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PETROLEUM GEOLOGY

Fracture Characterization and In-Situ Stress Analysis in Tight Carbonates of Potwar Basin, Pakistan

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ABSTRACT

Tight carbonate reservoirs represent a key target for hydrocarbon exploration in structurally complex foreland basins such as the Potwar Basin of northern Pakistan. This study aims to characterize fracture networks and in-situ stress fields within the Eocene Sakesar Limestone and Chorgali Formation. A multidisciplinary approach was adopted, integrating high-resolution Formation MicroImager (FMI) logs, core observations, borehole breakout analysis, and regional structural data. Results show that the fracture network is dominated by high-angle NE-SW trending sets, with secondary NW-SE orientations reflecting local structural complexities. Fracture densities range from 3 to 12 fractures per meter, with the highest intensities occurring near fault-bounded structural highs. Stress analysis indicates a strike-slip to transpressional regime, with maximum horizontal stress (Sh_{max}) oriented NE-SW (~045°). Estimated magnitudes are Sv = 22-24 MPa/km, Sh_{min} = 18-20 MPa/km, and Sh_{max} = 26-30 MPa/km. These findings identify favorable zones for horizontal well placement and hydraulic fracturing, reducing drilling risks and improving completion design. The study provides a novel, integrated framework for optimizing the development of tight carbonate reservoirs in the Potwar Basin and offers insights applicable to similar foreland fold-and-thrust belt settings.

Palabras clave: Potwar Basin; Tight carbonate reservoirs; Fracture characterization; In-situ stress analysis; Geomechanics.

Caracterización de fracturas y análisis de esfuerzos *in situ* en carbonatos compactos de la Cuenca de Potwar, Pakistán

RESUMEN

Los yacimientos de carbonatos compactos representan un objetivo clave para la exploración de hidrocarburos en cuencas de antepaís estructuralmente complejas, como la Cuenca de Potwar en el norte de Pakistán. El presente estudio tiene como objetivo caracterizar las redes de fracturas y los campos de esfuerzos *in situ* dentro de la caliza Sakesar y la Formación Chorgali del Eoceno. Con este fin se adoptó un enfoque multidisciplinario, que integra registros de Formation MicroImager (FMI) de alta resolución, observaciones de núcleos, análisis de rotura de pozos y datos estructurales regionales. Los resultados muestran que la red de fracturas está dominada por conjuntos de alta inclinación con orientación NE-SO, con orientaciones secundarias NO-SE que reflejan complejidades estructurales locales. La densidad de fracturas varía de 3 a 12 fracturas por metro, con las mayores intensidades cerca de altos estructurales limitados por fallas. El análisis de esfuerzos indica un régimen de desgarre a transpresional, con el esfuerzo horizontal máximo (Shmax) orientado NE-SO (~045°). Las magnitudes estimadas son Sv = 22-24 MPa/km, Shmin = 18-20 MPa/km y Shmax = 26-30 MPa/km. Estos resultados identifican zonas favorables para la ubicación de pozos horizontales y fracturamiento hidráulico, reduciendo riesgos de perforación y mejorando el diseño de terminaciones. El estudio proporciona un marco integrado y novedoso para optimizar el desarrollo de yacimientos de carbonatos compactos en la Cuenca de Potwar y ofrece perspectivas aplicables a entornos similares en cinturones de pliegues y cabalgamientos de antepaís.

Keywords: Cuenca de Potwar; yacimientos de carbonatos compactos; caracterización de fracturas; análisis de esfuerzos in situ; geomecánica.

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1. Introduction

Global energy industry is focusing more on unconventional hydrocarbon resources which includes tight carbonates to meet rising energy demand. Tight carbonate reservoirs are characterized by low matrix porosity and permeability making the existing natural fractures critical pathways for hydrocarbon flow (Durrani et al., 2020; Shao et al., 2020; Shah et al., 2024; Talib et al., 2023). Recent studies have emphasized the significance of fracture networks in enhancing permeability and fluid connectivity in carbonate plays worldwide (Laubach et al., 2019). Potwar Basin of northern Pakistan provide promising case study as it hosts thick carbonate successions in complex tectonic setting that has formed extensive fracturing and faulting across the basin. Historically exploration efforts in Potwar Basin have prioritized structural traps but recent developments highlight need for detailed fracture and stress analyses to optimize reservoir performance in tight carbonates (Jadoon et al., 2015). Natural fractures can enhance effective permeability and facilitate fluid drainage; however, their contribution strongly depends on fracture orientation, density, connectivity, and the prevailing in-situ stress regime (Laubach et al., 2019).

