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Presented by:

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Option: Petroleum geophysics

Fault Seal analysis for prospect de-risking in hydrocarbon exploration

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To the countless moments of doubt and triumph,
To the version of myself that never gave up.
To the coffee that fueled the quest for knowledge,
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To my uncles, my cousins whose camaraderie, shared memories, and enduring friendship have enriched my life beyond measure.
To my friends, "Leila" "Fatene" "Feriel" "Abir" "Malak" "Zineb" "Abir" "Anfel", "Djamila" and "Hadjer" who became my chosen family.
To the unseen forces that guided my path,
Thank you for always being there for me,
And for believing in the beauty of my aspirations,
This is for you all, with all my love and gratitude.

Ines ZERKOUK

Abstract

Faults are crucial features in the oil and gas industry; exploring hydrocarbons without fully understanding fault mechanisms is risky because faults can act either as traps or conduits for fluid flow, impacting reservoir viability. Misinterpreting fault behavior can lead to unsuccessful drilling, increased costs, and inefficient resource management. The aim of this work is to emphasize the need for thorough fault seal analysis, including understanding juxtaposition seals, where a reservoir is juxtaposed against non-reservoir rock, and membrane seals, where a reservoir is juxtaposed against another reservoir. This highlights the need for estimating the Shale Gouge Ratio (SGR), which quantifies the proportion of shale in the fault zone and influences the fault's ability to impede fluid flow.

This analysis process begins with integrating seismic interpretation and depth conversion to create a subsurface image, followed by constructing lithology and petrophysical geocellular models through a facies and petrophysical study using well data. Subsequently, the fault seal analysis is conducted.

This methodology is applied to the Ordovician reservoir formation in the Oued Toughert field in the Sbâa Basin, Algeria. The findings reveal sand/shale and shale/shale contacts along the fault, and SGR calculations consistently surpass the 20% threshold, confirming the fault's effectiveness as a seal for hydrocarbon migration.

Key words: Fault seal analysis, Juxtaposition Seal, Membrane seal, Shale Gouge Ratio (SGR).

Résumé

Les failles sont des éléments cruciaux dans l'industrie du pétrole et du gaz. Il est risqué d'explorer les hydrocarbures sans comprendre parfaitement les mécanismes des failles, car celles-ci peuvent agir comme des pièges ou des conduits pour l'écoulement des fluides, ce qui a un impact sur la viabilité des réservoirs. Une mauvaise interprétation du comportement des failles peut conduire à des forages infructueux, à une augmentation des coûts et à une gestion inefficace des ressources. L'objectif de ce travail est de souligner la nécessité d'une analyse approfondie de la faille, y compris la compréhension des étanchéités de juxtaposition, où un réservoir est juxtaposé à une roche non réservoir, et des étanchéités de membrane, où un réservoir est juxtaposé à un autre réservoir. Il est donc nécessaire d'estimer le Shale Gouge Ratio (SGR), qui quantifie la proportion des argiles dans la zone de faille et influe sur la capacité de la faille à empêcher l'écoulement des fluides.

Ce processus d'analyse commence par l'intégration de l'interprétation sismique et de la conversion temps-profondeurs pour créer une image de la subsurface, suivie de la construction de modèles géocellulaires lithologiques et pétrophysiques par une étude de faciès et pétrophysique utilisant des données de puits. L'analyse de l'étanchéité des failles est ensuite réalisée.

Cette méthodologie est appliquée à la formation réservoir de l'Ordovicien dans le champ d'Oued Toughert dans le bassin de Sbâa, en Algérie. Les résultats révèlent des contacts sable/shale et shale/shale le long de la faille, et les calculs SGR dépassent systématiquement le seuil de 20 %, ce qui confirme l'efficacité de la faille en tant que joint d'étanchéité pour la migration des hydrocarbures.

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General Introduction

General Introduction

Oil and gas exploration is a complex and diverse process aimed at discovering and evaluating hydrocarbon deposits beneath the Earth's surface. In order to meet the world's energy demands and promote economic growth, this exploration process is essential. The ultimate goal of oil and gas exploration is to generate prospects, which are potential hydrocarbon reservoirs identified through various geological, geophysical, and geochemical methods. These prospects often involve intricate geological features such as faults, which can both enhance and impede the accumulation and extraction of hydrocarbons.

Faults are fractures in the Earth's crust along which there has been displacement of the sides relative to one another parallel to the fracture. They play a dual role in hydrocarbon exploration. On one hand, faults can act as conduits for hydrocarbon migration, allowing oil and gas to move from source rocks to reservoir rocks. On the other hand, they can serve as barriers or seals that trap hydrocarbons in the reservoir. Determining whether a fault acts as a seal or a conduit is critical for successful hydrocarbon exploration and production. This necessitates a comprehensive fault seal analysis, which is designed to evaluate the sealing capacity of faults and their impact on hydrocarbon accumulation.

Inaccurate evaluation of fault sealing capacity can lead to significant economic and operational risks, such as non-productive drilling or the loss of hydrocarbons. Therefore, understanding and analysing these faults is vital to mitigate risks associated with hydrocarbon exploration and production such as drilling dry wells or encountering unexpected reservoir behaviours.

Fault seal analysis is a detailed and systematic process that aims to assess the potential of faults to either prevent or facilitate the flow of hydrocarbons. It can be categorised into two primary types: juxtaposition seal analysis and membrane seal analysis. Juxtaposition seal analysis examines the relative positions of lithological units across a fault plane to determine if reservoir rocks are juxtaposed against non-reservoir rocks, indicating a potential seal, or against other reservoir rocks, suggesting possible hydrocarbon migration.

Membrane seal analysis, on the other hand, evaluates the ability of fault rocks to act as impermeable barriers to fluid flow. The key parameter in membrane seal analysis is the Shale Gouge Ratio (SGR), which quantifies the proportion of shale material that forms within the fault zone. A high SGR value indicates a higher likelihood of the fault acting as a seal due to the impermeable nature of shale.

To conduct a thorough fault seal analysis, a structured workflow is applied. The workflow begins with data interpretation, where seismic data, well logs, and geological maps are analysed to understand subsurface structures. This is followed by structural mapping, which creates detailed maps of faults and horizons. Static modelling then integrates these maps and data into a 3D geological model representing the subsurface at a specific time. Property modelling populates this model with petrophysical properties such as porosity, permeability and Vsh (Volume of shale). Finally, fault seal analysis, including both juxtaposition and membrane seal analyses, assesses the sealing capacity of faults, crucial for predicting hydrocarbon accumulation and migration. This comprehensive approach ensures a thorough evaluation of potential reservoirs, mitigating risks and optimising exploration and production strategies.

This dissertation is divided into 4 chapters:

Chapter 01: Generalities, this very first chapter provides an introduction to the fundamental concepts (prospect, petroleum system, traps, fault types and geological risks) that set the stage for understanding the importance and complexity of fault seal analysis.

Chapter 02: Fault seal analysis theory, this part delves into the theory of fault seal analysis, including juxtaposition and membrane seals, and the methods and models used to evaluate fault seals, with a focus on Shale Gouge Ratio (SGR).

Chapter 03: Study area and data overview, this chapter presents the geological settings of the Sbâa basin and the used data, setting the groundwork for the application.

Chapter 04: Application, this final chapter applies the fault seal analysis workflow to the study area. It concludes with a discussion of the results and confirmation of the sealing effectiveness.

CHAPTER 01: GENERALITIES

Chapter 01: Generalities

1. Concept of the prospect

The prospect is an area of exploration in which hydrocarbons have been predicted to exist in economic quantity. A prospect is typically an anomaly that explorationists advocate for drilling a well, such as a geologic structure or a seismic amplitude anomaly. Drilling a prospect is justified if there is evidence of an active petroleum system, a reasonable chance of finding reservoir-quality rock, an adequate-sized trap, sufficient sealing rock, and and favorable circumstances for the production and migration of hydrocarbons to fill the trap. Although the term prospect also refers to a particular drilling location, it is more appropriately used in the context of exploration. A collection of prospects sharing similar characteristics forms a play.

Potential accumulation, often referred to as a potential trap, is well enough defined to be an appropriate target for drilling. Drilling is required to assess potential accumulation in order to ascertain whether or not it contains petroleum of commercial quantities. The term "prospect" is dropped after drilling is complete and the site is referred to as either a producing field or a dry hole.

A prospect's evaluation is based on two factors: how likely is it that hydrocarbons will be found at this location, and are the economics such that drilling will result in a profit margin large enough to cover the costs?

In petroleum exploration, the decision-making process regarding drilling locations is often described as a blend of art and science. When conducting a primary search for hydrocarbons, the first step is usually to observe the surface terrain Location of faults at the surface are very important because they indicate where potential structural traps may lie beneath the surface in reservoir rocks.

Prospect identification typically relies on geological understanding of the area and seismic interpretation. Nonetheless, we frequently note that even while every vital element of the petroleum system is present, the drilled prospect is dry because of the inherent uncertainties in the data. Such failures are mostly attributed to a lack of understanding of seal capacity, reservoir heterogeneity, source rock presence and maturation, hydrocarbon migration, and relative timing of these processes.

It requires a tremendous effort to merge the understanding of larger scale basin evolution with local and wellbore scale understanding of all potentially controlling geological factors.

Geophysical data can provide an accurate structure of the reservoir and a detailed characterization of the subsurface fluids and their properties , also the fluid saturation changes during the reservoir life cycle. Therefore, both static and dynamic characterization of the reservoir are required (Robertson, 1989). The transformation of seismic data from the time domain to the depth domain, facilitated by integrating well and seismic velocity data, provides a comprehensive depiction of the reservoir's structural layout. This process reveals intricate details, such as fault lines, which play a crucial role in defining the reservoir's configuration (Aminzadeh and Dasgupta , 2013) .

2. The petroleum system

The concept of the petroleum system was formulated by Magoon and Dow in 1994, where all of the controlling factors, which determine the presence of petroleum in an accumulation were identified. In order to delineate a petroleum system within a sedimentary basin, it's imperative to pinpoint the source rock, the origin of petroleum maturation. This involves assessing the maturity level and timing of hydrocarbon generation from the source rock. In addition, the means of migration of these hydrocarbons to the reservoir rock and within the reservoir rock to the trap must also be identified (Kundu, 2023). The elements of a petroleum system are the source rock, the reservoir rock, the trap and the processes of hydrocarbon generation, migration, accumulation and preservation.

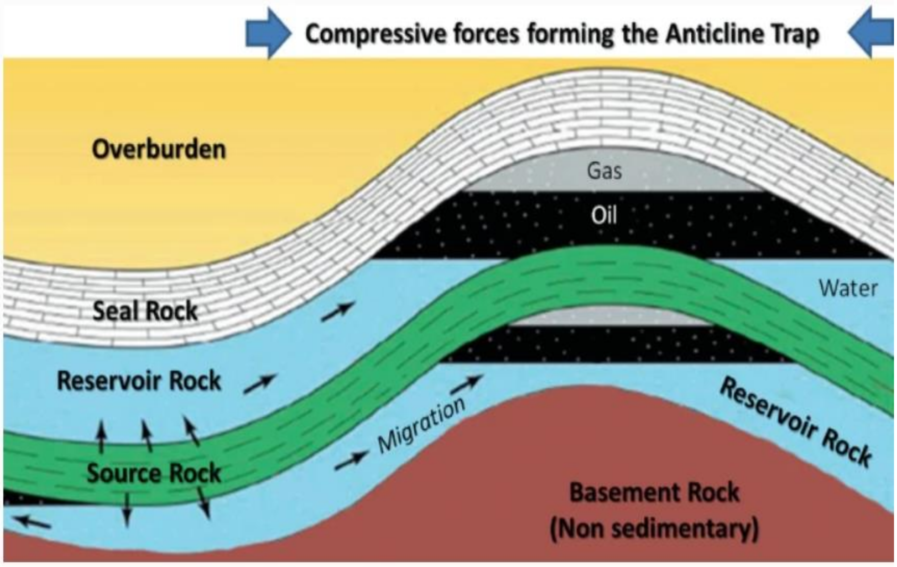

Figure 1-1: Elements of the petroleum system (Kundu, 2023) .

Petroleum systems are most likely to occur in sedimentary basins characterised by extensive sedimentary deposition over time, as indicated by the presence of thick sedimentary sequences formed in diverse depositional environments. This increases the probability of occurrence of a source rock rich in organic matter and the occurrence of porous and permeable reservoir rocks in vicinity, and also the occurrence of a non-permeable seal or cap rock protected by thick overburden.

2.1. Source rock

The source rock is one essential component of a petroleum system. In this rock petroleum is formed through the thermal maturation of organic matter. The source rock was deposited in an environment that is favourable to growth of organic matter. Organic-rich shale makes up the majority of source rocks. Shale comes in a range of colours, including black, grey, reddish, brownish, and greenish grey. The green and grey one has a higher level of organic matter, making them potential source rocks. Although shale has microscopic pores, it is often porous but not permeable. The source rock may or may not be active, depending on the sedimentary basin's thermal history. The part of the source rock that is buried deep enough to produce hydrocarbons is known as an active source rock. In contrast, the inactive source rock is the part that has not reached the critical temperature to create hydrocarbons. Hydrocarbons are recovered from inactive shale by heating it in a furnace, which is mined as oil shale.

2.1.Reservoir rock

The permeable and porous formations known as reservoir rocks are what accommodate and retain the hydrocarbons released from the source rock. Consequently, the capacity of a reservoir rock to accommodate , store, and permeate petroleum in commercial quantities is one of its most important characteristics.

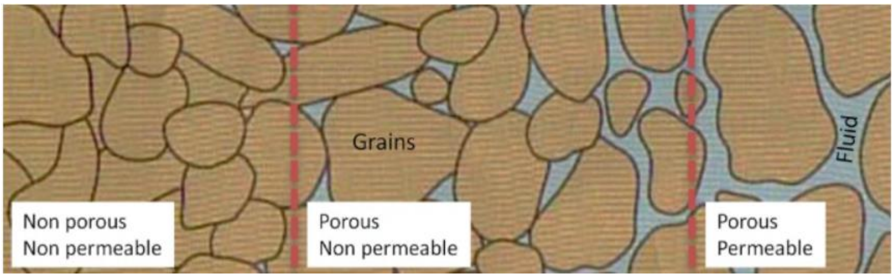

Figure 1-2 : Porosity and permeability in rocks (Kundu, 2023) .

2.3. Seal rock

Above the reservoir rock, at a topographically higher position, lies a layer known as the seal rock. Its purpose is to prevent the hydrocarbons that get trapped in the reservoir rock from migrating farther, which facilitates the formation of a localised accumulation known as a trap. Petroleum migrates to higher ground, pushing aside the water above it because it is less dense than water. These buoyancy-driven accumulations are easily marked by the water-oil interface in the petroleum trap.

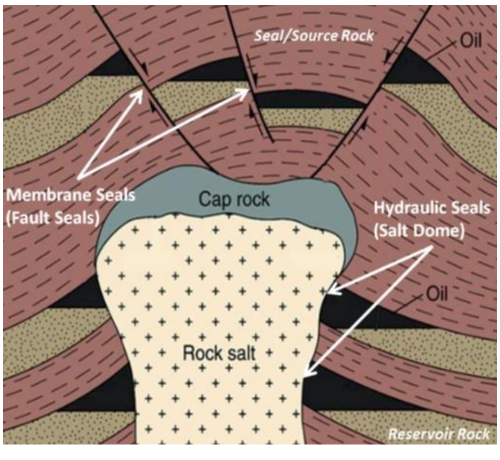

Figure 1-3 : Membrane and hydraulic seals (Kundu, 2023).

2.4. Overburden

The total amount of rocks that are situated on top of a petroleum accumulation is known as the overburden. To keep up the accumulation, overburden is required for multiple reasons. Firstly, it helps raise the temperature of the underlying source rock to mature petroleum through lithostratigraphic pressure. Secondly, it prevents the seal rock from eroding.

The overburden needs to be thick in order to create lithostatic pressure, and the source rock needs to be a poor heat conductor in order to hold the heat generated by the pressure inside. Silica-rich sedimentary rocks, such sandstone, siltstone, and shale, typically transfer heat less well than salt and limestone. In addition to the overburden's thermal properties, heat flow within the section affects the source rock. The source rock reaches the crucial oil-forming temperatures through a combination of the overburden's thickness, thermal characteristics, and heat flow.

2.5. Petroleum system processes

The processes of the petroleum system include accumulation, migration, maturation, and trap formation. These processes are typically timed in a petroleum system to increase the likelihood of a hydrocarbon accumulation in the trap.

2.5.1. Trap creation

An economically significant amount of oil can accumulate in a reservoir rock by stopping its migration through a mechanism called a trap. It usually occurs when a reservoir rock is positioned against a seal in such a way that it blocks migration and favours accumulation up . This means that the three crucial elements of a petroleum trap are the reservoir, the seal, and the geometric closure.

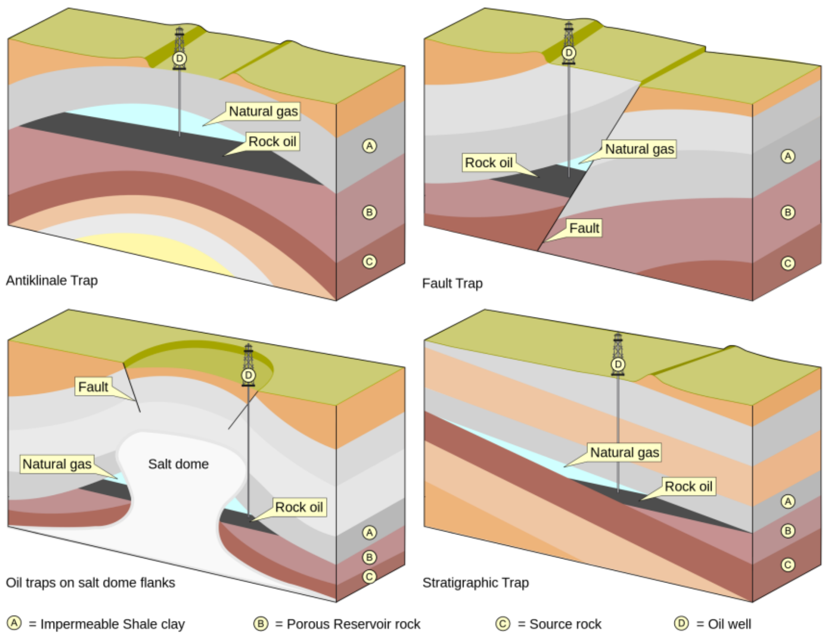

Figure 1-4 : Trap types (Wikimedia Commons 2015).

The closure geometry formed by traps prevent hydrocarbons from migrating , and by displacing the water in the pores , it enables hydrocarbons accumulation . Due to the immiscibility of water, gas, and oil, they occur stratified within the trap. This stratification is planar and contained within the boundaries of the reservoir rock . Since gas is he lightest substance, it is always above oil at the top , and since water is the heaviest , it is always at the bottom.

2.5.2. Maturation

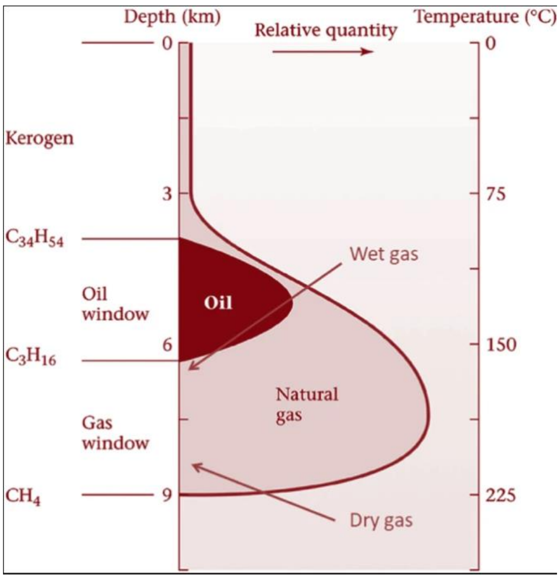

Figure 1-5 : Stages of maturation (Kundu, 2023).

The process of maturation begins when the source rock is heated to approximately 70 °C and continues exponentially with temperature. Long-chained hydrocarbons can more easily break down into shorter ones at higher temperatures. The shortest hydrocarbons, methane and ethane, which are gases under normal conditions, are generated when the temperature hits 200 °C. Deeper depths can support greater temperatures that convert nearly all of the kerogen into hydrocarbons, while shallower depths can only sustain temperatures that are too low for intense oil generation. Temperatures are extremely high in the later stages of the oil window, which breaks down oil into condensates or "wet gas." All of the oil and condensates transform into methane, sometimes known as "dry gas," when the source rock enters the gas window.

2.5.3. Migration and accumulation

The source rock's pore pressure rises with maturation. The source rock fractures because of an increase in pore pressure, releasing gas and oil into the formations below and above. This is a primary gas and oil migration. When nearby rock is porous, gas and oil displace the water within the pores. Oil and gas, being hydrodynamically lighter, move upward due to buoyancy in the reservoir rock and accumulate at the trap. Secondary migration is the movement of gas and oil from the reservoir rock into the trap.

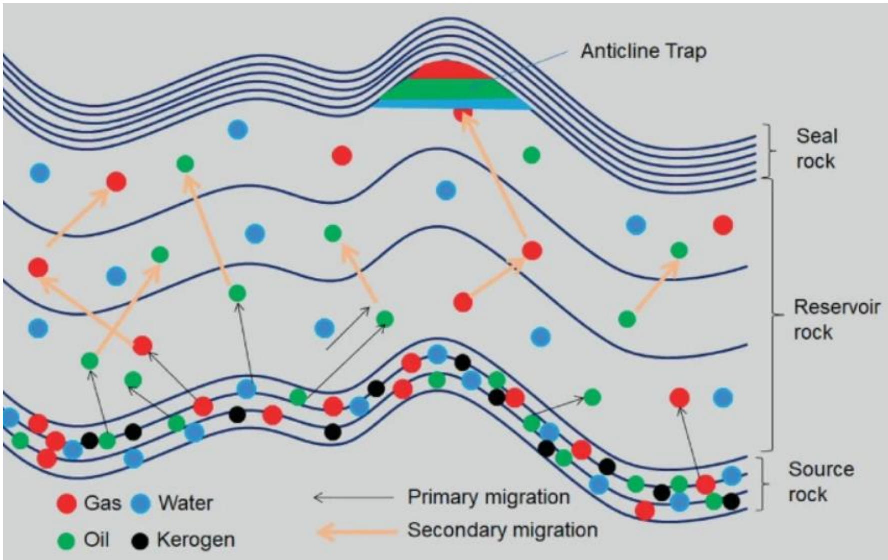

Figure 1-6 : Maturation and migration of oil and gas (Kundu, 2023).

The accumulation process entails displacing the reservoir's original water with gas and oil. Water, gas, and oil lay stratified according to their densities in petroleum accumulations. In the trap, gas lays on top of oil, while oil covers water.

2.6.Extents of petroleum system

The extent of a petroleum system is from the base of the active source rock's spread to the uppermost point of the reservoir rock, where the seal rock and overburden limit hydrocarbon migration. Its geographical extents define the aerial extent of the petroleum system that can be mapped, to which all investigations must be confined. The vertical rock column that extends from the lowest point of the gas window to the highest point of the overburden is known as the stratigraphic extension. Although it might be difficult to pinpoint the exact boundaries of a petroleum system, a general awareness of these limits is necessary in order to focus exploration targets in sedimentary basins.

