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Petrophysical Evaluation of Reservoir Quality from Well Logs of the Sokor-1 Formation, Termit Basin, Southeastern Niger

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ABSTRACT: This study presents petrophysical analysis of the Sokor-1 Formation, Termit Basin, Southeastern Niger, using well log data from six wells to assess reservoir quality and hydrocarbon potential. Five sand groups (E-1 to E-5) were analyzed for net-to-gross ratio (NTG), shale volume (Vsh), porosity (Φ), permeability (K), and hydrocarbon saturation (Sh). The results indicate clear variations in reservoir properties across sand groups and wells. E-1 exhibits the highest reservoir quality, with high porosity (27–33%), low to moderate shale content (10–19%), high permeability (up to 208 mD), and high hydrocarbon saturation (up to 56%), reflecting well-developed fluvial channel sandstones. E-2 and E-3 show moderate and heterogeneous reservoir characteristics, with NTG and permeability strongly influenced by shale content and depositional heterogeneity. E-4 contains very clean sandstones with moderate connectivity, while E-5 shows consistent reservoir properties across wells, with good NTG, porosity, and hydrocarbon saturation. These variations highlight the influence that could have depositional facies and diagenetic processes on reservoir storage and fluid flow in the Sokor-1 Formation. The study demonstrates that integrated petrophysical analysis provides a reliable framework for assessing hydrocarbon potential and guiding exploration in heterogeneous sand-dominated systems.

KEYWORDS: Fana low uplift, Sokor-1 Formation, Petrophysical analysis, Reservoir quality.

1 INTRODUCTION

Hydrocarbons are commonly found in sandstone, carbonate, and shale formations, as well as basement (Ezekwe, 2010). The reservoir rocks that contain oil and gas accumulations are broadly sandstones and carbonates (Ezekwe, 2011; Dandekar, 2013; Ganat, 2019). Rift basins are well known as prolific hydrocarbon-bearing provinces worldwide (Lambiase and Morley, 1999).

The West and Central African Rift System (WCARS) is a typical intracontinental Cretaceous-Paleogene rift system (Fig. 1a). Strike-slip and extensional basins were formed mainly by the mechanical separation of the African crustal block during the Early Cretaceous on Precambrian crystalline and metamorphic basement (Fairhead, 1988; Binks and Fairhead, 1992; Guiraud and Maurin, 1992; Genik, 1993; Fairhead et al., 2013). Rifting was stronger in the Early Cretaceous and Paleogene and weaker in the Late Cretaceous (Dou *et al*., 2007). Oil pay zones include the Lower Cretaceous strata in the Doba and Doseo Basins in Chad, Muglad Basin in Sudan, Upper Cretaceous in the Muglad Basin of Sudan, in the Doba Basin of Chad, and in the Termit Basin of Niger, and Paleogene in the Termit Basin of Niger and Melut Basins of Sudan (Dou *et al*., 2007; Mahgoub et al., 2016). Structurally complex reservoirs form a distinct class of reservoir in which fault arrays and fracture networks, in particular, exert an overriding control on petroleum trapping and production behavior (Sorkhabi & Tsuji, 2005). It is essential to fully understand the reservoir properties, including porosity, the thickness of the water-saturated zone, and the extent of the reservoir, to assess recoverable hydrocarbons (Schlumberger, 1989). These factors are critical because they form the basis for reservoir volumetric analysis, which is used to measure the quantity of hydrocarbons present (Edwards & Santogrossi, 1990). The primary reservoirs are in the Sokor-1 Formation, mostly sandstones, which host significant hydrocarbon reserves in the Termit Basin (Liu et al., 2015, 2017). Fu and Sun (2012) addressed the study of sequences, stratigraphy, and sedimentary systems of the Paleogene. Study of Cretaceous Sequential Stratigraphy and Sedimentary Systems in the Termit Basin of West Africa (Tang et al., 2015). Chang and

Zung (2017) studied Eocene Sokor-1 Reservoir Characterization of the Formation and 3D Characterization; Nasaruddin et al. (2017) studied the petrophysical analysis of the E5 sand group of Sokor-1 Formation; Diagenesis and reservoir quality evolution of the Paleogene Sokor-1 Formation were carried out by Hamma and Harouna (2019). Well-Based Quantitative Reservoir Characterization of the Eocene Sokor-1 Formation and rock physics studies have been done by Amadou et al. (2021a). Hamma et al. (2022) investigated the Effect of Oil in Place on Sandstone Reservoir Quality of Dibeilla Prospect. Ari et al. (2024) characterized the reservoir fluid of the Sokor1 Formation, Fana tectonic unit. Prospect evaluation of the Paleogene Sokor-1 reservoirs in Fana Field, Termit Basin, using geophysical well logs and sedimentological data was conducted by Issaka et al. (2024). Limited studies on sand group reservoir properties and unreliable shale volume estimates hinder reservoir assessment in the Fana area, necessitating a focused evaluation of petrophysical parameters. This paper aims to evaluate the petrophysical properties from well logs analysis of the Sokor-1 Formation in the Fana Low Uplift, Termit Basin, southeastern Niger (Fig. 1b).