A comprehensive understanding of the fracture system and stress field is therefore essential for planning horizontal wells, designing hydraulic fracturing treatments, and formulating field development strategies. The integration of borehole image logs, core data, and geomechanical analysis provides a robust framework for characterizing fracture networks and assessing present-day stress conditions.

Recent regional studies demonstrate that integrating image-log fracture analysis with calibrated mechanical earth models (MEMs) improves well design by defining safe mud-weight windows and trajectory constraints (Allawi & Al-Jawad, 2023). In mature fields, 4D finite-element modeling has documented significant reductions in horizontal stresses during depletion, which narrow the operational mud-weight window and affect stimulation designs (Allawi & Al-Jawad, 2022). Emerging semi-analytical estimators of elastic properties provide a rapid, porosity-driven method for seeding MEMs where core is sparse (Allawi et al., 2024). Comparable MEM-based analyses in southern Iraq also highlight the importance of polyaxial failure criteria when estimating SHmax from breakout geometry (Allawi, 2024).

This study specifically aims to characterize fractures and analyze in-situ stresses within the Eocene Sakesar Limestone and Chorgali Formation of the Potwar Basin. By combining Formation MicroImager (FMI) logs, core observations, borehole breakout analysis, and regional structural information, the research not only supports effective reservoir development but also reduces drilling and completion risks. The novelty of this work lies in presenting the first integrated fracture-stress characterization of Eocene carbonates in the Potwar Basin, contributing to regional understanding while offering comparative insights for foreland basin plays globally.

2. Geological Setting

Potwar Basin located in northwestern part of Pakistan represents southernmost extent of Himalayan foreland fold-and-thrust belt (Fig. 1). It is bordered to north by Main Boundary Thrust (MBT) to the south by Salt Range Thrust and to east by Jhelum Fault. Basin covers approximately 20,000 km² and is structurally complex due to multiple phases of Cenozoic compression (Baker et al., 1988; Shah, 2023; Yeats & Hussain, 1987). Stratigraphic succession of basin spans from Precambrian to Quaternary with thick pile of sedimentary rocks dominated by marine-continental deposits. Among these Eocene Sakesar Limestone and Chorgali Formation are very significant for their hydrocarbon potential as there have been successful discoveries in other parts of Basin. Sakesar Limestone was deposited in shallow marine carbonate shelf environment and it is typically massive to thickly bedded whereas Chorgali Formation represents transitional unit with mixed carbonate and shale facies. Structurally Potwar Basin is characterized by north-verging thrust faults and back-thrusts and large-scale detachment folds. Deformation style is largely thin-skinned, detaching on evaporite-rich Salt Range Formation which acts as regional décollement surface (Jadoon et al., 2015; Jaumé & Lillie, 1988).

Fracturing in Eocene carbonates is mainly related to regional compressional tectonics associated with Himalayan orogeny (Khan et al., 2022). Fractures are mostly high-angle open to partially mineralized and exhibit variety of orientations reflecting polyphase stress history of basin (Talib et al., 2023). These fractures enhance secondary porosity and are important for fluid migration and storage in tight carbonate matrices (Jadoon et al., 2005; Khan et al., 2022). Understanding this geological context is very important for correctly and properly interpreting fracture patterns and stress orientations and for predicting fracture behavior at reservoir scale. It provides foundation for integrating borehole image logs and core data in a basin wide geomechanical model that can inform both exploration and production strategies.

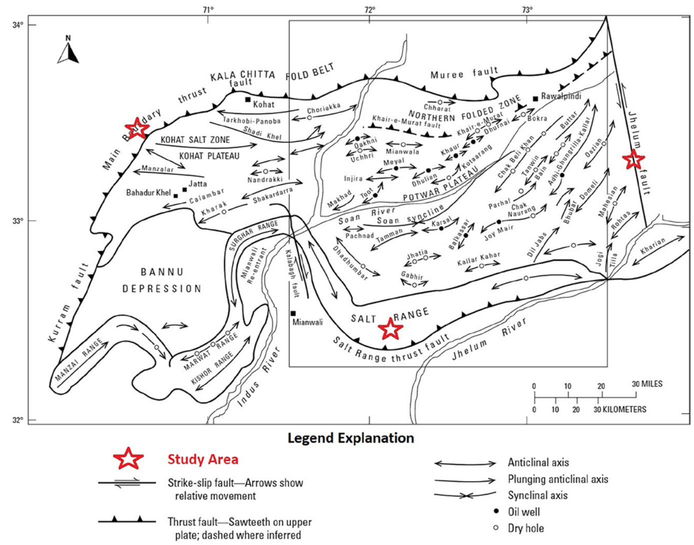


Figure 1. Location map of the Potwar Basin and study area (after Shah et al., 2023; Shah, 2024). Major structural features are shown, including the Main Boundary Thrust (MBT), Salt Range Thrust (SRT), and Jhelum Fault. The study area is marked with a red star and labeled accordingly. A north arrow is provided for orientation. Legend explanation includes faults, thrusts, and study area markers.

