basin geometry was controlled by the uplift to the south, feeding clastics northwards towards the shoreline of the Abu Gharadig Basin. Generally, deeper marine environments prevailed during Late Cretaceous and Paleogene times resulted in the deposition of the carbonate dominated Khoman and Apollonia Formations [7]. The NEAG-5 Field is located onshore in the north eastern part of the Abu Gharadig Basin, Western Desert, Egypt. This basin in this area is characterized by a complex structure with hydrocarbon bearing from the Jurassic to the Cretaceous (Fig. 2) [24]. The Middle Bahariya Formation of Cenomanian age constitutes the primary reservoir interval in NEAG-5. It is bounded by the fluvial dominated Kharita Formation below and the more marine Abu Roash Formation above.

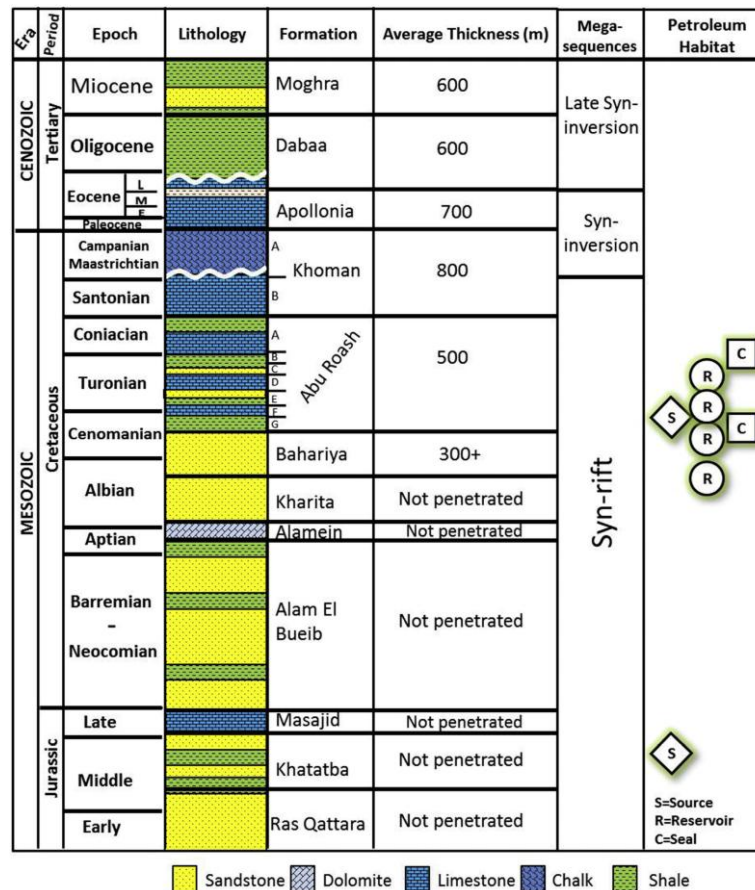


Fig. 2. Generalized stratigraphic column of Abu Gharadig Basin [24].

The Middle Bahariya was deposited in a tidally influenced marginal to shallow marine environment, comprising a range of depositional elements including barrier bars, tidal channels, mud flats, and heterolithic facies (Fig. 3) [25]. This depositional complexity resulted in rapid vertical and lateral facies changes, which were further modified by diagenetic processes such as clay anathogenesis, cementation, and dissolution [26]. These processes collectively contributed to the observed heterogeneity in reservoir quality across the field.

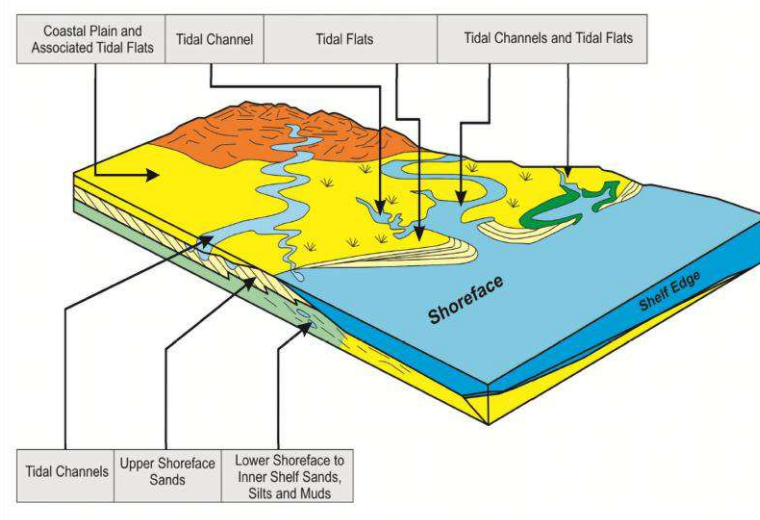


Fig. 3. Middle Bahariya tidal flat depositional setting [25].

2.2 Structure and tectonics

The Abu Gharadig Basin phases at least 2 of rifting (Jurassic and Cretaceous). Jurassic rifting occurred in response to relative sinistral movement between Laurasia and North Africa and resulted in NE-SW rift trends and associated with NW-SE elongated antiforms [1]. Subsequent Cretaceous rifting occurred in response to dextral plate movements and resulted in a WNW ESE rift trend (and associated NE-SW elongated antiforms) being superimposed on the primary Jurassic fault trends [27]. Pronounced inversion started in the Santonian reactivated structures along these fault trends. NEAG-5 structure is a NW-SE faulted 3-way dip closure at the Cretaceous and Eocene Level (Fig. 1).

3. Data and Methodology

High quality core data from the NEAG 5-9 well were used as the primary calibration dataset. The core covers the full spectrum of reservoir qualities within the Middle Bahariya Formation. Routine core analysis provided porosity and permeability measurements, while special core analysis (SCAL) supplied pore throat and capillary pressure information used for rock typing [28]. The well data of conventional open hole logs, including sonic, resistivity, density, neutron and gamma ray, were available for all wells in the field by [29] and [30]. Borehole image logs were used in selected wells to support facies interpretation and validate electrofacies results[31] (Table 1).

Table 1. Data inventory for NEAG-5 wells.

Wells	BS	CAL	GR	DEN	NEU	Sonic	RES	Core Data	Deviation Survey	Pressure Data	Sample	Image	Mud Type	Tool Type
NEAG5-1	YES	YES	YES	YES	YES	YES	YES	NO	YES	YES	YES	YES	OBM	LWD
NEAG5-2	YES	YES	YES	YES	YES	NO	YES	NO	YES	YES	YES	NO	WBM	LWD
NEAG5-3	YES	YES	YES	YES	YES	NO	YES	NO	YES	YES	NO	NO	WBM	LWD
NEAG5-7	YES	YES	YES	YES	YES	NO	YES	NO	YES	YES	YES	NO	WBM	LWD
NEAG5-9	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	NO	NO	WBM	WL

The X-Ray Diffraction Measurements analysis was performed on selected core plugs to quantify whole rock and clay mineral composition. In this section, the XRD Measurements are discussed and analyzed. (Table 2) shows the results of XRD analysis performed on 12 core plugs in the study.

Table 2. XRD Data for 12 Core Plugs.