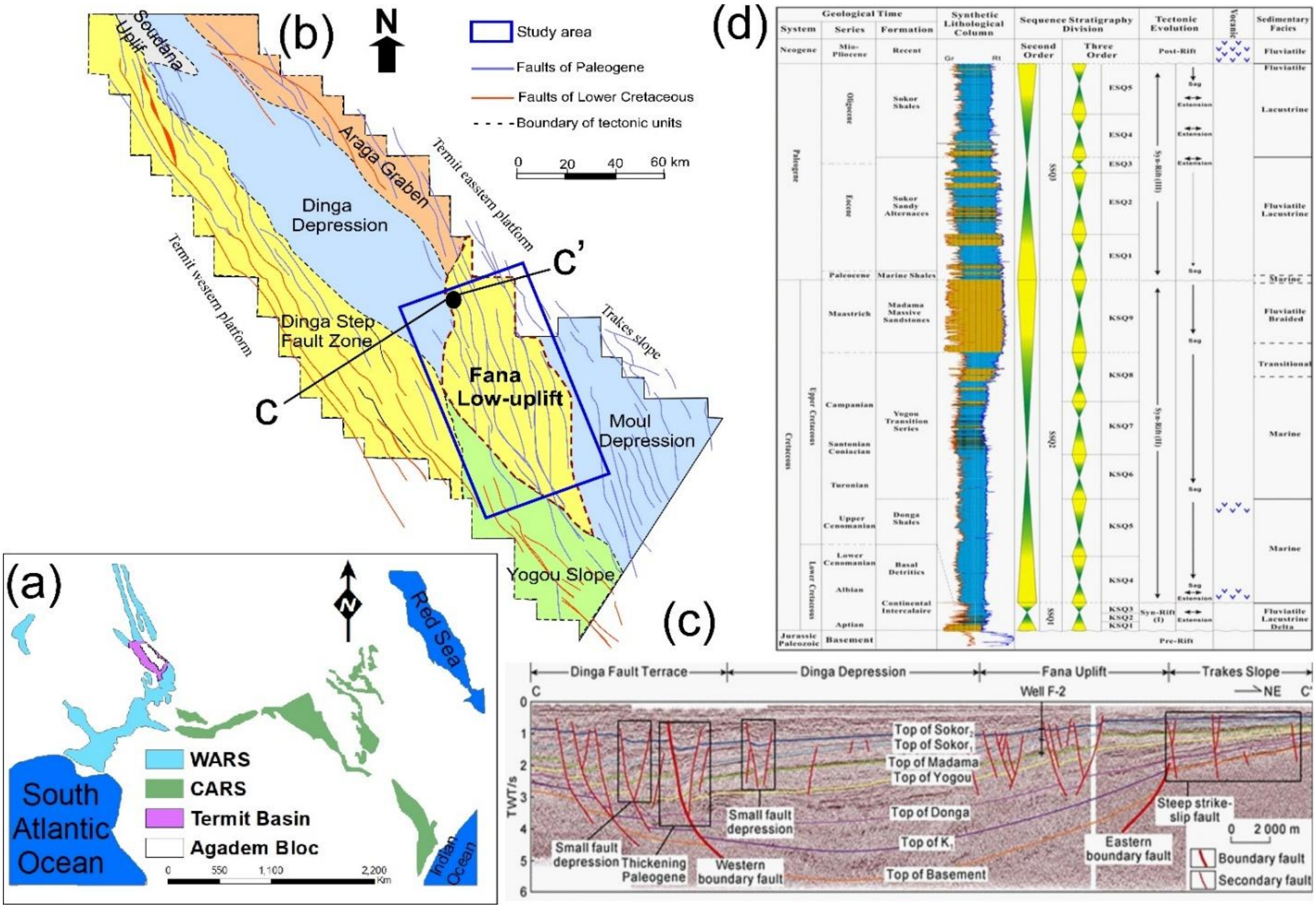

Fig. 1. (a) Map of West and Central African rift system with the location of Termit Basin (Genik, 1993); (b) Structural unit division of the Termit Basin with study area location; (c) Stratigraphic column of the Termit Basin (CNPC, 2012); (d) Seismic section in the central Termit Basin (Wang et al., 2022)

2 GEOLOGICAL OVERVIEW

The study area is located in the Agadem oil block, where the Fana low uplift separates the Dinga and Moul depressions (Fig. 1b), which are important source-rock areas (CNPC, 2012; Mao et al., 2019; Lai et al., 2019). This rift system formed from the breakup of Gondwana and the opening of the Atlantic and Indian Oceans in the early Cretaceous (Fairhead, 1986; Genik, 1993; Zanguina et al., 1998). Termit Basin evolved through multiple tectonic phases from the Pan-African to the Neogene (Fig. 1c). Two types of fault systems control this basin (Fig. 1c): the first is a NW-SE-trending fault, corresponding to Lower Cretaceous faults that were reactivated during the Paleogene, while the second is a NNE-SSE-trending fault, which is recent and formed during the Paleogene (Wang et al., 2022). The Precambrian to Jurassic crystalline basement of the Termit Basin (Fig. 1d) is unconformably overlain by a sedimentary succession, ranging from the early Cretaceous to the Quaternary (Zanguina et al., 1998). These formations are of continental and marine origin. They consist mainly of mudstone, sandstone, shale, siltstone, and sand (Wan et al., 2014; Lai et al., 2018).

Most petroleum was generated from the Upper marine source rocks of the Yogou Formation, which are in the early to mid-maturity stages, while the Donga source rocks are mature to over-mature. The Upper Cretaceous sandstones of the Madama formation constitute secondary reservoirs in the Termit Basin (Genik, 1993; Zanguina et al., 1998; Harouna & Philp, 2012; Wan et al., 2014; Liu et al., 2015, 2017; Lihong et al., 2017; Hamma et al., 2023; Ari et al., 2025). The Sokor-1 source rocks are thermally mature to immature, whereas those of Sokor-2 are thermally immature in most areas (Harouna et al., 2012; Wan et al., 2014; Hamma et al., 2023). The oil discoveries from the Termit Basin mainly occur in the Sokor-1 reservoirs (Genik, 1993; Harouna and Philp, 2012; Xiao et al., 2019). The Sokor-1 Formation is divided into five distinct sand groups, E1-E5 sand groups. Each sand group contains reservoir units mostly sandstones interbedded with mudstones (Hamma & Harouna, 2019; Ari et al., 2024). The thick mudstones of the Sokor-2 Formation (Fig. 1) represent the regional seal for the Sokor-1 reservoirs (Genik, 1993; Wan et al., 2014; Hamma and Harouna, 2019; Wang et al., 2022). Neogene sediments are dominated by quartz- and feldspar-rich fluvial sandstones interbedded with mudstones and occasional gravels, unconformably overlying the Paleogene (Fig. 1). Quaternary deposits are primarily aeolian sands (CNPCNP, 2012).

3 Dataset And Methods

3.1 Dataset

The data used in this study are the wireline logs from the Sokor-1 Formation. These data from six wells, F-1 to F-6, include gamma-ray (Gr), resistivity (LLD), neutron, and density logs. The NW-SE-oriented wells (Fig. 2) are in the Fana low uplift tectonic unit in the Agadem oil block, Termit Basin (Fig. 1).

