The Critical Roles of Geomechanical Modeling During Exploration Phase

Osman Hamid, Reza Sanaee, and Gbenga Oluyemi

Robert Gorden University-Aberdeen UK

Abstract

Reservoir development from exploration to abandonment benefits from integrated geomechanical modeling to set guidelines and long-term operational strategies. Due to increasing operational challenges, geomechanics has become an essential part of the oil and gas industry's daily route practice. These challenges arise when dealing with deep and tight, unconventional subsalt reservoirs, especially when drilling deviated or horizontal boreholes in a depleted formation in the minimum stress direction when intended to place multistage hydraulic fractures. This study provides innovative geomechanical solutions to address exploration challenges.

This integrated approach will incorporate all available data to construct 3D geomechanical static models to assess and characterize the reservoir properties. These properties include reservoir quality index, sweet spot, reservoir compartmentalization, pore pressure prediction, in-situ stress regime, and presence of faults and fractures. The study will also investigate the relationship between in-situ stress, fractures, faults distributions, and fluid flow and correlate fracture properties variations to the lithology changes.

The results from this study will be used as guidelines strategies for hydrocarbon exploration. The research will address the impact of the in-situ stress variations on petroleum systems, fault seal integrity evaluation, reservoir mapping, and heterogeneity. The study also provides an understanding of vertical and lateral variations of the in-situ stresses and their impact on well placement and well spacing. The types of geomechanical modeling implemented here can be used to accurately drill a safe and cost-effective wellbore that meets completion and stimulation requirements and maximize hydrocarbon production.

Implementing this innovative geomechanical workflow addresses exploration challenges and plays an essential role during reservoir development to characterize the reservoirs and optimize operations. The studies showed that implementing this workflow improves

reservoir developments by saving millions of dollars and minimizing the non-productive time during the planning and exploration phase.

Introduction

Many researchers have investigated the role of geomechanical modeling for specific field applications. Most of the operational organizations have set their objectives and key performance indicators (KPIs) separately, e.g., the KPIs of the drilling domain is to drill a borehole safely to total depth (TD) without considering completion and stimulation strategies. Some researchers have used seismic velocities to evaluate the role of geomechanics during the exploration to assess: Reservoir quality index, sweet spot, reservoir compartmentalization, pore pressure prediction in-situ stress regime, and presence of faults and fractures.

Geomechanical modeling becomes more critical, especially when dealing with challenging tectonic environments and drilling long horizontal wellbores in conventional and unconventional reservoirs. Academia and the oil and gas industry focus on advanced geomechanical approaches for drilling and stimulation.

Characterization of the geomechanical parameter during the exploration phase plays a critical role in borehole placement, understanding hydrocarbon migration, pore pressure predictions, fault stress regime, and fault and fracture identifications. During this phase, the availability and quality of seismic velocities are crucial to assess the reservoir properties, such as reservoir quality index, sweet spot, reservoir compartmentalization, pore pressure prediction, in-situ stress regime, and presence of faults and fractures.

Structural and Geological Setting

Thomas (1998) has investigated the relationship between in-situ stress, fractures, faults distributions, and fluid flow for field development; his work correlated fracture properties variations to lithology changes. Sayers et al. (2001) predicted pore pressure for the pre-drill model to predict the drilling safe mud weight window from seismic velocities. Hantschel et al. (2011) used geomechanics through a time scale to calculate stresses and strain to improve fracture orientations and fault properties predictions. Herwanger and Koutsbeloulis (2011) have established 3D exploration geomechanical models to characterize the subsurface mechanical properties and stresses in offshore northwest Australia. Wendebourg et al. (2014) applied the geomechanical principles, at the basin scale, in exploration to determine how stress field variations impact petroleum systems, top and fault seal integrity, as well as pore pressure and reservoir quality variations. et al. (2016 and 2018) characterized reservoir sweet spots based on stress-dependent permeability studies. Their recommendations were to use the model for field developments without considering the challenges of drilling and stimulations operations. Addis (2017) showed how detailed geological knowledge could improve the geomechanical characterization and analysis of the field development.

Geomechanical models for exploration will be started by constructing a structural framework. These models will be performed using acoustic impedance to characterize stratigraphic/structural elements such as faults/folds and surfaces (**Fig.1**). This figure shows the underlying Cusiana fault, which defines the structure of the field as an active tectonic region, indicated by severe wellbore stability while drilling the first exploration well (Skelton et al. 1995).

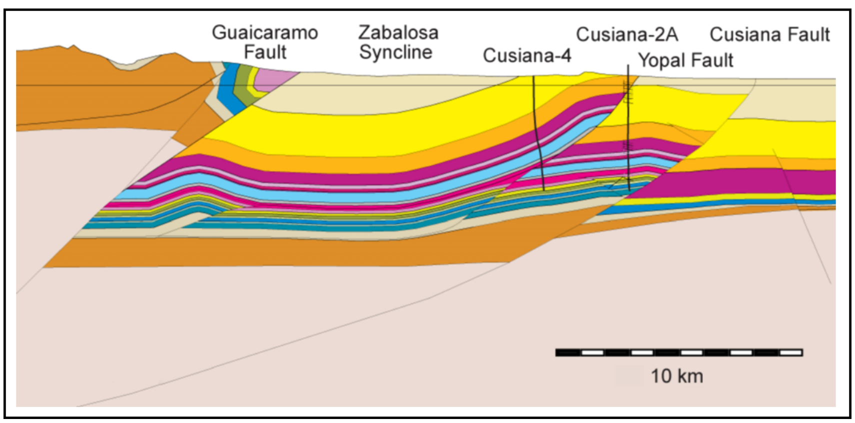

Figure 1: Cross-section of the Cusiana structure in Colombia showing the bed inclination adjacent to the thrust faults (Skelton et al. 1995)

During exploration, the geomechanical modeling focused on rock mechanical properties estimation, stress, and pore pressure calculation with limited integration of tectonic and structural features on well placement, drilling, and completion strategies. This study will bridge the gaps during the exploration phase by studying the impact of formation heterogeneities and structural features on the field development. The research also provides an innovative methodology to integrate the geomechanical parameters that provide guidelines for reservoir development. These processes started from well placement in a drillable zone with stress variations to ensure better completion and stimulation to maximize hydrocarbon production.

With current advancements in technology, the oil and gas industry focuses on establishing integrating modeling approaches, especially in complex offshore environments, such as deep-water, tight formation, and unconventional resources with low porosity and permeability, to minimize operational uncertainty and reduce cost and maximize hydrocarbon production. The operational challenges and difficulties increase as the practices move towards highly deviated and long horizontal wellbores, such as highly faulted and fractured zones, high-pressure high temperature (HPHT) environment, and formation heterogeneities that impact reservoir quality.

This chapter studies the impact of regional and micro-scale tectonic stress and strain, structural discontinuities, and rock deformation such as faults, folds, natural fracture, bedding plans, mechanical properties, and in-situ stresses characterization, pore pressure prediction. This research aims to identify the sweet spots or areas with a high potential of hydrocarbon exploitation, wellbore placement, and optimization to ensure safe drilling, effective completion/stimulation operations, and maximizing hydrocarbon production. These objectives can be achieved by building 1D/3D Geomechanical models using available geological information, seismic velocities, petrophysical logs, and core data.

Geomechanical principles will be applied to evaluate the roles of tectonic structures and depositional sequences. The models will include sweet spot, in-situ stress variations and their regime, pore pressure/fracture gradient prediction.

These parameters will be used to identify suitable rig selections, reservoir quality variations, caprock, fault seal integrity, and reservoir compartmentalization. This characterization will lead to significant enhancement in oil and gas operations.

The Role of the Geological Structures on Exploration Geomechanics

Exploration geomechanical models start by constructing structural features to characterize stratigraphical and structural elements. A seismic survey will be used for this modeling type to map faults/folds, salt dome, shale ridges, and formation unconformities.

Tectonic deformation (macro/micro) results from internal stress conditions caused by tectonic forces in the subsurface. The redistributions and stress changes ($\Delta\sigma$) that generated by various local forces depend on the depth of burial, magnitude, and directions of applied force, the distance from fault zone, created stress regime, and the position of the point of interest (e.g., hanging wall or footwall). These macro-structures can generate multiple micro-tectonic features that create a new geomechanical environment that impacts field developments.

Impact of structural features, such as folds, faults, and salt domes on well placement and drilling operations

Fractures are expected to occur in brittle reservoir rocks of low porosity where favorable tectonic events have developed (Golf-Racht 1982). **Fig. 2A** shows micro-fractures or damaged zone that developed due to faulting processes, while **Fig. 2B** shows faults and micro-fractures development around the salt dome. **Fig. 3** shows the tectonic forces that create a folding system; this model is based on solid material mechanics for bending; this process depends on the depth of burier, type and strength of the formation, and the magnitude and orientation of the applied forces. The figure showed two types of rock deformation; in the center of the upper part, tensile failure is developed perpendicular to the applied forces that generate the tensile fractures. This effect might get weaker from the center due to compressive forces at the model's edges. In the center of the lower part due to the bending loads that generate high strain in this region, which leads to compressive failures. Understanding and characterizing such complex structures will help in the field development as these tectonic features have critical implications on the drilling and completion operation and fluid flow.