Stratigraphic Framework

The Potwar Basin preserves a thick sedimentary succession ranging from the Precambrian to the Quaternary, dominated by marine-continental deposits associated with foreland basin development (Kadri, 1995; Kazmi & Jan, 1997). The stratigraphy includes Cambrian sandstones and carbonates, Permian mixed siliciclastics and carbonates, Jurassic clastics, Paleogene carbonates, and Neogene molasse deposits. The Eocene formations, particularly the Sakesar Limestone and Chorgali Formation, are the primary reservoir targets of this study due to their hydrocarbon potential and extensive fracture development.

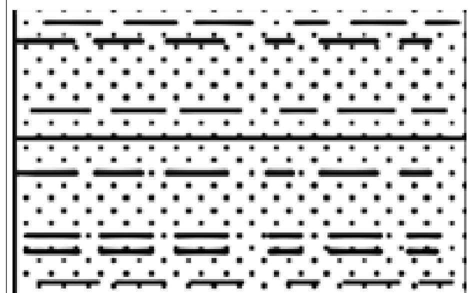
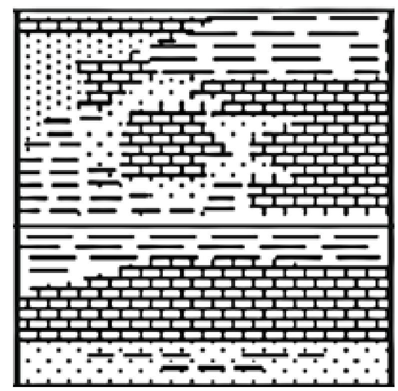
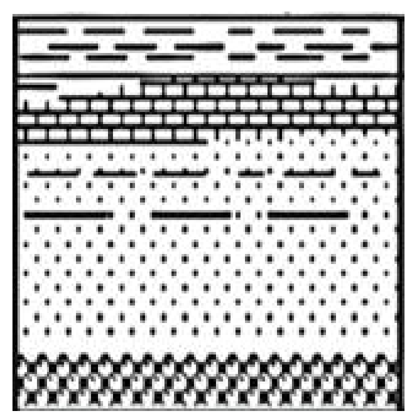
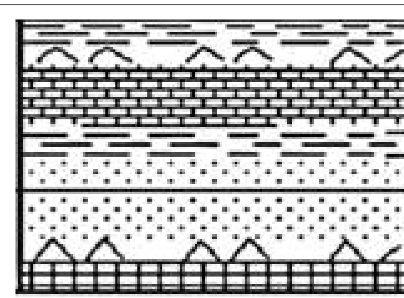
Table 1 summarizes the general stratigraphy of the Potwar Basin, highlighting key formations, lithologies, and depositional settings. This stratigraphic framework places the studied Eocene carbonates within their broader geological context and illustrates their position above the Paleocene Patala and Lockhart formations and below the younger Miocene molasse (Nagri, Chinji, and Murree formations).

3. Data and Methodology

3.1 Data Sources

1. This study integrates multiple datasets to characterize fracture networks and in-situ stress regimes in the Potwar Basin carbonates:
2. Formation MicroImager (FMI) logs from four wells provided high-resolution borehole wall images for fracture and bedding analysis.
3. Core samples from selected intervals in two wells supplied direct evidence of fracture attributes (aperture, mineral infill, surface roughness).
4. Caliper and sonic logs supported borehole breakout identification and wellbore stability analysis, contributing to stress orientation and magnitude estimates.
5. Regional structural maps and cross-sections contextualized local fracture patterns within the broader tectonic framework.

Table 1. General Stratigraphy of the Potwar Basin.