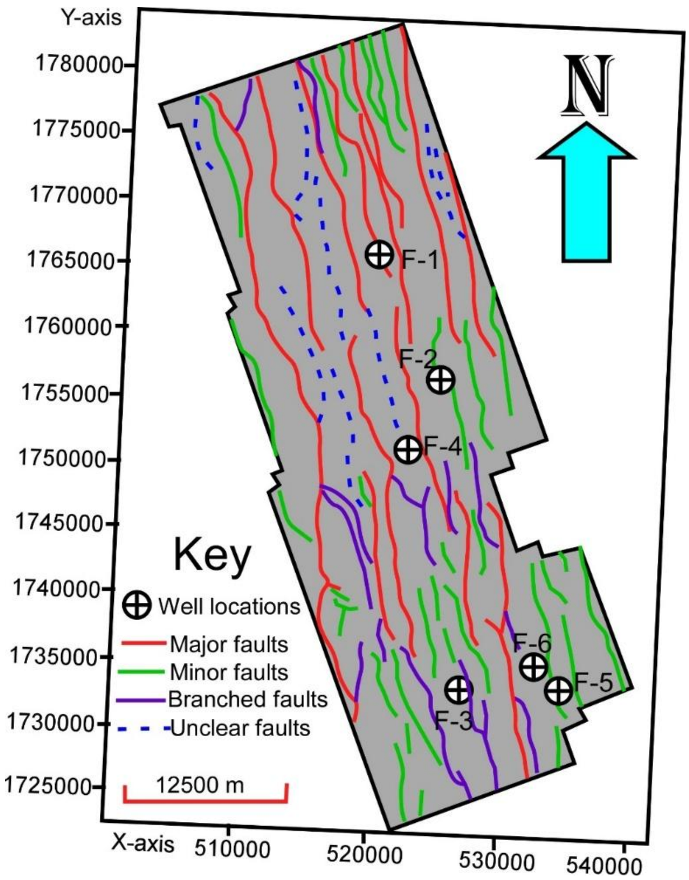

Fig. 2. Wells locations within the Fana field

3.2 Methods

Reservoir units from the Sokor-1 Formation were differentiated from non-reservoirs by using the gamma-ray logs combined with resistivity, neutron, and density logs (Asquith and Gibson, 2004; Darling, 2005; Cannon, 2016). Standard petrophysical interpretation techniques were used to evaluate the reservoir petrophysical properties of the wells. In this work, the parameters determined are net-to-gross, volume of shale (Vsh), porosity (Φ), permeability (k), water saturation (Sw), and hydrocarbon saturation (Sh).

The net-to-gross (NTG) ratio is an essential parameter of a reservoir because it reflects the degree of cleanness of the reservoir. A gamma-ray log is used to determine gross reservoir thickness and net reservoir thickness (Bate et al., 2023), as illustrated below by the following formulas.

Gross sand thickness (GST) = Base of sand - Top of sand (1)

Net sand thickness (NST) = Gross sand thickness –shale thickness (2)

Net-to-gross (NTG) $=\frac{NST}{GST}$ (3)

The shale volume (Vsh) was calculated using the Larionov formula, as the Sokor-1 Formation is a Tertiary sedimentary rock.

$Vsh=0.083*(2^{3.7*IGR}-1)$ (4)

$I_{GR}=\frac{GRlog-Grmin}{GRmax-GRmin}$ (5)

Where:

I_{GR} = Gamma-ray index; GRlog = Gamma-ray log reading in the zone of interest; GRmax = Maximum gamma-ray reading for the shale; GRmin = Minimum gamma-ray reading for the clean sand.

The total porosity was calculated from density logs using the density of the matrix value of 2.65 gm/cc and the density of the fluid as derived from the neutron/density cross plot. The effective porosity was deduced by including the volume of shale in the total porosity using the following equations.

Total porosity $(\Phi T)=\frac{\rho ma-\rho b}{\rho ma-\rho f}$ (6)

Total porosity of shale $(\Phi Tsh)=\frac{\rho ma-\rho sh}{\rho ma-\rho f}$ (7)

Effective porosity $(\Phi E)=\Phi t-(\Phi Tsh*VSh)$ (8)

Where:

ρma= density of the matrix; $\rho b =$ bulk density; $\rho f = fluid\ density.$

The permeability values in this work were deduced using the formula below, established by Tixier (1949).

$K=\left[\frac{250*\Phi 3}{Swir}\right]^2$ (9)

Where:

K=permeability (mD); Swir=Irreducible water saturation (%); ΦT=Total porosity (%).

The Schlumberger method below is used to calculate the irreducible water saturation, Swir.

Irreducible water saturation (Swir) = $(F/200)^{1/2}$ (10)

Obtaining a reliable estimation of water saturation requires several empirical relationships; these relationships were established in a series of experiments undertaken by Archie (1942) using the following formula.

Water saturation (Sw) $=\sqrt[n]{\frac{Rw.F}{Rt}}$ (11)

Where:

Sw=the water saturation; a=the tortuosity factor; Rw represents the degree of water resistivity; Rt=the true resistivity of the hole; F = the formation factor; n = lithology-dependent factor.

Hydrocarbon saturation (Sh) is calculated from water saturation by the following equation.

Hydrocarbon saturation (Sh) =1-Sw (12)

4 RESULTS AND INTERPRETATION

4.1 PETROPHYSICAL PROPERTIES OF THE RESERVOIRS

The petrophysical evaluation of reservoir units of the E-1 to E-5 sand groups across wells F-1 to F-6 reveals significant variations in reservoir quality in terms of net-to-gross ratio (NTG), shale volume (Vsh), porosity (Φ), permeability (K), and hydrocarbon saturation (Sh) (Table 1).

The net-to-gross ratio (NTG) ranges from 0.34 in well F-4 to 0.88 in well F-2. The high NTG observed in well F-2 suggests a thick proportion of reservoir-quality sandstone, whereas the lower value in well F-4 indicates a relatively thinner net reservoir interval. The shale volume (Vsh) varies from 9.9% in well F-3 to 19.3% in well F-1, reflecting moderate clay content across the wells. Lower shale content in wells such as wells F-2 and F-3 indicates cleaner sandstone intervals that are favorable for reservoir development. Porosity (Φ) ranges from 27.55% in well F-5 to 33.3% in well F-2, indicating a very good pore storage capacity throughout the sand group. Permeability (K) varies widely, ranging from 54.08 mD in well F-6 to 208.09 mD in well F-3. Such high permeability values in some wells suggest well-sorted and highly connected pore networks. The hydrocarbon saturation (Sh) varies between 27.3% and 56.3%, with the highest value observed in well F-2, indicating significant hydrocarbon accumulation in this well. Overall, the variation in the E-1 sand group reservoir units indicates good reservoir quality but heterogeneous distribution of reservoir properties across wells.