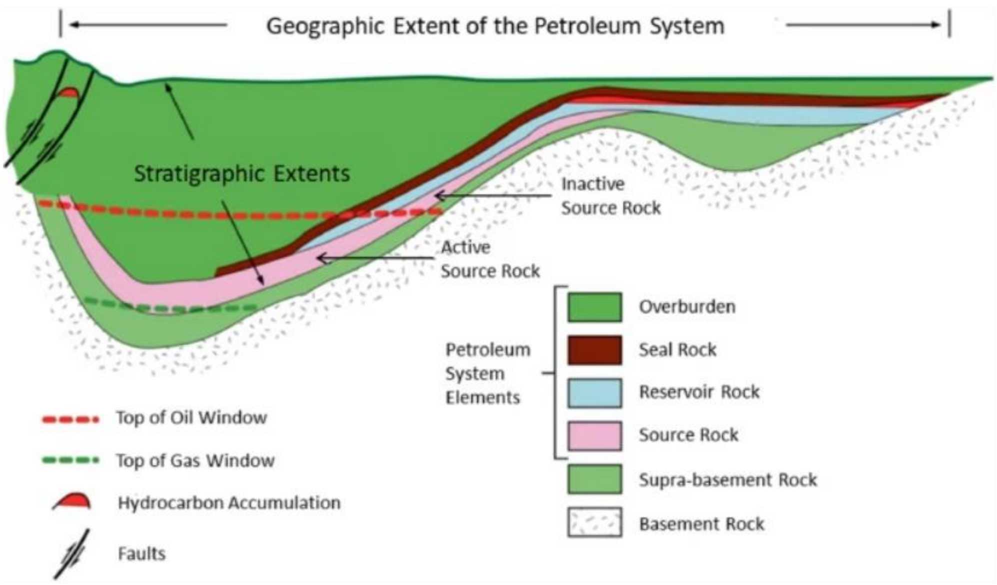

Figure 1-7 : Geographic and Stratigraphic Extents of a Petroleum System (Kundu, 2023).

3. Oil and gas trap types

Generally, traps are categorised based on the mechanism that results in the hydrocarbons accumulation. Stratigraphic traps, which are associated with depositional or diagenetic characteristics in the sedimentary sequence, and structural traps, which are created by structural deformation of rocks, are the two primary categories of traps.

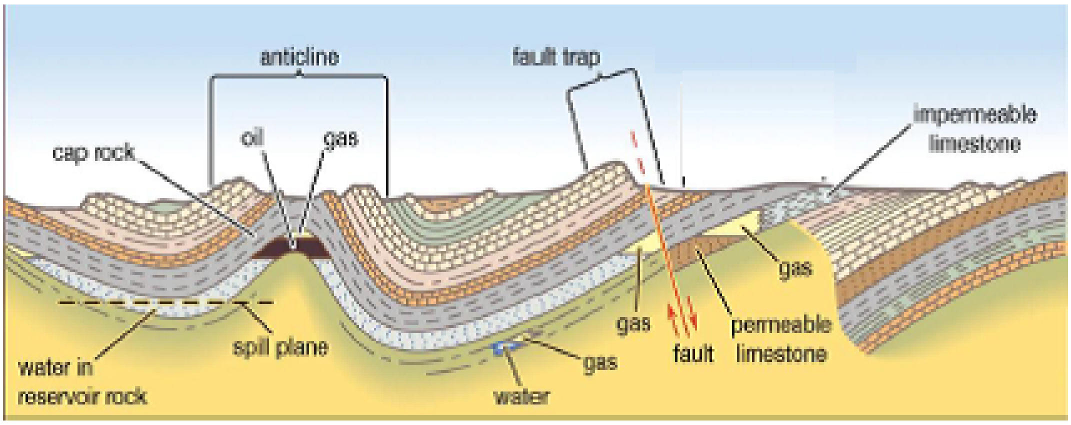

Figure 1-8 : Structural and stratigraphic traps (Kopp, 1998)

3.1.Structural Traps

A particular kind of geological trap known as a structural trap develops when tectonic, diapiric, gravitational, and compactional processes alter the subsurface's structure. These alterations prevent hydrocarbons from migrating upward and may cause a petroleum reservoir to form.

Since structural traps contain the majority of the world's found petroleum resources, they are the most significant kind of trap. The anticline trap, the fault trap, and the salt dome trap are the three fundamental types of structural traps.

3.1.1. Anticlinal (fold) Trap

An area of the subsurface where the strata have been pushed to create a dome-shaped structure is called an anticline. Hydrocarbons can accumulate at the crest until the anticline is filled to the spill point, which is the highest point at which hydrocarbons can escape the anticline, if there is an impermeable rock layer present in this dome shaped. The hydrocarbon industry finds this kind of trap to be the most serious by far. Anticline traps are often lengthy, oval land domes that are visible while studying a geological map.

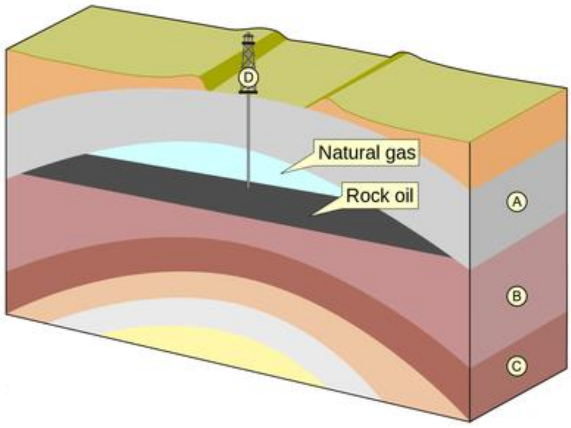

Figure 1-9 : Anticline trap (Wikimedia Commons 2015).

3.1.2. Fault Trap

The movement of permeable and impermeable rock strata along a fault line creates this trap. The hydrocarbons are prevented from migrating further by the faulting of the permeable reservoir rock, which is now adjacent to an impermeable rock. An impermeable material, like clay, may occasionally be smeared along the fault line, acting to impede movement. We call this a clay smear.

3.1.3. Salt dome Trap

Because clastic rocks are more buoyant, masses of salt are pushed up through them and eventually break through, rising towards the surface (see salt dome). Being impermeable, this salt obstructs the flow of hydrocarbons through permeable rock layers by blocking the channel, similar to what a fault trap does. This is one of the reasons, in spite of the numerous technological difficulties involved, that subsalt imaging is receiving so much attention.

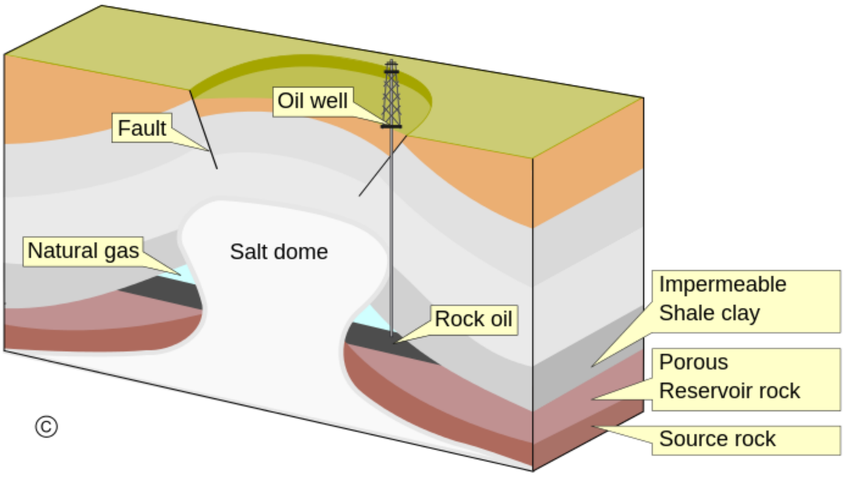

Figure 1-10 : Salt dome trap (Wikimedia Commons 2015).

3.2. Stratigraphic traps

Stratigraphic traps are created by any variation in the stratigraphy that is independent of structural deformation, although many stratigraphic traps involve a tectonic component such as tilting of strata.

Two main groups can be recognized:

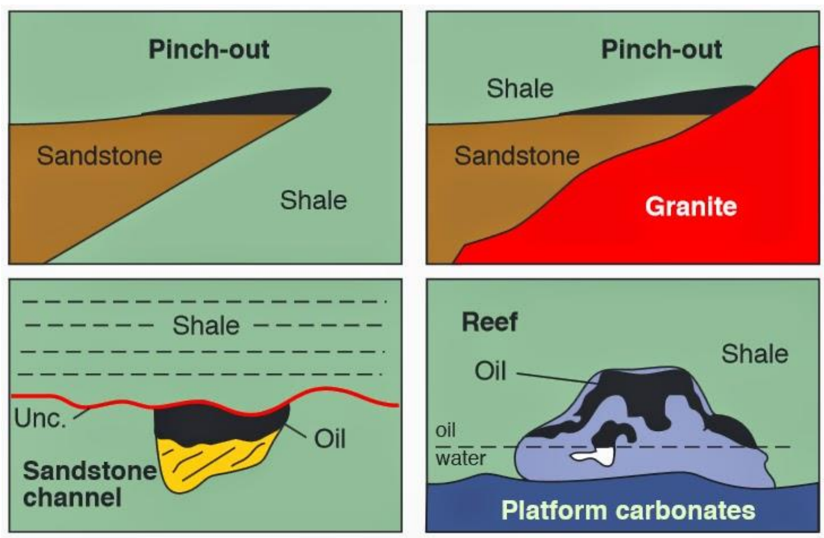

Figure 1-11 : Examples of stratigraphic traps (Kundu, 2023).

Primary

Variations in the facies that formed during sedimentation give rise to primary stratigraphic traps. These include features like lenses, pinch-outs, and suitable facies changes.

Secondary

Secondary stratigraphic traps are the consequence of post-sedimentation alterations primarily due to diagenesis. These include variations caused by cementation or porosity augmentation by dissolution.

4. Fault types

Faults are geological features that result from the movement of the Earth's crust. They play a crucial role in hydrocarbon exploration especially in Algeria, as they are a dominant type of traps, due to their ability to influence hydrocarbon migration and accumulation. Faults can be classified into different types based on their geometry, movement, and the type of rock they cut through. Understanding these types is essential for effectively locating potential hydrocarbon reservoirs.

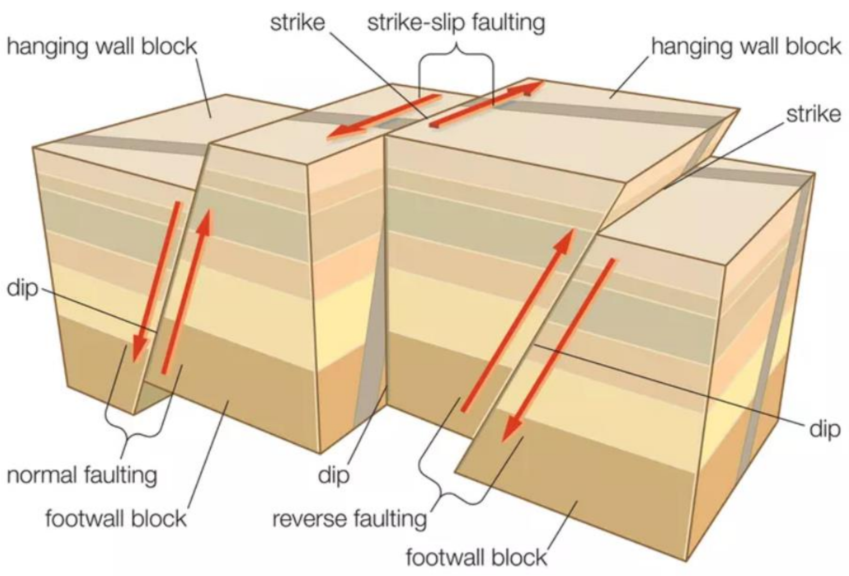

Figure 1-12 : Fault types (Wikimedia Commons 2015).

4.1. Normal Faults

Normal faults are characterized by the hanging wall moving down relative to the footwall due to extensional forces. They are typically associated with divergent plate boundaries and are common in areas undergoing crustal extension.

4.2.Reverse Faults

Reverse faults happen when compressional forces cause the hanging wall to rise upward relative to the footwall. They are commonly found in areas undergoing crustal shortening, such as convergent plate boundaries.

4.3.Strike-Slip Faults

Strike-slip faults are characterized by horizontal displacement along the fault plane, with minimal vertical movement .They are typically associated with transform plate boundaries and are caused by lateral shearing forces.

5. The geological risks in hydrocarbons exploration

When assessing the risk associated with a particular prospect or segment, the first step is to estimate the probability of geological success while taking into consideration the random factors of each element of the Petroleum System being independent from the seismic information related to the fluid effects. (Nosjean et al , 2021).

Five categories of independent random geological parameters comprise one of the classic ways for determining the geological probability of success, according to Rose's (2004) research:

1)

the probability of the source rock's presence and its quality. It needs to be present in a significant enough volume and thermally mature. It must be sufficiently thick, rich (from an organic perspective, i.e., TOC), and extensive enough to generate enough hydrocarbons allowing at least the minimum filing case of the evaluated prospect .

2)

The probability of an effective migration pathway leading to closures that existed at the time of migration. This hydrocarbon migration must be efficient enough to charge the closures with volumes adequate to detect.

3)

The probability of the presence and quality of reservoir rock from the time of migration until today (e.g. with limited diagenetic effects, erosion). The reservoir must be at least of some minimal thickness sufficient to contain detectable quantities of hydrocarbons.

4)

The probability of the presence and effectiveness of a closure (i.e. being able to retain HC) in the assessed prospect. These include structural or stratigraphic traps and the confidence that the traps have been mapped accurately.

5)

The probability of containment of the evaluated closure. This relates to the presence of adequate sealing rocks able to retain the HC at least for the minimum estimated volume case. The containment must preserve through time the accumulated HC from any leakage, flushing or degradation.

In mature hydrocarbon basins, fault seal failure is often the primary cause of "dry holes" where expected hydrocarbon accumulations are not found. Careful fault seal analysis can help reduce this exploration risk .

CHAPTER 02: FAULT SEAL ANALYSIS THEORY

Chapter 02: Fault Seal Analysis Theory

1. Introduction

In Algeria, faults are particularly significant due to their prevalence and their association with anticlines (faulted anticlines), one of the most common types of hydrocarbons traps in the region.

This geological configuration creates favourable conditions for the trapping and accumulation of hydrocarbons, making faulted anticlines prime targets for exploration and production activities in the Algerian oil and gas industry.

Faults serve several important functions such as:

Reservoir compartmentalization: faults can compartmentalise reservoirs, dividing them into separate zones. This compartmentalization affects the distribution and behaviour of hydrocarbons within the reservoir, influencing production strategies and reservoir management practices.

Sealing mechanisms: faults may also act as seals, preventing the vertical migration of hydrocarbons beyond a certain depth or compartments within the reservoir; this sealing effect is crucial for maintaining the integrity and productivity of hydrocarbons accumulations.

2. Geological Factors affecting fault sealing

Several factors determine whether a fault serves as a conduit or a barrier for hydrocarbon migration. There are several different aspects that can affect a fault's sealing qualities. Among them are a few crucial elements: the sandstone content of a faulted interval; the burial depth of a fault segment; the dip angle of a fault plane; the throw (vertical displacement) of a fault; and the fluid pressure within mudstone (Luo et al, 2023).

- **Fault plane tightness:** It is challenging for hydrocarbons to migrate along a fault plane if the fault sealing is strong and the fractures in the fault zone are tight. If not, the hydrocarbon migration conduit caused by the fault will remain open. The amount of normal stress on the fault plane mostly determines the tightness of the fault plane. Rocks in the fault zone become less porous and permeable due to larger normal stress, which can even cause the fault to close.

- **Fault activity:** Highly permeable conduits for fluid flow are provided by active faults and fractures. One major aspect contributing to fault opening is fault activity. Generally speaking, during an active faulting episode, the dislocation distance of a single stratum on both sides of the fault can be used to quantify fault activity

- **Fault type:** Seals are more likely to occur on reverse and strike-slip faults than on normal faults. Normal stress on the fault plane is only obtained from the gravity of the hanging wall strata because the tensile stress in the fault plane's dip direction influences the formation of normal faults. The normal stress on the fault plane is a combination of the stress caused by tectonic compression and the gravity of the hanging wall strata. The reverse fault is created in a compression stress field. As normal stress increases, impermeable minerals like fault gouge and mylonite form between the fault planes due to friction between the strata in the two walls and the tendency of the fractures between the walls to seal. Similar changes will take place on the fault plane of strike-slip faults when the tectonic stress is significantly larger than the gravity of hanging wall strata.

- **Lithologic juxtaposition across the fault:** Fluid flow conduits are easily formed when sandstone strata on opposite sides of a fault are juxtaposed, and the physical characteristics of the rocks inside the fault zone determine the fault's sealability. The likelihood of hydrocarbon migration through the fracture is significantly decreased when sandstones are juxtaposed with mudstone or other impermeable rocks with a strong capillary force. On a lithologic juxtaposition map of the two walls of the fault, this kind of sealing can be found.

- **Fault zone mudstone smearing:** When mudrocks are integrated into the fault zone, an argillaceous smear layer may develop on the fault planes. The primary cause of fault sealing in clastic strata is smearing. When mudstone makes up the majority of the fractured strata, the fault zone's porosity and permeability decrease with increasing mudstone content; conversely, the likelihood of hydrocarbon migration increases with increasing expulsion pressure. Smeared layers in the fault zone are more likely to form at shallow depths where the sediments are not consolidated because mudstone compaction rises with depth. Additionally, the sealing capacity of the mudstone smears will increase with burial depth.

- **Cementation in fault zone:** Mineral precipitation happens when a fault is inactive because of modifications in the surrounding environment or interactions between fluid and rock when fluid flows through initially opening and permeable fractures. The cement causes the fault zone to lose pore space either totally or partially, which finally causes the fault zone to seal. The amount of dissolved minerals in the fluid, the fluid pressure anomaly during seepage, and the distance of fluid penetrating into rock can affect cementation. Nevertheless, it is challenging to use straightforward mathematical techniques to forecast the cementation sealing of the fault zone.

It is evident from the preceding research that a variety of geological conditions can influence a fault’s sealing. Each factor's role may interact with those of other factors. For this reason, assessing fault sealing has never been easy in the field of petroleum geology research. To perform quantitative/semi-quantitative analysis of the fault connectivity during hydrocarbon migration, it is imperative to ascertain the critical parameters controlling fault sealing from these components (Luo et al, 2023).

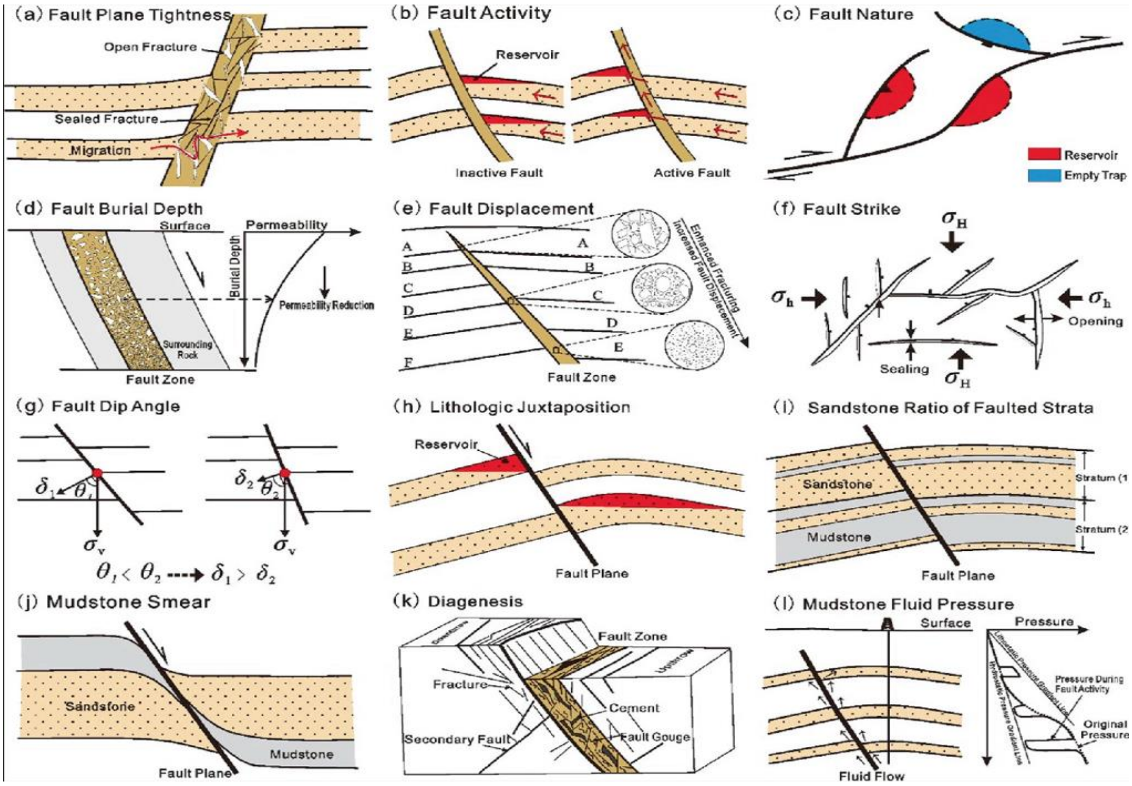

Figure 2-13 : Schematic illustrations showing possible effects of some geologic factors on fault activities, which can be quantified using routine exploration data to characterise fault sealing (Luo et al, 2023).

3. Theory and definitions

Hydrocarbon traps and sealed compartments formation within hydrocarbon reservoirs have mainly been attributed to faults. Predicting the fault system's expected sealing behaviour is desirable when a fault interrupts a reservoir sequence (Knipe, 1997, Yielding et al., 1997).

For a better understanding of the risks associated with fault-controlled prospects and production from faulted fields, it is imperative to comprehend the mechanisms that result in fault seals. Given particular information about a fault cutting a reservoir sequence, it is desirable to estimate the likely sealing behaviour of each fault system component. This assessment requires a deep understanding of the origin and distribution of sealing characteristics along individual faults in addition to a complete understanding of the fault geometries that are being examined.

A fault seal can develop as a result of the juxtaposition of reservoirs and non-reservoirs or from the development of fault rock with high entry pressure. A comprehensive well investigation and seismic mapping are used in the process for assessing these possibilities.

A first-order seal analysis is used to identify reservoir juxtaposition areas over the fault surface using the mapped horizons and a refined reservoir stratigraphy. The second-order stage of the analysis determines if the sand/sand contact is likely to support a pressure differential. Gouge ratio and smear factor are the two types of lithology-dependent features that are established.

The gouge ratio represents the approximate amount of fine-grained material that is entrained from the wall rocks into the fault gouge. The profile thickness of a shale drawn along the fault zone during faulting is estimated using smear factor approaches, such as shale smear factor and clay smear potential. The fact that each of these factors varies along the fault surface suggests that faults cannot be simply categorised as sealing or non-sealing. An important part of their application is the calibration of these parameters in areas where cross-fault pressure differentials are directly known from wells on both sides of a fault. Despite their various settings, our calibration for several data sets provides very consistent results. For example, a typical threshold between a low across-fault pressure difference and a large seal is a shale gouge ratio of approximately 20% (volume of shale in the slipping interval) (Yielding & Freeman, 1997).

Modern techniques demonstrate that there are two ways to ensure fault seal: first, in the case of reservoir against non reservoir juxtaposition, the sealing is ensured by the juxtaposition of permeable rocks against non-permeable rocks; this is known as a juxtaposition seal; second, in the case of reservoir against reservoir juxtaposition class, the fault containment must ensure a barrier to hydrocarbon migration; this is known as a membrane seal.

4. Juxtaposition Seal

According to earlier research (Allan, 1989; Knipe, 1997), juxtaposition seals are connected to cases in which cross fault juxtaposition with low permeability non-reservoir units takes place. When a fault cuts through a series of beds, the hanging wall may be thought of as moving laterally for strike slip faults, upward for reverse faults, and downward for normal faults. The juxtaposition of rocks with diffrent lithologies or petrophysical properties in the hanging wall and footwall is caused by the relative movement between the two fault walls. The petrophysical features of rocks differing in lithology, such as porosity, permeability, and capillary entry pressure, result in a permeability gradient between the various rocks placed between the hanging wall and the footwall. The process can result in juxtaposition sealing between the hanging wall and the footwall. When a sandstone bed is juxtaposed with a mudstone/shale bed, for example, juxtaposition seals may occur; otherwise, it might not form when a sandstone bed juxtaposes with another sandstone bed.

