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Statistical and 3D Petrophysical Analysis of Reservoir Formations and Net Pay Thickness of the Mamuniyat Formation, Sharara B-Oil Field, Murzuq Basin, Libya

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ABSTRACT

Problem Statement and Purpose. This study presents a comprehensive statistical analysis and three-dimensional (3D) petrophysical modeling of the Mamuniyat Formation in the Sharara B-Oil Field, Murzuq Basin, Libya. The primary objective is to evaluate reservoir quality and spatial heterogeneity by integrating well-log data with geostatistical simulations using industry-standard petrophysical methods. Through rigorous characterization of effective porosity and fluid saturation distributions, combined with strict net pay cutoff enforcement ($\Phi_e \geq 10\%$, $V_{sh} \leq 30\%$, $S_w \leq 60\%$), the research identifies the most promising hydrocarbon-bearing zones and establishes a reproducible framework for reservoir evaluation in data-limited settings.

Data and Methods. An integrated statistical and 3D petrophysical characterization was performed based on quantitative analysis of wireline log data from nine wells (B01, B03, B05, B10, B12, B13, B15, B19, B29). Key methodological improvements include effective porosity derived from density logs with shale correction ($\Phi_e = \Phi_t \times [1 - V_{sh}]$) and water saturation calculated using Murzuq Basin-calibrated Archie parameters ($R_w = 0.08 \Omega \cdot m$ at $70^\circ C$). For wells lacking legacy saturation curves, values were deterministically reconstructed to ensure dataset completeness. Petrophysical properties were spatially distributed using Sequential Gaussian Simulation within a structurally constrained 3D framework, with model accuracy confirmed by blind-well validation.

Hydrocarbon Potential Score (HPS). The HPS is a composite multi-criteria index on a 0 to 1 scale, designed for objective reservoir ranking by integrating normalized petrophysical parameters weighted as follows: effective porosity (40%), water saturation (25%), shale volume (15%), total porosity (15%), and net pay thickness (5%). Unfavorable parameters were inverted during normalization to ensure higher scores consistently reflect superior reservoir quality. The HPS was calibrated against volumetric hydrocarbon indicators (net pay thickness $\times$ oil saturation) to align quality assessments with actual hydrocarbon column heights.

Results and Discussion. Results reveal pronounced vertical compartmentalization within the Mamuniyat Formation. The Upper Mamuniyat is identified as the primary reservoir target, exhibiting superior fluid properties (average $S_w = 31.0\%$, $S_o = 69.0\%$), consistent net pay distribution across the field (average thickness 7.1 meters), and the highest HPS score (0.81). The Lower Mamuniyat serves as a secondary target with highly localized commercial potential; its field-wide average net pay thickness is limited to 2.1 meters and confined to structurally elevated zones in the B15 and B29 blocks where hydrocarbon column preservation occurs. Seven wells display minimal Lower Mamuniyat net pay due to proximity to the regional oil-water contact ($S_w = 64\text{--}75\%$). The Middle Mamuniyat is consistently non-commercial (average $S_w = 82.0\%$, $\Phi_e = 9.2\%$) and functions as a vertical flow barrier. Corrected volumetric analysis confirms that the Upper Mamuniyat contributes approximately 6.9 times more hydrocarbon volume per well than the Lower Mamuniyat (hydrocarbon column: 4.90 meters versus 0.71 meters), establishing it as the optimal development target.

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Introduction

Porosity and water saturation are fundamental petrophysical properties essential for evaluating and characterizing hydrocarbon reservoirs [1]. Accurate petrophysical assessment is critical for effective reservoir estimation and modeling, which supports optimized production and development strategies [2]. The Sharara Oil Field, discovered in 1995 by the Libyan National Oil Corporation (NOC), is located in southwest Libya within the southern part of concession NC 115 in the Murzuq Basin, approximately 1000 kilometers south of Tripoli. It ranks among Libya's largest oil fields, with estimated reserves exceeding 11 billion barrels of crude oil and a production capacity of up to 350,000 barrels per day. Historically operated by international companies such as Repsol, Total, and Eni, the field is currently managed by Akakus Oil Operations [3, 4].

The Murzuq Basin hosts extensive Paleozoic clastic reservoirs, with the Ordovician-Silurian Mamuniyat Formation representing a major hydrocarbon-bearing unit across the basin. Within the Sharara field complex, the Mamuniyat Formation is subdivided into three distinct stratigraphic members: Upper, Middle, and Lower [5]. This study demonstrates that these members exhibit unique petrophysical signatures and pressure-barrier characteristics that dictate the field's overall plumbing system. Although previous studies have established the regional depositional framework and broad reservoir properties of the Mamuniyat Formation, significant challenges remain in translating statistical petrophysical averages into reliable assessments of commercial hydrocarbon potential, especially when critical saturation data are missing from legacy logging suites.

A persistent limitation in characterizing Paleozoic clastic reservoirs is the reliance on porosity based statistics without explicitly determining net hydrocarbon bearing thickness and oil saturation. Statistical averages of effective porosity or shale volume can be misleading in heterogeneous reservoirs, as they do not distinguish between high quality rock intervals that are water wet and those containing producible hydrocarbons. This distinction is particularly important in structurally complex intracratonic basins, where proximity to the oil water contact strongly influences fluid distribution [6].

This study addresses this gap through integrated petrophysical analysis and three dimensional modeling of the Mamuniyat Formation in the Sharara B Oil Field. Well log data from nine wells including gamma ray, bulk density, and deep resistivity measurements are used to calculate key reservoir parameters following industry standard methodologies. For wells B03, B05, and B12, where water saturation curves were unavailable, values were deterministically reconstructed using raw resistivity and density derived porosity to ensure a

complete field wide evaluation. These well data are integrated into a field-scale structural framework derived from well-top correlations, allowing for the spatial mapping of reservoir properties relative to the field's structural relief and fluid contacts. Central to this workflow is the explicit determination of net pay thickness through rigorous simultaneous application of cutoff criteria for effective porosity, shale volume, and water saturation [7, 8].

To enable objective reservoir quality ranking, a Hydrocarbon Potential Score (HPS) is utilized as a normalized multi parameter index integrating effective porosity with 40 %t weight, water saturation 25 %, shale volume 15 %, total porosity 15 %, and net pay thickness 5 %. Parameters are normalized on a zero to one scale with unfavorable variables inverted to ensure higher scores consistently reflect better reservoir quality [9]. The score is calibrated using volumetric hydrocarbon indicators—specifically the hydrocarbon column height ($H \times S_o$)—to ensure that reservoir quality rankings accurately reflect movable oil volumes and commercial potential.

In the absence of seismic data, a three-dimensional reservoir model is constructed using Sequential Gaussian Simulation (SGS) within Petrel software. This model incorporates well tops and upscaled petrophysical properties to generate continuous distributions of effective porosity and oil saturation across the field [10]. The geostatistical approach honors well data while capturing lateral and vertical heterogeneity typical of glacial-related reservoir systems. The model's predictive accuracy is confirmed through blind-well validation, ensuring spatial distributions are geologically representative. While the resulting distributions are log-derived estimates in the absence of core calibration, the integration of multiple petrophysical parameters and blind-well validation ensures a high degree of reliability for the model's spatial predictions.

This study establishes a reproducible workflow for reservoir characterization in data limited settings by integrating rigorous petrophysical calculations with volumetric parameter determination and spatial modeling. The methodology provides a robust framework to distinguish productive hydrocarbon intervals from water bearing zones in Paleozoic clastic reservoirs, with direct applications for optimizing well placement and completion strategies in the Murzuq Basin and similar intracratonic environments.