Table 1. Petrophysical properties of the sand group reservoirs of the studied wells F-1 to F-6

Wells name	Reservoir units	NTG	Vsh (%)	Φ (%)	K (mD)	Sh (%)
F-1	E-1	0.50	19.30	30.00	88.90	27.30
F-2	E-1	0.88	12.40	33.30	198.77	56.30
F-3	E-1	0.73	9.90	28.00	208.09	53.95
F-4	E-1	0.34	11.90	31.00	72.13	37.30
F-5	E-1	0.52	18.70	27.55	54.33	35.70
F-6	E-1	0.46	13.65	29.85	54.06	36.10
Average values		0.57	14.31	29.95	112.71	41.11
F-1	E-2	0.31	20.23	27.70	61.63	27.57
F-2	E-2	0.72	14.70	31.45	83.36	38.15
F-3	E-2	0.32	11.40	28.50	56.95	38.80
F-4	E-2	0.25	8.65	28.60	60.63	37.45
F-5	E-2	0.69	10.75	31.05	159.21	52.05
F-6	E-2	0.06	8.90	32.60	67.69	22.10
Average values		0.41	0.41	29.60	81.07	36.50
F-1	E-3	0.46	16.70	28.35	79.10	32.65
F-2	E-3	0.68	5.80	30.25	92.72	39.10
F-3	E-3	0.60	3.60	26.80	52.82	35.10
F-4	E-3	0.64	8.50	29.25	53.15	30.05
F-5	E-3	0.18	25.40	27.80	17.27	30.00
F-6	E-3	0.36	6.90	29.65	55.22	26.55
Average values		0.5	0.50	29.00	63.10	32.20
F-3	E-4	0.50	1.70	24.80	46.93	39.40
F-4	E-4	0.28	3.20	28.60	55.37	26.20
Average values		0.17	0.17	26.70	13.82	32.80
F-3	E-5	0.66	7.60	24.90	39.67	38.70
F-4	E-5	0.61	13.50	29.90	50.55	33.50
Average values		0.65	0.65	26.60	43.29	37.00

Reservoir units in sand group E-2 also show considerable variability in petrophysical parameters between wells. The NTG values range from 0.06 in well F-6 to 0.72 in well F-2, indicating a strong variation in sandstone thickness across the study area. The shale volume varies between 8.65% and 20.23%, suggesting alternating sandstone and shale intervals. Higher shale content in some wells may reduce effective reservoir quality. The porosity values range from 27.7% to 32.6%, indicating good reservoir storage capacity across the wells. The permeability ranges from 56.95 mD in well F-3 to 159.21 mD in well F-5, reflecting differences in pore connectivity and possibly variations in grain sorting and diagenesis. The hydrocarbon saturation varies between 22.1% and 52.05%, indicating uneven hydrocarbon distribution across the sand group. Overall, the variation of reservoir properties in sand group E-2 reflects heterogeneous reservoir conditions probably controlled by lithological variability and shale distribution.

Sand group reservoir units E-3 exhibit moderate variability in petrophysical properties across wells. The NTG values range from 0.18 in well F-5 to 0.68 in well F-2, suggesting variations in the thickness and continuity of the reservoir sandstone bodies. The shale volume ranges from 3.6% in well F-3 to 25.4% in well F-5, indicating strong lithological heterogeneity. The low shale content in wells such as well F-2 and well F-3 suggests cleaner sandstone intervals. The porosity ranges between 26.8% and 30.25%, indicating consistently good storage capacity across the sand group. The permeability varies from 17.27 mD in well F-5 to 92.72 mD in well F-2, indicating moderate fluid flow potential but with significant variability. The hydrocarbon saturation ranges between 26.55% and 39.10%, suggesting moderate hydrocarbon presence. Overall, reservoir quality in sand group E-3 is strongly influenced by variations in shale content and sandstone distribution. In contrast, reservoir units in the E-3 sand group show relatively lower reservoir quality. Although the shale volume remains low (10.48%), the NTG decreases to 36.45%, indicating thinner or less continuous reservoir sands. The porosity remains relatively high at 29% (Table 1), but permeability decreases to 63.10 mD, suggesting moderate reservoir performance. Hydrocarbon saturation averages 32.20%, reflecting moderate hydrocarbon presence within the units.

Sand group E-4 is represented by wells F-3 and F-4 and shows relatively uniform petrophysical characteristics of reservoirs. The NTG values range from 0.28 in well F-4 to 0.50 in well F-3, indicating moderate reservoir development. The shale volume is very low, ranging between 1.7% and 3.2%, suggesting extremely clean sandstone intervals. The porosity varies from 24.8% to 28.6%, indicating good pore storage capacity. The permeability ranges between 46.93 mD and 55.37 mD, suggesting moderate reservoir connectivity. The hydrocarbon saturation varies between 26.2% and 39.4%, indicating moderate hydrocarbon accumulation. Overall, E-4 represents clean sandstones with moderate reservoir quality. Reservoir units within sand group E-4 exhibit the lowest NTG values (approximately 28%), suggesting limited reservoir thickness or lateral continuity. However, the shale content is very low (2.45%), indicating very clean sandstone intervals. The porosity averages 26.70%, while permeability is moderate (≈44 mD). Despite the relatively good porosity, the reduced NTG and permeability suggest that sand group E-4 reservoirs represent a moderately productive reservoir units.

Sand group E-5 also occurs in wells F-3 and F-4 and shows relatively consistent reservoir properties. The NTG values range between 0.61 and 0.66, indicating well-developed sandstone bodies. The shale volume ranges from 7.6% to 13.5%, suggesting moderate clay content. The porosity varies between 24.9% and 29.9%, reflecting good reservoir storage capacity. The permeability ranges from 39.67 mD to 50.55 mD, indicating moderate fluid flow potential. The hydrocarbon saturation varies between 33.5% and 38.7%, suggesting favorable hydrocarbon presence. Overall, E-5 shows relatively stable reservoir properties across wells, indicating a consistent depositional environment. The sand group E-5 has reservoir units that show relatively favorable characteristics, with a high NTG of 61.30% and a low shale volume of 9.60%, indicating well-developed reservoir sands. The average porosity is 26.60%, while permeability averages 43.29 mD, suggesting moderate fluid flow capacity. Hydrocarbon saturation values of approximately 37% indicate the presence of economically significant hydrocarbon accumulations.

