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Full Length Article

Integrated approach and insights into shale gas potential: Geological, petrophysical, geochemical, and geomechanical evaluation of the Khatatba Formation (Western Desert, Egypt)

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ABSTRACT

This study provides a comprehensive assessment of the shale gas potential of the Middle Jurassic Khatatba Formation in the Obaiyed Field, Western Desert, Egypt, by integrating geological, petrophysical, geochemical, and geomechanical datasets into a unified workflow. The multidisciplinary approach allows for the identification of shale gas "sweet spots" and addresses critical operational risks associated with drilling and completion. Petrophysical evaluation indicates heterogeneity, with total porosity ranging from 6 to 12%, effective porosity between 4 and 8%, shale volume often exceeding 40% but locally decreasing below 30%, and permeability within 0.01–0.1 mD. Gas storage capacity is enhanced at depths greater than 3800 m, where free gas contents are significant and adsorbed gas reaches 1.5–2.0 cm^3/g in Total Organic Carbon (TOC)-rich intervals. Geochemical analysis confirms that the Upper Safa Member is thermally mature within the gas window, with TOC averaging ~4 wt% and mixed Type II–III kerogens, while traces of CO_2 (0.8–2.0 mol%) and H_2S (25–80 ppm) raise concerns about casing corrosion and necessitate careful material selection. Geomechanical results reveal brittle intervals with high Young's modulus and low Poisson's ratio, fracture gradients ranging from 25 to 30 MPa/km, and maximum horizontal stress (σHmax) typically 1.2–1.5 times the minimum horizontal stress (σhmin), defining a narrow safe mud weight window. Seismic inversion delineates TOC-rich, low-impedance intervals as optimal drilling targets, while fault-bounded compartments highlight both opportunities for hydrocarbon trapping and risks of reservoir compartmentalization. The integration of reservoir quality (RQ) and completion quality (CQ) with stress and pressure profiles enables optimized well orientation and trajectory planning, particularly recommending horizontal wells perpendicular to σHmax in the lower Upper Safa Member. This integrated evaluation confirms the Upper Safa Member as the most promising shale gas target within the Khatatba Formation and establishes a transferable workflow for unconventional reservoir development worldwide.

1. Introduction

The history of unconventional shale reservoirs marks a significant shift in the energy sector, as it represents the transition from reliance on conventional oil and gas resources to advanced extraction technologies, which have unlocked vast hydrocarbon reserves within shale formations. This journey began in 1859 with the drilling of the first oil well in Pennsylvania, signaling the dawn of the petroleum industry (Jarvie et al., 2007; Rickman et al., 2008). For decades, conventional oil and gas reservoirs provided the bulk of global energy supplies. However, as these fields matured and production rates declined, the need for alternative sources became increasingly urgent. The significance of shale gas was first recognized in the United States, where the combination of horizontal

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drilling and hydraulic fracturing techniques made it possible economically extract natural gas from formations such as the Barnett Shale in Texas (Bowker, 2007; Sone and Zoback, 2013; Zheng et al., 2020). This breakthrough set off a revolution in the energy industry, transforming the U.S. from a net importer to a net exporter of natural gas and influencing global energy dynamics (Evenick and McClain, 2013).

The importance of unconventional shale reservoirs extends well beyond the United States, with significant developments in countries like China, Argentina, Canada, and Australia (Velay et al., 2014; Wang et al., 2013). In Egypt, the Western Desert's Khatatba Shale has attracted attention for its potential to contribute significantly to the country's energy future. However, the exploitation of shale gas is not without challenges, including geological, petrophysical, geochemical, and geomechanical risks that must be addressed to determine the sweet spots for hydraulic fracturing (Curtis, 2002; Eshkalak and King, 2014; Farfour and Yoon, 2015; Wang et al., 2020; Zheng et al., 2020). The delineation of "sweet spots" in unconventional shale reservoirs remains one of the most critical challenges in shale gas exploration and development. These sweet spots are zones characterized by high Total Organic Carbon (TOC), sufficient lateral and vertical extent, and mechanical properties suitable for hydraulic fracturing. Accurately identifying such zones is essential for maximizing hydrocarbon production and ensuring the economic viability of shale gas projects. However, unconventional reservoirs, such as the Middle Jurassic Khatatba Formation in the Obaiyed field, Western Desert, Egypt, pose significant challenges due to their low permeability, heterogeneous geological structures, and complex depositional environments. This study highlights the necessity of integrating innovative geoscientific techniques—particularly seismic, geochemical, well logs, and geomechanical data—in overcoming the challenges associated with unconventional shale reservoirs, especially within the Middle Jurassic Khatatba Formation in the Obaiyed field, Egypt (Fig. 1).

The exploitation of unconventional shale reservoirs, characterized by their low permeability and complex geological structures, requires the development of sophisticated geological and geophysical methods. In this work, we emphasize the integration of seismic interpretation, geochemical analysis, well log data, and geomechanical modeling as key techniques for optimizing drilling strategies and ensuring the economic viability of shale gas projects. Seismic interpretation is critical for mapping the subsurface and identifying structural features that influence reservoir quality and hydrocarbon distribution (El-Qalamoshy et al., 2023; Farfour et al., 2021a; Reda et al., 2024; Shehata et al., 2023). Geochemical analysis provides insights into the organic content, types of organic matter and thermal maturity of the shale, which are essential for assessing its hydrocarbon potential (Abd-Allah et al., 2019, 2021; Abdel-Fattah et al., 2017, 2024a; Salama et al., 2021; Soliman et al., 2022). Well log analysis is used to evaluate the lithology, organic richness (TOC), and shale reservoir properties, aiding in the identification of sweet spots for shale gas development (Abdel-Fattah et al., 2018). Geomechanical modeling aids in understanding the stress regime and mechanical properties of the shale, crucial for designing effective hydraulic fracturing treatments (Farfour et al., 2015; Farfour et al., 2021b; Zhang, 2013; Zheng et al., 2020). Together, these techniques provide a comprehensive understanding of the reservoir, guiding drilling decisions and enhancing the quality of the well completions.

By applying this multidisciplinary approach, this work aims to delineate sweet spots within the Upper Safa Member of the Khatatba Formation, thereby optimizing drilling strategies and enhancing reservoir completion quality. The methodologies and insights presented here not only contribute to the efficient

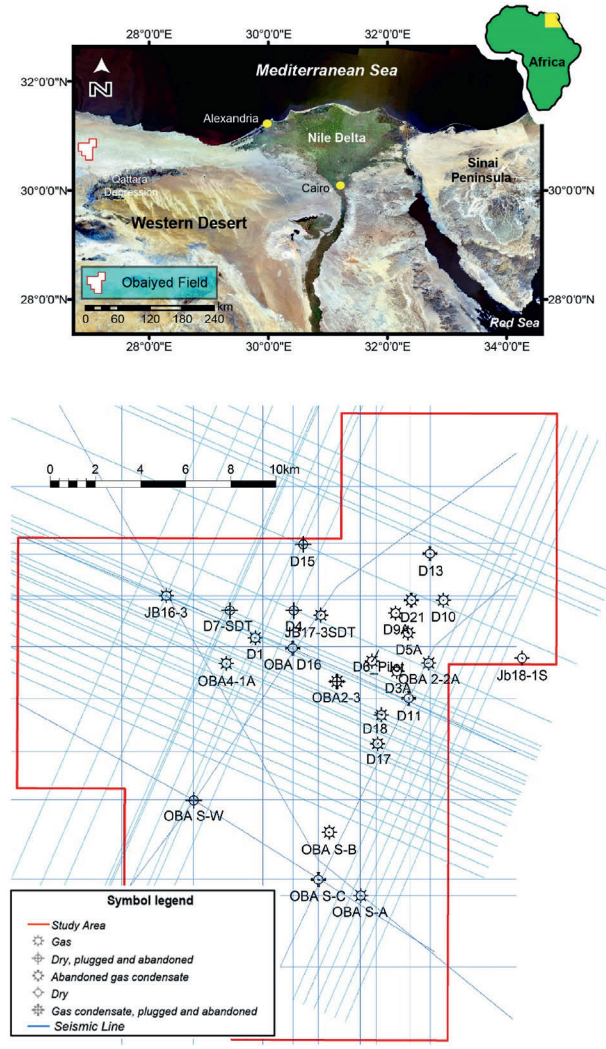

Fig. 1. Location map of the Obaiyed field in the Western Desert, Egypt, along with the base map showing the available dataset used in this study.

development of the Khatatba Shale but also provide a model for tackling similar challenges in unconventional reservoirs globally.

2. Geological setting

The Khatatba Formation, a Middle Jurassic sedimentary unit in the Western Desert of Egypt (Fig. 2), plays a significant role in the region's hydrocarbon exploration and production. The Western Desert itself is a prolific hydrocarbon province, characterized by a complex structural and stratigraphic framework that has evolved over several tectonic phases (Bishop, 2001; Dolson et al., 2002).

The structural framework of the Western Desert is shaped by a series of extensional tectonic events that have influenced the deposition and preservation of the Khatatba Formation. The primary structural features include rift basins, fault systems, and horst-graben structures, formed during the Mesozoic rifting episodes associated with the opening of the Neo-Tethys Ocean. The Western Desert is divided into several basins, including the Shoushan, Matruh, Alamein, and Abu Gharadig basins, which are delineated by major fault systems such as the Qattara Depression and the Sitra Fault (Keeley et al., 1990a, 1990b; Younes, 2003). The Khatatba Formation is predominantly found in the Shoushan Basin, where it exhibits a complex structural setting influenced by

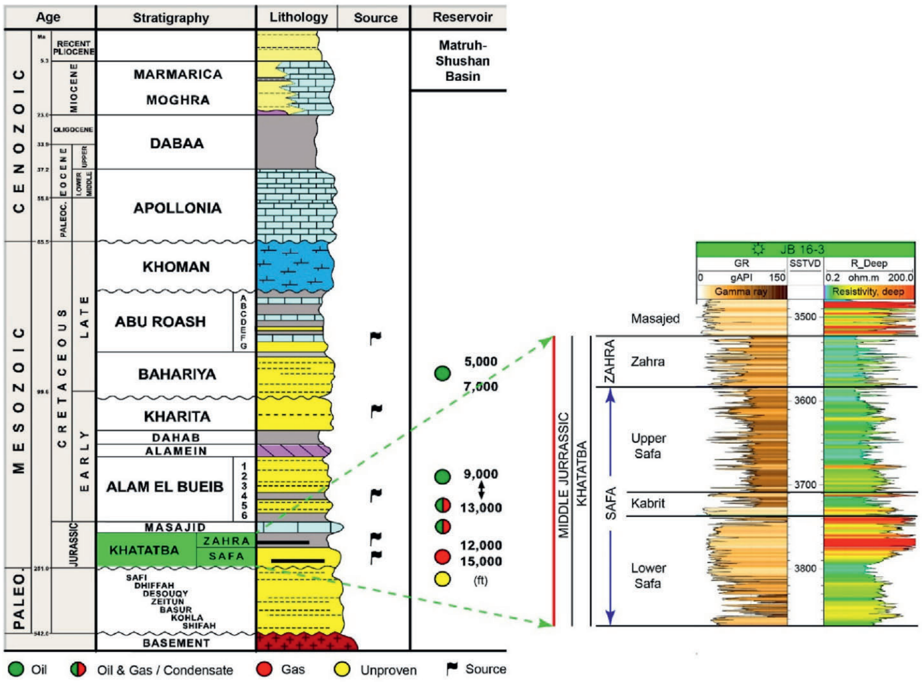

Fig. 2. Lithostratigraphic column of the Obaiyed field in the Western Desert, Egypt, and log types for the Middle Jurassic Khatatba Shale Formation.

extensional tectonics. Normal faulting during the Jurassic created accommodation space for the deposition of thick siliciclastic sequences. The tectonic activity continued into the Cretaceous, further modifying the basin architecture and influencing the distribution and thickness of the Khatatba sediments. These structural complexities create numerous traps and play a crucial role in the hydrocarbon potential of the formation (Abdel-Fattah et al., 2024a, 2024b).