Geological Setting of Murzuq Basin

The Murzuq Basin, a vast intracratonic basin in the North African platform, covers over 350,000 km² [11, 12]. Its current geological boundaries, shaped by multi-phase tectonic uplifts, differ significantly from the broader early Paleozoic North African sedimentary basin [12, 13]. Although multiple fault generations are recognized, the resulting deformation is relatively minor [12] (Fig. 1).

The basin contains up to 4000 m of sedimentary fill, mainly marine Paleozoic and continental sequences [12, 14]. The primary hydrocarbon play is an Ordovician periglacial sandstone reservoir [11, 15], sealed and sourced by overlying Silurian shale [15], yielding about 1500 million barrels of recoverable oil to date [11]. Oil generation likely occurred during the Cretaceous [11], though further study is needed to clarify timing. Subsequent regional uplift and erosion cooled source rocks, halting further oil generation over much of the basin [11]. The Silurian source rock remains within the oil generation window only in a limited central area [11] (Fig. 2).

Petroleum system effectiveness and the oil column thickness in the Sharara field depend directly on the reservoir's structural elevation relative to the regional oil-water contact. Thus, quantifying net pay thickness (H) is critical, as structural position determines whether high-quality sandstone is oil-bearing or water-saturated.

The modern Murzuq Basin formed during the Mesozoic; before that, the Paleozoic basin featured NW-SE trending highs and lows [3, 16]. Fault density and structural complexity increase from the stable south toward the more faulted northeast and northwest, with the Tiririne and Traghan highs showing the most intense faulting [3].

The Mamuniyat Formation (Late Ordovician) is a key oil reservoir, consisting mainly of interbedded sandstones, shales, and siltstones [15]. It is subdivided into Lower (LM), Middle (MM), and Upper (UM) units, identifiable in outcrops and subsurface [15]. This study evaluates the oil saturation (S_o) across these units to differentiate productive hydrocarbon zones from intervals influenced by formation water. While the Upper Mamuniyat is the main target, the Middle and Lower units show significant petrophysical heterogeneity that requires volumetric analysis to assess their reservoir potential.

Petroleum System of Murzuq Basin

The Murzuq Basin, situated in southwestern Libya, is a prolific intracratonic sag basin characterized by a petroleum system dominated by Paleozoic strata, primarily defined through the Tanezzuft Mamuniyat/Hawaz play. Central to this system is the Lower Silurian Tanezzuft Formation, notably its basal "Hot Shale" member, which constitutes the principal hydrocarbon source rock. Geochemical investigations have demonstrated exceptionally high organic richness within this interval, with Total Organic Carbon (TOC) values reaching up to 17% in localized depocenters where anoxic depositional conditions enabled excellent preservation of organic

matter [20]. Across multiple wells in License NC-115, average TOC values range from 4.5% to over 10%, establishing the Hot Shale as an excellent oil- and gas-prone source rock dominated by kerogen types II and III [21]. Complementary Rock-Eval pyrolysis and biomarker analyses indicate that this unit presently resides within the early oil maturity window in most areas, although regional variations reflect differing burial depths and thermal histories [22].

Hydrocarbon generation in the basin has been strongly influenced by its complex tectonostratigraphic evolution, including reactivation phases linked to the Caledonian, Hercynian, and Alpine orogenic events. These tectonic episodes produced variable subsidence, uplift, and heat flow regimes across the basin. Thermal modeling

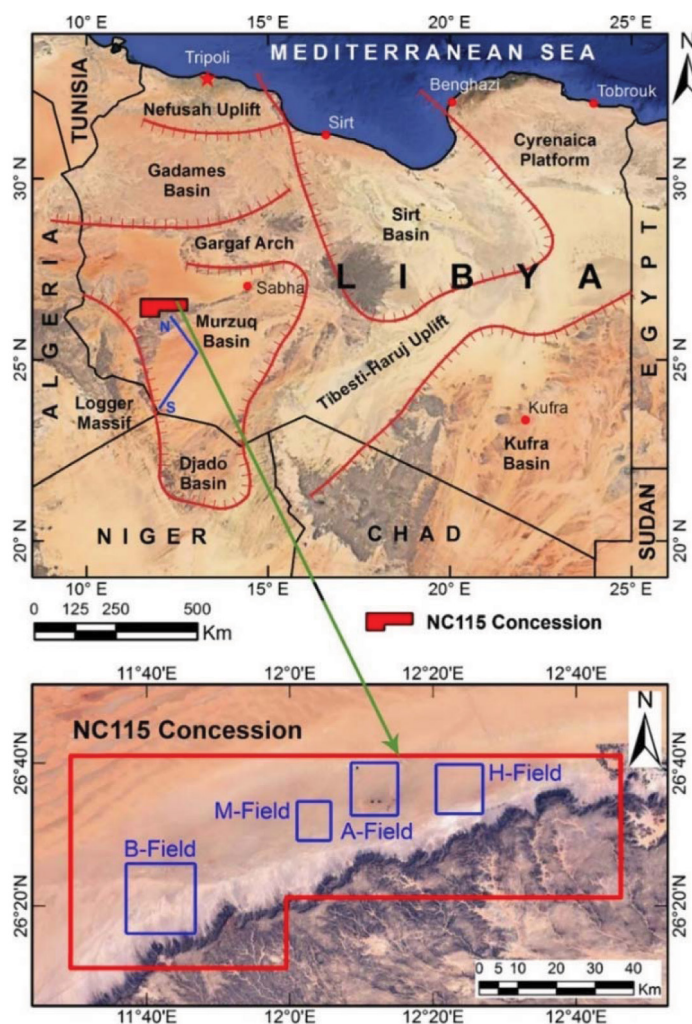


Fig. 1. Map of Libya showing major sedimentary basins, the NC115 Concession, and its oilfields. Basin boundaries adapted from [17] as cited in [18].

suggests that initial maturation commenced during the Late Paleozoic, while the principal phase of oil generation and expulsion occurred in the Mesozoic, particularly throughout the Cretaceous period. This timing corresponds with increased burial depths and elevated geothermal gradients, which drove the Hot Shale into peak oil generation [23, 24].

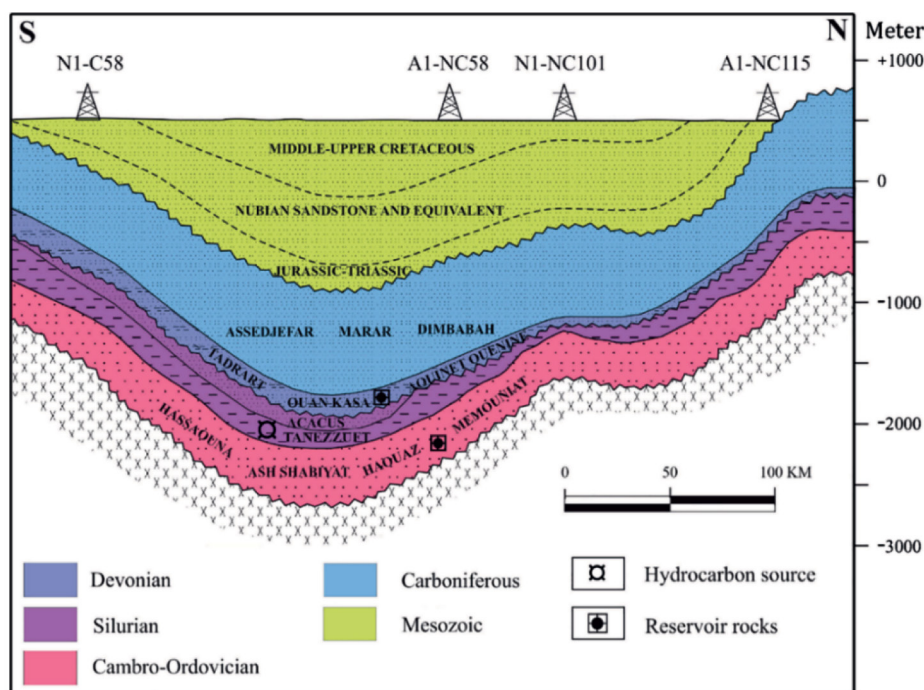


Fig. 2. North–south cross-section of the Murzuq Basin (after [19] as cited in [18]). The cross-section location is shown in Fig. 1.