Age / Epoch (Age System)	**LITHOLOGY DESCRIPTION**	**Formation**	**LITHOLOGY**
Neogene (Pliocene, Miocene, Oligocene)	Sandstone, sandstone and clay	Nagri, Chinji, Kamlial, Murree	
Oligocene	**Unconformity**		
Paleogene (Eocene, Paleocene)	Limestone, shale, sandstone	Chorgali, Sakesar, Nammal, Patala, Lockhart, Hangu	
Mesozoic & Late Permian	**Unconformity**		
Jurassic Permian Early Permian	Sandstone, limestone, shale, siltstone, conglomerate	Datta, Chhidru, Wargal, Amb, Sardhai, Warcha, Dandot, Tobra	
Carboniferous to Ordovician	**Unconformity**		
Cambrian to Precambrian (Infra-Cambrian)	Shale, dolomite, sandstone and siltstone	Baghanwala, Jutana, Kussak, Khewra	
	Marl, claystone and siltstone, salt	Salt Range	

3.2 Fracture Characterization

Fracture identification from FMI logs was performed using Interactive Petrophysics software (Version 6.1 2024), recording attributes including fracture type (open, partially mineralized, healed), orientation (dip and azimuth), and density (fractures/m). Rose diagrams were generated to visualize dominant orientations and depth-dependent variations. Core analysis provided validation of FMI results, with fractures measured for aperture (0.1-1.2 mm), mineralization (calcite, pyrite), and spacing. Stylolite-related fractures were also documented. These datasets were cross-calibrated to reduce bias from image log interpretation.

3.3 In-Situ Stress Analysis

Borehole Breakout Analysis

Borehole breakouts were identified as elliptical enlargements in the caliper/FMI images, forming in the direction of minimum horizontal stress (Shmin). Consequently, the maximum horizontal stress (SHmax) orientation is perpendicular to breakout azimuth.

Stress Magnitude Estimation

Stress magnitudes were quantified using established equations:

i. Vertical stress (Sv):

$$S_v = \int_0^z \rho\ (z) g dz$$

where ρ(z) is bulk density (from density logs) and g is gravitational acceleration.

ii. Minimum horizontal stress (Shmin):

$$Sh_{min} = P_p + \alpha\ (S_v - P_p) + T$$

where P_p = pore pressure, α = Biot's coefficient, and T = tectonic stress term (calibrated with leak-off tests where available).

iii. Maximum horizontal stress (SH_{max}):

Derived from breakout width (Wb) and rock compressive strength (σ_c) using the Kirsch equations for wellbore failure (Liu et al., 2025; Zobak, 2007):

$$SH_{max} = \frac{\sigma_c + 3\ Sh_{min} - Sv}{1 - \sin\phi}$$

where ϕ is internal friction angle of the rock.

Breakout-based estimates were cross-checked with empirical correlations from sonic velocity and pore pressure data (Akbarpour & Abdideh, 2020; Allawi & Al-Jawad, 2021).

3.4 Geomechanical Model Integration

The fracture and stress datasets were integrated into a 3D geomechanical framework to generate maps of fracture intensity and stress orientation. Depth-dependent stress profiles were developed for each well, and stress regime classification (normal, strike-slip, reverse) followed the Andersonian criteria using relative magnitudes of Sv, Shmin, and SHmax. These results guided the identification of zones favorable for hydraulic stimulation and horizontal well design.

3.5 Workflow Summary

The adopted workflow followed a stepwise integration of multiple datasets to ensure a robust fracture-stress characterization. The process began with data acquisition, including FMI logs, core samples, caliper and sonic logs, and regional structural information. These were subjected to fracture characterization, where FMI images were interpreted using specialized software and validated against core observations to record fracture types, orientations, densities, and apertures. In parallel, borehole breakout analysis was conducted from caliper and FMI logs to determine SHmax orientation. Subsequently, stress magnitudes were estimated by integrating density-derived overburden (Sv), leak-off and sonic-derived Shmin, and breakout-constrained SHmax calculations based on Kirsch equations and rock strength parameters. All results were then combined into a 3D geomechanical model, which produced fracture intensity maps, stress regime classifications, and stress-fracture alignment evaluations for reservoir development. This workflow not only enhances accuracy by cross-validating multiple datasets but also directly links stress estimates to drilling and completion design, a strength compared with purely structural or seismic-based interpretations. Nonetheless, limitations remain, such as dependence on well coverage, log quality, and the choice of failure criterion, which can introduce uncertainty. Despite these constraints, the methodology provides a comprehensive and transferable framework for evaluating tight carbonate reservoirs, consistent with approaches used in regional MEM-based workflows (Allawi & Al-Jawad, 2022; Allawi & Al-Jawad, 2023; Allawi, 2024).