Stratigraphically, the Khatatba Formation is part of the Middle Jurassic succession in the Western Desert and is known for its significant hydrocarbon reservoirs. The formation overlies the Ras Qattara Formation and is conformably overlain by the Bahrein Formation. It is subdivided into several members, each characterized by distinct lithological and depositional features (El Gezeery and Omran, 1991; Shehata et al., 2023). The Khatatba Formation consists of a mixed siliciclastic and carbonate sequence deposited in a variety of environments ranging from fluvial to marine settings. The lower part of the formation is characterized by fluvial to deltaic sandstones, which are interbedded with shales and siltstones. These sandstones are often reservoir rocks with good porosity and permeability. The upper part of the Khatatba Formation transitions into more marine-influenced deposits, including shales, siltstones, and carbonates, reflecting a transgressive phase during the Middle Jurassic (Hantar, 1990, 1990b; Sarhan and Abdel-Fattah, 2024). The depositional environment of the Khatatba Formation suggests a complex interplay of fluvial, deltaic, and shallow marine processes. The presence of coal seams and organic-rich shales indicates periods of high organic productivity and preservation, which are critical for the formation's hydrocarbon potential. Geochemical analyses of these shales have shown them to be excellent source rocks, contributing to the overall petroleum system in the Western Desert (Younes, 2003).

The Khatatba Formation in the Western Desert of Egypt is situated within a structurally complex and stratigraphically diverse setting (Bishop, 2001; Dolson et al., 2002). The formation's geological characteristics, influenced by extensional tectonics and varying depositional environments, make it a significant target for hydrocarbon exploration. Understanding its structural and stratigraphic framework is essential for optimizing exploration and production strategies in this prolific hydrocarbon province (Abdel-Fattah, 2015; Reda et al., 2024).

The Khatatba Formation, located in the Western Desert of Egypt, is a significant Middle Jurassic stratigraphic unit known for its potential as a hydrocarbon reservoir. This formation is subdivided into several members, each characterized by distinct lithological and depositional features that contribute to its overall geological complexity and reservoir potential (Said, 1990). The Khatatba Formation is a stratigraphically diverse unit with multiple members (Fig. 2), each contributing unique geological characteristics that influence the formation's overall reservoir potential. Understanding the distinct lithological and depositional features of the Lower Safa, Kabrit, Upper Safa, and Zahra Members is essential for effective exploration and development of hydrocarbon resources within the Khatatba Formation (Abdallah and El-Baz, 2002; Abdel-Fattah, 2015).

The Lower Safa Member forms the basal unit of the Khatatba Formation (Fig. 2) and mainly consists of fluvial to deltaic sandstones interbedded with shales and siltstones (Abdallah and El-Baz, 2002; El Gezeery and Omran, 1991; Said, 1990). These sandstones are often characterized by high porosity and permeability, making them excellent reservoir rocks. The depositional environment of the Lower Safa Member reflects a transition from terrestrial to more marine-influenced settings, which contributes to the variability in sediment composition and reservoir quality. This member is crucial for understanding the early stages of sediment deposition in the Khatatba Formation and its potential for hydrocarbon accumulation.

The Upper Safa Member is one of the most significant intervals within the Khatatba Formation (Fig. 2). This member is characterized by a combination of marine shales and sandstones, reflecting a more stable marine depositional environment compared to the Lower Safa (Abdallah and El-Baz, 2002; El Gezeery and Omran, 1991; Said, 1990). The Upper Safa Member is noted for its high organic content, with Total Organic Carbon

(TOC) values averaging around 4%, and predominantly Type II kerogen, which is conducive to both oil and gas generation. The thickness of the Upper Safa Member is approximately 150 m, and its organic-rich shales make it a prime target for shale gas exploration and development.

The Kabrit and Zahra Members represent a transition to more carbonate-dominated depositional environments (Keeley et al., 1990b; Younes, 2003). These members are composed primarily of shallow marine limestones and dolomites, with occasional interbedded shales and siltstones (Fig. 2). The carbonate facies of the Kabrit and Zahra members suggest deposition in a relatively stable, shallow marine environment, which differs from the more siliciclastic-dominated lower members of the Khatatba Formation. These carbonate units can act as both reservoirs and seals within the broader stratigraphic framework of the Khatatba Formation, contributing to the complexity and potential of the hydrocarbon system.

3. Materials and methods

This study utilized a comprehensive set of geological and geophysical data provided by Badr El Din Petroleum Company (BAPETCO) to evaluate the Middle Jurassic Khatatba Formation in the Obaiyed field, Western Desert, Egypt. The materials included 25 ditch cutting samples, mud logs, 24 wells with a suite of wireline logs [Gamma Ray (GR), Caliper (CALI), Density (RHOB), Neutron (CNL), Sonic (ΔTp & ΔTs), and Resistivity logs], and 70 seismic profiles extracted from a 3D seismic cube. The integration of these datasets facilitated a multi-faceted approach to shale reservoir characterization.

Seismic interpretation and well log analysis were the primary methods employed to define the depositional environment, depth, and thickness of the Khatatba Shale Formation (Abdel-Fattah et al., 2020, 2023). Seismic interpretation, involving the analysis of 70 seismic profiles, was crucial for mapping structural features and stratigraphic boundaries. Well log data from 24 wells provided detailed information on lithology, enabling the identification of shale intervals with potential hydrocarbon content. These logs were essential for tracking the depth and thickness of the shale, helping to build a comprehensive geological model of the study area.

Following the geological evaluation, a detailed petrophysical analysis was conducted to quantify the reservoir properties of the Khatatba Shale. Conventional well logs were used to estimate porosity, permeability, shale volume, and gas storage capacity, which represent key parameters for reservoir quality evaluation in shale reservoirs (Hunt, 1996; Rickman et al., 2008).

The total porosity (ϕ_t) was derived from density and neutron logs (Hunt, 1996):

$$\boldsymbol{\phi_t} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \tag{1}$$

where ρ_{ma} is the matrix density, ρ_b is the bulk density, and ρ_f is the fluid density. Effective porosity (ϕ_e) was obtained after correcting for shale volume.

Shale volume (V_{sh}) was calculated from the gamma-ray log using the linear response method (Makky et al., 2014):

$$\boldsymbol{V_{sh}} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \tag{2}$$

where GR_{log} is the measured gamma-ray, and GR_{min} and GR_{max} represent the clean sand and shale baselines, respectively.

Permeability (k) was estimated using an empirical porosity–saturation relationship suitable for shaly formations, such as Timur's equation (Rickman et al., 2008):

$$\boldsymbol{k} = 0.136 \times \frac{\phi e^4}{{S_{wi}}^2} \tag{3}$$

where S_{wi} denotes irreducible water saturation.

Gas storage capacity was evaluated in terms of both free gas and adsorbed gas. Free gas content (G_f) was determined from effective porosity, reservoir pressure (P_r), and gas compressibility factor (Z) (Zoback, 2007):

$$\boldsymbol{G_f} = \frac{\phi_e\ (1 - S_W)\ P_r}{ZRT} \tag{4}$$

where S_w is water saturation, R is the gas constant, and T is the reservoir temperature.

Adsorbed gas content (G_{ads}) was calculated using the Langmuir isotherm (Hunt, 1996):

$$\boldsymbol{G_{ads}} = \frac{V_L\ P}{P + P_L} \tag{5}$$

where V_L is the Langmuir volume (maximum adsorption capacity), and P_L is the Langmuir pressure.

This petrophysical analysis provided quantitative estimates of shale volume, porosity, permeability, and gas content, which were integrated into the Reservoir Quality (RQ) assessment to strengthen the shale gas evaluation of the Upper Safa Member (Makky et al., 2014; Rickman et al., 2008).

The geochemical analysis was performed using the 25 ditch cutting samples (Table 1) to assess the organic richness and maturity of the shale. Rock-Eval pyrolysis was used to determine the quantity and type of hydrocarbons present (Gharib et al., 2024; Leila et al., 2023; Mahdi et al., 2022). TOC measurements quantified the organic content, and vitrinite reflectance (%Ro) indicated the thermal maturity of the organic matter. Well log data complemented these analyses by providing continuous profiles of organic richness across different depths (Makky et al., 2014). These geochemical evaluations were vital for understanding the reservoir quality (RQ), particularly the potential of the shale to generate hydrocarbons.

The geomechanical properties of the shale were assessed to evaluate the completion quality (CQ) for hydraulic fracturing. Well logs and seismic data were used to calculate key parameters such as Young's modulus, Poisson's ratio, and bulk modulus (Eshkalak and King, 2014; Farfour et al., 2021b; Farfour and Yoon, 2015; Zheng et al., 2020). The brittleness index was determined to predict the shale's response to hydraulic fracturing. Seismic inversion techniques were applied to integrate these geomechanical properties with the seismic data, helping to delineate sweet spots characterized by high TOC and favorable mechanical properties (Bosch et al., 2010; Farfour et al., 2021a; Kenter and Backer, 2001; Negm et al., 2025; Pendrel, 2001). This comprehensive geomechanical analysis was critical for optimizing well-completion strategies and enhancing reservoir stimulation efforts.