Plug No	Depth (m)	Mineralogical Composition Weight (%)										Total (wt %)
		Smectite	Illite	Kaolinite	Quartz	Plagioclase Feldspars	K-Feldspars	Calcite	Dolomite	Siderite	Pyrite	
87	1170.52	2.3	0.1	10.78	69.31	1.6	8.17	0	0	4.77	2.97	100
88	1170.8	3.8	1.2	6.18	77.09	1.33	7.35	0	0	1.8	1.25	100
89	1171.05	0	0	5.13	82.02	1.33	5	0	0	3.67	2.85	100
90	1171.28	0	0	9.48	79.35	1.74	9.43	0	0	0	0	100
130	1182.52	3.1	0.8	8.48	63.72	2.89	11.89	0	0	9.12	0	100
137	1184.29	0	0	4.62	75.64	4	10.15	4.4	1.19	0	0	100
139	1184.77	2.1	1	4.07	74.74	3.51	11.42	0	1.77	1.39	0	100
144	1186.03	2.8	0.4	10.32	69	3.59	8.79	0	1.34	3.76	0	100
166	1191.6	5.2	0	9.38	36.26	2.34	18.75	0	0	26.07	2	100
181	1195.28	0	0	1	94.91	1.14	2.95	0	0	0	0	100
187	1196.78	0	0	0.56	91.11	1.22	7.11	0	0	0	0	100
189	1197.3	0	0	1	82.36	2.58	7.95	6.11	0	0	0	100

4. Results

4.1 Permeability variations

Using the global regression covers all the reservoir facies has a correlation coefficient ($R^2 = 0.86$) shows the permeability changes with porosity in cross plot between permeability and porosity (Fig. 4). There is significant difference in permeability against the same porosity values is observed [4,10]. In red circle highlighted in the porosity permeability cross plot at porosity value 28%, show that the permeability ranges between 0.9 mD and 700 mD. Show in (Table 3) the heterogeneity ranges between the variations

of the porosity (4% to 37%) while the permeability (0.01 mD to 1900 mD).

Table 3. Core Data Statistical Analysis.

Minimum Porosity	Average Porosity	Maximum Porosity
4 %	20 %	37 %
Minimum Permeability	Average Permeability	Maximum Permeability
0.01 mD	10 mD	1900 mD

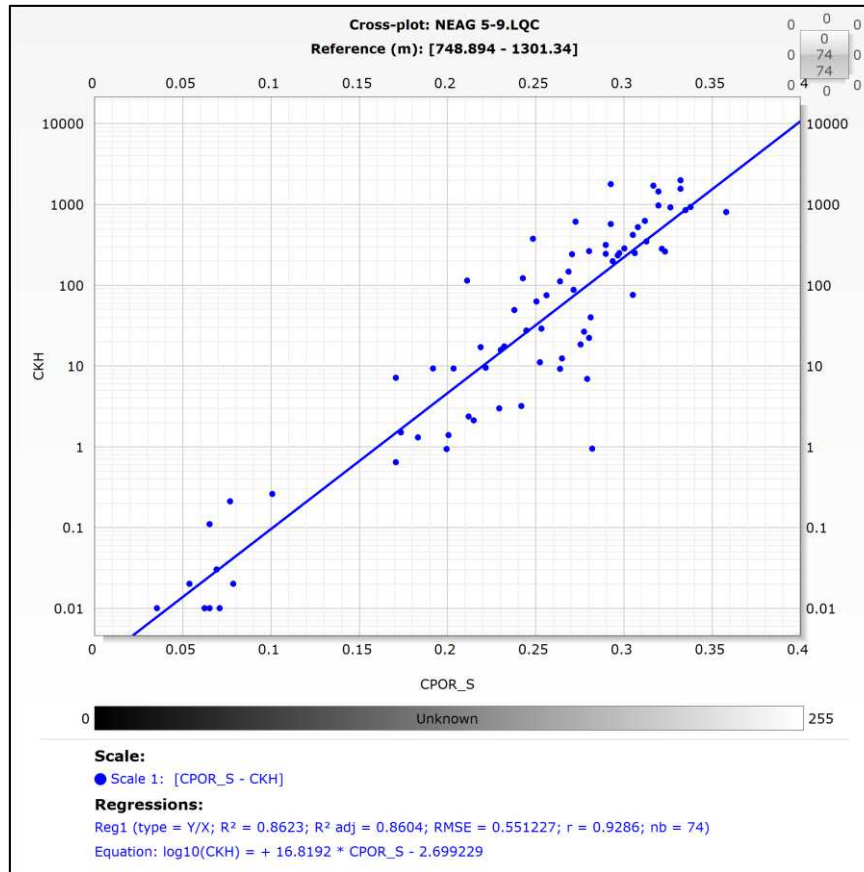


Fig. 4. Global trend of Core Porosity and Core Permeability Cross Plot cover all the facies could lead to wrong reservoir permeability prediction R2=0.86, NEAG 5-9 RCA Data.

4.2 Rock Typing and Electrofacies Modeling - Stratigraphic Modified Lorenz Plot (SMLP)

The modified Lorenz pattern based on stratigraphy (SMLP) is a proposed method suitable for determining rock species. The Lorenz diagram is separated by plotting the cumulative flow capacity in terms of the cumulative storage capacity, while preserving their stratigraphic order[16] . Slope changes in the SMLP diagram indicate changes in the flow properties of the porous medium (Fig. 5) [32].

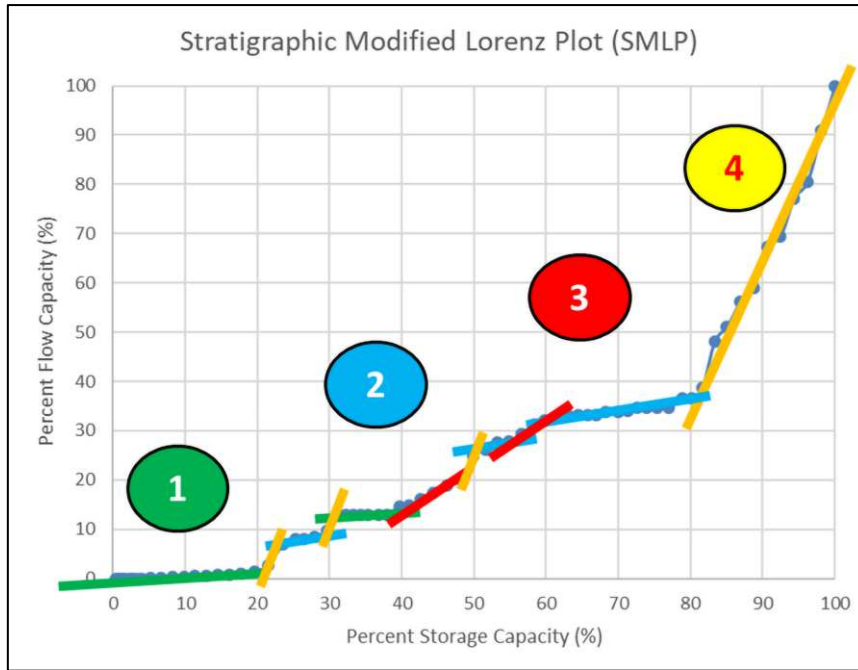


Fig. 5. Flow capacity and storage capacity for NEAG5-9 core data [32].

-Winland Equation

Winland established a relationship between pore throat versus the changes of porosity and permeability [33,34]. In this experimental study used 300 samples injected with mercury and performed multi regression analysis based on pore radius at mercury saturation 35% per plugs [35].

$$\log R_{35} = 0.732 + 0.588 \log K - 0.864 \log \phi \text{ -----(1)}$$

dropping the core data (porosity and permeability) plugs on Winland cross plot (Fig. 6). Classified the rock types based on the clouded areas relative to the pore throats. Consequently RT-4 is above the pore throat 10 mm (Mega zone), RT-3 around pore throat 5 mm (Macro zone), RT-2 range between 2.5mm to 0.5 mm (Meso zone) and RT-1 around 0.1mm (Micro zone). Four rock types (RTs) have been identified from stratigraphic modified Lorenz plot and Winland R35 methods.