4. Results

4.1 Fracture Characteristics from FMI Logs

The FMI logs reveal a complex fracture network within the Sakesar Limestone and Chorgali Formation. The identified fractures include high-angle open fractures, partially mineralized fractures, and rare healed fractures. Comparative rose diagrams of fracture orientations for the four studied wells (Fig. 2) illustrate both commonalities and differences across the basin. A dominant NE-SW orientation (040°-060°) is evident across all wells, consistent with the Himalayan compressional stress regime. However, variations between wells were observed. Wells located closer to fault-bounded structural highs (e.g., Well C and Well A) show higher fracture density and stronger clustering along the NE-SW direction, while wells farther from major faults (e.g., Well B) exhibit more scattered orientations, including subordinate NW-SE sets. Well D highlights secondary orientations with slightly lower fracture densities. This grouped presentation underscores that structural position exerts a strong control on fracture intensity and orientation, allowing direct cross-well comparison. Such spatial variability highlights the influence of structural setting on fracture orientation and intensity.

4.2 Core Observations

Core descriptions confirm FMI log interpretations, showing well-developed fracture surfaces with variable apertures (ranging from 0.1 mm to 1.2 mm). Many fractures exhibit partial mineral infill of calcite and minor pyrite, indicating episodes of fluid movement and post-fracture mineralization. Open fractures in core samples align with those identified as conductive on FMI logs, strengthening the confidence in image log interpretations. In some intervals, stylolite-related fractures were also documented, which may contribute additional secondary porosity. A detailed summary of fracture attributes, including dominant azimuths, dip ranges, densities, aperture variations, and mineralization types identified in each well, is presented in Table 2.

4.3 In-Situ Stress Orientation and Magnitudes

Borehole breakout analysis consistently indicates that the maximum horizontal stress (SHmax) orientation is approximately NE-SW (mean azimuth ~045°), in agreement with regional tectonic trends (Khan et al., 2022). Estimated vertical stress (Sv) gradients range from 22 to 24 MPa/km, consistent with the overburden in this part of the basin. Minimum horizontal stress (Shmin) values range between 18 and 20 MPa/km, while SHmax estimates vary from 26 to 30 MPa/km (Table 3).