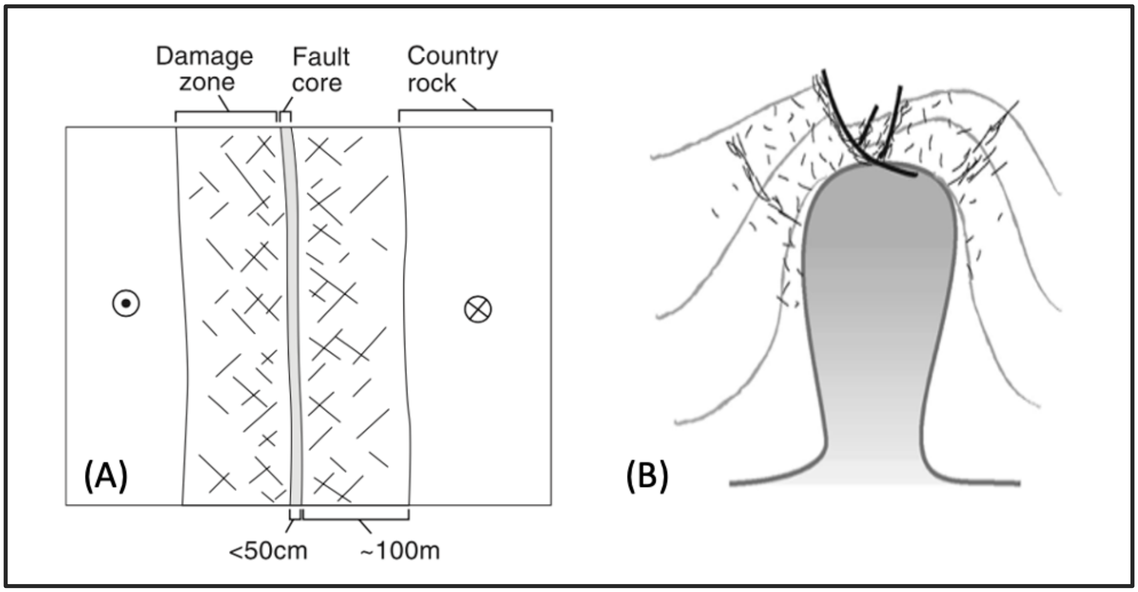

Figure 2: Micro-fractures at the fault margin (A) (After Faulkner et al. 2003). Tectonic features developed around a salt dome (B) (Modified after Fossen et al. 2007).

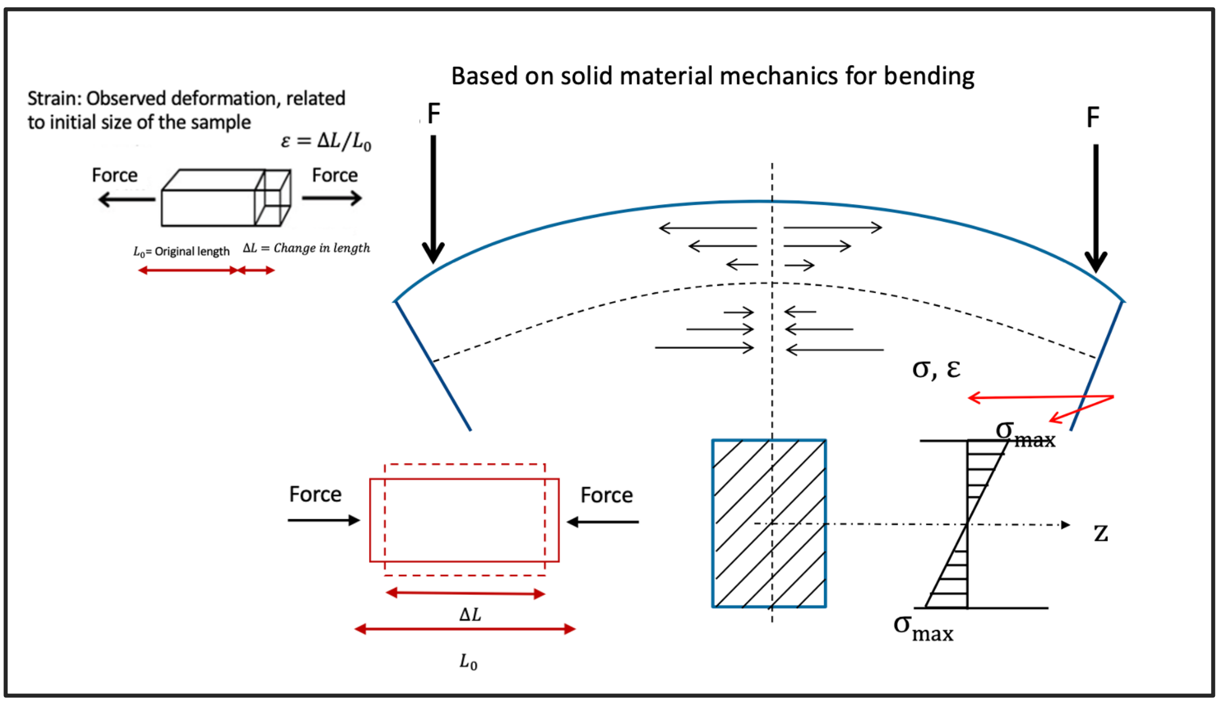

Figure 3: Tectonic forces and folding mechanism

One of the most challenging structural features, especially in a marine environment, is the presence of salt bodies. The presence of salt bodies intrudes vertically into the subsurface formation creates different geomechanical conditions around the salt bodies and in pre-salt reservoirs, including stresses redistribution, stress rotation, and changes in mechanical properties, especially when exiting that salt dome (rubble zones). Understanding the nature of these features can improve the drilling operations by accurately designing the appropriate mud system to safely drill through the salt and rubble zones. **Fig.4** Depicts a 3D static model constructed using seismic velocity that shows a salt structure in a marine environment, the salt velocities, indicated in red color, ranging from 14000 to 15000 ft/sec.

The stresses and pore pressure around a salt body will be redistributed under equilibrate action during visco-elastic stress relation (Minghwen et al. 2020). A 3D numerical model covering salt dome has been built to characterize stress redistribution around the salt body based on seismic velocities. **Fig. 5** shows salt intrusion in grey color, principal stress in the sediments around the salt body, and the stress profile at a wellbore drilled adjacent to this salt body. As shown in the figure, the principal horizontal stresses are reduced in the vicinity of the salt body, leading to a narrow mud weight window, which has many complications on drilling operations. Such as creating drilling-induced fracture that leads to mud losses, non-productive drilling time, and loss of revenue.