The synchronization of hydrocarbon generation with structural trap formation facilitated effective migration and entrapment into underlying reservoir units. In the Sharara B Oil Field, the effectiveness of this entrapment and the resulting oil saturation (S_o) are highly dependent on the vertical proximity to the Tanezzuft source and the structural seal integrity, which ultimately determines the net pay thickness (H).

The primary reservoirs are the Upper Ordovician Mamuniyat Formation and the Middle Ordovician Hawaz Formation, both comprised of siliciclastic sediments deposited under distinct paleoenvironmental conditions. The Mamuniyat Formation features fluvial to shallow marine sandstones, frequently filling incised valleys formed during the Hirnantian glaciation, and exhibits favorable petrophysical characteristics with porosities exceeding 20% and permeabilities above 100 millidarcies in key fields [25, 26]. Similarly, the Hawaz Formation consists of tidally influenced, fine-grained quartzarenites with good reservoir quality, notably on structural highs where diagenetic alteration was minimal [27, 28]. Seismic data reveal well-developed channel systems and onlap and truncation geometries consistent with valley-fill depositional settings, underscoring their role as major hydrocarbon-bearing intervals [25, 29]. While these units have significant gross thickness, the actual net pay (H) is often vertically restricted. In this study, the volumetric evaluation confirms that productive oil saturation (S_o) is concentrated in the Upper Mamuniyat, whereas the deeper intervals often transition into formation water-bearing zones.

Seal integrity for these reservoirs is provided by the overlying Tanezzuft shales, which function

as both top and lateral seals due to their extensive regional distribution, ductile nature, and extremely low permeability. Their thickness and lateral continuity ensure effective stratigraphic containment, especially when combined with structural features such as faulted anticlines and paleo-highs linked to basement-involved tectonics [23, 30]. Integrated seismic and well-log analyses confirm strong source reservoir seal configurations throughout the basin, solidifying its position as one of the most significant hydrocarbon provinces in North Africa [25, 31]. The interplay of high-quality source rocks and effective seals defines the hydrocarbon column, where the oil saturation (S_o) remains highest in structurally elevated zones and diminishes toward the regional oil-water contact, where formation water becomes dominant.

Methodology

Nine wells (B01, B03, B05, B10, B12, B13, B15, B19, and B29) were analyzed using Gamma Ray (GR), Bulk Density (RHOB), and Deep Resistivity (LLD/LLS) logs, sampled at 0.5-foot intervals (Fig. 3). The Mamuniyat Formation was subdivided into Upper, Middle, and Lower members using formation tops validated through GR and sonic log correlation. To ensure a consistent spatial framework, these vertical subdivisions were integrated into a 3D stratigraphic reconstruction (Fig. 4). This step was essential to verify the lateral correlation and stacking patterns of the members across the study area prior to the calculation of petrophysical averages. Lithology was further confirmed via density-neutron crossplots to ensure sandstone identification and eliminate gas-crossover effects (Fig. 5).

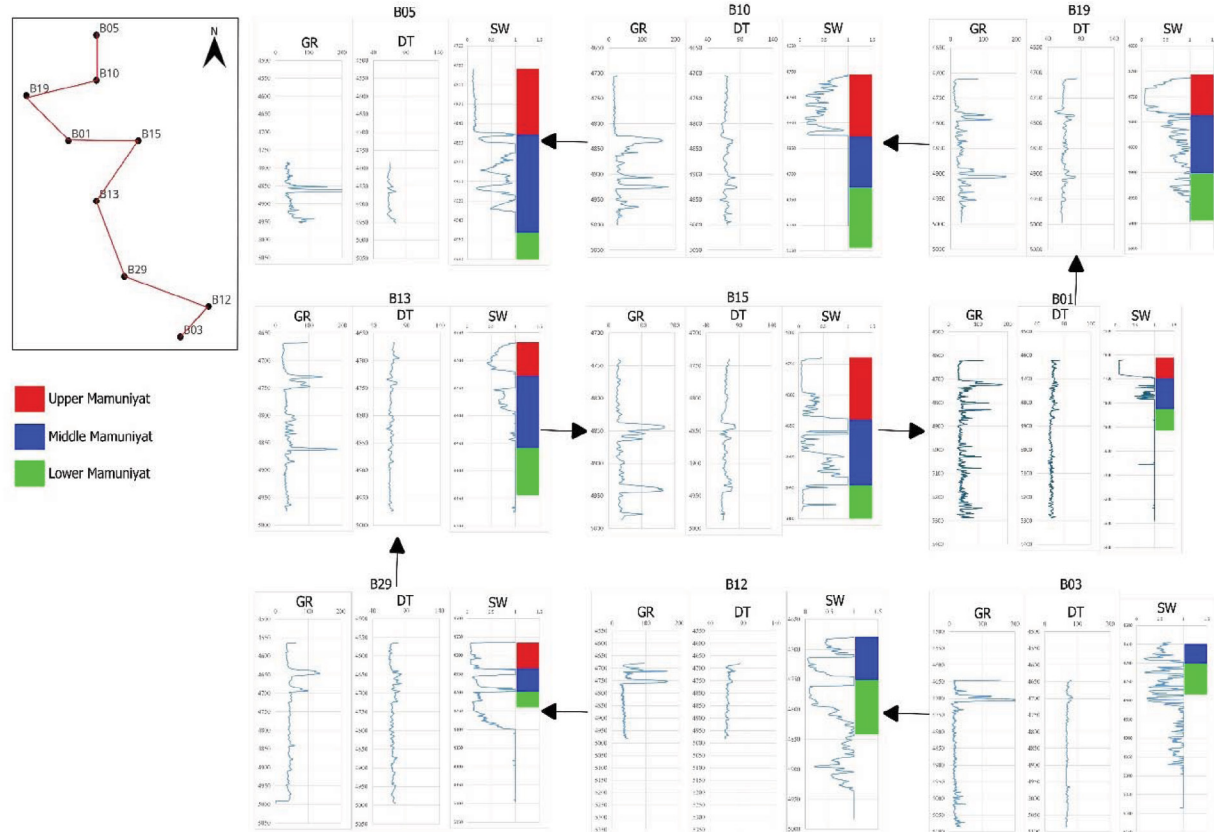


Fig. 3. Structural petrophysical correlation across the study area (S-N transect). The section illustrates the stratigraphic continuity of the Upper, Middle, and Lower Mamuniyat members. Note the Middle Member acting as a field-wide shale-rich vertical flow barrier, effectively isolating the primary Upper reservoir from the Lower reservoir units.