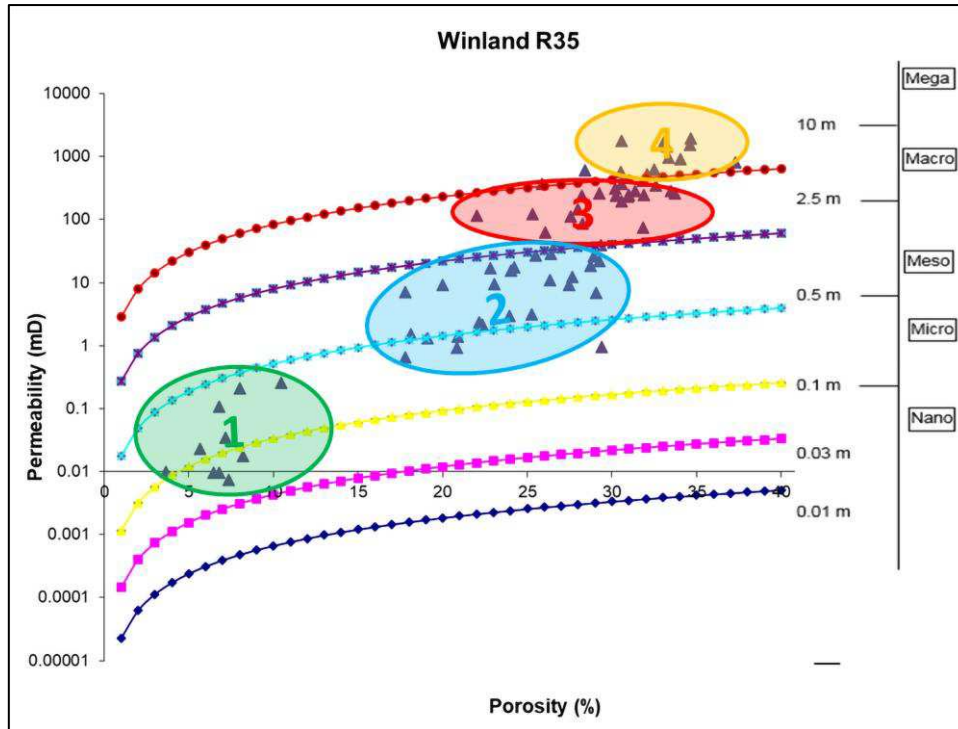


Fig. 6. Rock type's definition using Winland cross plot [35].

The four reservoir rock types identified from the core based SMLP and Winland R35 analyses were subsequently used as the reference framework for evaluating the log derived electrofacies. An unsupervised Indexed and Probabilized Self Organizing Map (IPSOM) clustering approach, implemented in Techlog, was applied to the selected well log responses. Four input logs were used in the IPSOM analysis: neutron porosity (NPHI), bulk density (RHOB), photoelectric factor (PEF) and volume of shale (Vsh) [18]. The four cluster solution was evaluated against the independently established core derived rock types in the cored NEAG 5-9 well [32]. The electrofacies obtained from IPSOM showed a consistent correspondence with the four reservoir rock types identified from the core data in NEAG 5-9. This agreement provided a core based validation of the IPSOM classification and demonstrated that the selected log responses were capable of distinguishing the main petrophysical characteristics associated with the four reservoir rock types [31]. Following this validation, the established IPSOM clustering model was applied to the uncored wells to predict the distribution of the corresponding rock types throughout the NEAG-5 field [10]. (Fig. 7). The four reservoir rock types were subsequently linked to electrofacies derived from conventional well logs using the Indexed and Probabilized Self Organizing Map (IPSOM) implemented in Techlog.

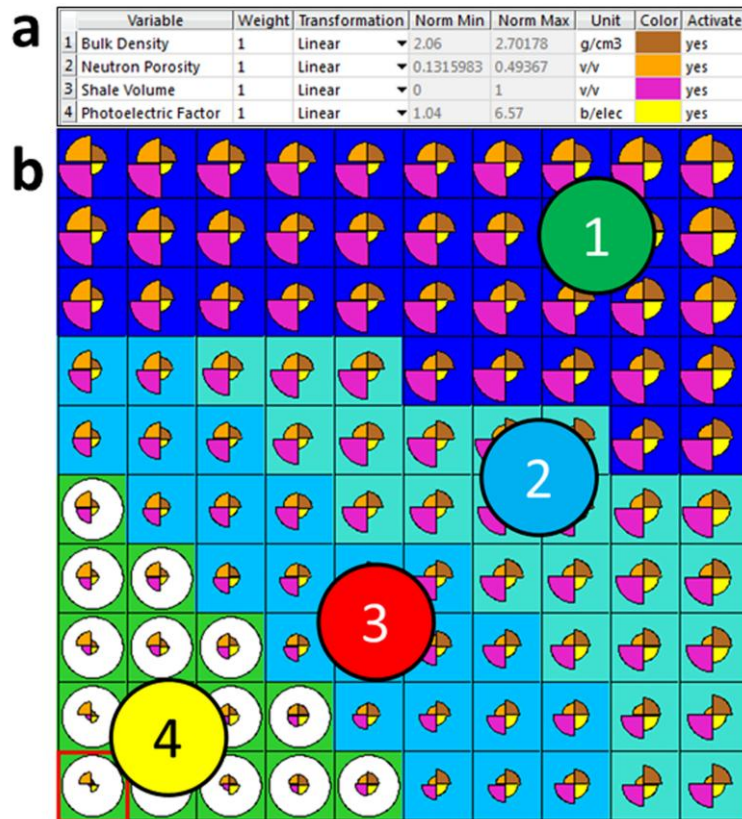


Fig. 7. a) Input well logs used for the IPSOM based electrofacies classification b) Self-Organized Map (SOM) Classified into 4 rock types.

The IPSOM generated electrofacies were compared with the core derived rock types using the cored interval of the NEAG 5-9 well. The electrofacies showing similar petrophysical characteristics to each core derived rock type were assigned to the corresponding rock type classification. This integration established a log based relationship between the four core derived reservoir rock types and their electrofacies responses, allowing the rock type classification to be propagated beyond the cored intervals. (Fig. 8) presents the resulting electrofacies distribution for the NEAG 5-9 well. RT-4 represents the best quality reservoir intervals, RT-3 represents moderate quality reservoir intervals, RT-2 represents lower quality reservoir intervals, whereas RT-1 represents the poorest quality and shale dominated intervals.