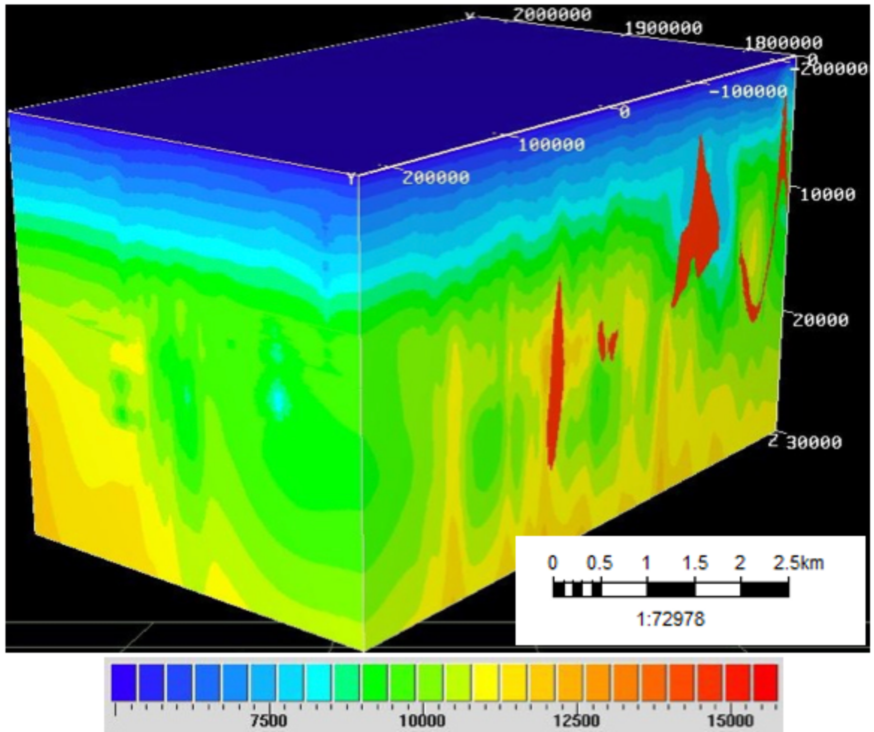

Figure 4: Seismic velocity modeling for offshore field

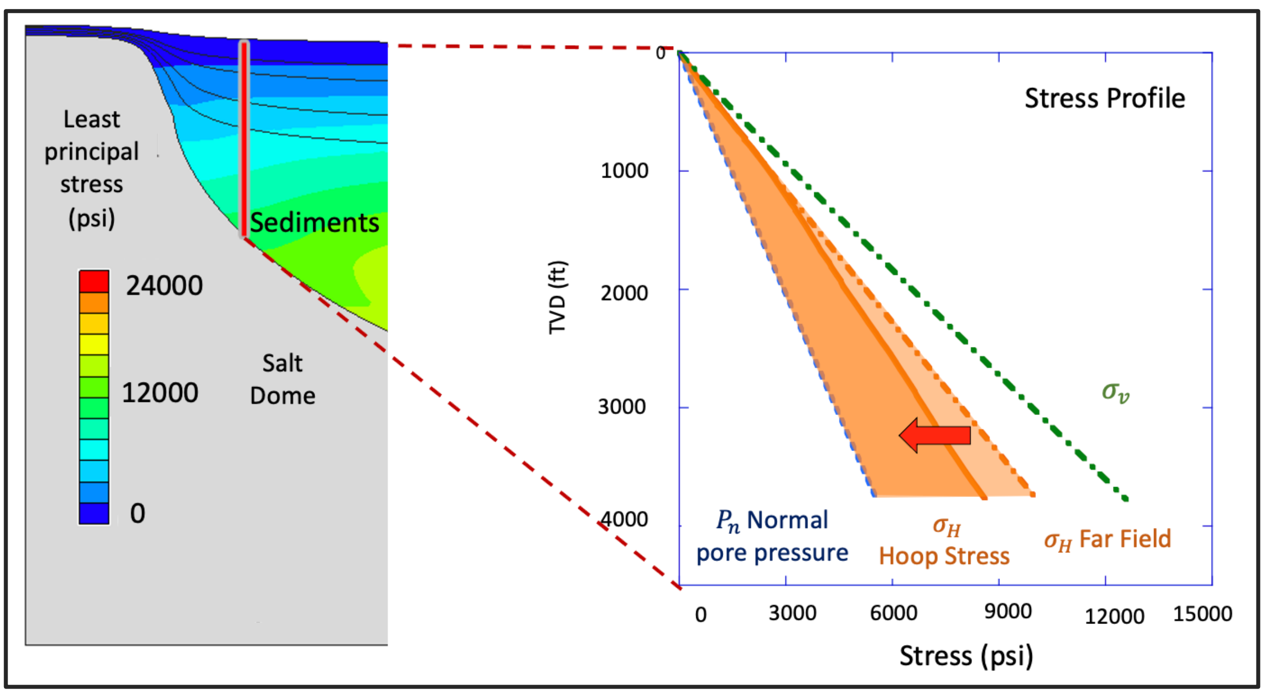

Figure 5: Changes of stress profile around the salt body

US Geological Survey defines a fault as a fracture or zone of fracture between two moving blocks of a rock due to tectonic forces. Anderson (1951) classified faults into three fault regimes, normal, strike-slip, and reverse faults, based on the principal stresses' magnitude and orientation. These tectonic activities have implications for field development, including exploration challenges, potential drilling risks, and stimulation-related problems. **Fig. 6** shows tectonic fault activities affecting formation B; three wells have been drilled targeting this formation. Wellbore I has experienced some drilling troubles such as lost circulations and tight holes across formation B as the wellbore has been drilled in the fault rubble zone. In contrast, well II has been completed without any drilling issues, well III experienced severe losses and many incidents of stuck pipes, and this well has been drilled in the fault zone. This type of drilling challenge can be avoided by using integrated and multi-disciplinary workflows in the drilling planning program.

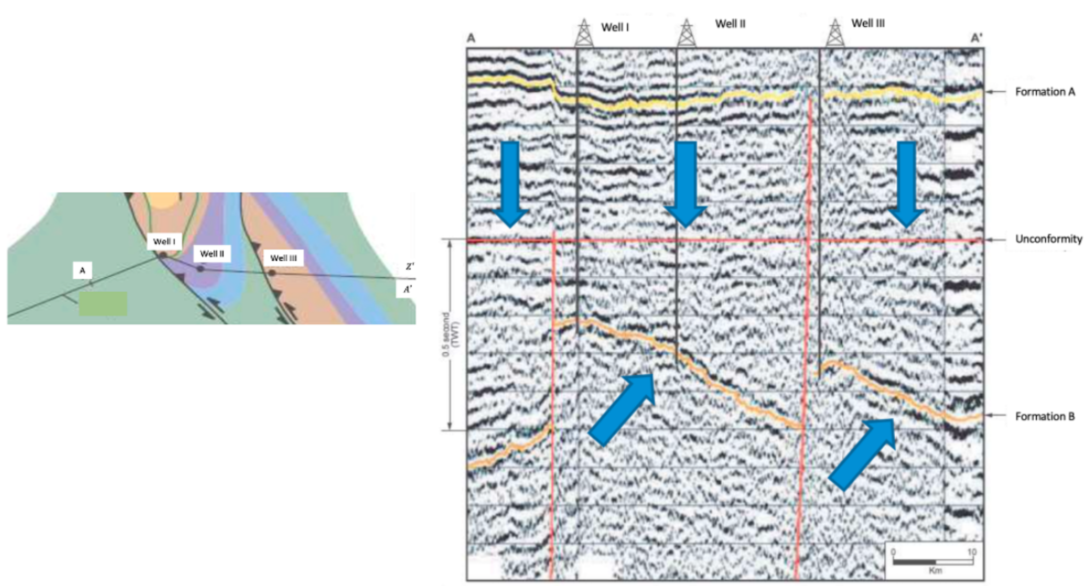

Figure 6: Tectonic activities and fault regime in the onshore field

Seismic has been used to construct stress profiles across the faulted area; acoustic velocities, density, porosity, and stresses have been evaluated in this section. Depending on fault displacements up-thrown and down-thrown, the overburden forces (assuming gradient of 1.1 psi/ft.) increase, the down-thrown was 750 FT, where the overburden load increased by 825 psi in the down-thrown block.

Fig. 7 shows a 2D map of part of the faulted area with seismic velocity in the background, **Fig.7A** showed up-thrown (F_1), down-thrown (F_2) blocks and the rubble fault zone, while **Fig.7B** showed wellbore I drilled in the upthrown layers and wellbore II drilled in the down-thrown formation. This figure showed average velocity variations in the up-thrown (around 4.3 km/sec.) and down-thrown around 5.3 km/sec., these changes in the velocities indicates that the down-thrown blocks have been subjected to larger forces that lead to rock compaction compared to the up-thrown part, which shows stress relief. This heterogeneity in the velocity reflects on the values of rock mechanical properties, e.g., Young's modulus, rock strength, Poisson's ratio, and reservoir properties, especially porosity and permeability. The variations in petrophysical and mechanical properties at the fault rubble zones depend on the tectonics forces and rock types. This tectonic environment creates critical operational challenges, especially drilling deviated and horizontal wellbores in these areas.

Table 1 shows the results of the core measurements results that have been conducted in several samples from wellbore I and II (**Fig. 7**); the figure shows petrophysical properties mainly: Acoustic velocities and bulk density, and rock mechanical properties, the data highlighted blue for the up-thrown zone, while the data in green from the down-thrown formation.

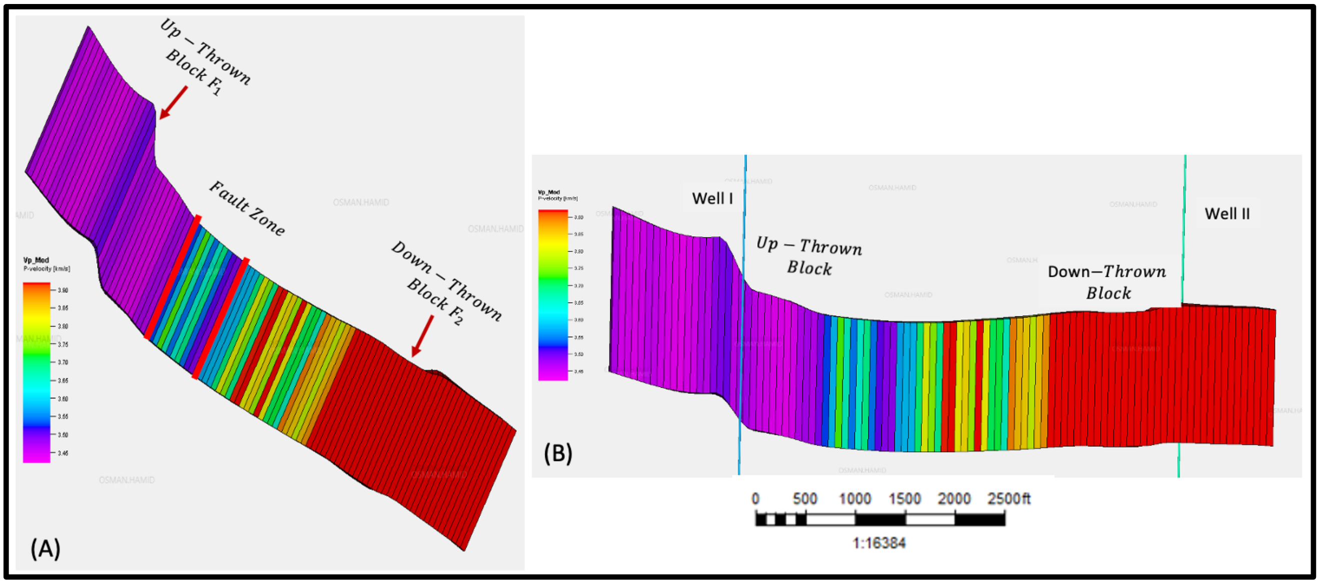

Figure 7: Seismic P-wave velocity across faulted area showing variations of the velocities in the up and downthrown

Reservoir heterogeneity can be quantified by the coefficient of variation(C_v), which can be calculated as

$$C_v = SDV/M_{ar} \quad (4.1)$$

$M_{ar} = Arithmetic\ mean$

$SDV = Standard\ Deviation$

The value of C_v can determine the value of heterogeneity. Romano et al. 2005 classified

C_v into the following categories:

$Low: C_v < M_{ar} - SDV$

$Intermediate: M_{ar} - SDV < C_v < M_{ar} + SDV$

$High: M_{ar} + SDV < C_v < 2M_{ar}$

Table 1: Petrophysical and geomechanical properties in the faulted area (Core plugs from Well I and II)