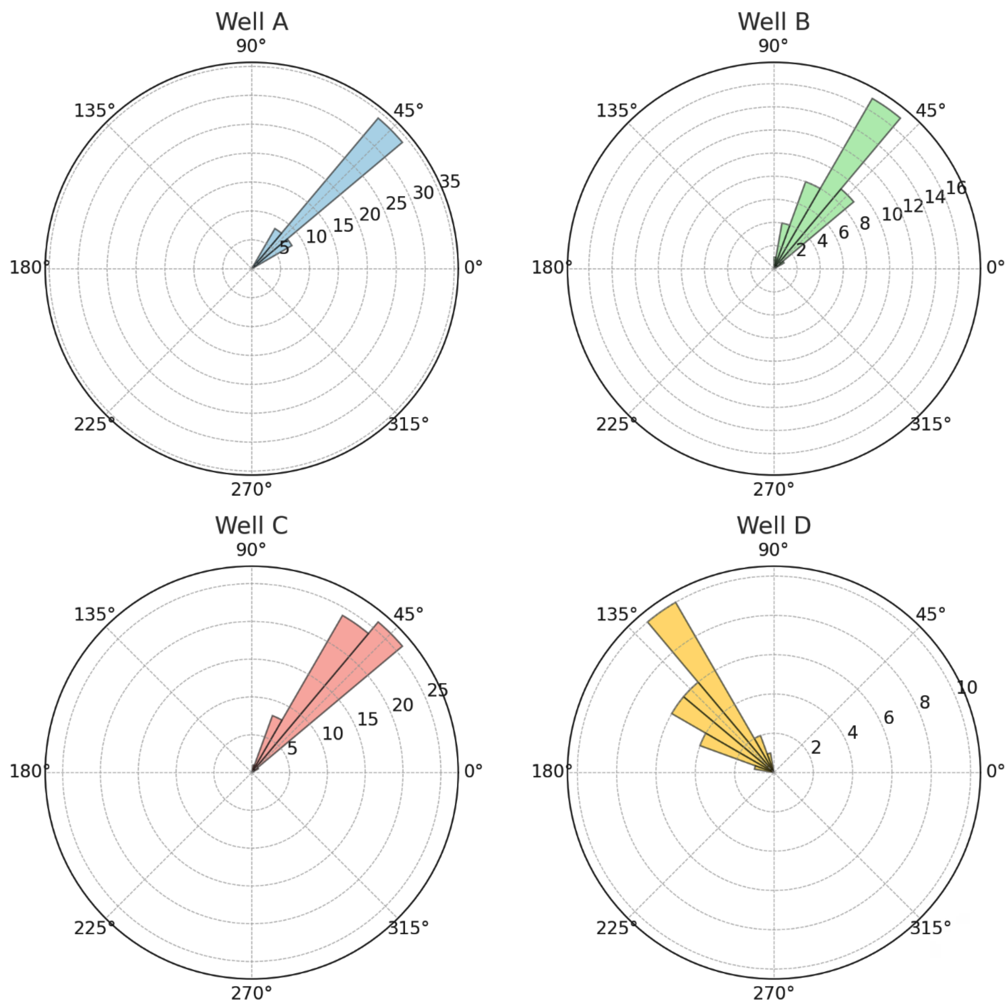


Figure 2. Comparative rose diagrams of fracture orientations from FMI log analysis in four wells (A-D) of the Potwar Basin. Wells A and C show higher fracture densities and strong NE-SW orientations linked to regional Himalayan compression, while Wells B and D illustrate lower densities and subordinate NW-SE sets, likely reflecting local structural complexity.

Table 2. Fracture Attributes Summary from FMI Logs

Well ID	Dominant Fracture Azimuth (°)	Dip (°)	Fracture Density (fractures/m)	Aperture Range (mm)	Mineralization
Well A	045	70-85	10	0.3 - 1.2	Partial calcite, minor pyrite
Well B	043	65-80	7	0.2 - 0.8	Partial calcite
Well C	046	75-85	12	0.5 - 1.0	Calcite filled, some open
Well D	044	60-80	9	0.3 - 1.1	Partial calcite, stylolites

Table 3. Estimated Stress Magnitudes and Orientations for Carbonate Intervals in the Potwar Basin (derived from breakout, density, and sonic log analysis).

Well ID	Depth Interval (m)	Sv (MPa/km)	Shmin (MPa/km)	SHmax (MPa/km)	SHmax Azimuth (°)
Well A	2,500 - 3,000	23	18	28	045
Well B	2,400 - 2,900	22.5	19	27	043
Well C	2,600 - 3,100	24	20	30	046
Well D	2,500 - 3,000	23	18.5	29	044

Uncertainty in Stress Estimates

Although the stress magnitudes are consistent with regional models, they carry inherent uncertainties. Breakout-derived SHmax orientations may vary by ±5°, and magnitude estimates for Shmin and SHmax have an uncertainty of ±2-3 MPa/km, primarily due to variability in log quality, breakout interpretation, and assumed rock strength parameters. These ranges may influence wellbore stability predictions and mud-weight design. Operationally, this necessitates conservative safety margins in well planning and emphasizes the value of real-time geomechanical monitoring.

The vertical variation of stress magnitudes across the carbonate reservoir interval is illustrated in Figure 3, which shows a representative stress profile from Well C highlighting Sv, Shmin, and SHmax trends with depth. Stress regime analysis indicates a strike-slip to transpressional stress environment, supporting the generation of both shear and extensional fractures, this stress setting enhances the potential for natural fracture reactivation during hydraulic stimulation (Su et al., 2025; Yang et al., 2025; Zhao et al., 2025).

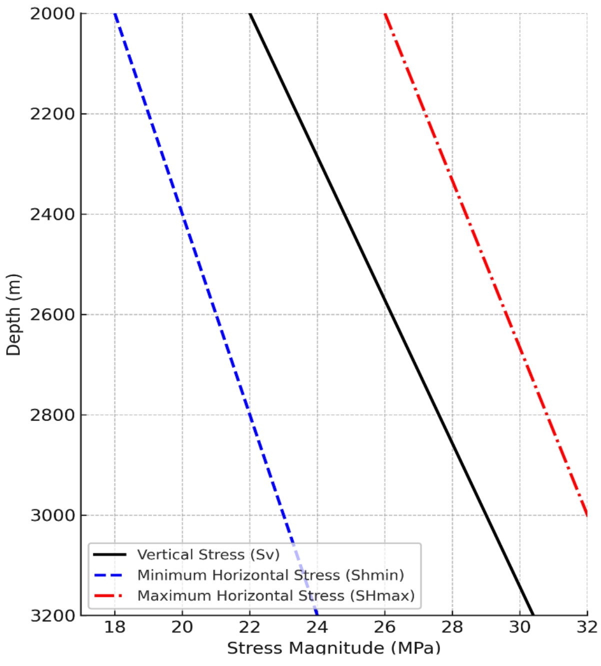


Figure 3. Geomechanical Cross-Section or Stress Profile

4.4 Integrated Geomechanical Interpretation

The integration of fracture and stress data indicates that the carbonate reservoir intervals possess both favorable fracture intensity and stress orientations conducive to fluid flow enhancement. Spatial analysis of fracture intensity maps shows higher densities near structural highs and fault-bounded blocks (Fig. 4). Stress regime plots highlight regions where SHmax orientation aligns optimally with dominant fracture sets, suggesting higher probabilities for fracture connectivity and opening under reservoir pressures (Fig. 5).