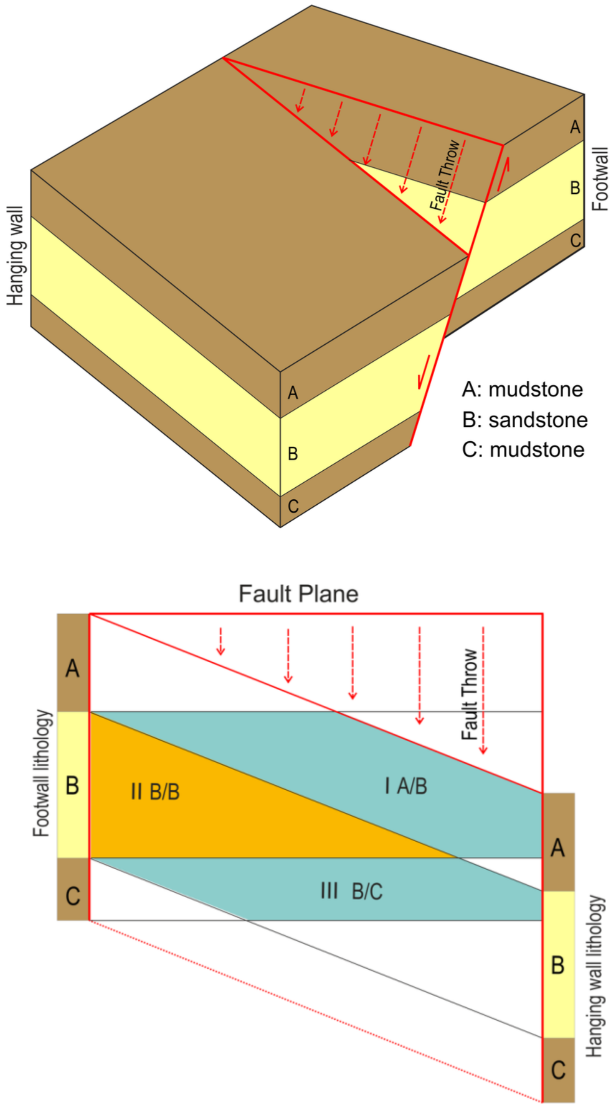

Figure 2-14 :A schematic diagram shows stratigraphic juxtaposition between the hanging wall and footwall (modified from Knipe et al., 1997).

This graphic is a schematic diagram that shows how juxtaposition seals occur. Different stratigraphic strata (A: mudstone; B: sandstone; C: mudstone) from the hanging wall and the footwall juxtaposes against one another as the hanging wall moves downward relative to the footwall. For instance, the hanging wall's mudstone bed (A) juxtaposes against the footwall's sandstone bed (B) in (polygon I) ; similarly, B of the hanging wall juxtaposes against B of the footwall in polygon II; and B of the hanging wall juxtaposes against C of the footwall in polygon III. Therefore, juxtaposition seals can occur in polygon I and polygon III but not in polygon II because sandstone has a higher permeability and a lower capillary entry pressure than mudstone.

In addition to the footwall and hanging wall's lithology, the layer thickness and fault throw are significant factors for juxtaposition sealing. If the fault throw exceeds the thickness of a porous layer (such as sandstones), juxtaposition seals may form, but if the fault throw is smaller than the thickness, the permeable layers might self-juxtapose to create conduits for hydrocarbon migration. Whereas a permeable layer thinner than the fault throw may provide juxtaposition sealing, for a certain fault throw a permeable layer thicker than the fault throw might self-juxtapose to build conduits for hydrocarbon migration.

5. Membrane Seal

Membrane seal is a crucial concept in fault seal analysis that focuses on the sealing mechanism driven by the capillary properties of fault rocks or gouges. This type of seal forms when the fault rock possesses high capillary entry pressures, effectively creating a barrier to fluid migration across the fault plane.

The capillary entry pressure of a fault rock is influenced by various factors, including the percentage of clay or shale material, grain size distribution, and degree of cementation. Clay-rich fault rocks typically have higher capillary entry pressures compared to cemented fault rocks. The presence of clay minerals, such as illite, smectite, and kaolinite, can significantly contribute to the sealing capacity of membrane seals.

The sealing mechanism of membrane seals is based on the concept of capillary pressure, which is the pressure difference across the curved surface of a fluid-fluid or fluid-solid interface. In the context of membrane seals, the capillary pressure acts to prevent the entry fluids (e.g., oil or gas) into the pore spaces of the fault rock. The capillary pressure required for the fluid to enter the fault rock is known as the capillary entry pressure. The fluid won't be able to penetrate the fault rock and the seal will still work if this last pressure is higher than the fluid's pressure. However, the seal may be broken, enabling fluid to flow over the fault plane, if the fluid pressure is higher than the fault rock's capillary entry pressure.

The sealing capacity of membrane seals can be influenced by various factors, such as changes in fluid pressure, temperature, and stress conditions. These factors can alter the capillary entry pressure of the fault rock, potentially affecting the sealing behaviour over time.

Fault sealing characteristics are crucial for hydrocarbon accumulation because they directly affect how well fault-block traps work. During early research, the sealing property of a fault in the normally deposited clastic strata can be qualitatively predicted by the lithologic juxtaposition relationship on both sides of the fault. However, as exploration technologies advance, this qualitative prediction approach will not be able to satisfy production needs. For this reason, it is very critical to carry out quantitative fault sealing property evaluation (Fan,2021). Three key parameters used in quantitative fault seal analysis are the Shale Smear Factor (SSF), Clay Smear Potential (CSP) and Shale Gouge Ratio (SGR). These parameters provide valuable insights into the likelihood of clay smear and the sealing capacity of faults, ultimately aiding in the optimization of exploration strategies and the identification of potential hydrocarbon traps.

5.1.Shale Smear Factor

Shale Smear Factor (SSF) was proposed by Lindsay et al. (1993) for estimating the magnitude of fault seals created by smearing clay/phyllosilicate-rich units, such as mudstones and shales. The SSF value is inversely proportional to the thickness and number of source units of clay/phyllosilicate and directly related to the fault throws. The potential to produce a continuous clay/phyllosilicate smear increases with thickness and number of source units of clay/phyllosilicate and decreases with fault throws, according to the SSF algorithm used to determine the extent of clay/phyllosilicate smears, and vice versa .

$$\text{SSF} = \frac{\textit{Fault throw}}{\textit{Shale layer thickness}} \qquad (1)$$

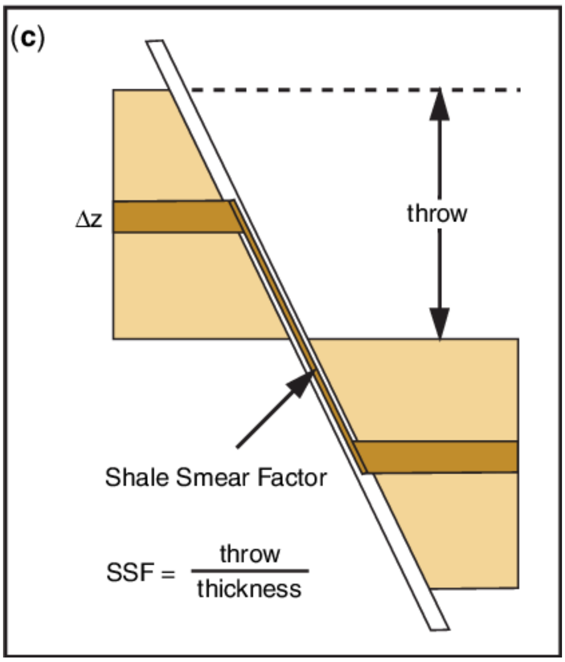

Figure 2-15 :Shale smear factor (Yielding,1997).

Since the shale smear factor is independent of the smear distance (although lateral variations in fault throw would have a similar influence on the calculated SSF), it remains constant between the offset terminations. A sealing layer on the fault surface is more likely to be associated with smaller SSF values, which also tend to correspond to continuous smears. For compound smears, the SSF values are not additive because thin shales dominate the total and give higher SSF values. In such cases, a straightforward application of SSF values would select the most sealing (minimum value) from the pertinent shale beds at that fault's point .

5.2.Clay Smear Potential

According to its description, the relative amount of clay that has been smeared from individual shale source beds at a certain location along a fault plane is represented by the clay smear potential. CSP is said to (1) decrease with greater fault throw, (2) rise with shale source bed thickness, and (3) increase with the number of source beds displaced past a specific location along a fault plane.

$$\text{CSP}=\sum \frac{(\mathit{Shales\ bed\ thickness})^2}{\mathit{Distance\ from\ source\ bed}} \qquad (2)$$

As for distance less than fault offset, Fulljames et al. (1996) have recently provided a more explicit expression of these relationships. The distances from that bed and the bed thickness are measured for a point that lies within the offset between an upthrown shale bed and the corresponding downthrown bed. Since the smear profile is considered to be symmetric, the point will usually be closer to either the upthrown termination or the downthrown termination of the bed. The distance is measured from the nearest termination of the bed. Smear distances and bed thicknesses are measured for all relevant beds if the point lies within the offset of more than one shale bed, and the results are summed up by applying equation (2).

The observed range was classified as high, medium, and low CSP using CSP calculations that were calibrated against known sealing and non-sealing faults. According to Bouvier et al. (1989), low CSP indicates a low likelihood of continuous clay smear seals that can trap hydrocarbons.

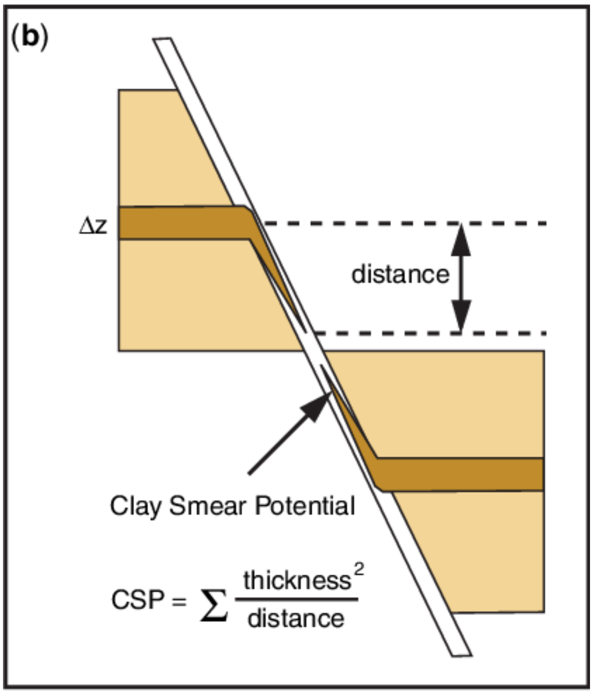

Figure 2-16 : Clay smear potential (CSP) given by the square of source-bed thickness divided by smear distance (Yielding,1997).

As described, CSP and SSF algorithms consider the offset and thickness of individual shale beds . However, because it is sometimes unfeasible to map every shale bed and take into account its effect at the fault surface, such an approach may be challenging to use directly in thick heterogeneous sequences. In such cases, we recommend the more straightforward approach of focusing only on the sequence's bulk properties at the reservoir mapping scale. We define the shale gouge ratio (SGR) which is the main attribute that determines the fault sealing property under static pressure conditions

5.3.Shale Gouge Ratio

According to Yielding et al. (1997), the Shale Gouge Ratio (SGR) was developed to estimate the content of clay present in faults based on the mixing of units with different clay contents in the throw interval. This makes fault seal evaluation easier in stacking sequences with more complexity. Within a distance scale equivalent to fault throw, the SGR is inversely proportional to fault throw and proportional to the cumulative thickness of the shale beds.

$$\text{SGR}=\frac{\sum(\,Shale\ bed\ thickness)}{Fault\ throw}\times 100\% \qquad (3)$$

Moreover, the SGR definition has been expanded to include a package of sediments. In this case, SGR is referred to as the proportion of clay in each unit throughout the throw interval .

$$\text{SGR}=\frac{\sum(Zone\ thickness)\times(\,Zone\ clay\ fraction)}{Fault\ throw}\times 100\% \qquad (4)$$

The SGR determines the average mixture of clays predicted to be present at several points on a fault, whereas the CSP and SSF estimate the fault sealing properties by taking the continuity of smearing of shale/mudstone strata into consideration.

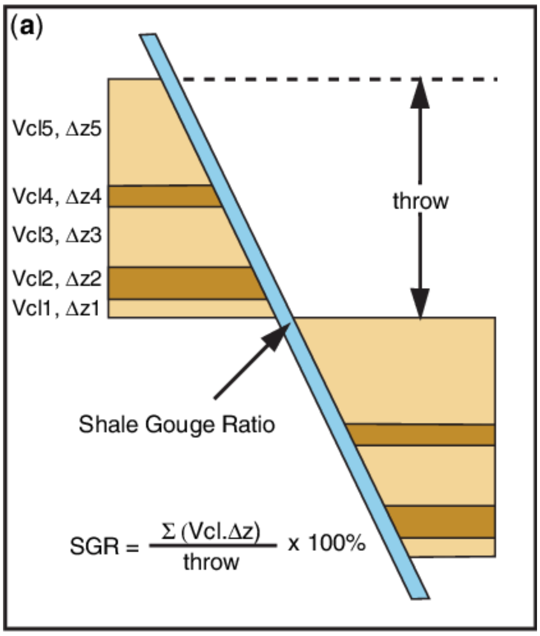

Figure 2-17 : SGR calculation model diagram (Yielding,1997).

So generally, the SGR shows the amount of shale or clay could be entrained in the fault zone through a range of processes. The amount of shale in the wall rocks increases the amount of shale in the fault zone, which increases capillary entry pressure. Fault displacement and shale fraction along the sequence are basically the required data ; this is definitely an oversimplification of the complex processes occurring in the fault zone . However , it offers a tractable upscaling of the lithological diversity at the fault surface.

Choice of SGR threshold

There's no single SGR value that guarantees a perfect fault seal. The key lies in the clay content within the fault zone – the higher the SGR, the more clay there is, potentially leading to a stronger seal. However, things get trickier when you consider factors like the specific type of clay and how the fault zone is structured. By analysing real-world data, geoscientists have developed a general guideline: SGR values above 20% suggest a robust seal, while lower values indicate a higher chance of fluid flow. It's important to remember that this isn't a definitive threshold, but rather a starting point. Additional data is needed for a more precise assessment of a specific fault's sealing effectiveness for a particular reservoir, in other words SGR thresholds vary among basins . However , the empirical threshold value can be used to assess prospects in case of the absence of SGR threshold in a given basin .

Chapter 03: Study Area and Data Overview

Chapter 03:Study area and data overview

1. Geographic location

The Sbâa Basin is situated in the southwest of the Saharan platform. It is bordered to the south by the high area of Bled El Mas, which extends west to the Kahal Tabelbala Chain (Ougarta), and to the east by the Azzene Arch. To the southeast, the basin is separated from the Ahnet-Tidikelt Basin by a narrow area between Bled El Mas and the Azzene Arch.

The Sbâa basin extends geographically between 27°30' and 29° North latitude and 1° East and 2° West longitude, covering around 40,000 km² (Figures 3-18 and 3-19).

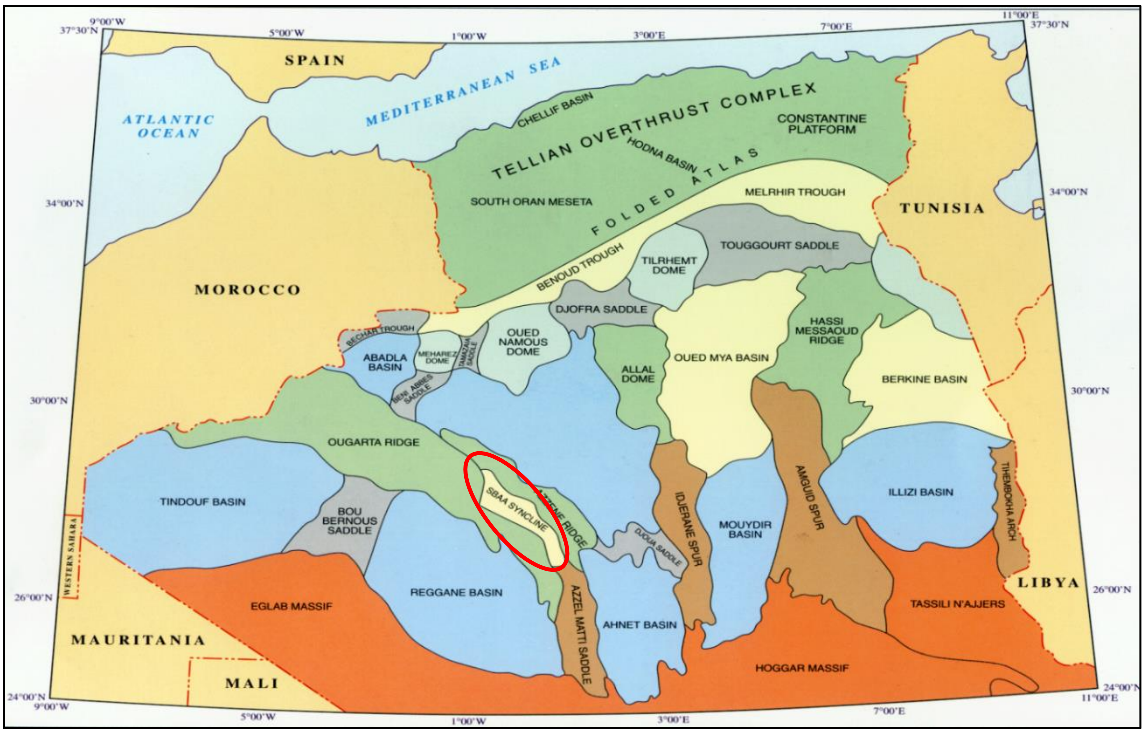

Figure 3-18 : Geographical location of the study area (Sonatrach-Exploration doc).

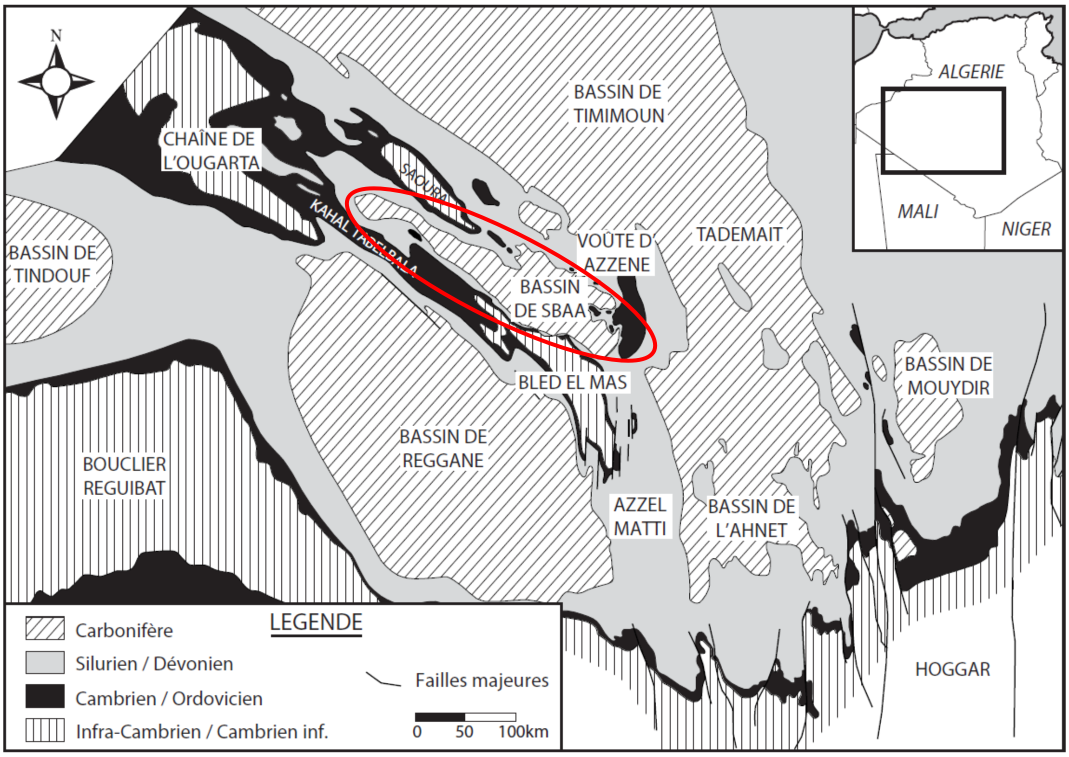

Figure 3-19 : Geological map (Sonatrach-Exploration doc).

2. Tectonic Phases

The Sbâa Basin is directly connected to the Ougarta ranges, which represent the major structural event in the western Sahara. This basin was formed during the Hercynian movement, resulting from a significant folding phase during the Hercynian orogeny. The Ougarta range separates the pericratonic basins of Tindouf and Reggane to the west from the Timimoun Basin to the east. The Sbâa Basin is located between the two main segments of the Ougarta range: the Kahal Tabelbala segment to the south (bordering the Reggane Basin) and the Saoura/Djbel Héche segment to the north (bordering the Timimoun Basin).

From a tectonic perspective, the Sbâa Basin shows a clear contrast between the south, which is less tectonically active, and the north, which is highly tectonized and deeply eroded. This differentiation, due to Hercynian movements, isolates the Sbâa Basin from the Timimoun Basin.

Besides the intense Hercynian tectonics, the region experienced very slight subsidence during the Mesozoic era, with limited reactivation during the Cretaceous and Tertiary periods.

3. Age of Faults & Structuring

The north-south direction of Bled El Mas, which influenced sedimentation during the Lower Paleozoic, and the Azzene Arch, active since the end of the Visean period.
The northwest-southeast direction of the Ougarta range, which impacted the paleogeography starting in the Silurian-Devonian period and became very active at the end of the Carboniferous during the Hercynian orogeny.

East-west and northeast-southwest directions are also significant, leading to the complex compressive structuring of this region.

4. Petroleum system

The following elements of the petroleum system can be distinguished:

- **Source rocks**

Radioactive Silurian shales.

Carbonate Silurian shales.

Basal Frasnian shales.

- **Reservoir rocks**

Ordovician (Unit IV) and Cambrian sandstones.

Strunian/Tournaisian sandstone (Sbaa sandstone, Upper Tournaisian).

Lower Devonian sandstone (Gedinnian).

- **Seal rocks**

Silurian shales.

Upper Tournaisian and Visean shales.

Middle Devonian shales.

- **Trap type**

Structural traps .

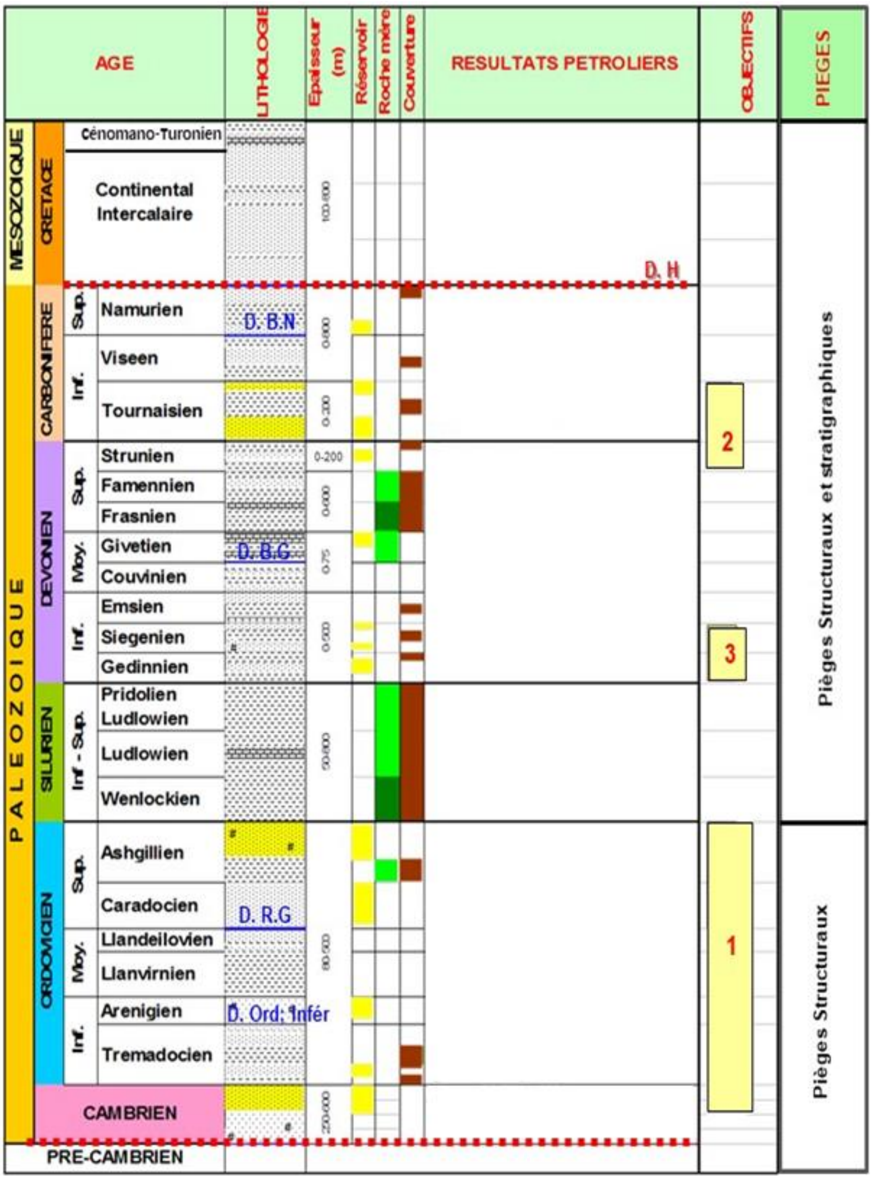

Figure 3-20 : Stratigraphic data sheet of the area(Sonatrach-Exploration doc).