	Vp (km/sec)	Vs (km/sec)	Density (g/cc)	Porosity	Permeability mD	E (Mpsi)	PR	UCS (psi)
	3.150	2.020	2.650	2.360	1.0960	2.156	0.375	6560.00
	3.800	2.650	2.640	3.420	1.7760	2.860	0.354	7500.00
	4.120	2.800	2.670	1.890	0.6700	3.140	0.315	8950.00
	4.300	3.100	2.680	1.000	0.1350	3.350	0.285	10250.00
	5.200	3.600	2.720	0.150	0.0205	4.800	0.210	15650.00
	5.350	3.750	2.726	0.210	0.0321	4.950	0.190	16750.00
	5.450	3.810	2.735	0.350	0.0874	5.130	0.175	17000.00
	5.890	3.900	2.740	0.350	0.0875	6.540	0.154	18240.00
Arithmetic	4.658	3.204	2.695	1.216	0.4881	4.116	0.257	12612.50
Geometric	4.567	3.135	2.695	0.702	0.1752	3.883	0.245	11764.25
Harmonic	4.473	3.059	2.695	0.413	0.0707	3.655	0.233	10924.30
SDV	0.952	0.675	0.040	1.214	0.6474	1.465	0.086	4766.40
Cv	0.204	0.211	0.015	0.998	1.3264	0.356	0.333	0.378

Fig. 8A, B and C are the plots of the mechanical properties from table 1, and it shows the variations in unconfined compressive strength (UCS), static Young's modulus (E_{sta}), and Poisson's ratio (ν), respectively. The down-thrown formation showed relatively high E_{sta}, high UCS and low ν, compare to the up-thrown formation indicating more forces acting on the down-thrown zones. This variation will reflect the magnitude of the in-situ stresses and formation pressure. Also, the core testing showed low porosity values for the down-thrown formation.

According to this classification, the data in table 1 shows low to intermediate heterogeneity. This heterogeneity in petrophysical and mechanical properties significantly impacts field development. It affects reservoir static and dynamic properties, including fluid mobility, especially in down-thrown areas where porosity is reduced due to tectonic forces and compaction.

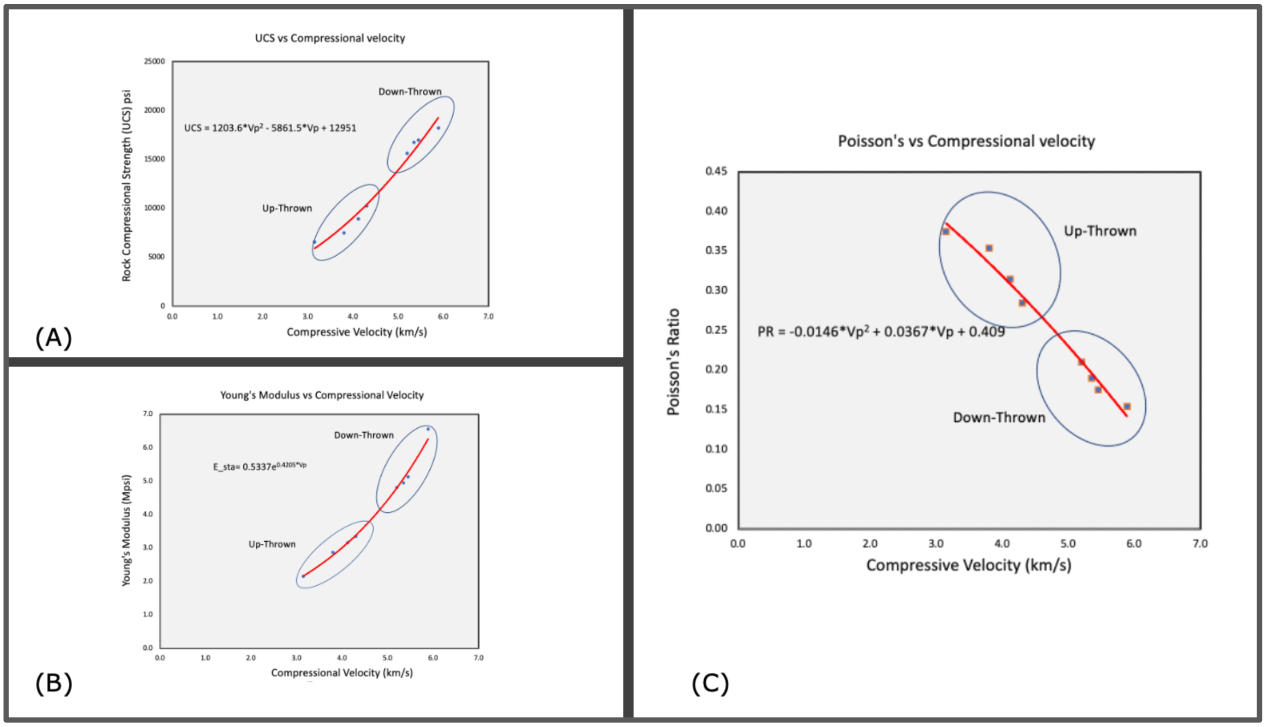

Figure 8: Variations in rock mechanical properties across the faulted area

The minimum horizontal stress magnitude has been modeled for the tectonic area using the poroelastic equation (2.14) (Hamid et al., 2016). The overburden stress assumes 1.1 psi/ft. Young's modulus and Poisson's ratio values have been calculated and calibrated using available seismic velocities, petrophysical log data, and core data. The formation pressure information has been modeled and calibrated using seismic data and MDT measurements from well I and II (**Fig. 9**).

The stress variations in the study area mainly depend on the fault thrown, which is 900 ft. resulting in 1000 psi vertical stress differences between up thrown and downthrown. The average TVD values in this field are around 12,000 ft and 12900 for up thrown and downthrown.

Table 2 shows a summary of the average gradient of the σ_{Hmin} at the up-thrown and down-thrown around fault I and II that were interpreted from the acquired mini-frac data from well I and II. **Fig. 9** shows the variations in the magnitude of the minimum horizontal in-situ stress in the vicinity of fault I and II. The thrown of fault I is around 900 ft. and the thrown of fault II is about 1575 ft. The differences in the magnitude of minimum horizontal stress between the up-thrown and down-thrown for fault I and fault II are 1272 and 2182 psi, respectively; these differences significantly impact all field operations, especially in horizontal wellbore drilling.

Table 2: Minimum horizontal stress characterization around fault I and II

Paramters	Fault I		Fault II
	Up thrown	Down thrown	Up thrown
TVD (ft.)	12000	12900	11325
Sig_Hmin magnitude (psi)	10080	11352	9170
Sig_Hmin gradient (psi/ft)	0.84	0.88	0.81

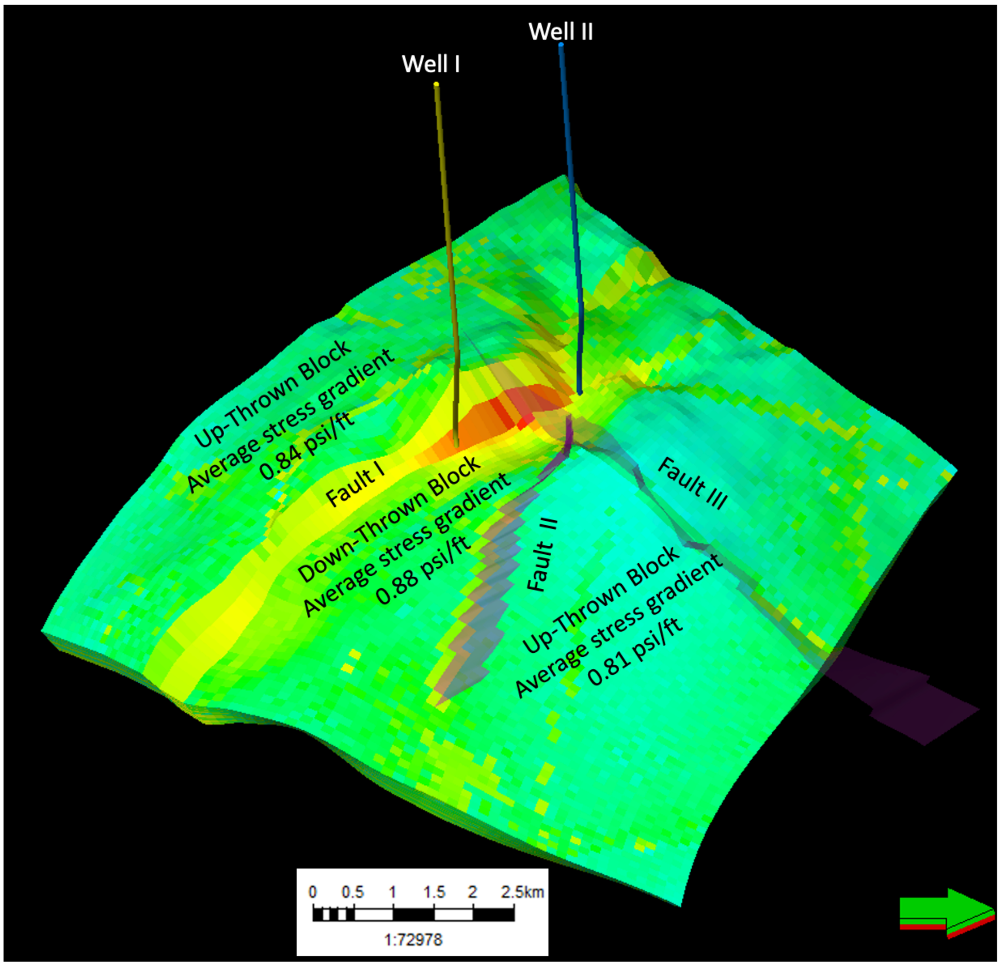

Figure 9: Variation of the minimum horizontal stress gradient in the high tectonic region

Exploration Challenges and Formation Heterogeneities.