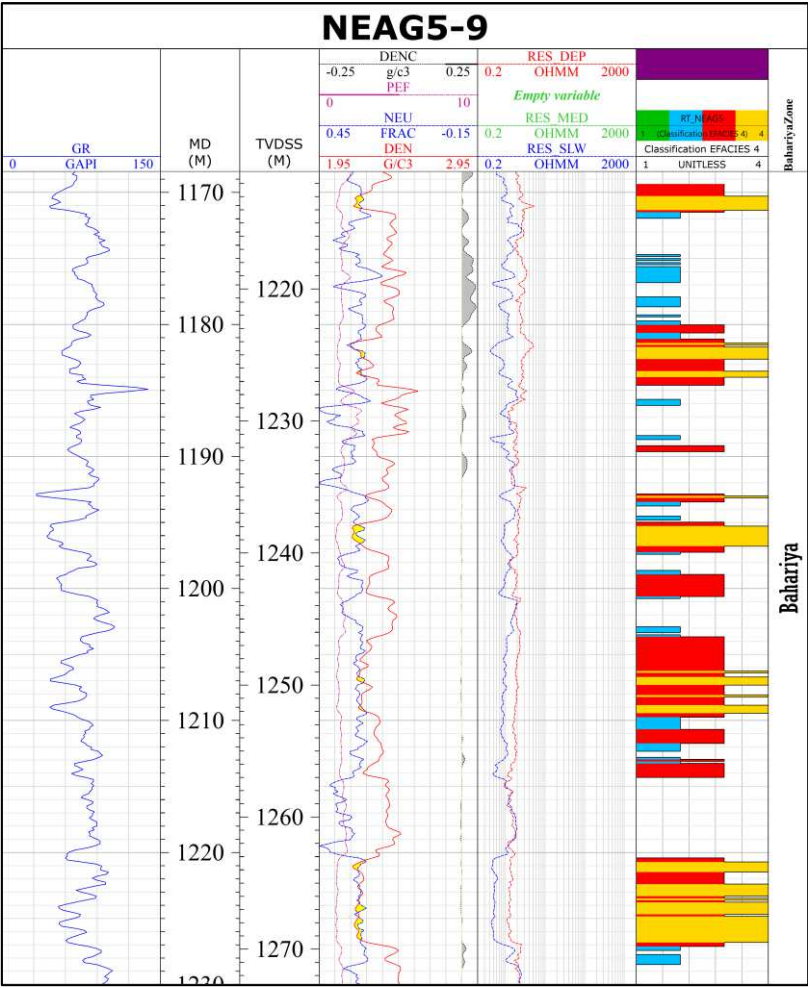


Fig. 8. Electrofacies distribution obtained from IPSOM and its correspondence with the core derived reservoir rock types in the NEAG 5-9 well.

4.3 Permeability Modeling

Porosity permeability relationships were established separately for each rock type using core data. The use of rock type specific transforms significantly improved permeability prediction compared to a single field wide relationship (Fig. 9).

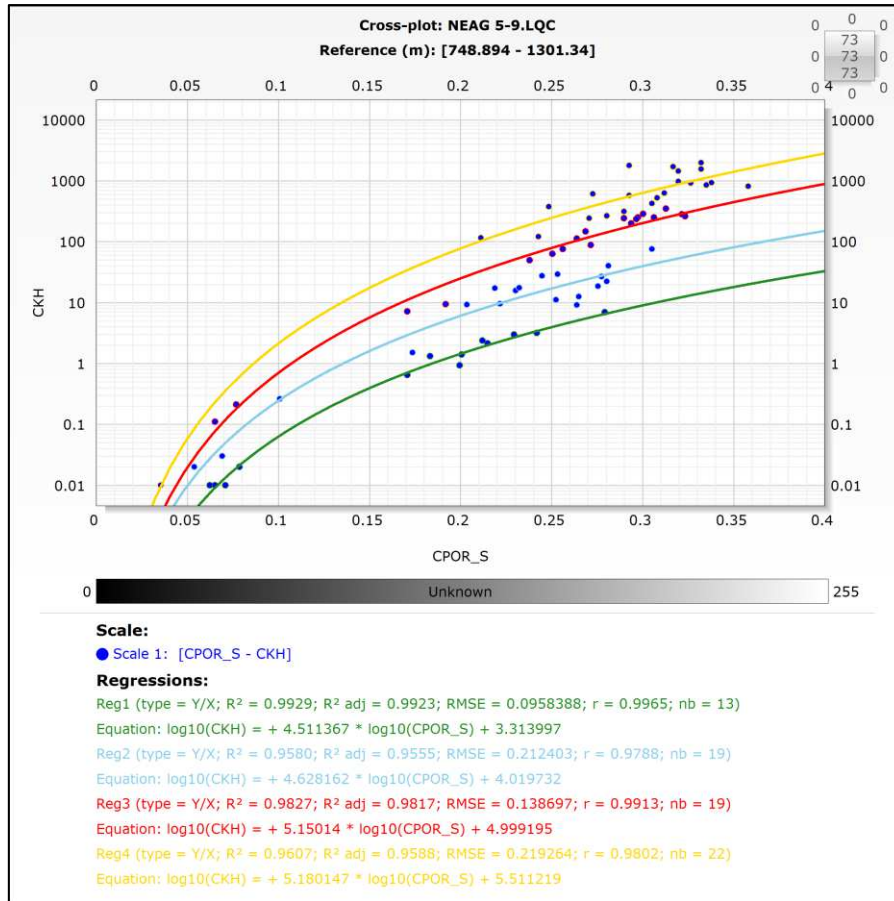


Fig. 9. Core Porosity and Core Permeability for all points with different qualities. Porosity permeability relations for each rock type. The substantially reduced scatter and lower RMSE values obtained within individual rock types demonstrate the benefit of conditioning permeability estimation to reservoir rock type.

In contrast, the calibrated transforms were applied to electrofacies logs in uncored wells, resulting in a continuous permeability profile across the field. This approach enabled consistent permeability modeling while honoring geological heterogeneity[12,36].

Consequently, the integrated workflow successfully captured permeability variations spanning more than three orders of magnitude. High quality rock types (RT-4) exhibited permeability exceeding 1000 mD. However, low quality units (RT-1) showed permeability below 1 mD despite overlapping porosity ranges.

The results highlight the limitations of porosity based reservoir quality assessment in shaly sand systems and emphasize the necessity of incorporating mineralogical and facies information into permeability modelling [28]. shows the equations for the relation between porosity and permeability were used per rock type. The following facies grouping was done: Calculation of permeability curve using POR-PERM transform per genetic unit: High quality reservoirs, Moderate reservoirs, low quality reservoirs and shale.

Therefore, using the new facies definition, the new porosity permeability transforms have been created per facies [14,37]. The available core air permeability measurements from NEAG 5-9 at ambient condition were regrouped per facies.

$$RT_1 \quad Perm = 10^{4.51 \cdot \log_{10}(\phi) + 3.314} \quad (2)$$

$$RT_2 \quad Perm = 10^{4.63 \cdot \log_{10}(\phi) + 4.02} \quad (3)$$

$$RT_3 \quad Perm = 10^{5.15 \cdot \log_{10}(\phi) + 4.99} \quad (4)$$

$$RT_4 \quad Perm = 10^{5.18 \cdot \log_{10}(\phi) + 5.51} \quad (5)$$

The comparison between the global and rock type specific relationships demonstrates the importance of reservoir rock typing for permeability estimation in the NEAG-5 reservoir [10,38] . The global porosity permeability relationship provides a reasonable overall trend; however it retains considerable scatter because samples with different pore structures, clay contents, and flow characteristics are represented by a single relationship. In contrast, separating the samples into reservoir rock types substantially reduces the prediction error and improves the strength of the porosity permeability relationships. The RMSE decreases from 0.5512 for the global relationship to 0.0958, 0.2120, 0.1380, and 0.2190 for RT-1, RT-2, RT-3, and RT-4, respectively, while the corresponding R2 values increase to 0.9929, 0.9520, 0.9827, and 0.9600 (Table 4). These results indicate that the variability in permeability is better captured when the porosity permeability relationship is conditioned to reservoir rock type rather than represented by a single field wide transform. This improvement is consistent with the observed differences in pore structure and mineralogical composition among the identified rock types. Each rock type represents a relatively more homogeneous combination of porosity, pore throat characteristics, clay content and pore connectivity. Consequently, samples within the same rock type exhibit a more consistent relationship between pore volume and fluid flow capacity [4] . The results therefore suggest that the observed scatter in the field wide porosity permeability relationship is not solely related to porosity variability, but also reflects differences in pore architecture and rock fabric between reservoir rock types.

Table 4. Statistical comparison of global and rock type specific porosity permeability relationships.

Relationship	Valid samples	R2	RMSE
Global	73	0.8623	0.5512
RT-1	13	0.9929	0.0958
RT-2	19	0.9520	0.2120
RT-3	19	0.9827	0.1380
RT-4	22	0.9600	0.2190

The different rock types by colored plotted on the log plot that represent the different qualities with the porosity calculated by density log. That matched with the porosity permeability cross plot. Permeability was calculated per rock type linear equations was derived for each rock type through core porosity vs core permeability cross plot which resulted in four different linear permeability equations. (Fig. 10) shows the different permeability trends for 73 core samples acquired in the NEAG 5-9 well in this study. Porosity Permeability Regressions for each rock type is constructed resulting in the equations used for the permeability calculation.