These integrated interpretations provide a comprehensive foundation for optimizing well placement, planning stimulation treatments, and improving reservoir productivity in the tight carbonate intervals of the Potwar Basin.

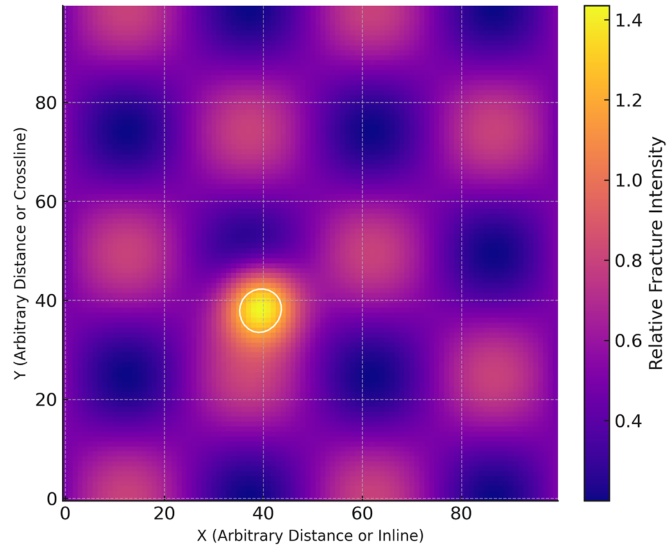


Figure 4. Stress regime and fracture tendency map of the Potwar Basin carbonates. Color-coded domains indicate regions of strike-slip to transpressional stress regimes. Superimposed fracture intensity data highlight zones with optimal alignment between SHmax and dominant fracture sets, suggesting favorable conditions for fracture reactivation and fluid flow.

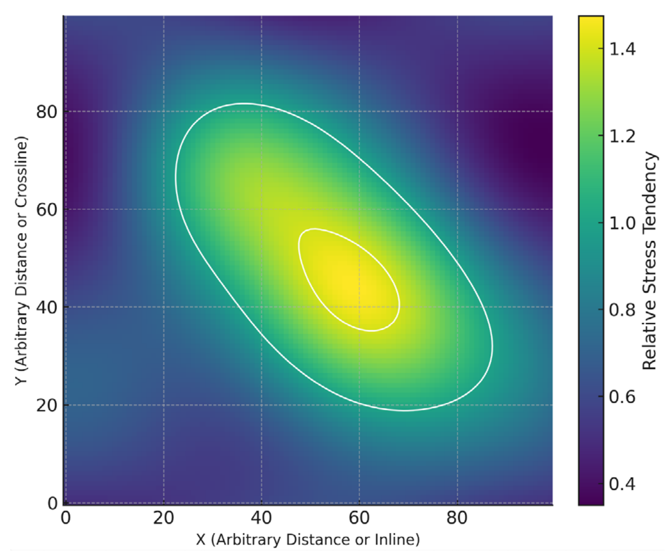


Figure 5. Integrated geomechanical interpretation showing combined fracture intensity and stress orientation. Areas of high fracture density near structural highs coincide with SHmax orientations, identifying ‘sweet spots’ for horizontal well placement and stimulation design.

5. Discussion

5.1 Implications for Reservoir Productivity

The presence of steeply dipping, high-density natural fractures significantly enhances the effective permeability of the Sakesar Limestone and Chorgali Formation, which would otherwise remain tight due to their low matrix porosity. Similar findings have been reported from other foreland basin carbonates where fracture networks provide the dominant flow conduits (Tian et al., 2025; Zhang et al., 2025a; Zhang et al., 2025b). In this study, fracture connectivity in regions where SHmax is optimally aligned indicates highly favorable conditions for fluid flow and drainage, thereby enhancing hydrocarbon recovery. Observed fracture apertures and partial mineralization also suggest that these fractures acted both as migration pathways and as localized traps for mineral precipitation. This dual role of fractures, observed in other carbonate reservoirs such as the Zagros Basin (Ahmadhadi et al., 2008), is critical for understanding long-term conductivity and predicting reservoir performance.