Formation heterogeneities which are resulted from geologic deposition and post-depositional history of a formation can impact all operations during the exploration phase from wellbore placement, drilling, completion, and stimulation operations. The heterogeneities of the reservoir formation can be evaluated from seismic velocities variations, which reflect rock types and formation properties, and petrophysical logs such as gamma-ray and other logs can predict the formation continuities. **Fig. 10** shows compressional velocity variations ranging from 4.9 to 6.0 km/s; the red zone indicated a relatively low porosity and high strength region, making it less favorable for field development.

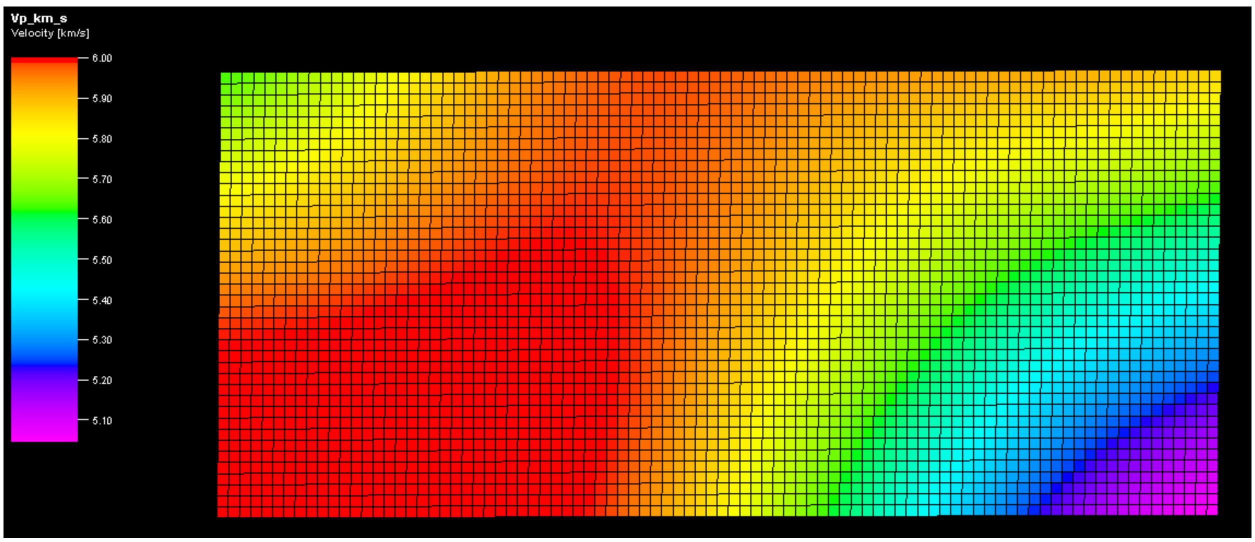

Figure 10: Geological heterogeneities indicated by seismic velocity variation in the onshore field in the Middle East Region.

Sandstone formation heterogeneities can also be assessed from core photos to address drilling and stimulation operations. These heterogeneities may contain discrete elements of thin tight cemented beds, thin, weak beds, ash beds or clay-rich beds and weak interfaces, and boundary/interface between contrasting lithofacies and natural vertical and horizontal fractures. These features can impact drilling operation, resulting in serious wellbore stability-related issues and hydraulic fracture height growth, including the risk of creating a horizontal component. **Fig. 11** shows the presence of shaly layers (dark color lines) within a tight sandstone reservoir, while **Fig. 12** shows shaly sandstone sequences within a core plug.

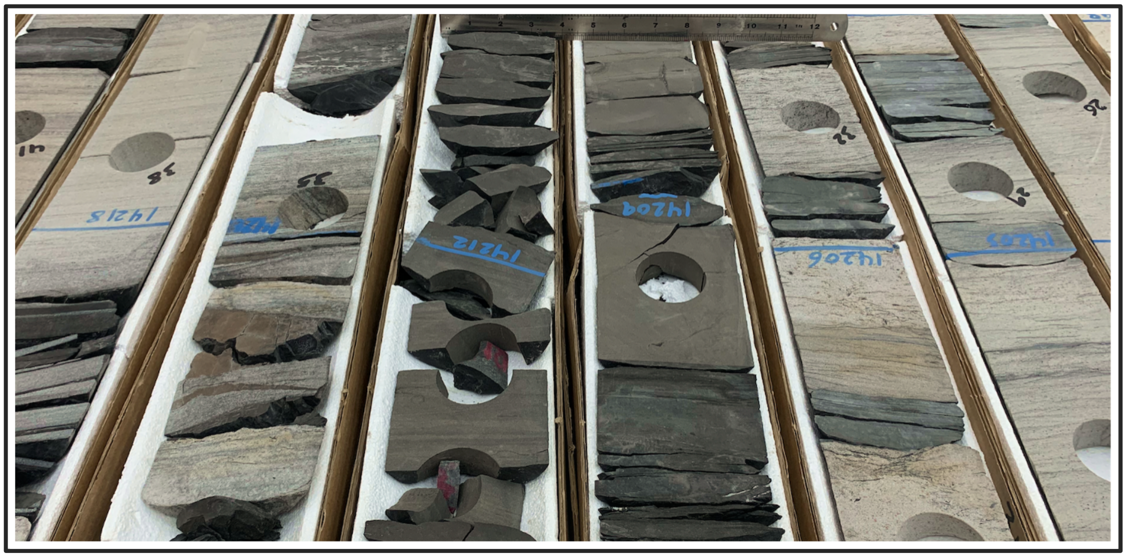

Figure 11: Variation in lithology in a sandstone formation

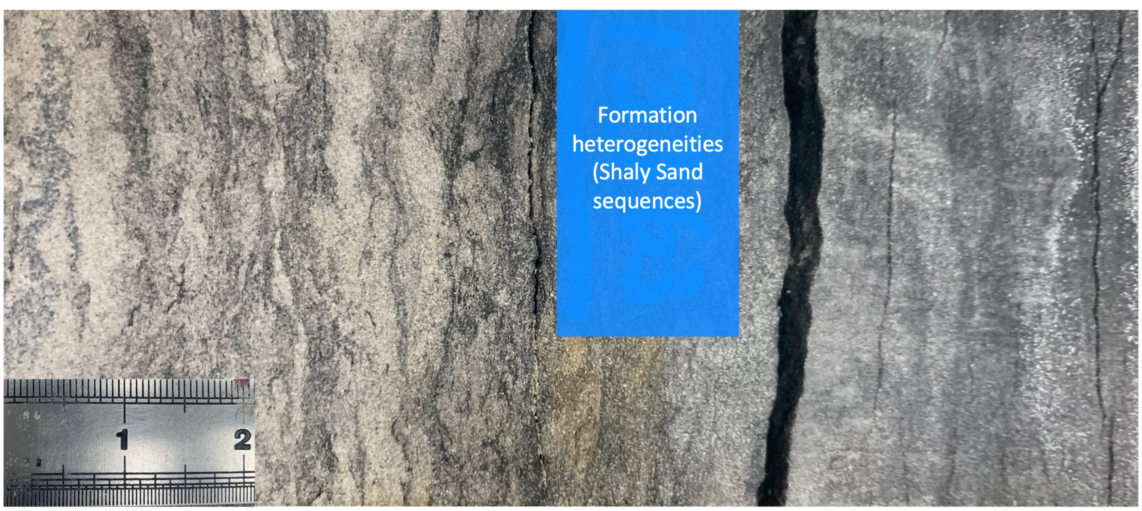

Figure 12: Formation heterogeneity in core plug scale

<u>Natural fracture and bedding plans characterization and their impact on drilling and stimulation</u>

Characterization of natural fractures and bedding plans is critical during the exploration phase. The distributions and orientations of the fractures and dip of bedding plans depend on many factors, including tectonic environment, in-situ stress regime, rock mechanical properties, rock types, facies, and mineralogy of the reservoirs. These naturally occurring discontinuities often comprise complex networks and create highly disordered geological conditions.

Wellbore stability-related issues, such as fluid losses, might be encountered during drilling fractured zones, mud losses depending on the natural fracture properties (Conductive, semi-conductive, or sealed), fracture gradient, and equivalent circulating density (ECD). The drilling fluid losses can be mitigated by adding lost circulation material (LCM) to the mud system.

Weak bedding planes can influence wellbore stability. Typically, instability will increase when drilling at an angle to the bedding plane, such as deviated wellbores. Failure due to bedding plane influence is often seen when drilling at angles within 15 degrees of parallel to the bedding.

The natural fracture and bedding can impact the field development (more information about their influence will be discussed in the drilling and stimulation geomechanics chapters). Understanding and characterizing the fracture properties will be conducted by studying the fracture from seismic technologies, image log interpretation, core samples, and Micro-CT scan.

Fig. 13 shows natural fracture prediction from seismic approaches using Ant-tracking technologies for unconventional shale formation, which is used to determine discontinuities in 3D seismic volumes. This information is critical for field development and operational strategies. **Fig. 14A** Showed resistive and conductive fractures interpreted from resistivity image log. In contrast, **Fig. 14B** showed a comparison between fractures interpreted from image logs (Clustered in yellow) and natural fractures modeled using discrete fracture network (DFN) approaches (Orange color); this comparison showed almost the same direction. This information plays a critical role in the azimuth of the wellbores during drilling, completion strategies, and fluid flow models.