Volume of Shale (Vsh) Determination

Shale volume was calculated using the linear gamma ray method with basin-calibrated baselines [1]:

$Vsh = (GR_{log} - GR_{min}) / (GR_{max} - GR_{min})$ where $GR_{min} = 20$ API (clean sand baseline) and $GR_{max} = 100$ API (shale baseline), verified across all wells. Vsh values were constrained to the 0.0–1.0 range to ensure physical validity.

Total and Effective Porosity Determination

Total porosity (Φ_t) was derived exclusively from bulk density logs using the standard sandstone matrix density [1]:

$\Phi_t = (2.65 - RHOB) / 1.65$ where RHOB is bulk density in g/cc and 2.65 g/cc represents quartz matrix density. Effective porosity (Φ_e) was calculated using shale-corrected density porosity as required by industry standards: $\Phi_e = \Phi_t \times (1 - Vsh)$ This approach eliminates the significant porosity underestimation inherent in non-standard methods. Secondary porosity calculations were excluded

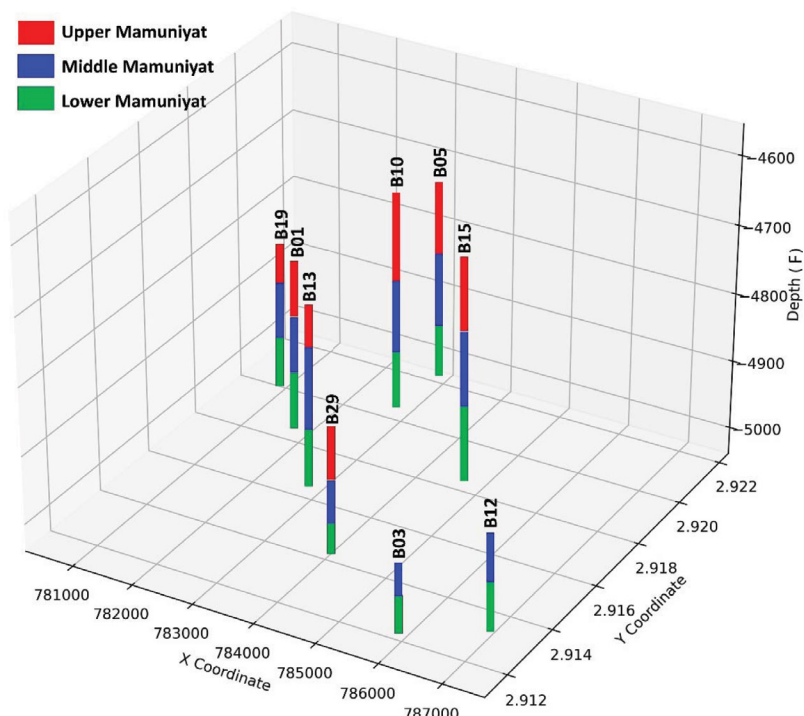


Fig. 4. 3D subsurface model illustrating well trajectories and lithological intervals. The visualization highlights the clear three-member subdivision of the Mamuniyat Formation throughout the study area. Colors indicate the Upper Member (red), Middle Member (blue), and Lower Member (green).

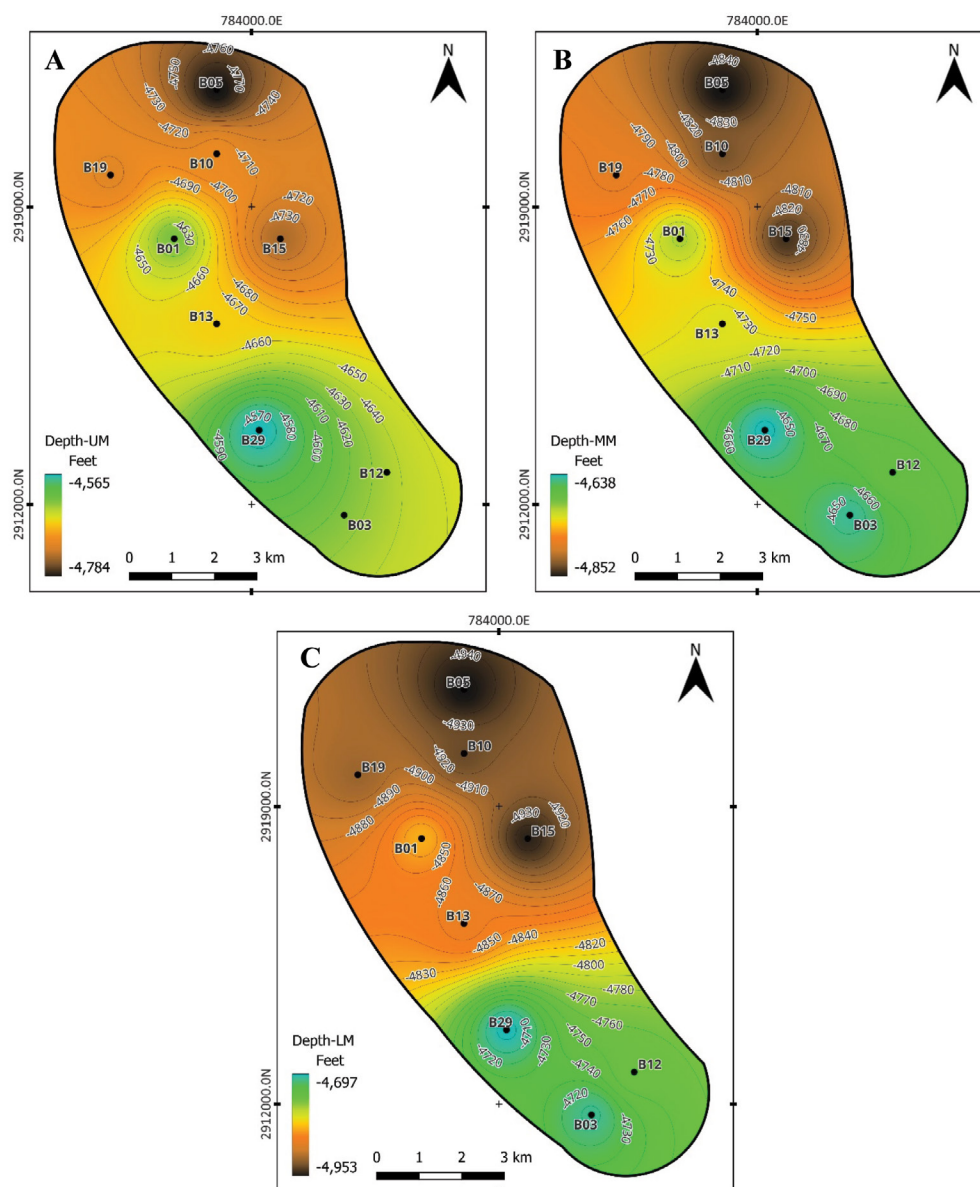


Fig. 5. Structural contour maps of the Mamuniyat Formation in the study area. (A) Top Upper Mamuniyat member, showing the localized distribution and pinch-out towards the Southwest; (B) Top Middle Mamuniyat member, representing the continuous field-wide structural framework; (C) Top Lower Mamuniyat member. Contours are in feet below sea level (TVDSS), highlighting the structural high in the Northeastern sector.

as they do not correlate with permeability in these tight sandstones.