In addition to standard Rock–Eval pyrolysis and vitrinite reflectance analyses, screening for corrosive gases such as H_2S and CO_2 was conducted. These gases are common in organic-rich shale successions and are known to cause casing corrosion, drill string degradation, and downhole equipment failure if not addressed (Kermani and Morshed, 2003; Smith and Williams, 1984). The presence of such gases was assessed by integrating gas chromatography of headspace samples, sour gas indices from pyrolysis, and cross-checks with available mud logging reports. This evaluation ensured that geochemical characterization included not only hydrocarbon potential but also operational risks related to drilling and completion (Burton et al., 2015).

Table 1
Petrophysical properties of the Upper Safa Member (Khatatba Shale) in the Obaiyed Field.

Well Name	Depth Interval (m)	Total Porosity (ϕt, %)	Effective Porosity (ϕe, %)	Shale Volume (Vsh, %)	Permeability (k, mD)	Free Gas Content (Gf, scf/ton)	Adsorbed Gas Content (Gads, cm^3/g)	Remarks
OBA-SW	3850–3950	8–10	6–8	40–45	0.05	120–150	1.6	TOC-rich, good adsorption
OBA-SB	3870–3960	7–9	5–7	35–42	0.07	130–160	1.8	Clean intervals enhance ϕe
OBA-SC	3880–3975	9–11	7–9	38–44	0.06	140–170	2.0	Best gas storage capacity
OBA-NW	3860–3960	8–9	6–7	39–43	0.05	125–145	1.7	Moderate porosity
OBA-NE	3865–3970	9–10	7–8	37–42	0.06	135–165	1.9	Balanced free & adsorbed gas
D11	3900–4000	6–8	4–6	45–50	0.03	100–120	1.5	Shale-dominated, lower quality
D16	3950–4050	8–9	6–7	42–46	0.04	115–140	1.7	Intermediate quality
JB18-1S	3860–3980	10–12	8–10	35–40	0.08	150–180	2.1	Thickest TOC-rich section

The geomechanical analysis of the Khatatba Shale Formation in the Obaiyed field involved several key steps to evaluate its mechanical behavior and suitability for hydraulic fracturing. The primary methods used include the calculation of elastic properties, brittleness index, fracture gradient (FG), fracture toughness (Kic), and poroelastic properties. Each method is critical in understanding the mechanical characteristics of the shale and predicting its response to fracturing treatments.

The elastic properties, including Young's Modulus (E) and Poisson's Ratio (ν), are essential indicators of the rock's brittleness and ductility. These properties were derived from the sonic logs, which measure compressional (V_p) and shear (V_s) wave velocities, and density logs (ρ). The following equations were used:

$$\boldsymbol{E} = \rho \left(V_p^2 - 2V_s^2\right) \frac{(1+\nu)(1+2\nu)}{1-\nu} \tag{6}$$

$$\boldsymbol{\nu} = \frac{V_p^2 - 2V_s^2}{2\left(V_p^2 - V_s^2\right)} \tag{7}$$

where ρ is the density, V_p is the compressional wave velocity, and Vs is the shear wave velocity. These calculations provided a detailed understanding of the rock's stiffness and deformability, which are crucial for assessing its fracturing potential (Fjar et al., 2008; Zoback, 2007).

The brittleness index (BI) is a key parameter that indicates the rock's ability to fracture. It was calculated using the elastic moduli, specifically Young's Modulus (E) and Poisson's Ratio (ν). The formula used is:

$$\boldsymbol{BI}_{elastic} = \frac{1}{2}\left[\frac{E - E_{min}}{E_{max} - E_{min}} + \frac{\nu_{max} - \nu}{\nu_{max} - \nu_{min}}\right] \times 100 \tag{8}$$

High values of BI suggest that the rock is more brittle and thus more favorable for hydraulic fracturing. This index helps in identifying zones within the shale formation that are more likely to respond well to fracturing treatments (Rickman et al., 2008).

Fracture gradient (FG) is the pressure gradient required to fracture the rock. It is derived from pore pressure and overburden stress profiles. Fracture toughness (K_{ic}) is a measure of a material's resistance to fracture when a crack is present. These were calculated using empirical relationships and well log data. The equations used are:

$$\boldsymbol{FG} = \frac{\sigma_H + \sigma_h + \sigma_\nu}{3} \tag{9}$$

$$\boldsymbol{K_{ic}} = \alpha \boldsymbol{E} \left(\frac{(1-\nu)}{(1+\nu)}\right) \tag{10}$$

where σ_H, σ_h, and σ_v are the horizontal and vertical stresses, and α is an empirical factor. These properties help in understanding the stress regime and mechanical behavior of the shale, essential for designing effective hydraulic fracturing treatments (Economides and Nolte, 2000; Jaeger et al., 2007).

In addition to elastic parameters, the geomechanical workflow incorporated estimation of the maximum horizontal stress (σH_{max}), minimum horizontal stress (σh_{min}), and formation pressure (P_p) profiles. The minimum horizontal stress was derived from poroelastic theory using the equation:

$$\sigma \boldsymbol{h}_{min} = \frac{\nu}{1-\nu}\left(\sigma_\nu - \alpha P_p\right) + \alpha P_p + \Delta T \tag{11}$$

where σ_v is the vertical stress from overburden density integration, ν is Poisson's ratio, α is Biot's coefficient, P_p is pore pressure, and ΔT accounts for thermal stresses (Zoback, 2007). The maximum horizontal stress (σH_{max}) was constrained using breakout and drilling-induced tensile fracture data from wellbore image logs, calibrated with laboratory-derived rock strength values (Eaton, 1969; Zoback, 2007). Formation pore pressure (P_p) curves were constructed using sonic and resistivity log-based Eaton methods, calibrated where available with MDT pressure data. These parameters were integrated to construct 1D geomechanical models for each well, later used in the identification of safe mud weight windows and fracture gradient envelopes.

By integrating geological, geochemical, and geomechanical analyses, this study aimed to provide a robust assessment of the shale gas potential in the Khatatba Formation (Fig. 3). The combined evaluation of reservoir quality (RQ) and completion quality (CQ) enabled the identification of optimal drilling and hydraulic fracturing targets, ensuring the economic viability and efficient development of the shale gas resources in the Obaiyed field (Western Desert, Egypt).

4. Results

4.1. Geological analysis

The geological analysis of shale reservoirs heavily relies on understanding the depth and thickness of the shale formations, as well as the depositional environment. The well log analysis for determining the lithology and depositional environment of the Khatatba Formation utilized gamma ray, density, neutron, and resistivity logs (Fig. 4). The Khatatba Formation is characterized by a combination of shale, sandstone, and siltstone. The gamma ray logs indicate high values in shale-dominated sections, while lower gamma ray values are observed in cleaner sandstone intervals, which are associated with more favorable reservoir properties. In

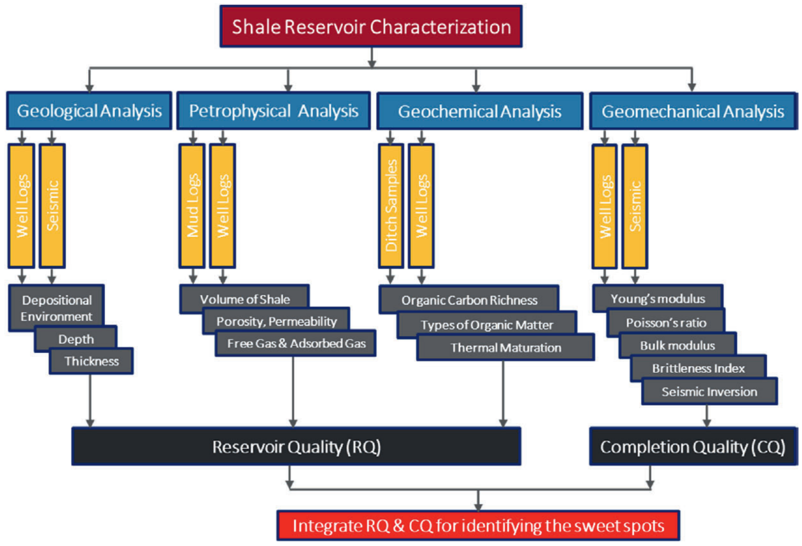

Fig. 3. Workflow illustrating the integrated approach for shale reservoir characterization, combining geological, geochemical, and geomechanical analyses to determine reservoir quality (RQ) and completion quality (CQ) for identifying optimal hydraulic fracturing sweet spots.

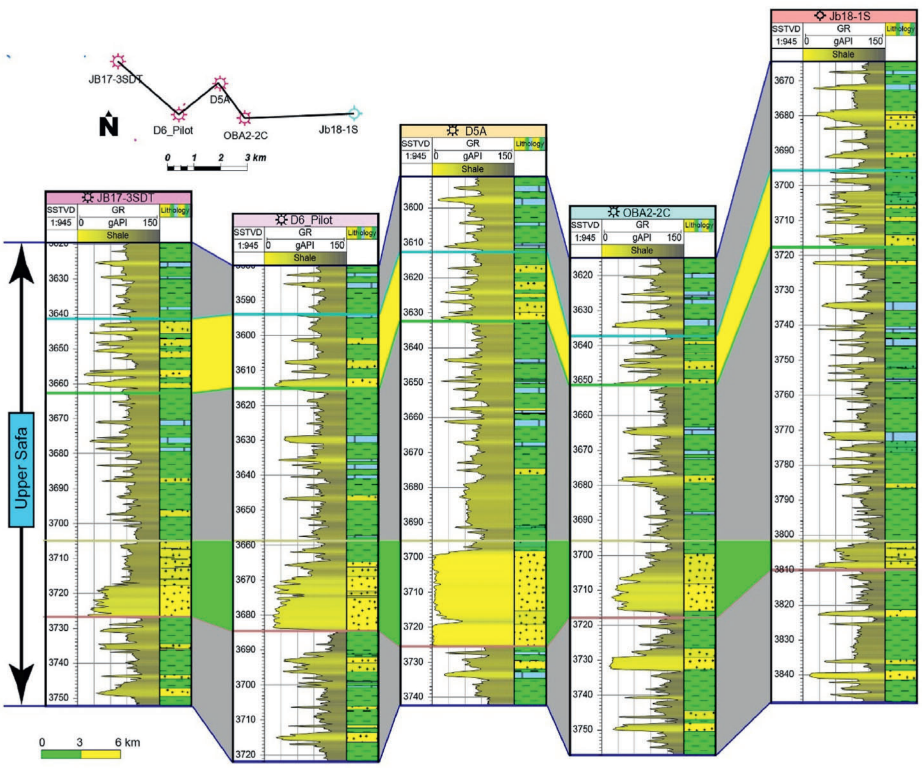

Fig. 4. West-East stratigraphic cross-section of the Upper Safa shale reservoir in the Obaiyed Field, highlighting shale-dominated intervals interbedded with potential reservoir sandstones. The gamma ray log indicates shale-rich sections associated with low-energy deposition, critical for hydrocarbon generation, while the interbedded sandstones reflect higher-energy environments, influencing reservoir compartmentalization and fluid flow.

terms of depositional environment, the well log data suggest that the Khatatba Formation was deposited in a mixed fluvial and marginal marine setting. The shale-dominated sections with higher gamma ray values indicate low-energy environments, such as floodplains or tidal flats, while the cleaner sandstones correspond to higher-energy environments, such as fluvial channels or deltaic deposits (Fig. 4). The Upper Safa Member, specifically, reflects a transition between these environments. It is predominantly composed of shale with interbedded sandstone layers. The gamma ray logs of the Upper Safa Member show irregular patterns, suggesting deposition in a fluctuating energy environment, likely transitioning from fluvial to tidal settings. The sandstone intervals within the Upper Safa are likely to represent channel-fill deposits, while the surrounding shale reflects more low-energy, fine-grained deposition.