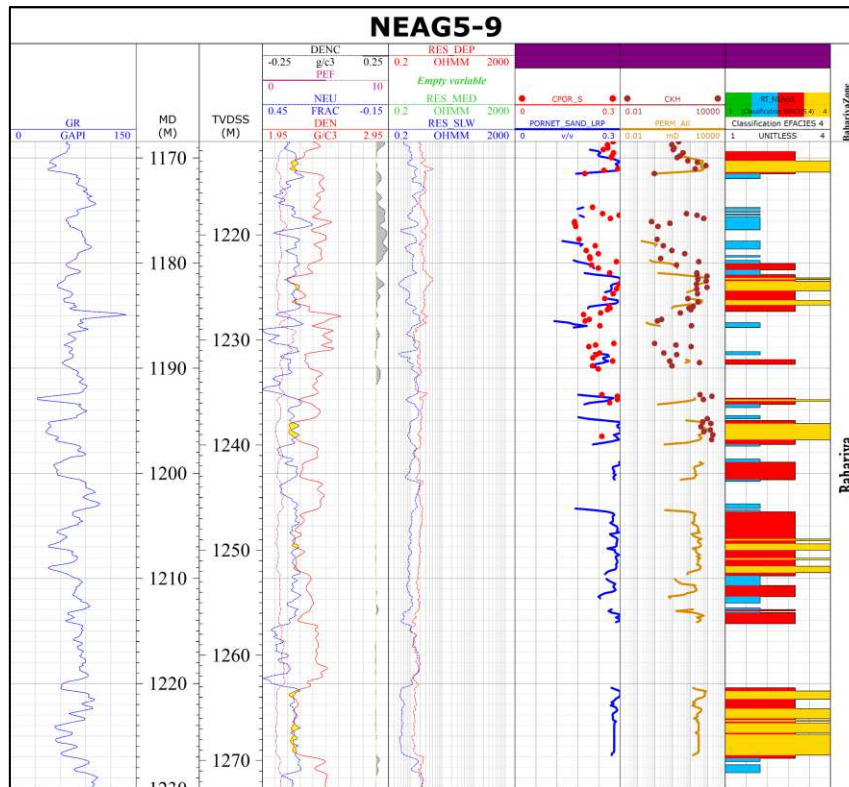


Fig. 10. Permeability and porosity curves show different permeability and porosity ranges for each rock type and the match with permeability and porosity core points.

4.4 Mineralogical Controls on Permeability

XRD results revealed significant variations in clay content and mineral composition among the identified rock types. RT-1 exhibited the highest clay content (approximately 44%), dominated by illite, kaolinite, and smectite. SEM images showed extensive pore filling and pore bridging clay textures, resulting in severely reduced permeability [2].

RT-2 displayed moderate clay content (~19%), with mixed clay morphologies partially obstructing pore throats. RT-3 showed further reduction in clay volume and improved pore connectivity. In contrast RT-4 was characterized by minimal clay content and the near absence of illite, leading to excellent permeability (Fig. 11).

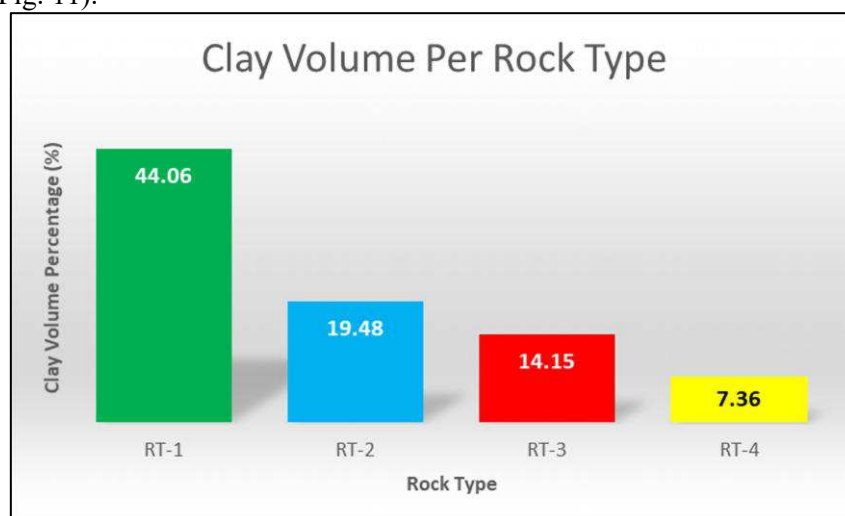


Fig. 11. Clay Mineral Content per rock type.

Consequently (Fig. 12) shows the clay content in each rock type and its impact on porosity and permeability. The highest clay content is found in RT-1, while the lowest is found in RT-4. This affects

the rock's quality in terms of porosity and permeability [3]. Petrophysical evaluation of the Middle Bahariya reservoir for each rock type confirmed that permeability changes are not correlate with porosity changes. In the highest quality RT-4, permeability reaches 1900 mD, while porosity reaches 37% due to a low clay content of 7%. In RT-3, permeability reaches 90 mD and clay content reaches 14%. RT-1 and RT-2 are considered lower quality due to low permeability and porosity levels, as clay content reaches 44%.

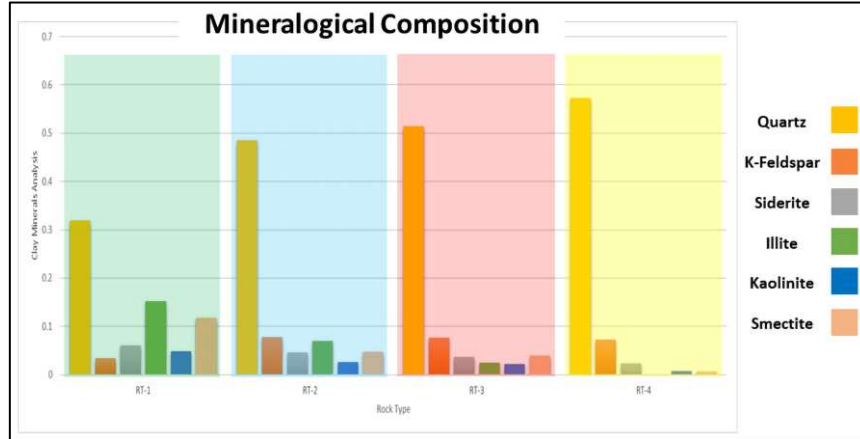


Fig. 12. Mineralogical Composition per rock type.

The main factors the main factors that were responsible for the reduction of permeability in the Middle Bahariya reservoir. The clay minerals are common in the Middle Bahariya reservoir and fills pores to varying degrees. The regression of the smectite, illite and kaolinite with permeability (Fig. 13) demonstrate that the decreases relatively with increasing clay minerals content with the varying effect of each mineral on permeability. This quantitative relationship supports the observed inverse association between clay abundance and permeability and provides additional evidence that clay related heterogeneity contributes to the large permeability variability observed within the reservoir. Dissolution of feldspar produces microporosity as the dissolved grains are replaced by clay minerals (Smectite, illite and kaolinite), which may result in the further heterogeneity of the reservoirs. [1] This difference suggests that the influence of clay mineralogy on permeability is mineral-specific and cannot be adequately represented by clay abundance alone.