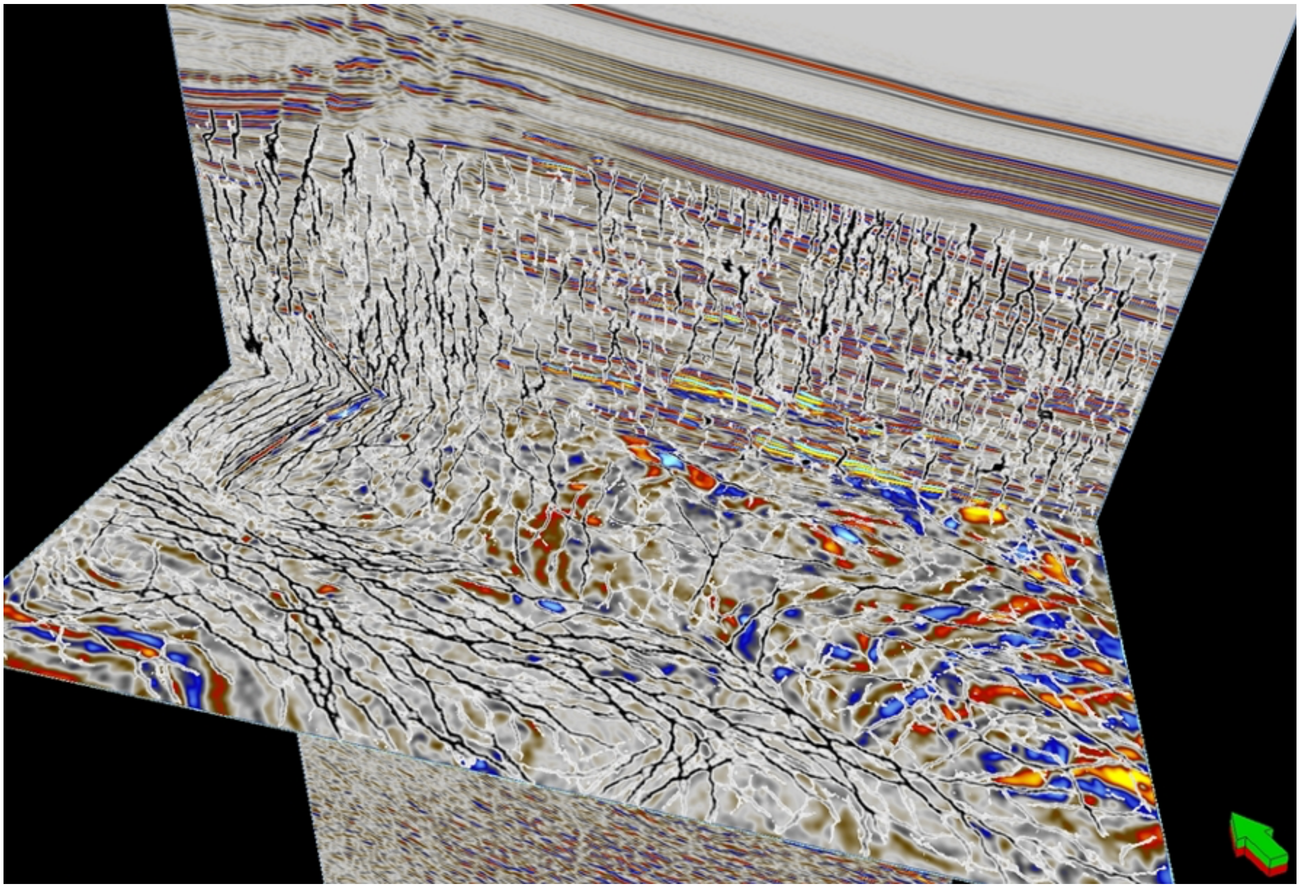

Figure 13: Natural fracture prediction from Seismic velocities in fractured carbonate reservoir

Fig. 15 showed natural fracture development in tight sandstone samples. **Fig.15A** illustrates simple fracture development as the natural fractures developed in one direction, while **Fig. 15B** depicted complex fracture development; this complexity will increase the drilling operational challenges and hydraulic fractures growth.

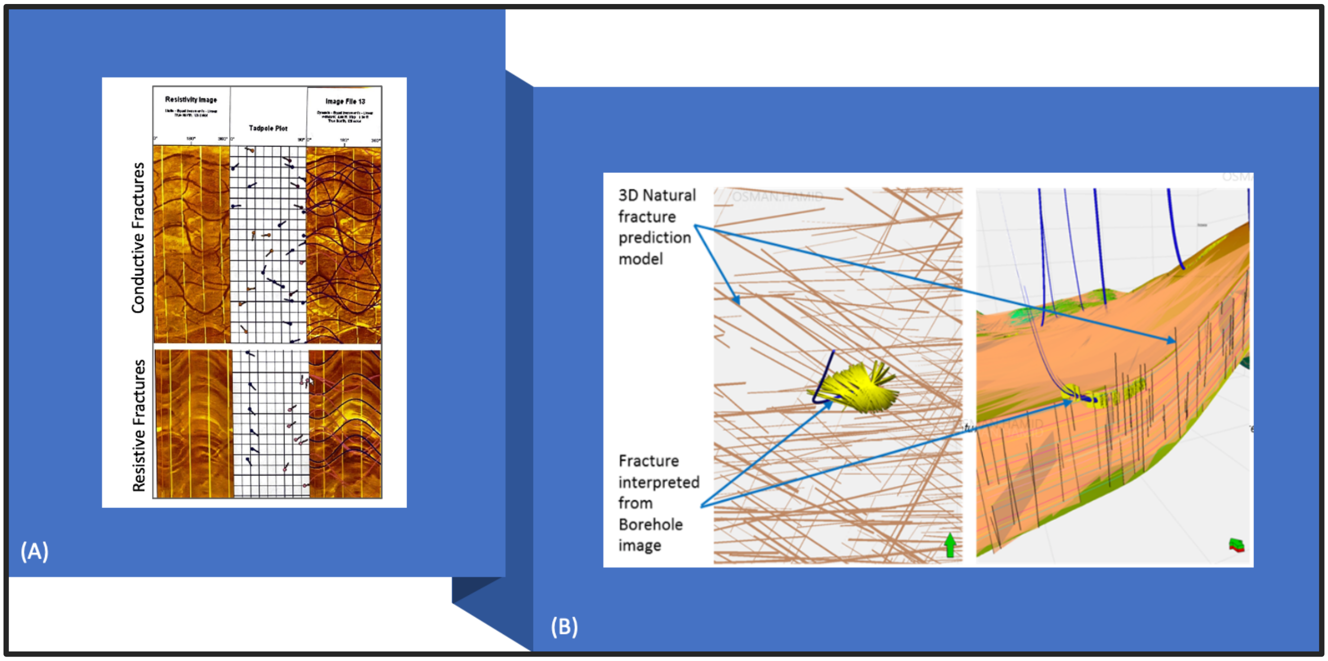

Figure 14: Natural fracture interpretation from image log compared to NF prediction from DFN for fracture sandstone reservoir

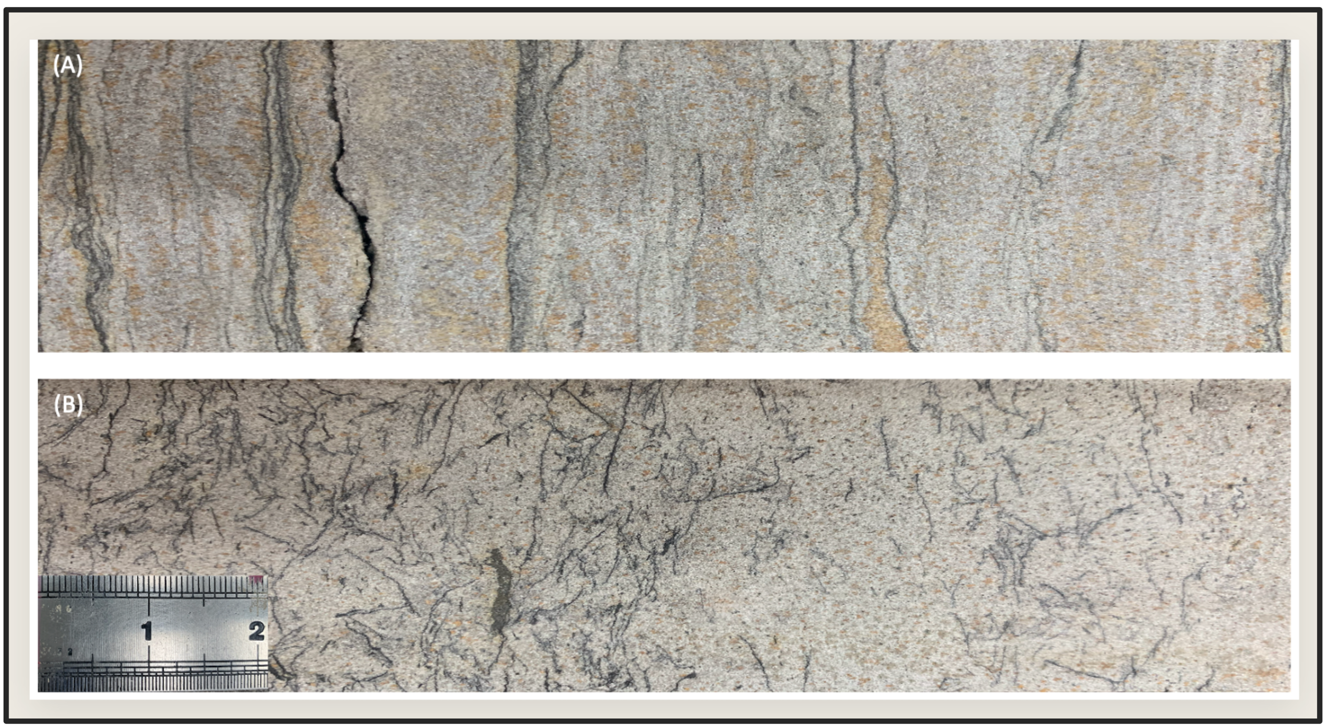

Figure 15: Natural fracture complexity in sandstone samples

Critically stressed fractures modeling and fluid flow

Fracture characterization, including permeability and deformation due to fluid flow, plays an essential role in hydrocarbon production during the development of naturally fractured reservoirs. The conventional way of characterization of the fracture is experimental, and modeling approaches. In this study, a conceptual model will be developed based on the structural style to study the fracture distributions, the influence of the fluid flow and geomechanics in the fracture conductivity, investigate the stress regime in the study area.