Seismic interpretation provides detailed subsurface images essential for mapping the depth and thickness of the shale formations. The Khatatba Shale provides valuable insights gained through seismic profiles extracted from a 3D seismic cube. These profiles allow to identify and characterize the structural features of the Khatatba Shale Formation, crucial for evaluating its potential as an unconventional shale gas reservoir. The thickness of the Khatatba Shale is one of its main advantages compared to other shale formations. It typically ranges from 100 to 550 m, with most intervals found between 150 and 450 m, and an average thickness around 450 m (Fig. 5). Additionally, the Upper Safa Member, another significant interval within the Khatatba Formation, has an average thickness of about 150 m. These substantial thicknesses provide a larger volume of rock capable of storing hydrocarbons, thereby increasing the reservoir potential. Seismic data accurately measures these thickness variations across the field, allowing for a better estimation of the total hydrocarbon volume. The depth of the Khatatba Shale, ranging from 3450 to 4070 m, is also a critical factor. Precise depth mappings obtained from seismic interpretation are essential for planning drilling operations and assessing the feasibility of hydraulic fracturing at these depths.

Moreover, seismic interpretation aids in identifying structural features such as faults, folds, and fractures that can significantly impact the shale's reservoir quality and its hydrocarbon production potential. These structural features can create traps for hydrocarbons or influence their migration pathways within the shale. By integrating seismic interpretation with other geological and geophysical data, a comprehensive geological model of the Khatatba Shale is developed. This model not only aids in identifying the most promising areas for exploration and production but also helps optimize drilling strategies and improve the overall efficiency of shale gas development in the Obaiyed field (Fig. 6).

The structural setting of the Khatatba Formation is dominated by normal faults, which are prevalent throughout the Obaiyed Field (Fig. 6). These normal faults are associated with extensional tectonics that occurred during the Jurassic period. The presence of normal faults is significant as they can create traps for hydrocarbons and influence the migration and accumulation of hydrocarbons within the reservoir. The faults typically trend in a northwest-southeast direction, aligning with the regional stress field during the time of their formation. The displacement along these faults varies, resulting in the juxtaposition of different reservoir units and creating compartments that can either enhance or hinder fluid flow depending on their orientation and connectivity.

4.2. Petrophysical analysis

The petrophysical evaluation of the Khatatba Shale, with emphasis on the Upper Safa Member, provides critical insights into its reservoir quality and hydrocarbon storage potential (Table 1). Porosity values derived from density–neutron log integration indicate an average total porosity (ϕ_t) ranging between 6 and 12%, with effective porosity (ϕ_e) reduced after correcting for shale content. These results highlight the dominance of microporous storage, consistent with shale gas systems.

The shale volume (V_{sh}), estimated from gamma-ray logs, shows considerable heterogeneity across the study wells. Shale content generally exceeds 40%, reflecting the fine-grained nature of the Upper Safa Member, with localized cleaner intervals (<30% V_{sh}) corresponding to interbedded sand-rich layers. These variations strongly control the effective porosity and permeability distribution within the reservoir.

Permeability estimates (k), calculated using the Timur relation, are characteristically low, in the order of 0.01–0.1 mD, which is typical of unconventional shale gas reservoirs. These low values

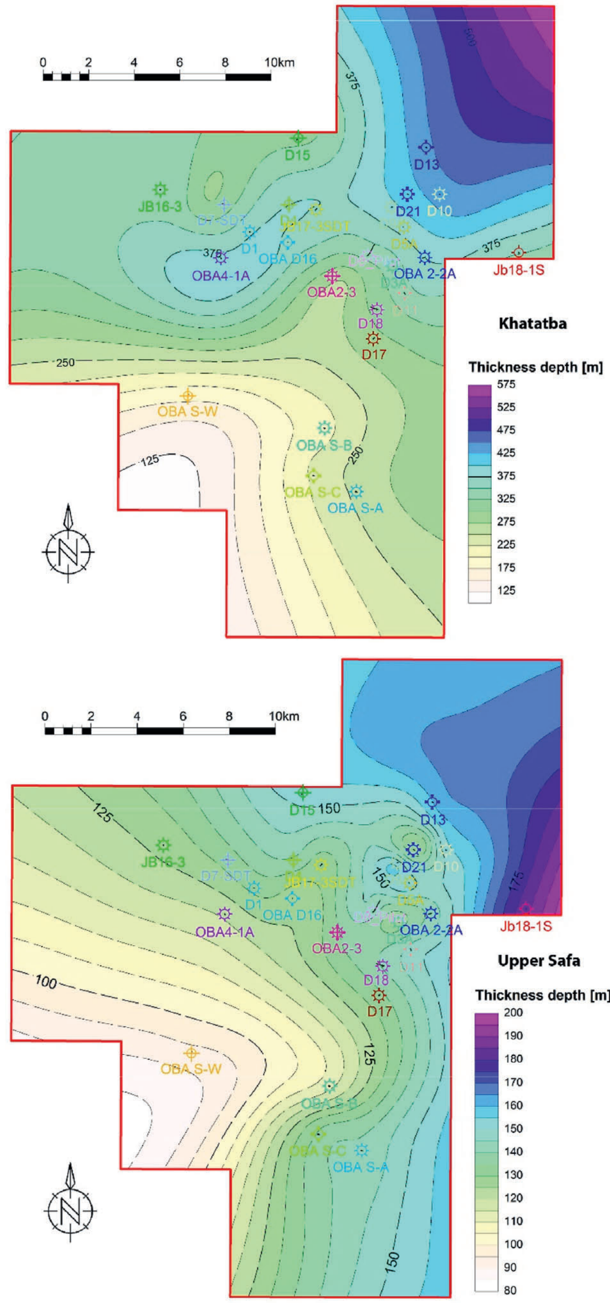

Fig. 5. Thickness maps of the Khatatba Shale and Upper Safa Member in the Obaiyed field, Western Desert, Egypt. The maps highlight the substantial thickness of the Khatatba Shale, averaging around 450 m, and the Upper Safa Member, averaging around 150 m, aiding in the identification of areas with higher hydrocarbon storage potential.

confirm that natural fracture networks and induced hydraulic fractures are essential for economic production.

The gas storage capacity of the shale reservoir was assessed in terms of free gas and adsorbed gas (Table 2). The free gas content (G_f), primarily controlled by effective porosity, reservoir pressure, and depth, shows significant potential in deeper intervals (>3800 m), where compaction and higher pressures enhance storage. Adsorbed gas content (Gads), estimated using Langmuir isotherm parameters, is positively correlated with total organic carbon (TOC) content and shale volume. High TOC intervals (>3–4 wt.%) in the Upper Safa Member yield adsorption capacities

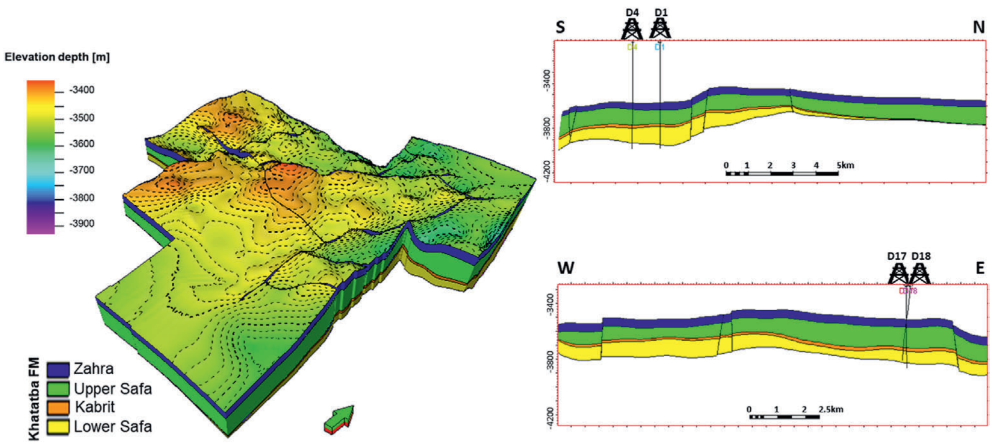

Fig. 6. 3D structural model and N–S and W-E cross-sections of the Khatatba Shale and Upper Safa Member in the Obaiyed field, Western Desert, Egypt. The model and cross-sections illustrate the structural and thickness distribution, with the Khatatba Shale averaging around 450 m and the Upper Safa Member averaging around 150 m, providing insights into the subsurface architecture and potential hydrocarbon storage zones.

Table 2
Occurrence of corrosive gases (CO_2, H_2S) in the Upper Safa Member (Khatatba Shale) and their operational implications.

Well Name	Depth Interval (m)	CO_2 (mol%/ppm)	H_2S (ppm)	Sulfur-rich Kerogen Association	Corrosion Risk to Casing/Drill Strings	Remarks
OBA-SW	3850–3950	1.5 mol%	50	Moderate	Medium	Localized CO_2 enrichment
OBA-SB	3870–3960	0.8 mol%	30	Low	Low	Minimal corrosive effect
OBA-SC	3880–3975	2.0 mol%	70	High	High	Needs corrosion-resistant casing
OBA-NW	3860–3960	1.2 mol%	45	Moderate	Medium	Sour zones present
OBA-NE	3865–3970	1.0 mol%	35	Moderate	Low–Medium	Monitor during drilling
D11	3900–4000	1.8 mol%	80	High	High	Strong H_2S influence
D16	3950–4050	1.3 mol%	40	Moderate	Medium	Acceptable with mitigation
JB18-1S	3860–3980	0.9 mol%	25	Low	Low	Least corrosive interval

exceeding 1.5–2.0 cm^3/g, confirming the importance of organic-rich shales as storage media.