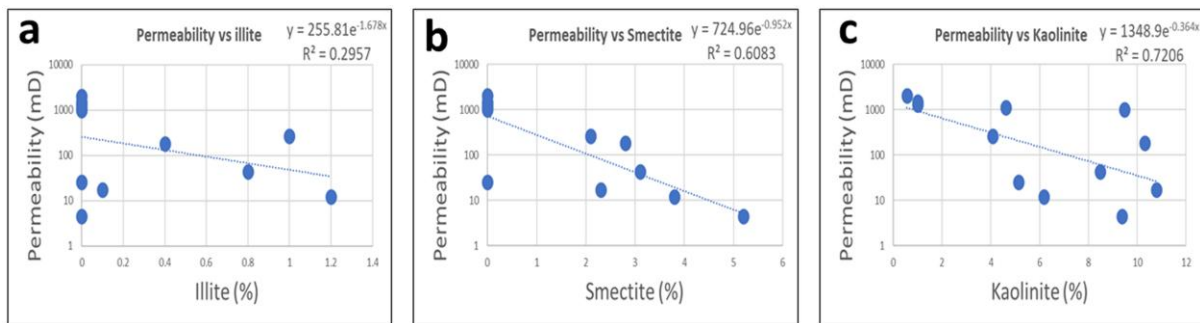


Fig. 13. Cross plots showing the relationship between content of common cemented clay minerals: a) illite, b) smectite and c) kaolinite with permeability in the Middle Bahariya reservoir.

Based on the established rock type classification porosity and permeability was calculated for all wells (Fig. 14) by the electrofacies modeling, which allowed for specific evaluation separate by rock types across the reservoir based on log signatures.

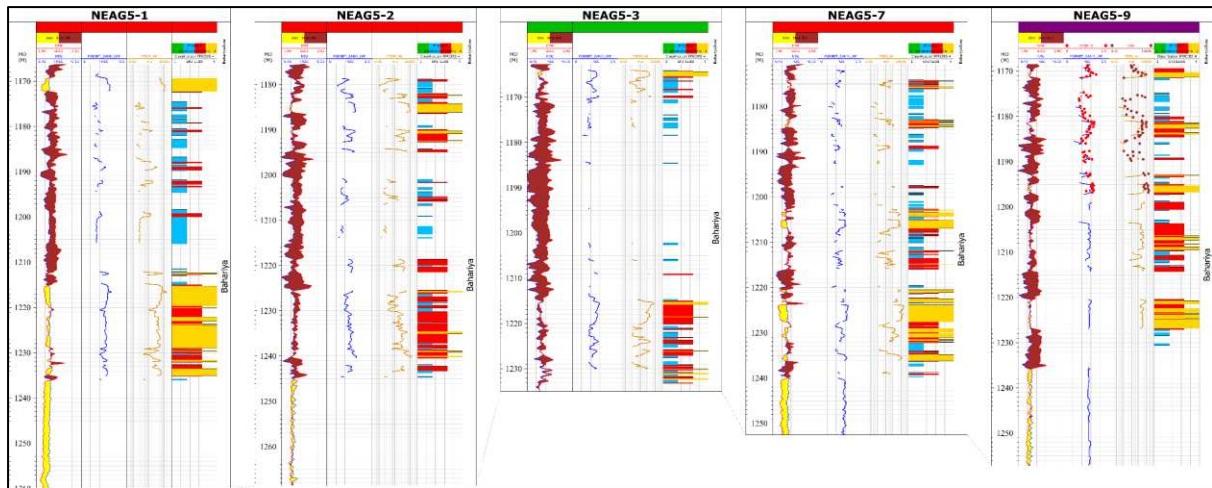


Fig. 14. Log panel showing the porosity and permeability calculations against the electrofacies model of Middle Bahariya reservoir.

The porosity permeability transforms established for each rock type, color-coded by total clay volume (smectite + kaolinite + illite), reveal a clear inverse relationship between reservoir quality and clay content (Fig. 15). Data points belonging to the highest qualities rock type classes cluster in the upper right region of the cross plot, characterised by the highest porosity and permeability values and the lowest clay volumes [2] . Progressively lower rock type classes occupy successively lower porosity permeability domains that coincide with systematically increasing clay content. Consequently, as porosity and permeability increase, the volume of pore filling and pore bridging clays decreases; conversely, elevated clay volumes correspond to marked reductions in both porosity and permeability. This distribution confirms that clay mineralogy and abundance exert a dominant control on permeability reduction within the Middle Bahariya reservoir, independent of the overall porosity trend [39].

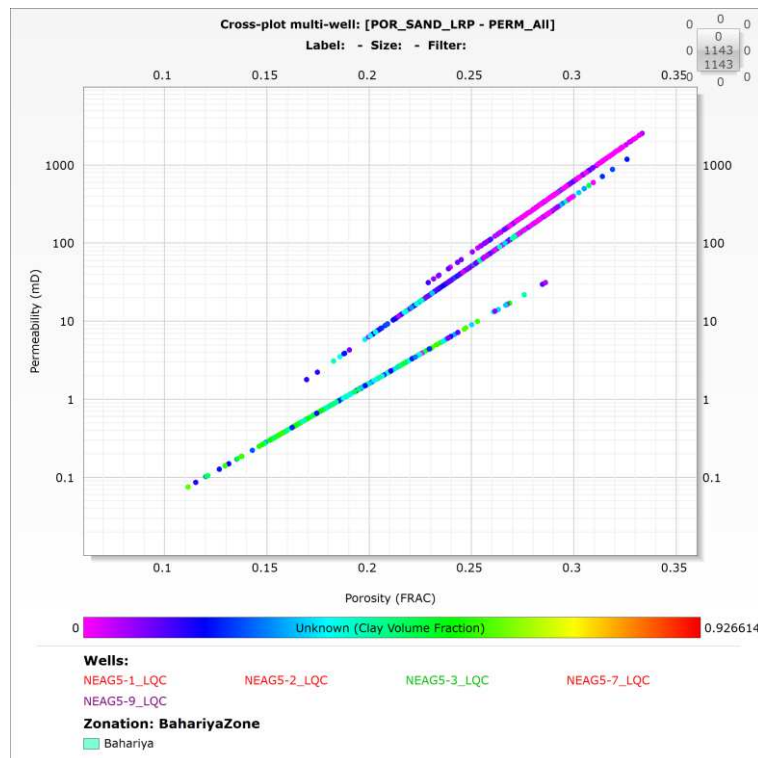


Fig. 15. Cross plot of porosity and rock type derived permeability, color coded by total clay content (Vclay), calculated from illite, smectite, and kaolinite. The plot illustrates the inverse association between clay content and reservoir quality, with higher porosity and permeability generally associated with lower clay content.

5. Discussion

5.1 Controls on permeability heterogeneity

The results obtained from core analysis, electrofacies modeling, XRD measurements, and SEM observations provide important insights into the geological and mineralogical controls governing permeability heterogeneity within the Middle Bahariya reservoir.

The identified reservoir rock types a strong relationship between clay content and reservoir quality. RT-1 presented the poorest reservoir properties due to high clay content by illite, kaolinite, and smectite. SEM confirmed that these clay minerals reduced pore connectivity. Otherwise, RT-4 showed excellent permeability values associated with low clay content and improved pore throat connectivity. Furthermore, the results further indicate that clay distribution are more critical than total clay volume alone in controlling reservoir flow behavior.

5.2 Electrofacies modeling and reservoir characterization

The integration of rock types with electrofacies modeling provided an effective workflow for extending rock typing into uncored intervals. The IPSOM model successfully differentiated reservoir quality variations using conventional well logs. The electrofacies classification improved permeability prediction compared to conventional porosity permeability transform across different depositional facies and geological heterogeneities more accurately. The integration of core analysis, electrofacies modeling, and mineralogical data enabled the construction of a consistent static reservoir characterization framework for the Middle Bahariya reservoir. The integration of machine learning electrofacies analysis with mineralogical controls on permeability provides a transferable methodology for improving permeability prediction in reservoirs affected by complex clay distributions and facies heterogeneity.