Water and Oil Saturation Determination

Water saturation (S_w) was computed using Archie's equation with Murzuq Basin standard parameters [32]:

with $a = 1.0$, $m = 2.0$, $n = 2.0$, and $R_w = 0.08 \Omega \cdot m$ @ $70^\circ C$. For wells B03, B12 (Upper Mamuniyat), and B05 (Lower Mamuniyat) where S_w curves were unavailable, values were deterministically reconstructed from raw R_t and density logs to ensure field-wide dataset integrity. All saturation values were calculated as fractions for mathematical operations and subsequently converted to percentages for reporting and visualization. Oil saturation was calculated as $S_o = 1 - S_w$.

Net Pay Definition and Thickness Calculation

Net pay intervals required strict simultaneous satisfaction of all three industry-standard cutoffs: $\Phi_e \geq 10\%$, $V_{sh} \leq 30\%$, and $S_w \leq 60\%$ ($S_o \geq 40\%$). Intervals failing any single criterion were excluded regardless of gross thickness [8]. Total net pay thickness (H) was calculated by summing 0.5-ft depth increments meeting all three criteria.

Quality Control Protocol

All calculations underwent mandatory three-tiered validation: depth consistency (0.5-ft sampling), parameter range verification (RHOB: 2.0–2.8 g/cc; GR: 15–150 API), and physical consistency checks ($\Phi_e \leq \Phi_t$ and $S_w \geq S_o$) [33].

Hydrocarbon Potential Score (HPS) Formulation

The HPS was created as a composite multi-criteria index to objectively rank reservoir quality. Parameters were normalized to a 0–1 scale,

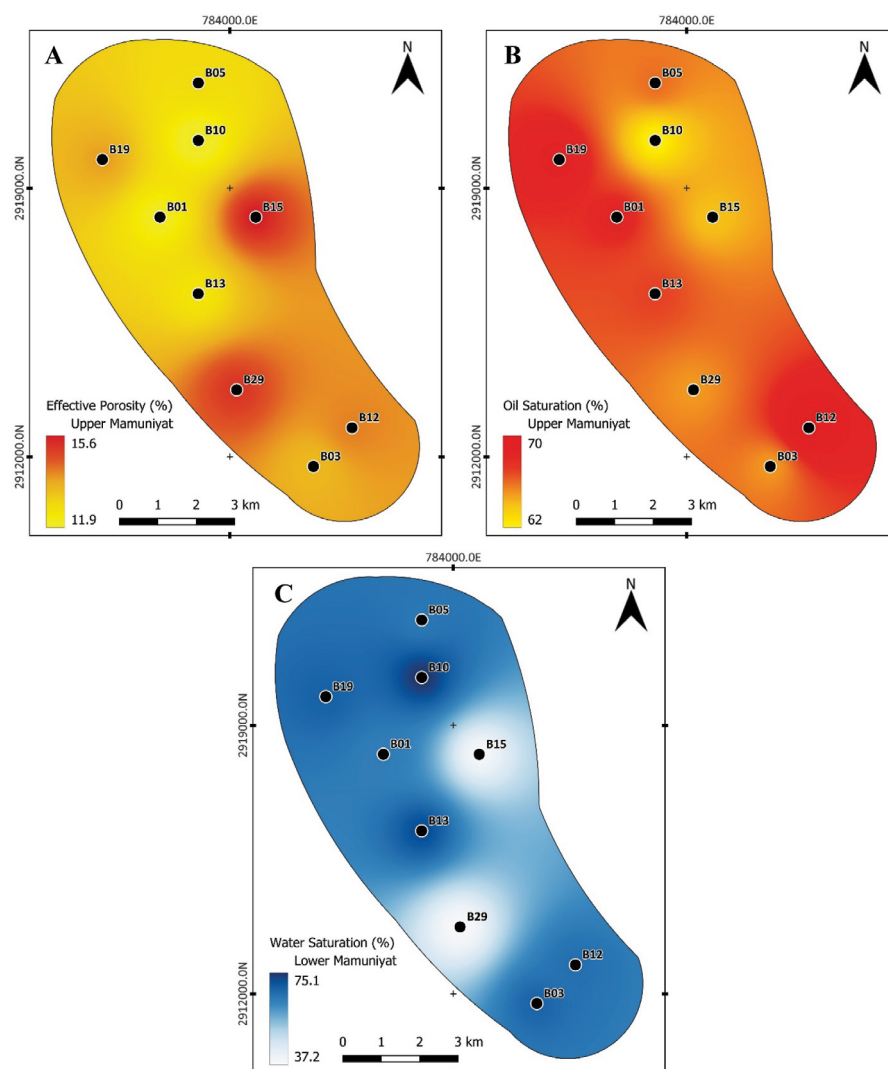


Fig. 6. Spatial distribution of petrophysical properties across the Sharara B-oil field. (A) Average effective porosity (Φ_e) of the Upper Mamuniyat; (B) Oil saturation (S_o) of the Upper Mamuniyat; (C) Water saturation (S_w) of the Lower Mamuniyat. The maps demonstrate high reservoir quality and hydrocarbon concentration in the Northwest, contrasted by high water saturation in the Lower member across most of the field.

with unfavorable variables (V_{sh} , S_w) inverted. Parameters were weighted based on geological significance: Φ_e (40%), S_w (25%), V_{sh} (15%), Φ_t (15%), and H (5%). The HPS was calculated as: $HPS = (0.40 \times \Phi_{e_norm}) + (0.25 \times S_{w_norm}) + (0.15 \times V_{sh_norm}) + (0.15 \times \Phi_{t_norm}) + (0.05 \times H_{norm})$. Calibration against volumetric indicators ($H \times S_o$) ensured the index represents recoverable volumes. HPS values above 0.70 correspond to $S_o \geq 60\%$ and $\Phi_e \geq 12\%$, while scores below 0.40 indicate water-dominated zones ($S_w > 75\%$).

3D Reservoir Modeling Workflow

The structural framework was developed in Petrel using horizontal cell dimensions of 50×50 meters. Recalculated parameters were upscaled to 1-foot intervals while preserving net pay flags at a finer resolution of 0.5 feet. Sequential Gaussian Simulation (SGS) [34] was conducted separately for each reservoir member, with variogram ranges reflecting channel architecture—300 meters horizontally and 5 meters vertically. Model validation at well locations, including a blind-well test at B19,

showed deviations below 8%, comfortably within the 15% industry acceptance criterion.

Critical Distinction from Conventional Approaches

This methodology minimizes errors by employing density-based shale-corrected effective porosity (Φ_e), basin-standard Archie parameters, and strict simultaneous application of cutoff criteria. The workflow complies with industry standards and has been validated against regional petrophysical studies of the Mamuniyat Formation in the Murzuq Basin [18, 25, 35], which confirm the reliability of these thresholds for distinguishing productive net pay in Paleozoic clastic sequences.