4.3. Geochemical analysis

Geochemical analysis is essential in evaluating the potential of shale reservoirs by assessing the TOC content and the type of organic matter present (Table 3). For a shale formation to be considered prospective for hydrocarbon production, the average TOC must generally exceed 2%. TOC is a direct measure of the organic richness of the shale, while the type of organic matter, classified into types I, II, and III kerogens, indicates the potential of the shale to generate oil or gas. Type I and II kerogens are particularly significant for oil and gas production, with Type II kerogens being commonly associated with marine depositional environments (Hunt, 1996).

The Khatatba Formation consists of four members: Zahra, Kabrit, Lower Safa, and Upper Safa. The Zahra Member generally exhibits low TOC values due to its carbonate-dominated composition, while the Upper Safa Member stands out with significantly higher TOC levels, particularly in its shale-rich intervals, making it the most promising target for hydrocarbon generation (Table 1). Geochemical data from the Upper Safa Member reveal strong potential for shale gas development (Figs. 7–11), with TOC content averaging around 4%, well above the threshold required for productive shale reservoirs (Fig. 7). The organic matter in this member predominantly consists of mixed Type II–III kerogens, ideal for generating both oil and gas. This high organic richness, combined with the favorable kerogen type, highlights the strong potential for hydrocarbon production. The presence of Type II kerogen further indicates deposition in a marine environment, consistent with the depositional history of the Khatatba Formation.

The geochemical characterization of organic matter in the Khatatba Formation is illustrated through two key plots (Fig. 8). Panel (A) shows the relationship between Hydrogen Index (HI) and Oxygen Index (OI), categorizing the organic matter into kerogen types. The data primarily fall within the Type II and Type III kerogen fields, indicating a mix of oil-prone and gas-prone organic matter influenced by varying depositional environments. Panel (B) displays the HI versus T_{max}, providing insights into the thermal maturity of the organic matter. Most data points align with the Type II kerogen trends, with T_{max} values indicating that the organic matter is in the oil and early gas generation windows. These results highlight the Khatatba Formation, particularly the Upper Safa Member, as a thermally mature, hydrocarbon-generating system with significant potential for oil and gas production.

Maturation is another critical aspect of geochemical analysis, as it assesses the thermal maturity of the organic matter. Vitrinite reflectance (%Ro) is commonly used to determine thermal maturity, with higher values indicating greater maturity and, consequently, a higher potential for hydrocarbon generation. The Upper Safa Member exhibits maturation levels suitable for gas generation, as indicated by vitrinite reflectance, T_{max} and Production index (PI) values that align with the peak gas window (Fig. 9). This combination of high TOC, favorable kerogen type, and appropriate thermal maturity underscores the Upper Safa Member's potential as a viable shale gas reservoir.

Most of the measured Ro values in the Khatatba Formation are concentrated in the Zahra Member and the upper part of the Upper Safa Member, reflecting varying levels of thermal maturity across

Table 3
Geochemical properties of the Middle Jurassic Khatatba Formation in the Obaiyed field, Western Desert, Egypt. This table lists well data, formation depth, sample types, and key geochemical parameters including Total Organic Carbon (TOC), S1, S2, S3, Tmax, Hydrogen Index (HI), Oxygen Index (OI), Production Index (PI), and Vitrinite Reflectance (%Ro).

Well Name	Mbr.	MD Depth (m)	Sample Type	TOC Wt. %	S_1 mg/g	S_2 mg/g	S_3 mg/g	T_{max} degC	HI S_2/TOC	OI S_3/TOC	PI $S_1/(S_1+S_2)$	Ro Values
OBYD D11	Zahra	3800	CUT	0.6	0.06	0.93	0.98	432	155.00	163.33	0.06	0.71
OBYD D11	Upper Safa	3890	CUT	1.37	0.07	1.62	1.14	446	118.25	83.21	0.04	0.75
OBYD D16	Zahra	3950	CUT	1.62	0.45	1.45	1.27	456	89.51	78.40	0.24	0.87
OBYD D16	Upper Safa	3960	CUT	2.35	0.77	2.27	2.27	453	96.60	96.60	0.25	0.85
OBYD S3	Zahra	3855	CUT	0.57	0.05	0.54	0.93	441	94.74	163.16	0.08	0.83
OBYD S3	Zahra	3915	CUT	1.02	0.06	0.82	1.17	444	80.39	114.71	0.07	0.84
OBYD S3	Upper Safa	3940	CUT	1.62	0.07	1.08	2.01	457	66.67	124.07	0.06	0.9
Obaiyed 3-1A	Zahra	3736	CUT	1.24	0.1	2.23	0.6	437	179.84	48.39	0.04	
Obaiyed 3-1A	Zahra	3778	CUT	1.1	0.07	1.85	0.69	436	168.18	62.73	0.04	
Obaiyed 3-1A	Zahra	3794	CUT	0.67	0.08	1.01	0.42	438	150.75	62.69	0.07	
Obaiyed 3-1A	Zahra	3800	CUT	0.86	0.13	1.94	0.68	434	225.58	79.07	0.06	
Obaiyed 3-1A	Zahra	3812	CUT	1.2	0.1	1.76	0.7	444	146.67	58.33	0.05	
Obaiyed 3-1A	Upper Safa	3840	CUT	1.08	0.1	2.27	0.6	441	210.19	55.56	0.04	
Obaiyed 3-1A	Upper Safa	3848	CUT	0.75	0.07	1.67	0.36	449	222.67	48.00	0.04	
Obaiyed 3-1A	Upper Safa	3866	CUT	2.06	0.11	2.9	0.87	452	140.78	42.23	0.04	
Obaiyed 2-2A	Zahra	3816	CUT	0.56	0.13	0.32	0.7	443	57.14	125.00	0.29	
Obaiyed 2-2A	Zahra	3848	CUT	0.54	0.08	0.25	0.62	449	46.30	114.81	0.24	
Obaiyed 2-2A	Zahra	3856	CUT	0.63	0.11	0.32	0.89	451	50.79	141.27	0.26	
Obaiyed 2-2A	Upper Safa	3872	CUT	2.27	0.57	1.88	1.82	460	82.82	80.18	0.23	
Obaiyed 2-2A	Upper Safa	3880	CUT	1.6	0.36	1.32	1.18	459	82.50	73.75	0.21	
Obaiyed 2-2A	Upper Safa	3884	CUT	7.4	2.01	10.78	1.08	459	145.68	14.59	0.16	
Obaiyed 2-2A	Upper Safa	3892	CUT	3.88	1.15	5.16	1.33	461	132.99	34.28	0.18	
Obaiyed 2-2A	Upper Safa	3908	CUT	2.04	0.5	1.83	1.28	463	89.71	62.75	0.21	
Obaiyed 2-2A	Upper Safa	3924	CUT	2.31	1.02	2.14	1.64	468	92.64	71.00	0.32	
Obaiyed 2-2A	Upper Safa	3928	CUT	1.33	0.51	1.35	1.51	464	101.50	113.53	0.27	

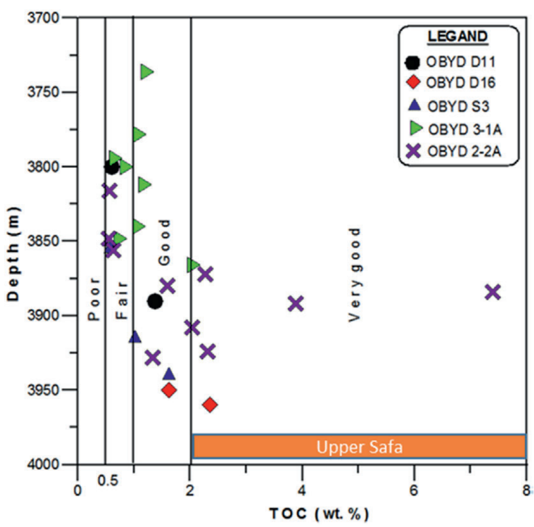

Fig. 7. Total Organic Carbon (TOC) values across different depths in the Middle Jurassic Khatatba Shale, illustrating the variation in organic richness. The figure highlights areas with higher TOC, indicating zones with greater potential for hydrocarbon generation and storage.

the formation (Fig. 9). The Zahra Member, characterized by lower TOC and predominantly carbonate lithology, exhibits limited hydrocarbon potential. In contrast, the Upper Safa Member demonstrates favorable characteristics, with higher TOC and maturity levels, making it a prime target for shale gas exploration. The maturation trends, visualized through figures incorporating trend lines, show a clear increase in Ro values with depth, particularly within the shale-dominated intervals of the Upper Safa Member. This trend indicates that the Upper Safa is entering the gas generation window, further highlighting its potential for hydrocarbon generation and accumulation.

Furthermore, TOC can be calculated from well logs, which is a crucial step in continuous reservoir characterization. This calculation involves using well log data, such as gamma-ray, density, and neutron logs, to estimate the TOC content indirectly (Fig. 10). The Delta-Log R method is one common approach (Makky et al., 2014), which utilizes resistivity and porosity logs to estimate TOC. By applying this method, continuous TOC profiles can be generated along the wellbore, providing a detailed understanding of the organic richness throughout the shale interval. This continuous TOC data is essential for identifying sweet spots with higher hydrocarbon potential and for making informed decisions about well placement and completion strategies.

The vertical and spatial distribution of Total Organic Carbon (TOC) > 2% within the Upper Safa Member reveals distinct intervals of organic richness and lateral heterogeneity across the study area (Fig. 11). Vertically, TOC >2% is concentrated in specific stratigraphic layers, indicating favorable conditions for organic matter accumulation and preservation during deposition. Spatially, high TOC zones are unevenly distributed, with prominent clusters around wells such as OBA-SW, OBA-SB, and OBA-SC. These regions of elevated TOC align closely with the structural framework of the Upper Safa Member, suggesting that both depositional environments and post-depositional tectonic processes have influenced the organic matter distribution. This pattern highlights the significance of these TOC-rich zones as potential “sweet spots” for hydrocarbon generation and exploration within the Upper Safa Member.