4.2 Comparision Of Reservoir Properties Across Sand Groups Between Wells

Fig. 3 illustrates the comparison between reservoir properties in each sand group across wells. The net-to-gross ratio (NTG) shows relatively high values in wells F-2 and F-3, indicating thicker sandstone intervals and better reservoir development. In contrast, wells F-4 and F-5 display slightly lower NTG values, suggesting increased shale intercalation. The shale volume (Vsh) is generally low to moderate across the wells, but slightly elevated in wells F-1 and F-4, which may negatively influence reservoir quality by reducing effective pore connectivity. Porosity (Φ) values are moderate across most wells, with F-2 and F-3 showing slightly higher porosity, implying well-sorted sandstone with favorable pore space. A significant observation is the high permeability (K) in well F-3, which indicates efficient fluid-flow pathways likely associated with coarse-grained or better-sorted sandstone facies. Hydrocarbon saturation (Sh) remains moderate across the wells, suggesting the presence of hydrocarbons but with variable accumulation efficiency. Overall, the E-1 sand group reservoir units have moderate reservoir quality with localized zones of enhanced permeability, particularly around wells F-2 and F-3 (Fig. 3).

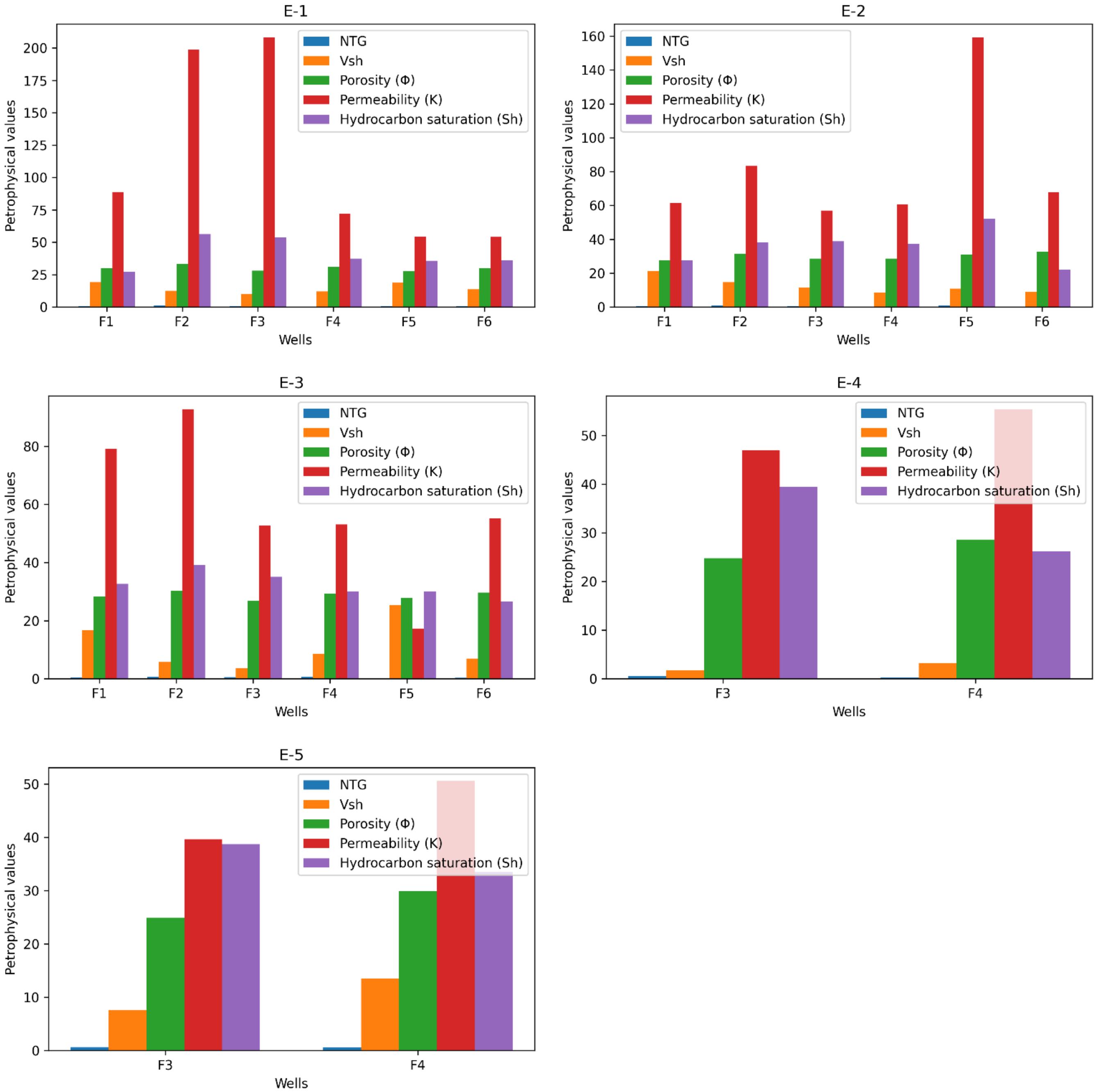

Fig. 3. Bar chart showing comparison of average petrophysical reservoir properties of the E-1 to E-5 sand groups, net-to-gross (NTG %), shale volume (vsh %), porosity (Φ%), permeability (K %), and hydrocarbon saturation (sh %), across wells

The reservoir units of the E-2 sand group demonstrate stronger heterogeneity in reservoir quality among the wells. The NTG values remain relatively high in wells F-3 and F-6, suggesting thicker reservoir sandstone intervals in these locations. The shale volume (Vsh) appears relatively low in most wells, particularly in wells F-2 and F-3, which supports improved reservoir quality in these areas. Porosity values increase slightly compared to those of the E-1 sand group (Fig. 3), with well F-3 again showing the highest porosity, indicating better pore development and storage capacity. A very prominent feature is the extremely high permeability observed in well F-5, which may indicate the presence of highly permeable channel sandstone facies or enhanced pore connectivity due to diagenetic dissolution. Hydrocarbon saturation is moderate to high across several wells, especially wells F-3 and F-6, suggesting favorable hydrocarbon accumulation in these zones. Overall, sand group E-2 likely has the most productive reservoir intervals, characterized by improved permeability and hydrocarbon saturation.

Fig. 3 shows moderate to high variability in reservoir properties among the six wells across sand group E-3. The net-to-gross ratio (NTG) is relatively high in wells F-3, F-4, and F-5, indicating thicker sandstone intervals and improved reservoir continuity. Conversely, wells F-1 and F-6 display lower NTG values, suggesting thinner reservoir sands or increased shale interbeds. The shale volume (Vsh) values remain generally low to moderate across the wells but appear slightly elevated in wells F-1 and F-5. Higher shale content may reduce reservoir quality by decreasing pore connectivity and effective permeability. Porosity (Φ) values are moderate across most wells, typically ranging between approximately 25–35%, which indicates relatively good storage capacity for hydrocarbons. Wells F-3 and F-4 appear to maintain slightly higher porosity values, suggesting better-developed pore networks. The permeability (K) values show significant variation across the wells. Wells F-1 and F-2 exhibit notably higher permeability compared with other wells, which may indicate coarser-grained sandstone facies or improved pore throat connectivity. In contrast, permeability is comparatively lower in well F-5, suggesting possible diagenetic cementation or finer sediment grain size. Hydrocarbon saturation (Sh) values are moderate across the wells but appear relatively higher in wells F-3 and F-5, indicating potential zones of hydrocarbon accumulation. Overall, the reservoir units of the E-3 sand group suggest heterogeneous reservoir quality, with wells F-3 and F-4 having relatively favorable reservoir characteristics due to higher NTG and porosity values (Fig. 3).