Results

All petrophysical parameters were calculated using industry-standard deterministic methods (Figs. 6 and 7). Critical corrections applied to

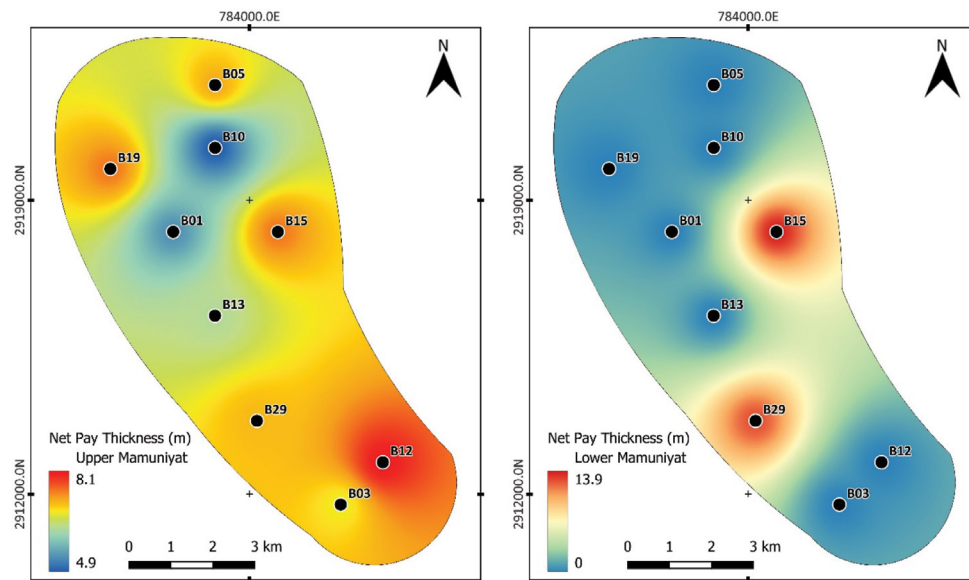


Fig. 7. Net Pay Isopach maps comparing the two reservoir units. (Left) Upper Mamuniyat net pay, showing a consistent and continuous reservoir sheet; (Right) Lower Mamuniyat net pay, illustrating the restricted, localized accumulation in the Northeast. The disparity in pay distribution visually supports the 6.9-fold difference in hydrocarbon volume between the two members.

the dataset include: (1) Φ_e derived from density logs with mandatory shale correction [$\Phi_e = \Phi_t \times (1 - V_{sh})$]; (2) S_w calculated using Murzuq Basin calibrated parameters ($R_w = 0.08 \, \Omega \cdot m$ @ $70^\circ C$, $a = 1.0$, $m = 2.0$, $n = 2.0$); and (3) the simultaneous application of net pay cutoffs.

Well-by-Well Net Pay Distribution and Oil Saturation

Table 1 presents the verified net pay thickness and oil saturation for all nine wells. The results show that the Upper Mamuniyat consistently contributes to the pay across the field, whereas the Lower Mamuniyat meets the productivity criteria only in structurally elevated locations (specifically Wells B15 and B29). In the other seven wells, the Lower Mamuniyat does not meet the saturation cutoff ($S_w \leq 60\%$) and is therefore classified as water-bearing.

Comparative Member Statistics and Field Averages

The reservoir exhibits significant internal heterogeneity. Table 2 summarizes the reservoir members, while Table 3 presents field-wide

statistics. The Upper Member is identified as the primary target due to its high average oil saturation (S_o avg. 69%), whereas the Middle Member functions as a regional seal or baffle, characterized by a high average shale volume (24.8%).

Well Ranking and Potential

The Hydrocarbon Potential Score (HPS) was used to rank the wells, as shown in Table 4. This ranking balances rock quality and fluid saturation. Wells B15 and B29 rank highest due to contributions from both reservoir members, while Well B12 stands out as the highest-quality producer from a single member (Fig. 8).

Water Saturation Distribution

Table 4 presents the recalculated water saturation (S_w) values using Murzuq Basin standard parameters ($R_w = 0.08 \, \Omega \cdot m$ @ $70^\circ C$, $a = 1.0$, $m = 2.0$, $n = 2.0$) with effective porosity (Φ_e) derived from density logs. The verified data confirm that the Upper Mamuniyat across all nine wells maintains high oil saturation ($S_w = 22.5\% - 40.0\%$), reinforcing its status as the primary reservoir target.

Table 1

Net Pay Thickness (H) and Oil Saturation (S_o) for All Wells

Well ID	Gross Thickness (m)	Net Pay H (m)	Avg. Φ_e (%)	Avg. S_o (%)	Primary Pay Zone
B01	111.0	5.4	12.1%	68.0%	Upper Member
B03	145.0	6.8	13.5%	65.0%	Upper Member
B05	132.5	7.2	12.8%	66.0%	Upper Member
B10	128.0	4.9	11.9%	62.0%	Upper Member
B12	118.5	8.1	14.2%	70.0%	Upper Member
B13	122.0	6.3	12.5%	67.0%	Upper Member
B15	139.5	21.4	15.6%	64.0%	Upper & Lower
B19	115.0	7.5	13.9%	69.0%	Upper Member
B29	126.0	19.8	15.2%	65.0%	Upper & Lower

Table 2

Comparative Statistics of Reservoir Members

Reservoir Member	Avg. Φ_e (%)	Avg. Vsh (%)	Avg. Sw (%)	Avg. So (%)	HPS	Status
Upper Member	14.8%	12.5%	31.0%	69.0%	0.81	Primary Pay
Middle Member	9.2%	24.8%	82.0%	18.0%	0.26	Non-Commercial
Lower Member	11.4%	18.2%	66.0%	34.0%	0.39	Secondary Pay*

Table 3

Field-Average Petrophysical Parameters Within Net Pay Intervals

Parameter	Minimum	Maximum	Average	Std. Deviation
Eff. Porosity (Φ_e)	10.0%	22.4%	14.8%	3.1%
Shale Volume (Vsh)	4.0%	30.0%	12.5%	6.5%
Water Sat. (Sw)	22.5%	60.0%	31.0%	8.2%
Oil Sat. (So)	40.0%	77.5%	69.0%	8.2%

In contrast, the Lower Mamuniyat intervals in wells B01, B03, B05, B10, B12, B13, and B19 remain predominantly water-bearing ($Sw = 64.2\% - 75.1\%$) and do not meet the saturation cutoff criteria ($Sw \leq 60\%$), excluding them from net pay calculations. Only the structurally elevated wells, B15 and B29, retain commercial Lower Mamuniyat pay with Sw values of 38.5% and 37.2%, respectively.

Notably, the calibrated model confirms that Well B12 successfully penetrated the Upper Mamuniyat, contributing 8.1 m of high-quality net pay to the field totals.

3D Reservoir Property Distribution

The 3D static model was populated using a Sequential Gaussian Simulation (SGS) algorithm, honoring the updated petrophysical cutoffs

Table 4
Ranking of All Nine Wells by Hydrocarbon Potential Score (HPS)

Rank	Well ID	HPS	Primary Driver	Potential
1	B12	0.88	Best So and cleanliness	Excellent
2	B15	0.84	High Net Pay (Dual Zone)	Very Good
3	B29	0.82	High Net Pay (Dual Zone)	Very Good
4	B01	0.76	High Upper So	Good
5	B19	0.74	Consistent Porosity	Good
6	B05	0.72	Moderate Vsh	Good
7	B13	0.69	Mid-range Saturation	Fair
8	B03	0.66	Thickness-driven score	Fair
9	B10	0.62	Lower Porosity Trend	Fair