The geochemical analysis confirmed that the Upper Safa Member is gas-prone with significant TOC enrichment; however, traces of CO_2 and H_2S were also detected in several intervals. Concentrations were generally low to moderate, but their occurrence indicates a potential risk of corrosion to wellbore casing and drill strings. In particular, intervals with higher sulfur content in kerogen (Type II/III) showed greater association with H_2S generation (Horsfield, 2013; Tissot and Welte, 1984). While

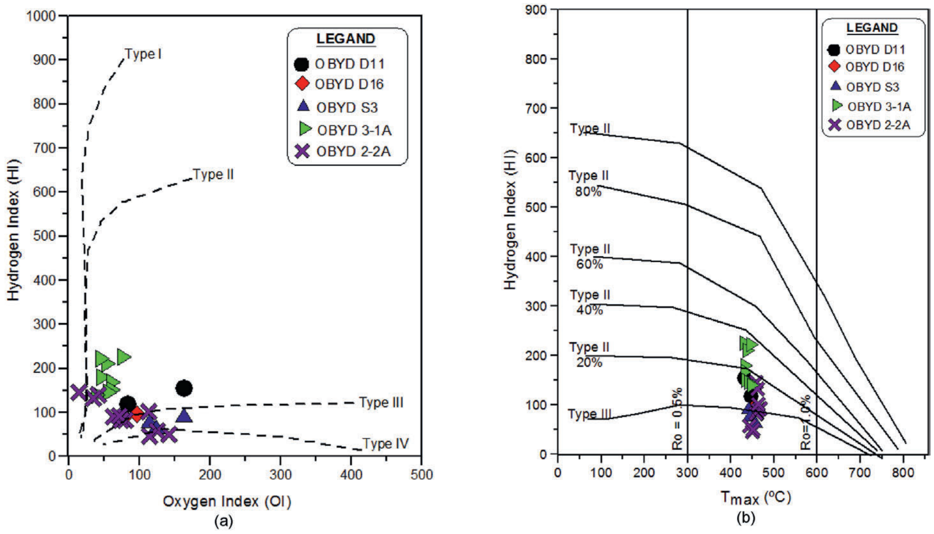

Fig. 8. Kerogen types in the Middle Jurassic Khatatba Shale: a) HI vs. OI plot indicating Type II (oil-prone) and Type III (gas-prone) kerogens. b) HI vs. T_{max} plot showing thermal maturity within the oil and early gas generation windows.

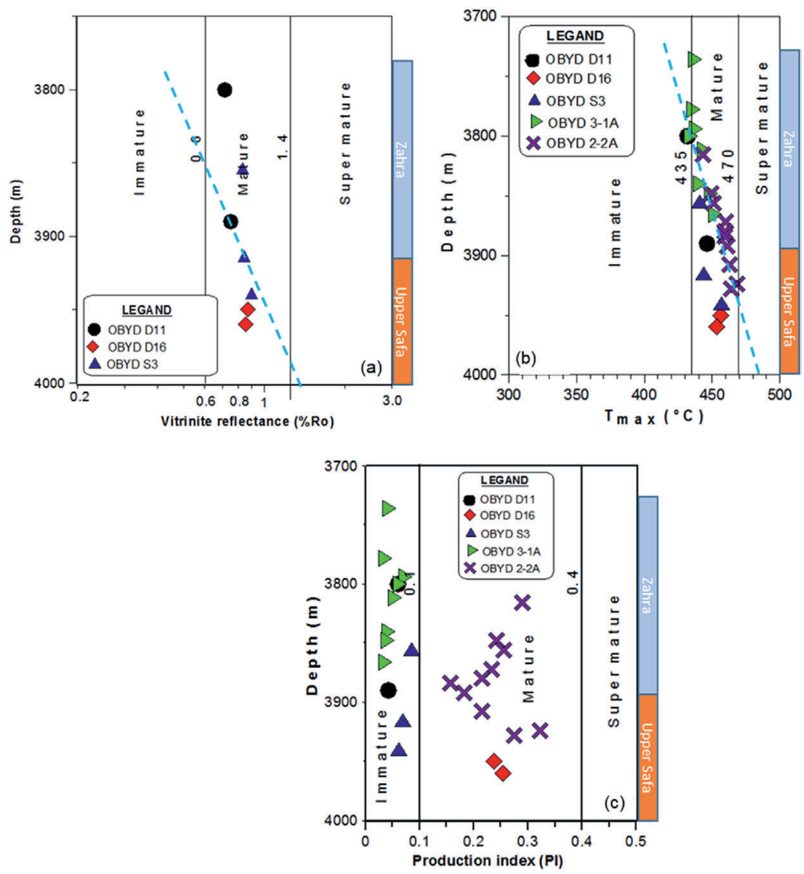

Fig. 9. Maturation indicators in the Middle Jurassic Khatatba Shale, based on (a) vitrinite reflectance (%Ro), (b) T_{max}, and (c) Production Index (PI). The figure illustrates the thermal maturity levels of the shale, showing areas that have reached the peak gas window and indicating the potential for hydrocarbon generation.

not prohibitive for development, these findings highlight the importance of incorporating corrosion-resistant casing materials and proper well completion strategies in future exploitation plans (Kermani and Smith, 1997; Nasr-El-Din and Al-Humaidan, 2001).

4.4. Geomechanical analysis

The geomechanical analysis is essential for determining the completion quality (CQ) of shale reservoirs, which is crucial for predicting effective stimulation through hydraulic fracturing. This

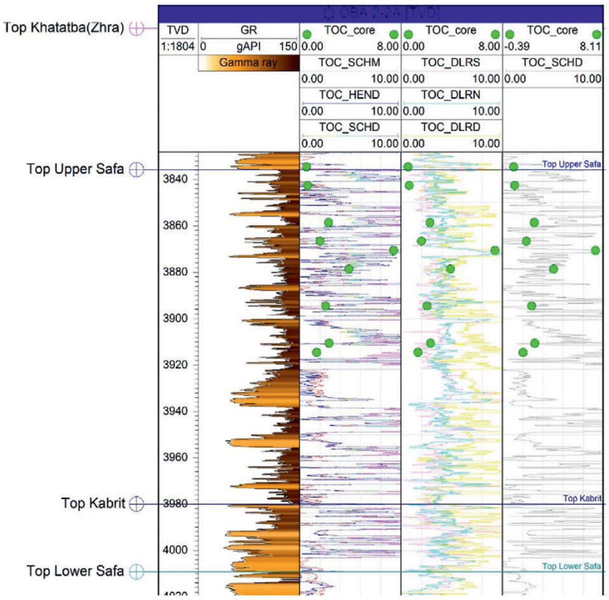

Fig. 10. Total Organic Carbon (TOC) values in the Middle Jurassic Khatatba Shale, derived from well log analysis and validated against TOC values obtained from ditch sample geochemical analysis. The figure demonstrates the consistency and reliability of well log-derived TOC measurements, highlighting the correlation between the two methods and confirming the organic richness of the shale.

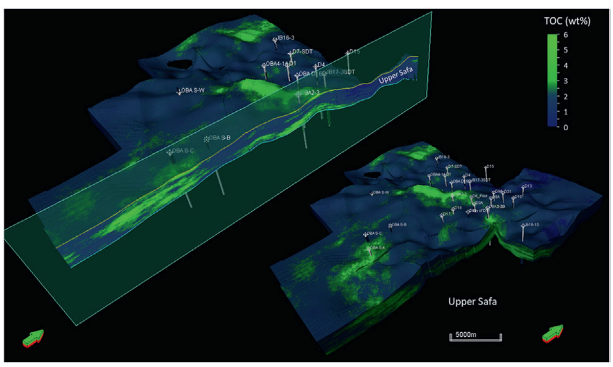

Fig. 11. Vertical and spatial distribution of Total Organic Carbon (TOC) > 2% within the Upper Safa Member. The color scale represents TOC concentrations, with green to yellow hues indicating TOC >2% and dark blue representing lower TOC values. The figure highlights distinct TOC-rich intervals vertically and laterally, concentrated around specific well locations (e.g., OBA-SW, OBA-SB, OBA-SC). These organic-rich zones align with the structural framework of the Upper Safa Member, marking them as potential "sweet spots" for hydrocarbon exploration and development.

analysis considers various factors, including mineralogy and elastic properties such as Young's modulus, Poisson's ratio, bulk modulus, and rock hardness. These properties significantly influence the brittleness and fracture potential of the shale. For the Khatatba Shale in the Obaiyed field, the analysis reveals that the lower part of the Upper Safa member is particularly brittle, making it a prime target for hydraulic fracturing (Fig. 12). This brittleness is indicated by P-impedance seismic inversion and log-derived geomechanical properties.

Identifying areas with great thickness is a primary goal in shale gas development as thicker shale intervals often correlate with higher hydrocarbon potential. In the Khatatba Shale, thickness variations are well documented, with some sections reaching up to 450 m. These thicker intervals are identified through seismic interpretation and well log data, providing valuable targets for drilling and completion. High TOC values, indicative of organic richness, are another critical factor. In the Upper Safa Shale, areas with TOC values exceeding 4% are considered particularly promising, as they suggest a high potential for hydrocarbon generation and storage.

Low fracture gradient (FG) areas are also important as they indicate zones where hydraulic fracturing can be more easily achieved. The geomechanical analysis of well D11, for instance, shows vertical changes in FG and fracture toughness (Kic) throughout the Khatatba Shale (Fig. 12). These variations help identify the most favorable zones for fracturing, optimizing the stimulation process. The P-Impedance and Fracture Gradient (FG) logs further delineate sweet spots, highlighting mechanically favorable zones with high impedance and low fracture resistance, ideal for hydraulic fracturing. The results show that the Upper Safa Member contains intervals with TOC exceeding 4%, low FG values suitable for fracture propagation, and sufficient thickness (average ~150 m), establishing it as the most promising target for shale gas production within the Khatatba Formation.

The geomechanical results indicate that the vertical stress (σ_v) increases linearly with depth and provides the upper bound for stress calibration (Fig. 13). The minimum horizontal stress (σh_{min}) curves range between 25 and 30 MPa/km, consistent with tectonically relaxed rift basin conditions, while maximum horizontal stress (σH_{max}) estimates are generally 1.2–1.5 times higher than σhmin. Formation pressure (P_p) analysis shows a near-hydrostatic trend in shallow intervals but reveals mild overpressure below ~3800 m, corresponding to organic-rich, low-permeability shale intervals. These trends are consistent across most study wells, with some local variations linked to lithological heterogeneity.