5.3 Implications of rock type specific permeability prediction

The main practical implication of the developed workflow is that permeability can be estimated using rock type specific relationships rather than relying on a single global porosity permeability transform. The substantially lower RMSE values obtained for all four reservoir rock types indicate that permeability estimation becomes more consistent when the geological and petrophysical heterogeneity of the reservoir is explicitly considered. This is particularly important for heterogeneous shaly sand reservoirs, where similar porosity values may correspond to markedly different permeability values because of variations in clay mineralogy, pore throat size, pore connectivity and diagenetic modification. Therefore, integrating electrofacies classification and reservoir rock typing with porosity permeability relationships provides a more representative framework for estimating permeability from well-log-derived porosity. From a reservoir modeling perspective, the rock type specific transforms provide a practical means of extending core derived permeability information to uncored intervals and wells. Once the reservoir rock type is predicted from the available well log responses, the corresponding porosity permeability relationship can be applied to estimate permeability for that rock type. This approach allows the permeability distribution to preserve the heterogeneity identified from core, mineralogical, and petrophysical data, rather than imposing a single permeability trend across the entire reservoir. Consequently, the resulting permeability model is expected to provide a more realistic representation of spatial permeability variability and can support reservoir characterization, static model construction, rock type definition and subsequent reservoir simulation and production-related evaluations.

5.4 Reservoir rock type characterization

The integrated analysis of routine core analysis (RCA), special core analysis (SCAL), electrofacies classification, and depositional facies interpretation enabled the development of representative reservoir rock type identification cards for the studied reservoir intervals (Fig. 16, Fig. 17, Fig. 18 and Fig. 19). Each rock type exhibits distinct petrophysical, pore throat, and depositional characteristics controlling reservoir quality and flow behavior.

RT-1

• Litho Facies:

- Heterolithic mud dominated with lenticular sands bedforms. Very fine grained glauconitic sandstone.

• Texture:

- Well sorted, very fine grained sandstone, subangular to rounded grains.
- Highly cemented and highly compacted with long.
- Av. Pore Size: 25 – 45 Mm
- Av. Grain Size: 90 – 110 Mm
- Av. Pore Throat: 0.1 Mm
- Av. Porosity: 6 % by volume
- Av. Permeability: 0.1 mD
- Reservoir quality/Pore interconnectivity: V.Poor
- Thin Section: over sized open inter particle porosity and common leached porosity.
- SEM: over sized inter particle porosity, minor amount of pore filling kaolinite cement.

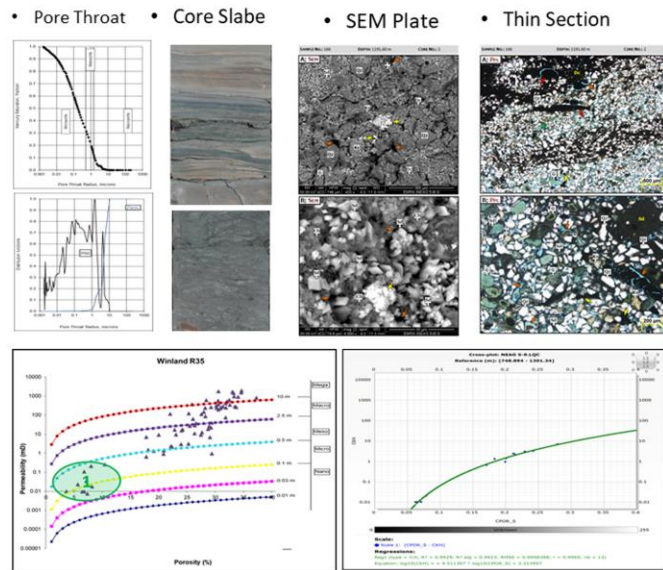


Fig. 16. RT-1 ID card with, porosity permeability cross plot, pore throat sizes distribution, core slab, SEM plate, thin section and winland R35.

RT-1 corresponds to poor-quality reservoir intervals characterized by porosity values ranging from 5 to 8% and permeability below 1 mD (Table 5). This rock type is commonly associated with laminated mud-flat facies strongly affected by silica cementation. The pore system is poorly connected, as indicated by an average pore throat radius of approximately 0.1 μm , resulting in high entry capillary pressure and elevated irreducible water saturation.

RT-2

• Litho Facies:

- Heterolithic mud dominated with lenticular sands bedforms. Very fine grained glauconitic sandstone.

• Texture:

- Well sorted, very fine grained sandstone, subangular to rounded grains.
- Moderately cemented and moderately compacted with long. Detrital clays occurs within laminae
- Av. Pore Size: 30 – 75 Mm
- Av. Grain Size: 105 – 125 Mm
- Av. Pore Throat: 0.5 Mm
- Av. Porosity: 15 % by volume
- Av. Permeability 1 mD
- Reservoir quality/Pore interconnectivity: Poor
- Thin Section: over sized open inter particle porosity and common leached porosity.
- SEM: over sized inter particle porosity, minor amount of pore filling kaolinite cement.

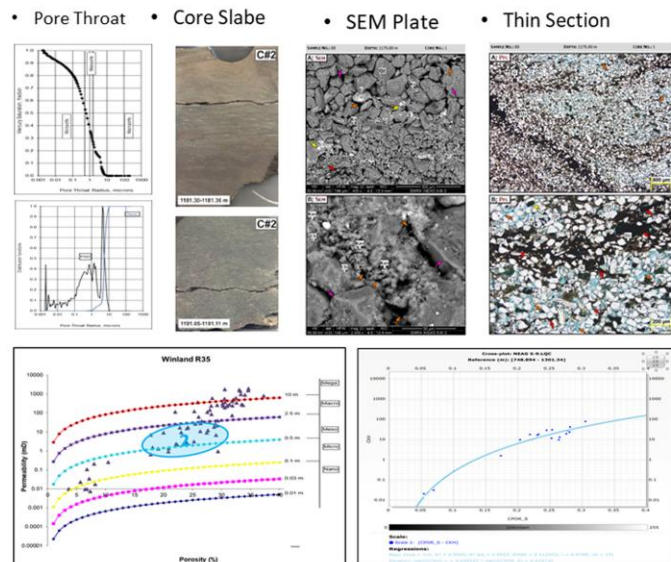


Fig. 17. RT-2 ID card with, porosity permeability cross plot, pore throat sizes distribution, core slab, SEM plate, thin section and winland R35.

RT-2 represents low-quality reservoir intervals with porosity ranging from 12 to 18% and permeability generally below 10 mD (Table 5). These intervals are commonly associated with mud-supported facies and fine-grained textures. The pore throat system remains weakly connected, with an average pore throat radius near 0.5 μm .

RT-3

• Litho Facies:

- Heterolithic sand dominated with mud drapes and wavy flasers

• Texture:

- Well sorted, very fine to fine grained sandstone, subangular to rounded grains.
- moderately cemented and weakly compacted. Av. Pore Size: 70 – 90 Mm
- Av. Grain Size: 120 – 160 Mm
- Av. Pore Throat: 5 Mm
- Ag. Porosity: 25 % by volume
- Av. Permeability: 10 mD
- Reservoir quality/Pore interconnectivity: Good
- Thin Section: Detrital clays are concentrated within laminate in addition to pore filling and grain coatings. Open inter particle porosity and rare leached pores
- SEM: pore filling kaolinite and siderite,.