5. Stratigraphic description

The Mesozoic is represented only by the deposits of the intercalary continental, 734m thick, formed at the top by white to yellowish, translucent, medium to coarse, rounded to sub-rounded sand with rare thin layers of white, reddish, siliceous shaley sandstone, finely consolidated, fine to medium, siliceous, moderately consolidated and dark grey, hard, dolomitic Limestone, then alternating grey, reddish-brown, pinkish to yellowish, sometimes ferruginous, fine to medium, sometimes coarse, sub-angular, moderately to well consolidated sandstone and grey, reddish-brown, strongly silty, indurated clay.

The Paleozoic is affected by Hercynian erosion, and this series begins with:

- **Carboniferous**: composed of:

The Namurian: is 616m thick, essentially shaley and slightly carbonated, with thin layers of white sandstone and dolomitic limestone.

The Visean: is 265m thick and is essentially a silty, fossiliferous shale with sandstone and limestone layers.

Tournaisian : is 62m thick, sandstone, silico-clay with micaceous shales.

Sbâa sandstone : 19m thick, very fine to fine sandstone, siliceous, friable, glauconitic, pyritic, silico-shaley with small lenses of micaceous clay.

Strunian with a thickness of 196m, composed of fine to very fine sandstone, siliceous, silico-clayous with intercalations of clay, indurated, laminated, silty, micaceous with traces of pyrite.

- **Devonian :**

Famennian : of 173m, composed of shale, indurated, silty, micaceous, laminated, with intercalations of fine to very fine sandstone, siliceous, micaceous, consolidated.

The Frasnian : 192m thick, is made up of microcrystalline limestone, with silty, laminated and carbonated shales.

Givetian: is composed of limestone 10m thick.

Silurian: is 331m thick, flaky, slightly carbonated, silty shales, indurated with pyrite nodules.

- **Ordovician:** the main Ordovician levels are as follows:

Unit IV: this represents the highest part of the Ordovician, with a thickness of 177m, and is formed of two sandstone levels separated by micro-conglomeratic shales.

Ramade Sandstone (20m): Fine to medium, sometimes coarse, siliceous, angular to sub-angular, well-consolidated, sometimes greenish grey-white sandstone, with fine lenses of grey to greenish grey, black, silty, hard, micaceous shale.

Two cores were taken in this interval, showing good reservoir parameters.

Micro-Conglomeratic clays (5m): Grey to black-grey, silty, indurated shales.

El Golea sandstone (152m): White to grey-white sandstone, very fine to fine, sometimes medium, angular to subangular, siliceous, well consolidated, sometimes silico-clayey, moderately hard to hard, with grey to grey-black, silty, indurated shales.

Alternating zones: 23m thick, alternating sandstones and shales.

- **Cambrian:** >152m thick, composed of fine to medium sandstone, siliceous to silico-quartzitic, well consolidated, hard and sometimes micro-conglomeratic with fine, indurated, silty, micaceous shale layers with traces of pyrite.

6. Structure description

Ordovician top mapping has shown that the Oued Toughert structure is an anticline extended against a NW-SE reverse fault with a throw of around 150m.
The surface area calculated from the fault plane to structural closure is 9.7Km², with an amplitude of around 100m.

7. Used Data

In this section, we present the findings from the integration of well data from W1 and W2 with the 3D seismic survey.

7.1.Seismic data

In our study, we used the 16Sbaa_3D seismic survey stored in the SEG-Y format, organized into in-line and cross-line sections. Generally speaking, the 3D seismic data used are of good resolution, an example of an inline from the 3D seismic volume is illustrated by figure 3-21.

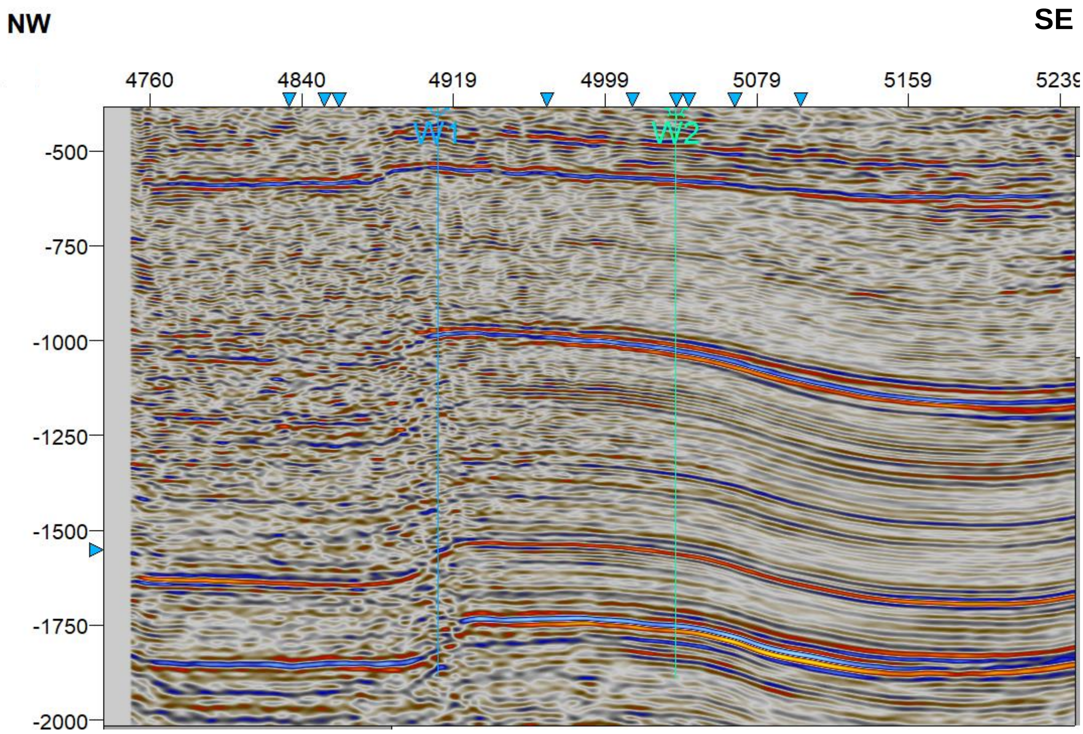

Figure 3-21 : In-line from 16Sbaa_3D seismic survey crossing wells W1 & W2.

7.2. Well data

Well data on the other hand, offers a more direct perspective on the subsurface, obtained through drilling and logging operations. This data encompasses various types of information gathered from wells, including:

Wellhead Information: provides the geographical context and basic details about each well, such as its location, depth, and operational status.

Well Tops: Descriptive records detailing the depths at which specific geological formations are encountered during drilling, aiding in the identification and correlation of subsurface layers. The tops we utilized in our study are: the Hercynian unconformity , the Visean , the Frasnian , the Givetian and the Ordovician .

Well Logs: Detailed measurements obtained by logging tools lowered into the wellbore, providing insights into lithology, porosity, fluid content, and other properties of the rock formations penetrated by the well. Figure 3-22 shows the logs used, which are gamma ray log, sonic log and Vsh log .

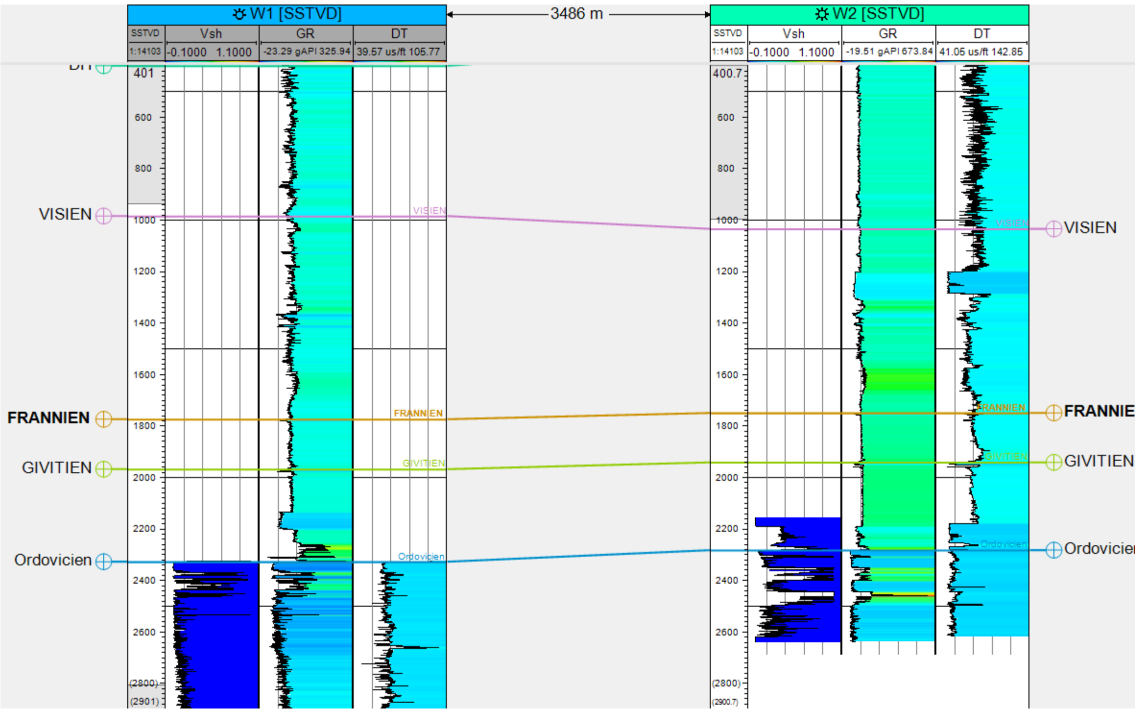

Figure 3-22 : Sonic, Gamma Ray and Vsh logs from W1 & W2.

Check Shot Data: Measurements of seismic wave travel times taken at discrete depths within the well, facilitating the construction of accurate velocity models for seismic processing and interpretation.

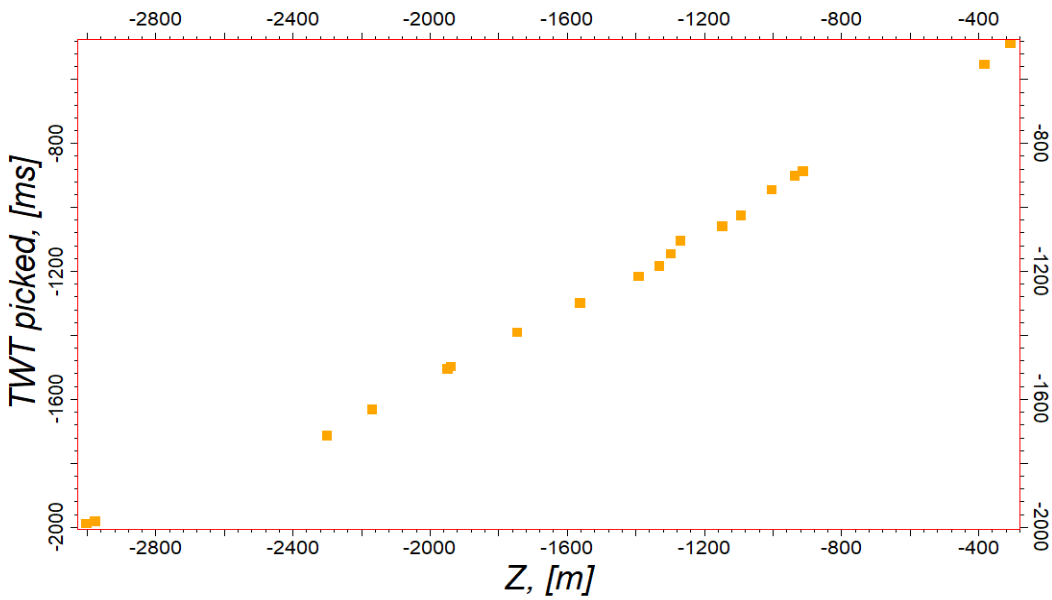

Figure 3-23 : Checkshot from W1.

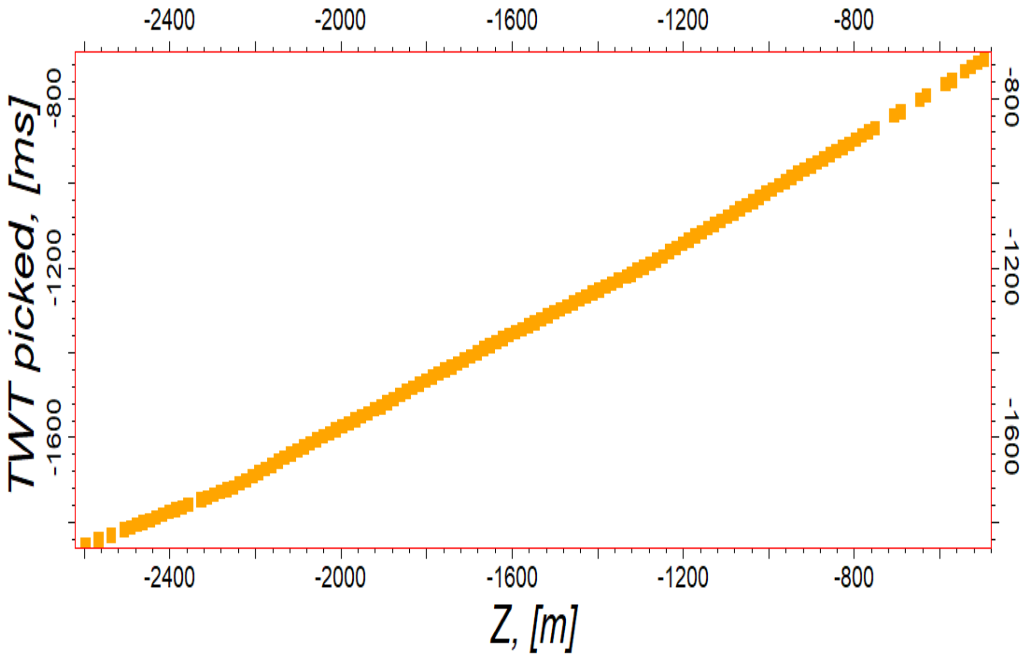

Figure 3-24 : Checkshot from W2.

Chapter 04: Application of the Fault Seal Analysis workflow

Chapter 04: Application of the Fault Seal Analysis workflow

1. Workflow

The workflow outlined (Figure 4-25) integrates various techniques to comprehensively analyse geological structures and reservoir properties. Beginning with the collection of inputs, primarily seismic and well data which are used in the interpretation of horizons and faults, we establish a foundational understanding of the subsurface architecture. This initial interpretation is further refined through the generation of isochrones maps and fault sticks.

The core system consists of three main components: structural modelling, facies modelling, and petrophysical modelling. Structural modelling involves interpreting seismic data to create a three-dimensional structural framework. Facies modelling is the next step, where well data are used to define different lithological units and their spatial distribution. Petrophysical modelling follows, where well log data are analysed to derive key petrophysical properties, enabling the creation of geocellular 3D models representing the distribution of the volume of shale (Vsh).

The outputs include a fault seal analysis study, wherein juxtaposition diagrams and Shale Gouge Ratio (SGR) calculations are performed using the previously generated 3D grids which provides qualitative and quantitative analysis, clarifying the sealing capacity of faults and aids in understanding fluid migration pathways within the reservoir.

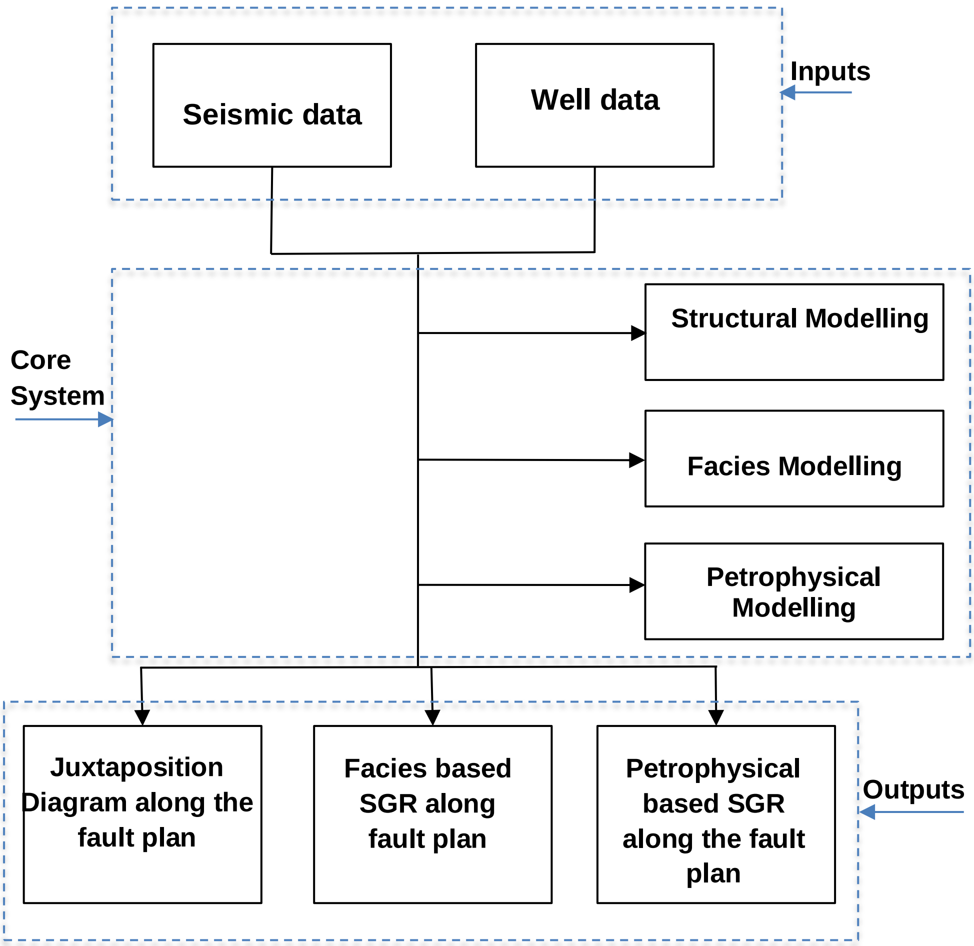

Figure 4-25 : Fault seal analysis workflow.

2. Seismic well tie

Establishing the relationship between seismic reflections and stratigraphy is indeed one of the first and most crucial steps in interpreting a seismic dataset. This process, known as seismic-to-well tie or seismic well tie.

The basic concept and theory of seismic well tie involve aligning geological properties and well logs with seismic data to enhance the interpretation of subsurface structures and identify potential hydrocarbon reservoirs. Seismic well tie is essential because seismic data is typically interpreted in the time domain, while well logs are recorded in the depth domain, requiring the use of velocities to bridge the gap between the two domains. Velocities play a crucial role in converting time functions between seismic and well logs, but the non-linear and depth-dependent nature of velocities makes obtaining a precise velocity model challenging.

A precise seismic well tie is vital for various applications such as reservoir characterization, seismic inversion, and seismic processing. For instance, in horizon interpretation, which involves matching stratigraphic markers from wells to seismic reflectors, a proper alignment is necessary to accurately resolve reflections associated with oil and gas-bearing reservoirs. Without a precise seismic well tie, the interpretation process may be compromised, leading to inaccuracies in identifying subsurface features and potential hydrocarbon resources

The seismic well tie process typically involves the following steps:

2.1.Depth-time conversion

Well log data is recorded in depth, while seismic data is recorded in time. A depth-time relationship is established using checkshot surveys or sonic logs to convert between the two domains.

2.2.Sonic calibration

Sonic calibration is a critical process in the field of geophysics, particularly in seismic applications, where sonic logs are calibrated to eliminate errors and discrepancies for accurate interpretation of subsurface structures and geological features. This calibration is essential to ensure that sonic measurements align with seismic data, allowing for precise correlation between the two datasets and enhancing the reliability of seismic interpretations. Sonic calibration involves adjusting sonic logs using various techniques such as check shots or VSP methods to correct for factors that can affect sonic measurements like :

➔ Low transmitter strength .

➔ Road noise .

➔ Amplitude attenuation of the compressional wave that might be caused by: high porosity, shale content , near borehole alteration ,fractures ,thin beds or hydrocarbons .

By calibrating sonic logs, geoscientists can improve the predictability and accuracy of seismic interpretations, leading to more informed decisions in oil and gas exploration and production.

2.3. Wavelet extraction

A wavelet is extracted from the seismic data to represent the source signature. This wavelet is used to generate synthetic seismograms from the well log data.

2.3.1. Deterministic wavelet extraction: This method creates the wavelet by modelling the reflections in a seismic trace, like a synthetic seismogram. By deconvolving the trace using the set of synthetic seismogram reflection coefficients, the wavelet is produced.

2.3.2. Statistical wavelet extraction: This approach does not require a model for the reflections. Rather, it generates a power spectrum of the data and makes several assumptions in order to create the wavelet, such as the power spectrum contains information about the wavelet (and not the geology) and that the wavelet is of a given phase (minimum, zero).

2.4. Synthetic seismogram generation

Synthetic seismograms are critical in understanding seismic data, as they serve as a bridge between well data and seismic data for interpretation tasks. The process of generating a synthetic seismogram involves convolving the reflectivity derived from sonic log and density log with the wavelet derived from seismic data. The quality of the match between a synthetic seismogram and actual seismic data depends on well log quality, seismic data processing quality, and the ability to extract a representative wavelet from seismic data.

2.5. Seismic-to-well tie

The synthetic seismogram is shifted, stretched, and squeezed to match the actual seismic data, establishing the relationship between the seismic reflections and the stratigraphy .

Seismic well tie enabled us to :

➔ Correlate seismic horizons with geological markers.

➔ Create accurate time-depth relationships .

➔ Comprehend the phase characteristics of seismic data .

➔ Interpret the seismic response of different lithologies and fluids at well locations.

Figures 4-26 & 4-27 show seismic well tie on the study area using wells W1 and W2. We observe a good match between synthetic and seismic data with a small-time shift which indicates that a successful correlation of seismic events with lithological variations in well logs was achieved.