The combination of σH_{max}, σh_{min}, and P_p curves provides critical constraints for wellbore stability and hydraulic fracturing design. Notably, the safe mud weight window derived from these stress profiles suggests that drilling in the Upper Safa shale is feasible, but narrow, requiring careful control of mud density to avoid shear failure or tensile fracturing.

Seismic inversion in the Khatatba Shale plays a crucial role in pinpointing sweet spots for optimal wellbore placement and reducing drilling risks (Fig. 14). By converting seismic reflection data into quantitative rock-property descriptions, seismic inversion helps delineate areas with high thickness, low fracture gradient, high TOC, and high impedance. These identified sweet spots ensure that wellbores are placed in the most promising zones, enhancing the efficiency of drilling operations and minimizing the risks associated with wellbore instability and suboptimal reservoir contact. The acoustic impedance cross-section between wells D10 and D11 further highlights the vertical and lateral variations in rock properties within the Khatatba Formation. Key stratigraphic markers, including the Top Khatatba (Zahra), Top Upper Safa, Top Kabrit, and Top Lower Safa, are clearly delineated, with impedance contrasts corresponding to lithological and reservoir property changes. High impedance zones, represented in red, are associated with dense lithologies such as limestone and compacted shales, while low impedance zones, shown in blue and green, indicate organic-rich shales and potential gas-bearing sandstones, particularly in the Upper Safa Member. This integrated approach not only improves the economic viability of shale gas projects but also enhances the overall safety and success rate of drilling activities in the Obaiyed field.

5. Discussion

The evaluation of the Khatatba Shale in the Obaiyed field, Western Desert, Egypt, against established shale reservoir criteria

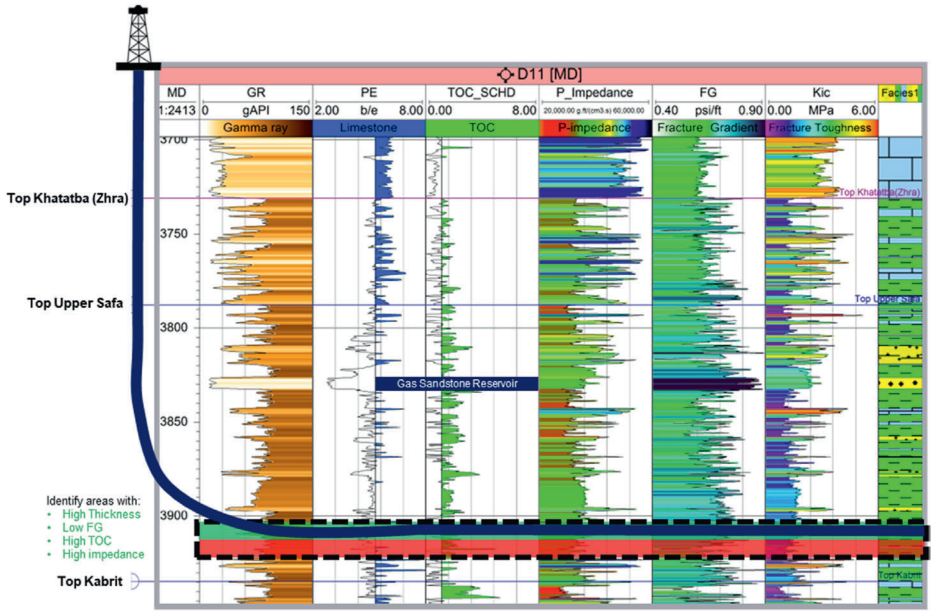

Fig. 12. Geomechanical analysis of well D11, illustrating vertical changes in fracture gradient (FG) and fracture toughness (Kic) throughout the Khatatba Shale, based on well log data. The figure highlights the variations in geomechanical properties, aiding in the identification of optimal zones for hydraulic fracturing.

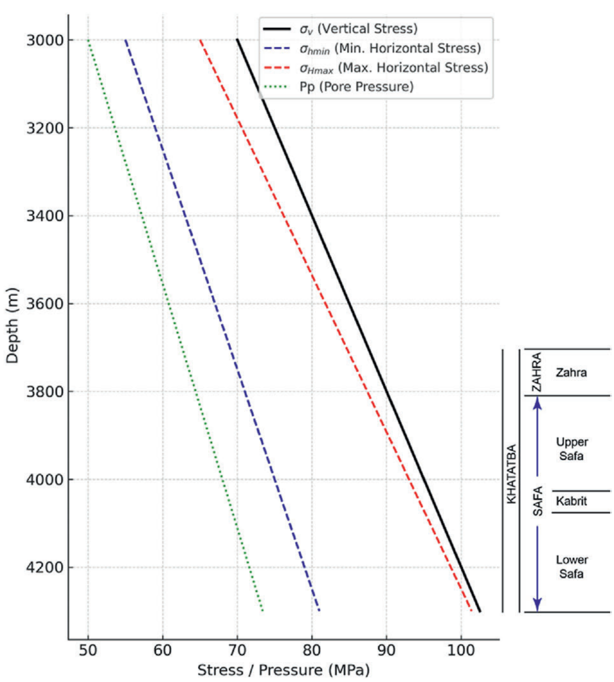

Fig. 13. Stress and pore pressure profiles with depth, alongside the stratigraphic column of the Middle Jurassic Khatatba Formation (Zahra, Upper Safa, Kabrit, and Lower Safa members).

(LI et al., 2022; Van Bergen et al., 2013) highlights its potential as a significant hydrocarbon resource. Key criteria such as thickness, depth, TOC content, thermal maturity, and geomechanical properties were assessed to determine the formation's viability for shale gas production. This integrated assessment underscores the importance of each criterion in understanding the reservoir quality (RQ) and completion quality (CQ), essential for optimizing exploration and production strategies.

5.1. Thickness and depth

Thickness is a fundamental criterion for evaluating shale reservoirs, as it influences both hydrocarbon storage capacity and economic feasibility (Eshkalak and King, 2014). Thicker intervals provide a greater volume of rock that can store hydrocarbons and reduce the number of wells required for extraction, thereby improving the overall cost-efficiency of exploration and production. Additionally, the depth of a formation plays a crucial role in enabling hydraulic fracturing, as sufficient overburden pressure is needed to propagate fractures effectively and enhance gas recovery from low-permeability reservoirs like shale.

In the context of the Khatatba Shale, the interplay of its thickness and depth creates a favorable environment for shale gas development (Figs. 5 and 6).

The isopach map of the Upper Safa formation reveals significant thickness variations, ranging from 80 to over 200 m, with the thickest intervals (>200 m) concentrated in the northeastern part of the study area near well JB18-1S. These thickness trends indicate structural control, with depocenters in the northeast suggesting favorable reservoir development due to increased accommodation space, likely influenced by syn-depositional tectonics or subsidence. Conversely, thinner zones in the southwest, around wells like OBA-S-W, may reflect uplifted or erosionally truncated areas with less reservoir potential. The thickest regions are prime targets for further exploration and development, as they are likely associated with better-developed reservoir facies, while thinner zones might correspond to lower depositional energy or non-reservoir facies. This thickness distribution emphasizes the need for integrating structural and petrophysical data to assess hydrocarbon potential in the area.

5.2. TOC content and thermal maturity

TOC content and thermal maturity are essential parameters for evaluating the hydrocarbon generation and storage potential of shale reservoirs. TOC values reflect the abundance of organic matter available for hydrocarbon conversion, while thermal

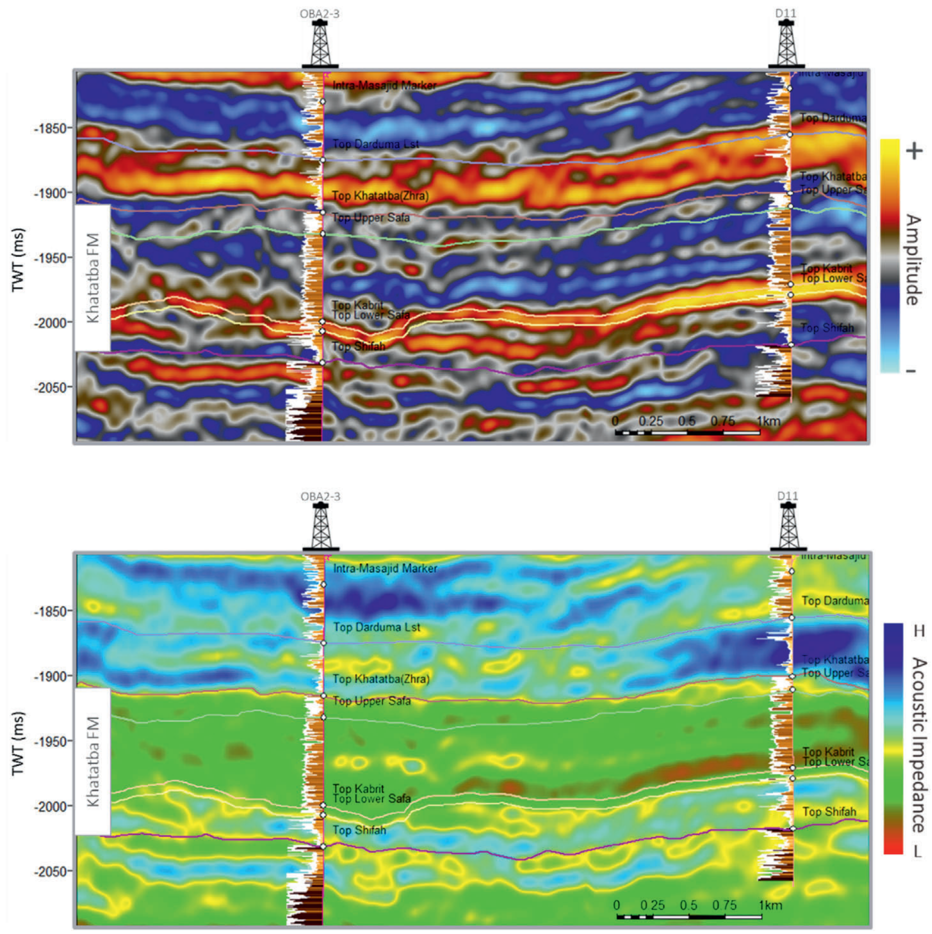

Fig. 14. Seismic inversion in the Khatatba Shale pinpointing sweet spots to optimize wellbore placement and reduce drilling risks. The figure demonstrates the identification of zones with high thickness, low fracture gradient, high TOC, and high impedance, which are crucial for efficient and safe drilling operations.

maturity determines whether the organic material has reached the transformation stage necessary for oil and gas production (Abdel-Fattah et al., 2024b; Gharib et al., 2024). These factors are integral to assessing both the quality and economic viability of a shale reservoir.