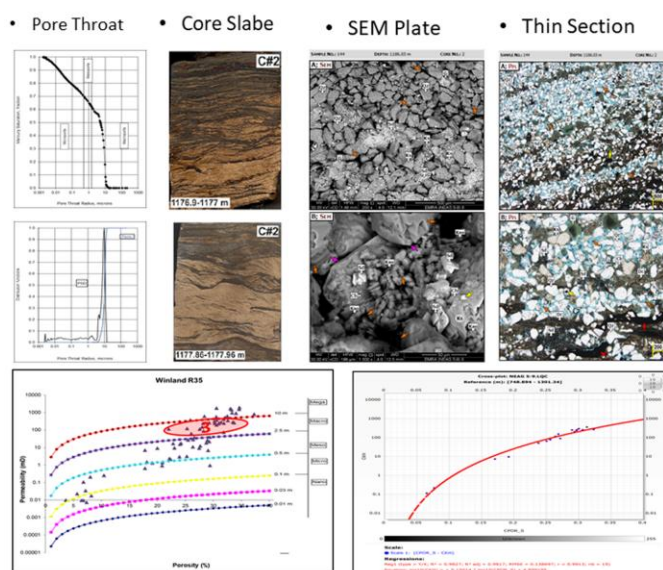


Fig. 18. RT-3 ID card with, porosity permeability cross plot, pore throat sizes distribution, core slab, SEM plate, thin section and winland R35.

RT-3 corresponds to moderate-quality reservoir intervals characterized by porosity values between 20 and 27% and permeability around 10 mD (Table 5). These facies are generally grain-supported with variable cement or matrix content. Secondary porosity generated by dissolution processes locally enhances pore connectivity. The average pore throat radius is approximately 5 μ m.

RT-4

• Litho Facies:

- Fine to medium grained sandstone with flasers/cross bedded sandstone with kaolinite filling and some chloride plates.

• Texture:

- Well sorted, fine grained sandstone, subangular to rounded grains.
- Poorly cemented and moderately compacted, without clay matrix.
- Av. Pore Size: 60 – 300 Mm
- Av. Grain Size: 190 – 200 Mm
- Av. Pore Throat: 10 Mm
- Av. Porosity: 32 % by volume
- Av. Permeability: 1000 mD
- Reservoir quality/Pore interconnectivity: V.Good
- Thin Section: over sized open inter particle porosity and common leached porosity.
- SEM: over sized inter particle porosity, minor amount of pore filling kaolinite cement.

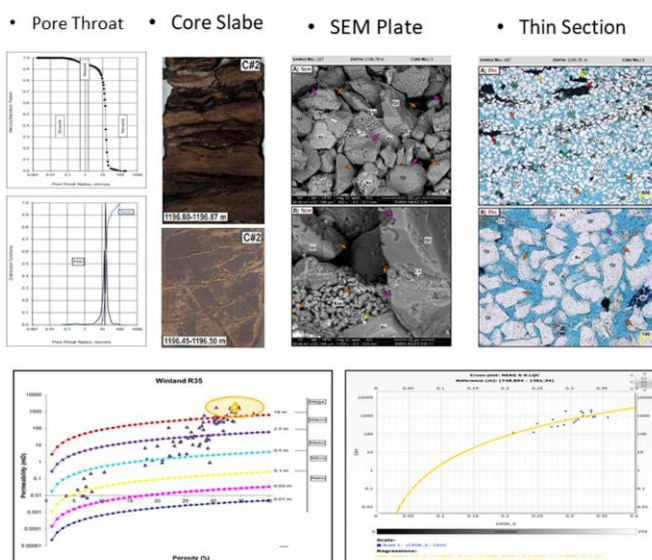


Fig. 19. RT-4 ID card with, porosity permeability cross plot, pore throat sizes distribution, core slab, SEM plate, thin section and winland R35.

RT-4 represents the highest quality reservoir intervals with porosity values ranging from 28 to 35% and permeability reaching up to 1000 mD (Table 5). These intervals are associated with grain supported facies exhibiting improved pore connectivity and larger pore throat systems, with an average pore throat radius near 10 μ m. The low clay content and enhanced pore connectivity significantly improve reservoir flow capacity.

Table 5. The Minimum, maximum and average values for porosity, permeability per rock type.

Variables	RT-1			RT-2			RT-3			RT-4		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Porosity (%)	4.28	6.36	8.77	12.	15.18	19.12	20.72	23.89	27.42	28.08	32.28	37.37
Permeability (mD)	0.015	0.535	1.11	2.45	5.95	9.683	11.4	54.78	99.87	101.4	1009	1918

6. Conclusion

This study presented an integrated reservoir characterization workflow for permeability prediction in the heterogeneous shaly sand reservoirs of the Middle Bahariya Formation in the NEAG-5 Field, Western Desert, Egypt. The workflow combined core analysis, rock types, machine learning based electrofacies modeling, XRD analysis, and SEM observations to investigate the main controls on permeability variability.

The major conclusions of this study can be summarized as follows:

- Permeability heterogeneity is primarily controlled by clay mineral content, clay morphology, and pore throat connectivity rather than porosity alone.
- Four reservoir rock types (RT-1 to RT-4) were identified using hydraulic flow unit analysis and Winland pore throat classification.
- High quality reservoir intervals are associated with low clay content and improved pore connectivity, whereas poor quality intervals contain abundant illite, kaolinite, and smectite.
- Electrofacies modeling successfully extended rock typing and permeability prediction into uncored wells using conventional well logs.
- Porosity permeability transforms based on rock types are significantly improved permeability estimation compared to conventional field wide transforms.
- The integrated workflow reduced uncertainty in static reservoir characterization and provided a reliable methodology for permeability prediction in heterogeneous shaly sandstone reservoirs.
- Rock type specific porosity permeability relationships substantially improved the statistical consistency of permeability estimation compared with the global relationship. The global model yielded an R2 of 0.8623 and an RMSE of 0.5512, whereas the four rock type specific models yielded R2 values of 0.9520 – 0.9929 and RMSE values of 0.0958 – 0.2190. This demonstrates that incorporating reservoir rock typing reduces the scatter associated with permeability heterogeneity and provides a more representative basis for permeability estimation in the NEAG-5 reservoir.
- The integrated workflow provides a practical approach for extending core derived permeability information to uncored intervals and wells. By predicting the reservoir rock type from well log responses and applying the corresponding rock type specific porosity permeability relationship, permeability can be distributed throughout the reservoir while preserving the heterogeneity associated with different flow units. This approach can improve the geological realism of permeability models and provide a stronger basis for reservoir characterization and subsequent flow modeling.

Data availability

Datasets generated during and/or analysed during the current study are available under request from the corresponding author [Mohamed Kassab] through the contacted Email: mkassab68@yahoo.com

Code Availability

This study did not involve the development of any custom or bespoke computational tool, algorithm, software, or pipeline. All computational and modelling tasks were performed using licensed, commercially available software (standard petrophysical and geological interpretation software **Techlog**). No custom code was generated or used, and therefore code deposition is not applicable to this study.

Ethics information

This manuscript has not been submitted to more than one journal for simultaneous consideration. The submitted work is original and not has been published elsewhere in any form or language (partially or in full). The results presented clearly, honestly, and without fabrication, falsification or inappropriate data manipulation (including image based manipulation).

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Author Contributions

Mohamed Kassab: Resources, Methodology, Investigation, review & editing. Aly Abbas: review & editing, Supervision. Waleed Osman: Visualization, Validation, Investigation, Formal analysis. Hisham Samir: Resources, Methodology, Investigation, Results, Data curation, Software, Writing.

Competing Interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Abbreviation List

Full Name	Abbreviation
Indexed and Probabilized Self Organizing Map	IPSOM
North East Abu Gharadig	NEAG
Permeability	K, Perm
Pore throat	R
Porosity	Ø
Reservoir Modelling Knowledge Base	RMKB
Rock Type	RT
Root Mean Square Error	RMSE
Routine core analysis	RCA
Scanning electron microscopy	SEM
Special core analysis	SCAL
Stands for Coefficient	R2
Stratigraphic Modified Lorenz Plot	SMLP
X-ray diffraction	XRD

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