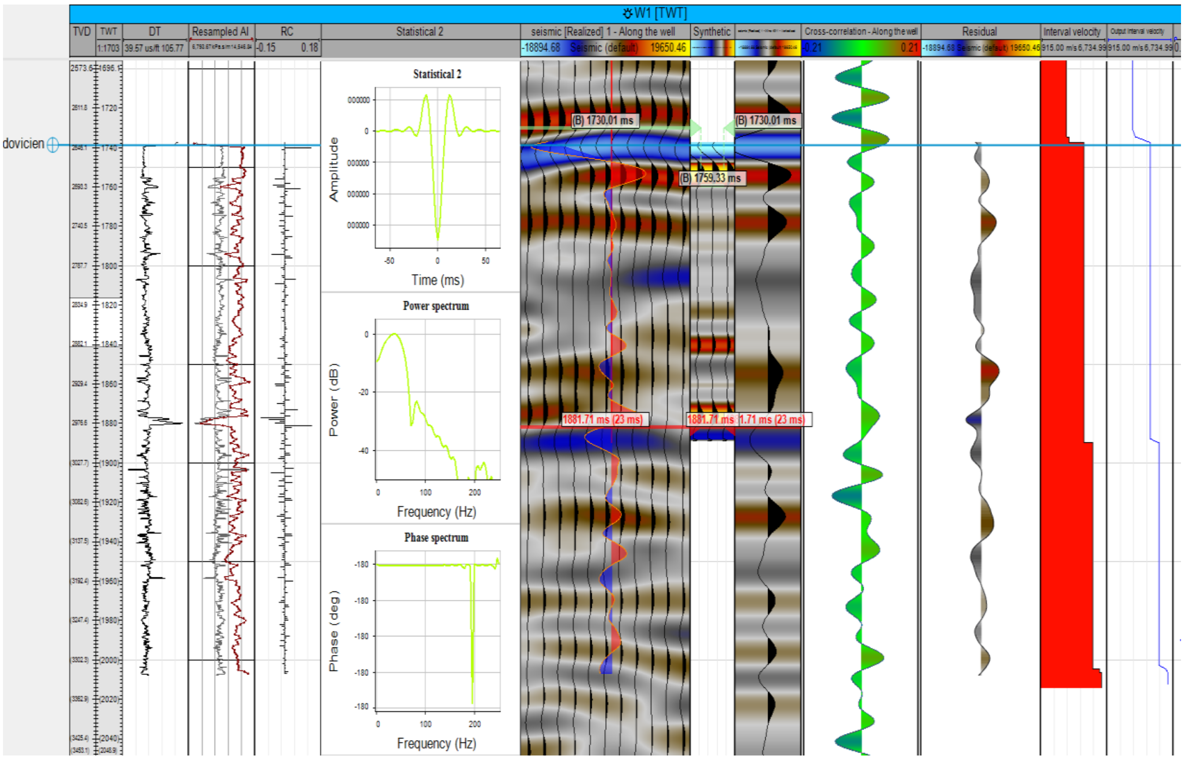

Figure 4-26 : Seismic well tie using W1.

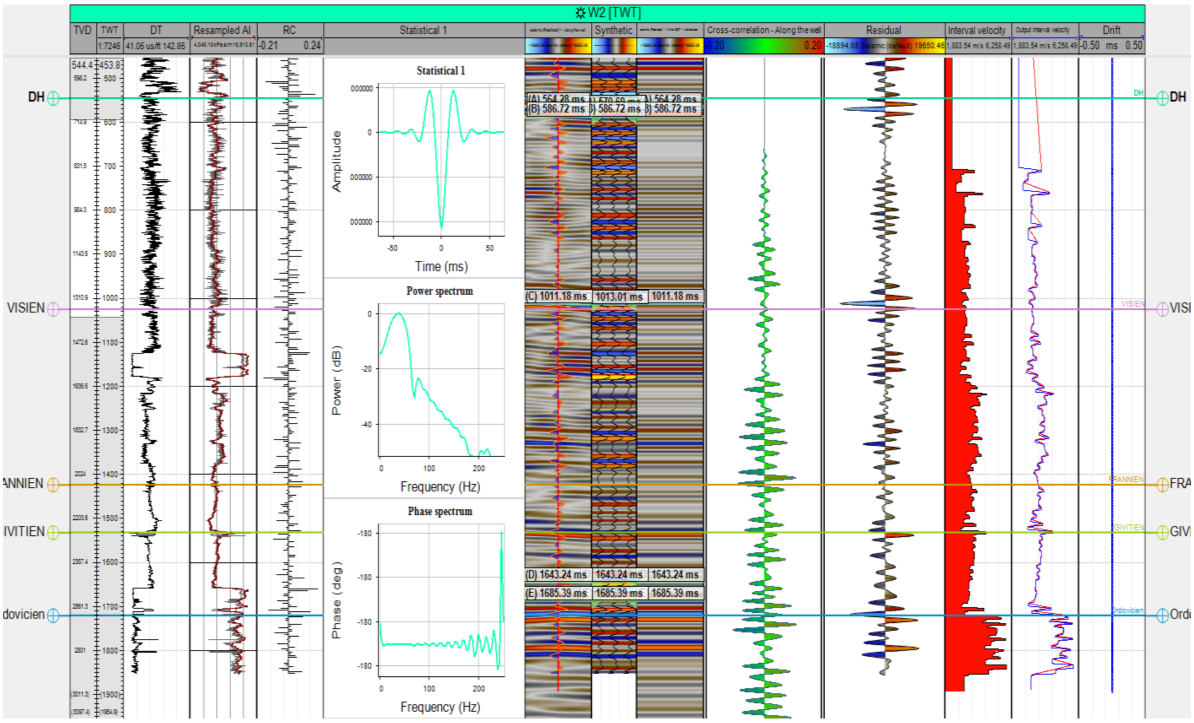

Figure 4-27 : Seismic well tie using W2.

3. Structural seismic data interpretation

Structural interpretation is the critical third step in seismic exploration, following the acquisition and data processing phases. This process involves analysing the processed seismic data to delineate subsurface geological structures, providing essential insights into the subsurface architecture. Through structural interpretation, geoscientists identify and characterise features such as fault systems, fractures, and folding patterns that define the geological framework of the study area. Utilising advanced software tools, seismic reflectors are traced and mapped to construct detailed geological models. These models help visualise the spatial relationships between different geological units and the structural complexities that influence hydrocarbon accumulation and migration.

The process begins with the careful examination of seismic sections, where continuous and discontinuous reflectors indicate various lithological and structural features. Interpretation involves both manual picking of key horizons and automated techniques to enhance accuracy and efficiency. Integrating well data, such as borehole logs and checkshot surveys, with seismic data is crucial in this step, as it allows for the calibration of seismic reflections with known geological markers, improving the reliability of the interpretation. Velocity models derived from well data are used to convert seismic time data into depth, enabling precise mapping of subsurface structures.

Throughout the structural interpretation, special attention is given to identifying traps and seals, as these are critical for the presence of hydrocarbons. The identified structures are analysed for their ability to trap hydrocarbons, considering aspects such as structural closures and the presence of impermeable layers that can act as seals. Additionally, the interpretation assesses the continuity and connectivity of potential reservoirs, which impacts the feasibility of hydrocarbon extraction.

Structural interpretation also includes the creation of detailed cross-sections and 3D models that provide a comprehensive view of the subsurface. These visualisations aid in understanding the geological history and tectonic evolution of the study area, which are essential for making informed exploration and development decisions.

Two fundamental steps in this process are horizons picking and fault picking.

3.1Horizon picking

3.1.1. Identification of key reflectors

In our seismic interpretation, we have identified and delineated five key geological horizons. These horizons include the Ordovician , Givetian , Frasnian , Visean and Hercynian unconformity (DH: Discordance Hercynienne). These reflectors were identified based on their continuity and amplitude contrasts in seismic sections.

3.1.2. Manual and automated picking

- Manual Picking

Seismic reflectors across seismic section are manually traced to ensure accuracy in defining the horizons. However, despite being more precise , this method is time consuming .

- Automated Picking: Advanced software algorithms can automatically track seismic reflectors based on their continuity and amplitude characteristics speeding up the interpretation process. However, it may require manual adjustments to correct errors.

3.1.3. Correlation and consistency

This process, being one of the most important steps in horizon picking, involves correlating seismic horizons across the entire 3D volume by controlling each grid cell and cross-section. This makes certain that the picked horizons are consistent and continuous throughout the seismic data. Correlation usually starts with sections that pass through well locations where horizons are already identified, providing a reliable reference for further interpretation.

3.2Fault picking

In addition to seismic horizons, we conducted an interpretation of Oued Toughert fault using the 3D seismic dataset. This feature appears as discontinuities or offsets, and thus was identified by examining seismic sections for breaks or shifts in the continuity of reflectors and looking for changes in reflector amplitude and dip.

Faults also could be traced either by manual picking which ensures a detailed and accurate delineation of fault geometries. Or by automated picking by using software tools that, as mentioned earlier, demands manual corrections despite being a faster method.

Figure 4-28 shows the interpreted horizons and fault on a random line oriented SW-NE from the 3D seismic survey in study area , while figure 4-29 shows its position on the study area.

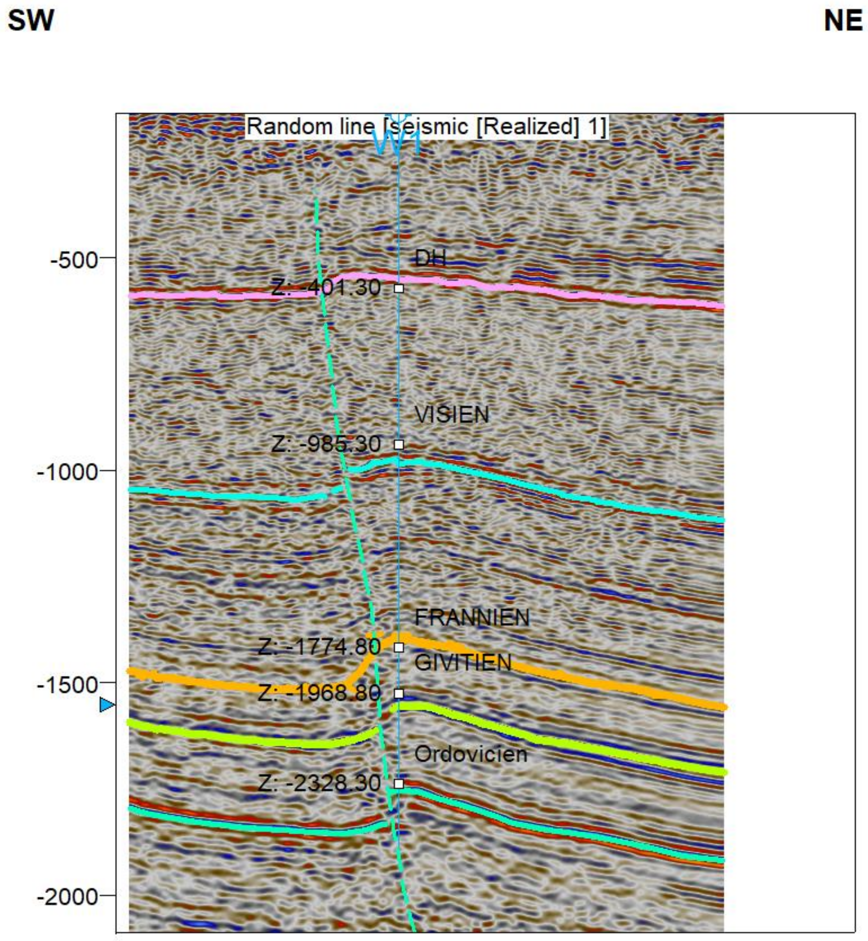

Figure 4-28 : Random line from 16Sbaa_3D seismic survey crossing well W1.

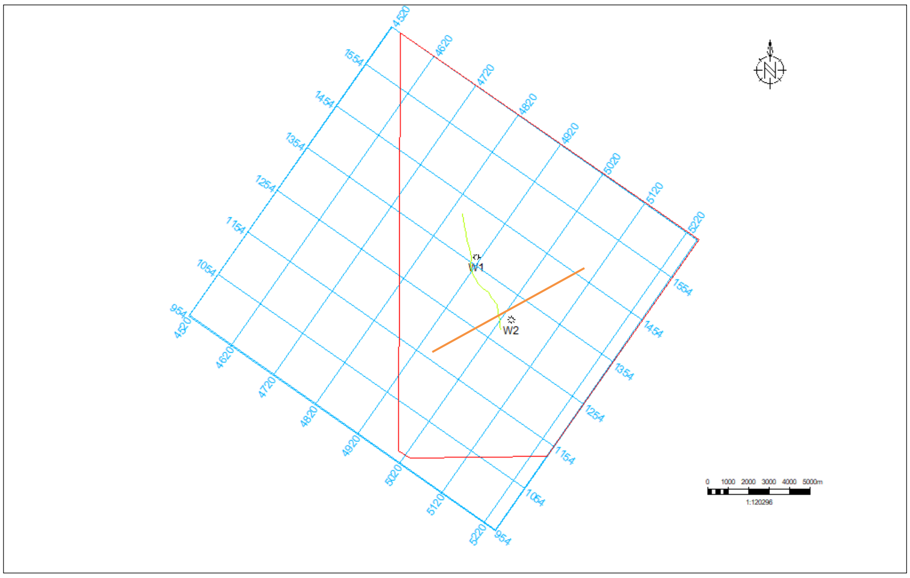

Figure 4-29 : Location map of 3D seismic survey position.

In summary, structural interpretation transforms raw seismic data into meaningful geological insights, bridging the gap between data acquisition and the practical aspects of hydrocarbon exploration. This step not only identifies the presence of geological structures but also evaluates their potential to host hydrocarbons, thereby guiding exploration efforts and reducing risks associated with drilling and development. Structural interpretation plays a crucial role in the seismic exploration workflow by providing the groundwork for successful hydrocarbons exploration through the meticulous analysis and integration of diverse data sources.

4. Structural mapping

After horizons and the fault have been interpreted, the next phase is structural mapping for each horizon which, generally, presents the result of seismic data interpretation.
We distinguish two major types of structural maps: isochrones and isobaths.

4.1.Isochrones maps

Isochrone maps, also known as time structure maps, represent the subsurface geological features in terms of seismic reflection time. These maps display lines of equal seismic two-way travel time to a particular geological horizon, providing a time-based visualisation of subsurface structures.

The results of our isochrones mapping are shown in the following figures.

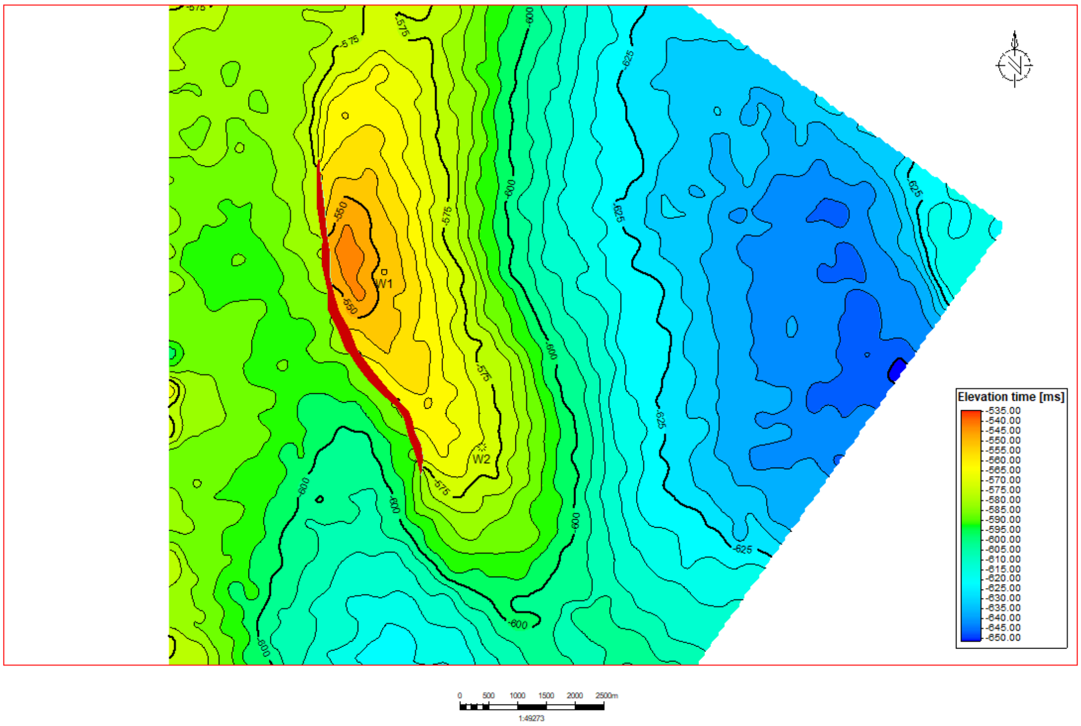

Figure 4-30 : Isochrones map on top of the Hercynian unconformity.

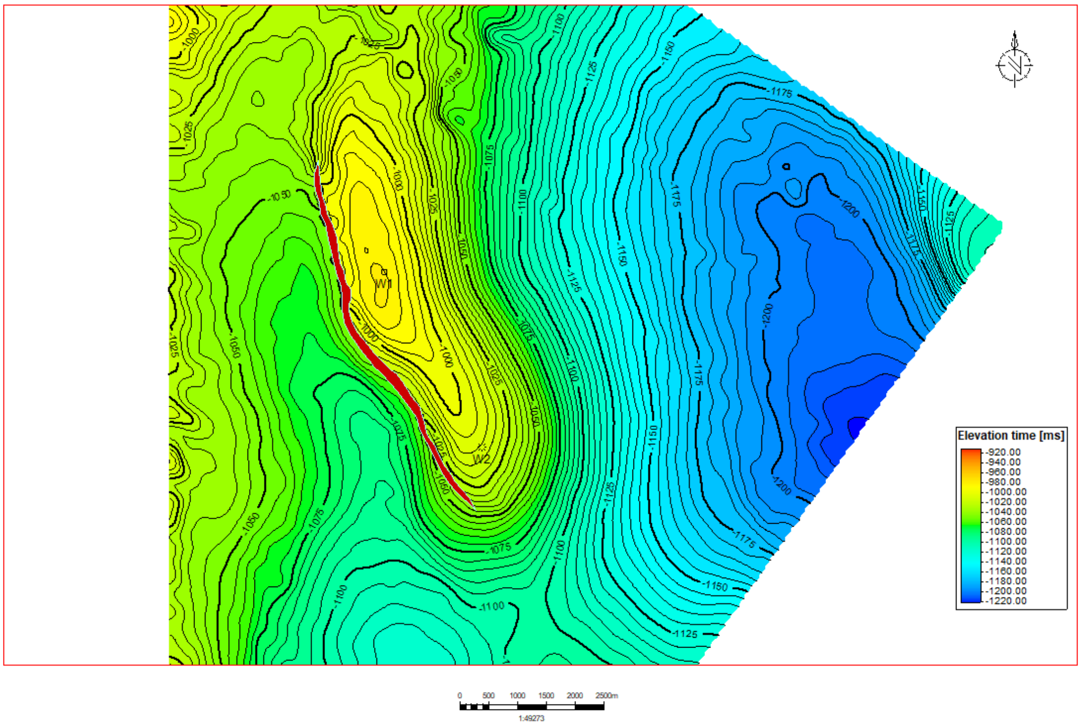

Figure 4-31 : Isochrones map on top of the Visean.

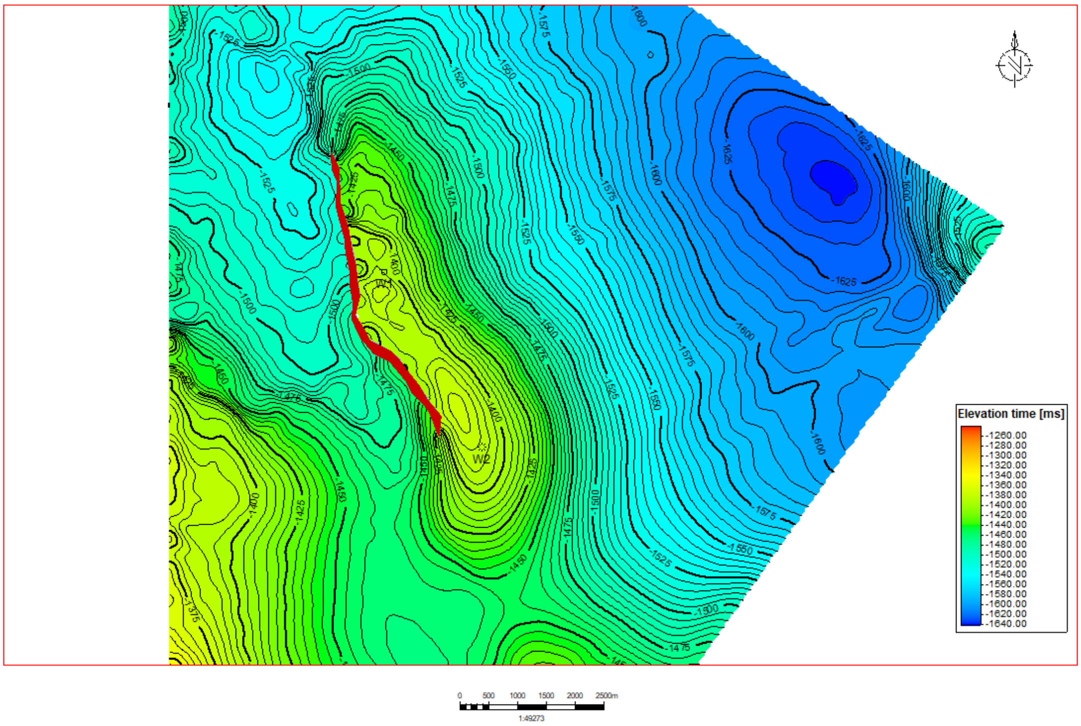

Figure 4-32 : Isochrones map on top of the Frasnian.

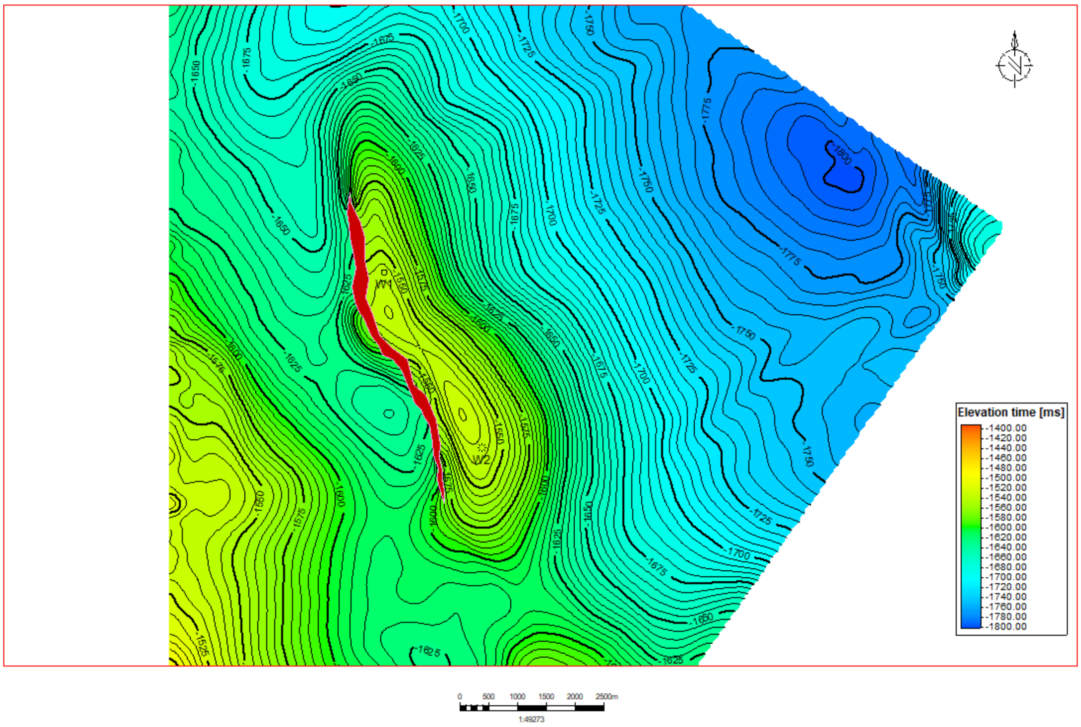

Figure 4-33 : Isochrones map on top of the Givetian.