5.2 Well Placement and Stimulation Strategy

The combined analysis of fracture orientations and in-situ stress fields provides direct guidance for horizontal well planning. Drilling wells perpendicular to SHmax allows optimal intersection of dominant fracture sets, maximizing reservoir productivity. Regions with higher fracture density and relatively low stress anisotropy are particularly suitable for hydraulic fracturing, as natural fractures in these zones are more likely to open under stimulation (Nelson, 2001). Identifying these high-potential zones reduces stimulation costs and operational risks. This approach is consistent with studies in tight reservoirs of the Middle East and North America, where aligning well trajectories with natural fracture trends has proven critical to production success (Dai & Santamarina, 2014).

5.3 Drilling and Completion Risks

Although fractures can enhance production, they also introduce operational risks. High-angle open fractures often cause significant mud losses, borehole enlargement, and stuck pipe incidents if not properly managed. Our stress data suggest a strike-slip to transpressional regime, which increases the likelihood of borehole breakout in deviated wells drilled parallel to Shmin. Similar challenges have been documented in fractured reservoirs of southern Iraq and the Zagros fold belt, where drilling-induced instability was mitigated by real-time geomechanical monitoring and optimized mud weights (Allawi & Al-Jawad, 2021). Proactive wellbore strengthening and adaptive drilling strategies are therefore essential for safe operations (Akbarpour & Abdideh, 2020).

5.4 Uncertainty in Stress Estimations

While the stress estimations are consistent with regional tectonic models, uncertainties remain due to the limitations of breakout-based methods and log data resolution. The calculated SHmax values carry an uncertainty of ±2-3 MPa/km, which may influence mud weight windows and stability predictions. Breakout azimuths also display a variability of ±5°, reflecting potential heterogeneity in local stress fields. Such uncertainties highlight the importance of applying conservative safety factors in drilling design and reinforce the value of real-time monitoring and mechanical earth model calibration during operations. Comparable studies in fractured reservoirs of the Middle East and Himalayan foreland have emphasized similar uncertainty ranges, underscoring the necessity of integrated, adaptive well planning.

5.5 Broader Geological Insights

The strong NE-SW orientation of SHmax and dominant fractures supports regional tectonic models of Himalayan compression transmitted into the Potwar Basin (Yeats & Hussain, 1987; Jaumé & Lillie, 1988). The identification of subordinate NW-SE fracture sets points to local structural complexities, potentially associated with oblique faulting or basement reactivation. These findings are consistent with analogous observations from other Himalayan foreland basins, where polyphase stress regimes produce cross-cutting fracture sets (Kumar et al., 2016). Thus, the present study not only refines the geomechanical understanding of the Potwar Basin but also contributes to broader models of foreland basin structural evolution.

6. Conclusion

This study provides a comprehensive assessment of fracture systems and in-situ stress regimes in the tight carbonate reservoirs of the Potwar Basin, with a focus on the Eocene Sakesar Limestone and Chorgali Formation. By integrating Formation MicroImager (FMI) logs, core data, borehole breakout analysis, and regional structural information, the research demonstrates the methodological strength of combining multiple datasets into a consistent geomechanical framework. The results reveal a complex but systematic fracture network dominated by high-angle NE-SW fractures, accompanied by secondary NW-SE sets reflecting local structural complexities. Fracture densities of 3-12 fractures per meter, coupled with steep dips, confirm that natural fractures play a critical role in enhancing effective permeability in otherwise low-porosity carbonate matrices. In-situ stress analysis further confirms a strike-slip to transpressional regime with NE-SW SHmax orientations. This alignment between fracture trends and stress orientation identifies high-potential zones for horizontal drilling and hydraulic stimulation.

These findings directly address the research gap highlighted in the Introduction, by moving beyond purely structural descriptions of the Potwar Basin to provide a quantitative, stress-calibrated fracture characterization. The insights reduce uncertainty in well placement, guide stimulation designs, and help mitigate drilling risks such as borehole instability and mud losses. Moreover, the results contribute to regional tectonic understanding by validating Himalayan compressional stress models and their influence on foreland carbonate reservoirs.

Future research should extend this integrated approach by incorporating rock physics-based inversion, machine learning, and 3D geomechanical modeling to further refine fracture prediction and facies characterization. Such advancements will enhance the accuracy of reservoir simulation and provide transferable methodologies for other foreland fold-and-thrust belt plays worldwide.

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Competing interests

The author(s) declare no competing interests.

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Data Availability Statement

The manuscript includes all data in it.

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