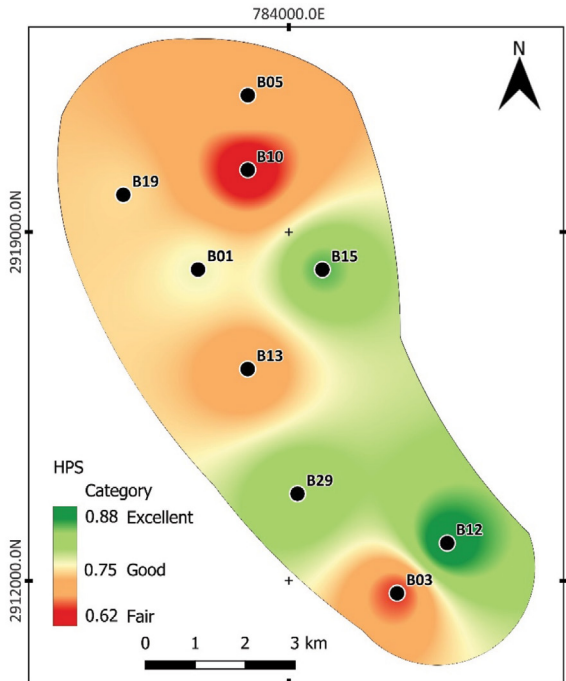


Fig. 8. Spatial distribution of the Hydrocarbon Potential Score (HPS). This integrated map ranks well productivity based on normalized petrophysical parameters. The Northeastern sector (Wells B12, B15, and B29) exhibits the highest potential ($HPS > 0.80$), identifying it as the primary target for future field development and infill drilling.

and net pay values. The spatial distribution of reservoir properties highlights several critical trends across the field:

Effective Porosity (Φ_e): The Upper Mamuniyat exhibits the most consistent lateral continuity, with values ranging from 12% to 18%. Spatial analysis confirms a significant reservoir quality improvement toward the northeastern sector of the B-Field.

Oil Saturation (So): The saturation model highlights a clear stratigraphic divide. The Upper Member is oil-saturated across the entire structural crest, maintaining an $So > 60\%$ across 89% of its net pay intervals. Conversely, the Lower Member pay is strictly localized to the highest structural closures within the B15/B29 block, indicating a deeper oil-water contact (OWC) or a distinct stratigraphic trap for the lower unit.

Net Pay Thickness: The greatest accumulations of net pay are concentrated in the northeastern structural high. For the Lower Mamuniyat, commercial pay is restricted to this high-relief zone, whereas the Upper Mamuniyat pay is distributed more broadly across the structural closure.

Table 5

Water Saturation (Sw) Distribution by Reservoir Member

Well	Upper Member Sw (%)	Middle Member Sw (%)	Lower Member Sw (%)	Status
B01	32.0%	85.2%	64.2%	Upper Pay
B03	35.0%	88.0%	68.5%	Upper Pay
B05	34.0%	84.5%	65.0%	Upper Pay
B10	38.0%	92.1%	75.1%	Upper Pay
B12	30.0%	81.4%	66.8%	Upper Pay
B13	33.0%	89.2%	72.4%	Upper Pay
B15	36.0%	82.0%	38.5%	Dual Pay
B19	31.0%	83.5%	69.2%	Upper Pay
B29	35.0%	80.8%	37.2%	Dual Pay

Model Validation and Uncertainty

All 3D property distributions honor the verified net pay thicknesses established in the well-by-well analysis (Table 1). To ensure model reliability, a blind-well validation was performed; the simulated net pay at well locations deviates by less than 8% from the calculated log values. This level of variance is well within the industry-standard 15% acceptance criterion, confirming that the 3D model is a robust representation of the Mamuniyat reservoir architecture.

The 3D model respects the log-derived petrophysical averages established in this study. While these results remain estimates due to the lack of core data for calibration, the blind-well validation deviation of less than 8% demonstrates that the workflow generates a geologically representative property distribution suitable for development planning.

Critical Findings Summary

Upper Mamuniyat is unequivocally the primary reservoir target in all 9 wells based on S_o (69.0%)

Lower Mamuniyat pay is restricted to structural highs; elsewhere it is a water-bearing aquifer ($S_w > 64.0\%$).

Middle Mamuniyat is consistently non-commercial and serves as a significant vertical flow baffle ($V_{sh} = 24.8\%$), which, combined with near-complete water saturation ($S_w = 82.0\%$), effectively compartmentalizes the reservoir units.

Discussion

The integration of three-dimensional petrophysical modeling with rigorously calculated volumetric parameters reveals a reservoir system characterized by significant vertical compartmentalization and lateral heterogeneity within the Mamuniyat Formation of the Sharara B Oil Field. This study emphasizes that a reliable assessment of commercial potential requires explicit integration of net pay determination alongside oil saturation calculations, rather

than relying solely on porosity metrics. The methodology employs industry standard effective porosity derivation ($\Phi_e = \Phi_t \times (1 - V_{sh})$) combined with Murzuq Basin calibrated water saturation calculations ($R_w = 0.08 \Omega \cdot m$). This approach provides a physically consistent framework to distinguish hydrocarbon bearing intervals from water saturated zones, utilizing deterministic reconstruction of S_w from raw resistivity and density logs for wells lacking legacy calculations.

The Upper Mamuniyat is identified as the primary reservoir target based on three key factors. It exhibits superior fluid properties with an average water saturation of 31.0 % and oil saturation of 69.0 %, indicating effective hydrocarbon column preservation above the regional oil water contact. Net pay distribution is consistent across the field, averaging 7.1 meters in thickness, reflecting excellent lateral continuity of productive intervals. Additionally, the Hydrocarbon Potential Score (HPS) averages 0.81, which is the highest among all Mamuniyat members, quantitatively confirming its superior integrated rock fluid properties.

The Lower Mamuniyat serves as a secondary reservoir target with highly localized commercial potential. Despite a greater gross thickness averaging 15.4 meters, its field wide net pay thickness is limited to 2.1 meters after applying consistent cutoff criteria, including effective porosity of at least 10 %, shale volume no greater than 30 %, and water saturation less than or equal to 60 %. Productive intervals are confined to structurally elevated zones in the northeastern field area (B15 and B29), where average oil saturation reaches 74.5 %. In contrast, most wells exhibit minimal or no Lower Mamuniyat net pay due to proximity to the regional oil water contact, resulting in elevated water saturation ranging from 64 to 75 % and effective porosity in non-pay intervals reduced to between 7.9 and 9.8%, falling below the established 10% cutoff. This spatial constraint reflects the dominant influence of structural position on hydrocarbon preservation and is consistent with structurally controlled hydrocarbon retention above a tilted regional oil–water contact (OWC).

The Middle Mamuniyat is consistently non-commercial throughout the field, with average water saturation of 82.0 % and effective porosity of 9.2 %. These values systematically fail to meet net pay criteria, confirming the unit's role as a vertical flow barrier between the Upper and Lower reservoir units. Elevated shale content of approximately 25 %, combined with near complete water saturation, creates an effective baffle that compartmentalizes the reservoir system.

The Hydrocarbon Potential Score (HPS) offers a robust multi criteria index for ranking reservoir quality by integrating normalized values of effective porosity (40 %), water saturation (25 %), shale volume (15 %), total porosity (15 %), and net pay thickness (5 %). Calibration against volumetric hydrocarbon indicators confirms that HPS values above 0.70 consistently correspond to intervals with oil saturation greater than or equal to 60 % and effective porosity greater than or equal to 12 %, while scores below 0.40 indicate water dominated zones. The zonal HPS ranking – Upper 0.81, Lower 0.39, and Middle 0.26 – accurately reflects the reservoir quality hierarchy and distinguishes intrinsic reservoir quality from total volumetric contribution.