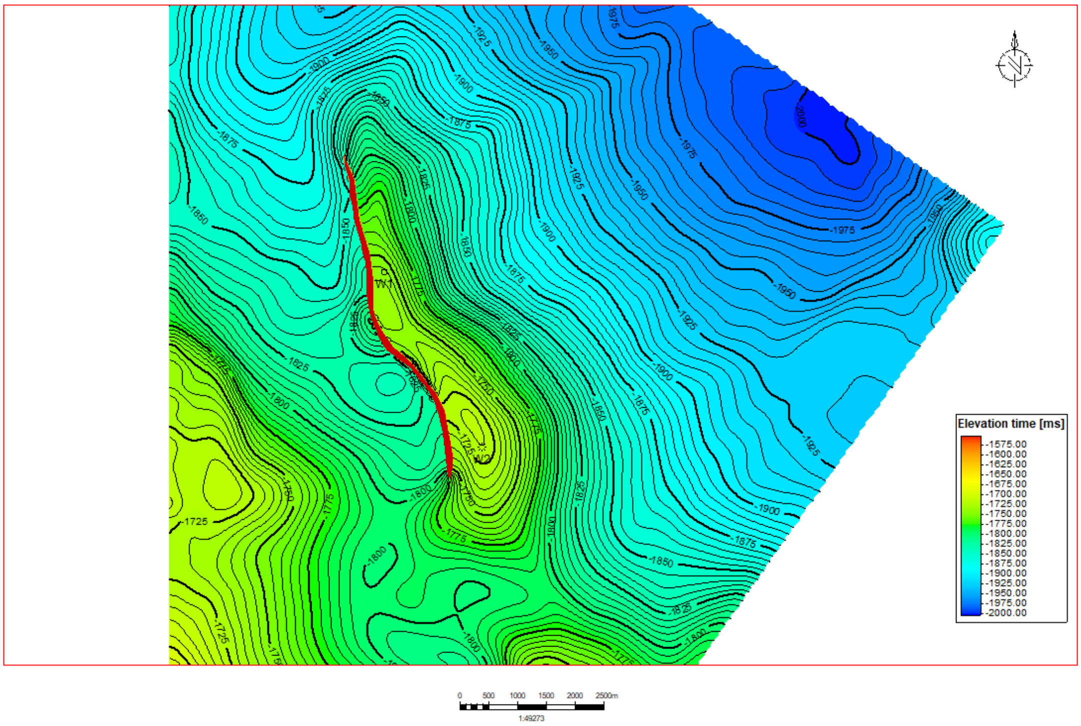

Figure 4-34 : Isochrones map on top of the Ordovician.

4.2. Time depth conversion

The estimation of subsurface velocities is the most challenging yet critical step in seismic interpretation because it directly controls the quality of depth images.

Time-depth conversion is a crucial step in order to transform seismic reflection time (isochrones) into actual depths (isobaths). This process is essential for creating accurate depth structure maps, which are used to visualise and analyse subsurface geological events.

There are several methods for achieving this , each method has its own applications .

4.2.1. Average velocity method

The average velocity method is a straightforward approach to time-depth conversion. It starts by collecting pairs of time and depth measurements from well data for the target horizon, treating the entire interval as a single layer. These pairs are used to calculate average velocities, which are then interpolated to create a continuous velocity map. By multiplying this velocity map with the time map, a depth map is generated using the formula:

$$\text{Depth} = \text{Average velocity} \times \text{TWT}/2$$

Advantages

- This method is very simple and quick to implement.
- Requires minimal data, primarily well depths and corresponding travel times.

Disadvantages

- The assumption of a constant velocity throughout the layer can lead to inaccuracies in areas with complex geology .
- This method is less accurate than more sophisticated approaches like the layer cake method.

After applying the average velocity method on top of the Ordovician , we found a shift of 14 m in W1 and 4 m in W2 compared to well tops data . Figure 4-35 shows the result:

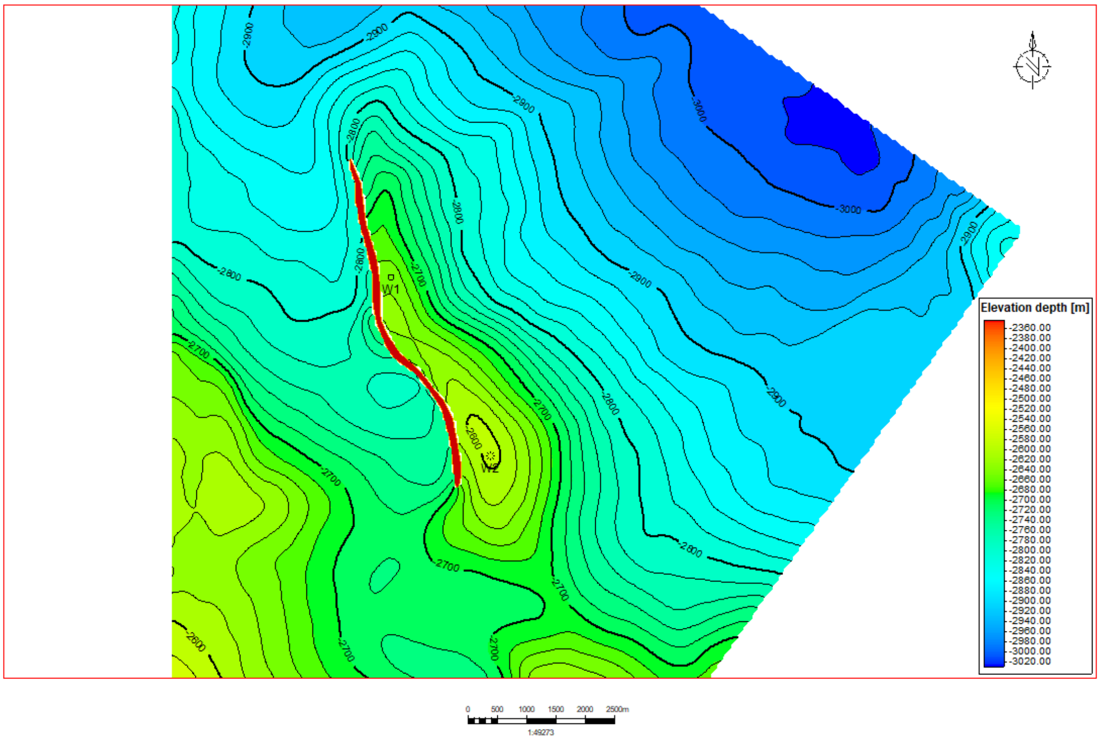

Figure 4-35 : Depth converted map using average velocity on top of the Ordovician.

While the average velocity method does not inherently incorporate detailed geological or structural information, it can be used in conjunction with other methods to provide a baseline or initial estimate. For example, average velocities can serve as a starting point for more detailed velocity modelling approaches, such as the layer cake method or interval velocity method.

4.2.2. Trend curve method

The depth conversion using the trend curve method involves modelling the velocity trend in the subsurface to accurately convert seismic data from time domain to depth domain. Here are the key steps in this process:

1- Analysing the available well data such as checkshots to determine the velocity trend in the subsurface. This trend can be linear, exponential or more complex depending on the geological setting.
2- Use statistical methods to fit a trend curve to the velocity data. This involves applying regression analysis to capture the relationship between velocity and depth.
3-Applying the trend curve: Using the trend curve equation to calculate the velocity at each depth point in the seismic data.

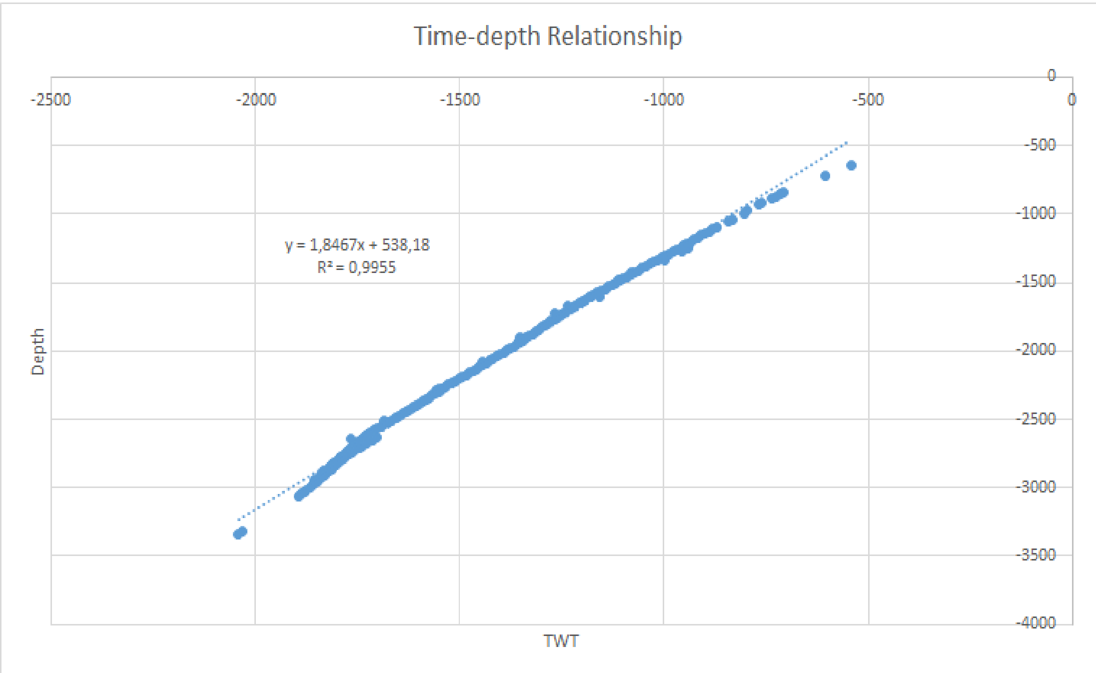

Figure 4-36 : Time-depth relationship driven from the Checkshot.

After generating the depth structural map, using the time depth relationship shown in the figure 4-36, to visualise the converted Ordovician horizon, the result is as follows.

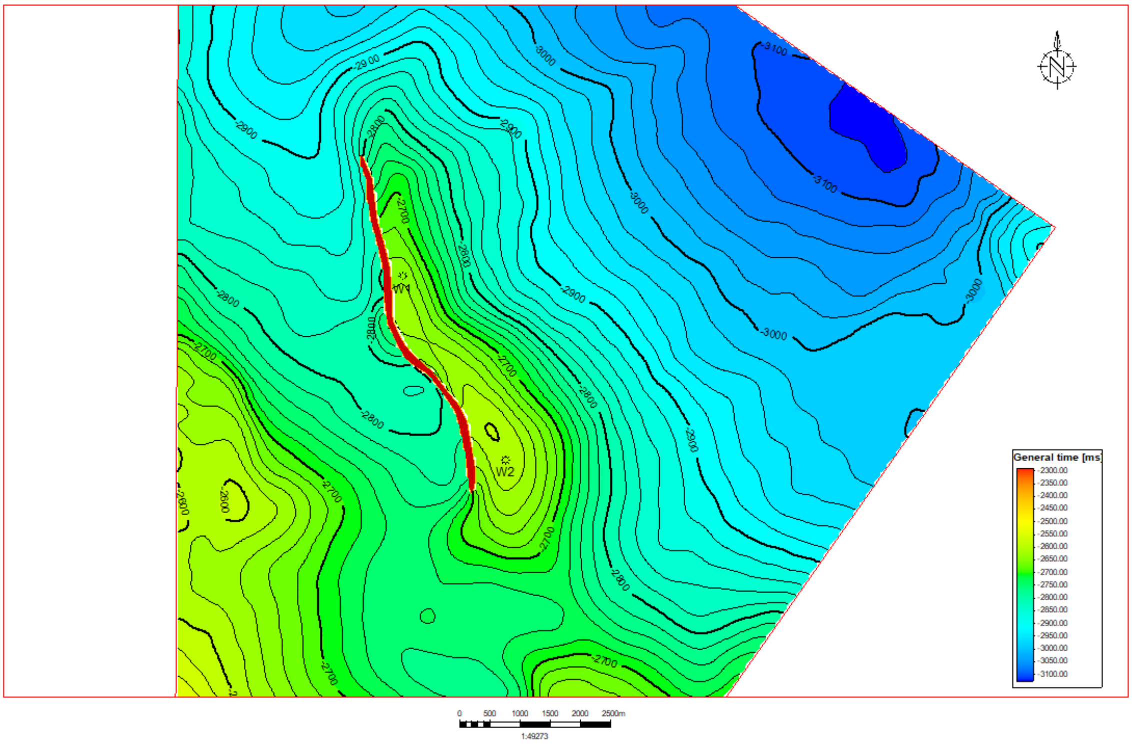

Figure 4-37: Depth converted map on top of the Ordovician.

Comparison against well top data shows that this method allows 5 m shift in W1 while 0 m shift in W2.

Although this method provides a more accurate depth conversion than the average velocity method in areas with gradual velocity changes, improving the reliability of geological models, it requires well-defined velocity trends, which may not always be available or easy to determine. Also, it may not adequately capture abrupt velocity changes or anomalies without additional calibration.

4.2.3. Layer cake method

The layer cake model is a widely used approach in time-depth conversion, dividing the subsurface into discrete horizontal layers, each assigned a constant velocity reflecting the compaction trend and geological characteristics based on well data analysing. This method is particularly effective in geological settings where distinct stratigraphic units have well defined velocity contrasts. This structured approach ensures that the velocity model accurately represents the subsurface conditions, providing a reliable basis for converting two-way time maps into depth maps.

The figure 4-38 shows the layer cake method applied on the Ordovician horizon .

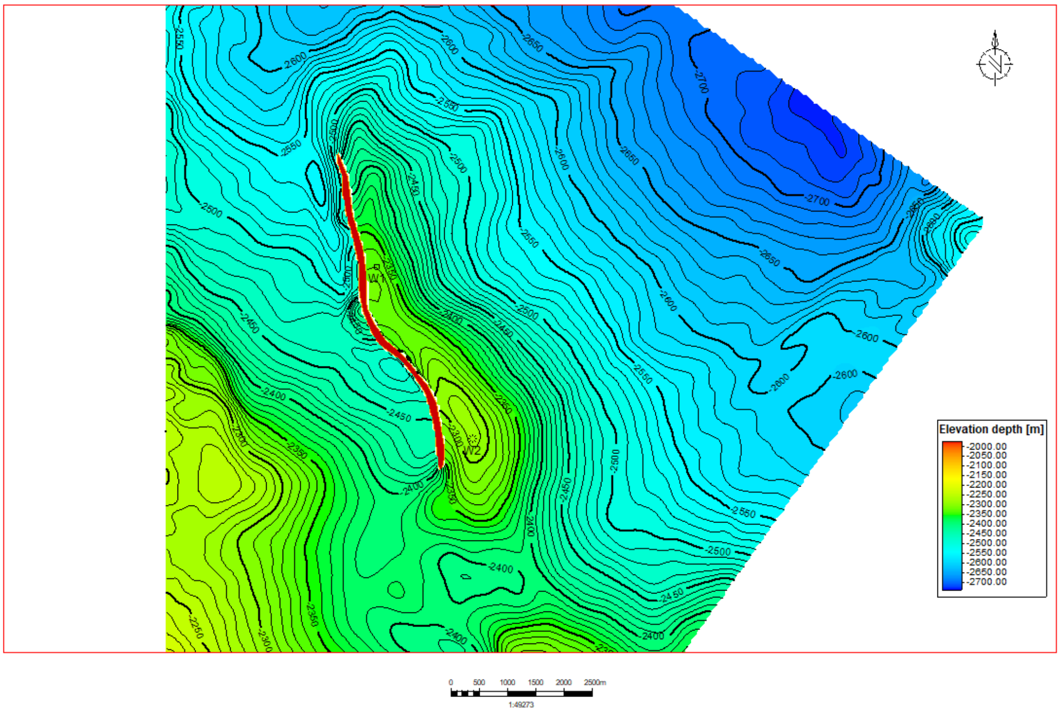

Figure 4-38: Isobaths map on top of the Ordovician.

After trying the 3 methods, we chose the layer cake method to fulfil our work since it gave us the best results with 0 m shift in both wells W1 and W2 and we applied it on the rest of the horizons as the figures 4-39, 4-40, 4-41 and 4-42 show.

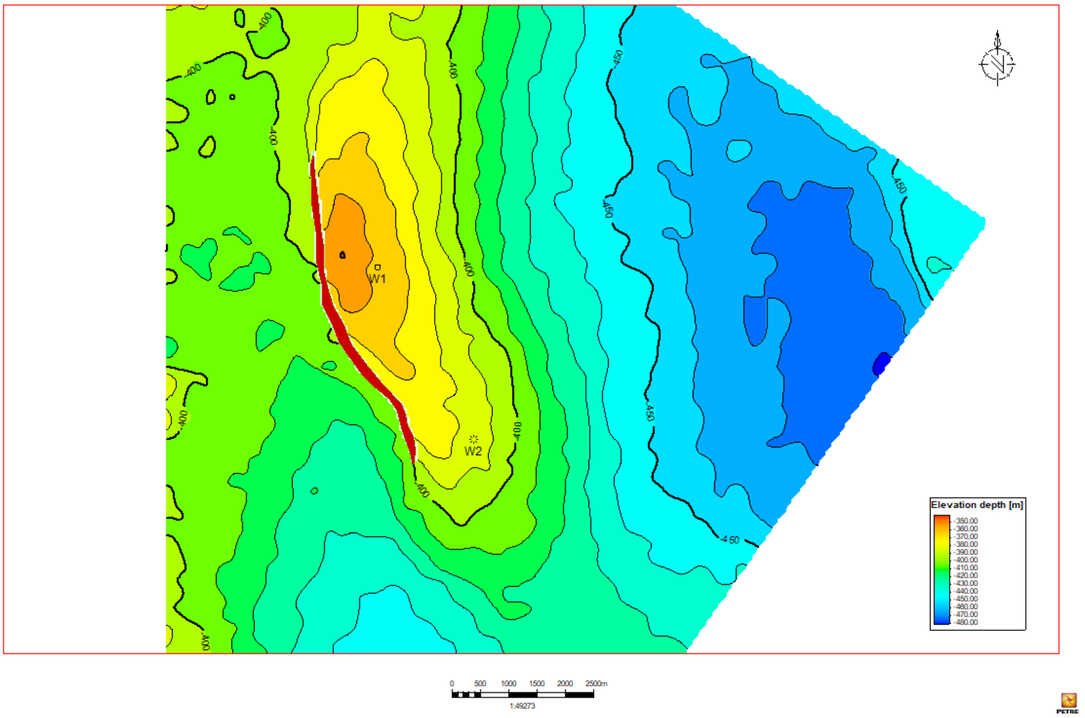

Figure 4-39: Isobaths on top of the Hercynian unconformity.

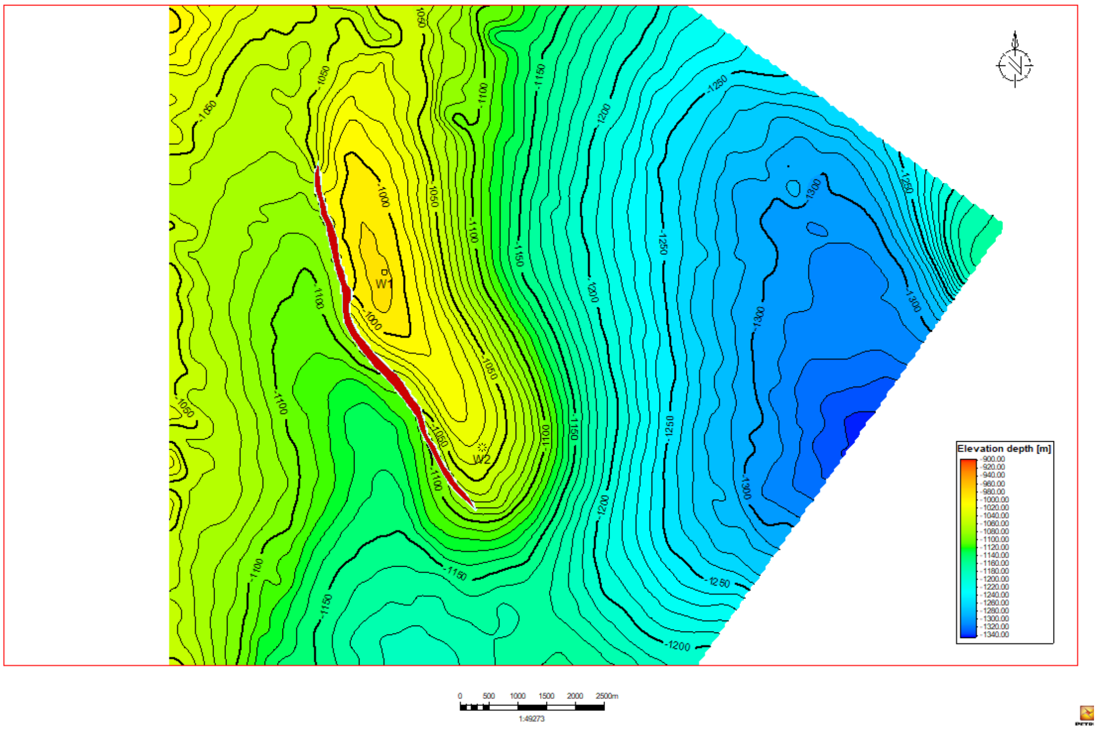

Figure 4-40 : Isobaths on top of the Visean.

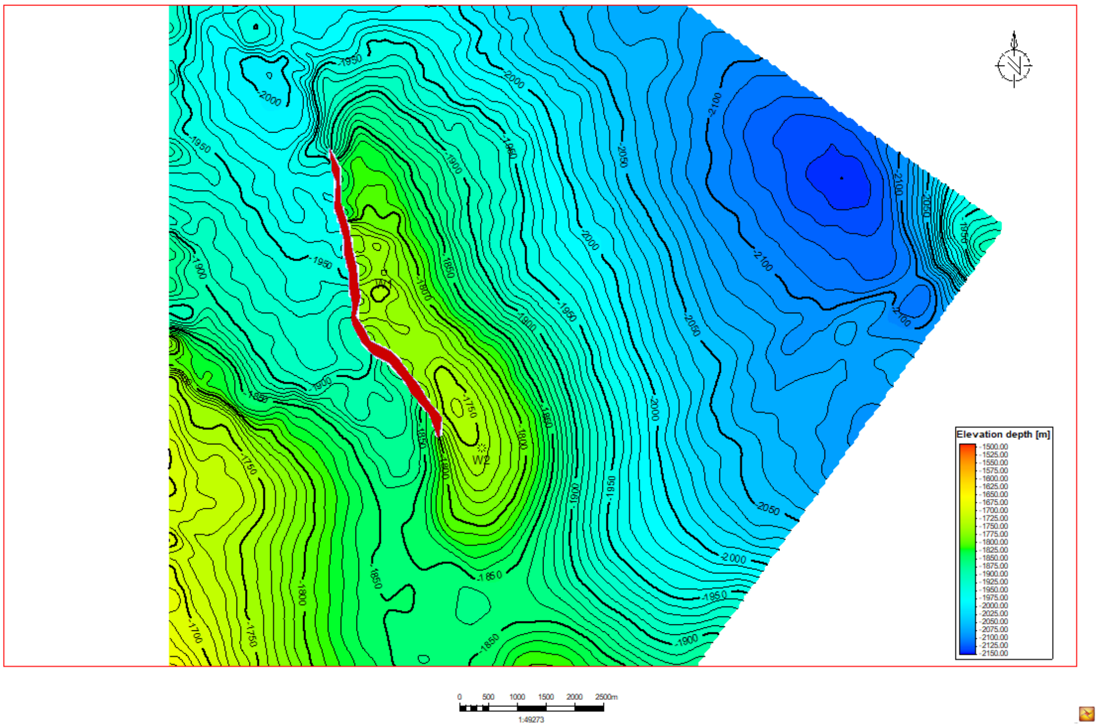

Figure 4-41: Isobaths map on top of the Frasnian.