Fig. 3 compares reservoir properties of the E-4 and E-5 sand groups, highlighting lateral variations in reservoir quality. The NTG values remain relatively high in most well combinations, particularly in reservoir units of sand group E-5 across well F-4, indicating significant sandstone thickness in this area of the reservoir. The shale volume (Vsh) is generally low across the wells, suggesting limited shale intercalation and therefore favorable reservoir conditions. However, a slightly higher Vsh value is observed in sand group E-5 from well F-4, which may locally influence reservoir performance. Porosity (Φ) values remain moderate, indicating adequate pore space for hydrocarbon storage. The E-4 sand group reservoir units from well F-4 exhibit relatively higher porosity, suggesting improved reservoir storage capacity. The permeability (K) values are particularly high in sand group E-4 and E-5 from well F-4, indicating efficient fluid flow pathways likely associated with well-sorted or coarser-grained sandstone facies. Hydrocarbon saturation (Sh) shows moderate to high values in several well combinations, especially in the E-4 sand group reservoir units from well F-3, suggesting favorable hydrocarbon accumulation in these areas. Overall, the E-4 and E-5 sand groups indicate generally good reservoir quality, due to their high permeability and moderate to high hydrocarbon saturation.

The comparison of reservoir properties across sand groups E-3 to E-5 reveals significant lateral heterogeneity within the reservoir system. The petrophysical properties determined in these sandstone reservoir units show good to very good porosity and moderate to good permeability (Asquith and Gibson, 2004). These reservoirs in sand group E5 have lower petrophysical properties than reservoirs in sand groups E1 to E4. These reservoirs are found with the highest petrophysical properties (Hamma et al., 2022; Hassane et al., 2021b).

4.3 Spatial Distribution Of Reservoir Properties

The permeability values decrease from well F-3 to well F-5 (Fig. 4). The variation in porosity is not similar to that of permeability. This variation can be split into two parts (Fig. 4): on the one hand, it decreases from well F-2 to well F-3, and on the other, from well F-4 to well F-5. These variations corroborate those that have indicated the existence of a heterogeneous lithology, as indicated earlier by (Amadou et al., 2021b), which impacted distributions of reservoir quality. The shale volume decreased from well F-3 toward wells F-1 (Fig. 4). This trend is similar to that of permeability. The hydrocarbon saturation increased from wells F-1 and F-6 toward well F-2 (Fig. 4).

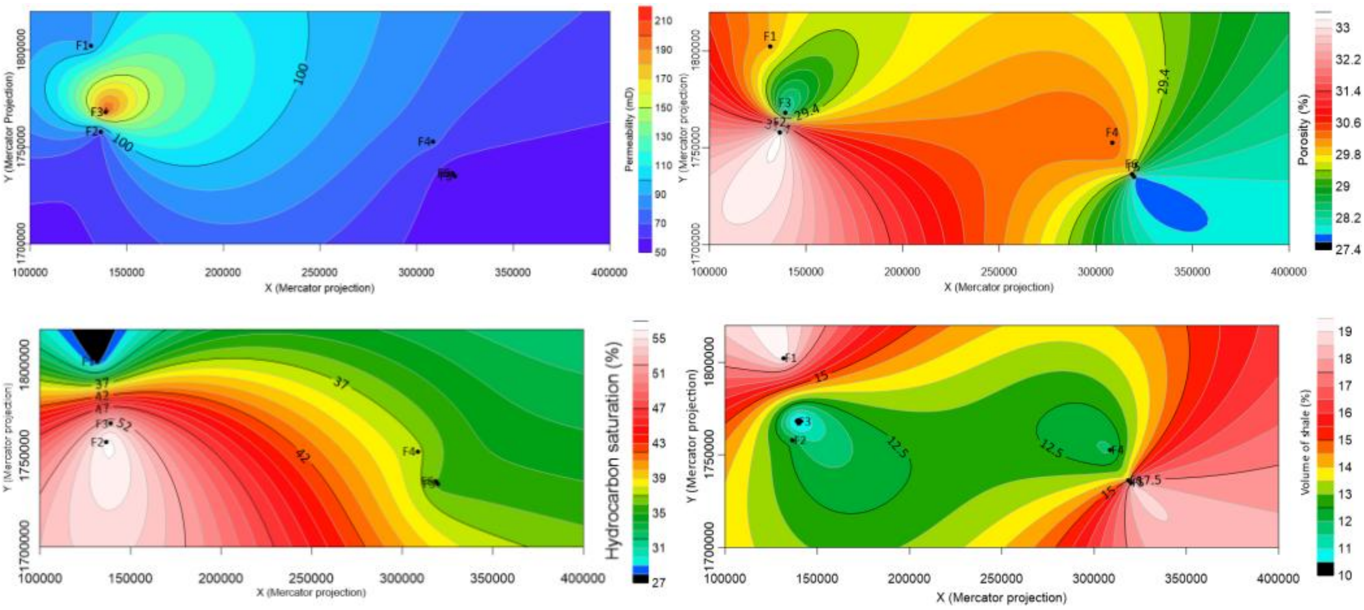

Fig. 4. Model of reservoir properties of the E-1 sand group of wells F-1-F-6

Fig. 5 showed that the porosity decreased from SE (well F-6) to NW (well F-1). In contrast, permeability increased from well F-6 toward F-1 (Fig. 5). Shale volume variation is similar to permeability variation. Hydrocarbon saturation is highest in the south-eastern section, from well F-1 to well F-6 (Fig. 5).