The Khatatba Shale's organic richness, with TOC levels surpassing the productive threshold, highlights its significant hydrocarbon generation potential (Figs. 7–11; Table 1). The Upper Safa Member shows a remarkable relationship between Total Organic Carbon (TOC) content and thermal maturity, solidifying its role as a key hydrocarbon-generating interval within the Khatatba Formation. The TOC distribution map highlights vertical and lateral heterogeneities, with concentrations exceeding 2% localized around specific wells, such as OBA-SW and OBA-SB. These zones align with structural features like fault-related traps, indicating that both depositional environments and post-depositional tectonic processes significantly influenced organic matter enrichment and preservation. The marine depositional environment, coupled with low-energy conditions, likely facilitated the accumulation of Type II kerogen, conducive to generating both oil and gas.

Thermal maturity analysis, supported by T_{max} and vitrinite reflectance (%Ro) values, confirms that the organic material in the Upper Safa Member has reached the gas generation window (Fig. 10). For example, T_{max} values exceeding 450 °C and Ro values ranging from 0.75% to 1.2% highlight advanced thermal evolution. These parameters indicate favorable geothermal gradients and burial histories that have enabled the transformation of organic material into hydrocarbons.

Furthermore, the spatial analysis of TOC and maturity across the Upper Safa Member reveals distinct "sweet spots" where hydrocarbon generation potential is maximized (Fig. 11). These zones coincide with areas of optimal thickness, as seen in the isopach map (Fig. 5), providing a greater volume of organic-rich rock for exploration. The geochemical and thermal data emphasize the role of structural compartmentalization in shaping hydrocarbon migration and accumulation patterns, with some fault-bounded blocks serving as efficient hydrocarbon traps.

The integration of TOC and thermal maturity data from the Upper Safa Member not only confirms its capacity as a hydrocarbon source but also highlights the importance of targeting regions with high TOC, appropriate thermal maturity, and favorable structural settings. These insights are critical for optimizing drilling strategies, reducing exploration risks, and enhancing economic viability in shale gas development within the Obaiyed field.

5.3. Geomechanical properties

Geomechanical properties are essential for assessing the completion quality (CQ) of shale reservoirs (Farfour et al., 2021b; Zhang, 2013), particularly their suitability for hydraulic fracturing. The geomechanical properties of the Upper Safa Member indicate its high suitability for hydraulic fracturing and its potential as a productive shale gas reservoir. figures (12 and 13) reveal the brittleness of the formation, particularly in the lower part of the Upper Safa Member, which is characterized by favorable elastic properties such as high Young's modulus and low Poisson's ratio. These properties make the rock more prone to fracturing, a critical factor in ensuring the effectiveness of hydraulic stimulation.

The vertical changes in fracture gradient (FG) and fracture toughness (Kic), as demonstrated in the geomechanical analysis, highlight the heterogeneity within the Upper Safa Member. The lower FG values in specific intervals suggest zones that require less pressure for fracture initiation and propagation, which enhances the efficiency of hydraulic fracturing operations. These low FG zones coincide with areas of high brittleness, further supporting their selection as primary targets for well placement and reservoir stimulation. Additionally, seismic inversion results provide insights into mechanical contrasts within the Upper Safa Member (Fig. 13). High impedance zones, indicative of compacted and brittle lithologies, are highlighted as potential sweet spots for fracturing. These zones align well with areas of high TOC and favorable thickness, enhancing their significance for hydrocarbon extraction.

The geomechanical heterogeneity observed in the Upper Safa Member underscores the need for an integrated approach to reservoir development. Identifying intervals with optimal elastic properties and low FG ensures the maximization of fracture propagation and connectivity, leading to improved reservoir stimulation and hydrocarbon recovery. This targeted geomechanical understanding of the Upper Safa Member provides a robust foundation for optimizing hydraulic fracturing designs and ensuring the economic viability of shale gas production in the Obaiyed field.

5.4. *Integrated risk assessment*

An integrated risk assessment approach that combines geological, petrophysical, geochemical, and geomechanical analyses provides a holistic framework for evaluating shale reservoirs (Haris et al., 2017; Hui et al., 2023; Jarvie, 2012; Rickman et al., 2008; Shang et al., 2021). Such integration is essential for identifying "sweet spots" within heterogeneous successions like the Khatatba Shale (Figs. 11, 12 and 14), as it allows simultaneous consideration of reservoir quality (RQ), completion quality (CQ), and operational risks.

The structural framework of the Upper Safa Member is strongly influenced by fault-bounded compartments (Fig. 6). These structures present both opportunities and risks: faults may enhance hydrocarbon migration and create effective traps but can also cause reservoir compartmentalization, complicating connectivity and pressure support (Morad et al., 2012; Zou et al., 2015). Therefore, structural interpretation must be carefully coupled with reservoir property analysis to optimize well placement and maximize recovery.

Petrophysical evaluation revealed significant heterogeneity in the Upper Safa Member, with total porosity ranging from 6 to 12%, effective porosity between 4 and 8%, shale volume often exceeding 40%, and permeability in the range of 0.01–0.1 mD (Table 1). Gas storage capacity is considerable, with free gas contents enhanced below 3800 m and adsorbed gas reaching 1.5–2.0 cm^3/g in TOC-rich intervals (Table 2). These findings indicate that productive sweet spots occur where porosity is higher, shale volume is reduced, and effective permeability supports gas mobility. Integration with geomechanical brittleness indices refines sweet spot identification, consistent with approaches applied in global shale plays (Passey et al., 2010; Sondergeld and Rai, 2011).

Geochemical characterization highlights both lateral and vertical heterogeneity in TOC and maturity (Figs. 12 and 14). The Upper Safa contains TOC averaging ~4 wt% with mixed Type II–III kerogens, and thermal maturity within the gas window, favoring dry gas generation (Table 3; Fig. 8). High TOC and maturity are often preserved in structural lows, which reduces the risk of drilling into less favorable zones (Jarvie, 2012). Importantly, geochemical analysis also confirmed the presence of corrosive gases—CO_2 (0.8–2.0 mol%) and H_2S (25–80 ppm)—in certain intervals. While concentrations are modest, their occurrence raises concerns for casing and drill string integrity. This necessitates the use of corrosion-resistant alloys, protective coatings, and appropriate monitoring programs (Kermani and Morshed, 2003; Nasr-El-Din and Al-Humaidan, 2001).

Geomechanical analysis further constrains the safe drilling and stimulation window. The vertical stress (σv), derived from overburden integration, increases linearly with depth, while the minimum horizontal stress ($\sigma hmin$) is 25–30 MPa/km and the maximum horizontal stress ($\sigma Hmax$) is 1.2–1.5 times $\sigma hmin$ (Fig. 13). These stress magnitudes, together with formation pressure (Pp) curves, define a relatively narrow safe mud weight window. Zones characterized by high Young's modulus and low Poisson's ratio correspond to brittle, gas-rich intervals that are most favorable for hydraulic fracturing. Conversely, intervals with high shale volume or lower brittleness present mechanical challenges and higher risks of wellbore instability (Sone and Zoback, 2013; Zoback, 2007).

Based on this integrated risk framework, horizontal wells targeting the lower Upper Safa Member are recommended. Optimal well orientation is perpendicular to $\sigma Hmax$, ensuring efficient fracture propagation. Targeting brittle, TOC-rich zones with porosity >8% and adsorbed gas >1.5 cm^3/g is expected to maximize hydraulic fracturing efficiency and production. Conversely, avoiding intervals with elevated shale volume or high corrosive gas content reduces operational risks and prolongs well integrity. This integrated strategy enhances both the technical feasibility and economic viability of shale gas development in the Khatatba Formation and provides a transferable workflow applicable to other unconventional plays worldwide (Hui et al., 2023; Zou et al., 2015).

6. Conclusions

This study provides a comprehensive assessment of the Middle Jurassic Khatatba Formation in the Obaiyed field, Western Desert, Egypt, by integrating geological, petrophysical, geochemical, and geomechanical datasets to evaluate shale gas potential and operational risks. The results confirm the Upper Safa Member as the most promising target due to its thickness (80–180 m), elevated TOC (~4 wt%), mixed Type II–III kerogens, and maturity within the gas window. Petrophysical analysis highlights heterogeneity, with porosity ranging from 6 to 12%, effective porosity of 4–8%, shale volume often exceeding 40%, permeability in the order of 0.01–0.1 mD, and gas storage capacity enhanced below 3800 m with adsorbed gas reaching 1.5–2.0 cm^3/g in TOC-rich intervals. Geochemical screening revealed variations in organic richness and maturity as well as the presence of corrosive gases (0.8–2.0 mol% CO_2 and 25–80 ppm H_2S), which pose potential risks to casing and drill strings, requiring corrosion-resistant completion designs. Geomechanical evaluation showed $\sigma hmin$ between 25 and 30 MPa/km and $\sigma Hmax$ 1.2–1.5 times higher, with pore pressure curves defining a narrow safe mud weight window and brittle zones characterized by high Young's modulus and low Poisson's ratio offering mechanically favorable targets for hydraulic fracturing. Seismic analysis further delineated fault-bounded compartments that influence migration and connectivity, while seismic inversion identified TOC-rich, low-impedance intervals as optimal drilling targets. Collectively, this integrated framework supports horizontal wells oriented perpendicular to σHmax and targeting brittle, TOC-rich intervals with porosity >8% and adsorbed gas >1.5 cm^3/g, while avoiding zones with high shale volume or corrosive gas presence. The workflow presented here minimizes drilling risks, enhances stimulation efficiency, and improves economic viability, offering a transferable model for unconventional shale reservoir development globally.

CRediT authorship contribution statement

Mohamed I. Abdel-Fattah: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Formal analysis, Data curation, Conceptualization. **Hamdan A. Hamdan:** Writing – review & editing, Writing – original draft, Methodology, Data curation, Conceptualization. **Adnan Q. Mahdi:** Writing – review & editing, Writing – original draft, Validation, Conceptualization. **Zakaria M. Abd-Allah:** Writing – original draft, Visualization, Methodology, Data curation, Conceptualization. **Nezar A. Hammouri:** Writing – review & editing, Writing – original draft, Software, Conceptualization. **Sara M. Abuzied:** Writing – review & editing, Writing – original draft, Software, Methodology, Data curation, Conceptualization.

Declaration of competing interest

The authors declare no competing interests.

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