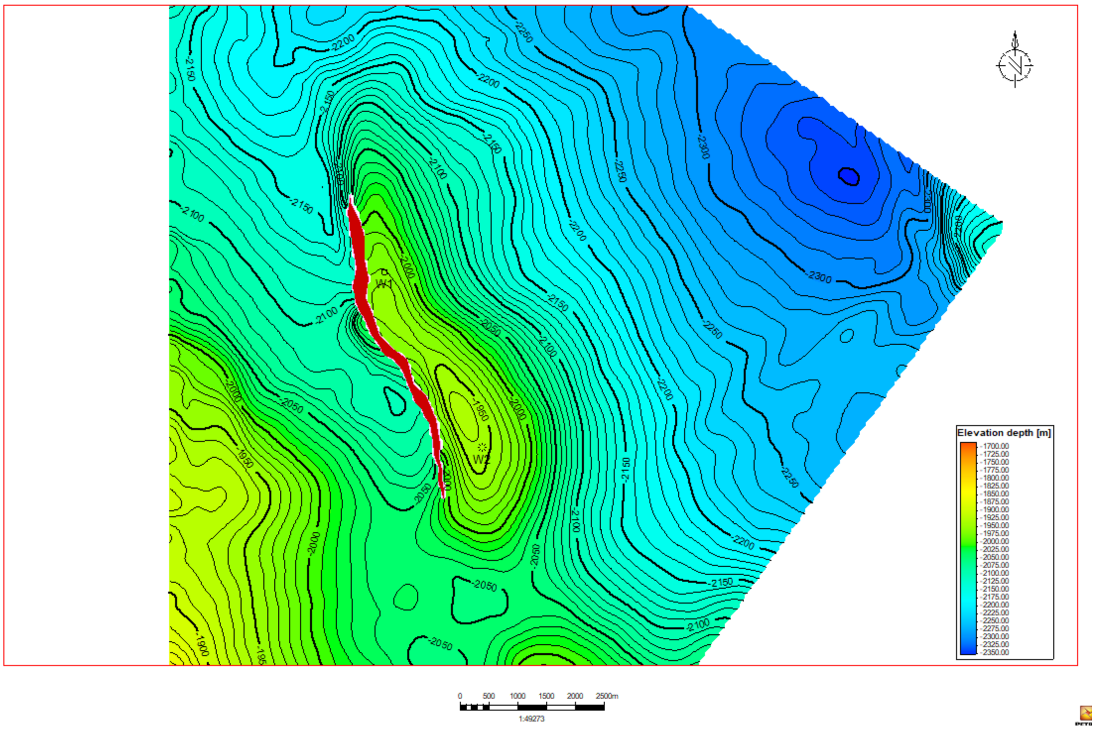

Figure 4-42: Isobaths map on top of the Givetian.

5. 3D Static Modelling

3D static modelling is a comprehensive and critical process in reservoir characterization and fault seal prediction workflows. This method involves creating a detailed, three-dimensional representation of the subsurface, integrating geological, geophysical, and petrophysical data. Known as "static" because it represents reservoir properties at a specific point in time without considering dynamic changes from production or injection activities, this process is essential for understanding and managing subsurface reservoirs. It aims to develop a highly accurate subsurface model that closely reflects geological reality, with the primary objective of predicting whether faults will act as a seal to fluid flow, which is crucial for effective reservoir management.

Steps in 3D Static Modelling for Fault Seal analysis:

5.1. Fault modelling

Depth Conversion: The process begins with the interpretation of fault sticks, which have been converted to depth from seismic time data. This step ensures that the faults are accurately positioned in the subsurface.

Surface Generation: The depth-converted fault sticks are used to generate continuous fault surfaces. This involves interpolating between the sticks to create smooth, coherent fault planes.

5.2. Pillar Gridding

Grid Construction: A 3D grid, known as a pillar grid, is created to represent the reservoir. This grid divides the subsurface into a network of cells that will be populated with geological properties.

Pillar Definition: Pillars are vertical lines that define the edges of the grid cells. They follow the geometry of the interpreted faults and horizons, ensuring the grid conforms to the structural framework of the reservoir.

5.3. Grid Refinement and Cleaning

Grid Refinement: The initial grid is refined to improve its resolution and accuracy. This step involves increasing the density of grid cells in areas of interest, such as near faults or key stratigraphic boundaries.

Grid Cleaning: Ensuring the grid is free from errors and inconsistencies is crucial. This involves checking for and correcting issues such as cell overlap, gaps, or distortions that could impact the model's accuracy.

5.4.Horizons Insertion

Horizon Modelling: Major stratigraphic horizons are inserted into the grid. These horizons are derived from seismic interpretation and well data, providing key surfaces that bound different geological layers.

Horizon Refinement: The horizons are refined to ensure they accurately represent the subsurface stratigraphy. This may involve adjusting the positions of the horizons to match well data more closely.

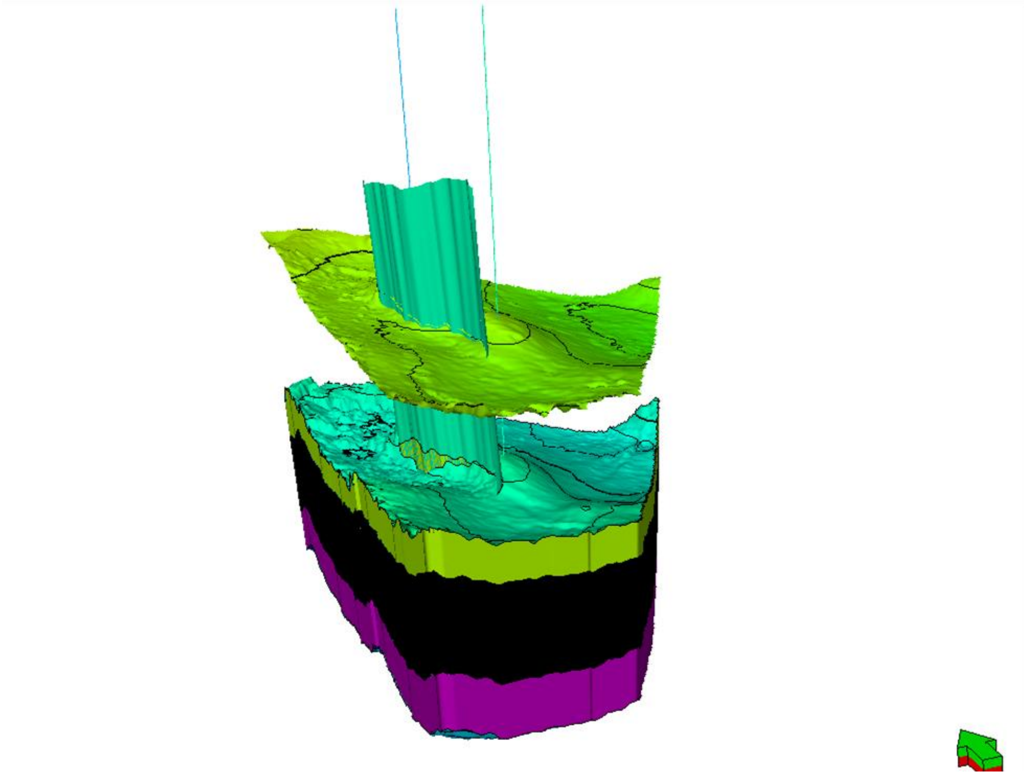

Figure 4-43: Generated static model.

The figure 4-43 illustrates the result of a comprehensive 3D static modelling process, showcasing a detailed subsurface model that integrates fault and horizon interpretations, along with the positions of two wells, W1 and W2. The static model prominently features a fault plane, highlighted to clearly show its structure and orientation within the reservoir, and multiple stratigraphic horizons, each represented by distinct, colour-coded layers. These horizons intersect with the fault, providing a clear visual of the subsurface stratigraphy. The wells trajectories, marked as vertical lines, penetrate through the different geological layers and the fault, validating the model with real data points. This accurate and realistic depiction, achieved through steps mentioned earlier.

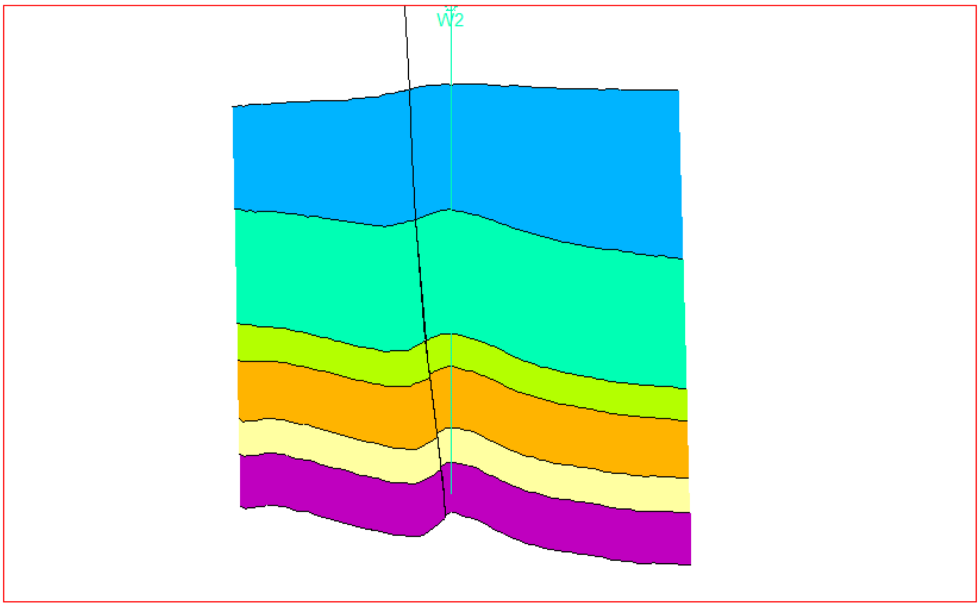

Figure 4-44: Transect from the static model.

Note: we observe two more horizons in the transect (Figure 4-44), the Cambrian and the Intercalary Continental, which were generated to include the maximum number of horizons in our study.

The 3D static model significantly enhances the representation of the fault plane, capturing the variation in throw, heave of the fault with great precision.

- **Accurate fault geometry**

The model incorporates high-resolution seismic data and detailed well information, allowing for a precise depiction of the fault's geometry. This integration ensures that the fault plane is accurately mapped, reflecting its true orientation and extent within the subsurface.

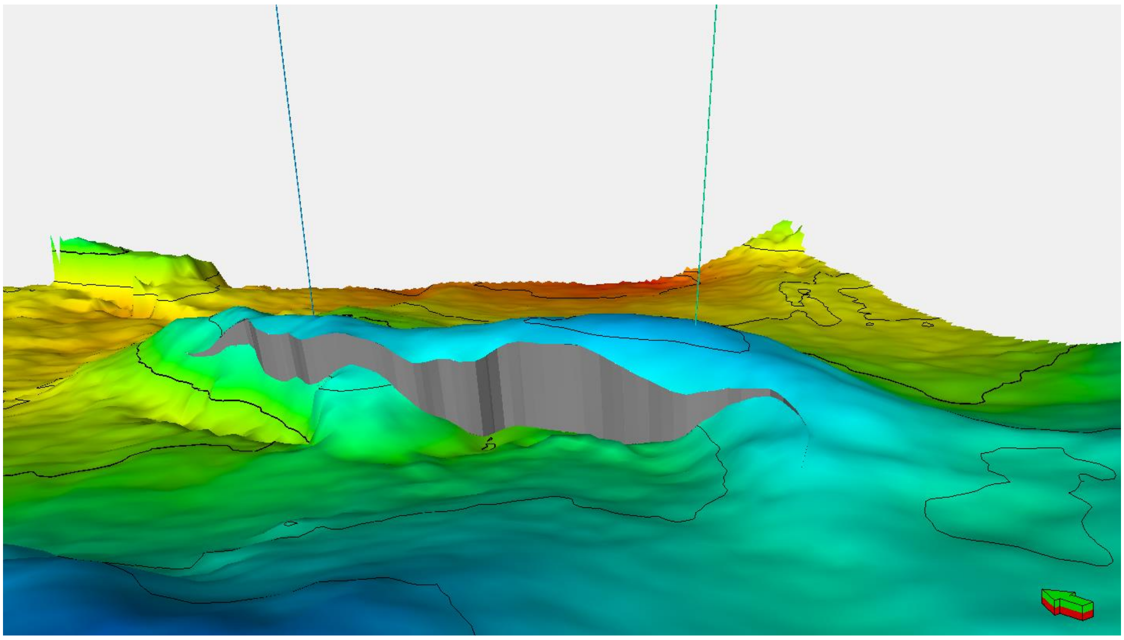

Figure 4-45: Oued Toughert fault plan.

- **Throw and Heave variation**

Throw : Throw refers to the vertical displacement that occurs along the fault plane. The 3D static model can depict these variations in throw with high accuracy, showing how the displacement changes along the length of the fault.

Heave : Heave is the horizontal displacement along the fault. The model provides a detailed view of how the heave varies, which is crucial for understanding the lateral separation of geological units and its impact on reservoir connectivity.

The figure 4-46 illustrates the throw profile along the fault intersection with the Ordovician horizon; it reveals the fault length of 7.2 km with the throw varying from 0 to 168 metres.

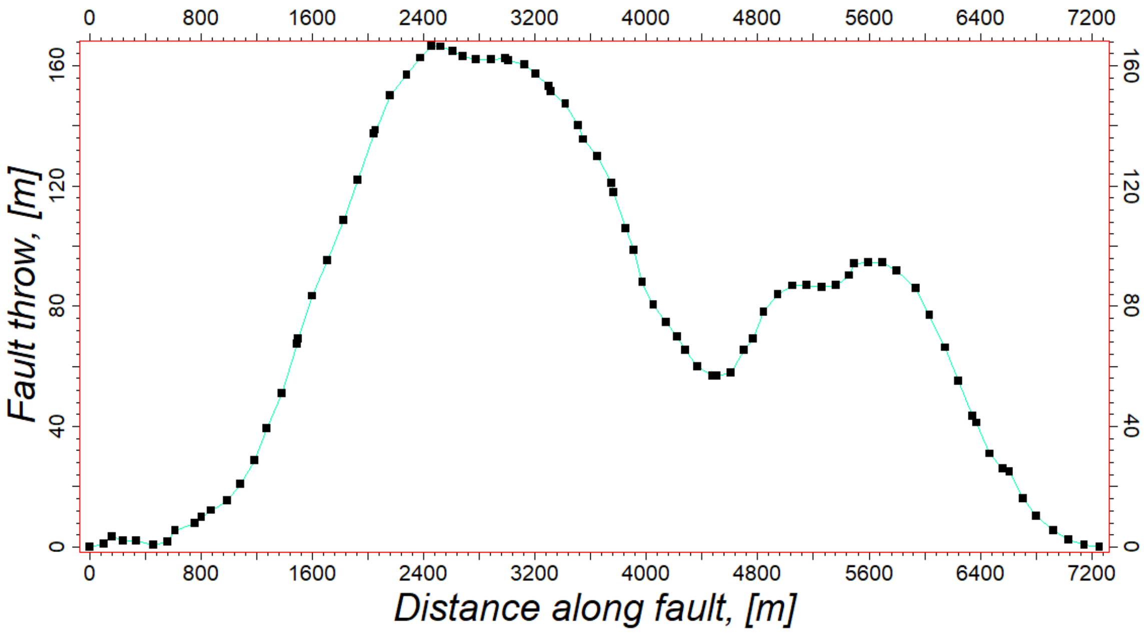

Figure 4-46: Variation of the throw along the fault (Ordovician).

The 3D model also offers improved visualisation of other fault components, including :

- **Structural elements**

Fault Curvature and Dip: The model can illustrate the curvature and dip of the fault plane, providing a three-dimensional perspective that highlights how these features change spatially. This is important for assessing the stability of the fault and its potential to trap hydrocarbons.

Linkage with Other Faults: By visualising the fault in 3D, the model can show how it links with other faults or fractures, revealing the broader structural framework of the reservoir. This information is crucial for predicting potential migration pathways for hydrocarbons or water.

- **Fault segmentation**

Sub-Faults and Relay Ramps: The model can identify and represent sub-faults and relay ramps, which are smaller fault segments and transitional zones that occur between major fault blocks. These features are important for understanding how stress and strain are distributed across the fault system.

Reservoir compartmentalization: By capturing these details, the model helps in understanding how the fault might compartmentalise the reservoir into distinct blocks, each with potentially different pressure and fluid characteristics.

6. Property modelling

The goal of property modelling in fault seal analysis is to develop a detailed and accurate representation of faults and their properties, including petrophysical characteristics and lithology. This model is essential for simulating fluid flow through faults and predicting the likelihood of fault sealing or leaking. By understanding these dynamics, geophysicists can optimise reservoir design and enhance the efficiency of production systems.

6.1. Facies Modelling

Facies modelling is a crucial step in reservoir characterization, involving the integration of lithological information from wells into a geocellular grid. This process allows for the accurate prediction of facies distribution throughout the reservoir by simulating various geological scenarios. By incorporating data from well logs, facies modelling provides a detailed understanding of subsurface heterogeneities, which is essential for effective reservoir management and development.

In this study, facies modelling was conducted using data from the two wells, W1 and W2. The gamma ray logs from these wells were instrumental in classifying different lithologies, specifically sand, shale and carbonate. This classification formed the basis for populating the geocellular grid, ensuring that the model accurately reflects the geological reality of the reservoir. Figure 4-47 illustrates the interpreted facies log, showcasing the special distribution of the identified facies within the reservoir.

By simulating multiple geological scenarios, the facies model helps predict the spatial arrangement of various rock types, thereby enhancing the accuracy of reservoir prediction. This approach not only aids in understanding the current state of the reservoir but also in planning future development and optimising production strategies. The resulting model is a powerful tool for visualising subsurface conditions and making informed decisions about reservoir management.

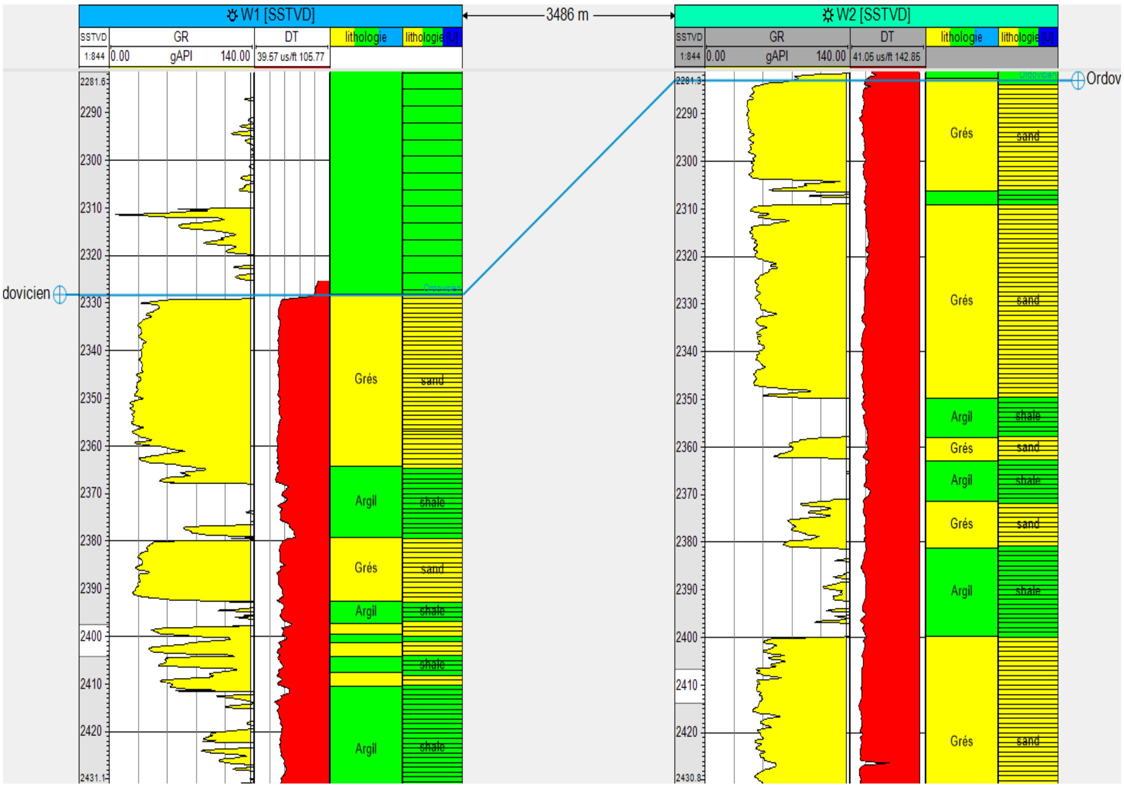

Figure 4-47: Facies classification of the two wells.

To populate the geocellular grid effectively, we employed a targeted approach for each geological zone. For the Ordovician zone, we utilised a kriging method, a geostatistical technique which involves interpolating the properties of the rock units based on the available data, (this method is particularly useful for areas where there is limited data availability, as it can help to fill in the gaps and provide a more complete picture of the subsurface).

For the Visean and Frasnian zones, we assigned shale facies, reflecting the predominant lithology observed in these intervals. Shales facies were populated based on well log data, ensuring consistency with geological expectations and known depositional environments.

The Givetian zone, characterised predominantly by carbonate formations, was populated with carbonate facies. This was done using a similar approach to the Visean and Frasnian zones.

Finally in the Cambrian zone, sand facies were populated to represent the primary lithology found in this layer.

The final facies model is illustrated in figure 4-48 while figure 4-49 is a transect from it.

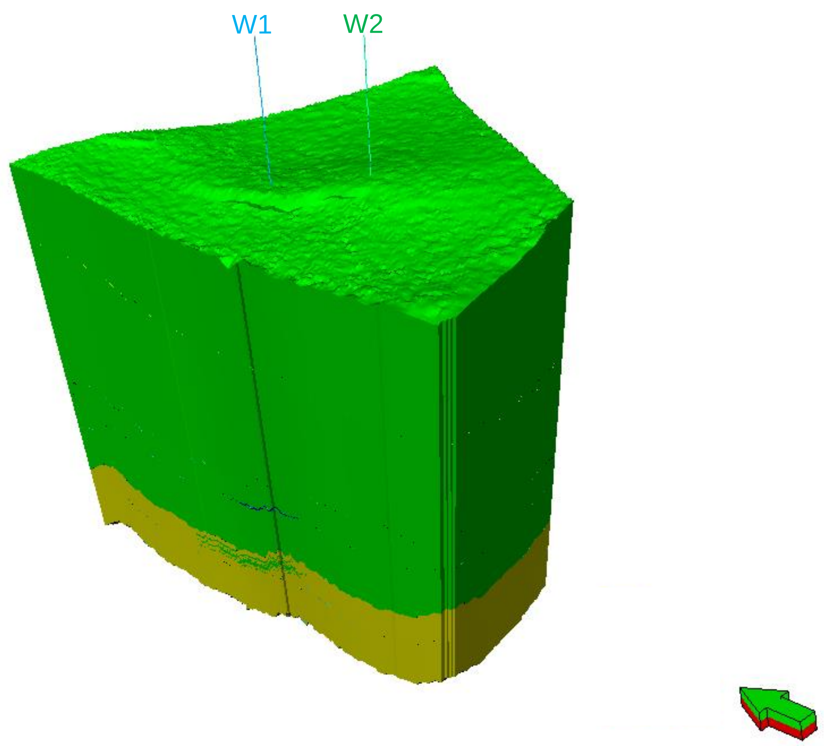

Figure 4-48: Facies model.

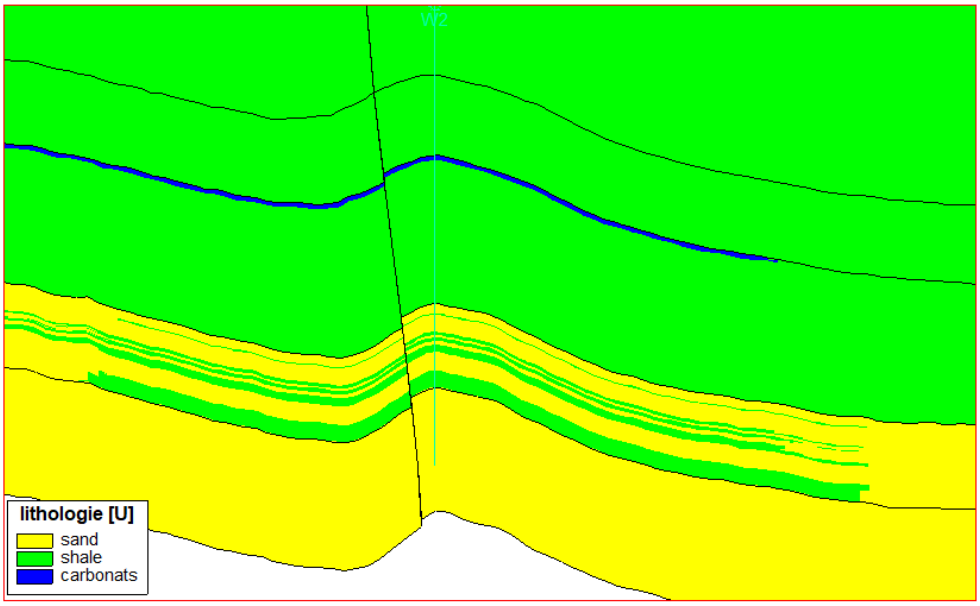

Figure 4-49: Transect from the facies model.