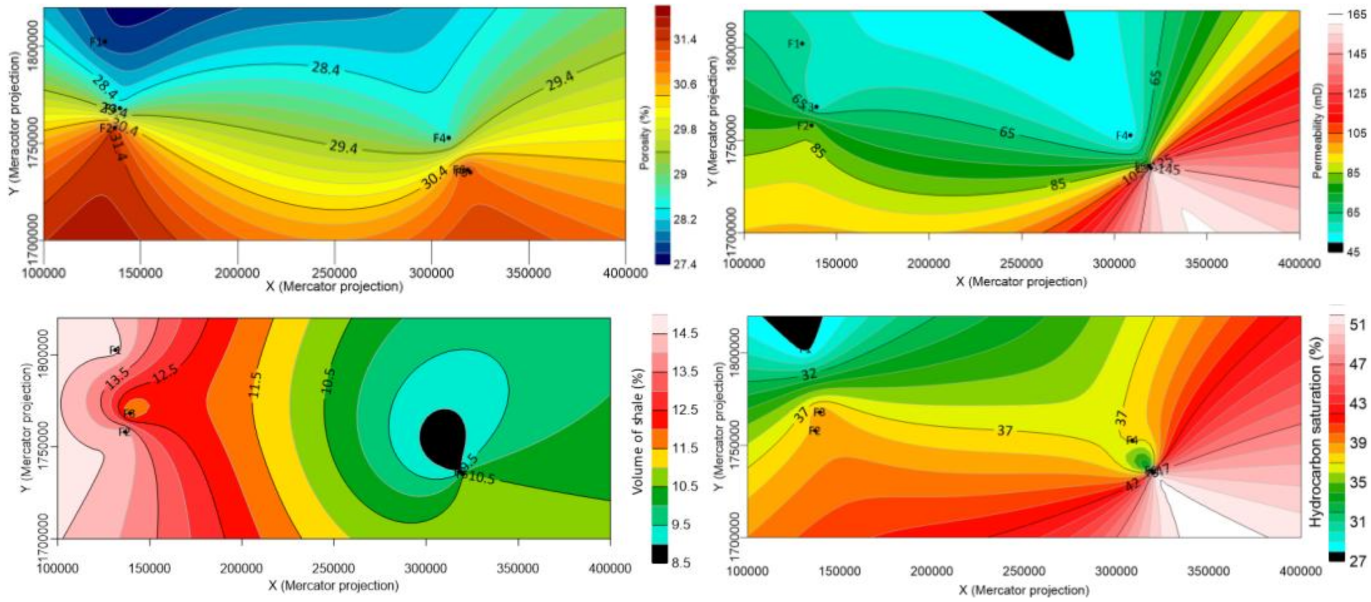

Fig. 5. Model of reservoir properties of the E-2 sand group of wells F-1-F-6

The porosity values increased from SW (well F-6) to NW (well F-3) (Fig. 6). Low permeability values are found to the southeast, towards well F-6. The highest permeability values are found in the north-west, towards well F-2. (Fig. 7). The shale content increased from well F-2 toward well F-6 (Fig. 6). The southeastern part is the most saturated with hydrocarbons (Fig. 6). These decreased from well F-5 to well F-1.

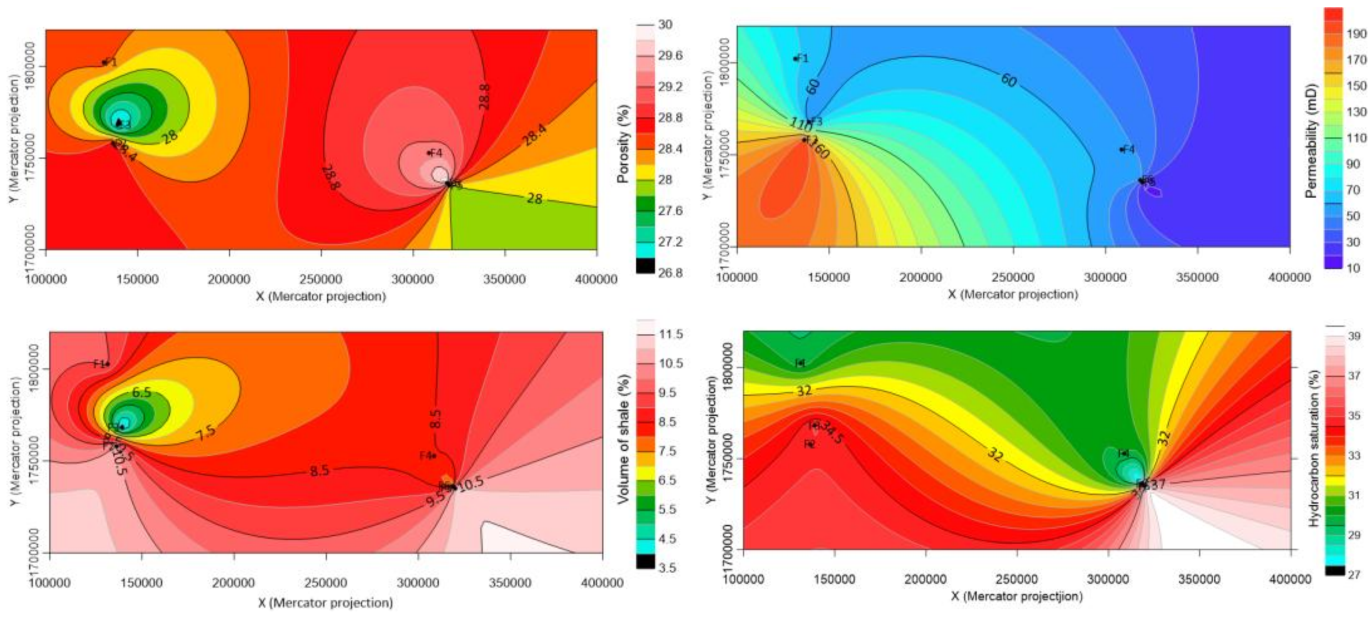

Fig. 6. Model of reservoir properties of the E-3 sand group of wells F-1-F-6

Two directions of porosity variation have been identified: that between wells F-1, F-2, and F-3 and that including wells F-4, F-5, and F-6 (Fig. 7). On the other hand, permeability decreases from northwest to southeast, from well F-1 to well F-5 (Fig. 7). The volume of shale increased from well F-3 to well F-5 (Fig. 7). The highest saturated reservoirs with hydrocarbons are in the northwestern part, increasing from well F-5 to F-1 (Fig. 7).