Critically stressed fractures are identified as a fracture favorably oriented to fail in shear under the present-day stress field, and they are characterized by good fluid flow. The critically stressed fractures are in a state of stress close to failure, allowing them to undergo a degree of shear.

Micro-structure development (during early stages of deposition-transition time during ductile and cementation periods)

Because of localized tectonic strain, micro-structural features are observed in deformed tight sandstone reservoirs. These features might affect rock mechanical properties compared with un-strained zones; the repeated sequences will impact drilling and stimulation operations.

Study of localized tectonic forces will lead to an understanding of the tectonic events that the targeted region experience; also, this might lead to local stress distribution and changes in reservoir quality, mainly porosity, permeability, and hydrocarbon mobility. **Fig. 16** shows random micro-tectonic folded features (Marked in red) ($3^{"}*5^{"}$) tight sandstone core plug. **Fig. 17** shows the deposition of shale inclusion within the sandstone matrix. This figure showed the development of tensile fracture within and around the inclusion boundaries; these tensional forces extended into the sandstone matrix, creating a set of fractures. The impact of these inclusions on the operations depends on the number and tensional forces they generate.

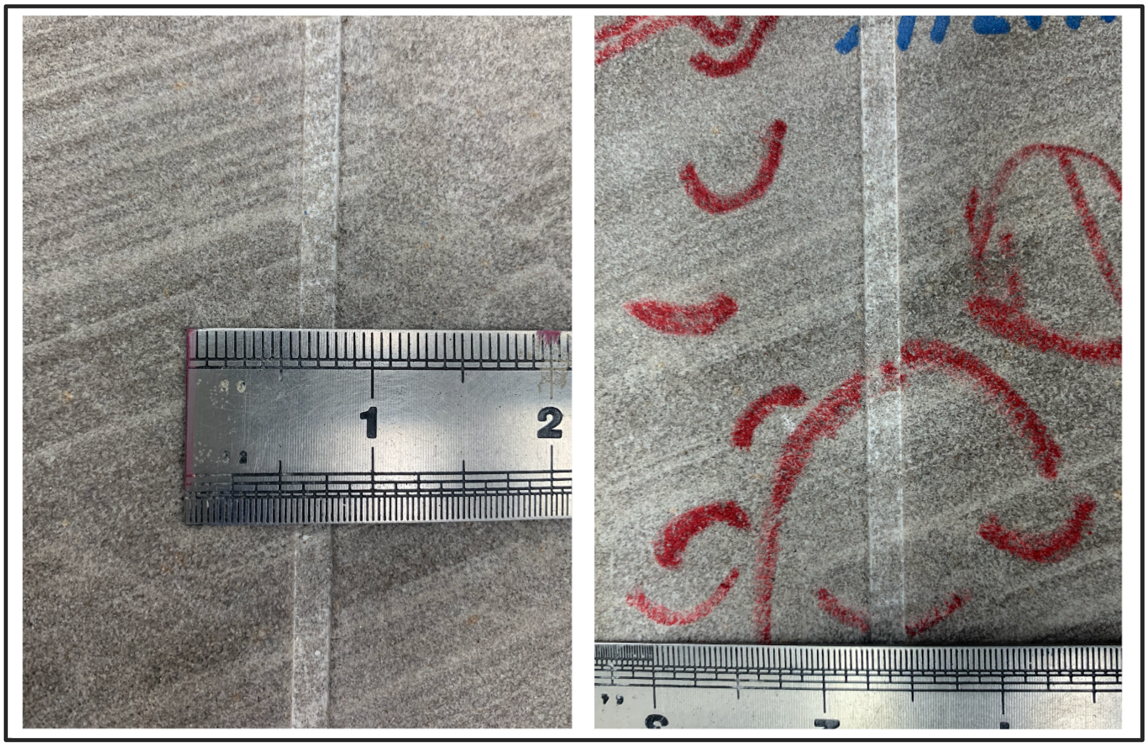

Figure 16: Microstructure complexity in sandstone samples

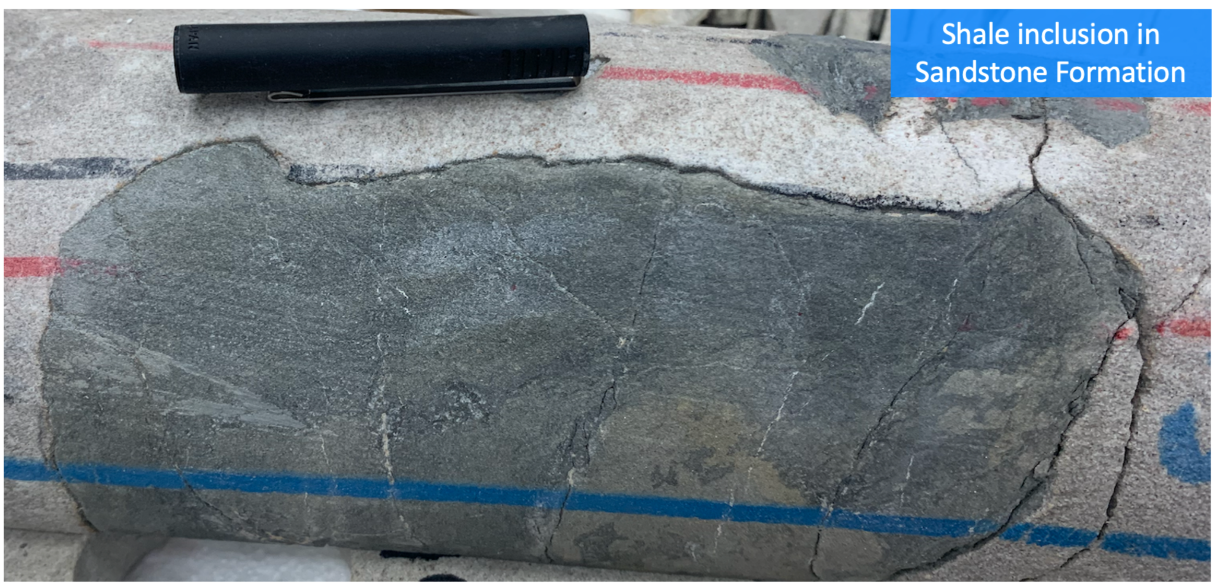

Figure 17: Shale inclusion in sandstone matrix

Analysis of Microstructure features

Laminations and crossbedding, a small-scale sequence of fine layers mainly in shale and sandstone formation, might impact the field development at the wellbore level. Quantifying lamination density and contrast provides valuable information for drilling and stimulation operations. Drilling in high-density laminated or cross-bedding intervals will cause wellbore stability issues, such as mud losses, wellbore collapse, and stuck drilling pipes. While during stimulation might provide a better pathway for the hydrocarbon flow and improve productivity. **Fig.18** shows lamination quantifications from density image log and formation Micro-Imager (FMI) Track 2 and 4. The analysis includes the lamination density (Track 5 and 6) and contrast (Track 7); Track 9 shows lamination severity, red color indicates high contrast (greater than 20 ohms.m), while green is low contrast.