6.2.Petrophysical Modelling

Petrophysical modelling is a critical step in the process of reservoir characterization, enabling the detailed population of a geocellular 3D grid with continuous petrophysical data derived from well logs. This data typically includes key parameters such as porosity, permeability and fluid saturation, all of which are essential for understanding the reservoir's properties and behaviour.

For fault seal analysis, the focus shifts towards understanding how petrophysical properties vary near faults and how these variations influence fluid flow across fault planes . In our study , we specifically populated the initial 3D static model with Vsh (volume of shale) data , derived from petrophysical interpretations of wells W1 and W2.

First, we carried out a Vsh Log interpretation following the next steps:

Data Extraction: Extracting Vsh logs from the well data, which indicate the proportion of shale in the reservoir rock. High Vsh values generally correspond to lower reservoir quality as shale typically has low permeability.

Cutoff Application: Applying a cutoff value of 40% to the Vsh logs to distinguish between different lithological units. This cutoff helps in accurately identifying and classifying shale-dominated zones.

Upscaling Vsh Logs: Upscaling the Vsh logs from the high-resolution well data to the coarser grid scale of the 3D model. This step is crucial to ensure that the petrophysical properties are accurately represented at the scale of the geological model.

Kriging Algorithm : The Vsh petrophysical model is generated by applying a kriging algorithm to the upscaled logs , providing a statistically sound method for interpolating the Vsh values across the 3D grid .

Second , we executed an integration with the 3D grid :

Grid Population with Vsh: Populating the 3D static model grid with the upscaled Vsh values. This involves assigning the upscaled Vsh values to the corresponding grid cells, providing a continuous representation of shale distribution throughout the reservoir.

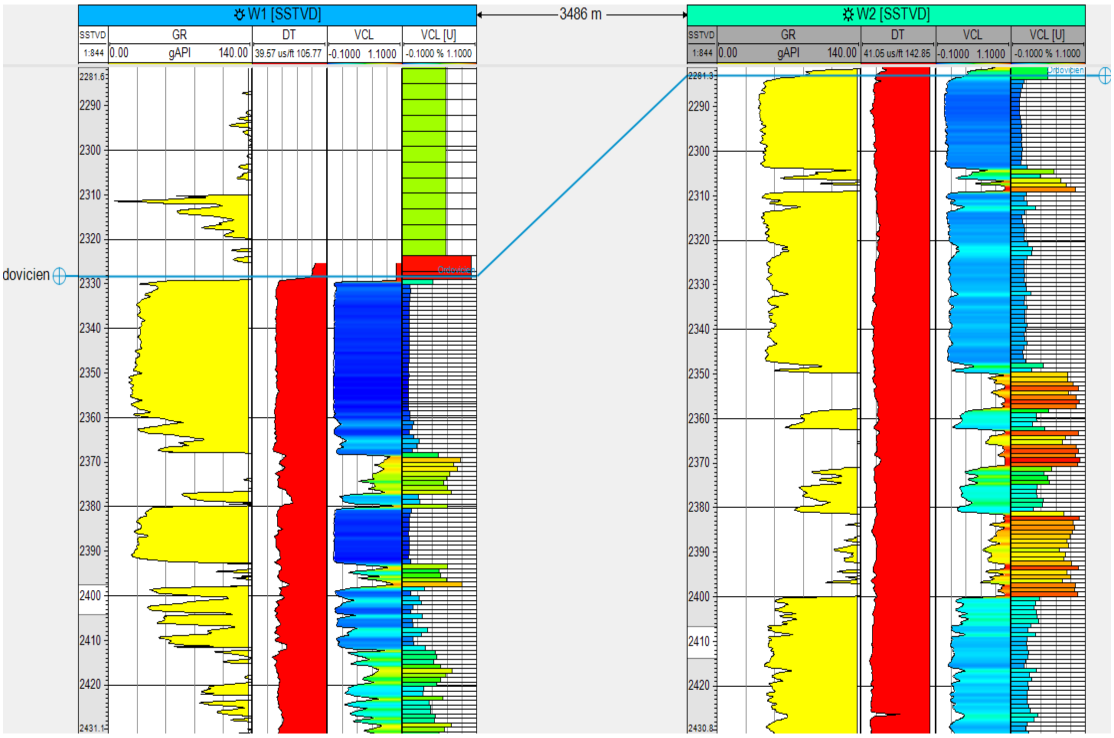

Figure 4-50 : Vsh logs and equivalent upscaled logs.

To visualise the results of the petrophysical modelling, figure 4-51 illustrates a transect of the 3D model showing the distribution of the Vsh properties across the Ordovician reservoir.

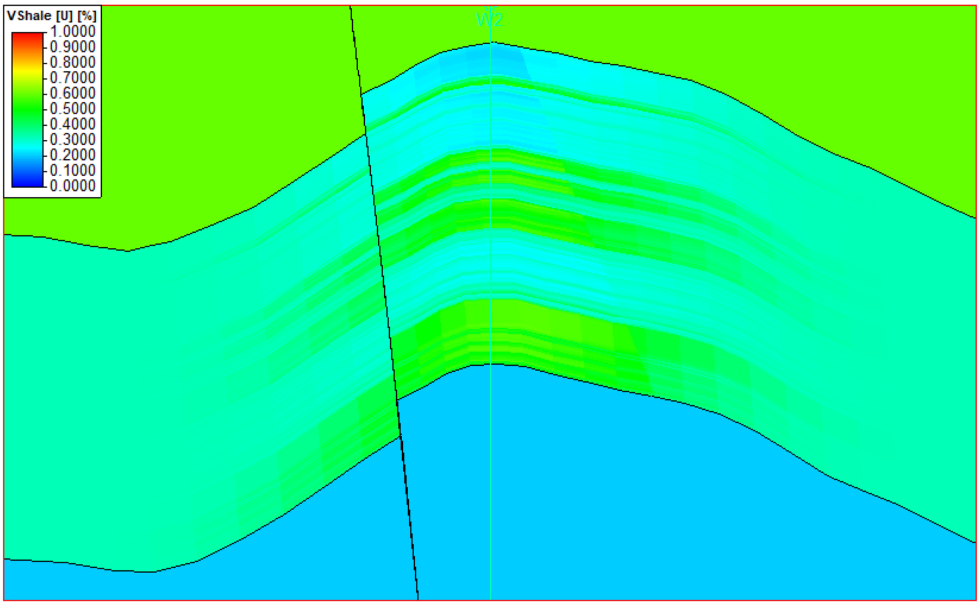

Figure 4-51 : Transect from the petrophysical model (Vsh).

7. Application of the fault seal analysis theory

To assess the sealing potential of the Oued Toughert fault within the Ordovician formation, we propose a comprehensive prediction protocol as illustrated in Figure 4-52. The first step in this protocol involves evaluating the juxtaposition seal. This is done by creating a detailed juxtaposition diagram using data from the facies model along the fault plane. The purpose of this diagram is to identify any instances where reservoir rocks are juxtaposed against each other across the fault plane. Such juxtapositions are critical because they can indicate potential pathways for fluid migration, which would compromise the fault's sealing capability.

If the juxtaposition diagram reveals no reservoir against reservoir contact, it confirms the presence of a juxtaposition seal. This means that the fault plane effectively separates the reservoir units, thereby acting as a barrier to fluid flow. This step is crucial as it provides the first indication of the fault's ability to seal and isolate different sections of the reservoir.

However, if reservoir against reservoir juxtaposition is detected, further analysis is necessary to determine the fault's sealing capacity. This leads to the next phase of the protocol, where the potential for a membrane seal is assessed. This is achieved by calculating the Shale Gouge Ratio (SGR) along the fault plane, using either the facies model or the Vsh petrophysical model. The SGR is a measure of the amount of shale present along the fault, which plays a significant role in the fault's ability to act as a barrier to fluid flow.

If the SGR threshold value is known for the specific basin area, we can predict the fault's sealing potential based on this threshold. Specifically, the fault is expected to be impermeable if the SGR exceeds the known threshold. In cases where the threshold is not known, a general rule is applied: the fault is considered a seal if SGR values along the fault plane exceed 20%. This method allows for a systematic and data-driven approach to evaluating the sealing characteristics of the Oued Toughert fault, ensuring that reservoir management decisions are based on robust geological evidence.

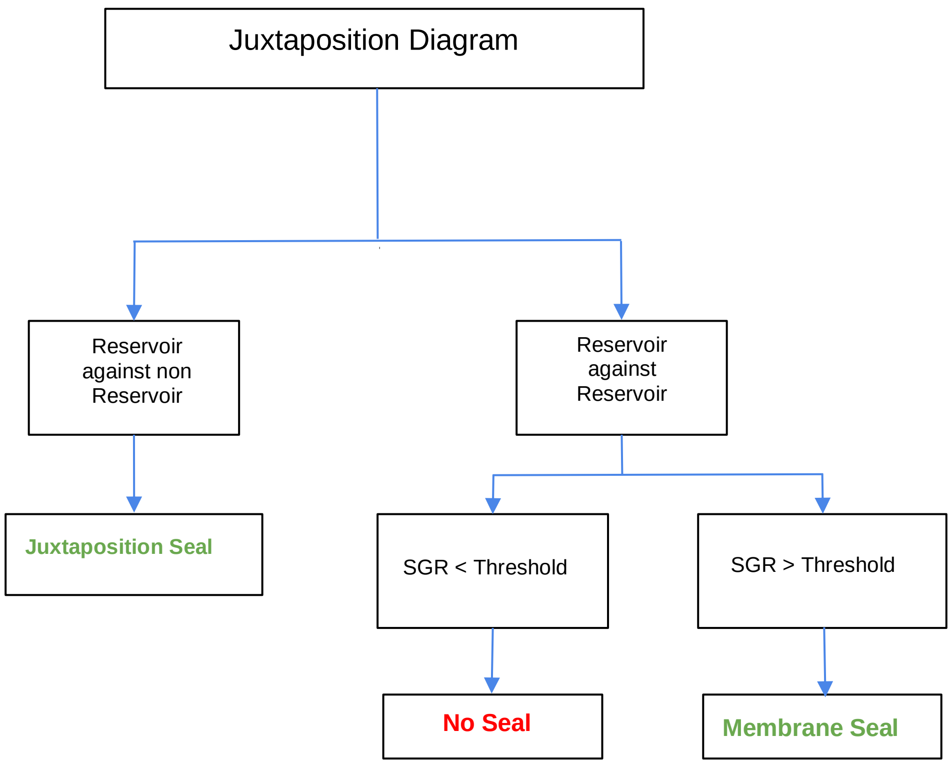

Figure 4-52: Fault Seal analysis protocol.

7.1. Juxtaposition Seal

A juxtaposition diagram was generated along the fault plan in order to evaluate the juxtaposition sealing capacity of the Oued Toughert fault, understand the lithological contacts and assess the potential for fluid flow barriers. This diagram was created by plotting the lithological units against the fault plane, highlighting the contact points between different lithologies.

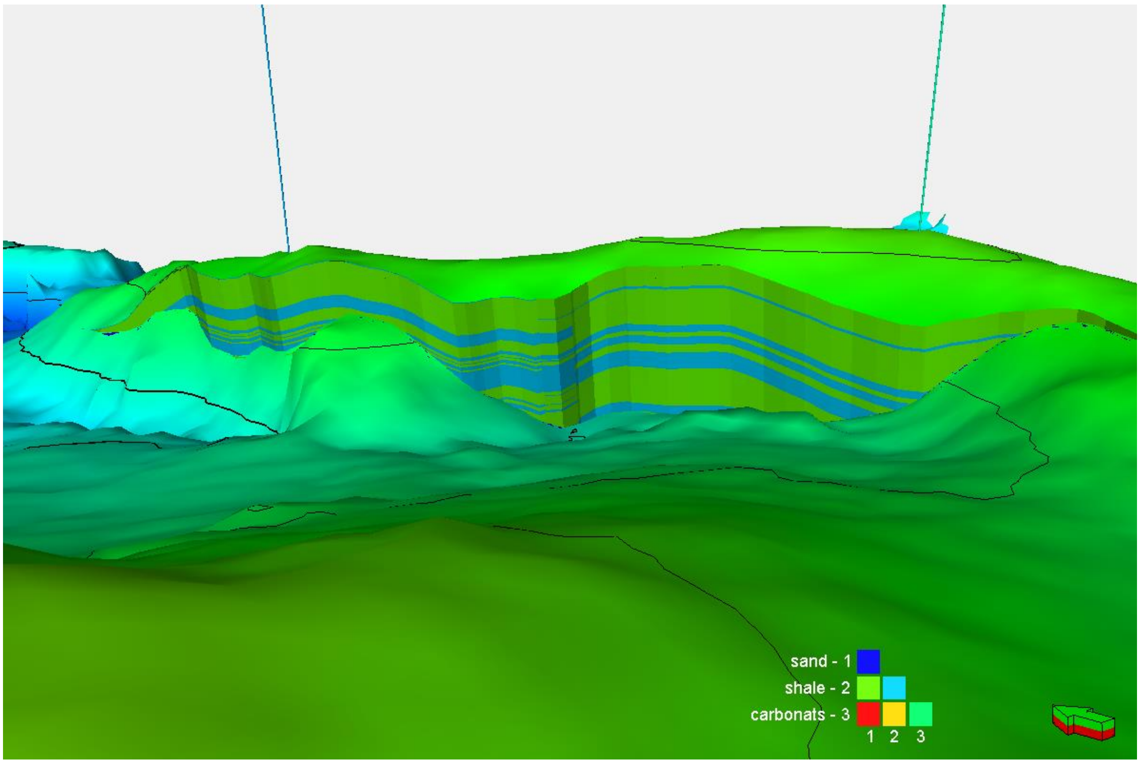

Figure 4-53: Juxtaposition diagram along the Oued Toughert fault plan.

7.1.1. Juxtaposition Seal Identification

The juxtaposition diagram revealed that along the Oued Toughert fault, reservoir beds (sandstone) are consistently juxtaposed against shale beds. This was observed all along the fault plane.

As shown in Figure 4-53, the contacts are either sand/shale or shale/shale, with no reservoir-reservoir juxtapositions detected.

7.1.2. Sealing confirmation

The consistent presence of sand/shale and shale/shale contacts along the fault plane strongly indicates a robust juxtaposition seal. This suggests that the Oued Toughert fault effectively blocks fluid flow, acting as a barrier and preventing cross-fault leakage.

7.2.Membrane Seal

To confirm the juxtaposition seal, we applied the membrane seal analysis under the assumption of a reservoir against reservoir juxtaposition. In this scenario, the fault itself must act as a barrier to hydrocarbon migration. We used two methods to calculate the Shale Gouge Ratio (SGR), which is a key indicator of a fault's sealing capacity .

7.2.1. Estimating the SGR using the facies model

This method involves analysing the distribution of different facies along the fault plane . By mapping the lithological units and their cumulative thicknesses in relation to the fault throw , we can determine the proportion of the shale material that has been smeared into the fault zone . The lithology model provides detailed insights into the geological composition along the fault , helping us assess its potential to act as a seal .The results of this analysis are shown in figure 4-54.

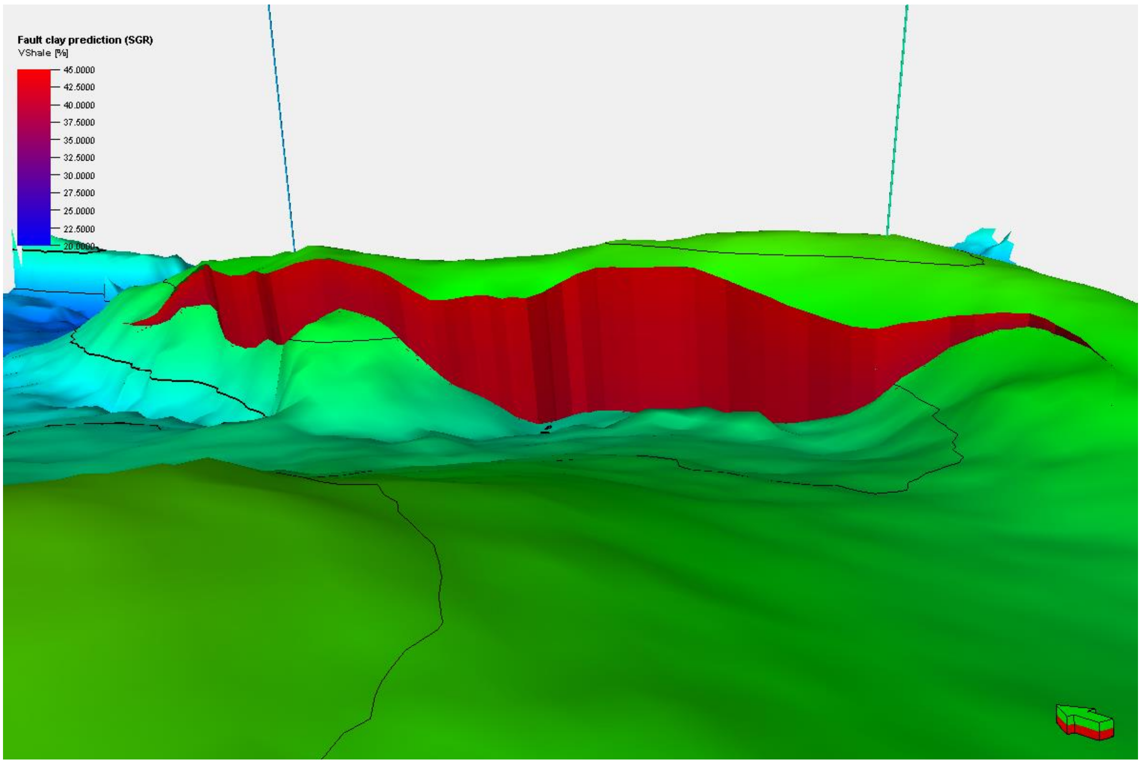

Figure 4-54 : SGR results using the facies model.

7.2.2. Estimating the SGR using the Vsh model

The Vsh logs provide a quantitative measure of the shale content in the subsurface formations. By upscaling the Vsh logs and applying a kriging algorithm, we generated a continuous Vsh model along the fault plane (Figure 4-55).

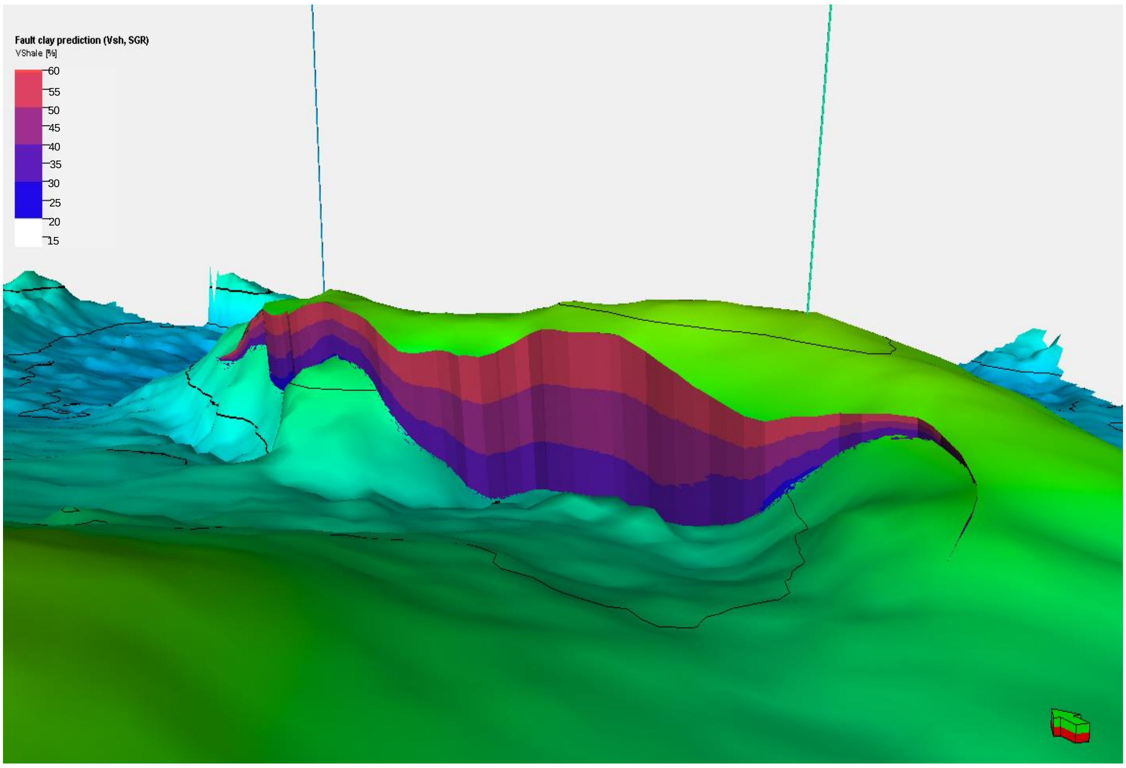

Figure 4-55: SGR results using the Vsh model.

7.3.Results and discussion

The SGR values calculated from the facies model range from 38 % to 45 %. These values are significantly higher than the critical threshold of 20%, below which a fault is expected to leak.

As for the SGR values obtained from the Vsh model, the following table illustrates their depth variation for the maximum fault heave:

Depth interval (m)	Vsh based SGR values (%)
2312 - 2367.5	30 – 40
2367.5 - 2428.7	40 – 50
2428.7 - 2480	50 – 60

Table 1-4: the variation of the Vsh based SGR values with depth for the maximum fault heave.

We observe that the SGR values derived from the Vsh model range from 30% to 60%. Similarly to the results from the lithology model, these SGR values are also above the 20% threshold. This consistency between the two methods reinforces our confidence in the fault's sealing capability.

Our study was further validated by the results from two exploration wells drilled in the area. Both wells successfully encountered gas, providing empirical evidence that supports our analyses. The presence of gas in these wells confirms that the Oued Toughert fault effectively acts as a seal, preventing hydrocarbon leakage and maintaining reservoir integrity. This real-world validation not only underscores the accuracy of our SGR-based predictions but also highlights the reliability of our comprehensive fault seal analysis. The successful gas discovery in both wells reinforces the fault's capability to serve as an impermeable barrier, thereby enhancing confidence in our reservoir management and optimization strategies.

Conclusion

Conclusion

This work delves into a comprehensive fault seal analysis conducted in the Ordovician reservoir formation within the Oued Toughert Field, located in the Sbâa Basin, Algeria.

In our study, both membrane seal and juxtaposition seal analyses were employed to evaluate the fault's sealing characteristics. The results of these analyses unequivocally demonstrated that the Oued Toughert fault effectively acts as a seal, preventing hydrocarbon leakage. The juxtaposition seal analysis confirmed that the fault effectively prevents direct hydrocarbon migration across its plane. Similarly, the membrane seal analysis revealed that the fault's impermeability is maintained even in scenarios where reservoir-reservoir juxtaposition occurs, further solidifying its sealing capacity.

Moreover, the validation of our study findings through the results obtained from two exploration wells drilled in the area further strengthens the reliability of our fault seal analysis. Both wells encountered gas, confirming that the fault effectively sealed the reservoir and prevented hydrocarbon leakage.

This validation highlights the importance of fault seal analysis in hydrocarbon exploration and production. By thoroughly evaluating fault seals, companies can significantly increase success rates. This leads to better use of resources and reduced financial risks. Detailed fault seal analysis goes beyond supporting successful drilling; it contributes to the overall efficiency and profitability of hydrocarbon extraction projects, not just in the Oued Toughert Field, but in similar geological settings.

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