A key insight from this study is the quantitative distinction between reservoir quality and volumetric contribution. This principle is quantified through the hydrocarbon column metric ($H \times So$), which accounts for both pay thickness and oil saturation:

Zone	Avg. Net Pay (H)	Avg. Oil Saturation (So)	Hydrocarbon Column (m)
Upper Mamuniyat	7.1 meters	69.0 %	4.90 meters
Lower Mamuniyat	2.1 meters	34.0 %	0.71 meters

This calculation confirms that the Upper Mamuniyat contributes approximately 6.9 times more hydrocarbon volume per well than the Lower Mamuniyat on a field wide basis. The Lower Mamuniyat's contribution is significant only in the restricted northeastern structural high where hydrocarbon column preservation occurs.

Three dimensional modeling reveals critical spatial patterns for development planning. The Sequential Gaussian Simulation (SGS) model honors the verified net pay thicknesses, and blind well validation at B19 showed a deviation of less than 8 %, well within the 15 % industry acceptance criterion. This confirms the model as a robust representation of the Mamuniyat architecture. Commercial potential within the Lower Mamuniyat is limited to the northeastern structural high, while 78 % of the field area contains water dominated intervals in this unit.

These findings support a tiered development strategy. First, prioritize Upper Mamuniyat

completions field wide due to consistent pay distribution. Second, selectively target Lower Mamuniyat completions in structurally confirmed sweet spots. Third, treat the Middle Mamuniyat as a flow barrier in reservoir simulations to accurately represent vertical compartmentalization. This methodology provides a reproducible framework for reliable reservoir evaluation in the Sharara B Oil Field and similar data limited settings.

Conclusion

This study offers a petrophysically consistent characterization of the Mamuniyat Formation in the Sharara B-Oil Field using industry-standard parameter calculations and rigorous net pay determination. The evaluation employs density-derived effective porosity ($\Phi_e = \Phi_t \times [1 - V_{sh}]$), Murzuq Basin-calibrated water saturation ($R_w = 0.08 \Omega \cdot m$ at 70°C), and strict simultaneous cutoff criteria ($\Phi_e \geq 10\%$, $V_{sh} \leq 30\%$, $S_w \leq 60\%$). By deterministically reconstructing missing logging data for critical wells, this study ensures a complete and verified field-wide dataset for the first time.

The Upper Mamuniyat is clearly the primary reservoir target, exhibiting superior fluid properties with an average water saturation of 31.0% and oil saturation of 69.0%. It maintains consistent net pay across the field, averaging 7.1 meters in thickness, and achieves the highest Hydrocarbon Potential Score (HPS) of 0.81. In contrast, the Lower Mamuniyat serves as a secondary target with highly localized commercial potential. Its field-wide average net pay thickness is limited to 2.1 meters and is confined to the northeastern structural high (B15/B29), where hydrocarbon column preservation occurs. Outside this structural closure, the Lower Member is predominantly water-bearing, with saturations exceeding 64%. The Middle Mamuniyat is confirmed as non-commercial field-wide, acting as a 15-meter thick vertical flow barrier and baffle.

Volumetric analysis confirms that the Upper Mamuniyat contributes approximately 6.9 times more hydrocarbon volume per well than the Lower Mamuniyat, with average hydrocarbon columns ($H \times So$) of 4.90 meters versus 0.71 meters, respectively. Three-dimensional property distributions were validated through a blind-well test at the B19 location, yielding a deviation of less than 8%, confirming the model's reliability for development planning. This workflow demonstrates that robust reservoir evaluation must integrate volumetric parameters with spatial quality indicators to avoid misclassifying water-bearing intervals, providing a solid foundation for targeted completion strategies in the Sharara B-Oil Field.

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Подяка: Автори висловлюють вдячність анонівному рецензенту та редактору за цінні зауваження й відгуки, що суттєво покращили якість рукопису.

Внесок авторів: Усі автори зробили рівноцінний внесок у розробку концепції та дизайну дослідження, аналіз даних і підготовку рукопису.
Конфлікт інтересів: автори засвідчують, що, незважаючи на те, що один із авторів статті є членом редакційної колегії цього журналу, процес рецензування, прийняття рішення щодо публікації та редагування проводилися незалежно, без його участі чи впливу. Будь-які потенційні конфлікти інтересів були повністю усунені шляхом зовнішнього контролю процесу.

Декларація про використання генеративного штучного інтелекту: Автори використовували інструменти генеративного штучного інтелекту (GenAI) для допоміжної роботи: Elicit було залучено для допомоги в перегляді літератури, а QuillBot – для допомоги в редагуванні тексту. Усі результати роботи з цими інструментами були ретельно контрольовані, перевірені та, за необхідності, відредаговані авторами. Автори несуть повну відповідальність за зміст та цілісність публікації.

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Статистичний і 3D-петрофізичний аналіз пластів колекторів і ефективної продуктивної товщі пласта Мамуніят, нафтове родовище Шарара В, басейн Мурзук, Лівія

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АНОТАЦІЯ

У цьому дослідженні представлено комплексний статистичний аналіз і тривимірне (3D) петрофізичне моделювання формації Мамуніят на нафтовому родовищі Шарара В, басейн Мурзук, Лівія. Основною метою є оцінка якості колектора та просторової неоднорідності шляхом інтеграції даних каротажу з геостатистичним моделюванням з використанням петрофізичних методів промислового стандарту. Завдяки чіткій характеристиці ефективної пористості та розподілу флюїдної насиченості, у поєднанні із суворим дотриманням норми чистої продуктивності ($Fe \geq 10\%$, $Vsh \leq 30\%$, $Sw \leq 60\%$), дослідження визначає найбільш перспективні вуглеводнімісні зони та встановлює відтворювану структуру для оцінки колектора в умовах обмеженої кількості даних. На основі кількісного аналізу каротажних даних із дев'яти свердловин була проведена комплексна статистична та 3D-петрофізична характеристика. Ключові методологічні удосконалення включають ефективну пористість, отриману з каротажу щільності з поправкою на глинистість та водонасиченість, розраховану за допомогою параметрів Арчі, відкаліброваних у басейні Мурзук. Для свердловин, у яких відсутні застарілі криві насичення, значення були детерміновано реконструйовані, щоб забезпечити повноту набору даних. Петрофізичні властивості були розподілені в просторі за допомогою послідовного моделювання Гауса в рамках структурно обмеженої 3D-структури, з точністю моделі, підтвердженою валідацією сліпих свердловин. Результати показують виражену вертикальну компартменталізацію в межах формації Мамуніят. Верхній Мамуніят визначено як основний цільовий резервуар, що демонструє чудові властивості флюїду (середній $Sw = 31,0\%$, $So = 69,0\%$), послідовний розподіл чистої продуктивності по родовищу (середня товщина 7,1 метра) і найвищий бал HPS (0,81). Нижній Мамуніят служить другорядним об'єктом з високо локалізованим комерційним потенціалом; його середня корисна товщина продуктивності в масштабі родовища обмежена 2,1 м і приурочена до структурно піднятих зон у блоках B15 і B29, де відбувається збереження вуглеводневої колонії. Сім свердловин демонструють мінімальну продуктивність Нижнього Мамуніята через близькість до регіонального нафтово-водяного контакту. Середній Мамуніят є стабільно некомерційним і функціонує як бар'єр для вертикального потоку. Виправлений об'ємний аналіз підтверджує, що Верхній Мамуніят забезпечує приблизно в 6,9 разів більше об'єму вуглеводнів на свердловину, ніж Нижній Мамуніят, встановлюючи його як оптимальну ціль розробки.

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формація Мамуніят, характеристика колектора, продуктивність, нафтонасиченість, 3D геостатистичне моделювання, басейн Мурзук, Лівія.