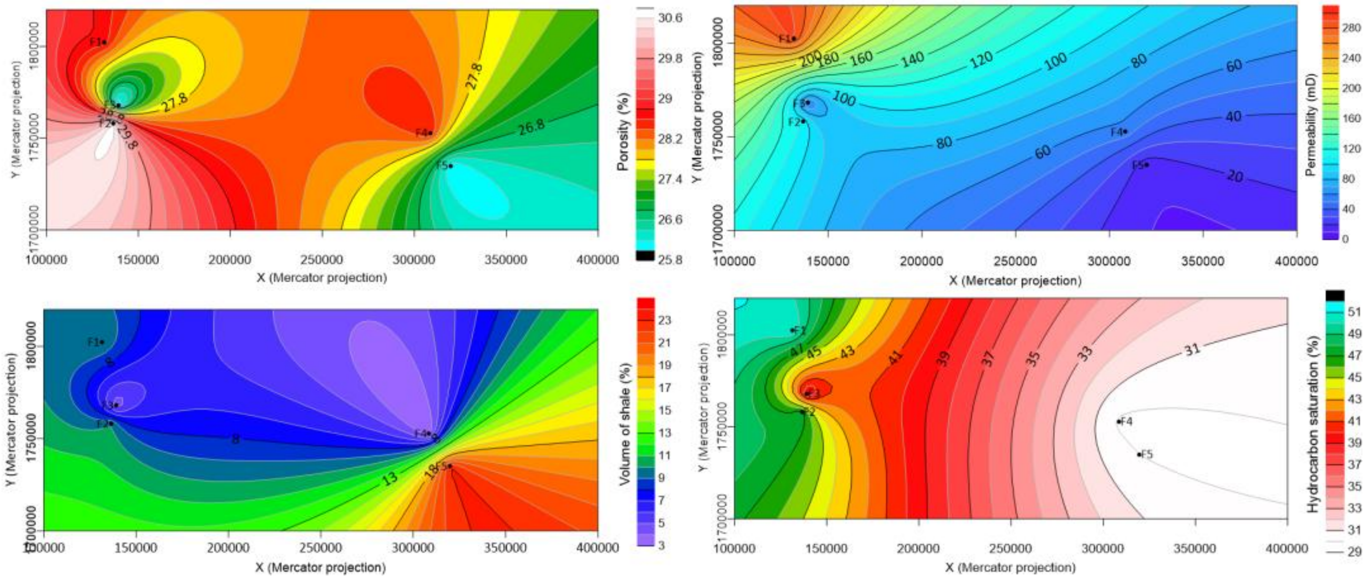

Fig. 7. Model of reservoir properties of the E-4 sand group of wells F-1-F-5

The porosity values decreased from well F-1 to well F-5, with well F-4 having the highest values (Fig. 8). The variation of the permeability and hydrocarbon saturation values is similar (Fig. 8). These decreased from well F-2 to well F-5. The shale volume has values decreasing from well F-2 to well F-5 (Fig. 8). Well F-5 has the lowest petrophysical properties, with a hydrocarbon saturation of 27%. In contrast, the best petrophysical properties are observed in the well F-2, with a hydrocarbon saturation of 58%.

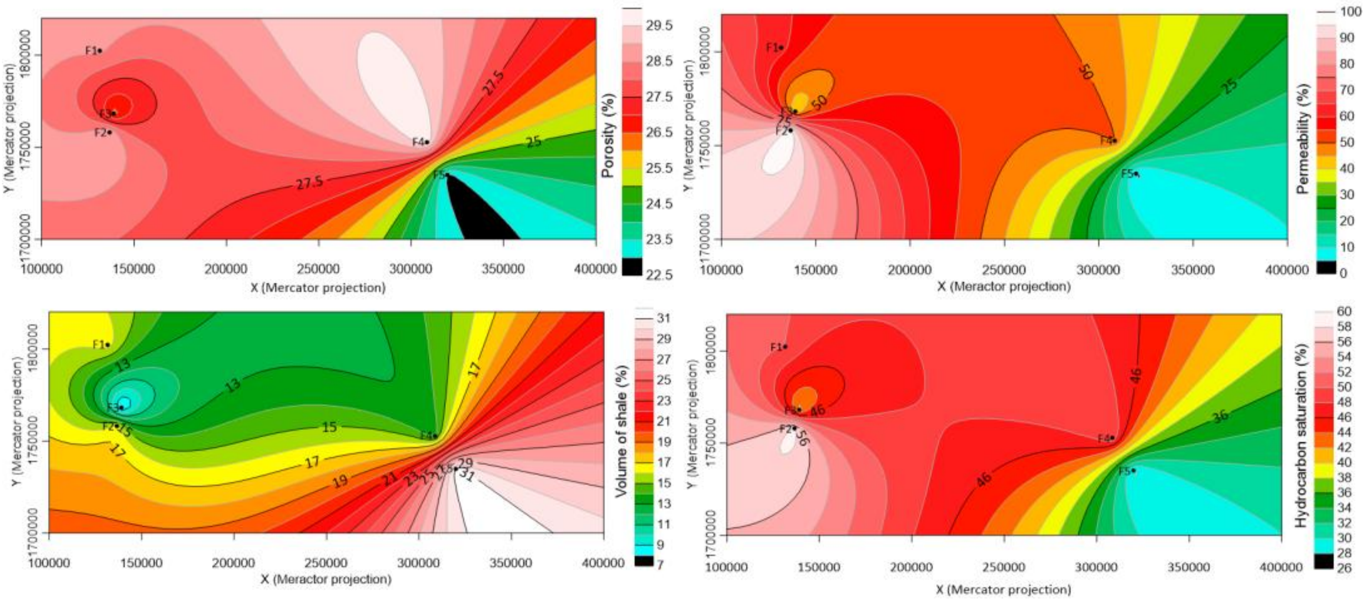

Fig. 8. Model of reservoir properties of the E-5 sand group of wells F-1-F-5

5 Conclusions

Overall, the petrophysical analysis indicates that the reservoir quality within the studied interval ranges from moderate to very good. Among the evaluated units, sand groups E-1 and E-2 have the most prospective reservoirs, characterized by high porosity, moderate to high permeability, and relatively high hydrocarbon saturation. The observed variations in reservoir quality are likely controlled by lithological heterogeneity and diagenetic processes such as compaction, cementation, and dissolution, which influence pore structure and fluid flow properties within the sandstone reservoirs. The variability observed among the wells reflects lateral heterogeneity in depositional facies within the fluvial-deltaic sedimentary system that characterizes the Sokor-1 Formation. Channelized sandstone bodies likely correspond to the higher-quality reservoirs, whereas lower-quality intervals may represent more distal or fine-grained depositional environments.

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DECLARATION OF COMPETING INTERESTS

The authors declare that they have no known conflicts of interest that could influence this paper.

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