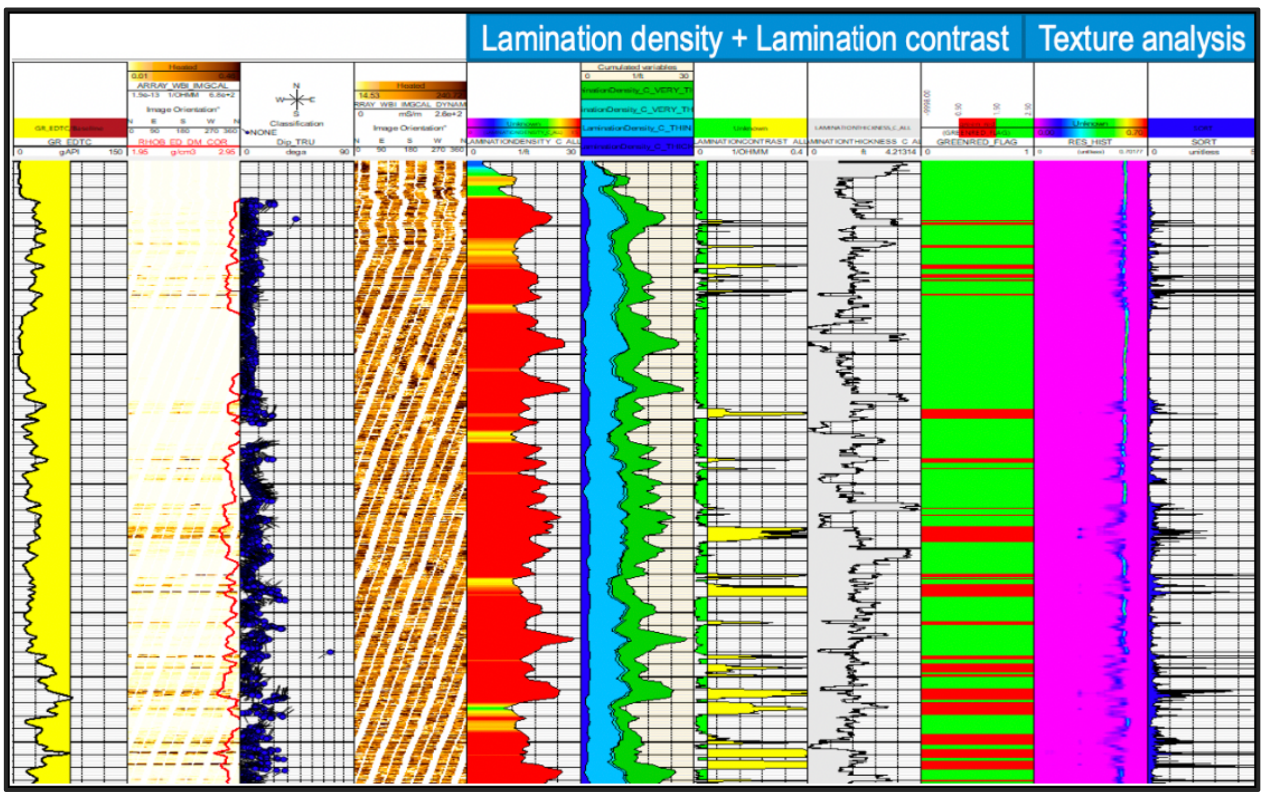

Figure 18: Lamination analysis for sandstone formation

The elector-facies analysis is a process of extraction of high-resolution information from image logs to generate types of facies, sand-count, and bed-thickness. **Fig.19** shows interpreted sand counting using resistivity response from electrical images and porosity as another cutoff; the figure shows three possible frac stages characterized by thick sand beds and high porosity. This analysis improves the frac stage selections and ensures stress barriers above and below the frac zone as indicated by shaly layers usually characterized by higher formation pressure and stress magnitude.

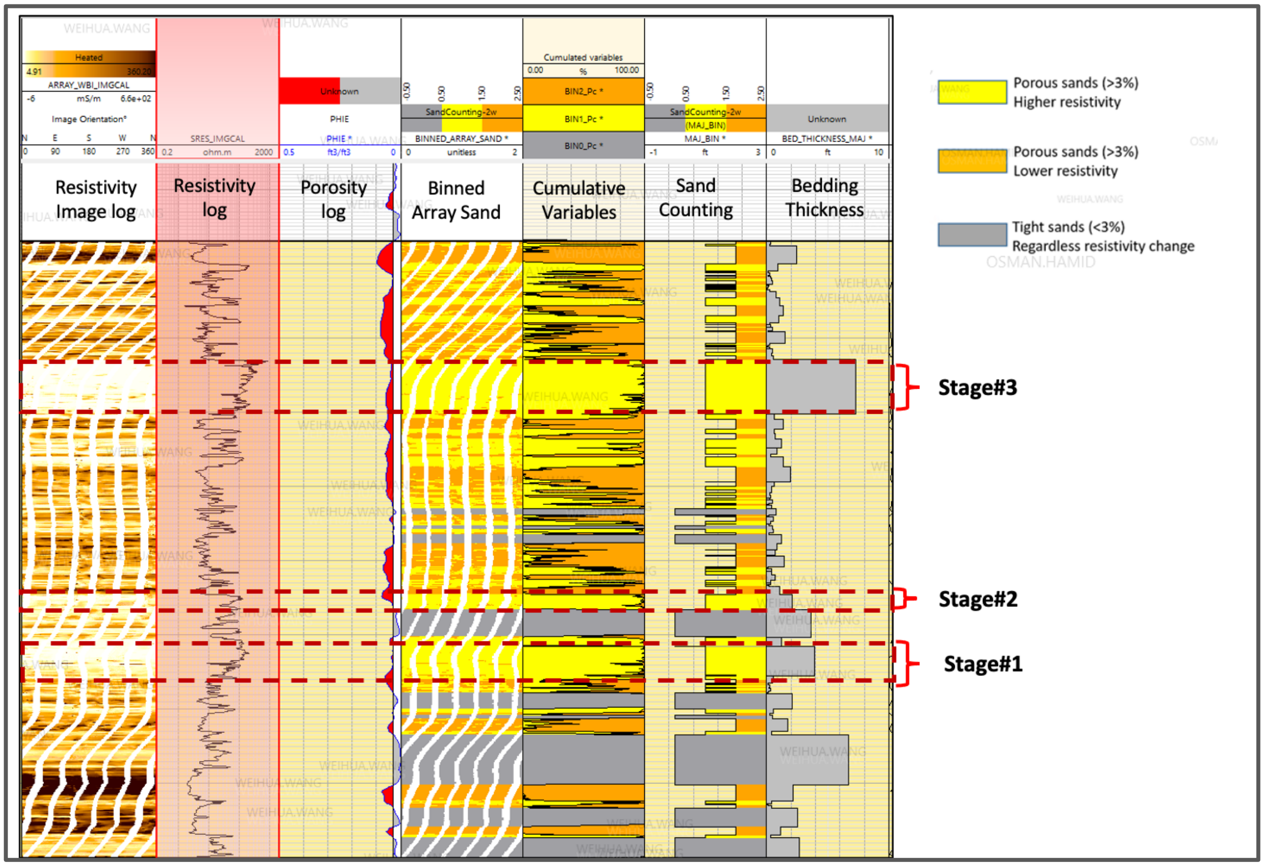

Figure 19: Impact of Electro-facies on fracture stage selection for tight sandstone formation

Conclusion

This study has explained in-depth the essential roles of structural features, reservoir heterogeneity, variations on rock mechanical properties, and stress on reservoir development and set guidelines and long-term operational strategies and decisions.

Structural features, such as faults, folds, and natural fracture, were characterized to provide guidelines to improve the drilling operations by avoiding all wellbore stability challenges such as loss circulation and cutting cleaning when drilling through fault rabble zones. On the other hand, the fracture corridors represent high potential areas for hydrocarbon production. In the complex folded regions, tensile and compressive failure were developed in the upper and lower part of the structure, respectively creating a challenging environment and implications on the drilling and completion operations and fluid flow.

The variations in rock mechanical properties and stresses in faulted regions have been evaluated to address the challenges for horizontal wellbore placement, drilling and completion strategies.

This research provides an understanding of the critical roles of geomechanical analysis and evaluations on operation strategies and economics by enhancing the efficiency of drilling and stimulation practices, which will lead to significant increase in hydrocarbon production.

References

1. Addis A.M. 2017. *The geology of geomechanics: petroleum geomechanical engineering in field development planning*. Turner, J. P., Healy, D., Hillis, R. R. & Welch, M. J. (eds) 2017. Geomechanics and Geology. Geological Society,
2. Anderson E. M., 1951. *The dynamics of faulting.* Oliver and Boyd, Edinburgh.
3. Anderson, E. M. (1905). *The dynamics of faulting, Trans*. Edin. Geol. Soc., 8, 387-402.
4. Faulkner, D.R., Lewis, A.C., Rutter, E.H., 2003. *On the internal structure and mechanics of large strike-slip fault zones: field observations of the Carboneras fault in southeastern Spain*. Tectonophysics 367 (3–4), 235–251.
5. Fossen H., Schultz R. A., Shipton Z. K., and Mair K., 2007. *Deformation bands in sandstone: a review*. Journal of the geological society, London, Vol. 164, 2007, pp. 755-769
6. Hamid O., and Rahim Z., and A. Ba-wazir O., (2014). *Wellbore Stability Analysis Using Acoustic Radial Profiles and an Elastoplastic Model*. SPE-171838-MS. Presented at the Abu Dhabi International Petroleum Exhibition and Conference held in Abu Dhabi, UAE, 10–13 November 2014.
7. Hamid O., Khan K., Rahim R., Omair A., Sajjad Ahmed A., and Mujahid Ahmed M., (2016). *Reducing Drilling Operational Risk and Non-Productive Time Using*

Real-Time Geomechanics Surveillance. SPE-18793-MS. Presented at the International Petroleum Technology Conference held in Bangkok, Thailand, 14-16 November (2016).

8. Hantschel; B. Wygral; M. Fuecker; A. Neber, (2011). *Modeling Basin-Scale Geomechanics Through Geological Time.* IPTC 15286- presented at the International Petroleum Technology Conference held in Bangkok, Thailand, 7–9 February 2012.

9. Herwanger, J., and Koutsbeloulis N. (2011). *Seismic Geomechanics, How to Build and calibrate Geomechanical Models Using 3D/4D Seismic data*. EAGE Publication.

10. Minghwen W., Gang L., Yunqiang S., and Cheng C., 2020. *Numerical Modeling of Stress Perturbations caused by Geometric Changes of Salt Bodies.* Petroleum Exploration and Development, Vol. 47, Issue 2 April 2020

11. Sayers C. M., and Marta J. Woodward M. J., 2001. *Enhanced Seismic Pore-Pressure Prediction.* Presented at the (2001) Offshore Technology Conference held in Houston, Texas, Apr 30 –3 May (2001).

12. Skelton, J., Hogg, T.W., Cross, R. & Verheggen, L. 1(1995). *Case history of directional drilling in the Cusiana field in Colombia.* Paper IADC/SPE 29380, presented at the IADC/SPE Drilling Conference, Feb 28–Mar 2 1(1995), Amsterdam, the Netherlands.

13. Thomas F., (1998). *In-situ stress, pore pressure, and hydrocarbon migration and accumulation in a sedimentary basin*. Ph.D. Thesis -Stanford University

14. Wendebourg J., Gout C., Onaisi A., Guy N., Colombo D., and Daniel J. M., (2014). *Basin Geomechanics for Exploration-Examples and Modeling Approaches*. AAPG Annual Conventional and Exhibition Houston TX USA.